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Medium-Term Oil Market Report

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CONTENTS

EXECUTIVE SUMMARY

Overview

Despite a considerable downward revision to our global oil demand forecast due to weaker economic growth projections and a doubling of oil prices over the past year, structural demand growth in developing countries and ongoing supply constraints continue to paint a tight market picture over the medium term. Oil demand remains concentrated in developing economies, with 90% of the growth spread between Asia, South America and the Middle East, reflecting the improving wealth and accelerating energy use in several high-population countries. In spite of a considerable increase in investment, non-OPEC crude supply will remain at or below 39 mb/d over the next five years, with the majority of the 1.2 mb/d of non-OPEC liquids growth coming from NGLs, condensates and biofuels. Refining investments continue apace, but with costs doubling over the past five years, planned expansions are put under regular financial scrutiny and projects are subject to ongoing slippage and are vulnerable to changes in refining margins. As such, with 48% of global product demand growth over the next five years concentrated in middle distillate fuels, generating sufficient product to meet demand will continue to be a challenge. Further, investment in upgrading capacity will lead to tighter fuel oil markets and will expose the heavy end of the barrel to strong additional pressures from tight LNG and coal markets.

Poor supply-side performance since 2004, in the face of strong demand pressures from developing countries, has forced oil prices up sharply to curb demand. These pressures have been exacerbated by refinery tightness, which limits the flexibility of the industry to meet the structurally strong demand growth for middle distillate fuel. While recognising that speculation can have a day-to-day impact on price moves, the fact that all producers are working virtually flat out and that there is no sign of any abnormal stockbuild gives a strong indication that current oil prices are justified by fundamentals. Similarly, while high forward prices may reflect concerns about peak oil or sustained demand growth, they too could only impact spot prices if they started to create a forward price premium sufficient to encourage stockbuilding.

Global Balance Summary
(million barrels per day)

	2008	2009	2010	2011	2012	2013
Global Demand	**86.87**	**87.74**	**89.20**	**90.74**	**92.39**	**94.14**
Non-OPEC Supply	49.92	50.54	50.60	50.68	50.68	51.08
OPEC NGLs, etc.	5.13	5.94	6.52	6.82	7.07	7.21
Global Supply excluding OPEC Crude	**55.05**	**56.48**	**57.12**	**57.50**	**57.75**	**58.29**
OPEC Crude Capacity	**35.34**	**36.44**	**37.35**	**37.25**	**37.58**	**37.87**
Call on OPEC Crude + Stock Ch.	**31.82**	**31.25**	**32.08**	**33.25**	**34.64**	**35.84**
Implied OPEC Spare Capacity[1]	3.52	5.19	5.27	4.00	2.93	2.03
Effective OPEC Spare Capacity[2]	2.52	4.19	4.27	3.00	1.93	1.03
as percentage of global demand	*2.9%*	*4.8%*	*4.8%*	*3.3%*	*2.1%*	*1.1%*
Changes since July 2007 MTOMR						
Global Demand	**-1.40**	**-2.29**	**-2.71**	**-3.10**	**-3.43**	
Non-OPEC Supply	-0.60	-0.63	-0.87	-1.04	-1.41	
OPEC NGLs, etc.	-0.38	-0.34	-0.20	-0.09	-0.01	
Global Supply excluding OPEC Crude	**-0.98**	**-0.97**	**-1.07**	**-1.13**	**-1.42**	
OPEC Crude Capacity	**-0.59**	**-0.13**	**-0.24**	**-1.14**	**-1.25**	
Call on OPEC Crude + Stock Ch.	**0.05**	**-0.85**	**-1.16**	**-1.49**	**-1.54**	
Implied OPEC Spare Capacity[1]	-0.17	1.19	1.40	0.82	0.75	

1 OPEC Capacity minus 'Call on Opec + Stock Ch.'

2 Historically effective OPEC spare capacity averages 1 mb/d below notional spare capacity.

Price Formation

In our section on price formation, we argue that fundamentals are setting the level of oil prices. While it is extremely important to have an open discussion on the role of fund flows and their effect on oil prices, there is a risk that the debate is losing context. Assertions of a 50% or higher premium by some analysts on the current price due to fund inflows largely rest on the observation that fund flows have increased. Often it is a case of political expediency to find a scapegoat for higher prices rather than undertake serious analysis or perhaps confront difficult decisions.

History has generally shown that speculative bubbles occur when speculators cause or facilitate speculative physical stockbuilding – look at past bubbles in tulip bulbs, silver, or even housing. A check on oil stocks does not indicate this is happening. More to the point, what about the surge in other commodities such as spot LNG, coal, steel and rice, or the doubling of iron ore prices, where capacity utilisation is very high, stocks very low and where speculation is fundamentally difficult?

Within this report, we welcome the announcement of a US *Commodity Futures Trading Commission (CFTC)* report on the role of fund flows on futures prices, scheduled to be released in September. In addition, our section on price formation tries to look at the debate from a different angle. The IEA has always argued that money flows and speculation can have a day-to-day influence on prices, but it is not one that can be sustained for any length of time without a market imbalance being apparent. It is not *who* takes the price to a different level that is important (speculators by their very nature should probably always be first to react to an event), but *whether* that level is representative of market fundamentals. From this perspective, the analysis of supply and demand conditions makes much more sense than daily position flows. But whichever way you try to look at this subject, you will never have a full perspective without extra financial market transparency or non-OECD inventory data.

Our analysis also tries to open the debate on the importance of refining and product demand trends in setting oil prices. We try to show that crude oil prices can be sensitised and even pushed dramatically higher by a constrained refining system or unexpectely strong demand in a product category. As such, we try to explain why traders regularly talk about crude prices being dragged up by gasoline or diesel.

Demand

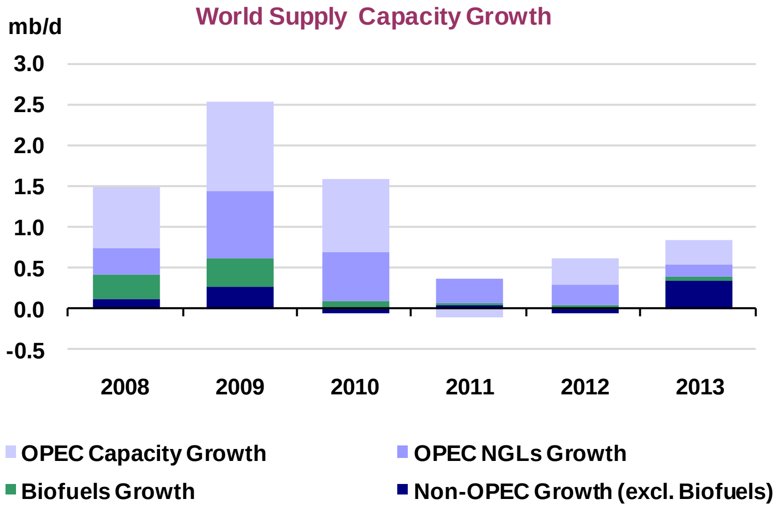
Global oil product demand is expected to grow by 1.6% per year on average over the next five years, rising from 86.9 mb/d in 2008 to 94.1 mb/d in 2013. The pattern of growth is diametrically opposed to the trends in supply, with the growth dragged down by slower GDP growth in 2008 and 2009, before returning to trend levels in 2010 and beyond. Of course, as with any forecast, there are risks - and at present these are focussed on the depth and global impact of the US economic slowdown. The outcome of such a scenario is discussed below, but it is important to note that there are also risks to supply.

High prices are clearly affecting consumer behaviour, particularly in the OECD transportation sector, with a visible switch away from SUVs and light trucks in the US. Most significantly, the big auto companies are indicating that they are slowing or halting production of these vehicles, focussing their efforts on smaller, more efficient and environmentally friendly cars.

Demand growth remains heavily concentrated in developing countries, where total consumption will nearly reach parity with mature economies by 2015. Within the non-OECD, growth is highly concentrated in three regions – Asia, the Middle East and South America, accounting for nearly 90% of global demand growth over the next five years. Of this, China and India account for almost half. By contrast, demand growth in OECD countries is expected to contract slightly over the next five years, albeit with modest growth continuing to be seen in the transportation sector. Globally, growth is concentrated in a small number of products, particularly middle distillates, and those associated with the petrochemicals industry (NGLs and naphtha), providing an ongoing technological challenge to the refining industry.

Supply

Over the next 18 months there appears to be the potential for a modest build in the supply cushion due to the combination of weaker economic growth and a concentration of new projects in OPEC and non-OPEC countries coming on line. However, the annual rate of expansion drops off considerably from the 1.5 - 2.5 mb/d seen through to 2010 to under 1 mb/d at the tail end of our forecast, just as global economic growth is forecast to pick up again. It is also worth noting that the lion's share of non-OPEC growth comes from condensates, NGLs and biofuels, with only a very limited contribution from non-OPEC crude supply. As a result, effective OPEC spare capacity temporarily rises above 4 mb/d in 2009 and 2010, before receding to minimal levels by 2013.



There are significant downward revisions for both non-OPEC supplies and OPEC capacity estimates from last year's *Medium-Term Oil Market Report (MTOMR)*. Project delays remain a major factor in supply-side underperformance, with slippage estimated at up to twelve months on average for the large projects surveyed, alongside an estimated doubling of costs. A detailed study of non-OPEC decline rates conducted earlier this year (already factored into our 2008 projections in the monthly Oil Market Report) found that average non-OPEC decline rates for mature fields over the past 10 years have been relatively constant at around 7.5% per year. Incorporating the result of this study into the five-year forecast, together with some adjustments to assumed OPEC field decline rates suggests that global net decline for the forecast (the implied decline level for the entirety of base year production) rises from 4% per annum in last year's *MTOMR* to 5.2% this year. Put another way, over 3.5 mb/d of new production is needed each year just to hold world production steady.

Crude Trade

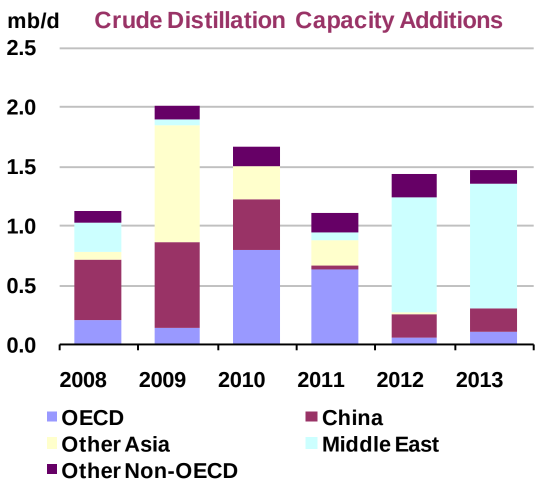
Global inter-regional crude oil trade could rise by 2.5 mb/d between 2008 and 2013, equating to around 1.5% annual compounded growth. The 1.8 mb/d downward revision to crude trade from last year is largely driven by the lower demand forecast, which reduces the call on oil imports from the Middle East. China will drive crude trade, with imports possibly rising from current volumes of around 4 mb/d to as much as 5.7 mb/d in 2013. Although export prospects from the Middle East are lowered, they may still rise from 16.0 mb/d in 2008 to 17.5 mb/d in 2013 and will be supplemented by rising condensate exports, probably heading east. The OECD import profile for the medium term is seen as much weaker, in line with a lower demand outlook.

Biofuels

Biofuels continue to add significant growth to the supply forecast, rising from 1.35 mb/d in 2008 to 1.95 mb/d by 2013. Although significant capacity additions have been proposed for the next five years, we maintain the cautious stance on future growth that we have held since 2006. Previously we have warned that the planned expansion in biofuel capacity seemed overly aggressive in relation to available feedstock and that more rapid growth could impact food prices. While it is wrong to attribute all the recent increase in grain prices to rapid biofuel expansions, it has undoubtedly had an impact. Similarly, we remain wary about the ongoing competition for first-generation feedstocks and also the growing political resistance to expansion in some areas. It is clear, however, that biofuels have helped to diversify energy supply. Compensating for the additional supplies that have been met through ethanol and biodiesel supply growth in Europe and the US since 2005 would require around 1 mb/d of crude oil to be processed. Given the poor performance of non-OPEC production and relatively low spare capacity, clearly much higher petroleum prices would be in place now if those biofuels had not been available.

Refining

Given the link between high crude prices and tight product markets, the refinery outlook is extremely important for both product supply and crude oil prices. This report sees 8.8 mb/d of crude distillation capacity being added to the refinery system between 2008 and 2013 – greater than projected upstream crude capacity additions but only really having a significant impact on product supply at the tail-end of the forecast.



With cost pressures adding 50% to investment expenditures over the past two years, and much shorter lead times between project completion than in the upstream, companies are forced to continually evaluate investment plans, prospective returns and likely delays. Coupled with growing lead times for delivery of key upgrading units, this has not only led to considerable slippage in the forecast, but also implies greater uncertainty over project plans slated for the tail-end of the forecast.

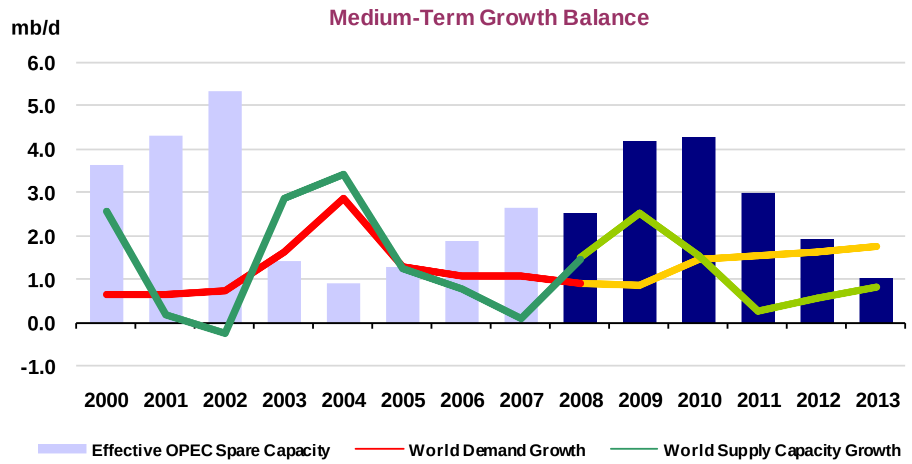
Regionally, refinery capacity growth is concentrated in China, Other Asia and the Middle East, with the three segments accounting for roughly a third of new distillation capacity additions. Considerable investment is also taking place in upgrading capacity and desulphurisation units to try to meet the challenge of the concentration of demand in transportation fuels and weak fuel oil cracks.

Spare Capacity and Market Implications

Given the evolution of demand and non-OPEC supplies (including biofuels and OPEC NGLs), there appears to be an improving trend in the market balance over the next 18 months, which reduces the call on OPEC by 0.6 mb/d in 2009 from 31.8 mb/d in 2008. Thereafter, the call on OPEC rises sharply to 35.84 mb/d by 2013. Similarly, effective OPEC spare capacity will rise to 4.2 mb/d in 2009 before falling to negligible levels of around 1 mb/d in 2013 – unless there are early discussions on additional projects.

Prices have largely been driven by the poor performance of non-OPEC crude supply since 2004, a feature that remains in place over the duration of the forecast. Similarly, despite large investments in refinery upgrading capacity, the concentration of demand growth in middle distillates is likely to continue to keep the market tight – although perhaps not quite as tight as 2008.

The outlook (which can of course be changed by policy shifts) appears to have considerable implications for the market. In particular, by 2013 Saudi Arabia would, if it remains the principal holder of spare capacity, be producing crude at almost 11.5 mb/d. As such, its implied spare capacity - according to our definition - would fall below its stated aim of holding 1.5 - 2.0 mb/d. But such a conclusion would ignore a number of key factors. Primarily, that Saudi Arabia at the 22 June Jeddah meeting identified a further 2.5 mb/d of new projects that could be brought onstream within three years of a decision being taken. However, to affect this outcome, such a decision is likely to have to be made within the next couple of years when spare capacity, implied by this scenario, would likely be at its highest level for eight years.



We must also note that beyond 2013, there are a number of projects that are scheduled to come onstream, which could have an impact on supplies in the ensuing years. Projects such as the Jack prospect in the US Gulf, the ultra-deep Gulf (Mexico), Jidong Nanpu (China), Tupi (Brazil) and Kashagan (Kazakhstan) are not expected to come onstream in the timeframe of this report, but could certainly provide additional supplies just beyond the scope of this report – if present technical and logistical challenges that could further stretch lead times are resolved.

Saudi Arabia, by having identified new domestic projects, has clearly helped to set a trend of transparency which is extremely helpful when considering the guide provided by the *MTOMR* forecast. We hope other producers will follow suit. We also would like to open the debate further, and have therefore been more explicit on our assumptions on price, GDP estimates and project lists for new upstream and downstream capacity additions. We cannot hope to achieve a number that everyone agrees with, but by defining the risks, assumptions and projects, the debate can narrow in on the areas of uncertainty.

Our core forecast is also supplemented by an examination of the implications of the IMF's low economic growth scenario – reflecting risks that the current economic slowdown may prove deeper and more extended than assumed. Lower economic growth translates directly into lower oil demand growth, lifting spare capacity over the next two years, but rising demand and lower capacity additions thereafter see spare capacity starts to decline at the same rapid rate as seen in the core forecast.

However, such a one sided assessment is merely illustrative. First, this alternative scenario estimate is not iterative – its price assumption does not differ from the core scenario, when in reality prices would probably fall. That would mean that demand would be higher than implied by a straigtht GDP analysis and investment would most likely be lower reducing the supply potential. Further, as this year's revisions exemplify, risks to the supply side are also on the downside. Quite simply, while lower economic growth would clearly reduce demand, the impact on balances may not be that significant.

PRICE FORMATION

Summary

- **High oil prices are the result of complicated interactions** between numerous factors, which vary in influence over time. We believe the primary driver of current high oil prices is strong demand growth in a number of highly populous countries, relative to the limited supply growth seen over the past few years. If supply is constrained and demand is increasing, prices have to rise.

- **There is little evidence** that large investment flows into the futures market are causing an imbalance between supply and demand, and are therefore contributing to high oil prices. Similarly, no definitive conclusion can be given without increased data transparency for market fundamentals, especially for stocks in non-OECD countries, and more comprehensive and better segregated data from financial markets, particularly for so-called over-the-counter (OTC) transactions.

- **Distillate tightness** has been extreme in late 2007/2008 and may have been the single largest factor behind the recent rise in prices. A "perfect storm" has arisen, with power outages in China, Australia, South America and South Africa increasing demand for backup power generation, while the economic closure of Chinese teapot refineries has curbed unofficial diesel production in China. Tight refining capacity – the inflexibility of the refining system to match structural shifts in demand growth – can both increase the demand for crude oil and create the conditions for higher crude and product prices.

- **Low spare crude production capacity** is a key indicator of market tightness, but it is not a perfect or proportionate barometer for assessing price levels. Quality considerations may render some spare capacity difficult to market given available levels of refinery upgrading capacity.

- **Stock levels may also be an imperfect gauge of relative market tightness**. The demand for stocks or perceptions of stock tightness can be related to shifting expectations for prices, supply, demand, refining margins and spare capacity. After 15 years of just-in-time inventories, there may be a trend towards holding a higher stock level due to ongoing geopolitical issues and the poor performance of non-OPEC supply. As such, historical comparisons may not reflect market tightness according to conventional measurement.

- **Marginal costs have risen sharply since 2003**, reflecting tightness in the service sector, together with limited access to low-cost oil reserves there is an increasing need to produce oil in ever-challenging regions and the need for more expensive technology. However, while rising marginal costs of production provide a floor to the oil price in the event of a price fall, they are unlikely to drive prices higher in the short term.

- **The weaker dollar has undoubtedly made a contribution** to higher oil prices, but only when priced in dollar terms. Yet oil prices in Euro terms have also hit record highs.

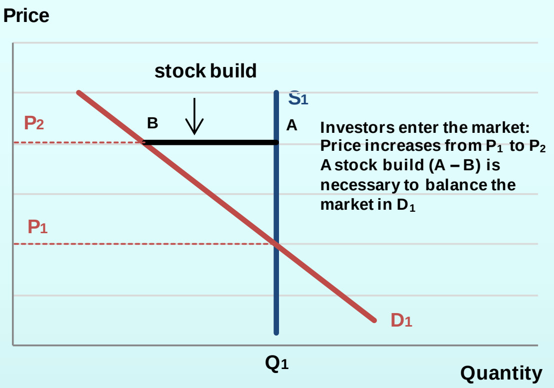
Overview

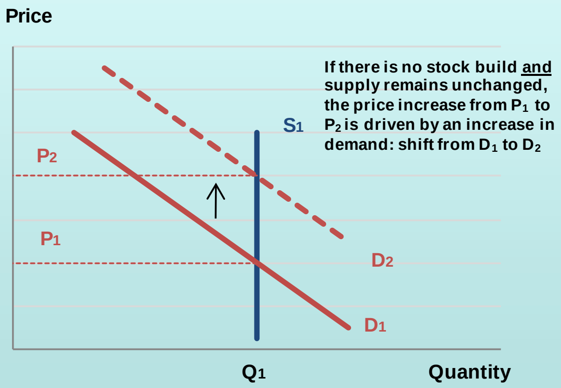
The doubling of oil prices between June 2007 and June 2008 has shocked both consumers and producers. Consumers in OECD and non-OECD countries alike are protesting, and, perhaps more importantly, changing their behaviour. Like alchemists looking for a way to turn basic elements into gold, everyone wants a simplistic explanation for high prices. The reality is that there are a multitude of interactions which are taking place and are combining to cause these high prices. In this section, we discuss some of the factors that we believe have contributed to higher oil prices. We would like at this point to thank the participants at the *IEA Expert Roundtable on Oil Price Formation* held in March 2008, which has helped to provide some of the ideas discussed in this report. At the same time, we stress that these ideas are a selection of thoughts the IEA feels are pertinent along with its own ideas, rather than a consensus of the discussions at the March meeting.

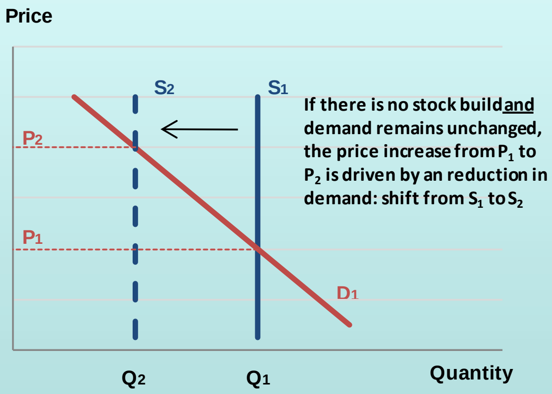
Some Basic Economic Concepts

While it may seem trivial, a quick and simplistic look at basic supply and demand economics tells us a lot about current market conditions.

The first chart shows the classic supply and demand graph, with an equilibrium price set by marginal supply and demand. If speculation drives prices above that equilibrium, then the market would be unbalanced. This would reduce demand, while at the same time supplies would remain unchanged or rise, leading to a stockbuild. Alternatively, higher prices reflect one of two other situations: tighter supply or higher demand.







Elaborating on this simplistic analysis provides an obvious conclusion: if a factor unrelated to supply or demand is driving spot oil prices, then this would be evidenced by larger-than-normal stocks, or production would have to be reduced to compensate.

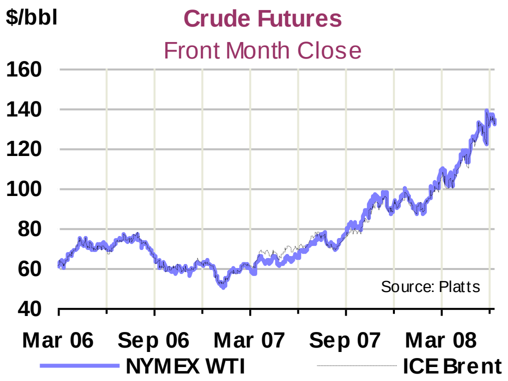
Do Speculators Cause High Prices?

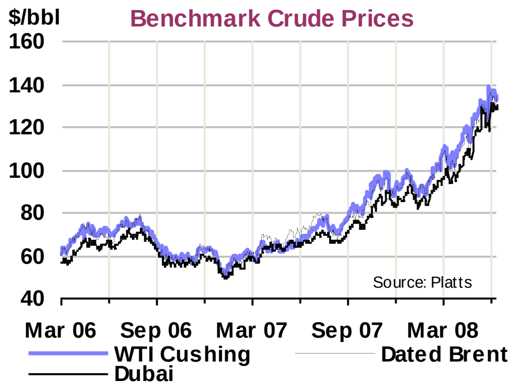
Speculators (those unrelated to the physical oil market, nor with an economic need to hedge against oil prices) and index fund investors tend to trade oil via futures markets. These forward prices are linked to spot prices either through the possibility of physical delivery or differential pricing. But while this analysis does not draw any conclusions on the impact of investment flows on forward prices, it is important to note two factors:

- Speculators play a well-understood economic role in the process of price discovery, liquidity and risk transference. In doing so, they lower the cost of transactions, make prices transparent and enable producers and consumers to reduce risk. By definition, speculators should be expected to enter the market when others feel the risk is too high, thereby providing a functioning market where otherwise liquidity would not exist;
- The economy is impacted by fluctuations in *spot* oil prices, not futures prices.

Speculators are naturally price makers, particularly when significant events occur, or there is considerable market volatility. The question therefore is not to determine whether speculators are first to push prices higher or lower, but whether their actions distort the oil market by pushing the oil price away from the equilibrium level at which supply and demand are matched. Even then, if prices appear to be at a non-equilibrium level, it has to be assessed whether there is an explanation other than speculative flows.

Since 2003 the volumes of investment funds in commodity markets, particularly oil, have been substantial, rising from an estimated $15 bn to $260 bn currently. (While they do not fit the traditional profile of speculators as they tend to have a longer time horizon, the evolution of investment product to consider a range of commodities, mean reversion tools and different investment time horizons suggests that their involvement, while predominantly still buy-side, can now be seen on both sides of the market.) This increase in money flows has coincided with a sharp rise in price for these commodities, leading many to conclude that financial flows have driven up prices. However, there is no clear evidence of causality.





As shown in *Some Basic Economic Concepts*, if speculators are driving spot oil prices, an imbalance in the form of higher stocks should be apparent. Alternatively, demand could be understated, which is a possibility. Another aspect would be supply reductions to legitimise higher prices – but with OPEC operating close to capacity and OECD crude stocks at five-year averages, this does not appear to be the case. Although we do not have perfect data on either financial flows or oil stocks, there are no clear signs that high prices are caused by investment inflows or speculative activity. A number of serious studies have failed to shown a 'smoking gun' explaining the run up in prices over the past year.

Critics of the argument that fundamentals are tight frequently point to the poor oil demand growth since 2005 – yet again, this betrays a lack of understanding of basic economics. There is little doubt that the surge in upstream investment has coincided with service sector constraints that have limited crude oil capacity growth. At the risk of stating the obvious, supply and demand, by definition, have to match: poor supply-side growth will be accompanied by equally tepid demand growth. But, if the demand potential is much higher, it would have to be choked off by higher prices.

To leave the argument here would risk a repetitive dispute: the fundamentalists argue that underlying demand is strong, but has been tempered by high prices, while the fund money proponents would argue that demand is weak and it is all due to speculation. Fortunately, there is a wealth of evidence that demand for all primary commodities is strong. Record prices and record demand is being seen across-the-board, and not just in those commodities where futures markets exist, but in physical markets where little or no speculative involvement takes place: LNG, coal, iron ore, minor metals, silicone, rice among others. Equally important is that price rises across the commodity spectrum are not synchronised, while they may have a common link in terms of growing demand from developing countries, the asynchronous behaviour shows they are responding to their own supply and demand balances.

Drawing the conclusion that spot prices are not driven by speculative funds does not exclude the possibility that investment inflows or expectations of constrained future supplies may be elevating *forward* prices, but if they are, they do not appear to be translating into higher spot prices through the delivery and pricing mechanisms that link the two. This is important: spot prices are the driver of end-user prices that feed through to the pump and the economy at large. But, yet again, we see a strong economic rational for high forward prices. This report shows that despite a dramatic increase in nominal investment, there is no clear sign of a recovery in crude oil capacity over the medium term. In other words, high forward prices are necessary to encourage a supply response and to ensure that demand is restrained.

The increase in fund flows is nearly universally portrayed as a negative influence, but there is a significant economic benefit. The injection of liquidity from investment flows has however prompted a dramatic transition within forward and futures markets. Oil futures have expanded from a relatively thin extension of spot market trading to a market which has significantly enhanced forward liquidity and functioning. The market transition is also clear from the investment products being offered by financial institutions. Whereas in 2004/05 investors were talking about long-term buy-side-only investments, held 1-6 months forward in commodity futures (and periodically rolled forward), there is now an entire array of investments taking advantage of long and short positions, trend, mean reversion and momentum along different maturities of commodity futures and with different basket compositions.

Clearly the oil market has evolved and the fact that there is no sign of distortions in the physical market suggests that investment flows have not generated high prices. This does not mean, however, that there has never been an impact. Several reports point to the period between 2005 and early 2006, during which the market was in contango. Prices were then rising and stocks were building in OECD countries. This is an area that requires more analysis, but it is worth noting that, at the time, there was little day-to-day correlation between commodities, which would have been expected with purchases of commodity baskets. So again, if the correlation between stocks and prices is not apparent and causality analysis shows no clear driving force, other factors were necessarily at play:

- *Low spare capacity*, which remained tight. By end-2004, effective OPEC spare capacity reached close to zero. While it increased over 2005, it remained low and much of the crude available was believed to be difficult-to-refine heavy, sour crude;
- *Geopolitical concerns*, which were high (Iran, Nigeria), perhaps increasing the desire to hold stocks;
- *Strong forward refining margins*, which may have encouraged stockbuilding by refiners looking to lock in a forward profit;
- *Expectations of rising future prices* (peak oil concerns, strong non-OECD demand growth), which may have encouraged further purchases;
- *Rising costs*, which were close to the marginal cost of production in 2004-2007;
- *Tight refining capacity*, which may have prompted crude stockbuilds and driven crude prices higher.

In sum, even if we originally assumed that rising prices were led higher as a result of investment flows at that time, with the benefit of hindsight we have to conclude that the rise in price coincided with rising marginal costs, strong reasons to hold additional stocks and apparent refining constraints.

A Look at Fundamentals

Supply and Demand

By definition, supply and demand must, with the exception of small deviations in stocks, always balance. Therefore, making an historical assessment of supply and demand is only possible in the context of price. In the past five years, there have been severe constraints on non-OPEC supplies due to lack of equipment, labour and access. Without the supply, by definition there can be no additional demand.

Furthermore, a number of highly populous developing countries are getting wealthier. It is only right that they should aspire to the standard of living seen in the OECD – one that includes the same intensity of use of energy. But if the supply of oil is restricted, then the only way in which balance can be achieved is through a gradual price increase until demand is curbed in OECD countries. In the past, we have seen this dynamics at work. In the present context demand growth has been much more resilient due both to subsidies protecting consumers, but more importantly to the robustness of economic growth outside the OECD.

Therefore, if we look at global oil demand trends, it is clear that growth has fallen significantly below levels that would have been expected from GDP growth alone. In other words, there has been a price effect – particularly in OECD countries. If potential demand had been in line with the weak trend in supply growth, then there would have been no upward pressures on prices. Moreover, the driving force of demand over the past few years has been in transportation fuels, where demand is less sensitive to prices, and where there have been constraints in the refining system to meet such demand. This scenario requires even higher product price moves to choke off consumption, which this report's *Refining* section argues could further extend crude prices.

Spare Capacity

Spare capacity tends to evolve cyclically in primary commodity industries. Regarding metals, it tends to take the form of idled high-marginal-cost smelters or mines. In agriculture, it may take the form of crop switching, lower use of yield-enhancing inputs, or idled land or crop rotation. In oil, spare capacity has existed in the industry for the past 30 years; building up steeply in the 1980s after high prices prompted a round of fuel efficiency and non-OPEC production expansions. Years of under-investment, however, have now reduced this to minimum levels, with the vast majority of the current 2 mb/d of spare capacity held by Saudi Arabia. Saudi spare capacity is intentional; elsewhere, it is accidental.

Low spare capacity *per se* does not mean higher prices. However, it reduces the ability of the market to respond to supply tightness and may therefore lead to an increase in demand for commercial stockholding. And capacity is not just tight in the upstream: the oil value chain has low spare capacity throughout. Further, low levels of spare capacity are generally indicative of a very tight market, from which accelerating price rises are common.

From an economic perspective, upstream spare capacity is symptomatic of a tight balance, but does not in itself does not affect the market balance and therefore prices. While low spare capacity may increase the desire to hold stocks, it would be stretching the point to argue that it would be better to hold supplies off the market to create spare capacity. If there is a trade-off between more production and more spare capacity more production is clearly most important. Similarly, spare capacity may have less of a market impact if it is uncertain, not expected to be used, or is of a quality that would be difficult to refine.

Stocks

Commercial stocks provide an instant source of supply for holders. Often they are held close to a refinery, pipeline or point of consumption. However, it is a common error to believe that market prices and direction can always be assessed by stock levels. True, when stocks are at bare minimum levels, there is no additional supply buffer and this can lead to volatile and explosive price moves.

However, stocks are only a source of supply if holders are prepared to use them or draw them down. Expectations of tight future supply, rising demand or higher prices could therefore lead to competitive stockbuilding or a desire to hold onto existing stocks. Therefore, it is possible under certain conditions that rising stocks or persistently high stocks could be associated with rising, rather than falling prices. Usually, prices fall as stocks build and vice versa.

Many analogies are made between current market concerns of peak oil and strong demand and other supply-side restrictions seen in the 1970s. Similarly, it should also be noted that at points during the second oil shock in 1979-81, commercial stocks trended higher as prices were rising.

Strategic stocks have to be looked at in a generally different light. In IEA member countries, strategic stocks are generally a source of supply purely to offset a supply-side disruption (this may not be the case with strategic stocks elsewhere). From an analytical perspective, such stocks confer no additional daily supply to the market (except in the event of an emergency), while their building should be regarded as a source of additional demand.

Refining

The impact of refining capacity on crude oil prices is extremely hard to model and therefore is often overlooked. Anecdotally, traders have referred to gasoline or diesel prices driving the market, but often the mechanism for such a process is not clear. The IEA believes that a lack of refinery upgrading capacity in particular and tight capacity in general has played a significant role in lifting crude oil prices since 2004. This may have been exacerbated by changes in product specifications both through their restrictive influence on product trade, but also because of volumetric constraints in the refining process.

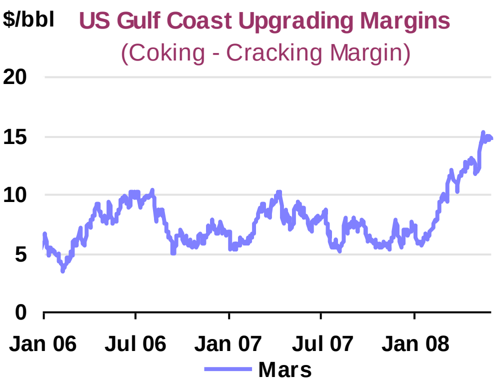
One crucial point in the discussion is that the refined product markets are individually traded and their prices reflect the supply and demand for each product. Refiners, therefore, should be willing to buy crude at a price which broadly relates to the sum of the refined product output of each refinery (less costs) or at a point where the refining margin is close to zero. In other words, while crude oil prices should be determined by the supply and demand for crude oil, if strong demand or tight refining capacity leads to higher product prices overall, refiners would be prepared to pay a higher price for crude oil.

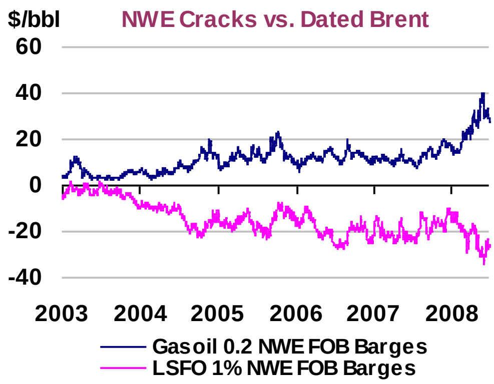
To illustrate this, let us consider the following example:

There are three refineries with a capacity of 1 mb/d each. Each can produce only 1 mb/d of diesel (and no other products), while the world produces only 3 mb/d of crude. There are zero operating costs and crude and diesel costs $60/bbl.

If (potential) diesel demand increases to 3.2 mb/d, refiners cannot respond, so the diesel price rises to $80/bbl to constrain demand to the maximum output of 3 mb/d. Should the price of crude change? On the one hand, the supply and demand for crude has not varied (because refiners cannot process any more). However, it is also true that refiners would still be prepared to pay up to the marginal revenue from a barrel of diesel for their crude. In other words, crude prices should remain at $60/bbl – but the higher refined product prices create the conditions for a change in the competitive demand for crude, or perhaps generate a desire to hold higher crude stocks, which in the end lead to an increase the price of crude.

The real world is obviously much more complicated than this simple model. Refiners produce a multitude of other products. If they have to meet the demand for a single product in tight supply they will inevitably deliver other products which, with finite storage, will have to be discounted to clear the market. As the financial return of a refinery will depend upon the ratio of product output relative to the sum of the product prices, raising refinery throughput to meet the demand for a single product could, in theory, lead to an infinite range of possibilities for the total sales revenue of the marginal barrel, contingent on output ratios and price elasticity of demand. Similarly though, there should also be a value for crude at which this refined product output is profitable.





However, the principle is clear. A mismatch between refinery upgrading capacity and demand creates tight product markets, which in turn have the potential to generate large shifts both in the demand for and in the price of crude. This effect could be exaggerated if there are strong competitive pressures to buy crude – triggered by the desire to buy crude stocks to lock in refining profits (particularly if forward product prices are strong), or there is tightness in the supply of crude or of particular crude grades.

Pouring Fat on the Fire

In recent months, middle distillates demand has soared in a number of countries across the globe, from Chile and Argentina to South Africa, Australia and China, due to the lack of natural gas, insufficient investments, accidents or other causes. This has had significant consequences in global crude and product markets. For example, Chinese diesel shortages have certainly contributed to rising distillate prices, and may in turn have contributed to higher crude oil prices. As if this were not enough, Europe has recently tightened sulphur specifications for diesel. This 'perfect storm' in the distillate market is arguably the single biggest cause of the current run up in prices.

There is an estimated 1.5 mb/d of unofficial 'teapot' refining capacity in China, which plays an important role in regional supplies. Traditionally, teapots either receive cheap crude oil from domestic suppliers or import fuel oil to produce low grade diesel and bitumen. However, with fuel oil prices liberalised and retail diesel prices capped, rising international prices have made it unprofitable for them to operate. As a result, they have severely curtailed output or shut down, contributing to localised diesel tightness.

PetroChina and Sinopec have increased imports of transportation fuels to offset these shortages, buying in diesel from the spot market. For the product market, the impact is two-fold. Fuel oil demand, in an already amply supplied market, has fallen, while diesel supplies have decreased and diesel demand has increased in what was already a tight middle distillate market.

Offsetting this diesel shortage requires higher world diesel prices to choke off demand and increase global refinery throughputs, but it also reduces fuel oil demand, thus requiring a bigger discount to clear the surplus. While, in theory, other overseas refiners could (if they have spare capacity) adopt the role of the teapots, this would not work in practice because the diesel produced would not meet China's quality specifications if imported and sold through official channels. Therefore, crude oil demand has also likely increased as a result.

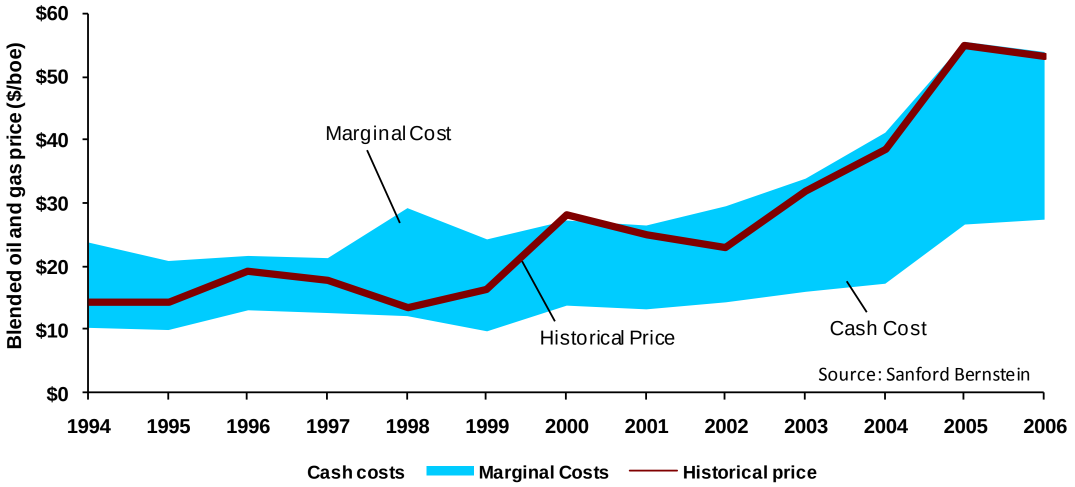
Marginal Costs

Tight service sector conditions, labour, equipment and raw materials have seen the cost of upstream and downstream production soar in recent years. It is the classic inflationary set-up, with too much money chasing too few goods. Rising investment in exploration or the construction of new refining capacity leads to competitive pressure on these limited resources, which in turn lead to higher costs. Higher costs increase risk and can lead to project postponement, longer lead times and therefore to production slippage. This has clearly contributed to the poor supply-side performance of the crude oil industry in recent years.

A further consideration are the changes in fiscal terms and contract conditions that have been seen over the past few years, which have led to a lower return to producers and investment uncertainty. While higher taxes or changing shares of output are not directly related to marginal costs, they have a similar impact on the return on an investment, and could therefore affect supply-side performance. However, large parts of the cost base are cyclical and could therefore ease as new rigs are built and additional manpower is recruited or trained.

Historically, oil trades close to the marginal cost of production, but with marginal costs currently estimated around $60-70/bbl (perhaps higher accounting for return on capital), clearly the current spot market price is much higher. While in theory competitive pressures should drive costs close to market prices, at the present time, there is a clear reluctance by the industry to pay significant fees, when it knows that new equipment will be available in a few years time at lower cost (for example after commissioning the building of proprietary rigs and other equipment). Furthermore, some analysts note that despite the large increase in spot oil prices, the financial return to oil companies has been eroded by windfall taxes and changes in contract terms. As such, rising marginal costs and higher taxes may actually lead to lower investment despite rising oil prices. In recognition of the need to incentivise output, the UK and Russia have recently announced significant tax changes.

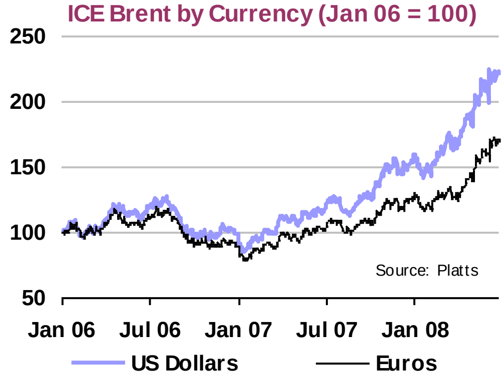
US Marginal Production Costs



Overall, the rise in marginal costs has been significant. Major projects have doubled in cost in the past few years. Some of those cost increases have been related to the weaker dollar. However, marginal cost tends to provide a base for prices, rather than act as a driving force. Ultimately, marginal costs of production are only relevant when there is no spare capacity and OPEC is operating flat out – even then, it is more likely that prices will be driven by demand. True, marginal supply in the oil market is generally provided by OPEC at a price which is unrelated to the marginal cost of production in non-OPEC countries. Here, a study of government expenditure and local investment needs may be more revealing than production costs.

The Dollar

At the *IEA Expert Round Table on Oil Price Formation* held earlier this year, there was a general consensus that the weaker dollar had been instrumental in rising oil and other commodity prices. While the issue is subject to considerable debate, we would broadly adhere to the view published by the IMF in its April 2008 *World Economic Outlook*, outlining the economic mechanisms by which a weaker dollar could feed through into higher commodity prices through various economic corridors. Others, however, note that such a direct linkage is not always apparent.



Perhaps the recent close linkage between oil prices and the dollar provides a further clue to its transmission mechanism. In broad terms, if the price of an underlying commodity is determined by the supply and demand for a commodity, then a depreciation of the underlying currency should generally result in a rise in its price. However, the impact of a currency shift would be expected to have varying impacts on the demand for a commodity and its cost of production in different parts of the world, with considerable time lags for these impacts to evolve. Therefore, a near-simultaneous revaluation of a commodity relative to shifts in the dollar necessarily represents a trader-led anticipation of the appropriate shifts, or perhaps the desire to buy more of that commodity as a store of value or in expectation of the trend continuing. The periods of non-correlation between commodity prices and the value of the underlying commodity may therefore represent a pause when the economic adjustments from those shifts pan out or because of the dominance of other market fundamentals.

However, while there is widespread agreement that a weaker dollar has contributed to higher oil prices in dollar denominated terms, the fact that oil prices are near record highs in other currencies shows that other factors are driving prices.

Conclusion

It is impossible to segment the current oil price into a sum of its parts. The dynamics of oil price formation are ever-changing. There are a number of elements which are, in our opinion, of paramount importance: strong underlying demand growth from non-OECD countries, poor supply growth, low spare capacity, a weaker dollar and a mismatch between refinery capacity and the structural growth in product demand. Many of these factors were shaped by structural forces and changes which were building for many years before prices started to rise.

