

MEDIUM-TERM OIL & GAS MARKETS

2011

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MEDIUM-TERM OIL & GAS MARKETS

2011

Oil and gas markets have been marked by an increased divergence in recent months. On the one hand, oil market developments have generated an unpleasant sense of déjà vu: rapid demand growth in emerging markets eclipsed sluggish supply growth to push prices higher even before the conflict in Libya tightened supplies still further. Oil prices around \$100/bbl are weighing down on an already-fragile macroeconomic and financial situation in the OECD, pressuring national budgets in the non-OECD and causing price inflation of other commodities, as well as political concerns about speculation. There is an uncanny resemblance to the first half of 2008. On the other hand, in the world of natural gas an amazing disconnect has developed as demand recovered to well above pre-financial-crisis levels in most major regions. Gas markets have tightened in Europe and Asia, where prices are about twice the level seen in the United States, as the unconventional gas revolution is in full swing. From the upstream implications of the Arab Spring to the macroeconomic consequences of the eurozone crisis, energy markets are experiencing one of the most uncertain periods in decades.

Medium-Term Oil and Gas Markets 2011 provides a comprehensive outlook for oil and gas fundamentals through 2016. The oil market analysis covers demand developments on a product-by-product and key-sector basis, as well as a detailed bottom-up assessment of upstream and refinery investments, trade flows, oil products supply and OPEC spare capacity. The gas market analysis offers a region-by-region assessment of demand and production, infrastructure investment, price developments and prospects for unconventional gas. It also examines the globalising LNG trade.

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The International Energy Agency (IEA), an autonomous agency, was established in November 1974. Its primary mandate was – and is – two-fold: to promote energy security amongst its member countries through collective response to physical disruptions in oil supply, and provide authoritative research and analysis on ways to ensure reliable, affordable and clean energy for its 28 member countries and beyond. The IEA carries out a comprehensive programme of energy co-operation among its member countries, each of which is obliged to hold oil stocks equivalent to 90 days of its net imports. The Agency's aims include the following objectives:

- Secure member countries' access to reliable and ample supplies of all forms of energy; in particular, through maintaining effective emergency response capabilities in case of oil supply disruptions.
- Promote sustainable energy policies that spur economic growth and environmental protection in a global context – particularly in terms of reducing greenhouse-gas emissions that contribute to climate change.
- Improve transparency of international markets through collection and analysis of energy data.
- Support global collaboration on energy technology to secure future energy supplies and mitigate their environmental impact, including through improved energy efficiency and development and deployment of low-carbon technologies.
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Energy Agency

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FOREWORD

For both the oil and gas markets, 2010 was characterised by the sharp recovery of the global economy after the recession of 2009. However, the two markets have gone their separate ways in recent months. On the one hand, oil markets have seen surging demand growth in emerging markets outstripping growth in supply, pushing prices higher, even before the conflict in Libya tightened supplies further. Oil prices around \$100/bbl are weighing down an already-fragile macroeconomic and financial situation in the OECD, pressuring national budgets in the non-OECD and encouraging price increases in other commodities, as well as fuelling political concerns about speculation. On the other hand, demand for natural gas has recovered to well above pre-financial-crisis levels in most major regions, but the unconventional gas revolution and ample LNG supplies have led to different supply and pricing patterns at the regional level. Gas markets have tightened in Europe and Asia, where prices are about twice the level seen in the United States, but even in those markets remain around half the level of current oil prices.

After the sharp increase in oil demand in the second part of 2010 as the global economy recovered more quickly than anticipated from the recession, we now foresee higher mid-decade demand. Oil demand growth of +1.2 mb/d per year during 2010-16 derives entirely from the non-OECD countries, with China alone accounting for over 40% of the increase. Abetted by persistent, if gradually diminishing, end-user price subsidies, rising income outstrips higher crude prices in the emerging markets. While China and others are not expected to attain anything like the per-capita oil use levels seen in the United States and elsewhere in the OECD, nonetheless favourable demographics, urbanisation and industrialisation push demand in the emerging markets sharply higher. Efficiency gains in the maturing OECD markets will check overall growth in oil demand there, leading to a yearly contraction of 260 kb/d. That decline is sharper than in our earlier projections, in part due to higher assumed prices.

Meanwhile, world demand for natural gas dramatically rebounded in 2010, overshadowing the 2.5% drop in demand experienced in 2009 and putting natural gas demand back on its pre-crisis track. As for oil, demand in most non-OECD regions was driven by economic growth and increasing needs in both the power and industrial sectors. China's gas demand increased 22%, making China the fourth largest gas user in the world. By contrast, growth in the OECD was largely driven by abnormal weather. Seasonally-adjusted figures show that underlying European gas demand is just back to 2007 levels. The surplus of gas, which materialised in 2009 with depressed demand and the increased supplies of both liquefied natural gas (LNG) and unconventional gas, was partly absorbed in 2010 by resurgent demand. Looking forward, natural gas use is expected to increase strongly over the next five years and the bulk of the incremental gas demand originates from the non-OECD region, in particular the Middle East and Asia, while the growth of gas consumption in some OECD countries, notably in Europe, will be moderated by high gas prices. The power generation sector remains the main driver for natural gas demand, both in the OECD and non-OECD regions.

The global oil market balance clearly shows that the flexibility provided by upstream spare capacity and OECD inventories has diminished considerably over the last 12 months, despite increased upstream activity levels and resurgent non-OPEC supply. Amid heightened tensions in the Middle

East and North Africa (MENA) region, there are already signs that the market considers the current, diminished supply cushion uncomfortably thin. On the other hand, if triple-digit oil prices do begin to inhibit economic recovery, then our lower GDP case suggests rising spare capacity and perhaps some temporary mid-term relief from relentless upward price pressures. High oil prices have brought forth substantial new supply, but structurally non-OPEC increments are sourced from higher cost areas. Over the next five years, global oil supply capacity, if not actual production, will increase to more than 100 mb/d, a net increase averaging 1.1 mb/d annually. Incremental supplies are evenly split between OPEC crude, OPEC natural gas liquids and non-OPEC total oil, with conventional crude oil accounting for less than 40% of the total increase.

A renewed upward surge in oil prices since the end of 2010 has been borne of tighter fundamentals, geopolitical risks and a myriad of market expectations for economic growth and emerging market demand, as well as ongoing concerns over the pace at which new supply can be added. Modern financial markets amplify trends rooted in fundamentals and influence short-term prices, even though we still believe that ultimately, market sentiment and expectations feed off both the prompt and anticipated future supply/demand picture. That said, prognoses for oil market fundamentals in 2016 and beyond will be crucially influenced by government actions to promote energy efficiency and the impact of price signals on behavioural changes at a global level.

In the gas market, although some observers predicted a slower increase in unconventional gas production in 2010, US shale gas production jumped again. Looking forward, non-OECD gas production will provide 90% of additional supply over the 2010-16 period. In particular, the growth in LNG trade is set to continue apace as new plants come on stream. Unconventional gas will continue to impact upon gas markets; its contribution leads to a doubling of estimated recoverable gas resources, which are also more evenly distributed across regions. The obstacles to develop unconventional gas are diverse though, and environmental concerns are increasingly in the spotlight and have deterred exploration in a few countries.

While US spot prices remain at low levels, natural gas prices have been surging in Europe and OECD Pacific, on the back of increasing oil prices and tightening gas markets. This remarkable trend is likely to continue due to abundant unconventional gas production in Northern America, while gas demand elsewhere could be further fostered by lower investment in the nuclear sector after the Fukushima accident.

From the upstream implications of the Arab Spring to the macroeconomic consequences of the euro-zone crisis, 'uncertainty' remains the key word for oil and gas markets. The pace of economic growth, energy efficiency trends on the back of higher oil prices, as well as investment levels that are needed to meet emerging countries' economic growth will determine future supply and demand balances for both the oil and gas markets.

I hope that this report will help bring more transparency and clarity on oil and gas market trends and help policymakers to become better aware of the important challenges that lie ahead for global energy markets.

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

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OIL

Overview

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OVERVIEW

High Prices and Robust Growth Can Co-Exist – For a While

Our latest medium-term price assumption stands \$15-\$20/bbl higher than in the 2010 outlook, yet 2015 oil demand is also now 0.9 mb/d higher. The juxtaposition of triple-digit oil prices and 4-5% global economic growth looks paradoxical, but partly reflects the time lags affecting oil market dynamics. High prices and buoyant economic (and oil demand) growth can co-exist – for a while. The market will ultimately adjust to higher prices, albeit supply and demand remain unresponsive in the short term. Indeed, oil's price inelasticity underpins the recent extended upward price shift in the face of resilient non-OECD demand growth and perennial supply-side risks.

Today's global market balance shows that supply flexibility – upstream spare capacity and OECD inventories – has diminished. The bull run evident since autumn 2010 therefore looks in large part to be justified by supply and demand fundamentals. Most analysts underestimated the near-3 mb/d post-recession demand rebound in 2010. Indeed, baseline revisions for 2010 partly explain a now-higher mid-decade demand prognosis. And despite increased upstream activity levels and resurgent non-OPEC supply, spare capacity has diminished. Overall, our business-as-usual case (global GDP growth averaging +4.5% per year) shows a tighter market during 2010-2012 than we envisaged back in December. Market conditions potentially ease marginally during 2013-2016, although arguably the 4 mb/d spare capacity implied for much of that period looks like a fairly thin supply cushion.

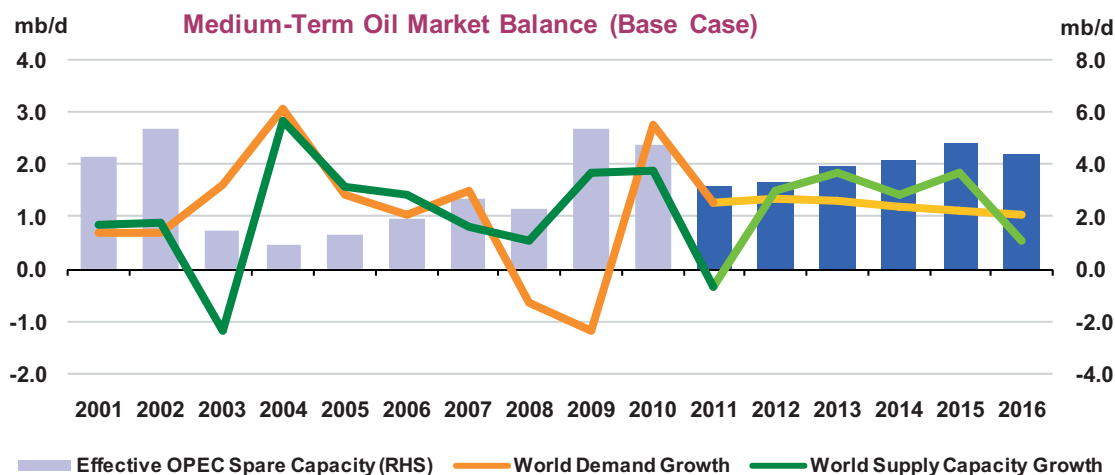
Global Balance Summary (Base Case)

(million barrels per day)

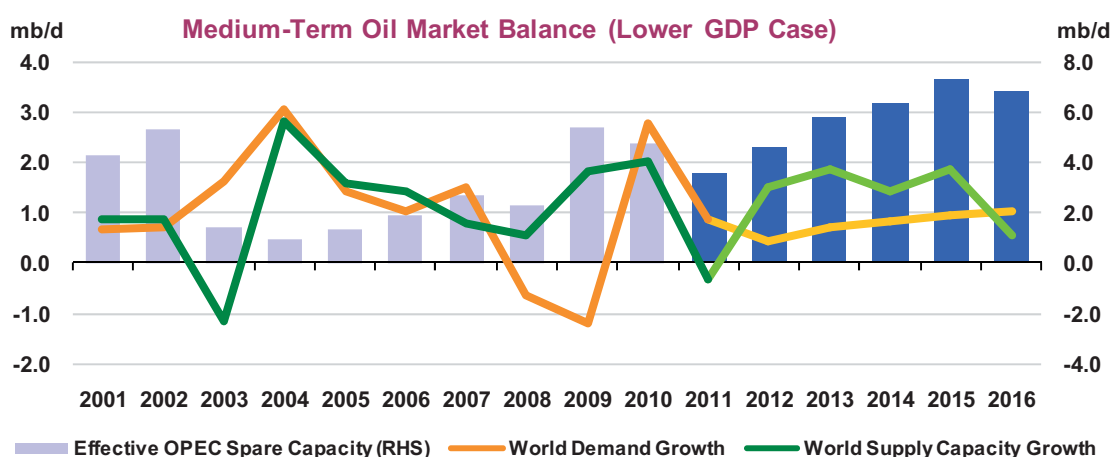
	2010	2011	2012	2013	2014	2015	2016
GDP Growth Assumption (% per year)	4.84	4.29	4.43	4.44	4.53	4.56	4.63
Global Demand	88.02	89.30	90.63	91.92	93.13	94.24	95.26
Non-OPEC Supply	52.71	53.28	54.18	54.22	54.33	55.11	55.36
OPEC NGLs, etc.	5.35	5.88	6.33	6.69	6.97	7.31	7.41
Global Supply excluding OPEC Crude	58.06	59.16	60.51	60.91	61.30	62.41	62.77
OPEC Crude Capacity	35.72	34.29	34.44	35.89	36.93	37.67	37.85
Call on OPEC Crude + Stock Ch.	29.96	30.14	30.12	31.02	31.83	31.82	32.49
Implied OPEC Spare Capacity ¹	5.76	4.15	4.32	4.88	5.10	5.85	5.36
Effective OPEC Spare Capacity ²	4.76	3.15	3.32	3.88	4.10	4.85	4.36
as percentage of global demand	5.4%	3.5%	3.7%	4.2%	4.4%	5.1%	4.6%
Changes since December 2010 MTOGM							
Global Demand	0.58	0.52	0.60	0.74	0.83	0.85	
Non-OPEC Supply	-0.07	-0.13	0.39	0.68	0.72	1.14	
OPEC NGLs, etc.	0.06	0.04	0.07	0.07	0.08	0.25	
Global Supply excluding OPEC Crude	-0.02	-0.09	0.46	0.75	0.80	1.38	
OPEC Crude Capacity	0.22	-0.93	-0.87	0.23	0.27	0.73	
Call on OPEC Crude + Stock Ch.	0.60	0.62	0.14	-0.01	0.03	-0.53	
Effective OPEC Spare Capacity ¹	-0.37	-1.55	-1.01	0.24	0.24	1.26	

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

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



If triple-digit oil prices do begin to inhibit economic recovery, then our lower GDP case suggests rising spare capacity and perhaps some temporary mid-term relief from relentless upward price pressures. One question mark, however, surrounds the robustness of supply in such a lower GDP world. Our simplified model generates unchanged supply capacities in the two cases. But as we note later, some North American expansion in non-OPEC supply confronts potential pipeline and infrastructure constraints. In a lower-growth world, project slippage, together with potentially slower OPEC investment, might keep markets tighter than the simplified low GDP balances suggest.

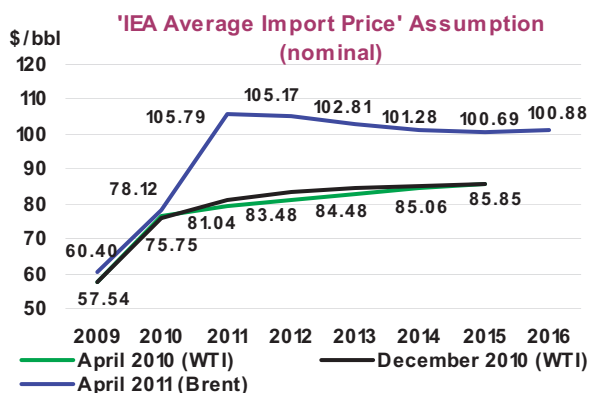


That said, high prices will ultimately lead to a correction. Efficiency gains and maturing OECD markets will constrain demand. High prices have generated a more optimistic non-OPEC supply outlook. But an eastward shift in the market's centre of gravity sustains annual oil demand growth around 1 mb/d in both scenarios, amid rising incomes and sticky price subsidies. This presents an ongoing challenge: OECD refiners face poor margins, yet rising environmental investments to stay in business; upstream projects are more complex and capital intensive. An ability to manage risk and sustain investment will be crucial for the industry in the years ahead if further damaging price spikes are to be avoided.

Oil Pricing

Last year's relatively stable, if elevated, prices have given way to a renewed upward surge, borne of tighter fundamentals, geopolitical risks and myriad market expectations for economic growth, emerging market demand and concerns over the pace at which new supply can be added. The price assumption that feeds our outlook now averages over \$103/bbl. Financial markets have augmented fundamentals in influencing short-term prices, even if we still believe that ultimately, market sentiment derives from prompt, and anticipated, supply/demand views.

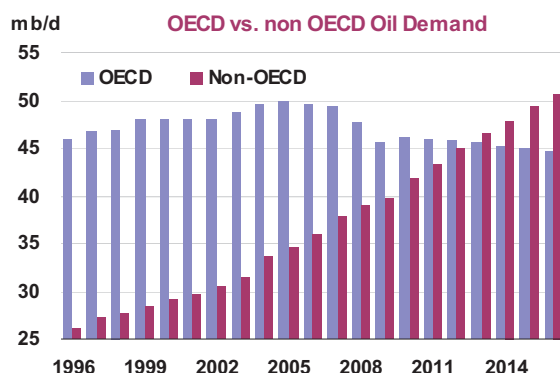
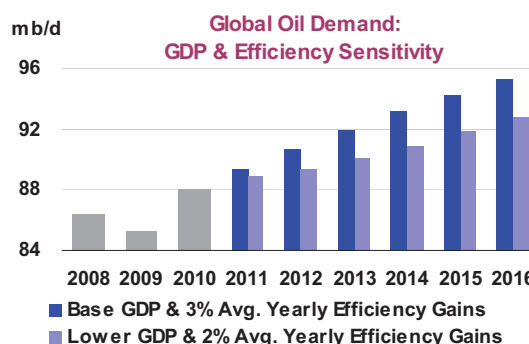
Popular wisdom has it that we live now with an inherently more volatile oil market than in the past, and in which exchange rates and speculative money flows actually drive oil price direction. Persuasive though such arguments may be, rigorous analysis suggests otherwise. We argue here that oil prices may affect exchange rates more than the converse. Moreover, levels of speculative activity, relative to risk hedging appetite within the market, look to be below those of 2008. There is little evidence of today's oil market being structurally more volatile than in the past. However, data gaps continue to impede analysts' ability to determine the relative role of specific physical and financial factors in influencing price. Regulatory moves to increase transparency and minimise systemic risk in commodity derivatives markets are welcome, although some market participants see risks of regulatory arbitrage and unintended negative consequences, affecting price discovery, market liquidity and the ability to hedge.



Demand

Our demand baseline stands 0.6 mb/d higher than anticipated back in December, after the stronger than expected post-recessionary surge in demand seen last year. Even the structurally declining OECD markets saw a (likely short-lived) rebound last year. With a similar base case GDP assumption (+4.5% annually through 2016), this higher baseline helps counteract a significantly stronger oil price assumption (\$103/bbl) to result in a demand outlook now 0.7 mb/d higher on average through 2016.

Net oil demand growth of 7.2 mb/d during 2010-2016 (+1.2 mb/d annually) derives entirely from the non-OECD countries, with China alone accounting for 41% of the total and other Asia and the Middle East a further 53% combined. Income outstrips high crude prices in the growth markets in the face of persistent, if gradually diminishing, end-user price subsidies. Critically, countries in the \$3,000-\$20,000 per capita income take-off range for oil demand will account for 45 mb/d of consumption by 2016, a volume that will have nearly doubled in just 20 years. While China and others are not expected to attain anything like the per capita oil use levels seen in the US and elsewhere in the OECD, nonetheless favourable demographics, urbanisation and industrialisation push demand in the emerging markets sharply higher. OECD demand contracts by 1.5 mb/d. That decline is sharper than in our earlier projections, in part due to higher assumed prices.



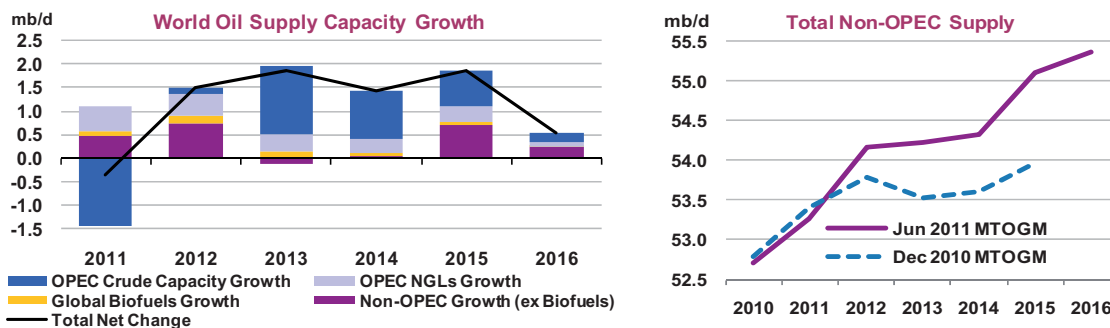
Transportation fuel use and gasoil/diesel predominate. Gasoil is now the fuel of choice in a multitude of applications including transportation, as well as industrial uses and power generation (with swing fuel characteristics akin to those previously held by residual fuel oil). Tightening marine bunker sulphur specifications from mid-decade also suggest a growing role for diesel at heavy fuel oil's expense. Transportation accounts for two thirds of incremental oil demand, although rising vehicle economy standards and growing biofuels use moderate the demand for refinery-sourced gasoline and diesel. The petrochemical sector also sees significant growth, with feedstock demand rising by 1.7 mb/d between 2010-2016. New capacity in Asia and the Middle East, much of it run on cheap ethane and LPG, places older, naphtha-fed capacity in the OECD under intense competitive pressure.

Any demand projection faces uncertainties, with economic risk one of the most important. Twinning weaker global GDP growth (3.3% annually) with slower gains in oil use efficiency results in 2016 demand some 2.4 mb/d lower than the base case, and implies annual demand growth of 0.8 mb/d. The implicitly lower crude price this scenario might entail could see a more aggressive dismantling of price subsidies in emerging markets, further curbing demand, at least in the short term. However, we think this will remain a step too far for policy makers, and do not assume widespread reform except in those countries already embarked upon price liberalisation. Short-term demand uncertainties also include substitution, notably in power generation. The years 2010 and 2011 have already shown that non-oil generation capacity outages can boost global oil demand, particularly diesel, by 0.5 mb/d or more.

Supply

Global oil supply capacity increases from 93.8 mb/d to 100.6 mb/d by 2016, a net increase averaging +1.1 mb/d annually. Incremental supplies are evenly split between OPEC crude, OPEC gas liquids and non-OPEC total oil, and conventional crude oil accounts for less than 40% of the total increase. Sustained high crude prices have boosted upstream activity, and although the spectre of resurgent costs and logistical constraints again hangs over the industry, the slate of active new projects is more than sufficient to offset high rates of mature oilfield decline. Based on field-by-field trends, the outlook assumes that 2010 baseline supply loses over 3 mb/d annually, at a rate of approximately 5%, slightly lower than last year's estimate. Higher spending since early-2009 has had a positive impact on existing assets, as well as accelerating new projects. Nonetheless, this highlights the three-to-one relationship between decline and demand growth the industry confronts each year. High prices have generated new supply, but non-OPEC growth is coming from higher cost areas.

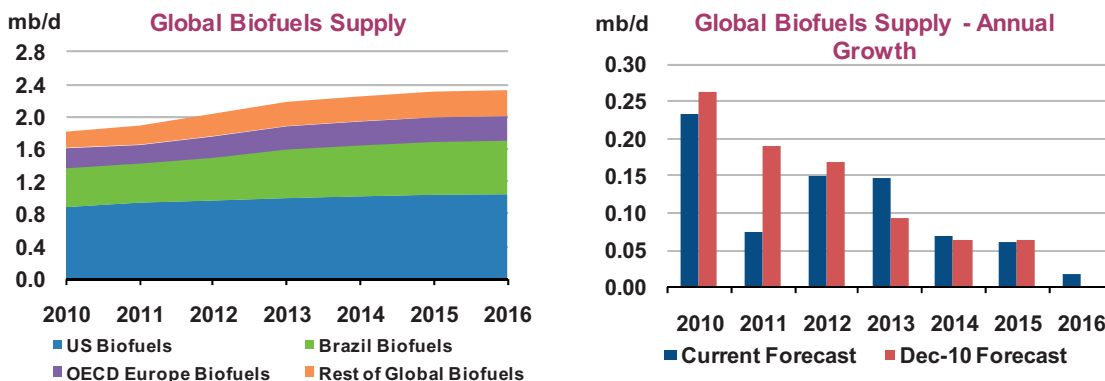
Libyan production capacity is assumed to recover slowly after the ongoing civil war, regaining pre-war levels near 1.6 mb/d only in 2014. In contrast, significant OPEC crude capacity growth is expected from joint venture investments in Iraq, Angola, and the UAE, with more limited gains coming from Nigeria and Venezuela. A methodological change lifts recent supply estimates for Venezuela by around 0.3 mb/d and modest net growth by 2016 derives from joint venture investments in the Orinoco belt. An adverse investment climate, however, sees Iranian crude capacity decline by 0.8 mb/d to 3.1 mb/d, falling below Iraq's capacity by 2014. Rapid natural gas developments drive OPEC natural gas liquid (NGL) and condensate supply higher by 2.1 mb/d to 7.4 mb/d in 2016, based on major expansion from the UAE, Qatar, Iran and Saudi Arabia.



The major adjustment to this year's supply projections comes from non-OPEC, with 2015 output now 1.1 mb/d higher than in December. A more optimistic picture for North American supplies, and for US light, tight oil production in particular, underpins this view. Around 1 mb/d of net growth from this source is expected during 2010-2016, offsetting a weaker post-Macondo outlook for the US Gulf of Mexico. Nonetheless, global deepwater supply increases in importance over the outlook period. Other key sources of non-OPEC supply growth include Brazil, Canada, Kazakhstan and Colombia, plus biofuels, NGLs and refinery processing gains. Global supply becomes marginally lighter, but sourer by 2016.

