OIL
Medium-Term Market Report 2012

Market Trends and Projections to 2017

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International Energy Agency

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International Energy Agency

INTERNATIONAL ENERGY AGENCY

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FOREWORD

Few markets are more talked about and yet less understood than the oil market. While the global fuel mix is getting more diversified and 'cleaner' fuels such as natural gas and renewables are gaining market share, oil is projected to remain the main source of energy for the foreseeable future. Because oil plays a role, whether directly or indirectly, in virtually every aspect of society, oil seems always to be in the news – but the relentless news flow can easily feel confusing and overwhelming, even for specialists.

This *Medium-Term Oil Market Report,* part of a series of five-year outlook reports that the IEA is devoting to each of the four main primary energy sources: oil, gas, coal and renewable energy, is an attempt to take stock, and make sense, of recent developments in the oil market, to place them in perspective and to draw their consequences for the next few years. A companion to the IEA's authoritative *Oil Market Report*, it serves as a bridge between that monthly snapshot of oil market conditions and the oil-related sections of the *World Energy Outlook*, which focuses on the longer term.

This report comes at an opportune time, because recent events and developments have been of exceptionally great import to the oil market. On the supply side, continued political upheaval in the Middle East and North Africa has disrupted crude exports from several countries, while the implementation of expanded international sanctions on Iran last July removed roughly 1 mb/d of third-quarter crude supplies. This was an illustration of the proverbial 'above-ground' risks facing the oil market, but oil production has also undergone momentous shifts below ground. The impact of innovative production technologies on North American supply has been larger than expected and truly transformative. At the same time, unplanned maintenance and technical disruptions at mature fields have reached an unprecedented scope, rekindling concerns about decline rates in ageing plays.

While crude disruptions in the Middle East and North Africa have attracted most of the media interest, the region has had its share of success stories, including surprisingly steep production increases in Iraq and Saudi Arabia and post-civil war Libya – sometimes at the expense of available spare production capacity. On the demand side, growth has been below forecast, as the economic recovery failed to live up to expectations. OECD countries remained plagued with persistent debt concerns, especially in the euro zone, and there are signs that even China may be slowing down.

Extrapolating in part from those recent trends, this report expects further growth in both North American production and Iraqi capacity. It has also ratcheted up expectations of economic expansion and oil demand growth back a few notches. The result is a noticeably more comfortable oil supply/demand balance by the end of the forecast period than previously expected and than has been the case through most of the last decade. The 'call on OPEC and stock changes' is expected to average below current OPEC production levels, while OPEC spare capacity is forecast to return to more comfortable levels than the sometimes razor-thin cushion that had worried market participants in recent years.

Behind this deceptively calm picture, however, this report unveils an oil map reshaped by broad regional shifts. Forecast growth in both demand and supply is more lopsided than ever, with most of the new supply expected from the Americas and most of the new demand from the 'East of Suez' region. These twin changes are pregnant with consequences for the midstream and downstream sectors, those often overlooked but critical links in the supply chain. International crude trade volumes are forecast to dip, while product trade is expected to grow in both volume and scope amid resurgent refining capacity expansion largely focused on Asia and the Middle East.

As this report makes clear, a projected return to more comfortable supply/demand balances also should not obscure the high level of risks facing the market, both on the demand and on the supply side. At the time of writing, the Syrian civil war still rages on, while the Iranian nuclear dispute remains unresolved. This report assumes that international sanctions on Iran will remain in place through the forecast period - obviously an untested hypothesis.

This report does not claim any special insight as to the outcome of the Syrian crisis or the Iranian nuclear dispute, both of which could have a significant impact on the oil market. It does represent our best effort at sketching out and succinctly and comprehensively analysing what we know about the medium-term oil market outlook at this point in time. In so doing, we hope that it will help policy makers, market participants, industry stakeholders and the public at large achieve a better understanding of the broader context in which the inevitable surprises, wherever they may come from, will play out.

This report is published under my authority as Executive Director of the IEA.

Maria van der Hoeven

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OVERVIEW

An oil market caught between crisis and normality

Revised assumptions, based on the market developments of the last 18 months, sketch out a seemingly more benign medium-term market outlook than set forth in the previous Medium-Term Oil and Gas Markets report of June 2011 (and its December 2011 update). Against the backdrop of sluggish economic growth and increasing energy efficiency, the demand outlook looks more subdued, while the transformative power of non-conventional oil production technologies applied in shale and tight formations in North America exceeds earlier expectations. With downwardly revised demand projections and the promise of new supplies, the 'call on OPEC' has been trimmed and OPEC spare capacity looks set to return to more comfortable levels than recent years. But this mild outlook is partly deceptive, given exceptional uncertainty about the global economy and heightened regional geopolitical risks. Headline figures about aggregate supply and demand also should not obscure the profound disruptions entailed by the regional redistribution of demand and supply growth for the midstream and downstream sectors.

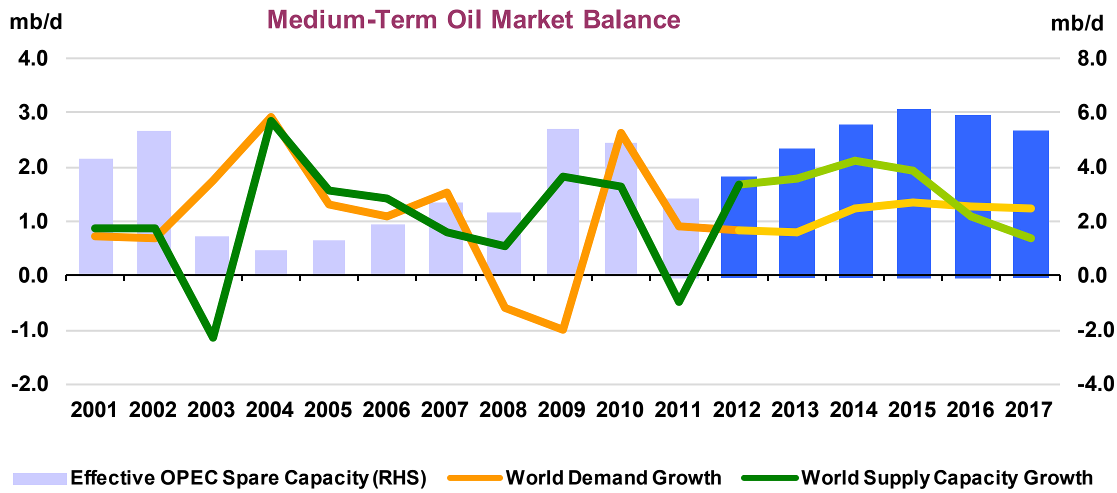
Global Balance Summary
(million barrels per day)

	2011	2012	2013	2014	2015	2016	2017
GDP Growth Assumption (% per year)	**3.69**	**3.26**	**3.61**	**3.86**	**4.04**	**4.17**	**4.26**
Global Demand	**88.95**	**89.79**	**90.60**	**91.82**	**93.16**	**94.45**	**95.68**
Non-OPEC Supply	52.78	53.22	53.96	54.80	55.96	56.84	57.53
OPEC NGLs, etc.	5.78	6.22	6.50	6.64	6.88	6.95	6.94
Global Supply excluding OPEC Crude	**58.56**	**59.44**	**60.46**	**61.44**	**62.84**	**63.79**	**64.47**
OPEC Crude Capacity	**34.21**	**35.00**	**35.78**	**36.90**	**37.42**	**37.55**	**37.54**
Call on OPEC Crude + Stock Ch.	**30.39**	**30.35**	**30.14**	**30.38**	**30.32**	**30.66**	**31.21**
Implied OPEC Spare Capacity[1]	3.81	4.65	5.64	6.52	7.09	6.89	6.34
Effective OPEC Spare Capacity[2]	2.81	3.65	4.64	5.52	6.09	5.89	5.34
as percentage of global demand	*3.2%*	*4.1%*	*5.1%*	*6.0%*	*6.5%*	*6.2%*	*5.6%*
Changes since December 2011 MTOGM							
Global Demand	**-0.05**	**-0.48**	**-0.93**	**-0.88**	**-0.68**	**-0.54**	
Non-OPEC Supply	0.10	-0.47	-0.12	0.27	0.30	0.76	
OPEC NGLs, etc.	-0.02	-0.14	-0.19	-0.24	-0.34	-0.42	
Global Supply excluding OPEC Crude	**0.08**	**-0.60**	**-0.32**	**0.03**	**-0.04**	**0.35**	
OPEC Crude Capacity	**-0.44**	**-0.48**	**-0.61**	**-0.14**	**-0.40**	**-0.53**	
Call on OPEC Crude + Stock Ch.	**-0.13**	**0.12**	**-0.61**	**-0.91**	**-0.65**	**-0.89**	
Effective OPEC Spare Capacity[1]	-0.31	-0.61	0.01	0.77	0.25	0.36	

1 OPEC Capacity minus 'Call on Opec + Stock Ch.' 2 Historically effective OPEC spare capacity averages 1 mb/d below notional spare capacity.

On the consumption front, both forecast growth rates and the assessment of current demand have been downwardly adjusted. Revisions to historical data and weaker-than-expected economic growth have cut the assessment of 2012 demand by roughly 500 kb/d. Expectations of economic growth through the forecast period have been reduced amid persistent OECD debt concerns, especially in the euro zone. Even China, the main engine of demand growth in the last decade, is showing signs of slowing down.

On the supply side, technological advances and innovation, despite logistical bottlenecks and constraints to market access, have unlocked more supply growth than anticipated in North America, a trend that is now expected to continue, albeit at a somewhat reduced rate, for the next five years. OPEC production has not been without surprises either. The Libyan production recovery of 2012 defied expectations, Iraqi output scaled new heights and Saudi Arabia has been producing at 30-year highs for most of 2012. Iraqi production growth is expected to continue for the next five years and beyond, as the country looks set on a growth path that, if everything falls into place, could lend it a pivotal role in meeting longer-term demand growth.



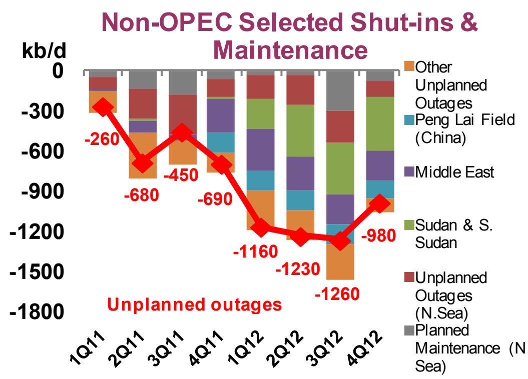
Yet those pockets of new supply in the last year have merely served as a buffer against shortfalls elsewhere. Disruptions – whether caused by political turmoil, unplanned maintenance or extreme weather – have been relentless and, taken in aggregate, unprecedented in scope. The last few years have also brought home the reality of Middle Eastern and North African geopolitical risk, not just as an abstract and remote threat hanging over the markets but as a concrete and immediate possibility. Following the Libyan disruption of 2011, political turmoil cut production in Yemen, Syria and Sudan, while the dispute between Iran and the international community over that country's nuclear program triggered in July the implementation of expanded international sanctions that have withheld around 1 mb/d of third-quarter supply from international markets. At the time of writing, the Syrian civil war keeps on raging, fuelling concerns about regional spill-over effects. With no end in sight to the Iranian dispute, this report assumes that current sanctions will remain in place for the duration of the forecast period, progressively eroding Iran's long-term production capacity. Yet the situation remains highly unpredictable and the sustainability of the sanctions over the longer term is evidently untested. Therefore, this should be understood as no more than a working assumption.

The mutually balancing effect of surging North American output and lower-than-expected global demand growth on the one hand and, on the other hand, supply shortfalls has kept prices elevated by historical standards over the last years, if highly volatile. At their March high, Brent crude prices came close $130, only to fall to lows of about $90 in June. Those gyrations have been accompanied by wide swings in both OECD commercial oil inventories and the 'miscellaneous to balance' line item in our balances, a.k.a. non-OECD commercial and strategic stocks. The IEA MTOMR model uses oil prices as an input of its forecasting model rather than an output. For better or worse, this report, as do others, relies on the futures curve as a source of price assumptions. Readings suggest a gradual easing of prices over the forecast period, in line with a shift to more comfortable supply/demand balances and OPEC spare capacity, though within a still historically elevated band.

Renewed focus on supply-side risks

As the recent subdued pace of demand growth and the rapid expansion of North American supplies are projected forward, our balances suggest the return of more comfortable balances than had been foreseen when the economic recovery seemed on surer footing. The call on OPEC, on an annual average basis, is not expected to exceed 31 mb/d until 2017, after remaining in the low 30 mb/d range through most of the forecast period. In contrast, last year's MTOMR foresaw a call of 32.5 mb/d by 2016. By the end of the forecast period, OPEC effective spare capacity is projected to more than double from 2.8 mb/d to somewhere between 5 mb/d and 7 mb/d, a level unseen since before the 2003-2008 rally, except briefly after the financial crisis of 2008-2009. This apparent 'normalisation' of market balances must be placed in context, however.

An important takeaway from recent experience is that after a decade dominated by concerns about runaway demand growth, elevated supply-side risks have become a fact of life in the oil market. Speaking of 'unprecedented uncertainty' may be an unwelcome cliché of oil market forecasting, especially when it is merely invoked as a way of hedging one's forecast. Yet an increase in uncertainty and risk is a tangible reality that must be taken on board in analysing recent market developments and forecasting medium-term trends. The increase in the disruption allowances included in our forecasts – a mathematical average of recent disruptions -- only partially captures this new reality. Last year's string of supply disruptions, in Syria, Yemen, Sudan, the North Sea, Brazil and the Gulf of Mexico, illustrated the possibility of a 'perfect storm' of coincidental disruptions in many oil provinces. Even those realized disruptions, however, pale in comparison with the new threat of unrest and political turmoil spreading further at the heart of the Middle East producing region.



Effective levels of spare capacity, or the market's ability to mobilise and deploy the full extent of nominal OPEC capacity, also becomes somewhat more problematic in the context of the Iranian nuclear dispute. Nonetheless, a return to more comfortable OPEC spare capacity levels increasingly looks like insurance against elevated disruption risks, not least within OPEC itself, as well as beyond. Whereas in the past, more comfortable OPEC spare capacity would normally have been associated with a downturn in price, a higher risk environment may allow elevated prices and relatively high spare capacity to coexist – just as the 2003-2008 rally had seen concurrently a run-up in prices and an inventory build fuelled by growing precautionary demand for storage.

A new oil map

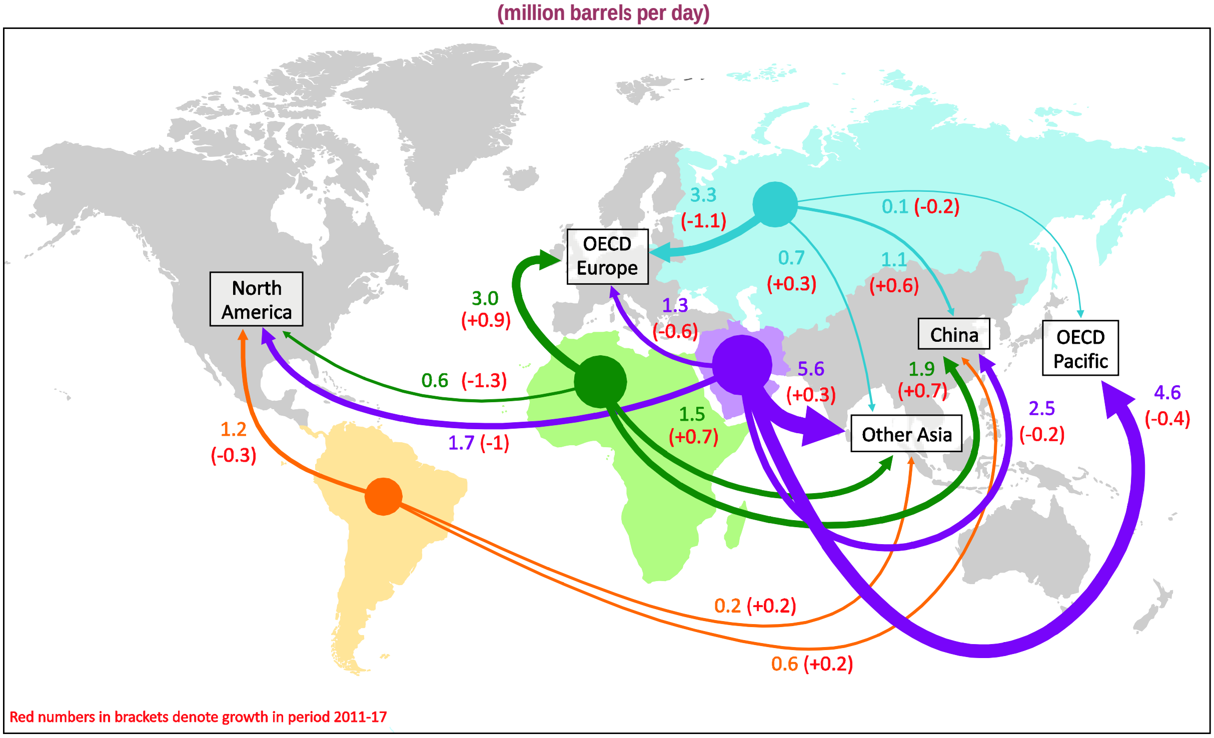
Beyond the headline supply/demand figures, the oil map will be deeply transformed in the next five years as the regional rebalancing of production and end-user consumption trickles through to the midstream and downstream sectors. The effects on global refining and crude and product trade are expected to be profound.

On the downstream side, shifts in the regional distribution of demand and in the makeup of the demand barrel by product, combined with new sources of supply growth, continue to reshape the global refining industry. OECD Europe, confronted with diminishing demand, challenging environmental standards, constraints in feedstock access and a refining fleet that includes many aging assets, faces continued capacity attrition. North America for the main part benefits from new, discounted feedstock supply, some of the lowest energy costs on the planet in the form of cheap natural gas, economies of scale and at its most advanced plants state-of-the-art technology. Within the US, eroding domestic demand and a glut of unconventional supply is converting a once inward-looking refining industry into a fast-growing export business. Increasing product exports from large Gulf Coast refineries support the nation's reindustrialisation fuelled by unconventional oil and gas, even as diminishing gasoline import needs pose a challenge to exporters elsewhere.

In Asia and the Middle East, it is capacity expansions, rather than declining demand, that fuel a comparable, and even greater, increase in product exports. China, India and Saudi Arabia lead the trend. But the exact scope of this evolution hinges on the potential emergence of a mismatch between Chinese domestic demand growth and the nation's ambitious program of capacity expansion. If all planned projects go ahead while demand growth slows as much as we forecast, China could emerge, at least for a while, as a new powerhouse in product exports, helped by its companies' growing footprint abroad in international refining, storage, terminal and logistics.

Crude exports in 2017 and growth over 2011-17 for key trade routes*

(million barrels per day)



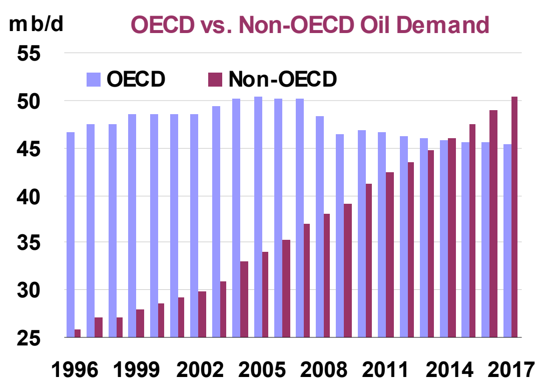
This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

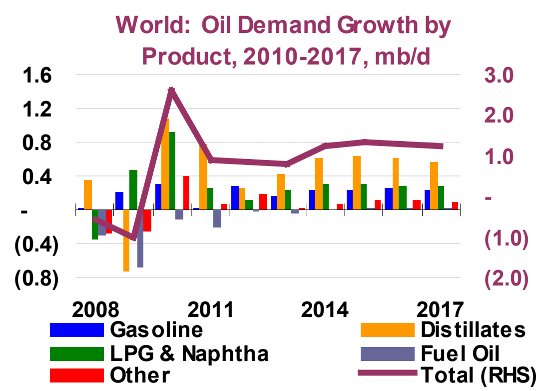
The redrawing of the oil map will also deeply affect trade flows. The crude trade map becomes increasingly split over the forecast period between a more and more self-contained western hemisphere and the rest of the world. Once a large importer, North America moves closer to balance thanks to surging non-conventional production in Canada and the US Mid-Continent. The changing quality of US domestic crude production also deeply affects US trade flows, backing out most light, sweet grades previously imported from West Africa and elsewhere. Robust demand growth in the Middle East and FSU regions combined with extensive refinery investments reduce crude supplies available to other regions.

The product trade map, in contrast, grows increasingly integrated and inter-dependent. Long-haul product trade volumes increase, providing the market with both heightened flexibility and, potentially, increased price volatility. As sustained demand growth for middle distillates runs ahead of supply, consumers at peak demand times grow increasingly dependent on imports and various remote markets increasingly compete for limited supply. In contrast, excess gasoline supply increasingly struggles to find market outlets. The implications for energy security, while beyond the scope of this report, may be significant.

Demand

Based on both recent economic performance and revisions to historical demand, our projection of global demand has been trimmed by roughly 500 kb/d since our December 2011 MTOGM report for the 2011-2016 period. Global oil product demand is now projected to increase by roughly 1.2% or 1.1 mb/d per year over the next five years to 95.7 mb/d in 2017 from 89.0 mb/d in 2011, based on the assumption of global economic growth of 3.9% per year. Over the course of the forecast periods, this translates into significantly slower growth than in previous forecasts, as OECD demand is expected to keep contracting while non-OECD growth now looks somewhat less robust than previously expected.





Within the non-OECD, Chinese demand is projected to enter into a period of somewhat lower growth than in the previous decade, as credit problems affecting the EU and other OECD countries trickle through to emerging and newly industrialised export economies. China's changing demographic outlook contributes to the more muted outlook. A compounding factor behind the lower global demand forecast is an expected improvement in average energy efficiency over the medium term. This report assumes that oil intensity declines by around 2.5% per year in the next five years.

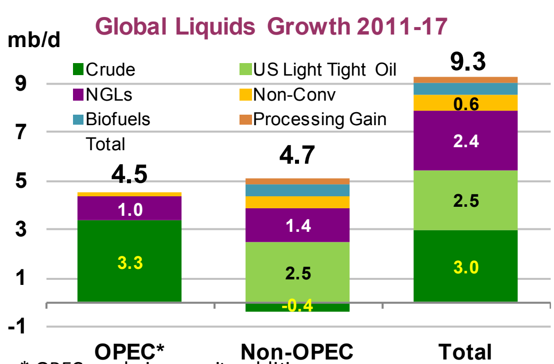
Despite the more subdued overall outlook, however, the reallocation of demand growth by region continues. The inclusion of several new countries in our OECD statistics since last year does not stop the OECD from ceding market share to non-OECD countries in terms of both economic might and oil demand. Non-OECD countries are projected to overtake the OECD in economic weight by 2016 and to account for nearly 52% of worldwide wealth by 2017, as China overtakes the US as the world's largest economy (at 18.2% and 17.5% of global GDP, respectively, on a purchasing power parity basis). In oil demand terms, non-OECD economies are projected to run ahead of the OECD as early as 2014. Broadly speaking, emerging and newly industrialised economies are more energy -intensive than the mature economies of the OECD. By 2017, the non-OECD share of global oil demand is forecast to reach 53%, up from just 36% as recently as 1996.

Non-OECD demand also accounts for all of the global increment over the forecast period, increasing by an average 2.9% or 1.3 mb/d per year, to 50.3 mb/d in 2017 from 42.4 mb/d in 2011. Asia and the Middle East lead the growth, followed by the former Soviet Union and Africa. In contrast, demand in the traditionally richer OECD edges lower, down by an average of 0.2 mb/d (or -0.4%) per annum, to 45.4 mb/d in 2017.

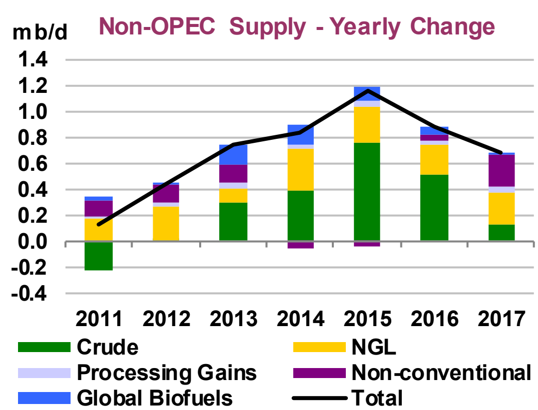
Shifts in the fuel mix also extend earlier trends. As in the past, demand growth continues to be dominated by the so-called middle of the barrel. Diesel/gasoil lead global oil use, with consumption projected to rise by 500 kb/d or 1.7% annually to 28.8 mb/d by 2017, from 26.1 mb/d in 2011. Non-OECD Asia will lead the growth (roughly 50% of total global growth), particularly China, where demand is forecast to rise by 3.9% per annum through the outlook period, to 11.3 mb/d by 2017.

Supply

While the demand outlook looks more subdued than in previous forecasts, the supply forecast has become more robust. Global production capacity is expected to increase by an aggregate 9.3 mb/d over the period to 102 mb/d in 2017, or 1.5 mb/d per year. Around 20% of liquids growth comes from Iraqi capacity and 40% comes from North American oil sands or light tight oil production. Natural gas liquids (NGL) supply grows by 2.4 mb/d from to 14.5 mb/d in 2017, of which non-OPEC NGLs (centred in the US) contribute around 60%.



* OPEC crude is capacity additions
Global Refinery processing gains included in Non-OPEC



OPEC crude oil production capacity is forecast to rise by a steep 3.34 mb/d over the 2011-2017 period, to 37.54 mb/d, with Iraq providing just over 50% of the increase. By contrast, sanctions hit Iran sees production capacity decline by more than 30% by 2017 compared to 2011 levels. This relatively higher capacity headline figure is skewed, however, by the temporary drop in OPEC capacity to a four-year low during the 2011 Libyan civil war. Recovering Libyan production provides a near 40% increase in our forecast and if removed from the calculations shows OPEC will raise capacity by a smaller 2.08 mb/d, in line with growth rates of previous years.

Non-OPEC supply is expected to increase by 4.8 mb/d from 2011 to 2017, or at an annual average of 790 kb/d (9%). Remarkably, roughly 80% of the growth comes from North American light tight oil and Canadian oil sands production, offsetting mature field decline elsewhere. This growth reflects the formidable power of the technological advances applied to developing unconventional resources – a technological revolution akin to the onset of 3-D seismic exploration and development in the 1980s. So far these technologies have been focused on the North American oil patch, reflecting not only the region's large non-conventional resources but also its favourable investment conditions. While there is a strong potential for the same transformative technologies to lift unconventional production elsewhere, that is not expected to bear fruit until after the forecast period.

For the next five years, there will thus be a striking regional imbalance in the allocation of non-OPEC supply growth, with the Americas accounting for the vast majority of the increment. In addition to the US and Canada, the Brazilian subsalt and Colombia are expected to contribute. OPEC member Venezuela may also see marginal growth in unconventional output, though the country is not expected to overcome its above-ground challenges in the forecast period, even in the event of a shift in political power.

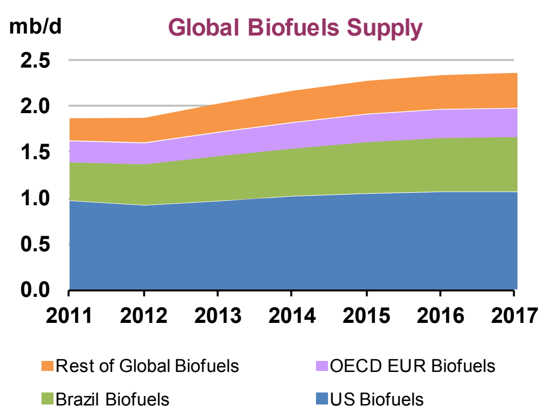
High oil prices drove capital spending up by around 8% in 2012, but they have also led to increased demand for labour and oilfield service equipment. Finding and development costs (and cost inflation) are slightly lower now than in 2011 (especially in the US). Lower crude prices would translate into lower drilling activity and production rates in the medium term, and therefore represent a downside risk to the forecast.

While the broad uptake of horizontal technologies to tap tight oil deposits outside of the US could increase oil supplies, geopolitical unrest could also threaten oil production and transport, especially in the Middle East and Africa.

Biofuels

Biofuel production is forecast to grow 0.5 mb/d over the medium-term, with volumes rising from 1.9 mb/d in 2011 to 2.4 mb/d in 2017.

Higher biodiesel output in the US and Latin America drives a slightly stronger medium-term growth than envisioned in the December 2011 forecast. The "advanced biofuels" sector is expected to grow rapidly, albeit from a very low base, rising to 180 kb/d in 2017 from 55 kb/d in 2011.

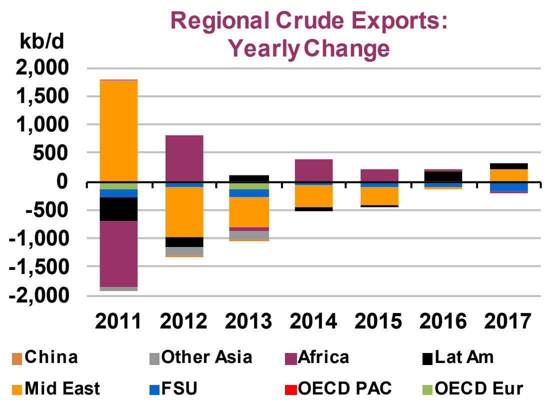


Crude trade[1]

The lopsided distribution of supply growth over the next five years is expected to carry significant implications for crude oil trade. As the US and Canada dominate non-OPEC growth, diminishing OECD American import requirements are expected to continue recent trends and cut inter-regional crude oil trade by a further 1.6 mb/d, to 32.9 mb/d. While the Middle East is expected to retain its role as

[1] Please note that in the Crude Trade, Refining and Product Supply discussions in this report, new OECD members Chile and Israel are accounted for in Latin America and the Middle East, respectively.

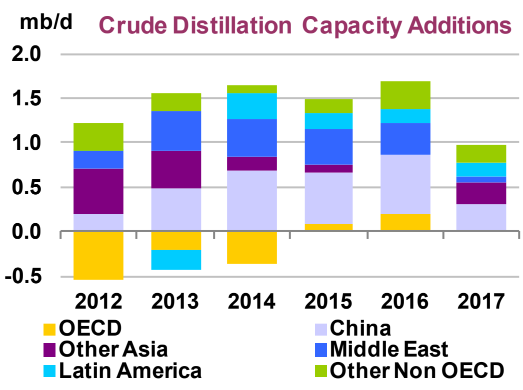
the world's key producer, increasing regional demand and refining capacity will keep more crude in the region, cutting available exports to markets by an aggregate 1.9 mb/d over the forecast period. Export potential in 2017 is still a respectable 15.9 mb/d, of which an even larger share will be going to East of Suez markets than is already the case. Africa remains the number two exporter, with exports projected at 7.7 mb/d by the end of the forecast period. The crude trade map will increasingly be split into two parts, a more self-contained western hemisphere and the rest of the world.

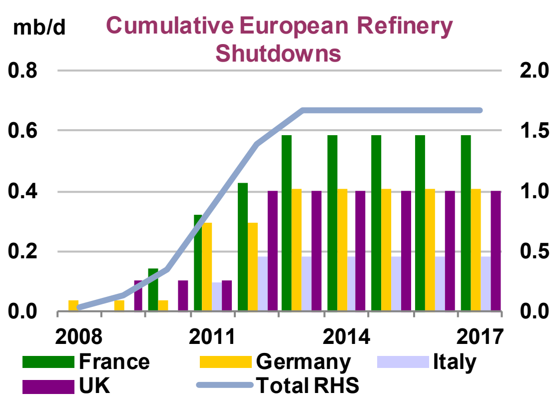


Not surprisingly, rising non-OECD consumption translates into a larger share of global crude imports for the region, reaching 15.4 mb/d in 2017. 'Other Asia' and China drive this growth as their import requirements are set to reach 8.1 mb/d (1.5 mb/d aggregated growth) and 6.1 mb/d (+1.1 mb/d) by 2017, respectively.

Refining and product supply[2]

Global refinery crude distillation (CDU) capacity is set to increase by close to 7 mb/d over the forecast period, faster than oil demand. This marks a reversal from the last three years, when oil product demand grew faster than capacity, resulting in an improvement in refining profitability in 2012. Upgrading and desulphurisation capacity also increase, respectively by 6.0 mb/d and 5.5 mb/d. Contraction in the OECD partly offsets capacity expansions elsewhere: more than half of the new CDU capacity comes from non-OECD Asia, led by China, while the Middle East provides significant additions.





As refining capacity grows faster than demand, refinery utilisation is expected to slip to 79% on average in 2017 from 83% in 2006-2008. It doesn't help refiners that new product supplies, such as biofuels, NGL and crude for direct burn, increasingly bypass the refinery system altogether. To return to 2006-2008 utilisation rates, an extra 4.4 mb/d of CDU capacity would have to be shut or

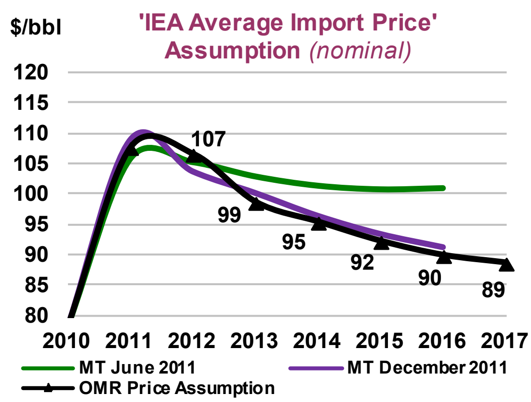
[2] Please note that in the Crude Trade, Refining and Product Supply discussions in this report, new OECD members Chile and Israel are accounted for in Latin America and the Middle East, respectively.

completion deferred compared to currently announced plans. Increased capacity will again undermine refining margins, unless more capacity is shut, more projects are delayed or cancelled, or demand surprises to the upside.

The main loser in the expansion of global refining capacity will be the OECD, especially Europe. Completed and committed shutdowns have already cut capacity by 1.3 mb/d since the December 2011 MTOGM update. Refinery closures now total 4 mb/d since the economic downturn of 2008, including 1.7 mb/d in Europe alone. Continued OECD demand contraction will call for additional industry consolidation before 2017. Despite the increase in refining capacity, however, middle distillate markets remain tight throughout the forecast period.

Oil pricing

Oil prices are expected to remain volatile over the forecast period amid heightened supply and demand uncertainty. Like those for other commodities, oil prices are inherently volatile and volatility itself varies over time. Inherent volatility in oil prices is primarily a result of uncertainty about global business conditions and lack of data, rather than financial speculation. In the next five years, the global business outlook looks exceptionally cloudy, and the shift in market share towards the non-OECD economy more often than not comes with deteriorating rather than improving data quality.



Shifts in oil prices have rekindled debate about the role of speculators and financial players in oil price volatility. Academic research is nearly unanimous in suggesting that speculators should not be viewed as adversarial agents. Rather, they are essential participants for the proper functioning of commodity derivatives markets, providing necessary liquidity, and thereby reducing market volatility. Recent regulatory measures, such as speculative position limits, aimed at limiting the participation and reducing the risk bearing capacity of "speculators" may have unintended consequences, such as decline in liquidity, higher hedging costs and increased volatility in energy markets.

The correlation between individual commodities and other asset classes, including equities and exchange rates, has been relatively high. Activities of financial players, commodity prices and other asset prices might just be responding in sync to unexpected global business conditions.

Financial and regulatory reform is expected to reshape financial flows and the forms of financial participation in the oil market, but may not necessarily affect price levels. New regulations have already affected over-the-counter (OTC) swaps markets. The migration of market activity from OTC derivatives to futures markets intensified ahead of the recent implementation of new swaps rules in US markets.

OIL PRICING

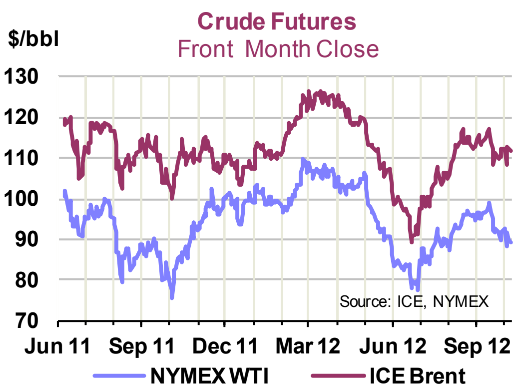
Summary

- **Prices for oil, like those for many other commodities, are inherently volatile and volatility itself varies over time.** Inherent volatility in oil prices is primarily a result of uncertainty about global business conditions and lack of data, rather than financial speculation.
- **The correlation between individual commodities and other asset classes, including equities and exchange rates, has been relatively high**. Activities of financial players, commodity prices and other asset prices appear to be increasingly responding to unexpected global business conditions.
- **New regulations have already impacted OTC swaps markets.** Migration from OTC derivatives markets to futures markets intensified just before the implementation of new swaps rules. Lack of consensus between regulators, as well as some of the new rules themselves, are seen by some observers to potentially have unintended consequences.
- **Oil prices can be affected by quantitative easing, but the extent of the impact might be very limited.** Policy actions, such as expansionary monetary policy, can impact commodity prices to the extent that they affect oil price fundamentals, such as real economic activity and interest rates.
- **Opinion remains polarised between those seeing the majority of recent price movement related to oil market fundamentals** and those who see speculative activity and the financialisation of commodities as amplifying price shifts in the short run.

Recent price developments

Global oil prices have remained at historic high levels over the past year though diverging market trends saw bench crudes trade in an exceptionally wide range over the past 12 months. Relatively anaemic global demand growth and higher inventories were largely eclipsed by heightened political risks and oil supply disruptions in the MENA region and the North Sea.

Futures prices for North Sea Brent and US WTI traded in a broad \$24-29/bbl range on a monthly basis, similar to the price trends seen in our June 2011 report. Brent crude prices reached a new monthly high of \$124.54/bbl in March 2012 due to unplanned outages in North Sea, Yemen, Syria and elsewhere among other non-OPEC producers. Implementation of new EU and US sanctions on Iran also added upward momentum to prices from July onwards. However, weaker demand and increased OPEC supplies pressured prices lower at times, with Brent futures falling to an 18-month low of \$95.93/bbl in June, before edging steadily higher by September to an average \$113.03/bbl. WTI futures largely moved in tandem with Brent, reaching a high of \$106.21/bbl in March before dipping to a low of \$82.41/bbl in June then rebounding to \$94.56/bbl in September.

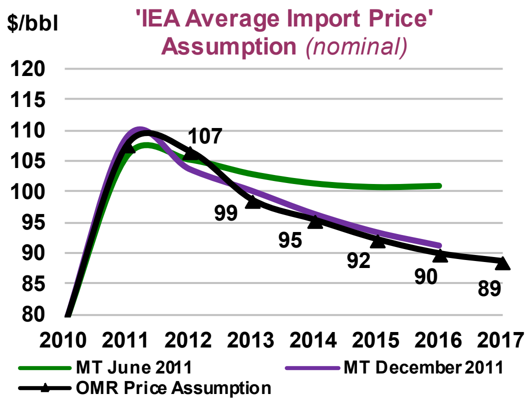


Overall, this report shows an easing of market balances yet price movements will remain hostage to political risks and operational issues as well the unsteady global economic recovery and financial market activity (see *'Emerging Issues in Oil Markets'*).

Methodology for calculating the IEA average import price

Our current price assumptions for the 2012-2017 period, based on the Brent futures strip and nominal IEA crude import prices, ranges from a high of just over $107/bbl in 2012 to a low of $89/bbl in 2017. WTI continues to remain disconnected from other international crudes and; as a result, we continue to use Brent futures as a baseline for this report. The price assumption derives from ICE Brent futures as of late-August 2011.

It is worth stating again that our short- and medium-term models deploy a non-reiterative price assumption, rather than a forecast. This assumption is broadly generated by using a combination of historical ICE Brent futures and the six-year forward price curve, which is then benchmarked against the average crude oil import price for IEA member countries. An average 2.3% historical discount for IEA import prices versus Brent futures is applied for the outlook period. The resultant price strip shown here is $1.35/bbl higher in 2012 than last year medium-term estimate, and between -$4 and -$11/bbl lower for the period 2013-2017.



Emerging issues in oil markets

Oil prices have experienced large fluctuations in recent years. The spike in crude oil prices in mid-2008 to more than $140/bbl, followed by a steep correction in late 2008/early 2009 and subsequent sharp rebound over the last three years have jolted the world economy, and spikes have pinched consumers at the fuel pump. In 2012 alone, WTI crude oil prices have fluctuated in a wide range from $78/bbl to $109/bbl.

Higher volatility will certainly impact both consumers and producers. Oil exporting countries can be negatively affected by the impacts of high volatility in oil prices on fiscal revenues, investment and confidence in the economy. Higher volatility can also have negative impacts on inflation and growth prospects in oil importing countries as well. However, careful examination of price data shows that recent observed volatility in the oil market either remains consistent with or is even lower than the historical average.

The debate on linkages between financial and physical oil markets has evolved over time. Opinion remains polarised between those seeing the majority of recent price movement being due to oil market fundamentals and those who see speculative activity and the financialisation of commodities as amplifying price shifts in the short run. On the one hand, while entrenched views on the role of speculation and fundamentals were evident among academia, a majority of economists tend to view speculators as playing a more limited role than fundamentals, at least over longer periods of time. On the other hand, many policymakers, producers and consumers remain convinced that speculation affects commodity prices still continues.

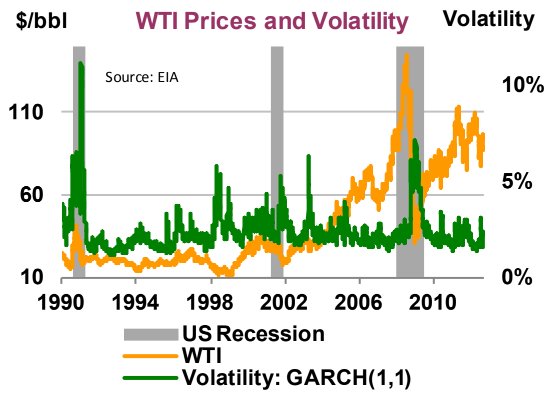
While the debate on the role of financial players on prices is not settled yet, one of the most important stylised facts since the height of the financial crisis and into the post-crisis period is that the correlation between individual commodities and other asset classes, including equities and exchange rates, has been relatively high. Some research argues that the increase in correlation alone reflects the fact that commodity markets in general were increasingly driven by broad trends in financial investment, and not by their own unique supply and demand factors. Others argued that activities of financial players, commodity prices and other asset prices might be increasingly responding to common factors, such as expectation of global economic activity or monetary policy.

Volatility in crude oil prices

Prices for oil, like those for many other commodities, are inherently volatile and volatility itself varies over time. However, it is important to distinguish volatility from absolute day-to-day changes in prices. Absolute price change does not give any information regarding the observed volatility in the market. It is important to note that volatility measures variability, or dispersion from a central tendency. In this respect, volatility does not measure the direction of price changes; rather it measures dispersion of prices from the mean.

In order to explore the nature of volatility inherent in WTI crude prices, the following Generalized AutoRegressive Conditional Heteroskedasticity (GARCH) model was estimated to produce conditional volatility for daily crude oil return r_t:

$$r_t = \mu + \epsilon_t \qquad \epsilon_t \sim N(0, \sqrt{h_t})$$
$$\epsilon_t = z_t \sqrt{h_t}$$
$$h_t = \vartheta + \alpha \epsilon_{t-1}^2 + \beta h_{t-1}$$



where h_t is the conditional variance and $\sigma_t = \sqrt{h_t}$ is the conditional standard deviation, which measures volatility. GARCH estimation produces a measure of conditional volatility which is less noisy than the absolute return approach but it requires that the model defining the true data generating process z_t be Gaussian, and that the time series be long enough for maximum likelihood estimation.

Much attention focused on how annualised average daily volatility peaked in January 2009 at 102%, followed by a rapid decline to relatively low levels. However, the historical peak for volatility was in January 1991, at an average annualised 108%. Up until July 2012, average annualised volatility for the year was relatively stable at around 25%. Volatility in WTI prices increased especially in July 2012, reaching more than 42%, reflecting a rapid decline in prices in late June and an increase in July. However, volatility fell to average level of 30% in August, which is 7% lower than historical average, at a time when the price level increased by almost $10/bbl.

Volatility is certainly related to uncertainty over the health of the global economy, as oil prices naturally track any macroeconomic news. The geopolitical risk premium also added to volatility in oil prices. In addition, the lack of supply chain flexibility amplifies the natural volatility in prices. Furthermore, data gaps, especially on physical demand, supply, inventories and transportation, contribute to price volatility.

Those who see speculative activity and the financialisation of commodities as amplifying price moves in the short run argue that speculative trading played a major role in crude oil price volatility. They contend that limiting speculative activity is necessary to abate volatility in oil prices (see, *e.g.*, Tang and Xiong (2011)). However, there are many academic studies showing that speculative activity does not lead to any price changes, but it rather reduces market volatility and illiquidity (see, *e.g.*, Buyuksahin, Brunetti and Harris (2012a, 2012b)).

The impact of speculation on prices

High oil prices have once again redirected attention to the role of speculators in oil markets. On the one hand, while entrenched views on the role of speculation and fundamentals were evident among academicians, a majority of economists tend to view speculators as playing a more limited role than fundamentals, at least over longer periods of time. On the other hand, producers, consumers and particularly policy makers increasingly blame speculators for fluctuations in commodity prices, particularly in energy prices, even though a futures market lacking speculators to take the other side of price-hedging transactions of physical market players would arguably be one that would be much more volatile. Some commentators even inadvertently associate speculative activity with manipulation. In the meantime, speculation and speculators have become so unpopular that some even propose an outright ban on speculation in commodity exchanges in general, and in oil markets in particular.

In general economic terms, buying or selling any asset in anticipation of a price change constitutes speculation. In this sense, the distinction between hedging and speculation in futures markets is less clear than it may appear. Traditionally, traders with a commercial interest in or an exposure to a physical commodity have been called hedgers, while those without an underlying exposure to offset have been called speculators. However, hedgers may also take a view on the price of a commodity or may not hedge in the futures market despite having an exposure to the commodity, choices that could be considered speculative. In this broader view of speculation, the precautionary buying of gasoline by motorists in anticipation of higher prices amid fear of future supply disruption can also be considered speculation. If they are correct in their predictions, though, the motorists actually are smoothing out the availability of supplies between the present and the future, thereby reducing volatility in gasoline prices by putting upward pressure in prices when gasoline is abundant while putting downward pressure on gasoline prices when gasoline is scarce. The same principle applies to other speculators.

If speculation is stabilising oil prices, why do politicians, producers and consumers seem so worried about the impact of speculators? The increased participation of traditional speculators as well as other financial institutions in commodity derivatives markets has led to claims that the trading activities of these speculators destabilise markets.

There is a tight link between physical and financial oil markets. If speculators anticipate higher demand for oil in the future based on information coming from physical markets, then futures prices will rise. In turn, spot prices will rise since some oil will be pulled off the market today due to the anticipation of higher future prices; however, oil comes back to the market again at a future time of relative scarcity, leading to a lower future spot price than would have been without inventory accumulation. The connection between inventory level and price level tends to moderate the volatility unless speculators are wrong. If they are wrong, then they incur a loss which they do not want. They have every incentive to be right in their anticipation. This is why we expect speculators to reduce volatility without having any effect on the long-run price level, which is determined by supply and demand. In other words, traditional speculative-stabilising theory suggests that profitable speculation must involve buying when the price is low and selling when the price is high so that irrational speculators or noise traders trading on irrelevant information will not survive in the market place.

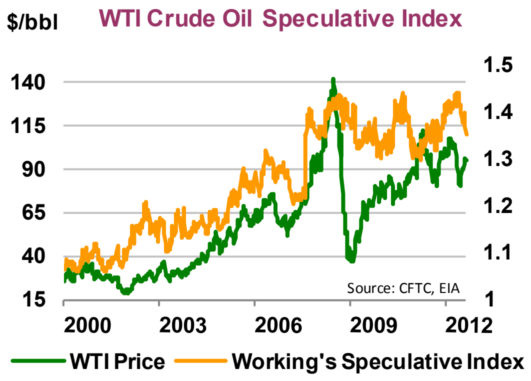
That said, concerns about hedge fund and index trading activities find support in some theoretical models where noise traders, speculative bubbles or herding (trading behaviour based on mimicking other traders rather than trading on fundamental information) can drive prices away from fundamental values and destabilize markets. Ultimately the question of whether these speculative groups destabilise markets or simply supply needed liquidity becomes an empirical issue.

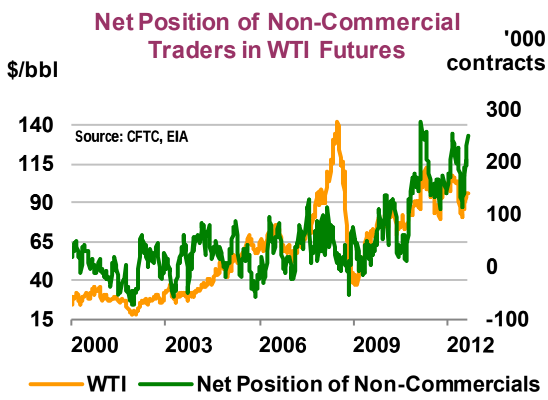
Recent research indicates that increased participation of commodity swap dealers and hedge funds has improved linkages between crude oil futures prices at different maturities, providing long-term hedging opportunities that would not have been possible without these traders. Furthermore, there is ample research showing that volatility in the crude market is reduced by the activity of speculators in general, and hedge funds and commodity swap dealers in particular. It is, of course, possible that these traders might attempt to move prices and increase volatility over short time intervals. Research using state of the art econometrics finds no systematic, deleterious causality running from so-called 'speculative' activity to prices (see, *e.g.*, Buyuksahin and Harris (2011) and Irwin and Sanders (2012)). Some research, however, shows that excess returns on crude oil futures are predictable, conditional on measures of speculative activity (see, *e.g.*, Singleton (2011)).

However, it is important to note that the predictability of crude oil returns by speculative activity does not imply causation, and hence does not imply that speculation distorts prices (see '*Predictability of WTI-Brent spread*'). In a recent overview paper, Kilian, Fattouh and Mahadeva (2012) reviewed the existing literature on the impact of speculation in oil markets and concluded that 'the existing evidence is not supportive of an important role of speculation in driving the spot price of oil after 2003. Instead, there is strong evidence that the co-movement between spot and futures prices reflects common economic fundamentals rather than the financialisation of oil futures markets.'

Recent data also show that there is no clear relationship between change in speculative activity, proxied by Working's (1960) speculative index (see the 2011 *Medium Term Oil and Gas Markets* report [MTOGM] for further discussion), and change in prices. Although prices and the speculative index appear to generally rise and fall together, the correlation between weekly price changes and changes in the speculative index is statistically insignificant – about -0.002 between 2000 and 2012. The negative correlation has increased somewhat after the collapse of Lehman Brothers and the financial crisis of 2008-2009, but it is still statistically insignificant at -0.005. Furthermore, Granger causality results also show that we can reject causality between change in speculative activity index and change in prices.

Speculators should not be viewed as adversarial agents. Rather, they are essential participants for the proper functioning of commodity derivatives markets by providing the necessary liquidity, thereby reducing market volatility. Recent regulatory measures, such as speculative position limits, aimed at limiting the participation and reducing the risk bearing capacity of "speculators" might have adverse consequences, such as decline in liquidity, higher hedging costs and higher volatility in energy markets.

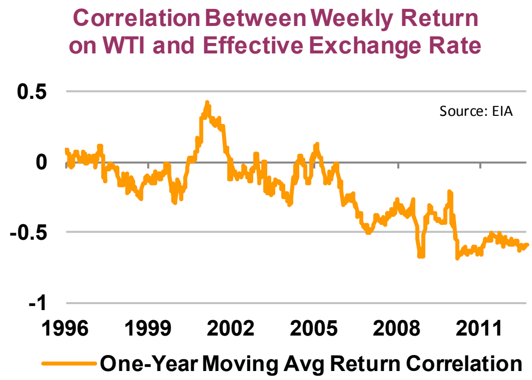




Exchange rates and oil prices

Most commodity prices, including oil, are quoted in US dollars and therefore it is logical to expect some kind of inverse relationship between commodity prices and the value of US dollar in terms of other currencies. Indeed especially after 2005, empirically there is clearly an inverse correlation between oil prices and trade-weighted nominal effective exchange rates – that is, other things being equal, oil prices rise if the dollar falls. An assessment of the one-year rolling average correlation between the weekly return on the oil price and the weekly return on the nominal effective exchange rate shows that this relationship has become stronger in recent years. The weekly return correlation between effective exchange rate and WTI was close to zero before 2005, but rose steadily after 2005, reaching more than -0.65 in October 2008 and stabilising around -0.6 after 2010.

This observed inverse correlation between exchange rate and oil prices led to the claim that US dollar weakness in recent years has contributed to the upward pressure on oil prices. It is very common to see the financial press suggesting that a weak dollar has pushed oil prices higher. However, this explanation is challenged by the empirical observations that a change in oil price tends to lead to a change in the exchange rate as predicted by economic theory.



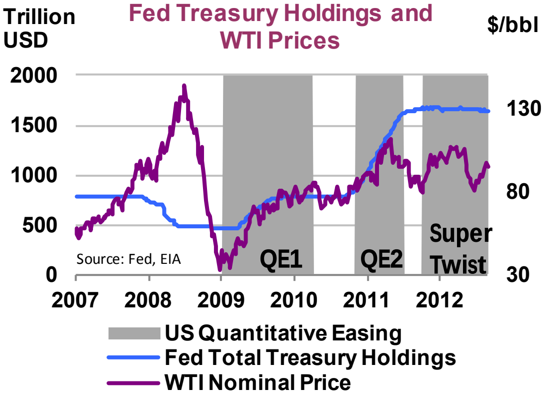
In the 2011 *MTOGM*, we suggested that the direction of causality tends to run from oil prices to the exchange rate, especially when we use lower frequency observations. This is consistent with the traditional terms of trade argument on the relationship between exchange rates and oil prices. Terms of trade effects suggest that when the price of an import rises, if the demand for that import is very inelastic (*i.e.* quantities demanded hardly fall at all when prices rise, as is the case for oil), the trade balance deteriorates, which would decrease the relative value of the local currency.

However, the interactions between the exchange rate and oil prices might be more complex than traditional economic theory predicts. Reverse causation, *i.e.* exchange rates influencing oil prices, is possible. Several transmission mechanisms could underpin such reverse causation. First, since oil is denominated in US dollars, a weaker dollar might lead to an increase in the demand for oil in non-dollar economies, which would cause the oil price to rise. Second, if oil producing countries have a target export revenue in their currencies to finance their government budget deficit, then with a weaker dollar they might reduce the supply of oil in order to drive up the price to achieve their targeted export revenue. Third, investors would likely increase their demand for commodities as a hedge against inflation when the dollar falls. This might put upward pressure on the price of oil. However, there is limited, if any, empirical evidence supporting these effects.

Apart from reverse causation, it is further argued that both the exchange rate and oil prices might be reacting to some other common factor. One such factor might be monetary policy. Since oil is a storable commodity, it reacts not only to current but also expected future monetary policy. Likewise, the exchange rate is also determined by current and expected monetary policy. Therefore, we should expect to see both oil prices and exchange rates as jointly determined.

Monetary policy and oil prices

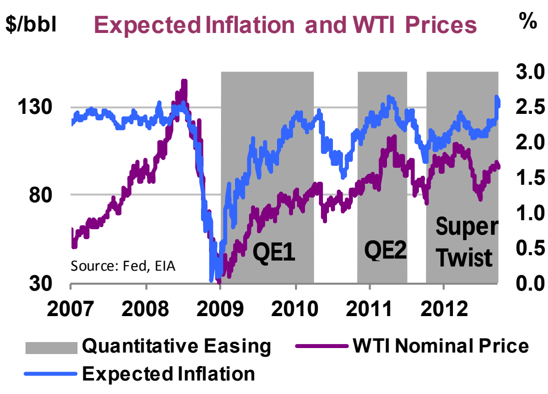
The debate over the impact of quantitative easing by major central banks has again intensified, especially following the announcement of another round of quantitative easing by the US Federal Reserve on 13 September 2012. Some commentators have argued that, in a world in which commodities constitute an asset class, there ought to be a positive relationship between quantitative easing and commodity prices via 'portfolio effects'– even if quantitative easing does not affect the demand or the supply of physical oil.



There is scant empirical evidence, however, to support the claim that financial investment in commodities affected commodity prices. Other commentators therefore point instead to the positive correlation between the Fed's Treasury-bond purchases and oil prices as evidence that quantitative easing is pushing commodity prices higher. Yet, the only observable positive correlation between bond purchases and oil prices coincided with the recovery of global economic activity in early 2009, when the latter led to an increase in the demand for oil. Therefore, it is in all likelihood misleading to argue that quantitative easing pushes commodity prices higher by just looking at such short-term correlations.

Monetary policy, of course, does have the potential to affect commodity prices. However, it is important to understand the transmission mechanism of how quantitative easing could affect commodity prices. The physical oil market is a highly competitive market, with physical prices determined by supply and demand. Hence, to impact energy prices, quantitative easing must impact physical supply or demand.

Expansionary monetary policy can change physical supply and demand of commodities, including oil, through several channels. One such channel is through expectations of higher inflation or strong growth. Still, if market participants interpret announcements of quantitative easing instead as signalling more problems in terms of lower growth prospects or more risk, then an announcement of quantitative easing might easily lead to a fall (rather than a rise) in prices. A second mechanism is through the interest rate channel. Low interest rates due to expansionary monetary policy may increase prices of storable commodities: by reducing the opportunity cost of carrying inventories,



thereby increasing inventory demand; by reducing the cost of holding reserves underground, thereby decreasing oil supply; and by increasing the demand for oil in non-dollar economies, whose prices are denominated in a now weakened dollar.

Empirical evidence on the impact of quantitative easing on oil prices is so far mixed. On the one hand, Kilian (2009a, 2009b) argues that the only episodes in which monetary policy regime shifts caused major oil price increases dated back to the 1970s. He argued that increases in global liquidity in the early and mid-1970s fostered a global output boom and surge in inflation, thereby driving up the prices of oil and other industrial commodities. Kilian further argues that it would take concerted regime shifts in many countries to exert enough demand pressure to drive global commodity prices. However, his analysis does not look into the period after 2008, where we observed the widespread introduction of unconventional monetary-policy measures by major central banks. On the other hand, Anzuini, Lombardi and Pagano (2012) find that conventional monetary policy (associated with a change in the short-term interest rate) had a limited effect on the oil price surge between 2003 and 2008 and that those effects were tied to the expected growth and inflation channels. However, their analysis also did not provide any evidence for the impact of unconventional monetary policy (associated with forward policy guidance and large-scale asset purchases) on commodity prices. Still, they suggest that the extraordinary monetary policy easing at a time when the lower bound on the interest rate has already been reached might push prices up, albeit to a small extent.

