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MEDIUM-TERM Oil Market Report

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Overview

Despite four years of high oil prices, this report sees increasing market tightness beyond 2010, with OPEC spare capacity declining to minimal levels by 2012. A stronger demand outlook, together with project slippage and geopolitical problems has led to downward revisions of OPEC spare capacity by 2 mb/d in 2009. Despite an increase in biofuels production and a bunching of supply projects over the next few years, OPEC spare capacity is expected to remain relatively constrained before 2009 when slowing upstream capacity growth and accelerating non-OECD demand once more pull it down to uncomfortably low levels.

Global Balance Summary
(million barrels per day)

	2007	2008	2009	2010	2011	2012
Global Demand	**86.13**	**88.27**	**90.02**	**91.91**	**93.84**	**95.82**
Non-OPEC Supply	49.98	50.99	51.65	51.94	52.20	52.56
OPEC NGLs, etc.	4.86	5.51	6.28	6.73	6.91	7.08
Global Supply excluding OPEC Crude	**54.83**	**56.50**	**57.93**	**58.67**	**59.10**	**59.64**
OPEC Crude Capacity	**34.40**	**35.46**	**36.10**	**37.11**	**37.92**	**38.36**
Call on OPEC Crude + Stock Ch.	**31.30**	**31.77**	**32.10**	**33.24**	**34.74**	**36.18**
Adjusted Call on OPEC Crude + Stock Ch.[1]	**31.89**	**32.39**	**32.73**	**33.87**	**35.37**	**36.81**
Implied OPEC Spare Capacity[2]	3.09	3.69	4.00	3.87	3.18	2.18
Adjusted OPEC Spare Capacity[3]	2.50	3.07	3.37	3.24	2.55	1.55
as percentage of global demand	*2.9%*	*3.5%*	*3.7%*	*3.5%*	*2.7%*	*1.6%*
Changes since February 2007 MTOMR						
Global Demand	**0.18**	**0.68**	**0.65**	**0.59**	**0.51**	
Non-OPEC Supply	-0.67	-0.72	-0.89	-0.89	-1.00	
OPEC NGLs, etc.	-0.03	0.20	0.28	0.31	0.21	
Global Supply excluding OPEC Crude	**-0.70**	**-0.52**	**-0.61**	**-0.58**	**-0.79**	
OPEC Crude Capacity	**-0.34**	**-0.79**	**-0.85**	**-0.77**	**-0.38**	
Call on OPEC Crude + Stock Ch.	**0.88**	**1.21**	**1.25**	**1.18**	**1.30**	
Adjusted Call on OPEC Crude + Stock Ch.[1]	**0.67**	**1.03**	**1.07**	**1.00**	**1.12**	
Implied OPEC Spare Capacity[2]	-1.28	-2.07	-2.23	-2.25	-2.02	
Adjusted OPEC Spare Capacity[3]	-1.07	-1.89	-2.05	-2.08	-1.84	

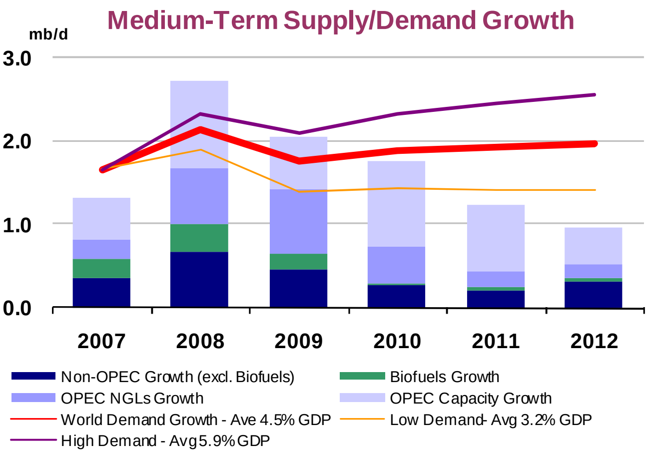
1 Arithmetic 'Call on OPEC + Stock Ch.' adjusted to include the most recent 8-quarter average of Miscellaneous to balance (627 kb/d from 2Q07 onwards) from OMR.
2 OPEC Capacity minus 'Call on Opec + Stock Ch.'
3 OPEC Capacity minus 'Adjusted Call on OPEC Crude + Stock Ch.' Historically effective OPEC spare capacity averages 1 mb/d below notional spare capacity.

It is possible that the supply crunch could be deferred – but not by much. The demand side of this analysis is based on country-level GDP growth forecasts from the OECD and IMF, which amount to a global average of around 4.5% annually. However, with GDP being the primary driver of our strong outlook, warnings from institutions that the risks to economic growth are skewed to the downside confer similar risks to our medium-term forecasts - but they do not necessarily dramatically alter the projections.

Lowering GDP growth to around 3.2% per year from 2008-2012 reduces annual oil demand growth from 2.2% to around 1.7% and the call on OPEC crude drops by around 2 mb/d by 2012. But this merely postpones by a year the point at which oil demand growth surpasses the growth in global oil capacity – in effect, delaying the return of minimal spare capacity by only a few years (unless the trend in upstream capacity growth changes). Indeed, any easing in expected tightness may be even less than this snapshot analysis suggests. In reality, falling demand growth would undoubtedly have a price impact, which could both cushion some of the GDP-related fall in demand and, on the supply side, may result in lower investment.

Essentially, concerns over the economic imbalances, for example, the current US housing market downturn, imply risks to the demand side. In the final analysis though, a tight oil market reappears by the end of the forecast period.

There are other risks. While we have thoroughly revised our supply methodology to take account of a sustained high level of oilfield outages, further downside risk on the supply side cannot be ruled out. Although steeper-than-expected field decline has not been a significant factor in the underperformance of the upstream sector over the past few years, small changes to the rate of forecast global decline can have a big impact on the supply side. However, on balance we believe that above-ground risks are likely to exceed below-ground risks for the medium term.



But these supply risks are also balanced. Our OPEC capacity forecast assumes that there will be no net expansion of capacity in Iran, Iraq and Venezuela and that the 0.5 mb/d of Nigerian capacity that has been shuttered for a year will not come back on line during the forecast period. Recent history would suggest that a conservative approach to OPEC capacity is justified – in recent years, *effective* OPEC capacity has averaged around 1 mb/d below nominal capacity[1]. But while such an allowance would, at present, provide a better indication of usable spare capacity, there is the potential that over time some of the constraints on this inaccessible portion could change – lifting the available reserve.

The refining industry, which has struggled to match strong global demand for transportation fuels with installed capacity, has responded to market incentives. Investment in sophisticated refinery capacity is continuing apace. Despite suffering from project inflation and slippage similar to that seen in the upstream sector (as a result of tightness in the service sector, labour, equipment and commodity markets) a significant improvement in refinery flexibility is foreseen.

Current refinery investment should increase the ability of the refining sector to process the heavy/sour OPEC spare capacity that was of little interest to refineries for the past few years. More fuel oil will be able to be upgraded into lighter transportation fuels; combined with growing biofuels supplies, the ability to meet demand growth in gasoline and diesel should improve. But this has implications for prices and price differentials. If gasoline and diesel demand can be more easily met, then the high differentials to crude oil are likely to ease. Similarly, the ability to upgrade the heavy end of the barrel implies that the large discounts needed to clear surplus fuel oil production will become a thing of the past. Differentials between light/sweet and heavy/sour crude oil should narrow.

It should be noted that the potential for distillate markets to ease over the next five years would be dwarfed by the impact of marine bunker fuels switching from fuel oil to distillate. As highlighted in the *Oil Market Report* dated 11 May 2007, a change on this scale would necessitate additional investment in upgrading capacity far above those that are currently forecast.

The IEA believes that the recent imbalances in the product market have had a significant knock-on effect on oil market volatility and outright prices. Therefore an easing of these tensions should reduce one of the price pressures that has been in place for the past few years. But like the modest rise in spare OPEC capacity by 2009, it could be short-lived. The *MTOMR* product supply forecast hinges on the assumption

[1] *MTOMR* notional spare capacity lies between the range quoted for implied and adjusted OPEC spare capacity. It is calculated by subtracting the *implied/adjusted call on OPEC* from OPEC capacity.

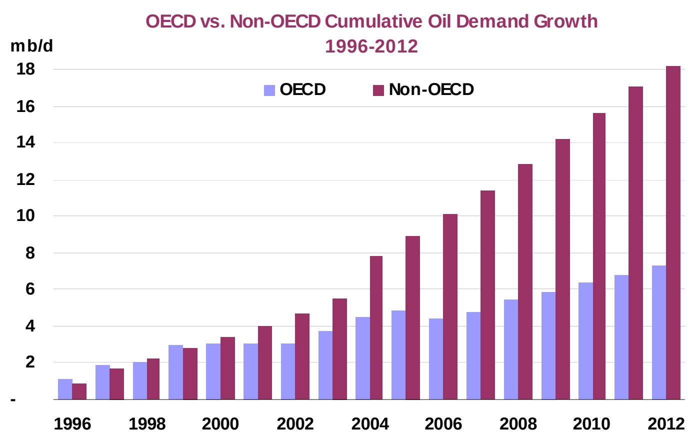
OMR spare capacity is calculated by subtracting *estimated OPEC production* from OPEC capacity. If on average OPEC produces above or below the call in any year, there is a large miscellaneous- to-balance or large stock moves, the *OMR* and *MTOMR* estimates of spare capacity may diverge.

that a number of large refining projects in the US will be approved in the coming months and that high-cost projects at the tail-end of the forecast do not slip further. If refining margins dip, with project lead times of 18 months to three years, further slippage is possible. As such, market dynamics suggest that it is unlikely that the refining industry will return to a long-term era of low refinery margins.

But the oil market cannot be looked at in isolation. Not only does oil look extremely tight in five years time, but this coincides with the prospects of even tighter natural gas markets at the turn of the decade. Over the past 25 years there has been substitution away from fuel oil and towards natural gas. However, when natural gas supplies have been insufficient or there have been supply problems (such as those seen following Hurricanes Katrina and Rita in 2005, Russia in 2006), fuel oil has been the natural substitute. By the end of the decade, such flexibility may be constrained, producing upward pressures on all hydrocarbons. Slower-than-expected GDP growth may provide a breathing space, but it is abundantly clear that if the path of demand does not change on its own, it may well be driven to change by higher prices.

Demand

Global oil product demand is forecast to expand by 1.9 mb/d or 2.2% per year on average, reaching 95.8 mb/d by 2012. Growth is driven by the stronger oil demand growth in non-OECD countries, particularly in Asia and the Middle East, where demand will grow more than three times faster than that of the OECD economies. These countries are moving towards the threshold level of income (around $3000 per capita) where their consumers buy cars and energy-consuming white goods. They also tend to be large players in the energy-intensive processing of primary commodities and heavy industry. The 2007 edition of the *World Energy Outlook* (to be published in November 2007) will focus on China and India and provide energy projections for all fuels for these two countries through to 2030 and will discuss their implications on global markets.



OECD oil product demand is expected to rise from 49.6 mb/d in 2007 to 52.1 mb/d in 2012, driven by transportation fuel demand growth in North America, where consumption is poised to grow twice as fast as in Europe or the Pacific (1.3% per year on average versus 0.7% and 0.6% in the latter two regions). In contrast, non-OECD oil product demand is poised to increase by, on average, 1.4 mb/d or 3.6% per year over the next five years, coming close to the point at which it will surpass total oil consumption in the OECD. While per capita consumption will remain well below that seen in the OECD, the developing world and emerging industrialised economies see their share of world oil consumption rise from 42% of global oil demand to 46% by 2012.

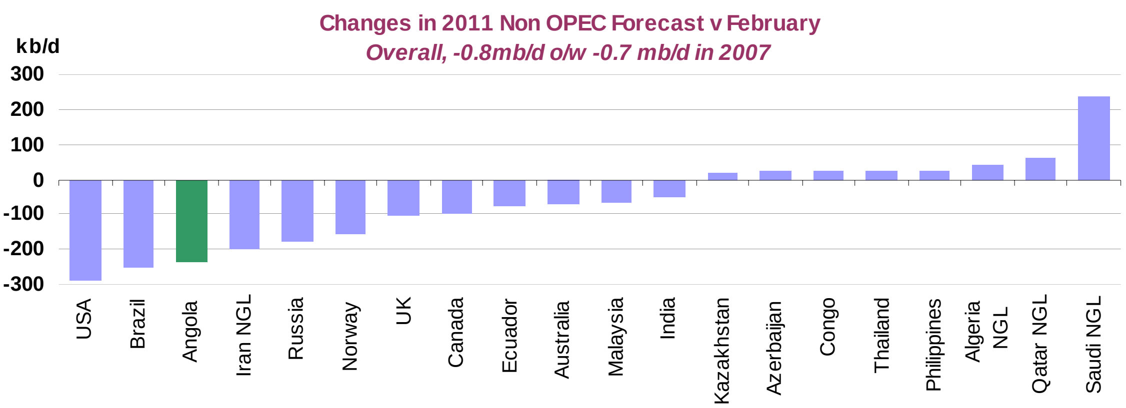
Transportation fuels will account for the bulk of demand growth in both OECD and non-OECD countries. These fuels, which include motor gasoline, jet fuel/kerosene and gasoil/diesel oil, are expected to represent roughly 67% of the increase in OECD consumption over the forecast period, and about 60% of the rise in non-OECD demand.

While concern about possible downside risks to GDP forecasts seems to dominate, there are upside risks as well. In particular, given the higher income elasticities in the non-OECD regions, stronger-than-projected economic growth in these regions could actually boost oil demand growth. Data uncertainties tend also to constitute an upside risk for forecasts. Historical demand-side data revisions have tended to be positive in both OECD and non-OECD countries, but they are of particular concern in non-OECD countries where data seldom provide a full view of market balances - particularly in the strong demand growth countries such as China, India, and some Middle Eastern countries.

Supply

The *MTOMR* projects strong non-OPEC liquids (crude, condensate, NGLs and biofuels) supply growth in 2007-2009 appearing to recede thereafter as the slate of verifiable investment projects diminishes. Total non-OPEC liquids supply growth to 2012 is pegged at 2.6 mb/d. Here too, upstream construction, drilling and service capacity will remain stretched, leaving forecasts prone to slippage due to cost over-runs and project delays. These above-ground risks are still seen as greater than those posed by resource depletion and other below-ground factors.

We revise downwards the non-OPEC forecast by 0.8 mb/d in 2011, partly reflecting slippage, but also incorporating a new 0.4 mb/d contingency factor, reflecting a tendency for unscheduled field outages. Supply-side uncertainty is further exacerbated by increasing instances of resource nationalism and geopolitical risk, constraining the ability of the industry to produce the 3.0 mb/d of new production needed each year to offset the effects of decline. Overall, this leads to average non-OPEC supply growth of 1.0% between 2007 and 2012, 0.4% below the growth seen in the previous seven years and roughly half the rate of demand growth projections.



Non-OPEC growth is boosted initially by OPEC gas liquids and by biofuels, although substantial increases also derive from new crude supplies from the US Gulf of Mexico, Canadian oil sands, the FSU, Brazil and sub-Saharan Africa. These offset sharp declines expected from elsewhere in the US and Canada, Mexico, the North Sea, and parts of Asia and the Middle East. Annual OPEC NGL and condensate supply growth continues around the 8% pace seen so far this decade and adds a net 2.6 mb/d to prevailing output – deferring an expected longer-term move to heavier/sourer global refinery feedstock supply.

OPEC crude capacity (constrained by ongoing security and investment issues in Iraq, Nigeria and Venezuela) is seen rising to 38.4 mb/d in 2012 from a 2007 average of 34.4 mb/d. Some 70% of the increase comes from Saudi Arabia (+1.8 mb/d), the UAE and Angola (+0.5 mb/d each), with smaller amounts elsewhere. OPEC spare capacity, which has steadily recovered from minimal levels at the end of 2004 to almost 3.0 mb/d at mid-2007 remains relatively constrained through to 2009, but declines sharply thereafter. These effects could be magnified if the effective level of spare capacity remains close to its historical 1 mb/d below nominal levels.

Substantially higher cash returns to shareholders stand in curious contrast to growing upstream supply tightness and essentially unchanged exploration and production (E&P) effort. Nominal E&P expenditures are up, but higher costs have eroded their purchasing power commensurately. However, it is clear that there are other issues at work.

In particular:

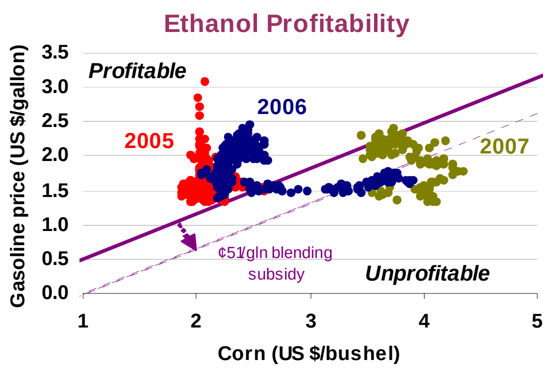
- Access and contractual conditions (even in OECD countries) are deteriorating.
- Hurdle rates for upstream investment may be too conservative (development costs have moved higher, albeit there are indications that cost inflation, is easing)
- Labour, equipment and service sector constraints may reduce the potential for expansion of the project base, at least through 2012.
- The rise of consumer-country NOCs and independent exploration companies is eroding the market share of more risk-averse IOCs, which endured years of lower returns after the oil price collapsed in the mid-1980s.

Biofuels

We project world supply of automotive biofuels to rise to 1.8 mb/d by 2012, roughly double the 0.9 mb/d produced in 2006. This is a relatively conservative production forecast considering the multiple policy statements and biofuels production targets: it projects output 1.2 mb/d below the potential level of capacity additions by the end of the forecast for a number of reasons.

Rising prices of feedstocks such as corn, sugar, soybeans, wheat and palm oil reinforce our concerns over the medium-term economic viability of the industry in certain regions to achieve targeted levels of growth. This conservatism is partly predicated on the lack of clear long-term mandates and subsidies in many countries to both force refiners to blend biofuels into their end-products and the structural and technical difficulties in doing so.

There are also lags to the price response from the agricultural sector and competition for arable acreage, which will lead to further increases in prices for both biofuel feedstocks and food. Indeed, current economics often favour using these feedstocks as foodstuffs rather than fuel, and technology for mass production of biofuels from other feedstocks falls outside the timeframe of this analysis.



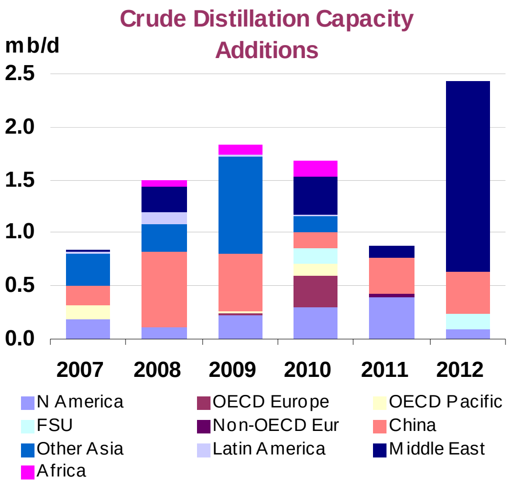
The profitability line (net of subsidies) has been estimated to take into account the value of ethanol on an energy basis, a price premium for octane and oxygen and a price premium for the sale of co-products.

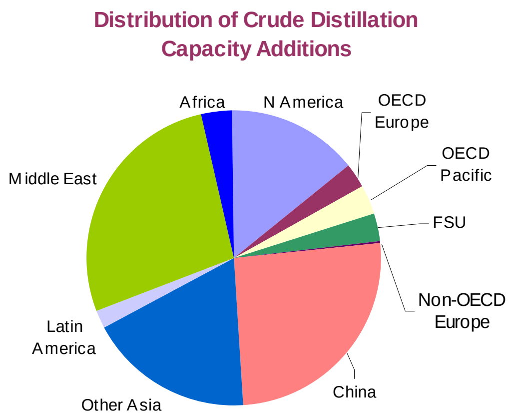
Nevertheless, our forecast still sees a considerable 50% supply growth in automotive biofuels between 2007 and 2009, with the most rapid volumetric growth taking place in the US, which is expected to hit its previous 2012 biofuels supply target three years early. By 2012 biofuels will still only account for only 2% of global oil supplies, they will account for 13% of the volumetric growth in gasoline and gasoil/diesel demand in the early stages of the forecast. This is causing investors to re-evaluate the need for incremental refinery capacity.

Refining and Product Supply

Global crude distillation capacity is expected to increase by 10.6 mb/d during the 2007-2012 period: 9.1 mb/d of new capacity and 1.5 mb/d of capacity creep. The Middle East and Asia account for 6.7 mb/d of the expansions, with refining capacity growth in these regions exceeding regional product demand. These investments certainly increase the flexibility of the refining industry to process the existing and future crude slate, particularly the tranche of heavy/sour crude spare capacity currently held by OPEC.

However, our projections for the refining sector are subject to the same caveats as the upstream, which together with three-year project lead times, suggests careful attention needs to be paid to the largest chunk of expansion – 3.3 mb/d from a handful of large projects between 2011 and 2012. These could be subject to additional delays if refinery economics were to deteriorate, or contractor-related bottlenecks were to increase in the intervening period – or if investors believe all the biofuels targets will be achieved.





Contingent on these investments going ahead, the IEA's recently completed Refinery and Product Supply Model indicates that the ability of refiners to expand gasoline supplies should improve significantly over the course of the next few years, and that the potential to both process heavy sour crudes and convert fuel oil into lighter products will increase. With fuel oil discounts of $15 to $30/barrel relative to crude over the past few years, there is the potential for the upgrading capacity additions to tighten fuel oil and ease gasoline differentials to benchmark crudes.

Cross-Market Implications

The potential effects of a combination of low OPEC spare capacity and slow non-OPEC production growth are of significant concern – all the more so when considered alongside tightness in other hydrocarbons - particularly the natural gas market.

The IEA's *Gas Market Review 2007(GMR)* noted that gas output in IEA member countries is either on a plateau or, in several countries, in decline at a rapid rate. At the same time, demand remains strong. The GMR also indicates a shortfall in the natural gas supply and infrastructure investments needed to meet increasing demand, leading to the conclusion that the natural gas market is likely to remain tight until 2012, and probably beyond. While in the medium to longer term (post-2015), investment in coal and nuclear power could ameliorate matters, investment impediments may force investors back to gas. Oil and gas price pressures look set to remain in the coming years.

The sequential analysis undertaken in the *MTOMR* suggests that while gas markets may look to fuel oil as an alternative, fuel oil supplies themselves will tighten. Ultimately this may lead to upward pressure on fuel oil and gas prices until electricity or industrial demand growth abates. Further, it raises serious concerns for gas market security, whereby the most cost-effective solution in many countries is to switch to fuel oil in the event of a supply disruption - fostering competition for supplies across the hydrocarbon sector.

DEMAND

Summary

- **Global oil product demand is forecast to expand by 2.2% per year on average between 2007 and 2012**, from 86.1 mb/d to 95.8 mb/d, underpinned by an annual global economic growth rate of +4.5% on average over the period. This represents an annual average volumetric growth of 1.9 mb/d. Growth will be driven by non-OECD countries, where demand is seen increasing more than three times as fast as in the OECD.

- **This forecast faces several risks.** On the downside, as highlighted by the IMF, these include global economic imbalances, financial market volatility, a more pronounced slowdown in the US, renewed inflationary pressures and a sustained hike in oil prices. There are also several upside uncertainties, notably China's volatile demand, which has surprised many in the past and which could surge again, as well as the potential for statistical revisions that could imply a faster growth rate for some countries.

Global Oil Demand (2007-2012)

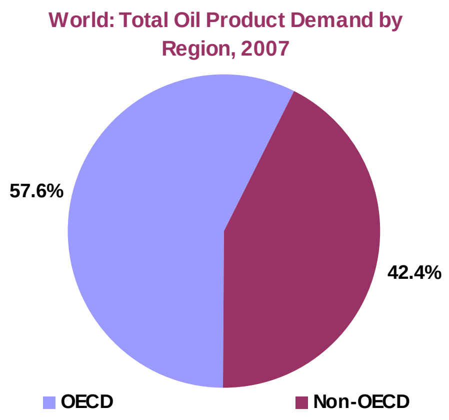
(million barrels per day)

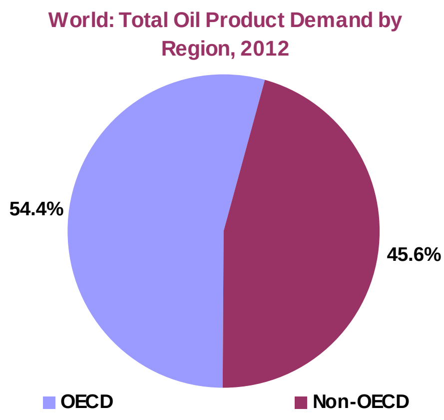
	1Q07	2Q07	3Q07	4Q07	2007	1Q08	2Q08	3Q08	4Q08	2008	2009	2010	2011	2012
Africa	3.1	3.1	3.0	3.1	3.1	3.2	3.1	3.1	3.2	3.1	3.2	3.3	3.5	3.6
Americas	31.0	30.8	31.5	31.6	31.2	31.6	31.4	32.0	32.0	31.7	32.2	32.7	33.1	33.6
Asia/Pacific	25.3	24.8	24.6	25.8	25.1	26.5	25.5	25.3	26.6	26.0	26.7	27.5	28.2	29.1
Europe	16.0	15.8	16.3	16.6	16.2	16.6	16.0	16.4	16.7	16.4	16.5	16.6	16.7	16.8
FSU	3.8	3.7	4.1	4.4	4.0	4.0	3.9	4.2	4.5	4.1	4.2	4.3	4.4	4.5
Middle East	6.4	6.5	6.8	6.5	6.6	6.7	6.8	7.1	6.8	6.9	7.2	7.5	7.9	8.2
World	**85.6**	**84.6**	**86.3**	**88.0**	**86.1**	**88.5**	**86.7**	**88.0**	**89.8**	**88.3**	**90.0**	**91.9**	**93.8**	**95.8**
Annual Chg (%)	0.5	1.6	2.6	3.0	2.0	3.5	2.5	2.0	2.0	2.5	2.0	2.1	2.1	2.1
Annual Chg (mb/d)	0.4	1.4	2.2	2.6	1.7	3.0	2.1	1.7	1.7	2.1	1.8	1.9	1.9	2.0

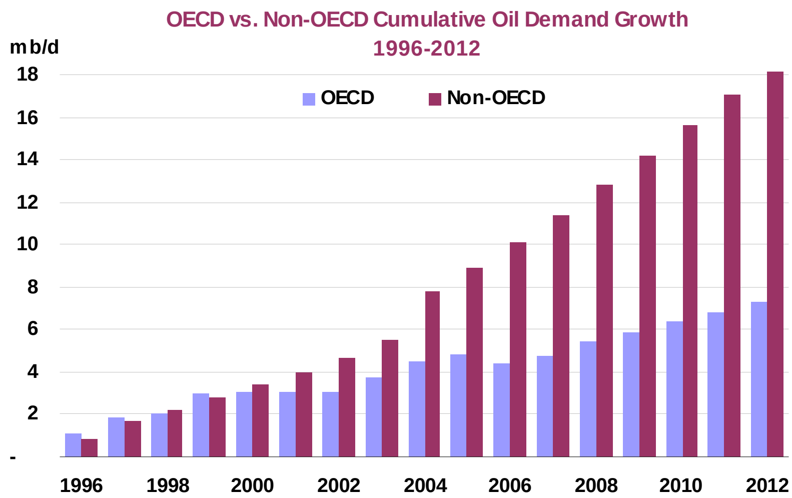
- **OECD oil product demand is expected to increase annually by 1.0 % on average over the forecast period**, from 49.6 mb/d in 2007 to 52.1 mb/d in 2012 – that is, an average yearly increase of 0.5 mb/d. OECD demand growth will be essentially sustained by North America, where consumption is poised to grow twice as fast as in Europe or the Pacific (+1.3% per year on average versus +0.7% and +0.6% in the latter two regions). Consumption growth will be driven by transportation fuels, but with different regional trends (gasoline in North America and diesel in Europe, with the Pacific more evenly balanced).

- **Non-OECD oil product demand is poised to increase by 3.6% on average per year over 2007-2012**, from 36.6 mb/d to 43.7 mb/d, equivalent to +1.4 mb/d per year, roughly in line with previous forecasts. It should be noted that the baselines for most countries and regions were revised, following the submission of new data or by reappraisals of apparent demand estimates. Data uncertainties pose upside risks to the forecast, particularly in the case of China, India and the FSU. Within non-OECD countries, two regions will stand as the major consumers over the forecast period: Asia, which is expected to represent about half of average non-OECD incremental demand growth, and the Middle East, accounting for almost a quarter.

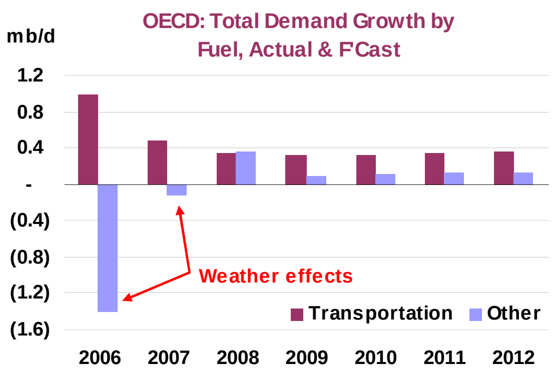
- **Non-OECD demand will remain lower than OECD consumption, despite faster growth.** By the end of the forecast period, non-OECD demand will account for almost 46% of total global demand, compared with slightly above 42% in 2007. Demand in non-OECD countries will increase more than three times as fast as OECD consumption; at this rate, non-OECD demand may well surpass OECD consumption by the mid of the next decade.

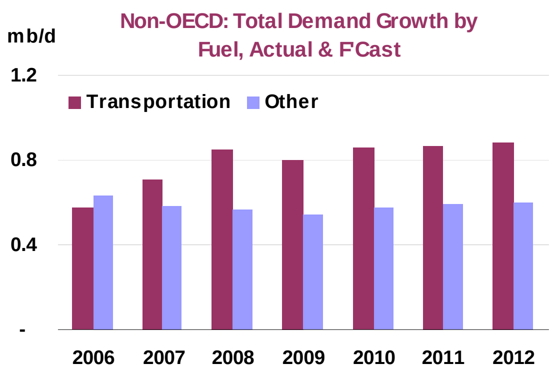


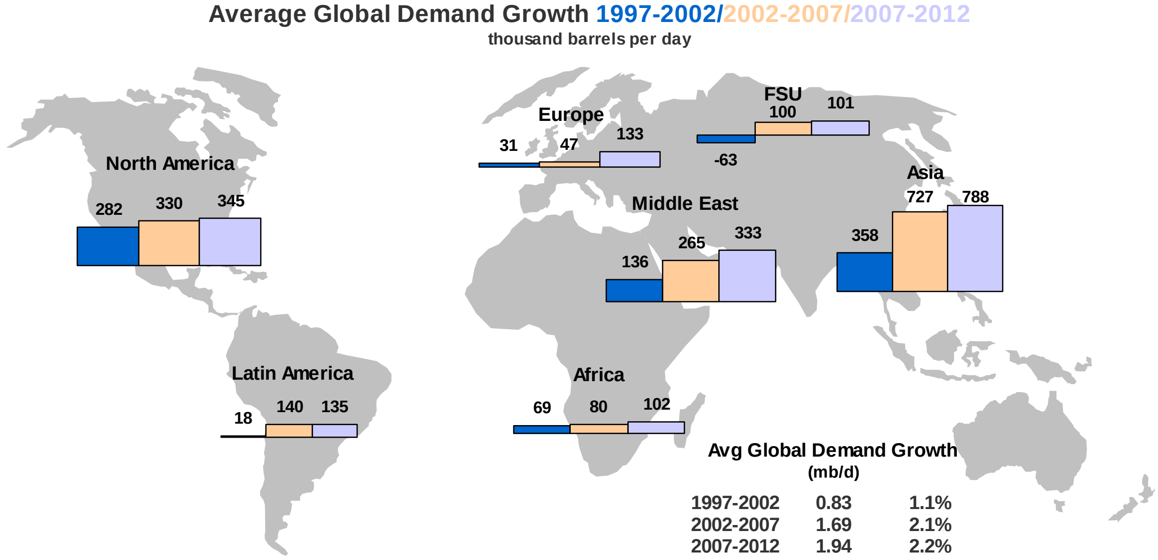




- **Transportation fuels will account for the bulk of demand growth in both OECD and non-OECD countries.** Transportation fuels, which include motor gasoline, jet fuel/kerosene and gasoil/diesel oil, are expected to represent roughly 67% of the cumulative increase in OECD consumption over the forecast period, and about 60% of the cumulative rise in non-OECD demand. This discrepancy between regions is explained by the fact that the share of oil-fired industrial and power generation activities will continue to be higher in developing, non-OECD countries. In the OECD, by contrast, the economic structure has shifted from industry to services, while electricity generation has increasingly favoured the use of natural gas. Nevertheless, if natural gas supplies fail to meet demand, the fuel oil market could become quite tight by the end of the forecast.





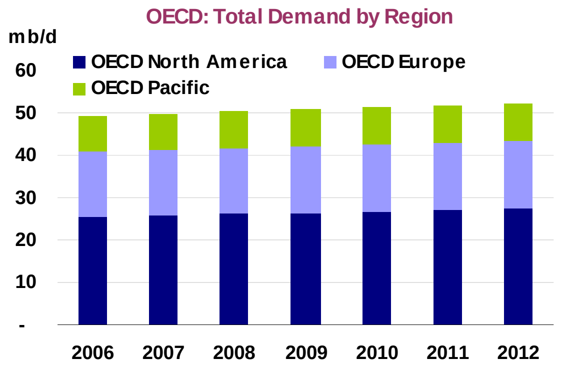


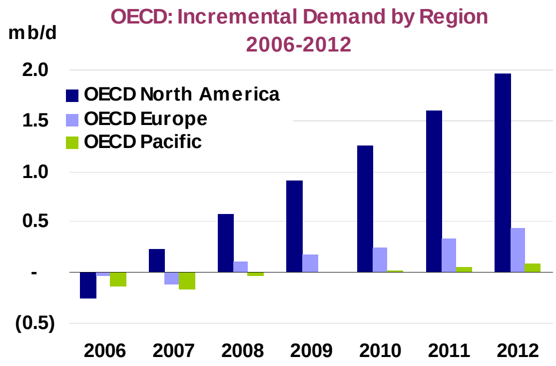
- **Biofuels are expected to expand significantly over the forecast period, but will remain marginal in terms of total oil demand.** We anticipate that ethanol (about 78% of total biofuels on average) and biodiesel will displace altogether 1.1 mb/d of oil product demand in 2007, rising to almost 1.8 mb/d in 2012. Ethanol is expected to displace roughly 27% of incremental gasoline demand; by contrast, biodiesel will only displace about 5% of incremental gasoil demand. Despite its rapid growth, however, ethanol consumption will only account for about 6% of global gasoline demand by the end of the forecast period, while biodiesel use will represent even less (slightly more than 1%) as a proportion of global gasoil consumption. Overall, biofuels demand will be concentrated in OECD countries.

OECD

Total oil product demand in the OECD is forecast to increase by 1.0% per year on average over the forecast period, from 49.6 mb/d in 2007 to 52.1 mb/d in 2012. In volumetric terms, this is equivalent to +0.5 mb/d per year on average. The main differences from the February *MTOMR* update are related to baseline revisions to several countries, particularly for 2005. Generally, data revisions to historical series for most OECD countries (2005 and before) were received in the first half of this year, and the changes were carried through in the forecast. In addition, the weak overall demand observed in late 2006 and early 2007, as a result of inordinately warm temperatures, is largely responsible for downward revisions in both years, and helps explain the relatively strong rebound in 2008 (since the forecast assumes normal weather conditions).

Finally, revisions to the IMF's medium-term GDP growth assumptions (*World Economic Outlook*, April 2007) are also included. Although the Fund revised down its outlook for the world's largest economy – the United States – given the uncertainties regarding housing and inflation, it also revised up its assessment of other key OECD countries – the Eurozone and Japan. In sum, even though the IMF warns of downside risks – the 'disorderly' unwinding of global imbalances, financial market volatility, a more pronounced slowdown in the US, renewed inflationary pressures and a sustained hike in oil prices – its core outlook is optimistic, suggesting that oil consumption will remain strong in the OECD (see *A Review of Demand Drivers*).