Biofuels

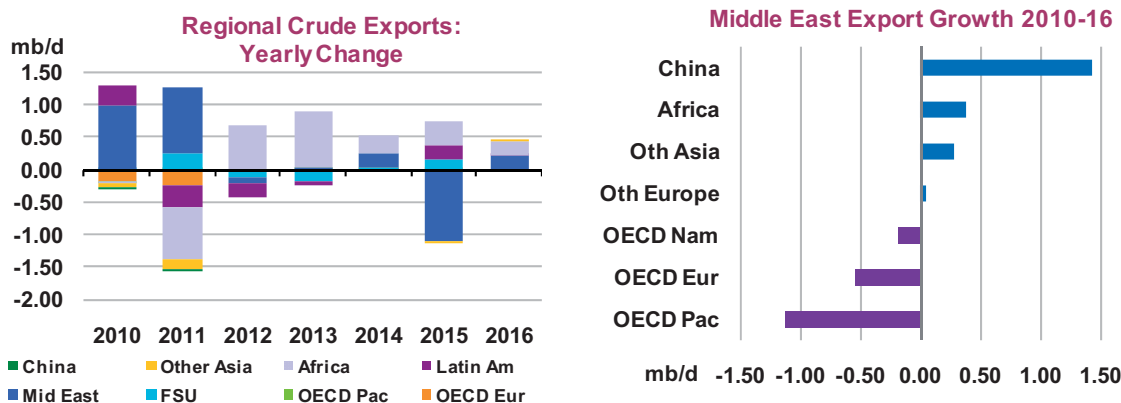
Medium-term biofuels supply growth now amounts to +0.5 mb/d, rising from 1.8 mb/d in 2010 to 2.3 mb/d in 2016, with Brazil and the US at the forefront. Nonetheless, prospects look less rosy now in Brazil and in Europe, with volatile ethanol prices and slower new distillery builds in Brazil underpinning the weaker outlook. That said, by 2016, ethanol and biodiesel should displace 5.3% and 1.5% of total global gasoline and gasoil demand, respectively, on an energy content basis.



Advanced biofuels technologies hold the prospect for significantly higher motor fuel penetration in the longer term, although IEA research suggests it may be 2030 before they achieve wide-spread cost competitiveness with hydrocarbon-derived fuels. Advanced biofuel capacity may nonetheless rise from 20 kb/d in 2010 to as much as 130 kb/d in 2016.

Crude Trade

Global inter-regional crude trade is expected to increase by 1.0 mb/d between 2010-2016 to reach 35.8 mb/d. This is a lesser increase than envisaged last year, as key producing regions are seen refining more output locally and exporting products. The Middle East remains the largest and key swing supply region, with exports increasing by 1.2 mb/d through 2014, before declining as new regional refining capacity, particularly in Saudi Arabia, absorbs extra crude volumes. Middle East sales average 16.7 mb/d by 2016, and exports to non-OECD Asia rise by more than 1.7 mb/d.



Africa sees the sharpest rise in exports, up by 1.6 mb/d to 8.8 mb/d in 2016, led by Nigeria and Angola. Asia again absorbs most of these extra volumes. While exports from the FSU remain stable, we expect a re-orientation of shipments, with deliveries to Pacific Rim reaching 1.4 mb/d by 2016, while sales into traditional European markets decline. Incremental crude production from Latin America is expected mainly to be absorbed locally, although the region remains an important supplier for North America. Despite rising demand for long haul crude, tanker markets will continue to face weak profitability, amid strong growth in the fleet across most classes of vessel.

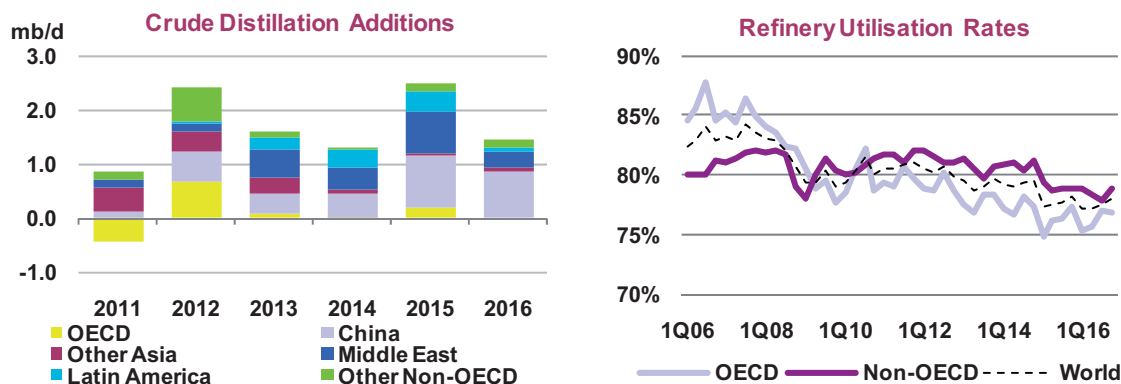
Asian Storage Expansions

Our view on inter-regional crude trade derives from the modelling of refinery crude runs. However, a potential temporary boost to crude trade volumes may also come from the build-up of strategic and commercial storage in Asia. This is taking place against a back-drop of burgeoning regional demand growth and amid rising awareness of supply security. China and India may eventually match IEA levels of stock cover, and government strategic crude storage capacity could reach over 600 mb (500 mb in China and 100 mb in India). Fill of sites completed by 2016 could add the equivalent of 240 kb/d to regional crude demand (if averaged over the next five years). Identified commercial storage additions, covering both crude and products, in China, India, Korea, Malaysia, Singapore and Indonesia could amount to an additional 320 mb, equivalent to 180 kb/d between 2012 and 2016.

Refining and Products Supply

With early-2011 refining margins mired below the heady levels seen at the middle of the last decade, we see a structural overhang in refining capacity persisting through the medium term. Globally, crude distillation capacity increases by 9.6 mb/d during 2010-2016 (95% of this in the non-OECD), with further additions in upgrading (6.9 mb/d) and desulphurisation (7.3 mb/d).

While capacity rationalisation amounting to around 1.8 mb/d has been identified within the OECD, it is offset by debottlenecking at other units and is insufficient to prevent utilisation rates there falling further, to around 75% by mid-decade. OECD Europe has also seen opportunistic purchasing of distressed refining assets by producers keen to get an operational toe-hold in a maturing, but nonetheless strategically placed, swing refining hub. Restoring global utilisation rates to the levels enjoyed in the last five years would require over 4 mb/d of capacity closures or project deferrals by 2016.



Robust new-build capacity in China, the Middle East, other Asia and Latin America, much of it highly complex and aimed strategically to add value to rising domestic crude production, will likely place older and less complex capacity in the OECD under increasing pressure. At the margin, further operating pressures derive from the fact that a rising proportion of final demand will be met by supplies such as gas liquids and biofuels, which by-pass the refining system altogether.

Given the pattern of product demand growth expected to 2016, middle distillate markets could remain relatively strong, the more so longer term if the switch to marine diesel continues. The fuel oil outlook also appears tighter than we envisaged last year, as lighter feedstock supplies, and high levels of committed upgrading investment combine with a slightly more robust demand outlook. FSU exports could diminish while an emerging imbalance between supply and demand in Asia and the Middle East may encourage Gulf producers to boost heavy sour crude production to a greater extent than we assume. Gasoline and naphtha continue to look surplus-prone, as North America's ability to absorb excess supply from Europe and Latin America diminishes.

OIL PRICING

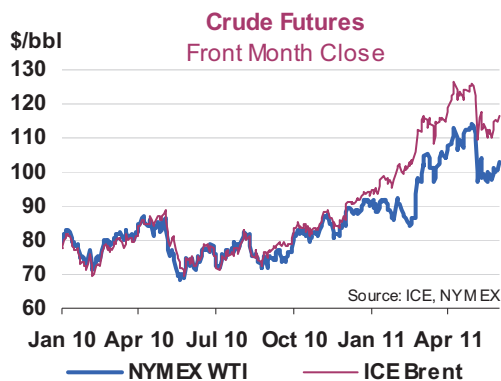
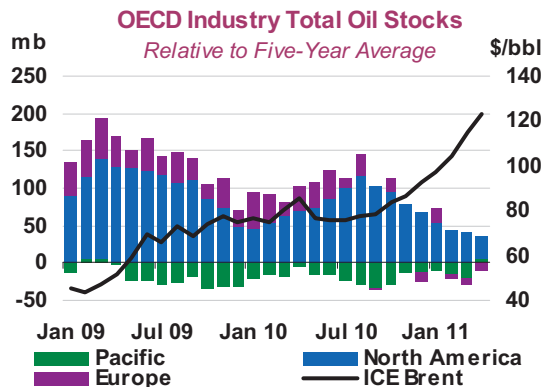
Summary

- **Crude prices have been on a steadily rising trend since 3Q10**, due initially to tightening 2H10 global fundamentals and, more recently, to a tide of political instability in the MENA region, including the loss of light, sweet Libyan crude supply. Although fears of an adverse impact on economic growth from high prices saw a brief downward correction in early-May, perceptions of ongoing market tightness sustain marker crude prices in excess of \$100/bbl.
- **The price assumption through 2016 feeding this year's models is \$15-\$20/bbl higher than that deployed in 2010**, and averages \$103/bbl for the IEA nominal import price. The assumption is based on the prevailing Brent futures strip in late-April 2011, when the modelling exercise commenced.
- **The apparent inverse correlation between exchange rates and oil prices does not imply causation.** Several econometric analyses suggest that causality may run from the oil price to the exchange rate, rather than in the opposite direction.
- **In recent years, the oil market has been characterised by rising, and at times, rapidly fluctuating, price levels.** However, careful examination of historical volatility shows that the daily levels observed during 2008-2009 are actually less than the peak volatility observed in the early 1990s. There is evidence also that underlying oil market volatility in recent months remains consistent with historical levels.
- **Financial players have been singled out for transforming the oil market into an intrinsically more volatile trading environment.** However, opinion remains highly polarised on the respective roles of hedgers and speculators, and on the concept of 'excessive' speculation in the crude oil market. Efforts to assess the price impact of key market influences are impeded by data shortcomings for both the physical and financial markets.
- **Regulatory efforts to increase transparency and reduce systemic risks in global over-the-counter (OTC) markets have intensified in the last year** despite a lack of a clear consensus on the impact of financial players on oil prices. Lack of consensus between regulators, as well as some of the new rules themselves, are seen by some observers to potentially have unintended consequences.

Recent Price Developments

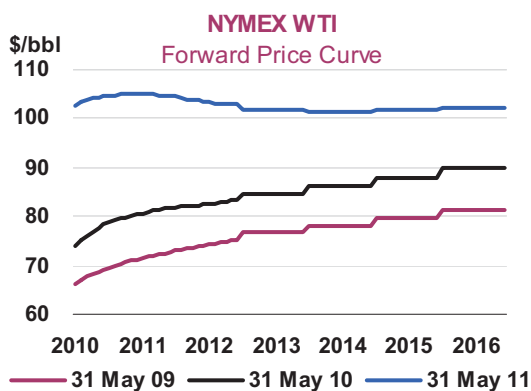
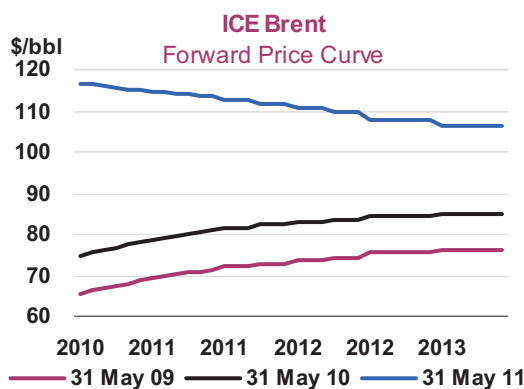
Since last June's *Medium-Term Oil and Gas Markets (MTOGM)* report, global oil prices have been driven higher by the recovery of the broader economy and, with it, resurgent global oil demand growth. The sharp escalation in political and oil supply risk in a number of countries in the MENA region has further supported prices since the start of 2011. As a result, benchmark Brent crude has traded on a monthly basis at loftier price levels from around \$75/bbl last July to \$125/bbl plus at the end of April (see '*Volatility in Crude Oil Prices*'). That compares with the relative market calm evident between autumn 2009 and autumn 2010, when crude prices traded in a narrower \$65/bbl to \$85/bbl range.

Financial market activity and macroeconomic developments continue to exert significant short-term influence on oil prices, but since 3Q10 supply and demand fundamentals have clearly dominated price direction (see 'Exchange Rates and Oil Prices').



Oil prices have been increasingly underpinned by a tighter supply and demand balance as non-OECD economies gathered steam, while structural decline in OECD oil demand temporarily reversed in the face of post-recession recovery. This year global oil demand is forecast to grow by a more modest 1.3 mb/d to 89.3 mb/d, compared to near 3 mb/d annual growth in 2010. In addition, the aftermath of Japan's catastrophic earthquake and tsunami in March, followed by a sharp commodity-wide correction in early-May, have pushed prices 10% lower amid concerns that prevailing price levels could themselves begin to impede economic recovery. Nonetheless, \$115/bbl Brent at writing remains high by historical standards.

Renewed concerns have emerged of a tighter market balance going forward due to stronger oil demand, alongside the steady erosion of industry inventories since mid-2010 in the OECD, and by implication, global stocks. More recently, a tighter supply outlook has emerged following the loss of a significant amount of crude oil from Libya in the wake of the country's civil war. This has also pushed 'effective' OPEC spare capacity down to around 4 mb/d.



Resurgent demand gathered steam in late 2010, which led to a gradual drawdown in global inventories, both onshore and offshore. This compares with the persistent high levels of oil inventories onshore and held offshore in floating storage that capped prompt futures prices in the early part of 2010.

However, the decline in global stocks has had a mixed impact on the two major benchmark crudes, US WTI and North Sea Brent, which in turn has once again raised questions about the former's price-setting role in global markets. Despite the overall drawdown in inventories, crude stock levels at the landlocked Cushing, Oklahoma storage terminals, the delivery point for the NYMEX WTI futures contract, continued to scale new heights over the past six months. This in turn exerted considerable downward pressure on prompt WTI futures prices relative to forward markets.

At the same time shrinking inventories on a global basis, among other issues, saw prices for the Brent contract steadily strengthen for the prompt month. By end-2010 Brent occasionally crossed over to a backwarddated price structure (prompt prices stronger than forward levels), before shifting more fully to backwardation in February 2011, in reaction to the developments in Libya. This, not surprisingly, coincided with the drawdown in OECD inventories. OECD total oil industry stocks declined from 84.2 mb above the five-year average in October to 12.9 mb in March, before rising back to 27.4 mb in April.

North Sea Brent historically traded at a discount to benchmark WTI, apart from very short periods in the past when stocks at Cushing, Oklahoma, approached near-maximum operational levels. But since 2006, that price relationship has broken down and by 2009 had been turned on its head, with WTI trading at a discount to Brent. The WTI-Brent discount averaged around $-\$0.75/\text{bbl}$ in 2010 but has widened sharply since the start of 2011, in large part due to mounting stocks of crude at Cushing. The discount widened to $-\$11.56/\text{bbl}$ on average from January to April 2011.



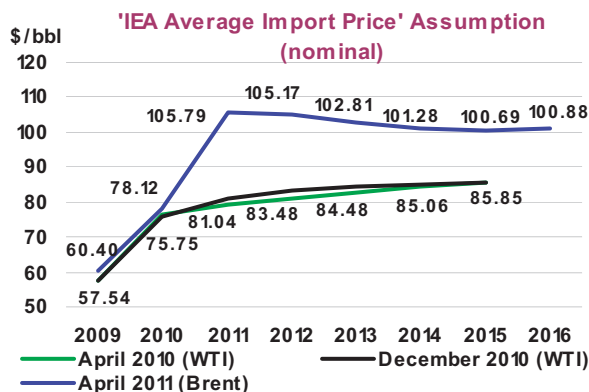
New pipelines, which opened in April 2010 and in February 2011, have been pumping more crude oil down from Canada to the US Midcontinent. As a result, Cushing crude stock levels kept breaking one record after another, enabled by expanding storage capacity. With WTI likely to remain weak relative to historical levels until new pipeline capacity to the US Gulf Coast is developed in the next two to three years, and with Brent seemingly for now more representative of international market fundamentals, our *MTOGM* price assumption this year switches from being based on the WTI futures strip to that for Brent.

Methodology for Calculating the IEA Average Import Price

Our current price assumptions for the 2011-2016 period, based on the Brent futures strip and nominal IEA crude import prices, ranges from a high of just over $\$105/\text{bbl}$ in 2011 to a low of $\$100.69/\text{bbl}$ in 2015. Recent volatility in the differentials between WTI and other international

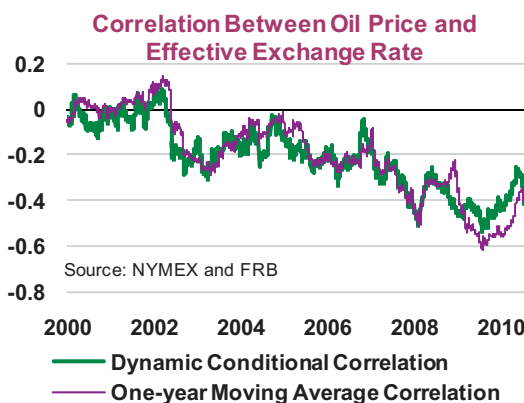
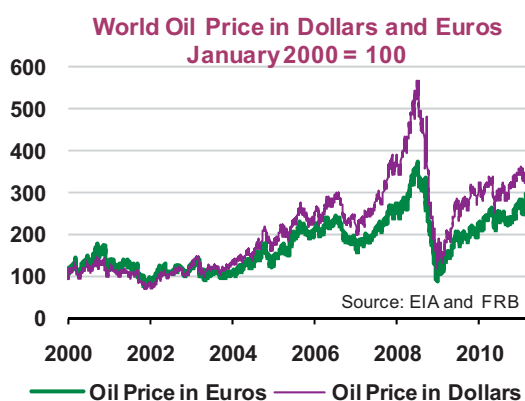
benchmarks has led us to switch to using Brent futures as a baseline for this report. The price assumption derives from ICE Brent futures as of late-April 2011.

It is worth stating again that our short- and medium-term models deploy a non-iterative 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 2.6% historical discount for IEA import prices versus Brent futures is applied for the outlook period. The resultant price strip shown here is between \$15-\$25/bbl higher than the equivalent (WTI-based) assumptions deployed for our medium-term modelling in 2010.



Exchange Rates and Oil Prices

US dollar weakness in recent years is frequently cited as one reason for high oil prices. It is very common to see the financial press suggesting that a weak dollar has pushed oil prices higher. Empirically, there is clearly an inverse correlation between oil prices and exchange rates – that is, other things being equal, oil prices rise if the dollar falls. An assessment of the dynamic conditional correlation (DCC) and of the one-year rolling average correlation between the daily change in the oil price and the daily change in the nominal effective exchange rate shows that this relationship has been relatively strong in recent years, although the negative correlation has been declining in recent months. What is less clear, though, is the direction of causality. Several econometric techniques suggest that causality may run from the oil price to the exchange rate, rather than the opposite.



This finding supports 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 the price is increased, as is the case for oil) this produces a deterioration in the trade balance, which will decrease the value of the local currency.

However, the relationship between the price of oil and the exchange rate might be much more complex than the initial terms of trade impacts would suggest. 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.

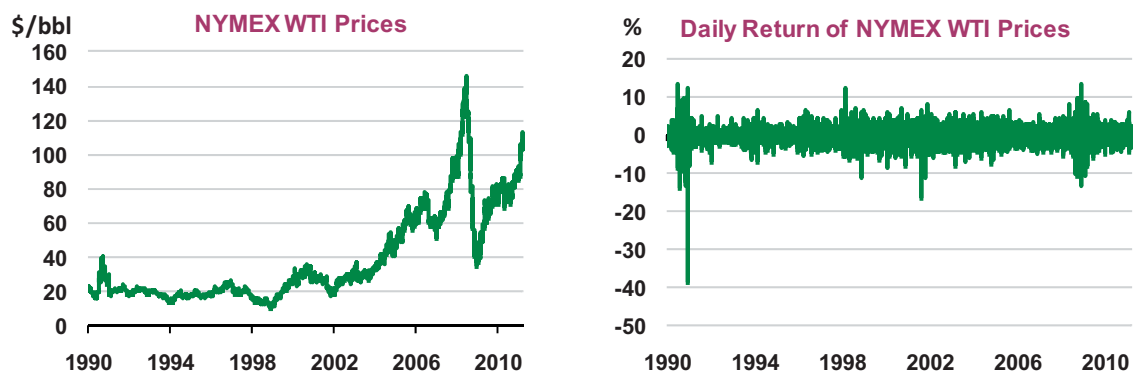
The interactions between the exchange rate and oil prices are more complex than traditional economic theory predicts. However, those believing in strong reverse causation from exchange rates to oil prices are effectively acknowledging the likelihood of a self-perpetuating cycle in which a weaker dollar drives crude higher which in turn sends the dollar even lower. The lack of clear evidence for such a spiral, so far, along with our own econometric findings, suggests that the more likely causation runs from oil prices to the exchange rate instead.

Volatility in Crude Oil Prices

Prices for oil, like those for many other commodities, are inherently volatile and volatility itself varies over time. In recent years, the oil market has been characterised by rising, and at times, rapidly fluctuating, price levels. In the last nine months alone, crude oil prices have fluctuated in a wide range from \$75/bbl to \$125/bbl. However, careful examination of historical patterns shows that the volatility observed during 2008-2009 is actually lower than the peak observed in 1990-1991.

The concept of volatility is often confused simply with rising prices; however, volatility can equally result in prices that are significantly lower than historical average levels. Volatility is the term used in finance for the day-to-day, week-to-week, month-to-month or year-to-year variation in asset or commodity prices. It measures how much a price changes either versus its constant long-term level or long-term trend.

Some recent academic studies have based their claim of higher prevailing volatility on the observation of exceptionally high absolute day-to-day changes in WTI crude oil prices. This measure is at best misleading. 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. A ten-dollar increase in an environment where the average oil price is about \$100/bbl does not imply higher volatility than a five-dollar increase when the average price is \$30/bbl.



While the average unit price of WTI crude oil was \$38/bbl between 1990 and 2011, prices have veered from \$147/bbl in mid-2008 to \$35/bbl in December 2008 and back to \$110/bbl in mid-April 2011. Although the average annualised daily returns between 1990 and 2011 on crude oil were about 7.7%, they registered a negative 8% between 2005 and 2011. A test for normality indicates that daily returns are not normally distributed. Both negative and positive shocks are responsible for the non-normality of daily returns.

In order to explore the nature of volatility inherent in WTI crude futures prices, daily time price series for the nearby contract (closest to delivery) have been constructed. Before maturity (the expiration date), most participants in the paper market either close out positions or roll them over from the nearby contract to the next-to-nearby contract. The problem of data seasonality due to rolling has been mitigated here by focussing on the nearby contract and excluding price changes caused by delivery mechanisms. Daily returns for each contract were computed using settlement prices set daily by the exchange at the market close. In particular, daily returns can be defined as $r_t = p_t - p_{t-1}$, where p_t is the natural logarithm of the settlement price on day t . Both p_t and p_{t-1} refer to the next-to-nearby contract for days on which a switch from the nearby to first deferred contract occurs.

As explained in the March 2011 *Oil Market Report*, there are various ways to measure volatility. In this report, four different historical volatility measures for WTI crude oil prices are presented. Historical volatility looks at past behaviour of price movements and measures the variation in the price. One such measure is the standard deviation. Standard deviation (σ) is computed from a set of historical data as

$$\sigma = \sqrt{\frac{1}{N-1} \sum_{t=1}^N (R_t - \mu)^2}$$

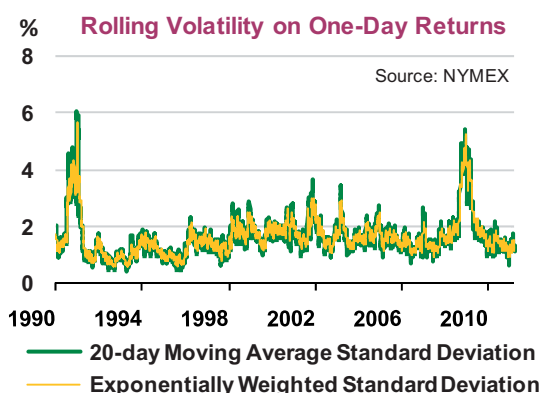
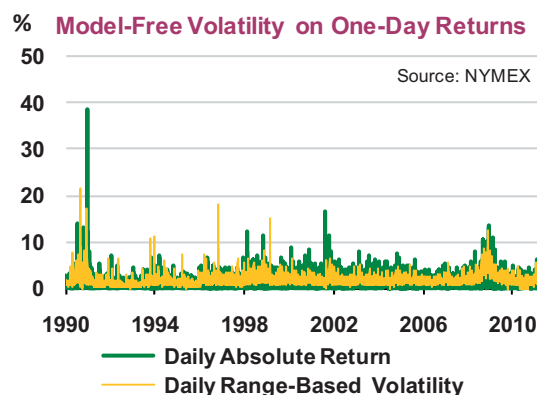
where R is the return calculated as the natural log of daily changes in the price of the underlying asset and μ is the mean return during the look-back period. However, the sample mean μ is seen by some analysts as a very inaccurate estimate of the true mean, especially for small samples; taking deviations around zero instead of sample mean typically increases volatility forecast accuracy. Twenty-day moving average and exponentially weighted moving average standard deviation show similar qualitative volatility estimation. In January 2009, annualised volatility peaked at 87%, a

ten-year high, followed by a rapid decline to relatively low levels. On the other hand, volatility reached its historical peak level (96% annually) in January 1991.

Apart from standard deviation-based volatility, model-free absolute return was calculated as a proxy for daily volatility as well as range-based volatility estimation. The high-low volatility is calculated as follows:

$$\sigma_t = \sqrt{\frac{[\ln H_t - \ln L_t]^2}{4 \ln 2}}$$

where H_t and L_t denote, respectively, the highest and lowest prices on day t . As expected, both range-based and absolute return proxies for daily volatility displayed very noisy volatility estimators. However, both estimators revealed the fact that the increased price volatility observed during 2008–2009 was temporary rather than permanent.



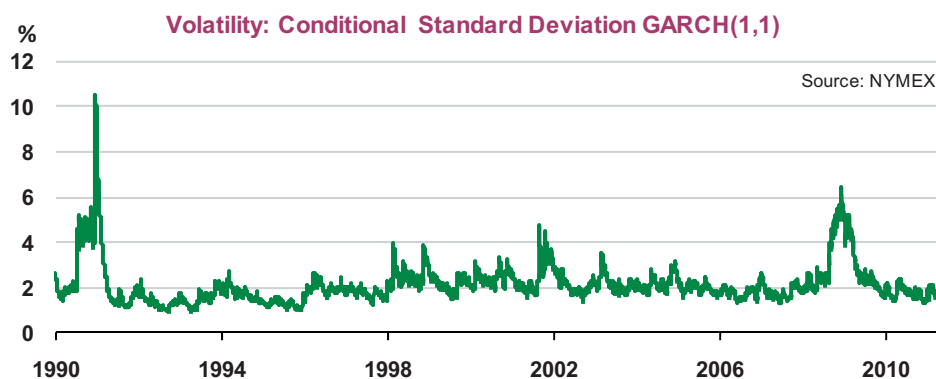
The empirical observation that volatility is not constant over time and that it has memory has led to more sophisticated time series models, known as generalised autoregressive conditional heteroskedasticity (GARCH) models. These models capture the persistence of volatility, time-varying mean as well as the non-constant nature of volatility. Since the conditional variance at time t is known at time $t-1$ by construction, it provides a one-step ahead conditional variance forecast.