There are very few empirical studies of whether unconventional monetary policies have any effect on commodity prices. Glick and Leduc (2011), using an event study methodology, find that commodity prices tend to fall following the announcement of such policy measures. However, their analysis only covers 11 observations, which precludes drawing conclusions at any conventional level of statistical significance.

Some anecdotal evidence regarding the effects of unconventional monetary expansion on commodity prices can be gleaned by looking at the impact of monetary easing on inflation expectations, interest rates, and aggregate economic activity. We find a strong positive correlation between oil prices and expected inflation, measured by the difference between the interest rate on ordinary ten-year government debt and ten-year inflation-protected Treasury debt. Expected inflation surged following the announcement of the first two rounds of quantitative easing, but started to fall while QE1 and QE2 were still in progress, though it is worth noting that the decline in expected inflation would likely have been higher without the asset purchase. Several extant papers find that QE1 and QE2 increased the ten-year expected inflation by a range of 0.96-1.5% and 0.05-0.16%, respectively (see, *e.g.*, Krishnamurthy and Vissing-Jorgensen (2011) and Farmer (2012)). It seems that QE1 had a bigger impact than QE2 in terms of affecting expected inflation – although it is important to note that QE1 was implemented when expected inflation was close to zero.

The empirical research to date shows that the Fed's large-scale asset purchases lowered the ten-year interest rate. Point estimates vary between 13-100 basis points, however, with most estimates between 15-20 basis points – see, *e.g.*, Hamilton and Wu (2011) and Williams (2011). While related research papers also find some minor positive impact on GDP and employment, it is very difficult to identify and measure the effect of quantitative easing on real economic activity due to the response time of the latter as well as difficulties in separating the effect of the Fed's action from other factors affecting aggregate demand. Hence, these extant estimates at the most suggest that oil prices might have been affected by quantitative easing, but the extent of the impact might be very limited – as suggested also by Anzuini, Lombardi and Pagano (2012).

The impact of the latest round of quantitative easing on oil prices will again be determined by its effect on inflationary expectations and aggregate demand. Although expected inflation rose from 2.38% to 2.64% on the day following QE3's announcement, it had fallen by 0.14% (to 2.50%) as of 20 September 2012. At the same time, WTI prices declined from $98/bbl to $92/bbl. One interpretation is that oil market participants may have seen the latest round of quantitative easing as a sign of worse-than-originally-perceived conditions of the economy in the coming months. Put differently, it is still too early to make any predictions on the possible impact of the recent quantitative easing on commodity prices.

Cross-market correlations

Investors, seeking to diversify their portfolio and hedge against rising inflation, have increased their exposure to commodities by directly purchasing commodities, by taking outright positions in commodity futures, or by acquiring stakes in exchange-traded commodity funds (ETFs) and in commodity index funds. This pattern has accelerated in recent years. According to index investment data collected by Barclays Capital for US and non-US assets under management, commodity index investment has increased from $55 billion in late 2004 to $406 billion in July 2012.

The initial surge in investment in commodities was due to the observed negative correlation between commodity returns and the other asset returns as well as positive correlation between inflation and commodity returns. Inflation and commodity returns proxied by returns on S&P Goldman Sachs commodity total return index remain positively correlated (0.57 since 1995 and 0.69 since September 2008). However, the recent positive correlations between commodities and the other asset classes raise the question of whether commodities can still be considered as an asset class in their own right, and particularly as a means to portfolio diversification, as well as whether commodity markets in general have increasingly being driven by broad trends in financial investment, and not by their own unique supply and demand factors.

A commonly used approach is to consider an investment as a separate asset class when:

- Its expected returns are higher than risk-free returns;
- Its returns perform differently from other asset classes in any given market environment; and
- Its returns may not be replicated with a linear combination of other asset classes.

Up until Lehman Brothers' demise in September 2008, commodities met all three criteria. However, since then, commodities have not displayed at least the last two characteristics of a separate asset class. Of course, there are episodes in history when commodities moved in sync with other assets, especially equities. Nevertheless, compared to other episodes in the last two decades, the last three years have seen different dynamics in their degree and duration.

Weekly Returns on Different Assets

	Jan 1995-Sep 2008	Sep 2008-Aug 2012
WTI Crude Oil	17.129	5.466
Treasury Bill	3.764	0.128
Treasury Bond	5.196	2.921
S&P 500	8.060	4.970
GSCI	10.728	-7.808
GSCI Energy	16.979	-11.616
GSCI Non-Energy	2.100	2.469
GSCI Agriculture	-0.672	5.480
GSCI Precious Metals	6.919	20.992
GSCI Industrial Metals	-0.333	-7.529
GSCI Livestock	7.770	-1.987

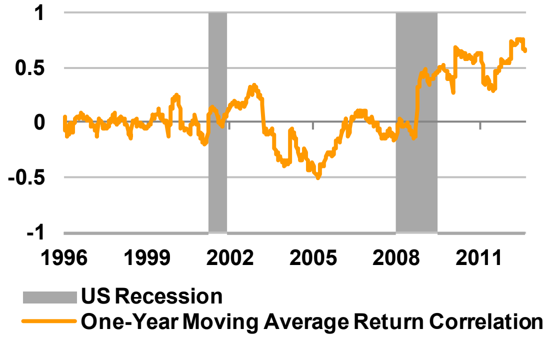
Between January 1995 and September 2008, annualised weekly returns on commodities proxied by Goldman Sachs commodity index exceeded equity returns. The unconditional correlation between commodity returns and stock returns was not statistically different from zero (as shown in the upper triangle of the correlation table). However, since September 2008, commodity returns registered negative returns as well as statistically significant positive correlation with equities (0.694) (as shown in the lower triangle of correlation table) returns.

Weekly Return Correlations (1991-2008: Upper Triangle; 2008-2012: Lower Triangle)

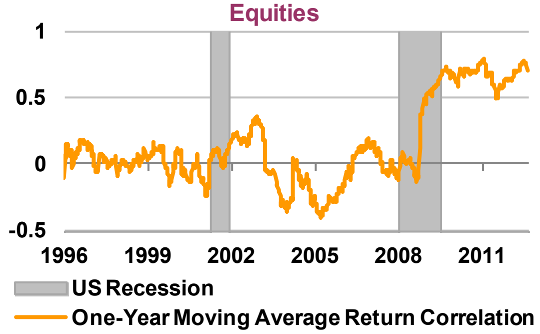
	WTI Crude Oil	Treasury Bill	Treasury Bond	GSCI	GSCI Energy	S&P 500
WTI Crude Oil	1.000	-0.028	-0.002	0.829	0.863	-0.021
Treasury Bill	-0.097	1.000	0.759	-0.023	-0.016	0.056
Treasury Bond	-0.004	0.376	1.000	0.019	0.035	0.067
GSCI	0.867	-0.180	-0.026	1.000	0.971	-0.007
GSCI Energy	0.890	-0.156	-0.009	0.986	1.000	-0.009
S&P 500	0.523	-0.221	-0.026	0.694	0.658	1.000

Besides the fact that the simple cross-correlations are different between pre- and post-crisis periods, one-year rolling measures of the correlations between equity and commodity return series fluctuated substantially throughout the sample period, especially after 2002. However, commodity-equity correlations soared after the demise of Lehman Brothers in September 2008 and have remained unusually high.

Correlation Between Weekly Return on WTI and S&P 500



Correlation Between Weekly Return on Investable Commodities and Equities

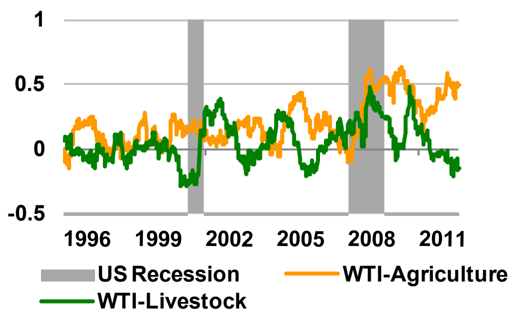


The strong correlation between commodities and equities during the post-crisis period is also evident between oil and equities as well as between oil and other commodities. The correlation between oil and equities was statistically insignificant before the crisis; however, it rose sharply in September 2008 and has stayed at elevated levels. Similarly, the correlation between oil and other commodities substantially increased. One-year rolling return correlations show that correlations between oil and other commodities, with the exception of live cattle, increased recently, almost reaching their historical peak during the height of the financial crisis.

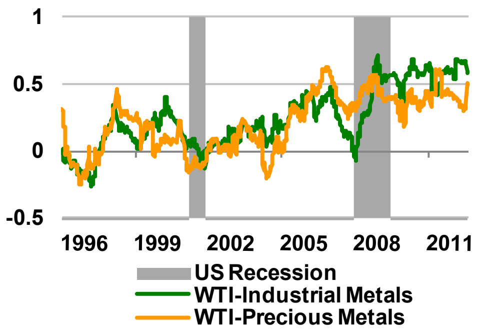
Weekly Return Correlations (1991-2008: Upper Triangle; 2008-2012: Lower Triangle)

	WTI	Non-Energy	Agriculture	Precious Metals	Livestock	Industrial Metals
WTI	1.000	0.197	0.144	0.187	0.038	0.156
Non-Energy	0.558	1.000	0.854	0.442	0.297	0.581
Agriculture	0.446	0.932	1.000	0.228	0.031	0.197
Precious Metals	0.380	0.483	0.351	1.000	0.000	0.414
Livestock	0.154	0.304	0.160	0.074	1.000	0.045
Industrial Metals	0.558	0.782	0.548	0.318	0.228	1.000

Correlation Between Return on WTI, Agriculture and Livestock



Correlation Between Weekly Return on WTI and Metals



Furthermore, regressing the weekly GSCI return on weekly stock returns for the two sub-periods considered above reveals that the variation in commodity returns is independent of either stocks or bond returns between January 1995 and September 2008 – but not afterwards. Specifically, the regression results after Lehman's demise suggest that more than 50% of the variation in commodity returns can be explained by variation in stock returns. The statistically significant coefficient on stock returns suggests that a 1% increase in stocks returns predicts 0.83% increase in commodity returns. Additionally, when weekly GSCI energy returns are regressed on stock returns, we find a statistically higher coefficient on stock returns, revealing that a 1% increase in stocks returns forecast almost a 1% increase in energy-commodity returns.

What do these findings imply for the separate asset status of commodities and the impact of financialisation on commodity prices? In the first place, these findings suggest that post-Lehman commodity returns might be replicated by returns on stocks. In this sense, one may conclude that commodities in the last four years do not appear to fulfil the three criteria to be considered as a separate asset class in their own right. However, the recent episode of high correlation between different assets may not be unique, and it is unclear whether the change observed in movements between asset classes, or more specifically commodity prices, are permanent.

The very fact that correlation estimates fluctuate significantly over time, however, is evidence of their short-term nature. As suggested by Buyuksahin, Haigh and Robe (2010), correlation estimates are relevant to short-term investors. For long-term investors, the key issue is whether there exists a long-term relation between the prices of commodities and equity investments even though these prices may move in sync in the short term. Several recent academic studies suggest that commodity co-movements increase during periods of financial market stress (see Buyuksahin, Haigh and Robe (2010)). A corollary is that in 'normal' times, commodities still provide benefits in terms of portfolio diversification. Therefore, it is too early to suggest that commodities no longer provide benefits in terms of portfolio diversification.

The increase in correlation between commodities and equities does not imply that commodity markets in general were increasingly driven by broad trends in financial investment, rather than by their own unique supply and demand factors. Several studies suggest that hedge funds or passive long-only investors' positions have predictive power in explaining the increased correlation between equities and commodities. However, as stated earlier, prediction does not necessarily imply causation. It might as well imply that activities of financial players, commodity prices and other asset prices might be increasingly responding to common factors, such as the growing importance of emerging markets in both commodity markets and global economic activity and the global character of the financial crisis in 2007-2009 (see, *e.g.*, Hamilton and Wu (2012)).

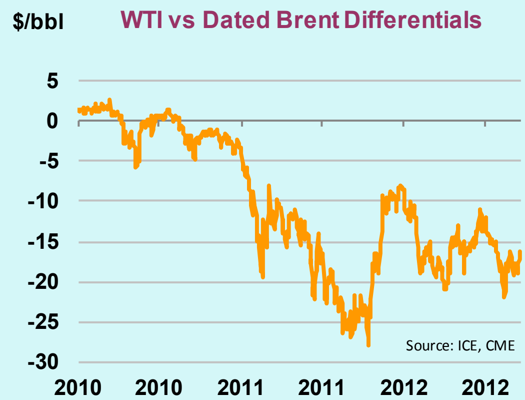
To sum up, physical oil prices are determined by physical supply and demand. Unexpected fluctuations in global business conditions determine the price of oil as well as other industrial commodity prices. Policy actions, such as expansionary monetary policy, can affect commodity prices to the extent that they can affect oil price fundamentals, such as real economic activity and interest rates. Inherent volatility in oil prices is primarily a result of uncertainty about global business conditions and lack of data, and not because of financial speculation. Despite this fact, significant new regulatory measures aimed at reducing systemic risk in financial markets are being developed, and will be implemented as early as 12 October 2012 (see 'Market Regulations'). These measures are likely to substantially limit the participation of non-commercial players within commodity derivatives markets – the very same players that contribute to reducing volatility in commodity markets.

Predictability of WTI-Brent spread

Prices for the West Texas Intermediate (WTI) and Brent crude oil benchmarks have historically been related. Technology and product demand have generally favoured WTI, with the latter regarded as being of slightly higher quality than Brent, generating a price differential between the two. Still, owing to their physical similarities and to a world oil market, the two reference crude grades have historically traded within a narrow price range – typically, within one to two dollars with WTI usually priced higher than Brent. Despite some short-lived episodes when the two benchmark prices diverged substantially, WTI light sweet crude oil typically sold at a 5% premium to Brent crude oil for much of the 1994-2010 periods. This historical relation between WTI and Brent crude oil prices, however, collapsed in 2011. Brent crude oil has since sold at an average premium of $16/bbl, or 14%, reaching a peak differential of $28/bbl in mid-October 2011.

That Brent might sometimes sell at a premium over WTI is not a new phenomenon. However, the massive increase in the magnitude and volatility of the differentials, and the duration of the current episode, raise questions about the causes of this new 'reality' and whether the weakening of WTI and strengthening of Brent prices are a temporary or permanent phenomenon.

Predictability of WTI-Brent spread (continued)



It has widely been argued that the recent developments could be due to a combination of factors: rising Canadian and onshore US crude supplies into Cushing; sluggish recovery of the US oil demand after the Great Recession; and bottlenecks impeding the shipment of crude oil from Cushing to the Gulf Coast. The consequences have been a record increase in stock levels in Cushing and a depression in WTI prices, especially at the front end of the crude futures curve. At the same time, lower supply and unplanned outages from the North Sea, the loss of Libyan crude and rising demand from large emerging market economies, especially in China, have exerted upward pressure on the price of Brent crude oil. In addition, given its seaborne access to markets, Brent crude has gained more acceptance as a global oil benchmark.

Some commentators have suggested that physical supply and demand factors alone cannot explain the magnitude and the duration of divergence between Brent and WTI crude oil prices, due to a simple economic principle: arbitrage. The arbitrage principle suggests that if goods are close substitutes and easily transported, then they should sell for a similar price. Since the transportation costs from Cushing to the Gulf of Mexico is typically not more than $10/bbl, and carry from the Gulf of Mexico to Europe costs an additional $3-4/bbl, a spread above $15/bbl should not be sustainable.

At the same time, many other market observers disagree with the notion that large WTI-Brent spreads necessarily imply a violation of the arbitrage principle. First, those other commentators argue that Brent and WTI crudes, although close substitutes, are not directly interchangeable due to different gravity and sulphur content – not to mention restrictions on US crude exports. Second, there is not enough capacity to move oil from Cushing to the Gulf Coast. This last fact suggests that improvements in the transportation infrastructure from the Midwest to the Gulf or changes in pipeline flows should narrow the spread between these two benchmark prices.

Notwithstanding those observations, some commentators argue that, alongside physical demand or supply considerations, financial factors might have played some role in widening the WTI-Brent spread. There are two main arguments as to how financial markets could play a role in widening the spread. The first is that, amid anticipation of rules on hard oil futures position limits by the CFTC, some speculators and commodity index dealers might have migrated from New York (CME Group) to London (ICE) in order to sidestep position limits.

The second hypothesis, which builds on the first, is related to changes in the structure of the forward curve for Brent and WTI crudes. The Brent curve has been in steep backwardation since December 2010. A recent flip into contango proved short-lived. In contrast, the WTI curve has stayed in contango. To long-only position holders such as commodity index traders (CITs), the Brent market thus offers a more favourable roll yield than WTI, and may have given CITs a stronger incentive to invest in Brent futures than in WTI. Holding other things equal, and assuming a flexibility switch positions across Brent and WTI, CIT positions in Brent contracts should therefore be expected to have increased, relative to WTI futures contracts, since December due to a more positive roll yield in Brent. Such a shift would be further reinforced by the increase in the share of Brent, and the decline in the share of WTI crude oil, in major commodity indices during the same period.

Predictability of WTI-Brent spread (continued)

Empirical evidence to date, however, suggests that changes in the positions of speculators in general, and of commodity index traders in particular, do not Granger-cause changes in oil futures price – see Buyuksahin and Harris (2011) and Irwin and Sanders (2012). Empirical evidence on the predictive power of CIT positions on commodity returns so far is likewise mixed. On the one hand, Hamilton and Wu (2012) find very little support for the claim that index buying has exerted a significant effect on commodity futures risk premia. On the other hand, Singleton (2011) argues that increases in money flows into commodity index funds predict higher subsequent futures returns; however, the proxy used to measure investment flows into index funds suffers from a number of limitations. Furthermore, his predictability results do not indicate that commodity index traders have caused oil prices to diverge from their fundamental value – merely, that commodity index traders anticipate such deviations.

Still, this recent 'financialisation' literature covers neither the volatility of the Brent-WTI spread in the winter of 2009 nor the emergence of an extraordinarily large and persistent oil price differential after December 2010. The latter period, though, witnessed major changes to the environment faced by CITs that might have affected Brent and WTI prices differentially – including the anticipation of stricter speculative position limits in the United States (but not Britain) and the reweighting of the main commodity price indices in favour of Brent (vs. WTI).

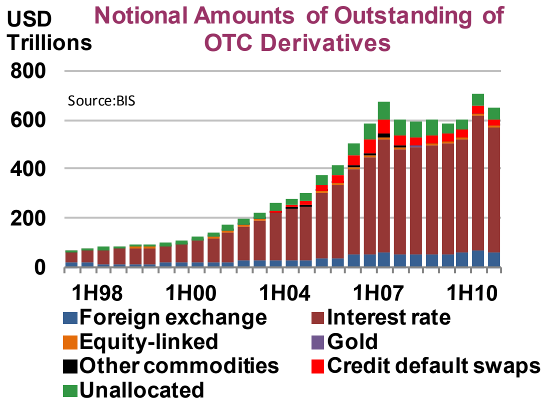
A recent paper by Buyuksahin et al (2012) seeks to isolate the predictive power of macroeconomic and physical-market fundamentals in this very context so as to identify whether paper-market variables (futures market liquidity, the composition of trading activity, and the overall level financial-market stress) can help forecast the Brent-WTI spread. On the physical side, the authors first control for the relative strengths of the world and U.S. business cycles. It turns out that both matter: U.S. economic activity for the WTI component of the spread, and world economic activity for the spread as a whole – but mainly following the emergence of transportation bottlenecks at the WTI futures delivery point of Cushing. A second set of fundamental explanatory variables summarises differential supply-demand imbalances for WTI and Brent crude oils. Observing that the WTI and Brent markets are not fully integrated, the authors focus on three variables: the effective 'spare' OPEC production capacity outside of Saudi Arabia to capture general market conditions for seaborne crudes; the output of the four crude streams (BFOE) that make up Brent; and different proxies for storage conditions in Cushing to capture physical-market conditions in the WTI's most immediate sphere of influence.

Notably, the authors' econometric analysis suggests that a dearth of storage capacity affects prices in a non-linear fashion. It also shows the importance of controlling for production constraints affecting seaborne crudes and for the macroeconomic performances of the US vs. the rest of the world. At the practical level, this new study therefore helps explain why the unusually large Brent-WTI spread has not been echoed in other commodity spreads – in particular, those involving Brent vs. Louisiana Light Sweet crudes and WTI vs. West Texas Sour (WTS) crudes.

On the financial side, the study investigates, through the prism of crude price spreads, the predictive power of CITs' paper-market positions. To do so, the authors draw on a database of individual end-of-day trader positions in WTI sweet crude oil futures (2004-2012) maintained by the US Commodity Futures Trading Commission (CFTC). The authors find some predictive power for the futures-market positions held by CITs – suggesting the empirical relevance of trading variables in a predictive model of the Brent-WTI spread, and shedding light on a heretofore unexplored dimension of energy markets' financialisation.

Market regulation

It has been more than three years since G20 leaders set the broad reform agenda to be implemented by the end of 2012 to reduce systemic risk and increase transparency in the over-the-counter (OTC) derivatives markets. As the deadline nears, regulators on both side of the Atlantic are busy with the adoption of extensive implementation rules for the Dodd- Frank Act in the US and the European Market Infrastructure Regulation (EMIR) in EU. While some of the Dodd-Frank rules in the US will be effective on 12 October 2012, EMIR entered into force on 16 August 2012; implementation will be gradual. However, European regulation still needs to wait for the adoption of Markets in Financial Instruments Directive (MiFID II) by the European Parliament and Council of Europe to ensure that EU oversight of European OTC derivatives markets is comparable with the Dodd- Frank Act in the US. Specifically, MiFID addresses rules related to the transparency and oversight of the financial markets, including the creation of a new trading venue category ('organised trading facility – OTF'), pre- and post-trade transparency, a position reporting obligation by type of participants, similar to the Large Trader Reporting System in the US, restriction on high frequency trading, and position limits or some other type of position management.



While the regulators on both sides of the Atlantic are finalising their rules to regulate OTC derivatives markets, the size of commodity derivatives markets, including gold, has declined from \$13.2 to \$3.1 trillion in notional value from June 2008 to December 2011 according to the latest Bank of International Settlements (BIS) survey. This survey shows that total notional value of all OTC derivatives reached \$648 trillion at the end of December 2011, of which \$2.6 trillion (0.4%) was commodity-related, excluding gold, derivatives. However, at their peak at end-June 2008, the total notional value of commodity derivatives, excluding gold, had reached a far higher value of \$12.6 trillion, or 1.87% of the total market.

Although the size and share of commodity-related OTC derivatives contracts compared to the overall OTC derivatives market have declined over the last four years, new regulations have already started to change OTC swaps markets, which will further reduce the size of OTC derivatives markets in general, and commodity and energy markets in particular. For example, in order to reduce their clients' exposure to compliance costs associated with the new rules imposed on swap transactions as well as not to deal with the complexity for swaps market participants relative to futures market participants, Intercontinental Exchange (ICE) announced that it plans to transition all existing OTC cleared energy swaps and option products, including crude and refined oil, natural gas, electric power, and natural gas liquids, to economically equivalent futures and option products on 15 October 2015, which corresponds to the compliance date for several new swaps rules. ICE further argued that already tested futures market regulations give market participants more certainty in regulation than untested regulation in swaps markets.

Chicago Mercantile Exchange (CME) also announced the launch of a deliverable interest rate swap futures contract on 13 November 2012, which will convert or be delivered into an OTC swap that is cleared by the CME upon expiry. The new contract not only provides the automatic netting of positions and margin savings achieved through cross margining versus all other futures and options cleared through CME Clearing, which is not possible with a swap contract, but also will not be subject to the proposed restrictions on block trades for swap execution facilities (SEFs). If successful, it is expected that most OTC interest rate swaps, which comprise 78% of the total notional value of all OTC swap contracts, migrate from the OTC market to the futures exchange.

Apart from changing the market structure, differences in US, European and Asian regulations might have the potential for market disruption or fragmentation resulting in increased systemic risks and reduced market liquidity. For example, although both the Dodd-Frank Act and EMIR have common rules, there are still differences between these two regulatory frameworks in clearing, membership of central clearing houses, margin requirements, swap execution facilities and position limits. The EU regulation has neither the US ‘Lincoln swap push-out’ rule, which restricts the derivatives trading activities of banks, nor the ‘Volcker’ rule, which prohibits proprietary trading operations. Restrictions on high frequency trading are proposed in MiFID II, but the US CFTC is still in the process of defining high frequency traders. The EU and the US also take different paths to the cross-border application of their rules. The proposed cross-border application of US rules was criticised by other regions, including the EU, Asia, Australia and Canada.

Besides the differences in US and EU regulations, a recent ruling by the district court in the US against the so-called position limit rule will potentially force regulators to revisit some of their final rules. The court found that the Commission overreached its mandate by imposing position limits without showing they were ‘necessary to diminish, eliminate or prevent’ excessive speculation.

The different speed of progress on agreed reforms to meet the end of 2012 deadline set by the G-20 in Pittsburgh in 2009 is likely to create regulatory arbitrage opportunities which might undermine the impact of new regulations even in countries where more stringent rules are to be implemented. For example, major rules in US regulation will become effective on 12 October 2012, while EU rulemaking is still in progress. Therefore, as we argued in our last *MTOMR*, more international coordination is needed for more consistent and effective oversight in OTC markets.

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DEMAND

Summary

- **Global oil product demand is projected to increase from 89.0 mb/d in 2011 to 95.7 mb/d in 2017 (a compound average growth rate of 1.2% or 1.1 mb/d per year).** This outlook is based on an average annual expansion in global economic activity of 3.9% and assumes that oil intensity declines by around 2.5% per year. Asia and the Middle East account for the bulk of the projected growth in demand (0.6 mb/d or 2.1% per year and 0.3 mb/d or 3.4% per year, respectively), followed by the former Soviet Union (0.1 mb/d or 2.9%) and Africa (0.1 mb/d or 3.0%). Overall, our assessments and projections of global demand have been trimmed by 0.6 mb/d on average for 2011-2016 since our December 2011 update, due mostly to reduced baseline data and a weaker macroeconomic backdrop.

Global Oil Demand (2011-2017)

(million barrels per day)

	1Q11	2Q11	3Q11	4Q11	2011	1Q12	2Q12	3Q12	4Q12	2012	2013	2014	2015	2016	2017
Africa	3.4	3.3	3.2	3.4	3.3	3.4	3.4	3.4	3.4	3.4	3.5	3.6	3.8	3.9	4.0
Americas	30.3	30.1	30.7	30.4	30.4	29.7	30.2	30.7	30.6	30.3	30.5	30.6	30.7	30.8	30.9
Asia/Pacific	29.0	27.7	27.8	29.2	28.4	30.0	28.6	28.4	29.7	29.2	29.5	30.1	30.9	31.6	32.3
Europe	15.0	14.9	15.5	14.9	15.1	14.5	14.6	15.1	14.7	14.7	14.5	14.5	14.4	14.4	14.3
FSU	4.2	4.4	4.6	4.6	4.4	4.4	4.5	4.7	4.7	4.6	4.8	4.9	5.1	5.2	5.2
Middle East	7.0	7.4	7.8	7.3	7.4	7.2	7.7	8.0	7.5	7.6	7.8	8.1	8.4	8.7	9.0
World	**88.8**	**87.7**	**89.5**	**89.8**	**89.0**	**89.2**	**89.0**	**90.4**	**90.6**	**89.8**	**90.6**	**91.8**	**93.2**	**94.5**	**95.7**
Annual Chg (%)	2.5	0.5	0.8	0.3	1.0	0.5	1.4	0.9	0.9	0.9	0.9	1.4	1.5	1.4	1.3
Annual Chg (mb/d)	2.1	0.4	0.7	0.3	0.9	0.5	1.2	0.8	0.8	0.8	0.8	1.2	1.3	1.3	1.2
Changes from last MTOGM (mb/d)	-0.17	-0.10	0.13	-0.07	-0.05	-0.73	-0.27	-0.39	-0.54	-0.48	-0.93	-0.88	-0.68	-0.54	

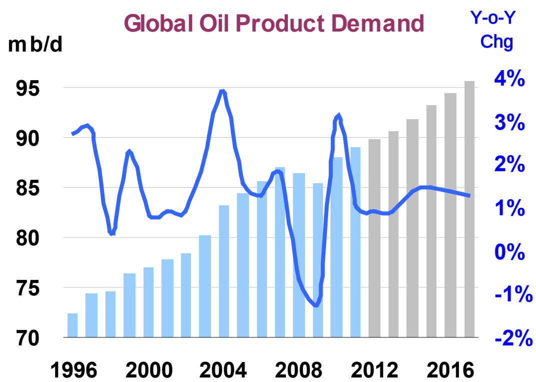
- **Oil demand in the emerging and newly industrialised economies of the non-OECD breaks through 50 mb/d by 2017**, rising by an average of 1.3 mb/d (or 2.9%) per annum over the six year period. In contrast, OECD demand declines by an average of 0.2 mb/d (or -0.4%) per annum, to 45.4 mb/d in 2017. The predicted OECD fall reflects a combination of continued efficiency gains, changes in consumer behaviour, market saturation and fuel switching. Total non-OECD demand is forecast to overtake its OECD counterpart in 2014. As non-OECD countries become wealthier, potential demand growth becomes more restrained, as the structural developments that are causing absolute contractions in OECD demand increasingly impact the non-OECD.
- **Diesel/gasoil will be the primary driver of global oil use, accounting for 40% of total demand growth and 30% of absolute demand.** Gasoil has increasingly dominated demand growth in recent years, given its multiple uses and drivers. Consumption globally is projected to rise to 28.8 mb/d by 2017, an average annual gain of 0.5 mb/d (or 1.7%) over the six-year forecast from 26.1 mb/d in 2011. Gasoil growth is concentrated in non-OECD Asia (roughly 56% of total global growth), particularly China. Demand in China is forecast to rise by 3.6% per annum, through the outlook, to 3.9 mb/d by 2017.
- **The health of the global economy poses a central risk to this outlook**, given sluggish OECD economic expansion, persistent debt issues in the OECD and signs of a slow down in China.

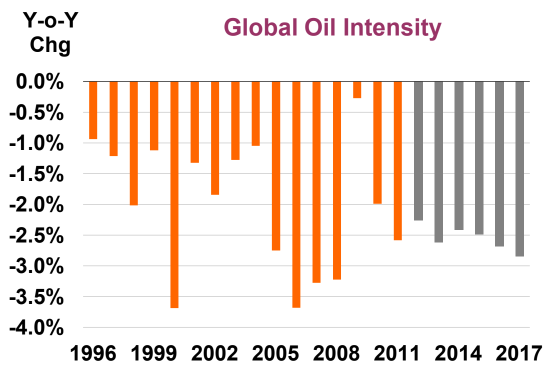
Reduced expectations of demand growth

Global oil product demand is expected to rise from 89.0 mb/d in 2011 to 95.7 mb/d in 2017 – a total increase of 6.7 mb/d, equivalent to an average yearly growth rate of 1.2% or 1.1 mb/d over the outlook period. Forecast demand is significantly lower than projected in the 2011 *MTOGM*, when the global economic recovery looked on surer footing. Several broad factors contribute to this downgrading of expectations, including much weaker-than-forecast economic expansion in 2012, downward adjustments to historical demand data for the period prior to 2012, and a more sober view of the economic outlook through the forecast period, compared to assumptions in the 2011 *MTOGM*.

A weaker macroeconomic backdrop

As in previous editions of this report, the prognosis is broadly based on the economic assumptions provided by the International Monetary Fund (*World Economic Outlook*, April 2012). Based on more recent indicators, we have taken a marginally more bearish stance on the economy, particularly over the next couple of years, assuming slightly slower growth rates for Europe, the US and China than the IMF's April release (closely in-line with IMF's since updated October report). This report assumes that global GDP growth will average 3.9%, in the period 2012-to-2017; below the 4.3% average seen in 2002-2007, prior to the financial crisis of 2008-2009. Heightened OECD debt concerns act as a brake on economic expansion, both in the OECD region itself and in export-oriented economies of the non-OECD region. In addition, we assume that oil use efficiency will improve by an average of 2.5% per annum, in 2011-2017, exactly in line with 2005-2011. Efficiency is expected to improve slightly faster in the non-OECD region, as the scope for further improvements in the OECD is more limited.

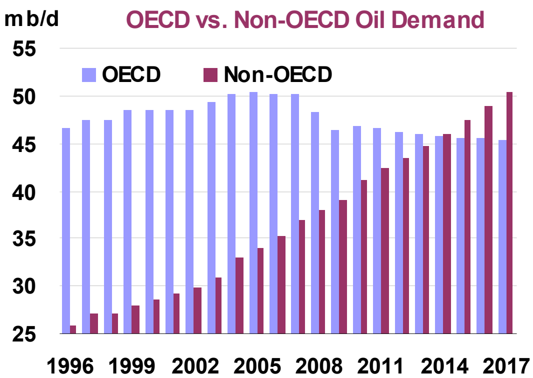


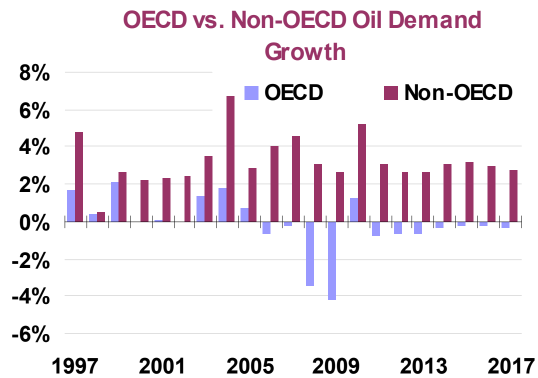


Expectations of global oil demand growth have been substantially reduced since the *Medium-Term Oil Market* (MTOM) update of December 2011, when a robust economic recovery was widely thought to be underway. This demand outlook is, on average, roughly 0.5 mb/d lower than the MTOM (for the period 2011-16) and closer to the projections made in December 2010. Adjustments to the non-OECD forecast, including both downward revisions to baseline demand and more subdued growth expectations, account for most of the cuts.

Baseline revisions leave forecast starting from a lower base

Revised IEA *Energy Statistics of non-OECD countries* for 2012, with complete 2010 data, reduced the baseline of non-OECD demand by around 300 kb/d, including steep cuts for Russia (-300 kb/d), China (-270 kb/d), Iran (-250 kb/d) and South Africa (-100 kb/d), partly offset by upside revisions in Singapore (120 kb/d), Saudi Arabia (100 kb/d), Thailand (100 kb/d) and Malaysia (90 kb/d). Signs of a slowdown in global demand growth in 2012, as Europe returned to recession and dragged down growth in exported-oriented emerging economies, compounded the impact of downward revisions to historical non-OECD demand. Global growth is forecast to remain relatively subdued in 2013. Growth is thus projected to slow down from a high of 3.1% in 2010 to a trend rate of around 1% in 2011-13. The latest projection for 2013 is 930 kb/d lower than the estimate made in December 2011. China dominates the downside revisions to the current and short-term outlook, with Chinese demand assumed to average 9.8 mb/d in 2013, 750 kb/d less than in the last MTOM estimate. This forecast assumes lower Chinese 'other products' demand (including steep downward revisions in prior estimates of direct crude burn) but higher naphtha demand than the latest IEA annual update. A downward adjustment of 370 kb/d to the assessment of Iranian demand, now pegged at 1.8 mb/d in 2013, also contributed to the reduced projection. The biggest reductions in LPG, 'other products' and residual fuel oil, 190 kb/d, 110 kb/d and 80 kb/d respectively, led the Iranian revision, reflecting a reduced baseline and the expected economic effect of international sanctions.





Continued shifts in the global demand map

While global oil consumption is now expected to expand at a more subdued pace than in the 2011 MTOGM, other features of the forecast remain unchanged. In particular, the lopsided regional distribution of growth, with strikingly different trends in the mature economies of the OECD and in emerging and newly industrialised countries, remains a central feature of the forecast, as is its corollary, the geographical redistribution of global oil consumption and growing market share of the non-OECD regions. Not surprisingly, the global convergence by which non-OECD economies are catching up with the industrialised world is redrawing the oil demand map. Non-OECD oil demand is forecast to overtake OECD oil demand as soon as 2014.

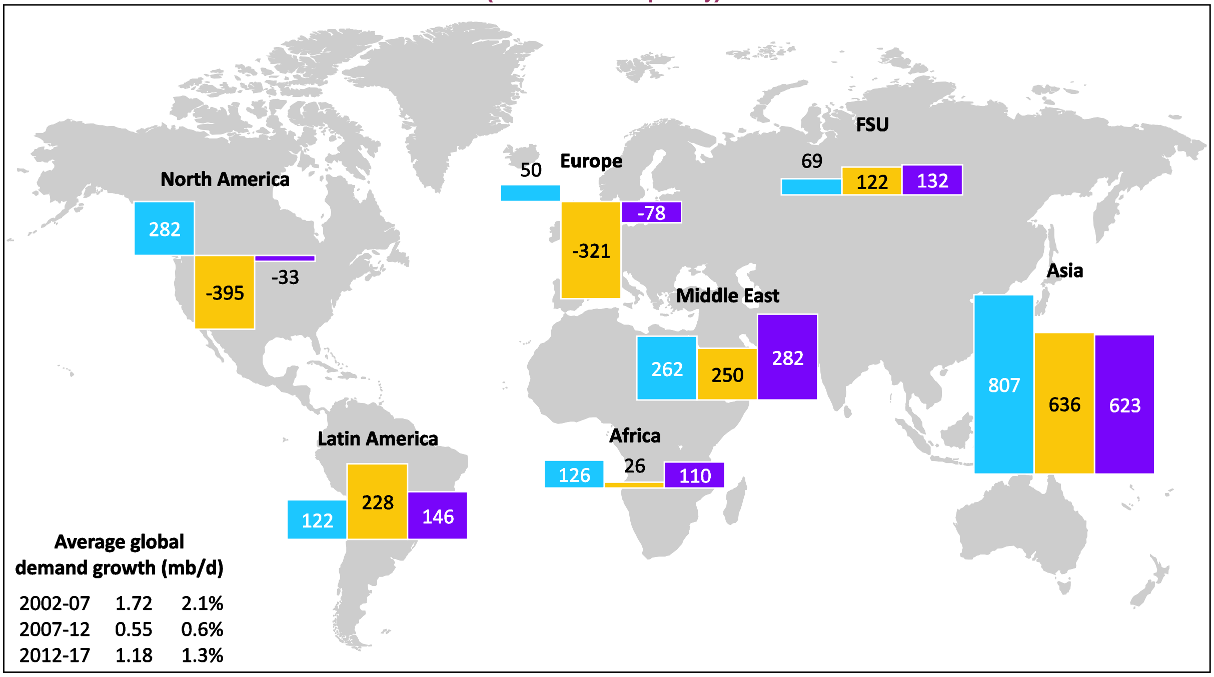
Non-OECD demand dominates projected growth

Despite the large downside revisions to the non-OECD series, oil demand growth will still derive entirely from non-OECD countries, where aggregate demand will rise by an average of 2.9% or 1.3 mb/d per year, from 42.4 mb/d in 2011 to 50.3 mb/d in 2017. In aggregate, non-OECD economies are forecast to account for 51.7% of worldwide wealth by 2017, versus 48.3% for the OECD. China is forecast to become the world's largest economy in 2017 (at 18.2% of global GDP, on a purchasing power parity basis), overtaking the US (17.7%). As non-OECD economies overtake the OECD in economic might (assumed to occur in 2016), so is their share of global oil demand forecast to exceed that of the OECD during the forecast period (specifically assumed to occur in 2014). By 2017, the non-OECD will dominate global oil demand (with a share of 53%, versus 47% for the OECD), compared with only 36% as recently as 1996.

Income growth is the primary driver of oil demand gains. Empirically, the OECD experience suggests that oil demand takes off exponentially when income per capita reaches around $3,000 (in real 2000 dollars) and begins to taper off after passing the $20,000 mark, following a so-called 'S curve' path. Countries within that range will account for 50% and 65% of the world's GDP and population, respectively, by 2017 (versus 29% and 24% in 1996). By the same token, their aggregate oil demand will surge by more than 80%, to almost 44 mb/d, in only 20 years.

Relatively sustained economic growth in the non-OECD region is expected to largely absorb the effect of high oil prices, a trend reinforced by the projected continuation of oil subsidies across many emerging and newly industrialised economies. Attempts at de-subsidisation in some non-OECD economies are expected to remain relatively limited in scope and thus only marginally dent oil consumption patterns. Social unrest in the Middle East and North Africa will likely limit the political scope for substantial subsidy reductions during the forecast period.

Average Global Oil Demand Growth 2002-2007/2007-2012/2012-2017
(thousand barrels per day)



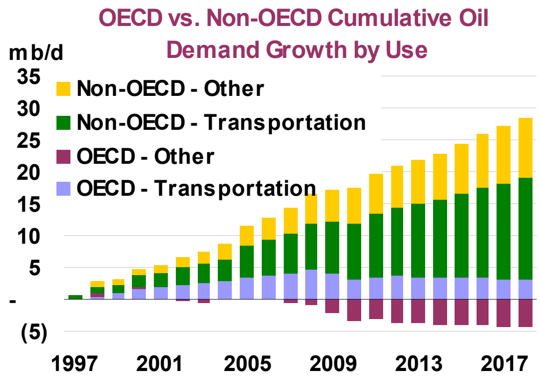
This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

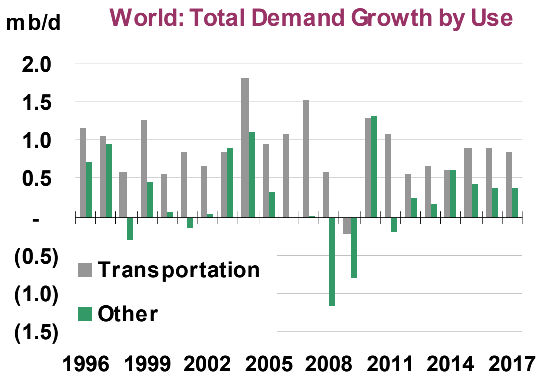
Absolute declines envisaged in the OECD

Continued growth in non-OECD demand will be counterbalanced with contraction in OECD consumption, as a period of structural decline is expected to continue through our forecast period. Several factors underpin this trend: slow population growth; a shift away from oil-intensive industries towards less oil-intensive services; slow economic growth; and a continuing policy shift in favour of environmental regulations and a less carbon-intensive economy.

OECD oil demand is expected to contract by 0.4% or 200 kb/d per year on average, from 46.6 mb/d in 2011 to 45.4 mb/d in 2017. Declines are envisaged across the main OECD product categories, with the exception of LPG and diesel. LPG benefits from additional petrochemical demand in the US.

Diesel demand is projected to rise as more stringent environmental regulations force shippers to switch over from fuel oil, whilst industrial use still grows in many industries (such as the shale oil/gas industry in the US) and a further modest dieselisation of the vehicle fleet is assumed. Consumption of residual fuel oil and heating oil are forecast to fall by the greatest degree, respectively posting compound decline rates of 2.9% and 1.5%. Bunker switching dampening fuel oil demand, whilst heating oil continues to loose market share to alternative fuels such as natural gas.





Total OECD demand is forecast to contract, through 2017, due to the combination of several factors:

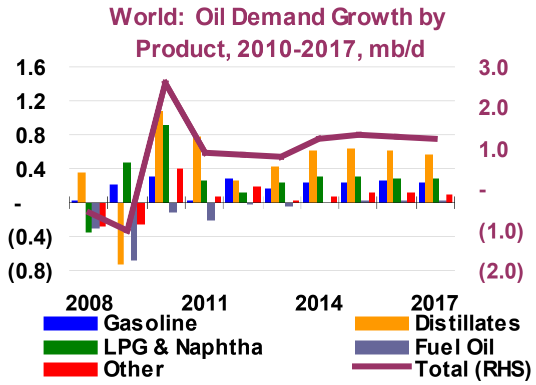
- Efficiency gains.
- Changes in consumer behaviour.
- Market saturation (notably in vehicle fleets across most developed economies).
- The structural decline in use of oil for both heating and industrial fuels (which will largely offset any latent buoyancy in transportation fuel demand), encouraged by an influx of cheap gas in North America in particular.

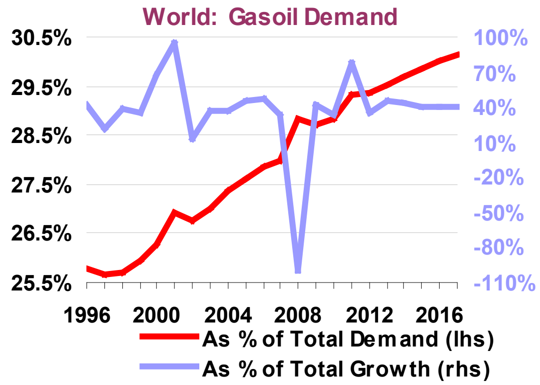
Middle Empire: demand growth favours the middle of the barrel

Broken down by product and sector, demand growth is just as unevenly distributed as in geographic terms. Extending earlier trends, the transport sector and gasoil/diesel account for most of incremental demand. Demand for gasoil/diesel is growing much faster than for demand of other fuels as a whole, supported in part by the product's many uses. Despite expansions in refining capacity, steep global growth in gasoil/demand is running ahead of supply growth. This is both a challenge for refiners and a cause of concern for end users as distillate balances are getting chronically tight.

Transportation fuel continue to underpin growth

In terms of sectors, transportation (road, railway and airborne) will be the primary driver of oil use (roughly two-thirds of both absolute global demand and growth), followed by industry/agriculture, heating/power generation and residential/commercial. The emergence of large integrated industrial complexes – such as a refinery coupled with a gas processing plant and a petrochemical facility – blurs the sectoral analysis, as decisions to use specific feedstocks (LPG or naphtha) partly depend on price and profitability at any given point in time.

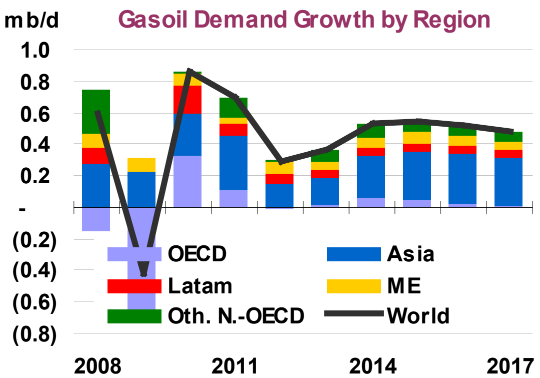


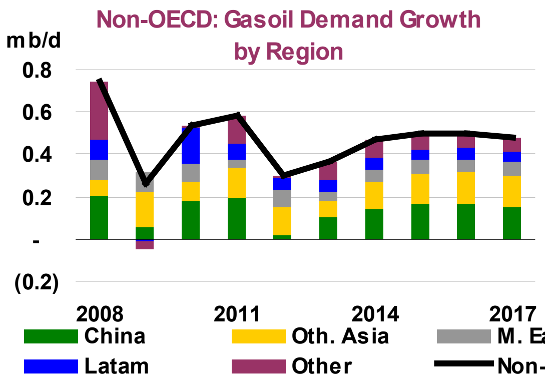


Gasoil/Diesel to gain a still larger share of the demand mix

Consumption is forecast to grow in all product categories bar residual fuel oil. Gasoil and LPG will lead the increase. Gasoil alone is forecast to account for approximately 40% of total forecast growth on average, in line with recent trends, while its share of total oil product demand will climb steadily to 30% by 2017.

Gasoil's versatility – it can be used for transport (on-road vehicles, ships and trains) and for residential, commercial and industrial purposes (space heating, agriculture, construction, power generation and petrochemicals, among others) – explains its phenomenal growth. Its multiple uses mean that demand growth can be affected by many factors, including the pace of underlying economic growth, policy driven fuel-switching (such as from gasoline to diesel in Europe or from residual fuel oil bunkers to marine gasoil), or weather-driven fuel switching for power generation such as shortfalls in hydroelectric output requiring the activation of diesel turbines or power sector outages triggering the utilisation of back-up diesel generators. The latter factor has become a particularly potent one in recent years, as chronic brownouts and blackouts in emerging or newly industrialised economies ranging from Pakistan to Nigeria coupled with income gains has created massive growth in demand for, and imports of, back-up diesel generators. The growing global stock of combined-cycle gas turbines that can run on gasoil if natural gas supplies are disrupted also has become a factor behind the rise in gasoil demand.





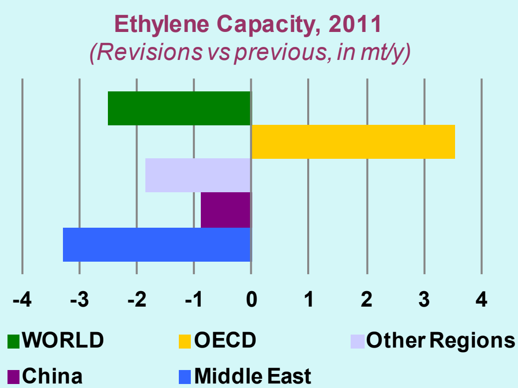
Non-OECD countries are forecast to dominate gasoil demand growth (averaging more than 95% of total demand growth in 2011-2017), reflecting the general trends highlighted above, with Asia taking the lead (accounting for just less than 60% of said non-OECD growth). China alone will represent nearly 30% of total non-OECD incremental gasoil use, for 2011-2017.

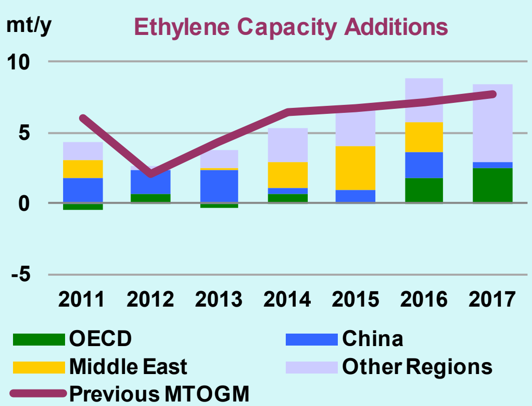
Robust expansions foreseen in LPG and Naphtha

Both naphtha and LPG will enjoy rising demand trends through the medium term-forecast, supported by continued growth in the global petrochemical industry (see *Revisiting the Ethylene Industry's Demand for Oil Products*). LPG demand growth outstripping naphtha, as more rapid supply growth is assumed; additional ethane (included in our LPG balance) is furnished from natural gas developments in the US. Naphtha demand is forecast to rise by an average of 1.1%, 2012-2017, while the corresponding growth trajectory for LPG is 1.9%. LPG is forecast to account for 17% of total oil product demand growth, led by ethane: market share is forecast to rise above 11% by 2017.

Revisiting the Ethylene industry's demand for oil products

Reviewing the petrochemical industry's evolution over the years, especially the development of ethylene production, helps provides a reality check to demand estimates for both naphtha and LPG. This year's sluggish economic outlook reduces previous forecasts of global ethylene capacity and associated oil demand, as the petrochemical sector has responded to a downturn in economic expectations by delaying new capacity and cutting oil consumption. This year, however, another factor looks set to trim earlier forecasts of oil demand from the petrochemical sector, namely the resurgence of the US ethylene industry on the back of surging LPG output. Thanks to rising shale and light tight oil production, the US ethylene industry is increasingly switching its feedstock from naphtha to ethane. This transition is making the petrochemical industry less oil intensive. Conversely, the switch to new or de-mothballed ethane-based crackers is causing a shortfall of propylene, a by-product of ethylene production. This is supporting propylene prices and putting a floor under naphtha demand, while also incentivising propane demand for propylene production at the margin.



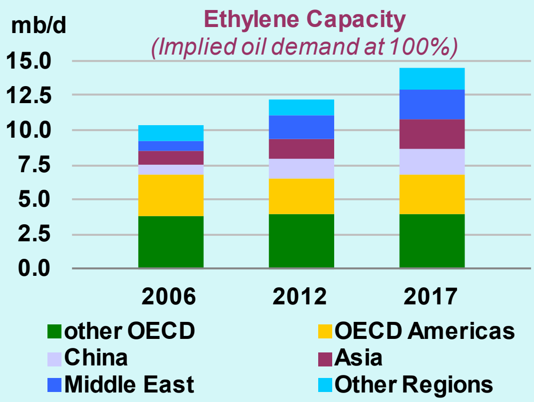


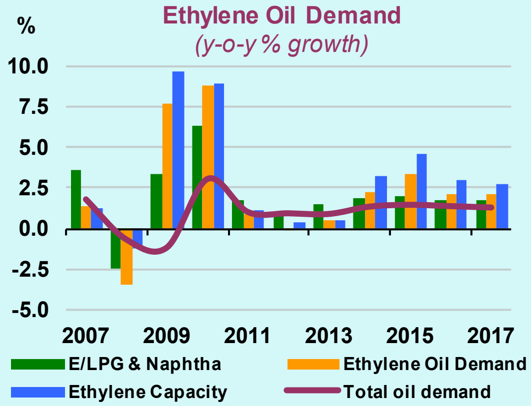
Global ethylene capacity is expected to rise to 183.4 million tonnes per year (mt/y) in 2017 from a downwardly revised 147.6 mt/y in 2011 – an increase of 35.7 mt/y and equivalent to yearly growth of 3.7%. As in previous editions of this report, nameplate capacity is based on an assessment of plants in operation up to 2012 and the expectation of capacity build-up over the forecast.

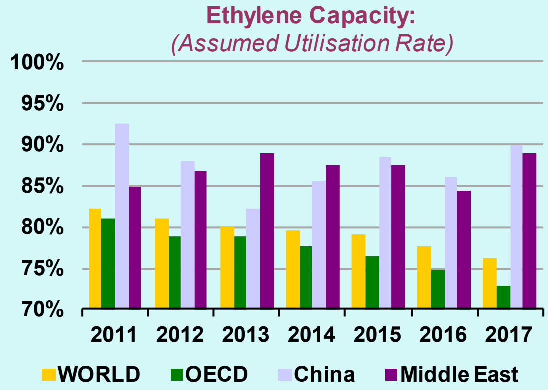
Compared with June 2011's *Medium-Term Oil and Gas Markets* (MTOGM), we have revised down the estimate of 2011 capacity by 3 mt/y, while the forecast for 2012 is reduced by 2.5 mt/y, to 150.2 mt/y. The latter revision due to baseline adjustments: decreases in other-Asia and China more than offsetting OECD gains (notably US). For 2013, we expect only 3.5 mt/y of new capacity or 0.8 mt/y less than last's year prognosis, due to subdued macroeconomic projections. Ethylene markets will be subject to increased competition between high-cost Asian and European naphtha crackers and less oil-intensive, lower-cost ethane crackers in the Middle East and the US.

Revisiting the Ethylene industry's demand for oil products (continued)

We attempt to assess the expansion of the ethylene industry and its implications for oil, especially light products. In 2012, oil equivalent demand for ethylene production stands at 12.2 mb/d, of which 36% is ethane/LPG, 55% naphtha and nearly 8.5% 'other products'. The US accounts for the largest share of total demand (17%), followed by China (12%), Saudi Arabia (8%), Japan (7%) and South Korea (6%). The biggest change from the previous forecast stems from the more rapid increase in Chinese demand and the emergence of Saudi Arabia as a major petrochemical hub.







In contrast to previous estimates, the revised outlook does not foresee a major change in the ranking of ethylene producers. Chinese oil demand for petrochemical production is catching up with the US, as new naphtha-based crackers lift Chinese demand. On the other hand, new US investments in cracking capacity, designed to leverage fast-rising, low-priced ethane and LPG production from shale gas and oil plays, is aimed at improving feedstock flexibility, ethylene yields and lower liquid feedstock requirements. The switch by US producers from naphtha to ethane should cut oil use from the ethylene industry without adversely impacting output, reflecting ethane's higher ethylene yields – 77.5% on average – than naphtha (30.3%). Ethane is also significantly lighter (17.2 mt/bbl versus 8.9 mt/bbl for naphtha), hence equal volumes can be maintained while reducing oil consumption in volumetric terms.

Plant utilisation is expected to fall to 76% in 2017 from 82% in 2011, lower than the previous estimate of 85% utilisation by 2016 – reflecting both reduced expectations of economic growth and the assumption of a broad-based feedstock shift in the US. Based on our assessment of plant utilisation, we estimate effective ethylene capacity at about 130.7 mt/y in 2011, implying an oil-based feedstock requirement of 10 mb/d, comprising 39% of LPG/ethane, 54% of naphtha and 7% other products. By 2017, demand from the ethylene industry is forecast to grow by almost 1 mb/d, to 11.1 mb/d, implying an effective capacity of nearly 151 mt/y. The feedstock mix will become lighter as LPG/ethane rises to 42%, while naphtha and 'other products' fall to 53% and 5%, respectively.

Revisiting the Ethylene industry's demand for oil products (continued)

Oil products demand for Ethylene Production under 80% Capacity Utilization (2011-2017)

	2011						2017						Total Oil Product Growth, 2011-17	
	Oil Product Inputs				Ethylene Output		Oil Product Inputs				Ethylene Output			
	kb/d	Share			kmt/y	World Share	kb/d	Share			kmt/y	World Share		
		LPG / Ethane	Naphtha	Other				LPG/ Ethane	Naphtha	Other			kb/d	%
OECD	**5,279**	**38%**	**55%**	**7%**	**67,529**	**52%**	**4,927**	**43%**	**51%**	**6%**	**65,681**	**45%**	**-352**	**-1.1**
Americas	2,229	69%	25%	6%	30,848	23%	2,061	80%	17%	3%	30,997	22%	-168	-1.3
Europe	1,795	17%	73%	10%	20,981	18%	1,639	19%	72%	9%	19,288	14%	-156	-1.5
Asia & Oceania	1,255	13%	82%	6%	15,699	10%	1,227	13%	82%	6%	15,396	9%	-28	-0.4
Non-OECD	**4,753**	**40%**	**54%**	**6%**	**63,195**	**48%**	**6,183**	**41%**	**55%**	**4%**	**85,233**	**55%**	**1,430**	**4.5**
Africa	68	89%	11%	0%	1,169	1%	148	78%	22%	0%	2,489	2%	80	13.8
Latin America	338	38%	60%	2%	4,658	3%	518	37%	63%	0%	7,431	5%	179	7.3
China	1,270	3%	88%	9%	15,030	11%	1,685	3%	92%	5%	20,578	13%	415	4.8
Asia	1,237	19%	71%	10%	14,669	12%	1,452	21%	72%	7%	19,910	15%	215	2.7
FSU	393	30%	58%	12%	4,938	3%	420	31%	55%	15%	5,044	3%	27	1.1
Middle East	1,397	94%	6%	0%	21,916	16%	1,898	90%	10%	0%	28,844	17%	500	5.2
Other Regions	50	25%	70%	5%	816	1%	63	25%	69%	6%	937	1%	13	3.9
WORLD	**10,032**	**39%**	**54%**	**7%**	**130,724**	**100%**	**11,111**	**42%**	**53%**	**5%**	**150,914**	**100%**	**1,078**	**1.7**

OECD Europe and Asia Oceania will lead the decline in utilisations, as their relatively old and small naphtha crackers suffer from weak margins, due to low demand and strong competition from new integrated petrochemical plants in China and low cost ethane crackers in the Middle East and the US (see 2011 MTOGM). In anticipation of those challenges, major European and Japanese petrochemical companies are restructuring their business models and consolidating operations to shift production from commodities such as polyethylene to highly specialised products. In the Americas, ethane/LPG demand is expected to increase as producers leverage that feedstock's low cost. Naphtha crackers are expected to run at reduced rates and specialise in propylene production and niche chemical products. Efficiency improvements in the Americas are expected to cut petrochemical demand for oil by 200 kb/d over the forecast period, to 2 mb/d. Amid sluggish demand, ethylene production is forecast to inch upwards by 0.15 mt/y to 31 mt/y, as a result of improving feedstock flexibility.