Oil demand growth will be underpinned by transportation fuels. Commercial and residential heating and residual fuel oil for power generation will continue to be displaced by natural gas and coal. Nevertheless, this prediction may be less certain by the tail-end of this forecast, which is based on the premise that there will be enough gas to fuel planned gas-fired power generation capacity, particularly in Europe. However, the latest edition of the IEA's *Gas Market Review* warns that there may be insufficient investment to expand Russian natural gas supplies to meet European demand growth by the end of the decade. Moreover, as refiners invest in upgrading capacity, the fuel oil market is expected to tighten by around the same period. While the refining system still would likely have sufficient capacity to meet unplanned fuel switching needs, there would indeed be a cost. Over the past three years, US natural gas prices have dictated fuel oil demand, but the increasing sophistication of the refining system is likely to foster a stronger price effect as demand fluctuates between the heavy and the light end of the barrel. Therefore, if natural gas supply growth proves lower than needed, there could well be a period of strong price competition between all forms of hydrocarbons.

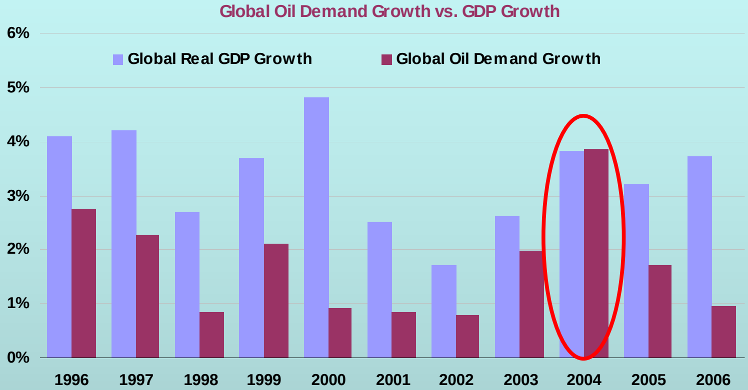
It is important to highlight that the demand forecast has incorporated the possible impact of biofuels (ethanol and biodiesel) on conventional gasoline and diesel, both for OECD and non-OECD countries. We have allowed for the meteoric rise in biofuels capacity to translate into higher output through to 2009. Afterwards, however, this report has constrained biofuels output – and hence consumption – below announced capacity levels in the absence of clear policies and given concerns over feedstock economics. In other words, the economics of the industry (or government subsidies) will determine whether additional plants are built. This also means that there is significant potential for further displacement of transportation fuels by biofuels by 2012, assuming that a significant expansion of the feedstock base occurs – provided feedstock prices remain sufficiently high.

Both ethanol and biodiesel demand are poised to grow very rapidly. Under our current assumptions, biofuels are expected to displace about 1.1 mb/d of oil product demand in 2007 and almost 1.8 mb/d by 2012. However, volumetric demand would be approximately 225 kb/d lower by the end of the forecast period if biofuels were not used, reflecting their lower energy content (30% less for ethanol, 10% less for biodiesel). More significantly, ethanol (about 78% of total biofuels demand on average over the forecast period) will meet close to 27% of the average incremental gasoline demand. By contrast, biodiesel will contribute to some 5% of the world's average incremental gasoil demand (diesel and other gasoil combined, given the lack of detail in non-OECD data). Even so, ethanol consumption will only correspond to about 6% of global gasoline demand by the end of the forecast period, while biodiesel use will represent slightly more than 1% of global gasoil demand. It should be noted, finally, that biofuels demand will be concentrated in OECD countries (52% for ethanol and 71% for biodiesel).

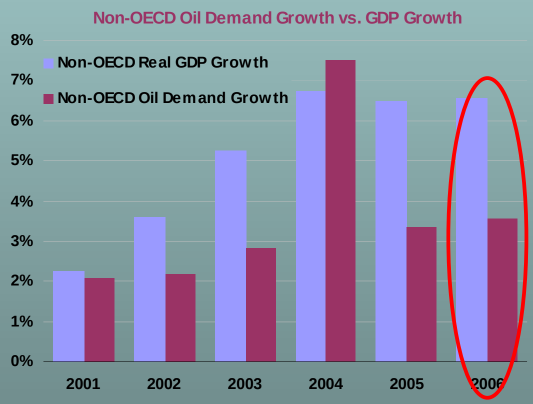
A Review of Demand Drivers

Most oil analysts would agree that economic growth is the main driver of demand growth. Our econometric demand model is indeed primarily driven by the GDP assumptions provided by the IMF's *World Economic Outlook*, combined with a price assumption of IEA import prices derived from the prevailing ICE Brent futures curve. Using historical data, this model is adjusted to account for short-term factors (unseasonable weather variations, retail tax changes, etc.) and longer-term structural shifts (such as interfuel substitution, changes in the vehicle fleet or petrochemical expansions, to name a few), in order to determine an underlying demand trend by product and country.

However, it is not always obvious that GDP is a leading force behind demand trends. This is due to differing sensitivities of oil demand growth to changes in income per capita, coupled with short-term anomalies. In 2004, for example, oil demand increased by slightly more than world GDP. This anomaly is better understood by distinguishing between mature and emerging economies.



The examination of mature economies – mostly OECD countries – suggests that economic activity, albeit important, is competing with other factors in determining oil demand trends. As the economic structure shifts towards services, transportation fuels become predominant in the overall demand barrel. The share of industry and oil-based power generation diminishes, and with them the use of heavier products such as gasoil and fuel oil. In addition, environmental considerations and access to new technology may prompt energy efficiency improvements and the use of less polluting fuels, for example natural gas.



By contrast, many emerging economies are often structurally energy intensive, being obliged to meet not only domestic demand growth but also the shortfall of heavy industrial activity observed in OECD countries. It can thus be argued that energy demand in emerging countries is partly fed by end-user demand in the OECD – as such, OECD countries are not necessarily becoming more energy efficient, but rather outsourcing their most energy-intensive industries to other countries.

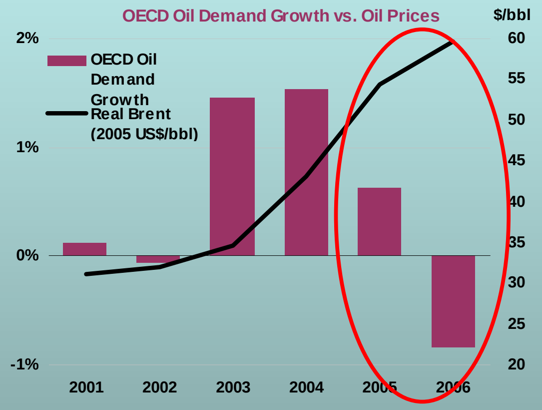
China, which is rapidly becoming the main producer of energy-intensive goods (steel, aluminium, etc.), is a case in point. Indeed, the country's 2004 demand surge (+15.8%) accounted for almost a third of global oil demand growth during that year – as electricity generation fell behind economic activity, utilities struggled to meet the shortfall by massively burning fuel oil, while private businesses and the population at large turned to back-up diesel generators. As power shortages eased given the rapid addition of non-oil power generation capacity, oil consumption growth slowed down, but continued economic expansion means that industrial, transportation and petrochemical oil requirements remain robust.

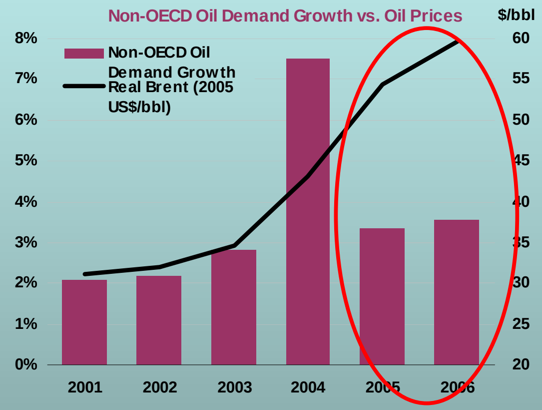
A Review of Demand Drivers (continued)

Moreover, China is not alone. Several highly populated non-OECD countries are in or about to reach the stage when oil demand takes off, namely when GDP per capita surpasses an estimated $3,000 threshold (in purchasing power parity terms). At this point, a middle class usually emerges, eager to purchase cars, fly in aeroplanes, install air-conditioners and, more generally, use energy-consuming appliances. Thus, in non-OECD countries, the link between GDP and oil demand is significantly stronger and will likely continue to foster oil consumption in the years ahead.

Turning to prices, the link between recent hikes in oil prices (close to levels seen in the late 1970s and early 1980s) and oil demand growth has been less apparent than in the past, mostly because large changes in spot crude prices are not always entirely passed on to retail prices. This is either because domestic price regimes have a large tax component that helps cushion the volatility of crude prices (as in many OECD countries, notably in Europe and the Pacific) or simply because retail prices are capped by the government, which absorbs crude price changes (generally through state-owned oil companies).

Nevertheless, prices remain an important determinant of oil demand. Indeed, current global oil demand is growing at about half the pace of a decade ago, despite a relatively similar economic performance, while crude prices have almost doubled in real terms. This price effect is more pronounced in mature economies than in non-OECD countries, partly due to the prevalence of controlled retail price regimes among the largest consumers (particularly China and Middle-Eastern countries).

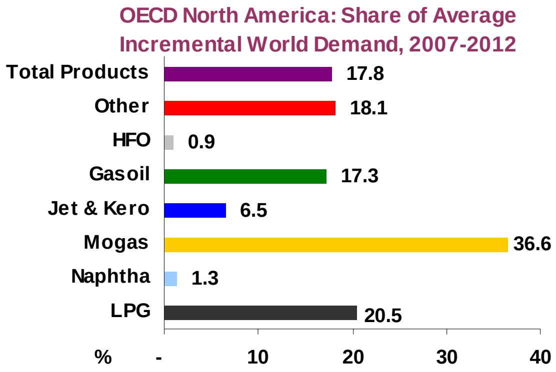


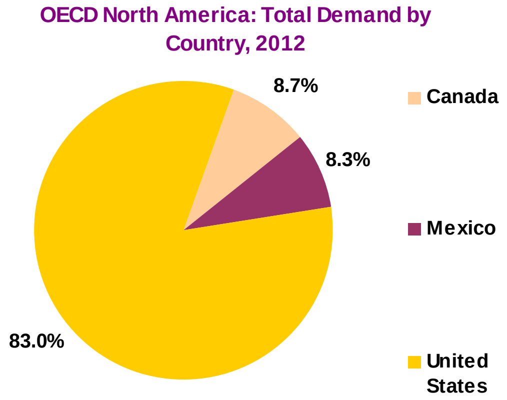


The fact that OECD demand appears to diminish as oil prices increase may come as a surprise. The growing share of transportation fuels implies that demand is actually becoming *less* – and not *more* – price elastic, since there are limited substitutes to gasoline, jet fuel or diesel, despite the growing appeal of biofuels. From this perspective, it can be argued that both 2005 and 2006 – the years when oil demand weakened – were anomalous. In 2005, hurricanes Katrina and Rita severely disrupted oil product supply in the United States, while the unusually warm winter of 2006 curbed consumption across much of the OECD. In fact, a more detailed analysis of the linkage between *retail prices* and *transportation fuels* in the US – as opposed to aggregated oil demand – suggests that recent price increases have actually had a limited influence on gasoline and diesel consumption, thus partially confirming the price inelasticity hypothesis (see "United States: Volatile Prices, Inelastic Demand").

Among non-OECD countries, the price effect becomes much more apparent when stripping out Chinese and Middle Eastern oil demand, which together account for roughly a third of total non-OECD consumption. Indeed, non-OECD oil demand ex China and the Middle East grew by 5.4% in 2004, but by only 2.7% in 2005 (the last year for which hard data are available) and by an estimated 2.2% in 2006. This halved pace of growth is mostly explained by the fact that most countries had no option but to let retail prices rise as administered regimes became fiscally unsustainable (e.g., in Thailand). As consumers became truly exposed to increases in international prices, oil product demand understandably slowed down. By contrast, the fact that demand accelerated over the past few years in China and the Middle East largely reflects the pervasiveness of capped retail prices, which have insulated consumers from price spikes, as well as booming economic growth, which has bolstered income per capita and hence energy use.

Within the OECD, oil demand growth will be mostly driven by **North America**, where consumption is forecast to grow annually by +1.3% on average between 2007 and 2012. This region will represent 52.7% of total OECD demand in 2012, and 67.8% of the OECD's average volumetric increase per year. In global terms, OECD North America will account for 28.7% of global oil product demand, but still modestly lower compared with 2007 (29.9%).





Regarding individual countries, the main engine of demand growth in OECD North America will continue to be the **United States**, which is expected to top regional consumption in all product categories (83.0% of OECD North America demand by 2012, compared with **Canada** and **Mexico**, with 8.7% and 8.3%, respectively).

Nevertheless, Mexico's oil product demand will rise at the fastest pace (+1.9% per year on average), as a result of demographic dynamics and a growing economy. By contrast, US consumption will expand by some 1.3% a year on average, mostly supported by transportation fuels as well as the country's sheer economic and demographic size, while Canada's demand should increase only modestly (+0.9% per year on average), in line with other mature OECD countries with relatively small populations.

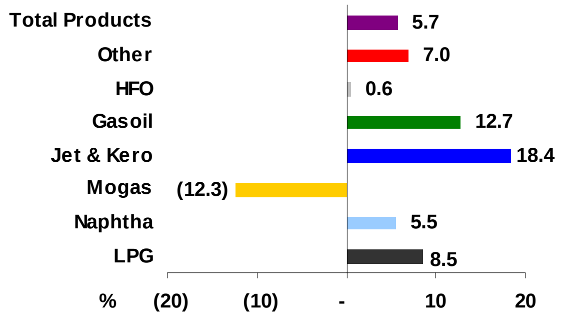
Transportation fuels (motor gasoline, jet/kerosene and diesel) are expected to be the main engine of demand growth in OECD North America. Transportation fuel demand in the region is closely related to income and distance travelled, with demand growth supported by low retail prices relative to other OECD countries – in the US, in particular, recent price increases have had a relatively limited impact on vehicle use. Meanwhile, Mexican consumers have remained largely insulated from increases in international oil prices, which have mostly been absorbed by the state-owned company, Pemex (in addition, Mexico's vehicle fleet is growing at a rapid pace, fuelled by buoyant credit lending). Nevertheless, consumers appear to be opting for more energy efficient cars over SUVs and light trucks, notably in the US. This trend could accelerate should new mandates to improve fuel efficiency be implemented (which seems very likely), particularly if combined with price incentives to encourage consumers to switch to the most efficient vehicles, rather than trading up to more efficient (but still comparatively energy intensive) SUVs. A shift in pricing policy could therefore have a depressing effect on oil demand growth, but this possibility is not contemplated in this report given the absence of concrete policy measures as of now.

By 2012, transportation fuels should account for about 65.3% of total regional demand, growing by an annual average of 1.4%. In terms of individual countries, transportation fuels will represent 68.4% of total demand in the US, 54.5% in Mexico and 45.1% in Canada (growing by 1.4%, 3.1% and 0.9%, respectively, over the forecast period). Moreover, gasoline is and will remain the main component of transportation fuels in all three countries, representing 31.4% of total demand in Canada, 38.1% in

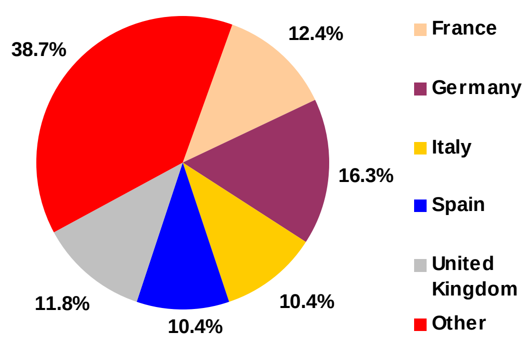
Mexico and 43.6% in the US. Nevertheless, it is worth noting that between 2007 and 2012 the share of diesel will increase by almost one percentage point in both Mexico and the US, to 13.5% and 17.0% of domestic demand, respectively (although it will remain unchanged in Canada at 8.0%). A large-scale switch to diesel-fuelled passenger cars, however, appears unlikely, particularly in the US. As such, the structure of the region's vehicle fleet will continue to be based on gasoline engines.

In **Europe**, demand will rise by +0.7% per year on average between 2007 and 2012. The region will account for 30.6% of total OECD demand in 2012, and for 21.6% of the OECD's annual average increase by volume. The share of OECD Europe in terms of global oil product demand will slightly diminish to 16.6% in 2012, compared with 17.9% in 2007.

OECD Europe: Share of Average Incremental World Demand, 2007-2012



OECD Europe: Total Demand by Country, 2012



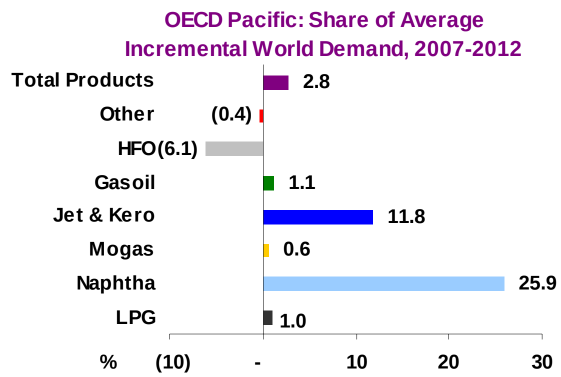
Unsurprisingly, oil product demand growth in Europe will be supported by its largest economies. Taken together, **France**, **Germany**, **Italy**, **Spain** and the **United Kingdom** are poised to represent almost two-thirds of total European demand by 2012 (61.3%). The evolution of consumption in those five countries (particularly in Germany, the largest) will thus largely shape regional trends, despite the fact that other countries such as the **Czech Republic**, **Hungary**, **Slovakia** or **Poland** will see a significant increase in demand – but from a relatively low base. This helps explain why overall demand growth in Europe will be relatively modest: consumption in the Big Five will remain subdued, despite their brighter economic outlook.

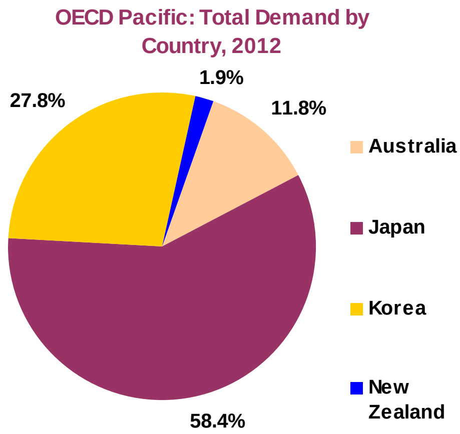
The reasons are two-fold. As in North America, the structure of demand in mature European countries will continue to shift in favour of transportation fuels. However, the growth in transportation fuel demand will remain limited given the continued 'dieselisation' of Europe's vehicle fleet, and will thus barely offset the decline in other products, which in North America will stagnate rather than shrink. European interfuel substitution is also more marked than in other OECD countries. In particular, the use of natural gas – prompted by environmental and cost considerations – is being favoured in Europe for heating and power generation, even though concerns about the security of supply – mostly regarding Russia – will possibly prevail for some time. Among the Big Five, for example, heating oil use will continue to decline in Germany and Italy. Given that both countries accounted for 31.3% of Europe's heating oil consumption in 2006 (Germany's share alone was 25.6%), demand for this product is expected to grow by a paltry 0.4% per year on average over the forecast period. In a similar vein, fuel oil demand is foreseen to fall in France, Germany, Italy and Spain (collectively 45.6% of Europe's demand in 2006, with Italy accounting for over 16.7% and Spain for 12.5%); overall, the consumption of this product will stagnate (+0.1% per year on average between 2007 and 2012).

Finally, in the **Pacific**, oil product consumption is expected to increase by +0.6% per year on average between 2007 and 2012, a similar pace to that foreseen in Europe. The Pacific will account for 16.7%

of total OECD demand in 2012, and for 10.6% of the OECD's average volumetric increase per year. By 2012, OECD Pacific demand will correspond to 9.1% of the world's total, almost one percentage point down from 2007.

Japan dominates the demand picture in OECD Pacific (with 58.4% of total regional demand by 2012). The second largest regional consumer – **Korea** – will account for less than half of Japan's share by then (27.8%). Uniquely among IEA member countries, Japan will see overall demand contract (-0.1% per year on average.





Given Japan's weight, the Pacific differs from other OECD areas in two crucial aspects: 1) transportation fuels will *not* be the largest component of demand (45.9% by 2012, compared with 65.3% in North America and 52.2% in Europe); and 2) the growth in transportation fuels (+0.9% per year on average over the forecast period) will be much slower than in North America (+1.4%) but about the same as in Europe (+0.8%).

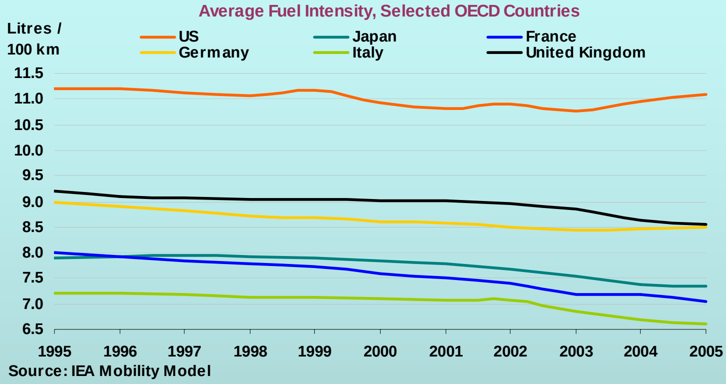
Neither Australia nor Korea, which expect relatively strong oil demand growth over the forecast period (+1.7% per year on average for both), are sufficient to counterbalance the Pacific's demand weakness – which, as noted, is mainly due to Japan. The demand structure in Australia is geared towards transportation fuels (in 2006, a whopping 76.9% of domestic demand), which will for the most part support consumption growth. Demand in Korea will be sustained by its expanding petrochemical sector, an avid consumer of naphtha, which is poised to represent 41.1% of its total demand by 2012).

Japan's demand weakness has several underlying causes. On the one hand, the country is promoting ever more efficient passenger cars (the so-called 'mini vehicles', which feature engines under 660cc). On the other hand, demographic trends – an increasingly older population (which drives less) and a growing share of female drivers (who prefer smaller vehicles) – also contribute to lower transportation fuel demand. As such, gasoline consumption (20.0% of total demand in 2006) is expected to decline by 0.3% per year on average between 2007 and 2012, while diesel (11.8% of demand) will increase by only +0.3% per year.

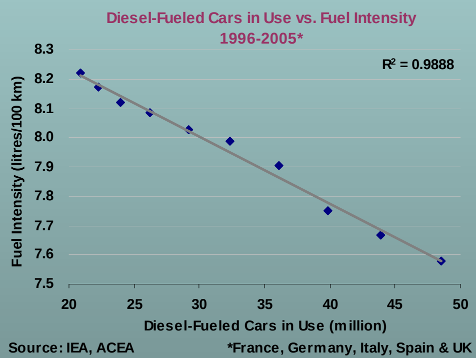
Two other large components of Japanese demand – residual fuel oil and 'other' products (essentially crude for direct burning), which together account for almost a fifth of total consumption – are also expected to decline over the forecast period (by 1.6% and 0.8%, respectively). Both are related to power generation, and will continue to be phased out in favour of natural gas (LNG) or, to a lesser extent, nuclear power. This prognosis is based on the premise that these alternative sources of power generation will be available. Nevertheless, the ongoing operational problems experienced by some of the country's nuclear utilities or lower-than-expected LNG deliveries could lead to temporary surges in the demand for fuel oil and direct crude, as in the recent past.

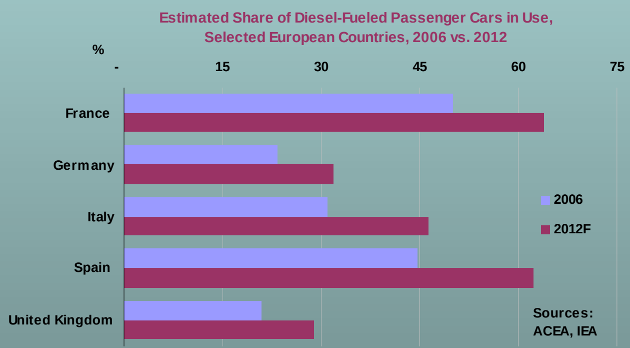
Europe: Diesel Takes The Lead

Engine size and efficiency differences in the OECD are related to market signals and government policies. Over the past decades, high fuel taxes and cost-conscious consumers in both Europe and Japan have prompted the industry to offer more efficient vehicles (generally diesel-powered in Europe, but gasoline-based in Japan). In the US, by contrast, low fuel taxes have not provided an incentive to switch to more efficient cars or to diesel engines. Car producers have focused mostly on selling big cars, SUVs and other types of light trucks. Nevertheless, the tide has changed in the US, given higher retail prices and concerns about energy security and CO_2 emissions, and the country may well adopt more stringent fuel standards, which are currently about a third lower than in the rest of the OECD. In Europe and Japan, indeed, fuel intensity varies between 6.5 and 9.5 litres of fuel per 100 km, compared with over 11 litres in the US.



Arguably, Europe's overall fleet energy efficiency (measured in litres per 100 km) has improved primarily as a result of the gradual diesel adoption, since a diesel engine is approximately 30% more efficient than a gasoline one. As shown below, the correlation between diesel cars in use and fuel intensity is very strong. Fuel intensity is also related to engine size: by contrast to the US, Europe's fleet comprises mostly small cars, with engines of less than 2000 cc.





Nevertheless, gasoline cars have also become more efficient over time. In this respect, it is useful to compare the largest European markets, namely France and Germany. In France, the share of diesel cars has significantly increased over the past decade. Diesel cars currently account for about half of the country's 29 million passenger cars in use. Given the importance of diesel, improvements in France's fuel efficiency are closely linked to the lower relative weight of gasoline cars in the fleet.

In Germany, by contrast, the 49-million passenger car fleet is overwhelmingly biased towards gasoline engines. The growth of diesel car registrations has been very steep, but it comes from a low base: a decade ago, diesel car in use represented only 14% of the passenger car fleet, rising to some 23% today. Thus, the decline in both fuel intensity and gasoline demand in Germany during the late 1990s – despite growing gasoline car sales – suggests that the average German gasoline-powered car also became much more efficient. Since 2003, however, fuel intensity has seemingly worsened, possibly reflecting the sales of larger vehicles such as SUVs. In Germany, and more generally in northern Europe, drivers tend indeed to prefer bigger and more powerful vehicles than elsewhere in the continent.

Europe: Diesel Takes The Lead (continued)

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The penetration of diesel engines has predictably increased the price inelasticity of diesel demand in Europe, while reducing that of gasoline. Data also show an inverse – albeit weaker – relationship between gasoline cars in use and retail prices, although this correlation varies significantly across countries. Nevertheless, given that gasoline and diesel prices tend to converge, drivers arguably tend to focus on diesel's efficiency gains. Moreover, the technology has matured, so diesel is no longer associated with noisy and smelly engines.

As such, the share of diesel is expected to increase in the continent's main markets, accounting for about 41% of total cars in use in Europe as a whole by 2012 (44% in the main five countries). Compared with the estimated figures for 2007 (32% and 34%, respectively), diesel penetration in Europe is thus poised to grow by over 5% per year on average over the forecast period. However, this forecast could err on the low side; given the regulatory trend towards more stringent emissions targets, European car makers may seek to market diesel cars more aggressively.

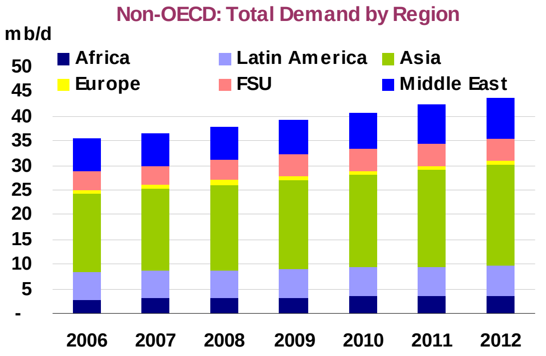
Based on this dieselization forecast, diesel demand in Europe (OECD and non-OECD) is expected to grow by some 1.8% per year on average between 2007 and 2012 (about +80 kb/d per year on average), while gasoline consumption will decline by about 1.9% per year over the forecast period (roughly -46 kb/d per year on average). Looking beyond 2012, though, new technological breakthroughs – such as cheaper hybrids or more efficient gasoline engines – and narrowing price differentials between diesel and gasoline could well reverse the dieselisation trend and herald the comeback of gasoline-fuelled vehicles across the continent.

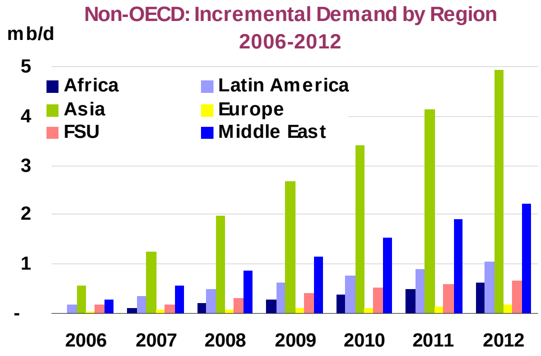
Non-OECD

Oil product demand in non-OECD countries is expected to race ahead at 3.6% per year on average between 2007 and 2012, from 36.6 mb/d to 43.7 mb/d, respectively. In volumetric terms, this is a gain of +1.4 mb/d per year on average, roughly in line with previous forecasts. However, the baselines for most non-OECD countries and regions were revised up (Africa, Latin America, Asia, FSU, Europe and the Middle East), due to the submission of new data, reappraisals of apparent demand estimates and new GDP assumptions.

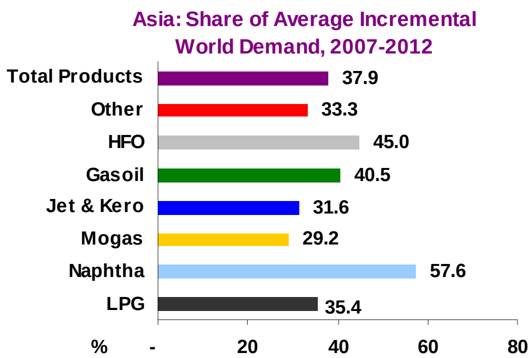
Within non-OECD countries, two regions will stand as the major consumers over the forecast period: Asia, which is expected to represent about half of non-OECD demand, and the Middle East, accounting for almost a quarter. Average growth will be particularly buoyant in China (+5.6%) and the Middle East (+4.6%), with other non-OECD countries growing between 2% and 3% per year on average. Non-OECD demand is poised to grow more than three times as fast as in the OECD, rapidly closing the gap in its share of global demand to 46% by 2012, compared with 42% in 2007 (but the strength of non-OECD consumption will arguably play a greater role regarding global price trends). Extrapolating from this trend, non-OECD demand should account for the majority of global oil demand somewhere beyond 2015. As always, it should be noted, though, that data quality and transparency issues, together with regulatory uncertainties, pose upside risks to the forecast, particularly in the case of China, India, several Asian countries and the FSU.

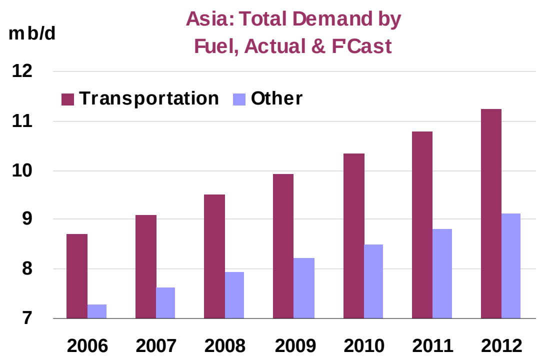
Oil demand growth in **Africa** is forecast to grow annually by +3.1% on average between 2007 and 2012, to reach 3.6 mb/d. The region will represent some 8.2% of total non-OECD demand in 2012, and about 7.2% of its average volumetric increase per year. Demand will be dominated by two countries, **Egypt** and **South Africa**, which together will represent about 37% of the continent's total by 2012. In global terms, African demand is relatively modest, accounting for only 3.7% of global oil product demand by 2012, barely unchanged when compared with 2007 (3.5%).





Asian demand growth (including China) is forecast to grow annually by some +4.1% on average between 2007 and 2012, to 20.4 mb/d. The region will account for 46.6% of total non-OECD demand in 2012, and about 51.4% of its average volumetric increase per year. Overall, Asian demand will have a larger share of global oil product demand by the end of the forecast period (21.3% in 2012, compared with 19.4% in 2007).

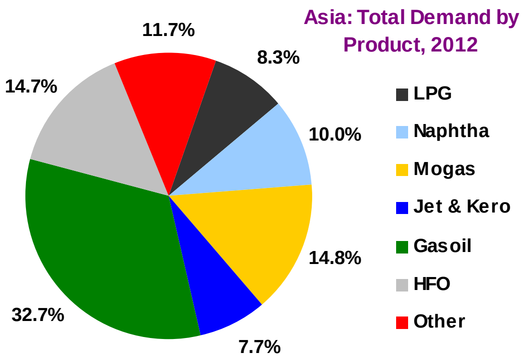


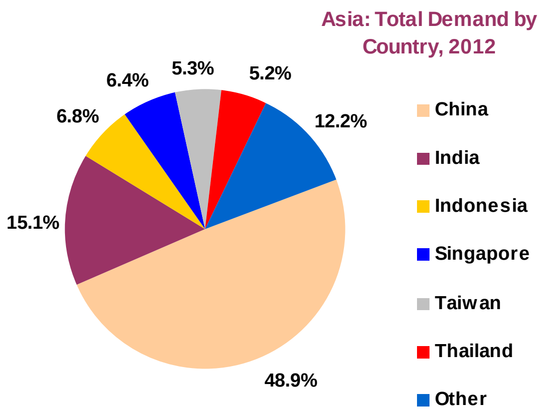


Across the region, transportation fuels (motor gasoline, jet/kerosene and gasoil) will be the main lever of demand growth, increasing by about 4.4% per year on average over the forecast period and accounting for 55.2% of total regional demand. This highlights the fact that the main sources of transportation fuel demand – the vehicle and aeroplane fleets – are growing very rapidly as these countries raise their income levels, particularly the largest ones (i.e., China and India).

By contrast to OECD countries, gasoil, rather than gasoline, is and will remain the main component of transportation fuels in Asia, and more generally, of non-OECD demand as a whole. Gasoil is expected to represent about a third of total demand by 2012, while gasoline will barely reach 15%. This is related to the relatively small size of most countries' passenger cars. In China, indeed, gasoline has a slightly larger share (16%), since the country's vehicle fleet, mainly gasoline-based, is much larger than in neighbouring countries. As such, the growing Chinese gasoline demand will account for 52.5% of the region's total gasoline consumption by 2012.

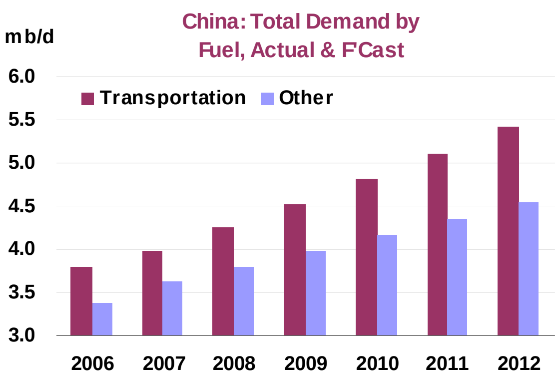
The main driver of demand growth in Asia will be **China** (48.9% of non-OECD Asian demand by 2012). Given the country's booming economy, oil product demand is projected to increase by 5.6% per year on average to almost 10.0 mb/d by 2012, consolidating its position as the second largest oil consumer after the US. This is equivalent to adding some 474 kb/d each year over the forecast period – roughly a quarter of the world's annual demand increase.

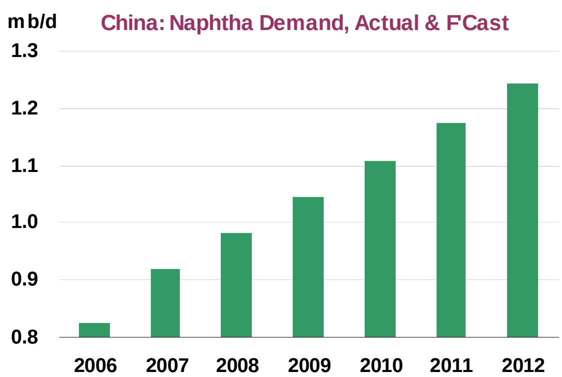




Chinese demand will be mostly driven by transportation fuels and naphtha. On the one hand, the country's mobility is poised to increase significantly as income per capita rises, entailing more vehicle sales and air travel. On the other, China has ambitious petrochemical plans, notably regarding ethylene production, which requires using naphtha as a feedstock.