The following GARCH model was estimated to produce conditional volatility for daily crude oil return r_t :

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

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 define the true data generating process, z_t be Gaussian, and that the time series be long enough for maximum likelihood estimation. GARCH conditional volatility estimation also suggests that the increase in volatility observed during 2008–2009 was a temporary phenomenon and that volatility in the oil market remains consistent with historical averages.

The apparent increase in the volatility of oil prices during 2008-2009 raises questions about the determinants of volatility in oil markets. Since oil is considered to have highly inelastic supply and demand curves, at least in the short run, neither supply nor demand initially responds much to price changes. Therefore, any shock to supply or demand will lead to large changes in oil prices. The dissemination of new information related to fundamentals results in price adjustments, as market participants evaluate the implications of this information. It has been further argued that the emergence of a new class of financial traders, as well as increased participation of non-commercial traders in crude oil derivatives markets, has transformed the oil market into an intrinsically more volatile market. The empirical evidence for these claims is examined, below.



Hedgers, Speculators and ‘Excessive’ Speculation in Futures Markets

The summer 2008 spike in crude oil prices to \$147/bbl, followed by a steep correction in late 2008/early-2009 and subsequent sharp rebound over the last two years have jolted the world economy and pinched consumers at the fuel pump. Given the predominance of crude oil in the world economy, the pace of change of prices generated substantial attention from regulators, legislators and commentators who have decried the existence of ‘excessive’ speculation in the crude oil futures markets. Indeed, the rise in participation by non-commercial traders during the preceding ten years provided further ammunition for those seeking causal connection with concurrent price increases.

Two of the most important functions of futures markets are the transfer of risk and price discovery. In a well-functioning futures market, hedgers interested in reducing their exposure to price risk find counterparties. In a market without speculative interest, long hedgers must find short hedgers with an equal and opposite hedging need. In fact, many traditional hedgers have dual liquidity needs, intending to offset their futures positions before physical delivery of crude oil. Speculators enhance liquidity and reduce search costs by taking the opposing positions when long hedgers do not perfectly match short hedgers. Speculators provide immediacy and facilitate the needs of hedgers by mitigating price risk, while adding to overall trading volume, which contributes to more liquid and well-functioning markets. In this regard, both groups can contribute to price discovery in futures markets. Futures prices reflect the opinions of all traders in the market.

An extensive body of theoretical and empirical literature has analysed whether returns in futures markets are related to commodity-specific risk (reflected in hedging pressures) or systematic risk (measured by the covariance between futures and stock returns or other macroeconomic variables). The majority of the empirical studies conclude that idiosyncratic risk (commodity-specific risk) is priced, with futures prices biased downward (upward) in commodity markets where hedgers' net position is short (long).

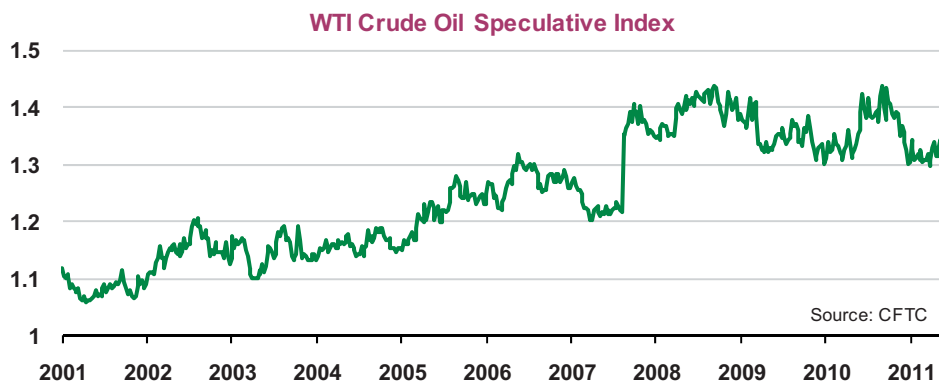
When speculators trade with one another in addition to trading with hedgers, the greater liquidity resulting from this 'excess speculation' should decrease hedgers' trading costs. Intuitively, then, the impact of hedging pressures on commodity returns should itself depend on the number and cost structures of speculators willing to take a position opposite that hedging pressure. This begs the question of whether there is any optimal level of speculation.

If long and short hedgers' respective positions in a given commodity futures market were exactly balanced (i.e., of the same magnitude at all maturities at market-clearing prices), then their positions would always offset one another and speculators would not be needed in that market. Because long and short hedgers do not always trade simultaneously or in the same quantity, however, speculators must step in to fill the unmet hedging demand.

In this restricted sense, the amount of speculative activity in commodity markets could be quite small. In practice, of course, speculators hold a range of views about the future and take positions on both sides of the market. As a result, speculative activity almost always substantially exceeds the level required to offset any unbalanced hedging. As suggested by Working (1960), the level of speculation is meaningful only in comparison with the level of hedging in the market. Increased speculative positions naturally arise with increased hedging pressure. In order to assess the adequacy of speculative activity in the crude oil market relative to hedging activity, we calculate Working's (1960) speculative index for all maturities as follows:

$$T = \begin{cases} 1 + \frac{SS}{HL + HS} & \text{if } HS \geq HL \\ 1 + \frac{SL}{HL + HS} & \text{if } HL \geq HS \end{cases}$$

where SS is short speculator (non-commercial) positions, SL is long speculator positions, HS is short hedge (commercial) positions and HL is long hedge positions. The speculative index value has risen over time to an average of 1.40 in 2008, implying that speculation in excess of minimal short and long hedging needs reached 40%. Of course, this increase can also result from speculators increasing spread trades as we observed in CFTC position data. While this rise in the speculative index to 1.40 may appear alarming, in fact it is comparable to historical index numbers observed in other commodity markets. Further, it is interesting to note that while a sharp rise in the speculative index was visible at the time crude prices rose to record highs in 2008, such a relationship is much less apparent for the 2010/2011 period. Indeed, it can be argued that the speculative index has been on a declining trend since 2008. As Working (1960) also notes, the speculative index measures excess speculation in technical terms, but not necessarily in economic terms.



Diverse Opinion on the Causes of Volatile Prices

Despite scant evidence of excessive speculation in the crude market since 2008, excessive speculation itself has the potential to disrupt markets. Shleifer and Summers (1990) note that herding can result from investors reacting to common signals or overreacting to recent news. As de Long et al. (1990) show, rational speculators trading via positive feedback strategies can increase volatility and destabilise prices. However, findings by Boyd et al. (2009) and Brunetti et al. (2010), respectively, suggest that herding among hedge funds is countercyclical and that it has not destabilised the crude oil futures markets during recent years. Some argue for the possibility that speculative trading might lead to higher prices if speculators increase their accumulation of inventories (e.g. Kilian and Murphy (2010) and Pirrong (2008)). Alquist and Kilian (2010) formally link forward looking behaviour and inventory building. Their model predicts that increased uncertainty about future oil supply shortfalls will lead the real price of oil to overshoot in the immediate short-run with no response from inventories. The real price of oil then gradually declines as inventories are slowly accumulated. Kilian and Murphy (2010) develop a structural model for crude oil that allows for shocks to the speculative demand. In their model, a positive shock to speculative demand increases both the real price of oil and oil inventories. They find no evidence that the 2003-2008 price surge had much to do with speculative demand shocks.

As suggested by Hamilton (2009b), crude oil inventories were significantly lower than historical levels in late 2007 and early 2008, when crude oil price changes were most dramatic. On the other hand, Davidson (2008) argues that the absence of higher inventories does not necessarily indicate the absence of excess speculation in the market. Using the Marshallian concept of ‘user cost’, Davidson argues that if oil prices are expected to rise in the future more rapidly than current interest rates, then producers can enhance total profits by leaving more oil underground today for future production. If oil producers do take the user costs of foregone profits into account in their profit maximising production decisions, then they may limit current production and above ground inventories may not rise. In this regard, Davidson (2008) points out that traditional hedgers, such as oil producers, might be involved in speculation. A similar argument is made by Parsons (2009), who argues that the change in the term structure for oil to a long lasting and deep contango late in 2004 can explain steady above-ground stockpiles of oil. Kilian and Murphy (2010), however, find no evidence that a negative oil supply shock played an important role in the spike in crude oil prices. In assessing the balance of these findings, however, it is important to note the lack of timely and detailed physical market data, including inventory data, especially for non-OECD countries, as well as the lack of OTC data.

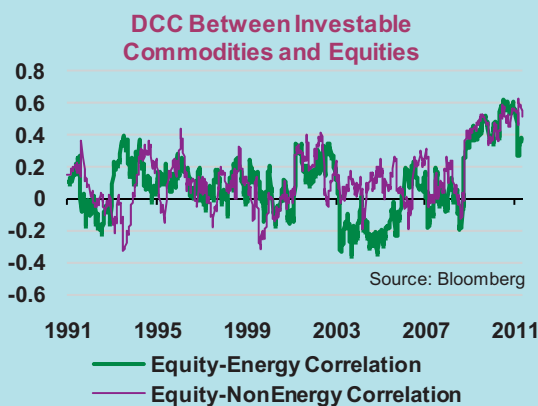
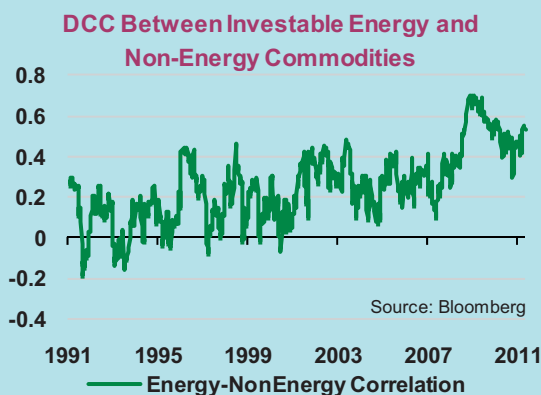
Kilian (2008) and Kilian (2009) propose a structural decomposition of the real price of oil into three components: shocks to the flow of supply of crude oil; shocks to global demand for all commodities; and

Diverse Opinion on the Causes of Volatile Prices (continued)

demand shocks that are specific to the crude oil market. Their empirical analysis provides evidence that the 2008 price hike was primarily a result of global demand shocks rather than supply shortages or crude oil-specific demand shocks. Hamilton (2009a) suggests that both factors – stagnant production and low short-run price elasticity – are needed for speculation to drive prices too high, but that financial speculation (by non-commercial entities) would also cause inventories to rise. He concludes that supply and demand fundamentals provide a more plausible explanation for the 2008 price spike. However, Hamilton (2009b) also suggests that it is possible for speculators to drive up prices without any change in inventories if the short-run price elasticity of demand is close to zero (an approximate condition of the oil market). Kilian and Murphy (2010) estimate the short-run oil price elasticity of demand at a significantly negative -0.24, much higher than existing estimates in the literature and, if accurate, further undermines speculation as an explanation for oil price increases.

Buyuksahin and Harris (2011) and Brunetti et al. (2010) also find that speculative activity in crude oil futures markets does not lead price changes, but reduces volatility by enhancing market liquidity. On the other hand, Tang and Xiong (2010) and Singleton (2011) find a significant impact from investment flows by non-user participants on prices and volatility of commodities. Tang and Xiong (2010) further argue that the average correlation between indexed commodities and between indexed commodities and equities increased due to the growing presence of commodity index investors after 2004. However, Buyuksahin and Robe (2011) suggest that increased correlation is a relatively new phenomenon and that hedge funds, rather than passive long-only investors' positions, might explain the increased correlation between equities and commodities. Specifically, they find no persistent increase in co-movements between returns on equities and investable commodities until the Lehman demise in September 2008. A corollary is that, in 'normal' times, commodities provide benefits in terms of portfolio diversification. However, commodity-equity return correlations jumped immediately after the Lehman collapse, reaching levels after November 2008 never before seen during 1991-2008. Furthermore, cross-market linkages have remained exceptionally strong since autumn 2008. Equity and energy markets did drift apart in February and March 2011 due to tensions in the Middle East. However, this drift was temporary. Equity-commodity return correlations have since rebounded – they were again higher as of April-May 2011 than at any point in the 1991-2007 period.

In short, academic opinion remains highly polarised on the respective roles of hedgers and speculators, and on the concept of 'excessive' speculation in the crude oil market. Despite this lack of a clear consensus, however, significant new regulatory measures aimed at reducing systemic risk in financial markets are being developed, which may substantially limit the participation of non-commercial players within commodity derivatives markets.



Market Regulation

It is almost a year since the US financial reform package, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act), became law on 21 July 2010. Since then, the CFTC has put forward 66 proposed and final rules under the Act. Meanwhile, the European Commission also unveiled its proposal for the regulation of OTC derivatives, central counterparties and trade repositories on 15 September 2010, followed by a public consultation report on the review of Markets in Financial Instruments Directive (MiFID). The main goal of these reform packages is to increase transparency and efficiency of the OTC derivatives markets and to reduce potential counterparty and systemic risks. However, as pointed out by the Financial Stability Board (FSB), clear signs have emerged that substantial cross-border differences in the pace of implementation, as well as differences in some rule-making areas, might lead to regulatory arbitrage, in which market participants will seek out lighter-touch jurisdictions, thereby shifting risk rather than mitigating it.

Although the CFTC has almost completed the proposal phase of the rule-making and started consideration of final rules, it has said it will miss the 16 July 2011 deadline for implementing those rules that will give it oversight of the OTC market. However, market participants indicated that it might take more than 2.5 years to implement the new rules once they are written. There is also uncertainty regarding the implementation schedule; regulators so far have failed to provide any timeline for the implementation sequence of the new rules. The European Commission, on the other hand, is still in the phase of proposing rules and setting a deadline for implementation by the end of 2012.

Because it primarily deals with privately-negotiated contracts, the OTC derivatives market is essentially opaque, in the sense that information is typically available only to the negotiating parties. Some argue that the lack of public information in the market prevents an appropriate assessment of overall risks by market participants and precludes them from taking the appropriate measures against default risks. New rules are expected to address these main problems in OTC markets: transparency and inherent systemic risk.

Transparency

In order to increase market transparency in OTC markets, new proposed rules call for:

- Standardising as many swaps as possible;
- Trading standardised swaps on designated contract organisations or swap execution facilities, where multiple traders can place bids and offers, thereby providing pre-trade transparency to market participants;
- Real-time reporting for cleared and uncleared swaps to centralised swap data repositories, thereby providing post-trade transparency; and
- The clearinghouse in the case of cleared swaps; swap dealers in the case of uncleared swaps will be required to disclose the pricing of swaps to the public, or to their counterparties, respectively.

While the US and EU's proposed rules on transparency are similar, there are certain differences that might lead to regulatory arbitrage. For example, as opposed to the strict CFTC proposal that swap execution facilities be either order-book or request-for-quote (RFQ) facilities, the EU has proposed a looser definition of these platforms, which it calls 'organised trading facilities', which do not require

order-book or RFQ facilities. This might create regulatory arbitrage opportunities, prompting banks to shift activity from the US to Europe to take advantage of a laxer regime.

Market participants have already raised concerns over some of the issues in the rules related to transparency. Their main concerns include the following:

- The opaqueness of the OTC markets is a myth: End-users in these markets are institutions and they have access to dealers' screens. OTC markets are also not less transparent than futures markets; hiding volumes in OTC markets is very difficult since traders know their counterparties.
- Swaps are not identical to futures: They argue that the OTC market is different from the futures markets and therefore should not be regulated in an identical fashion.
- Standardisation and exchange trading: Swaps can trade infrequently, often in significant sizes, between dealers and end-users or speculators. If trading activity in the futures markets is any evidence, a relatively small number of highly liquid instruments have been effectively traded on the exchange. In contrast, the failure rate of exchange trading models in less liquid instruments has been very high.
- Real time reporting increases transaction costs, which will lead to lower liquidity, thereby increasing the cost of hedging.

Systemic Risk

The second purpose of the financial reforms is to lower inherent risk in the OTC market. In order to lower the risks, new rules call for:

- Comprehensive regulation of swap dealers and major swap participants to minimise systemic risk, via registration, capital and margin requirements and standards of conduct;
- Clearing requirements for standardised swaps through an intermediary company with sufficient capital, such as clearing houses or central counterparties (CCPs), to eliminate counterparty risk. Mandatory clearing requirements will not apply to existing swaps, however they still need to be reported to swap data repositories or directly to regulators;
- Exempting end-users using swaps to hedge or mitigate commercial risk from mandatory clearing; and
- Imposing aggregate position limits and large trader reporting requirements for swaps.

In the US, contracts between financial entities have to be cleared and subjected to mandatory capital and margin requirements. On the other hand, end-users are not subjected to the same requirements even if their counterparty is a swap dealer or major swap participants. The EU proposal is different from the US in that it gives exemption from mandatory clearing only to non-financial entities, which do not exceed a clearing threshold level of position. The EU proposal further calls for margin requirements even for non-cleared swaps. The US and EU proposed rules for position limits provide another challenge for global consensus. While the US proposed hard position limits on swap dealers and major swap participants' position in the spot-month, non-spot month as well as all-month combined, the EU proposal calls for a hard position limit only in spot month contracts but position management systems for all other contracts, similar to position accountability levels in the US exchanges. This will authorise regulators to demand traders to reduce their positions if needed.

Critics argue that some of the proposed regulations might have unintended consequences in the market place. These include:

- Low liquidity: Liquidity in OTC markets is generally provided by the dealers, who use their own capital to make the markets. Market participants contend that the Volcker rule, which restricts banking entities' proprietary trading, or investing in or sponsoring hedge funds or private equity firms, has the potential to change the structure of the market by lowering liquidity. Notwithstanding the potential for diminished risk to lead to lower interest rates, if liquidity were to decline due to margin requirements, clearing costs or any other clause in the regulation, the process of price discovery and the risk transfer function of these markets would be significantly compromised.
- Shifting risk from market participants to clearing houses: Some argue that mandatory clearing concentrates risk among a few large entities.
- Increased end-user costs: There are end-user complaints about costs possibly increasing were the counterparty to transfer some of the clearing costs to end-users; in addition, the broad definition of swap dealers would classify some end-users as financial entities, which would then be subject to mandatory capital and margin requirements.
- Hard position limits will severely constrain trading activity which would lead to increased, rather than reduced, volatility. Liquidity in futures markets, and especially in swaps markets, will, it is argued, be unnecessarily impaired. Producers and end users would have a smaller pool of counterparty firms to hedge their price risk with, which in turn increases the bid/ask spread, thereby creating more volatility. The proposed rule can also potentially constrain the size of trading entities. This would lead to market dependence on small speculators as institutional investors hit their respective position limits and are forced out of the market, thereby lowering liquidity and increasing trading costs. Higher trading costs would, in turn, force some entities to establish smaller positions.

Regulatory efforts to increase transparency and reduce systemic risks in global OTC markets have intensified in the last year. Some observers have argued that the CFTC has rushed to meet arbitrary deadlines without properly analysing the costs and benefits of new rules for swaps markets. However, despite the rapid pace of rule-making, the US is likely to miss the July 2011 deadline for the implementation of the rules under the Dodd-Frank Act. This might create legal issues for existing contracts, since they would lose the protection granted by Commodity Futures Modernisation Act (CFMA) of 2000. Slow progress on agreed reforms to meet the end of 2012 deadline set by the G-20 in Pittsburgh in 2009 is seen as another problem, notably the apparent lack of international consensus between regulators on how to achieve the key elements of the reform agenda. Regulatory arbitrage opportunities might undermine the impact of new regulations even in countries where more stringent rules are to be implemented. Therefore, more international coordination is needed for more consistent and effective oversight in OTC markets. Cross-country differences in new rules and implementation will be discussed in more detail in upcoming *Oil Market Reports*.

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OIL DEMAND

Summary

- **Global oil product demand is projected to increase from 88.0 mb/d in 2010 to 95.3 mb/d in 2016 (averaging +1.3% or +1.2 mb/d per year).** This outlook is based on global economic activity expanding by 4.5% per year, and assumes that oil intensity declines by 3% per year. Demand growth is driven exclusively by non-OECD countries (+3.2% or +1.5 mb/d per year), whereas OECD oil demand contracts by 0.6% or 260 kb/d annually. Overall, global demand is 0.7 mb/d higher on average for 2010-2015 when compared with our December 2010 update.

Global Oil Demand (2010-2016)

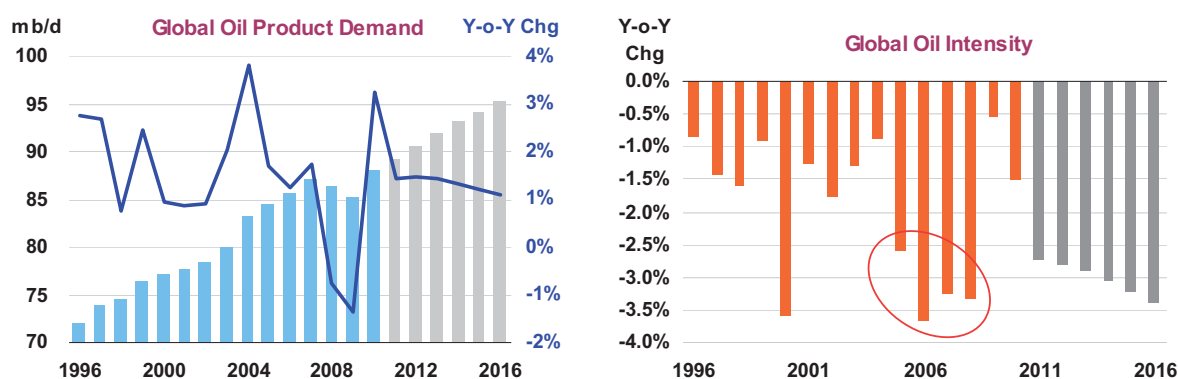
	(million barrels per day)														
	1Q10	2Q10	3Q10	4Q10	2010	1Q11	2Q11	3Q11	4Q11	2011	2012	2013	2014	2015	2016
Africa	3.3	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.5	3.6	3.8	3.9	4.0
Americas	29.6	30.0	30.7	30.4	30.2	30.2	30.2	30.7	30.4	30.3	30.5	30.6	30.6	30.7	30.7
Asia/Pacific	27.2	26.9	26.7	28.3	27.3	28.6	27.9	27.8	28.9	28.3	29.0	29.8	30.6	31.4	32.1
Europe	14.9	14.8	15.5	15.4	15.1	14.7	14.6	15.3	15.3	15.0	15.0	14.9	14.8	14.6	14.5
FSU	4.2	4.1	4.4	4.4	4.3	4.3	4.2	4.5	4.5	4.3	4.5	4.5	4.5	4.5	4.5
Middle East	7.4	7.8	8.2	7.7	7.8	7.6	7.9	8.5	7.8	7.9	8.2	8.5	8.8	9.2	9.5
World	86.5	87.1	88.8	89.6	88.0	88.7	88.1	90.0	90.3	89.3	90.6	91.9	93.1	94.2	95.3
Annual Chg (%)	2.5	3.2	3.6	3.7	3.3	2.5	1.1	1.4	0.8	1.4	1.5	1.4	1.3	1.2	1.1
Annual Chg (mb/d)	2.1	2.7	3.1	3.2	2.8	2.2	1.0	1.2	0.7	1.3	1.3	1.3	1.2	1.1	1.0
Changes from last MTOGM (mb/d)	0.17	0.15	0.18	1.79	0.58	0.74	-0.06	0.41	1.01	0.52	0.60	0.74	0.83	0.85	

- **Oil demand in countries within the crucial \$3,000-\$20,000 per capita income range, which traditionally features exponential growth, reaches almost 45 mb/d by 2016,** almost doubling in only 20 years. By contrast, most higher-income OECD countries face continued efficiency gains, behavioural changes, market saturation and structural decline in some fuels. The predominance of income as a key growth driver for almost half of global oil demand, the persistence of price subsidies in many emerging markets and the concentration of demand in sectors with few immediate alternatives to oil sustain growth even under a now-higher crude price assumption.
- **Transportation will be the primary driver of global oil use, accounting for two-thirds of both absolute demand and growth.** Sectoral analysis is becoming complicated, however, by a blurring of data reporting and fuel specifications, a growing concern for key non-OECD markets. Gasoil alone, which has effectively become the 'king of fuels', given its multiple uses and drivers, will account for over 40% of total demand growth, while its share of total demand will climb steadily to almost 30% by 2016. Gasoil growth is concentrated in non-OECD Asia (roughly 50% of total global growth), particularly in China.
- **The health of the global economy poses a central risk to this outlook,** given mounting inflationary pressures, persistent OECD indebtedness, investment-driven economic growth in the non-OECD and global current account imbalances. Under a 'lower GDP' case (averaging +3.3% per year over 2010-2016) and slower efficiency gains (2% per year), global oil demand would reach 92.8 mb/d by 2016 – some 2.4 mb/d less than in the base case. The evolution of oil prices and the extent of short- and long-term fuel switching are other key uncertainties.

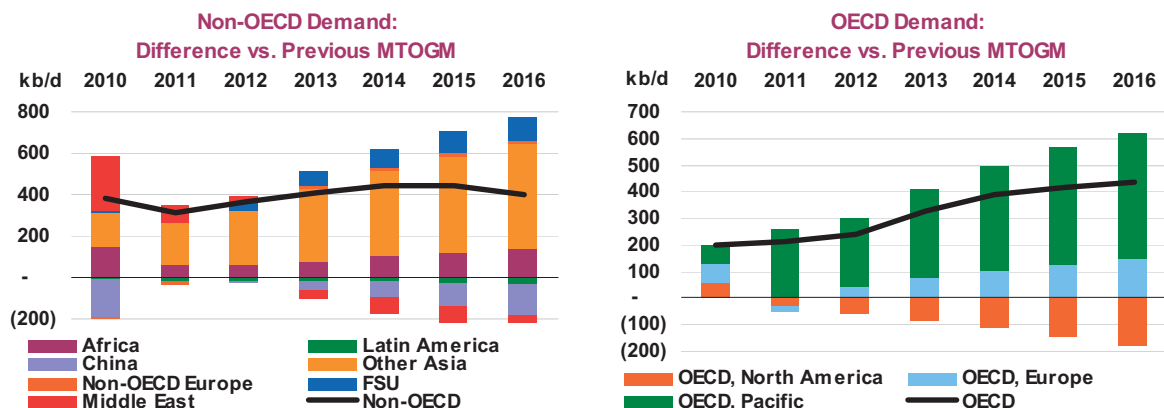
Global Overview

Global oil product demand is expected to rise from 88.0 mb/d in 2010 to 95.3 mb/d in 2016 – a total increase of 7.2 mb/d, equivalent to an average yearly growth of 1.3% or 1.2 mb/d over the outlook period. As in previous editions of this report, this prognosis is based on the economic assumptions provided by the International Monetary Fund (*World Economic Outlook*, April 2011), which sees global GDP growth averaging 4.5% over 2010-2016, and on a futures price strip as of late April, which suggests that the oil price (Brent) will average roughly \$102/bbl (in nominal terms) over 2010-2016 or \$97/bbl in real terms (2010 dollars).