The non-OECD share of global ethylene output is expected to rise to 55% by 2017 from 48% in 2011. Increases in China, Asia (India, Thailand and Malaysia) and the Middle East (Saudi Arabia, UAE and Qatar) are forecast to lift oil demand from those regions by 0.4 mb/d, 0.2 mb/d and 0.5 mb/d, respectively. While China and Asia will raise their demand for naphtha, the Middle Eastern increase by 2017 will be 0.4 mb/d of ethane/LPG and 0.1 mb/d of naphtha.

US Ethylene industry to become less oil intensive

The shale oil and gas revolution in the US has caused ethane and LPG to trade at a deepening discount to naphtha since mid-2009. For the first time in about a decade, US Gulf Coast market participants are expanding their capital investments in a bid to capture the lower cost and high ethylene-yield of ethane and LPG. Reports estimate that ethane margins from the ethylene to high-density polyethylene (HDPE) industrial chain are twice as high as those in the naphtha-to-HDPE chain. Input costs for North American ethylene are 50% lower than North East Asia, a region that sets the global price for the ethylene chain.

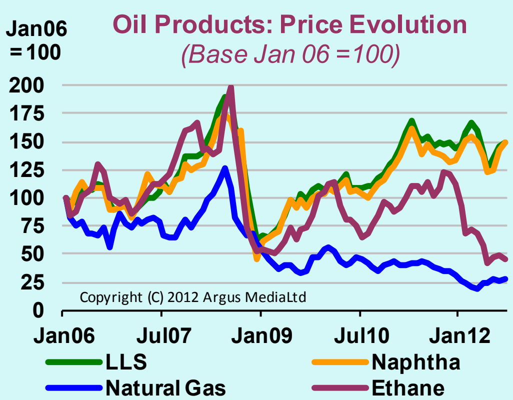
Between 2013 and 2015, several US projects, including both new capacity build-up and, in at least one case, the reactivation of an idled facility, are aimed at increasing ethylene output from lighter feeds. Three new world scale petrochemical complexes, integrating ethane cracking and polyethylene units, are expected to come on stream in 2016-2017. Two of those projects, of 0.8 mt/y and 1.5 mt/y respectively, are planned in Texas, where the Eagle Ford shale play will supply a cost-competitive feedstock. The third, a 1 mt/y integrated ethane cracker, is planned in the Marcellus shale gas basin, where a fractionation gas plant is also expected to feed crackers in Canada, which are currently being revamped to process lighter feedstock.

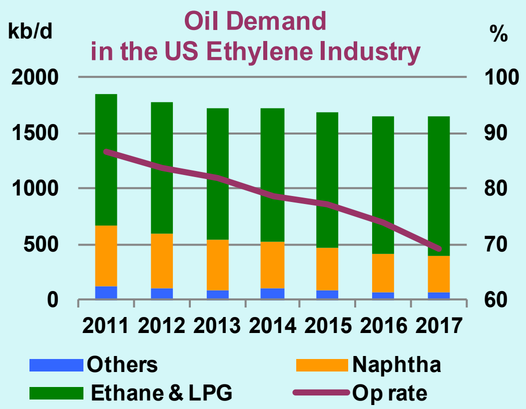
Revisiting the Ethylene industry's demand for oil products (continued)

This new cycle of investment will not significantly lift oil demand. The aim of these projects is to profit from a cheaper feedstock. Between 2011 and 2017, our model suggests that industry upgrades will lift ethane/LPG demand by 70 kb/d, but cut demand for naphtha by 200 kb/d and 'others' by 60 kb/d. Ethane crackers are forecast to maintain an average utilisation rate of 96%, while naphtha crackers operate at 55% of capacity on average. Overall US operating rates are expected to average 79%. By the end of the forecast, however, uncompetitive naphtha crackers would suffer from extremely unfavourable conditions, signalling the need for rationalization. In sum, we expect oil demand from the US ethylene industry to drop from 1.84 mb/d in 2011 to 1.65 mb/d in 2017 (-190 kb/d or -1.8%).

Ethylene Capacity Changes
(thousand tonnes per year)

	2012		2013-17	
	Naphtha	Gas	Naphtha	Gas
Feed Flexibility	60	110	0	0
Expansion & Flexibility	149	0	0	986
New Crackers	0	0	0	3,300
Others	0	0	411	0
Total	**209**	**110**	**411**	**4,286**



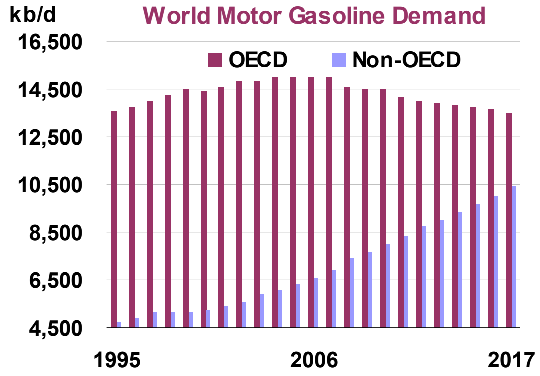


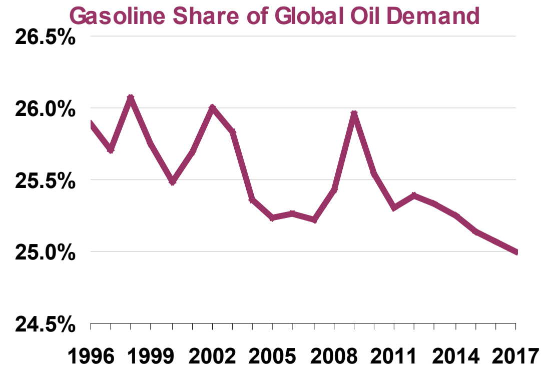
Naphtha cracking for propylene production

The flip side of more efficient, lower-cost, ethane-based ethylene production is a drop in associated propylene, butadiene and butylenes production. Those by-products are highly valued in the refining sector (where they are used in alkylation units to improve gasoline quality) and in polypropylene plants. A typical ethane cracker yields 3.1% propylene and 3% butylenes-butadiene, compared to yields of 16.1% and 19%, respectively, in a naphtha cracker. Some naphtha-based cracking capacity is expected to remain in operation, supported by demand for those 'by-products' of ethylene manufacturing. Depending on market conditions, engineers can adjust those naphtha-based crackers to maximise either ethylene or propylene output. Whereas previously ethylene would have been the more desirable product, current market trends could incentivise production of propylene, butadiene and butylenes. Producers in Europe and Asia are shifting targets to leverage the uptrend in by-products markets and invest in 'niche' speciality chemical plants.

Reduced propylene output from ethane crackers may also support propylene production from propane, which had long been uneconomical. Like that of ethane, US propane availability has benefited from rising shale oil and gas production, resulting in increased supply and lower prices. Propane dehydrogenation (PDH), a technology used to produce propylene from propane with approximately an 85% conversion efficiency, has become cost competitive under current market conditions. A 545 mt/yr plant is already operating in Houston, with an implied propane demand of 22 kb/d. Two more facilities are expected to be commissioned, early-2015, adding 1,350 mt/y of capacity, or 54 kb/d of propane demand. Beyond the US, at least 12 plants worldwide are currently operating, with a combined capacity of 4.9 mt/y of propylene or 200 kb/d of implied propane demand. By 2017, new projects in China, Saudi Arabia and the US could lift propane-based propylene capacity to 15.3 mt/yr, implying 610 kb/d of propane demand. Should all these projects reach completion, naphtha cracking for propylene production would face severe competition, at least in regions where propane is abundant, secure and cost competitive.

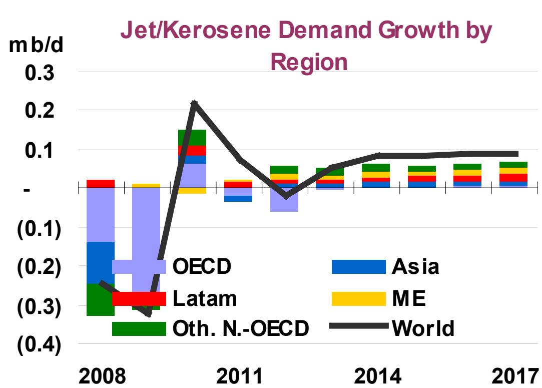
Gasoline and jet fuel: a tale of two regions

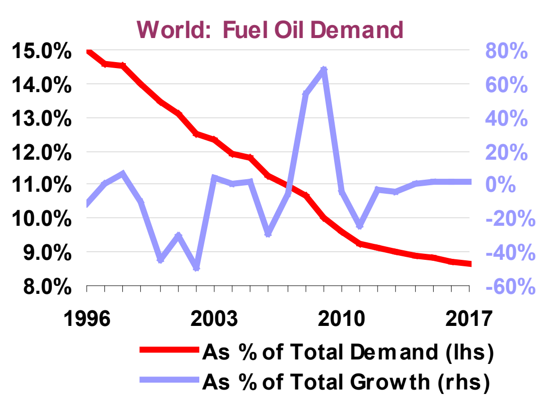




While accounting for a diminishing share of the global product mix, gasoline demand is still forecast at more than one-fifth of projected global demand growth within the outlook. Emerging markets completely dominate gasoline growth, with roughly 2 mb/d of additional consumption envisaged from non-OECD participants, outweighing a 620 kb/d OECD decline. The persistently expanding non-OECD car fleet, which is forecast to be underpinned by the relatively robust economic backdrop, should be more than enough to outweigh the opposing influence provided by engine efficiency gains. Such momentum will be insufficient to reverse declines in the OECD, as only small gains are envisaged in the developed world car fleet while efficiency gains remain notable. Non-OECD gasoline consumption rises by an average of 3.7% per annum, in 2011-2017, outweighing the average fall of 0.7% foreseen in the OECD.

Having endured a particularly harsh credit crunch, in 2008-2009, the airline industry rebounded strongly in 2010, particularly in the OECD, but has since endured a double-dip, in 2011-2012, as economic momentum has slowed. Assuming the underlying macroeconomic predictions – that global GDP growth picks up post-2013 – are right, modest demand growth is forecast to return, led by non-OECD countries, which will account for roughly two-thirds of global jet/kerosene demand growth. China is likely to provide the strongest individual demand growth, contributing just under a quarter of the total predicted expansion, in 2011-2017. Runway capacity constraints, in many developed countries, will act as additional drags on to the jet/kerosene forecast.





Flat fuel oil demand trend

The residual fuel oil market will provide only a very slight impetus to global demand growth, as modest non-OECD gains barely neutralise substantial (but from a lower base) reductions in the OECD outlook early in the period. Product switching, for environmental and price reasons, leads the downside, with both natural gas (in power sector) and gasoil (bunkers) taking up the slack. Bunkers provide one of the greatest uncertainties in the baseline, as they are technically all marine fuels and are inherently tricky to track. Estimates of global bunker demand range from 3.5 to 7 mb/d, with our own estimate for 2011 put at 4.8 mb/d – fuel oil accounting for 3.7 mb/d of total bunkers (1.1 mb/d gasoil). Assuming that we are right in this estimate, and that continued OECD efforts are made to reduce the sulphur content (notably in 2015 when tighter regulations come into effect), heavy fuel oil demand for marine transportation will likely remain unchanged as non-OECD growth cancels OECD declines. The fuel oil market overall is similarly forecast to remain flat, at around 8.2 mb/d, throughout the forecast. Slowly returning nuclear capacities in Japan will further reduce the fuel oil forecast: although only a very gradual resumption is assumed, this at least differs dramatically from the sharp drop that was seen in 2011-2012 which accordingly boosted fuel oil demand. The pace with which the nuclear industry in Japan returns adds an additional element of uncertainty to the demand numbers (see *Nuclear Dilemma*). We currently assume four-to-six reactors will be back by the end of 2013, however much uncertainty surrounds this assumption. A slower restart of idled nuclear capacity would provide additional support to fuel oil demand.

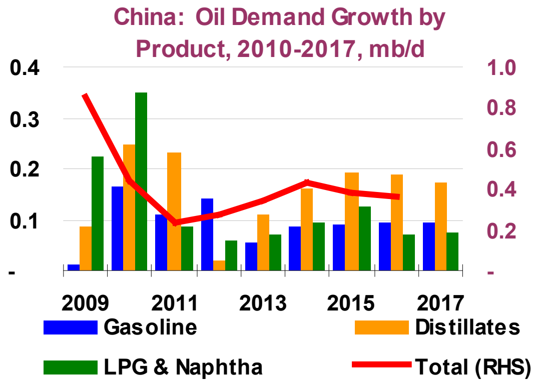
Is China taking a back seat in non-OECD demand growth?

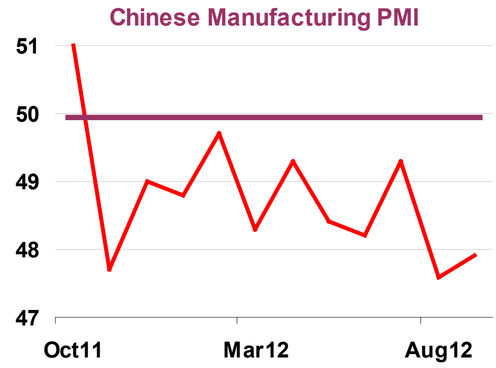
Although the non-OECD region continues to drive global consumption growth, if at a slower pace than previously forecast, the international distribution of demand growth within the non-OECD group is shifting. For Chinese demand, 2012 may be signalling the start of a new chapter. Having led global demand growth for the last few years, Chinese demand appears to be shifting to a slower pace of growth, though the sheer size of the Chinese economy means that even smaller percentage gains, coming on top of an elevated demand baseline, may still have a large market impact. But while China may be slowing in relative terms, oil demand in other non-OECD economies look set to keep growing as fast and even faster than in recent years.

Signs of slowdown in Chinese demand

China has led global oil demand growth this past decade, with gains in the ten years prior to 2012 averaging 7% per annum. Early estimates of apparent demand (*i.e.* refinery production plus net product imports) show a steep deceleration in 2012, to growth of 2.6%, as the Chinese economy has shown serious signs of slowing. Manufacturing sentiment – a key determinant of oil demand growth, particularly for gasoil – slipped into "contracting" territory in November 2011, and has since remained below the key 50-threshold. This report estimates that Chinese oil demand growth will recover somewhat from recent lows, rising to 4.3% in 2015. However, expectations of future growth have been trimmed since the MTOM.

Having expanded by an average of 11% in the seven-years, 2005-2011, a notable deceleration in economic growth to around 8% is foreseen during 2012-2017, and even this has a potential bias to further downside revisions. Post-2015, even weaker Chinese oil demand growth is assumed, with gains of 3.6% envisaged in 2016 and 3.3% in 2017, as the effect of an aging population compounds the impact of tightening efficiency standards and environmental regulations.





A number of factors will contribute to the relatively modest Chinese demand outlook:

- Demographic trends: the strict enforcement of the one-child policy, circa-1979, has created serious population constraints for the impending medium-term time frame. Notably growth in the key working age population, *i.e.* 33-to-54, is set to slow to around 5 million people in total, over the current decade, down from growth of 90 million people in 2000-2010.
- Average incomes in China have already passed a number of important milestones, and their movement into higher income thresholds will likely coincide with weaker oil demand growth. In rapidly developing Asian economies, for example, progress through \$5,000 per person has previously signalled a shift to slower demand growth. At these levels urban dwellers have already bought enough automobiles to cause gridlock in most of China's big population centres. As average incomes in China are forecast to rise up towards \$10,000 by 2017 a declining proportion of this income will be spent on energy-intensive goods, as consumers increasingly consume services. Japan, Taiwan and South Korea, for example, once their average income rose above \$5,000, saw nearly four percentage points stripped from their oil demand growth.
- Heavy infrastructural spending in recent years leaves less need for further large-scale expenditures. China, in 2011, spent over 50% of GDP on investments (a rough proxy for infrastructural spending), a staggering level by any standard. Further increases are envisaged over the next couple of years, but growth could be capped by the large increases that have already been seen recently.
- Property markets could weaken further, restraining consumer (and to a lesser degree business) confidence. The value of Chinese real estate, as a proportion of GDP, is already 9%, well above levels seen in other countries before experiencing corrections.
- Heightened private sector debt. Although the government runs a current account surplus, combined household and corporation debt levels exceed 125% of GDP. Such debts will continue to restrain confidence, and hence economic growth, through the medium term time horizon.

Other non-OECD economies continue to depict strong gains

Other non-OECD countries are expected to grow more rapidly than China, with strong gains projected across the rest of Asia (notably India and Indonesia), the economies of the former Soviet Union, the Middle East, Africa and to a lesser degree Latin America.

Indian oil product demand is forecast to increase by an average of 3.5% per annum, in 2011-2017, as demographic growth and an expanding industrial base support rapid growth. Both diesel and gasoline demand are expected to grow by 5% or more per annum through to 2017. The possibility of reduced diesel subsidies could shift some of the growth from diesel to gasoline but is not expected to dent transport fuel demand growth significantly overall. There is also more scope for infrastructure spending than in China, which would provide extra support for Indian oil product demand.

The **former Soviet Union** has been one of the biggest demand surprises in recent years, as demand growth came in close to 7% in 2011 – more than triple the estimate made in last year's report – with gasoil (+9.7%), fuel oil (+8.0%) and LPG (+7.9%) leading the momentum. Early estimates of 2012 demand imply a similarly large uptick on previous expectations, with Russia in particular leading the revisions. Whereas concerns about a declining former Soviet Union population base were restricting previous growth projections, we have now adjusted our model to better capture rapid income growth seen recently and projected forward through 2017. Demand growth of just under 3% per annum is assumed through the forecast period, as continued price subsidies (outside of Russia) reduce the incentive to push through efficiency gains.

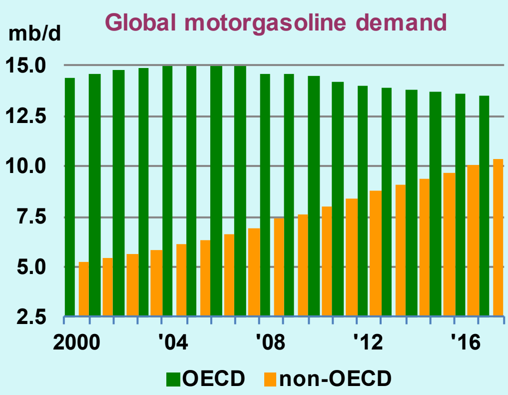
Robust demand growth is also assumed in the **Middle East**, following the recent trend but at a decelerated trajectory. A fast-growing population base underpins the relatively strong consumption projections for the Middle East, with compound growth of 3.4% per annum assumed, in the period 2011-2017. Efforts to reduce oil subsidies are not expected to make a significant impact during the forecast period, and policies designed to diversify out of oil for power generation likewise are expected to have a greater impact after 2017 than before. Robust transportation fuel demand will underpin the Middle Eastern demand profile through the forecast: gasoline rising by an average of around 3.8% per annum, 2011-2017; jet/kerosene 3.1%; and gasoil/diesel 2.9%. Relatively strong growth – plus 4% per annum – is also envisaged in 'other products', underpinned by crude oil for direct burn in the power sector. Particular notable overall expansions are foreseen in Saudi Arabia and Iraq, respectively rising by average compound rates of 4.5% and 5.4%. An additional layer of uncertainty surrounds the outlook for Iran, as we are assuming flat demand in our base case numbers. However, dependent upon how the political situation unfolds, much stronger/weaker demand would likely emerge. Similar ambiguity encloses the demand estimates for Syria and the Yemen.

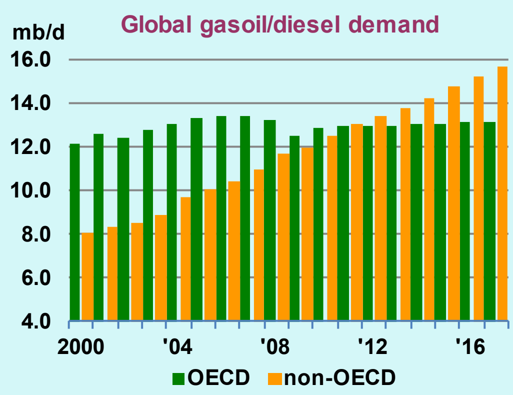
The **Latin American** demand forecast is for a more modest 2.2% per annum growth, 2011-2017, as the relatively higher oil-import dependence of the region increases the underlying incentive to economise on consumption. Assumed efficiency gains, just short of 2% per annum through the forecast and close to the pre-recessionary period, have a counterbalancing impact on the otherwise heavily supportive impact of strong population growth and an expanding income base.

Having fallen in 2010, and stagnated in 2011, early estimates of **African** demand point towards a sharp acceleration in 2012, with momentum building in 2013. The earlier slump based largely upon the heavy political disruptions seen across much of North Africa, while the gains of 2012-2013 are based largely upon the resumption of relative normality. Such political uncertainties factor in an additional level of doubt into the demand numbers, but those are the cards one must play with so assumptions for the future have to be made. Assuming no more serious political upheaval through the forecast, demand growth of around 3% per annum is projected, underpinned as it is with rapidly expanding income growth. At first glance this trajectory might seem low but seeing as the previous six-year average was just over 2% per annum and prior to that it was still only 3%, such expected growth is consistent with the historical context.

The composition of transportation fuel demand growth

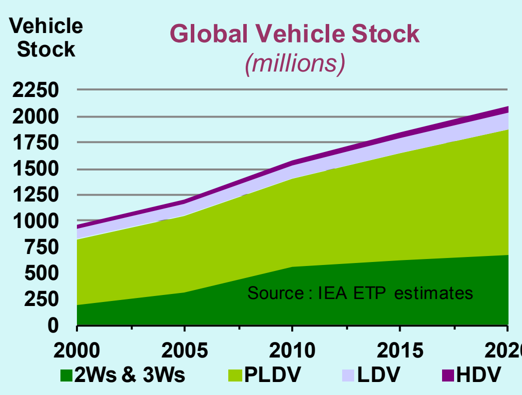
Transportation demand for refined products will undergo significant shifts, due to changes in the vehicle fleet, driving demand and fuel economy. During 2011-17, gasoline demand should grow by 1.4 mb/d to 23.9 mb/d (1.0% per year), while gasoil/diesel grows by 2.7 mb/d to 28.8 mb/d (1.7% per year). Growth will be led by non-OECD economies, which are expected to increase their share of global gasoline demand by 6 percentage points, to 43%, and gasoil/diesel by 4 percentage points, to 54%. OECD gasoline consumption will inch 0.7% a year lower, suppressed by high prices and more efficient vehicle choices. OECD demand for gasoil/diesel, a key input in several industries and the on-road fuel of choice in Europe and Japan, is expected to edge upwards by 0.2% a year. In the non-OECD region, gasoline demand is projected to rise yearly by 3.7% and gasoil/diesel demand by an average of 3.1%.

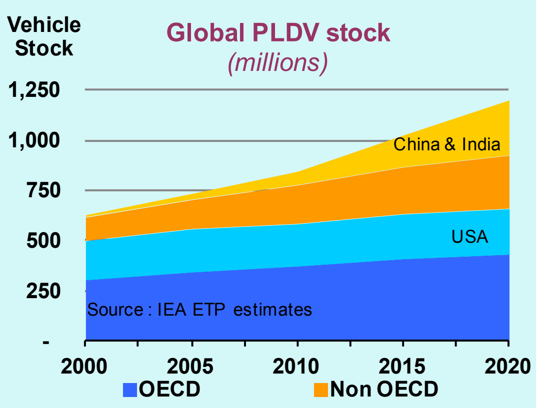




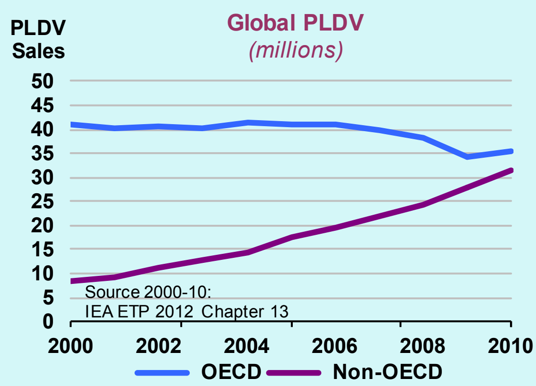
Transportation fuel demand is composed of vehicle fleet structure, activity and intensity. The main *structural* factor consisting of the vehicle fleet and their respective energy sources (gasoline, diesel, electricity, etc.). A*ctivity* is measured by the product of vehicle stock and annual driving distance. Finally, *intensity*, also known as fuel economy, refers to how much energy a vehicle requires to move from point A to B, and is measured in litres per 100 kilometres. A technique to structure transportation fuel demand is to specify a conceptual model: Δ demand = Δ fleet size + Δ VMT - Δ fuel economy. Each one of those three factors is expected to undergo changes in the forecast period.

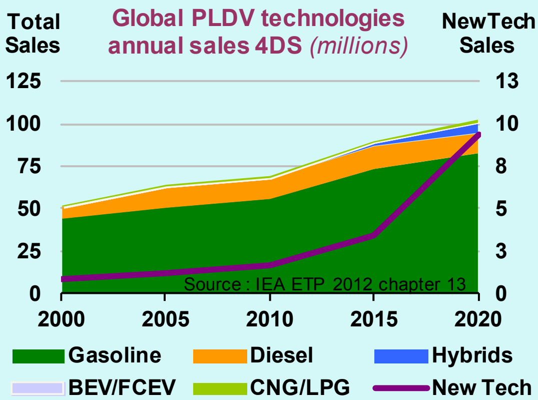
The IEA estimates that the global vehicle fleet will grow to 1.96 billion vehicles by 2017, an average gain of 3% per annum, 2011-2017. In 2011, two and three wheelers (2Ws & 3Ws) accounted for 35% of the total stock, passenger light-duty vehicles (PLDV) 53%, light-duty vehicles (LDV) 8% and heavy-duty vehicles (HDV) 3%. While the share of the latter two remains constant, PLDV's share will raise to 56%, as 2Ws and 3Ws sales lose pace, with rising non-OECD incomes the key driver.





The composition of transportation fuel demand growth (continued)





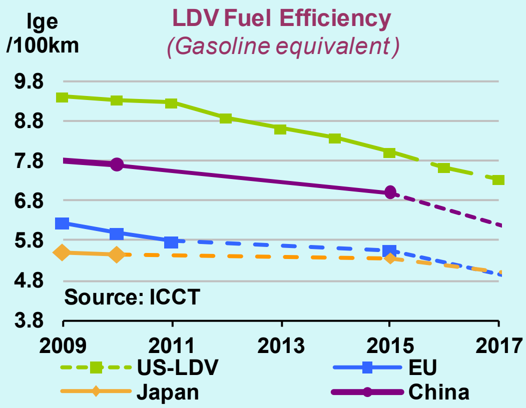
China and India alone are expected to see a combined increase close to 17% in their PLDV fleet, leading non-OECD average growth of 3.5% per annum. In contrast, the OECD fleet is expected to inch higher by 1.6%, driven mostly by the US, the main PLDV market. PLDV annual sales shrank in the OECD during 2005-2010, by an average 2.8%, to 35.6 million vehicles, as relatively high fuel prices compounded the effect of the economic weakness. Non-OECD vehicle sales rose by an average of 12.1% per annum, just above 31 million vehicles, on the back of growing incomes and, in some cases, subsidised fuels. Non-OECD PDLV numbers are estimated to overtake the OECD, in the early years of our forecast, supporting transport fuels demand growth and trade flows into the region. We estimate that vehicle sales will grow by an average of almost 1.0% per annum in the OECD and 6.1% in the non-OECD, 2011-2017.

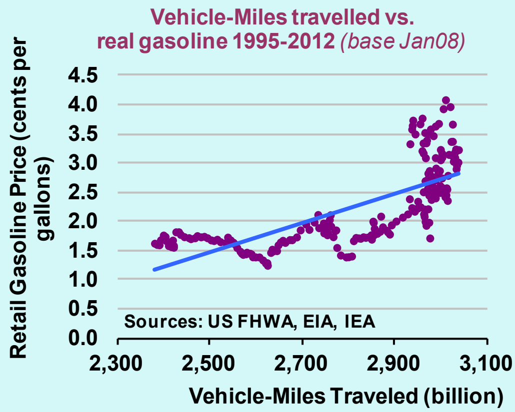
IEA estimates that gasoline and diesel will remain the main source of energy during the forecast. In 2000, gasoline and diesel powered 98.5% of all sold PLDV, with the remaining 1.5% running mostly on CNG/LPG. Ten years later, hybrid sales of 0.8 million still equate to a market share close to 1% – a slow market penetration explained in part by the high upfront price premium of hybrids over conventional vehicles, paid back in fuel savings over the entire life-cycle of the vehicle. *Fuel Economy Roadmap* (2012) provides an estimate of potential fuel economy improvement and cost relative to a 2005 vehicle; a ‘full hybridisation’ process for a gasoline and diesel vehicle will cost the industry, hence the consumer, €6,270 and €6,125 per vehicle, respectively. This premium potentially yielding 63% efficiency gains in gasoline and 52% in diesel, making it recoverable in a five-to-seven year period with an annual usage of above 15,000 km. Existent technologies could yield, if combined, 51% and 39% efficiency gains for gasoline and diesel, respectively, for less than 60% of the ‘full hybridisation’ cost. During the outlook, we expect the share of conventional technologies using only gasoline/diesel to shrink from 97% in 2011 to 94% in 2017, while hybrids’ market share would reach 3% to 5% by 2017.

Government policy is supporting shifts towards more efficient vehicles through regulations, such as US CAFE standards or EU directives. In the US, where fuel economy standards are less stringent than in other countries, the CAFE target for new PLDVs and LDVs in 2011 was 9.3 litres/100km (standard adjusted by ICCT to EU NEDC for comparison purpose), which will be improved by an annual 3.8% to 7.6 litres/100km by 2016 and a proposed 7.3 litres/100km in 2017. The comparable EU and Japanese fuel economy standards for 2015 are set at 5.6 litres/100km and 5.4 litres/100km, respectively. In China and South Korea, fuel standards are set for 2015 to 7.0 litres/100km and 6.55 litres/100km, respectively.

Measuring transportation *activity*, or vehicle usage, can be a challenge, as trailing indicators often reflect more a modelling effort to estimate average usage than a gathering of hard data. Detailed US VMT data suggest that vehicle usage eased when the real price approached $4/gal. If we can extrapolate this reaction to other OECD countries, as fuel prices increase, we can expect consumers to choose cheaper transportation options and/or to purchase more efficient vehicles, decisions that will drive down oil intensity. Finally, non-OECD demand will increase accordingly with income growth, but will remain tempered by gasoline and diesel prices, wherever distorting subsidies are not present.

The composition of transportation fuel demand growth (continued)





The impact of transport technology trends, especially after 2015, supports our tame annual growth forecast for gasoline (1.0%) and diesel (1.7%). This is the case even though the main structural element of transport demand, the vehicle stock, is expected to rise by an average of 3%, 2011-2017 (non-OECD: 6.1% and OECD: 0.9%). Although we foresee a relatively sluggish introduction of super energy efficient vehicles (hybrids), reaching in an optimistic scenario 4% of vehicle sales by 2017, we are projecting a marked step up in average fuel efficiency of vehicles. Finally, we expect that the price of oil will also have a big impact on usage, VMT, in the US.

Issues in inter-fuel substitution

While income growth remains as a rule the leading driver of oil demand growth, inter-fuel substitution can be an important factor behind changes in demand levels and oil uses. This can cut both ways. Diversification out of oil (in favour of nuclear, natural gas, or renewable energy) naturally reduces the share of oil in the fuel mix and undermines oil demand in both growth and absolute terms. Recent experience has shown, however, that inter-fuel substitution could also benefit oil, when oil was called in as a substitute for another source of energy that had become either unavailable or uneconomical. Such was the case in Latin America at various times in the last decade when droughts curtailed hydroelectricity generation, or more recently in Japan in the wake of the 2011 Fukushima accident, the effects of which are expected to keep unwinding over the forecast period. In contrast, rapid growth in US unconventional gas supply is rekindling interest in new market outlets for natural gas, notably in the oil-dominated transportation sector. While progress may be achieved toward converting rail transport to natural gas in the next few years, this report does not anticipate any groundbreaking or transformational shift within the forecast period, as the most economical opportunities for fuel switching from oil to natural gas in the US appear to have already been tapped, even at historically low natural gas prices.

Fuel switching prospects in the US 'golden age' of natural gas

US natural gas supplies have enjoyed a boom over the past couple of years, as the fruits of the shale gas revolution led US production to expand to about 650 billion cubic meters (bcm) in 2011 from about 570 bcm in 2008 (please see in this report's Supply section the box titled *Key oil supply considerations: Natural gas and natural gas liquids*). Further supply growth of 6.4% year-on-year was seen in the first half of 2012. Prices fell sharply on strong production growth: the benchmark US Henry Hub price averaged \$8.86/mmBtu in 2008, but dropped by more than half in 2011, to

$4/mmBtu, extending its decline in 1H12 to $2.37/mmBtu. Lower natural gas prices accordingly stimulated rapid growth in natural gas consumption, up to 690 bcm in 2011 from 659 bcm in 2008.

Assuming the “cheap” gas revolution continues, what is the likelihood that the “golden age of gas” will play out at the expense of oil consumption in the US? For producers, continued output growth raises the challenge of finding new market outlets. Their success in meeting that challenge will depend on a combination of four key factors: price (our US natural gas production forecast is based on the Henry Hub natural gas forward curve as of April 2012), technology, policy and infrastructure. New outlets may emerge in the form of LNG exports – the US government has already approved one liquefaction plant, and others are being considered. Cheap natural gas feedstock is also spurring a petrochemical renaissance in the US, in particular in areas near shale gas formations or with easy access to new supply. Last, continued growth in natural gas production may entail a resurgence in, or continuation of, fuel-on-fuel competition between natural gas and oil products, as well as between natural gas and coal.

Over the last decades, large-scale fuel switching from oil to natural gas has already taken place for stationary uses such as power generation and space heating, but virtually none at all for transportation. In order to claim more market share from oil, natural gas would need to either continue displacing oil for stationary uses, or make inroads into transport. In both cases, the prospects of a rapid shift in the next five years look relatively dim, though not necessarily insignificant. The potential for natural gas to gain market share is stronger beyond the forecast period.

In power generation and space heating, further gas penetration is constrained by market saturation and infrastructure hurdles. Oil’s share of US power generation is now down to a fraction of what is used to be; further natural gas penetration of the electricity sector is now more likely to come at the expense of coal. Following massive penetration of the space heating segment by natural gas in the US Midwest and the Mid-Atlantic region, further inroads into that market segment may take large infrastructure building, mostly in New England, the last US heating oil stronghold – whether natural gas distribution or new gas-fired power generation capacity to replace oil with electricity. Given the capital costs and lead times entailed, this looks unlikely to happen on a large scale within five years.

That leaves the transport sector. There are two ways in which natural gas could penetrate that market: through the use of compressed natural gas (CNG) or LNG in combustion engines, or via electric vehicles powered by gas-fired electrical stations. Bus networks in several states have already switched over to gas or plan to do so. Additional use of natural gas in public transportation markets is assumed through to 2017. Other candidates for switching include garbage truck fleets and similar vehicles running on short-haul, dedicated routes where a refuelling infrastructure network can easily be set up. Efforts to move taxi services across to natural gas, as has been pioneered in other countries, could be seen. Progress, however, would largely depend on policy support and infrastructure building, which given current fiscal constraints looks unlikely in the near to medium term. Vehicle use, as a share of total US natural gas consumption, remains exceptionally low, at 0.14% according to the EIA, but has increased by roughly a third compared to 2008 (0.11%).

The rail transportation sector is another candidate for conversion to natural gas. Several railroad companies are reportedly considering setting up micro-LNG liquefaction plants along their network. As railways currently run on diesel, a premium fuel in relatively short supply, switching to low-cost natural gas could yield large savings. Diesel consumption by the US rail sector averaged around 170 kb/d in 2010, but may since have risen sharply given the rapid, if poorly measured, increase in rail transport over the last couple of years, not least to move crude oil stranded in Cushing and around the Bakken formation. Our forecast assumes that the rail sector doesn't switch from diesel to natural gas during the forecast period; should it do so, however, US diesel consumption would likely be significantly reduced.

Another possibility is that gas channelled into electrical generation could make mass ownership of electric vehicles a more realistic prospect. Such large-scale moves are, however, not likely within the forecasting timeframe of this report; the average replacement cycle for most vehicles is fifteen years and, to date, the uptick in purchases of electric vehicles has been slow. Increased penetration of more efficient vehicle technology – such as hybrids – is the most likely change in the US transport sector, an assumption that is incorporated in this report.

Nuclear dilemma

The Fukushima disaster brought serious attention to the future of nuclear power. Germany and Switzerland, for example, quickly decided to phase out nuclear electricity, while much debate has embarked upon its future elsewhere. Nuclear output in OECD countries fell by more than 6%, or 140 TWh, in 2011, according to IEA *Monthly Energy Statistics*. Most of the drop was attributable to Japan and Germany, which together accounted for more than a 150 TWh contraction. In the short term such shocks, if unplanned, boost oil demand, as was the case with Japan in 2011 when incremental oil demand was around 150 kb/d over the "norm" or pre-tsunami level. According to the Federation of Electric Power Companies (FEPC) of Japan, the power mix in 2011 saw nuclear generation drop from a five-year average of 28% to 17%, while thermal plants powered by fossil fuels rose from a five-year average of 50% to 60%. The thermal generation fuel mix in 2011 was split: LNG (43%), coal (43%), crude oil (7%) and residual fuel oil (RFO, 7%). As a generalisation, the first two are used as inputs for base load electricity generation, while oil products are burned for peak electricity demand. Coal generation capacity remained largely unchanged, bar some 3% decrease imputable to plants damaged after the tsunami. Growth in Japanese fossil fuel demand for power generation was split LNG (56%), direct crude burning (27%) and RFO (20%).

The outlook for 2012 is for incremental Japanese oil demand of 360 kb/d over the "norm", as two reactors re-started mid-year in an effort to satisfy peak summer demand. Looking further ahead the outlook clouds with uncertainty, as public opinion remains overtly against nuclear power but economic and environmental reality imply there may be little alternative.

The government announced, September 14, that Japan would aim for zero nuclear power by 2040. This move does not necessarily preclude re-starts in the meantime, although the timing of any impending resumptions may incur delays. The implementation of the no-nuclear strategy is far from clear-cut, whilst numerous conditions, caveats and challenges remain, with reviews likely. A newly established regulatory body in charge of nuclear safety has been tasked with defining new standards and assessing the situation of all plants before any re-start decisions.

Despite this uncertainty, this forecast assumes the gradual re-starts of Japanese nuclear generation capacity over the next couple of years, but at a very slow pace. This dampens the oil product demand outlook, as previously oil demand was raised by the sudden addition of replacement demand (fuel oil and 'other products'). The question now is how rapidly this replacement demand evaporates, not whether any additional replacement demand will be required. More rapid nuclear resumptions would reduce the near-term demand forecast, as less oil would be consumed, but likely leave little change to the tail-end of the outlook, as restart dates are simply moved. On the other hand, a complete refusal to restart nuclear capacity would provide an additional stimulus of around 0.2 mb/d of extra oil demand, according to our model. Even here this could be reduced as previously closed coal facilities have reportedly reopened recently, whilst additional gas plants are being built.

Germany is a different story entirely, as its exit was already planned and, hence, no impact upon oil consumption was seen. Oil and nuclear are not natural alternatives, as nuclear (once it is built) provides relatively cheap base-load capacity to the electricity industry, whereas oil is rarely used for base-load power where it provides an uneconomically expensive alternative (unless relative prices dramatically change). Plans to move a country off nuclear power will almost always coexist alongside plans to hike natural gas or renewable capacity. The German power sector, for example, increased imports of electricity and also witnessed significant increases in domestic generation from renewable sources, especially roof-top solar power. France has also recently announced a desire to move away from nuclear power, albeit gradually, with plans to close its oldest nuclear power plant, Fessenheim, by 2017. Much debate, however, remains around the timing of any such move, and oil is unlikely to be the fuel of choice in any replacement scenario.

Uncertainty

Base case projections for demand growing by an average of 1.2% per annum, to 95.7 mb/d by 2017, are dependent upon numerous factors which could easily knock the demand forecast off track. The economic risks are, currently at least, heavily skewed to the downside. The base case outlook also assumes that the health of the troubled European economy slowly improves, which is still clouded with uncertainty. Chinese economic growth could also fall below expectations.

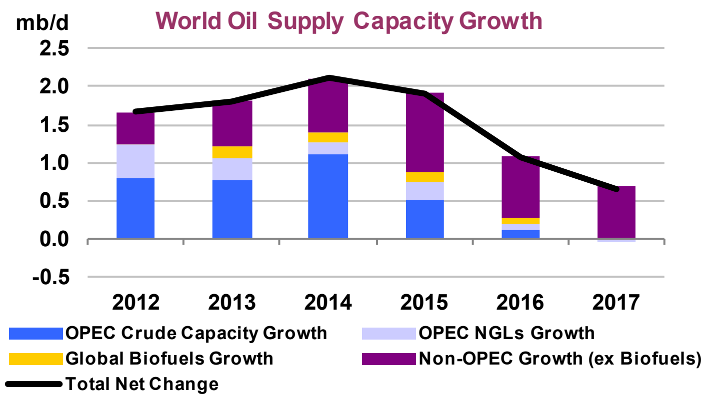
The other great uncertainty within any demand projection is the price assumption that underlies it. In this report we use the futures strip, thus essentially the amalgamation of what traders bet will happen to prices. Of course prices could (and will) vary from this strip, which with all else being held equal would alter consumption trends – higher prices reducing demand and *vice versa*. Any bias in the price should be equally weighted to the downside or upside, as we are essentially using an average of views of buyers and sellers in the market via the futures strip.

Political upheaval, of the kind experienced in both Africa and the Middle East in 2011, could further shake consumption prospects, although in an inherently unpredictable fashion hence their non-inclusion in our numbers. Additional uncertainty also surrounds policy decisions, as efforts to promote non-oil consumption would, of course, further quell demand. One of the biggest uncertainties is the future of nuclear energy in Japan, as outlined above.

SUPPLY

Summary

- **Global supply capacity is expected to increase by 9.3 mb/d to 102 mb/d in 2017, or 1.5 mb/d per year.** Around 20% of liquids growth comes from Iraqi capacity, and 40% comes from North American oil sands or light, tight oil (LTO) production.
- **NGL supply grows by 2.4 mb/d from 12.0 mb/d in 2011 to 14.5 mb/d in 2017, with growth split evenly between OPEC and non-OPEC.** OPEC NGLs and non-conventional supplies grow to 6.9 mb/d in 2017, a growth of 1.2 mb/d from 2011 levels. Saudi Arabia and the UAE are major contributors to growth.
- **OPEC crude oil production capacity is forecast to rise by a steep 3.34 mb/d over the 2011-2017 period, to 37.5 mb/d, with Iraq providing just over 50% of the increase.** By contrast, sanctions hit Iran sees capacity decline by more than 30% by 2017. This year's relatively higher capacity headline figure is skewed, however, by the temporary drop in OPEC capacity to a four-year low during the 2011 Libyan civil war. If the exceptional jump in Libya is removed from the calculations, capacity rises by 2.08 mb/d, in line with growth rates of previous years.
- **Non-OPEC oil supply is expected to grow by 4.7 mb/d from 2011 to 57.5 mb/d in 2017, or at an annual average of 790 kb/d (1.5%).** Approximately 80% of the growth comes from North American LTO and Canadian oil sands production and offsets mature field decline elsewhere.
- **Biofuels production is expected to grow 0.5 mb/d over the medium-term, with volumes rising from 1.9 mb/d in 2011 to 2.4 mb/d in 2017.** Higher biodiesel output in the US and Latin America drives a slightly stronger medium-term growth than envisioned in the December 2011 forecast. The advanced biofuels sector should grow from 55 kb/d to 180 kb/d in 2017.

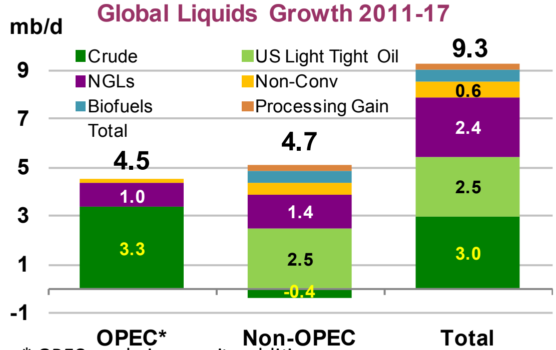


- **High oil prices increased capital spending by around 8% in 2012, but high prices have also led to increased demand for labour and oilfield service equipment.** Finding and development costs (and cost inflation) are currently slightly lower than in 2011, possibly reflecting drilling and completion technique and cost improvements (at least in the US). Markedly lower prices would reduce drilling activity and production rates in the medium term.
- **The broad uptake of unconventional drilling techniques outside of the US could increase oil supplies, subject to favorable policy support facilitating exploration.** But geopolitical unrest could also threaten oil production and transport, especially in the Middle East and Africa.

Global oil supply overview

Global supply capacity is expected to increase by 9.3 mb/d to 102 mb/d in 2017, or 1.5 mb/d per year. Around 20% of liquids growth comes from Iraqi capacity, and 40% comes from North American oil sands and light tight oil (LTO) production. Global crude supply capacity, 81% of global oil supplies in

2011, is expected to grow by 5.5 mb/d over the period to 80.7 mb/d, accounting for almost 60% of the growth in total liquids supply.



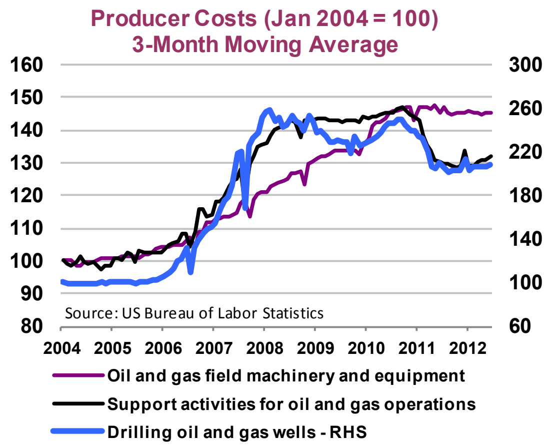
* OPEC crude is capacity additions
Global Refinery processing gains included in Non-OPEC

Deepwater trends

The share of deepwater production as a share of global supplies is expected to increase from 6% in 2011 to around 8% by 2017 (from 5.5 to 8.2 mb/d), with the lion's share of this growth centred in Brazil's deepwater (>1000 feet). Technological advancements in subsea development systems are also helping to increase production from deepwater fields, especially those in the US Gulf of Mexico, Brazil, Nigeria, and Angola. Fields that may have been considered too small, deep, or remote to develop using production platforms in the early phases of deepwater exploration are being "tied back" via subsea flow lines to existing platforms, significantly reducing both costs and the lag from discovery to initial production. Better technologies for subsea completions and improved access to drilling and production equipment designed for deep and ultra-deep waters have also facilitated exploitation of deeper and more remote discoveries. Finally, operators are developing deposits in close proximity to existing production and transportation facilities to minimise costs.

Cost inflation and investment trends

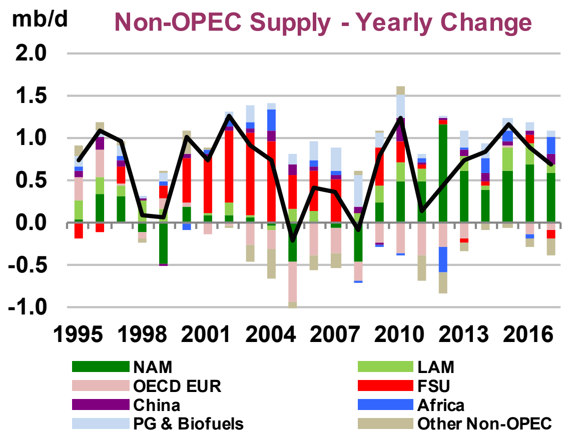
Strong oil prices led to increased drilling and exploration, which spurred incremental demand for oilfield-related goods and services over the last year. Higher service costs have contributed to an 8% increase in upstream oil and gas capital expenditures in 2012 to over $600 billion in 2012. However, recent statistics from the Bureau of Labor Statistics and IHS indicate producer costs peaked in early 2011, and the subsequent decline has enabled producers to renegotiate contracts at more favourable terms. Limited supplies of deepwater rigs contributed to a rapid increase in deepwater daily rig rates in 2012, and have kept costs for equipment broadly at 2011 levels. Most offshore oil rigs were built during the mid-1970s to the early 1980s when the prospect of drilling at depths of 1,500 or 2,000 feet was the limit.

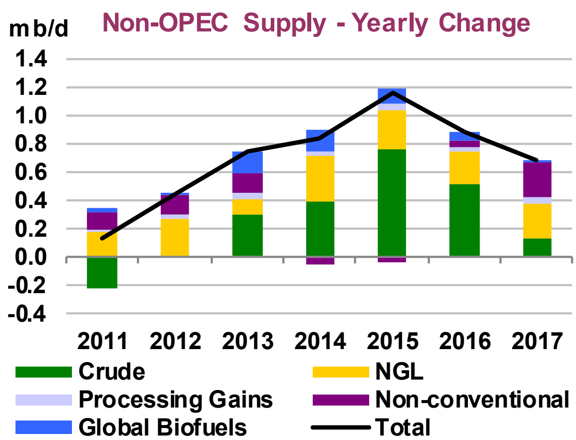


Non-OPEC overview

The single most important development for non-OPEC supplies in the last year has been the rapid and largely unexpected increase in LTO production in the United States. The pace and scale of development has arrested a 2% annual decline in US crude production over the last decade and stands to raise US oil output to 11.4 mb/d by 2017, a 40% increase from 2011. Recent rapid growth has insulated non-OPEC output from unplanned outages that ranged from 0.7-1.3 mb/d over the last year. Though unplanned outages are likely to remain prevalent, the application of unconventional technologies in North America, new deepwater projects, and improved recovery rates should raise non-OPEC supplies by 1.3% per year from 52.8 mb/d in 2011 to 57.5 mb/d by 2017.

In the FSU, Russia is forecast to maintain output at broadly current levels. Ambitious expectations from Azerbaijan and Kazakhstan have fallen to the wayside as mature field decline has set in and projects continue to be delayed, respectively. Latin American production is actually expected to decline slightly in 2012, after adding almost 200 kb/d on average to non-OPEC supplies in both 2010 and in 2011. Sabotage in Colombia and high offshore decline rates and maintenance in Brazil are mostly responsible for the poor growth trend of late, but Brazilian crude supply stands to add at least 0.7 mb/d over the forecast period.





Non-OPEC Supply

(million barrels per day)

	2010	2011	2012	2013	2014	2015	2016	2017	2017-11
Americas*	14.1	14.6	15.7	16.3	16.7	17.4	18.0	18.6	4.0
Europe	4.1	3.8	3.5	3.3	3.3	3.3	3.2	3.1	-0.7
Pacific	0.7	0.6	0.5	0.5	0.6	0.6	0.6	0.6	0.0
Total OECD	**18.9**	**18.9**	**19.8**	**20.2**	**20.6**	**21.3**	**21.8**	**22.3**	**3.4**
Former USSR*	13.5	13.6	13.7	13.6	13.6	13.6	13.7	13.6	0.1
Europe	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0
China	4.1	4.1	4.1	4.2	4.3	4.4	4.4	4.5	0.4
Other Asia	3.7	3.6	3.6	3.5	3.4	3.4	3.4	3.3	-0.3
Latin America	4.1	4.2	4.2	4.4	4.4	4.7	5.0	5.0	0.8
Middle East	1.7	1.6	1.5	1.5	1.4	1.3	1.3	1.2	-0.5
Africa	2.6	2.6	2.3	2.3	2.5	2.6	2.6	2.8	0.2
Total Non-OECD	**29.8**	**29.9**	**29.5**	**29.6**	**29.8**	**30.2**	**30.4**	**30.5**	**0.7**
Processing Gains	2.1	2.1	2.1	2.2	2.2	2.3	2.3	2.3	0.2
Global Biofuels	1.8	1.9	1.9	2.0	2.2	2.3	2.3	2.4	0.5
Total Non-OPEC	**52.7**	**52.8**	**53.2**	**54.0**	**54.8**	**56.0**	**56.9**	**57.5**	**4.8**
Annual Chg	1.2	0.1	0.5	0.7	0.8	1.2	0.9	0.7	
Changes from December '11	0.0	0.1	-0.4	-0.1	0.3	0.3	0.8		
Changes from last MTOGMR	-0.1	-0.5	-0.9	-0.3	0.5	0.9	1.5		

*Americas includes Chile, FSU does not include Estonia

The market pays much attention to developments in the North Sea as its production serves as the benchmark for the Brent marker price. Project additions and the return to production of the large Buzzard field in the UK are expected to keep declining production in check. That said, there are significant downside risks to the outlook as the fields age and outages increase in frequency and volumetric impact. Market participants and forecasters should not forget that enhancements to production will sometimes require months of downtime, and in mature fields, enhancement projects are usually intended to slow down decline rather than increase production. Through field level analysis we observe this trend in the North Sea, and it is happening in other mature basins too.

The areas with the most downside risk are probably in Africa and the Middle East, where geopolitical-related outages, pipeline sabotage, a murky investment climate, and challenging operating environments stand to thwart country and company goals. That said, current projections expect non-OPEC African countries to contribute 200 kb/d (or 4% of total non-OPEC growth) in the short term, especially in 2014, assuming that Sudan and South Sudan can resume the roughly 350 kb/d of output that has been shut in. New producer Uganda should come on stage in the medium term, adding slightly more than 200 kb/d from Tullow-operated fields; while output from Equatorial Guinea and Ghana are also set to grow. In the Middle East, the market is and will continue to pay attention to Yemen and Syria for the volume at risk of disruption (up to 0.5 mb/d), but also because violence there could spread to their neighbours and serve as a tinderbox for unrest and violence in other parts of the Middle East and Arab world.

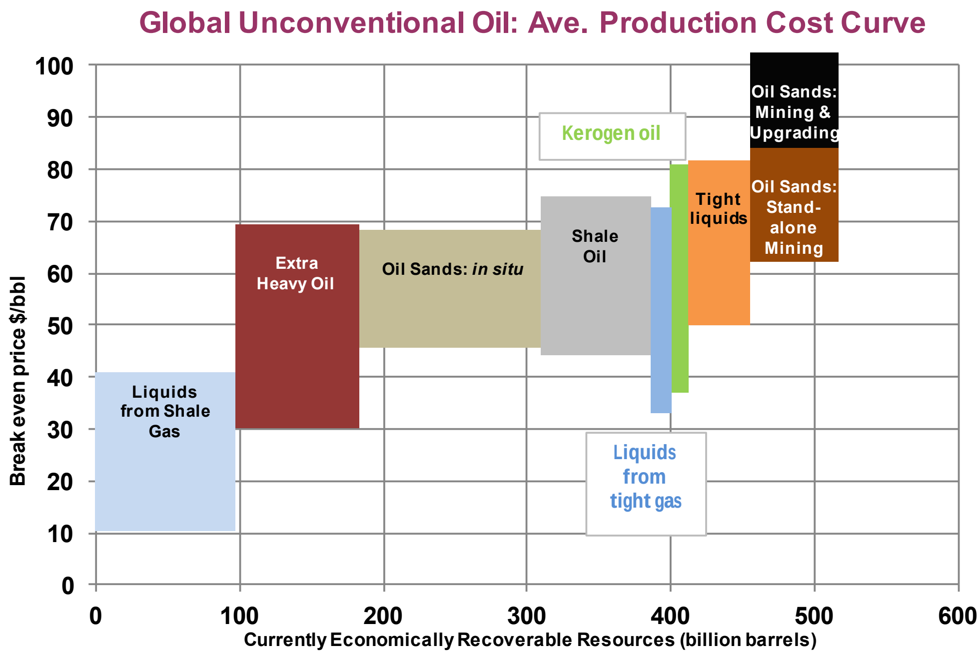
Trends and risks

Several trends merit highlighting before reviewing region-specific developments. Following a decade of mostly lacklustre non-OPEC supply growth, the combination of higher long term prices and the possibility of supply shortages led to the exploitation of reserves in difficult oil formations centred mostly in industrialised countries. Horizontal drilling with multistage hydraulic fracturing led to improvements in production rates and strong growth of non-OPEC supply of 780 kb/d in 2009 and 1.2 mb/d in 2010. But growth rates fell in 2011 as unplanned outages, labour unrest, and geopolitical conflicts cut growth to only 130 kb/d. While these issues have removed around 0.7-1.3 mb/d from the market in the last few quarters, their impact has so far been overshadowed by LTO and oil sands production growth.

North American unconventional supplies

North American LTO and Canadian oil sands are expected to add 3.7 mb/d over the forecast period, reaching 6.4 mb/d in 2017, or 11% of non-OPEC supplies. In the US, new volumes of production are coming mostly from shale reservoirs that are composed of low permeability, fine-grained rocks that form from the compaction of silt and clay-sized particles. The rapid increase in production from these so-called tight oil plays is softening the blow from other non-OPEC unplanned outages. The extent to which hydraulic fracturing and horizontal drilling technologies can be applied in other tight formations remains uncertain. Companies are hinting at good prospects in China, Argentina, Australia, and Russia, though each brings its own set of challenges.

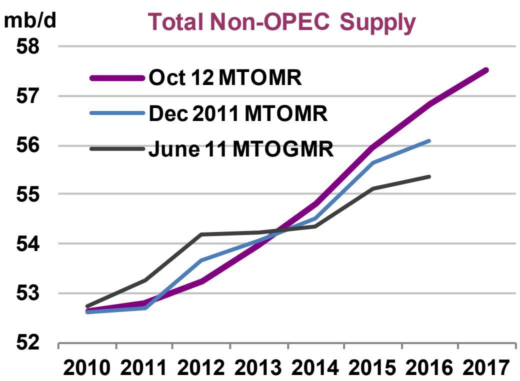
The cost curve shown below is modified from years past to focus on unconventional oil supplies. Canadian and other shale and tight liquids have average production costs in the range of $40-$100 per barrel. At this point, the upstream economics of unconventional supply remains broadly favorable, but transport constraints and cost inflation could threaten favorable investment decisions on new projects.