Some of these factors, such as marginal costs, are partly cyclical, while others could be rectified by more investment, better policies, improved dialogue between producers and consumers, better transparency and allowing the market to do its job. There is no panacea, but a simple look through the history of commodity markets should show that explosive price movements are symptomatic of an aggressive tug-of-war between supply and demand. Blaming speculation is an easy solution which avoids taking the necessary steps to improve supply-side access and investment or to implement measures to improve energy efficiency.

DEMAND

Summary

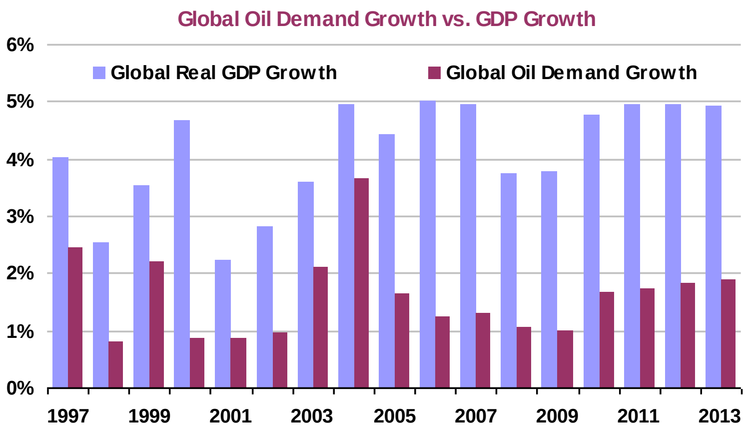
- **Global oil product demand is expected to grow by 1.6% per year on average between 2008 and 2013**, from 86.9 mb/d to 94.1 mb/d. This represents a volumetric growth of 1.5 mb/d per year on average. Oil demand will increase essentially in non-OECD countries, driven by growth in Asia/Pacific, the Middle East and Latin America, while oil consumption in the OECD is projected to decline over the forecast period. Moreover, from 2010 world demand growth is expected to accelerate noticeably as the world economy improves.

Global Oil Demand (2008-2013)

(million barrels per day)

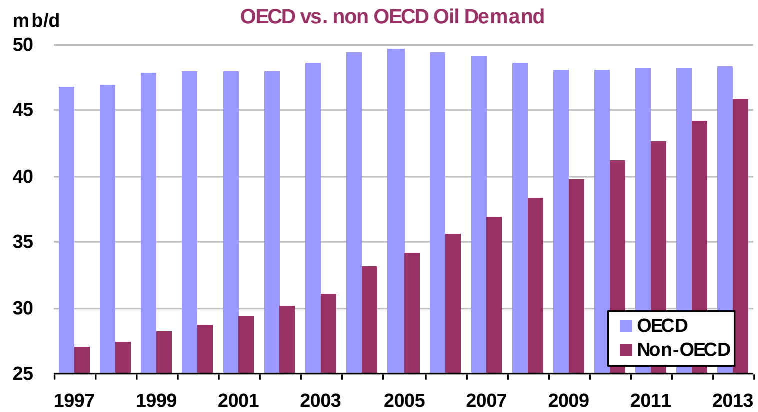
	1Q08	2Q08	3Q08	4Q08	2008	1Q09	2Q09	3Q09	4Q09	2009	2010	2011	2012	2013
Africa	3.1	3.1	3.0	3.2	3.1	3.2	3.2	3.1	3.2	3.2	3.2	3.3	3.3	3.4
Americas	30.4	30.9	31.1	31.2	30.9	30.2	30.7	31.0	31.0	30.7	31.0	31.3	31.6	31.9
Asia/Pacific	26.3	25.5	24.9	26.3	25.7	26.9	26.0	25.5	26.9	26.3	27.0	27.6	28.4	29.1
Europe	16.0	15.9	16.1	16.2	16.0	15.9	15.7	16.0	16.2	15.9	15.9	16.0	16.0	16.0
FSU	4.1	4.0	4.3	4.4	4.2	4.3	4.1	4.4	4.5	4.3	4.5	4.6	4.8	4.9
Middle East	6.7	6.8	7.1	6.8	6.9	7.1	7.1	7.5	7.2	7.2	7.6	8.0	8.4	8.8
World	**86.6**	**86.2**	**86.6**	**88.1**	**86.9**	**87.6**	**86.8**	**87.5**	**89.0**	**87.7**	**89.2**	**90.7**	**92.4**	**94.1**
Annual Chg (%)	0.6	1.3	1.2	1.1	1.1	1.1	0.8	1.0	1.1	1.0	1.7	1.7	1.8	1.9
Annual Chg (mb/d)	0.6	1.1	1.0	1.0	0.9	1.0	0.7	0.9	0.9	0.9	1.5	1.5	1.6	1.7
Changes from last MTOMR (mb/d)	-1.94	-0.56	-1.41	-1.68	-1.40	-2.50	-1.84	-2.30	-2.49	-2.29	-2.71	-3.10	-3.43	

- **The GDP projections that underlie this prognosis are those published by the International Monetary Fund; the oil price is assumed to remain constant at $110/bbl in real terms (2008 base) over the period.** This outlook, however, presents several risks, including: 1) the health of the global economy, 2) the evolution of commodity prices (notably oil), 3) eventual changes to administered price regimes in key consuming countries, 4) weather conditions and 5) supply developments regarding alternative fuels.

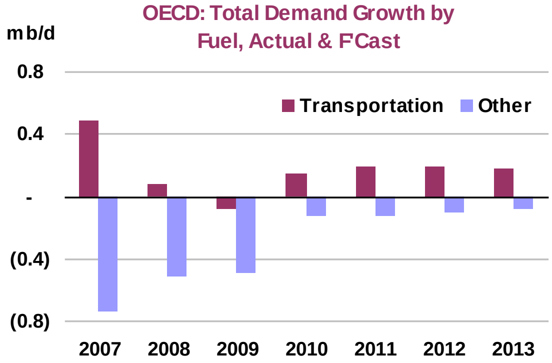


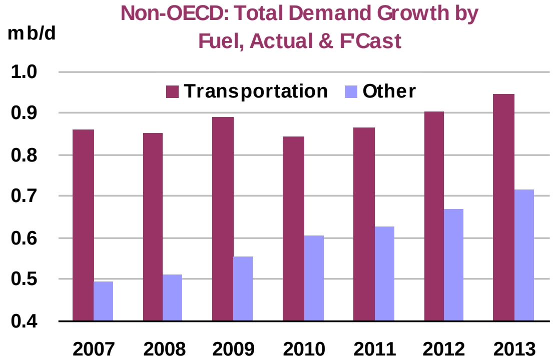
- **OECD oil product demand is expected to *decrease* annually by 0.1% on average over the forecast period**, from 48.6 mb/d in 2008 to 48.3 mb/d in 2013 – an average yearly decline of almost 70 kb/d. This assessment constitutes the major change versus last year's *Medium-Term Oil Market Report (MTOMR)*. Given high oil prices, expected to prevail, and the marked US economic slowdown, which is seen lasting at least until 2010, the US is no longer seen as supporting oil demand growth in North America (now expected at -0.1% per year on average) and by extension in the OECD at large. Demand in Europe and the Pacific, meanwhile, was similarly revised down and is now also seen contracting (-0.1% and -0.4% per year on average, respectively) over the forecast period.

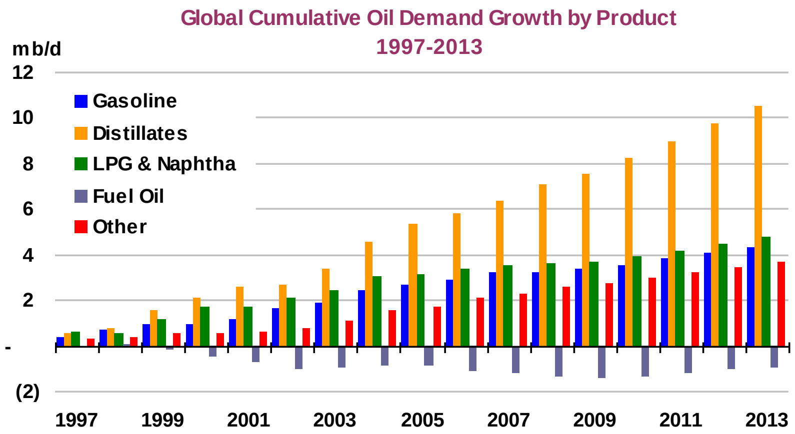
- **Non-OECD oil product demand, by contrast, is forecast to increase by 3.7% on average per year over 2008-2013**, from 38.2 mb/d to 45.8 mb/d, equivalent to +1.5 mb/d per year. This outlook is largely unchanged from our previous assessment, but masks some offsetting intra-regional adjustments. Some regions such as Latin America look much stronger, while the outlook for others such as Africa has been adjusted down, due to a) baseline revisions for most countries following the submission of new data for 2006, b) changes in historical estimates, c) the inclusion of new and improved data sources and methodologies, particularly in the case of the Former Soviet Union (FSU), and d) different assumptions regarding economic growth and oil prices. Data uncertainties, however, continue to pose additional risks to the prognosis. Several key countries in the three main regions driving non-OECD oil demand growth – Asia, the Middle East and Latin America, in that order – still provide insufficient or hard-to-interpret demand figures.



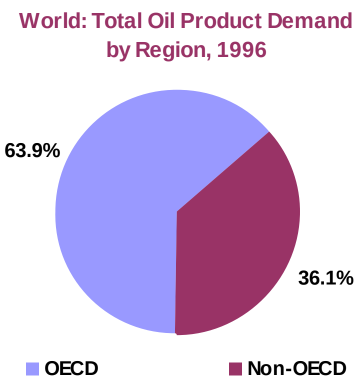
- **The bulk of oil demand growth in both OECD and non-OECD countries will be concentrated in transportation fuels.** Collectively, only the consumption of motor gasoline, jet fuel/kerosene and gasoil/diesel oil is poised to increase in the OECD (+0.4% per year on average), yet it will not offset the structural decline in other products (-1.0% per year). In non-OECD countries, transportation fuels demand (+3.8% per year) will grow slightly faster than demand for other products (+3.5% per year), and is expected to represent roughly 59% of the cumulative demand rise. Within the OECD gasoline will continue to account for the lion's share of demand in North America, with over 44% of total demand by 2013, while diesel will reign unchallenged in Europe, with a 31% market share. In the Pacific, meanwhile, both products will be more evenly balanced (a 18% share for gasoline and 16% for diesel). In most non-OECD countries, gasoline will tend to prevail over diesel, with the exception of Asia, by far the largest gasoil consumer among emerging regions. As such, the overall picture in terms of product categories highlights an interesting trend: distillates (jet fuel, kerosene, diesel and other gasoil) have become – and will remain – the main growth drivers of world oil demand, followed by LPG and naphtha (mostly used as petrochemical feedstocks) and gasoline.

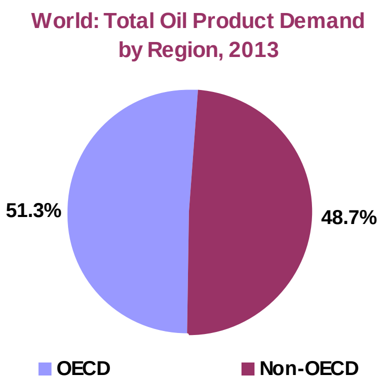


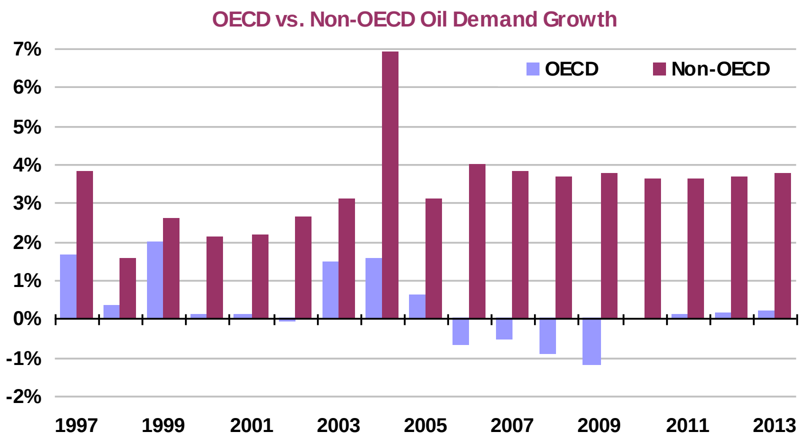


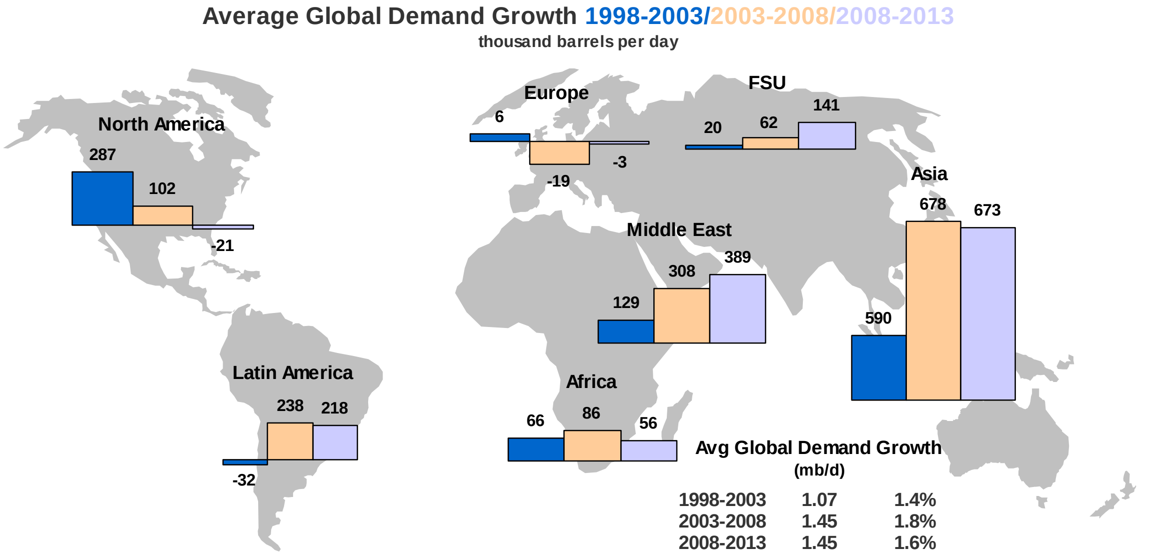


- **By the end of the forecast period, global oil demand will be almost evenly split between OECD and non-OECD countries.** By 2013, non-OECD demand will account for almost 49% of total global demand, compared with 36% in 1996, because of much faster growth when compared to OECD countries. Global oil demand growth will indeed essentially come from emerging countries, and on this basis non-OECD demand could for the first time ever surpass consumption in mature economies by around 2015. In addition to differing growth rates, this trend is also related to different economic and social structures: the share of petrochemical, and oil-fired industrial and power generation activities, will rapidly expand in non-OECD countries. In the OECD, by contrast, economic activity will continue to shift from industry to services, while electricity generation and heating needs will increasingly rely on natural gas or other sources.





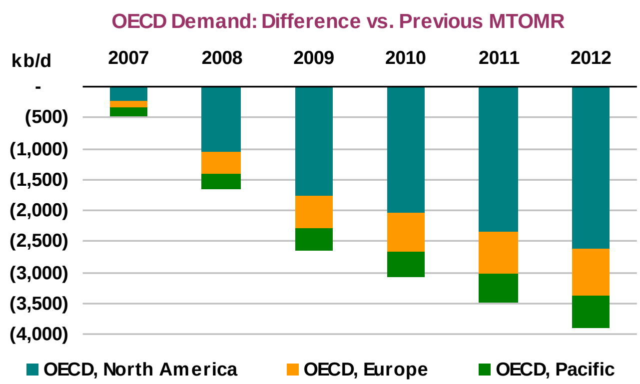




OECD

The evolution of oil product demand in the OECD looks markedly different when compared to last year's *MTOMR*. Indeed, demand is now forecast to *decrease* by 0.1% per year on average over the forecast period, equivalent to a contraction of 70 kb/d per year, from 48.6 mb/d in 2008 to 48.3 mb/d in 2013 – compared with the last *MTOMR*'s expected *increase* of 1% per year on average. Bearing in mind that the time frame is not identical (2008-2013 versus 2007-2012), this translates into a significant revision: 3.9 mb/d less than previously envisaged by 2012. In fact, OECD adjustments account for the bulk of global forecast revisions. While these revisions appear dramatic, the last report cautioned our reservations on the underlying assumptions that drove the forecast, and indeed these have emerged. The reasons for this adjustment are essentially three:

1. Significantly worsened economic prospects in the United States, the world's largest consumer, as well as lower expectations for most other OECD economies;
2. A sustained and sharp increase in oil prices, which have more than doubled from last year; and;
3. Overall mild winter conditions in 2008, for the third year in a row, which have contributed to lower the demand baseline (although some countries, as the US, were colder than normal).



The economic woes that have beset the US since the mortgage bubble burst during summer 2007 and the relentless rise in oil prices are arguably the most important factors behind our revisions. When we first issued our 2007-2012 prognosis in July 2007, the International Monetary Fund (IMF), albeit aware of the subprime and credit risks, was still predicting in its April 2007 *World Economic Outlook (WEO)* that US GDP growth not only would be as high as +2.8% in 2008 but also that it would exceed 3% per year on average over the following four years. More generally, the IMF was then seeing advanced economies expanding by about 2% per year on average over the forecast period. A year later, in its April 2008 WEO, the IMF drastically cut its prediction for US economic growth to only +0.5% in 2008 and +0.6% in 2009, and also revised down its outlook for several countries that face housing problems on their own (Spain, United Kingdom) or deeper structural issues (France, Italy).

In the same vein, the average WTI nominal oil price was around $74/bbl in July 2007, and forward curves suggested that it would hover around $85/bbl in real terms until 2012. Ten months later, the nominal price has more than doubled, and could average about $110/bbl in real terms until 2013. Overall, the combined impact of lower economic growth and a higher oil price have weighed down significantly on our OECD prediction. Going forward, there remains the risk that our prevailing price assumptions (constant in real terms at $110/bbl over the forecast period) are too low or that growth projections remain too optimistic.

The relatively mild weather conditions during the 2007-2008 winter also had an effect on our baseline. Although temperatures were colder than in the previous year, they were largely below the ten-year average in most OECD areas – the third mild winter in a row. This translated in markedly lower-than-expected use of heating oil, fuel oil and heating kerosene in several key countries such as the US, Germany (a trend exacerbated by low consumer stocks) and Japan. Weather patterns and power generation needs can indeed prompt very large swings in consumption levels (in excess of 500 kb/d on average). Yet this forecast assumes normal weather conditions (on the basis of a ten-year average, which is therefore gradually adjusting for what appears to be a trend towards milder Northern Hemisphere winters), so it factors in only a moderate rebound in the years ahead. (It should also be noted that final annual 2006 data submissions will come in a few weeks after the publication of this report, and that will likely entail some additional baseline adjustments.)

Forecasting Risks: Treading Carefully

The demand outlook presented in this report is subject to several caveats. First and foremost, this prognosis depends on the evolution of the global economy. According to the International Monetary Fund, the world economy will expand by +4.4% on average over the period. This global figure, however, hides significant differences in regional performance. The outlook of the world's largest economy, the US, has been revised down significantly following the mortgage and credit crises that erupted in mid-2007. Although the country is seen rebounding strongly as early as 2010, there is a risk that the slowdown could be more prolonged than expected. Other big economies, which are currently expected to remain largely unaffected, could eventually be penalised if the outlook for advanced economies worsens.

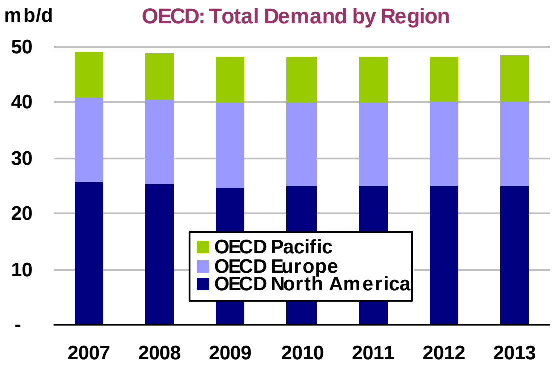
Second, the price of commodities (notably oil) and food could well rise further, aggravating inflationary pressures in many countries that are already facing severe problems at current levels. This report assumes a constant oil price, broadly based on the futures curve as of end-May. This is not a price forecast, since the price will change for supply and demand to find an equilibrium, but it allows an examination of the path of oil demand.

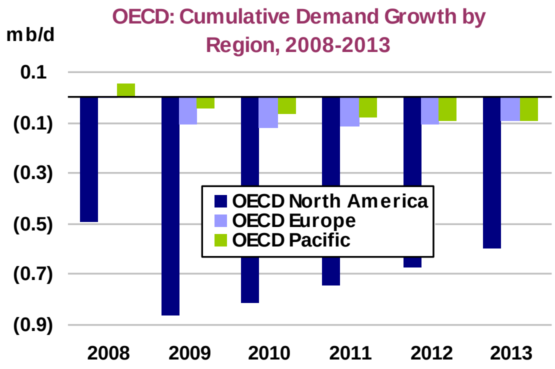
Third, this outlook assumes that administered price regimes in key consuming countries, notably in non-OECD regions, will move gradually towards free market prices over the course of the forecast; if change happens more suddenly and abruptly, oil demand growth in those areas – and worldwide – would likely be slower.

Fourth, weather risks, notably in the OECD, are also significant; whether winters are milder or colder than normal can induce very large swings in yearly oil demand. This forecast, though, is based on normal weather conditions, defined as a ten-year average of observed temperatures.

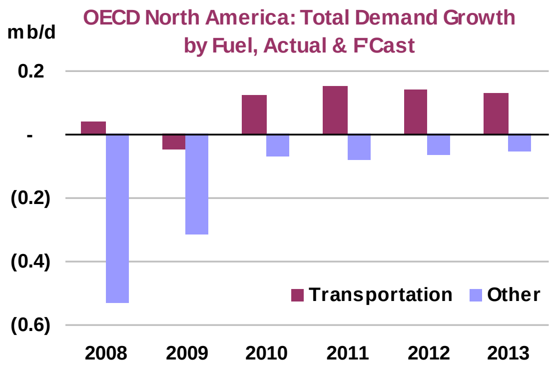
Finally, if the supply of alternative fuels – such as natural gas or biofuels, which are underpinning interfuel substitution for several refined products including heating oil or fuel oil – fails to meet expectations (either because of supply issues, policy changes or due to adjustments in relative prices), this outlook could be markedly altered.

Yet the main trends identified in the previous *MTOMR* still hold. First, oil demand growth will be largely buttressed by transportation fuels – motor gasoline, jet fuel/kerosene and diesel oil. These will be the *only* source of OECD demand *growth* over the forecast period. Second, other fuels will continue to decrease on aggregate, given interfuel substitution (notably commercial and residential heating and residual fuel oil for power generation, displaced mostly by natural gas and renewables) or competition from other geographical areas (particularly in the case of LPG and naphtha, as the world's emerging petrochemical power hubs will be located in Asia and the Middle East). Of course, this prediction will depend on whether there will be enough natural gas available, notably in Europe, as indigenous production falls sharply (for example, in the UK) and given that worries over Russia's lack of investment have become more acute since last year. Limited gas supplies could foster a renewed interest in fuel oil. Moreover, it is unclear whether the global refining system will be able to cope with more stringent specifications and the increase in distillate demand.





As the US economy rebounds, oil demand growth in the OECD will be again driven by **North America**, albeit at a lower pace and only from 2010 onwards. Over the entire forecast period, however, consumption in the region is forecast to decline by 0.1% per year on average (from 25.0 mb/d in 2008 to 24.9 mb/d in 2013), compared with the much more optimistic assumption of +1.3% per year in the last *MTOMR*. This represents about 31% of the OECD's average yearly volumetric decrease. In absolute terms, OECD North America will account for almost 52% of total OECD demand in 2013 and almost 27% of global oil product demand by the end of the forecast period.

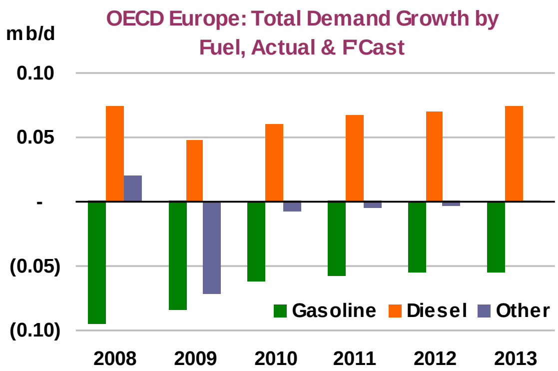


Oil demand in OECD North America will continue to be overwhelmingly dominated by the US (82% of regional demand by 2013). Thus, even though demand should growth faster in neighbouring countries (+0.9% per year on average in both Canada and Mexico), the evolution of consumption patterns in the US will arguably have long-lasting consequences not only for the region but for the world as well, given that the US accounts for a quarter of global demand. Under current GDP and oil price assumptions, transportation fuels in the US are expected to expand by 0.3% per year on average from 2008 to 2013, accounting for roughly 73% of total US demand in 2013. Four factors, however, could alter this prognosis:

- In the short term, *continued oil price rises* (at the time of writing, oil remained above $135/bbl, having twice neared the $140/bbl mark, while US gasoline had passed the $4/gallon threshold), which may further reduce discretionary driving and increase the use of public transportation where available;
- In the medium to long term, *an accelerated fleet turnover in favour of smaller cars* and away from SUVs and light trucks, as consumers become convinced that high prices are not due to temporary spikes and therefore likely to remain at high levels;
- *More stringent federal mandates on fuel efficiency*, which despite a recent review of CAFE standards, remain low when compared with other OECD countries (moreover, several states have successfully challenged the federal government's monopoly on efficiency regulations); and;
- *A gradual switch to diesel-fuelled passenger cars*, unthinkable in the recent past but now gaining attention given technological advances (in fact, several large European car manufacturers will begin selling diesel models in the US this year), which would contribute to lift the region's vehicle fleet

efficiency but also pose new challenges in terms of refining capabilities, even though the fleet's structure will likely continue to be based on gasoline engines for many years to come. (However, such an efficiency-based switch may well prove difficult, considering the constraints on diesel supplies and the widening price differentials between diesel and gasoline.)

In **Europe**, the outlook for demand is also lower than previously anticipated. Oil demand is expected to decrease by 0.1% per year on average, from 15.3 mb/d in 2008 to 15.2 mb/d in 2013 (instead of growing by 0.7% per year as predicted in the last *MTOMR*). This weaker outlook is mostly due to less buoyant economic growth assumptions, to higher oil prices, and to a much lower baseline for heating oil and fuel oil as a result of mild winters and a lower rate of stock filling in key countries. The region will account for 26% of the OECD's annual average decrease by volume over the forecast period. Oil demand in OECD Europe will stand at about 31% of OECD oil product demand in 2013, and roughly 16% of global oil product demand.



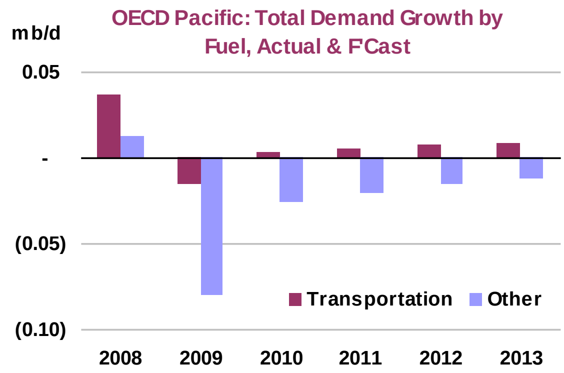
As with North America, the evolution of oil demand in Europe will be largely dictated by developments in its largest economies – France, Germany, Italy, Spain and the United Kingdom will account for 60% of total European demand by 2013 – despite much faster growth in other countries (such as the Czech Republic, Hungary, Poland, Slovakia or Turkey). Indeed, as long as consumption in the Big Five continues to contract, overall demand growth in Europe will continue to decline. The weakness in the largest countries is due to a variety of factors: lower economic growth; population decline (notably in Italy and Germany); the ongoing "dieselisation" of Europe's vehicle fleet; and the gradual interfuel substitution of fuel oil and heating oil in favour of natural gas and renewable energy sources.

With respect to transportation fuels (the bulk of demand), the increasing use of middle distillates (diesel and jet fuel) will largely offset the decline in gasoline consumption – as such, overall transportation fuels demand should remain unchanged. Older, mostly gasoline-fuelled cars will be scrapped and replaced by diesel vehicles; meanwhile, jet fuel consumption will continue to be supported by increasing passenger travel, despite airline efficiency gains as a result of cost-cutting efforts. In the longer term, however, the fleet dieselisation may arguably slow down (in fact, this is already starting to occur). On the one hand, the rise in diesel prices, both in absolute terms and relative to gasoline, will make diesel vehicles more expensive to run, and this could gradually prompt a renewed interest in gasoline engines. On the other hand, the diesel market is already mature in several countries (in France, Belgium, Spain and Portugal diesel cars currently account for approximately 70% of total sales).

Fuel oil use will continue to slide as Europe's two largest consumers, Italy and Spain (27% of regional demand in 2008), adopt other energy sources for power generation (natural gas, renewables and even nuclear). Yet a floor for fuel oil demand will remain. On the one hand, the potential for further interfuel substitution in energy generation will become more limited. Fuel oil power plants currently account for about 10-15% of total generation capacity, and it is unlikely that several islands will ever abandon fuel oil as other sources such as natural gas would be more expensive. Moreover, power plants burning coal or biomass require some fuel oil (or diesel) to start up. On the other hand, bunker demand in the Netherlands and Belgium (accounting for another 27% of regional demand) is poised to expand sharply, mostly given increasing freight traffic in the ports of Rotterdam and Antwerp.

In the **Pacific**, the outlook has also been revised down when compared with the last *MTOMR*. Oil product consumption is expected to decrease by 0.4% per year on average over the five-year forecast period (instead of growing by 0.6% per year), from 8.3 mb/d to 8.2 mb/d. The Pacific will thus account for 17% of total OECD demand by 2013, and for 43% of its average volumetric decrease per year. In terms of worldwide comparisons, OECD Pacific demand will represent 9% of global consumption by the end of the forecast period.

As in other OECD areas, one country will dominate oil demand developments in OECD Pacific: Japan (with 56% of total regional demand by 2013), only distantly followed by Korea (30%), Australia (13%) and New Zealand (2%). As such, the relatively strong oil demand growth seen in the latter three countries will barely offset Japan's structural decline (-1.8% per year on average over the forecast period), underpinned by demographic trends, increasingly efficient vehicles and the growing use of electricity for heating purposes.

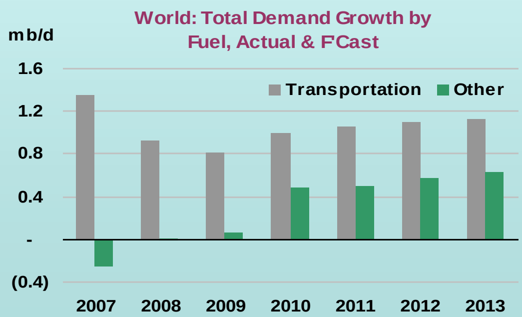


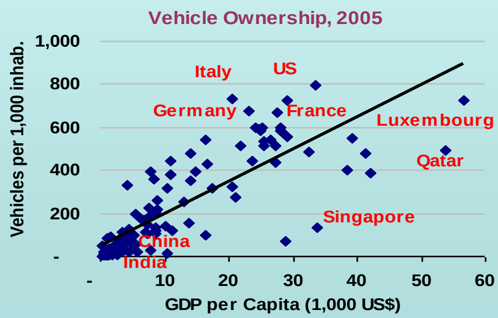
Moreover, uniquely among other OECD areas, the structure of demand in the Pacific will not be overwhelmingly geared towards transportation fuels (46% of regional demand by 2013, compared with 69% in North America and 54% in Europe). Other products play a substantial role: naphtha in Korea, given the country's large and rapidly expanding petrochemical sector, and, above all, residual fuel oil and crude for direct burning in Japan. The latter products, mainly used for power generation, were on the decline until very recently, being phased out in favour of natural gas (LNG) and, to a lesser extent, nuclear power. However, the operational problems experienced by some of the country's nuclear utilities since mid-2007 have led to a dramatic surge in the consumption of both fuel oil and direct crude. This forecast assumes that currently shut-down plants will resume operations by mid-2009, but if further delays occur or other issues arise (such as much higher LNG prices) Japanese demand could arguably be higher.

Transportation: The Driver of Global Demand Growth

The transportation sector will remain the main driver of world oil demand growth in the medium term. Transportation fuels – gasoline, jet fuel/kerosene and gas/diesel oil – are expected to increase by almost 2% per year on average over the forecast period. Their share of total oil demand will rise slightly, from 58% in 2008 to 59% in 2013. The key determinants of transportation fuels demand, in turn, are income and population growth, particularly in emerging countries. Global population is set to increase from 6.9 billion in 2007 to 7.1 billion in 2013, with 93% of the growth taking place in non-OECD countries. By the same token, based on the IEA's extensive research on transportation issues (notably the *World Energy Outlook 2007* and the recently released *Energy Technology Perspectives 2008*), we estimate that the world's total vehicle fleet (including 2/3 wheelers) could reach as many as 1.2 billion vehicles by 2013 (an increase of 35%, or 3.8% per annum over 2005), as ownership rates rise sharply in key emerging countries such as China and India.

These dramatic projections would suggest that oil demand will continue to increase relentlessly in the longer term. There are, however, several offsetting factors at play that could contribute to slow down transportation fuels demand: the development of alternative technologies, more stringent government policies on fuel economy standards and vehicle performance, and behavioural changes as a result of high oil prices.





Transportation: The Driver of Global Demand Growth (continued)

While biofuels have made a significant contribution in meeting transport demand growth over the past few years, they will only account for 3.5% of total transportation fuels by 2013. This could obviously change in the case of a major technological breakthrough (second-generation biofuels based on a wider range of feedstocks), but at this point such progress is uncertain and therefore not envisaged in this report. In the same vein, even though sales of hybrid vehicles have picked up, notably in the US, they remain a niche market. Meanwhile, the development, and mass commercialisation, of hydrogen and fuel cell vehicles also depends on technological advances that would significantly reduce costs, while the production of non-conventional oil and Fischer-Tropsch synthetic fuels requires considerable amounts of energy and releases large quantities of CO_2. As such, neither of these sources is assumed to have a significant effect within the timeframe of this report.

By contrast, efforts to improve fuel efficiency will likely be more effective. The average light-duty vehicle (LDV) fuel economy is expected to improve in most regions during the forecast period. This will result from policy changes in most OECD countries, and by strong sales of small cars in much of the developing world. The share of sport-utility vehicles (SUVs) is expected to decline in many regions as first-time drivers purchase cheaper, smaller vehicles, with possibly the exception of China, where SUV sales are booming (currently at twice the growth rate of the passenger market as a whole).

- In the US, the *Energy Independence and Security Act* (EISA), which includes far-reaching implications for the transportation sector, was passed in December of 2007. It raises the corporate average fuel economy (CAFE) standards for passenger cars for the first time since 1975 from almost 17 miles per gallon (mpg) to a minimum of 27.5 mpg by 2020, and mandates efficiency standards – for the first time ever – for medium- and heavy-duty vehicles. In addition, the law requires biofuels production to rise almost five-fold by 2022.
- In Japan, the Top Runner Program sets fuel efficiency standards on a market basis. The products comprising a particular category of goods must achieve the energy efficiency of the best-rated product within that group by a specified year, rather than aiming at attaining the group's average efficiency (as mandated in the past). Regarding vehicles, the current target is 16 km/litre by 2010, compared to 13 km/l under the previous standard.
- In the European Union, an ambitious strategy to reduce carbon dioxide emissions from new cars and vans sold in the region, which would effectively imply substantial fuel savings, is currently under review. The proposed measures would enable the EU to reach its long-established objective of limiting average CO_2 emissions to 120 grams per km (on an industry basis) by 2012 or, if possible, to 130 grams per km (with additional measures under the so-called 'integrated approach'). That would imply a reduction of 20-25% from current levels, equivalent to a fuel economy of 4.9 l/100 km for diesel cars and 5.5 l/100 km for gasoline cars (4.5 l/100 km and 5.0 l/100 km, respectively, under the integrated approach). This new legislative framework will replace current voluntary commitments by the car industry, which have brought about limited progress. France and Germany recently agreed to apply this limit to new cars by 2012, in order to give the industry enough time to comply.

Moreover, several countries, notably in Europe (France, Spain, the Netherlands and the UK) are encouraging the purchase of more efficient, cleaner and generally smaller cars by offering fiscal advantages or rebates. However, the impact of these policies will be rather limited in the medium term given the life of the average vehicle (estimated at 15 years in the OECD and 18 years in non-OECD countries).

Sustained high prices will probably have a more immediate impact upon oil demand, by prompting consumers to change their driving behaviour. Anecdotal evidence suggests is already happening, most notably in the US, where motorists are driving less and opting for smaller, more efficient cars. However, as long as key consuming countries – more prominently China and most oil producers – maintain low retail price through caps or subsidies (despite recent adjustments), this behavioural change will largely be restricted to OECD countries. As such, demand for transportation fuels will continue to grow apace in non-OECD countries.

Non-OECD

Oil product demand in non-OECD countries is expected to rise by 3.7% per year on average between 2008 (38.2 mb/d) and 2013 (45.8 mb/d). In volumetric terms, this is equivalent to a gain of 1.5 mb/d per year on average. As such, global oil demand growth will essentially be driven by non-OECD countries, which will more than offset the decline in OECD demand. Compared with the previous *MTOMR*, which foresaw an annual average growth rate of 3.6% (albeit over 2007-2012), the forecast average growth in volumetric terms is revised up by only 30 kb/d by 2012. The reasons for this small divergence are to be found in:

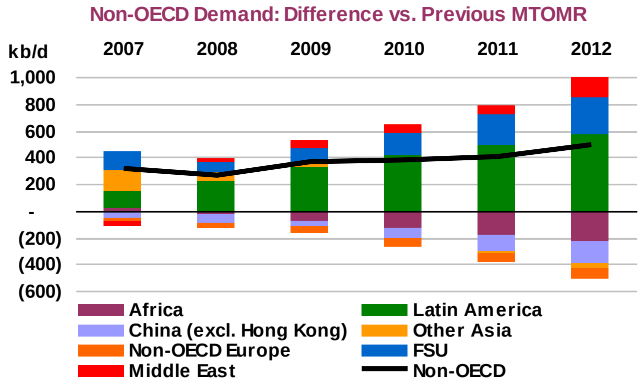
a) Baseline revisions for most countries following the submission of new data for 2006, which were generally lower than expected (in many cases reflecting the impact of high oil prices);

b) The reappraisal of historical estimates in several relatively large countries, such as India;

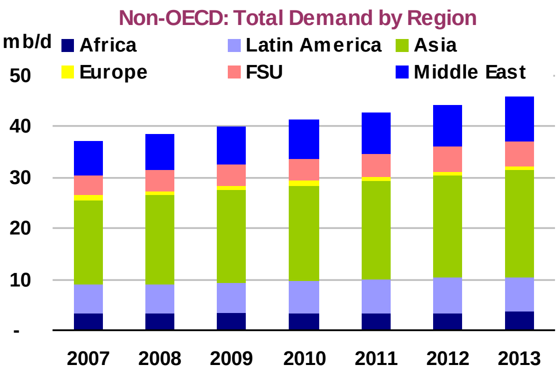
c) Upward adjustments to GDP assumptions for some key countries, which largely offset downward revisions elsewhere; and;

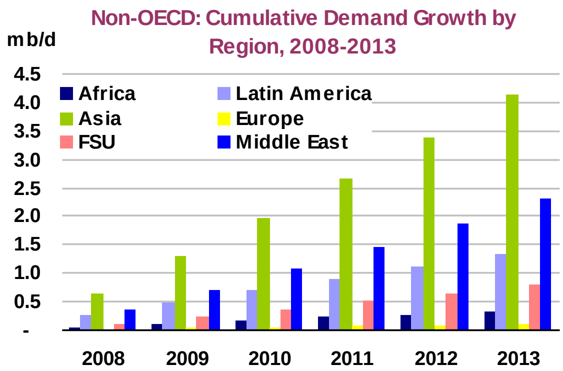
d) The inclusion of new and improved data sources and methodologies, particularly in the case of the countries comprising the FSU.

In the end, by virtue of compounding from different starting baselines, some regions such as Latin America now look much stronger, while the outlook for others, such as Africa, is somewhat lower than previously anticipated. Nevertheless, it should be emphasised once again that data quality and transparency issues continue to pose upside risks to the forecast, particularly in fast-growing countries.



The main themes regarding the evolution of non-OECD demand are essentially unchanged with respect to the last *MTOMR*. First, three regions will dominate over the forecast period: Asia (including China), which is expected to represent almost 46% of non-OECD demand by 2013, the Middle East (19%) and Latin America (15%) – and accounting for roughly 48%, 27% and 15%, respectively, of average global growth over the forecast period. Second, robust economic growth, despite the slowdown in mature economies, and the prevalence of administered price regimes in these regions, unlikely to be entirely dismantled in key consuming countries for political and social reasons (although we assume that retail prices will be gradually raised), underpin the demand outlook. In fact, the inclusion of Latin America in the league of leading oil demand growth regions is largely due to much stronger assumptions regarding economic activity, notably in its largest countries (Argentina, Brazil, Venezuela, and to a lesser extent, Chile), and to capped end-user prices (particularly in Argentina and Venezuela), which are feeding runaway growth across several oil product categories.





As such, non-OECD demand is projected to continue growing, in sharp contrast to the OECD, where it is expected to gradually contract. By 2013, non-OECD demand will account for almost 49% of total global demand, compared with only 36% in 1996, and should for the first time ever surpass mature economies by around 2015. Aside from differing growth rates, non-OECD demand growth is also related to structural differences. Indeed, the share of petrochemical and oil-fired industrial and power generation activities will further expand in several large countries – as opposed to the trend observed in the OECD, where the economic shift from industry to services is expected to continue, while power generation and heating needs will increasingly rely on natural gas or other sources. Yet continued high prices could eventually encourage fuel switching in some non-OECD countries, as long as alternative energy sources become available.

Decoupled Globalisation?

As the United States slips into a sharp economic slowdown, some observers predict that this will inevitably affect the rest of the world. The argument behind this view is that globalisation has synchronised the world's main economies via trade and financial flows. However, even though a US downturn will likely affect other countries, there is some evidence that the so-called 'decoupling' effect – understood as a more limited impact on developing economies than that observed in the past – is actually taking place. As such, the outlook of global economic activity and oil demand growth is brighter than commonly assumed – a conclusion that is tacitly shared by the IMF, whose 2008 global GDP growth forecast is still a relatively healthy 3.7%, despite the woes of the US economy.

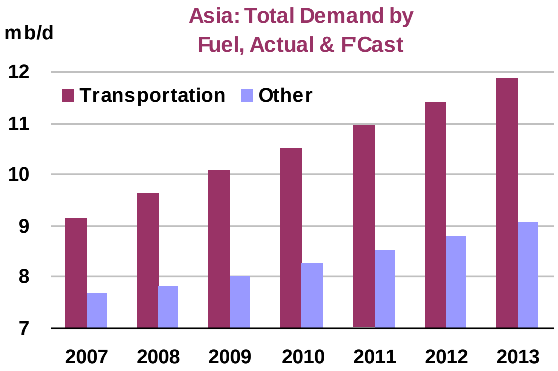
Three key structural factors support the decoupling case: 1) emerging countries trade increasingly among themselves, rather than with developed economies; 2) domestic investment and demand, as opposed to net exports, have become the main driver of economic growth in the largest emerging economies; and 3) the price of commodities – a key export from developing economies – is no longer primarily sustained by demand from rich countries, but mostly by emerging ones, engineering in turn a boom among commodity exporters. China is the exemplary incarnation of these trends. Half of its exports go to other emerging countries, notably Brazil, India and Russia; its domestic consumption and investment (of which almost half is devoted to infrastructure and property) contribute to roughly 80% of nominal GDP growth; its domestic demand is boosted by productivity gains and growing wages; and its sustained appetite for commodities, ranging from oil and iron ore to coal and soy, has underpinned price booms in other emerging (and a few developed) countries.

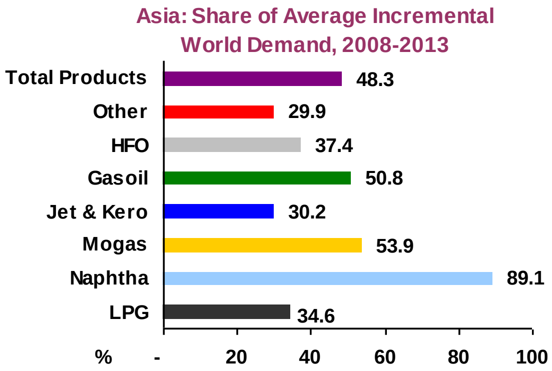
A protracted US recession is not yet on the horizon, according to the IMF forecast, which still sees low but nonetheless positive US growth in both 2008 and 2009, despite the continuing problems in the country's financial and housing sectors, the fall of the dollar, signs of weakening activity in manufacturing and services, and rising inflationary concerns. Yet the course of the global economy is arguably increasingly dependent upon Chinese developments. What is then the outlook for China's economy? As noted, China's export sector can weather falling US demand, as long as demand elsewhere remains buoyant and its domestic demand is considerable. This, in turn, is likely to have a supportive effect for other developing economies, particularly primary commodity producers (strong Chinese demand for commodities => higher income in exporting countries => growing demand for Chinese goods => further Chinese demand for commodities).