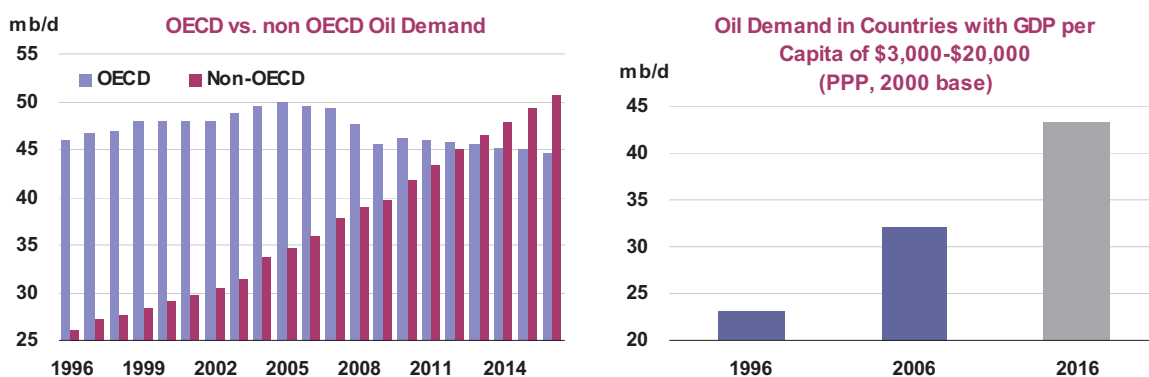
In addition, we assume that oil use efficiency will improve by 3% per year on average, in line with recent trends – akin to the pre-2009 period, when non-OECD demand rose in prominence within the global market (2004-2008). The gain in efficiency – or more precisely, the decline in oil intensity – can be defined as the ratio of the change in demand over the change in real income. The gradual fall in oil intensity over time is in practice a proxy of declining income elasticity (the amount of oil required to produce a unit of GDP). Moreover, this demand outlook posits that efficiency will improve slightly faster in the non-OECD, as the scope for marked gains in the OECD – after the drastic improvements following the oil shocks of the 1970s and 1980s – is more limited.



Compared with the December 2010 update, this demand outlook is, on average, some 0.7 mb/d higher (over 2010-15). These revisions – roughly evenly split between the non-OECD and the OECD – result from several causes. The inclusion of consolidated non-OECD data for 2009 lifts the baseline for most countries excepting China. The baseline is further boosted by the extraordinary 2010 growth surge recorded in both the non-OECD and OECD countries alike, following the sharp recession-induced 2009 plunge. Moreover, the prospects for several regions are also reappraised. In the non-OECD, oil demand, particularly for gasoline and distillates, is now projected to grow slightly faster in Asia, Africa and the FSU. In the OECD, meanwhile, the forecast for the Pacific has been significantly hiked; Japan is expected to temporarily burn much more residual fuel oil and sweet crude to offset the loss of earthquake-stricken nuclear power generation capacity, as well as additional gasoil as reconstruction efforts proceed. In North America, the pace of decline has been slightly raised on weaker expectations for all-important gasoline demand.



Oil demand growth will derive entirely from non-OECD countries, where aggregate demand will rise by 3.2% or 1.5 mb/d per year on average, from 41.9 mb/d in 2010 to 50.7 mb/d in 2016. By 2016, the non-OECD will dominate global oil demand (a share of 53% versus 47% for the OECD), compared with only 36% as recently as 1996. This expected rise in demand will be the consequence of sustained economic growth, collectively averaging 6.7% per year over 2010-2016, almost three times as fast as in the OECD – and largely underpinning global economic activity. The resilience of emerging economies – which navigated relatively unscathed through the rough waters of the Great Recession of 2008-2009 – will likely alter the balance of global economic power. Collectively, the non-OECD will account for 51.4% of worldwide wealth by 2016, versus 48.6% for the OECD. Although the US will remain the world's largest economy, China will follow closely (17.8% and 17.5% of global GDP, respectively, on a purchasing power parity basis).

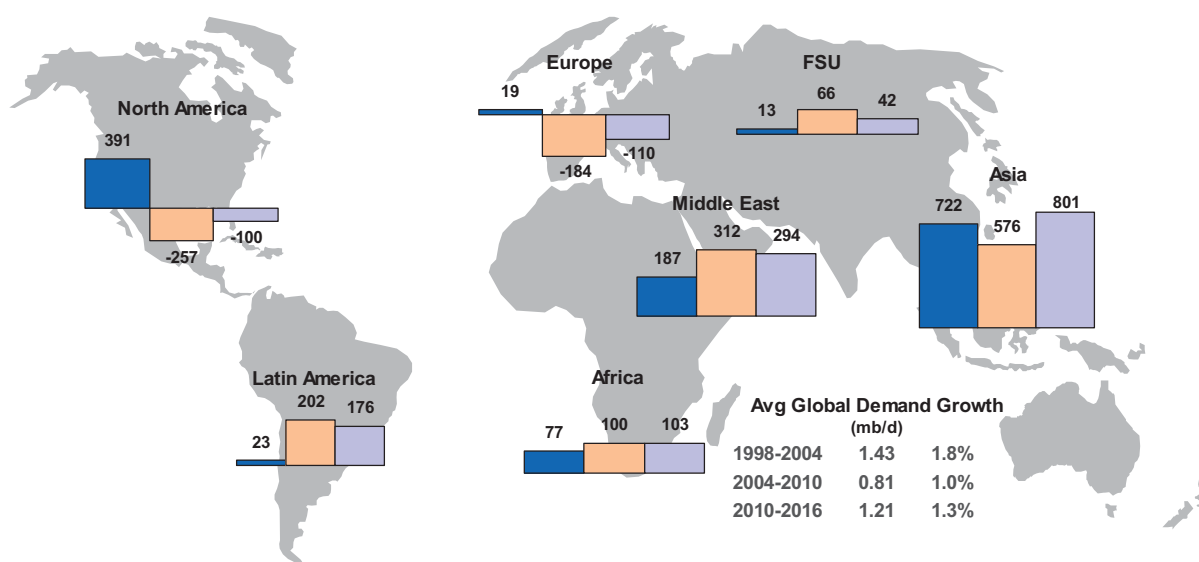


The dynamics of demand growth – mostly concentrated in Asia, the Middle East and Latin America – are largely based on income per capita trends. Empirically, the OECD experience suggests that oil demand takes off exponentially when income per capita reaches around \$3,000 (in real 2000 dollars) and begins to taper off after passing the \$20,000 mark, following a so-called 'S curve' path. Countries within that range will account for 49% and 65% of the world's GDP and population, respectively, by 2016 (versus 29% and 24% in 1996). By the same token, their aggregate oil demand will roughly double to almost 45 mb/d in only 20 years.

Crucially, since income will remain the primary growth driver of almost half of global demand over the medium to longer term, higher international oil prices are likely to have a minor effect upon oil demand. Even the gradual removal of end-user subsidies (still partly or fully in place in many non-OECD countries) would probably only tame runaway demand growth, rather than choke it off entirely. Put another way, low price elasticity in the non-OECD will generally sustain demand growth even in the face of high crude prices, notably in the largest emerging countries – unless prices were to reach levels that begin to derail the entire global economy. Recent, partial reforms to administered price regimes in countries such as India or Iran suggest that demand can resume its previous growth trend shortly after the initial price shock. A more lasting impact would require full price liberalisation, a goal that is socially and politically difficult to achieve – and, with some notable exceptions, not on the policy agenda of many major emerging countries within the forecast period (particularly in several MENA countries, where political discontent has recently become pervasive). By contrast, sustained high oil prices would instead likely accelerate the decline of OECD demand, something that is borne out in the sharper decline now expected in that area.

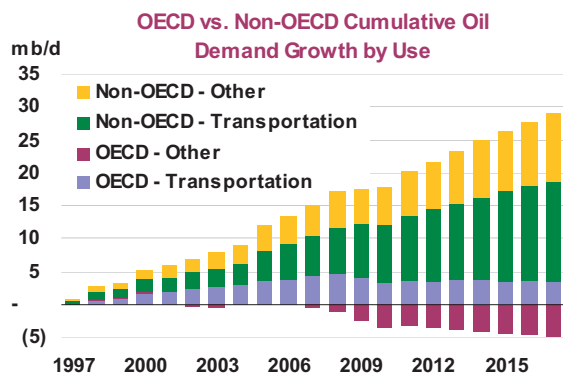
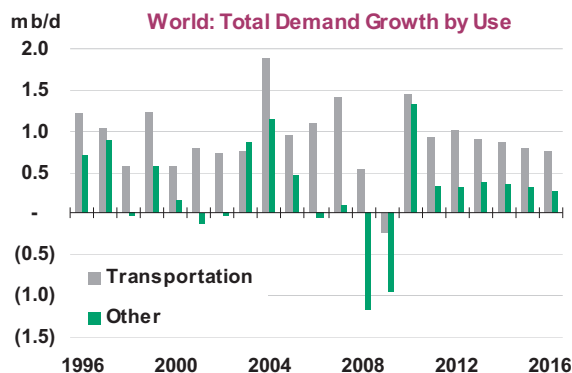
OECD oil demand is therefore expected to contract by 0.6% or 260 kb/d per year on average, from 46.1 mb/d in 2010 to 44.6 mb/d in 2016. This is due to the combination of several factors: 1) a higher underlying crude price assumption; 2) the effect of high average income per capita levels (well above the \$20,000 tapering-off threshold in most countries); 3) continued efficiency gains (both in terms of processes and new technologies); 4) behavioural changes (for example, anecdotal evidence indicates that a growing share of the urban young, notably in Europe and the Pacific, is much less eager to purchase cars, while rising oil prices are gradually altering driving habits in North America); 5) market saturation (notably in vehicle fleets across most developed economies); and 6) the structural decline in both heating and industrial fuels (which will largely offset any latent buoyancy in transportation fuel demand).

Average Global Oil Demand Growth 1998-2004/2004-2010/2010-2016
thousand barrels per day



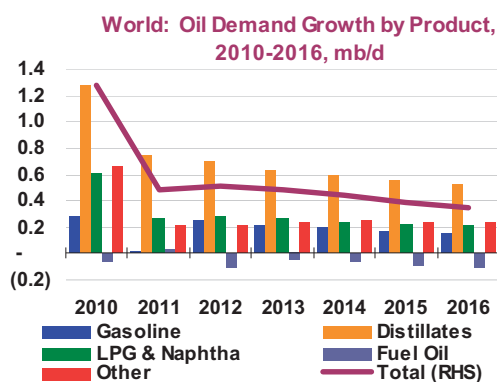
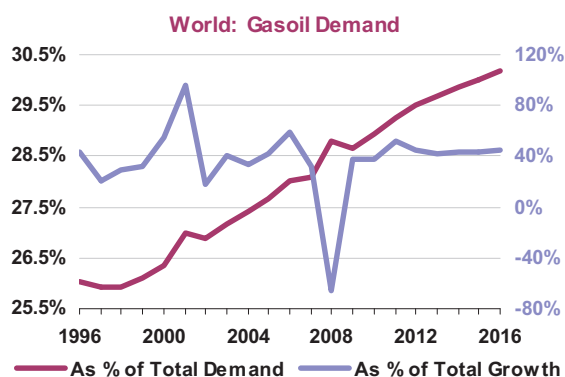
In terms of sectors, transportation (road, railway and airborne) will be the primary driver of oil use (roughly two-thirds of both absolute global demand and growth), followed by industry/agriculture, heating/power generation and residential/commercial. In practice, however, establishing a precise sectoral split is becoming increasingly difficult. Sectoral data are frequently incomplete; it is often impossible to determine, say, exactly how much fuel is used for heating and for power generation in any given facility. Moreover, some products are put to different use depending on the region; for example, LPG is a household fuel in many emerging countries, but primarily a petrochemical feedstock in advanced economies. Similarly, residual fuel oil is typically used for power generation across the non-OECD, but mostly for bunkers in the OECD. The emergence of large integrated industrial complexes – such as a refinery coupled with a gas processing plant and a petrochemical facility – further blurs the picture, as decisions to use specific feedstocks (say LPG or naphtha) partly depend on price and profitability at any given point in time.

The homogenisation of product specifications, while logical in terms of costs and logistics, is also complicating data reporting. The move to uniform 10 ppm gasoil in the OECD, for example, obscures end-user distinctions – some product will likely be used for road transportation, some will be blended for bunkers or with biodiesel, some will be used for power generation or industrial purposes and some will be used for household heating. Although these data issues are generally universal, they tend to be more widespread in the non-OECD. As this area becomes the centre of gravity of global oil demand, the need for more detailed and differentiated data reporting in order to identify and anticipate changing market trends will become ever more evident.

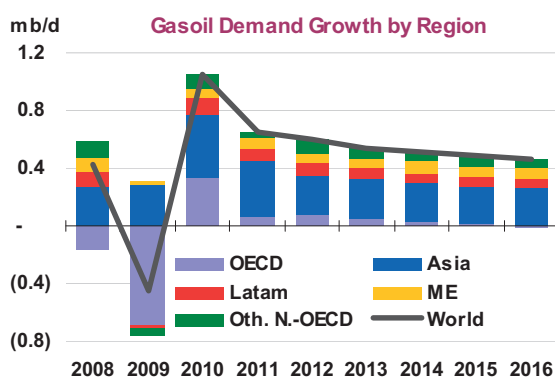
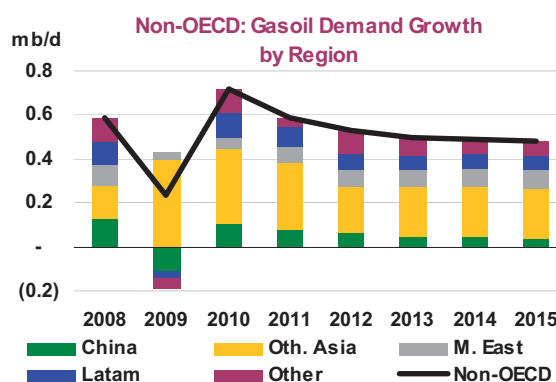


Gasoil is the strongest product in terms of medium-term demand growth. Demand for all product categories bar residual fuel oil will certainly increase, but gasoil alone accounts for almost 40% of total forecast growth on average, in line with recent trends, while its share of total oil product demand will climb steadily to almost 30% by 2016. Indeed, gasoil has effectively become the oil product of choice. It can be used for on-road vehicles, ships and trains, and for residential, commercial and industrial purposes (space heating, agriculture, construction, power generation and petrochemicals, among others). Similarly, the drivers of gasoil demand are also manifold, including economic growth, interfuel substitution (from gasoline to diesel, from heating oil to natural gas/electricity or from fuel oil bunkers to marine gasoil), weather conditions and power sector outages. Power generation is becoming a particularly critical demand driver: small-scale gasoil

generators play an important role in emerging economies by providing back-up power capacity, while the growing global stock of combined-cycle gas turbines can also run on gasoil if natural gas supplies are disrupted.



Gasoil demand growth will be concentrated in the non-OECD (about 90% on average of global gasoil demand growth over 2010-2016), reflecting the general trends highlighted above, with Asia taking the lead. The region will account for roughly 50% of global average gasoil demand growth and for almost 60% of non-OECD gasoil growth. China alone will represent some 9% of total non-OECD incremental gasoil use – almost equivalent to total OECD gasoil growth.



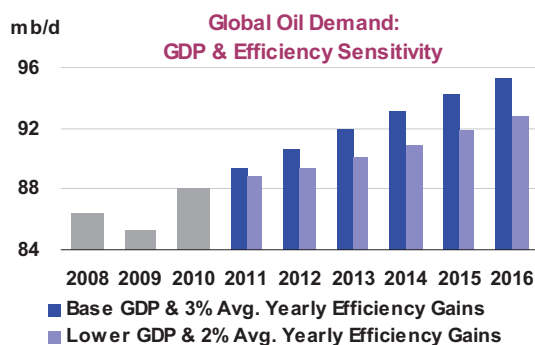
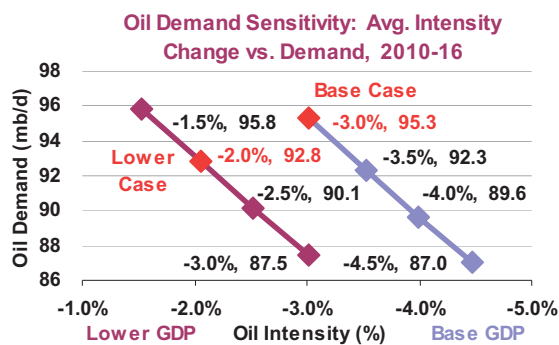
Needless to say, this demand outlook faces diverse risks, given the inherent complexity of oil demand drivers. A central risk relates to the health of the global economy. Many observers, most notably the IMF, argue that the ongoing global economic recovery is firmly on track. This may well be the case, but the steady rise in commodity prices, particularly oil since 3Q10, is creating inflationary pressures that greatly complicate the task of central bankers and policy-makers around the world. Some analysts fret that sharp fiscal and monetary tightening will inevitably follow, potentially engendering a marked global slowdown – and perhaps a hard landing in some large emerging markets as well. Moreover, many of the issues that led to or resulted from the Great Recession – such as over-indebtedness in the OECD, investment- rather than consumption-driven economic growth in the non-OECD or global current account imbalances – persist.

As such, we maintain the sensitivity analysis deployed in previous issues of this report, examining the profile of global oil demand under a 'lower GDP' case, whereby economic growth would be about a quarter lower over 2010-2016 (+3.3% per year on average) than under the base case. Conceivably, short of a major oil supply disruption, less buoyant economic activity would ultimately entail somewhat lower oil prices and in turn reduce the incentive to curb oil intensity aggressively, thus slowing down yearly efficiency gains to 2%. Global oil demand would grow in this case by 0.9% or 0.8 mb/d per year, reaching 92.8 mb/d by 2016 – some 2.4 mb/d less than in the base case. As discussed earlier, emerging countries would be more sensitive to changes in GDP and efficiency; non-OECD average annual oil demand growth, at +1.1 mb/d, would thus be roughly 0.3 mb/d weaker. Advanced economies, by contrast, already typically feature fairly low income elasticity; as such, OECD demand would decline by 0.3 mb/d on average, only 0.1 mb/d faster than under the base case.

Oil Demand Sensitivity

(million barrels per day)

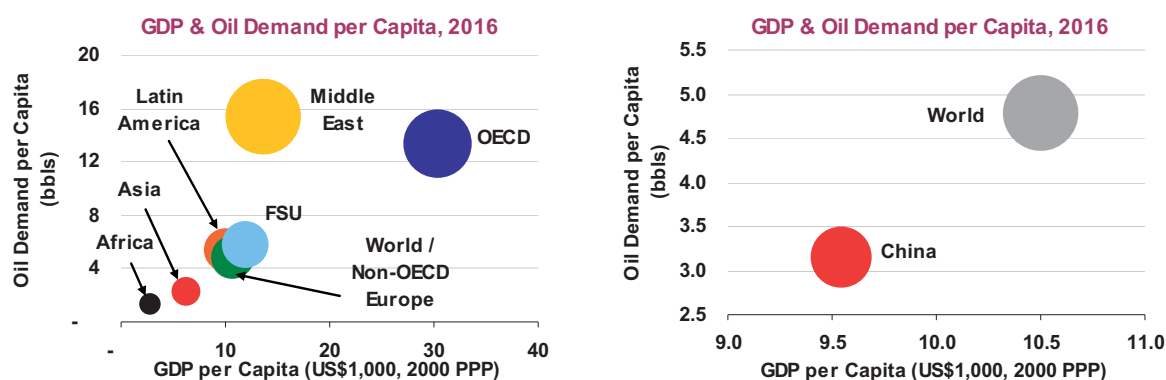
	2010	2011	2012	2013	2014	2015	2016	Avg. Yearly Growth, 2010-2016		
								%	mb/d	
Base GDP & 3% Avg. Yearly Efficiency Gains										
Global GDP (y-o-y chg)	4.8%	4.3%	4.4%	4.4%	4.5%	4.6%	4.6%	4.5%		
OECD	46.1	45.9	45.7	45.5	45.3	44.9	44.6	-0.6%	-0.26	
Non-OECD	41.9	43.4	44.9	46.4	47.9	49.3	50.7	3.2%	1.46	
World	88.0	89.3	90.6	91.9	93.1	94.2	95.3	1.3%	1.21	
Lower GDP & 2% Avg. Yearly Efficiency Gains										
Global GDP (y-o-y chg)	4.8%	2.9%	3.0%	3.0%	3.0%	3.0%	3.1%	3.3%		
OECD	46.1	45.8	45.3	45.0	44.7	44.4	44.2	-0.7%	-0.33	
Non-OECD	41.9	43.1	44.0	45.0	46.2	47.4	48.6	2.5%	1.13	
World	88.0	88.9	89.3	90.0	90.9	91.8	92.8	0.9%	0.80	
Lower vs. Base										
Global GDP (% points)	0.00	-1.39	-1.44	-1.46	-1.50	-1.53	-1.57	-1.27		
OECD	0.00	-0.12	-0.40	-0.52	-0.56	-0.52	-0.41	-0.15	-0.07	
Non-OECD	0.00	-0.29	-0.90	-1.37	-1.70	-1.92	-2.02	-0.70	-0.34	
World	0.00	-0.41	-1.30	-1.89	-2.26	-2.44	-2.43	-0.44	-0.40	



It is worth noting that more restrained efficiency gains have a powerful offsetting effect. Under a pure GDP sensitivity analysis – holding the decline in oil intensity unchanged at 3% per year – global oil demand would be almost 8 mb/d lower by 2016. However, assuming a slower, 2% per year intensity decline counters the GDP effect by roughly two-thirds. As shown in the chart above, this

simulation suggests that every 0.5 percentage-point change in the pace of oil intensity decline (under both GDP cases), roughly implies a 3 mb/d shift in oil demand by 2016. Clearly, for the longer term, this highlights how investment in new, more energy-efficient capital stock can play a crucial role in moderating oil demand levels, even if our projections have to be based necessarily on existing technologies and investment trends.

The evolution of international crude prices poses another substantial uncertainty for the outlook. Although, as argued before, rising income per capita will remain a far more central driver of global oil demand growth than prices, another spike in international oil prices may jeopardise the ongoing global economic recovery (whether or not that contributes to triggering another recession) – and could even force some countries to eliminate end-user subsidies altogether, as the financial burden would become unbearable, fostering further social and political turmoil. However, the assumed oil price path that underpins this outlook excludes the total elimination of subsidies. After all, only a handful of countries – most prominently China – took advantage of the 2009 recession-triggered price plunge to reform domestic policies, yet most stopped short of moving towards fully-blown price liberalisation. Now, as prices have again reached high levels, coupled with political unrest in MENA countries, the transition to fully market-based prices is even more unlikely.



Nonetheless, the prevalence of subsidies encourages waste and fosters a development model largely based on oil-intensive industries. This is particularly true of the Middle East, which in 2010 used roughly four times more oil per capita compared with the non-OECD average, yet produced only twice as much economic output per capita. This situation will worsen over the medium term; by 2016, Middle Eastern oil consumption per capita is expected to be some 15% higher than in the OECD, yet generate only half as much GDP. Interestingly, oil demand per capita in China is seen remaining well below global levels by 2016, even though GDP per capita will by then be approaching the world's average. That country – which will largely drive total oil demand growth over the next years – will arguably be far more oil efficient than most of its non-OECD peers. The country has ambitious energy efficiency targets under its 2011-2015 plan that, *ceteris paribus*, should also curb oil demand growth per capita. This presupposes that there will be no repeat of last-ditch efforts to meet emission and efficiency targets by curtailing coal-fired power generation, thus resulting in a temporary surge in gasoil demand, as seen at end-2010.

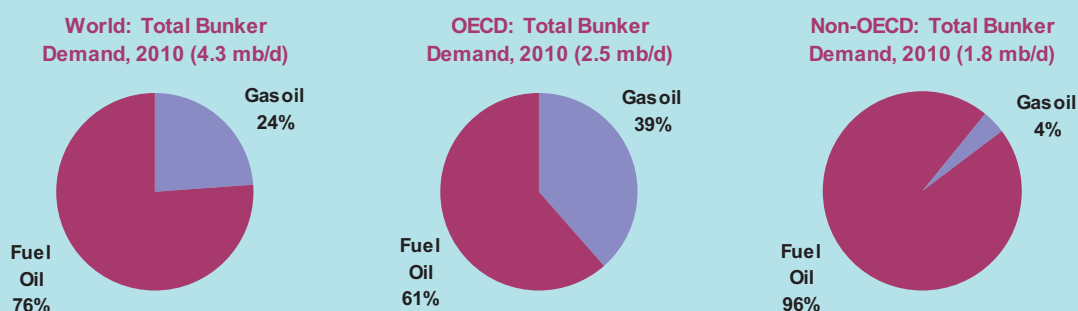
This points to a third major uncertainty for the outlook: the extent of interfuel substitution between oil and other energy sources. Power generation disruptions, either accidental (i.e., drought, interruptions to natural gas supplies or nuclear accidents) or policy-mandated, can sharply influence oil product demand in the short term, particularly with respect to gasoil. Similarly, the adoption of new, disruptive transportation technologies will further alter the demand picture – albeit well after this report’s timeframe.

Ultra-efficient vehicles will likely entail a stagnation, if not outright decline, in oil-based transportation fuel demand. However, the timing and extent are difficult to ascertain, as that will depend on the pace of fleet turnover and, perhaps more importantly, on whether such new technologies are widely spread in emerging markets. From that perspective, China will probably feature a greater proportion of highly efficient vehicles in its overall fleet in just a few years than most OECD countries, which will need more time to turn over their larger, older fleets. Moreover, these technologies will themselves contribute to alter oil product balances; if, for example, electric cars, rather than hybrids, were to become the vehicles of choice in key markets, the required electricity could well partly be met by, say, additional gasoil burning. As such, it is premature to foresee the peak of non-OECD demand, akin to the OECD (where demand peaked in 2005) – and certainly not within this report’s forecast period.