It should be emphasised, though, that our China forecast faces a number of uncertainties. First, there is the issue of data quality. Data are often incomplete or of questionable quality (historical trade and refining figures, in particular, are never revised). This obliges analysts to make a number of assumptions – notably on stocks and output from 'teapot' refineries – in order to calculate apparent demand. Given that the same qualms apply to economic data – is GDP growth actually higher than reported? – estimating China's true income elasticities is an exercise fraught with uncertainty.



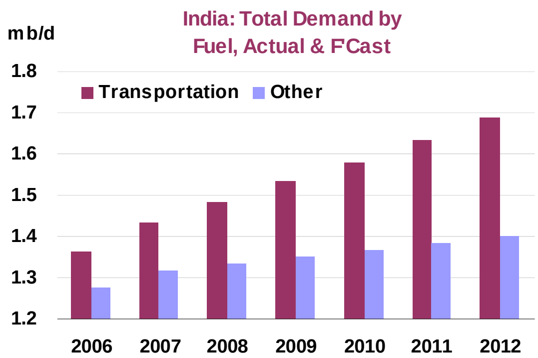


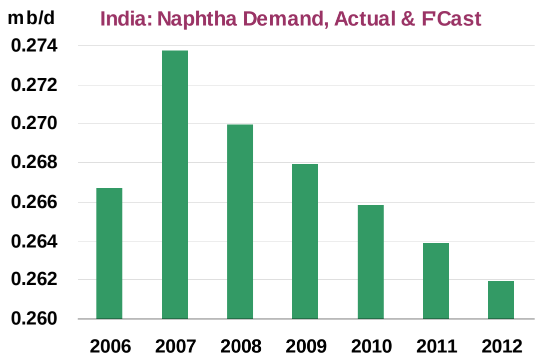
Second, there is the question of government policies, particularly regarding prices. By choosing to maintain relatively low retail prices for key products in order to insulate consumers from rises in international prices, the government has arguably encouraged excessive consumption, notably of gasoline and diesel. If price caps were abolished, retail prices would probably rise, slowing demand growth. However, if international prices remain high, the much-touted liberalisation of the domestic market and the implementation of a motor fuel tax will probably remain on hold in the medium-term, with only token concessions to the WTO (such as the recent rules allowing more players into the distribution and marketing sectors, which in practice favour the big state-owned companies).

Third, a repeat of the dramatic 2004 demand surge, prompted by electricity shortages (which induced a significant rise in gasoil and residual fuel oil use), cannot be excluded by the tail-end of the forecast. Despite the rapid expansion of the country's power generation capacity (mostly coal-based), regional imbalances are likely to remain, with some high-growth areas struggling to meet consumption. Finally, it remains to be seen whether the petrochemical capacity expansion will actually happen. Middle

Eastern countries have similar ambitions, and while there should be sufficient naphtha to justify capacity expansions, it remains to be seen whether there will be sufficient demand for end-use products (ethylene, propylene, etc.). For the moment, we have constrained our forecast demand for naphtha in these regions – but if the projects go ahead as planned, naphtha demand in China and the Middle East could be higher (but lower elsewhere).

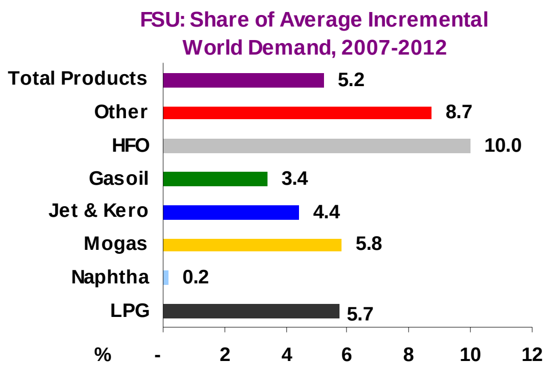
With 3.1 mb/d by 2012, **India** will follow China in a distant second position with respect to non-OECD Asian oil product demand, with 15.1% of the region's total. However, the country's oil demand will grow by only 2.3% per year on average over the forecast period, despite strong economic growth (which is likely to match China's). In fact, the Indian economy is less energy-intensive than the Chinese, being much more oriented towards services than manufacturing. As such, demand growth will be almost exclusively driven by transportation fuels. It is worth emphasising that, despite the similar size of their populations, India and China are *not* in the same league with regards to oil demand. The frequently quoted concept of 'Chindia' is misleading: India's demand will barely represent a third of China's by 2012 – a level not much higher than that expected in other countries with a smaller population, such as Brazil or Saudi Arabia, to cite only two.





As in the case of China, India's demand growth forecast faces several uncertainties. These include: a) poor data quality (the main problem being under-reported product imports, followed by adulteration, notably of diesel, which is mixed with cheaper kerosene); b) the uncertainty regarding the liberalisation of retail prices (which force the refining industry to incur heavy financial losses in the domestic market); c) unclear prospects regarding the supply of natural gas and particularly of LNG (the lack of gas could well reverse what had been, until very recently, a structural decline of naphtha demand, but we assume that enough gas will be available given a large price differential in favour of LNG); and d) infrastructure bottlenecks and other inefficiencies that could cap growth if left unaddressed (it should be noted, though, that the government has engaged in an ambitious road building plan, with construction proceeding apace).

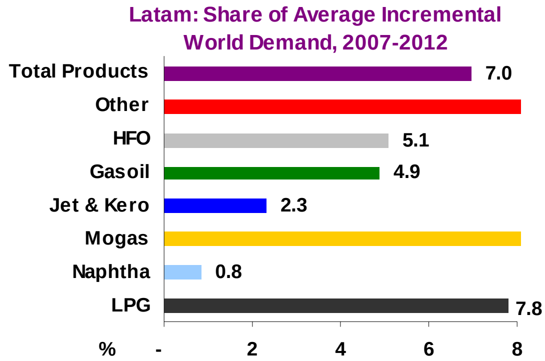
Oil product demand growth in **non-OECD Europe** is forecast to grow annually by +2.8% on average between 2007 and 2012. With 0.9 mb/d by 2012, the region will account for only 2.1% of total non-OECD demand, and about 1.6% of its average volumetric increase per year. The picture is dominated by **Romania**, with 26.2% of regional demand by 2012 – however, the countries that comprised the **Former Yugoslavia** will collectively represent 39.2%. In global terms, non-OECD European demand is marginal: only 0.9% of global oil product demand by 2012, identical to its 2007 share.



In the **FSU**, oil product demand is expected to increase annually by +2.4% on average between 2007 and 2012, essentially pulled by **Russia**, whose economic prospects are strong. In addition, we expect that this country will burn more fuel oil in power generation in order to free additional volumes of natural gas for export. With 4.5 mb/d, the region will represent 10.2% of total non-OECD demand (7.1% of its average volumetric increase per year) and 4.7% of global oil product demand by 2012.

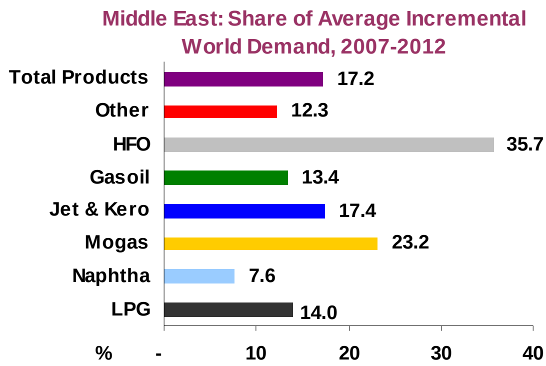
This FSU forecast has potential upside risks, since the limited availability and quality of data complicates the assessment of the region's outlook. In particular, we note the limited use of naphtha in official demand submissions, which does not tie in with exports and estimated product supply figures.

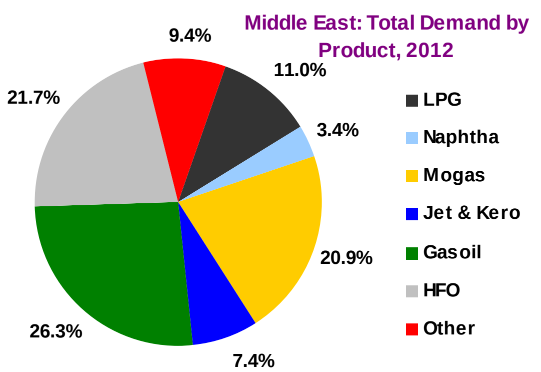
In **Latin America**, oil demand is forecast to increase by +2.3% on average between 2007 and 2012, to almost 6.2 mb/d. By 2012, this will be equivalent to roughly 14.1% of total non-OECD demand (9.4% of its average volumetric increase per year) and 6.4% of global oil product demand. The region is largely dominated by **Brazil**, with 42.3% of Latin American oil demand by 2012.

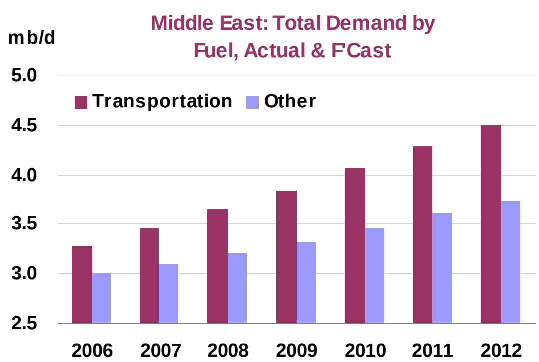


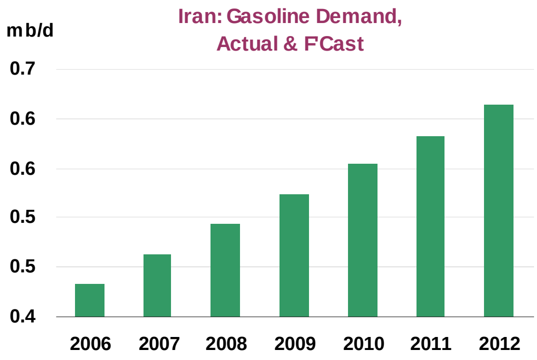
Finally, oil product demand in the **Middle East** is expected to increase by a respectable +4.6% on average per year between 2007 and 2012, equivalent to adding 333 kb/d per year on average. By the end of the forecast period, with 8.2 mb/d, the region will represent 18.8% of total non-OECD demand (23.3% of its average volumetric increase per year) and 8.6% of global oil product demand.

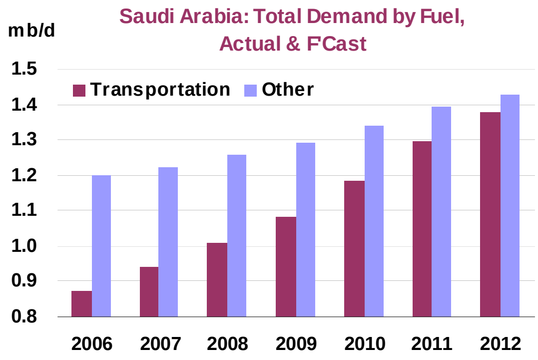
Unsurprisingly, transportation fuels – gasoline, jet/kerosene and gasoil – and residual fuel oil will represent roughly three-quarters of Middle-Eastern demand. Indeed, demand is expected to be sustained by three main factors: buoyant economic growth (fuelled by high oil prices, a construction boom and industrial expansion), a young and growing population, and heavily subsidised retail prices. In terms of individual products, naphtha demand will be supported by the region's ambition to become a major petrochemical hub. Gasoline consumption, meanwhile, will grow on the back of extremely low oil prices (in most oil-producing countries, cheap fuel is considered an entitlement). Electricity needs, meanwhile, will support gasoil and fuel oil demand, given the lack of gas for power generation. Two countries, **Iran** (2.3 mb/d by 2012) and **Saudi Arabia** (2.8 mb/d) will dominate the region's demand, with a joint share of 61.7%.











Despite this picture of robust growth, this forecast faces a key uncertainty: whether regional governments will eventually attempt to curb a galloping demand for transportation fuels. This is particularly true of Iran. The country's insufficient refining capacity, combined with what are possibly the lowest retail prices in the world, has led to a surge of onerous gasoline imports that are seriously threatening the government's fiscal position (in addition to its self-perceived geopolitical vulnerability to imports). After much prevarication, the government recently decided to implement a price hike (May), coupled with a rationing scheme (June). Even though the price increase was significant in percentage terms (25%), in reality gasoline prices remain very low and demand is unlikely to be capped significantly. Moreover, fearing an escalating political backlash, the government may adjust the rationing scheme (at the time of writing, riots had reportedly erupted in several Iranian cities).

SUPPLY

Summary

- **Total non-OPEC supply (including biofuels and OPEC NGL)** reaches 52.6 mb/d in 2012 from 50.0 mb/d in 2007. Growth averages +1.0% annually versus 1.4% during 2000-2007. Strong growth in 2007-2009 recedes thereafter as the slate of active investment projects diminishes, raising questions over the adequacy of the industry's recent exploration effort. However, later phase developments in the FSU and west Africa could see renewed growth post-2012.

- **Non-OPEC growth** is driven initially by OPEC gas liquids and biofuels, but with substantial increases from crude supplies out of the US GOM, Canadian oil sands, the FSU, Brazil and sub-Saharan Africa. These offset sharp declines expected elsewhere in the US and Canada, and from Mexico, the North Sea, and parts of Asia and the Middle East. A levelling off in non-OPEC conventional crude supply is notable, but is inconclusive as evidence for an imminent oil supply peak.

- **Upstream construction, drilling and service capacity remains stretched,** leaving forecasts prone to adjustment due to cost over-runs and project slippage. The non-OPEC forecast has been revised down by 0.8 mb/d for 2011, partly reflecting slippage, but also with the inclusion of a new 0.4 mb/d contingency factor, reflecting a tendency for unscheduled field outages. Supply-side uncertainty is further exacerbated by increased instances of resource nationalism and geopolitical risk.

- **Net oilfield decline rates** average 4.6% annually for non-OPEC and 3.2% per year for OPEC crude. Aggregate levels mask much sharper declines in a 15-20% per annum range for mature producing areas and for many recent deepwater developments. All told, the forecast suggests the industry needs to generate 3.0 mb/d of new supply each year just to offset decline. Notwithstanding, above-ground supply risks are seen exceeding below-ground risks in the medium term.

- **OPEC NGL and condensate supply** reaches 7.1 mb/d in 2012. Growth of near 8% annually continues the levels evident so far this decade and adds a net 2.2 mb/d to prevailing output. Growth centres on Saudi Arabia, Qatar, Iran and Nigeria against a backdrop of reduced flaring and producer attempts to boost domestic gas use. Rising condensate supply defers an expected longer term move to heavier/sourer global refinery feedstock.

- **OPEC crude capacity** is seen rising to 38.4 mb/d in 2012 from a 2007 average of 34.4 mb/d. Some 70% of the increase comes from Saudi Arabia (+1.8 mb/d), the UAE and Angola (+0.5 mb/d each). Lesser increments come from Kuwait, Nigeria, Algeria and Libya. Forecast capacity is below OPEC's own estimates of near 40 mb/d for 2010, largely due to this report's caution on Iraqi, Venezuelan and Niger Delta capacity, where security and investment risks predominate.

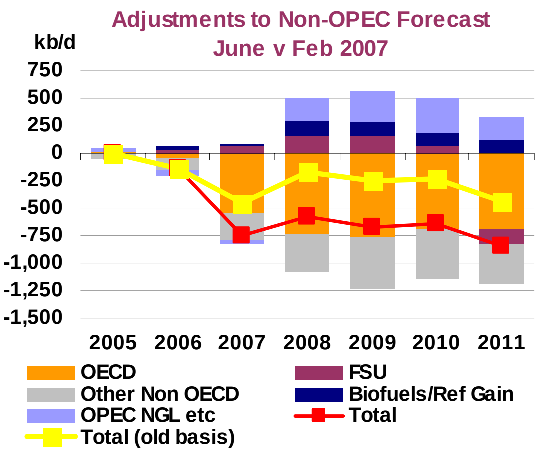
- **OPEC effective spare capacity** has steadily recovered from 2004 lows below 1.0 mb/d to nearly 3.0 mb/d at mid-2007. Further increases are likely through 2009, albeit the cushion of upstream supply flexibility remains low by historical standards at below 5% of global demand. Moreover, spare capacity declines sharply again from 2010 onwards. Based on the 'call on OPEC crude and stock change', OPEC's share of global demand dips from 37% in 2007 to 36% in 2008 and 2009 but rises again to 38% by 2012.

The Non-OPEC Supply Forecast

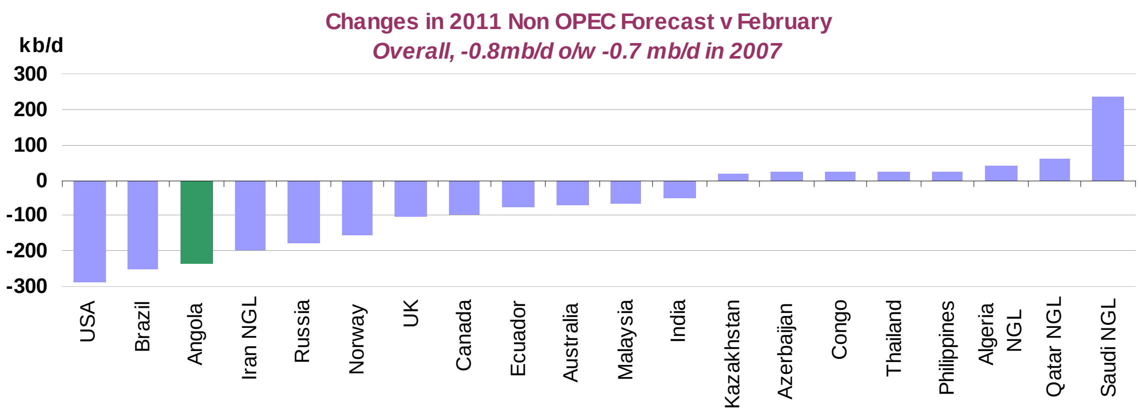
Downward Revisions to the Forecast

Downward adjustments to the July 2006 non-OPEC forecast were already apparent in the February 2007 update, when 1.1 mb/d was cut from the original 2011 projections, with project slippage a key reason. This time, a combination of revisions to baseline 2007 supply data (-700 kb/d versus February), slippage and the application of a 0.4 mb/d 'reliability' adjustment (see Annexe) reduce the 2011 forecast by a further 0.8 mb/d. Average annual adjustments for 2007-2011 are 0.6 mb/d, or around 1.1%. That level drops to 0.3 mb/d net of the 'reliability' adjustment. In all, our July 2006 projections for 2011 non-OPEC output have now been cut by 1.8 mb/d.

Since the February *MTOMR* update, over 3.2 mb/d of new projects in the 2007 to 2011 period have seen their timing slip, emphasising the scale of the problem. Slippage varies between two and 36 months, but is typically around six months. As a result, we have been more aggressive in our assessment of project timing, particularly with those where delay is most likely, but the temptation to slip all new projects for the forecast is resisted. Nonetheless, shortages of labour, raw materials, fabrication and drilling capacity and transport infrastructure may continue to undermine output growth for some time.



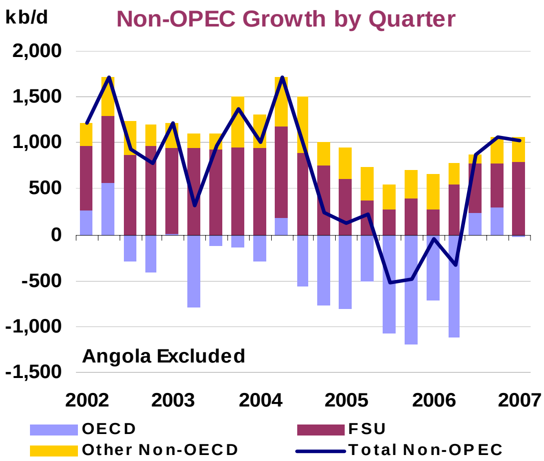
Latin America and the Asia Pacific region account for the bulk of the net 0.4 mb/d downward revisions to non-OECD countries. In the OECD, project delays, accelerating decline rates and the impact of aging infrastructure on unscheduled outages and extended maintenance are all reflected in the new forecasts for Australia, Canada, Norway, UK, and US. Perhaps counter-intuitively, the forecast for Mexico remains largely unchanged. Net of weather effects, we have tended to marginally understate Mexican supply in recent years, with the result that no further downward contingency is applied here. Nonetheless, Mexican crude production is expected to fall by 0.4 mb/d between 2007 and 2012. But the adjustments are not all one way, with supply from the FSU (through 2011), OPEC gas liquids and biofuels higher than our previous estimates.

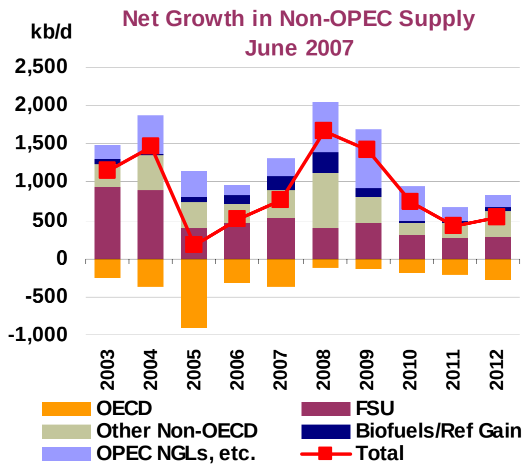


Potential delays to new field developments are also reflected by downward revisions for Brazilian and Angolan deepwater supply (Angola has now joined OPEC but remains in the non-OPEC graph above for illustrative purposes). Geopolitical problems and an unattractive upstream investment environment also act as a drag on forecast Iranian NGL supply, which is revised down by 0.2 mb/d. A deteriorating upstream investment environment and weaker 2006/2007 supply drag down the medium term forecast for Russia, Ecuador and Malaysia. However, additional gas utilisation projects not included in February boost the latest forecasts for Algerian, Qatari and Saudi Arabian NGL supply by a combined 340 kb/d.

New Production Outpacing Decline for Now

Despite underperformance in 2005/2006, overall non-OPEC supply growth has recently rebounded, averaging +1.0 mb/d for 3Q06 through to 1Q07. Seasonal factors impede supply during 2Q/3Q07, before growth accelerates at the end of the year and into 2008/2009. Total non-OPEC growth averages +1.0 mb/d in 2008 and +0.65 mb/d in 2009, augmented by some 0.7 mb/d of OPEC gas liquids growth in both years. A temporary surge in OPEC NGL comes from Saudi Arabia, Qatar and Iran. Renewed North American oil growth (GOM and Canadian oil sands), allied to continued Russian and Caspian expansion, new field developments offshore Brazil and a number of sub-Saharan Africa projects account for the rise in crude supply. A combined 550 kb/d of new global biofuels supply in 2008/2009 completes the picture, before an assumed cap on non-US/Brazilian biofuels post-2009 kicks in. But in 2010-2012, non-OPEC supply growth slows with a diminishing slate of active development projects.

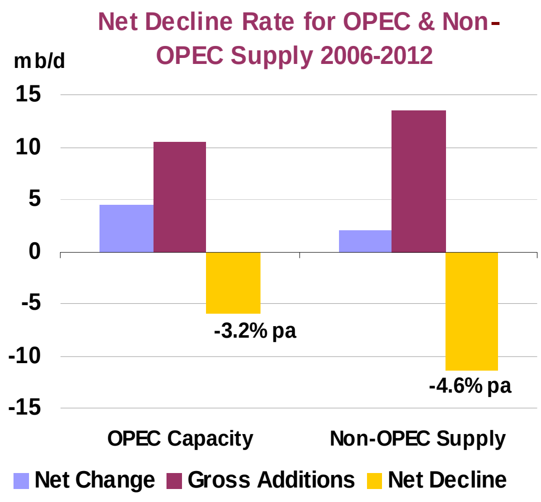




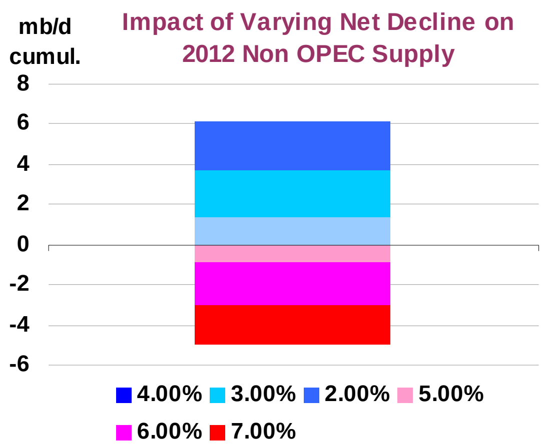
Although project slippage removed 0.5 mb/d from potential non-OPEC supply in 2005 and 2006, a sizeable slate of new field start-ups underpins the renewed growth expected for the short term. One year ago, this report envisaged a total of 15 mb/d coming from new projects starting up in the 2006-2011 timeframe. This year, the figure remains at 13.6 mb/d for 2007-2012. New production is most pronounced in 2008 at 2.6 mb/d, a similar volume to a year ago, with project slippage *into* 2008 from 2007 counteracting various instances of slippages *from* 2008 to 2009. Notably, Angola has moved from the non-OPEC camp and into OPEC, removing over 1.5 mb/d of new production for 2007-2012 previously in the non-OPEC forecast. However, project timings across the non-OPEC forecast continue to slip on problems accessing raw materials, equipment and labour.

Estimating the Impact of Decline Rates

An average global decline rate is difficult to discern from a field-by-field forecast (with a constant ebb and flow of fields entering decline, offset by others where decline is reversed by the application of EOR or satellite developments). However, a proxy can be calculated by comparing net change in non-OPEC supply for 2007-2012 and gross capacity additions. As seen below, the implied net non-OPEC decline rate for baseload production is around 4.6% per year. This covers not only fields in decline, but also older supply which is at or approaching plateau. With net decline from OPEC assumed at 3.2% per year, this gives a global annual decline of 4%, suggesting that 3.2 mb/d of new production must be found each year just to stand still. Moreover, this net global decline for existing assets masks fairly aggressive assumptions for parts of the OECD and for deepwater projects elsewhere. Development schedules for the latter can show rapid ramp-up followed by abrupt annual decline in a 15%-plus range.



Decline rates are often cited as the key area of forecast oil supply uncertainty. The illustration below shows how changes in the net non-OPEC decline-rate impact upon the forecast for 2012. Our derived net decline of 4.6% per year results in non-OPEC oil supply (excluding biofuels and processing gain) in 2012 of 48.8 mb/d. Increasing that decline rate to 5% would net 875 kb/d off the total, and a range of decline rates from 2% to 7% swings 2012 non–OPEC supply by 11 mb/d in total.



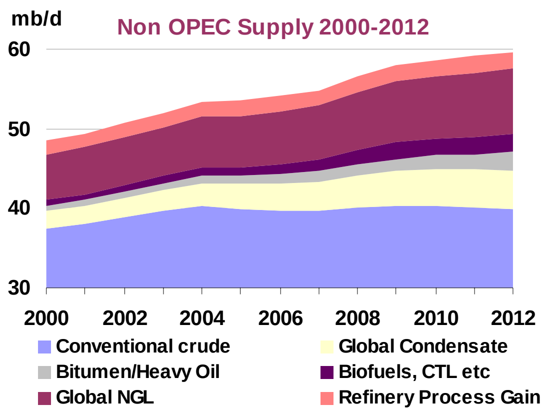
Without minimising the importance of this variable, particularly given a shortage of comprehensive field-specific production and reserves data, our analysis suggests that variance from the original non-OPEC forecast in recent years has not primarily been due to understatement of field decline rates. Rather, we believe that project slippage, weather, and unplanned production stoppages for technical, economic and geopolitical reasons, have been, and will continue to be in the next five years, the main risk factors. Put another way, while we continue to monitor and actively adjust for shifts in field and aggregate decline, we see above-ground risks more prevalent, for now, than below-ground risks.

Increases Come from Non-Conventional Supply

The concept of peak oil production and its timing are emotive subjects which raise intense debate. Much rests on the definition of which segment of global oil production is deemed to be at or approaching peak. Certainly our forecast suggests that the non-OPEC, conventional crude component of global production appears, for now, to have reached an effective plateau, rather than a peak. Having attained 40 mb/d back in 2003, conventional crude supply has remained unchanged since and could do so through 2012. While significant increases are expected from the FSU, Brazil and sub-Saharan Africa, these are only sufficient to offset declines in crude supply elsewhere. Put another way, all of the growth in non-OPEC supply over 2007-2012 comes from gas liquids, extra heavy oil, biofuels (and, by 2012, 145 kb/d of coal-to-liquids from China). As overall non-OPEC liquids capacity increases, this plateau reduces the share of non-OPEC conventional crude supply from 77% in 2000, to 74% in 2006 and 67% in 2012.

While there might be a temptation to extrapolate this trend, citing a peak in conventional oil output, a degree of caution is in order. Firstly, the concept of 'conventional' oil changes with time, technology and economics. In the early 1970s, much offshore production was deemed unconventional, but this portion of global supply has since grown to account for 30% of the total. Evolving economies of scale and infrastructure development could do the same for GTL, oil sands and ultra-deepwater reserves in the future, shifting today's unconventional resource into tomorrow's conventional supply category. Moreover, rapidly-growing condensate and NGL supply is scarcely 'non-conventional' in a technical sense now.

We also note that for certain regions, notably the FSU and West Africa, the turn of the current decade is likely to mark a hiatus in crude supply growth. Strong growth is expected to resume here towards the middle of the next decade. Whether this will be sufficient to offset the declines expected for mature OECD crude supply, preventing overall decline for non-OPEC, is less easy to predict.



Finally, we note that focussing on non-OPEC crude alone is a rather selective way of considering the sustainability of global oil production. Peak or plateau production is frequently taken as shorthand for impending resource exhaustion. While hydrocarbon resources are finite, nonetheless issues of access to reserves, prevailing investment regime and availability of upstream infrastructure and capital seem greater barriers to medium-term growth than limits to the resource base itself.

Upstream Operating Environment Remains Stretched

In last year's *MTOMR*, we identified several factors which characterised the upstream operating and investment environment for 2006-2011. These were:

1. Rising crude oil price assumptions employed by operating companies;
2. Increasing spending and activity levels;
3. The expanding reach of consumer country NOCs;
4. A declining trend in exploration expenditure as a share of IOC total spending;
5. High costs and tightness in construction, drilling and service capacity;
6. Correspondingly, a tendency for new upstream project delays;
7. A compounding impact of delays to new pipeline and gas processing capacity ;
8. Proliferating geopolitical risks and barriers to oil company access.

Arguably, the first three factors could accelerate the pace of expansion in non-OPEC and OPEC supply. However, the balance of risks deriving from factors 4-8 lies heavily on the downside and would seem to argue for slower growth in global production capacity relative to historical trends.

One year on, most of these factors remain equally relevant. Price assumptions are robust for 2007:

- NOCs and governments budgeting for an average $45/bbl (versus $35/bbl a year ago);
- International company and independent producer price assumptions levelling off close to $55/bbl;
- New projects still being tested at prices down to as low as $35/bbl.

Spending and activity levels have also remained high. Industry spending surveys by Lehman Brothers and Citigroup suggest ongoing growth in upstream activity, notably outside of North America. Increases in expected capital spend in 2007 lie in a 10-15% range, with similar growth for 2008. While this is well below the final 2006 estimate of a 25 % increase in spending, inflated partly by cost over-runs, there is a tendency for advance estimates to be revised higher.

Resource Nationalism Back in Vogue

Resource nationalism has become a key oil and gas market buzzword of late, but is neither a new phenomenon, nor the sole preserve of rigidly centralised economies. All governments try to maximise returns from natural resources. Previous phases of resource nationalism have included Mexican nationalisation in the 1930s and the creation of OPEC in 1960. The latest manifestations in the 1970s, and again in the 2000s, have coincided with tighter markets and higher prices. There is a degree of 'chicken and egg' about nationalism and high prices, but the potential for a self-perpetuating cycle is clear.

Recent fiscal and corporate developments in the UK and Norwegian upstream at the relatively benign end of the scale, through to a new hydrocarbon law in Iraq, the rising economic challenges facing Mexican monopoly Pemex, and on to the increasingly NOC-dominated upstream in Russia and Venezuela show a wide range of national policy approaches to hydrocarbon resource management.

It would be wrong to see resource nationalism in overly simplistic terms. All governments, OECD and non-OECD alike, tend to use higher oil prices as a pretext to shift revenue flows in their favour. But an increasingly dominant national oil company, sudden and unilateral changes in upstream ownership and operating regime and barriers to, or higher costs for, upstream entry characterise resource nationalism in its more extreme form. So too can the actions of consumer country NOCs and monopoly pipeline operators, reacting to security of supply concerns or perhaps using them to expand geopolitical influence abroad. That said, shifting fiscal/operating regime, by itself, does not necessarily signify resource nationalism: after all upstream contracts habitually evolve as a country matures from frontier to established producer, and on to late-production stage.

Nonetheless, a host government's aspirations for increased rents and control can perpetuate high prices in the short and medium term. These can lead to distorted flows of upstream investment capital, particularly if returns are used to directly fund social programmes which become embedded in national spending. Often political and social spending needs grow to the point where oil exploration and development investment is compromised, in turn reducing oil and gas exports. That said, high prices in the 1970s encouraged demand restraint and new frontier exploration (ironically spawning new national oil companies (NOCs) in the North Sea, Brazil etc).

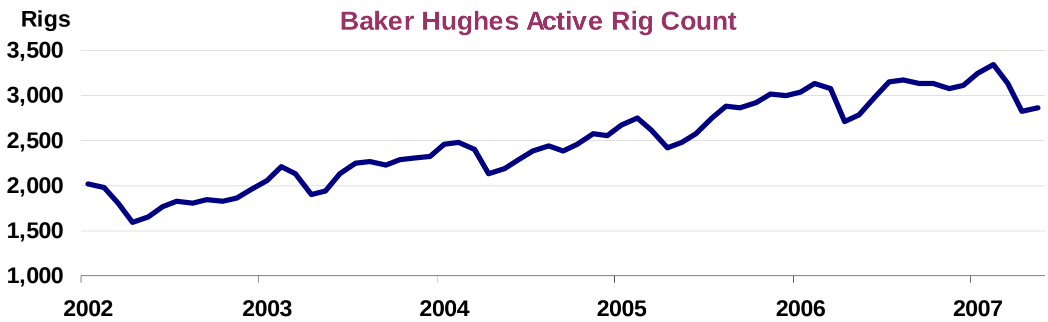
Eventually the downswing in the cycle tends to lead to lower prices and revenue streams, encouraging host governments to reintroduce more open-access and international company-friendly policies. International expertise is sought to stem mature field decline, to exploit more difficult-to-find oil or to manage complex, integrated oil, gas and petrochemical projects - areas where international companies still retain an edge.

Arguably, the cycle may prove more prolonged this time around. Banks remain happy to fund new projects, regardless of the promoter, so long as default is unlikely. Rising supply and revenue streams likely have further to run in key producing countries. And technical and intellectual capital is accessible via service companies that have expanded their R&D expertise (filling a void left by IOCs' apparent downgrading of R&D as a priority).

Ultimately, what counts are sustained levels of upstream investment. Returns will be optimised for all participants through a combination of careful resource management, unhindered access to reserves and intellectual and financial capital and via balanced contractual arrangements. As access to reserves in producer countries becomes ever more restricted, it is little wonder that consumers focus on supply diversity, both geographically and by fuel form. This can create a vicious circle for investment as producer concerns over demand security and the need for capacity expansion then arise. Sustaining producer-consumer dialogue becomes all the more important in such an environment.

Drilling indicators also remain positive, with the steady rise in international rig activity continuing until early 2007. The sharp decline in drilling activity seen in 2Q07 is focussed on a collapse in Canadian natural gas drilling due to weaker gas prices. That said, the availability of deepwater drilling capacity will likely remain constrained for another 18-24 months before substantial new capacity is activated. Given the rising share of offshore supply in the world total, potential slippage for the likes of Brazil, GOM, northern Russia, the Caspian and West Africa takes on added significance.

Cost inflation for raw materials, service and drilling capacity shows some signs of moderating, although industry consensus points to a levelling in upstream costs rather than a substantial fall. Healthy spending increases have therefore largely been absorbed by double-digit inflation, limiting any automatic feed-through of high prices into incremental discoveries and production. Nor has there been a discernable rise in exploration's share of upstream spending, or in net reserve additions, despite sustained high prices, although access and regulatory uncertainty, borne partly of a spate of resource nationalism, partly explain this. Moreover, given current tight labour and service markets, any attempt to boost exploration activity presently might do more to fuel further inflation rather than generate extra oil.