A bigger uncertainty concerns the Eurozone, which has become China's main trading partner and which is arguably more prone to be affected by a US slowdown, as the IMF predicts. Yet Europe may manage to hold its ground, as long as capital exports from Germany – which is the main engine of the European economy – remain relatively strong. Perhaps more crucially, as long as the yuan remains undervalued vis-à-vis the euro, China's exports to Europe should also remain reasonably buoyant. And even if exports to Europe were to fall dramatically, China's significant foreign currency reserves – resulting from its huge current account surpluses – gives it leeway to conduct a countercyclical fiscal policy if needed.

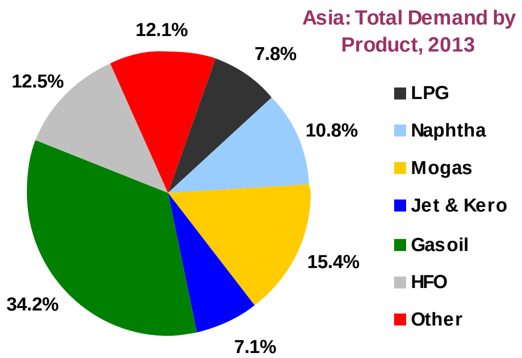
Asian demand (including China) is forecast to grow by some +3.7% or roughly +700 kb/d per year on average between 2008 (17.4 mb/d) and 2013 (20.9 mb/d). This outlook is some 200 kb/d below our previous estimate (by 2012), largely because of baseline changes in several countries, notably China and India. The region will account for 46% of total non-OECD demand by the end of the forecast period, and also for about 46% of its average volumetric increase per year. In global terms, Asian demand will represent 22% of total oil product demand by 2013, but almost 48% of worldwide growth.

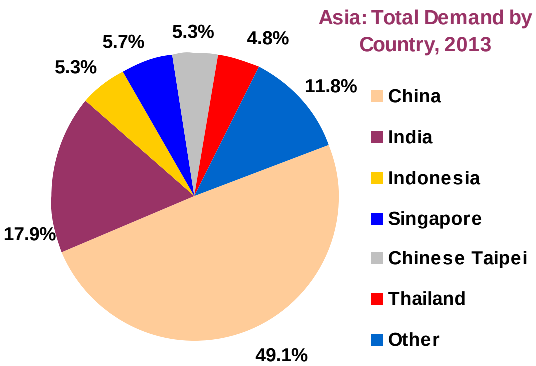
As elsewhere, the rise in mobility – prompted by higher income levels and embodied in the rapidly growing vehicle and aeroplane fleets across the region – will be the main driver of oil demand growth. Administered end-user price regimes (mostly in China, where they remain below international prices despite a significant hike in June 2008) will also play a role: transportation fuels will thus rise much faster than total demand, by 4.5% per year on average over the forecast period, representing 57% of total regional demand by 2013. Gasoil will continue to command the lion's share of the region's oil product mix, as it has multiple applications (transportation, agriculture and small-scale power generation), and will thus account for roughly a third of total demand by 2013. By contrast, gasoline will hover around 15%, but this share is likely to rise further after the forecast period as passenger vehicle fleets expand, notably in China, where most cars run on gasoline.





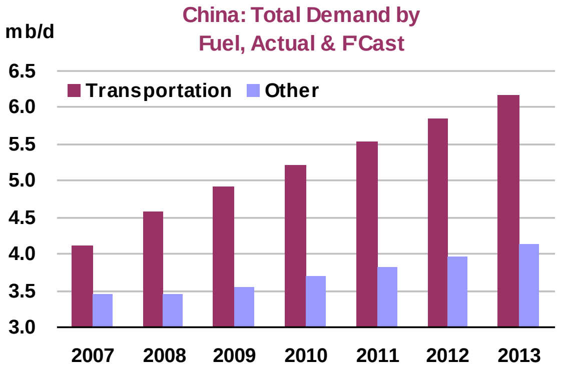
Given its sheer size, China will remain the main driver of demand growth in Asia (49% of regional demand or 10.3 mb/d by 2013). Assuming, as predicted by the IMF, annual double-digit economic growth over most of the forecast period, Chinese oil product demand is projected to increase by 5.2% or +460 kb/d per year on average, accounting for over half of US50 demand by 2013 (10.3 mb/d vs. 19.9 mb/d, respectively). Between 2004, which marked the surge of Chinese demand growth, and the end of the forecast period, the country's consumption will have risen by almost 5 mb/d – more than total demand in any country bar the US. China will account for almost a third of the world's annual demand increase in the 2008-2013 period. As in the rest of the world, the country's demand growth will be driven by transportation fuels, mirroring its rising average income per capita. Demand for other product categories, particularly naphtha, is also set to expand significantly, although this could be moderated by competition from abroad (see *Asia and the Middle East Set to Dominate Petrochemical Capacity Additions*). China is eager to become a petrochemical powerhouse in Asia, notably regarding ethylene production, following the path of neighbouring Korea.

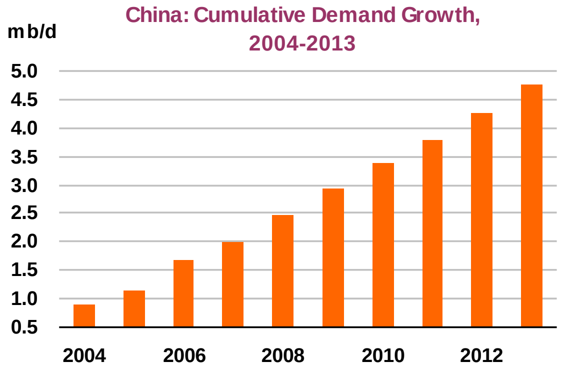




Yet this forecast is 170 kb/d lower than previously expected (by 2012). This is related to baseline revisions, as noted earlier, but also reflects two persistent issues in China: incomplete statistical data and oil product price controls. China has long recognised the need to improve the quality and scope of its energy and economic statistics, and has recently taken more vigorous steps towards that end. Still, the lack of official monthly figures on oil demand obliges analysts to calculate 'apparent' demand, which requires making assumptions on key figures, such as crude and oil product stocks, and the size, configuration and output from the independent and small 'teapot' refineries. Furthermore, existing trade and refining data are implausibly definitive – that is, they are never revised – unlike in most other countries, where retroactive corrections are the norm, since initial data are generally preliminary estimates. In addition, many economists are wary of published GDP growth figures (there are differing opinions, though, on whether the 'adjustment' is upward or downward). In any case, official GDP data have consistently exceeded most forecasts. Therefore, the calculation of China's income and price elasticities is subject to considerable uncertainty, which in turn affects oil demand prognoses.

Second, there is the issue of the demand distortions brought about by China's current end-user pricing policy. Although China is certainly not the only country to employ price controls, capped end-user prices cause several problems. They shield Chinese consumers from rising – and higher – international oil prices and therefore encourage higher demand than would otherwise be the case (runaway demand, in turn, has contributed to the global diesel tightness). They can also lead to product shortages, as local refiners find that supplying the domestic market becomes unprofitable when the price of feedstocks rise. Given currently soaring international prices, many teapots, in particular, have either shut down or operate well below capacity, leading to a significant fall in fuel oil demand (their feedstock of choice) and contributing to the global fuel oil glut.



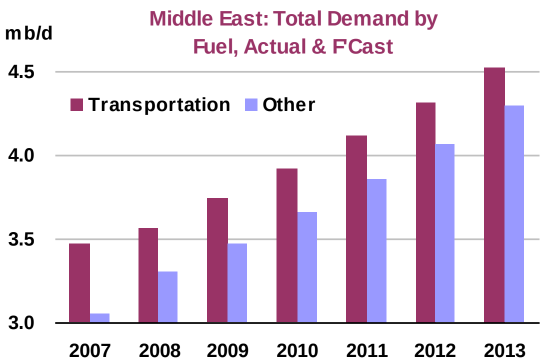


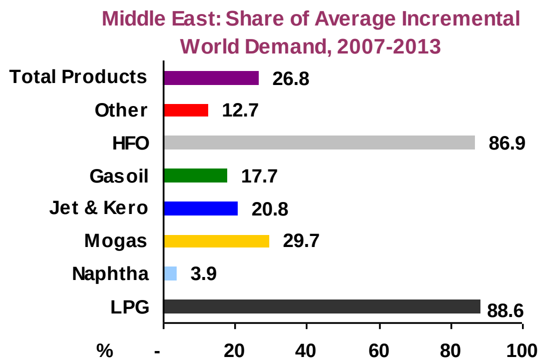
Since late 2007, and prior to the gasoline and gasoil price hike of mid-June 2008 (about 15%, taking the average of the largest Chinese cities), the government had dismissed calls for price adjustments beyond the 9% raise in November 2007, citing the threat of additional inflationary pressures. Seeking to prevent shortages, especially ahead of the Olympic Games, it adopted an alternative strategy that included three main pillars: 1) an explicit monthly subsidy policy aimed at state-owned refiners PetroChina and Sinopec, as a way to cushion their downstream losses; 2) a temporary refund of the value-added tax levied on gasoline and gasoil imports; and 3) a mandate for wholesalers to hold minimum stocks. Nevertheless, as localised shortages reportedly persisted, notably in south-eastern provinces, increasing prices became unavoidable in order to ensure adequate supplies. While the impact of these measures cannot be predicted at this time, nor the pace of further implementation of China's long-held pledge to bring product prices in line with the global market, this forecast is based on the premise that capped prices will continue to be gradually adjusted (by some 10-15% per year). Paradoxically, even if economic growth were to slow down slightly (and/or if end-user prices were to be suddenly liberalised), Chinese oil consumption could potentially increase. Indeed, pent-up demand in China is arguably significant, only limited by the so far intractable supply constraints.

Pricing distortions are not limited to the oil sector; they are also present in the power industry. Despite the dramatic expansion of the country's mostly coal-based power generation capacity, recurrent blackouts, notably in south-eastern China (accompanied by an ensuing spike in gasoil and residual consumption in order to fuel backup generators), cannot be dismissed. Power shortages occurred in 2004 and again in early 2008, following a series of disruptive snow storms, and in the former case led to a surprise surge in gasoil use. Admittedly, transportation bottlenecks and the closure of small coal mines have played an important role in creating shortages. Yet this has been aggravated by pricing issues: power producers, facing rising fuel (coal) prices, have reportedly reduced generation rates. In June 2008, the government decreed a 4.7% increase in capped end-user prices (excluding residential rates) and a freeze on prices for thermal coal destined for power generators, following earlier injunctions to generators to fully supply the market and to increase their fuel stocks. However, if power shortages are to be averted in the years ahead, a larger raise will probably be necessary. Such policy decisions will thus continue to have significant implications for oil demand.

Elsewhere in Asia, Indian demand will come in a distant second after China, with 18% of regional demand or 3.7 mb/d by 2013, notwithstanding a roughly similar population. Since the Indian economy is much less energy-intensive, the country's oil demand growth is expected to increase at a lower pace, despite an expanding vehicle and aeroplane fleet and capped end-user prices for some products. Meanwhile, demand growth in other large Asian nations – Indonesia, Malaysia, Chinese Taipei and Thailand – are expected to see subdued growth over the period, largely due to higher prices (which recently prompted the partial removal of end-user subsidies in some countries). Only Singapore and Pakistan are seen posting robust growth, given increasing bunker demand in the former and capped retail prices in the latter.

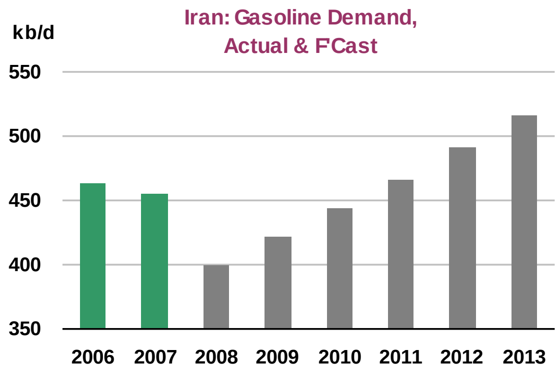
Oil product demand in the **Middle East** is projected to grow by +5.1% or 390 kb/d per year on average between 2008 (6.9 mb/d) and 2013 (8.8 mb/d). This is some 150 kb/d higher than estimated in the last *MTOMR* (by 2012), largely because of a reappraisal of the region's petrochemical potential and despite Iran's fall in gasoline demand. By the end of the forecast period, the region will account for roughly 19% of total non-OECD demand and 26% of its average volumetric increase per year. With respect to global volumes, Middle-Eastern demand will represent 9.4% of global oil product demand and almost 27% of global growth over the period. As in Asia, demand is driven by strong economic momentum (the IMF has actually revised *up* its GDP forecast for this region) and continued urbanisation, industrialisation and population growth, coupled with favourable end-user administered price regimes (among the lowest in the world and unlikely to be altered). Therefore, demand for transportation fuels is expected to soar, growing by 4.9% per year over the forecast period. Demand for residual fuel oil and naphtha is also poised to increase sharply: the former to fuel ever growing power needs (also partly met with gasoil), given the lack of natural gas facilities, and the latter to feed the region's expanding petrochemical sector. In country terms, Saudi Arabia (3.2 mb/d by 2013) and Iran (2.4 mb/d) will continue to dominate the region's demand picture, with a joint share of 63%.





The only country in the region that has attempted to rein in galloping demand for transportation fuels is Iran. Motivated as much by geopolitical worries (its dependence on imports given insufficient refining capacity) as by financial considerations (a yawning fiscal deficit and growing inflationary pressures), the government launched a gasoline rationing scheme in mid-2007 that appears to be surprisingly successful. The government was indeed pragmatic in its approach: soon after implementing the programme, it doubled the quotas to 120 litres per month to deal with political and social discontent; it then allowed a black market to flourish; and finally, it recently set the price for gasoline volumes above the rationing quota at the same level as that prevailing in the black market (which arguably reflected the equilibrium price). Nevertheless, it can be argued that rationing brought only a temporary respite: by the turn of the decade gasoline demand will have reached and even surpassed its pre-rationing levels, growing by around 5.3% per year from 2009 – admittedly, however, at a lower pace than the 10% growth rates observed in the past. (Some of the reduced demand, though, could simply represent less smuggling to other countries – if so, there could be a partly compensating, but as yet unidentified, increase in demand elsewhere.)

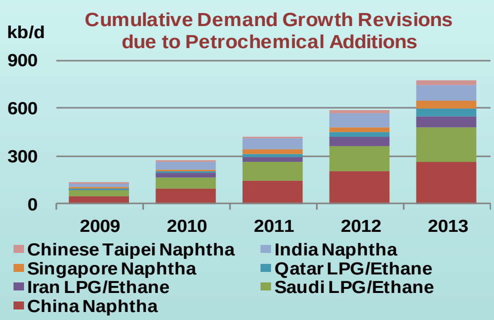
Having temporarily tamed runaway gasoline demand, the government is now setting its sights on gasoil, which accounts for the lion's share of demand (currently 36%) and of which consumption has also markedly risen over the past two years (+9.4% in 2006 and +13.7% in 2007). The growth in gasoil demand is related to several factors: capped prices, smuggling out of Iran, and interfuel substitution away from gasoline following the introduction of rationing in mid-2007. The government was reportedly aiming at introducing a diesel rationing scheme by late May, but at the time of writing this has not occurred. Although smart cards have apparently been distributed, formal gasoil quotas are yet to be announced. Indeed, the government is treading carefully: as opposed to gasoline, which is consumed by a relatively small sector of the population, gasoil permeates most spheres of economic activity. It is not only widely used in the industrial and agricultural sectors, but it also largely fuels the country's truck fleet; as such, disrupting gasoil supplies could have far-reaching effects in terms of economic growth and inflation. Therefore, since there is no evidence yet that the gasoil programme will be implemented and, if so, whether it will emulate the success of gasoline rationing, our forecast is not taking into account any significant reduction in Iranian gasoil demand.



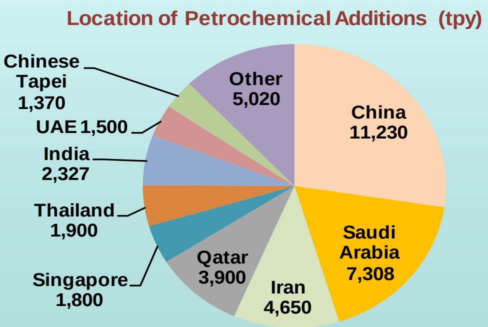
Asia and the Middle East Set to Dominate Petrochemical Capacity Additions

A renewed assessment of the massive planned additions to petrochemical production capacity over the next five years has prompted upward revisions to naphtha and LPG/ethane demand forecasts. Prospective additions could total 40 million tonnes per annum (mtpa) of new or expanded primary petrochemical production capacity by 2013. These are overwhelmingly centred in Asia, most notably in China, but also significantly in the Middle East (Saudi Arabia, Iran and Qatar).

By 2013, oil demand projections now incorporate an extra 440 kb/d for naphtha (affecting China, Singapore, India and Chinese Taipei) and 330 kb/d of LPG/ethane (including Saudi Arabia, Iran and Qatar) due to upwardly-revised demand from the petrochemical sector. It should be noted, however, that overall revisions to LPG and naphtha demand for these countries are different, as many other factors/drivers besides the petrochemical sector have been also accounted for.



Note: Overall demand revisions for these categories differ as they incorporate other factors besides the Petrochemicals reassessment



Asia and the Middle East Set to Dominate Petrochemical Capacity Additions (continued)

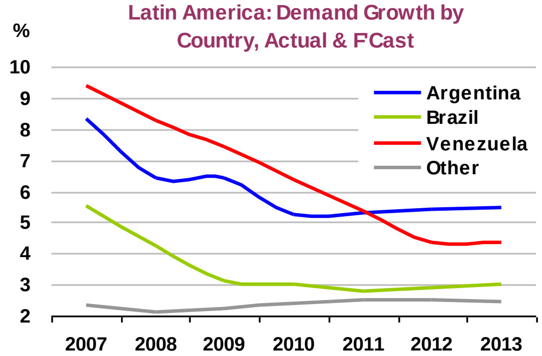
Incremental capacity in **China** could make up over a quarter of global petrochemical additions in the medium term. Economic growth is driving a surge in Chinese consumer needs and boosting export potential for products derived from petrochemicals. Additional capacity includes at least six major new plants (some 800 mtpa of primary ethylene/propylene production capacity) from Sinopec, either on its own or under joint-ventures, and three from PetroChina, alongside various other expansions. Elsewhere in **Asia** (ex-China), there are large projects in India, Singapore, Thailand and Chinese Taipei. The potential emergence of Asia (as a whole) as the largest petrochemical producing region represents a geographical shift from the traditional centres of supply, namely OECD North America and Europe.

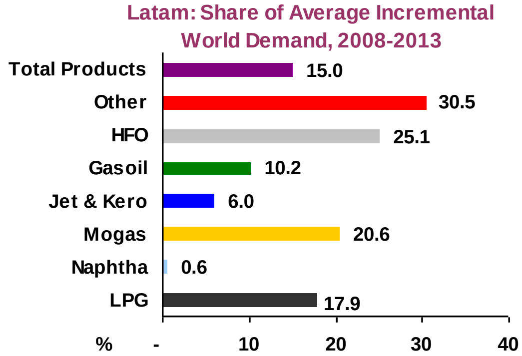
Over the next five years, the **Middle East** could also become one of the world's key petrochemical hubs. Gas liquids and ethane are important petrochemical feedstocks. Producing countries are hoping to utilise new petrochemical production to capitalise on expansions to regional national gas and gas liquids production. Moreover, strong economic growth in the Middle East (linked to high oil revenues) should provide a domestic market for petrochemical derivatives. In Saudi Arabia, additions include at least five major projects (each of 1 mtpa plus), three due online in 2008-9 at Jubail alongside the new PetroRabigh plant and Saudi Aramco's Ras Tanura 2 development (in conjunction with Dow Chemical). In Iran, the National Petrochemical Company and its subsidiaries are behind several large expansions due to utilise feedstock from gas processing plants. Qatar also aims to exploit its gas-producing potential with three 1.3 mtpa-capacity plants. We have identified further significant additions in the United Arab Emirates, Kuwait and Oman.

Some caution must be exercised in assessing the impact of these projects on oil demand. Alongside the typical risks which affect upstream and downstream projects (such as credit constraints, fallibility of contracts or terms, engineering or raw material limitations), there are downside risks associated with the availability of feedstock. Competition for naphtha supplies (or condensate supplies allied to splitting capacity) could intensify in the medium term, while petrochemical projects linked to gas liquids feedstock will hinge on corresponding oil and gas supply growth prospects. Furthermore, calculating the impact of incremental petrochemical production on oil demand over the medium term is complicated by the desire by operators to maximise feedstock flexibility – the ability to adapt feedstock according to evolving prices differentials (e.g., switching from naphtha to LPG).

This demand scenario incorporates available feedstock data (admittedly, from only a very limited number of countries) and assumptions based on existing plants, historical trends and global utilisation. While additional expansions above those tracked here could increase the naphtha and LPG/ethane forecasts further, it is unclear to what extent regional competition for feedstocks could impact profitability and ultimately growth in the sector. Feedstock substitution, which may well become more prevalent in the medium term, has also volumetric implications for oil demand that require further study. Equally, the regional dynamics of demand for petrochemical derivatives could undermine global production capacity growth.

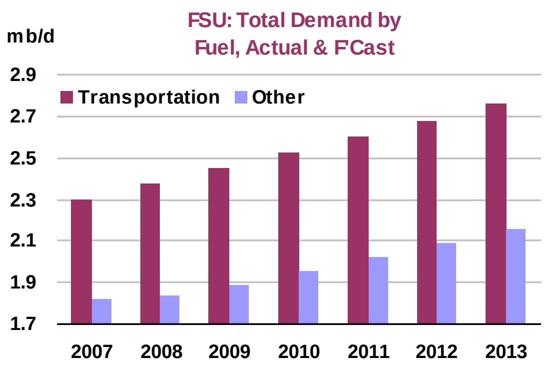
In **Latin America**, oil demand is expected to increase by +3.5% or almost +220 kb/d per year on average between 2008 (5.9 mb/d) and 2013 (6.9 mb/d). This outlook is much stronger than previously anticipated (almost 570 kb/d higher by 2012). As noted earlier, this is largely due to significant upward revisions for both baseline figures and economic growth assumptions, and to the likely prevalence of administered price regimes in key countries. By 2013, Latin America will account for roughly 15% of total non-OECD demand and 14% of its average volumetric increase per year. It will represent 7.4% of global oil product demand and 15% of global average cumulative growth.

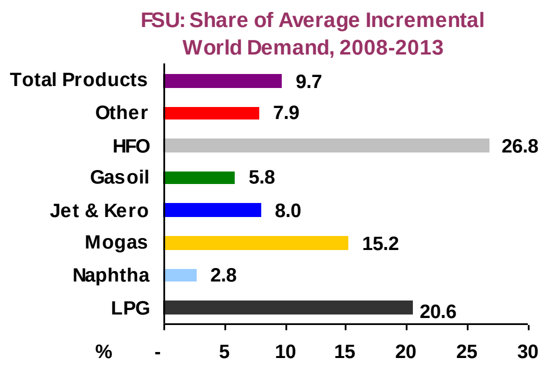




Latin American demand will continue to be largely dominated by Brazil (40% of oil demand by 2013). Oil demand *growth*, however, will be actually fuelled mostly by Argentina and Venezuela. Albeit much smaller than their giant neighbour (12% and 16% of regional demand, respectively), both countries feature capped – and very low – end-user prices, which are feeding runaway growth, notably in transportation fuels. Oil demand growth in Argentina and Venezuela (both at +5.6% per year on average) will be almost double Brazil's rate (+3.0%). Economic growth in Argentina and Venezuela, though, could slow down if inflationary pressures and fiscal imbalances persist.

In the **FSU**, oil product demand is seen increasing by +3.1% or 140 kb/d per year on average between 2008 (4.2 mb/d) and 2013 (4.9 mb/d). The region will represent 11% of total non-OECD demand by 2013 (and 9% of its average volumetric increase per year). It will account for 5.2% of global oil product demand by the end of the forecast period (and 9.7% of global growth). Although in volumetric terms this outlook is 280 kb/d higher versus the last *MTOMR* (by 2012), the series is not strictly comparable, since we introduced in April 2008 a new methodology to estimate the region's demand. Instead of defining 'apparent' demand as domestic crude production minus net crude and product exports – a method prone to frequent and large revisions, mostly because of large swings in trade figures – FSU demand is now the sum of actual inland deliveries and end-user demand in each of the region's countries.

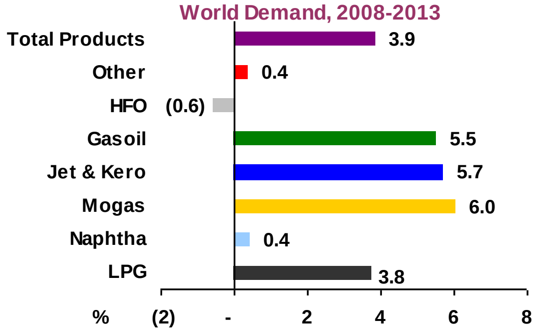




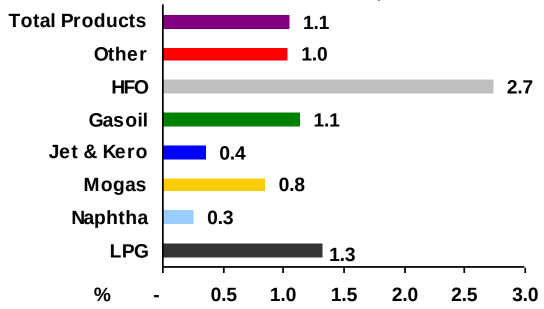
Although the quality and availability of data are still mixed, a thorough evaluation and inclusion of old and new sources, most notably for Russia, has significantly improved our assessment of FSU demand. Russia – the largest consumer in the region – should account for almost 70% of FSU demand by 2013. Given its strong economic prospects, this country will largely drive FSU oil demand growth with respect to transportation fuels, since Russia is poised to become one of the world's largest car markets. Russia could also potentially boost regional fuel oil demand for power generation in order to free additional volumes of natural gas for export. The recently announced, gradual liberalisation of domestic natural gas prices may further encourage fuel switching in favour of oil, but it may also prompt efficiency improvements.

Oil demand growth in **Africa** is expected to grow by +1.7% per year on average (almost +60 kb/d per year) between 2008 and 2013, from 3.1 mb/d to 3.4 mb/d, respectively – about 230 kb/d less than previously anticipated (by 2012), because of a larger-than-expected adjustment to the baseline. By the end of the forecast period, the continent will represent 7% of total non-OECD demand and 3.6% of global oil product demand. Africa will account for almost 4% of the average incremental growth among non-OECD countries and for 4% of global growth by 2013. Demand will continue be dominated by two countries, Egypt and South Africa – almost 40% of the continent's total by 2013. It should be noted that South African demand is set to be stronger than previously anticipated: over the past two years the country has been beset by severe coal-fired power shortages as result of lack of investment (no new plants have been built in the past five years). This has led to an increasing use of alternative sources (mainly gasoil and fuel oil), a situation that is likely to continue at least until 2012-2013.

Africa: Share of Average Incremental World Demand, 2008-2013



Non-OECD Europe: Share of Average Incremental World Demand, 2008-2013



Finally, oil product demand growth in non-OECD **Europe** is forecast to grow annually by +1.9% or +15 kb/d per year on average between 2008 (760 kb/d) and 2013 (840 kb/d). This is some 75 kb/d less than previously estimated (by 2012). Romania is the largest consumer, with 25% of regional demand by 2013. Yet demand in non-OECD Europe is relatively marginal. By the end of the forecast period, the region will account for less than 2% of total non-OECD demand and for 0.9% of global demand. In terms of growth, this is also the case: Europe will represent about 1% of the average annual volumetric increase among non-OECD countries and some 1.1% of global growth.

Demand Scenarios

All oil demand forecasts face an enormous degree of uncertainty, given the complexity and the scope of the many factors at play. This is particularly true in the case of a five-year forecast, as the final outcome is bound to be considerably affected by slight shifts in key variables. Still, we have attempted to assess how oil demand would evolve if the pace of economic growth differs from the base scenario, which underpins the outlook that has been discussed so far. It should be emphasised that the alternative scenario is merely illustrative; we are not assigning it a probability of occurrence. Moreover, it is also static, based on a *ceteris paribus* approach – changing one variable while keeping all others constant – which overlooks the iterations between GDP and price (for example, high prices would eventually further curb worldwide economic growth).

The 'low GDP, base price' scenario presented here is based on the *downside scenario* proposed by the IMF (*World Economic Outlook*, April 2008), which assumes a sharper economic slowdown over 2008-10 in key economic areas, notably the US, the Eurozone, Japan and 'emerging Asia' (which includes China, Hong Kong, India, Indonesia, Korea, Malaysia, Philippines, Singapore, Thailand and Chinese Taipei). The IMF developed this scenario on the basis of a further deterioration of credit conditions (but prior to the sharp oil price increase observed over the past few months).

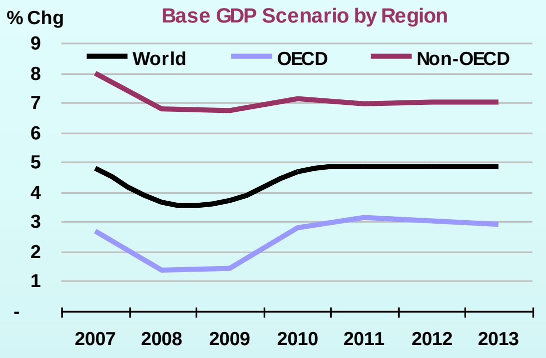
The tables and charts below summarise the results. The figures for 2007 are identical for both scenarios, as that year is the starting point; GDP and price vary only from 2008 onwards (long-term elasticities by country, though, are held constant). As can be seen, under the 'low GDP, base price' scenario, yearly demand growth would be only two-thirds as high as in the base case. Moreover, the effects of the low scenario would be much more significant in advanced economies than in emerging countries. In the OECD, aggregated economic output would contract in both 2008 and 2009. Meanwhile, economic activity in non-OECD countries, while lower, would still be buoyant. In addition, OECD countries are not shielded from rising prices by administered regimes, contrary to most of the largest consuming nations in non-OECD areas. As such, non-OECD oil demand growth depends essentially upon economic activity.

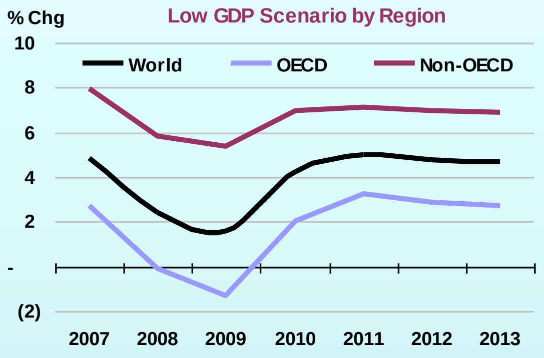
Demand Scenarios by Regions								Avg. Yearly Growth, 2008-2013		Diff. vs Base	
mb/d	2007	2008	2009	2010	2011	2012	2013				
Base								%	k bbls	%	k bbls
OECD	**49.1**	**48.6**	**48.1**	**48.1**	**48.1**	**48.2**	**48.3**	**-0.1%**	**(69)**		
Non-OECD	**36.9**	**38.2**	**39.7**	**41.1**	**42.6**	**44.2**	**45.8**	**3.7%**	**1,522**		
World	**86.0**	**86.9**	**87.7**	**89.2**	**90.7**	**92.4**	**94.1**	**1.6%**	**1,454**		
Low GDP, Base Price											
OECD	49.1	48.4	47.0	46.6	46.6	46.5	46.5	-0.8%	(376)	-0.6%	(307)
Non-OECD	36.9	38.1	39.2	40.4	41.8	43.3	44.8	3.3%	1,348	-0.4%	(174)
World	86.0	86.5	86.2	87.1	88.4	89.8	91.4	1.1%	973	-0.5%	(481)

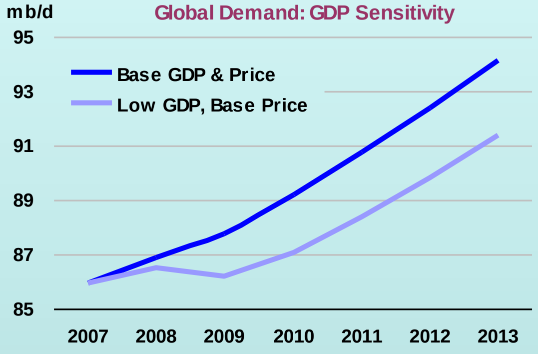
Demand Scenarios (continued)

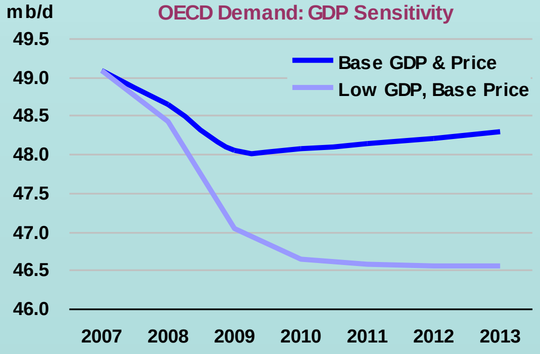
Demand Scenarios, Selected Countries

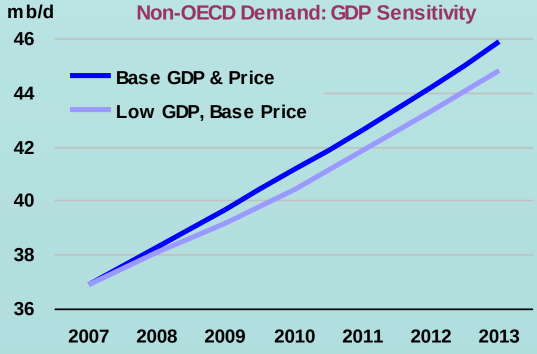
mb/d	2007	2008	2009	2010	2011	2012	2013	Avg. Yearly Growth, 2008-2013 %	Avg. Yearly Growth, 2008-2013 k bbls	Diff. vs Base %	Diff. vs Base k bbls
Base											
US50	**20.8**	**20.3**	**19.9**	**19.9**	**19.9**	**19.9**	**19.9**	**-0.3%**	**(69)**		
China	**7.5**	**8.0**	**8.5**	**8.9**	**9.3**	**9.8**	**10.3**	**5.2%**	**457**		
Japan	**5.0**	**5.0**	**4.9**	**4.8**	**4.7**	**4.6**	**4.6**	**-1.8%**	**(87)**		
Low GDP, Base Price											
US50	20.8	20.2	19.6	19.5	19.5	19.5	19.5	-0.8%	(151)	-0.4%	(82)
China	7.5	8.0	8.4	8.8	9.2	9.6	10.1	4.8%	422	-0.4%	(35)
Japan	5.0	5.0	4.8	4.7	4.6	4.6	4.5	-2.1%	(99)	-0.3%	(12)











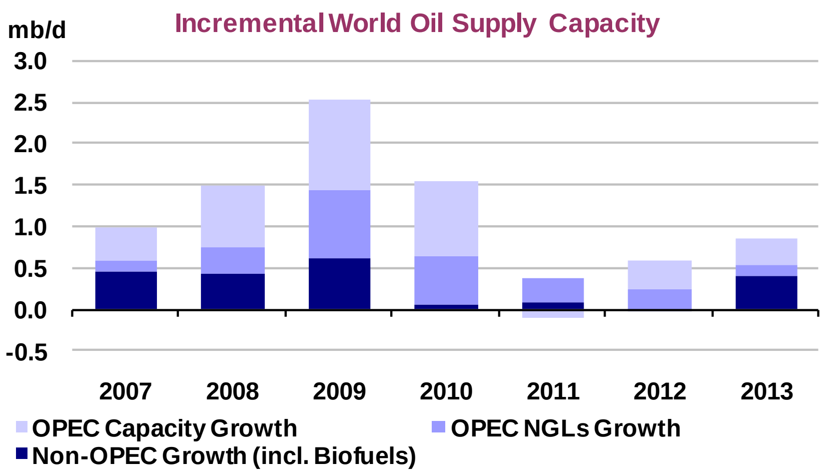
SUPPLY

Summary

- **Global oil supply capacity**, rises by 1.5-2.5 mb/d annually through 2010, but slows to grow at sub-1 mb/d levels during 2011-2013. Total capacity (non-OPEC production plus OPEC NGLs plus OPEC crude capacity) reaches 94.5 mb/d in 2010 from 90.4 mb/d in 2008, and 96.2 mb/d by 2013. OPEC drives the initial increase, with initial signs of non-OPEC recovery for 2013 onwards.

- **An analysis of major project slippage** suggests delays of up to 12 months on average, with costs commonly doubling. **The implied annual decline** for global baseline supply in the forecast has been revised up from 4% last year to 5.2% pa. As a result, forecast total capacity levels (OPEC plus non-OPEC) for 2012 are some 2.7 mb/d lower than in last year's forecast.

- **Total non-OPEC production** rises to 51.1 mb/d in 2013 from an estimated 49.9 mb/d in 2008. Growth thus slows to 0.5% annually, from levels closer to 1% in 2003-2008 and 2% during 1998-2003. Forecast non-OPEC production is assessed lower than in last year's projections by 0.6 mb/d for 2008, by 865 kb/d for 2010 and by 1.4 mb/d for 2012.



- **Non-OPEC growth** is concentrated pre-2010, then falls to minimal levels until 2013. The Americas, the FSU and global biofuels drive growth, with ongoing decline in Europe, OECD Asia and non-OPEC Middle East. Crude oil supply levels off, then declines, while gas liquids and non-conventional oils continue to grow throughout. Cautious assumptions are applied over start-up and early volumes for newer discoveries offshore the US, Mexico, Brazil and China.

- **Forecast OPEC condensate and NGL growth** matches levels seen during 2003-2008, averaging 7% per year. Total production reaches 7.2 mb/d by 2013, from 5.1 mb/d in 2008. The bulk of increased supply comes from Saudi Arabia, Qatar, Iran and the UAE.

- **OPEC crude oil capacity** rises by 2.5 mb/d over 2008-2013 to reach 37.9 mb/d. Saudi Arabia and to a lesser extent Iraq, Nigeria and the UAE, account for most of the increase. However, with OPEC countries also facing project delays and cost over-runs, the forecast is over 1 mb/d lower than that of last year.

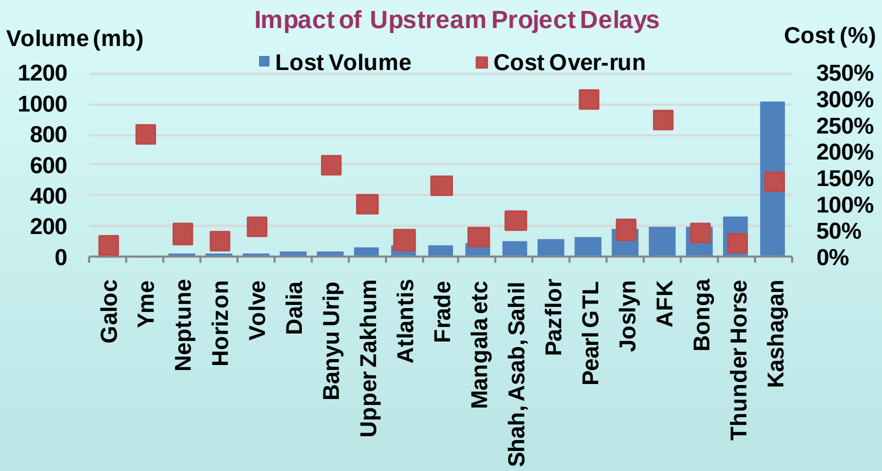
- **A lighter, sweeter global crude slate** through to 2011 is largely the result of rising OPEC and FSU condensate and light crude supply. However, rising Saudi and Canadian heavy/sour oil supplies see the trends reverse towards a heavier/sourer barrel for 2011-2013.

- **Effective OPEC spare capacity** rises from 2.5 mb/d in 2008 to over 4 mb/d for 2009 and 2010, albeit remaining comparatively tight at below 5% of global demand. But spare capacity is likely to dwindle to minimal levels by 2013 in the absence of accelerated supply-side investment or further efforts to stem demand growth.

Project Delays and Cost Escalation

A substantial amount of previously-expected new production is removed from this year's forecast for OPEC and non-OPEC capacity. Non-OPEC 2012 supply is 1.4 mb/d below last year's estimate, while OPEC capacity is a further 1.3 mb/d lower. Project deadlines are being stretched and budgets inflated beyond original plans by an endemic shortage of qualified labour, raw materials, drilling and fabrication/engineering capacity which is raising costs. While the graph below is neither exhaustive nor a strict ranking of project performance, clearly, projects across the spectrum of operators (NOC, IOC, independents), geographical locations, types of development (onshore, offshore, deepwater), and processes (conventional, oil sands, GTL) face significant delays and inflation. This effectively removes supply from an already-stretched market and diverts cash flow otherwise destined for investment in other new projects.

Bearing in mind the limitations inherent in this sort of overview, we nonetheless highlight nearly 20 projects, either recently completed or due, with delays ranging from three months to seven years. Excluding the exceptional cases of Kashagan and Thunder Horse, average project delay in this sample is 15 months. As we focus on recent, larger, higher profile or more easily traceable projects, a true global average might be less than this – perhaps at or below 12 months. Taking the 2005-2012 start-up period for these projects alone implies a loss to global supply averaging at least 1.0 mb/d.

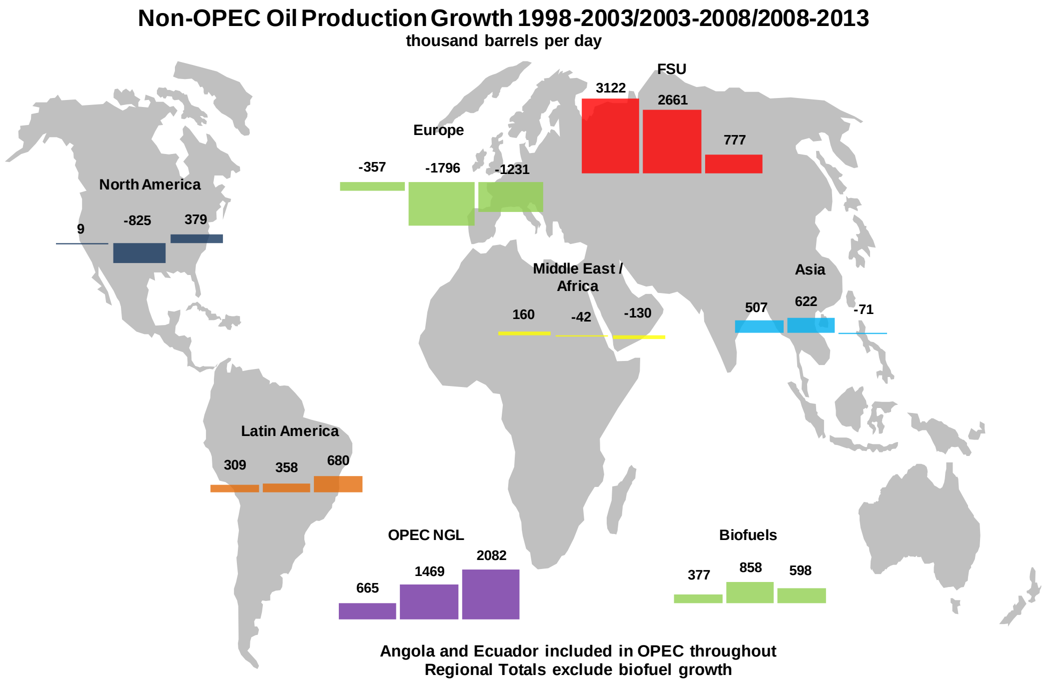


Cost over-runs are also extensive, ranging from 25% to a four-fold increase at the extreme (Qatar's Pearl GTL project). Again, data are incomplete, or may be inconsistent. Estimates for the AFK project in Saudi Arabia refer only to that project's gas-processing component, while other projects have been scaled up or down between initial and latest estimate. Nonetheless, a doubling from initial estimate to out-turn capital expenditure is reasonably representative of current market conditions.

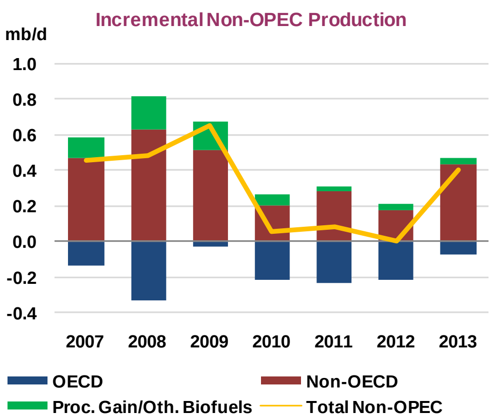
With little sign of engineering and labour bottlenecks easing for the medium term, higher oil company revenues via higher prices will continue to be offset by high costs. Project delays, together with mature field decline and unscheduled outages, will remain a drag on capacity growth for the foreseeable future. Oil supply growth from the middle of the next decade onwards will depend, amongst other factors, on the ability of the drilling, manufacturing and service sectors to expand their capacity and the pace at which this can be achieved.