Uncharted Waters: The Outlook for Bunker Demand

By its very nature, the international market for bunker fuels is one of the most opaque. Bunkers are technically any type of fuel used aboard ships (the name derives from storage containers in both ships and ports), but in practice comprise predominantly residual fuel oil and gasoil. However, demand is difficult to track with precision, given the world's large number of ports and vessels. The various fuel specifications (mainly viscosity and sulphur), different conversion factors and the rising importance of marine gasoil blur the picture further. As such, estimates of the size of this market vary greatly, ranging from 180 million tonnes (mt) to as much as 320 mt, equivalent to roughly 3.7-6.5 mb/d.

Our own data suggest that global bunker demand (including seaborne and inland waterway transport) averaged some 4.3 mb/d (about 235 mt) in 2010. This is equivalent to 13% of aggregated gasoil and fuel oil demand or 5% of total oil product demand, with residual fuel oil accounting for 76% of the total, versus 24% for marine gasoil. However, whereas the share of gasoil is becoming substantial in the OECD, owing to increasingly stringent environmental legislation, it remains marginal in the non-OECD. These figures, however, are rough estimates, compiled from various sources and thus liable to revisions.

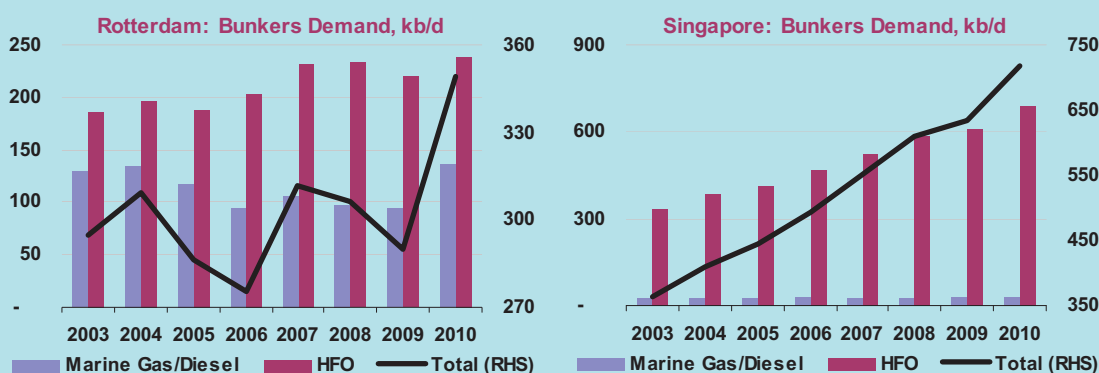


Until the early 1970s, no international bunker specifications or regulations were in place; bunkers were traded only on the basis of their viscosity (expressed in centistokes and ranging from 180 cst to 500 cst or more). As such, bunkers were effectively the refining sector's sink hole for lower-quality fuel. The trend toward emissions regulations began in 1973, with the adoption of the International Convention for the Prevention of Pollution from Ships (MARPOL), administered by the United Nations' International Maritime Organisation (IMO). In particular, MARPOL's Annex VI (2005), and its 2008 amendments (in force since 2010), established a specific timeline to gradually reduce ozone-depleting substances, nitrogen oxides, sulphur oxides, particulate matter and volatile organic compounds in various "Emission Control Areas" (ECAs) around the world. Annex VI has been ratified by 63 countries, which account for some 90% of the gross tonnage of the world's merchant fleet.

In practice, the regulatory effort has focused mainly on sulphur reduction, leading to the establishment of "Sulphur Emission Control Areas" (SECAs) in the Baltic Sea (2006) and the North Sea/English Channel (2007). A North American SECA (including the US and Canada) will be created in mid-2012. According to some observers, new SECAs/ECAs are likely to be established in other areas/countries over the next decade, including Mexico, Panama, Puerto Rico, the Norwegian and Barents Seas, the Arctic, the Mediterranean, Japan, South Korea, Hong Kong, Australia, the Straits of Malacca and Antarctica. Since 2008, the sulphur content in bunker fuels has been limited to 4.5% for Annex VI parties, but to 1% in both European SECAs, in line with stricter European Union regulations (2010). Over the next decade, sulphur levels are to be further curbed: to 3.5% in 2012 (globally), 0.1% in 2015 (in ECAs) and 0.5% in 2020-25 (worldwide, subject to a review to be completed by 2018).

Uncharted Waters: The Outlook for Bunker Demand (continued)

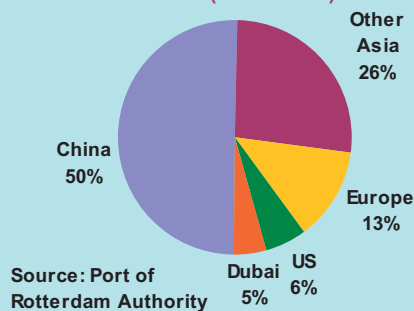
As noted, environmental regulations have already fostered a marked increase in low-sulphur gasoil use in the OECD, most notably in Europe. Data from the port of Rotterdam – the largest supplier of bunker fuels in Europe – show that marine gasoil demand surged in 2010, well exceeding growth recorded before the 2008-09 global economic recession. Meanwhile, high-sulphur fuel oil use has risen only modestly, suggesting some degree of interfuel substitution. By contrast, in the port of Singapore – the world's largest bunkering hub – marine gasoil is virtually non-existent, with demand (and growth) driven essentially by heavy fuel oil. Anecdotal evidence suggests that a similar pattern prevails in the third largest bunkering port, Fujairah (UAE).



Looking ahead, the demand for bunkers will largely depend on global economic growth and trade flows: as the Great Recession unfolded, both container traffic and bunker consumption plummeted. Rotterdam, for example, saw container volumes (expressed in twenty-foot equivalent units or TEUs) fall by almost 10% year-on-year and total bunker demand contract by over 6% in 2009; in Singapore TEUs shrank by almost 14%, while yearly bunker demand growth slowed by two-thirds to roughly 4%. Global economic prospects, though, suggest that global trade will fully recover and rise sharply, notably in Asia, which already holds 13 of the 20 largest ports in the world, accounting for roughly three-quarters of total container trade.

The bunkers outlook will also depend on how ship owners, operators and indeed refiners react to the new, more stringent sulphur regulations. In theory, many ships would effectively need to carry two, if not three, types of fuel on board: high-sulphur fuel oil for high-sea navigation, low-sulphur fuel oil for using when entering an ECA and ultra-low-sulphur gasoil for berthing (in Europe). These requirements are already costly for ships calling in European ports: some estimates currently put bunker costs at more than 50% of total average operating expenditures per ship in Europe. More worryingly for ship operators, bunker costs may well rise more in future. Indeed, some observers contend that there will be simply not enough low-sulphur bunker fuel supplies to meet expected demand, since many refiners are reluctant to invest in expensive upgrades, in part because of the uncertainty surrounding the exact size of the bunkers markets. This will put further pressure on an already tight distillate market, as ship operators will have to purchase more gasoil instead, likely leading to a sharp increase in product prices.

World: Top 20 Container Ports, 2010 (254 mTEUs)

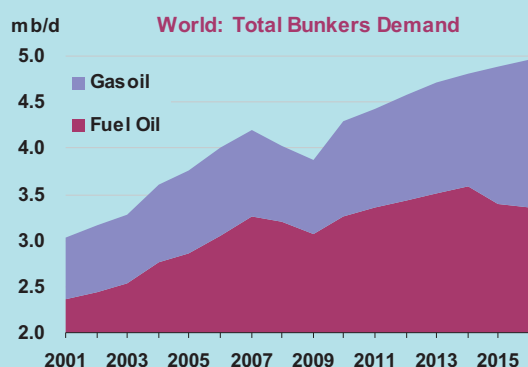
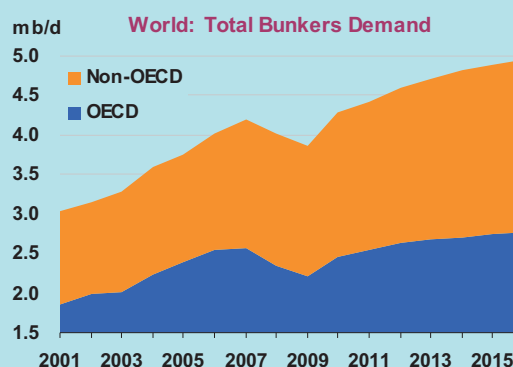


Uncharted Waters: The Outlook for Bunker Demand (continued)

Therefore, other regulatory compliance strategies will be needed – including fuel efficiency improvements, emission abatement technologies and the adoption of alternative fuels. On the efficiency side, the most obvious response has been ‘slow steaming’ – i.e., navigating at slower speeds in high-seas, which can cut some 10-15% of fuel oil demand. Other measures to increase efficiency include installing electronic-injection systems, carrying low-energy refrigerated containers, optimising water ballasts or redesigning hulls, among others. Abatement technologies essentially comprise exhaust cleaning systems such as filters and sulphur scrubbers. Albeit still expensive, scrubbers are seen as the most cost-effective option in the medium-term (from 2014 onwards), particularly if installed in the largest vessels – indeed, according to some estimates, of the approximately 100,000 ships currently in operation, 10% account for almost two-thirds of total bunker fuel oil consumption.

Alternative fuels, meanwhile, include LNG, nuclear and renewables. Although some 20 LNG-fuelled ships are already in operation, the widespread adoption of this fuel is problematic as it requires huge tanks and readily available supplies. In addition, there may be concerns about potential safety risks (real or perceived). Therefore, LNG vessels are likely to sail only in specific regions such as northern Europe, but may gradually become more popular if LNG prices decouple substantially and durably from oil-based bunker fuel prices. Nuclear propulsion would eliminate emissions altogether, but costs and, perhaps more importantly, safety, disposal and acceptability concerns are likely to remain key obstacles. By contrast, wind power may fare better: two reconverted German ships, the *Beluga-Sky Sails* and the *Michael-A*, already save 20-50% of their normal fuel requirements by deploying gigantic sails in high seas. Finally, biodiesel is increasingly used, but mostly for cabotage rather than high-sea navigation, as it requires converting vessels and, more worryingly, is both prone to contamination and very corrosive.

Taking into account all the above-mentioned factors, global bunker demand is projected to rise to almost 5.0 mb/d in 2016 (+0.7 mb/d from 2010). However, the pace of growth is expected to slow down as the new sulphur regulations come into force. On the one hand, the worldwide 3.5% sulphur limit (2012) will curb fuel oil demand growth; on the other, the ECA 0.1% sulphur limit (2015) will rein in fuel oil use sharply in the OECD (as all existing ECAs will be located there), but will boost gasoil demand, further accelerating the offsetting substitution trend. Further ahead – beyond the scope of this report – overall bunker demand is expected to grow at a very moderate pace until 2025 (when the global 0.5% sulphur limit kicks in) and then decline again. Interestingly, some analysts contend that, in the longer term, bunker fuel oil demand will grow again as scrubbers become a standard feature in most ships – if so, that would bring much needed relief to refiners and ship operators alike.

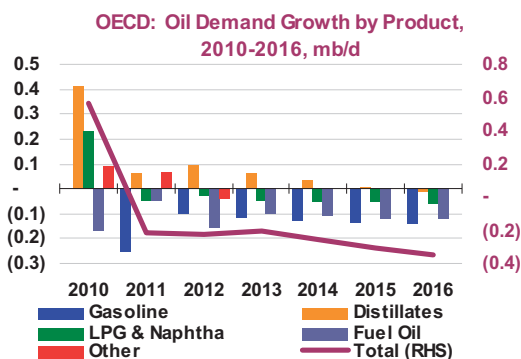
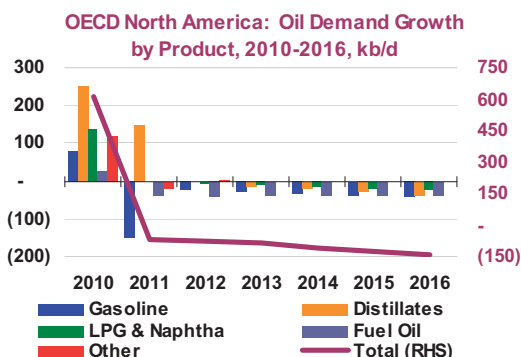
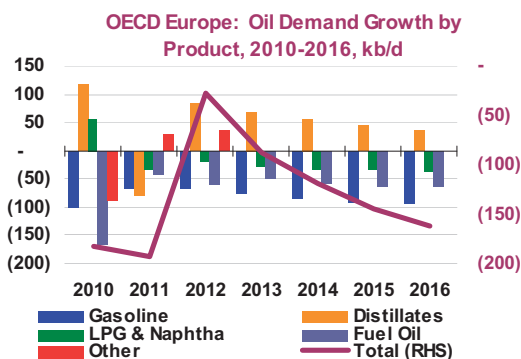
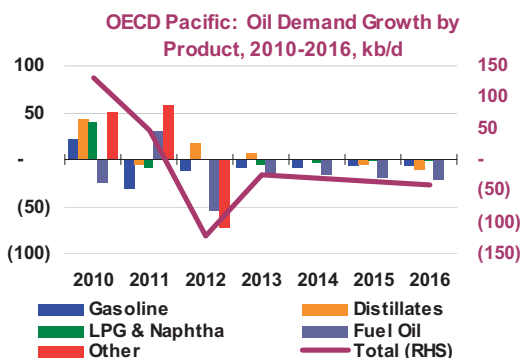


OECD

Oil product demand in the OECD is expected to fall by 0.6% or 260 kb/d per year on average, from 46.1 mb/d in 2010 to 44.6 mb/d in 2016. Rising demand for diesel and jet fuel is offset by declining gasoline consumption, leaving transport demand flat. Oil-fuelled heating and power generation uses will continue to decline structurally, albeit at a slower pace in the Pacific, where thermal generation will partly compensate for nuclear outages in Japan, and in Europe, where substitution for power generation has been largely completed. Petrochemical activity will decline, except in North America, given cheaper ethane feedstocks.

The growth in diesel demand will slow down, but it will continue to prevail over gasoline growth for overall transportation use. However, the dieselisation trend has shown signs of stagnating in some saturated European markets, while the tightening of heavy-truck fuel economy standards in the US from 2014 may begin to bite diesel demand, though only marginally at first. Still, increased diesel penetration of light duty vehicle fleets, particularly in faster-growing economies, such as Turkey and Korea, and expanding road and rail freight will underpin diesel growth. Moreover, low-sulphur bunker standards will boost marine diesel demand from 2015. Meanwhile, enhanced vehicle fuel economy, notably in the US and Canada, will drag down gasoline consumption.

Increased natural gas availability will spur substitution away from heating oil and residual fuel, particularly in the US and Canada. Nuclear outages in Japan, however, have increased short-term demand for thermal generation and may skew the long-term power picture in other countries, notably Germany, which plans to phase out nuclear power over the next decade. In the medium term, most incremental switching from nuclear will be met by natural gas (LNG), coal and, to a lesser extent, renewables, with fuel oil used only for peak power demand. In addition, restricted availability of low-sulphur fuel oil will likely curb residual bunker demand from 2015.



OECD North America: Demand Trends, Main Refined Products

Product	Volume, 2016 (mb/d)	Avg. Yearly Growth, 2010-2016 kb/d	%	Comments
LPG & Naphtha	3.18	-12.2	-0.4%	Petrochemical activity boosted by economic recovery in 2010 and cheap gas feedstocks, but naphtha-based activity stagnant/declining in the US and Canada from 2011; growth expected in Mexico, but from a low base
Gasoline (including ethanol)	10.32	-52.4	-0.5%	Declining demand in the US and Canada on increasingly stringent light vehicle fuel economy rules outweighing rising vehicle-miles travelled; consumption continuing to grow in Mexico on an expanding vehicle fleet
Jet Fuel & Kerosene	1.75	16.1	1.0%	Growing in all three countries; air travel boosted by economic recovery, particularly in Mexico's expanding market, offsetting fleet and operational efficiency gains
Gasoil (including biodiesel)	4.77	-9.2	-0.2%	Diesel growing in all three countries, driven by economic activity and offsetting continued displacement of heating oil by natural gas and electricity; marginal impact of heavy vehicle efficiency standards on diesel growth in long term (but greater in the longer term)
Residual Fuel Oil	0.73	-39.0	-4.6%	Declining use for power generation in all three countries, with fuel oil substituted by cheaper and less polluting natural gas and other sources
Total Oil Products	23.31	-99.6	-0.4%	

OECD Europe: Demand Trends, Main Refined Products

Product	Volume, 2016 (mb/d)	Avg. Yearly Growth, 2010-2016 kb/d	%	Comments
LPG & Naphtha	1.95	-31.1	-1.5%	Petrochemical activity declining in 'core' countries (France, Germany, Italy, Spain and the United Kingdom) on cheaper gas feedstocks and strong non-OECD competition; moderate growth in several 'peripheral' (eastern) countries
Gasoline (including ethanol)	1.71	-80.1	-4.0%	Continued efficiency gains and substitution towards diesel, albeit slowing in core countries; limited offsetting from increased ethanol blending (with greater overall volumes required for same energy content) and moderate growth in peripheral countries
Jet Fuel & Kerosene	1.36	14.4	1.1%	Resumed air travel following the economic recovery, particularly in peripheral countries' expanding markets but also in key airport hubs in core countries; offsetting efficiency gains in aircraft fleets and airlines operations
Gasoil (including biodiesel)	6.26	20.6	0.3%	Diesel fleets expanding in peripheral, less saturated countries; continued substitution of heating oil by natural gas and to a lesser extent electricity (from conventional sources and renewables); rising marine gasoil bunker demand following introduction of low-sulphur legislation in 2015
Residual Fuel Oil	0.94	-56.7	-5.0%	Declining use for power generation on substitution by other energy sources (mainly natural gas and renewables), although less so in large countries, where this process has largely been completed; rising bunker demand in the Netherlands and Belgium as global trade recovers
Total Oil Products	13.71	-122.4	-0.9%	

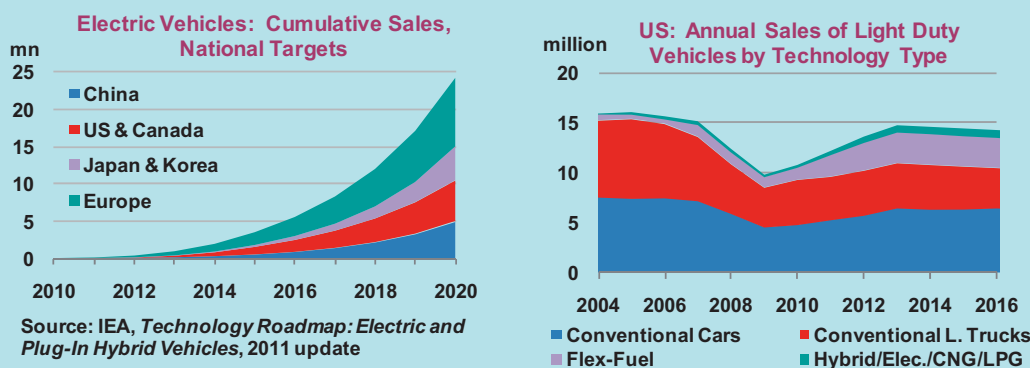
OECD Pacific: Demand Trends, Main Refined Products

Product	Volume, 2016 (mb/d)	Avg. Yearly Growth, 2010-2016 kb/d	%	Comments
LPG & Naphtha	2.51	-3.6	-0.1%	Stagnant in Korea but declining rapidly in Japan after a temporary post-recession surge on strong competition from emerging petrochemical producers in non-OECD Asia and the Middle East
Gasoline (including ethanol)	1.50	-12.6	-0.8%	Declining in Japan given demographic, technological and behavioural changes; marginal or stagnant growth in Korea, Australia and New Zealand
Jet Fuel & Kerosene	0.73	-24.2	-3.0%	Rapidly declining kerosene consumption given sustained switch to electricity-based heating in Japan and Korea, largely offsetting recovery-driven jet fuel growth in all countries (Australia, Japan, Korea and New Zealand)
Gasoil (including biodiesel)	1.76	24.2	1.5%	Growing diesel use in all countries on rebounding economic activity; post-earthquake reconstruction in Japan supporting other gasoil demand
Residual Fuel Oil	0.63	-16.1	-2.4%	Declining across the region, displaced by natural gas and other energy sources; partial offsetting from Japan's increased thermal generation needs in the face of post-earthquake nuclear power outages
Total Oil Products	7.58	-34.6	-0.4%	

Road Transportation: Increased Interfuel Substitution Ahead?

The evolution of vehicle fleets in key Atlantic Basin markets – the US, Brazil and Europe – is likely to bring about profound changes in oil product demand in the years ahead. Electric and natural gas vehicles have been touted as holding significant potential, offsetting expected growth in other oil-based transportation modes where demand is more inelastic, notably air travel and shipping – and thus contributing to ease oil product balances. Nevertheless, these technologies will only influence oil demand over the long term. A more immediate impact will rather come from continued improvements in fleet efficiency, as well as from increasing biofuels use.

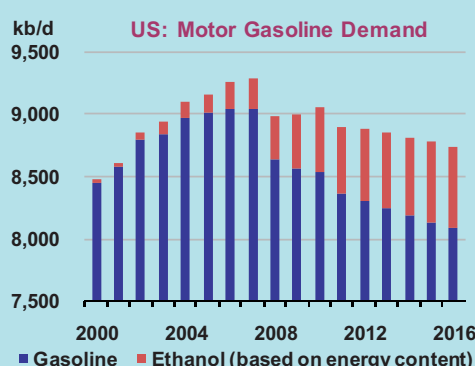
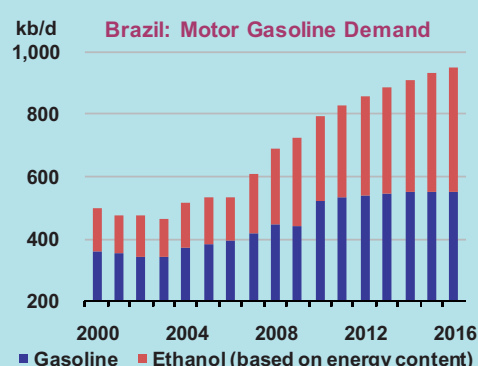
The widespread adoption of electric vehicles would undeniably reduce liquid fuel demand. The fuel economy of the forthcoming Chevrolet Volt, for example, will be 60 miles per gallon (3.9 litres per 100 km) – double the 30 mpg (7.8 litres per 100 km) average for new 2011 model cars in the US. With over ten electric vehicle models to be launched over 2011-2015 – including plug-in hybrids (PHEVs), which run on electricity or gasoline, and all-electric vehicles (EVs) – the Obama administration's call for one million electric cars on US roads by 2015 looks realistic from a capacity standpoint. In Europe, the introduction of such vehicles is likely to follow a similar pattern. In fact, Europe and North America are expected to account for 45% and 30%, respectively, of total cumulative sales of EV and PHEV by 2016 (5.5 million vehicles, based on national targets). However, their mass adoption will depend upon consumer appetite overcoming their higher cost and range limitation relative to conventional vehicles. Sustained high oil prices will help, but a combination of battery cost improvements and government monetary incentives will be necessary to meet sales targets over the next decade.



Meanwhile, low natural gas prices and prospects of abundant shale gas supplies have also raised expectations for natural gas vehicles (NGVs). Gas at \$9/MBtu (Europe's five-year average price under oil-linked contracts) competes favourably with gasoline if crude oil prices exceed \$80/bbl, as is now the case (cf. IEA Working Paper, *The Contribution of Natural Gas Vehicles to Sustainable Transport*, 2010). However, this requires the establishment of an extensive – and expensive – gas distribution grid for NGVs. Since such infrastructure is limited in OECD markets – currently, there are only 1,000 gas fuelling stations in the US – NGVs will likely cater only to niche markets (e.g., transit buses and municipal/company fleets) in the US and Europe, in the absence of major capital investment. In Brazil, where infrastructure is more developed, NGVs comprise only 5% of the light vehicle fleet. In fact, NGV conversions have stalled in recent years, given strong competition from ethanol. Moreover, the government appears intent to favour the use of gas for power generation rather than transportation. Therefore, the scope for substitution away from oil looks limited as well.

Road Transportation: Increased Interfuel Substitution Ahead? (continued)

Given the obstacles facing alternative technologies, any changes in transportation fuel demand over the medium term will instead be realised through further improvements in vehicle fleet efficiency and increasing biofuels use. In the US, assuming that a) fuel economy standards become more stringent, as intended; b) one million electric vehicles are introduced by 2015; c) light vehicle sales rise to 14-15 million per year (below pre-crisis levels but higher than the 11 million sold in 2010); d) the share of flex-fuel vehicles increases from 4% of total light vehicles in 2010 to almost 10% by 2016; and e) current ethanol blending requirements are maintained, oil-based gasoline demand will decline. Overall, total demand for gasoline (including ethanol) is expected to fall by 0.6% per year on average over 2010-2016. Regarding diesel, by contrast, a slow turnover of medium- and heavy-trucks means that tightening fuel economy standards from 2014 will have only a marginal effect upon demand. Moreover, although biodiesel blending is projected to rise, its share relative to the total diesel pool is likely to remain low.



In Brazil, substitution will largely depend on biofuels. With economic growth averaging over 4% per year, the lack of official fuel economy standards and government attempts to cap end-user prices, gasoline and gasoil demand should grow by 3.0% and 3.3% per year on average over 2010-2016. Flex-fuel vehicles will play a crucial role; in 2009, they accounted for 35% of the total light vehicle stock. From 2007 to early 2011, moreover, flex-fuel vehicles represented over 85% of total sales – a share that has held steady even in periods of high ethanol prices. Still, capacity constraints and restrictions limiting the pass-through of rising crude prices to end-users may hinder the ability of ethanol supplies to keep up with gasoline demand growth. As such, although the share of ethanol, on a volumetric basis, is seen rising to almost 60% of the total gasoline pool by 2016, Brazil will still require additional volumes of oil-based gasoline. Meanwhile, the 5% blending standard and rising volumes of biodiesel production will help to slow growth in oil-based diesel demand, though only moderately.