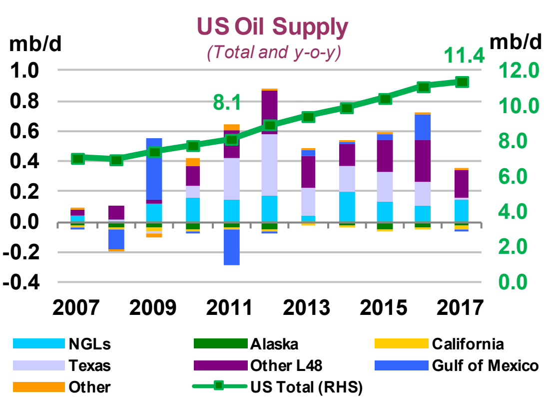


Source: IEA analysis of Rystad Energy data. Rystad develops estimates based on bottom up analysis of global fields, licenses, and potentially recoverable resources given currently available technology and activity levels. All resource values depicted in the graph are cumulative expected production from 2012 until 2100, excluding already produced oil through 2011. Oil and field condensate only, not natural gas plant liquids. Note that for oil sands development costs CERI, Alberta ERCB, and NEB are used.

Revisions to forecast

The non-OPEC supply outlook is more pessimistic over 2012-2013, and more optimistic in the 2014-2016 range than the prior two outlooks. Major revisions include an across-the-board increase in estimates for US LTO prospects. For 2016, LTO supplies of around 3.1 mb/d (not including natural gas plant liquids) are more than twice as high as in June 2011's *MTOGMR*. Broadly speaking, OECD supplies are expected to be 1.3 mb/d higher in 2016 than forecast in December 2011, more than offsetting a gloomier view in non-OECD countries. The UK and Norway's production level is 200 kb/d lower on average, while the Brazilian crude outlook is also lower by almost 300 kb/d.





Region- and country-level analysis

OECD Americas

United States

US oil output stands to grow by 3.3 mb/d from 8.1 mb/d in 2011 to 11.4 mb/d in 2017. LTO accounts for 75% of this growth. Production of crude and condensate from shale oil and tight oil formations especially in Texas and North Dakota, grows by 2.5 mb/d in 2011 to 3.3 mb/d in 2017, and these volumes drive a 5% annual increase (0.8 mb/d in total) in NGL supplies to 3.0 mb/d in 2017.

US light, tight oil: forecast challenges

In the absence of a publicly available monthly series of light, tight oil (LTO) production, the IEA must allocate shares of each play by US state and make new assumptions about the growth rates for LTO and non-LTO going forward. Projections and even historical data may differ due to variations in defining what tight oil is. IEA estimates of a growth of 2.5 mb/d from 2011 to 2017 may be lower than other forecasts because we do not include natural gas plant liquids, and we maintain a more conservative view on average estimated ultimate recovery in respective plays. In addition, we err on the conservative side since insufficient data exists in some plays to adequately estimate decline rates.

Forecasts of light, tight oil production are influenced by assumptions about the remaining unproved TRR (technically recoverable resources) for a continuous-type shale gas or tight oil area using assumptions about (1) land area, (2) well spacing (wells per square mile or acres per well), (3) percentage of area untested, (4) percentage of area with potential, and (5) Estimated Ultimate Recovery (EUR) per well (based on an average type curve). Forecasters must then make assumptions on industrial activity and rig counts, commodity prices, logistics constraints, technological improvement, and lag times (for example from the time a well is completed to the time oil is sold). With a short history of well level data, forecasters must make several assumptions leading to wide variations in views.

In the absence of well-level data, the IEA and other organisations have much to learn about forecasting tight oil production. For the purposes of this outlook, we have analyzed several forecasts and their respective assumptions and have employed relatively conservative assumptions about production from the Eagle Ford and the Bakken plays, where combined production should grow by 1.7 mb/d to reach 2.3 mb/d in 2017. From the perspective of the industry and due to forecasting challenges, we remain conservative for the following reasons:

- **Labor and supply chain management.** Lack of lodging, traffic, and socio-economic impacts on communities could impact the pace of production growth significantly; public policy will have to balance this with employment impacts.
- **Takeaway capacity.** The lack of low-cost takeaway capacity will crimp producer profit margins most acutely in the Bakken, and to a lesser extent in the Eagle Ford play and the Permian basin. Temporary transport bottlenecks have already caused significant discounts of the price of oil offered for sale from the Permian Basin in Texas and the Bakken play.
- **Financing.** Companies may be challenged to attract capital to respond to commodity price changes and if banks assess that companies are over-leveraged.
- **Environmental concerns.** State and federal regulators, as well as the public, are concerned about the extent of water use, the risk of water contamination, and natural gas flaring.
- **Comingled conventional oil.** It can be difficult to distinguish between oil produced from LTO and oil that is collected at the same time from non-tight or non-shale formations, thus skewing resource and production estimates.
- **Decline and Initial Production Rates.** A short historical series for well-level production data constrains analysts' ability to develop indicative well production profiles (called type curves) and thus average EUR. Observed 24-hour or 30-day initial production (IP) rates can be cherry-picked by operators and may not be indicative of an acreage's average productivity. Though companies are observing improvements in IP from better exploration or better application of technology, they also face a tradeoff between IP rates per well and EUR per land area. For example, a company that adds frack stages in a longer well will generate a higher EUR per well, but EUR per square mile might remain the same or be lower.

US light tight oil: forecast challenges (continued)

- **Finite Number of Sweet Spots Per Play.** A "sweet spot" is an ideal combination of permeability, porosity, thickness, depth, mineralogy, and organic content. As wells in the sweet spots are drilled in known plays, there is a finite number of sweet spots. Once they are drilled, higher capital and thus higher breakeven prices are required to maintain production.

Likewise, we see the following factors as key upside risks to the US forecast in the Medium Term:

- **Infill drilling and improvements in well spacing.** New technologies are enabling producers to extend the length of their lateral drilling, improve the design of wells, more specifically target areas for drilling, and identify new prospects in the same and new areas.
- **Financial attractiveness.** Companies are bound to consider tight oil assets favourably compared to longer lead time, conventional opportunities since tight oil assets generate high up front cash flows.
- **Continued technological developments.** New technologies are making operators more efficient in the drilling and completion phase. Pad drilling reduces drill time per well and allows operators to drill multiple wells in a given site in a shorter timeframe. Longer laterals have lowered completion costs, maximised reservoir contact, and multiplied the number of completed a crew can complete in a period.

The outlook for LTO production in North America remains highly uncertain, and will remain subject to revision based on actual production trends and future company plans. Current supply chain and labour and takeaway capacity issues have not yet dented the pace of growth of LTO since breakeven prices, on average, remain at favourable levels compared to realised prices operators receive. Indeed, oil prices will be the ultimate determinant of the pace and scale of LTO growth. In the absence of a relaxation of crude export restrictions from the US, marketed prices for light oil and NGLs will be determined by the compatibility of new output with downstream processing capability.

US Crude Oil and Condensate Production

(thousand barrels per day)

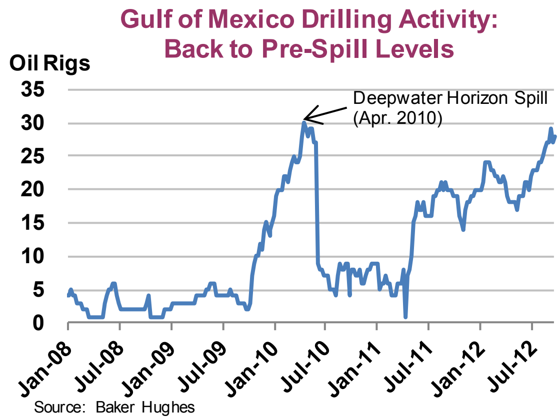
	2010	2011	2012	2013	2014	2015	2016	2017	2017-2011
Williston Basin (including Bakken)	270	390	620	770	980	1,090	1,170	1,250	860
Barnett	20	20	30	40	50	60	60	70	50
Eagle Ford	70	150	280	450	580	760	940	1,010	860
Monterey	10	10	10	20	30	40	50	50	40
Niobrara	30	40	60	70	90	110	120	120	80
Other Light Tight Oil*	110	230	310	420	540	670	770	830	600
Total Light Tight Oil	**510**	**840**	**1,310**	**1,770**	**2,270**	**2,730**	**3,110**	**3,330**	**2,490**
Gulf of Mexico	1,550	1,320	1,310	1,360	1,380	1,420	1,580	1,580	260
Alaska	600	560	520	520	500	450	420	390	-170
Other L48 Crude and Condensate	2,820	2,940	3,150	3,060	2,860	2,790	2,830	2,790	-150
Total US Crude and Condensate	**5,480**	**5,660**	**6,290**	**6,710**	**7,010**	**7,390**	**7,940**	**8,090**	**2,430**

*Includes other LTO from Oklahoma, Texas, Ohio, New Mexico and other emerging plays

Gulf of Mexico

Offshore production of oil on the Outer Continental Shelf (OCS) dipped in 2011 from 2010, but is still higher than in 2008. New projects that will add oil in the medium term are listed in the supplementary tables and should raise output by 260 kb/d to 1.6 mb/d. A drilling moratorium following the 2010 Macondo disaster in the Gulf temporarily slowed new exploration activities in the deepwater until October 2010. An interim and final rule released over the last year raised standards for performance and maintenance on subsea equipment. They also increased the number of inspectors, instituted stronger ethics rules, required regulatory certification of drilling plans, and enforced additional rules on contractors. Rules concerning blow out preventers are still in draft form.

With some of these new safety measures in place, the first permit for new deepwater wells was not issued until Feb 2011. Since then, around 60 new deepwater wells have been approved but only recently has drilling activity returned to pre-Macondo levels.



Mexico

Mexican production is expected to fall at an annual rate of around 2% per year from 2011 to 2017 based on current policies. Pemex successfully stemmed the rapid decline at the mature Cantarell field from -30% in 2008 to around -10% in 2011, yet oil from the KMZ field, which grew by over 100 kb/d to 850 kb/d since 2008 has now stabilised, and is set to decline from 2015. Pemex's ability to increase its investment spending on EOR activities, additional drilling, and in offshore deposits will depend on its ability to generate positive net income. In 2011 and in prior years, Pemex paid more in taxes and duties than its gross income, resulting in losses after taking these payments to the government into account. President-elect Peña Nieto has expressed a desire to reform Pemex, but with the government receiving around a third of its revenue from oil production, any changes will have to be balanced against the budgetary impact. Once in office he could indeed propose new laws to the Mexican Congress to change our views, but it remains too early to tell if policy changes can make a difference in output. A key consideration will be the extent to which Pemex will be able to partner with foreign companies that provide technology and knowledge.

Canada

Production of oil sands (bitumen and upgraded synthetic crude) is expected to increase by 1.1 mb/d by 2017 (of which two-thirds is from in situ bitumen production). Canadian LTO is still in its infancy compared to the growth rates seen in the US, but horizontal drilling is underway in tight oil plays in Saskatchewan, Manitoba, Alberta, and British Columbia where production is estimated at around 240 kb/d. Based on estimates from the National Energy Board and Alberta's ERCB, we expect this amount to increase to around 330 kb/d in 2017. Initial results have shown high decline rates at Canadian LTO plays, and many are remotely located or otherwise transport constrained. Canada's oil output is expected to increase from 3.5 mb/d in 2011 to 4.6 mb/d in 2017.

Transport bottlenecks to dent Canadian unconventional growth

Rising LTO production growth in the mid-continent of North America is crimping the availability of qualified personnel and discounting realised Canadian oil prices. The outlook for Canada assumes these factors remain a fixture of North American markets for the foreseeable future leading to project delays in the medium-term timeframe. Increasing volumes of Canadian bitumen production will still find their way to US markets as heavy oil refining capacity is added, but Canadian producers will have to seek new markets.

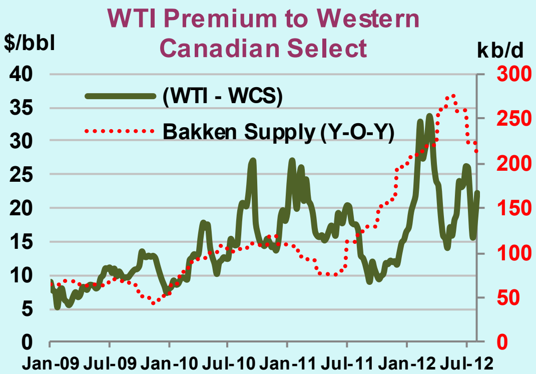
Canadian Oil Sands Supply Cost Comparison

(WTI Equivalent, $/bbl)

	CERI	ERCB	NEB
SAGD	64.62	47-57	50-60
Integrated Mining & Upgrading	91.07	88-102	85-95
Stand-alone Mine	81.51	61-81	65-75

Transport bottlenecks to dent Canadian unconventional growth (continued)

Low pipeline spare capacity to increase reliance on rail. Canadian crude moves to the US via the Enbridge Mainline (2.3 mb/d), Kinder Morgan's Trans Mountain and Express Pipelines (0.6 mb/d), and TransCanada's Keystone pipeline (0.6 mb/d), which provides producers with around 3.5 mb/d of capacity. However, rising production will eventually bring these pipeline routes to their capacity. In addition, both Canadian and US LTO are directly competing for space on many of the same routes. A 145-kb/d expansion of the connection from the Bakken play in North Dakota to an Enbridge mainline connection in Manitoba is expected to enter service in 2013, but otherwise the production of Bakken oil far exceeds the 210 kb/d in capacity on the existing route. Enbridge also plans expansions totalling 280 kb/d by the end of 2014 on its Southern Access and Alberta Clipper lines, and around 700 kb/d of new capacity or existing capacity expansions are proposed by end-2014 to deliver oil to PADD 2. One westbound route, Kinder Morgan's TransMountain Expansion would expand capacity on an existing route but faces some opposition at its terminus (Vancouver).



Expansions of capacity on existing lines are likely to move forward, but new lines will face the same challenges that Keystone XL is facing. The Northern Gateway project has become a hot button political issue in Canada, similar to Keystone XL in the US. Inter-provincial pipelines also face their own set of challenges. British Columbia, the federal government, and Alberta will have to make difficult decisions about how the cost of a spill is mitigated and how economic benefits are shared.

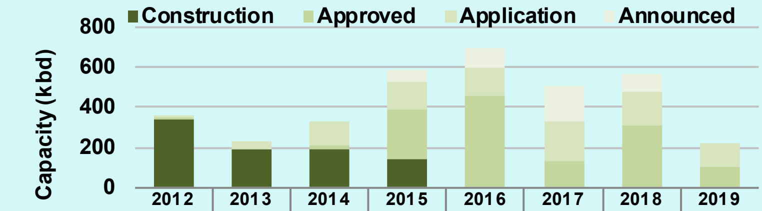
Short-term alternatives. In the meantime some companies like Southern Pacific are talking about railing 20 kb/d south, and CERI estimates that anywhere from 50-200 kb/d of rail capacity could be available to move Alberta's oil. Rail companies themselves claim they can do up to 1 mb/d. If the TransMountain expansion, Keystone XL, and Northern Gateway are not built by the end of the medium term timeframe (2017), then capacity constraints will slow project development. Other likely options include plans to convert eastbound natural gas lines to oil since Marcellus natural gas exports from the US has reduced the need for Western Canadian gas. Likewise, producers are discussing opportunities to reverse oil pipelines that would allow Canadian oil sands to flow to Eastern Canadian refiners.

Market conditions. Tight pipeline capacity is one of the major reasons that Canadian crudes are priced at a discount to WTI, but the spike in the discounts has hurt Canadian producers' bottom line this year and many are questioning to what extent they will remain a fixture in the market in 2013 and the medium term. This past summer, Western Canadian Select, a blended heavy oil that consists of conventional heavy oil and unconventional diluted bitumen or dilbit, was trading in a range of \$60-\$80/bbl, a \$10-20/bbl discount to WTI and around \$30-35/bbl lower than Brent. Western Canadian oil production, 70% of which lands in the Midwest (PADD 2) will sell at a discount because of the lack of spare capacity on pipelines to the US and its heavier crude quality. When the Alberta Clipper and Keystone were added, the differential thinned, but as these lines reach their limits the sparse spare capacity threatens the netbacks for all Western Canadian producers. Moreover, as long as Bakken production increases at a faster rate than takeaway capacity from PADD 2 and from Cushing, Oklahoma, downward pressures on WTI will keep the discount wide. The differential stayed wide even in light of significant outages of upgraded synthetic crude in 1H12.

***Company reactions*.** In July Suncor indicated "in principle there is an opportunity to not progress on [the Fort Hills and Joslyn mining] projects." Those projects are slated to produce a combined 260 kb/d by 2017, but the company indicated that the projects are moving "backwards not forwards." A ConocoPhillips executive explained recently they are looking for "smart growth" not "growth at any cost" at their Narrows Lake, Christina Lake, Foster Creek and Surmont assets.

Transport bottlenecks to dent Canadian unconventional growth (continued)

Status of Oil Sands Projects



	2012	2013	2014	2015	2016	2017	2018	2019
Announced				60	98	175	90	
Application	4	42	127	147	138	195	160	115
Approved	5	5	16	240	455	133	313	103
Construction	343	188	190	144				

Source: Alberta Oil Sands Information Quarterly, Summer '12.

Financing. Financing oil sands expansion may also be more difficult. While mining projects entail a larger upfront capital expenditure, smaller-scale in situ projects allow producers to better gauge markets (and even the regulatory and environmental management burden) at a given time. Besides the market conditions, regulatory changes to emissions thresholds for air and water pollutants and SO_2 could also limit expansions and increase costs. Shell recently noted that its 100-kb/d Jackpine expansion might exceed these new limits.

Labour constraints threatening projects. With welders and machinery operators able to receive six-figure sums by working for just a quarter of the year, a sign of short supply, companies must now make their employment arrangements more flexible. In addition, whereas oil sands producers used to face a more flexible market, they are now constrained in their ability to attract qualified workers from the US in light of the rapid growth in LTO developments.

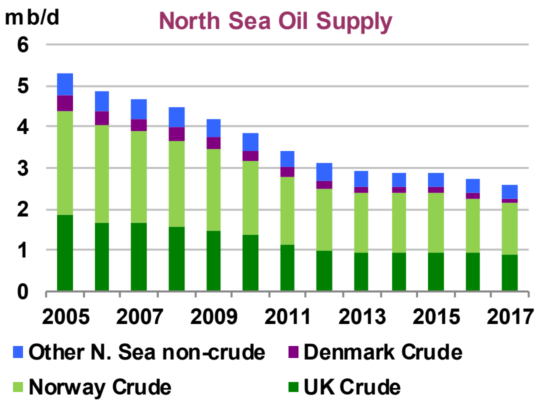
Outlook. All told, we take a cautious view of the growth in projects that have not already begun construction or received regulator approval in this outlook. In 2011, mined and in situ oil sands output stood at around 1.6 mb/d and should increase by 1.1 mb/d to 2.7 mb/d by 2017. We take a conservative view on this growth potential because based on the analysis shown in the chart above, of the 2.4 mb/d that companies expect to come online between 2013 and 2017, 980 kb/d (or 42%) is still in the application or announced phases. Of that amount, 240 kb/d expected from mining and/or upgrading projects like Joslyn are likely to be delayed until after 2017 because of transport bottlenecks.

North Sea

UK

UK oil production should fall by 200 kb/d to 910 kb/d in 2017, or a reduction of around 3.3% per year. We assume a decline rate of around 20-22% at declining fields. As a reference, Oil and Gas UK, an industry organisation, projects production in the range of 0.9-1.4 mb/d in 2017 depending on what is assumed about projects being sanctioned. New fields expected to come online in the medium term include Clair Ridge, Alder, a redevelopment at Schiehallion, Golden Eagle, Catcher, and the Jasmine project.

In the next five years, there is more upside than downside risk to these forecasts as long as the price remains at current levels. Producers are using EOR techniques, advanced seismic, and improved water management to extend the life of mature fields, enhance efficiency, and identify new oil targets. However, using these EOR techniques inevitably depends on cost, technical and commercial conditions, and the fiscal regime. Tax changes to be enacted in 2012 are designed to improve the recovery rate at brownfields, small fields, and frontier areas of the UK Continental Shelf. Taxation of offshore oil and gas is a complex combination of ring fenced corporation tax, a supplementary tax on profits, and a petroleum revenue tax (PRT) on fields sanctioned before March 1993. In total, the marginal rate of tax is either 62% or 81% depending on whether or not the field is subject to PRT. Compared to the current tax code, the revisions would double the value of the Small Field Allowance and double the field size which can qualify. The change to the supplementary tax (an increase from 20% to 32%) threatened to hurt recovery maximisation, so the proposals approved by the Treasury in September 2012 soften the increase in the tax burden for certain types of fields compared to the 2011 changes.



For example, income from some mature oil fields would be shielded from the supplementary charge to encourage them to maximise recovery rates. Fields affected would include those in the Montrose area and Arbroath. The tax proposals would also benefit heavy oil fields such as Bentley, Kraken, Bressay, and the Mariner fields. Finally, there are additional allowances for large deepwater fields, especially Chevron's Rosebank development west of Shetlands.

Norway

New fields are expected to offset mature field decline in Norway, but production falls over the 2011-2017 timeframe by around 330 kb/d to 1.7 mb/d. A short term bump from new gas condensate and some crude oil projects should offset mature field decline in 2013-2015. In recent years Norwegian production has benefited particularly from improvements in EOR, while a string of exploration successes stands to support overall Norwegian production when these longer-term projects begin coming online post-2017.

In 2012, Statoil and its partners announced the discovery of the supergiant Aldous and Avaldsnes finds, now called Johan Sverdrup, one of the largest oil finds in recent memory in the North Sea. While Sverdrup is only expected to contribute marginally in 2017, its impact on Norway's production profile in the next decade should not be underestimated. Major project additions in the medium term include Yme, Eni's Goliat, BP's Skarv, and a slew of Statoil projects. Statoil's projects alone in the 2012-2017 timeframe include 155 kb/d of capacity that has already received a final investment decision (FID), and an additional 190 kb/d under development.

Downside risks to the outlook include the possibility of short-term impacts from labour strikes and long-term and cost-driven impacts from project delays. Rigorous safety standards narrow the selection of rigs operators can use, and high labour costs are behind recent increases in rig costs. This is causing delays to drilling programmes. Project delays and increasing costs have resulted in an outlook on average 80 kb/d lower than in December.

Middle East and Africa

We deliberately exercise caution with the forecast for Syria, Yemen, Sudan, and South Sudan as circumstances change every week, affecting our views on both the short and medium-term supply outlook. For the purposes of this forecast, we have assumed that Syria's output continues to decline from current levels of 160 kb/d to less than 100 kb/d in 2017 due to lack of investment and continued internal unrest. Yemen's output is likely to continue to suffer from sabotage in the medium term, keeping output under 160 kb/d on average. Sudan and South Sudan are expected to rebound to a combined 360 kb/d by 2015, though still 100 kb/d less than 2010's sum total, and remain broadly at these levels until 2017. As the situation is so fluid, we recommend reading the monthly OMR religiously for updates to this forecast.

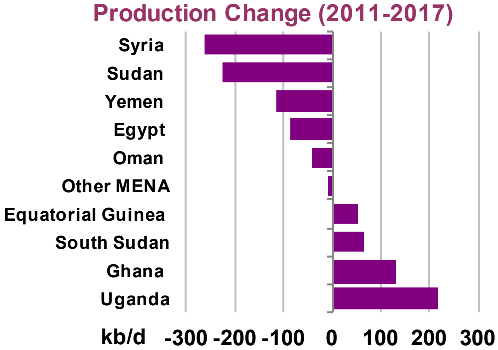
Oman

Private operators, partnering with Omani oil companies have successfully increased oil production through enhanced oil recovery. Oman's production is expected to increase to 950 kb/d in 2013 but then begin to decline to around 850 kb/d by 2017 as contributions from EOR projects fail to offset mature field decline. We assume that government majority-owned Petroleum Development Oman (PDO) can successfully enhance recovery with its Harwheel EOR project. The latter project started in late April 2012 and is likely to add around 40 kb/d by 2014. The project was delayed by around a year, due to the rising costs and infrastructure constraints that PDO and other Omani producers including Oxy face in bringing on tertiary recovery projects. Also, production now stands around 125 kb/d at Oxy's Mukhaizna EOR project. Oxy has had to reign in expectations for higher output because cost cutting measures on well monitoring backfired and resulted in the company having to drill additional injection wells, pushing the project costs four times higher. Other ramping EOR projects that should add around 40 kb/d in total in the medium term include the Qarn Alam fractured carbonate steam injection project and the Amal East and West steamflood, which will inject waste heat from a power station.

Egypt

Despite the political transition, Egypt's oil production has maintained levels of around 730 kb/d from 2010-2012 though in the medium term, production is expected to fall by around 90 kb/d (or 2% per year) due to a lack of major projects. After a series of administrative-related delays, we expect that the West Nile Delta gas project is likely to come online late in 2016 and add some NGL volumes.

Non-OPEC Middle East & Africa Production Change (2011-2017)



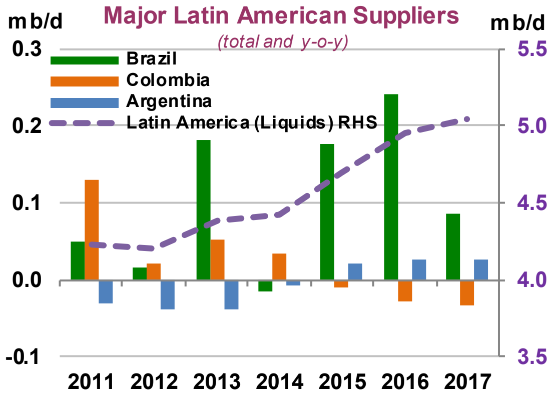
Other Africa: Equatorial Guinea, Ghana, Uganda

Production in non-OPEC African countries stands to grow from around 2.6 mb/d to 2.8 mb/d by 2017 or 7%, though this outlook could prove too pessimistic if recent Sudan/South Sudan oil export and security-related agreements bear fruit. **Ghana's** production is currently averaging 80 kb/d and stands to more than than double to around 200 kb/d by 2017. Increasing production from the Tullow-operated Jubilee field from around 80 kb/d to 120 kb/d over the next two years should raise output in the medium term. The Tweneboa/Enyenra/Ntomme (TEN) project, with Tullow as the operator and majority stakeholder, will also produce from a 100 kb/d FPSO but not until the latter part of the outlook. **Equatorial Guinea's** output will likely remain at around 300 kb/d as the Aseng field begins to decline. **Uganda** stands to add 200 kb/d to production in the next five years as Tullow, CNOOC, and Total develop reserves in Lake Albert Rift Basin. According to Tullow, small scale production is expected in 2012, but larger scale output is not expected until around 2016, or 36 months from when the Government approves a basin-wide development plan. The plan would include a refinery and a pipeline as Uganda is export constrained. Some other regional operators have proposed to incorporate new production from Kenya and even legacy and new production from South Sudan into an interstate pipeline. **Congo (Brazzaville),** which is producing around 300 kb/d, also stands to increase its output slightly in the medium term through Total's 100-kb/d extension of the Moho-Bilondo field, called Moho North.

Latin America

Brazil

Petrobras has recently acknowledged the company's shortcomings in delivering projects on time and on budget and has scaled back medium-term output projections. In addition, improved field and well-level analysis and the leak at the Frade field have caused a 270-kb/d lower expectation for Brazil, compared to December 2011's forecast. Net of the decline trends at existing wells discussed below, Brazilian crude output should experience a major jump in 2013, 2015, and 2016 as new projects come online, vaulting production by 680 kb/d from 2011 to 2.8 mb/d in 2017.



Petrobras management has reigned in expectations for project startups and additions, pledges to improve cost efficiency at mature fields, and hopes to manage local content requirements. The new targets will still not be easy to meet since costs are rising, and the current, tight deepwater rig market is likely to cause delays in the next year. Observers say that the previous targets had been of lesser priority than enhancing the local content, but now there is a realisation that the local companies cannot meet the project sponsors' objectives. Some restrictions are being relaxed, such as the need for pipe laying vessels or pre-fabricated offshore modules to be built in Brazil.

In the medium term, Petrobras will be bringing online several new FPSOs to capitalise on the resources at Parque das Baleias, Bauna and Piracaba (formerly Tiro and Sidon), Sapinhoá (formerly Guará), and other parts of the giant and already-producing Lula field. Roncador platforms P-55 and P-62 are also expected online before 2015, and along with the aforementioned projects, should add around 750 kb/d of new production capacity. Later in the outlook, additional production should come from the BM-S-9 and BM-S-11 areas in the Santos Basin. Privately owned OGX-operated fields could also add to growth, though the performance of the company's Tubarão Azul field has been well below initial expectations.

Petrobras' ability to bring production online on schedule from pre-salt deposits in the Santos basin is a major downside risk to the outlook. Petrobras and other investors will need to obtain cost effective directional drilling services; they will need to properly manage the wax that can build up in long distance subsea pipelines; and they will need to ensure well integrity where relatively high amounts of carbon dioxide and H2S are present in associated gas. The industry can address these challenges, but they will serve to compound the costs in a deepwater drilling environment. In addition, issues related to local content and the impact of the Frade leak on the foreign investment climate are also sources of downside risk and will be addressed in future issues of the *OMR.*

A Campos Basin well decline rate analysis

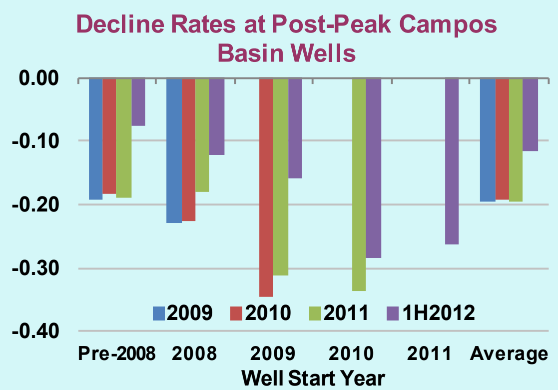
With the advantage of more detailed field and well level monthly statistics, analysts can now more effectively assess the challenge facing Petrobras to improve output efficiency and to meet overall production targets. Based on a well-level decline rate analysis described below, Brazil will have to add 130 kb/d of new production to make up for the annual decline at Campos basin declining wells.

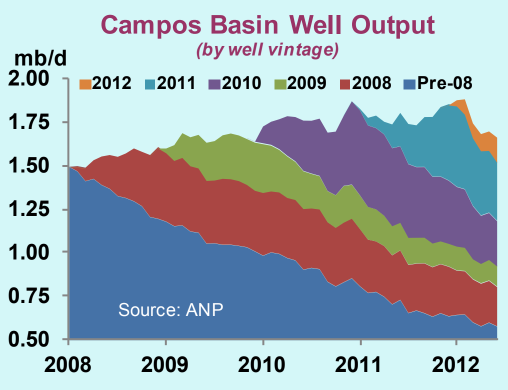
Offshore fields comprise over 90% of Brazil's crude output, of which the Campos basin provides around 75%. Over 700 different wells were analyzed, over half of which had already peaked (called post-peak) by 2009 and half that peaked at some point in the period between Jan 2009 to June 2012.*

- In the first half of 2012, the median annual decline rate of post-peak Campos wells was -12% with a large degree of variability based on the start year.
- Pre-2008 wells comprise 35% of current basin production and are declining by an average of -8%. The worst performing quartile of wells declined at more than 30% in 2011, while the best quartile declined by less than 8%.
- Wells that came online in 2010 (17% of Campos output) are declining at a very high 34% in 2011 and wells that started in 2011 are declining by around 26% in 1H12.
- Water cut levels (ratio of water to total liquids) are currently at around 59% and will be a leading indicator of decline rates in the near future. Pre-2008 wells averaged 68% water cut, and wells added in 2010 averaged 48%.

The significance of these trends imply that the existing wells in the Campos basin should decline next year in a range of around 25-35%, with a less steep rate of decline in the years thereafter. The data also indicates that newly added wells in 2011 performed better in the first year after peaking than wells added in 2009 or 2010. The analysis also shows that based on decline rates observed in the sample and an assumption that these rates improve each year, Brazil's new wells will have to add at least 130 kb/d to maintain output at end-2011 levels of 1.8 mb/d.

Petrobras realises this and is thus planning a $5-6 billion programme to improve platform production to 90% efficiency (or potential) at its shallow and deepwater offshore assets in the Campos Basin, in contrast to current efficiency rates of around 70%. Most importantly, analyst reports note that according to management the efficiency problems are due to old equipment, not reservoir problems. The company plans to improve separation and water injection facilities, as well as subsea installations. Each time this work occurs at a platform, output is expected to suffer temporarily, with the first instances beginning this summer.





A note on methodology: Annual decline rate calculations excluded fields that were ramping up during the period. A change in annual average of well production rates (where production is non-zero) is used, for example the average output in 2010 vs. the average in 2009. For a given year, we excluded months where production stopped briefly. In the text above the median of declines is used. Production weighted averages were also calculated, but results were similar and showed an average 2 percentage point better decline rate than choosing the median. An in-depth discussion on decline rate calculations was included in *World Energy Outlook 2008*.

Argentina

Production is kept broadly stable, falling by 1% to 680 kb/d by 2017 from 2011 levels. Looking forward, Argentina will need continued investment and an improved regulatory framework to turn resources into reserves. Argentina has shale oil and gas potential in the Vaca Muerta formation, but the government's move to expropriate Repsol's share of Argentina's state-owned YPF in March 2012 alarmed investors and stands to hurt the country's investment climate. Borrowing costs have already increased. Therefore, we do not foresee large quantities of shale oil in the forecast. That said, Vaca Muerta contains only 81 million barrels of 3P oil reserves, but much further exploration is needed to confirm the 7.2 billion barrels of prospective and contingent resources. Producers and service sector players in Argentina might also fear that they will be subject to increased scrutiny by the government over their commercial decisions. It has also raised the ire of the US, Mexico, and the EU and is sure to affect Argentina's trade relations. Absent guarantees of contract stability from the government, producers are unlikely to risk significant investment to develop shale deposits in the Neuquén basin and to employ costly technologies to enhance existing production.

Resources and Reserves of the Vaca Muerta Formation

	Oil & Condensate (mb)	Total (mboe)
Prospective Resources*	6,128	21,167
Contingent Resources*	1,115	1,525
Possible	33	48
Probable	25	35
Proven	23	33
Total 3P Reserves	81	116

Source: Ryder Scott.

*Contingent resources are potentially recoverable hydrocarbon quantities based on previous exploratory activity that includes discoveries. These resources cannot be considered currently commercial and could be economically viable. Prospective resources are potentially recoverable hydrocarbon quantities based on an area where preliminary data is available but where no discovery wells have been drilled.

Former Soviet Union

Kazakhstan

In Kazakhstan, the first phase of the Kashagan field is expected to come online (finally) in 2013, and ramp to around 350 kb/d by 2015. The much-awaited start-up of the Kashagan field has involved four project delays, a 13-year project lead time, and a 2008 renegotiation with the Government of Kazakhstan over the contract terms. Phase 1's capital cost of $25 billion is around 150% higher than originally envisioned in 2004. After the field begins commercial production next summer, it should raise Kazakhstan's output to 1.8 mb/d in 2017, a 160 kb/d increase from 2011's levels. Declines at mature fields, including the giant Tengiz field, reduce the otherwise positive impact of new Kashagan output. The Consortium developing the field remains in discussion about the second phase of the project that at one point was designed to lift output to around 1.5 mb/d. Other major increments to production in the medium term are the third phase of the Karachaganak gas and gas condensate field. Design and engineering are expected to start in January and the field is expected to add around 50 kb/d in 2017 assuming that the KPO B.V. consortium agrees on financing the next steps. Zhaikmunai is likely to contribute around 50 kb/d of new condensate and LPG by 2017 from new processing facilities at the Chinarevskoye gas field. Tengiz itself is in the queue for an expansion, but TengizChevroil expects to move to the engineering and design phase in 2013. This means that a proposed 250-300 kb/d increment to the existing oil supply would fall outside of the five-year timeframe.

Russia

Based on IEA analysis, we estimate that Russia's crude production, net of greenfields, declined at around 2% annually during 2009 and the first half of 2010. After that point, companies slowed the decline to around -0.5%. Improving recovery rates at legacy fields, mainly through waterflood optimisation, infill drilling, and horizontal wells, are likely to provide more support to Russia's overall production growth in the medium term than new projects (though they will be harder for analysts to track). While broader uptake of the new technologies will occur, companies can employ these technologies only as long as the tax burden keeps the projects economic.

Brown but not out. High oil prices in the last couple years have led to increased drilling intensity and new wells. But not all newly completed wells have led to higher overall field output. Actually, a focus on improved technology that delivers higher flow rates at existing wells is a primary contributor to increased output. Also, companies that managed their well stock better and more actively used EOR methods such as optimising water floods and tapping previously by-passed layers. Bashneft reportedly optimised its pump management, leading to a 10% increase in crude output from 1Q10 to the present. At the Samotlor field, TNK-BP indicated it had reduced excessive drilling and focused instead on using sidetracking and conserving non-productive wells. They also used real-time drilling technologies and used conformance control chemicals to improve oil recovery. These developments are likely being applied at other mature fields in Russia, though companies will need more expensive technologies as the share of more challenging-to-recover reserves rises. On balance, the increased amount of oil produced is likely to offset the higher cost of EOR and other related chemicals on a per barrel basis.

Tax breaks and the impact of 60-66[3]. Outside observers are mixed on the success of the 60-66 regime, enacted in October 2011. Broadly speaking, brownfield production growth of around 0.7% has continued since the enactment of the regime by reducing the government tax take on crude exports and by increasing domestic prices on crude oil. The impact on production is less clear-cut, but it is apparent to authorities that budget revenues have suffered. Looking forward, the parliament stands to approve amendments that would formalise a reduction in the crude export duty for frontier areas (Yamal, Eastern Siberia),[4] in contrast to the more subjective monthly application of the export tax reduction levied by the Finance Ministry. Outside of the crude and product export duty mechanism, there are discussions underway to introduce export duty tax breaks for producers of high viscosity (over 30 Millipascal seconds) oil and from tight formations. Onshore resources are already benefitting from tax concessions through adjustments to the mineral extraction tax (MET), which have supported oil investment in the Caspian and Eastern Siberia. Offshore, the zero export duty and differentiated MET has helped Rosneft attract foreign investors such as ExxonMobil, Eni, and Statoil to work with it in the Arctic.

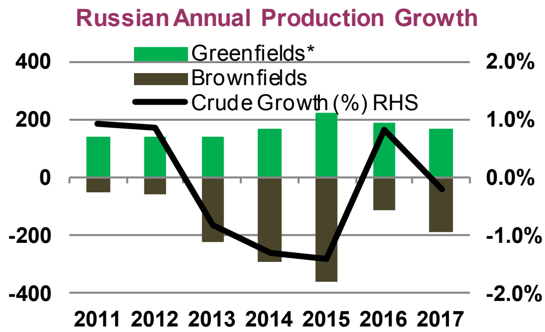
Yet, these policies are a departure from efforts to design a profit-based tax system (rather than revenue based), which analysts suggest would have placed assets on an equal playing field regardless of development stage (brownfield or greenfield) or the asset's size. Rather, in the medium term, tax policy is likely to be field-specific and focused mainly on new developments. Yet the Ministry of Energy and Ministry of Finance continue to propose changes to the tax code, which does not facilitate expedient project development; it just creates a more uncertain investment climate.

Bazhenov≠Bakken. Despite the recent hype, additional horizontal drilling in the Bazhenov shale layer is not expected to contribute to overall output in the medium term. With companies like ExxonMobil signing deals to work with Rosneft in the region, the upside potential to the largest source rock in the

[3] The first number (in %) is the maximum rate of marginal crude oil export duty and the second (also in %) is a proportion of refined products export duty to crude oil export duty.
[4] At oil prices above $50/bbl the new duty will equal 45% of the difference between the spot price and $50/bbl. The exemptions will be granted to projects until their IRR reaches 16.3%. Other amendments will be required for developers and producers to gain eligibility for the reduction but at this stage it appears that a field would be eligible if it has a reserve base of at least 73 million bbl and has 95% of its reserves remaining.

world should not be underestimated in the longer term. Some wells were drilled by Salym Petroleum with disappointing results where flow rates fell precipitously after the first year. The Bazhenov is widely dispersed over a very large Western Siberian swamp, and it may be difficult to find the sweet spots that are not directly underneath conventional reservoirs. Moreover, operators drilling horizontally will need to obtain rigs capable of drilling longer horizontal wells. All of these factors, in addition to preferential tax treatment, must be addressed before operators can turn this large prospective resource into commercial production. In sum, the Bazhenov and the Bakken are very different reservoirs; operators will have to overcome many hurdles in order to find sweet spots in shale basins in Russia and elsewhere.

New Supplies. In the medium term, greenfield additions and condensate will keep production levels in the 10.5-10.6 mb/d range, slightly below current levels. Relatively small capital investments improved productivity at the brownfields and generated large returns, but greenfield assets will require much larger sums of capital and new technologies. Natural gas liquids also stand to add materially to Russia's medium-term output levels. Natural gas plant liquids and condensate are expected to increase by 200 kb/d to 900 kb/d by 2017. Specifically, gas fields such as Urengoy and Zapolyarnoye in the Yamal-Nenets region should add major liquids volumes in the medium term. Crude output is also expected to grow in coming years with year-round production at GazpromNeft's Novoportovskoye, Bashneft's Trebs and Titov, and LUKoil's Pyakyakhinskoye. By 2016, TNK-BP's Messoyakh and Russkoye fields should come online and eventually add over 900 kb/d by the time they reach their peak at end-decade. In the Caspian, LUKoil's Yuri Korchagin field should plateau at 40 kb/d in 2015 before beginning to decline, while the Vladimir Filanovsky field will see reduced growth as a result of reduced export duty concessions. Offshore, Sakhalin-1 is now only averaging 150 kb/d, compared to around 170 kb/d in 1H11 and will not increase output markedly until the Arktun-Dagi field comes online in 2014. The outlook assumes that oil from the oft-delayed, 150-kb/d Prirazlomnoye field will come online, but even with an export tax reduction the project's profitability will remain uncertain.



*Greenfield production includes Sakhalin, Vankor, Verkhnechonskoye, Uvat, Salym, Caspian, and other major field additions of the last 3 years.

Outlook. As the rate of brownfield decline accelerates in the short term, the government may take additional measures to stabilise growth, especially since brownfield performance has helped support overall production levels and budget revenues in the past couple years. The government could take a cue from other countries' tax structures, like those in the North Sea, where tax code changes have helped stem mature field decline. These mature fields are the key driver of budget revenues, but Russian producers will have to have a clear picture of their future tax burden in order to justify the expense of unlocking their assets' full potential.

Azerbaijan

Expectations for Azerbaijan are significantly reduced since June and December of last year due to lacklustre performance at the AIOC-operated ACG fields in the Caspian Sea. Production at the ACG fields has fallen by around 100 kb/d on average over the last year despite the completion of maintenance and now stands at around 700 kb/d. BP, the operator, has indicated that the peak production rate for the field (envisioned at 1.0-1.2 mb/d), may be lower than initially thought. Now, the company is reviewing its field management plans in order to deliver an extended production plateau. BP plans to work at improving reservoir modeling, sidetracks, recompletions, and equipment upgrades to optimise the field's output. In sum, with lower ACG production and the addition of West Chirag in 2014, Azerbaijan's production falls by around 90 kb/d to 830 kb/d in 2017, or around 10% – a far cry from the 1.1 mb/d in 2016 forecast in June 2011.

Non-OECD Asia

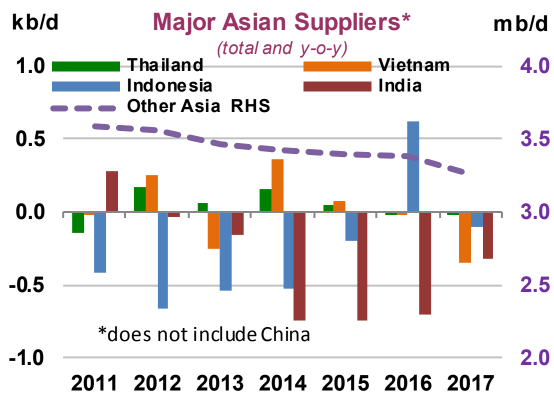
China

China produced around 4.1 mb/d in 2011, but output should be able to rise consistently in coming years by around 2% per year to 4.5 mb/d in 2017. At existing fields, infill drilling, satellite field development, and other EOR opportunities should be able to keep production declines in check. More efficient development drilling has kept pace with production declines, providing Chinese companies with better returns on their wells. We take a more optimistic view of shale opportunities in China and believe that the Chinese will seek to employ new horizontal drilling techniques and hydraulic fracturing in their fields as quickly as possible. For example, Hess recently reported high per well drilling costs (50-60 million yuan or $8.5-9.5 million) and not ideal returns at five wells, though it had planned to drill twelve at the 500 kb/d Shengli field. Hess is also studying the tight oil formations at the Daqing field, and Sinopec has already drilled two horizontal wells at the Henan field. That said, we do not expect this output until the end of the forecast because of the more complex geology, the Chinese companies' lack of technical expertise and pipeline bottlenecks.

Offshore, production from Peng-Lai 19-3, which has been shut in for around a year, should support a short term increase in 2013. Also, current CTL projects, as well as new projects from the Jincheng and Yankuang Groups, should add around 60 kb/d in the medium term.

Other Asia

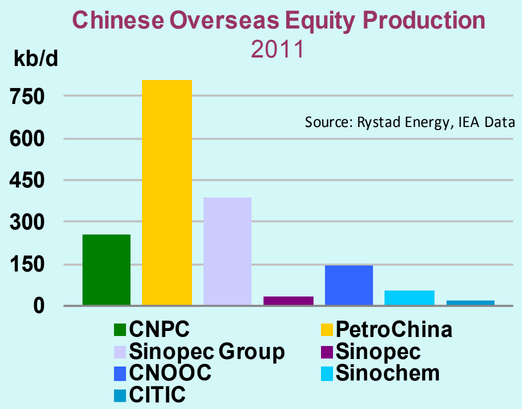
With the exception of the Banyu Urip field in Indonesia, most of the growth from Asian countries will come from improving and adding to already-producing fields with EOR and other technologies. In **Malaysia**, Shell and Petronas are working to bring online six new platform-based EOR projects in the Baram Delta and in the North Sabah area between 2013-15 that could help improve Malaysia's current recovery rates of 23-26%. All told, net of other declines, these additions raise production in Malaysia to over 700 kb/d in 2017, around 50 kb/d higher than 2011 levels. In **Indonesia,** the delayed Banyu Urip project is expected to ramp up to more than 150 kb/d in 2014-2015, keeping the medium term average decline rate to around -3% per year and bringing output to around 790 kb/d in 2017.



Overseas investments by China's national oil companies

In 2010, China's national oil companies (NOCs) made their largest investments ever overseas. In 2011 and the first half of 2012, investment slowed somewhat but the NOCs still spent over $23 billon on upstream oil and gas acquisitions in 2011 and more than $7 billion in the first half of 2012. Chinese NOCs are more accepted in industrialised countries than in prior years because of their access to capital, their successful partnerships in emerging markets, and the opportunities for reciprocal access to Chinese and other Asian markets.

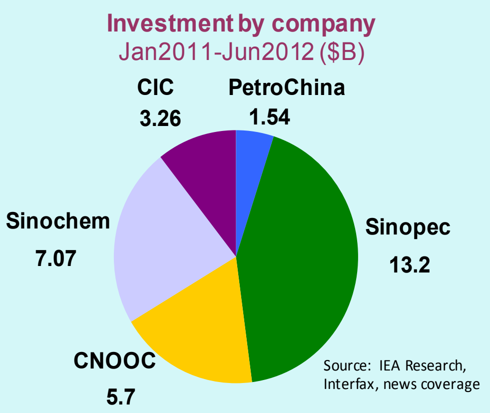
Based on available data we estimate that by the end of 2011, Chinese NOCs had equity oil production of 1.7 mb/d outside Chinese borders. PetroChina was the clear leader, with 800 kb/d. Their gas production overseas is still low, although it is expected to increase in the coming years due to new upstream acquisition in gas production. An interesting addition to the group of equity producers is CITIC, the giant investment group formed in the 1980s. Sinopec, China's largest refiner, led the way with over $13 billion spent on acquisitions in upstream oil and gas during this period, in contrast to previous years, when Sinopec lagged behind its peers in overseas upstream investment.



CNOOC entered the US shale gas and Canadian oil sands production arenas in 2011 with gusto. In July 2012, the announcement of CNOOC's bid to take over Canada's Nexen for over $15 billion grabbed immediate media attention worldwide. Learning from its failed bid for Unocal in 2005, CNOOC prepared carefully since it would require Canadian and US government approvals.

Nexen's assets are in Canada, US territory in the Gulf of Mexico, as well as offshore West Africa and the North Sea. The takeover of Nexen would increase investment flows into the North American oil and gas industry, raise the capitalisation of Nexen's peers, allow CNOOC to book new reserves, and provide the company with access to key technical know-how that the company could potentially apply to China's domestic unconventional oil and gas reserves.

Unlike the earlier days of Chinese companies' overseas expansion, however, the recent acquisitions have demonstrated clearly that these companies are moving away from riskier parts of the world towards more politically stable investment climates and more technically challenging resource areas. In addition to unconventional oil and gas, the acquisitions since January 2011 have also focused on deepwater assets and LNG, which are as much educational opportunities as investment targets. Before the Nexen bid, the NOCs had already made large investments into shale gas and oil sands in Canada and deep-water production in Latin America. At the same time, NOCs' acquisitions in OECD countries are now greeted with less skepticism than in the past. This attitude shift towards China's NOCs, bolstered by successful co-operation with IOCs in the Middle East and elsewhere, has paved the way for their current inroads in North and South America, Europe, and Australia.



Overseas investments by China's NOCs (continued)

Although announcements of overseas acquisitions by NOCs are often couched in the language of energy security, there is no evidence that the Chinese government imposes a quota on the NOCs regarding the amount of their overseas equity oil that they must ship to China. Marketing decisions concerning the NOCs' equity oil are based on the details of each production-sharing contract and by commercial considerations. Also, NOCs extended their investment activity to include mid- and downstream sectors by building or starting new pipelines from Central Asia and Myanmar, and by applying their "Market-for-Resources" strategy to co-operation with resource-rich counties such as Saudi Arabia, resulting in joint investments in filling stations in China and refineries in both countries.

The majority of overseas investments concluded by Chinese NOCs are in the form of co-operation agreements with either host-country NOCs or IOCs. Growing Chinese domestic markets have attracted foreign companies to partner with Chinese NOCs in the past. Today, the more relaxed regulatory environment in China allows foreign NOCs and IOCs to enter not only downstream markets (*e.g.* by building refineries or filling stations) but also to participate in upstream offshore deepwater and unconventional gas production. China's 12th Five-Year Plan supports the acceleration of the exploration and development of deep-water and unconventional hydrocarbon resources. In 2012, BP and Eni have since joined Chevron and ConocoPhillips to partner with CNOOC to develop Chinese offshore deepwater blocks. In September 2012, China opened its second round of shale gas bidding to Chinese-foreign joint ventures. This new policy is expected to provide opportunities for more foreign companies to join Chevron and Shell in entering the potentially large Chinese shale gas market. These new policies may also help to ease some concerns raised in Canada and US during the approval process of CNOOC's bid for Nexen over reciprocal openness of China's upstream oil and gas sector.

Non-crude liquids and other market drivers

Key oil supply considerations: natural gas and natural gas liquids

Natural gas liquids: the unsung hero of supply forecasts

NGL production is the unsung hero of the non-OPEC supply forecast, comprising 30% of the growth in non-OPEC supply. Canadian NGLs are forecast to increase by 21% (130 kb/d) to 760 kb/d by 2017, but US NGL production does even better, increasing 36% to over 3 mb/d by 2017. In the US, NGL output is expected to grow by 6% per year to over 3 mb/d in 2017 as producers target liquids rich plays and need to process associated gas. The IEA *Medium Term Gas Report* assumes that natural gas prices will begin to appreciate again in the medium term, yet the probability that they will reach levels of $7-9/mmBtu seen in 2007-08 is very low. As long as the oil/gas ratio remains large, producers will continue to tap NGL-rich plays.

The sustained growth in US liquids extraction has led to temporary stock excesses in the first half of 2012 at both Conway and Mt. Belvieu NGL hubs, leading observers to warn of a supply glut. Prices of NGLs are currently half of January 2012 levels. Moreover, stocks of ethane and propane are currently high, in part because of increases in production, but also as a result of the unseasonably warm winter of 2011-2012 and infrastructure and processing bottlenecks. Some of the congestion will be eased as pipeline expansions carry stocks from Conway to the Gulf coast, and short-term cracking capacity is also expected to grow as industry converts under-utilised crackers to accept lighter feedstock. Driven by favourable economics, NOVA Chemicals, Shell, and other players plan to expand their processing infrastructure in the Marcellus Basin. Enbridge and Enterprise have also announced new pipeline projects which will ease the transport issues over the medium term.

Key oil supply considerations: natural gas and natural gas liquids (continued)

Though short-run hiccups are to be expected, medium term petrochemical demand is expected to come closer in line with burgeoning feedstock supply. Total capacity gains from announced and permitted projects could increase US fractionation capacity by as much as one-third by 2017. Improvements of a smaller magnitude in propane dehydrogenation are also under development.

Further downstream, additional LPG exports are expected to satisfy demand from Latin America. While export of NGLs has not been historically significant for the US, planned port expansions indicate that the US is likely to become a net exporter of LPG. Likewise, the basic plastics - products of ethylene and propylene - are exportable and show growth potential. Foreign demand for plastics and LPG, and favourable domestic production margins are also contributing to gains in processed NGL production despite increasingly popular bearish sentiments about the market. *See "Revisiting the Ethylene Industry's Demand for Oil Products".*

Moreover, potential demand growth in the petrochemical industry for ethane will not be the only driver of demand growth for NGLs. NGL exports to Canada may be able to make up for temporary demand reductions in the US through their use as diluents in the pipeline, for blending at upgraders, and as solvents in *in situ* production. Exports of pentanes plus to Canada more than tripled to 92 kb/d in April of 2011 and have since remained at those levels.

Therefore upstream and demand-driven factors influence the future supply of natural gas plant liquids in the US. Yet, each NGL component is subject to unique economics, such that each component's price is related in some fashion to other components. For example, Gulf Coast processing plants can substitute between lighter and heavier NGLs. Also, N-butanes and pentanes plus are important to refining and blending of both kerosene and motor gasoline and can substitute for refined crude products in some cases. Inter-sectoral substitution explains why supplies continue to grow despite scepticism about NGL supplies. For example, LPG supply in particular may potentially alleviate some seasonal substitution effects between ethane and propane for petrochemical uses with refinery naphtha.

In sum, the flexibility along the supply stream and between sectors is likely to correct for individual market fluctuations over the medium term. As the petrochemical industry modifies plants to accept lighter liquids, additional offsets to demand declines for heavier NGLs should be taken up by refiners and blenders in the short term and via North American exports in the medium term. Growth in supplies should continue through 2017 when the lion's share of cracking facilities and infrastructure additions are scheduled for completion. Forward looking producers have already incorporated these indicators into future planning. US LPG export capacity and growth have huge potential – the extent of which may only begin to be realised over the medium term.

US natural gas production defies gravity, but for how long?

When Henry Hub natural gas prices suddenly dropped from their peak in mid-2008 ($12.7/MBtu) to reach the much lower level of $4/MBtu in 2009, gas producers complained that such levels would not be sustainable and that the economics of shale gas production meant that US gas production growth would start slowing down, or even decrease. Instead, natural gas production gained 13 bcm (+2.3%). A slight uptick in prices in 2010 to $4.4/MBtu was accompanied by further raised output of 3.4%, but the real surprise came from a 47 bcm (+7.8%) gain in 2011 amidst a fall in prices to $4/MBtu.

Key oil supply considerations: natural gas and natural gas liquids (continued)

The unique driver behind the US incremental gas production of around 110 bcm over 2007-11 to 650 bcm is shale gas, whereby its incremental production of 160 bcm implies that it actually displaced more expensive gas, such as tight gas or offshore gas. Shale gas production has had a tendency to systematically exceed many analysts' forecasts. Multiple reasons could explain this phenomenon and the difficulty to forecast accurately future US (*i.e.* shale) gas production. Among these factors are improvements in the efficiency of drilling and production, continuous investments of foreign (and in particular Asian) companies and IOCs in shale gas assets, and independent gas producers hedging part of their gas production. But the key driver behind the recent dramatic increase lies in the contribution of liquids' (oil and NGLs) revenues. As it had in the past, natural gas once again became a by-product, whose price level was not the priority as companies switched from dry gas to liquid-rich plays.

Anticipating US gas production developments requires an understanding of the gas/liquid/NGL content of new shale plays as well as the pricing dynamics between these products. Some of the aforementioned factors are starting to decline in importance, especially after a record mild winter 2012 sent prices to an average level of $2.5/MBtu over the first half of 2012. Recent highly publicised producers' falling revenues and significant write-downs incentivise them to shut in production. Even though natural gas production still gained 20 bcm (+6.4%) over the first half of 2012, or a 40 bcm increase on an annual basis, the monthly increases in late spring (+1%) were no longer as buoyant as in the past, in part a response to prices dropping below the psychological barrier of $2/MBtu. An average price of $2.5/MBtu is below production costs of many plays, unless the liquid component can compensate, which is the case for associated gas, but not for dry gas. Hedging is now limited in the coming years with Henry Hub future gas prices staying below $4/MBtu until at least end-2014, while efficiency improvements seem to have become more challenging.

While some shale plays like the Barnett and Haynesville will benefit from liquids revenues, these plays are still expected to decline due to a mixture of shut-ins and lower investments. Marcellus and Eagle Ford will still drive gas production up. For most other plays, production is expected to be either flat or slightly increasing due to growing LTO output driving up associated gas production.

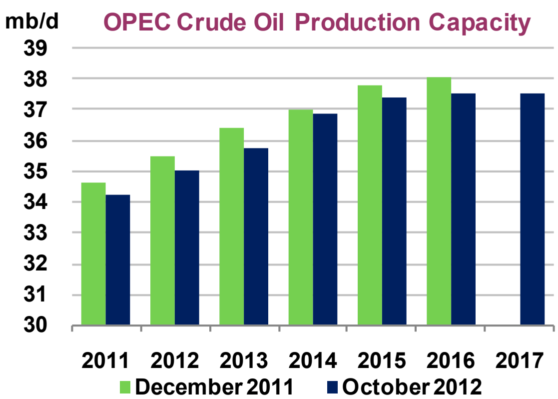
According to the *Medium-Term Gas Market Report 2012*, US gas production growth should slow down, reaching 680 bcm by 2013, up from 651 bcm in 2011, due to persistently low gas prices.[5] Although the surplus in underground gas storage is no longer as substantial as during spring 2012, storage levels early September 2012 still stood at 8 bcm above the five-year average. This surplus is unlikely to allow a significant increase in gas prices in the coming months unless the winter is particularly cold. As prices are assumed to progressively increase to a comfort zone of around $4-5/MBtu by 2014, natural gas production growth is expected to pick up again and increase to around 770 bcm by 2017. Rising US gas demand, notably in the power and industrial sector, combined with the possibility of LNG exports should provide a market for this increasing gas production.