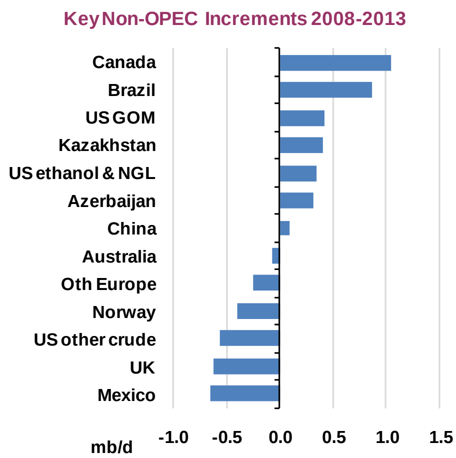
Non-OPEC Production Trends

The slow-down evident in non-OPEC production growth over the last 10 years should continue for 2008-2013, as ongoing (though, as discussed in *Non-OPEC Decline Rates* below, not noticeably accelerating) mature field decline is accompanied by prolonged bottlenecks, which slow new capacity expansion. There is no shortage of active projects for 2008-2013, with at least 250 major new field or field expansion projects due on stream. These add a collective 16 mb/d of new crude oil, condensate and NGL production. However, with around 3 mb/d of non-OPEC productive capacity lost each year under an assumed baseline decline of 6.5%, net non-OPEC supply growth comes in at only 1.2 mb/d overall. Net growth was 2.1 mb/d during 2003-2008 and nearly 4.5 mb/d for 1998-2003.



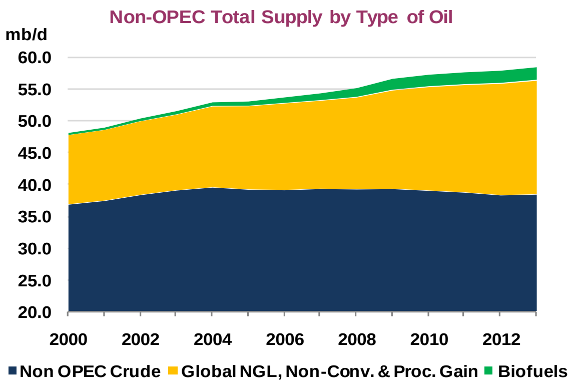
Strong growth comes from North and Latin America, the FSU and global biofuels supply, but output from Europe, Asia, Africa and the Middle East non-OPEC countries declines. Moreover, an abrupt slow-down from Russia results in FSU growth being cut from 2.7 mb/d for 2003-2008 to only 0.8 mb/d for 2008-2013. Of a total 1.4 mb/d which has been reduced from our forecast for 2012 compared with last year, around 0.5 mb/d derives from downgraded Russian supply. This is less a reflection of resource constraints, more of impediments to investment, as the country grapples with an unattractive tax structure and with continued questions over official attitudes to foreign company involvement.

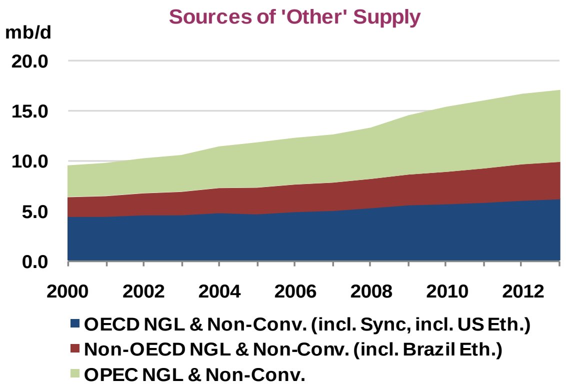




Breaking down the forecast annually, non-OPEC output rises by an average 0.5 mb/d in 2008 and 2009 before slowing to negligible levels through 2012. Output then regains momentum in 2013, possibly heralding a period of renewed growth towards mid-decade. Key to the slowdown for 2009-2012 in our view is project slippage, which may have pushed around 1mb/d of new capacity from late-decade start-up to 2013 and beyond, and ongoing mature field decline. We also take a conservative view of several new prospective areas, which may substantially add to post-2013 non-OPEC supply, but which are characterised by uncertainty over reserve levels, technical risks and development schedules. These include ultra-deepwater areas off the US, Mexico, China and Brazil, the Canadian oil sands, eastern Africa and yet-to-be developed resources in Russia and the Caspian republics. Projects such as the Jack prospect in the US Gulf, onshore Chicontepec and the ultra deep Gulf (Mexico), Jidong Nanpu (China), Tupi (Brazil) and Kashagan (Kazakhstan) either make a limited contribution, or no contribution at all, to our outlook through 2013. Again, this is not to doubt the resource potential, but to acknowledge that bringing on new capacity in such challenging or frontier environments will take longer and be more costly than 'conventional', easier to access developments have in the past. Indeed, with more conventional resources becoming off limits in terms of access for international companies, or for reasons of fiscal or physical risk, traditional upstream project lead times may arguably be stretching from around five years into a five- to 10-year range. In short, while oil likely remains a cyclical business, prone to periods of under-investment followed by overinvestment, the length of the cycles could be stretching.

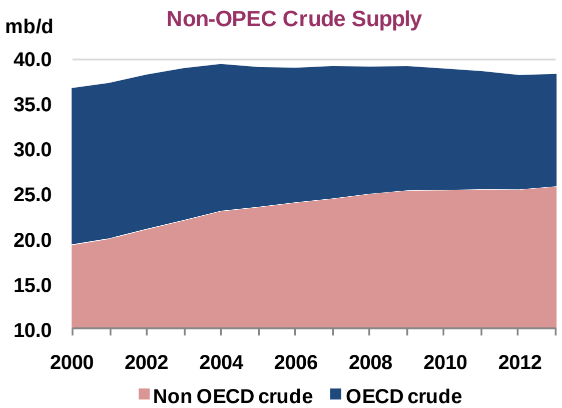
The physical composition of non-OPEC supply going forward is worth examining. Non-OPEC crude output

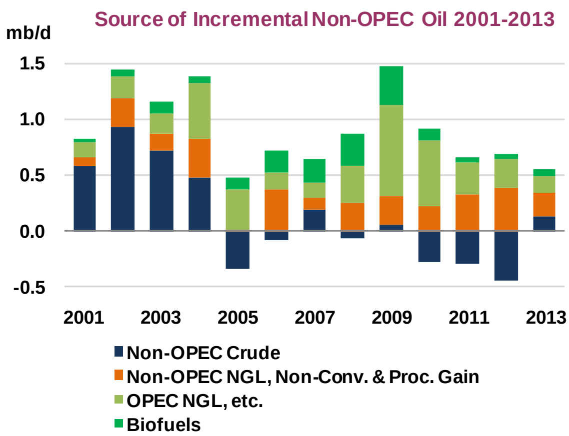




has levelled off at 39 mb/d since 2004 and is expected to slip back towards 38 mb/d by 2013. In contrast to a net 0.8 mb/d of non-OECD crude growth (primarily from the FSU and Brazil), OECD crude production falls by 1.6 mb/d to reach 12.6 mb/d in 2013 on lower North Sea, Australian and US onshore supply. That aside, taking the levelling off in crude overall as irrefutable evidence of 'peak oil' risks overlooking the potential for multiple peaks to occur, and for so-called 'non-conventional' oil sources to become 'conventional' over time. Unlike crude oil, 'other' sources of supply potentially grow strongly through the forecast:

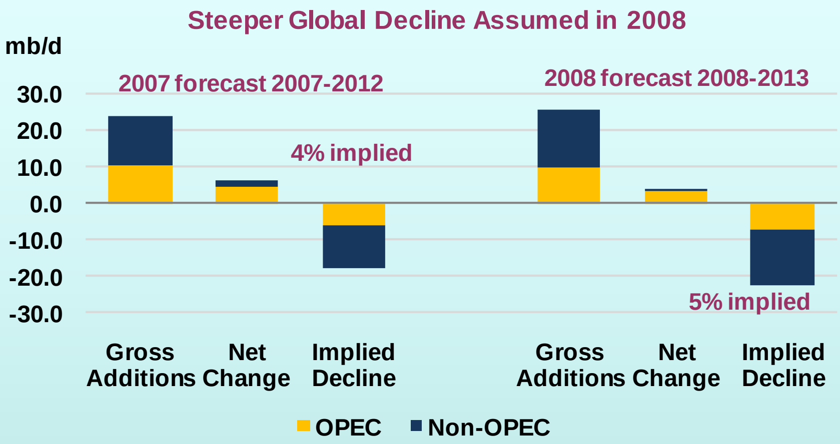
- OPEC NGLs grow by a weighty 2.1 mb/d (+7% pa) during 2008-2013 to reach 7.2 mb/d;
- Global biofuels increase by 0.6 mb/d (+7.6% pa) to attain 1.95 mb/d;
- Non-OPEC NGL and non-conventionals such as mined tar sands and GTLs rise by 1.4 mb/d (+2.8% pa) to reach 10.8 mb/d.





Implied Decline Steeper for This Year's Forecast

Last year's forecast, covering 2007-2012, was based on net decline for OPEC and non-OPEC combined of around 4% annually. This number is not a measure of the managed decline rate applicable for mature oil fields (which we try to assess on an individual basis where possible). Rather, it is the inferred decline which can be applied to the entire current supply base (comprising not only fields in decline, but also those at plateau or building towards plateau) and which results from comparing gross capacity additions and our net expected change in global supply.



This year, net decline comes in rather higher, at 5.2% annually for 2008-2013. Put another way, global crude and NGL supply (excluding biofuels and refinery gains) loses around 3.7 mb/d each year through the forecast because of field maturity. Last year's forecast assumed a slightly lesser level of decline at around 3 mb/d each year. It is clear, from the above graph, that the key change lies within the non-OPEC forecast. Here, despite expected gross capacity additions being higher than in last year's outlook (15.9 mb/d v 13.6 mb/d), net growth in non-OPEC crude and NGL supply is expected to be only 0.6 mb/d compared with 2.0 mb/d in July 2007.

Of course net decline as we define it here encompasses factors other than physical decline rate *per se.* It also captures changes in assumed new field build-up profiles, outages or reservoir performance. Nonetheless, part of the reason for the steeper implied net decline does derive from some detailed work we undertook on observed, mature field decline rates for the past decade in the non-OPEC countries (*OMR* dated 11 March 2008 – see below). This showed that, contrary to popular wisdom, non-OPEC observed decline has not appreciably accelerated this decade, but rather, after stripping out distorting weather-related and other field disruption factors, remains close to an average 8% per year. While observed non-OPEC decline overall is not seen to be accelerating, the suggested 8% level was nonetheless higher than we employed in last year's *MTOMR* – hence the steeper net decline figure which we illustrate above.

Non OPEC Regional Developments

North America

Divergent trends affect North America, with Mexican output in sharp decline, contrasting with strong, oilsands-derived growth from Canada. The US sees a short-term surge from the Gulf of Mexico (GOM) and from ethanol fuels, gradually replaced by decline as mature crude oil production falls. In all, North American supply rises by 570kb/d during 2008-2013 (+0.8% pa) to reach 14.7 mb/d. US and Canadian forecasts have been revised up from last year on stronger baseline supply and a more resilient outlook for ethanol, lower 48 US and conventional Canadian crude production, and regional NGLs. But escalating costs and lead times cut the Canadian oil sands forecast from last year.

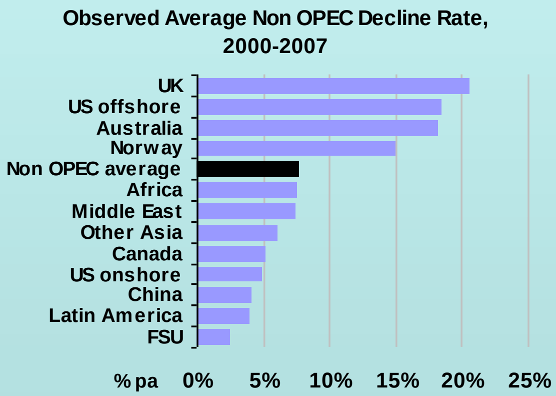
Forecast North American growth contrasts sharply with the 470 kb/d decline (or 825 kb/d, if ethanol growth is excluded) seen during 2003-2008, when severe hurricane disruptions to Gulf of Mexico (GOM) output, extended outages to Canadian oil sands and offshore East Coast facilities, and the onset of decline for Mexico's Cantarell field all featured. Our forecast includes a typical seasonal hurricane outage assumption and a field reliability factor, although exceptional events hold the potential to curb production from our base scenario.

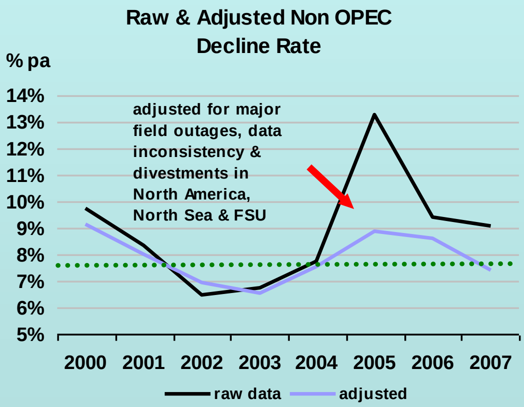
Non-OPEC Decline Rates – Stripping Out the 'Noise' (from Oil Market Report dated 11 March 2008)

Non-OPEC supply has consistently lagged analyst expectations since 2004. Some assign this to accelerating decline rates, with a conclusion that it will preclude material future growth in supply. Our analysis suggests that, while sizeable volumes of non-OPEC crude and condensate have to be replaced due to depletion, averaging nearly 2 mb/d per annum (pa) so far this decade, raw year-on-year production data have to be treated with caution. This data can exaggerate decline due to resource depletion, by masking temporary or systematic reductions in output from other causes. These can include weather-related outages, strikes and security-related disruptions, lower investment and mechanical break-downs. Since our forecast methodology specifically includes adjustments to supply to account for field 'reliability', our projected decline rate has to be based on 'clean' historical data net of these factors.

This periodic review of non-OPEC oil field decline rates* focuses on mature crude oil and condensate fields (not NGL and non-conventional oil) showing sustained, yearly output decline over periods of at least 12-18 months. Aggregate decline rates are production weighted, and reflect managed, rather than natural, decline, according to prevailing investment levels. The results from 1999-2007 production data suggest aggregate non-OPEC decline of 7.7% pa, and that this has not accelerated markedly in the period under review (notwithstanding, boosting recovery over the short term can imply faster longer-term decline).

We have previously discussed 4-5% as an appropriate forecast net decline for all current base load non-OPEC production, encompassing fields in decline and those at, or building to, plateau. This has not changed in light of our recent assessment, since the distinct, 7.7% level applies only to the mature portion of production that is in sustained decline. Moreover, the latest analysis generally accords with the decline rates previously assumed in OMR projections, resulting in only modest, and largely offsetting, alterations in the forecast decline rate. Deviation in non-OPEC outcome versus forecast in 2008 thus seems unlikely to derive primarily from decline rates, unless observed rates shift markedly this year. Put another way, we believe that sluggish non-OPEC performance is being driven by other, largely above-ground constraints, not solely by resource depletion, important though this is for the longer term.





Building from disaggregated data, we have calculated adjusted decline rates for regional and non-OPEC totals, which net out the impact of non-geological factors. Not surprisingly, decline rates vary significantly geographically and over time. However, a surge in 'raw' decline rates in 2005 and 2006 to levels at or above 10% needs to be seen in the context of the distortions from Hurricanes Katrina and Rita, extended North Sea field shut-ins, asset divestments in Russia etc. Once these factors are excluded, 'real' decline comes in closer to the decade average. We would not claim to have captured all above-ground related field outages, nor to have sufficient field-specific production data to make a definitive judgement on decline rates themselves. But for this nine year snapshot at least, oscillation around a 7.7% pa mean is more representative than widely perceived acceleration.

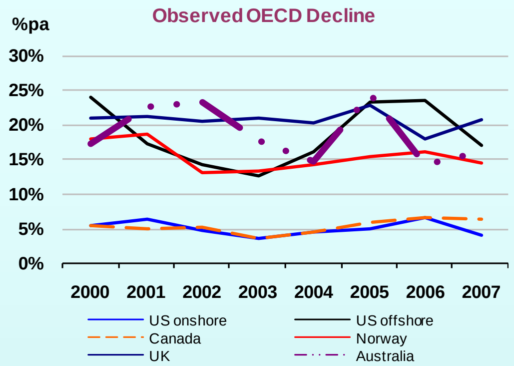
The mature producing areas of the OECD tend to show the sharpest decline. Depleted assets in the North Sea, Australia and offshore US all exhibit typical decline of at least 15% pa (as indeed do parts of Mexico's offshore production, included here alongside non-OECD Latin America). Newer fields in these areas - often deepwater, smaller accumulations of oil - are also prone to rapid build to plateau, followed quickly by sharp decline. Deepwater development planning and well configurations differ markedly from onshore fields, aiming to rapidly recoup high up-front expenditures.

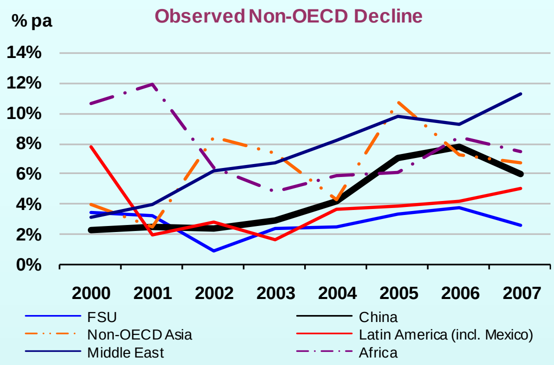
One proviso is worth noting however, both for these and for other areas. Detailed data for 2004-2007 field outages are more extensive than for 1999-2003. This raises the possibility that:

- adjusted 1999-2003 decline would be shallower than shown above, and as a consequence, average decline for the entire period in reality is below our headline 7.7% pa level;

- consequently, some acceleration in decline rates did occur in the later years under study.

Notwithstanding this uncertainty due to variable data quality, and while some individual fields undoubtedly show signs of decline accelerating over time, there is no compelling evidence that aggregate decline is picking up speed, after non-geological factors have been accounted for.





Elsewhere in the OECD, decline from onshore US and Canadian production (excluding the Alberta mining and upgrading projects) looks fairly stable at around 5% per annum, close to the industry rule-of-thumb for onshore production. Indeed, the surprisingly static overall profile of decline in OECD basins may actually suggest the beginnings of a price response on the supply side. Renewed drilling and enhanced oil recovery (EOR) may, at the margin, be starting to help offset natural decline, although it is dangerous to be too definitive about this. Indeed there is some evidence that engineering shortages are restricting EOR effort by the IOCs at smaller assets. Nonetheless, EOR projects can be lower profile than new green field developments, and can slip below analysts' radar, being the (albeit more cost-intensive) upstream equivalent of refinery capacity creep.

Regional aggregate decline rates for the non-OECD (plus OECD Mexico) vary from 2.5% per annum for the FSU and 4% pa for China and Latin America to 6-7.5% pa for Asia, the Middle East and Africa. The preponderance of Russian onshore production in the FSU total, and an early-decade surge in Russian brown field spending, helps explain low aggregate FSU levels. However, the mix of company and field-specific production data obscures the FSU picture. Latin American decline rates are surprisingly shallow, despite the inclusion of Mexican production. However, Mexico's ageing Cantarell field only entered sustained decline in 2005, having earlier seen production sustained by the application of a nitrogen injection programme. We have for some time assumed that Cantarell decline attains steeper levels around 15% for 2008 and beyond. Decline from Brazil's deepwater Campos Basin fields is also, so far, limited, playing a minor role compared with prevailing shallower onshore declines in determining the regional average. Our longer-term forecasts assume that the pace of deepwater decline accelerates, gaining rising importance for national/regional averages.

On a trend basis, China, other Asia and the Middle East have seen mature field decline accelerate this decade. The ageing onshore Daqing and Shengli fields, plus maturing early-phase offshore developments, have seen Chinese declines gathering pace. The rising proportion of offshore production in Asia and the problems in sustaining output from older, more complex Middle Eastern carbonate reservoirs may underpin the accelerating trend for the other two regions.

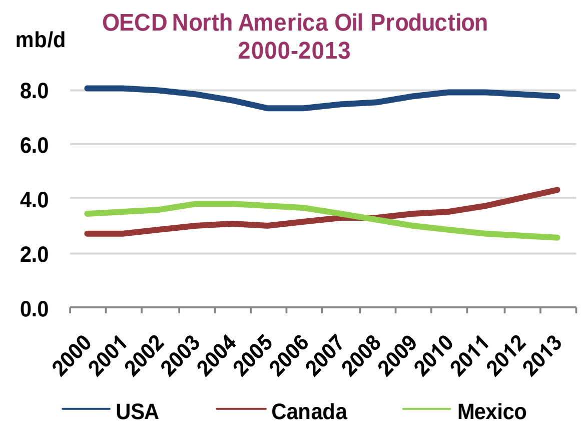
* An extensive study of the impact of decline rates on longer-term oil and gas supply will also be included in the *World Energy Outlook (WEO)* for release in November 2008

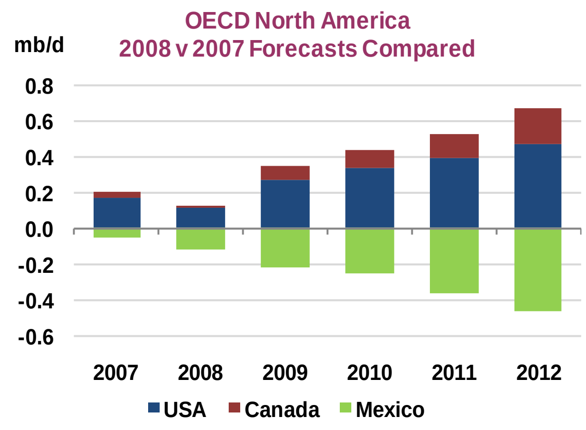
US oil production rises from 7.55 mb/d in 2008 to 7.95 mb/d in 2011 before falling to 7.75 mb/d in 2013, with crude oil comprising around 65% of the total. Fuel ethanol rises from 540 kb/d in 2008 to 730 kb/d in 2010, although we cap supplies at this level thereafter, in common with all non-Brazilian biofuels output, due to continuing question marks over economics, sustainability and environmental factors. Nonetheless, US ethanol growth has been impressive, having risen from only 105 kb/d in 2000.

GOM production is still recovering from storm outages in 2004 and 2005. Output averaged nearly 1.6 mb/d in 2003, 1.28 mb/d in 2005 and a preliminary 1.34 mb/d in 2007. A number of deepwater developments drive further expansion to 1.85 mb/d in 2011, before output levels off through 2013. Prominent projects include 2007's Atlantis (200 kb/d), with the much-delayed 210 kb/d Thunder Horse project now expected to be contributing substantial volumes by late 2008, followed by two

100 kb/d-plus projects - Shenzi and Tahiti - from mid-2009. Longer-term growth from the GOM depends partly on what is assessed as huge potential from the sub-salt resources of the Lower Tertiary trend in ultra-deep waters.

Canadian growth prospects hinge on development of the 310 billion barrels of potential ultimately recoverable bitumen and heavy oil from Alberta's oil sands. Plans for significant extra production from offshore east coast Newfoundland and Labrador, including the 150 kb/d Hebron development, have been pushed back beyond the end of our forecast, although satellite field developments help sustain offshore east coast production at around 350-400 kb/d through the period.





With prevailing logistical and energy supply bottlenecks for Albertan oil sands development, proven reserves are assessed at a more modest 12-17 billion barrel range by government and industry. There is little question that oil sands growth can underpin Canadian production for many years to come (longer-term outlooks see production potentially rising three- to four-fold by 2020 from around 1.3 mb/d this year). However, project timings are stretching, new oil sands projects presently require upwards of $80/bbl crude to make a profit (that could change depending on cost trends), questions over gas, diluent, water and power supply abound and the advent of carbon capture and other environmental mandates may see short-term production lag more ambitious industry targets.

Our forecast sees combined mining and in-situ oilsands output reaching 1.3 mb/d in 2008, 1.6 mb/d in 2010 and potentially 2.46 mb/d in 2013, not out of line with recent National Energy Board (NEB) and producers' association (CAPP) forecasts. A number of 100 kb/d-plus increments come from mining/upgrading projects, including those planned by existing operators Shell, Suncor and Syncrude, together with the CNRL Horizon project due onstream in late 2008. Broader-based in-situ expansion takes output from 615 kb/d in 2008, to 725 kb/d in 2010 and 1.13 mb/d in 2013.

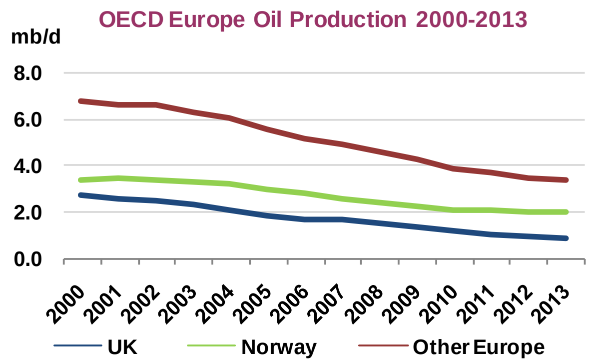
Mexican oil production is expected to see continued decline without accelerated fiscal and energy sector reform. Total oil production reaches 2.6 mb/d in 2013 from an expected 3.2mb/d in 2008 and 3.8 mb/d in 2004. In fact, steady NGL supplies mask a still-more precipitous decline in crude, which averages 2.2 mb/d in 2013 from 2.9 mb/d this year and 3.4 mb/d in 2004. The medium-term forecast for Mexico has been substantially revised down on evidence of sharper Cantarell production decline, an earlier peak for Ku-Maloop-Zaap and slow progress on oil sector reform.

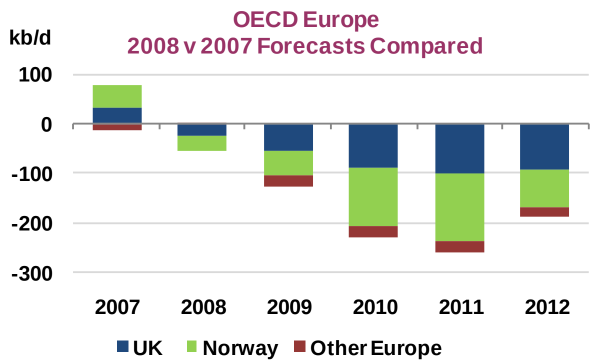
The baseload Cantarell field which accounts for 46% of total Mexican crude output is currently declining at around 25% pa. Replacement volumes from the nearby Ku-Maloob-Zaap complex are now seen declining from 2011 and we have limited the contribution from vast, but difficult to access, onshore Chicontepec reserves to some 300 kb/d by 2013 from some 50 kb/d currently. Extensive fiscal reforms would be needed to allow state-run Pemex to reverse this trend, and while longer-term expansion potential exists in ultra-deepwater fields on the fringe of US Gulf waters, there is no sign of a constitutional ban on private or foreign oil sector equity participation being overturned soon.

OECD Europe

North Sea production, forming the majority of the OECD Europe total, appears to be in terminal decline, despite prospects for significant developments offshore northern Norway, notably for gas and gas liquids, and for EOR. In the UK, efforts continue to focus on extending field life and maximising recovery from mature fields, with in general the major international operators divesting assets, their place being taken by independent operators. In both the UK and Norwegian sectors, marginal tax rates will likely take on increasing importance, alongside access to capital, in determining whether prevailing decline, frequently at levels around 10-15% pa, can be moderated.

All told, OECD Europe production falls from an estimated 4.6 mb/d in 2008, to 3.4 mb/d in 2013. In the case of both Norway and the UK, our projections come in close to the lower end of the range of national government forecasts. Elsewhere, Danish production is seen dipping below 300 kb/d in 2008 and falling towards 200 kb/d by 2013. A brief upsurge in Italian production above 100 kb/d from the middle of this decade is expected to be short-lived, with overall decline setting in again from 2008.



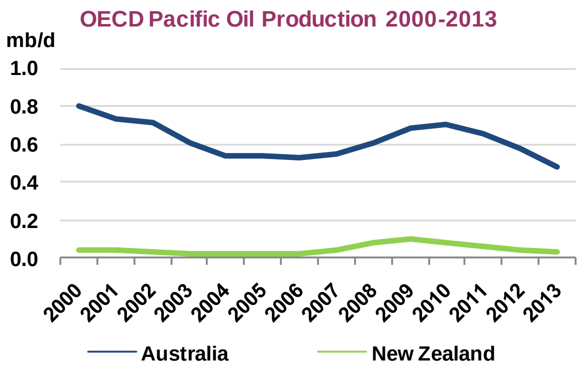


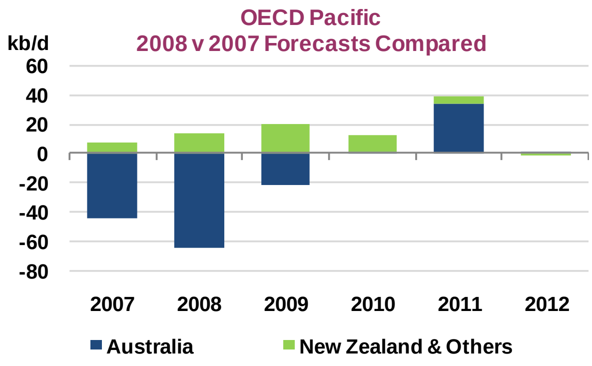
UK production received a temporary respite from decline in 2007, with total output stable at 1.66 mb/d. Ramp up of supplies from Nexen's 200 kb/d Buzzard field in the Forties complex and the reactivated 45 kb/d Dumbarton field underpinned this. However, new volumes henceforward are not expected to be sufficient to offset decline rates at mature fields that we estimate in the last decade have averaged some 20% pa. Total output averages around 1.5 mb/d in 2008 and drops to 0.9 mb/d by the end of the forecast period. This is despite a small number of significant new field developments in a 50-100 kb/d-range, including Ettrick, Cheviot and Lochnagar.

Norwegian production has lost an average of nearly 200 kb/d each year since 2004, a rate of decline that is expected to continue in 2008 and 2009, despite upstream investment levels for 2009 rising by 40% to $22 billion. However, several new projects such as Skarv, Goliat, Tyrihans, Morvin and Froy redevelopment, all onstream towards the end of the forecast, help to moderate decline. Total oil production drops from 2.56 mb/d in 2007 to 2.09 mb/d in 2010, levelling off at close to 2 mb/d for the end of the forecast period.

OECD Pacific

The region faces a mini-surge in supply from new offshore fields, notably Stybarrow, Angel, Vincent, Pyrenees and Skua/Montara in **Australia**, predominantly off the North West Shelf, together with the Tui and Maari developments in shallow waters offshore **New Zealand**. Australian oil output rises to 700 kb/d by 2010, with New Zealand output potentially peaking at some 100 kb/d in 2009.





However, with the exception of Pyrenees, with estimated recoverable reserves of around 100 mb, most of the fields are relatively small, and are being developed with a view to sharp ramp-up to peak output, followed by sharp decline. After 2010 therefore, regional production falls back again, in Australia to 480 kb/d by 2013 and to below 35 kb/d for New Zealand.

Former Soviet Union (FSU)

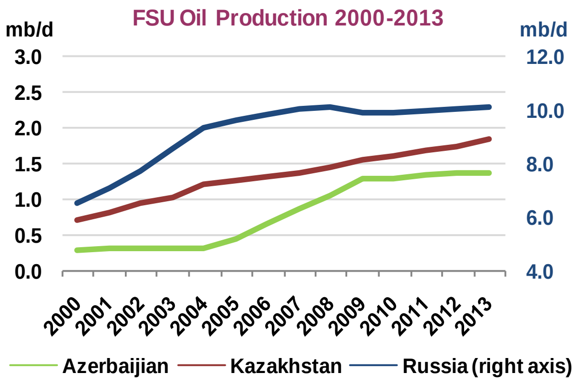
FSU supply growth remains key to the expected non-OPEC increase for 2008-2013, generating 0.8 mb/d of a net 1.2 mb/d increase. However, regional growth has slowed from inflated, near-3 mb/d increases seen during 1998-2003 and 2003-2008. Questions remain over the investment environment in Russia, albeit fledgling signs of tax reform are appearing. Moreover, higher fiscal take, an uncertain foreign company equity role and persistent questions of export diversification impact upon expectations for Azerbaijan and Kazakhstan. Matching or slightly exceeding expectations from last year for 2007/2008, forecast FSU supply is then trimmed by 750 kb/d by 2012, the result of deferred investment at existing fields and delays in activating new projects.

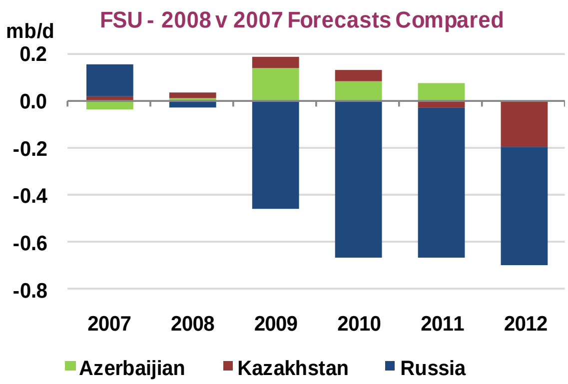
Russian production in early 2008 has dipped below levels of a year ago for the first time since early 1999. With combined export and mineral extraction taxes taking 75% of revenue at $100/bbl, incremental investment is becoming economically tenuous. The country's largest producers, including Rosneft, Gazprom and Lukoil, have called for fiscal reform, and the government is responding, with an initial raising of the production tax threshold from January 2009. However, the pace of further reform is uncertain and questions remain over foreign company upstream participation. Recent output performance suggests spending at existing fields is being strained, failing to mitigate mature field decline. Our forecast is based on a simplified model examining the top 20 new investment projects, allied to an assumed 4% level of base load production decline. This is steeper than the 3% assumed last year, partly to reflect the apparent spending slow-down. Moreover, several of the major projects envisaged in last year's forecast have seen time lines slip by one to two years.

Total Russian production slips from 10.1 mb/d in 2008 to below 10 mb/d for 2009-2011 as incremental volumes from the Sakhalin 2, Vankor, Salym and Uzhno-Kylchuyuskoye projects are offset by decline elsewhere. However, a modest rebound in growth occurs from 2012 onwards as initial volumes from new East Siberian assets become available (subject to transportation infrastructure). Total production reaches 10.0 mb/d in 2012 and 10.1 mb/d in 2013. However, the forecast remains highly sensitive to the assumed rate of decline employed for base load output, with a range of 1%-5% generating 2013 production anywhere between 9.5-11.5 mb/d. Should investment levels recover in the event of continued fiscal changes, supply could be higher than the scenario shown here.

Around 600-700 kb/d is expected from East Siberia by 2012, consistent with phase-1 of the delayed East Siberia to Pacific Ocean (ESPO) pipeline, now expected onstream in late 2009/early 2010. Plans to cut gas flaring are also reflected in a modest increase in Russian NGL and condensate volumes, assumed to attain some 535 kb/d by 2013 from around 475 kb/d currently.

In **Kazakhstan**, where production has doubled to 1.4 mb/d since 2000, robust growth is expected to continue through 2013, based on expansion from the existing Tengiz and Karachaganak fields. Total production attains 1.85 mb/d in our forecast by 2013. Expansion of the CPC pipeline from northern Kazakhstan to Novorossiysk on Russia's Black Sea coast still appears stalled. This was until recently seen as an essential prerequisite for higher Tengiz and, later, Kashagan volumes. But now a degree of export diversification has been achieved using rail, pipeline shipments to China and a new plan to ship Kazakh barrels via the existing Baku-Tbilisi-Ceyhan (BTC) pipeline. The key change to our Kazakh forecast is a scaling back of expectations for the Kashagan project. Although early volumes could be higher than previously assumed (at 370 kb/d versus 250 kb/d), we have pushed back first oil from 2011 to 2013, after continued technical and restructuring issues for the producing consortium.

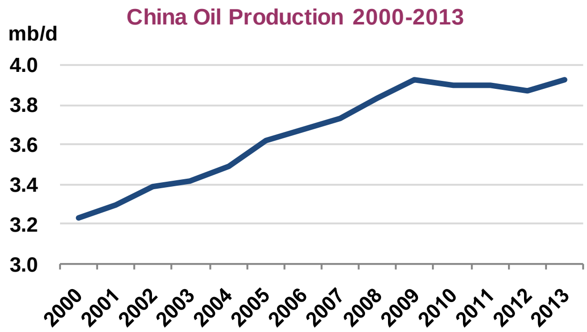


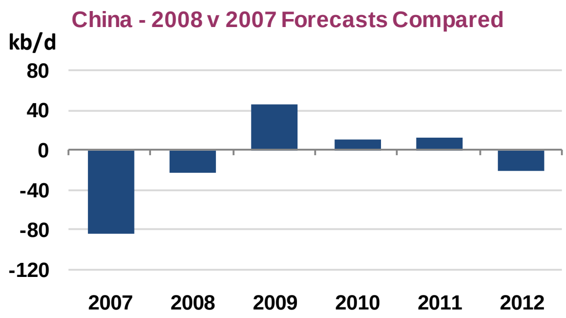


Azerbaijan's production reached 870 kb/d in 2007 from around 650 kb/d in 2006. We now see a sharper build-up in production from the BP-operated Azeri-Chirag-Guneshli (ACG) fields, which are seen breaking through 1.0 mb/d by early 2009, from current levels around 735 kb/d. In addition, recent reports suggest upside recoverable reserve potential in the ACG complex versus existing estimates of 5.4 billion barrels, perhaps to as high as 9 billion barrels. We had earlier assumed some dip in ACG supplies as early as 2012, although this now looks too pessimistic, even on existing schedules and reserve levels, so we have revised up the forecast accordingly. BP expects satellites at Chirag and Azeri will sustain production around 1.0 mb/d until 2015, with 2019 being cited in the event that higher resource levels prove accurate.

China

Since the mid-1990s China has seen steady annual growth in oil production averaging 75 kb/d. This has lagged domestic oil demand growth, prompting overseas expansion by the Chinese state oil companies. Our forecast envisages Chinese total oil production reaching 3.9 mb/d by the end of the decade (from 3.7 mb/d in 2007), before levelling off. A recent trend of eastern onshore decline versus offshore growth from the Bohai Gulf and Pearl River Basin continues, with offshore production reaching 760 kb/d in 2013 from around 550 kb/d in 2007. We have factored in initial production of 130 kb/d from the Jidong Nanpu field by 2013, which Chinese authorities say contains upwards of 3 billion barrels of proven reserves. Ultimate production levels closer to 500 kb/d are envisaged, and development work was launched in February 2008. This is offset by continued decline at the mature onshore Daqing and Shengli fields, which are seen dropping by a combined 235 kb/d (around 4% pa) through the forecast.

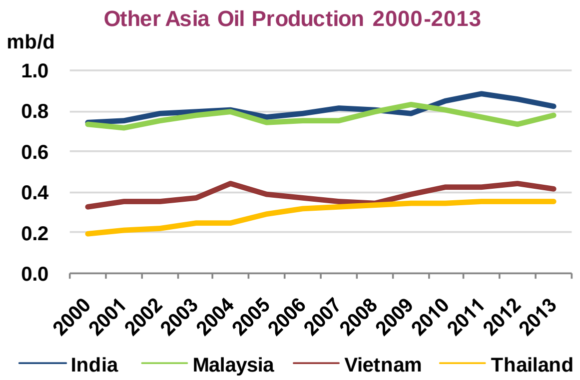


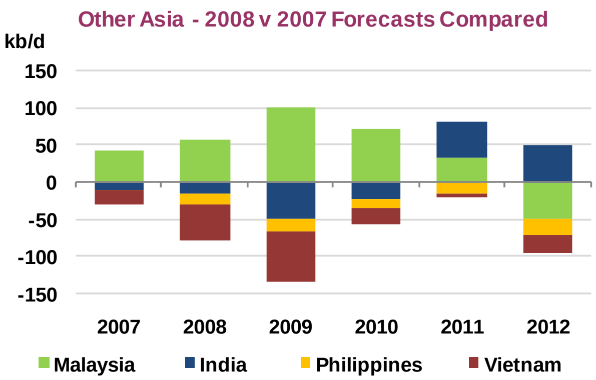


Upside potential for the Chinese forecast does exist however. Coal-to-liquids (CTL) technology has significant potential. However, without significant new developments in the last year, and bearing in mind energy and water supply constraints, we retain a cautious view, with CTL seen providing 160 kb/d by late 2012, from the various phases of the Shenhua project. Initial output from this project is scheduled for late 2008. Also, recent gains from the northerly onshore Changqing field have taken output to 260 kb/d versus 160 kb/d in 2004. Our forecast assumes a levelling off close to 300 kb/d by 2010, although details on specific plans for further expansion in future could result in a higher forecast. Finally, successful field tests in China for CO_2-EOR suggest the potential for an extra 150-300 kb/d in time, although we do not include this for now in the absence of specific ongoing projects.

Other Asia

Output from other Asian producers gains a collective 130 kb/d during 2008-2010 to reach 2.85 mb/d, but slips to 2.73 mb/d by 2013. Thailand, India and Vietnam see rising supply overall, while Malaysian production oscillates around prevailing 800 kb/d levels. Project timings are generally slipped from the last forecast, and both Vietnam and India's 2007 output also lagged previous expectations.





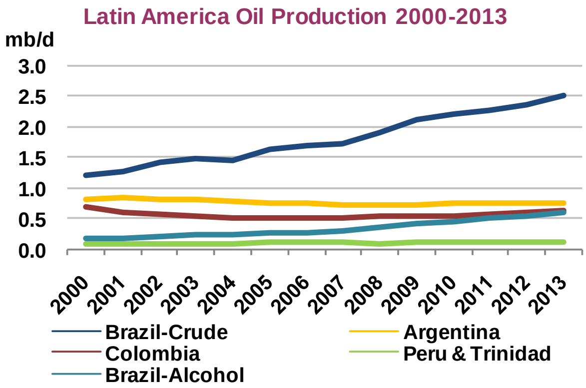
Initial growth from **Malaysia** derives from the 120 kb/d offshore Kikeh project, which entered service in August 2007. Further late-forecast growth comes from Shell's 150 kb/d Gumusut-Kakap project which we envisage to come onstream around mid-2012.

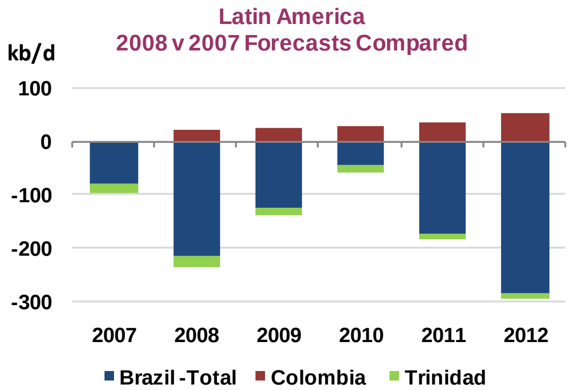
For **India**, onshore Rajasthan is expected to become an important source of new supply, with the 125 kb/d Mangala project from 2009, and a combined 50 kb/d from Bhagyama and Aishwariya in 2010. Recoverable reserve levels here have been upgraded to 685 mb, and work on a long-delayed pipeline to ship the crude to near Jamnagar has commenced.

Latin America

Having accounted for all of the 1.0 mb/d regional production growth seen in the past 10 years, Brazil remains the key growth source in Latin America through 2013. Total Brazilian oil production rises from

2.3 mb/d in 2008 to 3.2 mb/d in 2013. Included in the 2008 total is around 360 kb/d of fuel ethanol production, increasing above 600 kb/d by the end of the forecast. Crude and NGL output rises from 2.0 mb/d to 2.6 mb/d, with new project start-ups in the offshore Campos and Santos Basins. However, project delays have resulted in a downward revision of 0.3 mb/d to our previous forecast for 2012, and further slippage cannot be discounted, notably given the preponderance of deepwater developments in expected new production.



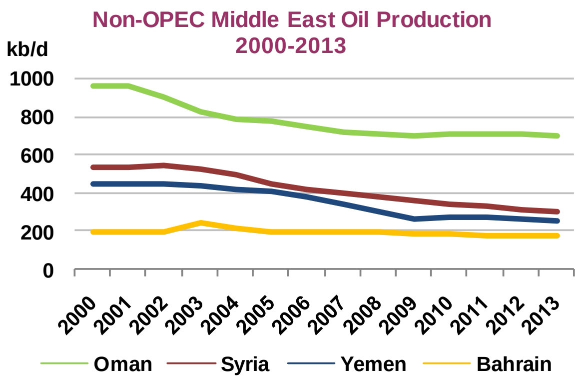


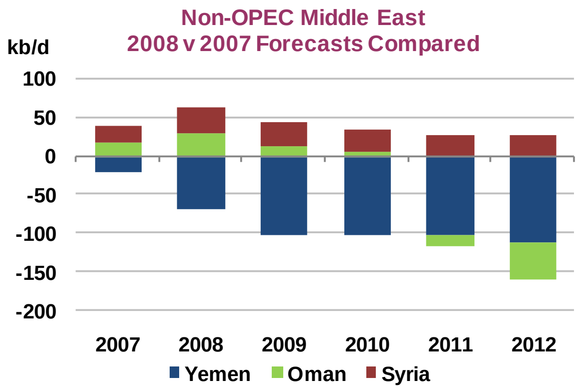
Longer-term potential from Brazil could be greater still following huge discoveries under the salt cap of the offshore Santos Basin. State company Petrobras envisages an eventual 1 mb/d of light oil production from the 5-8 billion barrel Tupi discovery, one of several in the area, with hydrocarbons located at total depths of around 6000 metres. However, with questions over the contract model needed to encourage further development, and chronic backlogs for building new drilling capacity reported by Brazilian shipyards, we take a cautious approach, factoring in volumes from Tupi only by 2012, and even then only reaching a comparatively modest 100 kb/d. Petrobras' own plans see a more accelerated programme involving permanent production facilities from end-2010.