Delays in natural gas expansion are another factor that can be added to the list of potential impediments to higher oil supply. For the Middle East and Russia, the IEA's *Natural Gas Market Review* has identified insufficient upstream investment. This undermines not only natural gas liquids (NGL) supply, but also oilfield reinjection of associated gas, potentially impeding crude oil production rates. That said, as producers recognise potential future shortages in gas for domestic or export markets, so efforts to boost supply by cutting gas flaring and transmission losses should intensify. Flaring currently amounts to some 150 bcm per year globally. Processing that could liberate 1.0 mb/d-plus of NGL. Nigeria, Russia and others have ambitious plans to curb flaring, which could help offset supply shortfalls elsewhere in the system, helping sustain oilfield reinjection and NGL supply.

Project Delays Now Becoming a Fact of Life

Project delays and deferrals remain a key drag on non-OPEC and OPEC capacity growth alike. Focussing on non-OPEC, in February we identified 27 projects worth 3.0 mb/d of peak output which had either slipped in timing or were removed from the forecast altogether compared with the July 2006 report. Between February and July 2007, a further 2.4 mb/d has been identified facing similar problems. Offsetting new project inclusions and accelerations amount to 860 kb/d, versus 650 kb/d added for the February forecast. Overall, delayed new field start-ups accounted for 35% of shortfalls versus original OECD forecast for 2004, and 65% in 2005 and 2006.

Slippage by project varies in severity from several months to several years. In extreme cases such as the Thunder Horse project in the US GOM, delays have pushed back start-up of 250 kb/d of production from an initially targeted summer 2005, to a latest estimate of end-2008. A succession of problems highlighting the growing complexity of deepwater developments has been evident for Thunder Horse:

- May 2005: extreme currents delay hook-up of semi-submersible for one month;
- July 2005: platform listing at 20-30° following passing of Hurricane Dennis;
- August/September 2005: Hurricanes Katrina and Rita further delay progress;
- October 2005: July incident cited as due to design/construction faults in the ballast system, not storm damage and start-up deferred into 2H06;
- June/July 2006: discovery of leaks in sub-sea manifold during commission testing push back start-up to early 2007;
- September 2006: BP announces all sub-sea production equipment to be replaced, with likely start-up now mid-2008;
- February 2007: Start-up again pushed back, to end-2008.

In many ways Thunder Horse suffered from the 'perfect storm', with initial design and construction faults, followed by exceptional hurricane impacts and, finally, more prosaic delays in an overheated upstream services market. Other projects may not face the same litany of problems as Thunder Horse, but as incremental non-OPEC supply becomes increasingly concentrated in technologically challenging areas, so cost over-run and delays will remain part of the industrial landscape.

Non-OPEC Forecast Methodology*

Non-OPEC projections are made, where possible, on a field-by-field basis. Some 40% of baseline 2006 supply derives from field-specific models, with 690 individual fields covered by 2012. Field-specific data allow decline rates and new field build-up and plateau to be modelled more effectively. However, a large proportion of baseline production data are a less satisfactory combination of national, onshore/offshore and undifferentiated crude/NGL aggregates.

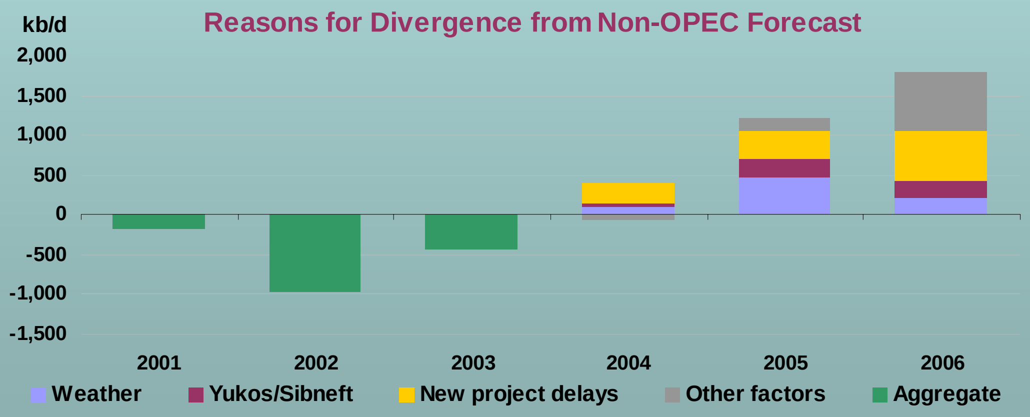
Where field-by-field data are available, decline is assumed once field depletion reaches around 50%. Decline is modelled using a combination of historical precedent, operator/service company guidance and generic decline trends. The rate of decline is steeper for mature and offshore deepwater fields, reaching as high as 15-20% annually. Onshore decline can be shallower, in a range of 0-10%.

New field start-ups are included based on best available information on timing, build-up and duration of plateau. The industry currently faces intense problems in meeting new project timing and cost targets. Information on potential slippage is included for individual projects as and when available. Timings on new projects are adjusted through the year in the *Oil Market Report (OMR)*as information on progress becomes clearer.

Projections contained in the *OMR* and *MTOMR* include allowances for maintenance downtime and typical seasonal outages (hurricane-related stoppages in North America, cyclone outages in Asia and seasonal supply reductions from Arctic areas). Traditionally other 'unexpected' factors like unscheduled shut-ins and extreme weather can reduce non-OPEC projections by a further 400 kb/d. For the first time, we now internalise a country-specific, non-OPEC 'reliability' factor reflecting this.

Adjusting Methodology This Year to Capture Rising Uncertainty

Last year's *MTOMR* highlighted the adverse impact that weather, Russian geopolitical developments and new project delays had on 2005 non-OPEC supply projections. Much the same prognosis can be applied to 2006, albeit 2006 data remain incomplete. While the OMR in 2001-2003 tended to understate non-OPEC supply, 2004-2006 has seen the opposite trend. In part, this derives from a prevailing 'business as usual' methodology, with normal operating conditions and on-schedule project completions assumed until contrary evidence arises. While 3Q06-1Q07 has seen non-OPEC annual growth recover to +1.0 mb/d, large risks remain for the 2007-2012 outlook.



Both the *OMR* and the *MTOMR* hitherto presented a headline non-OPEC forecast unadjusted for supply contingencies, but appended with cautionary notes on a tendency for supply to 'under-shoot' initial projections by 300-400 kb/d. Beginning with the OMR of March 2007, an 'adjusted call on OPEC crude and stock change', in parallel with the base 'call', was introduced, containing adjustments for non-OPEC supply risk (350 kb/d). Henceforward a historically-derived 'reliability' adjustment is instead included in the headline non-OPEC supply forecast.

Non-OPEC Forecast Methodology* (continued)

Overall, the largest area of risk has been in the OECD, ironically for the countries which have the most detailed data on monthly production. In the past three years, OECD supply has slipped 1.0 mb/d below initial forecast, although heavier than usual storm losses and project slippage account for an estimated 35% of this shortfall in 2004 and 65% in 2005 and 2006. The reliability factor defined above represents the residual difference between initial forecast and outcome, after netting off slippage and extreme weather. Its inclusion in the forecast explicitly acknowledges that, given tight drilling and service markets and ageing infrastructure, unscheduled outages are now part of the industrial landscape.

To more clearly incorporate this non-OPEC reliability factor in the forecast, henceforward an allowance of -410 kb/d for non-OPEC supply will be included, allocated by main country and region (not by field). This is net of weather and slippage adjustments, which we already attempt to capture in the base forecast, and is based on an observed five year average divergence from initial forecast. The adjustments show up as aggregated miscellaneous-to-balance line items by country in the field-by-field database. Adjustments have been calculated as follows:

USA	-125 kb/d	Azerbaijan	+26 kb/d
Canada	-97 kb/d	Kazakhstan	+25 kb/d
Mexico	+27 kb/d	Brazil	-34 kb/d
UK	-125 kb/d	Colombia	+20 kb/d
Norway	-162 kb/d	Egypt	-24 kb/d
Other OECD Europe	-24 kb/d	China	+97 kb/d
Australia	+22 kb/d	Malaysia	-34 kb/d
Total Net Non-OPEC Adjustment = - 410 kb/d (applied 2Q07 onwards)			

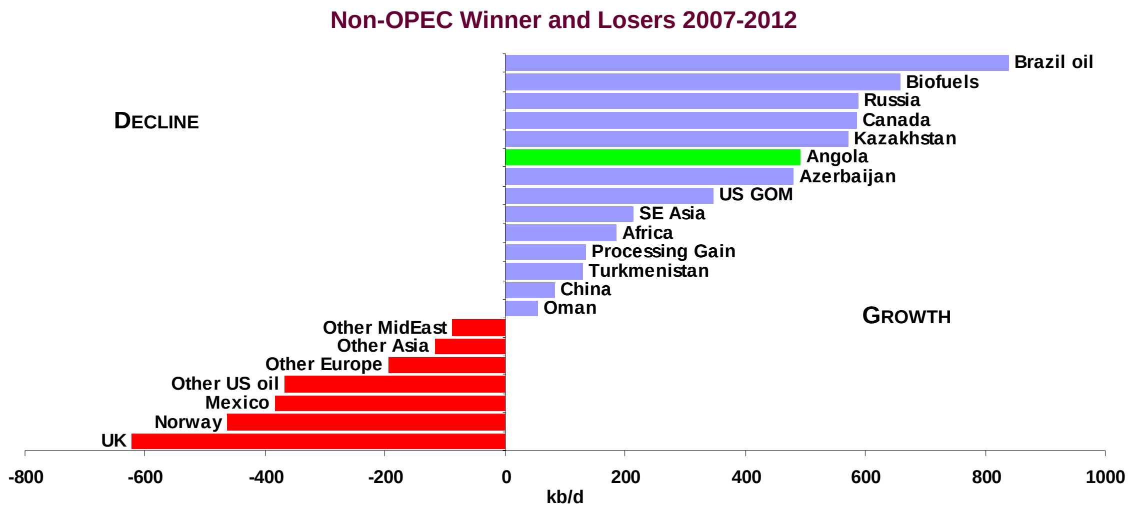
Judgement is exercised before automatically employing reliability adjustments. Previous experience is already included in the forecast for individual fields, making additional, automatic adjustment inappropriate in some cases. For example, Russian 2001-2006 production exceeded initial forecasts by 250 kb/d on average. But carrying this through 2007-2012 contradicts a now demonstrably poorer investment environment. The latter is already captured as information on growth plans and project slippage has been incorporated. Similarly, early decade overestimation of Oman's production has given way to more accurate projections for 2004-2006, making further systematic reductions inappropriate.

The reliability adjustments will anyway evolve over time in both scale and location as forecasts are replaced by actual production data. There may be an inbuilt conservatism for the new forecast by use of a constant factor rather than a fixed proportion of the changing production base. But, as noted below, the current upstream investment and operating environment probably justifies this approach.

* (see also page 23 of the *MTOMR* July 2006)

Winners and Losers in Non-OPEC Supply 2007-2012

Overall, non-OPEC supply (net of Angola, but including biofuels and refinery processing gain) increases by 2.6 mb/d during 2007-2012 at an average rate of +1.0% per year. This compares to annual growth during 2000-2007 of 1.4% and a total increment of 4.6 mb/d. As noted above, growth is concentrated during 2008 and 2009, tailing off to 0.3 mb/d annually during 2010-2012. However, while a large list of scheduled development projects inflates the 2008/2009 total, should project slippage prove greater than currently anticipated, the profile could prove less front end-loaded than suggested here. Clearly, the departure of Angola from the non-OPEC fold has transferred a significant source of growth (0.5 mb/d) for the 2007-2012 period into the OPEC camp. However, the West African state is still expected to expand output substantially before its production comes under OPEC quota control.



Non-OPEC growth also remains concentrated geographically, with Brazil, the Caspian states, Russia and Canada each providing 20%-plus of the net growth figure. None is without risks, as technical, logistical and geopolitical question marks apply in varying degrees to supply growth from each. Biofuels growth also accounts for 25% of the total, concentrated on Brazilian and US ethanol (see Biofuels section). Other major growth areas include the US Gulf of Mexico, West Africa, a quartet of SE Asian producers and China. Production is expected to decline sharply onshore USA, in the North Sea, Mexico, other Asia and among non-OPEC Middle Eastern producers.

Brazil

Oil production has increased by more than 0.5 mb/d so far this decade, with a further 0.1 mb/d growth in fuel ethanol. Oil supply increments have centred on deepwater development of the Campos Basin offshore Rio de Janeiro, which accounts for 1.4 mb/d out of total Brazilian crude output of 1.7 mb/d. Growth through 2012 remains centred offshore, and total crude oil supply is seen reaching 2.67 mb/d by 2012, with Campos Basin production accounting for 2.5 mb/d of the total.

Major new production comes from expansions at state company Petrobras' Jubarte, Roncador, Marlim, Golfinho and Albacore fields. Foreign company production currently centres on Shell's 50 kb/d Bijupira Salema, but up to 300 kb/d of new offshore output is scheduled to come from new Shell, Chevron and Norsk Hydro developments by 2012. While a diversifying upstream production base augers well for future growth, Petrobras' policy of maximising Brazilian content in new facility construction to date has led to some delays in meeting project schedules.

Canada

Total Canadian oil supply, including NGL and oil sands, was some 3.2 mb/d in 2006 and is seen reaching 3.29 mb/d in 2007 and 3.87 mb/d in 2012. The mainstay of growth in Canadian supply in the medium term is the Alberta oil sands, where production has already risen from 600 kb/d in 2000 to

Recent Estimates of Canadian Oil Reserves
(billion barrels)

	BP	OGJ	CAPP	AEUB	World Oil*	NRCan
Proven conventional & NGL	6.9		5.6		4.4	
Proven/under development oilsands	10.2		8.6		7.6	
Total 'proven'	17.1	179.2	14.2		12.0	
Remaining Potential conventional						12.7
Established oilsands	163.5+10.2=173.7			173		
Ultimate recoverable oilsands				315		310.8

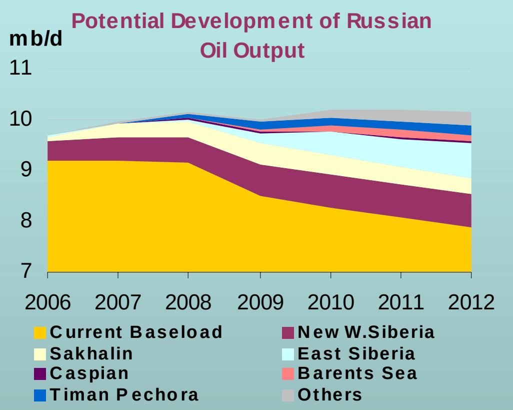
* excludes NGL

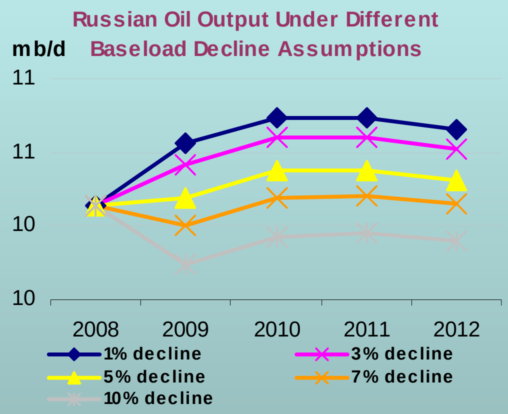
1.2 mb/d in 2006. Few would question the ultimate resource potential of Alberta's oil sands. However, some confusion surrounds categorisation of Canada's oil sands reserves. Initial moves by the Oil and Gas Journal to place 174 billion barrels of *established* oil sands reserves alongside a more modest 5 billion barrels of *proven* conventional reserves saw Canada apparently leapfrog to second place in the global proven reserves league behind Saudi Arabia. Other subsequent estimates show a more nuanced approach, itemising 7-10 billion bbls of oil sands reserves under development as proven, giving a total proven reserve level of closer to 15 billion bbls. While reserve risk for the oil sands (and Venezuela's *Orinoco*) is low, uncertain project economics would seem to make lower proven reserve estimates prudent.

FSU Supply Growth I - Russia

Russian oil production could level off during 2010-2012, growth potentially stalling until mid-decade. Taking the top 20 main development projects scheduled through to 2012, along with assumed 3% pa net decline for baseload production, output reaches around 10.6 mb/d by 2010, from an actual 9.9 mb/d in 1Q07. Overall, output then dips to 10.5 mb/d by 2012. Assumed decline is a key variable in a forecast such as this, although the relatively low net level of 3% is balanced by a highly selective list of new field developments. But an uncertain Russian investment climate and tight drilling/service capacity justify caution on new project start-up.

Significant increments in 2007/2008 come from Sakhalin 1 (now building towards peak 250 kb/d), year-round production from late 2008 from Sakhalin 2, Rosneft's Vankor project, plus initial volumes from Lukoil in Timan Pechora and the North Caspian. During 2009-2011, more significant volumes begin to emerge from Rosneft, Surgutneftegaz, TNK-BP and Russneft in East Siberia. In all, we assume that East Siberian supply is capped at 600 kb/d through 2012, enough to fill phase 1 of the East Siberia-Pacific Ocean (ESPO) pipeline. Growing volumes also become available towards the end of the forecast period from TNK-BP's Uvat field in West Siberia, and from Gasprom/Rosneft's Priramloznoye in the Barents Sea.





Without publicly available field-specific data, it is not possible to perform an in-depth, field-by-field analysis for Russia. Our approach therefore combines a simplified key field overview such as the above, with an examination of company growth plans, government and industry forecasts and an assessment of likely pipeline capacity availability. The range of industry forecasts shows 2010 production lying in a 10.0-11.1 mb/d range, with traditionally conservative government outlooks showing a 2010 level of 10.2 mb/d. Although higher than this, our forecast is well below published growth targets for producers like Rosneft, Lukoil and TNK-BP.

Drawing longer-term conclusions from a five-year forecast is hazardous. Operators of multi-phase projects (such as Sakhalin) envisage modest decline from early production phases by 2010-2012, but a sharp build in supply again by the middle of the next decade. Extrapolating a decline in Russian production in the longer term would therefore be premature before examining post-2012 prospects in detail.

Production of conventional crude and NGL in Canada is expected to show continued decline. Offshore Newfoundland/Labrador production has risen from negligible levels in the 1990s to 300 kb/d in 2006 and there are signs of promising new potential here also. But development of new fields such as Hebron-Ben Nevis has been deferred by disagreements between the operators and the provincial government over the share of equity and returns from the projects, delaying substantial output growth well into the next decade.

Azerbaijan

Production from Azerbaijan is expected to reach almost 900 kb/d in 2007, from 650 kb/d in 2006 and further increases in offshore supply take production to 1.38 mb/d in 2012. Production from the BP-operated Azeri-Chirag-Guneshli fields in the Caspian reach 950 kb/d by late 2009, and sustain that level through 2012. Liquids supply from the recently-started Shah Deniz gasfield gradually reaches 50 kb/d. And while production from state operator Socar is seen gradually declining, new production at the end of the forecast period is expected to come from recent offshore discoveries such as Inam and Yalama.

Kazakhstan

Kazakh production growth has lagged neighbouring Azerbaijan's in the past two years and may continue to do so through to 2009. Delays in expanding pipeline infrastructure, notably the CPC pipeline to the Black Sea, have hampered development of the Tengiz and Karachaganak fields. Eventual CPC expansion should allow Tengiz output to rise to 640 kb/d in 2012 from 265 kb/d in 2006. Recently, Russia also agreed to increase Karachaganak gas and condensate processing at its Orenburg plant.

Meanwhile, ENI's much-delayed offshore Kashagan project is expected in service by 2011, rising towards 300 kb/d output by late 2012. Later development phases at the 11 billion barrel field are expected to take Kashagan production to 1.5 mb/d by 2019. Although this is 25% higher than earlier estimates, costs at the project have also ballooned, with phase one now seen costing almost double a 2004-sanctioned figure of $10 billion. Problems centre on the field's high pressure and hydrogen sulphide (H2S) content. Overall Kazakh production reaches 1.9 mb/d in 2012 from 1.3 mb/d in 2006.

US Gulf of Mexico (GOM)

Total US crude production is seen declining by 170 kb/d over 2007-2012. However, while Alaska and other onshore lower-48 production drops, offshore Gulf of Mexico (GOM) production gains a net 345 kb/d. Output hits 1.8 mb/d in 2010/2011, before dipping to 1.7 mb/d by 2012. These projections are net of a rolling five-year average hurricane adjustment, which deflates GOM capacity by 10% in 3Q and 4Q each year. Moreover, net annual decline for base-load output is assumed at 15%, reflecting a tendency for deepwater fields to peak rapidly, followed by sharp decline.

Much of the growth in new production comes from a pair of delayed, 200 kb/d-plus projects, namely Atlantis and Thunder Horse. However, significant new contributions also comes from Genghis Khan, Neptune, Phoenix (formerly Typhoon), Tahiti, Mirage, Blind Faith, Thunder Hawk, Shenzi, Clipper, Great White, Trident, Chinook, Tubular Bells, and Puma. In all, peak new supply from identified projects amounts to 1.1 mb/d. Again, judgement has been exercised on realistic start-up dates, mindful of recent slippage (at writing Chevron had just announced an unspecified delay due to metallurgical problems in the system used to anchor the Tahiti production facility to the seabed). Overall, 2008 could prove a bumper year for new supply in this region, with potentially seven new field start-ups.

FSU Supply Growth Prospects II - Diversifying Export Routes

Longer-term FSU crude and condensate supply growth will need new export routes, not least given Russian pipeline monopoly Transneft's attempts to diversify export markets while reducing reliance on transit states. The following existing and proposed FSU projects incorporate a high level of uncertainty in terms of expansion, economics, timing, dedicated crude supply and geopolitical factors. Nor is the list exhaustive. However it illustrates the progress being made to avoid future transport bottlenecks:

- **East Siberia Pacific Ocean (ESPO)**

  Under construction. Phase 1 (600 kb/d) completion scheduled late 2008, with apparently committed crude supply. China to take initial 300 kb/d, leaving balance to be railed to Pacific. Phase 2 expansion to 1.6 mb/d depends on highly uncertain level of East Siberian reserves.

- **Baltic Pipeline System (BPS)-2**

  Transneft now planning the 1 mb/d, $2.5 billion line. On approval, estimated 15-month construction. Could limit future Druzhba transit shipments to Europe via Belarus. Questions over crude supply, Russian willingness to cede central European markets to Caspian oil and whether rationale is obtaining increased European prices. Project viability boosted by recently announced Sovcomflot tanker orders.

- **Turkish Straits Bypass**

  Seen as essential to clear Black Sea/Turkish Straits bottlenecks and a pre-requisite for CPC expansion. 1.5 mb/d Samsun-Ceyhan link now moving ahead. Russian-sponsored 0.7 mb/d Bourgas to Alexandroupolis line has clearer crude supply commitments. Two more tentative projects run from Bourgas to Vlore and from Constanta to Trieste, but doubtful all four projects (4 mb/d) will proceed.

- **Baku-Tbilisi-Ceyhan (BTC)**

  Principal Mediterranean exit route for Azeri crude. Capacity now boosted to 1 mb/d from earlier 750 kb/d (recent throughput 620 kb/d). May ultimately reach 2.2 mb/d. Delays on CPC expansion may attract Kazakh Tengiz (early 08) and Kashagan (post-2010) oil to BTC. But, delays facing associated Trans-Caspian shipment facilities.

- **Kazakh Caspian Transport System (KCTS)**

  Planned combination of 500 kb/d pipeline from Kashagan to Kuryk on Caspian coast plus dedicated fleet of trans-Caspian tankers shuttling oil to Baku and BTC. Scheduled to enter service 2010/2011

- **Caspian Pipeline Consortium (CPC)**

  Key exit route for Kazakh crude via Novorossiysk on Russian Black Sea. Proposed doubling of capacity to 1.4 mb/d is stalled. Transneft now controls Russia's 24% stake, seeking a 40% tariff increase. Eventual Russian go-ahead for expansion may be used to lure Kazakh oil back from using BTC.

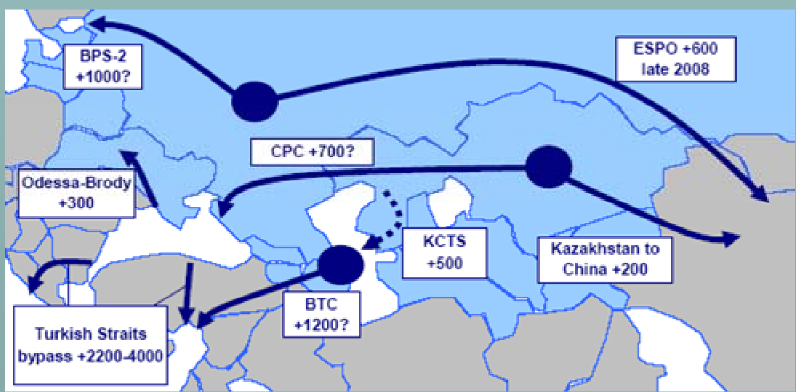
- **Kazakhstan to China Pipeline**

  Existing 200 kb/d Atasu-Alashankou-Dushanzi link began in July 2006 and scheduled to carry 100 kb/d of eastern Kazakh crude in 2007. Feeds Chinese refineries in Xinjiang province. Potential for Russian crude delivery to China also. Proposed Kenkiyak-Kumkol link will subsequently also tie in Caspian and western Kazakh crude. Ultimate capacity for crude delivery to China could reach 400 kb/d.

- **Odessa to Brody**

  Long-discussed reversal of 300 kb/d pipeline capacity to fulfil original role of supplying Caspian oil to central Europe. Currently ships 100 kb/d of Russian crude to the Black Sea. Extension planned to Plock, Poland.

Prospective FSU Export Routes
(thousand barrels per day)



Other Sources of Growth

Brazil, Russia, Kazakhstan, Azerbaijan, Canada, biofuels and the US GOM account for the bulk of expected net non-OPEC growth to 2012, offset in part by sizeable declines from the North Sea, Mexico, non-GOM USA and others. However, modest increments amounting to a total of 400 kb/d also come from south East Asia and Africa. Key in South East Asia are Vietnam, Malaysia and the Philippines. **Vietnam** will see production from its workhorse Bach Ho field decline, but boosted crude and condensate supply is due from Su Tu Vang, Su Tu Trang, Ca Ngu Vang and Song Doc. **Malaysian** supply rises with development of the Kikeh and Gumusut fields, while recent discoveries off the **Philippines** could treble current 20 kb/d production.

The profile for African non-OPEC supply growth now looks more modest following Angola's migration to the OPEC fold. However, net growth amounts to 185 kb/d during 2007-2012, driven by increases from Mauritania, Sudan and Congo. **Mauritania** has seen initial promise at the Chinguetti field turn to disappointment after reservoir problems. However, national output could attain 125 kb/d from a current 30 kb/d with development of reserves at Tiof and Tevet. New pipeline capacity has boosted **Sudanese** supply close to 500 kb/d. Geopolitical uncertainty remains, and future expansion may be limited by OPEC quota considerations if Sudan, as rumoured, joins the cartel. Nonetheless, existing discoveries are likely to support a rise in production above 570 kb/d for the outlook period**.** **Congolese** production, while potentially slipping to 220 kb/d in 2007, could regain earlier 280 kb/d-plus levels on development of the Moho-Bilondo, Tchibeli and Libondo fields.

UK and Norway

Accelerating decline from mature fields, extended maintenance and a proliferation of unscheduled field outages have combined to see North Sea oil production consistently underperform versus initial expectations in recent years. There seems no reason to expect a turnaround in output, given the mature nature of the UK and Norway's established producing basins. Frontier areas in the Norwegian Arctic and NW Shetland have yet to prove geologically or economically viable as significant sources of replacement supplies. Costs there are high, given an absence of established infrastructure, and it will likely require amended fiscal and access terms before these areas become genuine offsets for mature field decline, likely beyond the horizon of this forecast. Combined oil supply has declined by 1.6 mb/d since 2000, falling annually by 8% in the UK and by 3% in Norway.

UK production could however see a slowing in decline, largely due to January 2007's start up at Nexen's Buzzard field in the Forties system. Plateau production of 200 kb/d is due in mid-2007. Other new start ups in the UK sector are likely to be smaller than Buzzard, although the Lochnagar project late in the forecast could add 100 kb/d. Together with the Dumbarton, Brenda, Brodgar/Callanish, Kessog, Perth, Tweedsmuir, Devenick, Emerald and Ettrick projects this helps stem overall UK decline in the period through 2012. Total UK liquids production averages 1.4 mb/d by 2009 and 1.0 mb/d in 2012, compared with 1.7 mb/d in 2006. This is towards the lower end of an official government forecast range of between 1.1-1.6 mb/d for 2012.

Official **Norwegian** government forecasts have also been reduced in recent months, as outturn supply has lagged expectations. There are anecdotal reports from companies of sharply accelerating decline at some older fields, and project delays have been cited as a key reason for government projections for 2007 being curbed to 2.6 mb/d from an earlier 3.0 mb/d. We are now working with a slightly lower expectation for Norway, total liquids coming in at 2.5 mb/d for 2007, partly due to the 'reliability' adjustment discussed above. Looking ahead, Norwegian production is seen declining to 2.25 mb/d by 2009 and 2.05 mb/d in 2012, taking average net annual decline to nearly 4% from the 3% so far this decade. Nonetheless, new developments such as Yme, Volve, Alvheim, Klegg, Skarv, Rimfaks, Tyrihans, Goliat and Ormen Lange (gas liquids) help stem otherwise sharper decline.

Mexico

Mexico faces the onset of sharp decline from its baseload Cantarell field (currently producing 1.5 mb/d, or 47%, of total crude output of 3.2 mb/d). Having already extensively reworked the Cantarell reservoir with infill drilling and nitrogen injection, Pemex confronts declines, potentially in a 15-20% per-annum range. Two key factors impede attempts to offset Cantarell decline:

- Mexico's constitution forbids foreign direct investment in upstream oil;
- State oil company Pemex faces crippling debt servicing and tax obligations, which severely restrict its ability to invest in new field developments.

Although tax reform is being proposed by the new government, without a significant change in policy, Mexican output will continue to decline. Reversing this requires substantially more investment annually than the $13.9 billion Pemex has for 2007. In our forecast, which assumes no radical policy change, Cantarell production falls below 650 kb/d by late 2012, partly offset by new output from the nearby Ku-Maloob-Zaap complex. KMZ production has risen from 240 kb/d in 2002 to 450 kb/d in 1Q07. It is seen reaching 600-700 kb/d beyond 2010. Other increments come from the Tabasco littoral, and onshore Chicontepec. However, Chicontepec's high cost and geological complexity restrict forecast supply to only 150 kb/d of reported 1.0 mb/d potential. In the longer term, Mexico's ability to sustain supply will depend on joint ventures to open up ultra-deepwater reserves. Total crude production falls to 2.7 mb/d in 2012 from 3.1 mb/d in 2007.

OPEC Supply

OPEC Crude Oil Capacity Developments

OPEC producers are expected to add a net 4.0 mb/d to installed crude capacity during 2007-2012. The years 2008 and 2010 see particularly strong growth, when new project start-ups drive OPEC capacity higher by over 1.0 mb/d in both years. The forecast takes account of new capacity investments and net decline from older fields (decline rates are assumed to range from 1-5% pa for onshore fields in the Mideast Gulf, through to 12-15% pa for deepwater fields). Overall, net decline for the group as a whole averages 3.2% annually, lower than the 4.6% evident from the non-OPEC forecast. This reflects in part the predominance of lower-decline onshore and shallow water production in the total (albeit deepwater production from Angola and Nigeria is taking on greater importance). OPEC therefore faces the task of replacing some 1.1 mb/d each year just to sustain capacity at existing levels.

Installed capacity reaches 38.4 mb/d in 2012, from a 2007 average of 34.4 mb/d (and 34.0 mb/d at the time of writing). OPEC's own projections see installed capacity of just under 40 mb/d by 2010, suggesting a more optimistic view on project additions and decline rates than employed here. *MTOMR* additions are concentrated in Saudi Arabia (45%), UAE (13%), Angola (13%) and Kuwait (11%), collectively 81% of the total. As previously, we err on the side of caution for producers facing uncertainty over the investment environment and internal security. Therefore, Iraq and Venezuela continue to see capacity capped at prevailing levels through the period (2.4 mb/d and 2.6 mb/d respectively). To this category is added Niger Delta production. Some 545 kb/d of Delta output has been shut for more than a year, including volumes of Forcados, Escravos and EA crude. While operators plan to reactivate this output, ongoing ethnic unrest renders any assumption on timing highly speculative. It is excluded from the forecast, but deepwater/NGL expansion in Nigeria continues.

OPEC crude projections in our February 2007 update excluded Angola and were held largely unchanged from last July. This time around, baseline 2007 capacity for OPEC excluding Angola of 32.7 mb/d is 1.0 mb/d below last year's equivalent. Lower than expected capacity in Indonesia, Iran, Nigeria and Iraq is responsible for this lower 'starting point'. Looking ahead, OPEC-11 capacity of 35.8 mb/d in 2011 is 500 kb/d below last year's expectation. Capacity for Algeria, Indonesia, Iran, Qatar and UAE looking forward is slightly weaker, stronger growth is expected now from Kuwait, Libya, Nigeria and Saudi Arabia.

In the context of the global supply/demand balance, OPEC spare capacity looks set to gradually increase through to 2009, continuing the trend evident since 2004. Current spare capacity however remains a modest 3.0 mb/d and even at its peak in 2009 is likely to remain below 5% of global demand. As non-OPEC growth recedes post-2009, OPEC spare capacity will likely also diminish sharply.

Sustainable OPEC Crude Production Capacity

(million barrels per day, yearly average)

	2006	2007	2008	2009	2010	2011	2012	Increment 2007-2012
Algeria	1.38	1.38	1.42	1.51	1.60	1.61	1.56	0.19
Indonesia	0.92	0.87	0.88	0.87	0.90	0.94	0.90	0.03
Iran	4.01	3.96	4.00	4.00	3.86	3.82	3.77	-0.19
Kuwait	2.60	2.65	2.83	2.84	2.98	3.07	3.06	0.42
Libya	1.70	1.75	1.84	1.84	1.88	1.94	1.92	0.17
Nigeria	2.46	2.47	2.37	2.48	2.62	2.78	2.84	0.37
Qatar	0.88	0.95	1.05	1.10	1.16	1.17	1.16	0.21
Saudi Arabia	10.73	10.80	11.17	11.46	12.17	12.31	12.57	1.77
UAE	2.67	2.88	2.89	2.85	2.90	3.17	3.38	0.50
Venezuela	2.67	2.62	2.62	2.62	2.62	2.62	2.62	0.00
Sub-total OPEC 10	**30.01**	**30.33**	**31.06**	**31.57**	**32.69**	**33.43**	**33.79**	**3.46**
Angola	1.37	1.67	2.00	2.13	2.02	2.09	2.17	0.50
Iraq	2.50	2.40	2.40	2.40	2.40	2.40	2.40	0.00
Total OPEC	**33.88**	**34.40**	**35.46**	**36.10**	**37.11**	**37.92**	**38.36**	**3.96**
annual increment	*0.67*	*0.51*	*1.06*	*0.64*	*1.01*	*0.81*	*0.44*	

For the time being, **Angola** (like Iraq) remains outside OPEC's production quota system. While there are rumours that the upcoming September OPEC meeting in Vienna may set a date or capacity trigger for Angola's entry, this report assumes capacity continues to expand, reaching 2.1 mb/d by late 2008 before stabilising in a 2.0-2.2 mb/d range thereafter. Total's 250 kb/d Rosa field started up in June, following the Dalia field last December. Further new production is scheduled from BBLT, Greater Plutonia and Kizomba C, while prospects boosting 2011/2012 production include Kizomba D, the Cravo and Perpetua complexes and Plutao/Saturno and Ceres.

Saudi Arabia is responsible for almost half of expected OPEC capacity growth to 2012, as capacity reaches 12.6 mb/d in 2012, a rise of 1.8 mb/d from 2007. The 900 kb/d Manifa project (Arab Heavy) is now included from 2011, with crude here likely destined for new complex Saudi refining capacity. Otherwise, Saudi crude expansion largely centres on its lighter/sweeter grades from Khursaniyah, Shaybah and Khurais, together with associated gas liquids. Questions over Saudi and other OPEC members' capacity expansion plans in the face of demand uncertainty are believed related to the next, post-2012, phase of expansion rather than the current cycle.

The **UAE** 2011 projection of 3.17 mb/d is around 0.1 mb/d lower than last time. Capacity rises further to 3.38 mb/d in 2012. Five-year growth nonetheless amounts to 500 kb/d (13% of total OPEC growth), deriving from the onshore Bab and Asab fields, plus offshore supply from Umm Shaif, Umm al Lulu, Nasr. Upper Zakum capacity is seen rising to 750 kb/d from 550 kb/d, although this has been slipped back in the forecast to 2012 after delays in finalising the development programme.