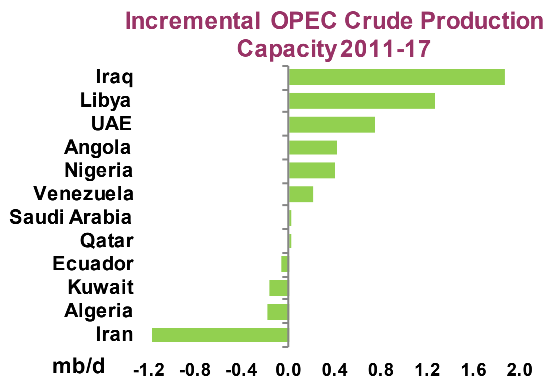
OPEC crude oil capacity outlook

OPEC crude oil production capacity is slated to rise by a steep 3.34 mb/d over the 2011-2017 period, to 37.54 mb/d, with Iraq providing just over 50% of the increase. This high headline figure is skewed, however, by the temporary drop in OPEC capacity during the 2011 Libyan civil war. OPEC installed capacity hit a four-year low in 2011 due to the loss of Libyan supplies, our comparison point for the outlook. Recovering Libyan production provides a near 40% increase in our forecast from that low 2011 baseline and if removed from the calculations shows OPEC will raise capacity by a smaller 2.08 mb/d, in line with growth rates of previous years. Capacity estimates are 90 kb/d lower on average for 2016 from our December 2011 report.

[5] The IEA does not forecast fuel prices in its Medium-Term reports but relies on the forward curve at a given time. For natural gas, this means the forward curve as of early April 2012.

OPEC crude capacity provides 35% of the 9.3 mb/d increase in global oil supplies over the 2011-2017 period. Iraq and Libya are the key contributors to the group's net capacity increases by 2017. The UAE, Angola and Nigeria are the three other major sources of growth. By contrast, four countries are expected to see capacity decline, with Iran off by more than 30% by 2017 compared to 2011 levels.





As a group, OPEC lags the surge in non-OPEC supplies over the forecast period and the stellar gains in oil sands and light tight oil. New OPEC crude production projects are estimated at a gross 7.97 mb/d at peak over the forecast period, with Iraq providing around 23% of the growth followed by Angola at 21% and Venezuela at 16%. That is some 2.65 mb/d below the forecast of OPEC's gross capacity additions of 10.6 mb/d for 2010-2016 in the June 2011 report.

New capacity will be partially offset by annual field decline rates of just under 775 kb/d, or 3.2% from the existing production base. Excluding Libya's extraordinary gains, decline rates are in line with historical trends, down 1.13 mb/d (3.4%) annually, close to the last year's assessment of 1.2 mb/d, or 3.5%. *MTOMR* capacity estimates are based on a combination of new project start-ups, and assessed base load supply, net of mature field decline.

Relatively high oil prices are a key driver of increased capacity of both crude and non-conventional resources in non-OPEC, but projects in more than half of OPEC countries – Iran, Kuwait, Algeria, Nigeria, Libya, Venezuela and Ecuador – are constrained by unfavourable fiscal regimes as well as political and security issues. Mature OPEC producers need advanced technology in order to maximise recovery rates but some lack the appropriate contract terms to attract foreign partners. This outlook sees a dearth of new projects at the tail-end of the forecast period, as IOCs await either improved contract terms or finalisation of pending oil legislation before making final investment decisions.

OPEC Spare Crude Production Capacity Outlook 2011-17

(million barrels per day)

	2011	2012	2013	2014	2015	2016	2017
OPEC Crude Capacity	**34.21**	**35.00**	**35.78**	**36.90**	**37.42**	**37.55**	**37.54**
Call on OPEC Crude + Stock Ch.	**30.39**	**30.35**	**30.14**	**30.38**	**30.32**	**30.66**	**31.21**
Adjusted Call on OPEC Crude + Stock Ch	**28.73**	**29.00**	**29.03**	**29.89**	**31.14**	**32.16**	**33.28**
Implied OPEC Spare Capacity	3.81	4.65	5.64	6.52	7.09	6.89	6.34
Effective OPEC Spare Capacity	2.81	3.65	4.64	5.52	6.09	5.89	5.34
as percentage of global demand	*3.2%*	*4.1%*	*5.1%*	*6.0%*	*6.5%*	*6.2%*	*5.6%*

OPEC's effective spare capacity is expected to rise over the forecast period as non-OPEC supplies outpace forecasts. OPEC's spare capacity recovers from 2011 lows of 2.81 mb/d and gradually reaches a peak of 6.09 mb/d in 2015 before trending lower through 2017. The IEA assesses current sustainable OPEC crude production capacity and provides an estimate of 'effective' spare capacity. Sustainable production capacity is oil that could theoretically be produced at the wellhead within 30 days and sustained at that level for 90 days. This installed capacity takes no account of short-term constraints such as maintenance or logistical issues. In an effort to provide a more realistic snapshot of current and future upstream supply flexibility, we also calculate an estimated 'effective' spare capacity as distinct from the nominal measure. OPEC's 'effective' spare capacity recognises that over the last decade, and on a consistent basis, around 1 mb/d of nominal spare capacity in countries including Iraq, Nigeria and Venezuela, has not been immediately available to the market for technical, security-related or infrastructure reasons. This observation that effective spare capacity has tended to lag nominal spare capacity by 1 mb/d during the last decade informs the discount applied to future levels of calculated nominal spare capacity in our projections.

Estimated OPEC Sustainable Crude Production Capacity

(In million barrels per day)

	2011	2012	2013	2014	2015	2016	2017	2011 -17
Algeria	1.22	1.18	1.17	1.21	1.15	1.09	1.04	*-0.18*
Angola	1.78	1.80	1.92	2.20	2.32	2.24	2.20	*0.43*
Ecuador	0.52	0.53	0.53	0.51	0.48	0.46	0.45	*-0.07*
Iran	3.70	3.27	3.07	2.95	2.84	2.69	2.51	*-1.19*
Iraq	2.91	3.14	3.67	4.06	4.15	4.41	4.77	*1.86*
Kuwait	2.86	2.84	2.80	2.77	2.75	2.72	2.69	*-0.16*
Libya	0.44	1.44	1.60	1.67	1.68	1.69	1.69	*1.26*
Nigeria	2.68	2.74	2.68	2.71	2.82	3.09	3.09	*0.40*
Qatar	0.78	0.78	0.78	0.83	0.82	0.81	0.79	*0.01*
Saudi Arabia	12.04	11.88	11.86	12.21	12.34	12.20	12.06	*0.02*
UAE	2.72	2.81	3.03	3.14	3.39	3.45	3.46	*0.74*
Venezuela	2.58	2.58	2.66	2.66	2.69	2.71	2.80	*0.22*
Total OPEC	**34.21**	**35.00**	**35.78**	**36.90**	**37.42**	**37.55**	**37.54**	***3.34***
Increment	*-1.03*	*0.79*	*0.78*	*1.12*	*0.51*	*0.13*	*0.00*	

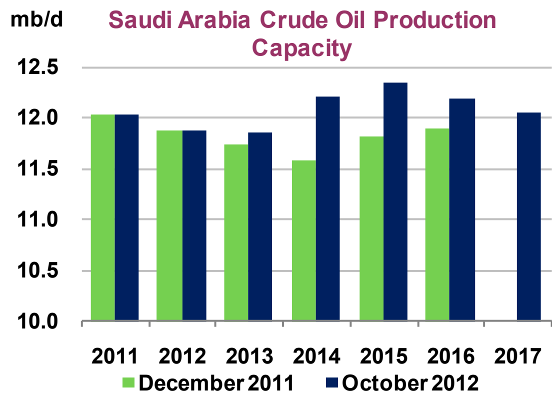
Contrasting outlook for Middle East producers

OPEC's Middle East crude oil capacity is estimated to rise by a net 1.28 mb/d to 26.28 mb/d by 2017, with Iraq's rise partially countered by Iran's descent. Aside from Iraq, the UAE is the only other Gulf member to significantly increase production capacity. Saudi Arabia, Kuwait and Qatar are largely unchanged over the period.

Iraq continues to face multiple political, infrastructure and security challenges but steady progress in overcoming some technical and logistical issues sees production capacity rising by 1.86 mb/d in the forecast period, reaching 4.8 mb/d by 2017. (see *'Iraq Production Capacity Scales New Heights'*). Looking beyond our forecast period, production capacity is expected to breach 6 mb/d in 2020, according to a special report released on 9 October 2012 as part of the IEA annual *World Energy Outlook (WEO)*.

By contrast, comprehensive sanctions imposed this past year on Iran's oil and financial sector by the international community are significantly affecting the country's oil outlook. Iran's production capacity is set to decline by 1.2 mb/d, to 2.5 mb/d by 2017 due to the country's inability to import the necessary equipment needed to maintain and increase capacity as well as the continued exit of foreign investors (See *'Iranian Capacity Crushed Under the Weight of International Sanctions'*).

Top OPEC producer **Saudi Arabia** breached the 10 mb/d output mark for the first time in more than three decades in 2012, leaving spare capacity of just under 2 mb/d. Installed capacity is forecast to hold within an 11.9-12.3 mb/d range through 2017. Saudi Arabia posts only a marginal rise of 20 kb/d, to 12.06 mb/d by 2017, with the 900 kb/d offshore Manifa field the only major project planned in the medium term. Moreover, the Manifa project, which is now slated to come onstream in late 2013/early 2014, is expected to just offset natural decline rates elsewhere. The heavy crude oil produced from the $16 billion development will almost exclusively be dedicated to supplying the country's three new refineries at Yanbu on the Red Sea, Jubail on the Arab Gulf and Jazan in the southwest of the country.



Other projects in the pipeline include upgrading of the Safaniya field, the world's largest offshore oil field. Rehabilitation plans include installing submersible pumps, upgrading crude-gathering facilities and power supply, with completion set for end-2013. The field, which produces Arab Heavy, has been in production since 1958. The upgrade of infrastructure is largely designed to maintain current production of just over 1 mb/d.

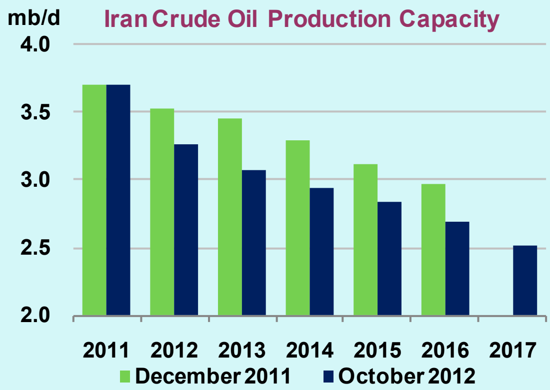
However, plans to expand the Wafra field in the Neutral Zone shared with Kuwait via steam injection have been delayed now beyond 2017. The FID has been postponed from 2013 to 2016. If approved, the project would be the largest steam injection project in the world. Cost factors and associated risks of the new steam injection technology are behind the postponement.

The escalation in political tensions between Iran and the international community has focused market attention yet again on Saudi Arabia's spare capacity. While several industry reports in recent months have raised doubts over the level of Saudi production capacity, Saudi Aramco has moved apace on rehabilitation of existing infrastructure and increased its drilling programme in an effort to stem decline rates. The current programme of work is designed to maintain existing production levels rather than boost capacity. The company, however, maintains that long-developed plans to boost capacity by a further 2.75 mb/d to 15 mb/d could be dusted off if needed.

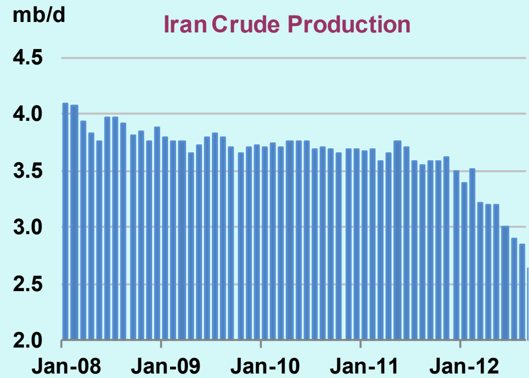
Iranian oil output crushed under the weight of international sanctions

The outlook for Iran's oil industry has darkened this past year as the US and EU implemented the most comprehensive sanctions yet on the country's oil and financial sectors. There is considerable uncertainty about the ultimate outcome of the dispute between Tehran and western countries over Iran's nuclear programme. At the time of writing, the oil outlook for Iran appears closely predicated on the prospects that the decade-long dispute and stand-off continues for the medium term. Iran's refusal to abide by IAEA and western demands has long cast a pall on the production outlook. Should Iran opt to yield to western pressures, its production capacity outlook would brighten. Alternatively, while international compliance with US and EU sanctions currently appears high, it is conceivable that compliance could weaken over time or that Iran could succeed in the future in skirting some of the sanctions. Other possible scenarios could include some form of retaliatory measure by Iran with potential effects on oil production in Iran or elsewhere.

Iranian oil output crushed under the weight of international sanctions (continued)



In this report, we assume that Iran and the international community fail to resolve their dispute over the forecast period and that sanctions remain in place. Under that scenario, crude oil production capacity is forecast to fall by a steep 1.19 mb/d, to 2.51 mb/d by 2017. Iran's NGL outlook has also been downgraded (see '*OPEC Gas Liquids Supply*.') The new sanctions are wide-ranging and have had far-reaching impact on global oil trade as Iran's traditional buyers are forced to navigate the complex web of new regulations or risk running afoul with the US regulators. Implementation of the new US sanctions on the banking sector have largely choked off access to international shipping and insurance markets and made it nearly impossible to arrange payments for sales for Iranian crude buyers. Crude oil exports are expected to hover in a narrow range around 1 mb/d in 4Q12 compared with around 2.5 mb/d over the same period a year ago.

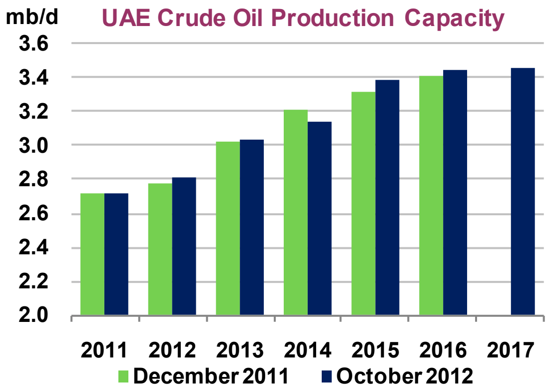


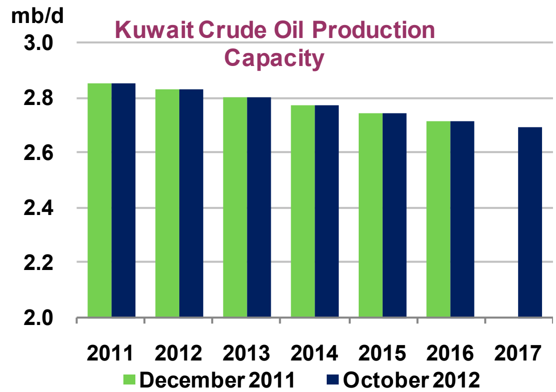
The biggest drop in exports came in July as the new sanctions were implemented. However, since then exports have edged higher after several key countries, including Japan, India and China, offered insurance and indemnity coverage on tankers for their companies lifting Iranian crude. So far, the US has also issued waivers from sanctions for countries that have shown a decline of anywhere from 10-20% in Iranian imports, which includes all the major buyers. As a result, Iranian supplies are likely to show only small incremental declines in the very near-term but the overall cumulative impact will be substantial in the medium term.

The latest escalation in sanctions is having an immediate impact on the country's oil operations. Though field level information is difficult to obtain, Iranian officials have confirmed that sanctions have forced the National Iranian Oil Company (NIOC) to shut-in production, with estimates ranging from 200 kb/d to as much as 500 kb/d by September 2012. Given that Iran's antiquated refineries run on the country's light crude oil, analysts expect fields with heavier crude output to be shut-in. Iranian oil executives have said they are using the current situation to implement maintenance work at some fields. However, Iran's ageing oil fields already suffer from high decline rates, estimated at at least 10%.

Decades of sanctions have deprived Iran's industry of the latest technology needed to stem decline rates. The latest round of sanctions will make it even more difficult to procure equipment and materials needed to maintain or develop fields. Most companies have exited Iran in recent years, in part due to the country's unattractive buyback contracts as well as the increasingly difficult operating environment due to sanctions. China appears the exception and is moving forward with further development of Iran's Azadegan and Yadavaran oil fields. That said, it is unlikely capacity will come online within the forecast period.

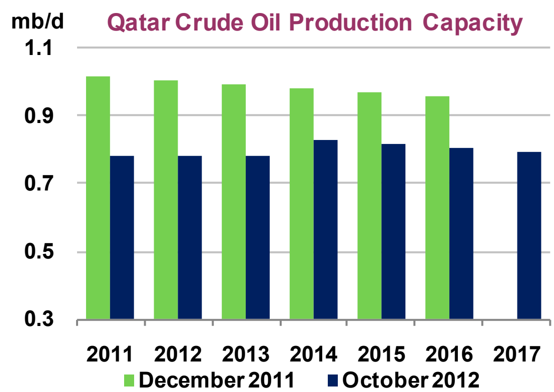
The **UAE's** crude oil production capacity is forecast to rise by a net 740 kb/d, to an average 3.46 mb/d by 2017, in line with its target of 3.5 mb/d. Capacity steadily rises over the forecast period, with start-up in 4Q12 of water and gas injection projects at mature onshore fields adding an estimated 200 kb/d at peak. Production from the Lower Zakum expansion planned at 125 kb/d is expected to start at end-2012 as infrastructure mothballed in the 1980s is slowly re-commissioned; bringing total field capacity to 450 kb/d. Capacity at the Upper Zakum field is slated to rise by 200 kb/d, to 750 kb/d in 2015. Development of the offshore Umm Lulu and Nasr fields, with combined output of 160 kb/d, is also underway, with first oil expected in 2014.





Longer term, the production outlook is less clear as legacy contracts expire in 2014 for onshore concessions and 2018 for offshore. Abu Dhabi's Supreme Petroleum Council has been alarmingly vague about its intentions on award requirements and, crucially, a timeline for announcing awards. As a result, partners have been reluctant to make substantial investment plans beyond their current contract expiration dates.

Qatar's crude oil production capacity is forecast to edge marginally higher until 2014, to 830 kb/d, before drifting down again, to 795 kb/d in 2017. Capacity estimates have been downwardly revised from our last report by an average 175 kb/d following disclosure that the al-Shaheen field has been producing well below previous estimates due to structural problems with the reservoir. Maximum output capacity is now seen at 300 kb/d compared with 450 kb/d previously. Several advanced technology projects are underway to offset natural decline rates and maintain production capacity at around 800 kb/d. A 70 kb/d increase at the 250 kb/d Dukhan field is expected to come online in late 2013/early 2014.



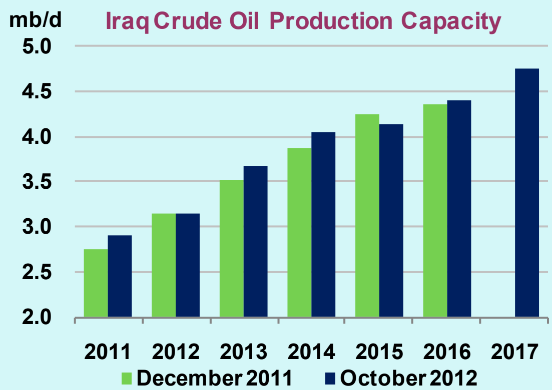
Political stalemate among **Kuwait's** ruling family and parliament over the future of the country's oil development continues to stymie progress on production capacity expansion plans in the medium term. Capacity is forecast to decline by 165 kb/d to 2.69 mb/d by 2017. After a capacity boost of around 250 kb/d in 2010-11 following the debottlenecking at the Mina al-Ahmadi terminal, which enabled increased flows from the giant Burgan field, there are currently no major development projects on the books over the next five years. Kuwait has set a production target of 4 mb/d by 2020 but this looks highly unlikely given the politically-charged investment climate. The country's plans to implement enhanced technical service agreements (ETSA) for the northern fields with BP stalled in 2008. Recent reports suggest Kuwait Petroleum Corp (KPC) is in the process of resurrecting talks over

ETSAs with Total but, if history is any guide, the process will likely be fraught with problems. The ETSA for the northern region, which includes the Ratqa, Raudhatain, Sabriyah, Abdali and Bahra fields, calls for raising production capacity by 350 kb/d to 1 mb/d.

Aside from political machinations, project plans could be derailed by the lack of natural gas needed for reinjection to maintain reservoir pressure. Kuwait Oil Co (KOC) signed the first new ETSA with Shell in 2010 for a $10 billion gas project but technical issues have delayed the three-phase development. Moreover, the project is under investigation by the country's parliament, which is questioning the competitiveness of the contract award.

Iraq crude production capacity set to scale new heights

Iraq's crude oil production is on course to reach key milestones over the next five years, with capacity forecast to increase by 1.86 mb/d to 4.77 mb/d by 2017. Production capacity is expected to breach 6 mb/d in 2020, according to a special in-depth report on Iraq released on 9 October 2012 as an early excerpt from the IEA's annual *World Energy Outlook (WEO)*.



After initial start-up of new joint venture projects at end-2010, production reached record levels of over 3 mb/d in mid-2012. Iraq continues to navigate a myriad of political, infrastructure and security challenges. The twelve major joint venture projects awarded to IOCs under 20-year service contracts have progressed at various paces. Four super-giant southern fields – Rumaila, West Qurna, Majnoon and Zubair – account for more than 70% of the capacity increase in the long term.

Much of the easy production has been brought online, but in order to post significant increases towards their output goals, a number of major projects need to make rapid progress. Aside from drilling activity, major water injection projects are needed to maintain reservoir pressure. The country's southern fields, in particular, are dependent on water injection. The massive Common Seawater Supply Facility (CSSF) on the drawing boards, which is designed to treat and pump seawater from the Gulf to the inland fields, faces major delays and obstacles. Exxon was initially tapped to coordinate the project but withdrew earlier this year. Given the delays and enormous amount of engineering work required, the project is not expected to be in operational until 2017 at the earliest.

The logistical constraints in the southern region of the country pose the most pressing problem in the medium term. Two 900 kb/d single point mooring (SPMs) systems that link to the key onshore Fao terminal were completed in the first half of 2012 but both SPMs are operating below capacity levels. Progress in overcoming some technical and logistical issues related to storage and pumping stations is critical to keep planned increased production output flowing but operational issues continue to delay development projects. With virtually no storage at the Fao terminal, production has to be shut-in at the field level when export flows are halted due to weather-related disruptions or technical problems. Plans to construct 24 new storage tanks are well behind schedule, with some technical contracts yet to be awarded. The earliest the tanks are envisaged is at end-2013 but in all probability they will not be completed until 2014. Rehabilitation of existing pipelines and pumping stations moving crude to Fao is also urgently needed given their current dilapidated state. Further delays could force IOCs to constrain production over the next several years.

Iraq crude production capacity set to scale new heights (continued)

Strains between the North and South persist

Development of oil fields in the northern region of the country is moving apace, with the Kurdistan Regional Government (KRG) awarding around 50 contracts with IOC's. Current production capacity of an estimated 200 kb/d is forecast to rise to just under 500 kb/d by 2017. The under explored region is considered one of the most attractive plays for conventional oil and gas available to IOCs, not only because of the geology but also due to more attractive contract terms. There are currently four oil fields in production: Tawke, Taq Taq, Khurmala Dome of the Kirkuk field and Shaikan. The Kor Mor gas field is also producing some condensates.

However, the contentious dispute between Baghdad and the KRG over primacy for oil policy and export agreements poses a significant potential risk for investors. Agreeing a stable regulatory framework is critical to support the multi-billion projects now being planned but, to date, the two sides are still wide apart. The central government in Baghdad controls export flows on the Kirkuk-Ceyhen pipeline that moves crude to the Turkish Mediterranean Sea, with Kurdish output piped in since they currently have no other export outlet. The KRG is still in the process of building transport infrastructure for its new production. A dispute over KRG payments to Baghdad for new production prompted a shut-in of production this summer. An agreement between Baghdad and the KRG was announced on 13 September to resume flows, at least temporarily. The KRG administration will resume exports of around 200 mb/d in 4Q12. In return, the federal government agreed to release around $900 million in overdue payments to the KRG. The payment resolution is a major step forward but the wider primacy issue may be harder to achieve.

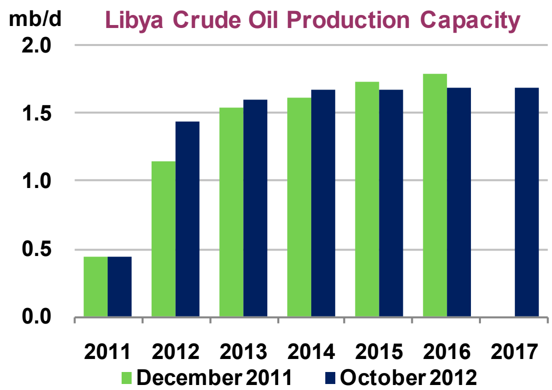
Adding further fuel to the North-South divide, the KRG's more attractive contract terms have lured a number of companies operating in the south to bid on contracts. Smaller companies initially moved into the northern region but much to the chagrin of Baghdad, the enormous potential and attractive terms brought in a number of major oil companies this year, including Chevron, Total and ExxonMobil. The later company, ExxonMobil, partnered in the West Qurna 1 field, in particular has run afoul with the central government. Baghdad has threatened to cancel IOC's contracts in the south but, while some type of compromise is expected, the protracted dispute could indeed slow progress in the north. Based on contracts already inked, the Kurdistan region could theoretically produce 1 mb/d over the medium term but companies are expected to take a go-slow approach given the billions of dollars of investment at risk given the unresolved policy/legal issues.

OPEC's African producers post strong growth, Algeria the exception

By the numbers, OPEC's African members are poised to post the largest regional increase in crude production capacity at 1.91 mb/d, to 8.02 mb/d by 2017. Libya, however, accounts for 65% of the growth as the recovery in the war-torn country's production exceeded initial expectations for 2012. Nigeria and Angola combined provide the remaining incremental growth though both countries have a history of operating below capacity levels. By contrast, Algeria sees capacity decline due to the unattractive terms for existing contracts. The slow recovery from the corruption scandal that rocked the state oil company in 2010 has also led to bureaucratic inertia.

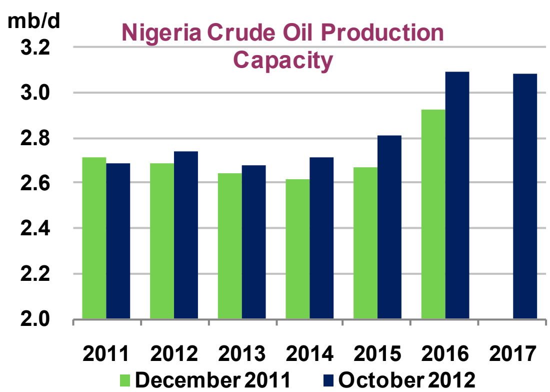
Amidst the ongoing security problems and political turmoil, **Libya** restored production capacity to about 85% of its pre-civil war levels in 2012. Current capacity is estimated at 1.5 mb/d, about 200 kb/d shy of its 1.7 mb/d 2010 level. By any measure, that is a significant achievement, but the country's ability to maintain or increase production capacity crucially will depend on the government restoring a rule of law. The extent of militia violence was tragically highlighted by the deadly attack on the US consulate in Benghazi and the murder of the American Ambassador and other US officials in September 2012. As a result, foreign operators have stepped up security, scaled back staff or delayed plans for a full return to the country. Oil service companies, seen as key to increasing capacity, have been slow to resume operations.

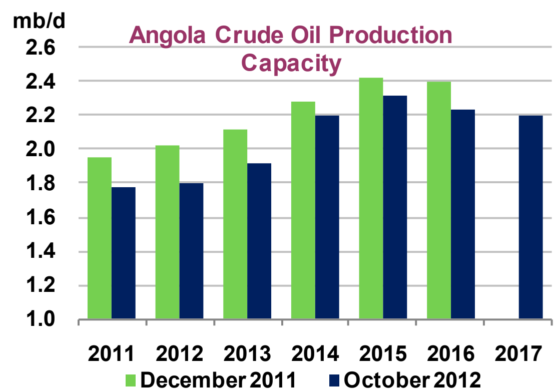
Even before the latest wave of violence, IOC partners considered the operational risks too great. Militias have reportedly actively taken on a significant role in the oil sector, operating security services for personnel and oil infrastructure, de facto forcing companies to pay for protection. The practice is reportedly widespread in the Sirte basin and in the southwest region where the ENI joint-venture Elephant field and the Repsol joint-venture Sharara fields are located.



Against the current unstable political and security climate, Libya's announcement that it plans to increase output capacity to 2.2 mb/d in the medium term was dismissed by a number of companies. As Libya's political process evolves and the security situation improves, incremental capacity expansions are expected. Production capacity is forecast to increase by 1.26 mb/d from 2011 average of 435 kb/d to 1.69 mb/d by 2017.

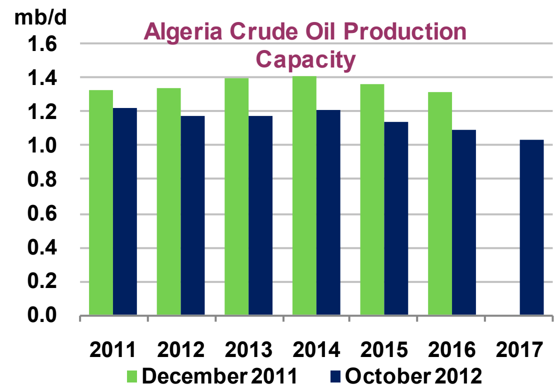
Nigerian capacity is forecast to rise by 400 kb/d, to 3.09 mb/d by 2017. As in previous years, however, the current slate of projects is far below Nigeria's potential due to ongoing security issues and, significantly, the long delay in finalising the controversial 'Petroleum Industry Bill' (PIB). Nigerian President Goodluck Jonathan approved the latest draft of the bill in August, and it now goes to the parliament for review in October 2012, which will likely be a further long, drawn out process. Moreover, foreign joint venture partners are highly critical of the draft bill as it stands. Shell, the country's largest joint venture producer, reportedly believes the new tax terms are not competitive and render the country's offshore oil and gas projects unviable. The still wide divide between the government and industry suggests project developments on the drawing board will be further delayed. In the medium term, several large offshore, deep-water projects and a number of smaller ones are set to be brought online over the 2012-17 period, with a total gross peak capacity addition of just under 1 mb/d. First oil from the Total-operated Usan field started earlier this year and will steadily ramp-up to its peak 180 kb/d capacity. The next big project is the 140 kb/d Bonga SW & Aparo fields, expected in 2014. The smaller 100 kb/d Nsiko and the 135 kb/d Bosi fields are planned for completion in 2015, followed by the 200 kb/d Egina fields in 2016. However, final investment decisions for projects in 2017 and beyond are not expected until the new PIB is adopted.





Angola's production capacity is forecast to rise by 425 kb/d over the period, to 2.2 mb/d. Capacity estimates have been revised lower by 165 kb/d from the December 2011 report, largely due to technical issues reducing capacity and steeper than forecast decline rates at the country's offshore fields. Several projects at the tail end of the forecast period may be delayed by ongoing problems in securing local partners capable of providing services. In total, 17 projects are planned that will add a gross 1.67 mb/d at their peak capacity over the next six years.

Indeed, recent projects have been showing delays of 6-12 months, which we attempt to factor into our forecast. Problems with equipment quality and in securing local partners with the expertise needed for complex deepwater projects have proven problematic in the past. The 150 kb/d PSVM project was delayed from its planned March 2012 start due to problems found with equipment during an inspection at the construction yards in Singapore while Total's 160 kb/d Clov project was delayed a year, to 2014, after Angola rejected the company's proposed partners.

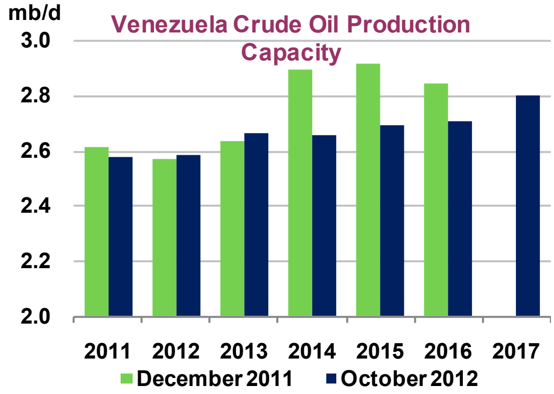


Algeria crude oil production capacity is forecast to decline by 181 kb/d, to 1.04 mb/d during the 2011-2017 period. In addition to chronic project delays, the capacity outlook has been revised lower due to baseline revisions resulting from new data. Combined, estimated capacity was lowered by 190 kb/d since our last update in December 2011. Algeria announced 17 September 2012 it amended its hydrocarbon law with improved tax terms. However, the changes largely affect frontier and shale investment, leaving exiting contract holders with relatively unattractive investment terms, especially given the significant technical challenges of the mature projects. IOCs also argue that state Sonatrach is still plagued by chronic red tape and institutional inertia after the 2010 corruption scandal, resulting in costly project delays of two-three years. Shell recently pulled out of the country while BP and Total have significantly reduced their presence over the past few years.

OPEC's Latin America capacity hindered by political agendas

Production capacity in OPEC's Latin American producers continues to be constrained by the region's resource nationalism and persistent project delays. **Venezuela** is now ranked as the world's top proven holder of reserves, which are defined as discovered volumes having a 90% potential of being developed, but produces just a fraction of its potential. After years of delays, the country has embarked in earnest on its massive development plan in the Orinoco heavy oil belt. New projects are slated to add 1.24 mb/d of gross capacity at peak production. Over the forecast period, however, net capacity growth will rise by just over 200 kb/d, to 2.8 mb/d, with the bulk of production not fully online until after the end of our forecast period.

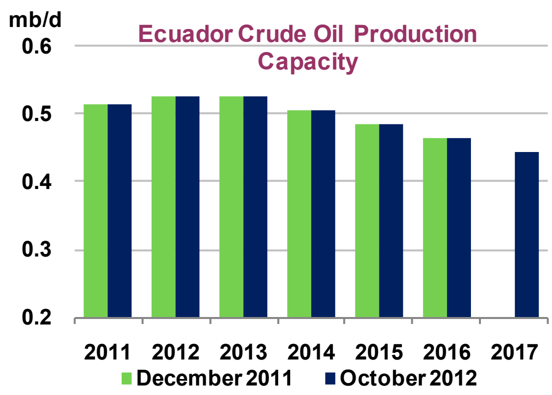
The re-election on 7 October 2012 of Venezuela's president Hugo Chavez to a new six-year term, extending his populist socialist rule to two decades, all but ensures development of the country's hydrocarbon industry will lag far behind its potential as the largest holder of reserves. Venezuela's chronic project delays largely stem from the drain on state-PDVSA's budget to fund social programmes. State PDVSA's debt with suppliers is linked to excessive operational and maintenance problems as well as funding for joint venture projects in the massive heavy oil Orinoco Belt. Chavez partially nationalised four projects in the Orinoco Belt in 2007, taking a majority stake in the projects. In response, ExxonMobil and ConocoPhillips quit their projects and are still embroiled in lawsuits over what the companies argue was unfair compensation for their holdings. BP, Chevron, Total and Statoil accepted the reduced equity stake as minority partners. One year later, companies were hit with a windfall oil tax of 50% on prices over $70/bbl and 60% over $100/bbbl. In 2010, the Chavez government partially nationalised oil service firms operating in the country, with a number of foreign companies having their drilling rigs and assets seized.



Nonetheless, the country's huge potential has enabled the Chavez administration government to sign lucrative oil-for-loans contracts with other companies and governments, especially with China. Given the billons of dollars at stake, we assume production growth will accelerate in the later years of the forecast period as partners demand returns on their investments. Project timelines for the six major contracts in Orinoco, however, remain stubbornly vague. The ill health of Chavez following his cancer diagnosis last year has injected further uncertainty about the country's future hydrocarbon policy and sanctity of contracts.

First production from the new contract awards at the Orinoco fields finally started in September 2012 but so far amounts to only a few thousand barrels a day. First output from the 200 kb/d Petromacareo joint venture with PetroVietnam at the Junin Block has started but under 1,000 b/d. The much smaller 45 kb/d Petromiranda project, with Russian partners Rosneft and Lukoil, also started production in September, at a minor 1,500 kb/d. CNPC's 400 kb/d Junin Block 4 joint venture and ENI's 240 kb/d Junin Block 5 project, are both expected online in 2013. However, ramp up in all projects is expected to be extremely slow given financial and operating constraints.

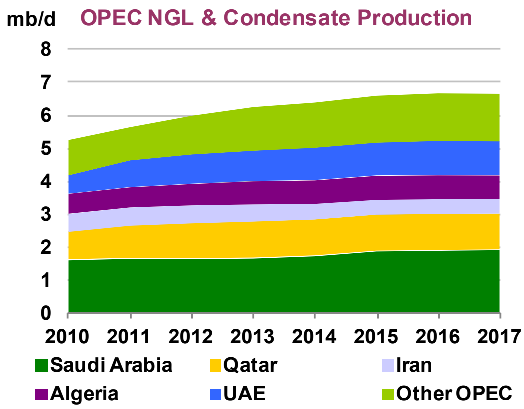
OPEC's smallest producer **Ecuador** is on track to see production decline over the next five years in line with previous expectations due to the country's recent wave of nationalising IOC assets. Production capacity is forecast to decline by 70 kb/d to 445 kb/d given the dearth of new development projects. The Pungarayacu heavy oil field is expected to eventually contribute 50 kb/d to capacity starting in 2012 while increased spending by Petroecuador may also marginally boost capacity. So far, plans on the books will fall short of offsetting the country's natural decline rate.



OPEC natural gas liquids supply

OPEC NGL, condensate and non-conventional production capacity is on course to rise by 1.16 mb/d, to 6.94 mb/d by 2017. A reassessment of Iranian future capacity in the wake of more stringent international sanctions is largely behind a downward revision of total OPEC by 420 kb/d since our December 2011 report. Saudi Arabia is expected to post the largest increase in capacity, closely followed by the UAE.

OPEC condensate capacity is expected to increase by 450 kb/d to 3.05 mb/d over 2011-17 while natural gas liquids are forecast to rise by 670 kb/d to 3.70 mb/d by 2017. Much of the growth in NGL capacity will be dedicated to meeting strong domestic demand for natural gas as a fuel for utilities, water desalination plants and industrial needs in the Middle East. Ever increasing demand for gas to maintain pressure at ageing fields is also driving NGL growth. Non-conventional supplies will more than double over the period, to 272 kb/d following up the start-up of a new gas-to-liquids (GTLs) plant in Qatar.



Iran's NGL capacity is now forecast to decline over the 2011-17 period, by about 110 kb/d to 430 kb/d. Iranian efforts to procure supplies, equipment and latest technology to maintain infrastructure are expected to be further hampered by new sanctions on the country's oil and banking industry. The EU's import ban and financial sanctions affecting the tanker industry are also expected to reduce condensate exports.

The current outlook also reflects a downward revision of 380 kb/d from our December 2011 forecast as new projects part of the South Pars development are delayed or postponed. The exit of joint venture partners, contractors and other support services is expected to result in a lack of financial capital as well as technology needed for the complex South Pars development phases. South Pars Phase 12, the most advanced project, is likely to see start-up delayed until 2015. Phases 15, 16, 17, and 18 are now not expected to be fully launched until after our forecast period.

Saudi Arabia, with the largest capacity, is on track to increase production by around 265 kb/d, to 1.93 mb/d by 2017. Start-up of the massive 240 kb/d Shaybah NGL development is planned for 2014. Two smaller projects are also expected in 2014: the Hasbah project with capacity of around 30 kb/d of natural gas liquids and the offshore Manifa field, which will provide 65 kb/d of condensate.

The **UAE's** NGL capacity is forecast to increase by around 215 kb/d, to 1.02 mb/d by 2017. The 140 kb/d Integrated Gas Development (IGD) project is expected online in 2013. The Shah Sour Gas project is expected to add a further 65 kb/d of condensate and other natural gas liquids. Further increases come from the ramp-up in capacity from the Habshan condensate and NGL projects.

Qatar's condensate and other NGL supply will rise a further 100 kb/d to 1.11 mb/d by 2017. Qatar has now brought on all its planned trains following the start-ups of the Qatargas 4, Train 7 in 2011 and Qatargas 3, Train 6 in October 2010. The end-2011 commissioning of the 120 kb/d Pearl 1 GTL project will boost the country's total GTL capacity to 155 kb/d over the forecast period. (GTLs are reported as non-conventional oil supply rather than included in NGL estimates).

Libya posts a dramatic recovery in its NGL capacity, up by 175 kb/d to 205 kb/d by 2017, in line with the rebound in crude production following the end of the civil war. Start-up of the NC 98 field in late 2013 will also contribute a further 80 kb/d to condensate capacity.

Algeria is also poised to increase capacity, by 110 kb/d to 725 kb/d by 2017. Hassi Messaoud will contribute 50 kb/d of LPG starting in 2012. Also this year, the Tisselit Nord Condensate project will add a smaller 10 kb/d while the MLE East project will add 10 kb/d of condensate and 14 kb/d of NGLs by 2017. El Merk will contribute around 30 kb/d each of condensate and NGLs starting in 2013.

Estimated OPEC Sustainable Condensate & NGL Production Capacity

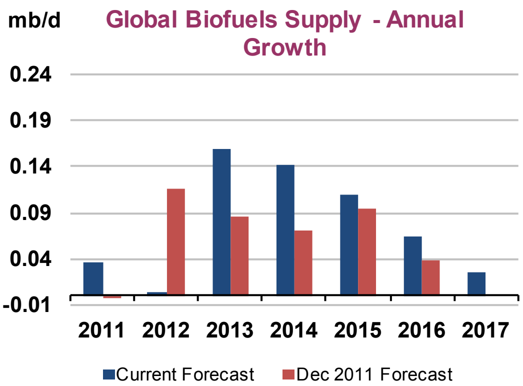
(In thousand barrels per day)

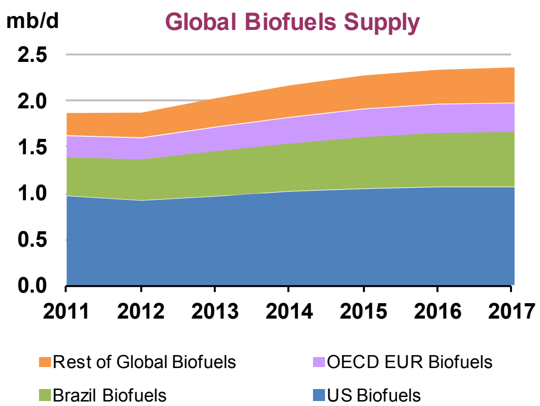
	2011	2012	2013	2014	2015	2016	2017	2011-17
Algeria	620	660	710	720	740	730	730	*110*
Angola	70	110	130	130	140	140	140	*70*
Ecuador	0	0	0	0	0	0	0	*0*
Iran	540	540	510	470	440	440	430	*-110*
Iraq	70	80	80	90	90	90	90	*20*
Kuwait	210	240	330	350	350	350	350	*140*
Libya	30	90	110	150	180	200	200	*180*
Nigeria	410	450	460	440	440	450	450	*30*
Qatar	1,010	1,090	1,130	1,120	1,120	1,120	1,110	*100*
Saudi Arabia	1,670	1,660	1,670	1,740	1,890	1,910	1,930	*260*
UAE	810	890	920	980	990	1,030	1,020	*210*
Venezuela	210	210	210	220	220	220	220	*0*
Total OPEC NGLs	**5,650**	**6,000**	**6,260**	**6,400**	**6,610**	**6,680**	**6,670**	***1,010***
Non-Conventional*	**120**	**220**	**240**	**240**	**270**	**270**	**270**	***150***
Total OPEC	**5,780**	**6,220**	**6,500**	**6,640**	**6,880**	**6,950**	**6,940**	***1,160***
Increment	*400*	*440*	*280*	*140*	*240*	*70*	*-10*	

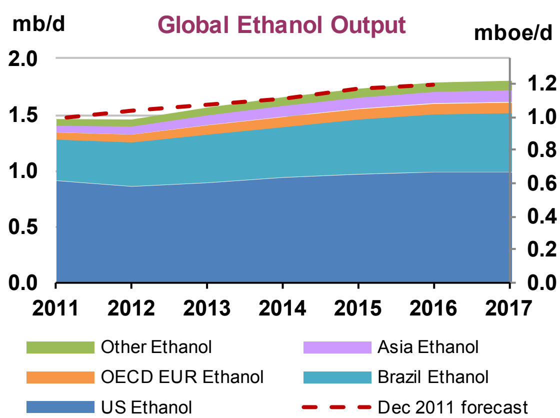
** Includes gas-to-liquids (GTLs).*

BIOFUELS

- **Biofuels production is expected to grow 0.5 mb/d over the medium-term,** with volumes rising from 1.9 mb/d in 2011 to 2.4 mb/d in 2017. This reflects a slightly stronger medium-term growth compared to our December 2011 forecast, up on average 50 kb/d annually for 2011-16, mainly based on higher biodiesel output in the US and Latin America.
- **2011 output is revised upwards by 50 kb/d compared to the December forecast, on stronger biodiesel output in the US, Indonesia and Germany.** For 2012, global biofuels production stalls at 1.9 mb/d, down 65 kb/d compared to our previous forecast, amid a severe drought leading to weaker US ethanol output, in addition to weaker Brazilian ethanol and OECD Europe biodiesel output.
- The **advanced biofuels** sector continues to show solid capacity growth off of a low baseline. With first commercial plants recently starting production, and a number of projects close to inauguration, we see total capacity growing from 55 kb/d in 2011 to around 180 kb/d in 2017.







Sustained medium-term growth, but short-term challenges ahead

Growth in global biofuels production has slowed down in the last two years, and 2012 total biofuels production is expected to remain virtually unchanged compared to the previous year. Over the medium term, we see global biofuels production growing by 0.5 mb/d, to reach 2.4 mb/d in 2017. This reflects an upward revision of 50 kb/d annually for 2011-16 compared to our December 2011 forecast, mainly due to higher biodiesel output in the US and Latin America. Adjusted for energy content versus oil, global biofuels supply increases from 1.3 mb/d in 2011 to 1.7 mb/d in 2017. Despite the expected growth in biofuels output over the medium-term, the current situation in some key producing regions has clouded the short-term outlook.

World Biofuels Production

(thousand barrels per day)

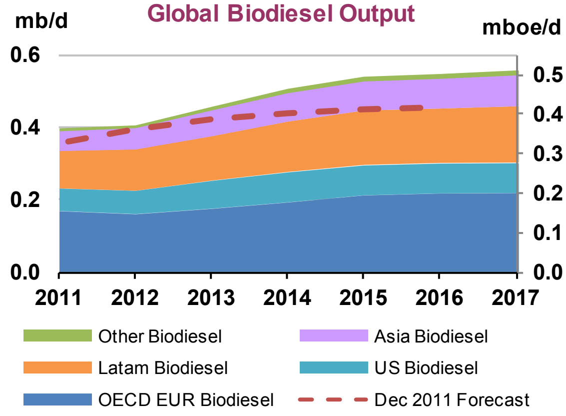
	2011	2012	2013	2014	2015	2016	2017
OECD North America	1,003	954	1,002	1,057	1,088	1,110	1,110
United States	970	920	966	1,020	1,048	1,068	1,068
OECD Europe	234	232	261	286	307	315	316
OECD Pacific	16	15	17	19	20	20	21
Total OECD	**1,254**	**1,201**	**1,280**	**1,362**	**1,415**	**1,445**	**1,447**
FSU	6	5	5	5	5	5	5
Non-OECD Europe	4	4	4	4	4	4	4
China	40	46	53	58	58	61	61
Other Asia	65	76	97	109	113	115	122
Latin America	494	535	584	626	677	703	720
Brazil	415	444	488	517	560	587	598
Middle East	0	0	0	0	0	0	0
Africa	3	4	7	9	10	12	13
Total Non-OECD	**612**	**669**	**749**	**810**	**867**	**901**	**924**
Total World	**1,866**	**1,870**	**2,030**	**2,172**	**2,282**	**2,346**	**2,371**
World - Revision vs December 2011	47	-64	10	83	100	124	n.a.

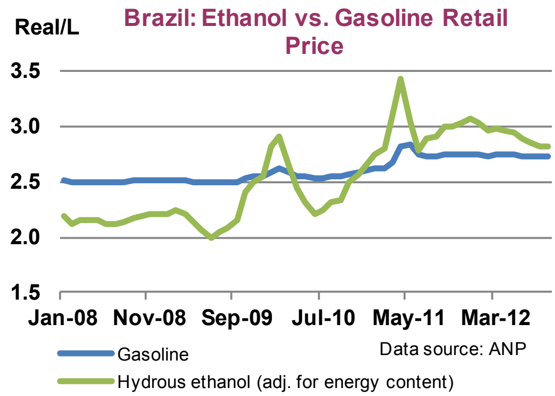
North American biofuel output continues to be led by **US** ethanol production. The latter is driven primarily by the mandate defined in the Renewable Fuels Standard (RFS2) after two other support measures - the tariff on imported ethanol, and the 45 cent/gallon blender's tax credit - expired at the end of 2011. While production seemed to be largely unaffected from the expiration, ethanol output has declined recently as the worst drought in more than 50 years severely compromised the 2012 corn harvest prospects and caused corn futures to skyrocket to around $8/bushel. This has put pressure on crushing margins for ethanol producers and led to a number of temporary plant closures in the last months. In addition, high corn prices have fuelled discussion of a possible waiver of the RFS2, but there is currently no indication that this will really happen.

Amid the current situation, we have revised our ethanol production estimate down on average by 55 kb/d to 890 kb/d in 2012 and by 30 kb/d for 2013, compared to the December 2011 forecast. In the medium term we expect US ethanol output to climb to 985 kb/d, accounting for 55% of world fuel ethanol production in 2017 compared to 60% in 2011. The recent EPA approval for retailers to sell E15 for use in post-2000 vehicles should increase ethanol's share of the US gasoline market, but administrative and technical hurdles still need to be overcome before the fuel is available nationwide.

The US biodiesel sector currently seems better off, despite a number of idle plants, and considerable overcapacity, and we estimate biodiesel production at 65 kb/d in 2012, up 20 kb/d from our previous forecast. With EPA raising the biodiesel mandate under the RFS2 to 1.28 billion gallons in 2013, up from 1 billion gallons in 2012, we expect biodiesel output to grow strongly through 2013 to reach 84 kb/d in 2014 and stay at this level throughout the forecast period.

Global Biodiesel Output

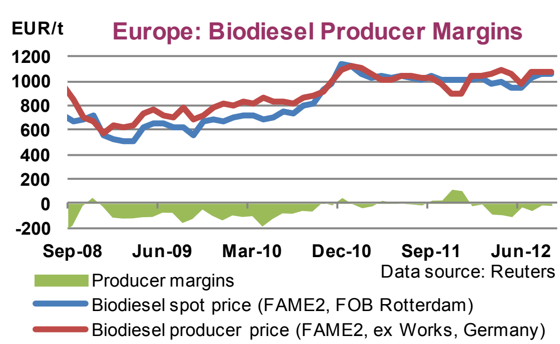




The outlook for **Brazil**, the largest biofuel producer in **Latin America**, is also gloomy; the sugarcane sector faces financial difficulties, with 40 mills reported to be in bankruptcy. With mediocre expectations for the 2012/13 sugarcane harvest and strong sugar prices making ethanol uncompetitive with regulated gasoline prices, and the mandatory ethanol blend remaining at 20% before being raised back to 25% in January 2013, we see most mills increasing their sugar output at the expense of ethanol production. Ethanol output in 2012 is thus revised to 395 kb/d in 2012, down 15 kb/d compared to our December 2011 update. Amid this situation, ethanol exports to the US dropped to 7 kb/d on average in 2011. At the same time imports from the US increased to 2.3 kb/d up from 0.1 kb/d a year earlier, but dropped this summer as the drought in the US reduced ethanol production. The prospects for Brazilian exports to the US are good as Brazilian sugarcane ethanol is the only biofuel on available at volumes needed to fulfil the RFS2 quota for "undifferentiated advanced biofuel". However, as the domestic ethanol mandated will be raised to 25% next year, ethanol available for export might well fall short of the volumes required in the US.

The current situation of the Brazilian ethanol sector leads to a 10 kb/d average downward revision, compared to our previous forecast. Brazil remains the world's second largest ethanol producer, accounting for 30% of world production by 2017, but it is not until 2014 that volumes exceed the record ethanol output of 2010. Total Latin American ethanol production climbs from 420 kb/d in 2012 to 565 kb/d in 2017.

The Latin American biodiesel sector is seen growing by 50% over the medium term, to reach 155 kb/d in 2017, up 30 kb/d in 2016 compared to our December forecast. Brazilian biodiesel output is forecasted to increase from 50 kb/d in 2012 to 70 kb/d in 2017. Thanks to rapid growth in recent years, **Argentine** biodiesel production reached similar volumes. However, a new quota system in Spain – the largest market for Argentine biodiesel – and Germany will now prevent Argentine imports to these countries, and a formal anti-dumping investigation by the European Commission could result in additional import duties that render the EU market unattractive for Argentine biodiesel. Unless domestic consumption picks up, or new export markets are found, we expect growth in biodiesel output to slow down over the next five years, with total production reaching 70 kb/d in 2017, up from 54 kb/d in 2012.



Note: Margins of individual producers can vary depending on feedstock costs, distance to retailer a.o.

In **Europe** biofuel production continues to be driven mainly by the EU's mandatory target for 10% renewable energy in transport by 2020, which also sets out mandatory sustainability requirements for biofuels. Since last summer, eight voluntary sustainability certification schemes for biofuels were recognised by the European Commission. However, an important decision on the implementation of emissions from indirect land use change into greenhouse gas balances of different biofuels has been postponed to fall 2012. Though not included in our analysis here, latest news on a draft EU legislation that, if adopted, would limit the share of grain-based biofuels to 5% of total transport energy consumption, reflect the growing scepticism towards these biofuels and could add to the uncertainty the EU's biofuel industry is facing regarding its future.

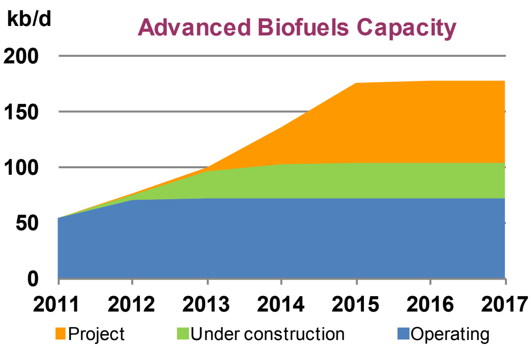
Amid a strong 2011 sugar beet harvest supporting ethanol output in **OECD Europe,** total production of 65 kb/d was 4 kb/d higher than expected in our December forecast. An extensive drought this summer affected Eastern European wheat production and dampened the outlook for 2012 as rising wheat prices put ethanol producer's margins under pressure. We thus expect total ethanol production in 2012 to grow only 6 kb/d year on year to 70 kb/d, but see new capacity additions, for instance in the UK, helping to increase ethanol output to about 95 kb/d in 2017.

The biodiesel sector in OECD Europe continues to suffer from extensive overcapacity and high feedstock costs that drove producers' margins into the red over the last months. We thus forecast 2012 biodiesel output at 160 kb/d, down 10 kb/d year-on-year, and 15 kb/d below our December 2011 forecast. Domestic production should benefit from new quota systems in Spain and Germany that exclude biodiesel from Argentina and Indonesia from counting towards the respective biofuels targets. In the medium term, we expect biodiesel production to pick up again and reach 220 kb/d in 2017, with Germany and France as key producing countries.

Non-OECD Asian biofuels production for 2012 was revised downwards from our December 2011 forecast on weaker baseline ethanol production, despite a slightly stronger biodiesel output compared to the previous estimate. Over the medium term, we expect Asian biofuels output to reach 180 kb/d in 2017. China continues to be the biggest regional producer, followed by Indonesia and Thailand, with its total output projected at 45 kb/d in 2012, 90% of which is ethanol. Indonesia remains the most important biodiesel producer in Asia, but recent policy measures in the EU (see above) could have a negative impact on its biodiesel exports and cloud the medium term outlook.

Advanced biofuels

Advanced biofuels, also referred to as second generation biofuels, are seen as important low-carbon fuel alternatives in the transport sector. Policy support in the US, the EU and other regions, has helped to trigger investments in pilot and demonstration plant, and some commercial-scale advanced biofuels projects have recently started production or are close to inauguration. At the end of 2011 total advanced biofuels nameplate capacity stood at 55 kb/d, with 65% in diesel/ jetfuel type biofuels, and 35% in gasoline replacement fuels (methanol, ethanol, butanol). The actual output from the operating plants is difficult to estimate as utilisation rates are typically well below nameplate capacity in the first years of production.



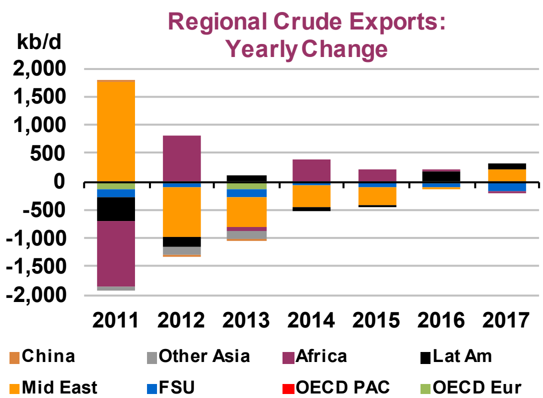
Note: Figure indicates status as of 2Q2012. No new projects have yet been announced after 2015

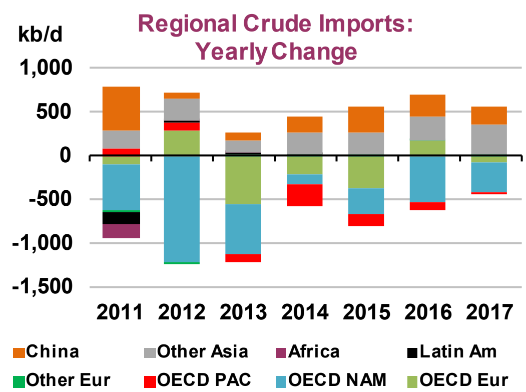
The advanced biofuels sector has moved in a promising direction, but challenges still lie ahead. Public funding provided to advanced biofuels research and production in the last years, for instance under the 2009 American Recovery and Reinvestment Act, is running out. This comes at a time at which companies will need to make substantial investments into commercial-scale production units in order to deliver cost reductions and efficiency gains. The pace of expansion of the advanced biofuels industry in the next years will, therefore, likely depend on continued policy support in form of financial incentives, or specific quotas for advanced biofuels. Based on a conservative assessment of announced projects, advanced biofuels capacity could grow to 180 kb/d in 2017, accounting for 5% of global biofuels capacity. North America will remain the key region for advanced biofuels production over the medium term, followed by Europe and Asia.