Notwithstanding a recent resumption of rebel attacks on key crude oil pipelines, **Colombia** appears to have stabilised oil production after it fell from 690 kb/d in 2000 to 530 kb/d in 2004. In contrast to some other local regimes, Bogota is aggressively trying to entice foreign investment of around $3 billion per year to bolster falling reserves and reinvigorate production. Heavy crude oil production from eastern fields is seen adding nearly 200 kb/d of new supply by the end of the forecast period, potentially taking total national output back in excess of 600 kb/d again by 2012/2013.

Middle East

Non-OPEC Middle East output looks likely to remain on a downward trend, with regional supplies dropping from 1.6 mb/d in 2008 to 1.4 mb/d in 2013. Projections for Yemen, and to a lesser extent Oman, have been scaled back compared with last year. In **Oman**, efforts to stem decade-long decline



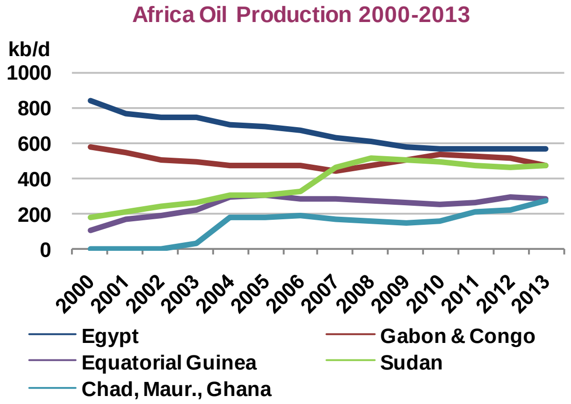


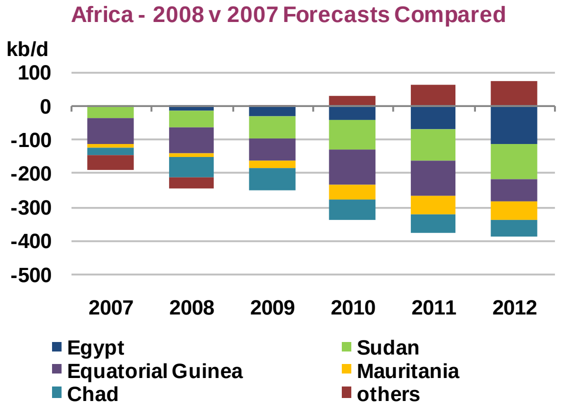
by the application of enhanced recovery programmes (EOR) at fields including Harweel and Qarn Alam have either been delayed or under-performed. However, EOR could prove sufficient to stabilise national crude and condensate production at close to 700 kb/d, compared with 960 kb/d in 2000.

A small number of ongoing projects in **Yemen** could halt recent output decline at 270 kb/d during 2009-2012, before renewed decline sets in thereafter. The Nabrajah and An Nagyah projects could add some 40 kb/d during 2008/2009, although this represents a scaling back from previous estimates. Government plans still cite a 500 kb/d target for 2013, albeit acknowledging that output will likely decline through 2010. If efforts to boost exploration, through new bidding rounds and by improving infrastructure succeed, a renewed rise in output may again materialise. However, recent output trends, combined with a spate of recent attacks by al-Qaeda targeting oil facilities suggest this may be more of a longer-term prospect.

Africa

Having risen from 2.1 mb/d to 2.4 mb/d during 2000-2007, non-OPEC African oil production is expected to level off through 2013, at around 2.5 mb/d. Early/mid-decade growth from producers such as Equatorial Guinea, Sudan and Chad has been followed by a scaling back of expectations for the future for a number of geological, technical and political reasons. Reservoir performance has been disappointing for the Chinguetti project offshore Mauritania, and the region's largest oil producer, **Egypt**, faces accelerating crude decline, albeit offset by rising NGL supplies from natural gas development.

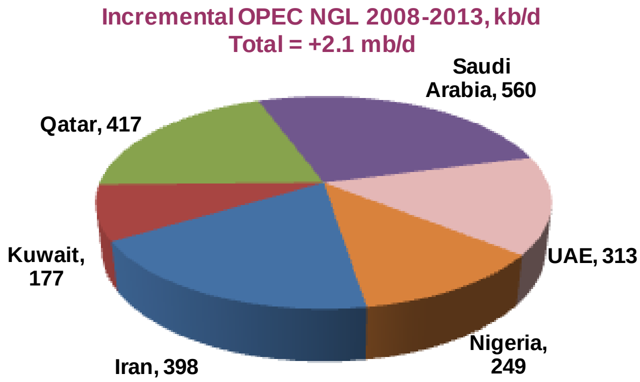




However, there are pockets of growth for the next five years. **Ghana** should see total production attain close to 150 kb/d by the end of the forecast period as the offshore Jubilee oil field enters service. We also assume that prolonged teething problems affecting **Mauritania's** Chinguetti field are overcome, allowing development of the adjacent Tiof and Tevet deposits and raising national output from 15 kb/d to 70 kb/d in the process. In **Congo**, rising supplies from the offshore Moho project take national output from 240 kb/d in 2008 to 280 kb/d by 2011.

OPEC Gas Liquids Supply

OPEC NGL should continue to grow strongly through 2013, against a backdrop of steady gas production growth of some 5% pa. Producers have long targeted a reduction in associated gas flaring. However, in many cases earlier plans for substantial gas export growth are now being superseded by a need to boost natural gas for oil field reinjection, domestic industrial, desalination and power supply use. Whatever the eventual use of the gas, NGL supply is likely to rise strongly, and our projections see the ratio of liquids to gas production rise towards 10 kb/d per bcm of gas, from recent levels of 8.5-9. A tailing off in firmly committed NGL and condensate projects relative to gas production late in the forecast reflects a tendency for wetter gas streams to be developed first, but also possibly some upside for gas liquids versus the levels forecast here. Many of the bottlenecks affecting raw materials, labour and service capacity for upstream oil are at least as prevalent for upstream and midstream gas. Indeed project slippage curbs this year's NGL forecast for 2008-2010 by 300 kb/d compared with last year's. We nonetheless expect OPEC NGL to reach close to 7.1 mb/d by 2012, largely in line with last year's total.



All told, production rises by 2.1 mb/d from 2008, to 7.2 mb/d by 2013. While this is an ambitious growth rate of 7% annually, it actually equates to the apparent percentage rate seen during 2003-2008. Saudi Arabia and Qatar generate nearly 50% of the increase, albeit plans are based on domestic gas use in the former and an LNG export programme for the latter. Iran, Nigeria, the UAE and Kuwait also see robust growth. Increments from Saudi Arabia, Iran and Nigeria are weaker than last year, but the UAE, Kuwait and Indonesia now see stronger growth than in our 2007 report.

Saudi Arabia's expansion derives from both associated and non-associated gas. The non-associated portion comes from Hawiyah processing facilities, due for start-up in second-half 2008 and ultimately generating 300 kb/d of NGL (a level we assume attained by 2011). Gas linked to crude oil output generates some 280 kb/d of NGL and condensate from Khursaniyah, 70 kb/d of condensate from Khurais and 50 kb/d of condensate from Manifa. Delays commissioning gas treatment facilities underpin the later-than-expected start-up at Khursaniyah from end-2007 to a latest expected start of 3Q 2008. In all, Saudi Arabia sees NGL output rise from 1.5 mb/d this year to 2.1 mb/d in 2013.

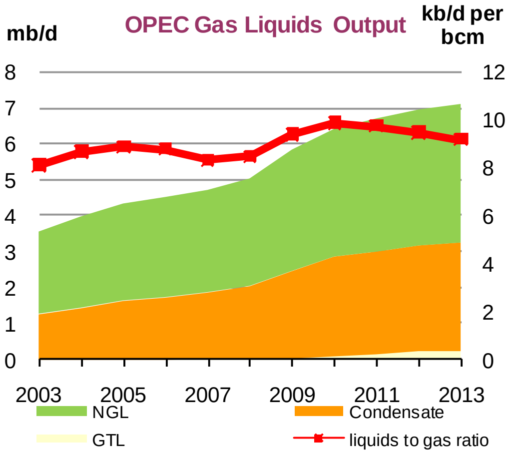
Qatar's expansion takes condensate output from an estimated 280 kb/d in 2008 to 510 kb/d in 2013, with other NGLs increasing in the same period from 335 kb/d to 520 kb/d. The forecast includes committed phases of the RasGas and Qatargas LNG projects (through Ras Gas III and Qatargas II respectively). Also included in the NGL numbers is an assumed 34 kb/d of oil products from the already-operational Oryx gas-to-liquids (GTL) project, plus phases 1 and 2 of the Pearl GTL project, assumed onstream sequentially in 2011 and 2012. Pearl will reportedly produce 140 kb/d of light products when fully operational. A second phase expansion of the Oryx project has not been included in the forecast after Oil Ministry comments that likely total 2012 GTL capacity is 174 kb/d.

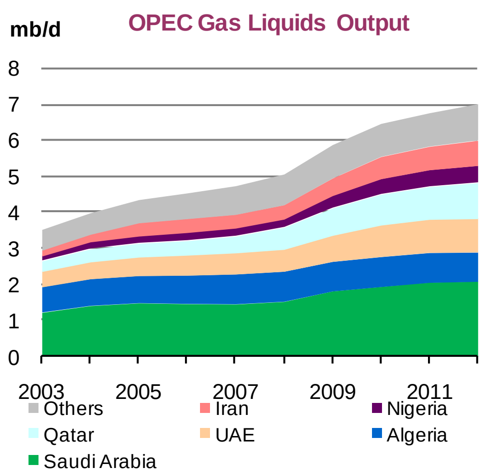
Qatar is unlikely to sanction significant further expansion of gas production beyond an expected 100 bcm pa in 2013 until reservoir studies for the offshore North field are completed and evaluated, in 2010 at the earliest.

The part of the North Field that extends into **Iranian** waters is known as South Pars. With proven reserves of 28 tcm, second only to Russia, Iran has nonetheless faced extended delays in bringing new gas capacity onstream. A combination of unattractive contract terms and the threat of sanctions against companies investing in Iran has hit both oil and gas investment. Moreover, ambitious gas export projects may be overtaken by domestic Iranian requirements for industry, power generation and oilfield reinjection. Reinjection requirements will reportedly more than double to 10 bcfd by 2012. Reflecting project uncertainty, we have confined incremental NGL/condensate production to:

1. South Pars phases 6-8 (on stream 3Q 2008);
2. South Pars phases 9-10 (on stream 3Q 2009) and;
3. South Pars phase 12 (1Q 2013).

For each project, start-up has been slipped by around one year compared with last year's forecast. However, NGL volumes have been upgraded slightly to reflect latest project information. In total Iranian gas liquids supply doubles from 400 kb/d to 800 kb/d between 2008 and 2013.





UAE gas liquids output is expected to increase by some 50% from 630 kb/d to 950 kb/d, with the bulk of this coming from third phase expansion of Abu Dhabi's Habshan gas plant, due to be completed by September 2008. This will generate 130 kb/d of condensate and 140 kb/d of ethane, LPG and naphtha, with the bulk of the dry gas reportedly destined for oilfield reinjection. Some 40% of Abu Dhabi's onshore wellhead gas production is reinjected.

Despite considerable upstream challenges related to insurgent activity, industrial unrest and project financing issues, **Nigeria**'s gas liquid output is expected to increase from 220 kb/d to 465 kb/d by 2013. NGLs from Chevron's imminent Agbami field start-up and from ExxonMobil's Qua Iboe NGL recovery project (also in 2008) add a combined 90 kb/d by 2009, while the 180 kb/d Akpo condensate field is itself due to be onstream in early 2009. Chevron also has plans to extract 34 kb/d of gas-to-liquids products from 300 mmcfd of currently flared gas at the Escravos fields. Initially slated for 2006 start-up, this project has repeatedly slipped and is now envisaged for completion in 2011.

Kuwait's gas liquids output is expected to increase from 165 kb/d this year to as much as 340 kb/d by 2013. This follows start-up in May of the country's first non-associated gas production from the northern Sabriya and Umm Niga gas fields. Phase one gas condensate supply will reach 50 kb/d, with up to 165 kb/d total output from 2012 when phase two enters service.

OPEC Crude Oil Capacity Developments

We have also substantially downgraded expectations for OPEC crude capacity for the 2008-2013 period. Running some 0.35 mb/d below last year's forecast for 2008-2010, projections drop to around 1.2 mb/d less than in last year's forecast for 2011 and 2012. As for our non-OPEC estimates, project slippage is a key reason for this weaker outlook. We nonetheless expect OPEC installed capacity to rise from 35.3 mb/d in 2008 to 37.4 mb/d in 2010 and 37.9 mb/d in 2013 - net growth in five years of 2.5 mb/d. Saudi Arabia, Angola and (for the first time in our medium-term forecast) Iraq see net additions for 2008-2010. There is then a brief hiatus in growth for 2011, before the next phase of expansions in 2011 and 2012 from Saudi Arabia and Nigeria take effect.

Last year our forecast assumed that two key producers – Iraq and Venezuela – would see static capacity through the period to 2012. Rather than being a rigorous forecast, this was merely based on our inability to discern a clear trend in likely capacity given huge geopolitical and industry investment

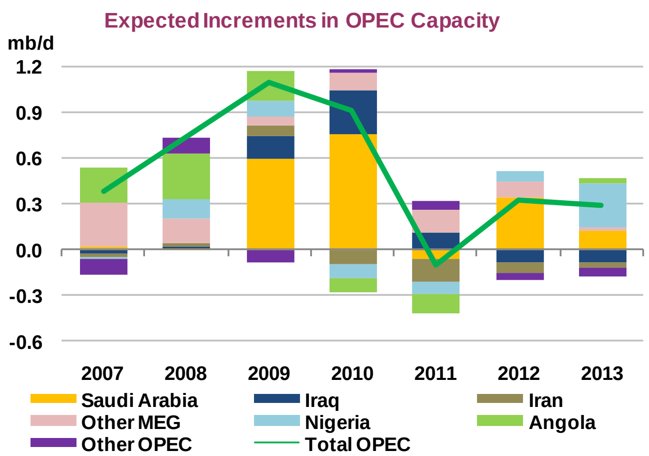
Estimated Average Sustainable Crude Production Capacity - 2008 forecast

(million barrels per day)

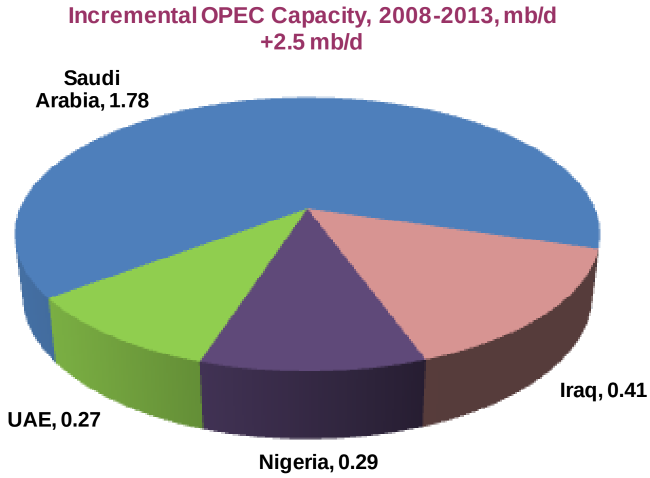
	2006	2007	2008	2009	2010	2011	2012	2013	*increment 08-13*
Algeria	1.41	1.44	1.45	1.42	1.39	1.38	1.39	1.39	*(0.06)*
Indonesia	0.90	0.84	0.84	0.81	0.84	0.87	0.84	0.77	*(0.07)*
Iran	4.01	3.99	4.01	4.08	3.98	3.83	3.77	3.72	*(0.28)*
Kuwait	2.57	2.61	2.63	2.65	2.72	2.80	2.80	2.77	*0.14*
Libya	1.69	1.73	1.80	1.79	1.83	1.87	1.87	1.90	*0.11*
Nigeria	2.45	2.44	2.56	2.67	2.57	2.50	2.56	2.85	*0.29*
Qatar	0.80	0.87	0.94	0.99	1.04	1.02	1.00	0.98	*0.04*
Saudi Arabia	10.70	10.72	10.74	11.34	12.10	12.04	12.39	12.52	*1.78*
UAE	2.60	2.78	2.85	2.83	2.82	2.91	3.04	3.11	*0.27*
Venezuela	2.67	2.59	2.62	2.62	2.62	2.62	2.62	2.62	-
Sub-total OPEC 10	**29.80**	**30.01**	**30.44**	**31.20**	**31.91**	**31.85**	**32.28**	**32.64**	***2.20***
Angola	1.37	1.61	1.92	2.12	2.03	1.90	1.89	1.93	*0.01*
Ecuador	0.54	0.50	0.50	0.49	0.48	0.46	0.44	0.42	*(0.08)*
Iraq	2.50	2.48	2.48	2.64	2.93	3.05	2.96	2.89	*0.41*
Total OPEC	**34.21**	**34.60**	**35.34**	**36.44**	**37.35**	**37.25**	**37.58**	**37.87**	***2.53***
increment	*0.55*	*0.35*	*0.68*	*1.13*	*0.92*	*-0.09*	*0.33*	*0.30*	

uncertainties. Although Venezuela has now effectively completed the renationalisation of its upstream industry, the investment climate remains clouded and potential expansion projects in the prolific Orinoco heavy oil belt have yet to be finalised. Several proposals exist but their precise funding and timing remain unclear. Moreover, considerable uncertainty surrounds the fate of production in older, conventional oilfields around Lake Maracaibo. We feel no more confident about making a detailed, project and field-specific forecast for Venezuela this year than we did last year, and so retain a "current capacity extended forward" approach until things become clearer.

In **Iraq** however, several months of stronger production and export performance, allied to progress in securing new field developments and contracts for existing field expansion have been apparent in the first half of 2008. Production has averaged 2.4 mb/d in 1Q 2008, versus 2.1 mb/d in 2007 as a whole. Several technical service agreements have been signed with major foreign companies that could add some 500-600 kb/d of output at existing fields within two years. And the Kurdish Regional Government is seeking export clearance for two fields developed on its territory - Tawke and Taq Taq – that could ultimately produce nearly 300 kb/d. This is not to say definitively that the situation on the ground in Iraq has stabilised, merely that, compared with last year, the prospects for higher production seem to have improved. Security issues, pipeline integrity, power supply, domestic refinery availability and the shape of a yet-to-be agreed hydrocarbon law could all derail expansion plans in months to come. But we feel justified in raising forecast Iraqi capacity from a current 2.5 mb/d towards 3.0 mb/d by 2013. Government estimates see around 3 mb/d of output being possible as early as 2009, but questions over timing and security encourage us to be more cautious.



The key driver of OPEC capacity growth for 2008-2013 is **Saudi Arabia**, where an increase of 1.8 mb/d could take capacity to 12.5 mb/d in 2013. IEA capacity estimates exclude 300-400 kb/d of Saudi condensate and Bahrain's share of Abu Safah crude, hence our own current and forecast levels lie below other published estimates which include these components. Main increments come from the Abu Hadriya-Fadhili-Khursaniyah (AFK) project (500 kb/d beginning in 2008), Shaybah at end-2008 worth 250 kb/d, the 1.2 mb/d expected from the Khurais project in 2009, alongside the smaller, 100 kb/d Nuayyim development and then 900 kb/d from the heavy/sour Manifa project in 2012. Delays in completing gas processing facilities at AFK will keep crude volumes at minimal levels until late this year, meaning the bulk of the capacity 'kick' from the project comes in 2009.



State company Aramco insists that AFK delays are not symptomatic of likely delays at their other projects. Nonetheless, latest market intelligence leads us to push back our estimates for the Nuayyim increment and for Manifa, by six to nine months compared with the July 2007 forecast.

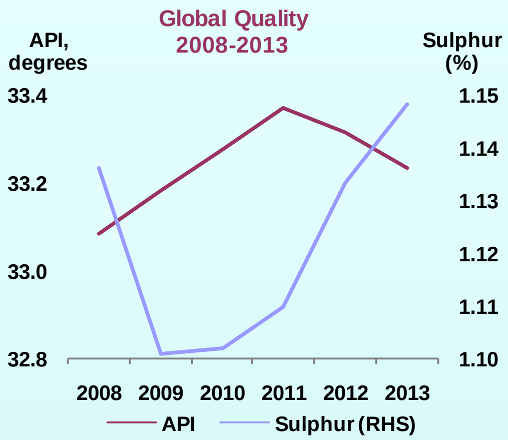
Until recently, there had been little indication of any Saudi plans to raise capacity above 12.5 mb/d, against a back-drop of assumed mature field decline of one to three percent annually, and an apparent policy of resting older assets. The Jeddah summit of 22 June however did see Saudi Arabia clearly state a preparedness to potentially raise capacity to 15 mb/d, subject to demand. This included increments from the Zuluf, Safaniyah and Berri fields, with a lead time for each of around three years being mentioned. Given the lack of any concrete investment decision as yet, we do not include this higher potential Saudi capacity level in our forecast, welcome though such an increment would be for an otherwise tight market.

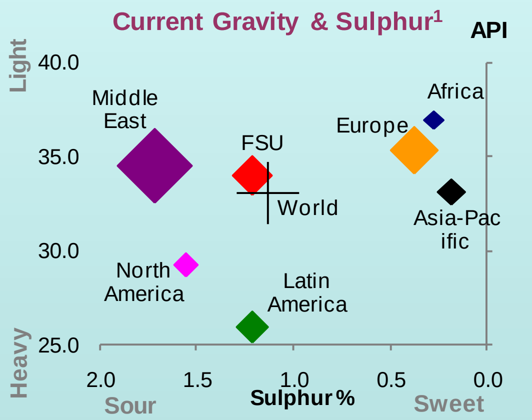
Recent developments in **Nigeria** have done little to encourage the belief that Nigerian capacity can be sustained, let alone expanded, on a net basis. Late April saw strike action briefly curb ExxonMobil's roughly 800 kb/d of production, and there are currently threats that Chevron's 300 kb/d of Nigerian output may be facing a similar fate. Late June also saw an until-now unprecedented attack on a deepwater facility, Shell's Bonga field, knocking out over 200 kb/d of liquids production and forcing the company to declare *force majeure* on exports for June and July, albeit production has now resumed. Along with renewed Escravos outages, this took estimated late-June offline capacity into a 700-800 kb/d-range, just as refineries worldwide are exiting maintenance and seeking transport-fuel rich Nigerian crude grades to meet summer motoring demand.

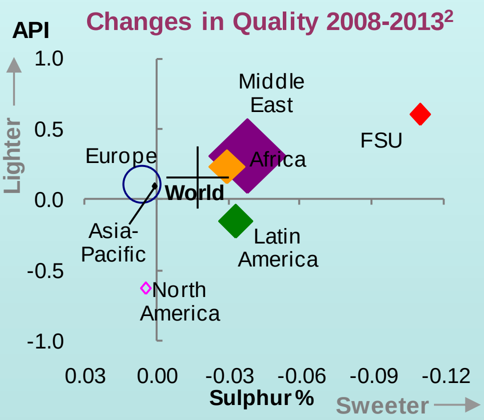
There are still issues over NNPC financial contributions to joint venture expenditure to be considered, and a long-running debate over the timing for companies to cut gas flaring and the imposition of penalties for those who persist. Some long-idled Niger Delta capacity may never be reinstated and we have boosted assumed decline for the Delta region to 5% pa in part to reflect this. Notwithstanding these manifold risks for Nigerian production, it is worth noting that headline Nigerian capacity has grown by a net 250 kb/d during 2003-2008, at the height of unrest, to reach this year's estimated 2.56 mb/d. For now we persist with an assumption that deepwater production and new field developments will proceed as they generally have over the past 2-3 years, since the most recent cycle of Niger Delta unrest began. Therefore the, albeit delayed, completion of offshore projects such as Agbami, Bosi, Usan and Bonga SW takes installed capacity to nearly 2.7 mb/d in 2009 and 2.85 mb/d by 2013. Any deterioration in offshore facility security could of course undermine this outlook.

The Potential Evolution of Oil Production by Quality

We have generated projections of global oil supply quality for 2008 through 2013 which focus solely on crude oil and gas condensate, excluding other NGLs. In so doing, we are trying to examine the type of feedstock global refiners will have to deal with in coming years. Perhaps surprisingly, rising condensate and lighter/sweeter crude supplies from OPEC and the FSU initially shift global quality towards higher API/lower sulphur for the period 2008-2011. Weighted average global API shifts from 33.1° to 33.4° in three years, while sulphur content falls from 1.14% in 2008 to 1.10-1.11% for 2009-2011. Middle Eastern output lightens from 34.5°API to 35.0°API in this period, with regional sulphur content dropping from 1.72% to 1.67%. Not only regional condensate supplies, but also a preponderance of lighter/sweeter crudes coming from Saudi Arabia's capacity expansion programme, drive this change. FSU supplies continue to lighten throughout the forecast period from 34.0° in 2008 to 34.6°API by 2013. Regional sulphur content also drops significantly, from 1.21% to 1.10%. Newer Russian supplies from eastern Siberia and northern areas tends to be both lighter and sweeter than base load Urals supply. Meanwhile, both Tengiz and Kashagan crudes from Kazakhstan are very light, albeit there are issues over hydrogen sulphide (H_2S) content. Rising Azeri output is also comparatively high in quality and is augmented by our assumption of higher production of Shah Deniz condensate. African supply also becomes lighter and sweeter over the forecast period,as medium gravity west African supplies plus Egyptian condensate replace some declining heavier or sourer barrels from locations such as Sudan and Chad.



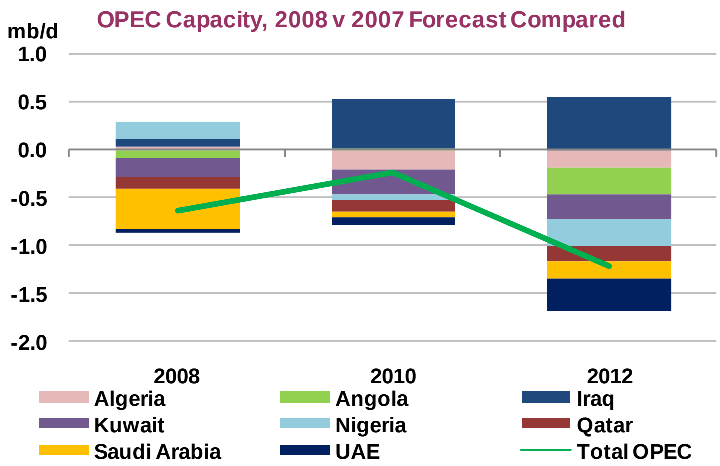




1 Symbols proportionate in size to regional production.
2 Symbols proportionate in size to changes in regional production. Hollow symbol denotes crude + condensate production in decline.

The trend begins to shift back in a more traditionally perceived direction during 2011-2013, as global supplies become marginally heavier (going from 33.4°API to 33.2°API) and markedly sourer (sulphur content rises from 1.11% to 1.15%). The regional drivers of this deterioration in quality for 2011-2013 are the Middle East and North America. In the Middle East, Saudi Arabia's Manifa project sees a shift back towards Arab Heavy crude (29°API and 2.8% sulphur), compared with the lighter/sweeter barrels brought on stream earlier in the forecast. From North America, the concentration of growth in this period in Alberta bitumen supplies drives the shift in regional quality.

Angola also sees short-term capacity growth, as production from 2007 start-ups Rosa, Plutonia and BBLT builds towards plateau, followed by Kizomba C and Gimboa in 2008 and Mafumeira in 2009. However, slippage of five projects we previously factored in for 2009-2011 (KLOV, Kizomba D, Pazflor and others in Blocks 31 and 32) to 2012 or 2013 undermines capacity growth for later in the forecast. Total installed capacity rises to 2.1 mb/d next year, but then levels off at 1.9-2.0 mb/d for the remainder of the forecast period as some older deepwater projects mature beyond 50% recovery and production enters decline.



UAE capacity is expected to reach 3.1 mb/d in 2013 from around 2.8 mb/d currently, well below an original official target of 3.5 mb/d by 2012. This is now seen in industry circles as possible by 2019 at the earliest. Costs for expansions at the offshore Upper Zakum project and onshore at Asab, Shah and Sahil have reportedly doubled amid contractor shortages. Onshore, the ADCO/Murban PSA expires in 2014, dissuading foreign partners from spending until the contract is renewed. Moreover, a looming domestic natural gas shortage may compromise volumes otherwise destined for reinjection at oilfields, notwithstanding the advent of piped gas from Qatar. With these elements in mind, we are disinclined to raise crude oil capacity towards the earlier 3.5 mb/d target, leaving our forecast some 340 kb/d lower than last year's equivalent.

CRUDE TRADE

Summary

- **Global inter-regional crude oil trade could rise by 2.5 mb/d between 2008 and 2013,** equating to around 1.5% annual compounded growth. Lower global demand is the main reason for a widespread downgrading of medium-term crude trade prospects since last July's *MTOMR*, with trade growth seen potentially 1.8 mb/d lower through 2012.

- **The Middle East will remain the key crude exporting region in the medium term,** with trade to other regions possibly rising from 16.0 mb/d in 2008 to 17.5 mb/d in 2013, despite a reduction of 1.1 mb/d in our export growth scenario through 2012. The FSU export outlook is reduced by a weaker supply forecast, limiting export growth to OECD countries in North America and Europe. However, incremental condensate cargoes (not included in our crude data) could extend global export growth by a further 1.5 mb/d, almost exclusively heading to Asian markets.

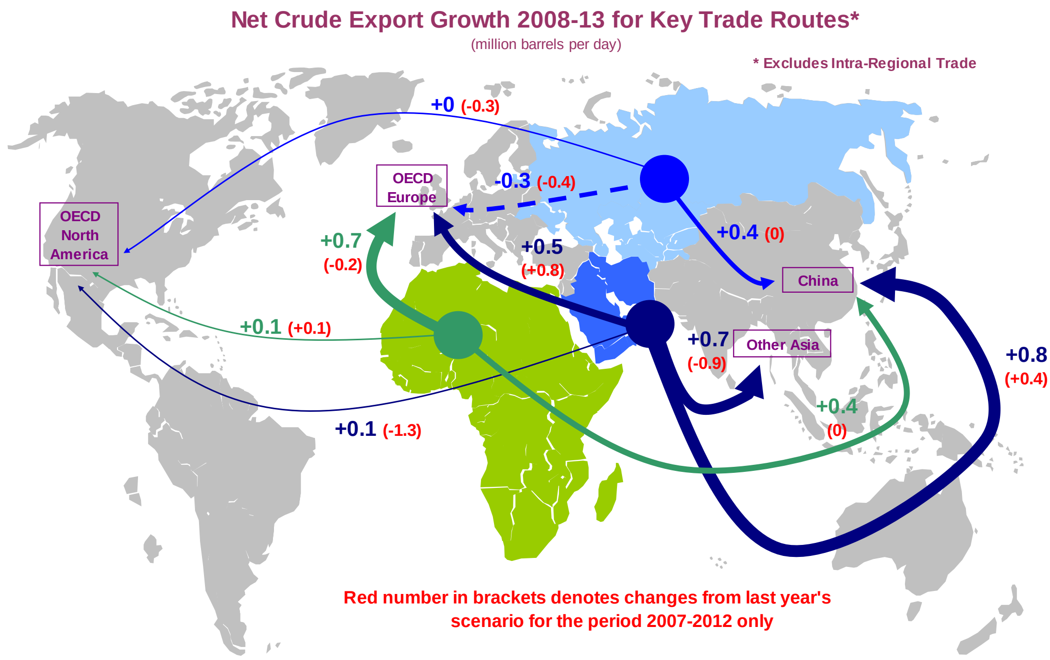
- **Chinese crude imports,** near 4 mb/d in early 2008, could reach an annual average of 5.7 mb/d by 2013 (putting average annual compound growth at 7%), as refining expansion forecasts remain firm. OECD import prospects are seen much lower, due to weaker demand, with growth in OECD North American imports of Middle Eastern crude potentially 1.3 mb/d less than envisaged in last July's scenario through 2012.

Overview and Methodology

Global inter-regional trade of crude oil could rise from 34.0 mb/d in 2008 to 36.5 mb/d in 2013. The major pull on incremental crude exports will continue to be China during this period, importing up to 1.6 mb/d of additional crude. OECD Europe and Other Asia could also attract 0.9 mb/d and 0.4 mb/d in incremental crude volumes over the next five years, respectively. By contrast, OECD Pacific imports may decrease by as much as 0.6 mb/d. According to our latest scenario, rising export volumes to all destinations are due to come mainly from the Middle East (1.5 mb/d in total growth from 2008-13) and Africa (0.9 mb/d).

Global crude trade is revised down from last year's *MTOMR* scenario in terms of both the absolute base and prospective growth. This is mainly due to the downward revision to our 'Call on OPEC' (used to allocate OPEC supplies) given the weaker demand outlook. Alongside lower OPEC volumes (affecting the Middle East and Africa), Russian exports in the medium term are also revised down as a result of a weaker supply outlook, while domestic refinery capacity expansion plans remain in place. With fewer global crude export cargoes available over the next five years, our scenario allocates lower import volumes to OECD North America, the area seeing the largest downward revisions to demand. By contrast, Chinese imports could remain strong through 2013, due to robust projected refinery additions, while Other Asia and OECD Europe imports should also see some growth, albeit to a lesser extent.

As in the *MTOMR* of July 2007, this year's medium-term crude trade scenario is driven by the allocation of incremental crude supplies to areas of crude demand growth, as dictated by refinery expansions. Condensate trade is not volumetrically reflected here and provisions are not made for evolving OPEC production targets or changes in crude prices which are, of course, two critical drivers of crude trade patterns. Further details on methodology can be found in last year's *MTOMR*, available for free at **www.oilmarketreport.com**.



Condensate trade growth is excluded above but could amount to 1.5 mb/d through 2013 broadly heading east from the Middle East and Africa

Regional Trade

Middle Eastern medium-term export prospects have been downgraded since last July's *MTOMR*, due mainly to a lower regional supply scenario (as the 'Call on OPEC', used to allocate OPEC supplies, has been revised down significantly as a result of a weaker demand outlook). However, the downgrading of potential export volumes (to other regions) was softened by reductions to domestic crude demand in the form of lower Middle Eastern refinery expansions. Middle Eastern crude exports could now potentially rise from 16.0 mb/d in 2008 to 17.5 mb/d in 2013. Significantly, rising condensate exports, most likely heading east, could add another 1 mb/d growth to these volumes.

Middle Eastern crude exports to OECD North America were previously expected to rise but are now seen as broadly flat in the medium term, matching anaemic demand growth there. This marks a significant downward shift to future long-haul crude trade. At the same time, a combination of a lower Middle East supply scenario alongside higher expectations for domestic refinery expansions reduces crude exports to Other Asia although rising condensate exports could offset. Crude volumes heading China- and OECD Europe-bound are seen as potentially higher than previously envisaged. Extra condensate may also offset some of the prospective decrease of 0.6 mb/d in Middle Eastern crude exports to OECD Pacific, again related to lower demand.

Exports from Africa have the potential to rise from 8.0 mb/d in 2008 to 8.9 mb/d in 2013, after little change to export growth from last year's crude trade scenario through 2012 (the comparable period). Regional exports to China may remain firm, reaching up to 1.8 mb/d in 2013, as a robust refinery expansion forecast is sustained there. OECD Europe is likely to remain the main customer for African crude over the next five years, with potential imports reaching 3.0 mb/d in 2013. African condensate exports (not included) may also rise by 0.5 mb/d, most likely heading to eastern markets.

The export scenario for the **FSU** is much lower than that suggested last year, as the supply outlook has been lowered while growth in domestic refining capacity could remain firm. OECD Europe may see less of an increase in imports of Kazakh crude than previously thought, due to intensifying competition from China. Meanwhile, our scenario allocates less Russian crude to OECD North American refiners, as the Urals supply forecast is reduced and US demand slows. FSU total exports may now only rise marginally in the medium term, from 6.6 mb/d in 2008 to 6.8 mb/d in 2013.

On the imports side, **China** will remain the largest incremental pull on global crude cargoes, with imports having the potential to rise from 4.1 mb/d in 2008 to 5.7 mb/d in 2013. Robust forecasts for incremental refining capacity are the main driver. Angolan cargoes may lead the rise initially, extending the surge in trade which saw them become China's no. 1 crude supplier in 1Q2008, although upstream project slippage could curtail this growth later in the forecast. Towards the end of the forecast period, Middle Eastern barrels could become more influential in the complex Chinese crude slate than previously expected, while the Kazakh-China pipeline may bring in an extra 400 kb/d of FSU grades post-2009. Strategic stockbuilding could also add to Chinese import growth in the forthcoming years.

Crude imports into the **Other Asia** region could rise from 4.3 mb/d in 2008 to 4.7 mb/d in 2013, although this would be supplemented by incremental condensate supplies from the Middle East not reflected in our crude trade scenario. Projected potential crude imports from the Middle East are revised down, reflecting slippage of some Asian refinery projects and lower Middle Eastern supplies. In the **OECD**, European imports could rise by as much as 0.9 mb/d through 2013 with extra OPEC volumes more than offsetting lower imports from Kazakhstan. However, a weaker demand outlook reduces potential North American crude imports considerably over the next five years, with a possible rise of just 0.2 mb/d between 2008 and 2013, to reach 7.7 mb/d. An OECD Pacific structural decline in demand is tracked by a reduction in imports by 0.6 mb/d, to finish at 5.7 mb/d in 2013.

Tanker Orders Keep Steaming In

Despite lower tanker earnings, tightening credit conditions and rising tanker construction costs, the volume of new tankers on order has risen further since last summer. Compared to the 140 million tonnes of tanker capacity on order that were reported in last year's *MTOMR*, the tanker orderbook currently constitutes 154 million tonnes and 42% of the existing fleet, according to Simpson, Spence and Young (SSY) shipbrokers.

Demand for tanker newbuilding has been threatened by several factors over the last year. Lower tanker profitability was prompted by long periods of weak charter rates (undermined by a net expansion of 5% of the tanker fleet in 2007) and rising bunker prices. Bunker costs currently amount to around $51,500/day for a VLCC trading from the Middle East to Korea or Japan, compared to some $40,000/day in mid-2007. The price of steel, the main shipbuilding raw material, has already risen by over $450/tonne since the start of 2008 to top $1000/tonne, an increase of more than 75%. Competition for shipyards, already stretched to capacity, intensified last year as demand for dry-bulk newbuildings surged on record-high earnings in that sector: 12-month time-charter rates for large carriers of iron ore and coal cargoes averaged $105,000/day in 2007, against $45,000/day in 2006. A new VLCC is now estimated to cost around $160 million (basis construction in Korea or Japan), compared to $140 million cited in the July 2007 *MTOMR*. This comes at a time of weaker economic prospects and growing constraints on credit.

Still, demand for new tankers has remained firm. An enormous surge in December freight rates after an oil spill off South Korea, almost matching the late-2004 all-time record highs on benchmark VLCC routes, compensated for many of the months of lower earnings for tanker owners. Besides, 2007 rates may have been lower on average than the previous two years, but still remained well above the 10-year average.

Greater potential for vessel deletions may have also helped sustain tanker newbuilding orders since last summer. The spill from the VLCC "Hebei Spirit" in South Korea in December 2007 prompted Korea to endorse the MARPOL IV phasing-out of single-hulled vessels by 2010 in its own waters. Other Asian countries, which may have previously relied on certain exemptions to defer a move to exclusive employment of double-hulls, could follow suit; the Philippines have already declared a phase-out of single-hulled tankers from June 2008. Currently, there are 117 single-hulled vessels representing 22% of the whole VLCC fleet, but these are outweighed by 211 such ships on order - all of which are, of course, double-hulled. A large number of VLCCs were sold for conversion to dry-bulk carriers in 2007. This is a process taking only around six months (subject to berth availability at the conversion yards), but the sale of a VLCC for scrap in March 2008 was the first since May 2004 and marks an upturn in scrapping rates. Whether scrapped or converted, there remains a large amount of tonnage deletions in prospect in the medium term.

Combining the orderbook with deletion projections from SSY, the outlook for the tanker fleet is one of a net expansion of around 18% by end-2010. This massively exceeds growth in seaborne crude trade projected over the same period. Barring short-term pinches, the tanker sector still looks less likely to be a structural constraint in the oil supply chain over the medium term than the supply and refining sectors.

BIOFUELS

Summary

- **Biofuels production will sustain the rapid growth seen in previous forecasts**, rising from 1.35 mb/d in 2008 to 1.95 mb/d by 2013. Downward revisions to output in many European and Asian countries on weak economics and project slippage are more than outweighed by higher-than-expected US ethanol production.

- **Downside risks to future biofuel growth remain**, however, due to weak profit margins, the fear that competition for feedstocks is driving up global food prices and widespread concerns about the true environmental and efficiency balance of first-generation biofuels. For those reasons we maintain a lower rate of biofuel output growth relative to the very large production capacity expansions under consideration. Total *potential* production capacity, were all planned plants to come online, would be 3.3 mb/d in 2013, up from 1.9 mb/d in 2008.

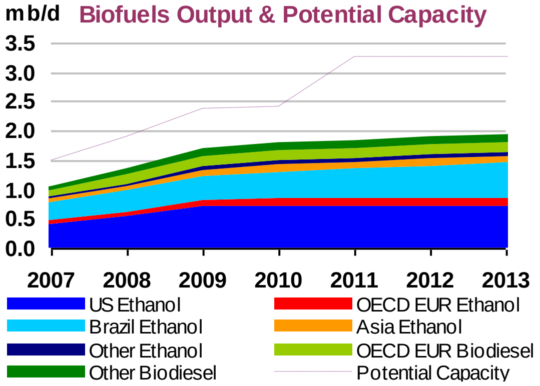
- **Biofuels account for around 50% of non-OPEC supply *growth*** by 2013. Despite representing only a small proportion of the absolute oil balance, ethanol and biodiesel could displace an estimated 5% and 1% of gasoline and gasoil/diesel supply respectively by 2013.

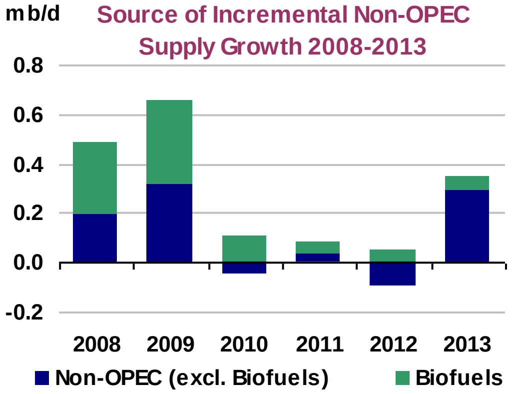
- **The US and Brazil remain the two largest biofuels producers** by far, driven by their ethanol industries, and accounting for much of global growth until 2013. Europe will remain the largest producer of biodiesel, while China's biofuels output approximately equals that of the rest of Asia.

- **Second-generation biofuels will only become commercially viable by around 2015** and thus remain outside our forecast with the exception of a handful of pilot plants. Nonetheless, there is potential for strong output growth and much hope is pinned on their contribution to displacement of conventional fossil fuels – notably as part of the recently-passed US renewables mandate.

Overview

Despite a wave of negative headlines, supply of liquid biofuels for transport is set to continue its rapid growth trajectory in coming years. Competition for feedstocks such as corn, wheat or soybeans have indeed, as we warned in previous reports, contributed to rising food prices, as have high oil and energy prices themselves (see for instance *OECD-FAO Agricultural Outlook 2008-2017* published earlier this year). Nevertheless, higher energy prices, combined with the desire to cut dependence on (imported) fossil fuels and environmental concerns, have encouraged continued political support for biofuels, notably in the US, now the world's largest producer.





In the US, actual production data, aggregated capacity numbers and the December 2007 passage of an ambitious mandate have resulted in rapid growth, leading us to revise up historical and forecast production. At the same time, despite high oil product prices, the economics of producing biofuels remain questionable in many other parts of the world. Outside the US and Brazil (the latter retains unique competitive advantages over all other producing countries), production has lagged expectations and many planned production plants have been cancelled or delayed. Planned mandates have not always been put in place or are being questioned.

Therefore we have revised down our global production figure for the recent past and the current year, but revised up our forecast for the future, largely due to higher ethanol production in the US. But going forward we retain our cautious stance of previous reports, bearing in mind that the economics of biofuels production may well remain doubtful, and that existing policies and subsidies may not remain in place. In addition, there are capacity limits to first-generation biofuels production due to land availability, infrastructure and high-blend constraints of the existing car fleet engines.

World Biofuels Production

(thousand barrels per day)

	2006	2007	2008	2009	2010	2011	2012	2013
OECD North America	343	475	596	766	799	799	799	799
United States	333	452	572	742	772	772	772	772
Canada	10	23	24	24	27	27	27	27
OECD Europe	134	151	226	277	279	279	279	279
Austria	1	6	8	9	9	9	9	9
Belgium	0	0	6	6	6	6	6	6
Germany	81	64	75	78	81	81	81	81
France	16	22	36	44	44	44	44	44
Italy	6	8	18	28	28	28	28	28
Netherlands	1	2	7	12	12	12	12	12
Poland	5	5	7	11	11	11	11	11
Spain	5	20	29	32	32	32	32	32
UK	5	5	11	28	28	28	28	28
OECD Pacific	6	9	16	20	22	22	22	22
Australia	5	7	13	16	19	19	19	19
Total OECD	**483**	**635**	**838**	**1,063**	**1,100**	**1,100**	**1,100**	**1,100**
FSU	2	2	3	10	10	10	10	10
Non-OECD Europe	1	1	3	5	5	5	5	5
China	33	42	51	74	81	81	81	81
Other Asia	30	51	69	85	89	89	89	89
India	8	12	14	14	18	18	18	18
Indonesia	2	6	8	8	8	8	8	8
Malaysia	1	4	9	10	10	10	10	10
Philippines	5	5	5	5	5	5	5	5
Singapore	1	6	8	8	8	8	8	8
Thailand	13	19	24	37	37	37	37	37
Latin America	300	321	381	446	499	545	596	651
Brazil	293	314	366	419	464	510	561	617
Colombia	4	4	4	10	13	13	13	13
Middle East	0	0	0	0	0	0	0	0
Africa	1	3	6	10	13	13	13	13
Total Non-OECD	**368**	**420**	**513**	**630**	**695**	**741**	**792**	**847**
Total World	**851**	**1,055**	**1,352**	**1,693**	**1,796**	**1,842**	**1,892**	**1,948**

Compiled from sources including BBK, EBB, eBio, FACTS, F.O. Licht, RFA, UNICA and government agencies

Hence we have capped production for all countries (bar Brazil) at 2010, in line with our methodology in previous *MTOMRs*, but advancing it by one year (in essence, this assumes that projects currently under construction will be finished, given a lead time of around 18 months for completion). We also maintain that only very small volumes of second-generation biofuels, i.e. those made from non-food crops through new technologies, will be produced by 2013, implying that commercial viability of these fuels and hence substantial production volumes is assumed to fall beyond the time horizon of this report (see *Hopes Pinned on Second-Generation Biofuels*).