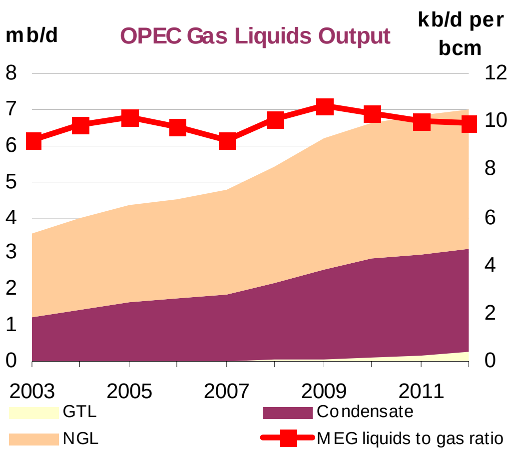
Kuwait's capacity is seen rising by around 0.4 mb/d to 3.06 mb/d by 2012, despite long-standing delays in agreeing an investment model for expansion of the northern oilfields. Baseload Burgan supply from the south of the country is now seen rising from 1.5 mb/d to 1.7 mb/d, while the GC-24 project at the northern Sabriya field potentially adds 160 kb/d. Work to make capacity of around 400 kb/d sustainable at the western fields of Minagish and Umm Gudair could add to capacity in 2008/2009, although decline is assumed to set in thereafter.

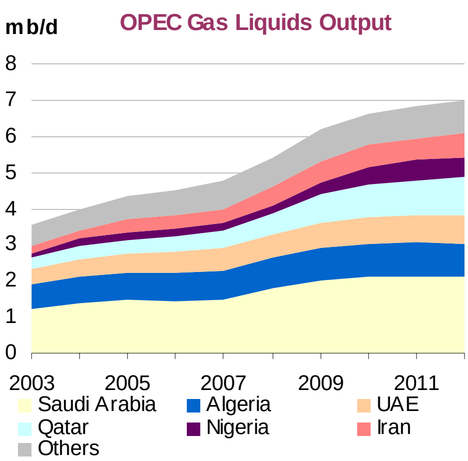
Iranian crude capacity for 2007 is revised below 4.0 mb/d from an earlier 4.2 mb/d. Forecast capacity is now 100 kb/d less than last year and reaches 3.77 mb/d by 2012. The country faces sizeable challenges offsetting aggressive decline at older onshore fields. The key onshore Azadegan and Yadavaran projects, which could add a combined 330 kb/d, have slipped further and are now only seen supplying significant volume in 2011/2012. New production from the Abuzar, Foroozan, Salman, Kharanj Parsi, and Masjid e Suleiman fields has also slipped by around six months. Buy-back contracts in Iran remain unattractive to international companies, and ongoing geopolitical uncertainty only acts to further dissuade outside investment. Reflecting diminished expectations, NIOC recently stressed improved recovery at existing fields and natural gas as priorities. Natural gas supply is a concern, albeit with limited impact on crude as field reinjection and domestic demand will likely be prioritised over exports.

As noted above, some 550 kb/d of long-term shut-in **Nigerian** production has been removed from estimates of current and future crude capacity. However, the five-year forecast for Nigerian capacity now sees 375 kb/d of net increase for 2007-2012 compared with the 315 kb/d envisaged last year for 2006-2011. Such has been the degree of instability affecting the Niger Delta and surrounding shallow water production that ongoing growth in deepwater supply has tended to be overlooked. Capacity here has trebled to 950 kb/d since 2003 and could rise to 1.3 mb/d in 2010 and 1.6 mb/d in 2012. New projects centre on the Agbami, Bonga, Bosi, Usan, Akpo and Nsiko fields. Total capacity reaches 2.84 mb/d in 2012 from 2.47 mb/d in 2007.

Pace of OPEC NGL Growth to Match Crude Oil

Looking at OPEC crude additions for 2006-2012 tells only half the story for potential capacity growth. Gas liquids (ethane, propane, butane and pentanes from gas processing plants plus field gas condensates) are expected to rise by +2.2 mb/d (+7.8% pa) and take potential OPEC NGL supply to 7.1 mb/d by 2012. The rate of increase matches growth evident during 2001-2006, as attempts to boost natural gas utilisation and to reduce flaring continue. Moreover, rising OPEC condensate supplies defer an eventual global shift to a heavier and sourer global crude slate.





The gas liquids supply forecast focuses on specific gas processing plant and condensate projects. The results are tested against aggregate natural gas supply projections contained in the *World Energy Outlook 2006*. Our forecast suggests the liquids–to-gas ratio for the Middle East Gulf (MEG) will remain around a current 10 kb/d per bcm. Although this looks conservative, a degree of caution over future NGL availability is in order. The current tight market for raw materials, labour, services and fabrication capacity renders gas and NGL supply projects equally risk-prone as those for crude oil. Gas reinjection requirements for oil production may also rise. Baseline NGL supply data is notoriously opaque, with ambiguities over reporting of ethane and condensate. Regulatory delays in consuming countries are undermining earlier strong expectations for future gas demand growth and exports. Finally, analysts partly rely on capacity rather than production in forecasting future increments, with data on decline rates at existing gas fields as scarce as for oil. But offsetting factors should sustain OPEC NGL growth in the next five to six years:

- OPEC gas development is increasingly targeting local, as opposed to export, markets, to free up oil for export. This diminishes the potential NGL supply impact of weaker international gas demand.
- The impetus to minimise gas flaring is growing.
- Much Middle Eastern gas is stranded, with a clear incentive to strip out liquids to maximise early revenue flows. Wet gas streams are preferentially developed ahead of dry gas for this reason.
- Qatar and Iran are tending towards modular gas supply and export infrastructure, less prone to time and cost over-runs than new, stand-alone projects (albeit Iran faces other impediments in terms of investment terms and local demand growth).
- A significant and growing amount of NGL supply will derive from non-associated gas, less prone to delays if crude capacity plans are deferred.

Over 50% of the expected increase in gas liquids supply by 2012 will come from Saudi Arabia and Qatar. A further 30% comes from Iran and Nigeria, even though projections for these two countries have been revised down since the July 2006 *MTOMR*. These four producers hold 35% of global gas reserves and account for 80% of gas liquids growth. Algeria and UAE remain substantial producers of NGL through 2012, at a combined 1.7 mb/d, albeit similar to current volumes. Replicating our approach to crude capacity, the uncertain investment environment in Iraq and Venezuela is reflected by a flat forecast NGL profile, though both could see much higher production over time.

Saudi Arabia is expected to see NGL output rise from 1.4 mb/d in 2006 to 2.1 mb/d by 2012. Saudi Arabia expects domestic gas sales to rise by 40 % by 2012. Recent associated gas-based growth is augmented over the next five years by gas plant liquids from the Manifa, Khursaniyah and Khurais oilfields. Expansion of the Hawiyah gas plant will also add NGL supply from non-associated gas. Total NGL supply dipped in 2006, partly because of curbs on crude oil production. However, moves to boost crude capacity towards 12.5 b/d will also entail substantial volumes of incremental gas liquids. The 900 kb/d Arab Heavy Manifa project also contributes up to 65 kb/d of gas condensate.

Qatar sits atop the 25 trillion cubic-metre North Field and is expected to see the fastest growth in OPEC NGL supply (+17% per annum) as various LNG export phases are brought on stream. A moratorium on new gas developments at North Field, pending reservoir studies running until 2012, does not affect already-sanctioned projects. Concerns emerged over a proliferation of gas utilisation projects and the dangers of over-rapid development damaging the reservoir. More recently, signs of increased North Field reservoir complexity have emerged, adding to project uncertainty and potentially raising costs and lead times. That said, Qatar is already the world's largest LNG exporter and is in line to almost triple these supply levels by 2012.

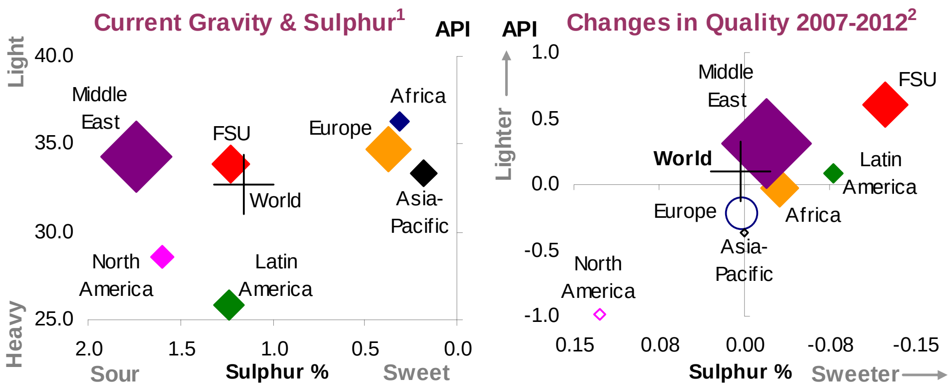
Qatari gas liquids could rise from 400 kb/d to 1.0 mb/d by 2012. Condensate supplies should rise by 350 kb/d, NGL by 50 kb/d, and gas-to-liquids (GTL) by 200 kb/d. We retain a conservative view on Qatargas 3 and train 7 at the Rasgas III project, with substantial liquids volumes not expected until 2012. Exxon recently cancelled the 150 kb/d Palm GTL project, reportedly due to doubling costs and reservoir complexity. Conversely, latest information pulls forward train 5 at the RasGas II project (which started in early 2007), while RasGas III and Qatargas 2 also now see earlier completion compared with our July 2006 projections. The recently-started Oryx (Sasol, Chevron, QP) and Shell/QP's Pearl GTL projects will produce 250 kb/d of high-quality products by early next decade.

Iran's plans centre on non-associated South Pars gas (an extension of the North Field), and an associated 3-4 billion barrels of condensate. Forecast NGL and condensate supply is scaled back by 200 kb/d since last *MTOMR*, the 2011 total now coming to 605 kb/d. Phases 6-8 and 9/10 are delayed on sour gas transport problems, but both should be close to peak in 2009/2010. Total has indefinitely deferred work on South Pars 11, so we defer all post-South Pars 10 output by at least a year. Nonetheless, 2006 supply of 400 kb/d reaches 650 kb/d by 2012, condensate rising by 200 kb/d. Despite geopolitical/investment uncertainty, a five-fold rise in NGL supply is evident so far this decade.

Deteriorating security in **Nigeria** has raised questions over expansion plans here too. Nonetheless offshore developments, to date largely been immune to the ethnic unrest in the Niger Delta, should result in incremental NGL next year from the EA and Gbaran/Ubie projects. We also assume 2009 start-up for Akpo condensate (180 kb/d) and Escravos GTL (35 kb/d). Ultimately, Nigerian liquids recovery will benefit from a government decree requiring eradication of gas flaring by 2008.

Likely Evolution of Global Supply Quality

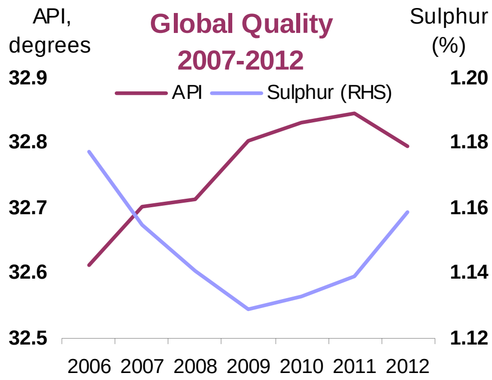
Global average crude and condensate quality for 2006 is estimated at 32.6°API and 1.18% sulphur. Looking at 2007-2012, the net change in global quality will be minimal, with gravity lightening from 32.7°API to 32.8°API. Global refinery feedstock becomes marginally sourer, as sulphur content increases from 1.15% to 1.16%. However, the five year trend masks divergent moves in the interim, as production first becomes both lighter and sweeter in the period through 2009, turning sourer thereafter. Despite becoming more sulphur-prone in the longer term, the global barrel continues to lighten.



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.

Dissecting these trends regionally provides some explanation for apparently contradictory movements in quality. The surge in OPEC condensate supplies during 2007-2009 underpins the increase in global quality. FSU supply is also becoming markedly lighter and sweeter in this period, as Urals crude is progressively replaced by Caspian volumes and by lighter/sweeter Sakhalin crude. While these elements continue to drive global supply lighter through 2012, lower-quality supply from the Americas, (Canadian oil sands, Brazil, GOM) begins to play an increasing role. This curbs the lightening of the global barrel, while also turning it sourer from a sulphur low of 1.13% in 2009, to 1.16% in 2012.

Focusing on OPEC quality emphasises the importance of condensate supply in influencing the aggregate trends. Including condensates in the calculation, OPEC average gravity rises from 34.3°API in early 2007 to 34.8°API in 2011, before dipping again in 2012. However, stripping out condensates leaves crude quality rather flatter in a 33.2-33.4°API range. Looking at sulphur too, the inclusion of condensate sees average sulphur fall from 1.36% in 2007 to 1.31% for 2009-2011, rising to 1.33% in 2012. Taking crude only, sulphur content dips from 1.43% in 2007 to around 1.4% during 2009-2011, rising again to 1.43% in 2012. Higher assumed volumes of Arab Heavy crude from Saudi Arabia towards the end of the forecast, as spare capacity elsewhere within OPEC is used up, partly accounts for the deterioration of OPEC and global crude quality by 2012.



BIOFUELS

Summary

- **The 2006 biofuels supply baseline has been raised by 79 kb/d to 863 kb/d**, to reflect strong growth and a more detailed capture of projects. By 2012, we see total global biofuels production at 1.75 mb/d; slightly more than double output in 2006.

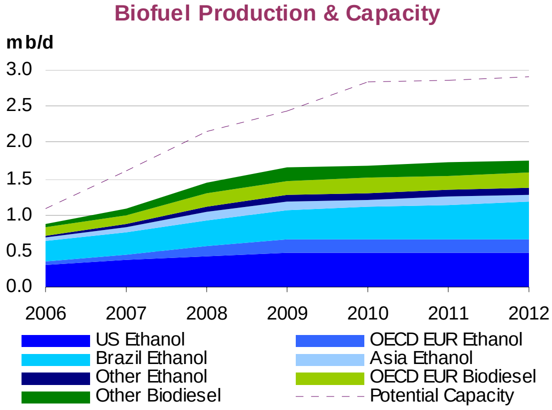
- **Our cautious stance on medium-term production potential has been maintained**. Price pressures this year on feedstocks such as corn, sugar, soybeans, wheat and palm oil reinforce our concerns over economic viability due to competition between first-generation biofuels and the food chain. Nevertheless, total *potential* production capacity amounts to 2.92 mb/d globally by 2012.

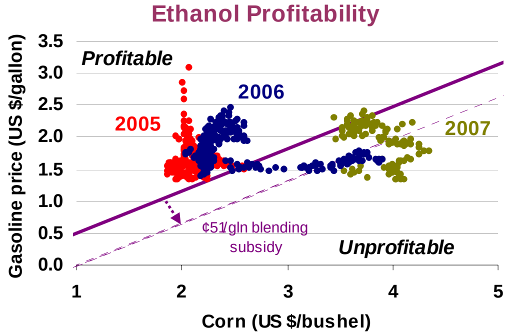
- **Political support for biofuels is almost certain to increase**, but until clear mandates and specific incentives are in place to support bold political targets it is impossible to gauge with any accuracy the impact these policies will have on biofuel output. Therefore, our projections take into account only those measures in place. Further, unless mandates provide sufficient incentive to ensure the necessary availability, infrastructure expansion and the adaptations sometimes necessary in the vehicle pool, ambitious policy goals may have the impact of reducing investment in refinery capacity.

Biofuels See Strong Growth but Medium-Term Forecast Remains Uncertain

Biofuels remain a hot topic. Interest in their production and potential for replacement of conventional petroleum-based refined products has, if anything, grown since last year's *MTOMR*. Nevertheless, despite political enthusiasm and support for what is seen by some to be an important but only partial solution to dependence upon (imported) oil, the depletion of liquid hydrocarbons and growing carbon emissions, the economics of first-generation biofuels are still uncertain and raise doubts as to whether the ambitious supply growth scenarios some sketch will be realised.

To start with, as foreseen in our first biofuels supply forecast one year ago, the price of corn (used for ethanol production) in February rose to a 10-year high in the US, but the price of ethanol fell. The combination of high feedstock prices and lower ethanol prices resulted in reported delays or even cancellation of some biofuel projects. But this is not a static issue. High corn prices led to record plantings in the US, eroding price peaks, but even at their recent lows, corn prices are 50% higher than 2005 levels. Predictably, increased corn plantings have reduced planted acreage of other crops, such as soybeans which, combined with poor weather in key producing regions, has raised the overall level of food prices. With such uncertainty, projecting biofuel viability is difficult.





The profitability line (net of subsidies) has been estimated to take into account the value of ethanol on an energy basis, a price premium for octane and oxygen and a price premium for the sale of co-products.

But new biofuel projects continue to be announced at a rapid pace and, even with these first-generation limitations and as yet to be defined mandates and subsidies, further country-by-country detail on biofuel projects has led us to raise our supply figures. We have hiked our 2006 production to a higher baseline of 863 kb/d and foresee production roughly doubling to 1.75 mb/d by 2012.

In the bigger picture though, we remain conservative in our outlook. Even though biofuels will represent a substantial share of incremental transportation fuel supply over the next five years (around 13% of gasoline and gasoil/diesel on a volumetric basis); as a whole, compared with total crude output, they will remain a rather marginal factor in the total oil mix, at not even 2%.

Revised Methodology and Its Implications

Measuring and forecasting biofuels supply and demand remains difficult because of the limited data available. Most countries do not yet provide disaggregated data, so we cannot track them with the same detail as for other fuels. But an expanded database now allows us to provide disaggregated supply capacity and production, while enabling us to show graphically the potential for substantially higher production if all or much of the announced capacity comes online. However, due to the same doubts we highlighted in previous *MTOMR*s, we have decided to cap production from 2009 (again excepting Brazil, which has a competitive advantage). Thus we deliberately fail to include a large number of potential projects where uncertainty about financing and construction, let alone completion dates, remains high.

Our model is supply-driven, as little to no data on biofuels consumption exist outside of the OECD and Brazil, and is often incomplete. Moreover, legislation shaped by policy is likely to remain the main driver of future forecast changes, which in the US, most importantly, is not yet in place. A much higher mandatory share of biofuels in US gasoline, for example, could have a considerable impact on the future supply and demand picture.

What Has Changed in Our Forecast?

Based upon our assessment of production capacity coming online, and evidence that production has risen more rapidly than expected in the past year, we have revised up our baseline 2006 global supply figure to 863 kb/d. In addition to other changes, this has been taken forward to our new five-year horizon in 2012. Therefore, we see production in 2007 averaging 1.09 mb/d, and by 2012 reaching 1.75 mb/d – a considerable rate of growth, but significantly below planned capacity figures.

A detailed examination of country-by-country projects has led us to revise up our total biofuels capacity figure from 2.05 mb/d (by 2011) to 2.92 mb/d by 2012. This leaves an underutilised capacity of 1.16 mb/d that could be brought online if the economics are right. This is however a capacity potential based on project intentions. More likely, given the low lead times and relatively low cost (compared with upstream or refinery investment), many projects, if our baseline conservatism is correct, will not see the light of day.

Given our assumption that crude oil prices follow the prevailing futures curve, and broad-based support in many countries with surplus agricultural production, biofuels will likely continue to receive much attention. As hinted above, even if President Bush's ambitious plans outlined in his State of the Union speech in January have been much questioned, some adapted version of his goal to significantly hike biofuels production in the US looks likely to be passed into law in 2007/08. Most probably this will double the 2012 mandatory biofuels share of 7.5 billion gallons (490 kb/d), required by the 2005 Renewable Fuels Act (RFA), to 15 billion gallons (980 kb/d), to be reached by 2015. This would be less than half of a larger 36 billion gallons of total renewables that is proposed to be included in the US energy mix by 2022.

Moreover, the US mandate is only one of many. The European Union (EU) looks predisposed to require 10% of its transport fuels to stem from biofuels (by 2020), to rise from a probable 2010 mandate of 5.75%. Several other countries such as Japan, India, China, Canada and Australia will require shares of between 5-10% by around 2010. In addition, existing subsidies (usually tax breaks) and import tariffs, at least in the US and the EU, look likely to stay in place until at least 2009.

World Biofuels Production

(thousand barrels per day)

	2006	2007	2008	2009	2010	2011	2012
OECD North America	340	458	528	586	586	586	586
United States	330	417	474	533	533	533	533
Canada	10	41	53	53	53	53	53
OECD Europe	150	177	311	377	377	377	377
Austria	1	2	9	11	11	11	11
Belgium	0	3	11	11	11	11	11
Germany	72	75	91	95	95	95	95
France	18	29	51	54	54	54	54
Italy	10	16	17	25	25	25	25
Netherlands	1	4	14	21	21	21	21
Poland	4	8	8	19	19	19	19
Spain	9	22	40	59	59	59	59
UK	3	6	24	42	42	42	42
OECD Pacific	8	19	23	27	27	27	27
Australia	5	15	19	23	23	23	23
Total OECD	**498**	**654**	**862**	**990**	**990**	**990**	**990**
FSU	1	3	3	7	7	7	7
Non-OECD Europe	1	2	5	5	5	5	5
China	29	37	61	61	61	61	61
Other Asia	33	62	116	120	120	120	120
India	10	14	27	29	29	29	29
Indonesia	2	12	21	21	21	21	21
Malaysia	2	10	21	21	21	21	21
Philippines	6	7	10	10	10	10	10
Singapore	0	2	12	12	12	12	12
Thailand	14	17	27	27	27	27	27
Latin America	301	335	397	457	491	525	564
Brazil	293	316	368	421	455	489	528
Colombia	4	9	12	14	14	14	14
Middle East	0	0	0	0	0	0	0
Africa	1	3	4	5	5	5	5
Total Non-OECD	**366**	**441**	**586**	**655**	**690**	**724**	**763**
Total World	**863**	**1,095**	**1,447**	**1,646**	**1,680**	**1,714**	**1,753**

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

Notwithstanding ambitious targets, the planned legislation in the US contains safety valves, for example allowing the President to waive the mandate if considered necessary. Blenders unable or unwilling to include the required share of biofuels are likely to be able to pay a fee to avoid this, and a renewable fuels credit trading system is envisaged. Similar policies are being adopted in some European countries. Ultimately, these opt-out clauses could be significant, essentially setting the marginal price for biofuels. For example, if (hypothetically) refiners can opt out of a 10% ethanol blend in gasoline for a penalty fee of 50 cents per gallon, the marginal cost of ethanol would be $5/gallon. Taken from the other side of the equation, the price a buyer would have to pay to displace corn from ethanol use would be around $10/bushel, or roughly double the record corn price.

Such a lifting of agricultural prices could have far-reaching global economic effects – even excluding the moral issues related to food supply. Higher crop prices might not be hugely significant in a developed economy, where food represents a relatively small portion of national income, but there would still be an inflationary impact. But more importantly, in developing countries, where spending on food represents a higher proportion of income, rising food prices have the potential to lift wage demands, raising both inflation, labour costs, and therefore also the price of imported manufactured goods into developed countries.

The inter-relationships are clearly complex, but like changes in the oil market, it has to be understood that the impact of biofuels will be worldwide and far-reaching. First-generation biofuel policies therefore have to be considered regarding their effect on global food availability and prices, and not simply on domestic production surpluses and local energy security concerns.

Regional Developments

In **North America**, US biofuel production (ethanol and biodiesel) has already grown more rapidly than expected, leading to upward revisions to 2006 and beyond. Given the bi-partisan political momentum in favour of an enlarged mandate, as well as existing subsidies, project plans are moving ahead quickly, and many more plants are being added to the existing list. Nevertheless, we have, as with other countries, kept our total US biofuel supply figure steady from its projected 2009 level of 533 kb/d. This compares with an estimated 840 kb/d of total capacity potentially already in place in 2009.

Europe already produces over half of global biodiesel output, a share we expect it to maintain throughout our forecast period, approximately doubling supply from 107 kb/d in 2006 to 213 kb/d from 2009. From 2008, however, we see ethanol production in Europe growing strongly too, reaching 171 kb/d in 2009. The European Union thus looks on track to meet its self-set goal of a 2% renewable share in fuels, and likely also its probable new mandate of 5.75% by 2010 (so far, this remains only a voluntary target). We see total Europe reaching biofuel production of 385 kb/d by 2009, compared with potential capacity of 748 kb/d by 2012.

Of the major biofuel-producing regions, doubts are greatest concerning realisation of all announced projects in the **Asia-Pacific**. According to our calculations, of a total potential production capacity of 604 kb/d by 2012, we estimate that around one third or 209 kb/d will realistically be produced by 2009. Of this, around one third again will stem from China, although recent announcements suggest that enthusiasm for biofuels has been tempered by awareness of competition for food and water. India, Thailand, Australia, Indonesia and Malaysia will all be producing around 20-30 kb/d by 2009, with the first three tilted towards ethanol output, and the last two stronger on biodiesel. Besides doubts about the sustainability of production economics – at the time of writing, Asian palm oil prices were high, having doubled over the previous 18 months – mandatory blending goals look far less certain than in the US or Europe.

Elsewhere, **Latin America** is the other key supply region, dominated by Brazil. Colombia, Peru, Venezuela and Argentina's forecast production combined should add another 33 kb/d by 2009, but this pales against Brazil's 421 kb/d in the same year. As in our two previous *MTOMR*s, we maintain Brazilian biofuel supply growth beyond 2009 due to its unique competitive advantage in terms of production costs, agriculture and infrastructure. Therefore, we see its output increasing by another 108 kb/d after 2009 to 528 kb/d by 2012.

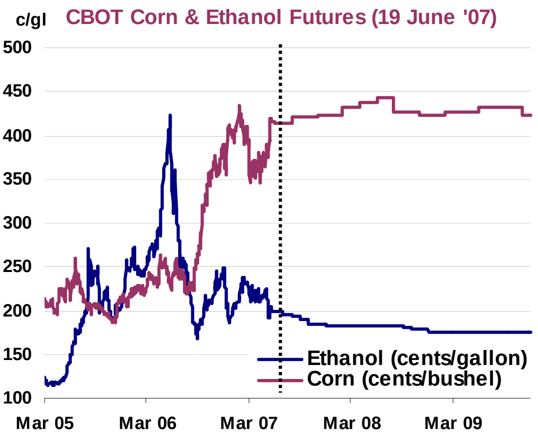
Doubts Remain

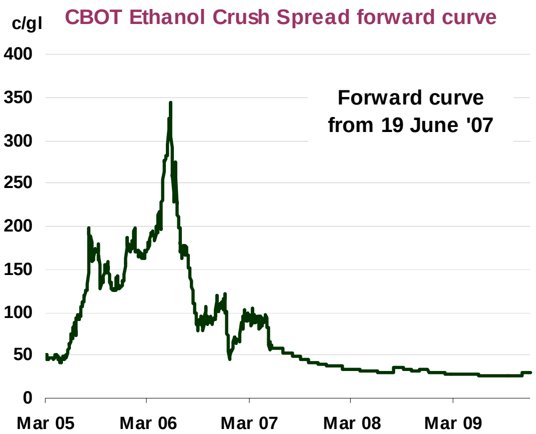
Considerable doubts keep us from being more upbeat about our forecast. Even assuming subsidies remain in place (e.g. in the US), it remains far from certain that it will stay profitable to produce ethanol or biodiesel. Ethanol's so-called *crush spread* or profit margin (based upon Chicago Board of Trade ethanol futures and its corn-based feedstock) has already retreated sharply from a $3.50/gallon peak in June 2006 to around $0.57/gallon at the time of writing, and a glance at the forward curve shows it retreating further over the next two years. Recent news reports have indicated that the US is already experiencing a surplus of ethanol (reflected in ethanol prices' recent slide) due to the growth in output outpacing infrastructure and the lack of incentives to blend it into the gasoline stream (the so-called 'blend wall').

News reports also indicate that some biofuels plants have been cancelled, while others are reportedly run at low utilisation rates due to unprofitable conditions. Uncertainty over policy can also cause difficulties, as the example of Germany illustrates. Having initially given biofuels sales tax breaks, the government backtracked when it felt the pain of lower tax revenues, thus, claim producers, making biofuels production unprofitable.

Competition for Feedstock

The issue of competition with foodstuffs will remain unresolved until a larger share of biofuels can be produced from non-food crops (provided these do not compete for the same acreage, e.g. jatropha, switch grass et al). At present, this competition can lead to lower allocations of biofuel crops to food uses. So for example the US, which is already the largest producer of corn (maize) and has a surplus, was able to assign less of its crop to food aid or exports (though a beneficial side effect is that production of valuable co-products of corn such as animal feedstock and biomass are raised). Elsewhere it may simply raise prices. The International Monetary Fund (IMF) warned in a recent report that global food prices had risen by 10% in 2006, in part due to higher US demand for corn (for ethanol production). Demonstrations against higher corn prices were reported in Mexico, where it is a staple of the national diet. The longer-term picture is unclear, but it is not difficult to see how emotive headlines blaming high food prices (and perhaps even shortages) on the developed world's thirst for transport fuels could cast a different and potentially disruptive light on biofuels' development.





Can more feedstock be produced? Even in the US, which looks set to hike its corn production impressively this year, doubts remain whether sufficient acreage can be dedicated to the right feedstocks. The US Department of Agriculture (USDA) reported that this year's planned ethanol production is likely to consume some 27% of the corn crop, which despite being at a record-high 12.5 billion bushels, will still require corn stocks to be drawn down if exports are to be maintained. Last year's ethanol production used 20% of the total corn crop, while reaching the US Department of Energy's (DoE) estimated production volume in 2012 would require one third of a greatly expanded corn crop, according to the US Government Accountability Office. Meanwhile, the EU estimates around 20% of its total arable land will have to be allocated to biofuels crops just to satisfy its required 5.75% share of road transport fuels by 2010.

To some extent help may come from higher corn yields based on new techniques or (genetically) modified crops. In the US at least, there is also the option to increase the use of land set aside for conservation purposes. However, once this 'set aside' land is exhausted, increases in output volumes of one crop will inevitably have an impact on others. Indeed, crop switching is already in evidence. For instance the global 2007/08 soybean crop is expected to fall on lower US output, as farmers there switch to increased corn planting (in theory this means less soybean crop with which to produce biodiesel).

There are similar worries about the environmental impact of biofuels. Hailed by some as an easy way to limit carbon emissions, others have pointed at the scope for environmental damage. The UN recently warned that, especially in Asia, forests are being razed for feedstock plantations, offsetting potential gains through carbon capture. Such needs can also compete with food production, as well as causing other environmental damage, such as loss of biodiversity and soil erosion. In many countries there is concern that increased corn production will put a significant strain on available water.

Infrastructure is Key

But even before some of these concerns are better understood, a debilitating hurdle to further ethanol production growth in the US may be insufficient infrastructure to deal with the extra volumes. While most corn-based ethanol is produced in the Midwest, and infrastructure to distribute and blend ethanol-blended gasoline is relatively widespread in the region, the same is not true for high-demand areas on the coasts. One issue is the need for what amounts to a separate distribution network prior to blending with gasoline, which can only take place at the distribution/retail level.

The question of widespread distribution is crucial. For technical reasons, conventional gasoline engines can handle a 10% share of ethanol without much trouble. Were all US cars to adopt this use, this would be approximately equivalent to the probable 2015 mandate of 15 billion gallons (980 kb/d). If not all cars use ethanol-blended gasoline – which is highly likely, bearing in mind that many large states do not mandate any biofuels share at all, e.g. Florida – and no incentives exist yet to change, the car fleet will have to be adapted. Given the relatively slow turnover of the fleet, this would presumably require legislation mandating flex-fuel vehicle sales to be put in place soon.

Rapidly introducing higher blends of ethanol, i.e. E85, an 85% ethanol/15% gasoline blend, would have an impact, but retailing restrictions limit this option. According to the US DoE, of a national total of around 170,000 filling stations, around 50,000 would have to be capable of pumping ethanol blends with a higher concentration. Currently some 1,200 have this capability, and are virtually exclusively located in the Midwest. Again, these issues could be addressed by legislation.

Medium-Term Outlook

Interest in developing newer, more efficient technology is enormous, and financial support will likely be included in planned legislation. Biofuel production forecasts discussed in this report are on the basis of first-generation technology, i.e. using conventional crops such as grains, seeds or vegetables as feedstock. Methods to convert cellulosic material (i.e. plant material, as opposed to sugar, starch or oil) into biofuels are being developed, and several small pilot plants exist. However, they are only expected to become commercial in a time frame that exceeds the horizon of this report, with even the more optimistic proponents hinting at 2012 at the earliest.

Regarding trade in biofuels, there are interesting contrasting positions. Some argue a dropping of import tariffs (e.g. in the US) would encourage production sites with a competitive advantage such as Brazil to boost output, which could in turn be exported to the US. But the USDA recently argued that were the current US import and blending subsidy to go, domestic production would fall by around 2 billion gallons (130 kb/d). For the moment, though, the Bush administration intends to keep the subsidy and tariff in place at least until 2010 and 2009 respectively, when they will expire.

If oil prices remain high and laws are enacted to not only mandate higher shares of biofuels in transport fuels but also introduce well-crafted measures to actually enable this in terms of infrastructure and logistics, there will be considerable scope for more growth than we have forecast.

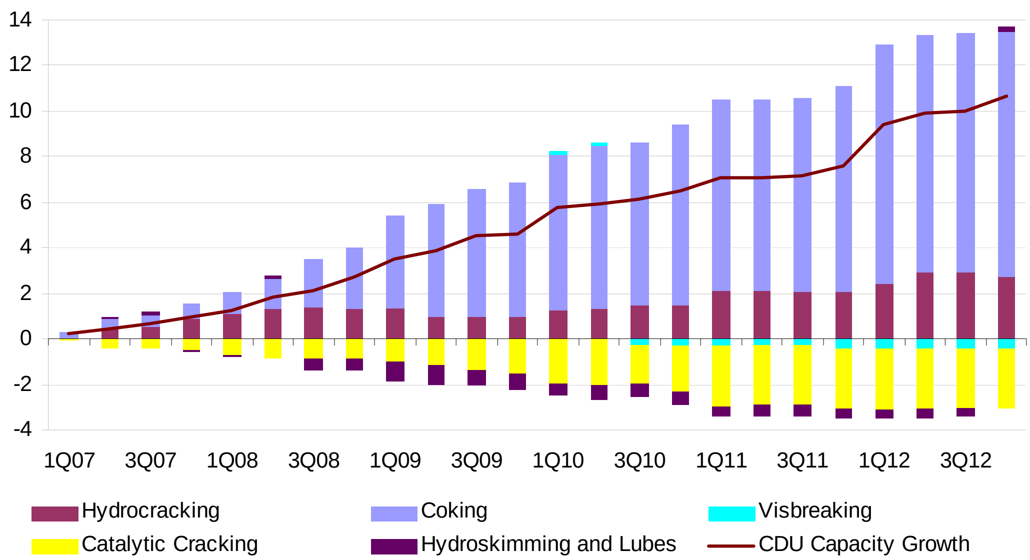
REFINERY ACTIVITY

Summary

- **Global crude distillation capacity is forecast to rise by 10.6 mb/d between 2007-2012.** New investments add 9.1 mb/d of crude distillation capacity and existing refineries in North America, Europe and the Pacific are assumed to add a further 1.5 mb/d through capacity creep.

- **Capacity growth remains heavily skewed towards 2011-2012**. 3.3 mb/d of new capacity is due to start in this period, from a few large projects. These could be subject to additional delays if refinery economics were to deteriorate, or contractor-related bottlenecks were to increase in the intervening period, materially altering the 2012 product supply outlook.

- **The Middle East and Asia will account for 6.7 mb/d of new crude distillation**. This exceeds expected regional demand growth as India and Saudi Arabia develop significant export-orientated refining capacity. Consequently, the Middle East will arguably supply the marginal barrel of product to importing regions as well as the marginal barrel of crude.



1: Includes re-classification of refineries to more complex type, following installation of upgrading capacity

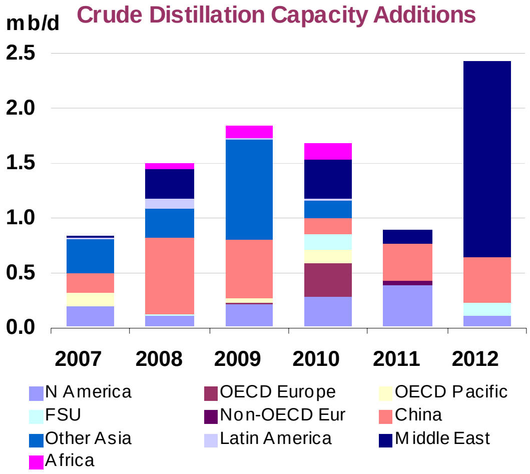
- **New refineries and upgrading capacity additions will boost product supply flexibility in the medium term.** A substantial increase in refining complexity is forecast to occur over the next five years. Consequently, the global refining industry will be better positioned to meet transportation fuel demand growth, albeit at the expense of fuel oil production. Analysis of regional product balances indicate the potential for an easing of light product cracks and some strengthening of fuel oil cracks.