CRUDE TRADE

Summary

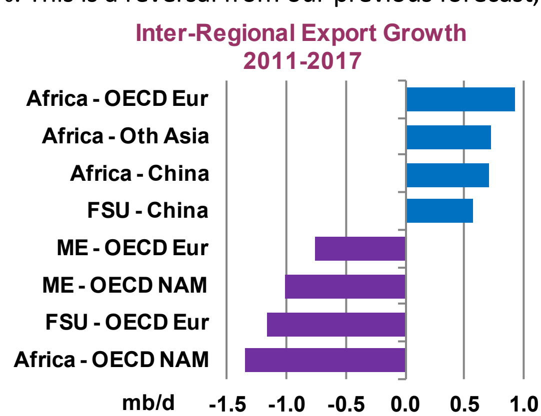
- **Inter-regional trade in crude oil is forecast to fall by 1.6 mb/d to 32.9 mb/d during 2011-2017** as rising US and Canadian production reduce North American import requirements.
- **The Middle East is expected to retain its role as the world's key exporter**, shipping 15.9 mb/d in 2017, but a larger share of production will go to markets east of Suez. Africa will consolidate its role as the number two exporter, increasing shipments albeit from a low Libya-affected 2011 baseline, by 1.4 mb/d to 7.7 mb/d over the forecast period.
- **Non-OECD importers are expected to steadily increase their share of global imports**, reaching 15.4 mb/d in 2017. 'Other Asia' and China drive this growth as their import requirements are set to reach 8.1 mb/d (+1.5 mb/d) and 6.1 mb/d (+1.1 mb/d) by 2017, respectively.





Overview and methodology

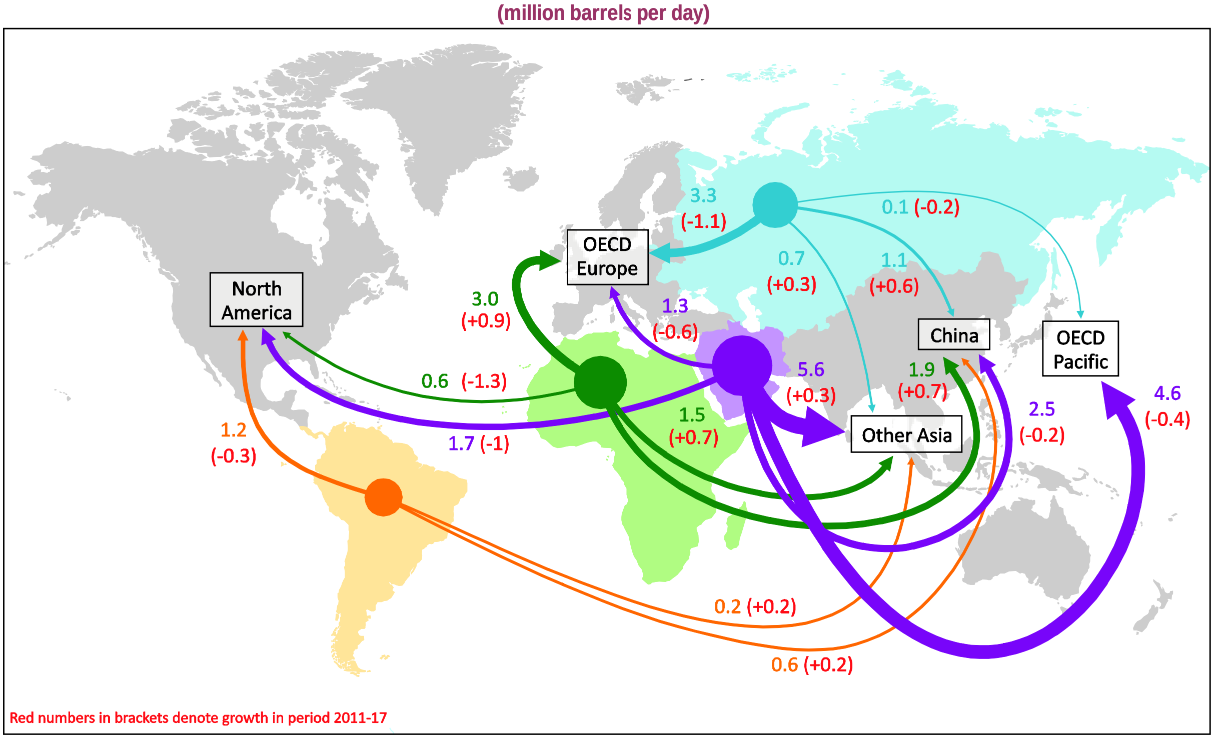
As in the June 2011 *MTOGM,* the evolution of inter-regional global trade flows has been modelled as a function of projected oil production, demand growth and refinery utilisation rates with incremental supplies being allocated based on expectations of refinery capacity expansion. On this basis, the global trade in crude oil and marketed condensate is projected to contract by 1.6 mb/d to 32.9 mb/d in 2017 from 34.5 mb/d in 2011, equivalent to an annual decline of 0.8%. This is a reversal from our previous forecast, which had expected trade to rise by 1.0 mb/d over 2010-2016. For 2016, the end of the previous forecast period, trade volumes are now forecast at 32.8 mb/d, compared to 35.8 mb/d previously. Lower volumes across the forecast arise in part from a more pessimistic demand projection but the trend of decreasing exports results from two supply-side factors: Firstly, and extending earlier trends, more crude oil is being refined close to the wellhead to be subsequently exported as products. Secondly, surging domestic supplies in OECD Americas, led by US light tight oil, are resulting in a cut to the region's import requirement.



On a regional basis, the Middle East will remain the leading oil exporter, shipping 15.9 mb/d in 2017, over twice as much as the next largest region and accounting for 48% of the global export market. Africa, despite a temporary setback in 2011 during the Libyan civil war, is set to consolidate its position as the world's second largest exporter over the outlook period, accounting for 24% (7.7 mb/d) of exports in 2017. In contrast to the previous outlook, FSU crude exports are now anticipated to decline by 600 kb/d to 6.0 mb/d by 2017, as increasing domestic demand cuts into volumes available for export. However, the region's market share will remain stable at slightly below 20%. Latin American shipments are now seen rising to 2.4 mb/d in 2017, a 7% market share and a reversal of the declining trend presented in the last outlook, largely on the delay and cancellation of refinery projects, notably in Brazil. The Middle East was the main source of crude export growth in 2011, largely after regional producers increased shipments to offset Libyan shut-ins. However, for the remainder of the forecast period, African and Latin American exporters account for the lion's share of growth, with Middle East exports not rising until 2017.

Crude exports in 2017 and growth over 2011-17 for key trade routes*

(million barrels per day)



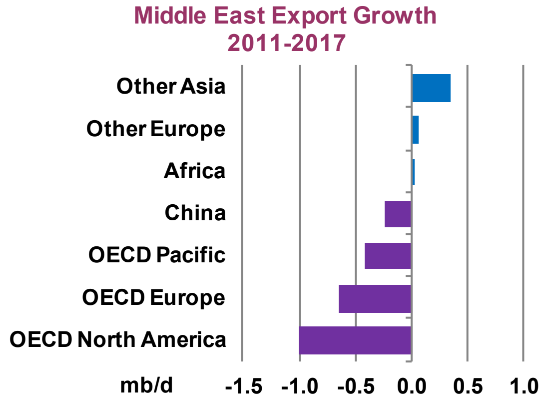
This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

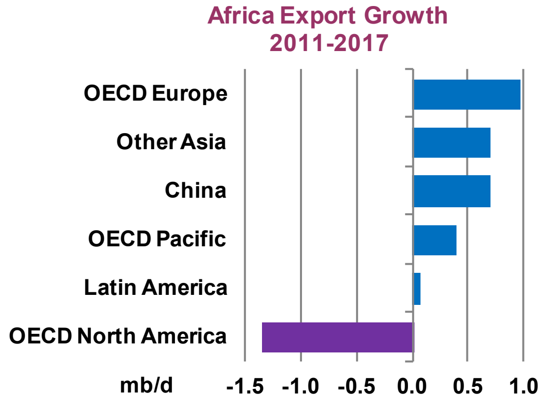
***excludes intra-regional trade**

Regional trade

Although the **Middle East** retains its status as the key oil exporting region, shipments from the region are set to plummet by an aggregate 1.9 mb/d over the forecast, or 1.9% annually. This is the strongest contraction of all net-exporting regions. This follows the construction of 1.4 mb/d of new regional refining capacity, notably in Saudi Arabia and the UAE, which will outstrip both incremental production and expected demand growth, leading to rising product exports. Compared to the previous report, export levels have been lowered across the forecast. 80% of the downward revision stems from lower production prospects in Oman, Syria and Yemen. From a high of 17.8 mb/d in

2011, regional exports are seen falling steadily to a nadir of 15.7 mb/d over 2015-2016 before rebounding to 15.9 mb/d in 2017. Subtle changes are also expected to affect the region's crude buyers over the forecast period. 'Other Asia' will strengthen its position as the region's biggest customer, increasing its share of Middle Eastern exports to 35% (5.6 mb/d) from 30% (5.3 mb/d) in 2011. In contrast, OECD North America, OECD Europe and OECD Pacific are anticipated to curtail Middle Eastern imports by 1.0 mb/d, 650 kb/d and 420 kb/d, respectively. Much of this is due to a weaker demand prognosis, the effect of which will be compounded in North America by rising domestic supply.



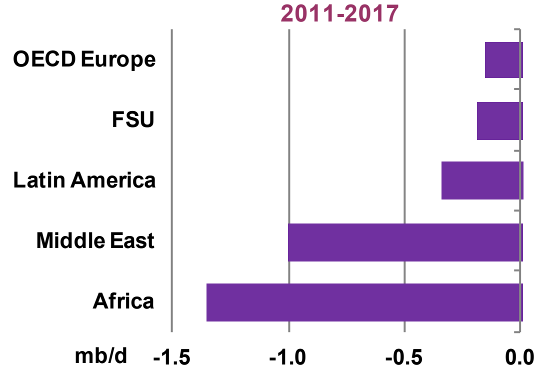


Exports from **Africa** are set to increase by 1.4 mb/d to 7.7 mb/d by 2017. After an initial 800 kb/d boost in 2011 on the back of returning Libyan supply, exports are set to progressively rise over 2013-2015, supported by higher Angolan and Nigerian output, before stabilising by 2016. At 3.4% the region is forecast to have the strongest annual growth of all exporting regions. As most African crudes are traded on spot markets, whereas Middle Eastern streams tend to be sold to term buyers, Africa has historically served as the world's main short-term swing supplier, shifting its crude exports' direction east or west depending on market conditions. Changing import requirements in North America has already reduced imports from West Africa to the US. This report expects OECD Americas to cut African imports by as much as 1.3 mb/d over the outlook period as rising domestic light, sweet crude production displaces Gulf Coast imports of West African grades of similar quality. This shift will largely depend on the expansion of pipeline capacity to move landlocked crude southwards. However, this is still partly subject to regulatory approval (see: *Pipeline Construction: Spotlight Switches to the Atlantic Basin*). Nonetheless, most African crudes will likely remain in the Atlantic Basin since OECD Europe is expected to increase volumes by 900 kb/d to take 3.0 mb/d by 2017. Elsewhere, non-OECD Asian buyers are seen taking 1.4 mb/d more in 2017 than in 2011, with China and 'Other Asia' importing 1.9 mb/d and 1.5 mb/d, respectively.

Aside from the late-2012 expansion of the ESPO line to 1.0 mb/d, no new major infrastructure projects are due on-line over the forecast that are expected to significantly affect international trade. Nevertheless, the **Former Soviet Union** is expected to continue to diversify export destinations with more oil being shipped eastwards. China is seen doubling its imports of regional crudes to 1.2 mb/d while 'Other Asia' is expected to take 300 kb/d more oil in 2017. In contrast, mature OECD markets are projected to reduce their imports from the region. Indeed, OECD Pacific could see its imports from the FSU fall to 100 kb/d by 2017. Nonetheless, OECD Europe will remain the region's largest customer in 2017 accounting for 55% (3.3 mb/d) of total FSU exports, however, this is 1.2 mb/d lower than 2011 when regional refiners took 67% of total FSU exports. Much of this reduction is likely to manifest itself in lower shipments via the Druzhba pipeline and Black Sea terminals, the former has already seen lower flows as producers divert oil towards more profitable Baltic outlets.

Latin America is expected to experience modest annual export growth of 1.3% over the forecast, this is in contrast to the June 2011 *MTOGM* where exports were seen contracting. The main difference is that 700 kb/d of refinery capacity expansions, notably in Brazil, have been delayed or cancelled. Despite an overall 200 kb/d rise, export volumes remain volatile over the forecast: Shipments are initially set to tumble by 200 kb/d over 2011-2012 in line with rising refinery throughputs. Following a period of stability over 2013-2015, they are seen to rise sharply by 400 kb/d to peak at 2.4 mb/d in 2017 on rising Venezuelan and Brazilian output. OECD Americas has traditionally been the region's main customer and this is set to continue, although due to its changing energy landscape the region is expected to progressively curtail its regional imports over the forecast so that in 2017 it will take 1.2 mb/d, compared to 1.6 mb/d in 2011. It is assumed that lighter Brazilian crudes will remain in the Atlantic Basin while incremental supplies of heavy, sour Venezuelan grades will likely be refined in complex Asian refineries. Indeed, by 2017, 35% of regional exports are seen heading to Asia, likely facilitated by the Panama Canal expansion due to be completed in 2014 and allowing Suezmax sized vessels to pass from the Atlantic to the Pacific basins. As such, China and 'Other Asia' are each seen upping their imports of Latin American crudes by 200 kb/d over the forecast.

OECD North America Import Growth 2011-2017

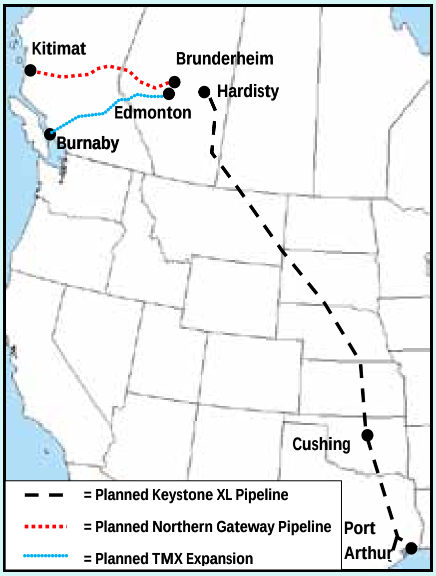


Overall, the **OECD** is anticipated to decrease its imports by a staggering 4.3 mb/d (-3.6% annual growth) over the forecast due to a combination of decreasing demand prospects, refinery closures and, in the case of OECD North America, growing regional supply. On an annual basis throughout the forecast, imports into OECD North America, OECD Europe and OECD Pacific are projected to contract by 9.5%, 1.4% and 1.3%, respectively. **Non-OECD importers** are set to increase their share of global imports from 37% in 2011 to 47% in 2017 with imports growing by 2.7 mb/d to reach 15.4 mb/d by 2017 as developing economies need to import more to satisfy rising domestic demand. Asia looks will drive this growth, 'Other Asia', led by India, is expected to increase imports by 1.5 mb/d, equating to 3.5% annual growth, to 8.1 mb/d by 2017. Meanwhile, China's import requirement is anticipated to rise by 1.1 mb/d (+3.3%) to 6.1 mb/d by 2017.

Crude tanker markets are unlikely to see much benefit from the trends outlined above. Given the current vast oversupply in the fleet and lack of planned vessel scrappage, even an uptick in tonne miles resulting from an increase in long-haul shipping from the Atlantic to Pacific basins is unlikely to provide prolonged upward momentum to freight rates. Therefore, as has been the case over the past two years, any rate spikes will likely result from short-term demand and supply imbalances. In contrast, product tankers will likely see an increase in demand with rising product trade as refining moves closer to the wellhead.

Pipeline construction: spotlight switches to the Atlantic Basin

Selected, Planned North American Pipeline Infrastructure



The rapid growth in Canadian oil sands and US light tight oil production in inland locations remote from markets has put the construction of new pipelines back on political agendas. In the last 20 years, the FSU has dominated the construction of large oil pipeline systems, first with the Baku-Tbilisi-Ceyhan (BTC) line and the Baltic Pipeline System (BPS), then by developing the East Siberia–Pacific Ocean pipeline (ESPO) and the BPS-2. While the spotlight is now moving to the Atlantic Basin, there are plans to continue development in the FSU over the medium-term. Other important projects are located in Latin America and South Asia. However, regardless of where these projects are located, their approval and construction will impact heavily on producers' ability to successfully market their crude.

Pipelines are generally considered the safest way of moving oil over long distances, but their high construction costs and long lead times and their significant environmental, commercial and geostrategic implications can make their the construction a contentious issue. That has certainly been the case of the $7.0 billion Keystone XL pipeline proposed by TransCanada to deliver 700 kb/d of mainly heavy oil from Alberta to the Cushing, Oklahoma storage hub and onwards to US Gulf Coast refineries**.**

Although discussed in more detail in *Transport Bottlenecks to Dent Canadian Unconventional Growth*, the advantages of the project include: support to US and Canadian economic growth, decreasing reliance on heavy, sour imports from less stable states such as Venezuela and the de-bottlenecking of US Midwest crudes. However, opponents cite environmental concerns, both in terms of potential spills in sensitive areas on the line's proposed route, and in terms of broader policy choices, specifically arguing against encouraging oil sand production, seen as having a high carbon footprint.

Early approval of the line was held up after the US Government rejected its proposed route in 1Q12 citing that it did not have sufficient time to determine whether the project in its current state was in the national interest given environmental concerns. The administration did not unequivocally state its opposition to the line, however, prompting TransCanada to submit a revised route proposal avoiding an ecologically sensitive area in Nebraska. A final decision on the revised route will not be taken until mid-2013 and if approved, the pipeline would likely not be completed before 2015 at the earliest.

Keystone XL is not the only pipeline under consideration to market Canadian crude, nor is it the only project considered to move crude from the US Midwest to the Gulf Coast. Regardless of the outcome of the Keystone XL permitting process, Canada is actively assessing a number of alternative projects to ship Alberta oil sands production to the west coast for use there or for onward delivery to Asia. Firstly, Enbridge's $5.5 billion, 1,177 km Northern Gateway project is currently in the initial consultation stage and if approved, could be inaugurated in late-2017 with a capacity of 525 kb/d. However, the chance of slippage to 2019 or even later appears high. Secondly, and the most advanced of the projects, is Kinder Morgan's $4.1 billion Trans Mountain Express (TMX) expansion project which could have the potential to move 750 kb/d from Edmonton, Alberta to Burnaby on the Pacific coast. If approved, construction could begin as early as 2016.

Pipeline construction: spotlight switches to the Atlantic Basin (continued)

Other plans to move Canadian crude to markets include reversing and/or expanding existing pipelines. These include a proposal to reverse Enbridge's Line 9 currently running from Montreal to the refining and petrochemical hub of Sarnia, Ontario, and an ancillary pipeline currently running from Portland, Maine to Montreal. Similarly, in the US, the 150 kb/d Seaway pipeline was reversed in mid-2012 and is slated for expansion to 400 kb/d by mid-2013 and subsequently to 850 kb/d by late 2014. The reversal of the line is in effect backing out light, sweet imports of coastal and imported grades into the Midwest. In addition, in the face of pipeline delays, rail movements of crude in the US and Canada have gained considerable momentum reaching close to 500 kb/d. The impact these infrastructure developments will have on Canadian and US oil production is discussed in *Transport Bottlenecks to Dent Canadian Unconventional Growth*.

Outside of North America, the FSU remains at the forefront of oil infrastructure development – especially if planned gas infrastructure is also included. Aside from the ongoing expansion of the Caspian Pipeline Consortium pipeline (CPC) to 1.3 mb/d, most forthcoming projects will be located in Russia. Late 2012 will see the launch Transneft's only large scale project over the forecast: The expansion of the ESPO-2 system connecting Skovorodino with Kozmino (previously connected by rail) which will increase capacity to 1 mb/d. Most subsequent Transneft projects will be smaller in scale than the near-5,000 km ESPO or the 1,170 km BPS-2. These include connecting frontier fields in remote Eastern Siberia and the far North to their network and expanding product transportation capacity.

While those projects continue apace, the recent expansion of the Transneft network has created excess export capacity, allowing producers flexibility in adjusting their crudes' export routes based on market conditions. As Russian crude production is forecast to remain relatively stable until 2017, this capacity overhang is likely to remain. At present, producers favour shipping oil via Primorsk and Ust Luga, which offer higher netbacks than via the Druzhba pipeline. Unless the Druzhba becomes more profitable for producers, more oil will likely continue to be shipped by sea, primarily to customers outside Europe.

The decrease in summer Arctic sea ice is opening the northern sea route to Russian producers seeking to reach Pacific Basin markets. But to take advantage of this opportunity would require upgrading pipelines feeding Baltic terminals such as Murmansk, Indiga and Varandey. Although such expansions will likely not be operational by the end of the forecast, some construction will undoubtedly take place. Previous Russian projects such as ESPO have shown that although some environmental opposition exists, especially from indigenous peoples, projects can be completed quickly and often ahead of time. The vastness of Russia is also an asset to planners since pipelines can be easily routed far from population centres and are therefore not as contentious as in more densely populated countries.

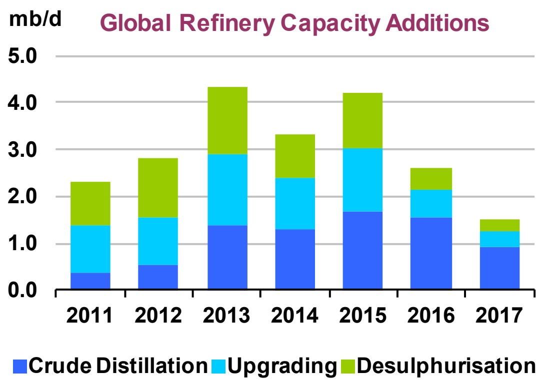
Elsewhere, major pipeline projects are either being constructed to bring new oil to market from producers undergoing rapid expansion or to supply states experiencing strong economic growth. In the former group, Latin America is the centre of pipeline construction reflecting onshore production growth in Colombia and potentially Venezuela. One of the most contentious projects is the near-1000 km long, 450 kb/d Bicentennial pipeline in Colombia being built to ship incremental supplies to the Atlantic Basin. Unlike previously outlined projects, issues here concern security in the face of threat from the Revolutionary Armed Forces of Colombia (FARC) as pipelines are often viewed as symbols of state economic power and as such are often targets for sabotage. In Columbia where the route runs through FARC territory this threat has so far manifested itself as kidnappings of workers rather than bombings targeting infrastructure. The line is heavily secured, although with phase 1 due online in 4Q12, and the FARC preferring to attack operational lines, the threat of attacks is likely to escalate upon start-up.

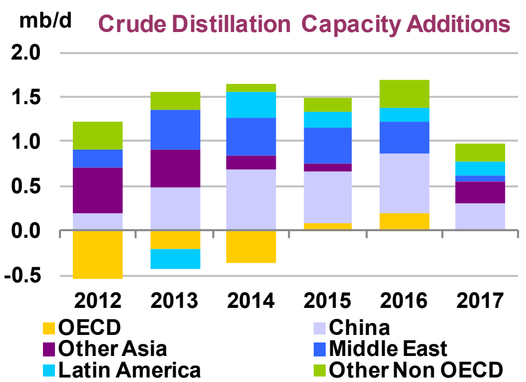
The 771 km Myanmar – China pipeline is presently in the final stages of construction, when completed this line will have the capacity to supply 440 kb/d of crude unloaded at Maday Island in the Bay of Bengal to refiners in China's landlocked Yunnan province. Although not likely to alter regional trade flows, the Chinese administration views it as a vital cog in China's energy security strategy since it will cut seaborne transit times and bypass the Malacca straights. Despite opposition on environmental and social grounds, its strategic benefits led to its prompt approval by both countries' administrations.

REFINING AND PRODUCT SUPPLY

Summary

- **Global refinery crude distillation (CDU) capacity is set to increase by close to 7.0 mb/d from 2011 to 2017, with expansions from 2013 onwards exceeding oil demand growth.** This marks a reversal from the last three years, when oil product demand grew faster than capacity. Upgrading and desulphurisation capacity are expected to grow by 5.9 mb/d and 5.5 mb/d, respectively.
- **The reallocation of refining capacity from mature markets to emerging and newly industrialised economies continues, with contraction in the OECD partly offsetting expansions elsewhere.** More than half of the new CDU capacity will come from non-OECD Asia, most notably China. Significant additions are expected in the Middle East, while restructuring in the OECD continues.
- **Refinery utilisation is expected to slip to 79% on average in 2017, from 83% in 2006-2008, led by lower OECD rates**. New supplies bypassing the refinery system compound the impact of refinery expansion. To return to 2006-2008 utilisation rates, an extra 4.4 mb/d of CDU capacity would have to be shut or completion deferred compared to current plans.

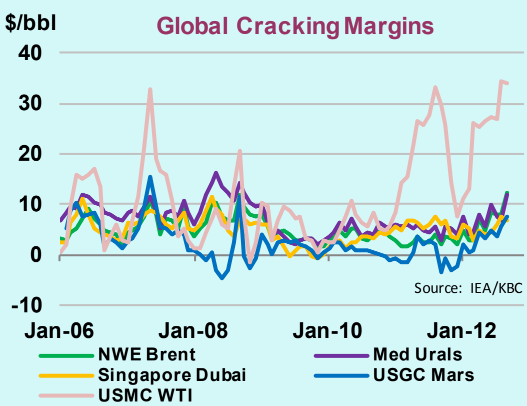


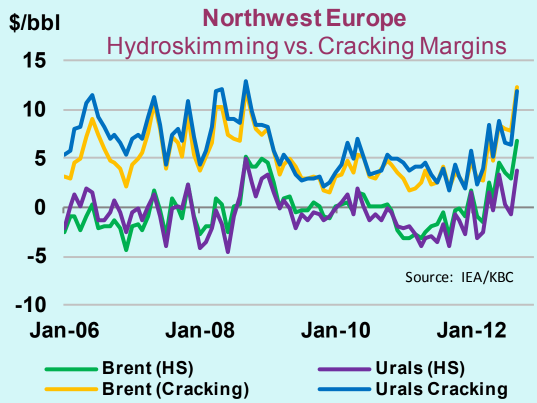


- **A recent improvement in global refining margins may prove temporary.** Unless more capacity is shut, projects delayed or cancelled, or demand surprises to the upside, margins will again come under pressure after a strong recovery in 2012.
- **OECD refinery rationalisation intensified over 2012, as completed and committed shutdowns cut capacity by 1.3 mb/d since our *December Update*.** Total refinery closures now amount to 4 mb/d since the economic downturn of 2008, led by a 1.7 mb/d cut in Europe. Continued OECD demand contraction will call for additional industry consolidation before 2017.
- **Despite the increase in refining capacity, middle distillate markets remain tight throughout the forecast period.** Product balances point to continued middle distillate tightness towards 2017, as diesel, gasoil and kerosene lead demand growth. Gasoline markets will remain under pressure, as North America achieves self-sufficiency while surpluses remain in Europe, the FSU and Asia. Fuel oil markets could also tighten, as decline in end-user demand has lost momentum, while the feedstock slate is becoming lighter and refiners upgrade plants to curb fuel oil output in favour of higher-value products.

2012 more than a marginal recovery

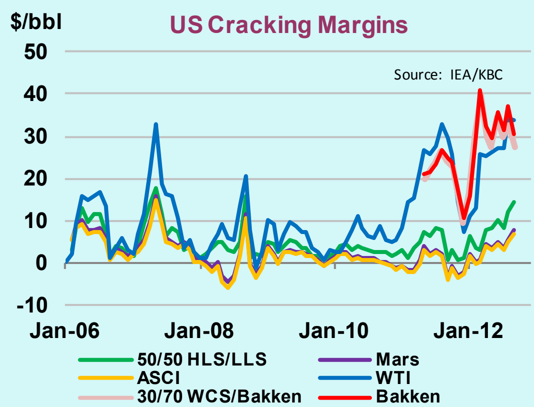
With the September issue of the *Oil Market Report*, the IEA introduced a new set of global indicator refinery margins for primary product markets in Northwest Europe, the Mediterranean, the US Gulf Coast, the US Midcontinent and Singapore. The margins are based on refinery yields developed by KBC Advanced Technologies and include refinery fuel costs but exclude other variable costs, depreciation and amortisation. Consequently, reported margins should be taken as an indicator, or proxy of, changes in profitability for a given refining centre, not of actual net cash margin – which will vary depending on size and complexity of the refinery, utilisation rate, local wages, employment and other regulations.





Since the beginning of this year, refining margins around the world have staged an impressive recovery from end-2011-lows. Europe, whose refinery industry in recent years has been pressured by declining demand and surplus capacity, saw margins improve sharply as regional industry rationalisation helped tighten product markets and lift product cracks. In September, Brent cracking margins reached their highest levels since at least 2006 in Northwest Europe. Even simple hydroskimming margins have performed relatively well, with Northwest Europe Brent attaining positive levels for a fifth consecutive month in September, resulting in high regional throughput rates.

While the recent recovery in European margins was both impressive and much called for, it pales when compared to US refinery profitability. US refiners benefit from not only discounted regional crude supplies but also cheap natural gas used as refinery feedstocks. In 2012, Gulf Coast margins all improved on higher diesel and gasoline crack spreads, especially on the back of refinery outages in the Gulf and Venezuela over the summer. Heavy/Light Louisiana Sweet (HLS/LLS) cracking and coking margins both attained close to $15/bbl at this time. However, even the US Gulf Coast margins fall short of the levels recorded in the US Midcontinent. There, margins calculated for refineries processing WTI, WCS and Bakken currently hover in a range of $25-$30/bbl. This premium enjoyed by the Midcontinent refiners is due to a persistent LLS-WTI differential since early 2011. Refineries processing Bakken crude have been enjoying a premium over those processing WTI in 2012, as the price of Bakken, despite its higher quality, has had to be discounted due to logistical constraints. In September, this trend reversed however, as Bakken regained its premium to WTI.



The recent improvement in refinery profitability is expected to be short-lived, with margins falling back from current highs in most refining centres, as localised product tightness ease. After three years of shrinking spare capacity, global refinery additions are set to exceed demand growth from 2013 onwards.

Refinery investment overview: diverging trends continue

Global refinery expansion plans are seen adding 7.0 mb/d of crude distillation (CDU) capacity post 2011, reaching 100.5 mb/d in 2017. Non-OECD growth is partially offset by an acceleration of refinery closures in the OECD, which are now seen shedding more than 1.1 mb/d of capacity in the same period.

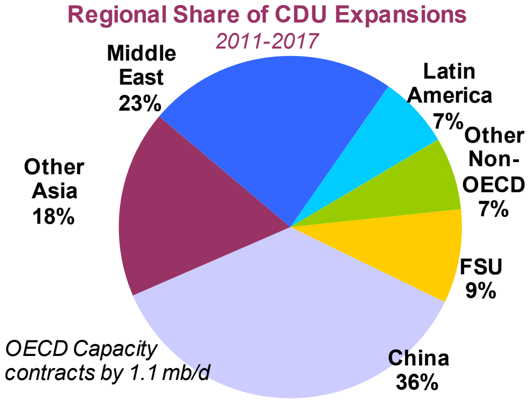
Global Crude Distillation Capacity[1,2]

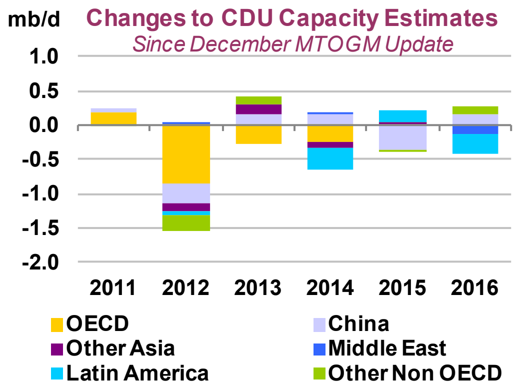
(million barrels per day)

	2011	2012	2013	2014	2015	2016	2017	2017-2011
OECD North America	21.4	21.2	21.3	21.4	21.4	21.4	21.4	0.0
OECD Europe	15.6	15.1	14.8	14.8	14.8	15.0	15.0	-0.6
OECD Pacific	8.5	8.5	8.4	8.0	8.0	8.0	8.0	-0.5
FSU	8.3	8.4	8.6	8.6	8.8	9.0	9.0	0.7
China	10.1	10.3	10.8	11.5	12.1	12.8	13.1	2.9
Other Asia	10.9	11.4	11.8	12.0	12.1	12.1	12.3	1.4
Middle East	8.1	8.2	8.7	9.1	9.5	9.9	10.0	1.9
Other Non-OECD	10.7	10.8	10.6	11.0	11.2	11.4	11.8	1.1
World	**93.5**	**94.0**	**95.0**	**96.4**	**97.8**	**99.5**	**100.5**	**7.0**

1. Includes Condensate Splitters 2. New OECD members Chile and Israel are accounted for in Latin America and the Middle East, respectively

Within the non-OECD, Asia accounts for over 50% of additions, led by China, which is still expected to expand its distillation capacity by some 2.9 mb/d despite a more subdued outlook for domestic demand growth. 'Other Asia', dominated by India, is set to add 1.4 mb/d of capacity in the period. The additions are concentrated in the earlier years of the forecast period; indeed a large portion of the new capacity has already been commissioned earlier in 2012. Major expansions are also taking place in the Middle East, with at least two mega projects in Saudi Arabia and one in the United Arab Emirates contributing to 1.9 mb/d of aggregate regional incremental capacity. Identified global upgrading and desulphurisation projects add 5.9 mb/d and 5.5 mb/d in the same period, respectively.



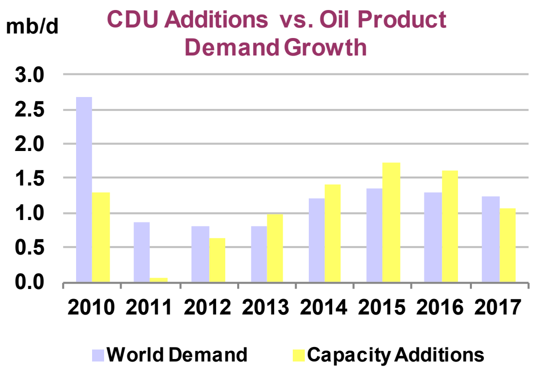


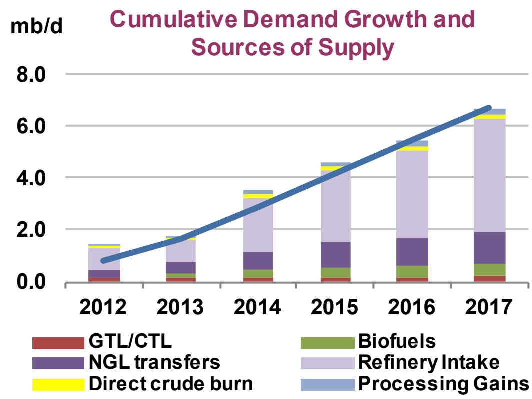
Since our December MTOGM update, our forecast of global additions to crude distillation capacity for the 2011-2016 period has been lowered by 2.4 mb/d. OECD economies account for the bulk of the adjustment, as industry restructuring continued at a brisk pace in 2012. OECD refining capacity expansions were reduced by almost 0.9 mb/d in 2012 alone, with additional shutdowns in all regions. Further closures have been announced for 2013 and 2014, in both Europe and the Pacific.

In the non-OECD some project delays have been incorporated to 2012 capacity estimates, and further out, some projects have slipped beyond the timeframe of the report or cancelled altogether. Expectations of downstream investments in Latin America are a case in point. Brazil's Petrobras, in a recently revised strategic plan, revisited all its downstream projects, either delaying or postponing them beyond the timeframe of this report. Expectations of incremental capacity in the region have been adjusted accordingly. While Chinese refinery expansion projects are mostly unchanged overall, some project delays, in part due to lower demand growth, take expansions to 2.9 mb/d for the 2012-2017 period, compared with 3.6 mb/d in 2010-2016 as published in our June *MTOGM*. More Chinese refinery projects could be delayed or cancelled if recent signs of slowdown in the Chinese economy, and therefore in Chinese domestic demand, were to be confirmed.

Refinery utilisation and throughputs: spare refining capacity on the rise

Spare refining capacity is expected to increase over the forecast period as planned additions outpace growth in end-user demand, albeit not as rapidly as in previous outlooks. Overall, firm net capacity additions are forecast at 7 mb/d, slightly ahead of demand growth, now assessed at 6.7 mb/d. But while industry rationalisation, project delays and cancellations are expected to blunt the impact of new capacity, refined hydrocarbons are playing a diminishing role in meeting incremental demand. As much as a third of demand growth is set to be met by supplies that will by-pass the refining system altogether, including biofuels, NGLs, CTLs/GTLs and crude for direct burn. As a result, global spare refinery capacity is expected to post a net increase of close to 3 mb/d, reversing a three-year contracting trend – unless, of course, more capacity is shut or more projects are delayed or cancelled.

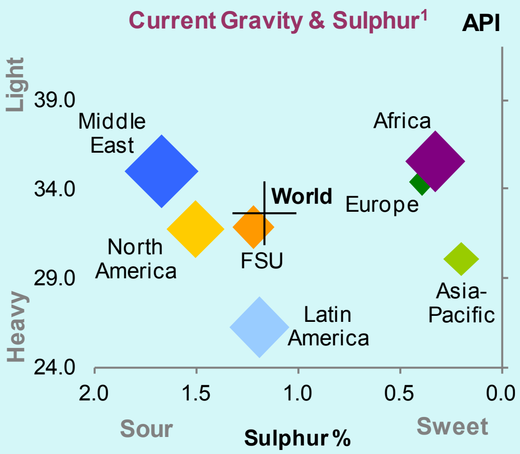




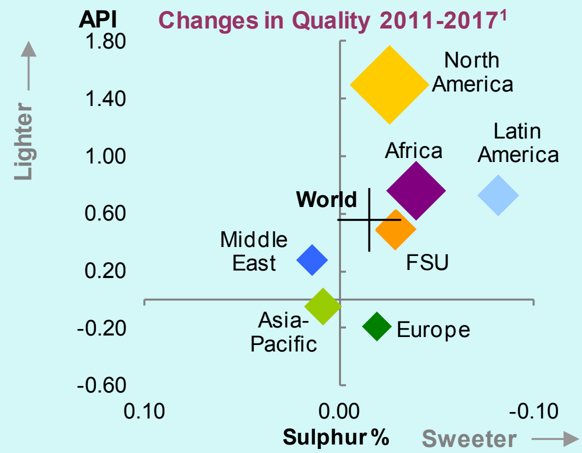
Rebounding spare refining capacity will in turn cause global refinery utilisation rates to fall to 79% in 2017, from 81% in 2011 (and 83% in 2006-2008). OECD refinery utilisation fails to rebound from low levels seen since the collapse of demand in 2009, though the decline is less dramatic than previously estimated, thanks to recent strong rates in North America and Korea, and refinery shutdowns in Japan and Europe. Non-OECD refiners sustain higher utilisation rates than the OECD, supported by fast-growing local demand and exports. New-built plants are often large and highly sophisticated, and benefit from better profitability than older legacy assets in mature markets. This forecast assumes that Chinese utilisation rates will fall over coming years, unless capacity expansions are scaled back. Alternatively, if China decides to build all planned refineries and run new plants at current utilisation rates, the country could grow in importance as a product exporter in the next five years. In this case, crude shipments to other regions and utilisation rates elsewhere would be significantly reduced.

Refinery feedstock grows lighter and sweeter

As in previous reports, the evolution in feedstock quality has been projected on a geographic basis of region of origin, not accounting for inter-regional trade flows. In contrast to the June 2011 *MTOGM*, world refinery feedstock is expected to become progressively lighter and sweeter throughout the forecast period, thanks to rising condensate and US light, tight oil supplies. Weighted average API gravity is projected to increase steadily from 32.7° to 33.2° over the outlook period, while sulphur content falls modestly from 1.17 % to 1.16%. This general trend masks some volatility over the forecast period, however. The steepest fall in sulphur content is projected to occur over 2012-2013, driven by a rapid ramp-up in US light, tight oil and Middle Eastern condensate production. Sulphur content then steadies over 2014-2015 before rising again with higher supplies of heavy, sulphurous Middle Eastern crudes and Canadian bitumen.



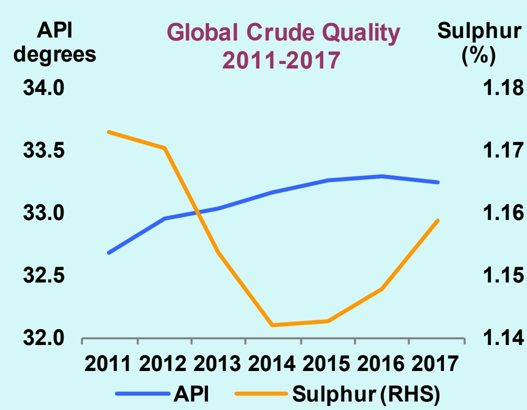
1 Symbols proportionate in size to regional production.



1 Symbols proportionate in size to production production growth

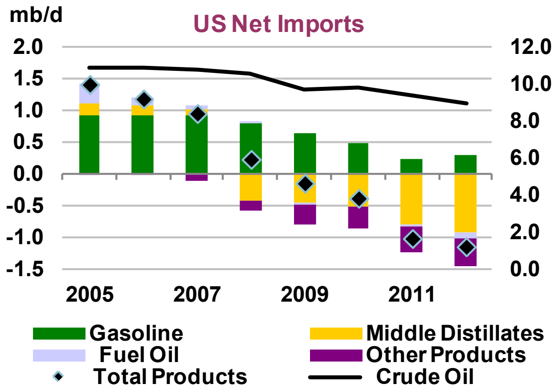
The trend towards lighter, sweeter supply is expected to be most pronounced in North America. Faster-than-expected growth in US light, tight oil, now forecast to rise by 2.4 mb/d from 2011 to 2017, is the main reason for the reversal of our forecast of crude quality, which previously projected that rising production of heavy, sour Canadian crude would lift average sulphur levels and lower gravity. Not only has the forecast of US light, tight oil production been adjusted upwards since the last report, expected Canadian heavy crude has also been reduced slightly.

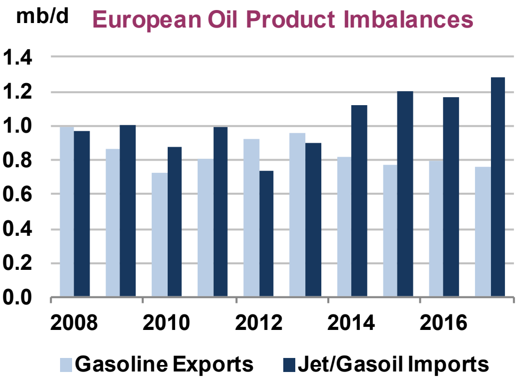
The lightening of feedstock quality will not be confined to North America. Latin American supply is also expected to become lighter due to rising Brazilian pre-salt production and lower growth prospects for heavy Venezuelan oil. Meanwhile, increasing supply from Angola and Nigeria and recovering Libyan production following the 2011 civil war are forecast to raise the API gravity of African supplies. FSU liquids will become lighter in line with increases is condensate production and from frontier Eastern Siberian fields. Even Middle Eastern supplies are projected to become modestly lighter by 2017 on increasing condensate production, notably from Qatar and Kuwait, and higher volumes of light Iraqi crudes. However, towards the end of the forecast period, this is set to be tempered as Saudi Arabia's Manifa heavy oil project come on stream. Supplies from OECD Asia Oceania and Europe are forecast to become heavier, the former due to rising production from the Australian Pyrenees and Van Gogh heavy oil projects and the latter from declining production at mature North Sea fields.



Product supply balances: what a difference a year makes

Global oil product balances will differ significantly by 2017 from both the current situation and earlier expectations of future changes. Most notable is the transformation of the North American market, not only with respect to crude oil and NGLs, but also to refined product markets. OECD North America, a net importer of some 900 kb/d of refined products in 2000, swung to net exporter status in 2009, and by 2011 had a surplus of some 600 kb/d. US product exports led the shift, averaging 2.6 mb/d in 2011, or more than 1 mb/d on a net basis, partly offset by rising imports from Mexico. North American gasoline imports could disappear entirely by 2017, while net distillate exports would shrink from current levels. Please note that in the refining, product supply and trade discussion, new OECD members Chile and Israel are included in Latin America and the Middle East respectively.





The transformation of European oil markets is equally startling. OECD European net imports of oil products were more than halved during the last decade, to just over 500 kb/d in total in 2011. The region's middle distillate imports averaged 830 kb/d, offset by gasoline exports of 820 kb/d, while other products amounted to 500 kb/d of net imports. A structural shift in demand, from gasoline to diesel, is continuing to cause refiners problems as they have to find outlets for surplus gasoline production, often at discounted prices. So far, North America remains the largest purchaser of gasoline, though exports to Africa and the Middle East are on the rise. The FSU is the main supplier of refined products to Europe with combined exports of 1.3 mb/d in 2011. Towards 2017, Europe's gasoline surplus will remain just under 0.8 mb/d, while middle distillate imports could surge to more than 1.3 mb/d as a result of capacity rationalisation and lower throughputs.

In the non-OECD, the FSU will remain the largest product exporter globally, with increasing export potential of both light and middle distillates through 2017 while refinery upgrades cut into fuel oil supplies. The Middle East could also increase its light and middle distillate exports, as incremental supplies initially surpass strong regional demand growth. Increased production of light products will partly result from fuel oil upgrading, however, creating a large fuel oil deficit for the region. Should the Middle East choose not to procure fuel oil from other regions, or substitute its use for crude oil or other fuel sources in power generation, local refiners could in theory opt to lower utilisation of upgrading units and rebalance production to regional needs. Here we assume that refinery yields will maximise output of higher-value products. Asia, and in particular China, remains the main wild card, given the relatively large role of government policy in shaping industry outcomes in the region. If China goes ahead with its ambitious refinery capacity expansion programme despite weaker demand, government policy regarding construction permits, oil pricing and import and exports will determine whether the country develops into a major global oil product supplier.

Products supply modelling – seeking the pressure points

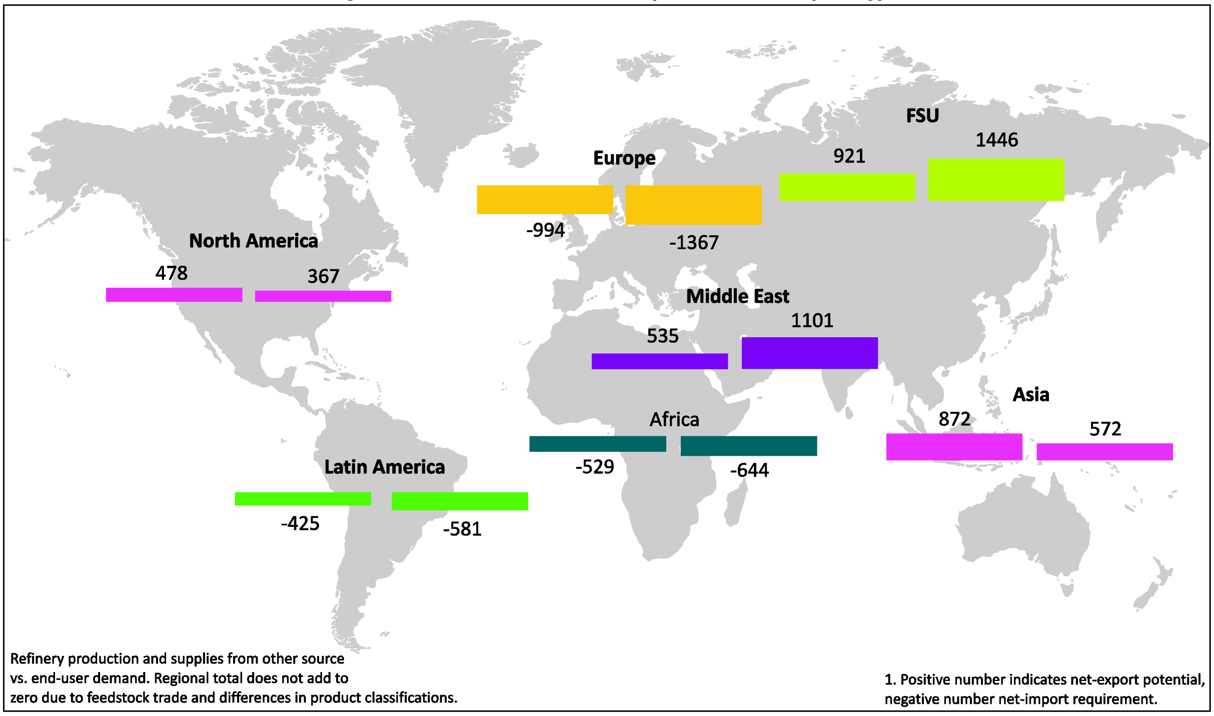
Our approach to modelling refined product supply is not designed to optimise the global/regional system, but rather to highlight where pressures may emerge within that system in the 2012-2017 timeframe. A number of simplifying assumptions underpin the analysis, changes to any one of which generate a significantly different outcome. The aim is to identify any mismatch between current and planned refining capacity and expected changes in crude feedstock quality and availability given current expectations of product demand growth. The model uses our Base Case demand profile, with global refinery throughput levels feeding off a balance whereby non-OPEC supply is maximised and OPEC acts as swing supplier. The model also assumes that the utilisation of higher value crude capacity is maximised. Finally, we also assume an operational 'merit order', with crude preferentially allocated to demand growth regions and more complex refining capacity. Our approach is non-iterative, when of course in reality the emergence of imbalances would tend to force changes in operating regime, crude allocation and ultimately capacity and investment levels themselves.

Middle distillates markets remain tight

Middle distillates markets will remain the tightest part of the barrel in the medium term, despite a slightly weaker forecast for global gasoil demand growth since earlier outlooks. As highlighted in the demand section, middle distillates, including gasoil/diesel and kerosene, are expected to account for 46% of total demand growth through 2017. While this is less than the +60% share envisaged earlier, it remains a challenge to global refiners, whose total middle distillate yield is currently assessed at only 39.4%. Given committed investments in upgrading units, the distillate yield could increase to 40.3% in 2017.

Product supply balances – gasoil/kerosene

Regional Balances in 2011 and 2017[1] (thousand barrels per day)



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

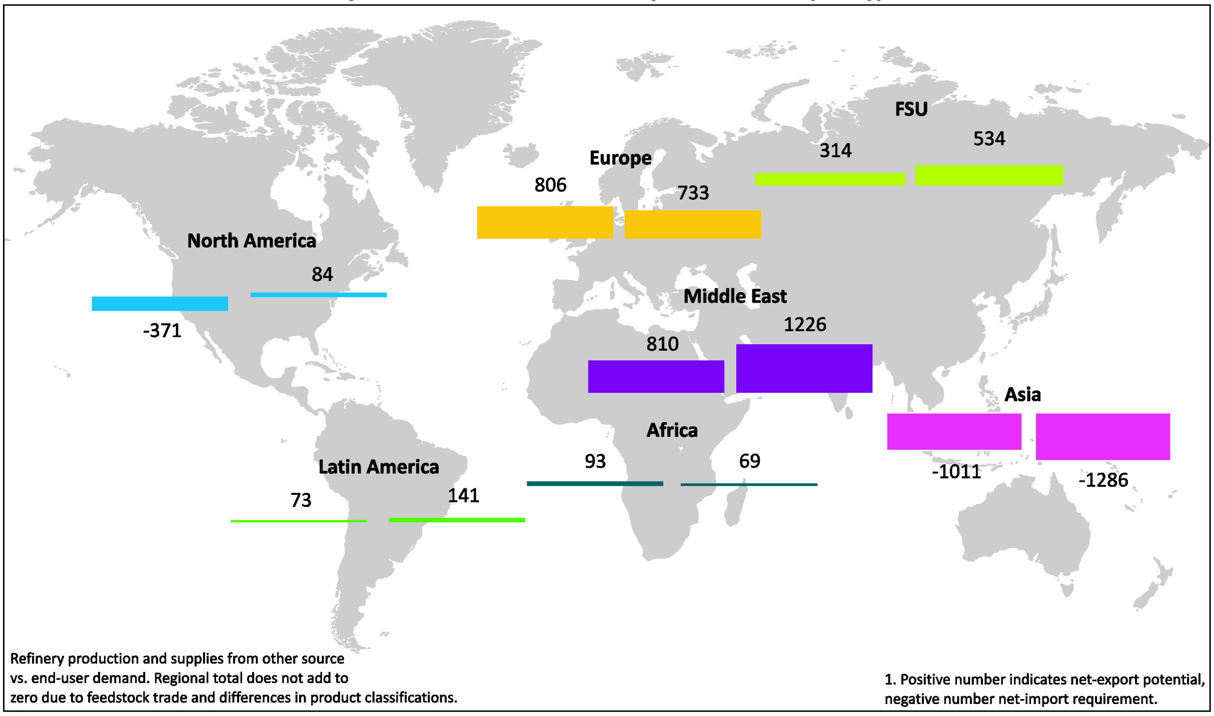
Regionally, Europe has the largest deficit in middle distillate supplies, and the region's net-imports for diesel, heating oil and jet kerosene averaged just under 1.0 mb/d in 2011. The lion's share of the imports came from the FSU, but increasing volumes were also sourced from North America, the Middle East and Asia, while smaller shipments to Africa provided some offset. Looking towards 2017, Europe's distillate deficit will most likely rise, with our base case scenario pointing to net imports attaining levels closer to 1.4 mb/d at the tail-end of the period. Additional volumes could be sourced from the FSU and the Middle East, as both regions could see higher export potential when refinery upgrades and new constructions are completed. North America should retain some export potential, although shrinking from 2010/2011 levels as demand growth outpaces additional production. US refiners are already shifting operating modes towards increased distillate yields to take advantage of favourable economics, and we assume this trend continues in the medium term. Increased import requirements will also come from Africa and Latin America, while Asian surpluses are set to decrease. The decline is less dramatic than seen in previous reports; as distillate demand growth in both China and other non-OECD Asia have been revised down from earlier reports, to 0.6 mb/d each, outpacing expected additional refinery outputs.

Light distillates moving towards oversupply

Light distillates comprise gasoline and naphtha. While naphtha can be used as a petrochemical feedstock, a chemical input to solvents and as a diluent for bitumen mining, its main use remains as a feedstock for producing high octane gasoline. As naphtha blending into gasoline depends on a multitude of factors at any given time, we treat naphtha and gasoline together in our product supply modelling. The naphtha balance is further complicated by the fact that it is produced both as a component of natural gas liquids (NGLs) and as conventional refinery output and the reporting of both its origin and use is often erroneous. Due to the combination of higher naphtha supplies derived from NGL fractionation, increased ethanol blending and structurally declining gasoline demand in mature OECD markets, the global naphtha/gasoline balance looks increasingly prone to surplus going forward.

Product supply balances – gasoline/naphtha

Regional Balances in 2011 and 2017[1] (thousand barrels per day)



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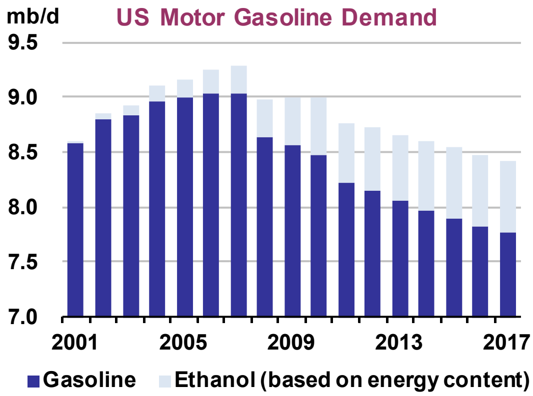
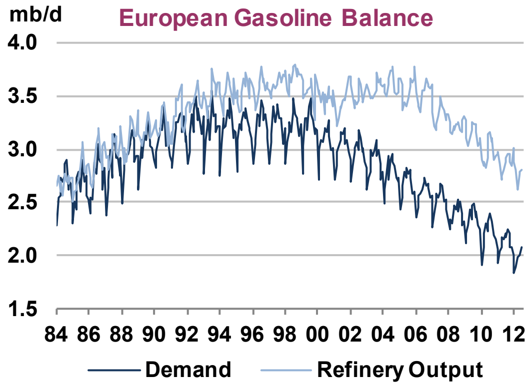
As noted above, the most significant change to global product balances derives from the changing North American energy landscape. The US is moving from being the world's largest importer of motor gasoline to a position of much greater self-sufficiency, balancing East Coast imports with growing Gulf Coast exports to neighbouring Mexico and several Latin American countries. North American net gasoline imports fell to roughly 600 kb/d in 2011 from a 2006 peak of 1.08 mb/d, due to several factors. Firstly, US gasoline demand peaked in 2007, and is expected to continue to edge lower through 2017. Secondly, ethanol supplies have displaced a significant share of oil-based gasoline, as mandated under the US Renewable Fuels Standard, cutting into East Coast import requirements. Thirdly, US Gulf Coast and Midcontinent refiners enjoy a competitive advantage in the form of discounted crude feedstock (WTI and linked crudes) and refinery fuel (natural gas) and have been running at a relatively robust rate. Assuming that either East Coast refineries continue to tap into Midwestern crude supply and new sources of cheap natural gas, or that inter-regional transportation bottlenecks between the Gulf Coast and East Coast markets can be overcome, North America has the potential to become fully self-sufficient by 2017, and potentially even a marginal net gasoline exporter.





The decline of North American gasoline imports is a challenge for European refiners, which traditionally have provided around 70% of regional imports. Since the mid-90s, the dieselisation of the European car fleet and shrinking demand have caused Europe to become increasingly oversupplied for gasoline. Only in 2006 did European refiners start reducing gasoline output, mostly on lower crude throughputs. While investments in technology and equipment have increased diesel yields at European plants, this shift has mostly taken place at the expense of fuel oil: while the average annual gasoil yield at European refineries increased to 39.2% in 2011 from 34.4% in 2000, gasoline yields only decreased from 22.6% to 20.8% in the same period.

In 2011, OECD Europe exported some 800 kb/d of gasoline. In addition to North American markets, Africa and the Middle East also provided outlets. As the North American import market is set to shrink further towards 2017, while European surpluses will continue to increase unless further refinery closures occur, Europe will likely struggle to find new markets. African import needs will increase modestly, but more supplies are also coming from the Middle East. Trade will continue between the Middle East and Asia, especially related to naphtha. Middle Eastern naphtha supplies rise sharply in the period, with surging NGL volumes. Most of these supplies will go to feed the expanding Asian petrochemical sector. The total Asian naphtha/gasoline shortfall could reach 1.3 mb/d in 2017, up from 1.0 mb/d in 2011, split between OECD Pacific, China and 'Other Asia'.