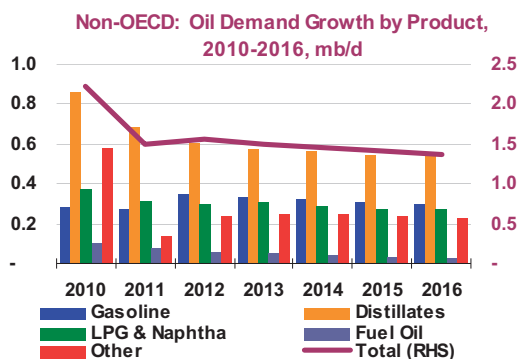
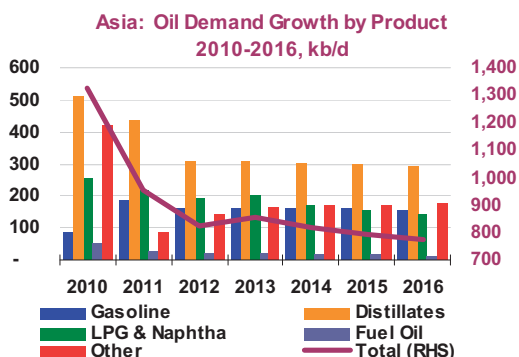
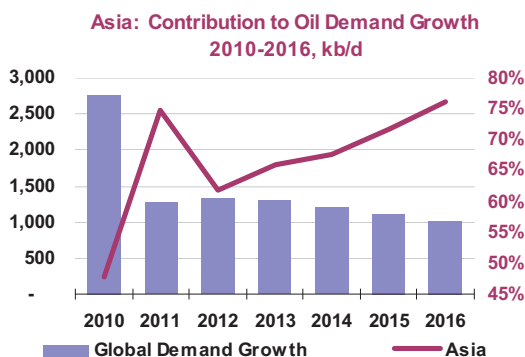
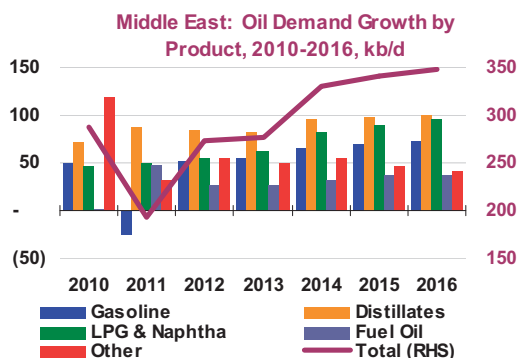
Finally, the European Union is aggressively pursuing interfuel substitution in road transport, aiming to halve conventional vehicles in urban areas by 2030 and increase the share of renewables to 10% by 2020. In addition, ambitious efficiency targets will limit CO₂ emissions from new passenger cars and light-duty vehicles from 2012 and 2017, respectively (it should be noted, though, that a number of compliant models have already hit the streets since 2010). Biofuels blending will prosper further on the back of increasing mandates and growing penetration of flex-fuel vehicles, with anecdotal evidence suggesting that the share of flex-fuel vehicles has steadily risen in France, Germany and Sweden, albeit from a relatively low base. The 'dieselisation' trend is also likely to continue, but at a slowing rate, partly because recent recession-induced fiscal incentives for the purchase of new cars tended to favour gasoline-fuelled engines at the margin. Overall, on-road transportation fuel demand in Europe will decline through to 2016.

NON-OECD

Total oil product demand in the non-OECD is expected to rise by 3.2% or +1.5 mb/d per year on average, from 41.9 mb/d in 2010 to 50.7 mb/d in 2016. Demand will be largely driven by middle distillates (roughly 40% of total growth). Gasoil, in particular, is a fuel closely related to economic growth and suitable, as noted earlier, for a range of uses, from transportation to power generation. Gasoline demand will also surge on the back of expanding vehicle fleets, while LPG and naphtha use will track petrochemical expansions. By contrast, demand for fuel oil will gradually fade, displaced by other energy sources such as natural gas.

Asia, where GDP will rise much faster than elsewhere, is and will remain the region where oil demand will increase the most, accounting for almost two-thirds of total non-OECD growth and three-quarters of global growth. Demand will be particularly buoyant in the region's giants – China and India – given their large population and rising income per capita in urban areas, but in other mid-sized countries – such as Indonesia, Singapore and Thailand – demand will also expand robustly. All product categories bar residual fuel oil – displaced by rising natural gas penetration – will register strong growth, on the back of greater mobility, petrochemical expansion, industrial and agricultural activity, and power generation.

The **Middle East** will feature the second fastest pace of growth. The region's dynamics are similar to Asia's: sustained economic expansion (based on oil and gas, petrochemicals, heavy industry and construction), favourable demographics (continued urbanisation and a young, growing population) and widespread end-user subsidies, unlikely to be dismantled in most countries (excepting Iran, which partially removed controls in 2010). The region is unique in one respect: surging power generation needs amid limited natural gas availability will foster growth in residual fuel and 'other' products (largely direct crude burn). Saudi Arabia, in fact, is expected to account for the bulk of growth in global direct crude use over 2010-2016.



Asia: Demand Trends, Main Refined Products

Product	Volume, Avg. Yearly Growth,			Comments
	2016 (mb/d)	2010-2016 kb/d	%	
LPG & Naphtha	4.84	180.5	4.3%	Growing on ambitious petrochemical expansions in the region's largest economies (China, Indonesia, Singapore, Taiwan and Thailand); declining in India on growing supplies of both domestic and imported natural gas
Gasoline (including ethanol)	4.05	163.7	4.7%	Surging as vehicle fleets expand on rising income per capita in urban areas and end-user price subsidies, with China accounting for over half of regional demand
Jet Fuel & Kerosene	1.47	31.9	2.3%	Growing jet fuel demand with rising air transportation and expanding aircraft fleets in the largest countries, offsetting a gradual phase-out of subsidised kerosene (the fuel of choice for the poor, notably in India and Indonesia) in favour of LPG
Gasoil (including biodiesel)	8.12	291.7	4.1%	Expanding strongly in all countries, driven by economic activity, end-user price subsidies and gasoil's multiple usages, ranging from transportation to industry, agriculture and power generation; upside risks given China's chronic coal-driven power shortages
Residual Fuel Oil	2.37	18.0	0.8%	Declining in the power generation sector because of natural gas substitution, notably in China and India; rising in Singapore on global trade recovery and strong bunkers demand
Total Oil Products	24.52	835.8	3.9%	

Middle East: Demand Trends, Main Refined Products

Product	Volume, Avg. Yearly Growth,			Comments
	2016 (mb/d)	2010-2016 kb/d	%	
LPG & Naphtha	1.83	72.7	4.6%	Surging demand on ambitious petrochemical expansions, particularly in Iran and Saudi Arabia, and insufficient natural gas supplies (yet LPG/ethane supplies from growing natural gas liquids production will become abundant in the longer term)
Gasoline (including ethanol)	1.65	48.2	3.3%	Rising rapidly on favourable demographics, rising incomes, urbanisation, expanding vehicle fleets and negligible end-user prices in the largest markets excepting Iran; end-user price subsidies expected to continue, despite mounting awareness of wasteful consumption
Jet Fuel & Kerosene	0.55	16.2	3.3%	Increasing as air traffic rises across the region, which is becoming a key global hub; demand growth driven by Iran, Iraq, Saudi Arabia and the UAE
Gasoil (including biodiesel)	2.41	75.0	3.5%	Surging demand on sustained economic activity, notably in the construction sector and, to a lesser extent, the power industry, with Iran, Iraq, Kuwait, Saudi Arabia, Syria and the UAE accounting for the bulk of the regional market
Residual Fuel Oil	1.73	34.8	2.2%	Growing moderately on power generation needs as alternative sources (mainly domestic natural gas) remain commercially unavailable across the region, particularly in Iran, Iraq, Kuwait and the UAE; declining only in Saudi Arabia on substitution by direct crude burning
Total Oil Products	9.51	293.7	3.5%	

Latin America: Demand Trends, Main Refined Products

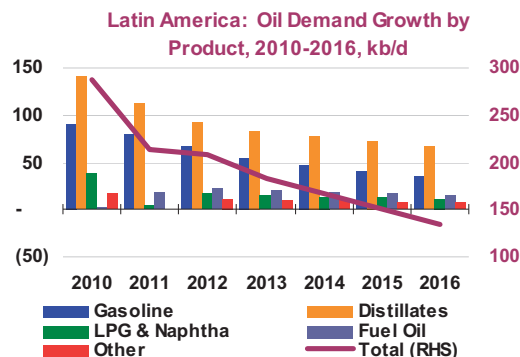
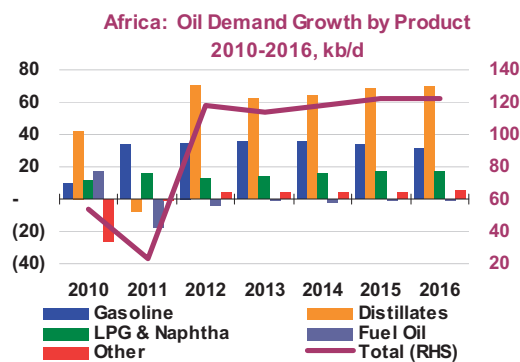
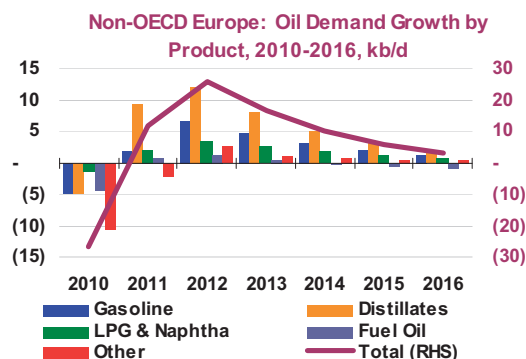
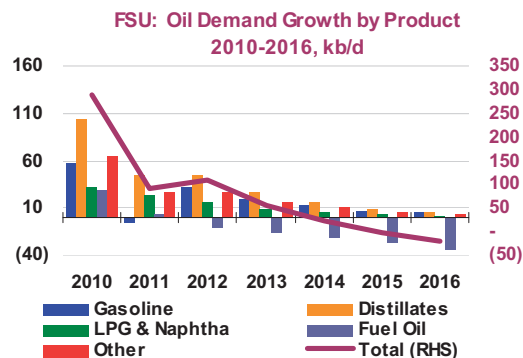
Product	Volume, Avg. Yearly Growth,			Comments
	2016 (mb/d)	2010-2016 kb/d	%	
LPG & Naphtha	0.93	11.9	1.3%	Growing petrochemical activity in Brazil, which accounts for 85% of regional demand; modest expansion in Argentina, Chile and Colombia, but from a very small base
Gasoline (including ethanol)	1.94	53.7	3.1%	Increasing in all countries, largely on rising urban incomes and expanding vehicle fleets, and in some cases on extensive end-user price subsidies; growth driven by Argentina, Brazil, Chile, Colombia, Ecuador, Peru and Venezuela
Jet Fuel & Kerosene	0.36	14.2	4.6%	Surging on expanding airline capacity and rising passenger travel, notably in Brazil, the region's largest economy (almost 50% of regional demand)
Gasoil (including biodiesel)	2.45	70.4	3.2%	Rising strongly on sustained economic activity (agriculture, industry, mining and freight) in all countries, as well as power generation on natural gas shortfalls and hydropower disruptions (but tempered by increasing regional gas production and LNG imports)
Residual Fuel Oil	0.83	18.1	2.4%	Increasing demand in areas with limited access to alternative power-generation sources (Central America and Caribbean islands); stagnant/declining in major countries on natural gas/gasoil substitution, with the exception of Venezuela, beset by chronic power shortages
Total Oil Products	7.34	176.0	2.6%	

Latin America will rank third in terms of growth, yet oil demand will be driven almost exclusively by transportation and industrial fuels. Demand for distillate (supported by agriculture, mining and air travel) and gasoline (spurred by the rising number of private vehicles) will increase steadily, most notably in Brazil. That country will account for over half of total regional oil demand growth, distantly followed by Argentina and Venezuela. As the region is not a significant petrochemical producer, growth in the light end of the barrel will come mostly from LPG, used by households. Fuel oil demand, meanwhile, should increase marginally, mostly where power generation alternatives are limited (Venezuela, Chile and several Central American countries), even though overall natural gas availability will also increase.

Africa will also post strong oil demand growth over the forecast period, with a profile akin to Latin America's. The continent is expected to record robust commodity-driven economic growth. However, the recent and ongoing political turmoil in several northern countries poses a downward risk to the forecast – even though we assume that Egyptian and Libyan demand will remain largely flat.

Non-OECD Europe is expected to post growth on the back of rising distillate, gasoline and LPG/naphtha needs. However, total growth will be marginal in terms of the global oil balance, since the region's aggregate demand is relatively small (about 750 kb/d on average over the forecast period).

In the **Former Soviet Union**, by contrast, demand is expected to grow only marginally, despite positive economic prospects, notably in Russia (70% of regional oil demand). Indeed, rising demand for transportation and industrial fuels will be largely offset by the decline in residual fuel oil consumption. The relatively plentiful availability of natural gas supplies in Europe will reduce Russia's need to boost fuel oil use in power generation, in order to meet its gas export commitments. In addition, there is a large scope for efficiency gains in that country.



Africa: Demand Trends, Main Refined Products

Product	Volume, 2016 (mb/d)	Avg. Yearly Growth, 2010-2016 kb/d %	Comments
LPG & Naphtha	0.47	15.2 3.7%	Rising petrochemical output in Morocco, South Africa and Sudan; stagnant in civil-war torn Libya, which accounts for two-thirds of regional petrochemical production
Gasoline (including ethanol)	0.98	34.3 4.0%	Growing strongly, notably in the region's more dynamic economies (Algeria, Angola, Egypt, Ghana, Nigeria, South Africa and Sudan), on rising income per capita, expanding vehicle fleets and price subsidies; stagnant in civil-war torn Libya
Jet Fuel & Kerosene	0.36	10.8 3.4%	Increasing as air travel rises in the largest economies (Egypt, Nigeria and South Africa), in emerging ones (Algeria, Angola, Ghana, Sudan) and in tourist-oriented ones (Kenya, Morocco, Senegal and Tunisia)
Gasoil (including biodiesel)	1.53	43.8 3.2%	Driven by economic activity in most countries, notably in Algeria, Angola, Egypt, Morocco, South Africa and Sudan; stagnant in civil-war torn Libya
Residual Fuel Oil	0.39	-4.6 -1.1%	Declining use for power generation among the largest consumer (Egypt) and in countries with abundant natural gas supplies (such as Algeria); but rising/stagnant elsewhere, notably in South Africa, beset by chronic power shortages
Total Oil Products	4.00	102.8 2.8%	

Non-OECD Europe: Demand Trends, Main Refined Products

Product	Volume, 2016 (mb/d)	Avg. Yearly Growth, 2010-2016 kb/d %	Comments
LPG & Naphtha	0.10	1.9 2.1%	Growing strongly in the region's three producing countries - Bulgaria, Romania and former Yugoslavia (mostly Serbia), but from a very low base
Gasoline (including ethanol)	0.13	3.2 2.7%	Increasing as income per capita rises, vehicle fleets expand and transportation infrastructure is developed in both the largest countries (Bulgaria, Croatia, Romania and Serbia) and those belonging to the European Union (notably Cyprus)
Jet Fuel & Kerosene	0.02	0.3 1.2%	Rising air traffic, resulting from higher income per capita and the increasing business and tourist appeal of Bulgaria, Croatia, Cyprus, Malta and Romania
Gasoil (including biodiesel)	0.31	6.2 2.1%	Growing in countries with a large industrial base (Romania, Serbia and Bulgaria), but also driven by the gradual 'dieselisation' of the vehicle fleet
Residual Fuel Oil	0.12	0.0 0.0%	Rising essentially in islands/archipelagos (Cyprus, Gibraltar and Malta), which are the largest users of residual fuel oil, needed to meet power generation requirements
Total Oil Products	0.77	12.1 1.7%	

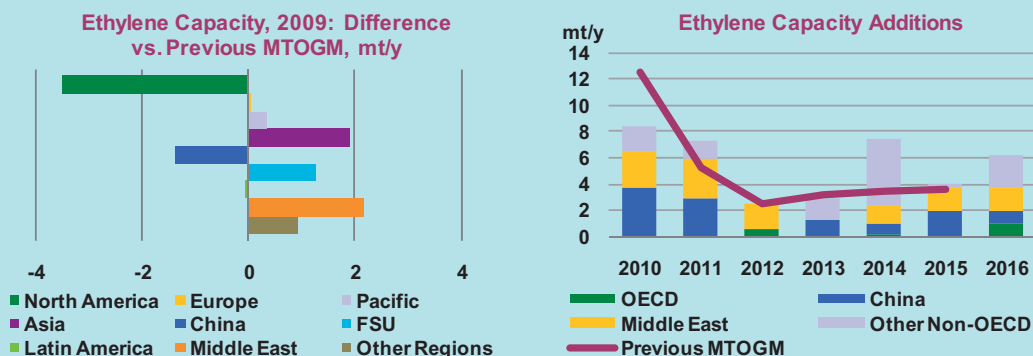
FSU: Demand Trends, Main Refined Products

Product	Volume, 2016 (mb/d)	Avg. Yearly Growth, 2010-2016 kb/d %	Comments
LPG & Naphtha	0.74	9.8 1.4%	Growing moderately on post-recession rising Russian petrochemical output (which accounts for almost 95% of regional naphtha demand)
Gasoline (including ethanol)	1.21	11.4 1.0%	Growing as vehicle fleets expand on the back of strong economic expansion and rising income per capita, particularly in Kazakhstan, Russia (the largest regional car market) and Ukraine
Jet Fuel & Kerosene	0.33	4.5 1.4%	Rising air business and leisure air travel and expanding aircraft fleets in Russia (over 80% of the region's market), followed by Azerbaijan, Kazakhstan, Kyrgyzstan, Turkmenistan and Ukraine
Gasoil (including biodiesel)	1.13	19.8 1.9%	Increasing as economic activity resumes across the region; demand growth largely driven by Belarus, Kazakhstan, Russia and Ukraine
Residual Fuel Oil	0.29	-18.0 -5.2%	Declining as abundant natural gas supplies reduce Russia's drive to divert gas supplies away from power generation in order to support exports; stagnant elsewhere
Total Oil Products	4.51	42.1 1.0%	

The Ethylene Market: A Tale of Two Feedstocks

In line with previous editions of this report, we have continued to deepen our analysis of the international petrochemical sector. In addition to our assessment of ethylene nameplate production capacity by country, we now attempt to model the global ethylene balance going forward, in order to assess its implications for petrochemical-based oil demand. Of course, the choice of feedstocks – typically LPG/ethane and naphtha – will depend on the nature of petrochemical facilities and plant economics. Nonetheless, the analysis provides interesting implications for two countries that will be instrumental in future petrochemical developments, namely China and Saudi Arabia, and for petrochemical complexes in the OECD.

Estimated global ethylene production capacity, at 137.4 million tonnes per year (mt/y) in 2009, stands 1.7 mt/y higher than in our previous report, with upward changes in the Middle East, Asia and the FSU largely offsetting downward adjustments in the OECD and China. Total 2010 capacity, at 146 mt/y, reflects a lower baseline and some project delays, but is expected to increase annually by 5.5 mt (or +3.2%) to 176 mt/y by 2016, with growth concentrated in non-OECD Asia and the Middle East. Indeed, non-OECD ethylene capacity, which currently represents 49% of the world's total, will account for 57% by the end of the forecast period. In the OECD, by contrast, overall capacity will remain broadly unchanged.

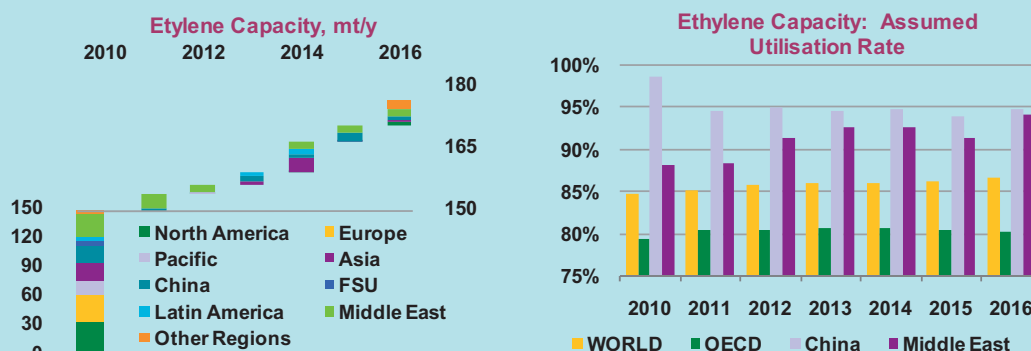


Turning to production *per se*, ethylene can be processed from different hydrocarbon-based feedstocks in ethane and naphtha crackers. In order to estimate aggregated oil product requirements, it is necessary to track each type of olefin plant on a country-by-country basis and apply specific yields and conversion factors – since ethylene output depends on the configuration of any given plant and the feedstocks employed.

Assuming utilisation rates of 86% – implying an effective global capacity of roughly 124 mt/y – and that, *ceteris paribus*, ethylene demand follows capacity, we estimate that oil-based feedstocks averaged approximately 9.2 mb/d in 2010 – comprising 34% of LPG/ethane, 59% of naphtha and 7% of other products, as shown in the table overleaf. Looking ahead, based on the 2009 baseline revision and stronger IMF GDP prognoses, we assume that average utilisation rates over 2010-2016 will be higher than previously expected in key non-OECD regions – 95% in China and 91% in the Middle East – but lower in the OECD (80% on average). Thus, with effective capacity hovering around 150 mt/y in 2016, oil product requirements are expected to increase to 10.9 mb/d, with LPG/ethane being the feedstock of choice in OECD North America, Africa and the Middle East, and naphtha being used elsewhere, notably in China, OECD Europe and OECD Pacific.

Feedstock	Yield	Conversion Factor (bbl/mt)
Ethane	77.5%	17.2
Propane	42.0%	12.4
Butane	40.0%	10.8
Naphtha	30.3%	8.9
Gasoil	21.4%	7.5
Other Products	18.0%	8

The Ethylene Market: A Tale of Two Feedstocks (continued)



In reality of course, the choice of feedstocks will depend upon a number of complex inter-relationships between inputs and petrochemical by-products. This is partly related to the transformation process: on average, for each 1.3 tonnes of ethane, an ethane cracker yields 1 tonne of ethylene and 0.3 tonnes of by-products; a naphtha cracker, meanwhile, produces 1 tonne of ethylene and 2.3 tonnes of by-products out of 3.3 tonnes of naphtha. As such, integrated industrial complexes can efficiently recover valuable by-products; aromatics from refining and petrochemical facilities can thus be processed into benzene, toluene and xylene (BTX). Not coincidentally, the most modern, naphtha-based petrochemical/refining complexes are currently being built in Asia.

Ethylene Balance under 86% Capacity Utilisation

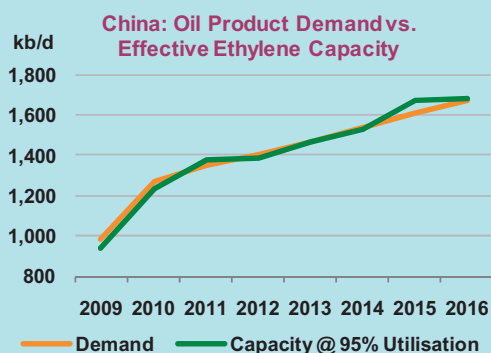
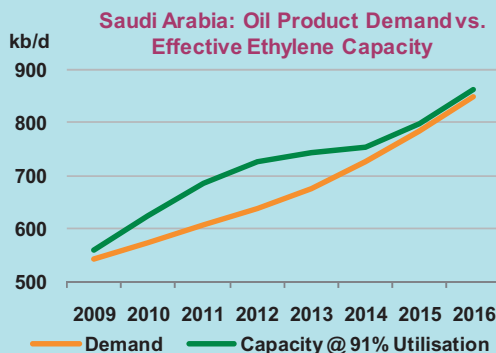
	2010						2016						Total Oil Product Growth, 2010-16	
	Oil Product Inputs				Ethylene Output		Oil Product Inputs				Ethylene Output			
	kb/d	LPG / Ethane	Naphtha	Other	km/t	World Share	kb/d	LPG / Ethane	Naphtha	Other	km/t	World Share	kb/d	%
OECD	4,604	32%	62%	6%	59,004	48%	4,743	34%	60%	6%	61,103	40%	139	0.5
North America	1,769	65%	27%	7%	24,327	20%	1,942	66%	27%	7%	26,855	18%	172	1.6
Europe	1,647	17%	75%	8%	20,429	17%	1,611	17%	75%	8%	19,971	13%	-36	-0.4
Pacific	1,188	6%	94%	0%	14,248	12%	1,190	6%	94%	0%	14,277	9%	2	0.0
Non-OECD	4,549	36%	57%	7%	64,644	52%	6,147	39%	55%	6%	90,969	60%	1,598	5.1
Africa	100	89%	11%	0%	1,523	1%	227	66%	34%	0%	3,354	2%	128	14.7
Latin America	327	35%	65%	0%	4,411	4%	492	35%	65%	0%	6,598	4%	165	7.1
China	1,236	1%	93%	6%	15,616	13%	1,686	1%	93%	5%	22,501	15%	450	5.3
Asia	1,148	24%	72%	4%	16,652	13%	1,409	24%	71%	5%	20,916	14%	260	3.5
FSU	360	19%	74%	6%	4,590	4%	372	19%	74%	6%	4,748	3%	12	0.6
Middle East	1,288	80%	6%	14%	20,718	17%	1,869	86%	4%	10%	31,686	21%	580	6.4
Other Regions	90	35%	63%	2%	1,134	1%	92	35%	63%	2%	1,165	1%	2	0.5
WORLD	9,153	34%	59%	7%	123,648	100%	10,890	37%	57%	6%	152,072	100%	1,736	2.9

Plant economics also play a role in the choice of feedstocks. The dynamics between naphtha, gasoline and crude prices, on the one hand, and olefin prices, on the other, will partially determine the attractiveness of using naphtha for petrochemical or motor gasoline production, for example. That said, light paraffinic naphtha is most apposite for petrochemical manufacture, while heavier naphthenic grades are better suited for gasoline. LPG/ethane prices, by contrast, tend to follow natural gas prices, which make it a cheaper feed where gas supplies are abundant. This is the case in the US Gulf Coast, for example; the advent of cheap shale gas has resulted in quite favourable cracker economics, particularly for integrated petrochemical complexes.

The Ethylene Market: A Tale of Two Feedstocks (continued)

Finally, it is worth examining petrochemical dynamics in China and Saudi Arabia, since both countries will play a central role regarding the global petrochemical balance. In China, assuming that domestic plants operate at an average of 95% of nameplate ethylene capacity over the forecast period, the country's total oil product feedstock requirements are projected to rise from roughly 1.2 mb/d in 2010 to almost 1.7 mb/d in 2016. New-build capacity in China will typically feature sophisticated, integrated petrochemical/refining complexes catering to adjacent demand centres.