Key Revisions to the IEA Forecast

From a downward-revised 2007 output of 1.06 mb/d, we now project production to grow to 1.35 mb/d this year and then to 1.80 mb/d by 2010[1]. Thereafter, non-capped Brazilian growth alone should take us to 1.95 mb/d by 2013. Furthermore, we continue to see strong growth in production capacity additions. Were all announced projects to come online, *potential* capacity by 2012/13 would reach 3.3 mb/d, some 350 kb/d more than forecast for 2012 in last year's *MTOMR*.

World Biofuels Production - Changes to Forecast from July 2007

(thousand barrels per day)

	2006	2007	2008	2009	2010	2011	2012
OECD North America	3	17	69	180	213	213	213
United States	3	35	98	209	239	239	239
Canada	-1	-18	-29	-29	-26	-26	-26
OECD Europe	-16	-26	-85	-101	-98	-98	-98
Austria	0	4	-1	-2	-2	-2	-2
Belgium	0	-3	-5	-5	-5	-5	-5
Germany	9	-11	-16	-16	-14	-14	-14
France	-2	-7	-15	-10	-10	-10	-10
Italy	-3	-8	1	3	3	3	3
Netherlands	0	-2	-7	-9	-9	-9	-9
Poland	1	-3	-1	-9	-9	-9	-9
Spain	-3	-2	-11	-27	-27	-27	-27
UK	2	-1	-13	-14	-14	-14	-14
OECD Pacific	-2	-10	-7	-7	-5	-5	-5
Australia	-1	-8	-6	-7	-5	-5	-5
Total OECD	**-15**	**-18**	**-23**	**72**	**110**	**110**	**110**
FSU	1	-1	1	2	2	2	2
Non-OECD Europe	0	-1	-1	0	0	0	0
China	5	5	-10	13	19	19	19
Other Asia	-3	-11	-48	-35	-32	-32	-32
India	-2	-2	-13	-15	-11	-11	-11
Indonesia	0	-6	-13	-13	-13	-13	-13
Malaysia	0	-6	-11	-11	-11	-11	-11
Philippines	0	-2	-4	-4	-4	-4	-4
Singapore	1	3	-3	-4	-4	-4	-4
Thailand	-1	1	-2	10	10	10	10
Latin America	0	-14	-16	-10	8	20	32
Brazil	0	-2	-2	-2	9	21	33
Colombia	0	-5	-8	-4	-1	-1	-1
Middle East	0	0	0	0	0	0	0
Africa	0	0	3	5	8	8	8
Total Non-OECD	**2**	**-21**	**-72**	**-25**	**6**	**17**	**29**
Total World	**-12**	**-40**	**-96**	**47**	**116**	**127**	**139**

Compiled from sources including BBK, EBB, eBio, FACTS, F.O. Licht, RFA, UNICA and government agencies

The downward revision for past figures in part stems from better and more comprehensive production data collected by the IEA (for OECD and a handful of non-OECD countries), which we have integrated into our largely capacity-driven model. A reassessment of biofuel production plants around the world – now a database of over 1,800 facilities – and a reappraisal of production economics led us to slightly lower our production assessments for many OECD and some non-OECD countries.

[1] All production figures quoted in this chapter refer to volumes, i.e. are not adjusted for lower energy content.

The plant-by-plant list clearly shows that, for many markets outside the US, numerous planned production facilities have either been delayed or wiped off the drawing-board. Broadly speaking, this is true for most European and Asian countries. Despite high oil prices, feedstock prices have in many cases risen even more strongly, putting the profitability of much production capacity into doubt. Moreover, the allegation that biofuels' feedstock needs have driven up food prices and question marks about environmental benefits have led many countries to reconsider planned or existing mandatory blending requirements and subsidies. These issues have again led us to cap growth in 2010 (for all countries except Brazil), taking into account the approximate lead time for plants and only including those currently under construction.

In contrast, *ethanol* production in the US has outstripped expectations. Firstly, monthly 2007/08 production figures have consistently shown higher-than-expected growth. Secondly, production capacity figures clearly point to faster expansion than our previous assessment. A reappraisal of individual production facilities shows that several plants have come online faster than assumed in last year's *MTOMR* and there are many new plants on the horizon. Moreover, the industry is beginning to see a degree of consolidation, with plants – especially those operated by larger enterprises – becoming bigger. As a result, we have also been prompted to revise up our US ethanol capacity figures – by around 70 kb/d for 2008 (to around 650 kb/d) and by an average 240 kb/d for subsequent years.

In addition, our forecast is based on the assumption that the economics of ethanol production, including subsidies, remain broadly profitable in 2008. Following a bumper US corn crop and high oil prices, at the very least US plants should be able to run at 2007's 82% average utilisation rate (which is considerably higher than many biodiesel production plants in parts of Europe).

Lastly, in December 2007 the US finally passed into law a new and ambitious renewable fuels mandate, which calls for an approximate four-fold production increase by 2022 (though not all of this is to be ethanol made from corn). Coupled with a subsidy of currently around ¢45/gallon (recently cut from ¢51/gallon), this clearly keeps investment in ethanol production capacity attractive. Thus, compared to last year's *MTOMR*, we have revised up our 2008 baseline US ethanol production by around 100 kb/d to 535 kb/d, which we see growing to 730 kb/d by 2010.

Mandates Only Partly a Driver of Growth

While mandates in certain countries – foremost in the US – provide a certain *floor* to growth, high oil prices and environmental concerns continue to ensure the search for non-fossil alternatives. But compared to last year's *MTOMR*, the passage of the US *Energy Independence and Security Act (EISA)* in December 2007 lends considerably more support to US ethanol (and biodiesel) producers and production.

Nevertheless, EISA is not set in stone. The bill started attracting criticism almost as soon as it had passed. This report does not forecast political developments and as such we have cautiously assumed that the bill's ethanol mandates will be met until 2010. (Last year we were forced to take an even more cautious stance, as the mandate had not yet become law). This fits with current production growth rates as well as production capacity either under construction or firmly planned. As such, it provides a floor to US biofuels production growth for the next few years.

In the European Union, the situation is not quite the same. Currently, a 5.75% *target* by 2010 is in place, which many countries were attempting to meet (or in some cases, hoping to exceed, e.g. France). In January 2008 the European Commission put forward a proposed directive, recommending the more ambitious goal of a 10% biofuels *mandate* to be reached by 2020, as part of an overall 20% share of renewables in the EU's energy mix. However, at the time of writing, this had not yet been adopted by the European Parliament and as such is still viewed as a more loose 'target' for the purpose of this report's forecasting.

US Renewable Fuel Standard (RFS): Mandated Biofuel Volumes (kb/d)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Conventional biofuels	**587**	**685**	**783**	**822**	**861**	**900**	**939**	**978**	**978**	**978**	**978**	**978**	**978**	**978**	**978**
of which ethanol	587	652	740	770	796	835	874	913	978	978	978	978	978	978	978
of which biodiesel		33	42	52	65	65	65	65							
Advanced biofuels		**39**	**62**	**88**	**130**	**179**	**245**	**359**	**473**	**587**	**718**	**848**	**978**	**1,174**	**1,370**
of which cellulosic ethanol			7	16	33	65	114	196	277	359	457	554	685	881	1,044
of which other advanced biofuel		39	55	72	98	114	130	163	196	228	261	294	294	294	326
TOTAL RFS	**587**	**724**	**845**	**910**	**992**	**1,080**	**1,184**	**1,337**	**1,451**	**1,566**	**1,696**	**1,826**	**1,957**	**2,153**	**2,348**

Given current polarised views on the assumed benefits of biofuels, it cannot in our opinion be taken for granted that the 10% goal will necessarily be mandated or met. Indeed, several EU countries have themselves expressed doubts that they will be able to meet the 5.75% target by 2010. Also, a current theme in the debate is to set environmental criteria (e.g. life-cycle energy efficiency, CO_2 emissions, crop source) that would limit certain kinds of biofuels – both for production and imports. Recent proposals along these lines could conceivably exclude biofuels based on corn, rapeseed and palm oil, which would mean a very substantial reduction in current production. On the other hand, it would serve to give a boost to second-generation fuels, for which many of these problems are no longer relevant.

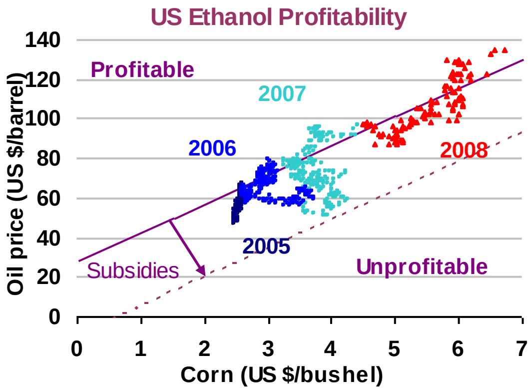
Four Reasons Suggesting a Ceiling to Growth

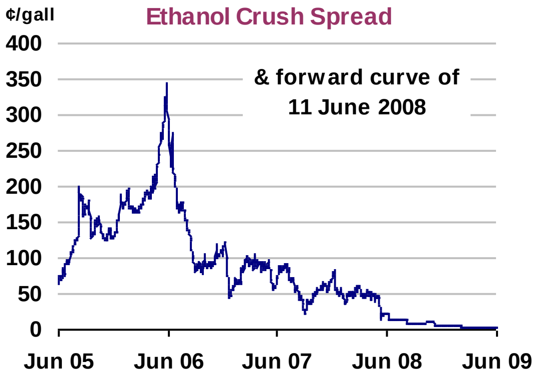
In the same way as mandates provide a minimum level of growth, there are reasons to assume that effectively there is also a ceiling to growth in biofuels supply – at least for first-generation fuels based on food crops. *Firstly*, leaving aside the political and/or moral question of how much increased biofuels production contributes to rising food prices, there is the issue of land availability. Even with a bumper corn (maize) crop in the US this year, it is estimated that just over one-third of the crop will go towards fuel ethanol production, and without more land devoted to corn production, or higher crop yields, rising ethanol production is clearly bound to raise this share.

Initial drafts of the bill that became EISA in December 2007 had considerably more ambitious mandates for corn-based ethanol, but according to most estimates, including by the US Department of Energy (DoE), production no higher than 12-15 billion gallons (~780-980 kb/d) is ultimately possible given land availability in the US. A previous and widely-read study by the US DoE and Department of Agriculture (USDA) also projected that 15 billion gallons is achievable (the so-called *Billion-Ton Study*, April 2005). The latter would actually also equate to approximately one-third of (expanded) corn output in 2015.

Secondly, infrastructure remains a key concern. In the US for instance, now the world's largest producer of biofuels, the issue is due to the fact that production is centred in the corn-producing Midwest, while the country's largest gasoline-consuming states are around the coastal fringe of the US. As ethanol can only be blended into gasoline in the latter stages of the supply chain, this effectively requires a secondary and stand-alone infrastructural network. Ethanol pipelines are as yet non-existent (though are being considered), requiring rail or truck transport to ship to refineries or blending terminals. In some cases, ethanol is also blended in fuel trucks just before delivery, a process known as 'splash blending'. Even at blending terminals, ports etc, separate tankage for ethanol is not always sufficient yet, limiting operations. For biodiesel, the problems are far less severe, as it can essentially be pumped and stored in combination with fossil diesel without much difficulty.

Vehicle technology is the *third* reason to argue for a ceiling to (ethanol) growth. Most countries and car manufacturers are confident that a 10% blend (so-called 'E10', i.e. 90% gasoline, 10% ethanol) can easily be introduced without any necessary technical modifications or appreciable impact on a vehicle's performance or engine. But for instance in the US, where the new EISA mandate implies a nationwide ethanol blend of approximately 5% of gasoline demand this year, regional differences in ethanol penetration mean that some regions require higher blend shares. While an E85 blend (i.e. 85% ethanol blended with 15% gasoline) is not uncommon in the Midwest, and vehicles have been adapted and cope accordingly, this is not true elsewhere. Technically it may be feasible to hike the percentage share without any repercussions, but current automobile manufacturers' warranties may not cover this. In Germany, worries that some older cars may be negatively affected even by an E10 ethanol blend recently caused a government debate over whether to pull back from supporting the plan to double the existing 5% mandate to 10% by 2009.





Lastly, there remains a big question mark over the potential profitability of biofuels production. As outlined above, the economics in the US of corn-based ethanol production currently appear satisfactory – at least when taking subsidies into account. But while it is difficult to exactly calculate the economics of biofuels production on an aggregate basis, European and Asian margins have reportedly been weak and many producers have complained about the need to either lower utilisation rates, suspend or even halt operations. Several producers have announced bankruptcy. While the constraints due to land availability, infrastructure and the vehicle fleet could in theory be addressed by second-generation biofuels and technology respectively, weak or negative profit margins for biofuels producers will be prohibitive. This is thus our main reason for retaining a cautious stance on future growth, even in the US.

Regional Developments

US and the Americas

The US, as outlined above, is both the largest biofuels producer in the world, and – with Brazil – the one with the greatest growth potential. This report had flagged these points in last year's edition, but the December passage of EISA has introduced the world's most ambitious mandate for biofuels. As outlined above, we remain sceptical whether this mandate can be achieved in its current form, though until 2010, we see rapid growth in line with mandate steps. On the basis of not only the mandate, but also higher-than-expected actual production figures, more rapid-than-expected capacity growth and steady if not stunning economics, we have thus revised up our production forecast by a substantial 100 kb/d in 2008 as well as by around 210 kb/d and 240 kb/d, respectively, in 2009/10.

From 2010, as with all other countries bar Brazil, we have nonetheless kept US biofuels production growth capped too. Biodiesel production too has grown rapidly in recent years, from a low base, but is forecast to remain relatively small compared to ethanol. In sum, US biofuels production will grow from an upwardly-revised 2008 baseline of 570 kb/d to 770 kb/d by 2010. Total *potential* capacity (i.e. either under construction or planned) could reach 1.1 mb/d by 2010.

At the time of writing, significant floods had hit the US Midwest. These may yet substantially affect US corn production and, given low corn stocks, in turn also affect ethanol output. Corn prices also rose, with some ethanol producers warning of delays to new start-ups, and profitability may be hit. More broadly speaking, the shift towards more crop-based biofuels use as an oil substitute – while in part an attempt to increase supply security by lowering crude oil imports – implies a shift from geopolitical to weather risk.

Biofuels' other giant remains Brazil which, as we outlined last year, enjoys a unique advantage in terms of production costs, agriculture and infrastructure. As our assumptions on Brazil have not changed, our production numbers have hardly changed. We have again kept output uncapped post-2010 and have revised growth up by 20-30 kb/d in the tail-end two years of our forecast. Despite some small downward revisions to other Latin American producing countries, the region as a whole has thus been revised up in the forecast.

Hopes Pinned on Second-Generation Biofuels

This report assumes that so-called second-generation or advanced biofuels – in other words ethanol and diesel produced from non-food, ligno-cellulosic plant biomass by biochemical or thermochemical techniques – will only become economically viable in significant volumes in a time period that falls beyond our 2013 horizon. Currently, there are four pilot plants in the US and a handful elsewhere (e.g. Germany, Japan), whose collective production is minimal (less than 1 kb/d in total).

According to the *ACT* scenario in the IEA's recently published *Energy Technology Perspectives 2008*, ligno-cellulosic ethanol production in the US will contribute around 50 kb/d by 2015. Most other assessments also do not foresee any substantial contribution to global biofuels production in the next five years, so this report has not included any in its framework.

Clearly, besides the price environment, technology and the precise nature of political and fiscal support for second-generation biofuels will determine when exactly they enter the market in a meaningful way. Other criteria for their success can be listed as firstly, the need for ample feedstocks, secondly the need for product compatibility with blending and transport infrastructure, and thirdly that advanced fuels are compatible with current engines and engine performance.

While for the time horizon of this report, second-generation biofuels are not much of an issue, concerns remain about the potential to ramp up production in the ambitious manner the recent US legislation mandates. EISA would already require around 65 kb/d of cellulosic ethanol by 2013 – the tail-end of this report's timeframe – which, as outlined above, we do not necessarily see happening.

It is worth emphasising that we retain a rather cautious stance on second-generation biofuels. Assuming the EISA mandate in the US stays in place, subsidies are maintained, or even increased[1], and technological breakthroughs come more quickly than expected, it is conceivable that production is ramped up in a more rapid fashion. After all, few had until recently expected the recent and expected strong growth in conventional US ethanol made from corn.

[1] The *Food, Conservation, and Energy Act* passed by the US Congress in May this year provides for a new $1.01/gallon subsidy/tax credit for cellulosic ethanol until 2012, while the existing blending subsidy for corn ethanol was trimmed from ¢51 to ¢45/gallon.

Europe

On average, OECD Europe has seen the largest downward revisions, as weak or negative margins crimp utilisation rates and slow capacity increases. In some cases, plants have even halted production or been forced to declare bankruptcy. But production is nonetheless increasing, given the impetus of high oil prices, environmental concerns and support policies/subsidies. From a downward-revised 2008 baseline of 225 kb/d total biofuels production, we see production growing to 280 kb/d by 2010. Unlike other regions, biodiesel is the dominant fuel, making up around two-thirds of total output in 2008, though declining to a share of around 60% by 2010.

The European biodiesel industry may have suffered due to what it sees as unfair competition from doubly-subsidised imports. In a process nicknamed 'splash and dash', it is alleged that biodiesel is sourced from Asia and imported into the US, where – when blended with a minimal amount (a 'splash') of regular diesel – it attracts a subsidy. Subsequently, it is sent over to the EU (the 'dash'), where it is eligible for a second subsidy, enabling it to undercut the price of EU-produced fuel. The European lobby group, European Biodiesel Board (EBB), has formally filed complaints against this process, which may eventually see it halted.

Asia-Pacific

Weak margins and project slippage have led us to revise down biofuels production numbers in most Asia-Pacific countries. Prices of palm oil – the most common feedstock for biodiesel production – have soared, as have those of other crops. In addition, regional producers have suffered perhaps more than in other parts of the world from bad press due to perceived feedstock competition with food production and deforestation to expand feedstock crop plantations.

From a downward-revised 2008 baseline of 135 kb/d in total Asia (OECD and non-OECD combined), we now see total biofuels production growing to 190 kb/d by 2010. Downward revisions were made for most producing countries, notably Thailand, India, Malaysia and Indonesia – among the region's largest. In contrast, we mostly revised up production figures for China, which we now estimate will increase production from around 50 kb/d in 2008 to around 80 kb/d in 2010. China will thus remain Asia's largest ethanol and biodiesel producer by far.

Implications for the Oil Market

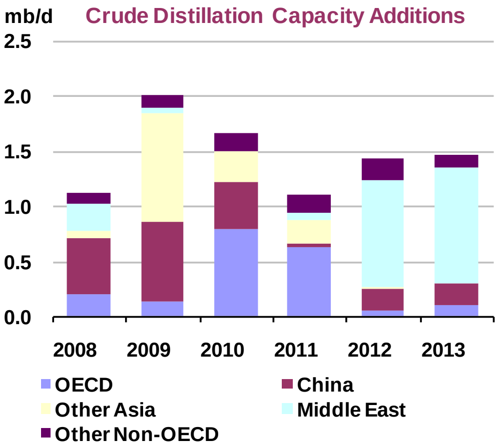
Biofuels production will remain a relatively small share of the oil product mix in the next five years. According to this report's estimates, ethanol will displace 5.0% of gasoline demand and biodiesel 1.0% of gasoil/diesel demand respectively by the end of our forecast period. But crucially, biofuels have become a substantial part of faltering non-OPEC supply growth, contributing around 50% of incremental supply in the 2008-2013 period.

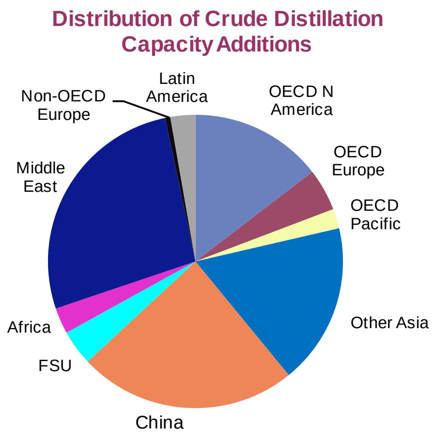
More dramatically perhaps, given that ethanol and biodiesel displace high-quality fossil fuel-based products, the actual volume of *crude oil* that is theoretically displaced is larger still. In other words, to produce 1 barrel of gasoline may require as much as 2 barrels of crude in a highly complex refinery and many more in a simpler plant. Assuming on the one hand a typical US cracking refinery gasoline yield of 47.5%, and on the other a typical European hydroskimming refinery gasoline yield of 6.4%, this implies that for average yearly global ethanol production growth of 110 kb/d in the period 2008-2013 anything between 230-1,720 kb/d of crude is being displaced. This is a hypothetical number, and given that the lion's share of ethanol production growth is set to come from the US, the lower end of the range would be more representative. Meagre non-OPEC supply growth, averaging 230 kb/d per year from 2008-13, is a major factor behind today's high physical and futures prices for oil. As a result, any contribution to growth from the biofuels sector will remain significant.

REFINERY ACTIVITY

Summary

- **Refinery investment is forecast to add 8.8 mb/d of crude distillation capacity between 2008 and 2013**. Growth is dominated by the Middle East, China and Other Asia. OECD regions account for just over 20% of the forecast increase, but more than a third of the investment in upgrading capacity.
- **Crude distillation capacity additions during 2008/2009 are dominated by China and Other Asia**, followed by the completion of projects within OECD North America and Europe during 2010 and 2011, before the large grassroots refineries in the Middle East dominate growth in 2012 and 2013.
- **Increasing cost pressures have added 50% to investment expenditures over the past two years,** forcing companies to re-evaluate investment plans, prospective returns and likely delays to completion dates. This, in combination with rising lead times for delivery of upgrading and hydrotreating units, has caused significant slippage to expected capacity expansions, reducing our 2012 global crude distillation capacity estimate by 1.0 mb/d from last year's assessment.





- **This forecast remains subject to certain risks. Specifically, the emergence of excess supply potential in the gasoline market,** particularly in the Atlantic Basin has, in combination with heavily negative fuel oil cracks, weakened refinery margins. This reduces the operating cash flow necessary to fund investments by refiners and the potential rate of return achievable.

Overview

Global refinery expansion plans are forecast to add 8.8 mb/d of crude distillation capacity by 2013. Growth is centred in the Middle East, China and Other Asia. These regions add a combined 6.0 mb/d, with some 2.6 mb/d due on line before the end of 2009 and the balance concentrated in 2012 and 2013.

OECD crude distillation capacity growth of 1.9 mb/d continues to be biased towards North America, with 1.3 mb/d of new crude capacity expected on stream before the end of the forecast period. The OECD forecast is relatively unchanged from last year's *MTOMR* in volume terms, but masks some intra-regional offsets. While some project slippage, due to regulatory delays and cost pressures, has occurred in North America, expectations for OECD Europe and the Pacific have been increased as a result of better visibility on several projects aimed at improving light product yields and product quality. In contrast to last year's forecast we have excluded capacity creep from our forecasts this year, thanks to better visibility on the smaller projects that we sensed we were missing previously.

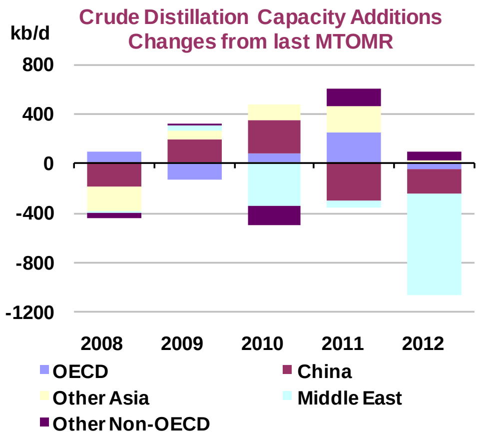
Forecast growth has, once again, been subject to significant downward revisions due to a combination of rising costs and tightness in engineering, contractor and fabrication markets. Rising costs have slowed the approval process by project sponsors, as they consider the implications for future returns on their investment. Furthermore, refinery unit manufacturers have reported a continued increase in their order backlogs, pushing delivery times further back and contributing to delays. Little respite is visible from these difficult conditions, raising the possibility that additional delays will develop in the future.

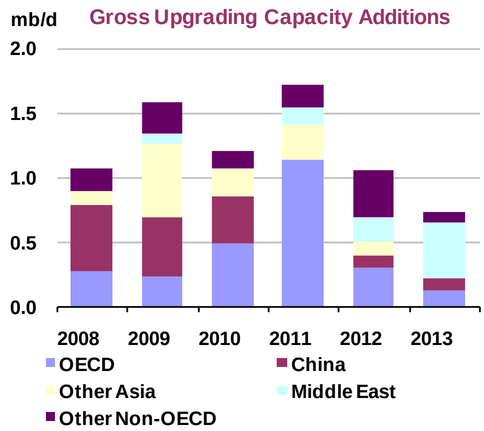
Global Crude Distillation Capacity Additions

(thousand barrels per day)

	2008	2009	2010	2011	2012	2013	Total
OECD	202	134	782	618	45	100	1,881
China	512	726	430	40	200	200	2,108
Other Asia	60	979	283	220	20		1,562
Middle East	246	50		60	962	1,050	2,368
Other Non-OECD	106	120	158	170	212	120	886
Total World	1,125	2,009	1,653	1,108	1,439	1,470	8,805
Changes from July 2007 MTOMR	-367	176	-31	245	-982		-959

Furthermore, the easing of gasoline market tightness, highlighted in last year's report, appears to have started to undermine gasoline cracks, reducing overall refinery profitability and threatening the financial viability of projects that are still in the design and engineering phase. These projects are typically due to start processing crude from 2012 onwards, creating the real possibility that these latter capacity expansions are more tenuous, in light of our revised crude supply and product demand forecasts and the weaker refining margin outlook. Under a scenario of depressed refining profitability we estimate that capacity growth could fall as low as 7.0 mb/d for the period 2008-2013, but strategic investment in the Middle East and China, in addition to the high profile projects in OECD North America underpin this level of growth.





Rising crude prices bring an additional financial burden to refineries. The operating cost of refining is directly linked to the cost of fuel consumed in generating the heat, pressure and hydrogen that form the crux of many refinery processes. Furthermore, the financing cost of processing crude has risen in line with the crude price, stretching balance sheets and weighing on operating cash flow. Lastly, the costs of other inputs into refining such as catalysts, have also risen due to heavy increases in precious metal prices, e.g. platinum.

The prevalence of capped product prices in several non-OECD countries is forcing refiners to shoulder an additional financial burden. Notably, both India and China are pushing refiners to ensure product supplies meet demand, despite the losses incurred by them in doing so. Such policies are constraining investment in India by some state refiners, while Chinese refiners have successfully obtained tax breaks and more frequent subsidy payments from the central government to ease the financial burden. Ultimately, a move to liberalise prices would remove this additional burden from refiners in both countries.

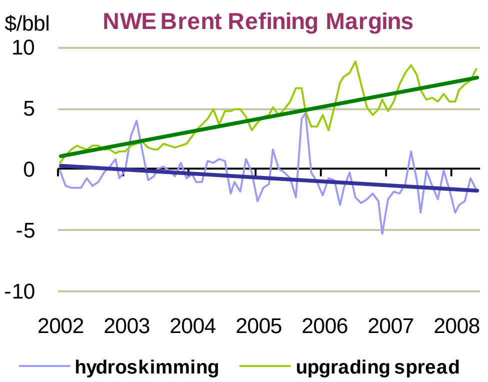
Nonetheless, capacity growth is set to accelerate throughout the course of 2008 and into 2009, driven by a build-up of projects in China and Other Asia, which are expected to add 2.3 mb/d by the end of 2009. Thereafter, growth eases back in 2010 with a shift in focus to OECD North America and Europe where the first of a series of large refinery expansions is expected to be completed. 2011 sees the low-point in forecast crude capacity growth at 1.1 mb/d, before accelerating again to almost 1.5 mb/d in 2012 and 2013.

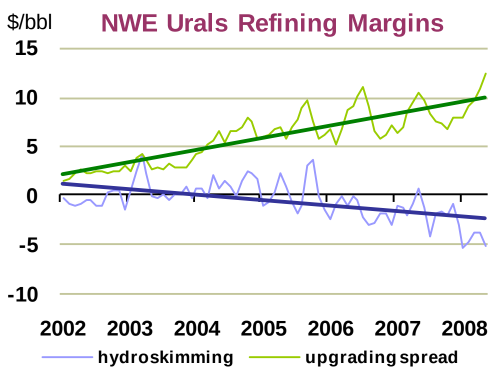
OECD regions account for only 21% of crude distillation capacity additions, but nearly one third of investment in upgrading units. Refiners in North America are driven by the prospect of cheaper, Canadian bitumen supplies, which require more intensive processing. In OECD Europe, the structural shortfall in diesel supply compared to regional demand has pushed refiners, particularly in the Iberian Peninsula, to press ahead with significant investment projects. In the OECD Pacific the Korean refiners' investment programmes, which are aimed at increasing the overall level of complexity, drive much of the forecast change in the region, with the last hydroskimming facility in Korea due to be upgraded to a hydrocracking configuration by late 2011.

Refinery Economics

Despite record distillate cracks, refining margins in the US and elsewhere, have fallen year-on-year as weak gasoline cracks and record-low fuel oil cracks weigh on refinery profitability. The apparent loss of pricing power in gasoline markets reflects the easing of market tightness due to the combination of anaemic global demand growth, rising ethanol blending and increased supply potential.

This rising supply potential was flagged in last year's report and, as expected, has been most evident in the Atlantic Basin. Here the structural mismatch of European refinery capacity to the continued dieselisation of the car fleet suggests that the growth in gasoline exports will continue into the medium term. However, the offsetting structural import requirement in North America looks likely to shrink in the coming years.





Consequently, European refiners will need to find alternative outlets for their surplus gasoline production, or compete more aggressively for North American market share. Even allowing for the ongoing shift in US refinery yields towards distillate, refiners on both sides of the Atlantic may be forced to reapply the voluntary run cuts that were evident over the first half of 2008, unless alternative markets for gasoline-type hydrocarbons, e.g. additional naphtha demand from petrochemical plants, are created by changes to price differentials.

In the longer term, one possible solution is for European refineries to replace catalytic cracking capacity with new hydrocracking capacity. However, this would require significant investment, which appears unlikely given the prospect of CO_2 emissions taxation in the future. Furthermore, despite the overall weakness in margin levels, the upgrading margin (as measured by the difference between hydroskimming and cracking margins) has continued to increase - a reflection of the continued need to minimise fuel oil production. The prospect of the arrival of large export-orientated refineries, in India at the end of 2008 and the Middle East in 2013, further clouds the economic outlook for refining investment over the medium term. Yet, refiners retain the option of cutting runs to address product market imbalances in an attempt to restore profitability to their business and the industry as a whole and these may become a more common occurrence in Europe and possibly the US in the future.

International Marine Bunkers – All Stop for Fuel Oil?

Perhaps the most important change in fuel quality that lies ahead is in the international marine bunker market. The International Maritime Organisation (IMO) appears ready to approve the move from the current 4.5% sulphur limit to a 3.5% limit in 2012 and a 0.5% limit for all bunker fuels by 2020, subject to a feasibility review in 2018, with 2025 as the fall-back position. Furthermore, the Sulphur Emission Control Areas (SECA), of which there are currently two, in the North Sea and the Baltic, would adopt a 1% sulphur limit in 2010 (from 1.5% currently) and a 0.1% limit in 2015. In addition to the existing SECAs, it is likely that additional SECAs, in the Mediterranean and on the US West Coast, will also come into force. The scale of the potential change in demand is enormous. Current demand estimates for international marine bunkers, the majority of which is fuel oil, range from 4.0 mb/d to 7.5 mb/d, with IEA statistics indicating the lower end of this.

Furthermore, it seems likely that the proposed IMO regulations will also allow ships to fit emission control technology, such as particulate scrubbers, in order to achieve the same environmental improvement as using 0.5% sulphur fuel. Current price spreads between 0.5% sulphur gasoil and high sulphur fuel oil suggest that such an investment would offer a payback period of around three months for ship owners. This raises the possibility that vessels will not necessarily change to 0.5% sulphur fuel and that some will continue to use high sulphur fuel oil.

In addition to the potential scale of the challenge facing refineries, it should be noted that while it is technically feasible to desulphurise fuel oil that is straight-run atmospheric residue, it is far more difficult to hydrotreat thermally or catalytically cracked residues. Consequently, it appears unlikely that refineries will opt to invest in large scale hydrotreating of fuel oil, as the current price differentials for low and high sulphur fuel oil do not generate a satisfactory return on the significant investment costs entailed. This suggests that where refiners do undertake investment it will be to upgrade the fuel oil into distillate.

Once again, not all of the fuel oil can be easily upgraded. Upgrading straight-run atmospheric residue requires refineries to spend around $3 billion per 100 kb/d of fuel oil to be converted (and secure CO2 permits for the additional units if this occurs in a region that introduces some form of carbon pricing). The bigger challenge lies in upgrading the fuel oil that is blended from thermally or catalytically cracked residues. Unlike straight-run atmospheric residues, these are difficult to process further raising a question mark as to how they could be converted into distillate. In theory such material could be processed by a coker and subsequently hydrocracked or severely hydrotreated.

Refineries will also need to compensate for the volume loss associated with upgrading fuel oil. Typically coking processes convert around 30% of the feedstock to coke, and produce small amounts of light and middle distillate that are not suitable for use in marine fuels. This suggests that additional crude will need to be processed to meet low-sulphur marine fuel demand.

Refiners therefore face the dual challenge of possibly having to convert a significant proportion of high sulphur fuel oil into 0.5% and 0.1% sulphur distillate, but that the demand for the fuel is not guaranteed as current price spreads offer ship owners a big incentive to install emission control technologies. Furthermore, unless there is a significant increase in engineering and fabrication industries' capacity to supply the necessary processing units, the risk remains that the 2020 deadline may slip back to 2025.

Uncertainty over the future return on an investment is not a new phenomenon. Nor is it restricted to refiners who publish quarterly earnings and face heavy scrutiny of their cash flow statements. Potential returns on investment are also a concern for national oil companies (NOCs). Although many of the projects proposed by them are seen as strategic investments, the participation of private sector companies in joint venture projects entails lengthy negotiations over the prospective returns. Furthermore, even those projects wholly within the control of NOCs have witnessed significant slippage in project timing and cost escalation.

Anecdotal evidence suggests that costs have increased by around 50% over the past two years, although scrutiny of the published industry cost statistics appears to understate this. Further cost increases look likely with the continued contractor and technology licensor companies working at capacity. Additionally, the increasing lead time for delivery of heavy plate vessels, necessary for much of the high-pressure processes integral to producing low-sulphur fuels, also indicates that investment will face continued challenges in years to come.

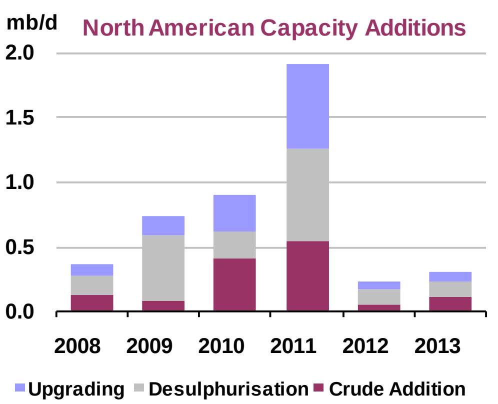
Regional Analysis of Capacity Expansions

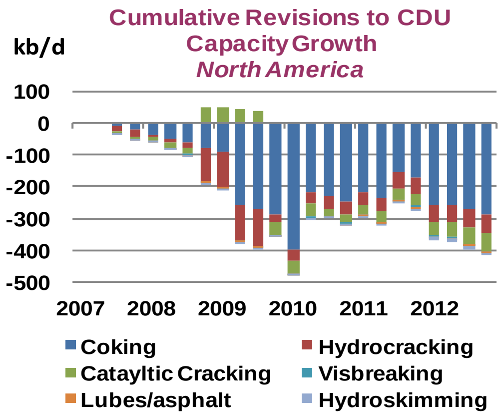
North America

North American crude distillation capacity is expected to increase by 1.3 mb/d, during the period 2008-2013 and is broadly in line with last year's forecast. Visible progress at several of the key large-scale expansion projects gives us some confidence that existing completion targets are likely to be met. However, as discussed above, delays from regulatory and environmental hurdles continue to present significant obstacles to refinery expansion plans.

Investment in North America seeks to achieve two priorities. Firstly, to increase the refinery's ability to process heavy sour crude and thus improve the competitive position of the refinery. Secondly, to meet the tighter environmental standards for stationary source emissions that are being demanded by environmental agencies.

The prospect of increased heavy Canadian crude supplies over the next five years has pushed several US refineries (largely in the northern US states) to retool their plants to benefit from this potentially cheaper, more difficult to process crude supply. Notable examples include ConocoPhillips' Wood River and Borger refineries, Marathon's Detroit refinery and BP's Whiting refinery. For the region as a whole, investment appears heavily biased towards upgrading, with the increase in crude distillation capacity roughly equal to the increase in both vacuum distillation, and the sum of hydrocracking and coking capacity. This will lift the production of transport fuels, while minimising fuel oil production.





Similarly, the expansion of Motiva's Port Arthur refinery, which we continue to assume will be on-stream in 2011, is also to allow processing of a heavier, sourer crude slate. We assume that at least 50% of the enlarged 600 kb/d refinery will run on Saudi Arabian Heavy crude. Lastly, the 180 kb/d expansion of Marathon's Garyville, Louisiana, refinery will enable the processing of heavier crude and raise the production of diesel, while reducing the production of fuel oil.

Detailed analysis of the expansion plan proposals, submitted to environmental agencies, suggest that refiners continue to invest significantly to apply the best available technologies to improve energy efficiency and environmental impact of their operations.

Mexican refinery capacity growth is almost wholly dependant on the much delayed Minatitlán refinery expansion. Greater clarity on how PEMEX will resolve the issue of rising project costs, given its budgetary constraints, suggests that it is closer to resolution than previously thought. We have, therefore, assumed that a completion date of 2010 is realistic for this project. Furthermore, we include upgrades to the Salamanca and Salina Cruz refineries by the end of the forecast period. However, the grassroots refinery suggested at Veracruz remains beyond the scope of this report and is unlikely to become a reality before 2015. The rising refined product import bill that PEMEX faces provides a clear impetus to address the structural shortfall in domestic refining capacity in the coming years, despite the ease with which gasoline supplies can currently be sourced from markets such as Europe.

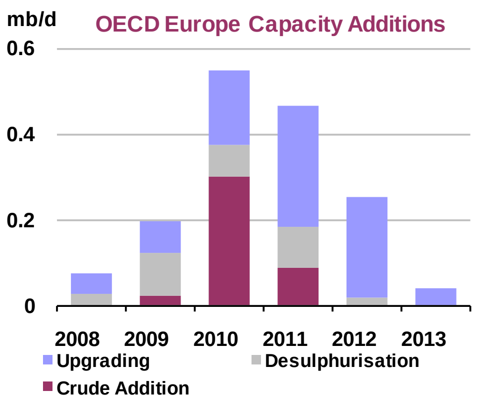
Key Projects	2008	2009	2010	2011	2012	2013
OECD North America		Borger	Garyville Minatitlan	Port Arthur Whiting Wood River Detroit		

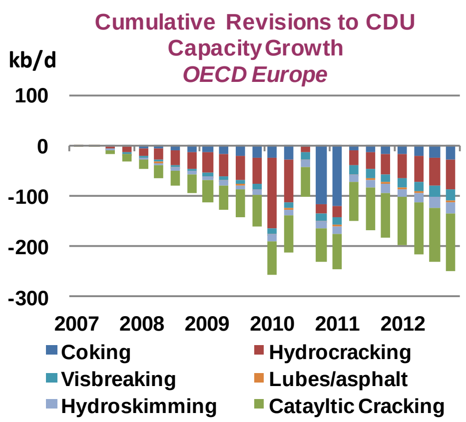
Canadian refinery crude distillation growth must rely on the 50 kb/d expansion of Valero's Montreal refinery this year and the 30 kb/d expansion of CCRL's Saskatchewan refinery which we assume will happen in 2012. However, we continue to exclude NLRC's 300 kb/d refinery in Newfoundland, as progress does not provide us with sufficient confidence to include it within the 2013 timeframe. Similarly, Irving's 300 kb/d refinery in New Brunswick is now targeting a 2015 start-up, which we consider more realistic than the previous 2012 estimate.

The growth in North American upgrading capacity (mainly coking and hydrocracking) remains strong, driven as it is by the switch to a heavier crude slate and the need to address rising demand for diesel. Hydrotreating capacity will also increase as refiners continue to prepare for tighter product specifications being applied to off-road diesel at the turn of the decade. Other hydrotreating additions focus on pretreating FCC feedstock to raise light product yields as more lower-quality VGO is produced from the Canadian synthetic crudes.

Europe

European (including both OECD and Non-OECD Europe) refinery expansion plans are aimed squarely at addressing the region's structural shortage in diesel. Increased crude distillation capacity of 400 kb/d is almost exclusively associated with projects to boost diesel production significantly through the installation of hydrocracking and/or coking capacity. Furthermore, it is once again striking that the





expansion of vacuum distillation, hydrocracking and diesel hydrotreating capacity is almost equal to the addition of crude distillation capacity.

Some project slippage has been seen in the region, reflecting the tight contractor market. One European refiner estimated that lead times for the delivery of pressure vessels had increased by 20% over the first nine months of the 2007, and is likely to increase further in the near future.

In the Mediterranean, projects in Spain (see text box below *The Iberian Peninsula – Driving European Refinery Investment*), Greece, Italy and Croatia are responsible for the increase in crude capacity, most of which is supporting the expansion of upgrading capacity. Furthermore, Italian refineries including Eni's Taranto, Sannazzaro and Porto Marghera plants and the Saras, Tamoil and IES refineries are forecast to add almost 70 kb/d of hydrocracking capacity and more than 35 kb/d of residue hydrocracking capacity by 2013.

We remain sceptical of the prospects for green field refineries at Ceyhan in Turkey within the 2013 timeframe, despite government approval of four separate projects. Similarly the proposed 110 kb/d Balboa refinery in northwest Spain is excluded due to a lack of visible progress.

The Iberian Peninsula – Driving European Refinery Investment

Refinery expansions in Portugal and Spain, deliver almost half of Europe's forecast capacity growth through to 2013. The region has retained its position as the second largest diesel importer in Europe, after France. Unlike French refineries, where we see little prospect of a material change in the complexity and product mix, Spanish and Portuguese refineries are set to undergo a period of rapid change in the next five years.

Net imports of diesel in the Iberian Peninsula have been increasing in recent years, as demand growth, averaging 5% over the last five years, has exceeded supply increases. In addition to the increasing regional supply shortfall, discussions with refiners cite three key reasons for the move to boost refinery complexity.

Firstly, the increasingly tight product specifications for transportation fuels that are due to come into force in Europe will necessitate significant investment even to maintain the status quo of Spanish refineries' competitive position.

Secondly, the prospect of tighter fuel oil specifications being introduced, both for inland and international marine bunkers, over the next five to 10 years will require additional hydrotreating investment which offers little opportunity for a satisfactory return on investment, at today's market prices.

Thirdly, the opportunity to switch the crude slate to a heavier, sourer intake, offer the prospect of increased margin potential.

Consequently, refineries have opted, in one form or another, to reduce the exposure to, or exit, the fuel oil market and at the same time convert the fuel oil into light products with a bias toward middle distillates.

The key projects in the region include:

- Repsol YPF's 110 kb/d expansion of the Cartagena refinery; converting a 100 kb/d hydroskimming refinery into a 220 kb/d full conversion refinery, through the addition of coking and hydrocracking units, This upgrade is expected to increase middle distillate supplies by 91 kb/d and reduce fuel oil production to almost zero. This project is forecast by Repsol YPF to cost $3.2bln, and we estimate it will be completed in 2011.
- Repsol YPF's plans to add coking capacity to its Tarragona and Bilbao refineries; which we forecast will be completed by late 2013.
- BP's completion in early 2009 of the project to add a 20 kb/d coker unit at its Castellon refinery.
- CEPSA's planned addition of hydrocracking at the Huelva refinery and mild hydrocracking capacity at the Cadiz refinery by the end of 2010.
- Galp Energia's investment plans at its Porto and Sines refineries, which by 2011 are expected to include a hydrocracker and visbreaker.

By contrast, France's large structural diesel deficit, which in 2007 was around 30% bigger in volume terms than Iberia's, shows little or no sign of improvement given the lack of French projects currently being undertaken to boost diesel production.