Fuel oil markets see unexpected strength

Global fuel oil markets could tighten through the medium term, as a recent stabilisation of demand is confronted by lower output. Global fuel oil production is estimated to have fallen to under 9 mb/d in 2011 from 11.3 mb/d in 2000. By 2017, global supplies could be as low as 7.6 mb/d. Over the last decades, demand for heavy fuel had also been declining. More recently, however, robust demand from the power generation sector, notably in Japan and the Middle East, has provided fuel oil markets with renewed support, and is expected to keep demand steady through 2017. Broadly speaking, fuel oil use in power generation will remain at risk from environmental policies and fuel substitution, while industrial use is also on a downwards slope. The main use of fuel oil is now as bunker fuels. In the medium term, however, the slow restart of Japan's nuclear power plants after the Fukushima earthquake and tsunami and expected delays in shifting Middle Eastern power generation demand away from oil will likely blunt the impact of those broader pressures.

Changing regulations regarding bunker fuel emissions could have a significant impact on both the fuel oil and distillate markets towards 2017 and beyond. As adoption of the 0.1% sulphur limit for sulphur emission control areas (SECAs) in 2015 approaches, the share of fuel oil in bunker demand will decrease steadily. In this scenario, we are not factoring in a world-wide switch to 0.5% sulphur from 2020, as this is still dependent on a review to be completed by 2018. Furthermore, scrubbing technology looks like a more cost effective option than desulphurising fuel oil at the refinery level or the complete switch to marine diesels. Nevertheless, if, as the International Maritime Organisation (IMO) study finds, the use of fuel oil would have to be abandoned, this will have enormous consequences for both fuel oil and gasoil balances post-2020.

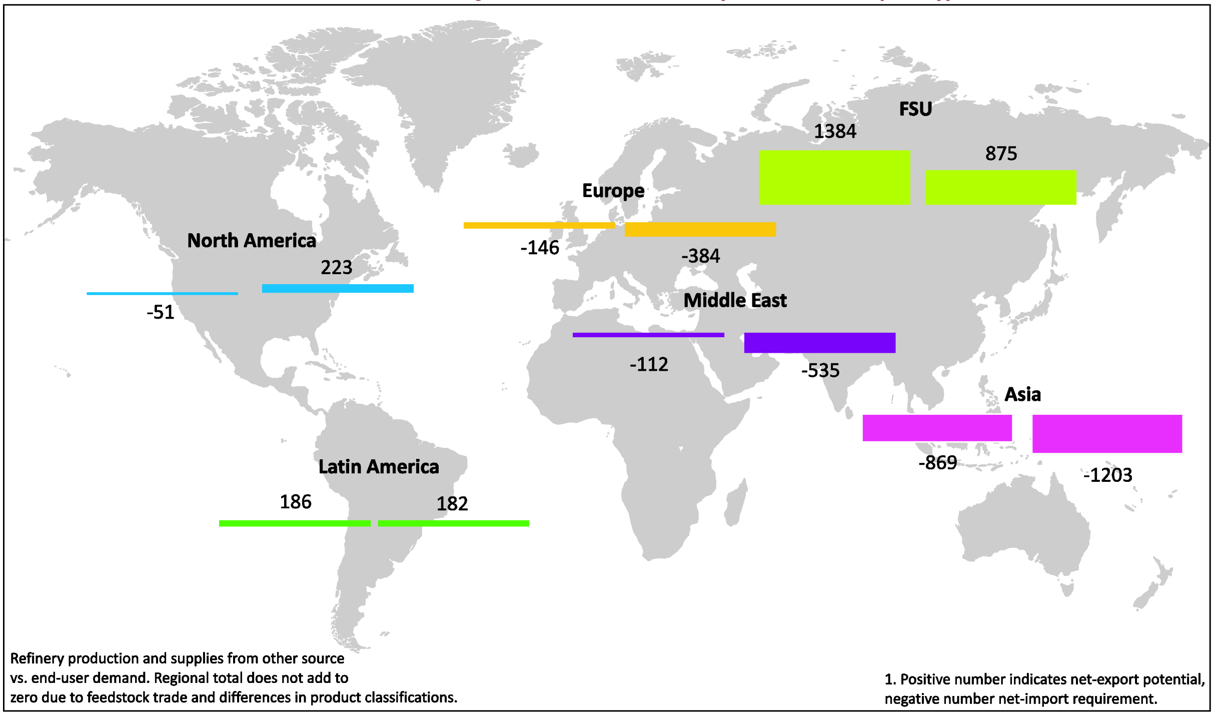
Bunker fuel quality changes

On 10 October 2008 the Marine Environment Protection Committee of the International Maritime Organisation (IMO) adopted the revised Annex VI, Prevention of Air Pollution from Ships, to the MARPOL 73/78 Convention. The Annex sets limits on nitrogen and sulphur oxide emissions from ship exhausts. Low-sulphur fuel also reduces particulate emissions from ships. The new Annex, which entered into force on 1 July 2010, determined that the highest sulphur content allowed in ship fuel will be reduced globally as of 1 January 2012 from 4.5% to 3.5% and as of 1 January 2020 to 0.5%. The revised Annex includes a provision for a review to be carried out by 2018 into the availability of low-sulphur fuel to meet the requirements by 2020. If this review concludes that there are not enough such fuels available, then the date of enforcement of this requirement will be put back to 1 January 2025. Sulphur content allowed in Sulphur Emission Control Areas (SECA) that currently include the Baltic Sea, the North Sea and the English Channel decreased as of 1 July 2010 from 1.5% to 1.0% and as of 1 January 2015 will fall to 0.1%. The use of exhaust gas cleaning systems will continue to be allowed, which means that vessels equipped with scrubbers may continue to use higher sulphur fuel. According to an IMO expert study, the use of heavy fuel oils will largely have to be abandoned once the sulphur content limit in fuel decreases to less than 1%. Lower sulphur limits for marine fuels will inevitably boost fuel costs, incurred through either very expensive desulphurisation of residues, or a shift to higher value middle distillates.

Fuel oil supplies meanwhile continue to decline as refiners invest in upgrading capacity and the feedstock slate becomes lighter and sweeter (see '*Refinery Feedstock Grows Lighter and Sweeter'*). The FSU, the largest provider of fuel oil to global markets, is set to reduce its export potential from almost 1.4 mb/d in 2011 to just under 0.9 mb/d in 2017, as refiners complete modernisation upgrades. The Middle East's fuel oil deficit meanwhile could increase to 0.5 mb/d in 2017 from around 100 kb/d currently. Middle Eastern fuel oil demand is expected to grow moderately over the period on increased power generation needs, while increased regional crude distillation capacity and processing depth are expected to cut into supply. The assumption that Middle Eastern OPEC producers continue to prioritise the production of higher-value lighter crudes also affects fuel oil yields in this scenario. Asia remains the largest importer of fuel oil, and import requirements could rise to 1.2 mb/d by 2017 on robust bunker fuel demand and increased power generation needs in Japan, from 0.9 mb/d in 2011.

Product supply balances – fuel oil

Potential Evolution in Regional Balances 2011-2017[1] (thousand barrels per day)



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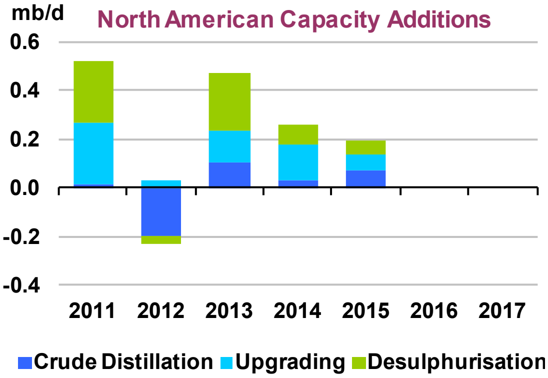
Regional developments

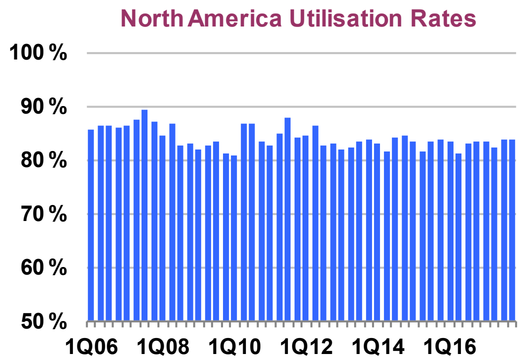
North America: birth of an export hub

The transformation of the US refinery sector in the last few years is nothing less than extra ordinary. On the back of surging regional production of both crude oil and natural gas, and the seemingly structural discount of WTI to Brent, the US refining industry has managed to stage an impressive comeback. The US, the world's largest refined product importer only a few years ago, has recently overtaken all other export hubs (ARA, Russia, India and Singapore) in terms of export volumes. The most recent data show the US50 currently exporting more than 2.6 mb/d of oil products. Simultaneously, net crude imports have declined from 10.1 mb/d in 2005, to 8.7 mb/d on average so far this year.

Diverging markets exist within the US, with the East Coast and US Virgin Islands struggling to compete with other US refiners benefitting from discounted US crude oil from the Midwest and natural gas used as refinery fuel. Since our December update, regional primary crude distillation additions have been lowered by 175 kb/d for the outlook period, leaving North American refining capacity unchanged from 2011 to 2017. The changes stem mainly from the shutdown of Hovensa's

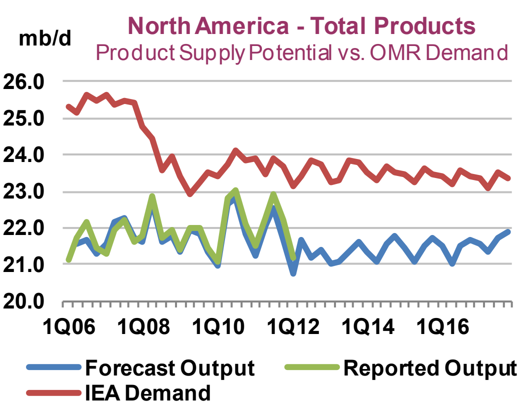
350 kb/d St. Croix refinery in 2012. The company had already shut a 150 kb/d crude distillation unit in 2011 in an attempt to improve its economics. Total refinery closures in North America amount to 1.3 mb/d since the economic downturn of 2008.

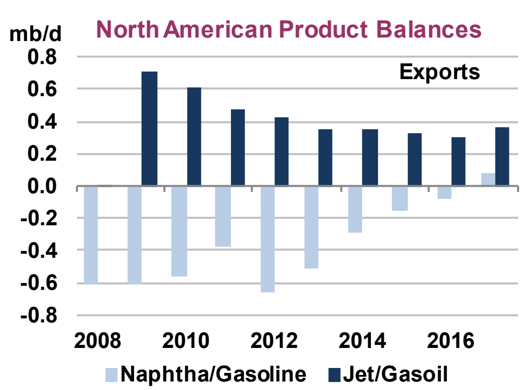




The situation on the East Coast has improved in the last six months, however, with two refineries that had been slated for shutdowns sold and now expected to remain in operation. ConocoPhillips' Trainer refinery resumed runs in September 2012, after having been sold to Delta earlier in the year and undergoing extensive maintenance and retooling work to increase its jet fuel yield. Also Sunoco's Philadelphia refinery was saved in a last minute deal with the Carlyle Group, who pledged to continue running the site. Sunoco's 175 kb/d Marcus Hook refinery in Philadelphia is still expected to halt operations permanently. A major setback in US refinery expansion plans this year came from the delayed start-up of the 325 kb/d expansion of Motiva's Port Arthur refinery. A leak damaged the new distillation unit soon after its launch, and the refinery ramp-up is now only expected in early-2013.

Other interesting developments are the change in US crude quality and feedstock choices. Several refineries are retooling their units to be able to process US domestic crudes, which are lighter and sweeter than previously imported Middle Eastern crudes. Improved margins have also seen several refineries embarking on expansion projects, and some new greenfield projects have even been proposed both in the US and Canada. While progress has been made on Pemex's refinery ambitions in Mexico, with site preparation started and EPC contracts expected for the long-proposed Tula Hildago refinery, completion is not expected before 2017. In all, refinery capacity in North America is expected to remain stable from 2011 to 2017, as the expansions discussed above offset closures in the Virgin Islands and on the East Coast during this period.

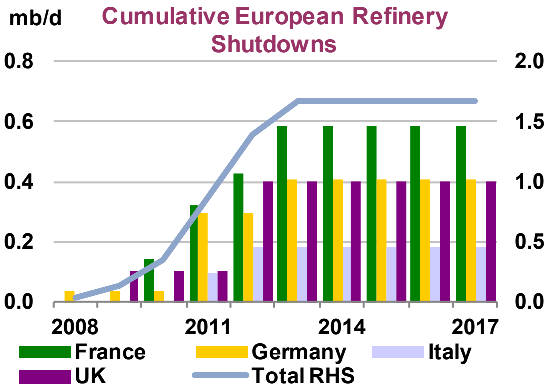


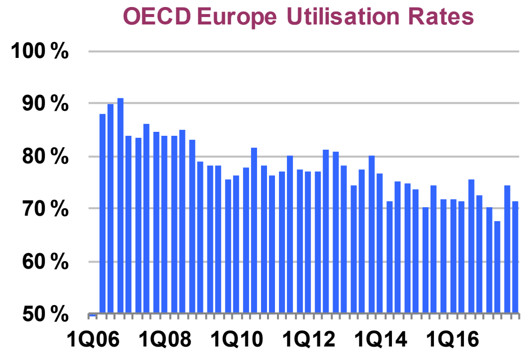


Because of the comparative advantage and very good margins experienced by US refiners, (see '*2012 More than a Marginal Recovery')*, we assume regional refiners will be able to maintain high utilisation rates in coming years, despite declining regional demand. North American demand declines 0.4 mb/d by 2017, with both naphtha/gasoline and fuel oil shrinking significantly. Only LPG, and to a lesser degree gasoil, is expected to grow over the period. As a result, the region's product balance will continue to evolve over coming years. North America exported almost 2.0 mb/d of oil products in 2011, of which 850 kb/d were middle distillates. At the same time, imports of gasoline averaged 750 kb/d in total, with both Mexico and the US reporting imports of 380 kb/d and 750 kb/d, respectively (US also exports gasoline to Mexico, hence US net gasoline imports average only 220 kb/d). In coming years, exports of middle distillates could shrink, while the region could already be a marginal net-exporter of gasoline by 2017. Of course, a different outcome is also possible if refiners continue to tweak refinery units and processes, allowing for higher distillate yields and production.

Europe: industry woes continue

The pressures on the European refining industry might see a temporary respite in coming years, as completed refinery closures are starting to pay off and regional distillation capacity is more in line with demand. Before the end of 2012, close to 1.4 mb/d of primary distillation capacity will have been shut in Europe, with another 350 kb/d scheduled for next year. These numbers assume Petroplus' 160 kb/d Petit Couronne refinery will close in 2013 as no buyer has yet been found. Most recently, both margins and utilisation rates have picked up, as product markets and inventories adjust to lower regional product supplies.

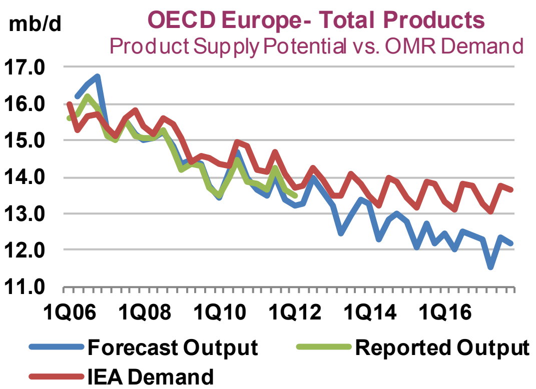


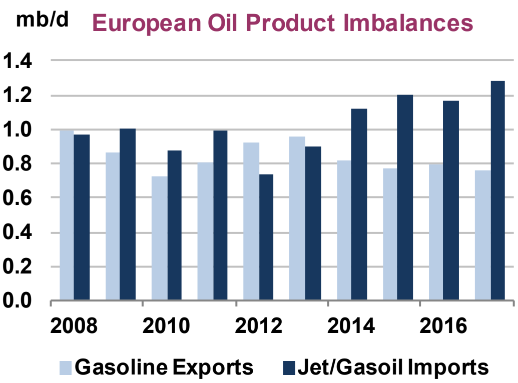


Nevertheless, in the medium-term, the region's oil product demand is set to continue to decline, by 840 kb/d in total from 2011 to 2017, albeit at slower rates than seen over 2011 and 2012. All products fall, though the largest declines stem from light products (naphtha and motor gasoline) and fuel oil. European demand already declined 1.4 mb/d from 2006 to 2011, but this decline has now largely been offset by shuttered regional refinery capacity.

After the completion of Spain's expansion of Huelva and Cartagena, in 2011 and 2012 respectively, only the proposed 200 kb/d Turcas/Socar Aliaga refinery in Turkey is expected to be completed at the tail end of the forecast period. As mentioned above, with a net 500 kb/d of capacity shut in 2012 and 350 kb/d scheduled for closure next year, total OECD European refinery capacity will drop by 640 kb/d from 2011 to 2017.

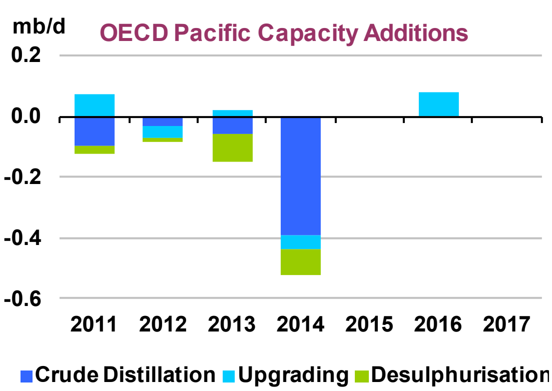
While Europe's gasoline surplus looks set to shrink only modestly over the medium-term, to remain around 800 kb/d, gasoil import requirements will increase further. The region's net imports for diesel, heating oil and jet kerosene averaged almost 1 mb/d in 2011 (including non-OECD Europe). The lion's share of imports came from the FSU, but increasing volumes were also sourced from North America, the Middle East and Asia, while smaller shipments to Africa provided some offset. Looking towards 2017, Europe's distillate deficit could attain levels of up to 1.4 mb/d in 2017.

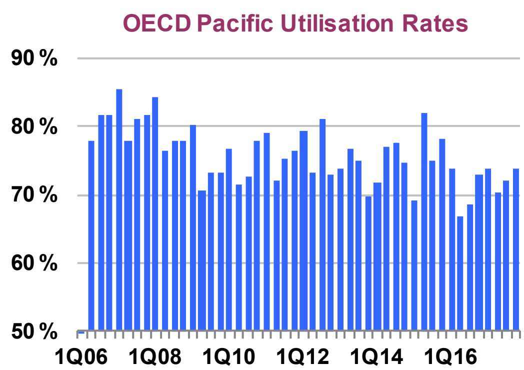




Pacific: renewed demand strength and exports lift utilisation rates

OECD Pacific refinery capacity rationalisation plans have recently been brought back on the agenda after previous efforts were stalled by the devastating earthquake and tsunami that hit Japan in March of last year. Since our December update, we have included another 400 kb/d of capacity destined for shutdown. In Australia, Caltex announced it will shut its 125 kb/d Kurnell refinery in 2014, while Shell brought forward the planned shutdown of the 85 kb/d Clyde plant from 2013 to 4Q2012. In Japan, Cosmo recently announced it will shut its 110 kb/d Sakaide refinery in 2013. Japan's largest refiner, JX Energy, has not made any further rationalisation plans and is only to decide on capacity cuts in late-2012. The company has, however, announced it plans to reduce capacity by 200 kb/d by March 2014, which we now include in our assessment.

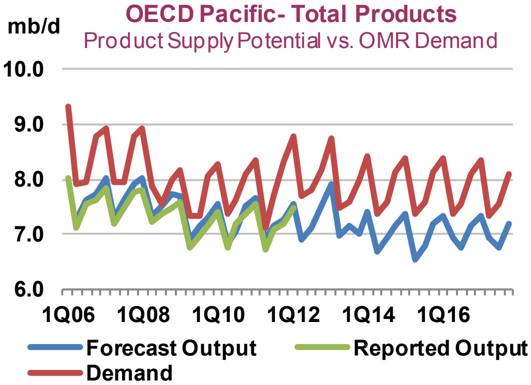


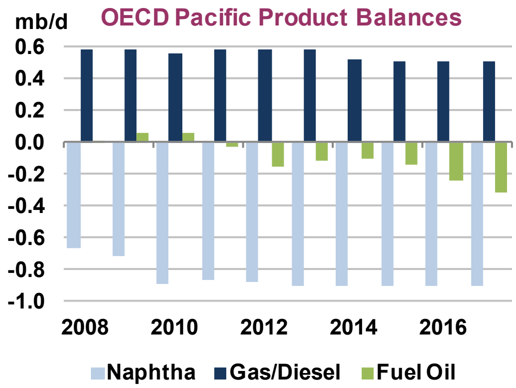


While further capacity will have to be cut in Japan, in accordance with a METI ordinance implemented in July 2010, complete company plans are not yet clear. The new regulation asks refiners to meet a cracking/CDU ratio of 13% or higher by the end of March 2014, effectively forcing plants to reduce their crude distillation capacity as investments in upgrading units are hard to justify.

The declining trend in OECD Pacific demand has been partly reversed in the aftermath of the Fukushima disaster. Regional demand contracted 0.8 mb/d from 2005 to 2010 on an aging and shrinking population and energy efficiency gains. Total demand has been revised up by 130 kb/d for the 2011-2016 period since our December update, however, due not only to increased fuel oil and crude oil demand for power generation demand in Japan, but also on a more favourable outlook for the petrochemical sector in South Korea. Total regional demand is now expected to remain largely unchanged from 2011 to 2017, as demand falls back over 2013 and 2014 after a surge in 2012, and then stabilise.

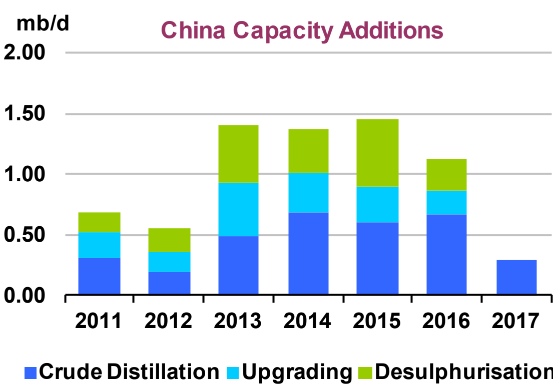
South Korean refiners have recently been able to maintain high refinery utilisation rates to meet both robust domestic demand and also increasing exports. The country exported more than 1 mb/d of oil products in 2011, mostly distillates and gasoline. At the same time, it imported almost 0.8 mb/d of naphtha to feed its extensive petrochemical sector. In the medium term, naphtha imports look set to remain near current levels while middle distillate exports diminish with lower capacity and higher demand over the period. Fuel oil import-requirements could increase as lower output by far outpaces limited demand declines.

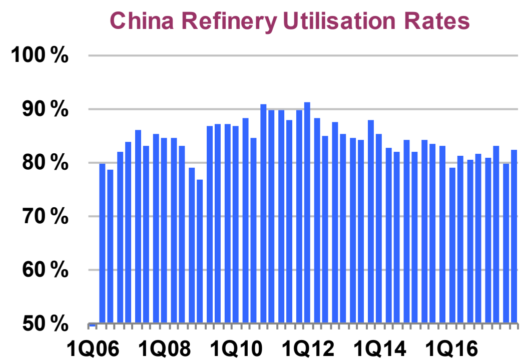




China: key contributor to capacity growth but outlook unclear

China remains the key contributor to global refinery capacity growth in the medium term, potentially adding 2.9 mb/d by 2017 through several large-scale refinery projects. Capacity additions are relatively evenly spread over forecast years, though net additions in 2012 were low on a comparable basis, adding less than 200 kb/d net. Some refinery projects have also been delayed to 2013.





Is Chinese refinery building at risk of overshooting?

In light of recent Chinese demand weakness and a less optimistic consumption outlook for coming years, the viability of China's refinery expansion plans has to be questioned. Since our last medium-term update, we have curtailed Chinese demand growth prospects to 2.1 mb/d for the 2012-2017 period, with 2016 demand more than 1 mb/d less than seen in our last forecast. Compared to the lower growth outlook, our estimate of 2.9 mb/d net capacity additions look high, and questions arise whether projects will be scaled back or if China will emerge as a major global refined product player.

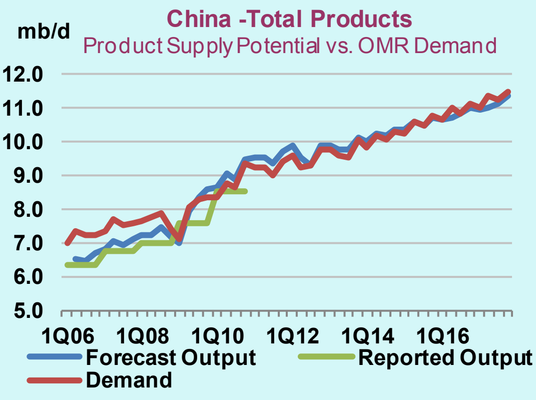
Our capacity expansion outlook is conservative compared to recent trends and to what many other market observers see for coming years. Some consultants see as much as 4-5 mb/d added in the same period, and even state-owned PetroChina said earlier this year they forecast Chinese distillation capacity to reach 15 mb/d by 2015, compared to 10.6 mb/d in 2010 (our estimate is 9.8 mb/d at end-2010).

Signs are emerging that the National Development and Reform Commission (NDRC) are trying to manage the country's expansion plans. We have previously assumed that NDRC would try to pace the country's refinery construction with its product demand growth, to maintain self-sufficiency in key products such as motor gasoline and diesel. The Commission is also trying to encourage the shutting down and phasing out of smaller less efficient refineries.

Furthermore, it seems state-run oil companies are scaling back their downstream expansion plans. Both Sinopec and PetroChina will commission less refining capacity this year than originally planned, due to lower-than-expected domestic demand and weak refining margins. Sinopec is postponing the start-up of its Maoming refinery to 2013, from an original start up date in 2012. The company's Shijazhuang expansion could be delayed to 2014. PetroChina has decided against expanding its Jinxi refinery in Liaoning after failing to secure government approval. Also, CNOOC has struggled to get the green light to build new refineries and has now abandoned plans to build or acquire new plants before 2015, and is instead focusing on upstream operations and improving efficiency and profits at existing downstream assets.

Despite some recent slippage in project completion dates, the chances China will overbuild are still pretty high. There is no apparent mechanism in place to stall refinery projects already approved. In addition, competition between national oil companies, none of whom would like to lose market share, could support continued expansions. For now we are maintaining our capacity estimate, but assume a decline in utilisation rates from recent levels to meet domestic demand for key products.

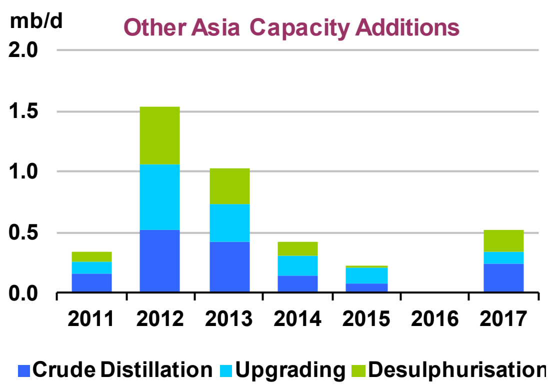
If all refineries included here are built, and operated at current utilisation rates, however, China could become a major regional and global product exporter. In 2011, China's net exports of naphtha and gasoline averaged less than 50 kb/d, while domestic middle distillate supplies and demand were perfectly balanced. Net fuel oil imports on the other hand averaged 250 kb/d. If the country did source crude, at the expense of other, less competitive, regions, it could have a surplus of 1.2 mb/d of products in 2017.

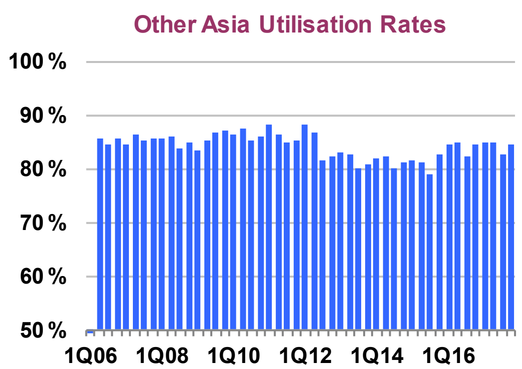


Furthermore, China recently granted the future Tianjin refinery (Rosneft/CNPC) the right to buy and sell oil products, export them and supply the domestic market. It is the first time Chinese authorities have granted such a right to a project with foreign capital. Chinese firms have also increased their presence and ownership in independent storage facilities in Asia, Europe and the Caribbean. This could signal a shift in Chinese policy towards a more competitive domestic refining industry with greater presence and reach in international product markets.

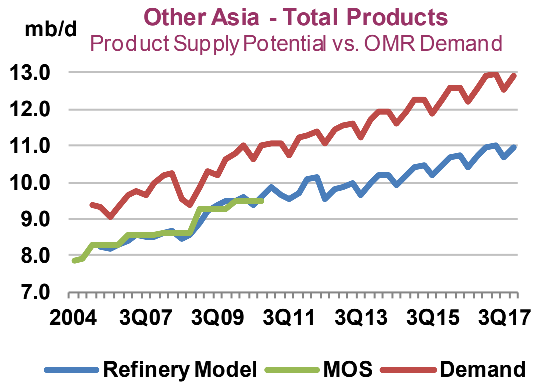
Non-OECD Asia: India continues to dominate

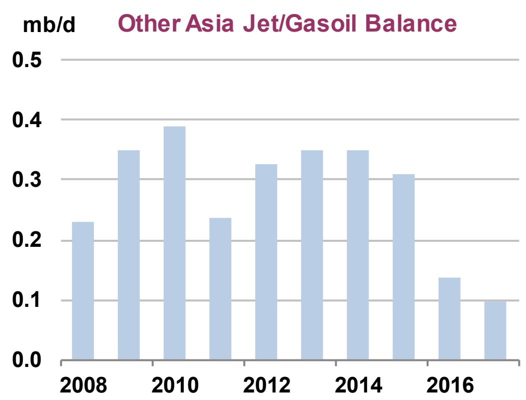
In 'Other Asia' crude distillation capacity is set to increase by 1.4 mb/d over the six-year period from 2011 to 2017. The additions are heavily concentrated in the earlier years, with most of the expansions taking place in 2012 and 2013. Indeed, a significant portion has already been commissioned, notably in India. This includes HPCL's 180 kb/d Bathinda refinery, a 120 kb/d expansion of Essar's Vadinar refinery and several other smaller upgrading projects. In Pakistan, Byco Petroleum is planning to start production from a new processing plant later this year. The plant, which will be the country's largest with nameplate capacity of 120 kb/d, was manufactured in Britain and assembled in Pakistan. Next year, we expect India's 120 kb/d Cuddalore project and IOC's 300 kb/d refinery at Paradip to be commissioned.





Key projects considered likely later in the period include a 70 kb/d expansion of the Chittagong refinery in Bangladesh, the 250 kb/d Kalifah project in Pakistan (IPIC/PARCO) and the 195 kb/d Nghi Son refinery in Vietnam. We still assume that the 205 kb/d Kaohsiung refinery in Taiwan will be shut in 2015, making good on a promise CPC Corporation made to local residents. The company agreed 20 years ago to close the Kaohsiung refinery by 2015 in exchange for local residents allowing the firm to build a new ethylene plant on the site. Other proposed projects in Vietnam, Indonesia and Malaysia are currently not included in the forecast due to uncertainties surrounding financing and completion dates.



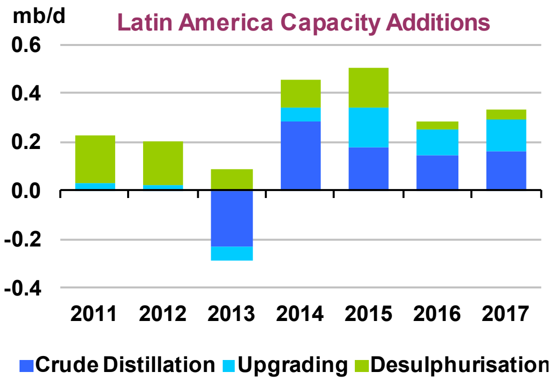


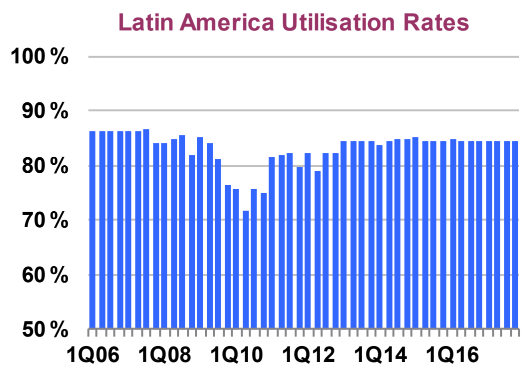
Despite impressive refinery capacity growth, the region's net refined oil product exports are expected to shrink as demand catches up with product supplies. Oil demand is set to grow by 1.8 mb/d from 2011 to 2017, with almost half of projected growth coming from middle distillates.

Motor gasoline consumption is also expected to rise by close to 0.5 mb/d over the forecast period. As a result, regional gasoil/kerosene exports are expected to fall from around 0.3 mb/d in 2011 to practically zero in 2017 in the absence of further refinery projects undertaken. Light product markets, including naphtha and motor gasoline stay relatively balanced through the forecast, while fuel oil import requirements could increase slightly, through 2014 before falling back towards 2017 to 600 kb/d, from about 700 kb/d in 2011, mirroring projected demand trends.

Latin America: delays keep oil product imports high

The outlook for Latin American investments and product supplies has been significantly altered since a year ago. Most importantly, Brazil's ambitious refinery expansion plans were scaled back with new management talking the helm at Petrobras. In its revised business and management plan for 2012-2016, Petrobras delayed the start-up of the 230 kb/d Abreu e Lima refinery. The project will now be launched in two phases of 115 kb/d each in 2014 and 2015. Costs have also escalated from $2.3 billion envisaged in 2005, to $20.1 billion estimated currently. The 165 kb/d Comperj project is also expected to be delayed, to 2017, from an earlier start-up target of 2014. Furthermore, the new plan states that projects under evaluation, including Premium I, Premium II as well as the second phase of Comperj, will not be finalised before 2017 and that "No new refinery will be built unless we are confident in reaching lower Capex and appropriate returns (aligned to international standards of cost and returns)". We had previously taken a conservative view of Brazilian expansions, and were only including the first phase of Premium I (300 kb/d in our project lists).

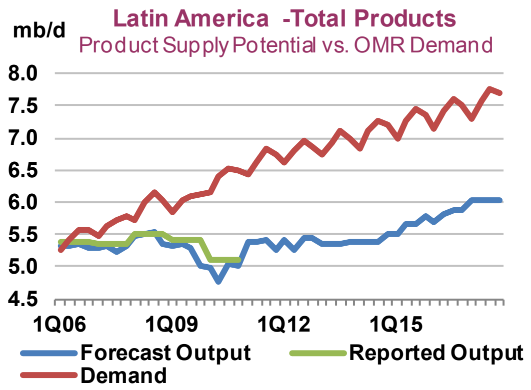


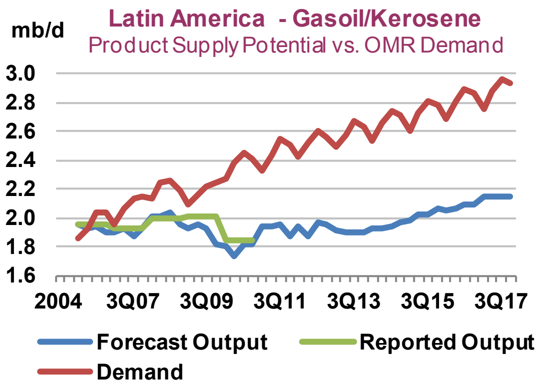


In addition to delays and cancellations in project completions in Brazil, the shutdown of Valero's Aruba refinery at the end of this year will take out a further 270 kb/d of distillation capacity. Valero announced in September it will permanently convert the plant, which has been shut since March due to poor margins, into a refined products terminal. As a result, total CDU expansions now only amount to 0.5 mb/d in the period, compared to more than 1 mb/d previously. Some projects will still augment capacity, however, including Colombia's expansion of the Barrancabermeja and Cartagena refineries, the expansion of Cuba's Cienfuegos refinery in 2014, and a new refinery in Costa Rica. Costa Rican refiner Recope and CNPC were planning to add 35 kb/d to the Limon refinery in 2013, but they have decided not to repair and expand the 25 kb/d plant after a fire last year, but instead build a new 65 kb/d plant, which will go into operation by 2016. Other projects are still seen as speculative.

Limited new capacity growth implies surging product imports will continue in the medium term. OECD countries, and most importantly the US, exported more than 1 mb/d of oil products to Latin

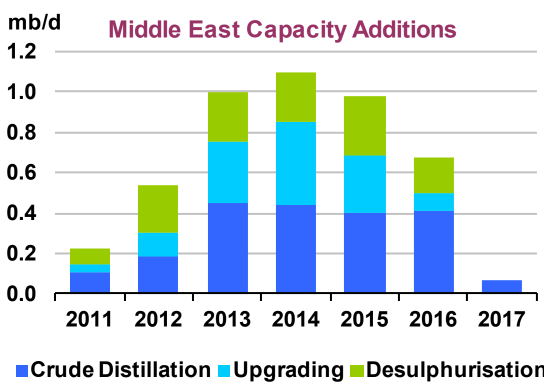
America in 2011, of which more than half was middle distillates, 20% fuel oil and another 20% motor gasoline. In terms of conventional transportation fuels, Latin America is net short, but the region augmented refinery output by around 400 kb/d of ethanol and 100 kb/d of biodiesel in 2011. While Brazil is the largest exporter of ethanol in the world, it also had to import large volumes from the US in 2011, as high world sugar prices and lower sugarcane harvest reduced the country's ethanol production by 20%. Total regional oil product demand is set to expand by 0.9 mb/d by 2017, with growth almost entirely accounted for by transportation fuels. As a result, gasoil import requirements could increase from an estimated 400 kb/d in 2011 to 600 kb/d in 2017. Naphtha/gasoline (including ethanol) markets tighten through 2013 before returning to surplus of around 100 kb/d in 2017.

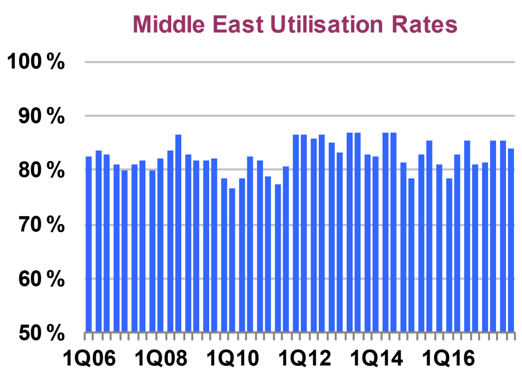




Middle East: additional refinery output surpassing demand growth – for now

The Middle East remains one of the key areas of growth, both in terms of refinery capacity expansions but also of domestic oil product demand in the medium term. Regional oil product demand is set to grow by 1.7 mb/d, or an average of 3.4% per year over the period, the highest growth rates in the world. At the same time, crude distillation capacity is on track to expand by 1.9 mb/d over the period. Three mega-projects in Saudi Arabia and the UAE will add 400 kb/d each in 2013, 2014 and 2015. Smaller expansions in Qatar, Iraq, Iran and Oman are also included.

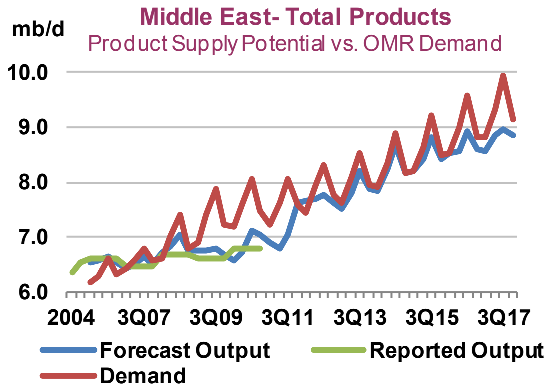


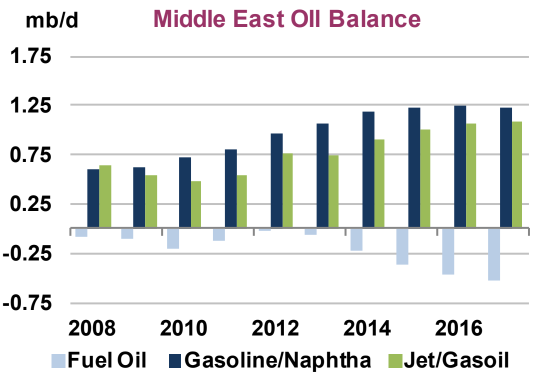


In addition to the 1.9 mb/d of projects included in these prognoses, a plethora of other projects could see the light of day before the end of the decade. In Saudi Arabia, for example, a third 400 kb/d refinery in Jazan is planned for completion in 2017, with likely start-up in 2018. The refinery will be a simple hydroskimming plant, making fuel oil for the marine terminal planned at the same site.

Ambitious expansion plans in Kuwait, Bahrain, Oman, the UAE, Iraq and Iran are so far excluded from the forecast as financing and political issues still have to be resolved, and their completion looks more likely after 2017. Kuwait has long been planning an extensive refinery upgrading and expansion program, including a new refinery at Al-Zour with a capacity of 615 kb/d, though the completion dates for the projects have repeatedly been pushed back because of a standoff between the government and parliament. Despite an official target date of 2017, we expect the plant to be commissioned in 2018 at the earliest.

Other regional investment plans include, amongst others, a 130 kb/d expansion of Bahrain's Sitra refinery, a new 230 kb/d refinery at Duqm in Oman, a 200 kb/d refinery at Fujairah in the UAE, as well as several grassroots projects in Iran and Iraq. While Iranian projects now seem less likely to be completed within this timeframe due to the increased sanctions, Iraq is also struggling to secure foreign investments to increase its domestic refining capacity. The country is looking for up to $30 billion to build four private-sector refineries, with a combined capacity of 740 kb/d, doubling existing refining capacity. While the government states it is ready to build the refineries on its own if foreign capital cannot be secured, we have so far only the 140 kb/d Karbala refinery coming online before 2017, as it appears to be the government's priority project. The 150 kb/d Missan plant, 150 kb/d Kirkuk plant and the 300 kb/d Nassiriya refinery could be completed later in the decade.

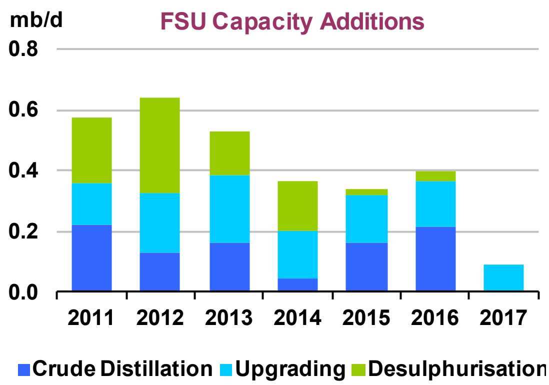


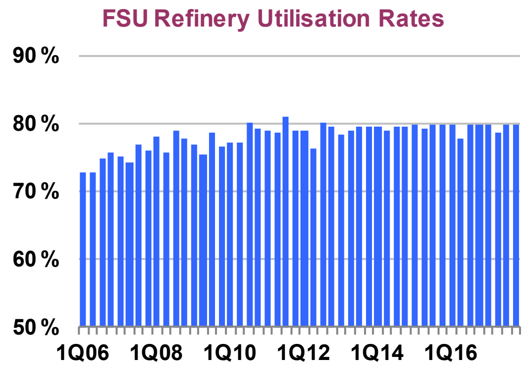


As a result of the region's increased refinery capacity and crude use, and lower crude supplies, Middle Eastern crude and product trade balances are expected to see significant changes in coming years. As discussed in the *Crude Trade Section*, total crude exports could fall by more than 1.9 mb/d by 2017 (from 2011), while increased regional refinery activity could boost product exports instead. The region's light and middle distillate exports are set to increase over the period while a large regional fuel oil deficit appears due to continued growth in power generation, desalination and bunker fuel demand while upgrading and expansion projects increases light product yields. Aramco's Jazan project, which will have a large fuel oil component in its production, will in part alleviate the shortage. Furthermore, a realignment of crude supply preferences is possible, with greater emphasis on heavier grades to ensure more adequate supply.

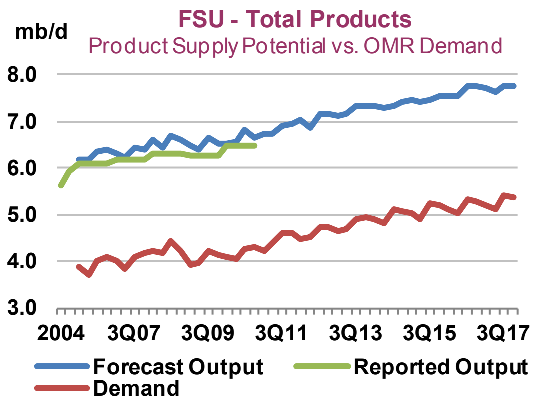
Former Soviet Union

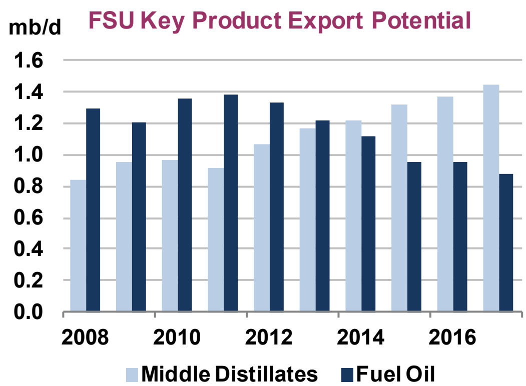
Despite a significant regional refinery capacity surplus, investments in the downstream sector in the FSU, and in particular in Russia, are continuing apace. FSU refinery capacity is estimated at 8.3 mb/d at the end of 2011, of which 5.5 mb/d was accounted for by Russia. 2012 marked the start up of the largest regional expansion in post-Soviet times, with the commissioning of Tatneft's 140 kb/d Taneco refinery in Nizhnekamsk. Future expansion plans are limited, but include Rosneft's plans to increase capacity at its Tuapse refinery by 140 kb/d at the end of 2012 and to build a small 20 kb/d refinery in Grozny in the Chechen Republic. The company also recently announced plans to build a 240 kb/d refinery in the Moscow region, but this project is still in its early stages. Other expansions include Antipinsky's 120 kb/d expansion and Lukoil's Nizhny Novgorod, both in 2016. In all, crude distillation capacity could add just over 0.7 mb/d by 2017, while more importantly upgrading and desulphurisation capacity is expanded by at least 1.0 mb/d and 0.7 mb/d, respectively.





While the US recently has taken over from Russia as the largest gasoil exporter in the world, the FSU is still the region that exports the largest share of its refinery output. In 2011, the region exported almost 2.8 mb/d of refined oil products, more than 40% of its total output. Regional demand growth expected in the medium term is largely in line with new distillation capacity, keeping export potential more or less stable. Interestingly, the upgrading projects should severely curtail fuel oil production, potentially curbing exports from around 1.4 mb/d in 2011 to only 0.9 mb/d in 2017. At the same time, a welcome boost in kerosene/gasoil surplus could be available, raising exports from 0.9 mb/d in 2011 to 1.5 mb/d in 2017, if projects are completed on time. Additional gasoline supplies could also add 120 kb/d to export flows.





Russian downstream investments raise light product yields and quality

Russian refinery upgrading projects are continuing apace, although some concerns about delays have recently arisen. Russia embarked on a multibillion dollar refinery modernisation programme, enabling the country to move towards higher fuel qualities over coming years. The programme, which was revised last October, includes specific deadlines for plant upgrades or new unit launches, as well as commitments to volumes and technical characteristics of the fuel supplied. Downstream companies have also agreed to allow the Russian state to audit progress on an annual basis. In exchange, the government agreed to revoke its ban on the domestic use of Euro 2 gasoline and diesel (500 ppm) - which had originally been introduced at the start of 2011, until January 2013. The same order pushed back the ban on Euro 3 fuels (150 ppm) to the start of 2015, from 2012, and a ban on Euro 4 fuels (50 ppm) to 2016 from 2015.

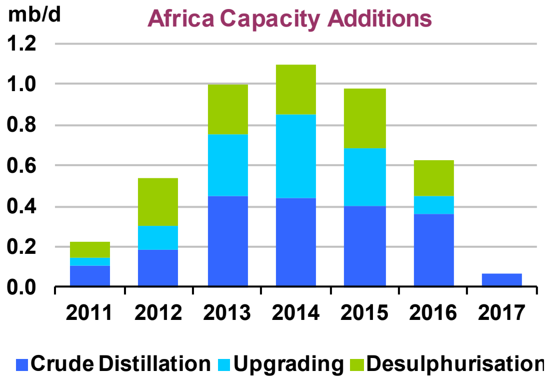
According to data from Rosstat and the Economics Ministry, Russian refining Capex increased from $1.4 billion in 2005 to $8.22 billion in 2011. The investments are mostly geared to upgrading existing capacity, rather than expanding distillation capacity, and to producing lighter and higher quality products.

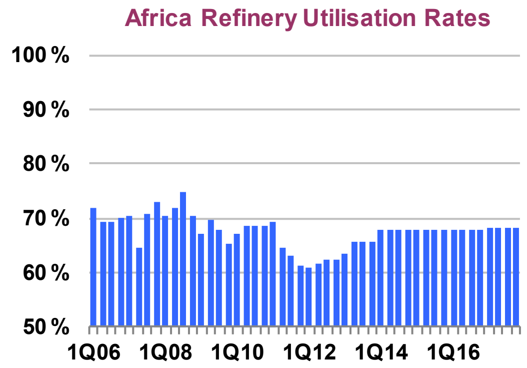
Fuel oil still represents more than a quarter of total refinery output, the majority of which is exported. Current export duties still favour fuel exports over crude oil, but the advantage to light products was removed last year in an attempt to encourage investment in upgrading units. As part of the bid to boost higher quality fuel production, Moscow also introduced a new export duty regime in October 2011, unifying the rates for shipments of all products. As a result, the export duty on dirty products increased to 66% of the duty on Urals, from 46.7% previously, while the duty on light products dropped from 67% to 66%. In addition, on 1 July Moscow raised excise tax for gasoline and diesel not complying with Euro 3 standards. Companies operating in Russia committed to build or upgrade between 116 and 124 secondary processing units by 2020, for a total investment of $33 billion, compared to only 20 units upgraded between 2008 and 2011. According to the Ministry, companies have so far fully met their deadlines, and 20 new or upgraded units are scheduled to be launched in 2012. However, a recent report suggests that key downstream companies, Rosneft, TNK-BP, Gazprom Neft, Lukoil, Bashneft and Surgutneftegaz were asking the government to postpone their modernisation deadlines by an average of one year in mid-August 2012. That said, new gasoline desulphurisation units have been launched at the Omsk and Yaroslavl refineries and new diesel desulphurisation units at the Kirishi and Volgograd refineries. New units at the Moscow and Saratov plants have been delayed to 2013, but all companies have extensive lists of upgrades in the pipeline.

Delays could affect the timing of the planned bans on lower quality fuels in Russia. If the government allows delays to the upgrading programs, they might also have to extend the deadline for selling Euro 2 fuels. However, if it allows the deadline to slip, the government might also then be forced to postpone its plans to equalize the export duty regimes for fuel oil and crude oil. Starting from 2015, the export duty rate for fuel oil will rise to the same as for Urals, hitting the profitability of refiners producing and exporting large amounts of fuel oil.

Africa: Little progress seen in adding capacity in the medium term

With little progress securing funds for African refinery projects, few refinery expansions are seen coming on line in the medium term. Less than 0.5 mb/d of new distillation capacity is expected to be added, with Algeria adding 150 kb/d through expansions of the Arzew and Skikda plants in 2016. Angola could add 120 kb/d through a grassroots project in Lobito in 2017. Egypt's Mostorod project is also back on track with $3.7 billion financing secured. The project will process fuel oil, rather than crude oil, as power stations switch to gas, so it is not technically an expansion project, rather an upgrade.





Elsewhere, other refinery projects are on the drawing board, which could help correct the product deficits. Amongst them are projects in South Sudan, Uganda, Gabon, Tunisia, Nigeria and South Africa. The latter has long been planning on expanding refining capacity, and most recently PetroSA joined up with Sinopec to jointly build the 400 kb/d refinery in Coega at a cost of $9-10 billion. In Tunisa, Qatar could build a 120 kb/d refinery at La Skhira, processing Libyan crudes. The plant could be completed by 2014 or 2015 and later expanded to 250 kb/d. The Nigerian government has signed a preliminary deal with two investment companies from Nigeria and the US to build six small refineries, with a combined capacity of 180 kb/d, at a cost of $4.5 billion. In addition to the ongoing modernisation and expansion of the Skikda and Arzew plants, Algerian state owned Sonatrach has proposed an ambitious refinery expansion program, including four new plants, in a bid to meet rapidly increasing domestic oil product demand. The four refineries could add 390 kb/d and be completed before 2018.

With an additional 1.8 mb/d of regional crude oil supplies coming on line in the period, from a low point in 2011 when Libyan production was shut-in, regional crude exports are expected to see a significant boost. The refinery capacity additions fail to keep pace with expected demand growth of some 645 kb/d from 2011 to 2017. The growth is practically evenly split between gasoline and distillates, with other products relatively unchanged. As a result, the region's need for imports of refined products is expected to increase over the period. Africa is currently a net importer of gasoline, middle distillates and fuel oil, while exporting naphtha and LPG (mainly from Algeria). The region's middle distillate imports could rise from an estimated 500 kb/d in 2011 to over 600 kb/d in 2017, while gasoline shortfalls could double from 170 kb/d in 2011 to 330 kb/d in 2017.

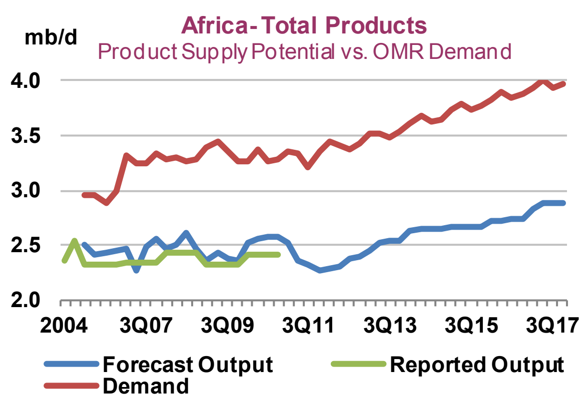


Table 1

WORLD OIL SUPPLY AND DEMAND

(million barrels per day)

	1Q11	2Q11	3Q11	4Q11	2011	1Q12	2Q12	3Q12	4Q12	2012	2013	2014	2015	2016	2017
OECD DEMAND															
Americas[1]	24.2	23.8	24.2	24.0	24.1	23.5	23.8	24.2	24.1	23.9	23.9	23.8	23.8	23.8	23.7
Europe[2]	14.3	14.2	14.8	14.2	14.4	13.8	13.8	14.3	14.0	14.0	13.8	13.7	13.7	13.6	13.5
Asia Oceania[3]	8.6	7.4	8.0	8.6	8.1	9.1	8.0	8.1	8.4	8.4	8.2	8.2	8.2	8.2	8.2
Total OECD	47.1	45.4	47.0	46.8	46.6	46.3	45.6	46.6	46.5	46.2	45.9	45.8	45.6	45.5	45.4
NON-OECD DEMAND															
FSU	4.2	4.4	4.6	4.6	4.4	4.4	4.5	4.7	4.7	4.6	4.8	4.9	5.1	5.2	5.2
Europe	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.8	0.8
China	9.3	9.3	9.0	9.4	9.2	9.6	9.3	9.3	9.8	9.5	9.8	10.1	10.5	10.9	11.3
Other Asia	11.1	11.1	10.8	11.2	11.0	11.3	11.4	11.1	11.4	11.3	11.5	11.8	12.2	12.5	12.8
Latin America	6.1	6.3	6.5	6.4	6.3	6.3	6.4	6.6	6.5	6.4	6.6	6.7	6.9	7.0	7.2
Middle East	7.0	7.4	7.8	7.3	7.4	7.2	7.7	8.0	7.5	7.6	7.8	8.1	8.4	8.7	9.0
Africa	3.4	3.3	3.2	3.4	3.3	3.4	3.4	3.4	3.4	3.4	3.5	3.6	3.8	3.9	4.0
Total Non-OECD	41.6	42.3	42.6	43.0	42.4	42.9	43.4	43.8	44.1	43.5	44.7	46.1	47.5	48.9	50.3
Total Demand[4]	88.8	87.7	89.5	89.8	89.0	89.2	89.0	90.4	90.6	89.8	90.6	91.8	93.2	94.5	95.7
OECD SUPPLY															
Americas[1,7]	14.3	14.3	14.5	15.3	14.6	15.6	15.6	15.7	16.1	15.7	16.3	16.7	17.4	18.0	18.6
Europe[2]	4.0	3.7	3.5	3.7	3.8	3.8	3.6	3.2	3.4	3.5	3.3	3.3	3.3	3.2	3.1
Asia Oceania[3]	0.6	0.6	0.6	0.6	0.6	0.5	0.5	0.6	0.5	0.5	0.5	0.6	0.6	0.6	0.6
Total OECD	18.9	18.6	18.6	19.6	18.9	19.9	19.7	19.4	20.0	19.8	20.2	20.6	21.3	21.8	22.3
NON-OECD SUPPLY															
FSU	13.6	13.6	13.5	13.6	13.6	13.7	13.6	13.5	13.7	13.6	13.6	13.6	13.6	13.7	13.6
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
China	4.2	4.2	4.0	4.0	4.1	4.2	4.1	4.1	4.1	4.1	4.2	4.3	4.4	4.4	4.5
Other Asia[5]	3.7	3.5	3.6	3.6	3.6	3.6	3.6	3.5	3.5	3.6	3.5	3.4	3.4	3.4	3.3
Latin America[5,7]	4.2	4.2	4.2	4.3	4.2	4.3	4.1	4.1	4.3	4.2	4.4	4.4	4.7	5.0	5.0
Middle East	1.8	1.7	1.7	1.5	1.6	1.4	1.5	1.5	1.5	1.5	1.5	1.4	1.3	1.3	1.2
Africa[5]	2.6	2.6	2.6	2.6	2.6	2.4	2.3	2.3	2.3	2.3	2.3	2.5	2.6	2.6	2.8
Total Non-OECD	30.2	29.8	29.8	29.7	29.9	29.8	29.3	29.2	29.5	29.4	29.6	29.8	30.2	30.4	30.5
Processing Gains[6]	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.2	2.1	2.1	2.2	2.2	2.3	2.3	2.3
Global Biofuels[7]	1.5	1.9	2.2	1.8	1.9	1.6	1.8	2.2	1.9	1.9	2.0	2.2	2.3	2.3	2.4
Total Non-OPEC[5]	52.8	52.4	52.7	53.2	52.8	53.4	52.9	52.9	53.6	53.2	54.0	54.8	56.0	56.8	57.5
OPEC															
Crude[8]	29.9	29.4	29.9	30.3	29.9	31.4	31.7								
OPEC NGLs	5.8	5.7	5.8	5.9	5.8	6.0	6.1	6.3	6.4	6.2	6.5	6.6	6.9	7.0	6.9
Total OPEC[5]	35.7	35.1	35.6	36.2	35.7	37.4	37.9								
Total Supply[9]	88.4	87.6	88.4	89.4	88.4	90.8	90.8								
Memo items:															
Call on OPEC crude + Stock ch.[10]	30.2	29.6	31.1	30.7	30.4	29.8	29.9	31.1	30.6	30.4	30.1	30.4	30.3	30.7	31.2

1 As of August 2012 OMR, OECD Americas includes Chile.
2 As of August 2012 OMR, OECD Europe includes Estonia and Slovenia.
3 As of August 2012 OMR, OECD Asia Oceania includes Israel.
4 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.
5 Other Asia includes Indonesia throughout. Latin America excludes Ecuador throughout. Africa excludes Angola throughout.
Total Non-OPEC excludes all countries that were members of OPEC at 1 January 2009.
Total OPEC comprises all countries which were OPEC members at 1 January 2009.
6 Net volumetric gains and losses in the refining process and marine transportation losses.
7 As of the June 2010 MTOGM, Global Biofuels comprise all world biofuel production including fuel ethanol from the US and Brazil.
8 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.
9 Comprises crude oil, condensates, NGLs, oil from non-conventional sources and other sources of supply.
10 Equals the arithmetic difference between total demand minus total non-OPEC supply minus OPEC NGLs.