In Saudi Arabia, meanwhile, assuming that ethylene crackers run at 91% of nameplate capacity on average, feedstock demand is set to increase from 620 kb/d in 2010 to 860 kb/d in 2016. The country's crackers will benefit from subsidised LPG/ethane prices; in addition, the Saudi petrochemical and oil industries are closely integrated, providing a cost advantage for the production of secondary petrochemicals. The country's favourable cost environment, though, is likely to encourage the construction of some excess ethylene capacity in 2010-2012, relative to the historical feedstock demand trend. This explains why our LPG/ethane demand forecast for Saudi Arabia initially lags behind anticipated cracker capacity increases.

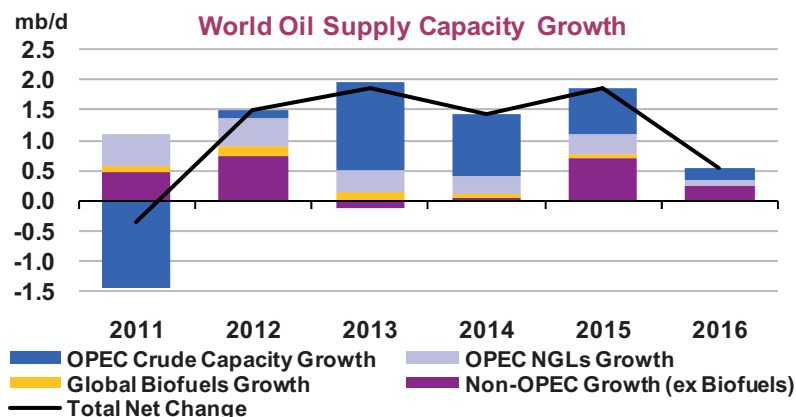


Both countries' competitive positions – and more generally, those of Asia and the Middle East as a whole – will put pressure upon older, smaller and less integrated petrochemical facilities in the OECD and elsewhere. Given rising oil prices, European naphtha crackers, for example, will likely be forced to buy more expensive feedstocks but sell cheaper end-user products. Indeed, the OECD's petrochemical sector faces many of the same competitive pressures as does its refining sector, implying that capacity rationalisation may lie ahead.

OIL SUPPLY

Summary

- **Global oil production capacity is set to rise from 93.8 mb/d in 2010 to 100.6 mb/d by 2016**, an increase of 6.8 mb/d. Incremental supply comes from non-OPEC, OPEC crude and OPEC natural gas liquids (NGLs) in roughly equal shares. Crude prices over \$100/bbl are prompting sustained investment in non-OPEC capacity; by contrast, capacity growth in many OPEC countries remains stalled due to a lack of investment and project delays. Higher forecast non-OPEC supply from 2013 onwards is largely behind a sharp upward revision in global supply capacity. In 2015, this is 2 mb/d higher than in our last forecast.
- **Non-OPEC supply (incl. NGLs) is projected to rise from 52.7 mb/d in 2010 to 55.4 mb/d in 2016**, implying an average annual increase of +0.4 mb/d. 2010 and 2011 are adjusted down by an average -0.1 mb/d on lower refinery processing gains, while 2012-2015 are revised up by +0.7 mb/d on average, largely due to significantly stronger growth projected for US light tight oil, produced from unconventional formations. Combined with higher output from Canadian oil sands, Brazilian deepwater and Colombian crude, the Americas now contribute virtually all incremental non-OPEC oil supply.



- **OPEC crude supply capacity rises from 35.7 mb/d in 2010 to 37.8 mb/d in 2016**, an increase of 2.1 mb/d. The near-total shut-in of Libyan oil production since early this year constrains capacity growth, and we assume operations only gradually return to normal in the course of 2013. Incremental supply capacity stems largely from Iraq, Angola and the UAE. Saudi Arabia has brought forward its next big upstream project, but still sees capacity shrink by 2016. Baseline production capacity for Venezuela is now assessed around 0.3 mb/d higher. Iran meanwhile sees a sharp decline in crude production capacity. OPEC NGLs production increases from 5.3 mb/d in 2010 to 7.4 mb/d in 2016, with increments centred on the Middle East Gulf.
- **In terms of composition of new supply barrels, global NGLs and condensate supply increases lead the pack** at +2.7 mb/d, just ahead of crude at +2.5 mb/d, while global non-conventional supplies (in this instance, adding biofuels and refinery processing gains) rise by +1.6 mb/d by 2016. Overall, refinery feedstock supplies become lighter but sourer over the outlook period.

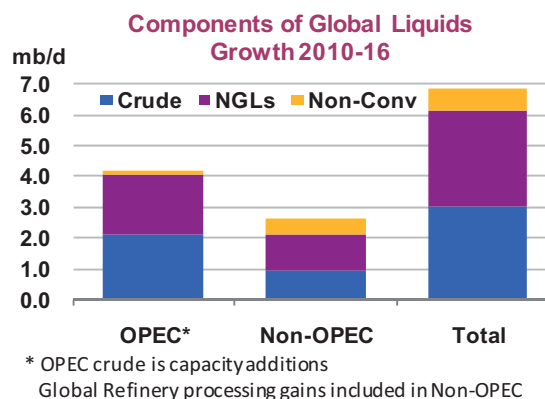
Global Oil Supply Overview

Global oil production capacity rises from 93.8 mb/d in 2010 to 100.6 mb/d by 2016, an increase of +6.8 mb/d, or +1.1 mb/d annually. Higher crude oil prices above \$100/bbl have led to increased investment in non-OPEC capacity; by contrast, OPEC expansion plans remain stalled due to underinvestment and project delays, among other reasons. A more bullish non-Opec supply outlook led to an increase in global production capacity, which for 2015 is around 2 mb/d higher than our December 2010 forecast. Growth stems in roughly equal share from non-OPEC oil supply, OPEC crude and OPEC NGLs (which include ethane and condensates).

The outlook for non-OPEC supply growth has improved due to sustained investment on the back of high oil prices and moderate success at slowing mature field decline. That said, decline still costs the industry an estimated 3.2 mb/d annually through the forecast period. OPEC crude production capacity in the near term has also taken a hit from the near-total shut-down of Libya's oil operations. This outlook assumes that Libyan production capacity can only be fully reinstated by 2015, after commencing gradual recovery from 2012. Production in other OPEC countries currently remains unaffected by the unrest affecting the wider MENA region, though in May, nearly two-thirds of production from non-OPEC Yemen (or around 170 kb/d) were briefly shut-in and the political situation remains highly volatile there, as it does in Syria.

Growth in OPEC crude production capacity is concentrated in three countries, of which Iraq provides the largest increment, at +1.5 mb/d, while Angola and the UAE add +0.7 mb/d and +0.5 mb/d respectively by 2016. Saudi Arabia, which has brought forward the development of its next large-scale project, Manifa, sees capacity oscillate within an 11.5-12.0 mb/d range through 2016. Iran's crude production capacity meanwhile is set to decline by a sharp -0.8 mb/d by 2016 due to a lack of investment. Sluggish capacity performance in other OPEC countries is underpinned by unattractive investment environments, project delays and a lack of enhanced oil recovery (EOR) technology. A reappraisal of Venezuelan crude supply, however, prompts an upward revision to the baseline of +0.3 mb/d on average for 2005-2010.

Non-OPEC growth is centred on a handful of countries, including Canada (+1.3 mb/d), Brazil (+1.0 mb/d) and now the US (+0.5 mb/d), following upward revisions to prospects for increased light tight oil output. In combination with growth in Colombia (+0.3 mb/d), the Americas emerge as the centre for non-OPEC supply growth by 2016. NGLs, biofuels and refinery processing gains also make significant contributions, as do Kazakhstan, and new producers Ghana and Uganda. Production in the North Sea and Mexico continues to decline steadily. Despite delays in the US Gulf of Mexico, global deepwater production is a source of new supplies; volumes are projected to rise from 6 mb/d in 2010 to 8.7 mb/d in 2016. Still, gas liquids (NGLs and condensates) and non-conventional oils including oil sands and biofuels outstrip conventional crude oil in generating global supply growth. All told, our supply projections infer a global refinery feedstock barrel that becomes lighter but higher in sulphur over the forecast period.



Non-OPEC Supply Overview

Non-OPEC oil supply averaged 52.7 mb/d in 2010 and is seen rising to 55.4 mb/d in 2016, equivalent to +0.4 mb/d per year. Compared to our last medium-term projections (see the December 2010 *Oil Market Report*), prospects for non-OPEC oil supply have been adjusted on average +0.5 mb/d higher per year, particularly towards the tail end of the forecast. Key upstream industry trends remain similar to those of the June 2010 *MTOGM*. Oil prices remain high; upstream investment has increased; cost, equipment and labour bottlenecks may be tightening, but less than in 2005-2008; and unlike 2005-2008, large-scale shut-ins affecting non-OPEC supply have remained rare. Meanwhile, observed decline rates to baseload supply have again slowed marginally in 2010, which is partly reflected in projections.

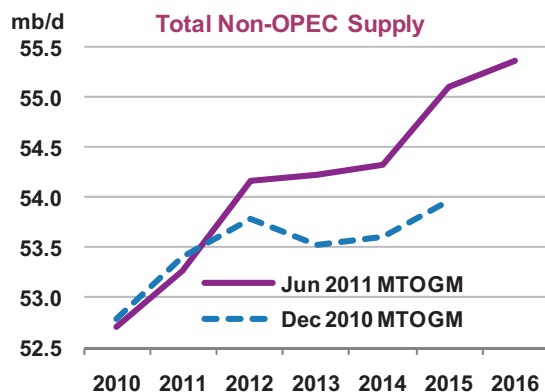
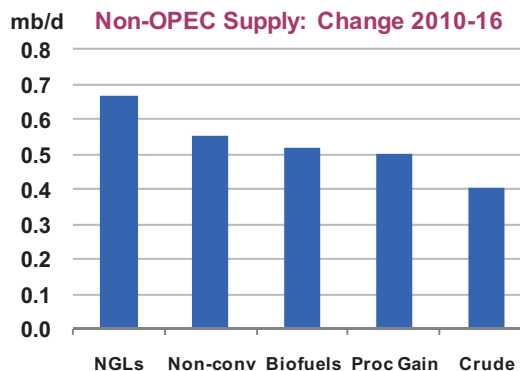
Non-OPEC Supply

(million barrels per day)

	2010	2011	2012	2013	2014	2015	2016	2010-16
North America	14.1	14.2	14.4	14.5	14.6	15.1	15.6	1.5
Europe	4.2	4.1	4.1	3.9	3.7	3.7	3.5	-0.7
Pacific	0.6	0.6	0.7	0.6	0.6	0.6	0.6	0.0
Total OECD	18.9	18.9	19.2	19.0	18.9	19.4	19.7	0.8
Former USSR	13.6	13.7	13.7	13.6	13.7	13.8	13.8	0.2
Europe	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0
China	4.1	4.2	4.3	4.3	4.3	4.3	4.2	0.1
Other Asia	3.7	3.6	3.5	3.6	3.6	3.5	3.3	-0.4
Latin America	4.1	4.3	4.6	4.7	4.8	5.1	5.3	1.3
Middle East	1.7	1.7	1.8	1.7	1.6	1.6	1.5	-0.2
Africa	2.6	2.6	2.6	2.6	2.6	2.5	2.5	-0.1
Total Non-OECD	29.9	30.3	30.7	30.6	30.7	30.9	30.7	0.8
Processing Gains	2.1	2.2	2.3	2.4	2.5	2.5	2.6	0.5
Global Biofuels	1.8	1.9	2.0	2.2	2.3	2.3	2.3	0.5
Total Non-OPEC	52.7	53.3	54.2	54.2	54.3	55.1	55.4	2.6
Annual Chg	1.1	0.6	0.9	0.0	0.1	0.8	0.3	
Changes from last MTOGM	-0.1	-0.1	0.4	0.7	0.7	1.1		

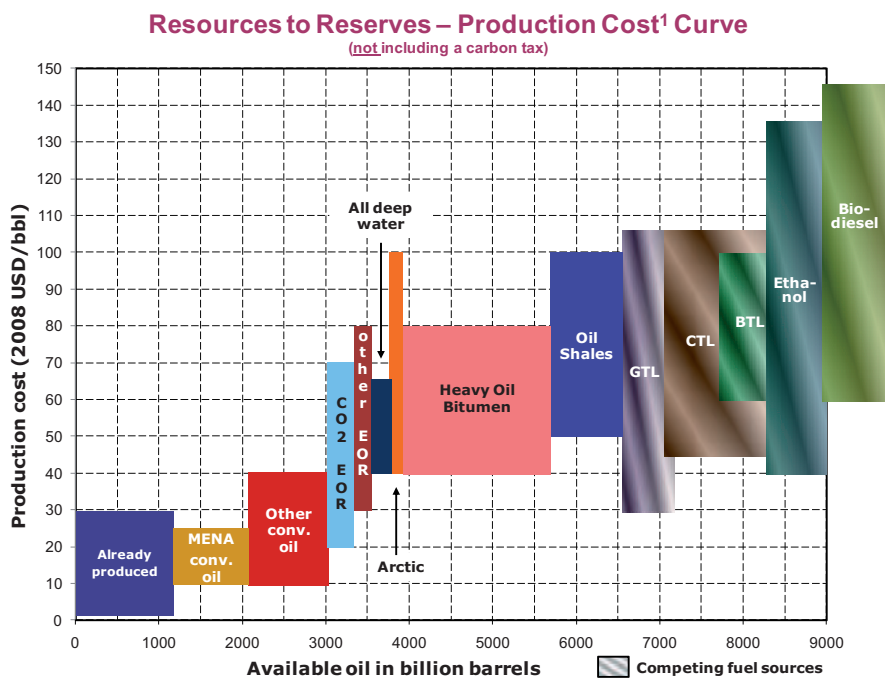
The most significant changes to the outlook stem from a reappraisal of US prospects. On the one hand, we maintain our assumption that delays to US Gulf of Mexico offshore projects amount to 0.3 mb/d by mid-decade, when compared with previous forecasts. But this is more than offset by a reappraisal of growth prospects for light tight oil production from unconventional, or shale, formations in the US, which are now seen adding 1 mb/d of capacity by 2016, thus contributing to net growth in overall US production. Combined with stronger increases in other US sources, as well as more robust growth in Canadian oil sands, North America sees the biggest regional upward revision and is now the strongest-growing non-OPEC region.

OECD countries also benefit from a reassessment and downgrade of our crude reliability adjustment from an average -410 kb/d to -200 kb/d (see *Non-OPEC Production Seen as More Reliable* in the *OMR* dated 12 May 2011). The most significant downward adjustments to the non-OPEC outlook accrue for the FSU, amid project slippage in Kazakhstan, and with a modest downward reassessment for global biofuels supply. Recalculated refinery processing gain is now -0.1 mb/d lower on average per annum.



Trends & Risks

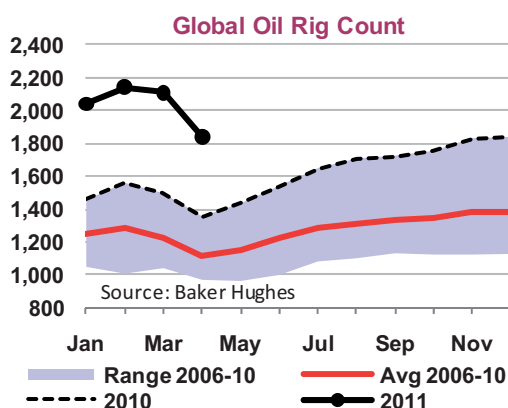
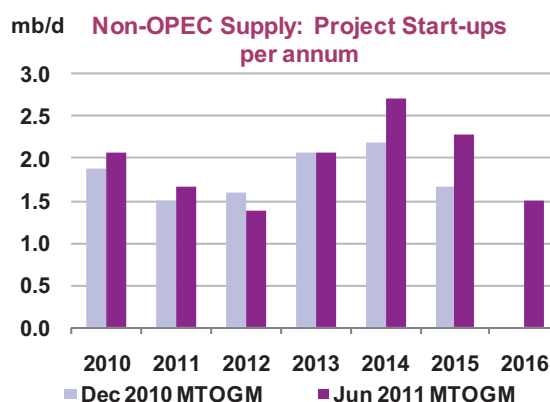
Many of the drivers of non-OPEC supply growth highlighted in the June 2010 *MTOGM* are still in place, and arguably, there are even more reasons to be bullish on sustained output growth in the medium term. Compared to the price assumption one year ago, which envisaged prices rising from \$77 to \$86/bbl by 2015 (nominal IEA average crude import prices), our current price assumption remains in excess of \$100/bbl. With the cost of developing the marginal non-OPEC barrel, be it in Brazil's deepwater or Canada's oil sands, estimated in the \$40-100/bbl range, and with most oil companies testing project profitability at prices significantly below \$100/bbl, the current view on upstream economics looks favourable, suggesting most upstream projects will go ahead.



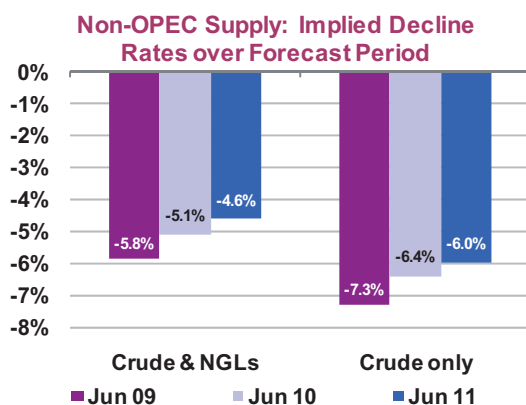
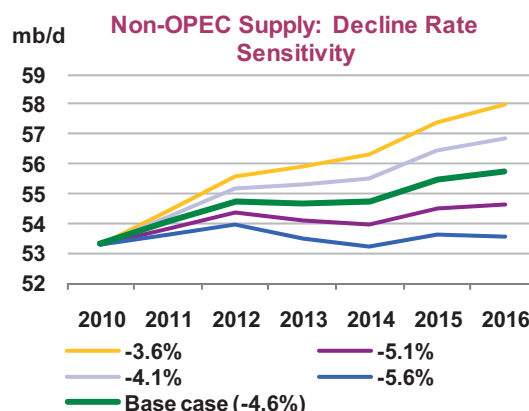
Source: An updated version of the IEA's 2005 publication *Resources to Reserves: Oil and Gas Technologies for the Energy Markets of the Future* to be published later this year.

¹Production cost is defined as the break-even point and does not include an assumed return on investment

As a result, upstream investment continues to grow, with latest estimates indicating that oil companies plan to invest between 10-20% more in 2011 than in 2010, with last year already having seen around 10% growth. With the exception of the US Gulf of Mexico, where permitting for new drilling has been slow and delays are expected, and Kazakhstan, where political wrangling over the terms of upstream deals signed over a decade ago has threatened to postpone projects, there are fewer signs now of project slippage than there were mid-to-late last decade. Drilling has increased, as measured by rig counts, currently hovering substantially higher than one year ago.



As highlighted in the June 2010 *MTOGM*, sustained investment in new upstream projects, but also in maintaining production at existing assets, is contributing to more robust non-OPEC supplies. Significant opportunity constraints in accessing some of the world's lower cost reserves have in many cases shifted international companies' focus to a greater reliance on boosting recovery rates at existing assets with the application of advanced reservoir management technologies. This is reflected in a slowing of observed field decline rates in the 2008-2010 period to an average of 6.2% for crude, and 4.9% for crude and NGLs combined. This deceleration is partly fed through into the forecast period, which sees slightly lower implied field decline rates of 6% for crude only and 4.6% for crude and NGLs combined. These are around 0.5 percentage points lower than observed one year ago.



Total estimated non-OPEC supply for mid-decade will be highly sensitive to assumed decline rates going forward, with every 0.5% swing in the implied rate equating to around 1 mb/d of 2016 supply. Thus a lower decline rate, combined with higher levels of new project start up later in the forecast, generate a 2015 supply level over 1 mb/d higher than projected in December.

Downside Risks to an Increasingly Optimistic Outlook

Despite favourable economics, downside risks persist for any supply forecast. Our projections suggest that market fundamentals could remain relatively well balanced in the medium term, yet we have detected initial signs of a slowdown in the pace of demand growth in price-responsive markets. Were there to be widespread demand destruction, due to high prices, this would likely lead to a readjustment, and in turn force a cyclical re-examination of planned investments.

Currently, production shut-ins due to MENA unrest remain largely concentrated in Libya, though in May, nearly two-thirds of Yemen's oil production was also briefly shut-in following sabotage and protests. Production in Syria, Bahrain and other countries in the region remains vulnerable to further unrest. Non-OPEC MENA production amounts to 2-2.5 mb/d in the 2010-2016 period. Resource nationalism has arguably waned, although high oil prices have seen the proposed imposition of higher or windfall taxes in Russia, the UK, the US and Venezuela, among others. Requirements on local sourcing of infrastructure, equipment and labour raise concerns about the timely completion of projects, e.g. in Brazil's pre-salt formations. Lastly, as always, even though we make adjustments for production volumes shut-in due to storm activity in the US (based on the five-year average), disruptions since 2008 have been relatively light. For 2011's season, all major forecasters envisage above-average activity with several storms blowing into hurricanes.

But might there be other, more specific risks to supply growth potential? Notably, our assumed strong growth in both Canadian oil sands and US light tight oil production depends on the timely completion of new transport infrastructure. We have identified over 1 mb/d of 2016 North American supply which could be at risk if this infrastructure is not forthcoming.

Most prominent is the Keystone XL pipeline, which would take 500+ kb/d of Canadian crude from the Oklahoma hub of Cushing to the US Gulf Coast – the first such direct connection. Producers in Canada and refiners in the US are keen, but it has attracted a lot of criticism due to environmental concerns about oil sands production. Two other key projects, the reversal of the Longhorn pipeline, and Enterprise/Energy Transfer's proposed line from Cushing to Houston, could add another 200 kb/d and 400 kb/d respectively of offtake from Cushing by 2013.

Key North American Crude Pipeline Projects

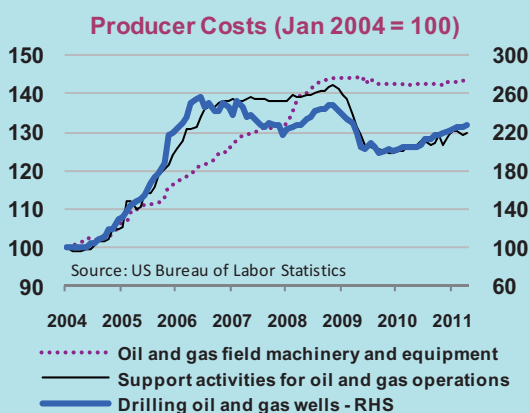
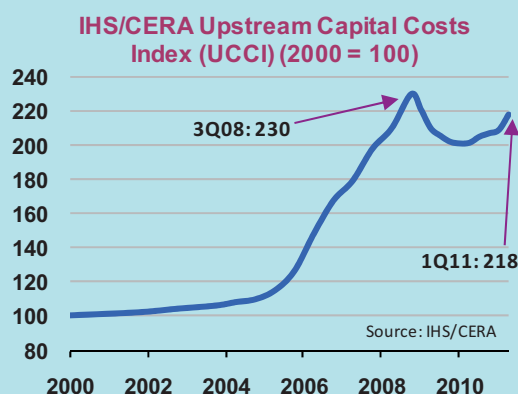
Name	Company	Route	Start-up	Capacity (kb/d)
Northern Gateway	Enbridge	Alberta-Pacific Coast	?	525
Keystone XL	TransCanada	Cushing-Port Arthur	Late 2013	500
Enterprise/Energy Transfer	Transfer	Cushing-Houston	Late 2012	400
TransMountain expansion	Kinder Morgan	Alberta-Pacific Coast	?	400
Seaway reversal	Conoco/Enterprise	Cushing-USGC	?	350
Longhorn reversal	Magellan	West Texas-Houston	Early 2013	200
Monarch	Enbridge	Cushing-USGC	?	150-300
Bakken Expansion		Bakken-Enbridge system	Late 2012	145
Bakken Marketlink		Bakken-Keystone XL	?	100
Bakken North Project		Bakken-Enbridge system	Late 2012	75

Downside Risks to an Increasingly Optimistic Outlook (continued)

Albertan oil sands producers would also like to expand the pipeline network to send oil to the Pacific Coast, from where it could be sold to the US West Coast or the wider Asia-Pacific market. Enbridge's Northern Gateway line and KinderMorgan's proposed TransMountain pipeline expansion would add another 525 kb/d and 400 kb/d respectively, though opposition by indigenous groups and environmentalists is strong.

Oil production from the Bakken formation, shared between North Dakota, Montana and Canada's Manitoba and Saskatchewan, also suffers from offtake bottlenecks. Currently, some Bakken crude is trucked to collection points, while at least 60-90 kb/d is being sent by rail to the Gulf Coast, and smaller volumes to Midwestern and Californian refineries. Some have suggested using barges down the Missouri/Mississippi river system to the US Gulf Coast refinery hub. But pipelines would be the cheapest means and hence several expansions have already taken place and more are being considered.

Arguably 1 mb/d of incremental Canadian crude supply and 200-300 kb/d from Bakken risks being stranded if pipeline delays materialise. However, our outlook implicitly assumes that necessary pipeline infrastructure is forthcoming, not least given the compelling economic and energy security arguments being deployed in their favour.



Finally, there are concerns that the explosion in upstream costs and labour shortages, as well as services bottlenecks that plagued Canadian oil sands development in particular in the 2008-2009 period may resurface. Two measurements of upstream costs – Bureau of Labor Statistics (BLS) data and calculations by consultancy IHS/CERA – point towards a continued increase since costs fell off sharply in line with prices, in 2008-2009 (these findings also match those published in the IEA's World Energy Outlook 2010). The pace of increase however looks more modest than seen during 2005-2008. The supply projections here already incorporate a degree of caution regarding new project completion and ramp-up to capacity, but further slippage should service capacity tighten appreciably in future cannot be discounted.

Revisions to Forecast

Regionally, upward revisions to the forecast are centred on North America, nearly evenly spread between the US and Canada. In the US, it is largely light tight oil, produced in unconventional basins onshore, that is seen significantly higher than in previous projections (see *After the Shale Gas Revolution, Now It's Oil's Turn*). In Canada, the upward revision results from stronger growth in NGLs, as well as Albertan bitumen and conventional crude in Saskatchewan. Projections for both countries also benefit from a crude reliability adjustment (now seen averaging -200 kb/d versus -410 kb/d previously, largely in OECD countries). Significant upward revisions were also made for China and OECD Europe. Downward adjustments were centred on the FSU, biofuels and Other Asia (largely Indonesia). Despite a full reappraisal of our NGLs projections on the basis of a new gas forecast, and many changes to individual countries' profiles, the total NGLs forecast is broadly unchanged (non-OPEC projections include field condensate and liquids from gas processing plants).