In Northwest Europe, expansion plans appear more limited. This may be partly due to recently completed upgrading projects, e.g. Total's hydrocracker in Gonfreville and Neste's residue hydrocracker at Porvoo. However, as in the Mediterranean, we expect significant work during the balance of 2008 to prepare for the tighter diesel and gasoline sulphur specifications coming into force at the beginning of 2009. Nevertheless, by 2013 investment in hydrocracking capacity at refineries in Germany, notably ConocoPhillips Wilhelmshaven, and the Czech Republic and Poland are all forecast to be completed.

Key Projects	2008	2009	2010	2011	2012	2013
OECD Europe		Castellon Sannazzaro	Cadiz, Huelva Lotos Gdansk	Cartagena	Sannazzaro	Tarragona

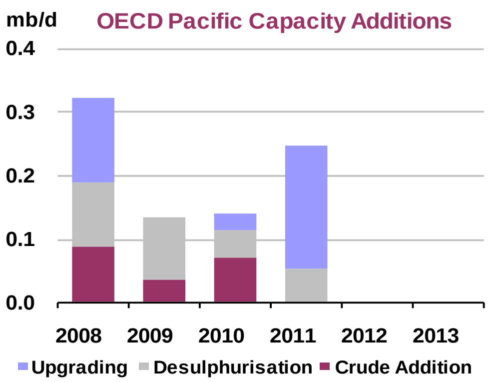
Little investment is expected in gasoline capacity in Europe, as the region already suffers from a structural surplus. Conversely, investment in diesel hydrotreating capacity is expected to continue with some 300 kb/d expected by 2013, as refiners are required to produce off-road diesel and marine gasoil for inland use meeting a strict 10 ppm sulphur limit possibly as soon as 2011.

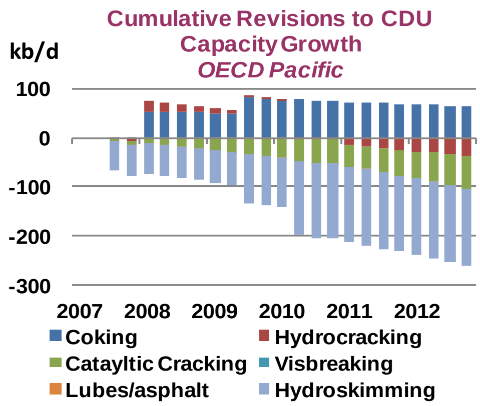
Non-OECD European investment plans are centred on the planned upgrades to INA's Rijeka and Sisak refineries which we expect to be completed by 2010 and the expansion of Petrobrazi's Ploiesti refinery by 2011. Several further refinery expansions have been announced, but they do not appear sufficiently developed to be included within our forecasts.

OECD Pacific

OECD Pacific refinery investments revolve around three core themes:

- How Japanese refiners meet the challenge of the long-term decline in domestic demand;
- The continued demand growth for petrochemical products (and hence feedstocks such as naphtha and LPG) within the region, and across the wider Asian area; and;
- Korean refiners' continued investment to increase the overall complexity of their operations through the addition of further upgrading capacity.





The long-term decline in Japanese demand in both transport fuels and residual fuel oil presents a challenge to refiners, given the high costs associated with exiting the industry. Declining transportation demand reflects Japan's demographics and continued technical innovation, which is raising fuel efficiency. Despite the resurgence in demand for fuel oil in Japan from power generators in recent quarters (following operating problems at several nuclear plants), a resumption of the long-term trend of substitution of fuel oil and crude for other fuel sources is likely later in the forecast period. This combination of factors is forcing refiners to adopt one of three strategies:

- Sell non-core refineries to third parties, or alternatively close the refinery and operate the location as a distribution terminal;
- Develop export markets for their refinery production. Recent monthly statistics point to a growing trade relationship between China and Japan, as rising export volumes of jet fuel and gasoline/diesel have been absorbed by growing Chinese imports; and
- Restructure operations to reduce costs and improve the competitive position, either by merging with other refining companies, through integrating with neighbouring facilities or investment in shared upgrading facilities.

Some investment in the region is aimed at boosting petrochemical feedstock production, with nearly half the forecast increase in crude distillation capacity linked to processing of condensate and the addition of associated petrochemical processing units.

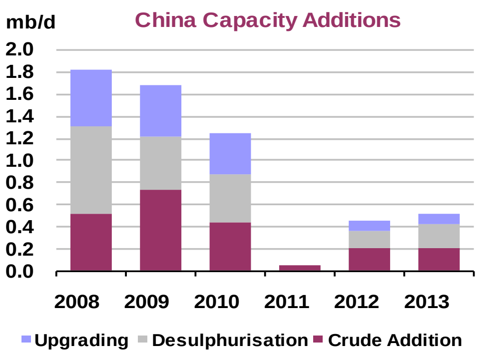
Korean refineries are forecast to add over 100 kb/d of both residue catalytic cracking and hydrocracking capacity during the period 2008 to 2013. This will significantly increase the average complexity of Korean refineries. Furthermore, the recent announcement of a hydrocracker project at SK Incheon's 275 kb/d refinery will upgrade Korea's last hydroskimming refinery and further reduce the fuel oil production from the region's biggest fuel oil net exporter.

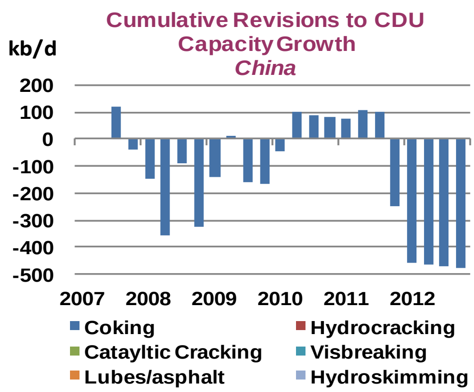
Key Projects	2008	2009	2010	2011	2012	2013
OECD Pacific	Yosu Ulsan		NZRC	Yosu SK Incheon		

Elsewhere, we retain our forecast crude distillation capacity expansion of 35 kb/d in New Zealand, as the refinery, gears up to meet domestic demand growth while continuing to require imports to meet marginal demand. Forthcoming work on hydrotreating capacity will ensure that the refinery can meet the tighter product specifications mandated for 2009.

China

Chinese crude distillation capacity additions contribute around 25% of the total global forecast growth through to 2013, as Chinese state refiners seek to meet expected strong domestic demand growth. Over half of the Chinese capacity growth is expected before the end of 2009 and 80% by the end of 2010, as numerous refinery expansions and grassroots projects start up. Thereafter, growth in refining capacity has a brief hiatus in 2011, before resuming at around 200 kb/d per annum during 2012 and 2013.





This forecast is not without risks, as Chinese refinery construction projects are reported to be battling the cost inflation seen elsewhere and, given the financial strain on state refiners, it is possible that projects could face delays if funding becomes an issue.

Furthermore, our forecasts may systematically overstate the net addition of crude distillation capacity where projects are expansions of existing facilities. The retooling of a refinery to process heavier, sourer crude, or highly acidic crudes may result in part of the current crude distillation capacity being closed or at least mothballed. Our analysis of proposed projects from published sources has highlighted the significant growth in new capacity but has given us less information regarding the prospects for mothballing of older units. We may therefore be slightly overstating the growth in Chinese refinery crude capacity.

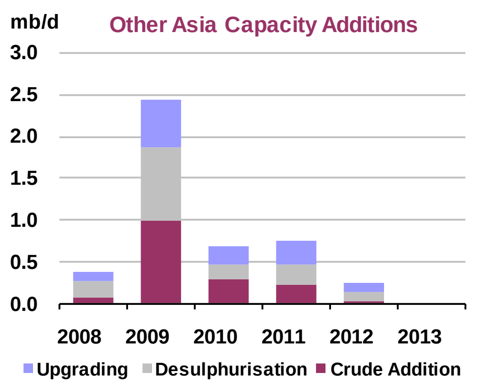
Key Projects	2008	2009	2010	2011	2012	2013
China	Huabei Wuhan Qingdao Luoyang	Dushanzi Huizhou Quanzhou Qinzhou	Tianjin Maoming	Maoming	Nansha	Weihai

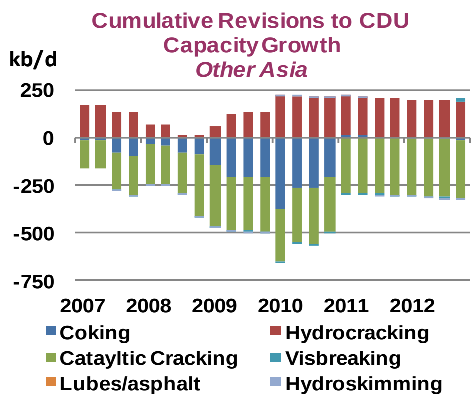
The recent earthquake in western China has led us to exclude the proposed Sichuan province refinery at Pengzhou. Furthermore, we have deferred the KPC/Sinopec Nansha refinery by one year, to late 2012, following reports of problems in obtaining environmental permits. Similarly we have deferred the Maoming refinery following reports that it has encountered problems with its environmental permits, despite approval by the NDRC. In common with other regions, much of the investment is aimed at improving fuel quality as Chinese regulations call for a progressive tightening of quality standards towards OECD standards, although there appears to be some uncertainty over the final timelines.

In addition to the expansion plans of CNOOC, CNPC and Sinopec, there could be a significant contribution to domestic product supply if the Chinese government can resolve the problem of poor utilisation of teapot and independent refineries. However, as long as domestic prices remain capped below world prices and feedstock prices are set by free markets, independent and teapot refiners face uncompensated losses and may be reluctant to operate at full capacity. Removing price caps on domestic sales would help to ensure a vibrant Chinese refining sector, but may in itself bring forth other policy issues which may prove problematic for the Chinese authorities.

Other Asia

Other Asia remains a key driver of global capacity expansion as the third largest area of growth behind the Middle East and China, with 1.6 mb/d of new crude distillation capacity within the timeframe of this report. Within the region, India is still the greatest contributor to growth, with some 1.2 mb/d of new crude distillation capacity. Unsurprisingly, this growth is driven to a large extent by the start-up of Reliance's 580 kb/d Jamnagar refinery expansion which we retain as being fully operational at the beginning of 2009. Elsewhere in the region, Vietnam and Thailand are expected to add over 100 kb/d each before the end of 2009 and growth of around 30 kb/d each in Malaysia and Indonesia





Reliance Petroleum's Jamnagar Refinery – The Star of India?

The start of Reliance Petroleum's 580 kb/d expansion to its Jamnagar refinery represents the largest single addition of refinery capacity globally since 1999, when the original 660 kb/d Jamnagar refinery started. This project represents one third of the entire growth in distillation capacity for the Other Asia region over the forecast period and an even higher proportion of upgrading capacity additions. The start of commercial operations is expected before the end of the year (and possibly before the end of 3Q08) and raises several questions for the medium-term refining outlook:

- Firstly, where will the refinery source its crude from? OPEC spare capacity is forecast to increase from around 2 mb/d currently, to an average of 4 mb/d in 2009. The addition of such a large increment of crude distillation capacity requires additional supplies or the displacement of crude from existing destinations.
- Secondly, where are its target markets? Its status as an Export Orientated Undertaking (EOU) according to Indian fiscal policy requires it to sell at least 75% of its production overseas. Given the significant quality premium its output will enjoy compared to Indian product specifications, all the production (with the exception of LPG) might realistically be exported, so what does this imply for India's domestic supplies?
- Lastly, what impact will the refinery have on global refinery margins? Margins are currently supported by strength in diesel cracks offsetting heavily negative fuel oil and poor gasoline cracks. Increased supplies of diesel suggest a weakening of diesel cracks, which could undermine margins, but at the same time, reduced fuel oil production may help support hydroskimming margins.

It uncertain at this juncture whether additional crude supplies will be made available from OPEC for the expanded Jamnagar refinery. OPEC's rising spare capacity, with the start-up of several key expansion projects, creates the opportunity for additional oil to be supplied to the market. Alternatively, Reliance will need to secure supplies that are currently being used elsewhere.

Our analysis of the proposed refining configuration suggests that the refinery could process crudes as heavy as 25˚API. Consequently, we assume that Reliance will have the potential to source crudes from every major exporting region, possibly with a bias towards heavy Middle Eastern and Latin American grades. The impact on global crude allocations will be felt across Asia and as far a field as the US. Many of the crude grades run at coking refineries are sold on term contracts, leaving little option for sellers to optimise their volumes to (new) third parties. Nevertheless, we see sufficient volumes available to the refinery on the spot market. Nor is it infeasible that the refinery could opt to process atmospheric residue given the heavily discounted price in the current market. Overall, the impact on heavy sour crude markets is likely to put downward pressure on coking margins for some grades, if additional supplies of heavy sour crude are not available.

Product exports are likely to target different regional markets, depending on the relative FOB netback values available. In common with existing Middle Eastern export refineries, production can be tailored to meet the multiple markets' product specifications. Distillate production is likely to be targeted towards the European market. The refinery was originally designed to make 50ppm sulphur material, but is now being modified to enable it to produce 10ppm sulphur diesel, a necessary change if Europe is to remain a viable market after January 2009. Gasoline exports will have to work harder to find markets, given our view that gasoline supplies will exceed demand in the coming years. However the installation of the world's largest FCC and alkylation units, and the required hydrotreating suggest Jamnagar will be capable of meeting the most demanding specifications, e.g. Euro-V, RBOB and CARBOB.

Indian markets may not initially see much benefit from the refinery start-up, given the export status that the refinery has. In addition to the artificially low domestic Indian price structure Reliance does not receive any form of subsidy from the government, as is the case with the state refiners. Furthermore, India may actually have higher import requirements if the existing 660 kb/d Jamnagar refinery is also converted into an EOU to improve its profitability. The refinery would need to raise exports from around 50% currently to above the 75% threshold to qualify for an exemption from the 5% import duty on crude imports, which domestic refiners are obliged to pay. This could increase the financial burden (highlighted above) currently being placed on the other state oil companies, if imports have to increase to meet the added supply shortfall for certain key products.

Herein lies the challenge for India. While Jamnagar will undoubtedly increase light product supplies to global markets vis-à-vis the same crude being run through less complex refineries, Indian product import requirements could increase, possibly quite dramatically. But for how long will India allow products to leave its shores while struggling to meet strong domestic demand growth?

The region is one of the major demand growth centres over the next five years, and consequently numerous refineries have been proposed. However, given the tight contractor market, we see many of the proposed grassroots refineries as unrealistic within the timeframe of this report.

The timing of Indian capacity growth has been moved back considerably since last year's report, due to three factors:

- Firstly, the tight contractor market has meant previous delivery targets for some refinery projects have proved too aggressive. Consequently, projects have been deferred, in some cases by up to two years;
- Proposed changes to the current seven-year tax holiday that new refineries enjoy have been a further source of project delay. A significant portion of the attractive project economics that Indian companies have based their investment decision-making process on is generated by this tax concession (assuming margins remain attractive). However, plans emerged in early 2008, to scrap this tax break for refineries starting operations after April 2009, effectively conferring the tax-holiday only on Reliance's Jamnagar II refinery. At the time of writing a revised proposal appears set to only exempt those refineries completed by 2012; and;
- The domestic pricing structure that Indian state refineries face, whereby they must meet one third of the losses incurred as a result of the capped pricing structure, has imposed significant financial burden on them. Consequently, several refineries with largely domestic sales portfolios have scrapped, postponed or significantly reduced planned investments.

The net effect of these developments is to move some 300 kb/d of capacity which we had forecast to have come on stream during 2007 and 2008, back to 2010/2011. The one exception to the widespread delays has been the expansion of Reliance's Jamnagar refinery, which we still expect to be operational in early 2009. Initial commissioning is expected possibly as early as the third quarter 2008, with units progressively brought online over the course of the year.

Key Projects	2008	2009	2010	2011	2012	2013
Other Asia		Jamnagar Dung Quat	Vadinar	Mangalore Bina		

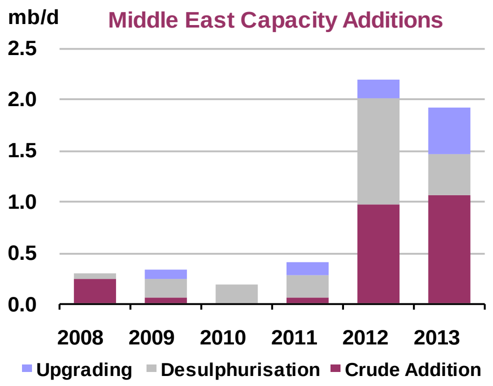
Vietnam's first refinery, the 130 kb/d Dung Quat project, is expected to start in 2009, thereby reducing Vietnam's 100% product import dependence. Furthermore, the country's strong demand growth has raised the likelihood of another one, and possibly two refineries being constructed, with rival groups considering various locations in the country. However, this report retains only the first project within the forecast period, pending visible progress on the other two projects.

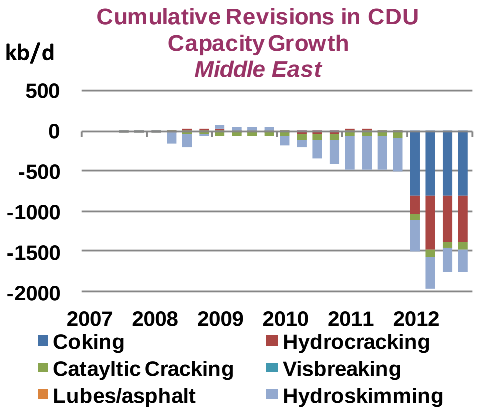
Middle East

The Middle East remains the largest single region for growth in crude distillation capacity, despite significant slippage in several projects' timings over the past 12 months. Overall distillation capacity is forecast to increase by 2.4 mb/d through to the end of 2013. However, growth is now significantly more weighted to the end of the forecast period than in last year's assessment, with only 0.4 mb/d of the increase in crude distillation capacity expected before 2012. The slippage in project timings is due to tight engineering/contractor markets and escalating costs as discussed in the overview.

Consequently, some projects have witnessed new delays of upwards of 18 months to two years. Iranian projects have been hardest hit, with the UN-approved economic sanctions, and direct pressure applied to potential JV refinery partners for the country's heavy oil refining projects, leaving us with little confidence that these projects are viable within this report's time horizon.

Within the region, Saudi Arabia retains its leading role, though the construction of one grassroots refinery, at Jubail (in a joint venture with Total) and the expansion of a further three on its own, including the 400 kb/d expansion of Ras Tanura. The planned construction of refineries at Yanbu (as a





JV with ConocoPhillips) and Jizan (by a yet-to-be-named private consortium) continue to be excluded from our forecasts due to a lack of visible progress. Arguably, the ConocoPhillips refinery appears less certain of progressing than it did last year. In addition to the high profile Jubail and Ras Tanura projects, which are forecast to add 800 kb/d of crude distillation capacity by 2013, we expect the existing JV refineries at Jubail and Yanbu to complete major upgrades to enhance product quality and light product yields before 2012. All told, we remain of the view that Saudi Aramco's capacity additions will increase Saudi Arabia's refinery capacity by 975 kb/d, albeit by 2013, compared to last year's estimate for 2012.

Progress at Kuwait's 615 kb/d al Zour refinery, with the award of engineering and construction contracts in 2008, persuades us that the project remains likely to be completed in late 2012. However, we recognise that this forecast is at risk and that continued timely progress will be required to meet this deadline, with the danger the project slips into early 2013, or possibly later. For the moment we similarly retain the closure of the ageing Shuaiba refinery concurrent with the al Zour start-up, but note that recent reports suggest the closure may be postponed based on domestic demand requirements. Furthermore, the upgrade at the Mina Abdullah refinery is again postponed to post-2013 as a lack of visible progress and the focus on the Al Zour project, suggest it is unlikely to be completed within this reports' time horizon.

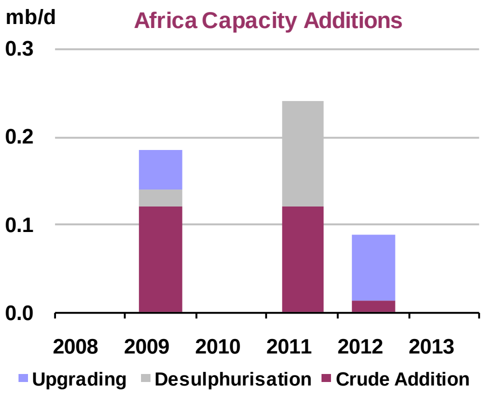
Iranian forecast capacity growth is increased from last year, despite significant slippage in project timings, following the inclusion of additional refinery expansion plans through to 2013. The likelihood of the three heavy oil refinery projects being completed within the timeframe remains low and they are once again excluded. Growth rests largely on the three planned 120 kb/d condensate splitters at Bandar Abbas, of which we include one by 2012, and expansion plans at for existing refineries at Bandar Abbas (ongoing), and Tabriz, Lavan and Isfahan (2012), aimed at increased processing of heavy/sour domestic crude and increased gasoline production.

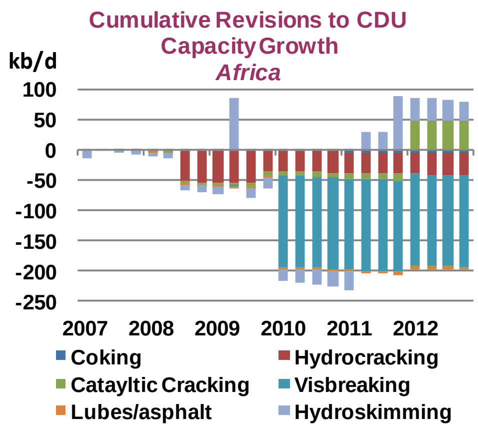
Key Projects	2008	2009	2010	2011	2012	2013
Middle East	Ras Laffan	Jebel Ali Rabigh	Tehran	Ruwais Haifa Abadan	Al Zour Yanbu exp Bandar Abbas	Ras Tanura Al Shaheen Jubail

Elsewhere in the region, we include the start-up of Qatar Petroleum's 250 kb/d Al Shaheen grassroots refinery in 2013. Similarly, we include the recently announced upgrade to the UAE's Ruwais refinery, which is aimed at improved ULSD production, but we exclude the larger 300 kb/d expansion and IPIC's proposed 200-300 kb/d Fujairah refinery due to a lack of visible progress. Lastly, we include a 60 kb/d expansion of the Haifa refinery in Israel where work appears to be progressing and a forecast completion date of 2011 seems realistic.

Africa

Despite the region's net product importer status, the prospect of significant growth in Africa's refining capacity over the period to 2013 looks limited. While some projects in this region have progressed, many more languish awaiting the commitment of capital, political backing and credible project sponsors. The region has long played the role as host to massive planned investments, but little progress is evident on the ground. Overall crude distillation capacity growth of 190 kb/d, compared to announced plans for nearly 1.9 mb/d, highlights the divergence between expectations and reality.





Algeria looks set to lead the way with a grassroots 100 kb/d condensate splitter due on stream in 2009, and the 60 kb/d expansion and upgrade of its Skikda refinery due for completion in 2011. Smaller upgrades to the Algiers and Arzew refineries are forecast for 2012, but we continue to exclude the 300 kb/d Tiaret refinery from our forecasts, awaiting confirmation of this project's timings, and ideally, an award of engineering and construction contracts.

Refinery expansion projects related to existing facilities in Egypt, Ghana and Morocco are also included in this year's forecast. The Egyptian Refining Company's installation of a hydrocracker and delayed coker at its Mostorod refinery will radically improve product quality when complete in 2012. Elsewhere in Egypt we see little prospect of the other refinery projects being completed before 2014.

Similarly, the expansion of the Mohammedia refinery in Morocco, which we assume will be completed in late 2009, includes a new hydrocracker and visbreaker, substantially reducing the output of fuel oil, while boosting distillate production. Lastly, we include a 60 kb/d increase in crude capacity of the Tema oil refinery, in Ghana, by late 2011, with the increased likelihood of increased domestic crude production, following a series of offshore oil discoveries.

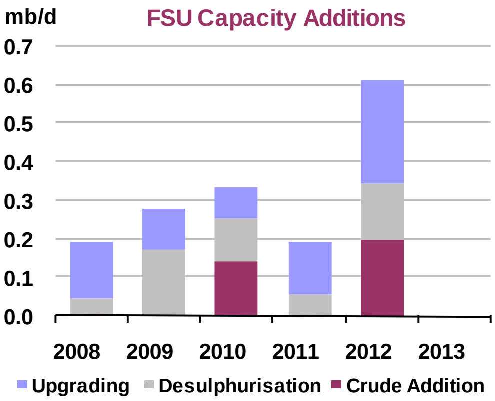
Refinery projects where we believe completion before 2014 is unrealistic include:

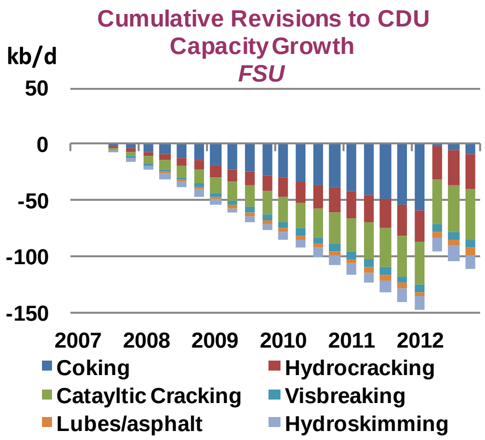
- Angola's 200 kb/d Lobito refinery;
- Egypt's array of grassroots refineries ranging from 180-400 kb/d;
- Libya, where despite the recent award of contract for the revamp of the Ras Lanuf refinery and another pending for the Zawia refinery, we expect these projects to complete post 2013;
- Sudan, where the four-fold increase in costs for the 100 kb/d Port Sudan refinery has reduced interest by Malaysia's Petronas; and
- South Africa, where plans for a 200 kb/d refinery are looking (realistically) at a 2015 start date.

Former Soviet Union

FSU refinery expansion plans appear set to raise light product yields significantly over the forecast period as refiners invest heavily in upgrading capacity additions. The investment programmes at Rosneft, Lukoil, TNK-BP, Surgutneftegaz and Tatneft's grassroots refinery at Nizhnekamsk, in Tatarstan, will raise light product yields, and reduce production of fuel oil.

Russian refinery expansion dominates the FSU's forecast crude distillation capacity growth, with around 80% of the regional total and the remainder in Belarus. Furthermore, upgrading capacity growth projections are even more heavily Russian biased, at around 90%, of regional expansion plans.





Unlike many other regions, refineries in the FSU are investing to raise the yield of both gasoline and middle distillates. Demand is growing for high-octane (and increasingly lower-sulphur) gasoline, with an offsetting decline in low-octane high sulphur gasoline. Consequently, investment in FCC capacity through to 2013 is comparable to that of North America, or the Middle East, despite having less than a quarter of the forecast crude distillation capacity growth.

The region has long been a net exporter of crude and products and certain refiners have continued to invest to meet rising demand for high-quality products both regionally and internationally. Russian authorities are pushing for the adoption of Euro-III quality standards for products (150 ppm sulphur gasoline and 350 ppm sulphur diesel) by 2009, but it appears uncertain at this point in time as to whether all refineries will be able to comply.

As previously highlighted in the *OMR* dated 13 February 2008, the current regressive tax structure for light products exports from Russia dilutes the incentive for refineries to invest in upgrading capacity. Fuel oil exports enjoy a $16/bbl discount in taxation, effectively removing a proportion of the incentive to upgrade fuel oil into light products. Despite these hurdles refiners appear set to raise the level of light product yields to maximise their profits. The commissioning of the dedicated 10 ppm sulphur diesel export pipeline to the Primorsk terminal in the Baltic is but one example of the lengths that oil companies will go to in order to realise the maximum value of their production, and we continue to expect further initiatives in coming years.

The only grassroots refinery expected to start up before 2013 is Tatneft's Nizhnekamsk refinery, which is forecast due for completion in two stages during 2010 and 2011. Key refinery expansion projects within our forecast of Russian investment include Rosneft's upgrade of the Komsomolsk and Tuapse refineries, which we expect will be completed by late 2012, Surgutneftgaz's three-stage upgrade of the Kirishi refinery by 2012 and Lukoil's planned investments in Volgograd, Ukhta, Perm and Nizhny Novgorod, due for completion over the next 18 months.

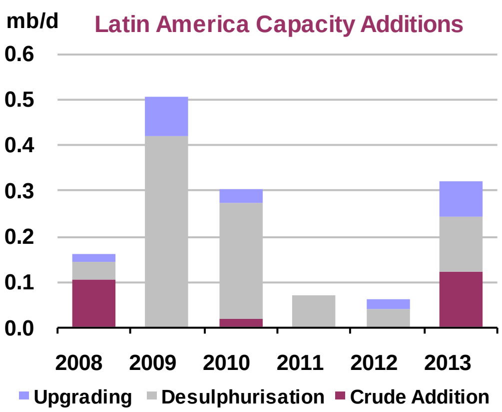
Outside of Russia, we expect the completion of the upgrade of the Belorussian refineries at Mozyr and Novopolotsk by 2012, the latter project having been delayed from late this decade. But we remain cautious as to the likely timing of the planned upgrade of Kazakh refineries by Kazmunaigaz. Further progress in firming up completion dates would allow us to incorporate these plans into our forecasts.

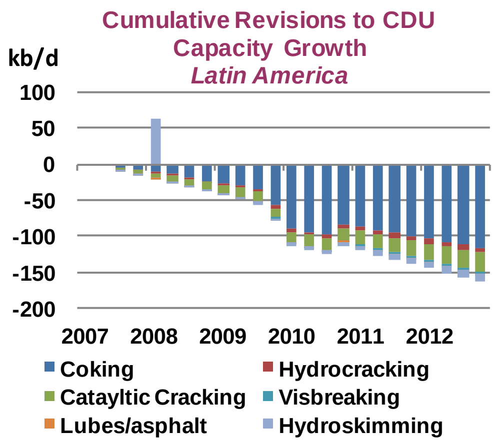
Elsewhere, we see little prospect of the planned grassroots refineries in Eastern Russia, variously reported as 200-400 kb/d in size, as being operational before the end of 2013. Similarly, the prospects for a new 240 kb/d refinery at Kirishi, a 120 kb/d Kazakh refinery and Turkmenistan and Azerbaijan upgrades are seen as too nascent to be included in our forecasts.

Latin and Central America

Latin American refinery expansion plans have increased from last year's forecast, but remain only a fraction of the region's potential if all the projects announced in recent year were to come to fruition. Many of the countries in the region remain net product importers and can easily justify the need for such investment. However the political, economic and financial barriers to such investment remain significant.

Brazil's Petrobras dominates the regional growth prospects, not unsurprisingly as it is the largest refiner in the region, with around 2 mb/d of crude distillation capacity, as part of its refinery investment programme. Heavy regional investment in hydrotreating capacity reflects several countries' attempts to improve sulphur levels in fuels, in common with other regions. The two refinery expansions forecast to be completed by 2013 are at the Cartagena refinery in Columbia and Petrojam's Kingston refinery, which are both expected to carry out major upgrades. However, in the intervening period none of a multitude of grassroots refineries proposed by the governments of Venezuela, Nicaragua, Panama and Ecuador are realistically expected to be complete. Nor do we currently include Brazil's Comperj and Abreu-e-Lima refineries, as continually revised timings for these projects leave us uncertain as to the true state-of-play and actual progress being achieved.





Coking capacity additions of around 160 kb/d in Brazil, and in Bolivia, Colombia and Ecuador in 2008, 2012 and 2013 are evenly split. Rising supplies of heavy sweet Brazilian crude drives much of the Brazilian expansion although we retain some 200 kb/d of imported West African crude imports in our forecast for Brazilian refineries through to 2013.

Product Supply Analysis

Overview

Global product demand growth of 7.3 mb/d is heavily biased towards **middle distillates**. This presents problems for refiners to meet such a high concentration of demand within one product group. This problem is compounded by the fact that refinery output is effectively already maximising distillate production, as evidenced by the recent strength in diesel cracks. Improved catalyst technology offers the prospect of higher distillate yields, but this will take time to materialise, while increases in the demand for diesel and jet fuel, driven by economic growth, look set to continue their strong trend in the short term.

Concurrent with the strong growth in middle distillate demand, the weak growth in **gasoline** increases the mismatch between the supply potential for various products. Gasoline demand growth is slowing as a result of weaker economic growth in the key North American market, and also due to the structural decline in OECD Europe and the Pacific.

Fuel oil demand is forecast to remain steady in overall terms, with declining OECD consumption offset by increased non-OECD demand, most notably in the Middle East. However, the prospect of lower fuel oil production, as refiners invest to boost light and middle distillates, leaves a potential shortfall that may ultimately support fuel oil cracks. By the end of the forecast period, this could result in competition between fuel oil, and light and middle distillates, and also other fuels used in power generation.

Gasoline and Naphtha

The potential for gasoline supplies over the 2008-2013 period exceeds the forecast demand growth by more than 400 kb/d. Cumulative global demand growth of around 1.1 mb/d by 2013 is weak, compared to historic growth rates. Furthermore, the rise in ethanol production cuts this figure by a further 0.4 mb/d, implying that the effective increase needed from refinery gasoline is just 0.7 mb/d. Considered against the increases in gasoline production from export refineries such as Jamnagar, there is little prospect of a return to the strength in gasoline cracks of recent years.

Increasing supply potential is clearly evident in the Atlantic Basin. The widespread investment in upgrading capacity in North America and the large-scale expansion of several US refineries all contribute to an increase in gasoline supply potential of around 200 kb/d. This compares to a net increase in North American gasoline demand of just 103 kb/d. Within this regional total, it is likely that the weaker US demand will be offset by continued growth in Mexican, and, to a lesser extent Canadian, demand. Consequently, we expect the US import requirement to decrease substantially from current levels, but be partially offset by rising Mexican imports. North American naphtha demand is also forecast to decline over the medium term, adding further pressure to the light distillate pool.

European gasoline demand remains in long-term structural decline, forcing the region's refiners to increase exports or accept lower crude runs. We assume that refiners maximise crude throughput in order to meet as much of the region's middle distillate demand as possible, subject to margin constraints. Consequently, we expect crude runs to remain at or near current levels through to 2013.

In the short term, the Atlantic Basin (including West Africa and Latin America) appears to have only limited potential to absorb increased supplies of gasoline from Europe. The recent weakness in gasoline cracks reflect the impact of increasing ethanol penetration in the US and European refiners' need to place increasing volumes into the best netback market, which currently remains North America. The completion of the large-scale US refinery expansions in 2010-2011 will contribute to pushing the

Atlantic Basin further towards being a net exporter. At this point, alternative markets for European gasoline will need to be found if European refineries are to avoid eroding margins.

Middle Eastern gasoline markets are forecast to move towards a more balanced position over the 2008-2013 period, subject to the large number of refining projects being completed on time. Demand growth remains strong in the region, underpinned by robust economic growth. In the short term, imports into the region are set to decrease slightly, driven by lower Iranian demand growth and the expansion of the Bandar Abbas refinery. The longer-term trend of increasing imports resumes over the 2009-2011 period, before the start of the refinery upgrades and expansions, increase regional supplies again. The period 2012-2013 sees a marked shift in regional trade balance, with the potential for the region to become a net exporter by 2013.

The Middle East remains a net exporter of naphtha with little incremental demand forecast in the region and similarly stable supplies until 2013, when the start-up of the Ras Tanura refinery bolsters Saudi Arabian supplies.

Strong Chinese gasoline demand growth during 2008-2013 will keep the pressure on local refineries to meet incremental demand through imports. However, the very strong increase in refining capacity expected over the next 18 months should alleviate some of the pressure in the near term. By 2010-2011, we expect the need for gasoline imports to re-emerge. In the latter years a rise in naphtha supply potential may offer some supply side flexibility between these two light distillates.

Middle Distillates

On aggregate, demand growth for jet fuel, kerosene, diesel and gasoil accounts for 48% of the total forecast increase in product demand. The concentration of demand in such similar products provides an enormous challenge for refiners. In addition to the forecast increase in the volume of distillates, product qualities will tighten appreciably, as Europe, the US and China, among others, progressively improve quality specification requirements. To meet this demand growth, refiners are investing heavily in distillate-producing upgrading units, such as cokers and hydrocrackers, and in the necessary hydrotreating capacity to produce low and ultra low-sulphur distillates.

Unlike gasoline, OECD demand for diesel/gasoil is forecast to continue rising during 2008-2013, driven largely by the continued dieselisation of European transport demand. Consequently, European imports will increase over the next two years, despite the completion of hydrocrackers in Germany and Italy. From 2010 onwards, the completion of further upgrading projects and expansion of Iberian refineries will raise middle distillate production and reduce net import requirements. The region will remain, however, a net importer of diesel through to 2013. Similarly, Europe will remain a net importer of jet fuel, despite weak demand growth and the boost to supplies from investment in hydrocrackers.

North American middle distillate supply potential will fall short of demand growth in the short term. During the 2010-2011 period, with the completion of the large refinery expansions highlighted in the refining section, the need for imports will ease, but towards the end of the forecast period we expect a resumption of increased import requirements, but this could be negated by the announcement of additional upgrading projects in the region, e.g. Harvest Energy's possible upgrade of the Come By Chance refinery.

China's gasoil/diesel supply potential looks set to keep pace with the 1 mb/d forecast increase in its demand over the 2008-2013 period. The start-up of processing at several large refineries over the next 18 months boosts the Chinese supply potential of gasoil/diesel by over 400 kb/d, offering the potential to significantly ease recent diesel shortages. During 2010-2011, the continued growth in demand outpaces the forecast supply addition from the expansion of the Tianjin and Maoming refineries and the start-up of the Quanzhou refinery, raising the prospect of renewed diesel imports. Jet imports are likely to dip in the short term, but then return to the longer-term upward trend.

Increased Asian supplies of diesel/gasoil and jet/kerosene will result from the start-up of the Jamnagar refinery expansion in late 2008. However, the region will remain a net import of distillates over the forecast period, as robust demand growth outpaces the overall refinery capacity growth.

Increased Middle East supply potential is not forecast to match demand growth in the short term, since expansions in 2008 and 2009 will mainly add supplies to naphtha and gasoline pool. The start-up of the big refineries/expansions in 2012/2013 boosts product supply prospects, turning the region into a net exporter.

Fuel Oil

The fuel oil market balance remains the most challenging of all. The push for higher distillate yields by refiners to meet the strong demand growth for diesel implies declining fuel oil yields. Over the forecast period, fuel oil demand growth of nearly 0.5 mb/d, largely in the Middle East, contrasts with a decline in the global supply potential of 2 mb/d. Obviously, this imbalance in the market cannot occur, suggesting that some demand requirements will be unfulfilled. Refineries could increase fuel oil supplies by not processing fuel oil through upgrading units, but current price spreads militate against this course of action. But if price spreads change, then higher fuel oil production would result in lower output across the rest of the barrel. Similarly, it is possible to increase fuel oil supplies by running more crude through spare hydroskimming refinery capacity. In the next few years, the higher OPEC spare capacity projected in this report would allow incremental fuel oil production to be realised, but by 2013 with minimal spare upstream capacity this would no longer be an option.

Furthermore, with increased tightness in LNG and coal markets likely over the medium term, the demand for fuel oil, may be harder to substitute and therefore its value relative to crude may improve. This in itself would reduce the incentive to upgrade fuel oil, but current spreads do not suggest such an environment is imminent.

Regionally, the OECD's decline in demand is more than offset by the reduction in fuel oil production, suggesting it will move to become a net importer before 2013. Demand growth in the Middle East will also increase imports in the coming years, and the region is likely to remain a net-importer through to 2013, despite the start of the al-Zour refinery in late 2012.

Other Asia retains the biggest pull on global fuel oil supplies and it looks likely that this trend will continue over the forecast period, with increasing imports through to 2013. Similarly, we see the dip in Chinese fuel oil imports in 2008 as temporary and it would appear likely that the longer term trend of rising imports is set to resume over the medium term.

Table 1
WORLD OIL SUPPLY AND DEMAND
(million barrels per day)

	1Q08	2Q08	3Q08	4Q08	2008	1Q09	2Q09	3Q09	4Q09	2009	1Q10	2Q10	3Q10	4Q10	2010	2011	2012	2013
OECD DEMAND																		
North America	24.8	25.0	25.2	25.2	25.0	24.4	24.7	24.8	24.8	24.7	24.5	24.6	25.0	24.8	24.7	24.8	24.9	24.9
Europe	15.1	15.1	15.4	15.5	15.3	15.1	14.9	15.3	15.4	15.2	15.0	14.9	15.3	15.4	15.2	15.2	15.2	15.2
Pacific	8.8	7.9	7.9	8.7	8.3	8.7	7.7	7.8	8.7	8.2	8.9	7.6	7.8	8.5	8.2	8.2	8.2	8.2
Total OECD	48.7	48.0	48.4	49.4	48.6	48.2	47.3	47.9	48.9	48.1	48.4	47.2	48.0	48.7	48.1	48.1	48.2	48.3
NON-OECD DEMAND																		
FSU	4.1	4.0	4.3	4.4	4.2	4.3	4.1	4.4	4.5	4.3	4.4	4.4	4.5	4.6	4.5	4.6	4.8	4.9
Europe	0.8	0.8	0.7	0.8	0.8	0.8	0.8	0.7	0.8	0.8	0.8	0.8	0.7	0.8	0.8	0.8	0.8	0.8
China	7.9	8.1	8.0	8.1	8.0	8.4	8.6	8.4	8.5	8.5	8.6	8.8	8.9	9.3	8.9	9.3	9.8	10.3
Other Asia	9.6	9.5	9.1	9.5	9.4	9.8	9.7	9.3	9.7	9.6	9.8	9.9	9.7	10.1	9.9	10.1	10.4	10.7
Latin America	5.7	5.8	6.0	6.0	5.9	5.9	6.0	6.2	6.2	6.1	6.1	6.3	6.4	6.4	6.3	6.5	6.7	6.9
Middle East	6.7	6.8	7.1	6.8	6.9	7.1	7.1	7.5	7.2	7.2	7.4	7.6	7.8	7.5	7.6	8.0	8.4	8.8
Africa	3.1	3.1	3.0	3.2	3.1	3.2	3.2	3.1	3.2	3.2	3.2	3.2	3.2	3.3	3.2	3.3	3.3	3.4
Total Non-OECD	37.9	38.1	38.2	38.7	38.2	39.4	39.5	39.6	40.2	39.7	40.4	40.9	41.3	41.9	41.1	42.6	44.2	45.8
Total Demand[1]	86.6	86.2	86.6	88.1	86.9	87.6	86.8	87.5	89.0	87.7	88.8	88.1	89.3	90.6	89.2	90.7	92.4	94.1
OECD SUPPLY																		
North America	14.2	13.9	14.1	14.4	14.1	14.6	14.2	14.1	14.3	14.3	14.8	14.5	14.1	14.4	14.4	14.5	14.6	14.7
Europe	4.9	4.5	4.3	4.6	4.6	4.6	4.2	4.0	4.2	4.3	4.2	3.9	3.7	3.9	3.9	3.7	3.5	3.4
Pacific	0.6	0.7	0.8	0.8	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.7	0.6
Total OECD	19.7	19.1	19.1	19.9	19.4	20.0	19.2	19.0	19.4	19.4	19.8	19.2	18.6	19.1	19.2	18.9	18.7	18.7
NON-OECD SUPPLY																		
FSU	12.8	12.9	13.1	13.5	13.1	13.5	13.4	13.1	13.0	13.3	13.6	13.3	13.1	13.1	13.3	13.5	13.6	13.9
Europe	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
China	3.8	3.8	3.9	3.9	3.8	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9
Other Asia	2.7	2.7	2.7	2.8	2.7	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.9	2.9	2.8	2.8	2.8	2.7
Latin America	3.9	4.0	4.1	4.2	4.1	4.3	4.3	4.3	4.3	4.3	4.5	4.5	4.5	4.5	4.5	4.6	4.8	5.0
Middle East	1.6	1.6	1.6	1.6	1.6	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.4
Africa[8]	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Total Non-OECD[8]	27.4	27.5	28.0	28.5	27.9	28.6	28.6	28.3	28.1	28.4	28.9	28.6	28.5	28.5	28.6	28.9	29.1	29.5
Processing Gains[2]	2.1	2.1	2.1	2.2	2.1	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.3	2.3
Other Biofuels[3]	0.4	0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Total Non-OPEC[4,8]	49.6	49.2	49.8	51.1	49.9	51.4	50.5	50.0	50.3	50.5	51.4	50.6	49.9	50.4	50.6	50.7	50.7	51.1
OPEC																		
Crude[5]	32.3																	
OPEC NGLs[6]	4.9	5.0	5.2	5.4	5.1	5.7	5.9	6.0	6.2	5.9	6.3	6.5	6.6	6.7	6.5	6.8	7.1	7.2
Total OPEC[8]	37.3																	
Total Supply[5]	87.0																	
Memo items:																		
Call on OPEC crude + Stock ch.[7]	32.1	32.0	31.6	31.6	31.8	30.6	30.4	31.4	32.6	31.3	31.0	31.0	32.8	33.4	32.1	33.2	34.6	35.8

1 Measured as deliveries from refineries and primary stocks, comprises inland deliveries, international marine bunkers, refinery fuel, crude for direct burning, oil from non-conventional sources and other sources of supply.
2 Net volumetric gains and losses in the refining process (excludes net gain/loss in former USSR, China and non-OECD Europe) and marine transportation losses.
3 Biofuels from sources outside Brazil and US.
4 Non-OPEC supplies include crude oil, condensates, NGL and non-conventional sources of supply such as synthetic crude, ethanol and MTBE.
5 As of the March 2006 OMR, Venezuelan Orinoco heavy crude production is included within Venezuelan crude estimates. Orimulsion fuel remains within the OPEC NGL & non-conventional category, but Orimulsion production reportedly ceased from January 2007.
6 Comprises crude oil, condensates, NGLs, oil from non-conventional sources and other sources of supply.
7 Equals the arithmetic difference between total demand minus total non-OPEC supply minus OPEC NGLs.
8 From 1 January 2007, Angola is included in OPEC data.