Table 1A

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

(million barrels per day)

	1Q11	2Q11	3Q11	4Q11	2011	1Q12	2Q12	3Q12	4Q12	2012	2013	2014	2015	2016	2017
OECD DEMAND															
Americas	0.1	0.2	0.3	0.3	0.2	-0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2	
Europe	0.0	0.0	0.0	-0.2	0.0	-0.2	-0.1	-0.3	-0.4	-0.2	-0.3	-0.3	-0.2	-0.1	
Asia Oceania	0.0	0.0	0.0	0.0	0.0	0.3	0.3	0.3	0.1	0.2	0.2	0.1	0.2	0.2	
Total OECD	0.2	0.2	0.4	0.0	0.2	-0.3	0.6	0.3	0.0	0.2	0.0	0.1	0.2	0.3	
NON-OECD DEMAND															
FSU	-0.2	-0.2	-0.2	-0.2	-0.2	-0.1	-0.1	-0.1	-0.2	-0.1	0.0	0.2	0.3	0.4	
Europe	0.1	0.1	0.0	0.1	0.1	0.1	0.1	0.0	0.0	0.1	0.1	0.1	0.1	0.1	
China	-0.3	-0.3	-0.3	-0.2	-0.3	-0.3	-0.8	-0.6	-0.3	-0.5	-0.7	-0.9	-0.9	-1.1	
Other Asia	0.4	0.4	0.4	0.5	0.4	0.3	0.3	0.3	0.3	0.3	0.2	0.1	0.1	0.1	
Latin America	0.1	0.1	0.2	0.1	0.1	0.1	0.1	0.1	0.0	0.1	0.0	0.0	0.0	0.1	
Middle East	-0.4	-0.3	-0.4	-0.3	-0.3	-0.4	-0.3	-0.4	-0.3	-0.4	-0.4	-0.4	-0.4	-0.4	
Africa	0.0	0.0	0.0	0.0	0.0	0.0	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	
Total Non-OECD	-0.3	-0.3	-0.3	-0.1	-0.2	-0.4	-0.8	-0.7	-0.6	-0.6	-0.9	-1.0	-0.9	-0.9	
Total Demand	-0.2	-0.1	0.1	-0.1	-0.1	-0.7	-0.3	-0.4	-0.5	-0.5	-0.9	-0.9	-0.7	-0.5	
OECD SUPPLY															
Americas	0.0	0.0	0.0	0.6	0.1	0.8	1.0	1.2	1.3	1.1	1.5	1.5	1.4	1.5	
Europe	-0.1	-0.1	-0.1	-0.3	-0.1	-0.3	-0.2	-0.6	-0.5	-0.4	-0.5	-0.4	-0.3	-0.2	
Asia Oceania	0.0	0.1	0.1	0.0	0.0	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	0.0	
Total OECD	0.0	0.0	-0.1	0.2	0.0	0.3	0.6	0.4	0.6	0.5	0.9	1.0	1.0	1.2	
NON-OECD SUPPLY															
FSU	0.0	0.0	0.0	-0.2	0.0	-0.1	-0.2	-0.2	-0.1	-0.1	-0.1	0.0	-0.1	0.0	
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	
China	0.0	0.0	0.0	-0.2	-0.1	-0.1	-0.2	-0.2	-0.2	-0.2	-0.2	-0.1	0.0	0.1	
Other Asia	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	-0.1	-0.1	0.0	
Latin America	0.0	0.0	0.1	0.1	0.0	-0.1	-0.3	-0.3	-0.2	-0.2	-0.3	-0.4	-0.5	-0.5	
Middle East	0.0	0.0	0.1	0.0	0.0	-0.2	-0.1	-0.1	-0.1	-0.1	0.0	0.0	0.0	0.0	
Africa	0.0	0.1	0.1	0.1	0.1	-0.1	-0.3	-0.3	-0.3	-0.2	-0.2	0.0	0.1	0.1	
Total Non-OECD	0.1	0.2	0.2	-0.1	0.1	-0.4	-1.0	-0.9	-0.8	-0.8	-0.8	-0.6	-0.6	-0.3	
Processing Gains	-0.1	-0.1	0.0	-0.1	-0.1	-0.1	-0.1	-0.1	-0.2	-0.1	-0.2	-0.2	-0.3	-0.3	
Global Biofuels	0.0	0.1	0.0	0.0	0.0	0.0	-0.1	-0.1	0.0	-0.1	0.0	0.1	0.1	0.1	
Total Non-OPEC	0.1	0.2	0.2	0.0	0.1	-0.2	-0.6	-0.7	-0.4	-0.5	-0.1	0.3	0.3	0.8	
OPEC															
Crude	-0.1	-0.1	-0.1												
OPEC NGLs	0.0	0.0	0.0	-0.1	0.0	-0.1	-0.1	-0.2	-0.2	-0.1	-0.2	-0.2	-0.3	-0.4	
Total OPEC	-0.1	-0.1	-0.1												
Total Supply	0.0	0.1	0.1												
Memo items:															
Call on OPEC crude + Stock ch.	-0.3	-0.3	0.0	0.0	-0.1	-0.4	0.4	0.4	0.1	0.1	-0.6	-0.9	-0.6	-0.9	

Table 2
SUMMARY OF GLOBAL OIL DEMAND

	1Q11	2Q11	3Q11	4Q11	2011	1Q12	2Q12	3Q12	4Q12	2012	2013	2014	2015	2016	2017
Demand (mb/d)															
Americas[1]	24.24	23.81	24.21	24.00	24.07	23.48	23.77	24.15	24.05	23.86	23.88	23.85	23.81	23.76	23.69
Europe[2]	14.30	14.20	14.78	14.18	14.37	13.78	13.82	14.34	14.00	13.99	13.80	13.73	13.67	13.60	13.53
Asia Oceania[3]	8.60	7.36	7.98	8.58	8.13	9.08	7.99	8.09	8.44	8.40	8.24	8.18	8.17	8.17	8.16
Total OECD	47.14	45.38	46.97	46.76	46.56	46.34	45.58	46.58	46.49	46.25	45.92	45.76	45.65	45.53	45.39
Asia	20.36	20.32	19.79	20.65	20.28	20.89	20.64	20.36	21.22	20.78	21.28	21.95	22.70	23.41	24.12
Middle East	6.97	7.38	7.82	7.34	7.38	7.18	7.69	8.04	7.50	7.60	7.80	8.07	8.37	8.69	9.01
Latin America	6.05	6.26	6.47	6.38	6.29	6.25	6.43	6.60	6.50	6.45	6.57	6.73	6.88	7.03	7.17
FSU	4.21	4.36	4.57	4.57	4.43	4.45	4.47	4.71	4.72	4.59	4.77	4.94	5.06	5.16	5.25
Africa	3.36	3.33	3.22	3.36	3.32	3.45	3.40	3.37	3.43	3.41	3.52	3.64	3.76	3.86	3.96
Europe	0.67	0.69	0.70	0.72	0.69	0.68	0.73	0.71	0.71	0.71	0.72	0.74	0.75	0.76	0.77
Total Non-OECD	41.62	42.34	42.57	43.02	42.39	42.90	43.38	43.79	44.08	43.54	44.67	46.07	47.52	48.92	50.29
World	88.76	87.72	89.54	89.77	88.95	89.24	88.96	90.36	90.58	89.79	90.60	91.82	93.16	94.45	95.68
of which:															
US50	*19.15*	*18.86*	*19.08*	*18.94*	*19.01*	*18.49*	*18.72*	*19.07*	*19.04*	*18.83*	*18.83*	*18.79*	*18.76*	*18.73*	*18.68*
*Euro5**	*8.68*	*8.52*	*8.85*	*8.50*	*8.64*	*8.26*	*8.20*	*8.55*	*8.35*	*8.34*	*8.21*	*8.14*	*8.07*	*8.00*	*7.93*
China	*9.27*	*9.26*	*9.03*	*9.42*	*9.24*	*9.59*	*9.26*	*9.29*	*9.78*	*9.48*	*9.75*	*10.10*	*10.53*	*10.91*	*11.28*
Japan	*4.83*	*3.91*	*4.31*	*4.81*	*4.46*	*5.28*	*4.30*	*4.36*	*4.63*	*4.64*	*4.47*	*4.39*	*4.36*	*4.34*	*4.32*
India	*3.54*	*3.61*	*3.29*	*3.60*	*3.51*	*3.67*	*3.74*	*3.49*	*3.67*	*3.64*	*3.74*	*3.89*	*4.03*	*4.18*	*4.33*
Russia	*2.99*	*3.20*	*3.42*	*3.39*	*3.25*	*3.21*	*3.30*	*3.54*	*3.52*	*3.39*	*3.57*	*3.72*	*3.83*	*3.92*	*3.99*
Brazil	*2.78*	*2.86*	*2.98*	*2.95*	*2.89*	*2.89*	*2.95*	*3.02*	*3.00*	*2.96*	*3.02*	*3.08*	*3.16*	*3.23*	*3.30*
Saudi Arabia	*2.56*	*2.94*	*3.18*	*2.81*	*2.87*	*2.66*	*3.09*	*3.38*	*2.99*	*3.03*	*3.16*	*3.30*	*3.45*	*3.60*	*3.75*
Korea	*2.36*	*2.05*	*2.21*	*2.30*	*2.23*	*2.31*	*2.19*	*2.25*	*2.32*	*2.27*	*2.27*	*2.27*	*2.27*	*2.27*	*2.27*
Canada	*2.32*	*2.22*	*2.36*	*2.26*	*2.29*	*2.21*	*2.28*	*2.37*	*2.28*	*2.28*	*2.31*	*2.30*	*2.28*	*2.27*	*2.24*
Mexico	*2.11*	*2.12*	*2.14*	*2.16*	*2.13*	*2.11*	*2.14*	*2.10*	*2.11*	*2.11*	*2.12*	*2.11*	*2.11*	*2.10*	*2.10*
Iran	*1.84*	*1.79*	*1.78*	*1.78*	*1.80*	*1.83*	*1.86*	*1.72*	*1.71*	*1.78*	*1.75*	*1.77*	*1.79*	*1.83*	*1.87*
Total	*62.43*	*61.32*	*62.64*	*62.93*	*62.33*	*62.52*	*62.04*	*63.14*	*63.40*	*62.78*	*63.19*	*63.86*	*64.64*	*65.37*	*66.04*
% of World	*70.34*	*69.91*	*69.96*	*70.10*	*70.08*	*70.06*	*69.74*	*69.87*	*69.99*	*69.92*	*69.75*	*69.54*	*69.39*	*69.21*	*69.03*
Annual Change (mb/d)															
Americas[1]	0.48	-0.23	-0.26	-0.18	-0.05	-0.76	-0.04	-0.06	0.05	-0.20	0.02	-0.03	-0.04	-0.05	-0.07
Europe[2]	-0.15	-0.18	-0.25	-0.76	-0.34	-0.52	-0.38	-0.44	-0.18	-0.38	-0.19	-0.07	-0.06	-0.07	-0.07
Asia Oceania[3]	0.06	-0.25	0.07	0.25	0.03	0.48	0.62	0.11	-0.14	0.27	-0.16	-0.06	-0.01	0.00	-0.01
Total OECD	0.40	-0.66	-0.44	-0.70	-0.35	-0.80	0.20	-0.39	-0.26	-0.31	-0.33	-0.17	-0.11	-0.12	-0.14
Asia	1.23	0.53	0.52	0.23	0.62	0.53	0.32	0.57	0.57	0.50	0.51	0.67	0.75	0.71	0.70
Middle East	0.03	0.04	0.02	0.11	0.05	0.21	0.31	0.22	0.16	0.23	0.20	0.26	0.30	0.32	0.32
Latin America	0.26	0.23	0.29	0.24	0.26	0.20	0.18	0.13	0.12	0.15	0.13	0.15	0.15	0.15	0.15
FSU	0.14	0.34	0.32	0.31	0.28	0.23	0.12	0.13	0.15	0.16	0.19	0.17	0.12	0.10	0.08
Africa	0.09	-0.04	-0.05	0.08	0.02	0.08	0.07	0.16	0.07	0.10	0.10	0.12	0.11	0.11	0.10
Europe	-0.01	0.00	0.02	0.02	0.01	0.02	0.05	0.01	-0.01	0.02	0.01	0.01	0.01	0.01	0.01
Total Non-OECD	1.75	1.10	1.12	0.99	1.24	1.27	1.04	1.22	1.07	1.15	1.14	1.39	1.45	1.41	1.36
World	2.14	0.44	0.68	0.29	0.88	0.48	1.24	0.82	0.80	0.84	0.81	1.22	1.34	1.29	1.23
Revisions to Oil Demand from Last Medium Term Report (mb/d)															
Americas[1]	0.14	0.18	0.34	0.26	0.23	-0.31	0.32	0.32	0.27	0.15	0.20	0.21	0.23	0.23	
Europe[2]	0.03	0.01	0.02	-0.25	-0.05	-0.23	-0.07	-0.25	-0.37	-0.23	-0.34	-0.28	-0.19	-0.09	
Asia Oceania[3]	0.00	0.00	0.03	0.00	0.01	0.25	0.33	0.28	0.13	0.25	0.15	0.13	0.16	0.20	
Total OECD	0.17	0.19	0.39	0.01	0.19	-0.29	0.57	0.35	0.04	0.17	0.02	0.07	0.20	0.34	
Asia	0.13	0.10	0.14	0.24	0.15	-0.03	-0.50	-0.29	-0.07	-0.22	-0.59	-0.78	-0.86	-0.99	
Middle East	-0.40	-0.34	-0.35	-0.25	-0.33	-0.42	-0.30	-0.38	-0.35	-0.36	-0.41	-0.41	-0.40	-0.41	
Latin America	0.13	0.12	0.16	0.14	0.14	0.12	0.11	0.10	0.05	0.09	0.04	0.04	0.04	0.06	
FSU	-0.22	-0.24	-0.24	-0.25	-0.23	-0.12	-0.10	-0.13	-0.17	-0.13	0.03	0.20	0.32	0.44	
Africa	-0.04	0.00	-0.01	-0.02	-0.02	-0.05	-0.13	-0.09	-0.09	-0.09	-0.09	-0.08	-0.08	-0.09	
Europe	0.06	0.05	0.04	0.07	0.05	0.06	0.08	0.05	0.05	0.06	0.06	0.07	0.08	0.10	
Total Non-OECD	-0.34	-0.29	-0.26	-0.07	-0.24	-0.43	-0.84	-0.74	-0.58	-0.65	-0.95	-0.95	-0.89	-0.88	
World	-0.17	-0.10	0.13	-0.07	-0.05	-0.73	-0.27	-0.39	-0.54	-0.48	-0.93	-0.88	-0.68	-0.54	
Revisions to Oil Demand Growth from Last Medium Term Report (mb/d)															
World	0.00	0.07	0.32	0.22	0.15	-0.55	-0.16	-0.52	-0.47	-0.43	-0.45	0.05	0.20	0.14	

1 As of the August 2012 OMR, includes Chile.
2 As of the August 2012 OMR, includes Estonia and Slovenia.
3 As of the August 2012 OMR, includes Israel.
* France, Germany, Italy, Spain and UK

Table 3
WORLD OIL PRODUCTION
(million barrels per day)

	1Q11	2Q11	3Q11	4Q11	2011	1Q12	2Q12	3Q12	4Q12	2012	2013	2014	2015	2016	2017
OPEC															
Crude Oil															
Saudi Arabia	8.55	8.90	9.34	9.37	9.04	9.65	9.77								
Iran	3.64	3.71	3.58	3.56	3.62	3.37	3.14								
Iraq	2.66	2.67	2.67	2.68	2.67	2.69	2.92								
UAE	2.48	2.48	2.53	2.54	2.50	2.61	2.65								
Kuwait	2.08	2.15	2.30	2.43	2.24	2.42	2.45								
Neutral Zone	0.56	0.59	0.60	0.60	0.59	0.60	0.60								
Qatar	0.74	0.74	0.73	0.74	0.74	0.75	0.74								
Angola	1.63	1.57	1.71	1.74	1.66	1.77	1.76								
Nigeria	2.14	2.25	2.26	2.06	2.18	2.06	2.17								
Libya	1.13	0.12	0.04	0.55	0.46	1.30	1.40								
Algeria	1.19	1.19	1.18	1.16	1.18	1.16	1.16								
Ecuador	0.50	0.50	0.49	0.49	0.50	0.48	0.48								
Venezuela	2.59	2.56	2.46	2.40	2.50	2.51	2.50								
Total Crude Oil	29.90	29.42	29.87	30.31	29.88	31.36	31.73								
Total NGLs[1]	5.77	5.72	5.76	5.85	5.78	6.05	6.13	6.33	6.35	6.22	6.50	6.64	6.88	6.95	6.94
Total OPEC[2]	35.67	35.14	35.64	36.16	35.65	37.41	37.86								
NON-OPEC[3]															
OECD															
Americas[7]	14.34	14.27	14.50	15.25	14.59	15.58	15.57	15.74	16.08	15.74	16.35	16.74	17.35	18.03	18.62
United States[6]	7.87	8.03	8.02	8.60	8.13	8.84	8.89	8.92	9.15	8.95	9.42	9.92	10.45	11.11	11.41
Mexico	2.97	2.96	2.92	2.92	2.94	2.92	2.94	2.91	2.84	2.90	2.78	2.73	2.70	2.57	2.60
Canada	3.49	3.26	3.55	3.72	3.51	3.80	3.72	3.90	4.07	3.87	4.13	4.07	4.20	4.34	4.60
Chile	0.01	0.01	0.01	0.01	0.01	0.02	0.01	0.01	0.02	0.01	0.01	0.01	0.01	0.01	0.01
Europe[8]	4.03	3.74	3.55	3.75	3.77	3.80	3.59	3.15	3.42	3.49	3.29	3.31	3.33	3.19	3.09
UK	1.26	1.15	0.94	1.10	1.11	1.11	1.01	0.82	0.96	0.97	0.93	0.94	0.94	0.93	0.91
Norway	2.14	1.98	1.99	2.05	2.04	2.09	1.98	1.76	1.88	1.93	1.80	1.85	1.90	1.80	1.71
Others	0.63	0.60	0.61	0.60	0.61	0.61	0.60	0.57	0.58	0.59	0.56	0.52	0.49	0.46	0.47
Asia Oceania[9]	0.56	0.57	0.57	0.58	0.57	0.52	0.55	0.55	0.55	0.54	0.53	0.56	0.59	0.59	0.59
Australia	0.47	0.49	0.48	0.49	0.48	0.43	0.46	0.47	0.46	0.46	0.45	0.49	0.52	0.52	0.52
Others	0.09	0.08	0.09	0.09	0.09	0.09	0.09	0.08	0.09	0.09	0.08	0.07	0.07	0.07	0.07
Total OECD	18.94	18.58	18.61	19.58	18.93	19.90	19.71	19.44	20.05	19.78	20.17	20.61	21.27	21.81	22.30
NON-OECD															
Former USSR	13.64	13.57	13.53	13.57	13.58	13.73	13.62	13.48	13.72	13.64	13.59	13.63	13.63	13.72	13.63
Russia	10.54	10.57	10.59	10.69	10.60	10.71	10.68	10.70	10.72	10.70	10.65	10.56	10.47	10.59	10.59
Others	3.10	3.01	2.94	2.89	2.98	3.02	2.94	2.79	3.00	2.94	2.94	3.08	3.16	3.13	3.04
Asia	7.87	7.68	7.61	7.59	7.69	7.79	7.66	7.64	7.63	7.68	7.66	7.73	7.76	7.79	7.79
China	4.20	4.16	4.05	4.00	4.10	4.18	4.10	4.11	4.11	4.12	4.20	4.30	4.36	4.41	4.54
Malaysia	0.70	0.61	0.65	0.67	0.66	0.70	0.67	0.66	0.65	0.67	0.66	0.70	0.74	0.74	0.71
India	0.93	0.91	0.91	0.89	0.91	0.90	0.90	0.90	0.92	0.91	0.89	0.82	0.74	0.67	0.64
Indonesia	0.94	0.93	0.94	0.92	0.93	0.90	0.88	0.85	0.84	0.87	0.81	0.76	0.74	0.80	0.79
Others	1.11	1.06	1.07	1.10	1.08	1.12	1.12	1.12	1.11	1.11	1.09	1.15	1.18	1.17	1.12
Europe	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.13	0.14	0.13	0.12	0.11	0.10	0.09
Latin America	4.20	4.18	4.21	4.33	4.23	4.28	4.15	4.13	4.27	4.21	4.39	4.42	4.70	4.95	5.04
Brazil[6]	2.18	2.18	2.16	2.25	2.19	2.26	2.12	2.17	2.28	2.21	2.39	2.39	2.59	2.85	2.95
Argentina	0.72	0.64	0.70	0.71	0.69	0.68	0.67	0.61	0.65	0.65	0.62	0.61	0.63	0.66	0.68
Colombia	0.87	0.93	0.93	0.95	0.92	0.93	0.94	0.94	0.94	0.94	0.99	1.03	1.02	0.99	0.96
Others	0.44	0.43	0.43	0.42	0.43	0.41	0.41	0.41	0.40	0.41	0.39	0.40	0.46	0.46	0.45
Middle East[4]	1.78	1.65	1.69	1.47	1.65	1.40	1.45	1.50	1.48	1.46	1.48	1.39	1.33	1.26	1.18
Oman	0.89	0.88	0.90	0.89	0.89	0.89	0.91	0.93	0.92	0.91	0.95	0.92	0.90	0.87	0.85
Syria	0.39	0.38	0.35	0.19	0.33	0.17	0.16	0.16	0.16	0.16	0.14	0.11	0.11	0.09	0.06
Yemen	0.30	0.19	0.24	0.18	0.23	0.14	0.18	0.21	0.21	0.19	0.20	0.18	0.15	0.13	0.11
Others	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.19	0.19	0.19	0.19	0.17	0.17	0.16	0.16
Africa	2.58	2.59	2.60	2.62	2.60	2.45	2.28	2.27	2.27	2.32	2.33	2.51	2.62	2.58	2.78
Egypt	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.73	0.73	0.73	0.72	0.70	0.69	0.67	0.65
Equatorial Guinea	0.26	0.25	0.25	0.25	0.25	0.29	0.28	0.28	0.28	0.28	0.29	0.32	0.31	0.30	0.30
Sudan	0.46	0.46	0.10	0.11	0.28	0.10	0.06	0.05	0.05	0.07	0.06	0.09	0.08	0.07	0.06
Others	1.12	1.14	1.52	1.53	1.33	1.32	1.20	1.21	1.20	1.23	1.26	1.40	1.55	1.54	1.77
Total Non-OECD	30.20	29.81	29.79	29.72	29.88	29.79	29.30	29.16	29.51	29.44	29.58	29.81	30.15	30.39	30.52
Processing Gains[5]	2.11	2.09	2.13	2.11	2.11	2.14	2.11	2.16	2.13	2.14	2.18	2.21	2.26	2.29	2.33
Global Biofuels[6]	1.51	1.93	2.18	1.83	1.87	1.56	1.82	2.16	1.94	1.87	2.03	2.17	2.28	2.35	2.37
TOTAL NON-OPEC[2]	52.76	52.41	52.71	53.24	52.78	53.39	52.94	52.92	53.62	53.22	53.96	54.80	55.96	56.84	57.53
TOTAL SUPPLY	88.43	87.56	88.35	89.40	88.44	90.80	90.80	52.92							

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 Total OPEC comprises all countries which were OPEC members at 1 January 2009.
Total Non-OPEC excludes all countries that were OPEC members at 1 January 2009.
3 Comprises crude oil, condensates, NGLs and oil from non-conventional sources.
4 Includes small amounts of production from Jordan and Bahrain.
5 Net volumetric gains and losses in refining and marine transportation losses.
6 As of the June 2010 MTOGM, Global Biofuels comprise all world biofuel production including fuel ethanol from the US and Brazil.
7 As of the August 2012 OMR, includes Chile.
8 As of the August 2012 OMR, includes Estonia and Slovenia.
9 As of the August 2012 OMR, includes Israel.

Table 3A: SELECTED NON-OPEC UPSTREAM PROJECT START-UPS

Country	Project	Peak Capacity (kbd)	Start Year	Country	Project	Peak Capacity (kbd)	Start Year	Country	Project	Peak Capacity (kbd)	Start Year
OECD Americas				Canada	Narrows Lake Phase 1	43	2017	Russia	Vladimir Filanovsky	150	2015
USA	Big Foot	75	2014	Canada	Mackay River Phase 2	40	2017	Russia	Yurubcheno-Tokhomskoye	150	2016
USA	Caesar	40	2012	Canada	Hangingstone Phase 2	35	2017	Russia	Chayadinskoye	50	2015
USA	Gunflint/Freedom	120	2015	Mexico	Ayatsil	100	2014	Azerbaijan	West Chirag Oil	150	2014
USA	Jack/St Malo	170	2015	Mexico	Tsimin	100	2014	Kazakhstan	Kashagan phase 1a	375	2013
USA	Kaskida	140	2016								
USA	Liberty	40	2013	***OECD Europe***		90	2014	***Asia***			
USA	Mad Dog tie-backs	100	2015	Italy	Tempa Rossa	50	2015	India	Bhagyam	60	2012
USA	Mars B	100	2015	Norway	Ekofisk extension	50	2015	Indonesia	Banu Urip	140	2014
USA	Tubular Bells	100	2015	Norway	Eldfish extension	20	2015	Indonesia	Bukit Tua	20	2014
USA	Vito	90	2015	Norway	Froy redevelopment	35	2016	Malaysia	Gumusut	130	2013
USA	Who Dat	55	2012	Norway	Goliat	100	2014	Malaysia	Malikai	50	2016
USA	Axe & Dalmation	10	2013	Norway	Gudrun/Sigrun	70	2014	Malaysia	Kebabangan	25	2015
USA	Knotty Head	20	2013	Norway	Skarv	80	2013	Vietnam	Hai Su Den/Hai Su Trang (JV with Talisman)	35	2011
USA	Lucius	70	2014	Norway	Johan Sverdrup	140	2017	Thailand	Manora	15	2014
USA	Stones	80	2013	Norway	Draupne	20	2016				
USA	Great White (incr)	40	2014	Norway	Dagny/Eirin	35	2017	***Latin America***			
Canada	North Steepbank Extension	180	2012	Norway	Hild	30	2016	Brazil	Baleia Azul	100	2012
Canada	Kearl Phase 1	110	2012	Norway	Knarr (Jordbaer)	25	2014	Brazil	Carioca (pre-salt)	50	2015
Canada	Christina Lake Phase D	40	2012	UK	Valemon (NGLs)	10	2015	Brazil	Sapinhoa pilot (pre-salt), formerly Guara	120	2013
Canada	Firebag Stage 4	63	2013	UK	Cheviot (former Emerald)	30	2014	Brazil	Guaiama	100	2015
Canada	Kirby (South) Phase 1	40	2013	UK	Clair expansion	35	2015	Brazil	Lula, Iracema South	150	2015
Canada	Christina Lake Phase E	40	2013	UK	Golden Eagle	60	2014	Brazil	Lula, NE Pilot, FPSO Cidade Paraty	120	2013
Canada	Christina Lake Phase 2B	35	2013	UK	Huntington	30	2012	Brazil	Papa Terra - BC-20	120	2013
Canada	Tamarack Phase 1	20	2013	UK	Andrew	40	2014	Brazil	Parque das Baleias P-58 (pre-salt)	175	2014
Canada	Sunrise Phase 1	60	2014	UK	West Franklin	20	2014	Brazil	Roncador Module 3, P-55	150	2014
Canada	Foster Creek Phase F	45	2014	UK	Fyne	20	2014	Brazil	Roncador P-62	150	2014
Canada	Cold Lake Phase 14-16	40	2014	UK	Jasmine	35	2013	Brazil	Bauna and Piracaba, formerly Tiro/Sidon	80	2012
Canada	Mackay River Phase 1	35	2014	UK	Solan	20	2014	Brazil	OGX Fields	60	2013-2015
Canada	Tamarack Phase 1	35	2014	UK	Lochnagar	75	2017	Brazil	Iara	100	2016
Canada	Great Divide expansion	24	2014	UK	Emerald	25	2014	Brazil	Siri	150	2015
Canada	Kearl Phase 2	110	2015	UK	Mariner	35	2016	Brazil	Franco transfer of rights	100	2016
Canada	Surmont Phase 2	109	2015	UK	Schiehallion Expansion	20	2015	Colombia	Various additions	50	2014
Canada	Dover Phase 1	50	2015					Peru	Block 67 Amazon	100	2014
Canada	Foster Creek Phase G	40	2015	***OECD Asia Oceania***							
Canada	Kai Kos Dehseh Corner	40	2015	Australia	Coniston	30	2013	***Middle East***			
Canada	Peace River Carmon Creek-Phase 1	40	2015	Australia	Montara (and Skua & Swift)	35	2011	Bahrain	Awali EOR	35	2013
Canada	Jackfish Phase 3	35	2015	Australia	North Rankin and Gorgon Liquids	50	2014	Oman	Harweel and other PDO EOR	40	2011
Canada	Hangingstone expansion	35	2015	Australia	Balnaves	25	2014	Oman	Mukhaizna EOR	50	2012
Canada	Germain Phase 2	30	2015	Australia	Other Additions	30	2015	Oman	Qarn Alam EOR (PDO)	40	2012
Canada	Blackgold Phase 2	20	2015								
Canada	Fort Hills Phase 1	165	2016	***FSU***				***Africa***			
Canada	Mildred Lake/Aurora North & Aurora South Train 1	100	2016	Russia	Arkutun-Daginskoye	90	2014	Congo	Moho North	100	2016
Canada	Sunrise Phase 2	50	2016	Russia	Bolshekhetsky	100	2013	Gabon	Various additions	10	2016
Canada	Christina Lake Phase F	50	2016	Russia	North Talakan	30	2012	Ghana	Tweneboa and Enyenra	105	2014
Canada	Christina Lake Phase 3A	50	2016	Russia	Novoportovskoye (yr round)	80	2014	Ivory Coast	Acajou	10	2017
Canada	Poplar Creek Phase 2	40	2016	Russia	Messoyakha	125	2017	Equatorial Guinea	Belinda (Alen)	40	2014
Canada	Mackay River MR2	40	2016	Russia	Prirazlomnoye	120	2013	Equatorial Guinea	Okume Complex additions	5	2014
Canada	Kirby (North) Phase 1	40	2016	Russia	Russkoye	150	2015	Mauritania	Banda (Tullow)	10	2015
Canada	Foster Creek Phase H	40	2016	Russia	Tagul	100	2016	Uganda	Albert Basin (Tullow/Heritage) next phases	150	2015
Canada	Pelican Lake Grand Rapids Phase A	60	2017	Russia	Trebs & Titov	120	2014	Niger	Tenere Bilma	70	2015
Canada	Christina Lake Phase G	50	2017	Russia	Tsentralnoye	100	2015				

Table 3B: SELECTED OPEC UPSTREAM PROJECT START-UPS

Country	Project	Peak Capacity (kbd)	Start Year	Country	Project	Peak Capacity (kbd)	Start Year	Country	Project	Peak Capacity (kbd)	Start Year
Crude Oil Projects								*NGL & Condensate Projects*			
Algeria	IAN/EOR	30	2012	Iraq	Majnoon Phase 1	200	2013	Algeria	MLE (Condensate)	10	2012
Algeria	Menzel Ledjmet East (MLE Block 405b)	32	2012	Iraq	W. Qurna 2 Phase 2	400	2014	Algeria	MLE (NGLs)	14	2012
Algeria	Takouazet	50	2012	Iraq	Badra	110	2014	Algeria	Tisselit Nord (Condensate)	10	2012
Algeria	El Merk	135	2013	Iraq	Kirkuk	50	2014	Algeria	Hassi Messaoud (LPG)	50	2012
Algeria	Bir Seba (Blocks 433a/416b)	36	2014	Iraq	Zubair Phase 2	100	2016	Algeria	El Merk (Condensate)	30	2013
Angola	PSVM (Block 31)	150	2012	Iraq	Nahr Bin Umar	70	2017	Algeria	El Merk (NGLs)	31	2013
Angola	Kizomba D-Satellites (Block 15) Clochas & Mavacola	140	2012	Libya	Amal	45	2014	Algeria	Gassi Touil (NGLs)	10	2013
Angola	Sangos/N'Goma (Block 15)	85	2013	Libya	Al Farigh 2	20	2015	Angola	Soyo LNG Project (Condensate)	10	2012
Angola	Platino, Chumbo, Cesio (Block 18W)	150	2013	Libya	Area 47 Ghadames Basin	50	2015	Angola	Soyo LNG Project (NGLs)	50	2012
Angola	SE PAJ (Block 31)	150	2014	Libya	Zuetina expansion	40	2016	Angola	Mafumeira Sul (NGLs)	10	2014
Angola	CLOV (Block 17)	160	2014	Nigeria	Usan	180	2012	Iran	Pars 9&10 (Condensate)	20	2013
Angola	Terra Miranda, Cordelia, Portia (Block 31)	150	2014	Nigeria	Erha North	50	2013	Iran	Pars 9&10 (NGLs)	20	2013
Angola	Mafumeira Sul (Block 0)	110	2014	Nigeria	Bonga SW & Aparo	140	2014	Iran	Pars 12 (Condensate)	20	2015
Angola	Cabaca Norte-1 (Block 15)	40	2014	Nigeria	Bonga NW	50	2014	Iran	Pars 12 (NGLs)	6	2015
Angola	Lucapa (Block 14)	100	2014	Nigeria	Egina	200	2014	Iran	Kharg NGL	20	2015
Angola	Lianzi (Congo-Brazzaville joint zone)	45	2014	Nigeria	Nsiko	100	2015	Libya	NC-98 Condensate	100	2013
Angola	Gindungo, Canela, Gengibre (Block 32)	150	2015	Nigeria	Bosi	135	2015	Nigeria	OKLNG (NGLs)	30	2015
Angola	Chissonga (Block 16)	150	2016	Nigeria	Uge	110	2016	Nigeria	Gbaran/Ubie (Condensate)	20	2016
Angola	Mostrado, Cola, Salsa, Manjericao (Block 32)	90	2017	Saudi Arabia	Manifa 1	500	2013	Qatar	Barzan (Condensate)	23	2015
Angola	Negage (Block 14)	50	2018	Saudi Arabia	Manifa 2	400	2015	Saudi Arabia	Manifa 1 (Condensate)	65	2013
Ecuador	Pungarayacu--Phase 1	30	2012	UAE	Lower Zakum expansion	125	2012	Saudi Arabia	Hasbah NGLs	30	2014
Ecuador	Pungarayacu--Phase 2	25	2013	UAE	ADCO Onshore-Sahil, Asab, Shah	65	2012	Saudi Arabia	Shaybah (NGLs)	210	2014
Iran	Yadavaran I	85	2012	UAE	ADCO Onshore Qusawirah\Bidah al Qemzan	65	2012	UAE	IGD--Integrated Gas Dev. (Condensate)	30	2013
Iran	South Pars	35	2013	UAE	Bab	80	2012	UAE	IGD--Integrated Gas Dev. (NGLs)	110	2013
Iran	Paranj	25	2013	UAE	Bab Rumaitha/Al-Dabbiya (NE)	75	2013	UAE	Shah Sour Gas (Condensates)	35	2015
Iran	Yaran	12	2014	UAE	Upper Zakum expansion	200	2015	UAE	Shah Sour Gas (NGLs)	32	2015
Iraq	Al Ahdab	50	2012	Venezuela	Junin Block 2-PetroVietnam	200	2012				
Iraq	Gharaf	230	2012	Venezuela	Junin Block 4--CNPC	400	2013				
Iraq	Rumaila Phase 2	400	2013	Venezuela	Junin Block 5--ENI	240	2013				
Iraq	W. Qurna 2 Phase 1	175	2013	Venezuela	Carabobo 1	400	2013				

Table 4
WORLD REFINERY CAPACITY ADDITIONS*

(thousand barrels per day)

	2012	2013	2014	2015	2016	2017	Total
Refinery Capacity Additions and Expansions[1]							
OECD North America	-195	105	29	75			14
OECD Europe	-514	-326			200		-640
OECD Pacific	-35	-60	-394				-489
FSU	133	162	48	160	215		718
Non-OECD Europe	110						110
China	188	490	680	600	670	300	2,928
Other Asia	529	420	152	80		250	1,431
Latin America	1	-226	285	175	148	165	548
Middle East	188	451	437	400	358	65	1,899
Africa	68	40	46		95	195	444
Total World	473	1,057	1,283	1,490	1,686	975	6,963
Upgrading Capacity Additions[2]		1					
OECD North America	28	131	150	64			373
OECD Europe	-56	-40		221			125
OECD Pacific	-35	18	-46		80		17
FSU	191	220	154	158	150	90	962
Non-OECD Europe	59		34	50			143
China	166	439	325	297	195		1,422
Other Asia	524	317	161	125		90	1,217
Latin America	23	-61	60	170	104	130	425
Middle East	119	300	413	281	95		1,208
Africa						57	57
Total World	1,018	1,323	1,251	1,366	624	367	5,948
Desulphurisation Capacity Additions[3]							
OECD North America	-36	240	85	60			349
OECD Europe	-157	-200		35			-323
OECD Pacific	-14	-89	-82				-184
FSU	312	144	160	20	35		671
Non-OECD Europe	40		45				85
China	198	470	371	560	253		1,851
Other Asia	484	284	104	25		180	1,076
Latin America	181	90	111	160	30	40	612
Middle East	230	245	250	302	172		1,198
Africa		95				42	137
Total World	1,237	1,278	1,044	1,162	489	262	5,473

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.
* New OECD members Chile and Israel are still accounted for in Latin America and Middle East, respectively. Estonia and Slovenia have no refineries.

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

(thousand barrels per day)

	2011	2012	2013	2014	2015	2016	Total
Refinery Capacity Additions and Expansions[1]							
OECD North America	185	-420	20	14	25		-176
OECD Europe		-299	-352		-200	200	-651
OECD Pacific		-135	-25	-274			-434
FSU		-190	110		40		-40
Non-OECD Europe		-6					-6
China	73	-258	170	160	-360	150	-65
Other Asia		-120	120	-69	20		-49
Latin America		-54	-271	-315	175	-235	-700
Middle East		10		20		-170	-140
Africa	-18	-134	40		-30	35	-107
Total World	240	-1,607	-188	-464	-330	-20	-2,368
Upgrading Capacity Additions[2]							
OECD North America	69	-303	71	65			-98
OECD Europe	-45	-14	-95				-154
OECD Pacific		-35	15	-21			-41
FSU	60	-26	-27	128	43	110	298
Non-OECD Europe		-34		-9	50		7
China	28	-202	195	27	-178	33	-97
Other Asia	-31	-45	5	125			54
Latin America		-27	-104	-300	170	-130	-391
Middle East	-85			196	61	-12	160
Africa	20	-20					
Total World	16	-705	59	211	146	2	-262
Desulphurisation Capacity Additions[3]							
OECD North America	75	-390	170				-145
OECD Europe		-48	-200				-248
OECD Pacific		-44	-69	-12			-125
FSU	90	78	-96	120	20	15	227
Non-OECD Europe		-45		45			
China		-234	141	24	-170	-44	-283
Other Asia	-45	-54	99	-35			-35
Latin America	-40	-32	-97	-225	160	-205	-439
Middle East		-60			187	-6	121
Africa		-95	95				
Total World	80	-924	43	-83	197	-240	-927

1 Comprises new refinery projects or expansions to existing facilities including condensate splitter additions. Assumes zero capacity creep.

2 Comprises stand-alone additions to coking, hydrocracking or FCC capacity. Excludes upgrading additions counted under 'Refinery Capacity Additions and Expansions' category.

3 Comprises stand-alone additions to hydrotreating and hydrodesulphurisation capacity. Excludes desulphurisation additions counted under 'Refinery Capacity Additions and Expansions' category.

* New OECD members Chile and Israel are still accounted for in Latin America and Middle East, respectively. Estonia and Slovenia have no refineries.

Table 4B: SELECTED REFINERY CRUDE DISTILATION PROJECT LIST

Country	Project	Capacity (kbd)	Start Year
OECD Americas			
Canada	Consumers' Cooperative Refineries Ltd. - Regina	30	2012
Canada	North West Redwater Partnership - Edmonton	50	2015
United States	Motiva Enterprises LLC - Port Arthur	325	2012
United States	Marathon Petroleum Co. LLC - Garyville	20	2012
United States	Marathon Petroleum Co. LLC - Detroit	15	2012
United States	Flint Hills Resources - North Pole	-70	2012
United States	Sunoco Inc. - Marcus Hook	-175	2012
United States	ConocoPhillips - Borger	50	2013
United States	Valero Energy Corp. - Sunray	25	2013
United States	BP PLC - Whiting	20	2013
United States	National Cooperative Refining Assoc. - McPherson	15	2014
United States	Holly Corp. - Woods Cross	14	2014
United States	Western Refining Inc. - El Paso	25	2015
US Virgin Islands	Hovensa LLC - St. Croix	-350	2012
OECD Europe			
Czech Republic	Paramo AS - Pardubice	-20	2012
France	LyondellBasel - Berre L'Etang	-105	2012
France	Petroplus - Petit Couronne	-162	2013
Germany	Shell - Harburg	-110	2013
Hungary	MOL Hungarian Oil & Gas Co. - Szazhalombatta	26	2013
Italy	Raffineria de Roma - Rome	-89	2012
Italy	Eni - Porto Marghera	-80	2013
Turkey	Turcas Petrol+SOCAR - Aliaga/Izmir	200	2016
United Kingdom,	ExxonMobil Refining & Supply Co. - Fawley	-80	2012
United Kingdom,	Petroplus - Coryton Essex	-220	2012
OECD Asia Oceania			
Australia	Shell Refinery - Clyde	-85	2012
Australia	Caltex Refineries (NSW) Ltd. - Kurnell	-124	2014
Japan	Cosmo Oil Co. Ltd. - Sakaide	-110	2013
Japan	Idemitsu Kosan Co. Ltd. - Shunan, Yamaguchi	-120	2014
Japan	JX Energy - Unidentified	-200	2014
South Korea	S-Oil Corp. - Ulsan	50	2012
Non-OECD Europe			
Bosnia	Zarubezhneft - Brod	60	2012
Romania	Petrobrazi SA - Ploiesti	50	2012
FSU			
Chechen Republic	Rosneft - Grozny	20	2015
Kazakhstan	Kazmunigas - Atyrau	48	2014
Russia	GAZPROMNEFT - Salavat	120	2012
Russia	Mari El refinery - Mari Republic	63	2012
Russia	TNK-BP - Ryazan	30	2012
Russia	GAZPROMNEFT - Salavat	-80	2012
Russia	Rosneft - Tuapse	140	2013
Russia	Alliance Co. - Khabarovsk	20	2013
Russia	Lukoil - Volgograd	120	2015
Russia	West Siberian Oil Refinery - Tomsk	60	2015
Russia	Verkhoturye - Sverdlovsk	60	2015
Russia	Lukoil - Volgograd	-100	2015
Russia	Antipinsky Refinery - Antipinsky	120	2016
Russia	Lukoil - Kstovo, Nizhny Novgorod	95	2016
China			
China	Sinopec - Jinling Nanjing	90	2012
China	CNPC - Huhhot Petchem	100	2012
China	Sinopec - Anqing	70	2012
China	Sinopec - Wuhan	20	2012
China	Sinopec - Maoming	200	2013
China	CNPC - Pengzhou	200	2013
China	CNPC - Renqui	100	2013
China	Sinopec - Shijiazhuang	60	2013
China	Sinochem KPC Shell - Quanzhou Fujiang	240	2014
China	Sinopec - Caofeidian	200	2014

Country	Project	Capacity (kbd)	Start Year
China	CNPC - Kunming/Anning	200	2014
China	CNOOC/Local Ningbo Daxie - Zhejiang	140	2014
China	CNPC/PDVSA - Jieyang, Guangdong	400	2015
China	Sinopec/KPC - Zhanjiang, southern Guangdong	300	2015
China	Sinopec - Zhenhai	300	2016
China	CNPC/Rosneft - Tianjin	300	2016
China	CNPC - Karamay, Xinjiang	100	2016
China	CNPC - Fushun	70	2016
China	CNPC/Qatar Petroleum/Shell - Zhejiang	400	2017
China	Local Refineries	-100 per year	2012/2017
Other Asia			
Bangladesh	Eastern Refinery Ltd. - Chittagong	70	2015
China, Taiwan	Chinese Petroleum Corp. - Kaohsiung	-205	2015
India	HPCL/MITTAL (HMEL) - Bathinda(GGSR)	180	2012
India	Essar Oil - Vadinar	120	2012
India	Mangalore Refinery & Petrochemicals Ltd. -	64	2012
India	Chennai Refinery - Madras	35	2012
India	Indian Oil Co. Ltd. - Paradip	300	2013
India	Nagarjuna oil Co - Cuddalore	120	2013
Pakistan	Byco Petroleum Pakistan Ltd. - Karachi	130	2012
Pakistan	IPIC/PARCO - Khalifah Coastal Refinery	250	2017
Thailand	Thai Oil Co. Ltd. - Sriracha	30	2014
Thailand	PTT PLC - Bangchak Bangkok	20	2015
Vietnam	Petro vietnam/KPC/Idemitsu Kosan - Nghi Son	195	2015
Middle East			
Iran	National Iranian Oil Co. - Arak	80	2012
Iran	National Iranian Oil Co. - Lavan Island	21	2013
Iraq	Kurdistan Govn. - Erbil	40	2012
Iraq	KRG - Sulaimaniya	34	2012
Iraq	INOC-ORA - Karbala	140	2016
Oman	Sohar Bitumen Refinery - Sohar	30	2013
Oman	Oman Refinery Co. - Sohar	72	2016
Saudi Arabia	SATORP (Saudi Aramco Total Refining and	400	2013
Saudi Arabia	Aramco Sinopec - Yanbu	400	2015
Saudi Arabia	Saudi Aramco - Rabigh 2	50	2017
UAE-Abu Dhabi	Abu Dhabi National Oil Co. - Ruwais2	417	2014
UAE-Dubai	Emirates National Oil Co. - Jebel Ali	20	2014
Latin America			
Argentina	Repsol YPF SA - La Plata	25	2013
Aruba	Valero Aruba Refinery - San Nicolas	-271	2013
Brazil	Petrobras - Araucaria, Parana	25	2012
Brazil	Petrobras/PDVSA - Pernambuco State Abreu e	115/115	2014/2015
Brazil	Petrobras - COMPERJ	165	2017
Colombia	Ecopetrol- Cartagena, Bolivar	85	2014
Colombia	Ecopetrol - Barrancabermeja-Santander	50	2016
Costa Rica	Recope - Limon	-24	2012
Costa Rica	Recope/CNPC - Limon	65	2016
Cuba	Cuba Petroleos - Cienfuegos	85	2014
Jamaica	Petrojam Ltd. - Kingston	20	2013
Peru	Petroperu SA - Talara, Piura	33	2016
Venezuela	PDVSA - Santa Inés (Barinas)	60	2015
Africa			
Algeria	Naftec SPA - Skikda	40	2013
Algeria	Sonatrach - Algiers	18	2014
Algeria	Naftec SPA - Arzew	75	2016
Algeria	Naftec SPA - Skikda	75	2017
Angola	Sonangol - Lobito	120	2017
Cameroon	SONARA - Cape Limboh Limbe	28	2014
Morocco	Societe Anonyme Marocaine de L'Industrie du	48	2012
Niger	CNPC - Ganaram	20	2012
Uganda	Tullow -JV - Albertine Graben	20	2016

Table 5
WORLD ETHANOL PRODUCTION[1]

(thousand barrels per day)

	2011	2012	2013	2014	2015	2016	2017
OECD Americas[2]	936	885	920	967	998	1,021	1,021
United States	907	855	888	936	965	984	984
Canada	28	29	31	31	33	36	36
OECD Europe[3]	65	71	85	92	94	96	96
Austria	2	2	2	2	2	2	2
Belgium	4	3	3	3	3	3	3
France	15	15	19	19	19	20	20
Germany	13	13	13	14	14	14	14
Italy	1	2	3	3	3	3	3
Netherlands	3	5	5	5	5	5	5
Poland	4	4	6	8	8	8	8
Spain	7	7	9	9	9	9	9
UK	5	6	10	12	14	14	14
OECD Asia Oceania[4]	9	7	8	10	10	11	11
Australia	9	7	8	9	9	9	10
Total OECD	**1,010**	**963**	**1,013**	**1,069**	**1,102**	**1,127**	**1,128**
FSU	4	3	4	4	4	4	4
Non-OECD Europe	2	1	1	1	1	1	1
China	37	43	49	52	52	55	55
Other Asia	20	27	37	44	46	46	50
India	6	8	9	9	9	9	10
Indonesia	0	1	2	2	3	3	3
Malaysia	0	0	0	0	0	0	0
Philippines	2	3	6	8	10	10	11
Singapore	1	1	1	1	1	1	1
Thailand	7	11	13	15	15	15	17
Latin America	391	421	462	488	528	554	565
Argentina	3	4	5	8	8	8	8
Brazil	369	395	432	452	492	519	530
Colombia	5	6	7	8	8	8	8
Middle East	0	0	0	0	0	0	0
Africa	2	3	5	6	7	9	9
Total Non-OECD	**457**	**500**	**558**	**595**	**638**	**669**	**684**
Total World	**1,467**	**1,463**	**1,571**	**1,664**	**1,740**	**1,796**	**1,812**

1 Volumetric production; to convert to energy adjusted production, ethanol is assumed to have 2/3 energy content of conventional gasoline.

2 As of August 2012 OMR, OECD Americas includes Chile.

3 As of August 2012 OMR, OECD Europe includes Estonia and Slovenia.

4 As of August 2012 OMR, OECD Asia Oceania includes Israel.

Table 5A
WORLD BIODIESEL PRODUCTION[1]

(thousand barrels per day)

	2011	2012	2013	2014	2015	2016	2017
OECD Americas[2]	67	69	83	90	90	90	90
United States	63	65	78	84	84	84	84
Canada	4	4	5	6	6	6	6
OECD Europe[3]	170	161	176	194	214	219	220
Austria	4	3	4	4	4	4	4
Belgium	6	6	6	7	7	7	7
France	32	35	38	39	39	41	41
Germany	55	48	49	54	58	58	58
Italy	12	11	13	16	16	16	16
Netherlands	7	8	8	10	11	11	12
Poland	4	4	6	8	8	8	8
Spain	13	11	14	16	20	20	20
UK	3	4	5	6	8	8	8
OECD Asia Oceania[4]	8	8	8	9	10	10	10
Australia	1	1	2	2	3	3	3
Total OECD	**244**	**238**	**267**	**293**	**313**	**318**	**319**
FSU	2	1	1	1	1	1	1
Non-OECD Europe	3	3	3	3	3	3	3
China	3	3	5	6	6	6	6
Other Asia	45	48	59	65	66	68	72
India	0	1	1	2	2	2	2
Indonesia	23	21	21	23	23	23	23
Malaysia	2	2	3	5	7	8	10
Philippines	2	3	4	4	4	4	4
Singapore	8	13	15	15	15	15	15
Thailand	9	10	14	16	16	16	18
Latin America	103	114	122	138	149	149	154
Argentina	47	54	54	60	67	67	72
Brazil	46	49	56	65	68	68	68
Colombia	6	7	9	9	11	11	11
Middle East	0	0	0	0	0	0	0
Africa	0	0	1	3	4	4	4
Total Non-OECD	**155**	**169**	**191**	**216**	**229**	**231**	**240**
Total World	**399**	**407**	**459**	**509**	**542**	**550**	**559**

1 Volumetric production; to convert to energy adjusted production, biodiesel is assumed to have 90% energy content of conventional diesel.

2 As of August 2012 OMR, OECD Americas includes Chile.

3 As of August 2012 OMR, OECD Europe includes Estonia and Slovenia.

4 As of August 2012 OMR, OECD Asia Oceania includes Israel.

Table 5B: SELECTED BIOFUEL PROJECT START-UPS

Country	Project	Output	Capacity (kbd)	Capacity (mly)	Start Year
OECD Americas					
USA	Diamond Green - Norco, Los Angeles	biodiesel (hydrotreated)	9	520	2013
USA	Cargill Inc. - Fort Dodge, Iowa	ethanol	8	435	2013
USA	AltAir/ Tesoro - Anacortes, Washington	biodiesel (hydrotreated)	7	380	2013
USA	Columbia Pacific - Clatskanie, Oregon	ethanol	7	416	2012
Canada	Northern Biodiesel Limited - Lloydminister, Alberta	biodiesel	5	265	2013
USA	Big River Resources - Boyceville, Wisconsin	ethanol	4	210	2012
USA	The Anderssons Albion Ethanol - Albion, Michigan	ethanol	4	205	2012
USA	POET - Coon Rapids, Iowa	ethanol	4	205	2012
Canada	Great Lakes Biodiesel - Welland, ON	biodiesel	3	170	2012
USA	BP Biofuels - Highlands County, Florida	cellulosic-ethanol	2	135	2014
USA	Dupont - Nevada, Iowa	cellulosic-ethanol	2	105	2014
USA	Abengoa Bioenergy - Hugoton, Kansas	cellulosic-ethanol	2	95	2013
USA	POET - Emmetsburg, Iowa	cellulosic-ethanol	2	95	2013
Canada	Lignol - Vancouver, British Columbia	cellulosic-ethanol	1	75	2015e
Canada	Mascoma - Drayton, Alberta	cellulosic-ethanol	1	75	2015e
Canada	Highland EnciroFuels - Highland County, Florida	cellulosic-ethanol	1	75	2013
OECD Europe					
UK	Vivergo - Hull	ethanol	7	420	2012
Hungary	Pannonia Ethanol	ethanol	4	250	2012
Portugal	Galp Energy/ Petrobras - Sines, Alentejo	biodiesel	4	225	2015e
Denmark	Heveiti - Gernaa	ethanol	3	200	2012
Switzerland	Green Bio Fuel Switzerland - Bad Zurzach, Aargau	biodiesel	2	135	2014
Finland	UPM - Lappeenranta	biodiesel (hydrotreated)	2	110	2014
Italy	Chemtex - Piedmont	cellulosic-ethanol	1	50	2012
Asia					
Australia	National Biodiesel - Port Kembla, New South Wales	biodiesel	5	290	2013
Indonesia	Perkebunan Nusantara & Ferrostaal Indonesia - Sei Mangkei	biodiesel	5	280	2014
Latin America					
Argentina	Green Pampas	ethanol	7	380	2014e
Brazil	Vale SA - Para	biodiesel	7	405	2015e
Argentina	Louis Dreyfus - General Lagos	biodiesel	6	340	2012
Brazil	Oleoplan - Veranopolis	biodiesel	5	300	2013
Argentina	Noble Agentina - Timbues, Santa Fe	biodiesel	5	280	2013
Argentina	ACA Bio - Cordorba	ethanol	3	120	2013
Brazil	Solazymes - Moema	biodiesel (algae)	2	125	2013

The IEA Monthly Oil Data Service

A unique source of official statistical data and the most comprehensive and up-to-date information available on the global oil market

The IEA *Monthly Oil Data Service (MODS)* provides a detailed database of historical and projected information used in preparing the IEA *Oil Market Report (OMR)*. This service comprises **three packages**, available separately or combined, on a subscription basis via the **Internet (http://modsinfo.iea.org)**. The MODS service is updated with the most recently available data on the day of official release of the *OMR*.

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    - ***Stocks:*** comprehensive monthly coverage of industry and government-controlled stock data in individual OECD countries and for the three OECD regions, covering crude oil, NGL and feedstocks, motor gasoline, middle distillates residual fuel oil and other products. Data are reported in thousand barrels. Historical monthly data back to January 1988, with data from 1984 to 1987 available on a quarterly basis.

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International Energy Agency

WORLD ENERGY OUTLOOK 2012

RELEASE: **12 NOVEMBER 2012**

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OIL
Medium-Term Market Report 2012

Supply shortfalls – from the Libyan civil war in 2011 and international sanctions on Iran in 2012 to a swathe of unplanned non-OPEC output stoppages – have buffeted the oil market, sending prices near 2008 highs and rekindling debate on the role of speculation in fuelling volatility. There have also been success stories. Growth in North American light, tight oil and non-conventional supply has reached game-changing levels. Iraqi production has scaled new heights, the Libyan production recovery in 2012 defied expectations and Saudi output surged to 30-year highs. On the demand front, the economic recovery has lost momentum. Market share continues to shift from mature to newly industrialised economies, but amid persistent concerns about the health of the former; China, the leading engine of oil demand growth of the last 15 years, is giving signs of slowdown.

Those developments have challenged earlier assumptions and significantly changed the oil market outlook for the next five years. The IEA *Medium-Term Oil Market Report* (*MTOMR*) – companion to the monthly *OMR* – draws their implications for the future. It provides detailed projections for oil supply at field level, crude quality trends, demand by product, refined product output and oil investments through 2017. It examines oil price formation, regulatory changes, OPEC dynamics and the future of spare capacity – while also reviewing the contribution of new supplies from deepwater, light tight oil, biofuel and natural gas liquids. It explores how market changes are reshaping the refining industry – and what that means for trade flows.

At a time of heightened economic and geopolitical risk, *MTOMR* is essential reading for anyone interested in oil market dynamics and in understanding the oil market context in which these risks are playing out.

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