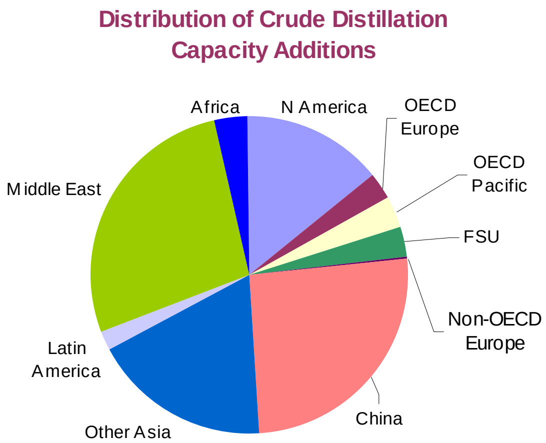
- **Gasoline market tightness should ease, possibly by 2008, followed by gasoil/diesel in 2010**. Jet market tightness is likely to persist until 2010 unless further unwinding in the other transportation fuel is forthcoming in the near term. Fuel oil markets could tighten significantly, unless we see a shift in behaviour by consumers or refiners.

Refinery Expansion Plans

Global crude distillation capacity is forecast to increase by 10.6 mb/d by 2012, of which;

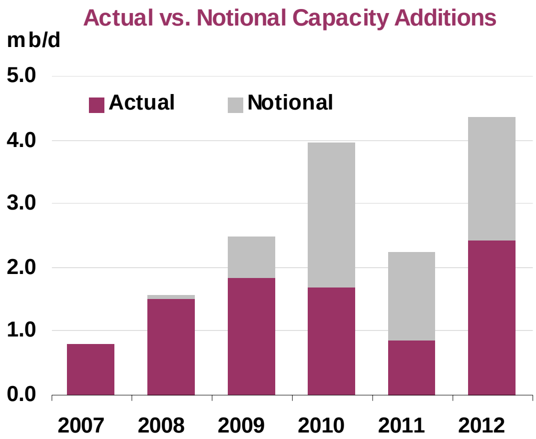
- 4.0 mb/d is attributable to the expansion of existing refineries mainly in the Asia Pacific regions and North America;
- 5.1 mb/d of growth comes from new-build distillation capacity largely in the Middle East, China and Other Asia (primarily India);
- 1.5 mb/d comes from capacity creep at existing refineries in OECD North America, Europe and Pacific.



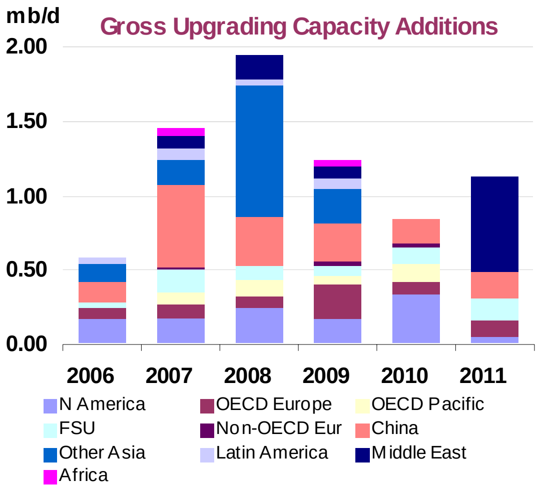


Project delays and cancellations have affected the refinery sector in a similar fashion to the upstream sector. Project slippage caused by cost escalation and lack of spare capacity at engineering contractors and service companies have been so severe they have led to a 2.6 mb/d downward revision to the 2006-2011 forecasts published in the *February MTOMR update*.

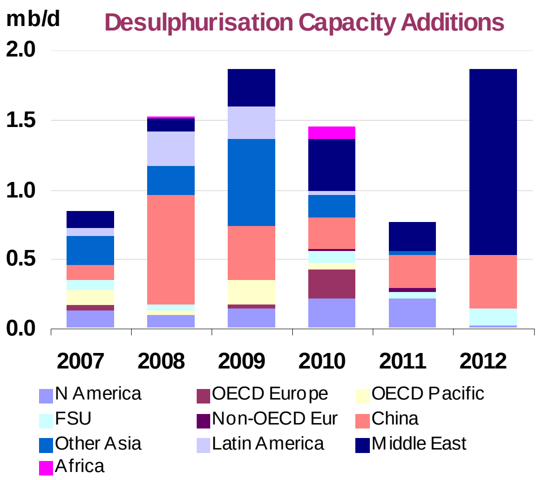
We have chosen to err on the side of caution with our forecasts, and have assumed a conservative timeframe for projects to commence operations. Furthermore, we have excluded projects accounting for a further 6.3 mb/d of crude distillation capacity which are unlikely to materialise within our forecast timeframe. Where appropriate, we have factored in some delays to those projects where we see a risk of contracts being re-tendered, because of overly-optimistic cost assumptions on the part of the project sponsors leading to a re-tender, or redesign of the proposed configuration. But there remains concern about the solidity of the 2.4 mb/d of distillation capacity that is currently forecast to commence operations in 2012.



These projects fall within the timeframe where changes to refining economics over the next two years (which we see declining) can result in changes to investment plans and could clearly have an impact the product supply outlook through to 2012. While the current tight markets for transportation fuels reflects structural demand shifts and a lack of upgrading capacity, the strong (even super-normal) margins available to complex refineries are providing a powerful incentive to invest in upgrading capacity.



These market signals are clearly working. Large-scale upgrading capacity additions of 7.2 mb/d over the next five years (including coking, catalytic and hydrocracking, visbreaking and residue cracking and hydrocracking) reflect not only the complex nature of the proposed new refineries, but also the significant investments taking place at existing plants. The work is predominantly concentrated in the addition of coking units to upgrade fuel oil and maximise gasoil/gasoline production and hydrocracking units to maximise middle distillate output. These investments are needed to address the current tightness in light products, to prepare for the longer-term projected trend towards more heavy/sour crudes and to attempt to capture the high return available due to a depressed fuel oil market.



Refiners are also continuing to invest heavily in hydrotreating capacity to remove sulphur from refined products. Hydrotreating capacity is expected to increase by 8.1 mb/d through to 2012. More than half of this total is to meet a global trend towards lower sulphur specifications in diesel. Other products expected to see a strong increase in hydrotreating capacity are naphtha, closely matching the expected increase in catalytic reforming capacity additions, and kerosene, reflecting the ongoing growth in jet demand. Atmospheric residue (fuel oil by another name) hydrotreating is also expected to see a similarly strong increase, although around 40% of the growth comes from Kuwait's al Zour project which is expected to start in late 2012.

In OECD regions no new refineries are expected, although several of the larger planned expansions are equivalent in scale to world class refineries. Investment is aimed at improving product quality, either through upgrading or hydrotreating additions, or adapting operations to handle an increasingly heavy, sour crude slate.

North America refineries capture both the bulk of the forecast 1.8 mb/d increase in OECD crude distillation capacity, and also the lion's share of upgrading capacity. Most of the expansions are being undertaken in the northern US states to process increasing amounts of heavy/sour Canadian crude.

In Europe, investment will focus on improving middle distillate production through the installation of upgrading capacity, to convert atmospheric residue into middle distillate. Pacific growth is similarly aimed at improving light product yields. Capacity growth in the non-OECD regions seeks to meet robust demand for transportation fuels and, therefore, in common with the OECD, improve light products yields and quality.

Refinery Construction Costs

Refinery expansion plans are increasingly subject to significant cost revisions. Some international (IOC) and national (NOC) oil companies appear to be factoring in cost increases of 30-50% or more, compared with previous estimates for capital budgeting purposes. Furthermore, some greenfield refinery projects have seen bids for the engineering, procurement and construction (EPC) contract at least double the envisaged costs. For example, Kuwait's proposed al Zour refinery was envisaged to cost $6bn by its sponsors, but bids were at least $15bn, or 150% above expectations. This reflects the tightness in EPC markets as order levels for new refining units, project management expertise and raw material costs continue to rise. EPC firms also tend to work for other industries such as power generation, chemical, heavy industries and of course upstream oil and gas. It is noteworthy that many of these other industries are also witnessing a upswing in investment activity further reducing the available pool of resources, not least the human resources necessary for large projects.

Some refiners suggest that the significant level of investment needed to improve product quality is one of the root causes of the tight service sector. One IOC recently estimated that 15-20% of its total downstream capex was allocated to product enhancements over the past five years (a level of expenditure that may well continue). In addition to this source of demand, the improved margin environment has boosted cashflows and resulted in refiners undertaking expansion work, citing high internal rates of return on the investment (20-30% is not uncommon). Lastly, investment in new refineries, at levels above those seen in recent years, has added a third source of demand, re-enforcing tightness in oil service industries.

Some estimates suggest that order backlogs at the main contracting firms have doubled in the last 2-3 years prompting several contractors and equipment fabricators to increase headcounts by up to 20-30%, or more. This response by the EPC firms is to be welcomed as, over time, it should help ease cost pressures. However, lead times between ordering items and their delivery have grown significantly - in some cases they have doubled, particularly for heavy walled reactors used in hydrocrackers and hydrotreaters. Deliveries for these items are now around 36-39 months, up from 12-18 a few years ago. All these factors have required refiners to re-appraise how they proceed with planned expansions.

In a tight contracting market environment firms remain wary of fixed price tenders. These shift the balance of risk from cost overruns from the refiner to the contractor. Hence bids for fixed price work, must necessarily contain sufficient margins to absorb future likely cost increases from other suppliers. Refiners such as Valero have pointed to contractor costs rising by 60% on the US Gulf Coast and have noted a simultaneous 35% decline in productivity.

How then do refiners respond to these pressures? The standard response is to re-engineer the proposal. Look to reduce costs, find alternative solutions, and substitute different technologies for those which are experiencing the highest cost pressure. This takes time and is a contributory factor to many of the delays we have witnessed to date in the sector. Some costs are difficult to avoid or engineer out of the design, e.g. valves, pumps, compressors, pipe-work and heavy walled reactors; the guts of many refinery processes. Here the cost increases force refiners to adopt new practices in order to meet deadlines:

- Ordering long lead time items earlier, possibly getting better prices than those available for quicker delivery;
- Adopting cost-plus, or open-book agreements with contractors, which effectively shift the risk of cost inflation back onto the refiner, for future cost increases from third party suppliers, but which may ultimately reduce the overall cost of the project;
- Developing better project management skills to work with EPC contractors to manage costs;
- Seek to lock-in project economics using financial derivatives where possible.

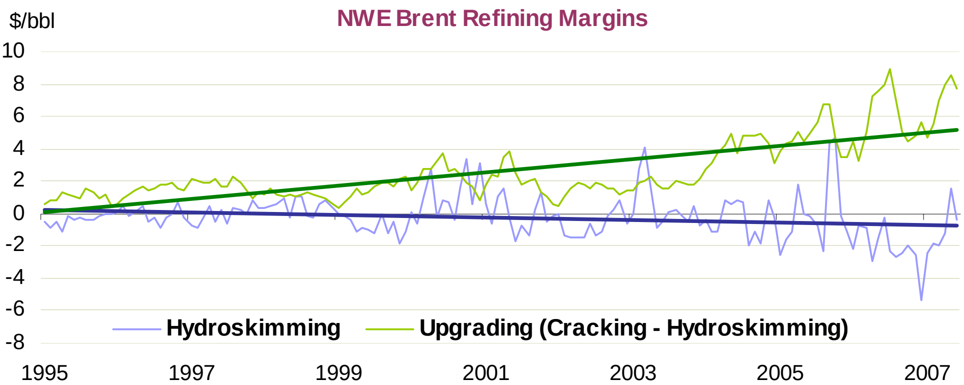
The current forecast for refinery investment suggests that the additions to refinery upgrading capacity will add significant flexibility to global product supply, but the continued push towards lower-sulphur fuels will mean that it will be some time before product specifications harmonise and ease constraints on inter-region product trade.

One factor which our forecasts do not capture adequately, but which has the potential to play an increasingly important role, is the overall age of the global refining industry. Discussions with refiners both in OECD and non-OECD countries clearly indicate that incremental investment in existing refineries is the most financially rewarding way to expand capacity. Financial returns from debottlenecking existing units continue to exceed those available from greenfield refinery projects. The difference relies on the ability to unlock the latent value of refining though comparatively small investments. However, while this method of capacity expansion is preferable in the short term it creates a problem over the longer term; namely the overall refinery infrastructure becomes significantly older than the core process units. Ageing infrastructure would appear to be contributing to increased reliability problems in markets such as the US. While a crude distillation unit, or FCC, may be only 10-15 years old, the steam generation systems, pipes and tank farms etc. may all be significantly older, possibly dating back to the original construction of the refinery several decades ago. Consequently, refiners may face a more challenging future to upgrade not just one unit to meet the latest environmental policy mandated sulphur specification, but also the regeneration of the infrastructure that is necessary to meet today's exacting product specifications.

Our forecasts show that, as a result of the investments being made over the next five years, 51% of world refining capacity will lie in non-OECD regions by 2012, up from today's 48%. Product trade should increase, and a growing proportion of that trade is likely to be sourced from OPEC member states, particularly in the Middle East - leaving the region to supply not only the marginal crude barrel, but arguably also the marginal product barrel.

Refinery Economics

IEA analysis suggests that the current strong margin environment is partly the result of a lack of upgrading capacity, combined with rigid transportation-led demand growth and is, to some extent, a knock-on effect of environmental and regulatory policies. There has been a historical tendency for over-investment to create spare capacity, which results in the refining industry generating low margins, often for protracted periods of time. However, it would appear that there has been far more caution in recent years than was seen in the previous two decades, helping to sustain the current high margin levels.



Refinery margin calculations are revealing. Current margins clearly reflect a lack of upgrading capacity, with heavy crude priced to reflect the marginal value of the crude to a cracking refinery rather than its worth to a full-conversion refinery. In other words, upgrading capacity units are running at their maximum and the marginal user who sets the price is the less complex refiner. Similarly, the price of light sweet crude is largely determined by the marginal European refiner, the hydroskimmer. With these simpler refineries having to meet the marginal demand for light products, then the end result is that crude throughputs have to rise, surplus fuel oil (particularly in the case of hydroskimmers) is sold at a loss compared with the crude price and there has to be an offsetting rise in the price of transport fuels.

Over the next five years we expect to see some improvement in fuel oil prices relative to other products as a result of the large additions of upgrading capacity that should ease the over-supplied fuel oil market and potentially reduce the need for such heavy discounting.

Similarly, as refinery complexity increases, there will be an increase in demand for heavy sour crude oil, narrowing the differential between light, sweet crudes and heavy sour grades. This should also increase demand for some of OPEC's spare capacity, which has recently struggled to find buyers, despite the tightness in product markets.

Furthermore, it is clear that refinery investment plans are also a function of expected developments in product markets. For example, the level of planned investment in hydrocracking capacity in the US exceeds that of either catalytic cracking or catalytic reforming. This suggests that refiners are investing to increase their ability to meet demand growth in diesel and possibly jet fuel, given the expected increase in gasoline production, both globally and in the Atlantic Basin.

Overall, the output of our global product supply model suggests a considerable improvement in the flexibility of the refining sector-particularly from 2009 onwards. But such flexibility is likely to reduce the current super-normal returns to complex refineries and upgrading units.

Such an outcome is not inevitable. While our refinery expansion forecast has already been constrained, further slippage cannot be ruled out. Further, with refinery expansion lead times of 18 months to 3 years, refinery investment plans towards the tail end of our forecasts in the current high cost environment will be constantly under review. Therefore, there remains a risk that investment is curtailed by the tail-end of the forecast period. (Discussions with industry tend to confirm this synopsis, with many ultra-cautious about the risks of creating surplus capacity given the poor historic trend of the industry returns.)

Expectations of future capacity additions, primarily by NOCs in Asia and the Middle East, many of whom belong to OPEC, are themselves a factor in determining investment in the OECD. While many of the reported refinery additions in these regions have already been excluded from the forecast, this still leaves a substantial number, of more credible projects, in the forecast. These projects, could in turn, deter investment by those refiners in the OECD with the finances to expand.

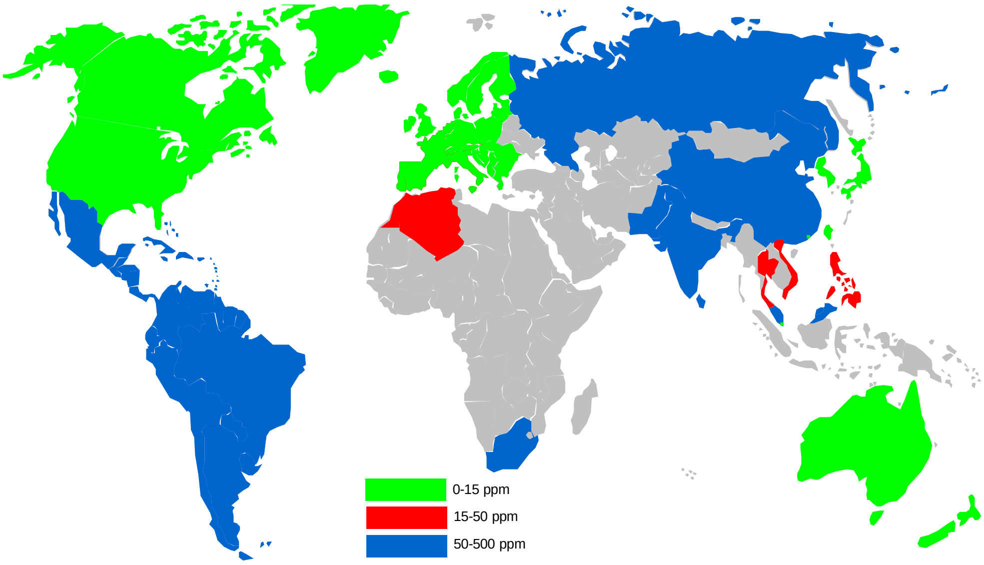
While these factors, together with the increased prevalence of more stringent and differentiated product quality specifications have the ability to support industry margins above their (albeit low) historical average for some time to come, it seems more likely they will provide the constraints that will trigger the next upswing in the refining margin cycle.

Product Quality Specifications

The next five years will see a further significant tightening of product specifications in many regions around the world for most products. Europe will enforce 10 ppm sulphur, from the current limit of 50 ppm, in gasoline and diesel in 2009. Further tightening of the distillate market may result from the adoption of 10 ppm sulphur limit in 2010 for off-road diesel, (a reduction of 99% from the 1000 ppm limit which will be in effect from the beginning of 2008), if the European Commission's fuel quality directive review is implemented. Similarly, the European Commission review seeks to introduce a new gasoline blend, with up to 10% ethanol to further its aim of achieving a minimum of 10% biofuels in transportation fuels by 2020.

In North America the US aims to limit benzene in gasoline to an annual average of 0.6%, by 2011, from today's 1% limit, further tightening gasoline specs. In addition there is the prospect of a federally mandated ethanol blend for gasoline at some stage. The distillate market is adjusting to the recent introduction of a 500 ppm sulphur limit in off-road diesel, including locomotive and marine use. Further tightening of distillate quality specifications are planned, with the adoption of ultra-low-sulphur diesel (ULSD) for all on-road (up from 80% currently) and off-road diesel in 2010 and locomotive and marine sectors in 2012.

Diesel Sulphur Specifications by 2012
(thousand barrels per day)



Fuel oil, which retains very high sulphur levels (10,000-35,000 ppm sulphur), is also set to face tighter specifications as a result of the International Maritime Organisation's Sulphur Emission Control Area (SECA) coming into force in the English Channel and North Sea in 2007. Furthermore, there is the possibility of their introduction to the Mediterranean and US West Coast, possibly as early as 2010.

The mandated use of low sulphur (1.5%) fuel oil (LSFO) may introduce further distortions to oil markets, as ships will have little alternative to using the fuel, except by switching to more expensive distillate, or installing onboard flue gas scrubbing equipment. Given the higher costs involved in these possibilities it is likely that shipping companies may be prepared to pay a significant premium to obtain supplies of LSFO in the short term.

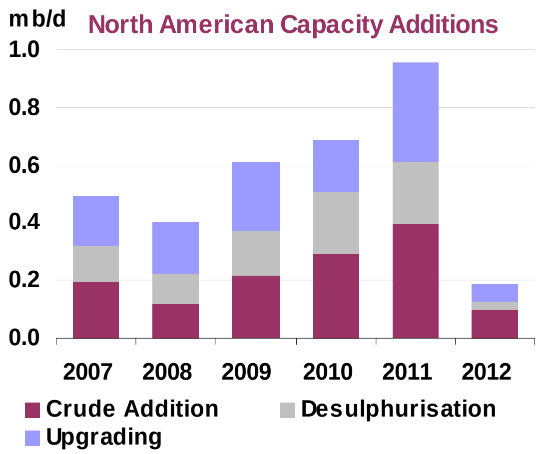
Overall, the proposed fuel quality changes will necessitate further investment by refiners, much of which is already in hand. However, despite the increasing adoption of tighter product specifications, it would appear that the global refining system is still some way off being able to remove product quality fragmentation as a barrier to inter-regional trade and this may support product prices in the coming years.

Regional Analysis of Capacity Expansion

North America

Despite the removal of some forecast capacity additions, North America remains a significant source of capacity growth, within the OECD and globally. We forecast refiners will add 1.3 mb/d of crude distillation capacity through new projects between 2007 and 2012. This forecast includes a number of large-scale expansion projects which we have assumed will be approved in the coming 12 months. Failure to do so would put at risk our forecast project start dates. Perhaps the most notable of these is the Motiva (a Shell/Saudi Aramco JV) 325 kb/d expansion of its Port Arthur, Texas refinery. Furthermore, we have removed Chevron's 200 kb/d expansion of its Pascagoula, Louisiana refinery, as a final investment decision is not due until 2008, or possibly later, suggesting it may not start operations before 2013.

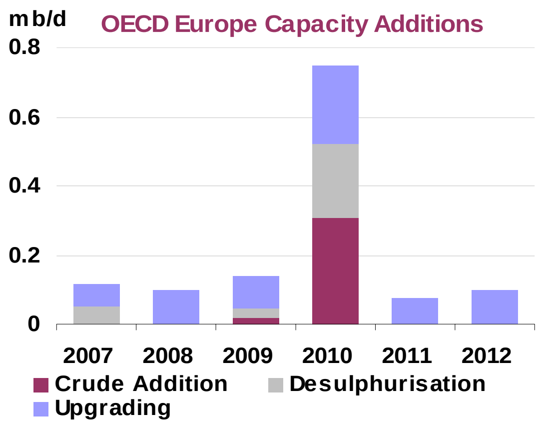
US crude distillation growth is forecast to total 1.1 mb/d. The four largest projects, all due to commence operations during 2010-2012, contribute 0.7 mb/d. Of these projects we have only been able to confirm that Marathon's 180 kb/d Garyville expansion has received final investment approval indicating that the remaining 0.5 mb/d of capacity may be subject to delays. Rising project costs have forced several refiners to defer, or scale-back, expansion plans in order to meet capital budgets. We continue to exclude a further 1 mb/d of capacity in Arizona, on the Gulf Coast and two projects in Northeast Canada, despite some progress at these two latter projects.



In addition to large–scale refinery expansion projects we forecast substantial investment in North American upgrading capacity, largely in new coking and hydrocracking units. Furthermore the industry is expected to continue to invest in substantial amounts of diesel, gasoline and, to a lesser extent, kerosene hydrotreating capacity through to 2012. The expansion of coking capacity is forecast to exceed 500 kb/d and is centred on refineries in Northern US states and Canada, as they prepare for increasing imports of heavy Canadian crude.

Europe

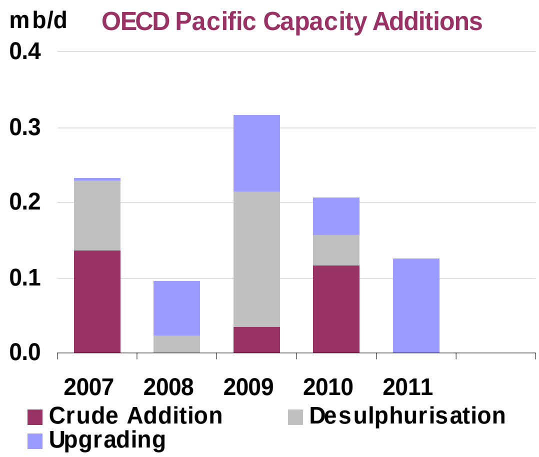
European refinery investment plans focus on improving distillate but reducing fuel oil production, given the regional production/demand imbalances. Forecast crude capacity expansion of 0.3 mb/d (net of closures) is linked to new upgrading capacity, particularly coking and hydrocracking capacity additions. Against the backdrop of anaemic demand growth, we retain the view that large-scale expansion of European crude distillation capacity is unlikely in the medium term. We have not included the recently proposed refineries at Ceyhan, in Turkey, due to a lack of detail on prospective completion dates and likely configurations. Furthermore, with the exception of necessary product quality enhancements, uncertainty over mandated market share levels for biofuels and potentially onerous environmental regulations post-2011 are likely to discourage investment in the region vis-à-vis the Middle East, or Asia.



Hydrocracking investment in Europe is forecast to increase capacity by a total 360 kb/d through to 2012, with a further 60 kb/d of residue hydrocracking. The vast majority of the capacity additions are in the Mediterranean post-2009. Similarly, the addition of 200 kb/d of coking capacity is largely due to projects in Spain, plus the planned expansion of the Szazhalombatta refinery in Hungary and the upgrade to Hellenic Petroleum's Elefsis refinery in Greece. We have also included the likely installation of a coker at the Wilhelmshaven refinery in 2012.

OECD Pacific

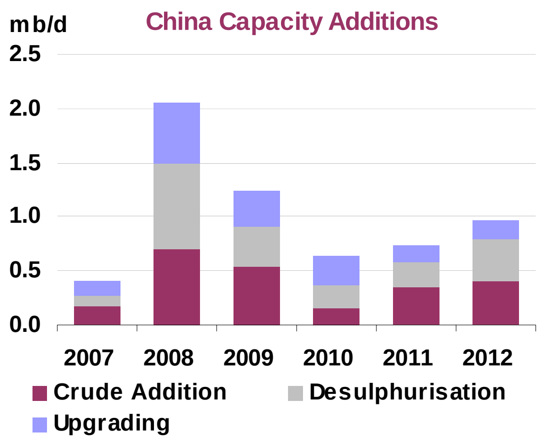
Further announcements of small-scale refinery expansion plans in the OECD Pacific continue the positive trend noted in our February *MTOMR update*. However, the removal of the 480 kb/d S-Oil refinery in South Korea, following the project's suspension, necessarily reduces overall growth in the region. Consequently, we forecast crude capacity to increase by 284 kb/d, through to 2012, down from our previous estimate of 500 kb/d. This includes the imminent restart of a mothballed 75 kb/d crude tower at SK Incheon refinery in Korea. The balance of the increase is centred on Japan with a 124 kb/d of additional distillation capacity, of which 94 kb/d is from new condensate splitters. The rest of the growth comes from expansion of the New Zealand Refining Company's Marsden Point Refinery by 35 kb/d, and a 50 kb/d condensate splitter in Australia, both due to commence operations in 2010.



Between them Korea and Japan account for all the planned upgrading investment in the region. The 50 kb/d of new coking capacity is all based in Japan, as is the 18 kb/d of new FCC capacity. Korea accounts for the entire 110 kb/d forecast residue hydrocracking additions and 150 kb/d residue FCC additions, with the expansions spread between SK Corp's Ulsan and LG-Caltex's Yosu refineries. Consequently, light product yields will increase over the 2007-2012 period, and the addition of over 340 kb/d of hydrotreating (60% of which is diesel hydrotreating) capacity should give refiners the ability to handle a higher proportion of heavy, sour crude. The Korean government was reported considering scrapping domestic product import tariffs which have historically supported Korean refiners in times of weak margins. This perhaps reflects the growing complexity of Korean refining capacity and an improvement in its ability to process heavier, poorer quality, cheaper crude.

China

China continues to contribute more than any other country to forecast refinery growth. New-build refineries and the expansion of existing plants will contribute 2.3 mb/d of additional crude capacity before the end of 2012. Forecast growth is dominated by Sinopec with 1.3 mb/d of new projects, including up to 360 kb/d of joint ventures. Chinese refineries, which already boast some of the highest levels of upgrading to distillation ratios in the world, will continue to invest in coking and hydrocracking capacity, adding over 500 kb/d of both, as they seek to maximise distillate production for transportation and naphtha for petrochemical feedstock. Similarly, hydrotreating capacity is expected to increase by over 2 mb/d: 60% of which is aimed at diesel production, ahead of tighter product specifications coming into force in 2008 and 2010.



However, capacity growth in 2007 is low by recent Chinese standards, with only 170 kb/d of refinery additions. There are only two large projects delivering the growth: Sinopec's 60 kb/d Yanshan expansion due on stream in the second quarter 2007 and PetroChina's 110 kb/d expansion of the Dushanzi refinery in the fourth quarter. Next year refining capacity growth accelerates, with Sinopec's new 200 kb/d Quindao and CNOOC's 240 kb/d Huizhou refineries starting. Additionally, expansions at five other refineries will add a further 260 kb/d of complex refining capacity.

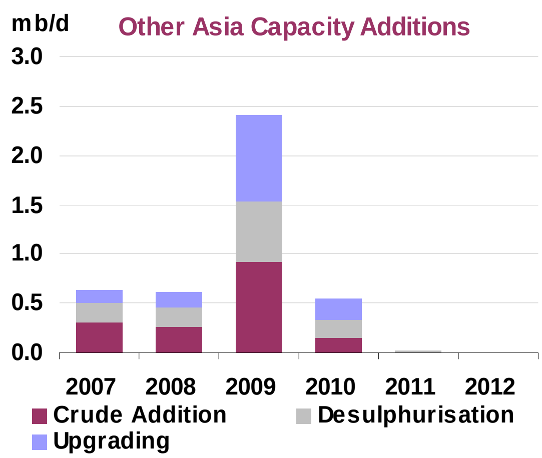
Growth in 2009 is dependant on:

- Petrochina's 200 kb/d Quinzhou refinery in the Guangxi region;
- The 130 kb/d expansion of Sinopec's Maoming refinery;
- The 160 kb/d expansion of the Fujian refinery for Sinopec, ExxonMobil and Saudi Aramco; and
- The 46 kb/d expansion of Petrochina's Fushun refinery.

Post-2009, growth will slow to 150 kb/d in 2010, with the expansion of Sinopec's 100 kb/d Tianjin refinery. The period 2011-2012 is expected to witness a further 740 kb/d of new refining capacity, driven by four or five additional projects, but actual capacity additions are likely to be dependant on China's demand growth over the intervening period and its consequential product supply requirements. Any slowdown in demand growth is likely to result in lower capacity additions than we have forecast.

Other Asia

Other Asian countries are forecast to contribute around 1.6 mb/d of new crude distillation capacity by 2012, slightly lower than our previous forecast on a like-for-like basis, following the exclusion of the 300 kb/d expansion of ONGC's Mangalore refinery. Offsetting this lower forecast for crude distillation, we have increased our estimate of likely upgrading capacity additions. Significantly higher additions of coking capacity are now expected in the region, particularly in India, with Foster Wheeler reported to have signed 10 license agreements for its delayed coking process in the country. Indian projects account for 1.4 mb/d of new crude distillation, roughly 85%, of the region's capacity increase. Elsewhere in the region, 270 kb/d of new crude capacity is forecast to come on stream by 2012, in Malaysia, Thailand and Vietnam.



Reliance Petroleum's 580 kb/d Jamnagar refinery is the largest addition in the region and is expected to commence operations at the end of 4Q08. Consequently, we have included it in our forecasts from 1Q09. The reported size of its upgrading capacity suggests this refinery will run heavy, sour crude, (possibly as heavy as 26°API) and we expect it to be capable of making 10 ppm sulphur diesel and gasoline for export markets in Europe and North America.

Additional projects in India are forecast to add another 0.8 mb/d of crude capacity in the period 2007-2012. We have included Bharat Petroleum's 120 kb/d Bina refinery in 2010, and new crude distillation, tied into upgrading capacity expansions, (particularly of delayed cokers), at IOC's Haldia (2007), Mumbai (2007) and Chennai (2010) refineries. ONGC's Mangalore refinery expansion to 300 kb/d in 2009 and the second phase of Essar's Vadinar expansion in late 2008 continue to form part of our forecast.

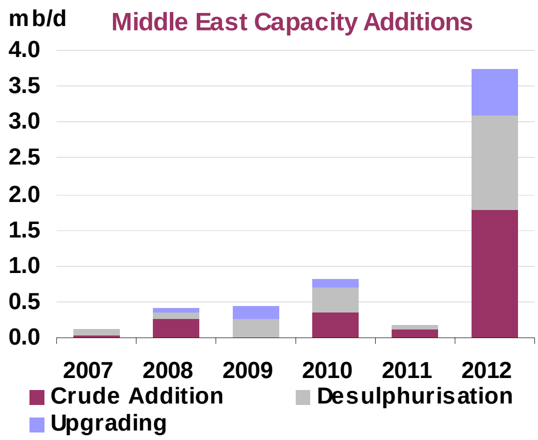
We exclude a further 1.8 mb/d of proposed crude distillation capacity in the region from our forecasts, as there is insufficient evidence to support the likelihood of its construction. Given the lack of progress due to political, economic or financial uncertainties, these projects will only be included in the future if their outlook improves. The past decade has not been an easy time for refiners in the region. Recovery from the financial crisis of 1997 has been slow, with crude runs in Singapore, the swing producer for the region, only returning to pre-crisis levels in the last 12-18 months. However, the region continues to generate healthy levels of demand growth, suggesting that some of the projects we currently exclude could be included in future reports if some of the uncertainties are resolved.

Middle East

At first glance, the Middle East continues to be the largest single region of refining capacity growth. However, our forecast now relies on a significant portion of the region's capacity coming on-stream in 2012; clearly indicating a risk that the forecast capacity additions may not be achieved within the timeframe. On a like-for-like basis (2006-2011) forecast capacity growth has been reduced from 2.9 mb/d to 0.9 mb/d. The majority of this 2.0 mb/d decline is pushed back to come on stream in 2012. Consequently, any further delays, above those already factored into our forecasts, could result in a significant shortfall, even on a global basis, of new build refinery capacity before 2012. Offsetting the more cautious view on project timing, we have increased our forecast for Iranian capacity additions, based on a more positive assessment of the sector's ability to source capital and Saudi Arabia, where we include the newly announced 400 kb/d project at Ras Tanura. Elsewhere, a lack of progress on projects in Qatar, Kuwait and the UAE all contribute to a slower rate of capacity additions.

Saudi Arabian refinery additions are expected to total some 975 kb/d through to 2012. Of this total, 800 kb/d is expected in 2012, with the start-up of Total's 400 kb/d Jubail refinery and the 400 kb/d Ras Tanura refinery. This latter project is designed to supply the domestic market's requirements. Consequently, production will be aimed at jet fuel, diesel and fuel oil; the latter grade has been revived as a preferred fuel for supplying domestic power generation requirements, given the lack of immediately available natural gas.

In addition to Total's export-orientated refinery, we still consider ConocoPhillips' 400 kb/d export refinery more likely to start in 2013 than 2012, but more visible progress, e.g. committing to a final investment decision and awarding an EPC contract, would allow us to bring this into the forecast. We have retained the planned expansions of the Ras Tanura and Yanbu refineries, which are forecast to add 175 kb/d in 2012. However, following the announcement of the Juaymah refinery, we suspect these expansions may subsequently be cancelled given the latter project better meets the needs of the Kingdom.