Table 1A

WORLD OIL SUPPLY AND DEMAND: CHANGES FROM LAST MEDIUM-TERM REPORT

(million barrels per day)

	1Q08	2Q08	3Q08	4Q08	2008	1Q09	2Q09	3Q09	4Q09	2009	1Q10	2Q10	3Q10	4Q10	2010	2011	2012	2013
OECD DEMAND																		
North America	-1.4	-0.7	-1.1	-1.1	-1.1	-1.9	-1.5	-1.7	-1.9	-1.8	-2.1	-1.9	-1.9	-2.3	-2.1	-2.3	-2.6	
Europe	-0.6	-0.1	-0.3	-0.4	-0.3	-0.5	-0.5	-0.5	-0.5	-0.5	-0.7	-0.6	-0.6	-0.6	-0.6	-0.7	-0.8	
Pacific	-0.5	-0.1	-0.2	-0.2	-0.2	-0.6	-0.3	-0.3	-0.3	-0.4	-0.5	-0.4	-0.4	-0.4	-0.4	-0.5	-0.5	
Total OECD	-2.4	-0.9	-1.6	-1.7	-1.7	-3.0	-2.3	-2.6	-2.7	-2.7	-3.3	-2.9	-2.9	-3.3	-3.1	-3.5	-3.9	
NON-OECD DEMAND																		
FSU	0.1	0.2	0.1	-0.1	0.1	-0.2	0.0	0.4	0.3	0.1	-0.2	0.1	0.4	0.3	0.2	0.2	0.3	
Europe	0.0	0.0	0.0	0.0	0.0	-0.1	-0.1	0.0	0.0	0.0	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	
China	0.0	-0.1	-0.1	-0.1	-0.1	0.2	0.2	-0.1	-0.4	0.0	0.0	-0.1	-0.1	-0.1	-0.1	-0.1	-0.2	
Other Asia	0.2	0.1	-0.1	0.0	0.1	0.3	0.1	-0.2	-0.1	0.0	0.0	0.1	-0.1	0.0	0.0	0.0	0.0	
Latin America	0.2	0.2	0.2	0.3	0.2	0.3	0.3	0.3	0.4	0.3	0.4	0.4	0.4	0.4	0.4	0.5	0.6	
Middle East	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.1	0.1	0.1	
Africa	0.0	0.0	0.0	0.0	0.0	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.2	-0.2	
Total Non-OECD	0.5	0.3	0.2	0.1	0.3	0.5	0.4	0.3	0.2	0.4	0.1	0.4	0.6	0.4	0.4	0.4	0.5	
Total Demand	-1.9	-0.6	-1.4	-1.7	-1.4	-2.5	-1.8	-2.3	-2.5	-2.3	-3.2	-2.4	-2.3	-2.9	-2.7	-3.1	-3.4	
OECD SUPPLY																		
North America	-0.2	-0.1	0.1	0.3	0.0	0.1	0.0	0.2	0.2	0.1	0.3	0.3	0.1	0.2	0.2	0.2	0.2	
Europe	0.0	-0.1	-0.1	0.0	-0.1	-0.1	-0.1	-0.2	-0.2	-0.1	-0.1	-0.2	-0.3	-0.3	-0.2	-0.3	-0.2	
Pacific	-0.1	0.0	0.0	0.0	-0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Total OECD	-0.3	-0.3	0.0	0.2	-0.1	0.1	0.0	0.0	0.0	0.0	0.1	0.1	-0.2	-0.1	0.0	0.0	0.0	
NON-OECD SUPPLY																		
FSU	0.0	-0.1	0.1	0.2	0.0	0.2	0.0	-0.5	-0.7	-0.2	-0.1	-0.4	-0.7	-0.8	-0.5	-0.6	-0.7	
Europe	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
China	-0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Other Asia	0.0	-0.1	-0.1	-0.1	-0.1	0.0	0.0	-0.1	-0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	
Latin America	-0.3	-0.3	-0.1	-0.1	-0.2	-0.1	-0.1	-0.1	-0.1	-0.1	0.0	0.0	0.0	-0.1	0.0	-0.1	-0.3	
Middle East	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	
Africa[8]	-0.2	-0.3	-0.2	-0.3	-0.2	-0.3	-0.3	-0.2	-0.2	-0.2	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	
Total Non-OECD[8]	-0.7	-0.8	-0.4	-0.1	-0.5	-0.2	-0.4	-0.9	-1.1	-0.7	-0.4	-0.8	-1.1	-1.2	-0.9	-1.1	-1.5	
Processing Gains	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	
Other Biofuels	-0.3	-0.2	-0.2	-0.1	-0.2	-0.2	-0.2	-0.2	-0.1	-0.2	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	
Total Non-OPEC	-1.1	-1.1	-0.4	0.2	-0.6	-0.2	-0.4	-0.8	-1.1	-0.6	-0.2	-0.6	-1.3	-1.3	-0.9	-1.0	-1.4	
OPEC NGLs	-0.3	-0.5	-0.4	-0.4	-0.4	-0.4	-0.3	-0.3	-0.3	-0.3	-0.2	-0.2	-0.2	-0.1	-0.2	-0.1	0.0	
Memo items:																		
Call on OPEC crude + Stock ch.	-0.5	1.0	-0.6	-1.4	-0.4	-1.9	-1.1	-1.1	-1.1	-1.3	-2.7	-1.6	-0.9	-1.5	-1.6	-2.0	-2.0	

Table 2

Summary of Global Oil Demand

	1Q08	2Q08	3Q08	4Q08	2008	1Q09	2Q09	3Q09	4Q09	2009	1Q10	2Q10	3Q10	4Q10	2010	2011	2012	2013
Demand (mb/d)																		
North America	24.75	25.05	25.16	25.19	25.04	24.36	24.69	24.81	24.80	24.67	24.50	24.61	24.95	24.80	24.72	24.78	24.86	24.93
Europe	15.14	15.14	15.36	15.47	15.28	15.09	14.91	15.27	15.40	15.17	15.04	14.93	15.29	15.37	15.16	15.16	15.17	15.19
Pacific	8.82	7.86	7.86	8.73	8.32	8.71	7.73	7.80	8.65	8.22	8.86	7.64	7.79	8.52	8.20	8.18	8.18	8.17
Total OECD	48.71	48.04	48.38	49.39	48.63	48.17	47.32	47.88	48.86	48.06	48.39	47.18	48.03	48.69	48.07	48.13	48.20	48.29
FSU	4.11	4.01	4.29	4.41	4.21	4.25	4.13	4.41	4.54	4.34	4.37	4.35	4.54	4.62	4.47	4.61	4.76	4.91
Europe	0.82	0.76	0.71	0.77	0.76	0.83	0.78	0.72	0.78	0.78	0.85	0.79	0.74	0.79	0.79	0.81	0.82	0.84
China	7.85	8.10	7.97	8.07	8.00	8.37	8.56	8.40	8.54	8.47	8.61	8.75	8.91	9.31	8.90	9.33	9.79	10.28
Other Asia	9.59	9.52	9.12	9.50	9.43	9.83	9.70	9.31	9.73	9.64	9.78	9.92	9.72	10.07	9.87	10.12	10.38	10.66
Latin America	5.66	5.82	5.97	5.96	5.85	5.87	6.04	6.20	6.19	6.08	6.10	6.31	6.40	6.36	6.29	6.51	6.72	6.94
Middle East	6.72	6.79	7.13	6.83	6.87	7.06	7.13	7.48	7.17	7.21	7.41	7.57	7.85	7.47	7.58	7.96	8.37	8.81
Africa	3.14	3.12	3.03	3.17	3.12	3.20	3.17	3.08	3.23	3.17	3.24	3.24	3.16	3.25	3.22	3.28	3.34	3.40
Total Non-OECD	37.89	38.12	38.22	38.72	38.24	39.41	39.52	39.60	40.18	39.68	40.37	40.94	41.31	41.88	41.13	42.62	44.19	45.85
World	86.60	86.16	86.59	88.11	86.87	87.58	86.84	87.47	89.04	87.74	88.76	88.12	89.34	90.57	89.20	90.75	92.39	94.14
of which:																		
US50	*20.00*	*20.32*	*20.43*	*20.37*	*20.28*	*19.59*	*19.95*	*20.06*	*19.97*	*19.89*	*19.64*	*19.85*	*20.14*	*19.92*	*19.89*	*19.90*	*19.91*	*19.94*
Euro4	*7.76*	*7.78*	*7.84*	*7.88*	*7.82*	*7.73*	*7.55*	*7.71*	*7.76*	*7.69*	*7.60*	*7.50*	*7.71*	*7.71*	*7.63*	*7.58*	*7.54*	*7.50*
Japan	*5.41*	*4.67*	*4.67*	*5.23*	*4.99*	*5.27*	*4.51*	*4.56*	*5.12*	*4.86*	*5.28*	*4.35*	*4.52*	*4.98*	*4.78*	*4.71*	*4.63*	*4.56*
Korea	*2.32*	*2.10*	*2.09*	*2.37*	*2.22*	*2.34*	*2.13*	*2.13*	*2.40*	*2.25*	*2.46*	*2.16*	*2.14*	*2.38*	*2.29*	*2.33*	*2.37*	*2.42*
Mexico	*2.02*	*2.10*	*2.00*	*2.09*	*2.05*	*2.02*	*2.10*	*2.00*	*2.10*	*2.05*	*2.06*	*2.08*	*2.07*	*2.09*	*2.08*	*2.10*	*2.13*	*2.15*
Canada	*2.34*	*2.28*	*2.38*	*2.35*	*2.34*	*2.36*	*2.29*	*2.38*	*2.35*	*2.35*	*2.40*	*2.32*	*2.37*	*2.40*	*2.37*	*2.40*	*2.43*	*2.45*
Brazil	*2.35*	*2.35*	*2.43*	*2.50*	*2.41*	*2.42*	*2.43*	*2.51*	*2.58*	*2.48*	*2.47*	*2.54*	*2.60*	*2.62*	*2.56*	*2.63*	*2.71*	*2.79*
India	*3.19*	*3.16*	*2.85*	*3.17*	*3.09*	*3.35*	*3.26*	*2.97*	*3.28*	*3.21*	*3.41*	*3.34*	*3.19*	*3.41*	*3.34*	*3.46*	*3.60*	*3.74*
Annual Change (% per annum)																		
North America	-3.5	-1.5	-1.3	-1.4	-1.9	-1.6	-1.4	-1.4	-1.5	-1.5	0.6	-0.3	0.6	0.0	0.2	0.3	0.3	0.3
Europe	-0.4	1.4	-0.2	-0.9	0.0	-0.3	-1.5	-0.6	-0.4	-0.7	-0.4	0.2	0.1	-0.2	-0.1	0.0	0.1	0.1
Pacific	0.0	0.7	0.6	1.0	0.6	-1.3	-1.6	-0.8	-0.9	-1.2	1.7	-1.2	-0.1	-1.5	-0.3	-0.2	-0.1	0.0
Total OECD	-1.9	-0.2	-0.7	-0.8	-0.9	-1.1	-1.5	-1.0	-1.1	-1.2	0.5	-0.3	0.3	-0.3	0.0	0.1	0.2	0.2
FSU	0.2	2.6	2.6	2.9	2.1	3.6	3.0	2.8	3.0	3.1	2.7	5.3	3.0	1.8	3.2	3.2	3.2	3.1
Europe	1.6	1.9	1.9	1.9	1.8	1.6	1.9	1.9	1.9	1.8	1.8	2.0	2.0	1.8	1.9	1.9	2.0	2.0
China	7.1	4.8	6.0	6.3	6.0	6.6	5.7	5.4	5.8	5.9	2.9	2.2	6.0	9.1	5.1	4.9	4.9	5.0
Other Asia	3.8	1.7	0.7	1.0	1.8	2.5	1.9	2.1	2.4	2.2	-0.5	2.2	4.5	3.4	2.4	2.5	2.6	2.7
Latin America	4.6	4.3	4.3	4.2	4.3	3.8	3.9	3.8	3.8	3.8	3.9	4.3	3.2	2.8	3.6	3.4	3.3	3.3
Middle East	4.9	4.3	6.0	6.1	5.3	5.0	5.1	4.9	5.0	5.0	5.0	6.2	4.9	4.1	5.1	5.1	5.2	5.3
Africa	1.6	1.4	1.4	1.5	1.5	1.6	1.6	1.6	1.7	1.7	1.3	2.2	2.5	0.7	1.7	1.7	1.8	1.8
Total Non-OECD	4.2	3.3	3.6	3.8	3.7	4.0	3.7	3.6	3.8	3.8	2.4	3.6	4.3	4.2	3.6	3.6	3.7	3.8
World	0.6	1.3	1.2	1.1	1.1	1.1	0.8	1.0	1.1	1.0	1.3	1.5	2.1	1.7	1.7	1.7	1.8	1.9
Annual Change (mb/d)																		
North America	-0.90	-0.39	-0.34	-0.35	-0.49	-0.39	-0.36	-0.35	-0.38	-0.37	0.14	-0.07	0.14	0.00	0.05	0.07	0.07	0.07
Europe	-0.05	0.21	-0.03	-0.14	0.00	-0.05	-0.23	-0.09	-0.07	-0.11	-0.06	0.02	0.02	-0.03	-0.01	0.00	0.01	0.02
Pacific	0.00	0.05	0.05	0.09	0.05	-0.11	-0.13	-0.06	-0.08	-0.10	0.15	-0.09	-0.01	-0.13	-0.02	-0.02	-0.01	0.00
Total OECD	-0.96	-0.12	-0.32	-0.40	-0.45	-0.55	-0.72	-0.50	-0.53	-0.58	0.22	-0.14	0.15	-0.16	0.02	0.05	0.08	0.09
FSU	0.01	0.10	0.11	0.13	0.09	0.15	0.12	0.12	0.13	0.13	0.12	0.22	0.13	0.08	0.14	0.14	0.15	0.15
Europe	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.01	0.01	0.01	0.02	0.02	0.02
China	0.52	0.37	0.45	0.48	0.46	0.52	0.46	0.43	0.46	0.47	0.24	0.19	0.51	0.78	0.43	0.44	0.46	0.49
Other Asia	0.35	0.16	0.06	0.10	0.17	0.24	0.18	0.19	0.23	0.21	-0.05	0.22	0.42	0.33	0.23	0.25	0.26	0.28
Latin America	0.25	0.24	0.24	0.24	0.24	0.21	0.22	0.23	0.23	0.22	0.23	0.26	0.20	0.17	0.22	0.21	0.21	0.22
Middle East	0.32	0.28	0.40	0.39	0.35	0.34	0.34	0.35	0.34	0.34	0.36	0.44	0.37	0.29	0.36	0.38	0.41	0.44
Africa	0.05	0.04	0.04	0.05	0.05	0.05	0.05	0.05	0.06	0.05	0.04	0.07	0.08	0.02	0.05	0.06	0.06	0.06
Total Non-OECD	1.51	1.21	1.32	1.40	1.36	1.52	1.40	1.38	1.47	1.44	0.95	1.41	1.71	1.70	1.45	1.49	1.57	1.66
World	0.55	1.09	1.01	1.00	0.91	0.98	0.68	0.88	0.93	0.87	1.18	1.27	1.87	1.53	1.46	1.54	1.65	1.75
Revisions to Oil Demand from Last Medium Term Report (mb/d)																		
North America	-1.39	-0.73	-1.06	-1.11	-1.07	-1.94	-1.51	-1.74	-1.90	-1.77	-2.14	-1.92	-1.94	-2.25	-2.06	-2.35	-2.64	-
Europe	-0.59	-0.05	-0.33	-0.42	-0.35	-0.52	-0.50	-0.53	-0.53	-0.52	-0.65	-0.56	-0.60	-0.63	-0.61	-0.69	-0.78	-
Pacific	-0.46	-0.10	-0.21	-0.21	-0.24	-0.59	-0.26	-0.33	-0.27	-0.36	-0.47	-0.38	-0.37	-0.43	-0.41	-0.46	-0.50	-
Total OECD	-2.43	-0.87	-1.60	-1.74	-1.66	-3.04	-2.27	-2.60	-2.70	-2.65	-3.26	-2.86	-2.91	-3.32	-3.09	-3.50	-3.92	-
FSU	0.11	0.16	0.13	-0.09	0.08	-0.17	0.00	0.36	0.28	0.12	-0.15	0.13	0.40	0.27	0.17	0.23	0.28	-
Europe	-0.05	-0.04	-0.04	-0.04	-0.04	-0.05	-0.05	-0.05	-0.05	-0.05	-0.06	-0.06	-0.05	-0.06	-0.06	-0.07	-0.08	-
China	0.03	-0.06	-0.06	-0.13	-0.06	0.17	0.16	-0.11	-0.35	-0.03	-0.04	-0.12	-0.08	-0.07	-0.08	-0.12	-0.17	-
Other Asia	0.22	0.09	-0.10	0.04	0.06	0.31	0.11	-0.24	-0.06	0.03	0.01	0.07	-0.08	0.02	0.00	-0.02	-0.03	-
Latin America	0.20	0.21	0.23	0.27	0.23	0.30	0.28	0.34	0.37	0.32	0.40	0.41	0.42	0.41	0.41	0.49	0.57	-
Middle East	0.01	-0.03	0.06	0.02	0.02	0.05	0.01	0.10	0.06	0.06	0.05	0.09	0.10	0.00	0.06	0.07	0.15	-
Africa	-0.04	-0.02	-0.04	-0.01	-0.03	-0.06	-0.08	-0.11	-0.05	-0.08	-0.13	-0.11	-0.13	-0.14	-0.13	-0.18	-0.23	-
Total Non-OECD	0.49	0.32	0.19	0.06	0.26	0.54	0.43	0.30	0.21	0.37	0.08	0.42	0.57	0.44	0.38	0.41	0.49	-
World	-1.94	-0.56	-1.41	-1.68	-1.40	-2.50	-1.84	-2.31	-2.49	-2.29	-3.18	-2.45	-2.34	-2.88	-2.71	-3.10	-3.43	-
Revisions to Oil Demand Growth from Last Medium Term Report (mb/d)																		
World	-2.42	-1.03	-0.71	-0.75	-1.22	-0.56	-1.28	-0.89	-0.82	-0.89	-0.68	-0.61	-0.03	-0.39	-0.42	-0.39	-0.33	-

Table 3
WORLD OIL PRODUCTION
(million barrels per day)

	1Q08	2Q08	3Q08	4Q08	2008	1Q09	2Q09	3Q09	4Q09	2009	1Q10	2Q10	3Q10	4Q10	2010	2011	2012	2013
OPEC[6]																		
Total NGLs[1]	4.94	4.96	5.17	5.42	5.12	5.65	5.89	6.03	6.19	5.94	6.34	6.46	6.58	6.71	6.53	6.82	7.07	7.21
NON-OPEC[2]																		
OECD																		
North America	14.21	13.89	14.05	14.42	14.14	14.62	14.16	14.11	14.31	14.30	14.76	14.49	14.10	14.40	14.43	14.48	14.61	14.71
United States	7.65	7.57	7.44	7.55	7.55	7.83	7.80	7.68	7.82	7.78	8.02	8.03	7.84	7.85	7.93	7.95	7.86	7.75
Mexico	3.28	3.21	3.23	3.26	3.24	3.16	3.08	3.00	2.93	3.04	3.01	2.95	2.89	2.84	2.92	2.77	2.67	2.60
Canada	3.28	3.11	3.39	3.61	3.35	3.63	3.28	3.44	3.56	3.48	3.72	3.51	3.37	3.71	3.58	3.76	4.07	4.36
Europe	4.89	4.47	4.34	4.60	4.58	4.56	4.22	4.04	4.23	4.26	4.19	3.87	3.71	3.90	3.92	3.71	3.47	3.40
UK	1.64	1.44	1.34	1.50	1.48	1.50	1.36	1.22	1.36	1.36	1.31	1.16	1.03	1.19	1.17	1.04	0.91	0.86
Norway	2.52	2.30	2.28	2.39	2.37	2.35	2.16	2.14	2.21	2.22	2.21	2.04	2.03	2.07	2.09	2.05	1.98	1.98
Others	0.73	0.73	0.72	0.72	0.72	0.70	0.69	0.68	0.67	0.69	0.67	0.67	0.66	0.65	0.66	0.62	0.58	0.55
Pacific	0.60	0.72	0.75	0.84	0.73	0.84	0.83	0.83	0.82	0.83	0.82	0.82	0.83	0.83	0.83	0.76	0.66	0.55
Australia	0.50	0.61	0.63	0.70	0.61	0.70	0.69	0.69	0.67	0.69	0.70	0.70	0.70	0.71	0.70	0.66	0.58	0.48
Others	0.11	0.11	0.12	0.14	0.12	0.14	0.14	0.14	0.15	0.14	0.12	0.12	0.12	0.12	0.12	0.10	0.08	0.07
Total OECD	19.71	19.08	19.15	19.87	19.45	20.02	19.21	18.99	19.36	19.39	19.77	19.18	18.64	19.14	19.18	18.95	18.74	18.66
NON-OECD																		
Former USSR	12.81	12.86	13.12	13.51	13.08	13.48	13.41	13.12	13.03	13.26	13.57	13.35	13.13	13.12	13.29	13.48	13.63	13.86
Russia	10.00	9.97	10.17	10.32	10.12	10.17	10.04	9.88	9.72	9.95	10.13	10.01	9.86	9.70	9.92	9.97	10.03	10.13
Others	2.81	2.89	2.95	3.19	2.96	3.31	3.38	3.24	3.30	3.31	3.43	3.34	3.28	3.41	3.37	3.51	3.60	3.73
Asia	6.44	6.51	6.58	6.67	6.55	6.72	6.71	6.70	6.70	6.70	6.71	6.72	6.76	6.79	6.74	6.72	6.64	6.65
China	3.76	3.83	3.86	3.88	3.83	3.92	3.92	3.93	3.91	3.92	3.88	3.89	3.90	3.93	3.90	3.90	3.87	3.92
Malaysia	0.77	0.79	0.81	0.82	0.80	0.82	0.83	0.84	0.83	0.83	0.81	0.81	0.81	0.80	0.81	0.77	0.74	0.78
India	0.81	0.81	0.81	0.80	0.81	0.80	0.79	0.78	0.81	0.79	0.82	0.83	0.87	0.88	0.85	0.88	0.86	0.83
Others	1.09	1.08	1.10	1.16	1.11	1.18	1.16	1.15	1.15	1.16	1.21	1.19	1.18	1.18	1.19	1.17	1.17	1.12
Europe	0.13	0.12	0.12	0.12	0.12	0.12	0.11	0.11	0.11	0.11	0.10	0.10	0.10	0.10	0.10	0.09	0.08	0.07
Latin America	3.95	3.98	4.15	4.19	4.07	4.28	4.33	4.35	4.34	4.32	4.49	4.49	4.50	4.49	4.49	4.61	4.77	5.00
Brazil	2.21	2.27	2.42	2.47	2.34	2.54	2.59	2.61	2.60	2.58	2.74	2.74	2.75	2.75	2.75	2.85	2.98	3.20
Argentina	0.75	0.73	0.75	0.75	0.75	0.76	0.76	0.75	0.75	0.76	0.77	0.77	0.76	0.76	0.76	0.77	0.76	0.76
Colombia	0.57	0.56	0.56	0.56	0.56	0.56	0.57	0.57	0.57	0.57	0.56	0.57	0.57	0.57	0.57	0.58	0.61	0.64
Ecuador	0.50	0.34	0.00	0.00	0.21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Others	-0.08	0.08	0.41	0.41	0.21	0.41	0.41	0.42	0.42	0.42	0.42	0.41	0.41	0.41	0.41	0.42	0.41	0.39
Middle East[3]	1.62	1.60	1.58	1.56	1.59	1.54	1.52	1.52	1.50	1.52	1.53	1.52	1.52	1.51	1.52	1.50	1.47	1.44
Oman	0.73	0.72	0.71	0.70	0.71	0.70	0.70	0.70	0.70	0.70	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71
Syria	0.39	0.38	0.38	0.37	0.38	0.37	0.36	0.36	0.36	0.36	0.35	0.35	0.34	0.34	0.35	0.33	0.32	0.31
Yemen	0.31	0.31	0.30	0.30	0.31	0.28	0.27	0.26	0.26	0.27	0.28	0.27	0.28	0.27	0.28	0.27	0.27	0.26
Africa[6]	2.46	2.47	2.50	2.48	2.48	2.49	2.48	2.48	2.48	2.48	2.47	2.46	2.46	2.46	2.46	2.48	2.49	2.50
Egypt	0.62	0.61	0.61	0.60	0.61	0.59	0.59	0.58	0.58	0.58	0.59	0.58	0.58	0.57	0.58	0.57	0.57	0.57
Equatorial Guinea	0.28	0.28	0.27	0.26	0.27	0.26	0.26	0.26	0.26	0.26	0.25	0.25	0.25	0.25	0.25	0.27	0.29	0.29
Sudan	0.52	0.52	0.52	0.51	0.52	0.51	0.51	0.51	0.51	0.51	0.50	0.50	0.50	0.50	0.50	0.48	0.47	0.48
Others	1.04	1.06	1.09	1.11	1.08	1.12	1.12	1.12	1.12	1.12	1.13	1.13	1.14	1.15	1.14	1.17	1.15	1.16
Total Non-OECD[6]	27.41	27.55	28.04	28.53	27.88	28.62	28.57	28.28	28.14	28.40	28.87	28.64	28.47	28.46	28.61	28.89	29.08	29.52
Processing Gains[4]	2.11	2.10	2.14	2.17	2.13	2.17	2.17	2.17	2.17	2.17	2.20	2.20	2.20	2.20	2.20	2.23	2.26	2.29
Other Biofuels[5]	0.39	0.46	0.46	0.52	0.46	0.55	0.58	0.58	0.60	0.58	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61
TOTAL NON-OPEC[6]	49.62	49.18	49.78	51.09	49.92	51.36	50.53	50.01	50.28	50.54	51.45	50.63	49.92	50.41	50.60	50.68	50.68	51.08

1 Includes condensates reported by OPEC countries, oil from non-conventional sources, e.g. Venezuelan Orimulsion (but not Orinoco extra-heavy oil), and non-oil inputs to Saudi Arabian MTBE. Orimulsion production reportedly ceased from January 2007.
2 Comprises crude oil, condensates, NGLs and oil from non-conventional sources.
3 Includes small amounts of production from Israel, Jordan and Bahrain.
4 Net volumetric gains and losses in refining (excludes net gain/loss in FSU, China and non-OECD Europe) and marine transportation losses.
5 Comprises Fuel Ethanol and Biodiesel supply from outside Brazil and US.
6 From 1 January 2007 onwards, Angola is included in OPEC data.

Table 4
WORLD REFINERY CAPACITY ADDITIONS
(thousand barrels per day)

	2008	2009	2010	2011	2012	2013	Total
Refinery Capacity Additions and Expansions[1]							
OECD North America	116	80	410	530	45	100	1,281
OECD Europe		20	301	88			409
OECD Pacific	86	34	71				191
FSU	3		140		200		343
Non-OECD Europe				50			50
China	512	726	430	40	200	200	2,108
Other Asia	60	979	283	220	20		1,562
Latin America	103		18			120	241
Middle East	246	50		60	962	1,050	2,368
Africa		120		120	12		252
Total World	1,125	2,009	1,653	1,108	1,439	1,470	8,805
Upgrading Capacity Additions[2]							
OECD North America	86	159	295	655	65	80	1,340
OECD Europe	45	73	172	282	231	40	843
OECD Pacific	133		25	195			353
FSU	145	107	79	140	270		742
Non-OECD Europe	16		26	34			76
China	516	458	365		90	90	1,520
Other Asia	107	570	209	276	110		1,272
Latin America	20	89	33		20	75	237
Middle East		80		136	189	445	850
Africa		45			77		122
Total World	1,069	1,581	1,204	1,718	1,051	730	7,354
Desulphurisation Capacity Additions[3]							
OECD North America	160	500	196	726	120	120	1,822
OECD Europe	28	102	75	95	19		318
OECD Pacific	102	100	42	52			296
FSU	43	170	115	54	145		527
Non-OECD Europe	3		4	30			38
China	787	487	444		164	224	2,106
Other Asia	195	880	182	241	110		1,608
Latin America	39	417	253	70	40	123	941
Middle East	40	195	182	206	1,048	417	2,088
Africa		20		120			140
Total World	1,396	2,870	1,493	1,594	1,647	884	9,884

1 Comprises new refinery projects or expansions to existing facilities including condensate splitter additions. Assumes zero capacity creep.
2 Comprises gross capacity additions to coking, hydrocracking, residue hydrocracking, visbreaking, FCC or RFCC capacity.
3 Comprises additions to hydrotreating and hydrodesulphurisation capacity.

Table 4a
WORLD REFINERY CAPACITY ADDITIONS:
Changes from Last Medium-Term Report

(thousand barrels per day)

	2008	2009	2010	2011	2012	2013	Total
Refinery Capacity Additions and Expansions[1]							
OECD North America		-135	120	135	-55		55
OECD Europe			-5	110			105
OECD Pacific	86		-44				-93
FSU					60		60
Non-OECD Europe				20			20
China	-194	190	280	-300	-200		-204
Other Asia	-198	69	129	220	20		88
Latin America		-18	-10				-28
Middle East	-10	50	-351	-60	-819		-1,190
Africa	-50	20	-150	120	12		-48
Total World	-367	176	-31	245	-982		-959
Upgrading Capacity Additions[2]							
OECD North America	-92	-80	116	313	5		247
OECD Europe	-55	-21	-55	209	131		184
OECD Pacific	60	-103	-25	70			-2
FSU	-9	15	10	27	115		138
Non-OECD Europe				4			4
China	-35	126	103	-155	-90		-122
Other Asia	-59	-315	-27	276	110		-102
Latin America	-59	58	-26		20		-36
Middle East	-80	-85	-94	136	-449		-572
Africa	-53	45	-30		77		39
Total World	-381	-360	-29	880	-81		29
Desulphurisation Capacity Additions[3]							
OECD North America	50	345	-22	511	95		933
OECD Europe	28	75	-141	96	19		70
OECD Pacific	80	-80		52			52
FSU		170	20	3	25		131
Non-OECD Europe							
China	-2	109	224	-240	-224		-155
Other Asia	-2	258	17	221	110		507
Latin America	-218	172	215	70	40		219
Middle East	-45	-71	-182	161	-280		-416
Africa	-20	20	-87	120			33
Total World	-129	999	45	994	-215		1,694

1 Comprises new refinery projects or expansions to existing facilities including condensate splitter additions. Assumes zero capacity creep.
2 Comprises stand-alone additions to coking, hydrocracking or FCC capacity. Excludes upgrading additions counted under 'Refinery Capacity Additions and Expansions' category.
3 Comprises stand-alone additions to hydrotreating and hydrodesulphurisation capacity. Excludes desulphurisation additions counted under 'Refinery Capacity Additions and Expansions' category.

TABLE 5: SELECTED NON-OPEC UPSTREAM PROJECT START-UPS

Country	Project	Peak Capacity (kbd)	Start Year	Country	Project	Peak Capacity (kbd)	Start Year	Country	Project	Peak Capacity (kbd)	Start Year
OECD North America				UK	Brodgar/Callanish (BritSats)	25	2008	Russia	Priobskoye	300	2008
Canada	Horizon, CNRL, (mining & syn) 1	100	2008	UK	Starling	3	2008	Russia	Uzhno-Khylchuyuskoye	150	2008
Canada	Imperial, Cold Lake	20	2008	UK	Perth	15	2008	Russia	Talakanskoye	85	2008
Canada	Primrose East expansion	40	2009	UK	Chestnut	10	2008	Russia	Uvat expansion	120	2008
Canada	North Amethyst, Sourth White Rose etc	150	2010	UK	Curlew C	7	2008	Russia	Salym	100	2008
Canada	Shell Scotford phase 2 (mining & ug)	100	2010	UK	Ettrick	30	2008	Russia	Kamennoye	60	2008
Canada	Horizon, CNRL, (mining & syn) 2	120	2011	UK	Jura	30	2008	Russia	incremental NGL & condensate	100	2008
Canada	Ka Kos Dehseh	100	2011	UK	Grouse (Kittiwake tie-back)	10	2009	Russia	Lunskoye	50	2009
Canada	Devon, Jackfish 2	60	2011	UK	Cheviot (former Emerald)	30	2010	Russia	Verkhnechonskoye	150	2009
Canada	CNRL, Kirby (mining & syn)	45	2011	UK	Kessog	25	2010	Russia	Other	30	2009
Canada	Suncor Voyager in situ	200	2012	UK	Various additions	150	2011	Russia	Kechimovskoye	35	2009
Canada	PetroCan, Fort Hills, mining & syn	140	2012	UK	Lochnagar	90	2012	Russia	Yuri Korchagin	40	2009
Canada	Imperial, Kearl 1, mining & syn	100	2012	***OECD Pacific***				Russia	Kuyumbinskoye	60	2010
Canada	ConocoPhilips, Surmont expansion	65	2012	Australia	Vincent	80	2008	Russia	Kharayaga	40	2011
Canada	Nexen, Long Lake 2	60	2012	Australia	Angel	50	2008	Russia	Prirazlomnoye	100	2011
Canada	Syncrude stage 3 db (mining & sync)	50	2012	Australia	Woollybutt South	12	2008	Russia	Vladimir Filanovsky	120	2012
Canada	Total, Joslyn, mining & syn	100	2013	Australia	Skua & Montara	45	2008	Russia	Odoptu	150	2013
Canada	Shell Scotford phase 3 (mining & ug)	100	2013	Australia	Pyrenees	70	2010	Russia	Arkutun-Daginskoye	150	2013
USA	Orion	55	2008	Australia	Kipper & Tuna	20	2011	Russia	Yurubcheno-Tokhomskye	50	2013
USA	Ooguruk	20	2008	Australia	Crux	30	2011	Turkmenistan	various phased offshore	160	2009
USA	Neptune	50	2008	Australia	Gorgon gas	10	2012	***Africa***			
USA	Phoenix (former Typhoon)	30	2008	Australia	Greater Sunrise (Sunrise & Troubador)	10	2012	Congo	Moho	90	2008
USA	Mirage	20	2008	New Zealand	Maari	35	2008	Congo	various others	10	2010
USA	Blind Faith	45	2008	New Zealand	Kupe (gas & cond & lpg)	10	2009	Egypt	Ivanhoe GTL	95	2010
USA	Thunder Horse	210	2008	***Asia***				Equatorial Guinea	various others	100	2010
USA	Nikaitchuk	60	2009	China	Shenhua 1-1	20	2008	Gabon	Olomi	20	2009
USA	Entrada	14	2009	China	Penglai-2	50	2008	Ghana	Jubilee 1	50	2010
USA	Shenzi	100	2009	China	Zhou Dong exp.	5	2008	Ghana	Jubilee 2	100	2012
USA	Tahiti	125	2009	China	Changqing increment	25	2008	Mauritania	Tevet	20	2010
USA	Blind Faith expansion	15	2009	China	Penglai-3	30	2009	Mauritania	Tiof	50	2011
USA	Thunder Hawk	40	2009	China	Changqing increment	10	2009	Sudan	Block 6 expansion	20	2008
USA	Clipper	12	2009	China	Shenhua 1-2	20	2010	Sudan	Block 5A expansion	20	2008
USA	Great White etc	100	2009	China	Shenhua 1-3	20	2010	Sudan	various others	100	2011
USA	Chinook & Cascade	80	2010	China	Shenhua 2	60	2011	***Latin America***			
USA	Texas misc	100	2010	China	Miscellaneous others	40	2012	Brazil	Marlim Leste P-53	180	2008
USA	Liberty	40	2011	China	Jidong Nanpu	300	2012	Brazil	Siri/Badejo test	15	2008
USA	Kaskida	140	2011	East Timor	Greater Sunrise (Sunrise & Troubador)	10	2012	Brazil	Marlim Sul 2 - P-51	150	2008
USA	Caesar	25	2011	India	Mangala	125	2009	Brazil	Jabuti	100	2009
USA	Louisiana misc	100	2011	India	Bhagyama	30	2010	Brazil	Frade - Chevron	80	2009
USA	Puma	40	2013	India	Aishwariya	20	2010	Brazil	Chinook/Peregrino - Norsk Hydro	100	2010
USA	Tubular Bells	40	2013	Malaysia	SK305	3	2008	Brazil	BC-10 - Shell Parque das Conchas	100	2010
Mexico	KMZ exp 2	165	2008	Malaysia	Bunga Pakma	17.5	2008	Brazil	Albacore extension	25	2010
Mexico	Chicontepec	300	2008	Malaysia	Various NGL	10	2010	Brazil	Pinauna	25	2010
Mexico	various NGL	20	2009	Malaysia	Gumusut	150	2012	Brazil	Marlim Sul 3 - P-56	100	2011
Mexico	KMZ exp 3	100	2009	Philippines	Galoc	17	2008	Brazil	Jubarte 2 P57	180	2011
Mexico	KMZ exp 4	60	2010	Philippines	Calauit	12	2010	Brazil	BC20-Papa Terra	210	2012
Mexico	Various new discoveries	250	2012	Thailand	various gas liquids	20	2008	Brazil	Tupi pilot	100	2012
OECD Europe				Thailand	Platong gas II	10	2011	Brazil	Cachalote	100	2012
Denmark	Adda	10	2010	Vietnam	Bunga Pakma	17.5	2008	Brazil	Espadarte module 3	100	2013
Denmark	Boje	5	2011	Vietnam	Ca Ngu Vang	20	2008	Brazil	Roncador P-55	150	2013
Netherlands	Schoonebeek	5	2008	Vietnam	Phuong Dong	20	2008	Colombia	Castilla expansion	100	2011
Norway	Vigdis East	11	2008	Vietnam	Song Doc	25	2008	Colombia	Rubiales expansion	80	2013
Norway	Dagny	5	2008	Vietnam	Su Tu Trang	70	2011	Peru	Camisea increments	30	2009
Norway	Volve	50	2008	Vietnam	Su Tu Vang	100	2008	Trinidad	Pointe a Pierre GTL/NGL	10	2008
Norway	Alvheim	50	2008	***FSU***				***Non-OPEC Middle East***			
Norway	Vilje	25	2008	Azerbaijan	Guneshli deep	320	2008	Oman	Harweel increment	10	2008
Norway	Heimdal Ost	10	2008	Azerbaijan	Balakhany Chirag & Balakhany Azeri extensions	150	2010	Oman	Harweel EOR	10	2009
Norway	Various additions	250	2010	Azerbaijan	Shah Deniz II	40	2013	Oman	PDO condensate	10	2009
Norway	Skarv	80	2012	Kazakhstan	Tengiz stepped expansion	375	2008	Oman	Harweel and other PDO EOR	25	2010
Norway	Goliat	50	2012	Kazakhstan	Karachaganak expansion	90	2009	Yemen	Block S1 An Nagyah	3	2008
Norway	Yme	40	2009	Kazakhstan	Tengiz phase 3	260	2013	Yemen	Block 43 Nabrajah	14	2008
Norway	Tyrihans N	65	2010	Kazakhstan	Kashagan phase 1	370	2013	Yemen	Block S1 An Nagyah	20	2009
Norway	Morvin	20	2010	Russia	Piltun Astokhskoye increment	140	2008	Yemen	Miscellaneous others	50	2010
Norway	Froy redevelopment	35	2012	Russia	Vankor	380	2008				

TABLE 6: SELECTED OPEC UPSTREAM PROJECT START-UPS

Country	Project	Peak Capacity (kbd)	Start Year	Country	Project	Peak Capacity (kbd)	Start Year	Country	Project	Peak Capacity (kbd)	Start Year
Crude Oil Projects								***NGL & Condensate Projects***			
Angola	Gimboa - block 4	50	2008	Libya	Nafoora expansion	150	2010	Algeria	MLE (block 405)	40	2010
Angola	Kizomba C - Mondo - block 15	100	2008	Libya	Al Jurf expansion	10	2010	Algeria	El Merk (Berkine 208)	50	2011
Angola	Kizomba C - Saxi/Batuque - block 15	100	2008	Libya	Al Farigh expansion	20	2010	Algeria	El Merk (Berkine 208)	100	2011
Angola	Mafumeira - block 0	30	2009	Libya	Amal	90	2010	Algeria	Gassi Touil	10	2013
Angola	Perpetia-Acacia-Zinia-Hortensia (Pazflor) (Block 17)	200	2012	Libya	Gialo expansion	50	2012	Indonesia	Kerisi-Hiu	20	2008
Angola	Negage - block 14	50	2012	Nigeria	Agbami	200	2008	Indonesia	Oyong NGL	1	2009
Angola	Plutao/Saturno/Venus/Marte 1 (Block 31)	130	2012	Nigeria	Ofon 2 expansion (Total)	60	2010	Indonesia	Ujung Pangkah	10	2009
Angola	Mavacola, Clochas, Reco Reco etc Kizomba satellites (D) - block 15	125	2012	Nigeria	Bonga SW/Aparo	150	2012	Indonesia	Gendalo/Gehem	25	2013
Angola	Ceres/Hebes/Palas (Block 31)	110	2013	Nigeria	Egina (Total)	150	2012	Iran	Pars 6-8	50	2008
Angola	Gindungo, Canela, Gengibre - Block 32	125	2013	Nigeria	Usan	180	2012	Iran	Pars 6-8	120	2008
Angola	Cravo-Lirio-Orquidea-Violeta (CLOV) (Block 17)	115	2013	Nigeria	Bosi	120	2012	Iran	Pars 9-10	34	2009
Indonesia	Banyu Urip (Cepu)	180	2009	Qatar	Al Shaheen increments	80	2008	Iran	Pars 9-10	80	2009
Indonesia	North Belut	25	2009	Qatar	Al Shaheen increments	70	2009	Iran	Pars 12	50	2013
Indonesia	Bukit Tua	20	2009	Qatar	Al Shaheen increments	35	2010	Iran	Pars 12	120	2013
Indonesia	Ujung Pangkah	15	2009	Saudi Arabia	Abu Hadriya	150	2008	Kuwait	Sabriyah & Umm Niqa I	50	2008
Indonesia	North Duri steamflood	60	2012	Saudi Arabia	Fadhili	100	2008	Kuwait	Sabriyah & Umm Niqa II	115	2011
Iran	Darkhovin II	110	2008	Saudi Arabia	Khursaniyah crude	250	2008	Libya	NC-98	60	2013
Iran	Khesht	35	2008	Saudi Arabia	Shaybah 2	250	2008	Nigeria	EA NGL	40	2008
Iran	Salman	50	2008	Saudi Arabia	Nuayim	100	2009	Nigeria	Agbami	50	2008
Iran	Masjid e Suleiman expansion	15	2008	Saudi Arabia	Khurais crude (incl Abu Jifan & Mazalij)	1200	2009	Nigeria	Akpo	180	2009
Iran	Azadegan I	50	2008	Saudi Arabia	Wafra etc - PNZ	10	2009	Nigeria	Escravos GTL	35	2011
Iran	Abuzar	30	2009	Saudi Arabia	Khafji/Hout etc - PNZ	10	2009	Qatar	Qatargas Train 4	160	2008
Iran	Jufeyr I	25	2009	Saudi Arabia	Manifa crude	900	2012	Qatar	RasGas Train 6 NGL	25	2009
Iran	Foroozan	80	2010	UAE	Rumaitha expansion	20	2008	Qatar	RasGas Train 6 condensate	50	2009
Iran	South Pars	35	2010	UAE	Umm Shaif expansion	75	2010	Qatar	Pearl GTL	70	2011
Iran	Darkhovin III	120	2012	UAE	Lower Zakum expansion	25	2010	Qatar	Pearl GTL	70	2012
Iran	Jufeyr II	25	2012	UAE	Onshore Adco expansions	150	2011	Saudi Arabia	Khursaniyah condensate	80	2008
Iran	Azadegan II	100	2012	UAE	Upper Zakum expansion	150	2012	Saudi Arabia	Khursaniyah NGL	210	2008
Iran	Kharg NGL	80	2012	UAE	Onshore Adco expansions	125	2012	Saudi Arabia	Hawiyah	300	2008
Iran	Kharg NGL	5	2012					Saudi Arabia	Khurais condensate	70	2009
Iran	Yadavaran I	85	2012					Saudi Arabia	Manifa condensate	50	2012
Iraq	Taq Taq 1	50	2008					UAE	Habshan 3 gas plant expansion	270	2008
Iraq	Rumaila TSA	100	2008					UAE	Asab 2 NGLs	71	2010
Iraq	Kirkuk TSA	100	2008								
Iraq	West Qurna TSA	100	2008								
Iraq	Suba and Luhais TSA	100	2008								
Iraq	Misan TSA	100	2008								
Iraq	Zubair TSA	100	2008								
Iraq	Taq Taq 2	150	2010								
Kuwait	Burgan water treatment etc	40	2008								
Kuwait	Wafra etc - PNZ	10	2009								
Kuwait	Khafji/Hout etc - PNZ	10	2009								
Kuwait	Burgan water treatment etc	120	2009								
Kuwait	Sabriya GC-24	160	2010								
Libya	El Shahara expansion	10	2008								
Libya	Elephant ramp-up	55	2008								
Libya	NC186 expansion	35	2008								
Libya	Verenex Ghadames Basin Area 47	50	2010								
Libya	Zuetina expansion	50	2010								

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Why have oil prices hit USD140 per barrel? How strong will oil demand be in the upcoming years? Will supply of crude oil, natural gas liquids and biofuels be sufficient to meet this future demand? And, no less crucially, what investments in refining capacity and technology can we expect and will these help ease some of the imbalance in strained oil product markets?

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