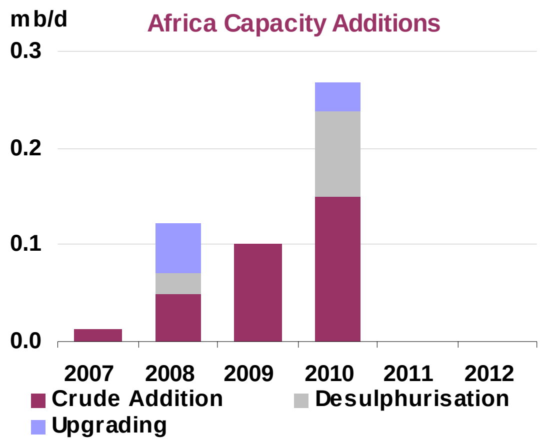
Iran has seen perhaps the largest shift in forecast capacity additions since the last update. Essentially we have positively reappraised our assessment of Iran's ability to finance the expansion of its refining sector. As highlighted last year, ending subsidies on gasoline prices may reduce demand and curb smuggling and reduce investment needs. However, the government's policies to limit demand through rationing are as yet unproven and the proposed refining projects could reduce gasoline imports (reported to cost upwards of \$5bn per year), by around 50%. Consequently, we expect the phased expansion of 360 kb/d of condensate splitters to start-up between summer 2010 and summer 2011. Furthermore, we expect 190 kb/d of expansions at the Arak, Lavan and Isfahan refineries, tied into significant increases in refinery complexity, during the 2009-2012 period. We have not included a further 480 kb/d of green field refining projects as these remain beyond what see as reasonable for NIOC/NIORDC to achieve before 2012.

Kuwait's plans for a 615 kb/d refinery at al-Zour are back on track, following a six month hiatus. Bids for the initial tender were around \$15bn, significantly ahead of the \$6bn budget. The tight contractor market and the fixed price nature of the tender were the root cause of the higher-than-expected bids. We expect the recently announced tender to result in lower bids being entered, but the Kuwaiti government will probably need to adopt a cost-plus, or open book agreement with its contractors if it wishes to achieve its revised budget of $12bn. We have pushed the expected start-up back to 4Q12, somewhat hedging our bets as to the contribution that this refinery will make to our forecasts. We have also delayed the start-up of the planned expansion of the Mina Abdullah refinery, to 2013, as we now consider it a more complex, and therefore time-consuming undertaking.

Africa

A lack of progress on key projects suggests that refinery operators are contending with the cost and resource pressures evident elsewhere. We have therefore revised down our growth forecasts for crude distillation to 313 kb/d, largely from projects in North and East Africa. Investment in upgrading capacity remains limited and new hydrotreating capacity is similarly sparse. South African refiners recently completed a round of investment, but the prospect of further tightening of the national quality specifications early next decade may yet generate further investment projects.

The construction of the 150 kb/d Port Sudan refinery by Petronas would appear to be still in the planning stages, awaiting final investment approval, despite comments by the Sudanese Government that construction has already started. Consequently, we have assumed that it will not be commissioned until late 2009, or early 2010. Similarly, the Libyan National Oil Company's protracted negotiations for improvements to the Azzawiya refinery, reported to cost around $1.5 billion, is unlikely to be completed before 2010. More encouragingly, the progress to-date on Morocco's Mohammedia refinery expansion would appear to support a completion of the project in the second half of 2008.

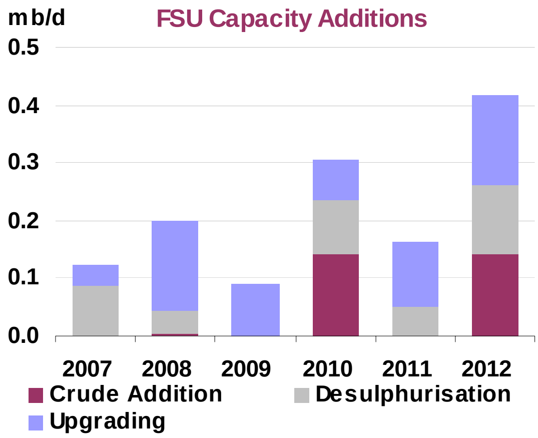


We continue to forecast the completion of a 100 kb/d Skikda condensate splitter in Algeria in 2009, but have removed the more complex 300 kb/d Tiaret refinery from 2011 projections as we believe the completion of this project now lies beyond the 2012 limit of our forecasts. The award of the 120 kb/d Shkira refinery in Tunisia to Qatar Petroleum has improved the prospects for the project to become a reality but it is excluded from our forecasts for the moment, until a more definitive timeframe for completion is given. Angola's plans for a 200 kb/d refinery at Lobito continue to appear more likely to become a reality post 2012 than before and we therefore continue to exclude this project.

Former Soviet Union

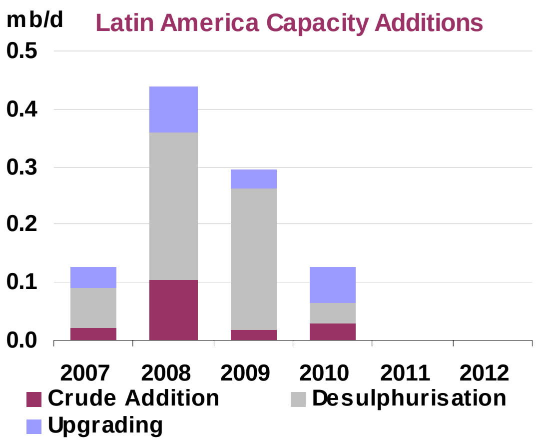
We have increased our forecast of capacity expansion in the Former Soviet Union (FSU) from the *February MTOMR update*. Regional growth is dominated by the expansion of existing Russian refineries. Planned investment will increase light-product yields and improve product quality. Significant additions to catalytic cracking and hydrocracking capacity, plus more limited investment in coking and visbreaking capacity should reduce fuel oil production and boost gasoline and distillate production through to 2012. Improved distillate and gasoline quality will be achieved through increased hydrotreating capacity and new naphtha reforming, isomerisation and alkylation units.

Investment in standalone refining capacity is more limited. Tatneft's $4.8 billion plan for a new 140 kb/d full-conversion refinery at Nizhnehamsk in 2010-2011 represents the only greenfield investment. This plant is expected to start-up in phases over 2010 and 2011. Rosneft's 140 kb/d expansion of the Tuapse refinery is the only large-scale refinery expansion project included in our forecasts. We remain cautious over the timing of this project, with contracts still to be awarded for its construction and therefore assume a completion date of late 2011. A further five greenfield projects could add 1.0 mb/d of crude distillation capacity, were they all to be realised, but prospects for completion before 2012 look unlikely.



Latin and Central America

Latin and Central American capacity growth forecasts have been reduced slightly from our previous report. Regional growth is dominated by Petrobras's planned upgrade to seven of its refineries, which will increase the ability to handle its domestic heavy, sour crude production. Some incremental crude distillation is expected to accompany the addition of 130 kb/d of new coking capacity through to 2012. Elsewhere, capacity growth is expected in Chile with the addition of a hydrocracker to ENAP's Biobio refinery, and a 20 kb/d coker at its Aconcagua refinery. Repsol's crude expansion and coker installation at its Lima refinery in Peru, and the phased improvements at the Point à Pierre refinery in Trinidad and Tobago will boost the yield and quality of light products.



As was the case last year, there are several additional projects which have not been included in our forecasts. Despite the progress evident at many of Petrobras's projects, we remain sceptical that the planned 200 kb/d Abreu e Lima refinery in Pernambuco state, a joint venture with Venezuela's PDVSA, is likely to be completed before 2012, with some reports suggesting a 2014 start date. Cost estimates have risen from $2.8 bn to $4.7 bn, suggesting that the company may well examine ways to reduce costs, probably delaying the project further. Similarly, the planned 150 kb/d Comperj petrochemicals refinery has seen cost estimates rise to $8.5 bn from earlier estimates of $6.5 bn. Consequently, we continue to exclude these projects from our forecasts. Elsewhere a further 2 mb/d of new refining projects are excluded due to a lack of evidence that they are being actively developed. These include:

- The 360 kb/d Central American Refining project in Panama, despite Qatar Petroleum's recent interest in the proposal;
- Venezuela's proposal for a 150 kb/d plant in Nicaragua;
- Argentina's proposed 150 kb/d refinery in Chubut;
- 700 kb/d of Venezuelan projects, including the Cabruta, Caripito and Barinas projects; and
- Colombia's proposed $2bn expansion of the Cartagena refinery.

Note on Methodology

This report forecasts future refinery capacity by making a thorough assessment of corporate plans for future greenfield and brownfield projects around the world. This assessment has to be both comprehensive and, due to the large number of projects that never see the light of day, highly critical. In compiling this forecast we have relied on published sources, including Purvin and Gertz, EMC, FACTS, industry journals, company websites and discussions with IOCs and NOCs and independent refiners. Ultimately, a judgement has been made as to whether a project is included in our forecast. We have considered the following criteria to assess this likelihood:

- Does the proposed refinery meet a market requirement?
- Are the sponsors credible?
- Do they have sufficient access to capital and capital markets
- Does the project have a realistic cost budget?
- Is the project supported by government policies?

Numerous refineries have been excluded for failing to meet some or even all of these criteria. Even if a project meets them there is no guarantee that it will actually make it through to completion. Given the scale of project slippage and cancellations seen over the past 12 months, it is clear that the refining industry is facing similar constraints (cost inflation, constrained labour, equipment and service markets) to those in the upstream sector. As a result we have cast a highly critical eye over planned projects, excluding those that we feel, on the balance of probability, are unlikely to succeed. As a result, we feel that the forecast risks are relatively balanced over the period to 2012: while there may be further cancellation and slippage announcements, it is possible that some projects could be brought forward. The net result is that by 2011 cumulative CDU capacity additions are around 2.6 mb/d below those reported in the *February MTOMR*.

We have also added further depth to the forecast by disaggregating proposed refining additions into their constituent refining units. Where possible this is based on information from published data and industry sources. Where we have been unable to obtain such information we have modelled the likely refinery configuration assuming typical upgrading unit capacities for the proposed size of crude distillation.

This change in methodology feeds directly into the IEA's Refinery and Product Supply Model, which integrates our product demand, crude supply and crude quality databases to drive our forecasts of crude demand, trade and product supply. For each of the ten regions modelled we categorise refineries based on the most complex type of upgrading capacity, as follows:

- Coking refineries – full upgrading refineries with the ability to minimise fuel oil yields, containing either delayed, flexi or fluid coking;
- Hydrocracking refineries – primarily focused on upgrading fuel oil into naphtha, jet fuel or diesel, using high pressure/temperature catalytic cracking in the presence of hydrogen;
- Catalytic cracking refineries – more common where it is necessary to maximise gasoline production, but can still yield significant quantities of fuel oil, depending on crude selection;
- Visbreaking refineries – using thermal cracking to improve the quality of fuel oil and minimise the use of low quality distillate to meet viscosity specifications;
- Hydroskimming refineries – those refineries that posses no upgrading capacity, but may have catalytic reforming and hydrotreating capacity. These typically yield the highest percentage of fuel oil. This category also includes topping refineries, which simply distil the crude; and
- Lubricant and asphalt refiners – those refineries that specifically produce asphalt or lubricants, processing either heavy sour crude, or atmospheric residue.

Our assessment on crude trade takes net additions to crude by quality (API and sulphur) and allocates them between regions taking account both of distance from source of production, historical trade patterns and the type of crude needed by new refineries or refinery units and regional product demand.

Our refining database then models the output of each unit (assuming full optimisation of capital-intensive units) to capture refinery output by product grade. The refinery configurations are then optimised to replicate regional operating conditions. For example, European refiners appear to maximise production of diesel, above all other products, so the model parameters are set to maximise distillate production for the region.

Considering historical data for each of the ten regions where the IEA assesses demand, we have constructed a product supply forecast for each region – benchmarked to the *Oil Market Report's* global product output database. Comparing this data with regional demand allows us to generate a regional trade matrix by product. From this we have derived some insights into the evolution of product markets and trade direction.

Product Supply Analysis

Overview

Integrating the refinery capacity forecasts into our global product supply model shows an increase in the flexibility of refiners to meet future product demand growth and provides some pointers for future crude and product price differentials. Shifts in price differentials will naturally change refinery economics, and are also likely to increase inter-regional product trade and could raise some interesting challenges for both industry and policymakers.

The new refineries coming on line in the next five years are, on average, more complex than existing refineries. Consequently, they will produce a higher percentage of light products and less fuel oil. In addition, the significant upgrading capacity additions will increase the demand for heavy/sour crude oils that are currently priced at a significant discount to light/sweet crudes.

Methodology

Over the medium term in a global refinery system, with relatively free trade of crude and products (and including biofuel supplies), by definition supply and demand will always match. If one product is tight, either refiners will produce more or consumers will reduce demand or substitute for another product or fuel if possible. However, it is more interesting to run the model on a static approach to see what imbalances emerge. In this analysis we have run the product supply model on the basis that, as at present, refiners will look to maximise the use of upgrading units and will buy the cheapest (heaviest and most sour) crude that their configuration will allow. We have taken this analysis forward, taking into account changes in global crude quality and incorporating the new refineries and upgrading units when we have assumed them to come on line.

We have explicitly assumed in our forecast that new refineries in crude exporting regions are supplied with crude, where necessary at the expense of crude exports. This in turn is likely to result in declining hydroskimming utilisation rates in some regions towards the end of the forecast period as it is assumed that more complex capacity will be better able to adjust to a lower margin environment than a less flexible hydroskimming refinery (although we recognise that in reality this will not always be the case.)

Gasoline

Globally, we expect the recently-tight gasoline market to start to ease in the very near future, with increased flexibility to expand supplies (including ethanol) increasing throughout the forecast period. This improvement comes with the caveat that there will still be myriad product specification and sulphur differences that could lead to a less-than-optimal trading environment, which may support gasoline cracks. The increased supply potential is most significant in the Atlantic Basin, where the structural surplus in European gasoline supply will persist; improving the region's potential to meet US import requirements through to 2009. And, by the end of the forecast period, US refiners will themselves start to close some of the gap in domestic supplies.

In other regions, the evolution of the gasoline balance proves mixed. The **Middle East** should remain a net importer of gasoline until 2012. In the intervening period much will rest on the outcome of Iran's plans to invest in FCC and condensate splitting capacity while at the same time implementing demand restraint measures. Saudi Arabia and Kuwait's capacity expansions in 2012 will rebalance regional gasoline production to demand. In **Latin America**, Brazilian refining investment in upgrading capacity will increase processing of heavy domestic Marlim crude oil. The net impact of these coking additions to the gasoline pool is limited as the refining of heavier crude will cut naphtha yields from crude distillation, but boost supplies of FCC and coker naphtha. **Other Asia** will become a significant exporter of gasoline, largely as a result of India's planned refining additions. The increase in supply potential will possibly increase exports to North America, the Middle East or Africa, given that we expect the OECD Pacific to also become more balanced by 2012. However, it may also raise the prospect of run cuts for hydroskimming refineries in the region.

Gasoil/Diesel

The gasoil/diesel market should remain tight in the short-term due to strong demand growth, but could ease from 2009 as higher global crude distillation capacity and investment in hydrocracking capacity come on line. However, some regions, particularly Europe, will remain importers. The European refining system is, according to our analysis, maximising diesel and gasoil production from distillation and upgrading units to meet transport and heating oil demand. Consequently, diesel production is forecast to increase following the addition of hydrocracking and coking capacity, but a more significant increase in production will not be achieved unless crude runs rise significantly.

North American demand growth is seen to accelerate over the forecast period, and, despite recent improvements in distillate yields, the region is likely to become a net importer of gasoil/diesel if yields do not improve further. However, there is some flexibility within the US refining system to bolster distillate supplies at the expense of gasoline (particularly given the growth in ethanol supplies), implying that price differentials between gasoline and diesel will be closely linked.

Overall, hydrocracking additions and increased runs are expected to cover the growth in gasoil/diesel demand, but tightening sulphur limits and increasing cetane requirements in diesel could further fragment the distillate market, reducing potential trade and supporting product cracks if insufficient desulphurisation capacity additions are seen.

It should be noted that the potential for distillate markets to ease over the next five years would be dwarfed by the impact of marine bunker fuels switching from fuel oil to distillate. As highlighted in the *Oil Market Report* dated 11 May 2007, a change on this scale would necessitate additional investment in upgrading capacity far above that which is currently forecast.

Jet and Kerosene

Strong jet/kerosene (jet) demand growth should keep the market balance tight through to 2009, before investment in hydrocracking capacity helps to ease potential tightness in the overall distillate pool. Regionally, Middle East jet exports, the source of the marginal barrel for many import regions, are set to decline as regional demand exceeds jet supply growth through to 2011. The large additions of new capacity forecast for the region in 2012 re-establish the region's ability to export. Furthermore, jet market tightness could be exacerbated, if diesel demand growth is stronger than expected, exerting downward pressure on jet yields, particularly in export regions.

Fuel Oil

Excluding a sudden weakening of fuel oil demand, either from the power sector, or indeed as a feedstock by refineries, we expect fuel oil markets to tighten significantly in the next five years. The driver of this abrupt change from current sloppy market conditions is the significant addition of upgrading capacity, which curtails fuel oil supply.

Refineries have invested in heavy oil upgrading units to take advantage of fuel oil's discount to crude prices. Consequently, net fuel oil output has remained relatively flat in recent years even though refinery runs have risen. For the period through to 2012 the new, largely complex refineries will have low fuel oil yields, and upgrading capacity additions at existing refineries will further cut fuel oil production. Comparing the likely addition of atmospheric residue from additional crude runs to planned upgrading capacity suggests that part of the additional upgrading unit feedstock must come from fuel oil currently sold to sectors such as power generation, industry and marine bunkers. We have not included a response within our forecast to reflect this tightening of the market, but note that the stronger prices needed to generate an increase in fuel oil supplies are also likely to generate a demand response.

Continuing to run refineries on the basis of maximum utilisation of upgrading facilities would see a decline in Middle Eastern fuel oil output in 2009, possibly making the region a net importer. This raises some interesting commercial and policy issues. Having invested heavily in upgrading capacity, the region is likely to feed these refineries with domestic heavy sour crudes to help maximise fuel oil output and to improve refinery returns. Not only will that reduce heavy sour crude availability for other regions, but even that may not be enough to meet robust demand growth for fuel oil from the power sector.

This leaves the Middle East with the dilemma of becoming a net regional fuel oil importer or reducing the feedstock to the upgrading units, sacrificing light product output for fuel oil and possibly importing more gasoline. Reduced demand in the region from bunkering, notably in the UAE, could ease the regional balance, but it would not alter the global outlook, merely shift the demand to another port. Of course there are other solutions. Investment in natural gas could be stepped up, or fuel efficiency measures could be implemented to optimise regional economic returns from each barrel of oil extracted.

The FSU has been the largest exporter of fuel oil in recent months, with exports reaching 1.0 mb/d. We see the region's fuel oil exports remaining relatively unchanged over the forecast period, dipping only in late 2011. Upgrading additions offset the increased fuel oil output from higher runs. However, Russian oil companies have indicated that they intend to significantly curtail fuel oil production by 2015 through investment in upgrading. This may also restrict the ability to use fuel oil domestically if the weather turns cold, or natural gas developments fail to keep pace with increased demand from European power generators.

Overall, it is Asia that is likely to feel the brunt of fuel oil tightness and with limited access to natural gas, there will likely be increased competition for a spectrum of hydrocarbons over the coming years. **China,** which has invested heavily in upgrading capacity in the past, currently produces a 5% fuel oil yield and is expected to see a tighter balance over the forecast period, as imports of around 500 kb/d of fuel oil are needed to meet bunker, industrial and teapot refinery demand. **Other Asia**, despite 1.6 mb/d of new refining capacity, is expected to see fuel oil output drop by 200 kb/d by 2012, at a time when demand is continued to grow, similarly tightening the region's fuel oil balance.

Conclusion

Demand for heavy/sour crudes over the coming years is likely to increase as more upgrading capacity is installed and fuel oil supplies tighten. This situation could be exacerbated if fuel oil becomes overpriced as a feedstock relative to heavy crude prices, further boosting demand for heavy sour crudes by refiners seeking to replace the fuel oil.

Our analysis also suggests that there will be more flexibility to produce middle and light distillates, which in turn suggests that the recent high premiums of gasoline and diesel to crude should ease – as should the high upgrading margins we have seen in recent years.

CRUDE TRADE

Summary

- **Global trade of crude oil and condensates (excluding intra-regional trade)** is forecast to rise by 5.2 mb/d between 2007 and 2012, or 3% per year on average. This marks a continuation of the growth in crude trade seen since 2003, as centres of crude supply and demand become increasingly disparate.

- **Middle Eastern exports of crude oil and condensates** are projected to rise from 17.1 mb/d to 19.7 mb/d between 2007 and 2012 and will increasingly head to North America, China and Other Asia. However, crude oil export growth is tempered by local refinery expansions, which in turn will boost product exports.

- Higher **crude exports from FSU** to Europe and the US are anticipated as North Sea supplies wane. **African exports** are seen to rise, driven by higher output from its new and former OPEC members over the medium term and its comparatively low regional crude demand growth. Similar incremental volumes on eastbound and westbound routes suggest that Africa will continue to be the major swing source of global crude supply. Increases in **Latin American** production will be largely diverted to domestic refinery additions, limiting export growth.

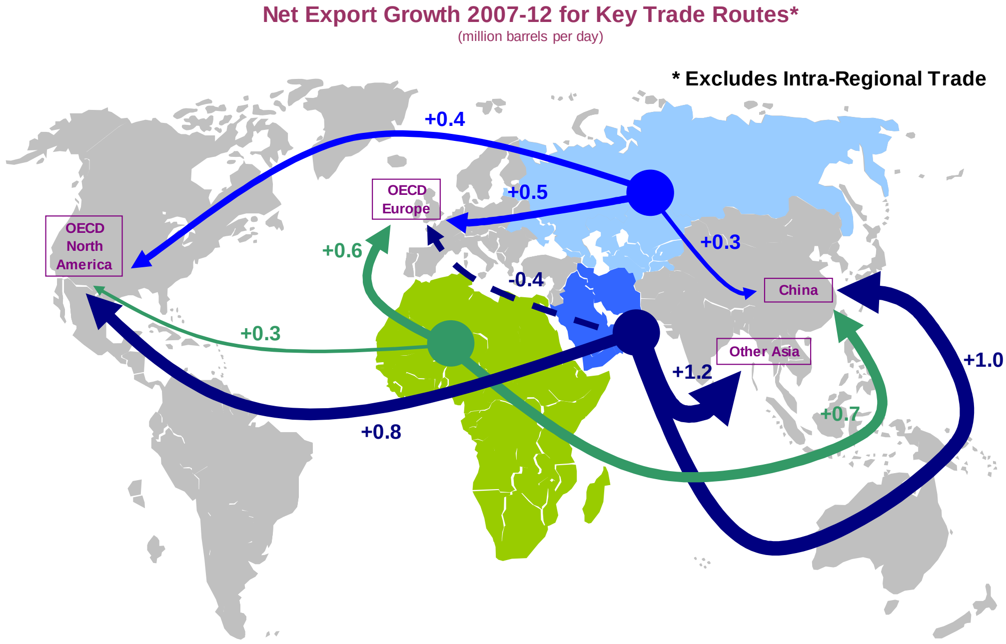
- **China and Other Asia imports**, key drivers of global trade growth since 2003, will continue to exert a major pull on incremental crude cargoes along with **OECD North America**, driven by refinery capacity additions. **OECD Europe** will become increasingly reliant on crude imports from the FSU and Africa in the medium term, exacerbated by lower North Sea production and reduced imports of Middle Eastern crude. **OECD Pacific imports** are forecast to remain essentially flat over the next five years.

Overview and Methodology

Crude oil trade is essentially driven by the allocation of incremental crude supplies to areas of crude demand growth, as dictated by refinery expansions. On the supply side, it is assumed, firstly, that non-OPEC upstream capacity growth will be fully utilised. Secondly, we assume that the growing call on OPEC will be met proportionately by OPEC members according to the call on their spare capacity. These volumes are then shipped to where they are needed. Crude demand and supply are matched according to changes in refinery capacity and complexity, and taking into account shifts in the crude quality, historical trade relationships and trade economics.

On this basis, China, Other Asia, OECD North America and the Middle East stand out as having the greatest potential thirst for incremental crude over the next five years. At the same time, medium-term crude (and condensate) supply growth will come increasingly from the Middle East, Africa, FSU, Canada and Brazil and decreasingly from the OECD Europe, US and Mexico. Emerging trade routes, such as FSU exports to the US or Chinese imports from the Atlantic basin will also be an important feature.

Global trade of crude oil and condensates (excluding intra-regional trade) is forecast to rise from 34.9 mb/d in 2007 to 40.1 mb/d in 2012. This equates to a 15% total increase, or 3% per year compound growth, and marks a continuation of the growth in crude trade seen since 2003. Medium-term supply and refinery capacity projections suggest that major consumer regions, such as the OECD and most of Asia, will continue to see local supply growth dwindle (or decrease further) while refinery



capacity expands. Refiners in these consumer regions will therefore increasingly look to bring in crude from the growing supply centres of Middle East, Africa and FSU.

Regional Trade

Refinery capacity additions in China, Other Asia and OECD North America represent the largest pull on incremental crude and condensate over the next five years, excluding intra-regional trade. **Chinese crude imports** are projected to grow by 80% over the medium term, from 2.5 mb/d in 2007 to 4.5 mb/d in 2012. This builds on the rapid rise in Chinese imports during the last five years (2001-06), which increased at a compound growth rate of 19% per year (or 140% in total, from a much lower base of 1.2 mb/d) and included an import surge of 35% in 2004. Around that time, Chinese crude imports were boosted by a dramatic upswing in cargoes arriving from Africa, most notably Angola, on top of more arrivals from the Middle East and the FSU. China's increasing thirst for crude over the medium term stems from refinery additions which will expand crude distillation capacity by over 2 mb/d by 2012, alongside plans for strategic crude storage. Chinese strategic storage capacity is reportedly due to reach 100 million barrels by 2008, although it may take somewhat longer to fill. Additional storage construction is also planned subsequent to this.

Imports into the Other Asia region (including Indian subcontinent and South East Asia) are projected to rise by 21% in the medium term, from 5.5 mb/d in 2007 to 6.6 mb/d in 2012. Refinery additions in India totalling 1.3 mb/d will be a key driver of regional crude demand growth in the medium term. The massive new Jamnagar complex (adding 580 kb/d of crude distillation capacity from early 2009) is a symbol of India's thrust to become a global refining hub. More modest refinery capacity additions are also expected to bolster crude demand in Vietnam and Taiwan.

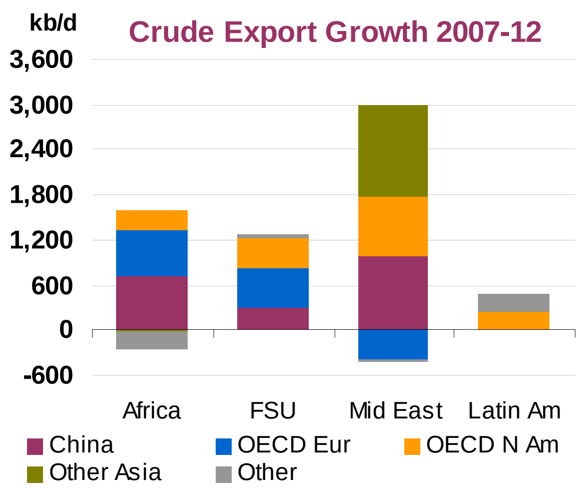
OECD North America imports are seen increasing by 19% over the next five years, from 7.8 mb/d in 2007 to 9.2 mb/d in 2012. This marks a clear upswing in import growth from a flatter overall trend seen between 2001 and 2006. This earlier period saw higher crude imports from Africa (+720 kb/d from a combination of Angola, Algeria and, less significantly, Nigeria) and Latin America (+260 kb/d) offset declines of 560 kb/d in imports from the North Sea (Norway and UK) and 470 kb/d from the Middle East (Iraq, Saudi Arabia and Kuwait).

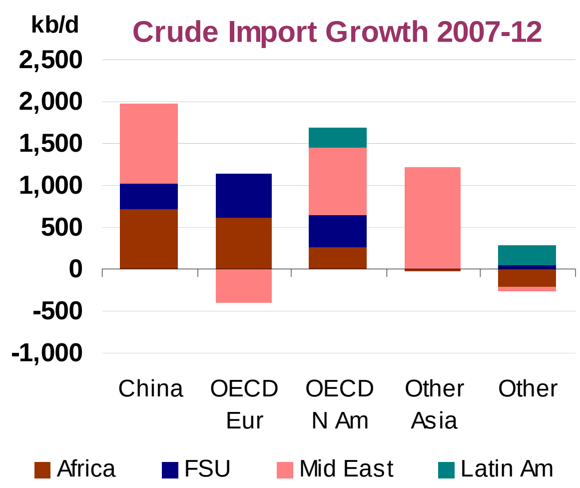
Over the next five years, the majority of incremental crude flows to these three consumer regions, and indeed globally, will come from the **Middle East**. Between 2007 and 2012, Middle Eastern exports to other regions are expected to grow by 2.6 mb/d or 15%, from 17.1 mb/d to 19.7 mb/d. This equates to 3% average yearly growth. Extra crude supplies will be large enough to maintain significant export growth despite the large volumes of additional regional crude demand needed to feed an increase of more than 2.5 mb/d in local crude distillation capacity by 2012.

Our assessment shows that medium-term exports from the Middle East to China could double, rising annually by 15% on average, to reach 1.9 mb/d by 2012. This is likely to include much higher volumes of Saudi Arabian crude, rising to 1.1 mb/d by 2012 compared with current levels of around 0.5 mb/d.

Between 2001 and 2006, Middle Eastern crude flows to Other Asia rose by 41%, or 7% per annum. Annual growth is projected to remain strong (relative to a higher base) at 5% in the next five years. Trade along this route can potentially reach 5.2 mb/d in 2012, 30% higher than 2007, with notable increases emanating from the UAE. Growth in exports to China and Other Asia was also the main reason behind a 2% annual rise in total Middle Eastern exports over the period 2001-2006.

Middle Eastern exports to OECD North America are forecast to rise by around 0.8 mb/d (5% annually, 29% in total) over the medium term, to reach 3.7 mb/d in 2012. Nearly half of this extra crude could potentially come from Saudi Arabia (overwhelmingly lighter crude) while imports from Qatar and UAE are also forecast to rise. This reverses the decline in flows (-4%) seen between 2001 and 2006.





Growth in African and FSU crude output and capacity will significantly outpace local crude demand growth. The consequent boost in exports from these regions will be of critical importance to global trade in the next five years. **African crude and condensate exports** are projected to grow by 19% (4% per annum) over the medium term, from 7.6 mb/d in 2007 to 9.1 mb/d in 2012. This continues the strong growth trend over the last five-year period (2001-06) when exports rose by, on average, 7% per year from a lower base. Export growth earlier this decade was driven by significant supply increments in Angola and Algeria (over 500 kb/d growth from 2001-06 each) alongside relatively slight domestic demand growth. The US absorbed many of the extra cargoes from both of these countries alongside surging Chinese imports of Angolan crude.

Over the next five years, African exports will be boosted primarily by higher output from its OPEC members, with Europe and China the main recipients of incremental flows. Volumes bound for Europe, including extra cargoes from Nigeria (geopolitics permitting) and Libya, are projected to reach 3.3 mb/d by 2012, compared with around 2.7 mb/d in 2007. Chinese imports of African crude are projected to rise from 1 mb/d in 2007 to 1.8 mb/d in 2012, growing by 11% per year, with notable increases in cargoes from Angola and Sudan in the next couple of years and Equatorial Guinea from 2009.

Growth in trade from Africa to western markets is forecast to be similar to eastbound volumes, suggesting that African exports will very much continue to be the major swing source of crude globally. US gasoline demand growth is projected to remain strong, maintaining the need for light, sweet grades such as Bonny Light, Saharan Blend and Angolan Girassol. OECD North America is forecast to receive an extra 250 kb/d of African crude (mainly Algerian and Angolan) over the next five years, offsetting declining imports from the North Sea (where supply decreases).

Exports from the Former Soviet Union are forecast to rise in the medium term by 4% per annum, from 6.3 mb/d in 2007 to 7.6 mb/d in 2012. This follows five years of strong export growth, which averaged 11% between 2001 and 2006, as improvements to export infrastructure allowed rising FSU supplies to increasingly flow to other regions. One key improvement has been the development of Russia's crude outlet through Primorsk in the Baltic, where exports have risen by at least 500 kb/d between 2004 and the present. The BTC and CPC pipelines have also been developed in recent years, allowing Caspian flows to other regions via the Mediterranean and Black Seas. Prospective expansions of outlets for FSU crude to the North and South, plus a new pipeline to the East and various Bosporus bypass projects, may all contribute to higher FSU exports in the medium term (see *Russian Export Outlets* in the Supply section)

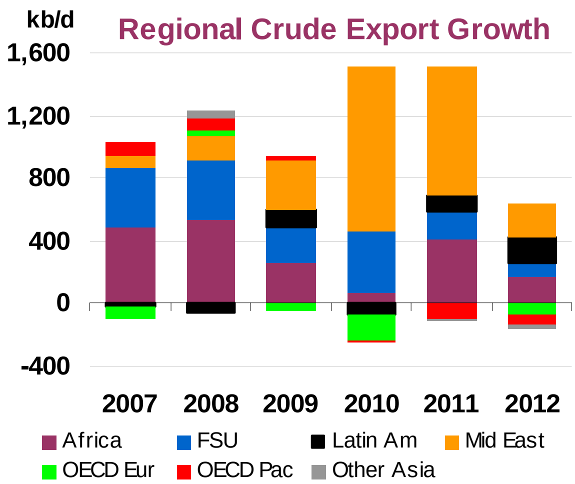
FSU exports to Europe, having already risen annually by 10% in the last five years, could rise by a further 0.5 mb/d to reach 5.8 mb/d in 2012. Azeri and Kazakh exports will drive this growth, potentially replacing some of Europe's sweet crude supplies lost to North Sea field decline, outpacing reduced flows of sourer Russian Urals which may be increasingly processed in complex Russian refineries. FSU countries are set to provide over half of European crude imports as of 2010.

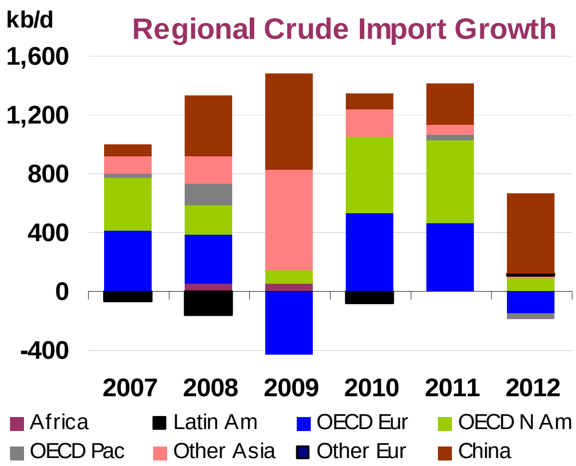
Trade to the US has the potential to double in the medium term to reach 700 kb/d by 2012. Growth in Eastbound FSU exports will be constrained by infrastructural limits. Rail transit capacity will mark the limit on any extra volumes heading to OECD Pacific and, moreover, China until the East Siberia pipeline is operational in 2009, with potential capacity of 600 kb/d according to plans.

Stronger imports of African and FSU and crude will potentially push **total imports of crude to OECD Europe** up from 10.5 mb/d in 2007 to 11.3 mb/d in 2012. This averages an increase of 1% per annum, marking a slowdown compared with growth seen between 2001 and 2006. Imports of Middle Eastern crude, which decreased by around 2% per year from 2001-06, could well continue to slow in the face of competition from African and FSU grades.

Exports from Latin America may increase from around 1.9 mb/d in 2007 to 2.1 mb/d in 2012. This equals 2% growth after approximately 4% annual growth seen between 2001 and 2006. Incremental exports in the last five years were driven by slight increases towards OECD North America and the first cargoes headed for China. In the medium term, trade to OECD North America is projected to increase by another 240 kb/d.

Despite large supply additions in Brazil in the medium term, crude export growth from Latin America will be limited as increasing amounts of crude are diverted to the domestic market. Crude demand should be inflated by rising refinery utilisation and some capacity additions, mainly in Brazil itself. Furthermore, small amounts of crude currently imported from West Africa and Middle East are likely to diminish as heightened domestic refinery sophistication allows Latin America to process its own heavier crudes.





OECD Pacific imports of crude oil and condensate will remain flat at around 7.1 mb/d in the medium term. Refinery additions are sparse over the next five years in OECD Pacific, with just a few minor expansions (30-60 kb/d) to crude distillation capacity in Japan, Australia and New Zealand. Imports from the Middle East will continue to dominate incoming volumes, remaining in the region of 6.0 mb/d. It is possible that growth in imports of crude from Saudi Arabia and of condensate from Qatar may offset slight decreases from other Middle Eastern countries.

Implications for the Tanker Market

A crude trade forecast slightly ahead of crude demand growth (in percentage terms) should theoretically suggest an increase in tanker employment, if the trend also applies to seaborne trade. Reconciling approximate seaborne crude trade volumes with a distance matrix reveals that tanker tonne-mile demand (trade volume multiplied by distance that cargoes are shipped, an indicator of tanker demand) should rise even more steeply, by 3.5%. The principal contributors to increased tonne-mile demand are higher long-haul exports to China and the US from Saudi Arabia and West Africa, outpacing the countering effect from lower long-haul exports from Middle East to OECD Europe and OECD Pacific.

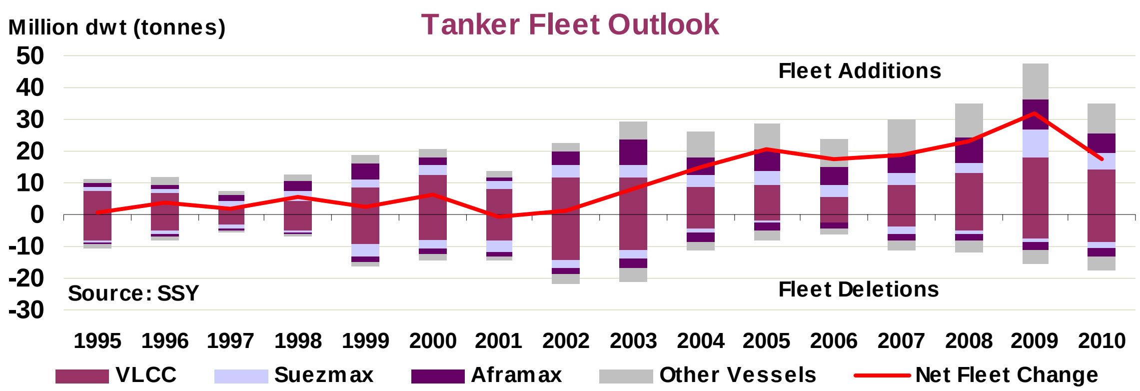
While increasing volumes of long-haul crude will essentially be shipped in two million-barrel (or larger) VLCCs, demand for million-barrel suezmax tankers should be supported by higher exports from FSU and North Africa via the Mediterranean and increased volumes leaving West Africa. Growth in Russian exports to Europe could boost employment of aframaxes, which carry around half a million barrels.

The tanker trade should be well placed to meet these challenges: there are more tankers on order today than at any point since the shipbuilding boom of the early 1970s. A current orderbook of around 140 million tonnes carrying capacity compares with just 73 million at the end of 2003. Today's orderbook implies that tankers to be delivered by the end of 2010 equate to almost 38% of existing fleet supply in cargo-carrying terms.

Orders for mid-range and smaller tankers are notably strong, alongside historically high orders for new VLCCs, Suezmaxes and Aframaxes. Massive demand, rising steel costs (plus safety requirements to use more steel in tanker design) and increased competition for shipyard space from other shipping sectors (amid a surge in orders for non-tanker ship types) have pushed tanker newbuild costs to record highs. This is despite ongoing growth in world shipbuilding capacity. A brand new VLCC constructed in Korea now costs around $133 million compared with an average $68 million in 2003. Shipyards in Korea, Japan and China are full until at least 2010.

A brimming orderbook provides the potential to redress the prevailing vessel undersupply, prompted by weak tanker ordering early this decade, which has supported freight rates over the last three years. However, this depends on how many vessels are scrapped.

High vessel earnings have kept scrappings at record lows over the last three years. No VLCC has been scrapped since 2004. While sustained lower freight rates would prompt an upswing in scrapping, a different, clearer threat to vessel supply is the 2010 (IMO) deadline for the phasing-out of all single-hulled tankers. In the VLCC sector, this would translate into a reduction in the current operational fleet by as much as 28%, as vessels are scrapped or converted into dedicated floating storage units, offshore oil production vessels or even dry-bulk carriers. However, certain exceptions may dilute this figure (such as for vessels with double-bottoms or double sides) and some vessels may continue to operate outside IMO signatory waters. Simpson, Spence and Young forecast vessel deletions to correspond to around 3% of the current tanker fleet annually through 2010, with the most pronounced declines in VLCC tonnage. When combined with orderbook data, SSY fleet projections suggest net annual expansions of the tanker fleet of around 6% by end-2010.



Despite potential support from firm trade growth and vessel phase-outs, freight rates in the medium term face genuine downside risk from an expanding fleet. However, perhaps a greater threat to freight rates is the downside risk from oil market fundamentals. Demand dented by an economic downturn or by higher prices following underperforming supply could significantly undermine oil trade and tanker demand.

Table 1

WORLD OIL SUPPLY AND DEMAND

(million barrels per day)

	1Q07	2Q07	3Q07	4Q07	2007	1Q08	2Q08	3Q08	4Q08	2008	1Q09	2Q09	3Q09	4Q09	2009	2010	2011	2012
OECD DEMAND																		
North America	25.7	25.4	25.9	26.0	25.8	26.1	25.8	26.2	26.3	26.1	26.3	26.2	26.5	26.7	26.4	26.8	27.1	27.5
Europe	15.1	15.0	15.6	15.8	15.4	15.7	15.2	15.7	15.9	15.6	15.6	15.4	15.8	15.9	15.7	15.8	15.9	15.9
Pacific	8.9	7.9	8.0	8.9	8.4	9.3	8.0	8.1	8.9	8.6	9.3	8.0	8.1	8.9	8.6	8.6	8.6	8.7
Total OECD	49.7	48.2	49.6	50.8	49.6	51.1	48.9	50.0	51.1	50.3	51.2	49.6	50.5	51.6	50.7	51.2	51.6	52.1
NON-OECD DEMAND																		
FSU	3.8	3.6	4.1	4.4	4.0	4.0	3.9	4.2	4.5	4.1	4.4	4.1	4.0	4.3	4.2	4.3	4.4	4.5
Europe	0.8	0.8	0.7	0.8	0.8	0.9	0.8	0.7	0.8	0.8	0.9	0.8	0.8	0.8	0.8	0.9	0.9	0.9
China	7.3	7.7	7.6	7.7	7.6	7.8	8.2	8.0	8.2	8.1	8.2	8.4	8.5	8.9	8.5	9.0	9.5	10.0
Other Asia	9.1	9.2	9.0	9.2	9.1	9.4	9.4	9.2	9.5	9.4	9.5	9.6	9.6	9.8	9.6	9.9	10.1	10.4
Latin America	5.3	5.5	5.6	5.5	5.5	5.5	5.6	5.7	5.7	5.6	5.6	5.8	5.9	5.8	5.8	5.9	6.0	6.2
Middle East	6.4	6.5	6.8	6.5	6.6	6.7	6.8	7.1	6.8	6.9	7.0	7.1	7.4	7.1	7.2	7.5	7.9	8.2
Africa	3.1	3.1	3.0	3.1	3.1	3.2	3.1	3.1	3.2	3.1	3.3	3.3	3.2	3.3	3.2	3.3	3.5	3.6
Total Non-OECD	35.8	36.3	36.7	37.3	36.6	37.4	37.8	38.0	38.7	38.0	38.9	39.1	39.3	40.0	39.3	40.7	42.2	43.7
Total Demand[1]	85.6	84.6	86.3	88.0	86.1	88.5	86.7	88.0	89.8	88.3	90.1	88.7	89.8	91.5	90.0	91.9	93.8	95.8
OECD SUPPLY																		
North America	14.4	14.0	14.0	14.1	14.1	14.4	14.0	13.9	14.2	14.1	14.5	14.1	13.9	14.1	14.2	14.2	14.3	14.4
Europe	5.2	4.7	4.7	4.9	4.9	4.9	4.6	4.4	4.6	4.6	4.7	4.3	4.2	4.4	4.4	4.1	4.0	3.7
Pacific	0.6	0.6	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.9	0.8	0.8	0.7	0.7
Total OECD	20.2	19.4	19.4	19.7	19.7	20.0	19.3	19.2	19.6	19.5	20.0	19.2	19.0	19.4	19.4	19.2	19.0	18.7
NON-OECD SUPPLY																		
FSU	12.5	12.6	12.6	12.8	12.6	12.8	13.0	13.0	13.3	13.0	13.3	13.5	13.6	13.7	13.5	13.8	14.1	14.4
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	3.7	3.8	3.9	3.8	3.8	3.9	3.8	3.8	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	2.7	2.7	2.7	2.7	2.8	2.8	2.8	2.8	2.8	2.9	2.9	2.8	2.8	2.8	2.8
Latin America	4.4	4.4	4.5	4.6	4.5	4.8	4.8	4.8	4.7	4.8	4.9	4.9	4.9	4.9	4.9	5.0	5.2	5.5
Middle East	1.7	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Africa[8]	2.6	2.6	2.6	2.6	2.6	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.8	2.8	2.8
Total Non-OECD[8]	27.8	27.9	28.0	28.3	28.0	28.6	28.8	28.9	29.1	28.8	29.3	29.5	29.6	29.7	29.5	30.0	30.4	31.0
Processing Gains[2]	1.9	1.9	1.9	1.9	1.9	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.1
Other Biofuels[3]	0.4	0.4	0.4	0.4	0.4	0.7	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Total Non-OPEC[4,8]	50.3	49.6	49.6	50.3	50.0	51.2	50.7	50.7	51.4	51.0	52.0	51.4	51.3	51.8	51.6	51.9	52.2	52.6
OPEC																		
Crude[5]	30.2																	
OPEC NGLs[6]	4.8	4.8	4.8	5.0	4.9	5.2	5.4	5.6	5.8	5.5	6.0	6.2	6.4	6.5	6.3	6.7	6.9	7.1
Total OPEC[8]	35.0																	
Total Supply[5]	85.3																	
Memo items:																		
Call on OPEC crude + Stock ch.[7]	30.5	30.2	31.8	32.7	31.3	32.1	30.6	31.8	32.6	31.8	32.0	31.0	32.1	33.2	32.1	33.2	34.7	36.2

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)

	1Q07	2Q07	3Q07	4Q07	2007	1Q08	2Q08	3Q08	4Q08	2008	1Q09	2Q09	3Q09	4Q09	2009	2010	2011	2012
OECD DEMAND																		
North America	0.2	0.0	0.1	-0.1	0.0	0.2	0.0	0.1	-0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Europe	-0.5	0.0	0.1	0.1	-0.1	0.3	0.0	0.1	0.2	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	
Pacific	-0.3	0.0	0.0	0.1	0.0	0.1	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	
Total OECD	-0.6	0.0	0.2	0.1	-0.1	0.6	0.0	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.2	
NON-OECD DEMAND																		
FSU	-0.2	-0.1	0.2	0.3	0.0	0.0	0.1	0.2	0.4	0.2	0.3	0.3	0.1	0.1	0.2	0.2	0.3	
Europe	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	
China	0.0	0.0	0.1	0.2	0.1	0.1	0.0	0.1	0.2	0.1	0.1	-0.3	0.1	0.5	0.1	0.1	0.1	
Other Asia	0.1	0.1	0.0	0.0	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.1	-0.1	0.0	-0.1	-0.2	
Latin America	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.2	0.2	0.3	0.3	0.2	0.3	0.2	0.2	
Middle East	-0.2	-0.2	-0.3	-0.2	-0.2	-0.2	-0.2	-0.3	-0.3	-0.2	-0.2	-0.3	-0.4	-0.3	-0.3	-0.3	-0.3	
Africa	0.1	0.0	0.1	0.0	0.0	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	
Total Non-OECD	0.0	0.0	0.3	0.7	0.2	0.3	0.2	0.4	0.7	0.4	0.4	0.1	0.3	0.6	0.4	0.3	0.3	
Total Demand	-0.6	0.0	0.5	0.8	0.2	0.9	0.2	0.6	0.9	0.7	0.7	0.4	0.6	0.9	0.6	0.6	0.5	
OECD SUPPLY																		
North America	-0.3	-0.4	-0.2	-0.3	-0.3	-0.4	-0.4	-0.4	-0.5	-0.4	-0.4	-0.5	-0.5	-0.5	-0.4	-0.4	-0.4	
Europe	0.0	-0.3	-0.3	-0.3	-0.2	-0.3	-0.3	-0.3	-0.3	-0.3	-0.2	-0.3	-0.3	-0.2	-0.3	-0.3	-0.3	
Pacific	-0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.1	-0.1	-0.1	0.0	-0.1	0.0	-0.1	
Total OECD	-0.4	-0.7	-0.5	-0.6	-0.5	-0.6	-0.7	-0.7	-0.8	-0.7	-0.7	-0.8	-0.8	-0.8	-0.8	-0.7	-0.7	
NON-OECD SUPPLY																		
FSU	0.1	0.1	0.0	0.1	0.1	0.0	0.1	0.2	0.3	0.2	0.1	0.1	0.2	0.2	0.2	0.1	-0.1	
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	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.1	0.1	0.1	0.1	0.1	
Other Asia	0.0	0.0	-0.1	-0.1	0.0	0.0	0.0	0.0	0.0	0.0	-0.1	-0.1	0.0	0.0	0.0	-0.1	-0.1	
Latin America	-0.1	-0.1	-0.1	-0.1	-0.1	-0.2	-0.3	-0.4	-0.5	-0.3	-0.4	-0.4	-0.4	-0.5	-0.4	-0.4	-0.3	
Middle East	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	0.0	0.0	0.0	
Africa8	-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	0.0	0.0	
Total Non-OECD8	-0.1	-0.2	-0.2	-0.1	-0.2	-0.2	-0.2	-0.3	-0.2	-0.2	-0.4	-0.3	-0.3	-0.3	-0.3	-0.4	-0.5	
Processing Gains	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	
Other Biofuels	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	
Total Non-OPEC	-0.5	-0.8	-0.7	-0.7	-0.7	-0.6	-0.7	-0.8	-0.8	-0.7	-0.9	-0.9	-0.9	-0.9	-0.9	-0.9	-1.0	
OPEC NGLs	0.0	0.0	-0.1	0.0	0.0	0.1	0.2	0.2	0.3	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.2	
Memo items:																		
Call on OPEC crude + Stock ch.	-0.1	0.8	1.3	1.5	0.9	1.5	0.8	1.2	1.4	1.2	1.3	1.0	1.2	1.5	1.3	1.2	1.3	

Table 2
Summary of Global Oil Demand

	1Q07	2Q07	3Q07	4Q07	2007	1Q08	2Q08	3Q08	4Q08	2008	1Q09	2Q09	3Q09	4Q09	2009	2010	2011	2012
Demand (mb/d)																		
North America	25.70	25.38	25.95	26.04	25.77	26.14	25.77	26.22	26.30	26.11	26.30	26.19	26.55	26.71	26.44	26.78	27.13	27.49
Europe	15.15	15.02	15.60	15.81	15.40	15.73	15.19	15.69	15.88	15.62	15.61	15.41	15.80	15.93	15.69	15.77	15.85	15.94
Pacific	8.88	7.85	8.01	8.91	8.41	9.28	7.95	8.07	8.94	8.56	9.30	7.99	8.14	8.93	8.59	8.61	8.65	8.68
Total OECD	49.73	48.25	49.56	50.76	49.58	51.14	48.92	49.98	51.13	50.29	51.21	49.59	50.48	51.56	50.71	51.16	51.63	52.12
FSU	3.77	3.61	4.08	4.44	3.97	4.00	3.85	4.16	4.50	4.13	4.43	4.13	4.05	4.26	4.22	4.31	4.39	4.48
Europe	0.84	0.78	0.73	0.78	0.78	0.86	0.80	0.75	0.81	0.81	0.89	0.83	0.77	0.83	0.83	0.85	0.88	0.90
China	7.27	7.72	7.63	7.74	7.59	7.82	8.15	8.03	8.21	8.05	8.19	8.40	8.51	8.89	8.50	8.98	9.46	9.96
Other Asia	9.14	9.19	8.95	9.18	9.11	9.37	9.43	9.21	9.46	9.37	9.52	9.60	9.55	9.79	9.61	9.87	10.14	10.42
Latin America	5.32	5.46	5.60	5.54	5.48	5.46	5.61	5.74	5.69	5.62	5.57	5.76	5.85	5.82	5.75	5.88	6.02	6.15
Middle East	6.41	6.53	6.77	6.51	6.56	6.71	6.82	7.07	6.81	6.85	7.01	7.12	7.38	7.11	7.16	7.51	7.89	8.22
Africa	3.09	3.05	2.98	3.09	3.05	3.19	3.14	3.07	3.18	3.15	3.26	3.25	3.19	3.28	3.24	3.35	3.45	3.56
Total Non-OECD	35.85	36.35	36.74	37.28	36.56	37.40	37.80	38.03	38.65	37.98	38.87	39.09	39.30	39.97	39.31	40.75	42.21	43.70
World	85.58	84.60	86.29	88.04	86.13	88.55	86.72	88.01	89.78	88.27	90.09	88.69	89.78	91.54	90.02	91.91	93.84	95.82
of which:																		
US50	*20.88*	*20.79*	*21.26*	*21.22*	*21.04*	*21.31*	*21.13*	*21.47*	*21.44*	*21.34*	*21.43*	*21.42*	*21.71*	*21.82*	*21.60*	*21.87*	*22.14*	*22.42*
Euro4	*7.84*	*7.75*	*8.14*	*8.24*	*7.99*	*8.20*	*7.85*	*8.17*	*8.26*	*8.12*	*8.09*	*7.95*	*8.19*	*8.20*	*8.11*	*8.11*	*8.11*	*8.11*
Japan	*5.45*	*4.65*	*4.84*	*5.42*	*5.09*	*5.71*	*4.69*	*4.84*	*5.40*	*5.16*	*5.69*	*4.67*	*4.84*	*5.36*	*5.14*	*5.11*	*5.09*	*5.07*
Korea	*2.34*	*2.12*	*2.07*	*2.35*	*2.22*	*2.44*	*2.16*	*2.12*	*2.39*	*2.28*	*2.49*	*2.19*	*2.16*	*2.41*	*2.31*	*2.34*	*2.38*	*2.42*
Mexico	*2.08*	*2.05*	*2.06*	*2.11*	*2.08*	*2.13*	*2.09*	*2.10*	*2.16*	*2.12*	*2.14*	*2.17*	*2.16*	*2.17*	*2.16*	*2.20*	*2.24*	*2.29*
Canada	*2.36*	*2.19*	*2.28*	*2.33*	*2.29*	*2.31*	*2.20*	*2.29*	*2.32*	*2.28*	*2.33*	*2.26*	*2.31*	*2.34*	*2.31*	*2.34*	*2.36*	*2.39*
Brazil	*2.25*	*2.27*	*2.36*	*2.35*	*2.31*	*2.30*	*2.33*	*2.41*	*2.41*	*2.36*	*2.34*	*2.41*	*2.46*	*2.48*	*2.42*	*2.48*	*2.54*	*2.60*
India	*2.88*	*2.79*	*2.54*	*2.79*	*2.75*	*2.94*	*2.86*	*2.61*	*2.85*	*2.82*	*2.94*	*2.87*	*2.76*	*2.94*	*2.88*	*2.95*	*3.02*	*3.09*
Annual Change (% per annum)																		
North America	2.2	1.1	1.9	2.6	1.9	1.7	1.6	1.0	1.0	1.3	0.6	1.6	1.2	1.5	1.3	1.3	1.3	1.3
Europe	-4.2	-0.4	0.7	1.6	-0.6	3.8	1.1	0.6	0.5	1.5	-0.7	1.4	0.7	0.3	0.4	0.5	0.5	0.6
Pacific	-4.5	-0.2	1.4	1.6	-0.5	4.5	1.3	0.8	0.4	1.8	0.2	0.5	0.8	-0.2	0.3	0.3	0.4	0.4
Total OECD	-1.1	0.4	1.4	2.1	0.7	2.8	1.4	0.8	0.7	1.4	0.1	1.4	1.0	0.8	0.8	0.9	0.9	0.9
FSU	-3.7	-3.3	2.7	3.3	-0.1	6.1	6.7	1.9	1.3	3.8	10.8	7.3	-2.6	-5.2	2.2	2.1	1.9	2.1
Europe	3.1	3.0	2.8	2.4	2.8	2.5	2.8	2.8	2.8	2.7	2.5	2.9	2.9	2.8	2.8	2.8	2.9	2.9
China	4.5	5.9	6.4	7.5	6.1	7.6	5.6	5.2	6.0	6.1	4.8	3.0	6.0	8.3	5.6	5.6	5.3	5.4
Other Asia	2.5	2.9	3.8	3.6	3.2	2.5	2.6	2.9	3.1	2.8	1.6	1.8	3.6	3.4	2.6	2.6	2.7	2.8
Latin America	3.3	3.3	3.6	3.0	3.3	2.6	2.6	2.6	2.7	2.6	2.1	2.8	1.9	2.3	2.3	2.2	2.3	2.3
Middle East	4.1	5.2	4.5	3.8	4.4	4.6	4.4	4.4	4.6	4.5	4.5	4.5	4.4	4.4	4.4	5.0	5.0	4.2
Africa	3.6	2.4	3.9	4.7	3.6	3.0	3.0	3.0	3.1	3.0	2.3	3.4	3.7	3.1	3.1	3.2	3.1	3.2
Total Non-OECD	2.7	3.3	4.3	4.4	3.7	4.3	4.0	3.5	3.7	3.9	3.9	3.4	3.3	3.4	3.5	3.7	3.6	3.5
World	0.5	1.6	2.6	3.0	2.0	3.5	2.5	2.0	2.0	2.5	1.7	2.3	2.0	1.9	2.0	2.1	2.1	2.1
Annual Change (mb/d)																		
North America	0.55	0.28	0.48	0.65	0.49	0.43	0.40	0.27	0.26	0.34	0.16	0.42	0.33	0.41	0.33	0.34	0.35	0.36
Europe	-0.66	-0.06	0.10	0.25	-0.09	0.58	0.17	0.09	0.07	0.23	-0.11	0.22	0.11	0.04	0.06	0.08	0.08	0.09
Pacific	-0.42	-0.02	0.11	0.14	-0.04	0.40	0.10	0.06	0.04	0.15	0.02	0.04	0.06	-0.02	0.02	0.03	0.03	0.04
Total OECD	-0.53	0.21	0.69	1.04	0.36	1.41	0.67	0.42	0.37	0.72	0.07	0.67	0.50	0.43	0.42	0.45	0.47	0.49
FSU	-0.15	-0.12	0.11	0.14	0.00	0.23	0.24	0.08	0.06	0.15	0.43	0.28	-0.11	-0.24	0.09	0.09	0.08	0.09
Europe	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.03
China	0.31	0.43	0.46	0.54	0.44	0.55	0.43	0.40	0.47	0.46	0.37	0.25	0.48	0.68	0.45	0.48	0.48	0.51
Other Asia	0.23	0.26	0.33	0.32	0.28	0.23	0.24	0.26	0.29	0.25	0.15	0.17	0.34	0.32	0.25	0.25	0.27	0.28
Latin America	0.17	0.17	0.19	0.16	0.18	0.14	0.14	0.15	0.15	0.14	0.11	0.16	0.11	0.13	0.13	0.13	0.13	0.14
Middle East	0.26	0.32	0.29	0.24	0.28	0.29	0.28	0.30	0.30	0.29	0.30	0.30	0.31	0.30	0.30	0.36	0.37	0.33
Africa	0.11	0.07	0.11	0.14	0.11	0.09	0.09	0.09	0.10	0.09	0.07	0.11	0.11	0.10	0.10	0.11	0.11	0.11
Total Non-OECD	0.95	1.16	1.51	1.55	1.30	1.56	1.46	1.29	1.38	1.42	1.47	1.29	1.27	1.32	1.34	1.44	1.46	1.49
World	0.42	1.36	2.21	2.59	1.65	2.97	2.12	1.71	1.75	2.13	1.54	1.96	1.77	1.75	1.76	1.89	1.93	1.97
Revisions to Oil Demand from Last Medium Term Report (mb/d)																		
North America	0.15	0.01	0.06	-0.09	0.03	0.23	-0.04	0.09	-0.08	0.05	0.02	0.04	0.04	0.02	0.03	0.01	-0.01	-
Europe	-0.46	-0.04	0.09	0.14	-0.07	0.27	0.02	0.12	0.18	0.15	0.16	0.16	0.18	0.16	0.16	0.18	0.18	-
Pacific	-0.27	0.04	0.02	0.06	-0.04	0.08	0.06	0.04	0.13	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.06	-
Total OECD	-0.58	0.01	0.17	0.11	-0.07	0.58	0.04	0.25	0.22	0.27	0.26	0.28	0.30	0.26	0.27	0.26	0.24	-
FSU	-0.20	-0.11	0.16	0.32	0.04	-0.04	0.07	0.23	0.37	0.16	0.31	0.28	0.10	0.11	0.20	0.24	0.26	-
Europe	0.05	0.04	0.04	0.04	0.04	0.06	0.05	0.05	0.05	0.05	0.07	0.06	0.06	0.06	0.06	0.07	0.08	-
China	0.00	-0.04	0.06	0.19	0.05	0.15	-0.04	0.05	0.24	0.10	0.06	-0.25	0.08	0.46	0.09	0.07	0.07	-
Other Asia	0.12	0.10	0.05	0.03	0.07	0.08	0.10	0.03	-0.02	0.05	-0.04	-0.02	0.08	-0.05	-0.01	-0.08	-0.17	-
Latin America	0.18	0.19	0.19	0.25	0.20	0.24	0.22	0.27	0.25	0.24	0.24	0.26	0.26	0.25	0.25	0.25	0.24	-
Middle East	-0.18	-0.20	-0.26	-0.20	-0.21	-0.20	-0.23	-0.31	-0.25	-0.25	-0.24	-0.27	-0.37	-0.30	-0.30	-0.30	-0.31	-
Africa	0.05	0.02	0.07	0.05	0.05	0.07	0.03	0.09	0.06	0.06	0.05	0.06	0.12	0.08	0.08	0.09	0.09	-
Total Non-OECD	0.01	-0.01	0.30	0.68	0.25	0.35	0.20	0.40	0.70	0.41	0.45	0.11	0.33	0.60	0.37	0.33	0.27	-
World	-0.57	0.00	0.47	0.79	0.18	0.93	0.24	0.65	0.92	0.68	0.70	0.39	0.63	0.86	0.65	0.59	0.51	-
Revisions to Oil Demand Growth from Last Medium Term Report (mb/d)																		
World	-0.73	0.01	0.54	0.99	0.21	1.50	0.24	0.18	0.13	0.51	-0.22	0.15	-0.02	-0.06	-0.04	-0.05	-0.08	-

Table 3
WORLD OIL PRODUCTION
(million barrels per day)

	1Q07	2Q07	3Q07	4Q07	2007	1Q08	2Q08	3Q08	4Q08	2008	1Q09	2Q09	3Q09	4Q09	2009	2010	2011	2012
OPEC[6]																		
Total NGLs[1]	4.76	4.80	4.83	5.03	4.86	5.21	5.41	5.57	5.85	5.51	6.04	6.21	6.37	6.49	6.28	6.73	6.91	7.08
NON-OPEC[2]																		
OECD																		
North America	14.36	14.04	13.99	14.08	14.12	14.39	14.02	13.95	14.16	14.13	14.49	14.14	13.93	14.11	14.16	14.25	14.31	14.40
United States	7.44	7.39	7.20	7.19	7.30	7.47	7.46	7.36	7.44	7.43	7.64	7.63	7.39	7.39	7.51	7.59	7.55	7.38
Mexico	3.57	3.58	3.51	3.46	3.53	3.41	3.39	3.34	3.31	3.36	3.32	3.28	3.24	3.20	3.26	3.17	3.13	3.14
Canada	3.35	3.08	3.28	3.44	3.29	3.52	3.16	3.25	3.41	3.33	3.52	3.23	3.30	3.51	3.39	3.49	3.63	3.87
Europe	5.24	4.73	4.67	4.90	4.88	4.92	4.57	4.42	4.62	4.63	4.65	4.29	4.21	4.40	4.39	4.15	3.97	3.66
UK	1.76	1.60	1.51	1.65	1.63	1.65	1.50	1.37	1.51	1.51	1.54	1.41	1.30	1.41	1.41	1.26	1.14	1.01
Norway	2.72	2.39	2.42	2.52	2.51	2.53	2.34	2.33	2.40	2.40	2.39	2.17	2.21	2.29	2.26	2.20	2.18	2.05
Others	0.76	0.74	0.74	0.73	0.74	0.73	0.73	0.72	0.71	0.72	0.72	0.71	0.71	0.70	0.71	0.68	0.64	0.60
Pacific	0.59	0.65	0.70	0.72	0.66	0.73	0.76	0.79	0.84	0.78	0.83	0.81	0.84	0.86	0.83	0.81	0.72	0.66
Australia	0.53	0.59	0.62	0.63	0.59	0.64	0.66	0.68	0.71	0.67	0.71	0.69	0.72	0.73	0.71	0.70	0.62	0.57
Others	0.06	0.06	0.08	0.09	0.07	0.09	0.10	0.11	0.12	0.11	0.12	0.12	0.12	0.13	0.12	0.11	0.10	0.09
Total OECD	20.19	19.42	19.36	19.70	19.66	20.03	19.34	19.16	19.62	19.54	19.97	19.24	18.98	19.37	19.38	19.20	18.99	18.72
NON-OECD																		
Former USSR	12.55	12.59	12.57	12.80	12.63	12.82	12.97	13.05	13.29	13.03	13.31	13.45	13.58	13.69	13.51	13.82	14.09	14.37
Russia	9.91	9.88	9.99	10.00	9.95	9.97	10.06	10.20	10.31	10.14	10.28	10.37	10.45	10.52	10.41	10.59	10.61	10.53
Others	2.63	2.71	2.58	2.80	2.68	2.85	2.91	2.85	2.98	2.90	3.03	3.08	3.13	3.17	3.10	3.23	3.47	3.84
Asia	6.46	6.50	6.53	6.54	6.51	6.56	6.58	6.64	6.71	6.62	6.68	6.69	6.72	6.72	6.70	6.72	6.64	6.69
China	3.75	3.80	3.85	3.85	3.81	3.86	3.85	3.84	3.87	3.86	3.89	3.88	3.87	3.86	3.87	3.89	3.88	3.89
Malaysia	0.74	0.70	0.69	0.71	0.71	0.72	0.74	0.76	0.75	0.74	0.73	0.72	0.74	0.73	0.73	0.74	0.73	0.79
India	0.82	0.82	0.82	0.82	0.82	0.83	0.82	0.82	0.82	0.82	0.81	0.83	0.85	0.88	0.84	0.87	0.84	0.81
Others	1.15	1.17	1.16	1.16	1.16	1.16	1.18	1.22	1.28	1.21	1.25	1.26	1.27	1.26	1.26	1.23	1.18	1.20
Europe	0.14	0.14	0.13	0.13	0.13	0.13	0.12	0.12	0.12	0.12	0.11	0.11	0.11	0.11	0.11	0.10	0.09	0.08
Latin America	4.39	4.41	4.46	4.58	4.46	4.75	4.77	4.75	4.73	4.75	4.90	4.90	4.90	4.91	4.90	4.99	5.23	5.48
Brazil	2.15	2.15	2.22	2.36	2.22	2.54	2.57	2.57	2.56	2.56	2.69	2.70	2.71	2.73	2.71	2.79	3.02	3.27
Argentina	0.77	0.77	0.76	0.76	0.76	0.75	0.75	0.75	0.74	0.75	0.76	0.75	0.75	0.74	0.75	0.76	0.76	0.78
Colombia	0.52	0.54	0.54	0.54	0.54	0.54	0.54	0.54	0.54	0.54	0.54	0.54	0.54	0.54	0.54	0.54	0.55	0.56
Ecuador	0.50	0.51	0.50	0.48	0.50	0.48	0.47	0.47	0.46	0.47	0.49	0.48	0.47	0.47	0.48	0.48	0.48	0.47
Others	0.45	0.44	0.45	0.44	0.45	0.44	0.44	0.44	0.43	0.44	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.42
Middle East[3]	1.66	1.64	1.64	1.61	1.64	1.62	1.60	1.58	1.56	1.59	1.59	1.57	1.58	1.57	1.58	1.58	1.59	1.61
Oman	0.72	0.71	0.70	0.69	0.70	0.69	0.69	0.68	0.68	0.68	0.69	0.68	0.69	0.70	0.69	0.71	0.73	0.76
Syria	0.39	0.38	0.38	0.37	0.38	0.36	0.35	0.34	0.33	0.35	0.34	0.33	0.33	0.32	0.33	0.32	0.30	0.29
Yemen	0.36	0.36	0.38	0.37	0.37	0.39	0.38	0.37	0.36	0.37	0.37	0.36	0.38	0.37	0.37	0.38	0.38	0.38
Africa[6]	2.60	2.60	2.63	2.65	2.62	2.69	2.73	2.74	2.73	2.73	2.74	2.75	2.72	2.70	2.73	2.77	2.80	2.81
Egypt	0.64	0.63	0.63	0.63	0.63	0.63	0.63	0.62	0.62	0.62	0.62	0.61	0.61	0.61	0.61	0.62	0.65	0.69
Equatorial Guinea	0.35	0.36	0.36	0.36	0.36	0.36	0.35	0.35	0.34	0.35	0.34	0.34	0.33	0.33	0.33	0.35	0.37	0.36
Sudan	0.48	0.51	0.52	0.52	0.51	0.57	0.58	0.57	0.57	0.57	0.58	0.58	0.58	0.57	0.58	0.59	0.57	0.57
Others	1.13	1.10	1.12	1.14	1.12	1.14	1.17	1.20	1.21	1.18	1.21	1.22	1.19	1.19	1.20	1.21	1.21	1.19
Total Non-OECD[6]	27.80	27.87	27.97	28.31	27.99	28.58	28.77	28.89	29.14	28.85	29.32	29.47	29.62	29.71	29.53	29.99	30.43	31.03
Processing Gains[4]	1.92	1.92	1.92	1.92	1.92	1.95	1.95	1.95	1.95	1.95	1.98	1.98	1.98	1.98	1.98	2.00	2.03	2.06
Other Biofuels[5]	0.40	0.40	0.40	0.40	0.40	0.66	0.66	0.66	0.66	0.66	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75
TOTAL NON-OPEC[6]	50.31	49.62	49.65	50.33	49.98	51.22	50.72	50.66	51.37	50.99	52.02	51.44	51.33	51.80	51.65	51.94	52.20	52.56

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)

	1Q07	2Q07	3Q07	4Q07	2007	1Q08	2Q08	3Q08	4Q08	2008	2009	2010	2011	2012	Total
Refinery Capacity Additions and Expansions[1]															
OECD North America	26	95	15	55	191		86		30	116	215	290	395	100	1,307
OECD Europe			-60		-60						20	306	-22		244
OECD Pacific			135		135						34	115			284
FSU							3			3		140		140	283
Non-OECD Europe													30		30
China		60		110	170	160	200		346	706	536	150	340	400	2,302
Other Asia	150		136	16	302	58		90	110	258	910	154			1,624
Latin America			20		20		103			103	18	28			169
Middle East		15			15		146	110		256		351	120	1,781	2,523
Africa	13				13			50		50	100	150			313
Total World	189	170	246	181	786	218	538	250	486	1,492	1,833	1,684	863	2,421	9,079
Upgrading Capacity Additions[2]															
OECD North America	106	25		45	176		51		127	178	239	179	342	60	1,174
OECD Europe		40	25		65		40	20	40	100	94	227	73	100	659
OECD Pacific		4			4	55	18			73	103	50	125		355
FSU			18	20	38	20	30	104		154	92	69	113	155	622
Non-OECD Europe									16	16		26	30		72
China	42	54		41	137	56	243	30	222	551	332	262	155	180	1,617
Other Asia	35		93		128		80	7	79	166	885	236			1,415
Latin America				35	35	29	20	30		79	31	59			205
Middle East		-10			-10			80		80	165	94		638	967
Africa								53		53		30			83
Total World	183	113	136	141	573	160	482	325	484	1,451	1,941	1,233	838	1,133	7,168
Desulphurisation Capacity Additions[3]															
OECD North America	72		56		128	40	25		45	110	155	218	215	25	851
OECD Europe	-29	47		35	53						27	215	-1		294
OECD Pacific		94			94			22		22	180	42			338
FSU				87	87		43			43		95	51	120	396
Non-OECD Europe									3	3		4	30		38
China		40		60	100	124	177	116	372	789	378	220	240	388	2,115
Other Asia	45		84	70	199	20	80	20	77	197	622	165	20		1,203
Latin America	10			61	71	121	75	60		256	244	38			609
Middle East		106			106		40	45		85	266	364	45	1,328	2,193
Africa								20		20		87			107
Total World	98	287	140	313	838	305	439	283	497	1,525	1,871	1,449	600	1,861	8,144

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.

How much oil will the world consume in 2012? What role will OPEC play in global oil production? Will biofuels become an important part of the oil market? How will the refinery sector cope? The International Energy Agency (IEA) *Medium-Term Oil Market Report* tackles these questions, adopting a perspective that goes beyond the traditional short-term market analysis provided in the IEA *Oil Market Report*.

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