Non-OPEC Supply - Revisions from last MTOGM

	(thousand barrels per day)					
	2010	2011	2012	2013	2014	2015
North America	69	289	455	688	948	1066
Europe	37	33	155	113	35	162
Pacific	-13	-52	13	40	74	129
Total OECD	93	271	623	841	1057	1357
Former USSR	-34	-89	-152	-163	-242	-209
Europe	-2	-2	-4	-9	-10	-8
China	13	25	44	81	96	108
Other Asia	64	7	-77	-19	-8	-53
Latin America	10	-17	153	17	-120	-39
Middle East	29	16	115	106	95	91
Africa	-36	-45	-38	-21	-37	-37
Total Non-OECD	43	-103	41	-9	-226	-148
Processing Gains	-209	-181	-134	-69	-39	9
Global Biofuels	-2	-116	-135	-82	-76	-81
Total Non-OPEC	-74	-129	395	681	717	1138

Revisions for total non-OPEC supply are focused on the latter years of the forecast, largely reflecting the growing contribution now seen from US light tight oil, but also US and Canadian NGLs, Canadian oil sands and slightly slower decline in Australia, the UK and Mexico. These adjustments are only partly offset by project slippage in Kazakhstan and, to a lesser extent, in Brazil, a curtailed global biofuels forecast and lower refinery processing gains.

Sources of Growth

The more bullish outlook for US crude oil prospects, in combination with strong growth expected for oil from Canadian oil sands, boosts North America to become the key source of incremental oil production by 2016. Latin America, previously the main source of regional growth, comes in close behind. Adding in higher biofuels output, which stems largely from US and Brazilian fuel ethanol, and a large chunk of refinery processing gains due to the relatively high complexity of US refineries, virtually all of non-OPEC's incremental oil supply will come from the Americas.

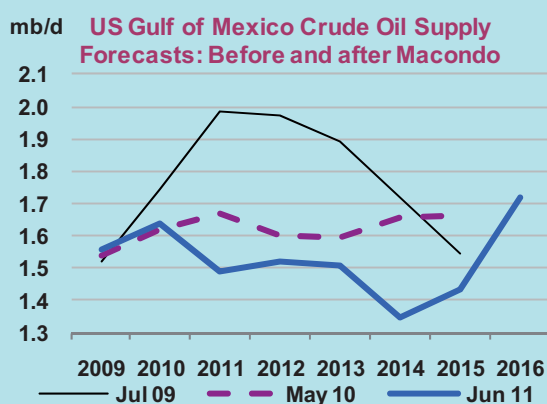
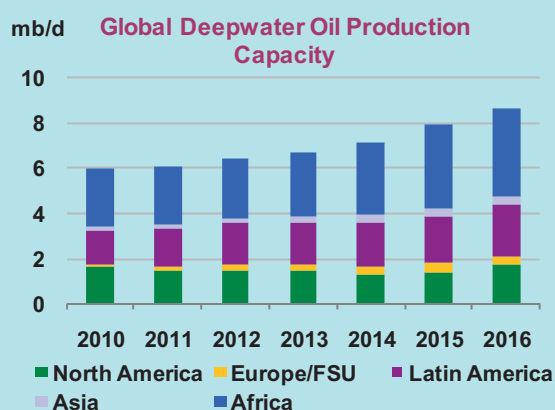
Deepwater Oil Prospects – One Year After Macondo

Just over a year after the blowout at the Macondo well in the US Gulf of Mexico (GoM), which led to the largest accidental oil spill in history; what precisely have the repercussions for oil markets been?

The initial outcome was a temporary drilling moratorium, which however only applied to exploratory or wholly-new wells, thus having little impact on current production. Nonetheless, it delayed various upstream projects, which we modelled by slipping start-up dates by one to two years. Even after the moratorium was formally lifted, it became apparent that relatively slow issuance of new permits would continue to delay field start-ups. As such, we maintain the assessment, included in our December 2010 update, that delays will result in regional production by 2015 being 0.3 mb/d lower than originally projected. This is so far borne out by revised company start-up plans.

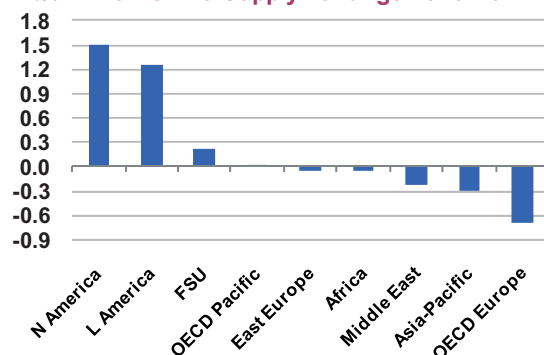
In the longer term, however, it is still unclear what the outcome will be. Regarding the specifics of the new regulatory regime, only a few new rules are in place, while findings from some key investigations have yet to be published. And the lawsuits have only just started, the outcome of which may result in a different perception of what went wrong and who was to blame.

Despite many uncertainties, the impact on international deepwater activity has so far been limited. While many countries with significant offshore oil and gas production reviewed their safety requirements, most declared their regimes to be already sufficiently robust to prevent similar accidents. In the US, things might return to normal even more quickly than most had thought. Due to the Republicans' gains in the 2010 mid-term elections, and against a background of jittery economic recovery and high oil prices, political momentum to boost US domestic oil production has grown. Hence President Obama recently reversed his previous position and called for the opening up of new areas in the GoM, but also offshore Alaska, with a view to reduce dependence on crude oil imports.

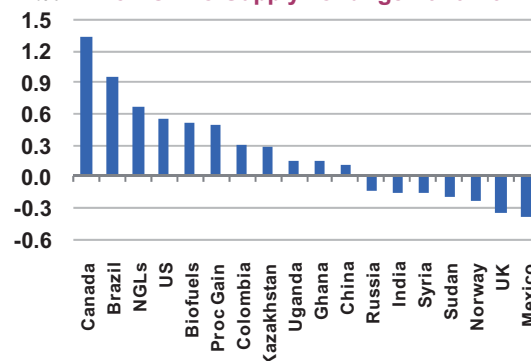


So, much of the world's future oil production is still likely to come from offshore areas. Given structural decline in North Sea and Mexican output, the offshore's overall share of global production will stay flat around 30%. But crucially, deepwater's share of offshore production will increase steadily, from 22% to 29% by 2016 (or from 6% to 9% of overall supply), with significant growth in Angola and Brazil. And there is potential for more to come, with some of the most promising new areas still relatively undeveloped, e.g. offshore Russia, large parts of West Africa, East Africa, Greenland and parts of Asia-Pacific. The full story of Macondo is not yet told, but deepwater oil production will remain a significant contributor to global oil supplies.

mb/d Non-OPEC Supply: Change 2010-16



mb/d Non-OPEC Supply: Change 2010-16



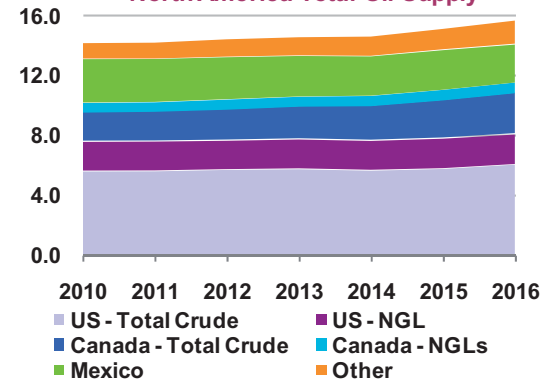
Nonetheless, individual countries outside the Americas also provide substantial production growth in the 2010-2016 period. Kazakhstan sees incremental output of +0.3 mb/d by 2016, despite slippage at the next phase expansions for Karachaganak and Tengiz and lower anticipated capacity for the first phase of Kashagan. New producers Uganda and Ghana each add around +150 kb/d. Azerbaijan, with persistent technical problems capping growth at its offshore Azeri-Chirag-Guneshli (ACG) complex, is now estimated to add only 45 kb/d by 2016. With Russian production seen declining by 130 kb/d by 2016, this reduces the FSU's contribution to growth. Mexico, the UK and Norway continue to show the most pronounced decline in oil production, at -380 kb/d, -340 kb/d and -240 kb/d respectively.

Regional Overview

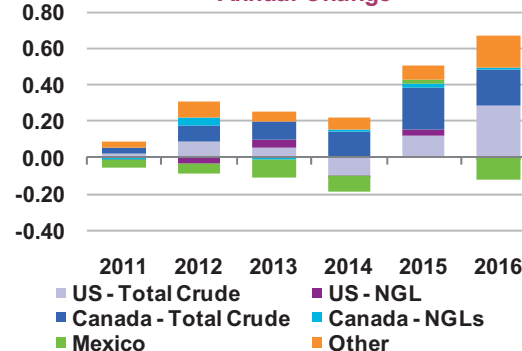
North America

North America is now seen as the strongest-growing non-OPEC region, with total oil production rising by 1.5 mb/d to 15.6 mb/d by 2016. Following upward revisions to **US** onshore crude from tight oil formations, total US oil production is now estimated to grow a healthy 0.5 mb/d to 8.3 mb/d by 2016. Mature Alaskan and Californian output will continue to decline, while output in the Gulf of Mexico is marred by delays until mid-decade, when growth resumes.

mb/d North America Total Oil Supply

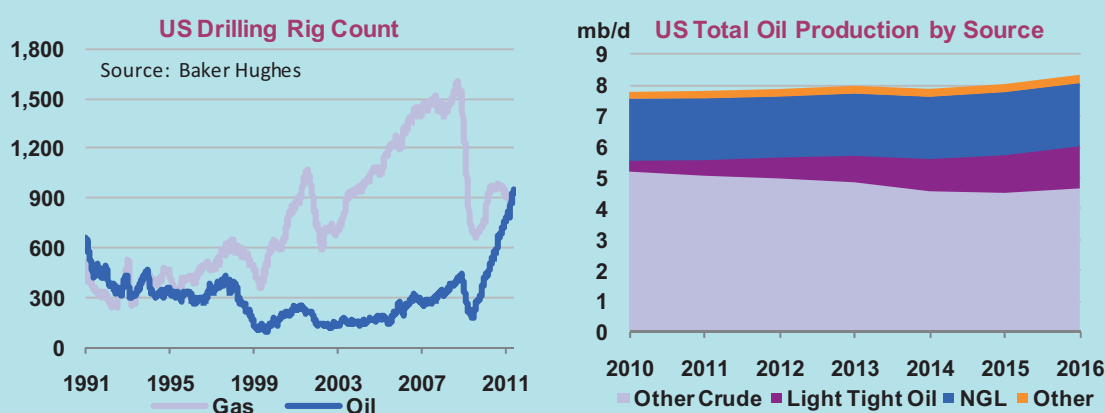


mb/d North America Total Oil Supply - Annual Change



After the Shale Gas Revolution, Now It's Oil's Turn

A revolution in the production of natural gas from unconventional geological formations – loosely known as shale gas – has seen US gas output surge. Divergent oil and gas prices have more recently resulted in the application of similar techniques to access hydrocarbon liquids reserves previously seen as too challenging or uneconomic to develop. Indeed, the fact that US oil production as a whole has actually increased in 2009 and 2010 is to some part due to stellar growth in light tight crude oil¹, also known as shale oil (not to be confused with oil shale², or kerogen oil, another potential, as yet untapped, source of unconventional oil). In the medium term, light tight oil is set to be the single largest driver of incremental US oil production, growing by +1 mb/d, more than offsetting delayed development in the US Gulf of Mexico, and contributing to overall US oil supply growth of +0.5 mb/d to 8.3 mb/d by 2016.



The application of two key techniques used successfully in developing unconventional gas – horizontal drilling and hydraulic fracturing – has proved to work equally well for liquids trapped in unconventional rock formations. Hydraulic fracturing involves pumping a mix of chemicals and water into wells at high pressure, thus cracking the rock containing the liquids, while horizontal drilling enables greater access to pockets of liquid, allowing more to be pumped to the surface. With the cost of developing these barrels estimated at under \$50/bbl – less than Canadian oil sands or ultra-deepwater crude – recent price levels have spurred substantial investment.

Many US-based companies can also transfer skills (and equipment) acquired in developing unconventional gas. Furthermore, the fact that natural gas prices in the US have been at a significant discount to crude (as a result of the gas glut), has led many companies to increasingly focus on drilling the liquids-rich pockets of their acreage. This largely explains the concurrent shift from drilling for gas to drilling for oil, as reflected in respective rig counts (see graph). Lastly, proven reserves are substantial, with estimates for the Bakken alone ranging into billions of barrels.

Estimates for the supply potential for light tight oil differ widely. Government statistics do not uniformly separate out light tight oil from other crude, and a portion of some of the more inflated output projections likely includes NGLs (which we try to exclude). These difficulties notwithstanding, a survey of estimates reveals that most projections see well over 1 mb/d of light tight oil around mid-decade and volumes reaching as much as 2-3 mb/d by 2020. We estimate that total US light tight oil production in

¹ Light tight crude oil is conventional crude oil trapped in geological formations with low permeability (e.g. shale), requiring special techniques to produce. It is reported as part of crude oil.

² Kerogen oil, often referred to as oil shale, is sedimentary rock containing kerogen, which when heated and processed releases liquid hydrocarbons similar to crude oil.

After the Shale Gas Revolution, Now It's Oil's Turn (continued)

2010 averaged 370 kb/d. Based on an outlook for the main five formations, taking into account past growth rates, company guidance and infrastructure development, we see total US light tight oil growing by +1 mb/d to 1.36 mb/d by 2016.

The most frequently-mentioned source of growth in light tight oil is the **Bakken formation**, which straddles the North Dakota/Montana border and extends into Manitoba and Saskatchewan in Canada. North Dakota has seen oil production rise from an average 85 kb/d in 1994-2004 to 220 kb/d in 2009 and 310 kb/d in 2010. The reserves base there is substantial. A US Geological Survey in 2008 estimated that Bakken held 4 billion bbls of recoverable oil, while in 2010, the North Dakota Geological Survey estimated an additional 2 billion bbls in the nearby Three Forks formation (incorporated with Bakken in our estimates). US independent producer Continental, the largest holder of acreage in the Bakken, meanwhile estimates that the formation holds as much as 24 billion bbls of (recoverable) oil equivalent, which would make it one of the largest concentrations of hydrocarbon liquids to be tapped in the US. Our projections see Bakken light tight oil output roughly tripling to 750 kb/d by 2016, with around 90% stemming from North Dakota.

US Light Tight Oil Production

(thousand barrels per day)

	2010	2011	2012	2013	2014	2015	2016
Bakken	268	363	472	566	651	716	752
Barnett	15	23	29	35	42	46	51
Eagle Ford	21	40	65	98	138	193	260
Monterey	7	8	10	20	30	40	50
Niobrara	61	85	114	143	179	215	247
TOTAL	372	519	691	863	1040	1210	1359

The second-largest source of growth is the **Eagle Ford** formation, in southern Texas, which we see growing from a mere 20 kb/d in 2010 to 260 kb/d by 2016. Unlike some of the other formations, it benefits from proximity to existing infrastructure, including pipelines, processing plants and not least, the Texas refinery hub on the coast. The **Niobrara** formation, which straddles Wyoming and Colorado, had an estimated average production of 60 kb/d in 2010, and is projected to also grow to around 250 kb/d by 2016. **Barnett** and **Monterey** are expected to grow to 50 kb/d each by 2016. Other formations, such as the Marcellus are being explored and developed, though the latter rather for gas.

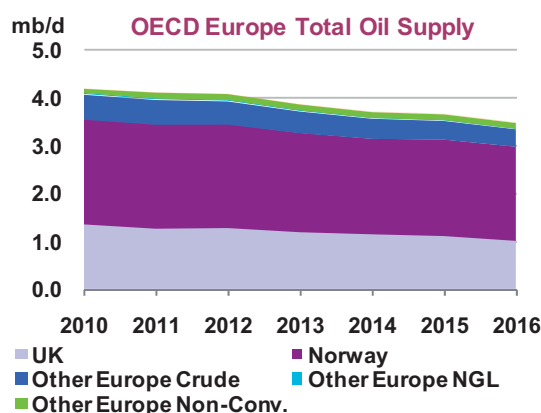
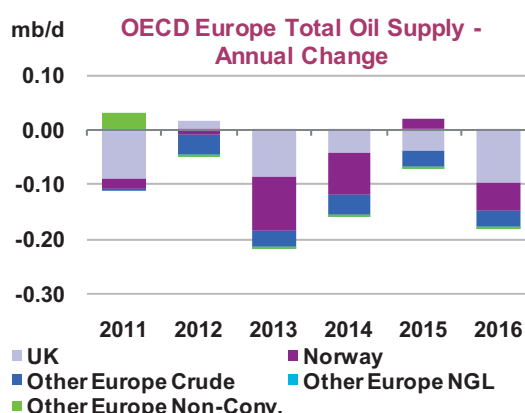
There are of course constraints to growth – actual and potential. Firstly, prices have to be sustained at a certain level in order to make development viable. Secondly, areas like North Dakota, which have historically not been large producers, have relatively little in the way of export infrastructure (see *Downside Risks to an Increasingly Optimistic Forecast*). Thirdly, there is also the possibility of a cost explosion, particularly for highly specialised hydraulic fracturing services, and a kind of boom and bust as observed temporarily in the Canadian oil sands. And fourthly, there are environmental concerns. Already, protests have focused on the possible contamination of drinking water aquifers, though evidence is not conclusive, and substantial water usage for hydraulic fracturing. France is likely to impose a moratorium on hydraulic fracturing. Conversely, UK lawmakers decided not to ban the technique. For the US however, we see potentially sustained high prices and security of supply concerns continuing to spur light tight oil development.

In **Canada**, NGLs and oil sands projections are seen higher compared to our last *MTOGM*. Total production is now expected to rise by 1.3 mb/d to 4.7 mb/d by 2016. Oil supply in **Mexico** is revised marginally higher but is still seen to decline by a sharp 0.4 mb/d to 2.6 mb/d by 2016.

Despite a pronounced slowing of decline rates at key fields such as Cantarell, Mexico so far lacks substantial new projects in the pipeline to boost production.

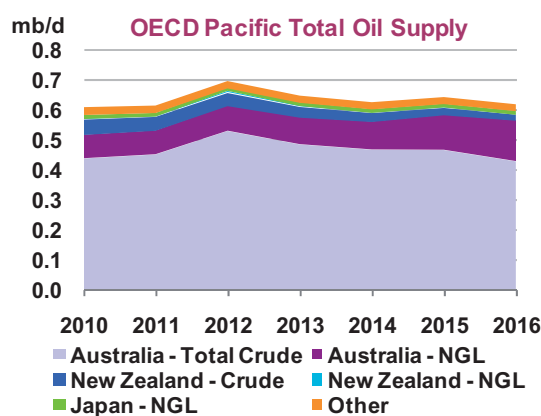
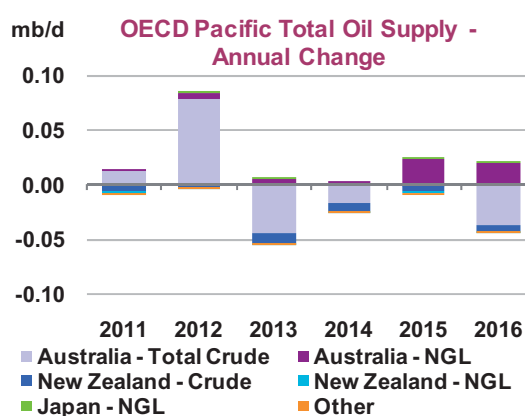
OECD Europe

OECD Europe's oil production is projected to experience the strongest decline of all non-OPEC regions, falling by 0.7 mb/d to 3.5 mb/d by 2016. **Norway's** outlook is revised down marginally and sees production dip from 2.2 mb/d to 1.9 mb/d by 2016. Despite a string of small projects, which are tied-back to existing infrastructure and can thus be brought onstream rapidly, Norway has recently suffered a series of mishaps at various offshore platforms, which has constrained output, and the production base is maturing. Notwithstanding a slight upward revision for the **UK**, production is expected to decline by 0.3 mb/d to just over 1 mb/d by 2016. A recent tax hike in the UK prompted howls from producers, but has not so far affected identified projects included in our forecast.



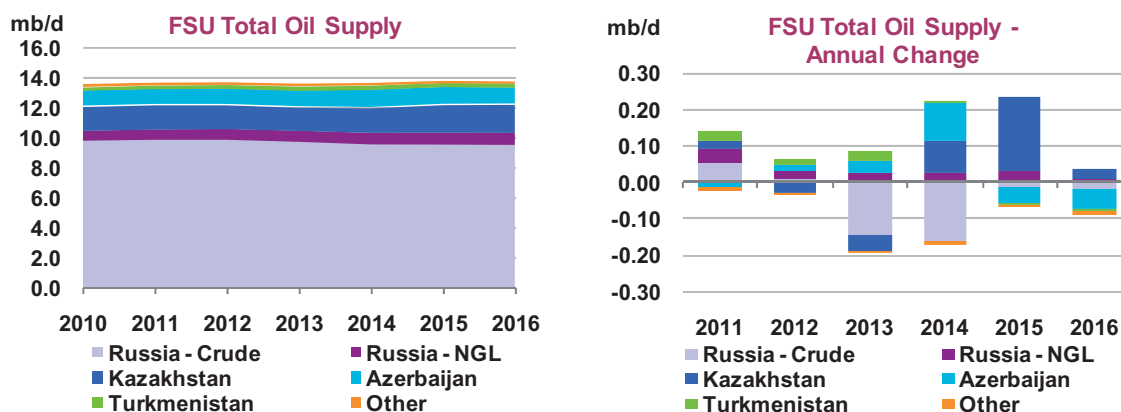
OECD Pacific

OECD Pacific oil production remains steady at just over 0.6 mb/d, as rising output from new field start-ups in **Australia** including Pyrenees, Van Gogh and Montara offsets decline at mature assets, and NGLs supply rises on the back of surging gas production. **New Zealand** crude and NGLs production is projected to decline steadily.



Former Soviet Union (FSU)

Compared to previous forecasts, the outlook for the FSU has been revised down. **Kazakhstan**, while still expected to grow by a sturdy +0.3 mb/d to 1.9 mb/d by 2016, suffers from major project slippage. The next phase of the expansion of the large Karachaganak field is now expected to come onstream in 2014, rather than the previously-assumed 2012. The super-giant Kashagan is still expected to see first production in 2013, but capacity of the first phases has been trimmed from 450 kb/d to 370 kb/d, to be reached by end-2015. The next step in Tengiz's development has been delayed to 2017, thus falling outside our time horizon. **Azerbaijan** continues to have technical problems at its large Azeri-Chirag-Guneshli (ACG) complex, evident since a major outage in 2008. As such, longer-term national capacity is trimmed, growing slowly to a lower 1.2 mb/d peak in 2014 and declining again to 1.1 mb/d by 2016.

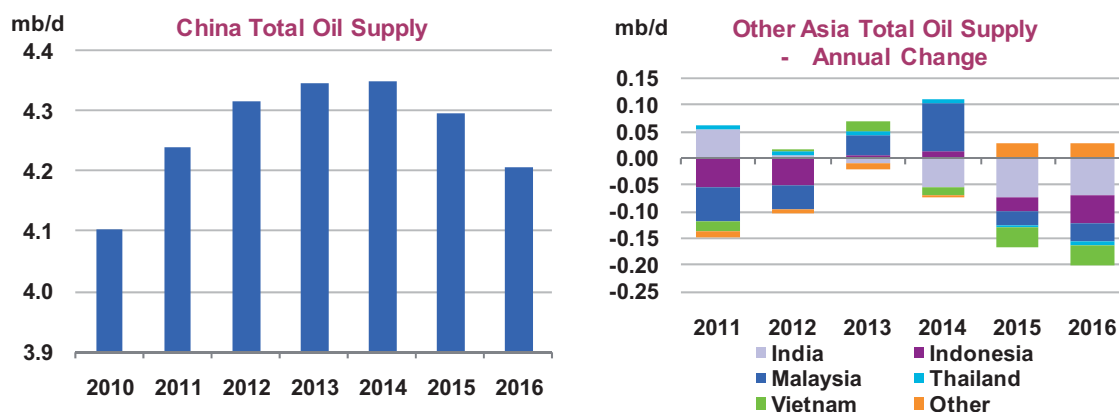


Prospects for the trend in oil production in **Russia** are little changed. However, some project slippage at the tail end of the forecast leaves total output sliding from 10.5 mb/d in 2010 to 10.3 mb/d in 2016. The possibility of a substantial tightening of the fiscal regime remains a key downside risk, though Russia's authorities evidently also remain aware of the need to stimulate investment in new and technically challenging areas. This forecast implicitly assumes that key tax breaks, especially for greenfields in new areas, e.g. Eastern Siberia, will remain in place where deemed necessary by the authorities. Incremental Russian supply through 2016 derives from a handful of key fields, including Vankor and Yurubcheno-Tokhomskoye in Eastern Siberia, but also Novoportovskoye in the Yamal-Nenets region and Trebs/Titov in Timan-Pechora. NGLs also add significant incremental supply. Net increments are nonetheless offset by a declining base, mainly in Western Siberia.

Asia-Pacific

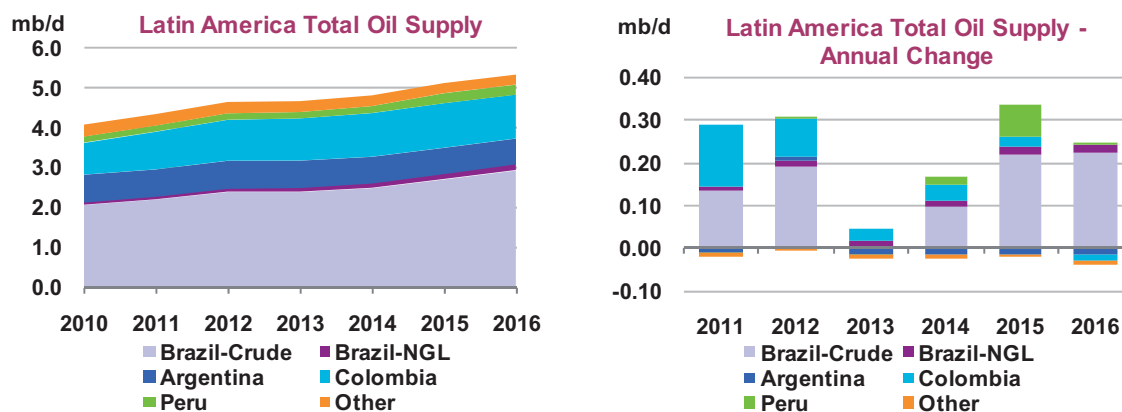
Projected oil output in **China** has been revised up slowly but steadily over the past several months, as producers manage both to boost output in the key offshore growth area, while successfully slowing decline at mature eastern onshore fields. Chinese oil production is seen rising from 4.1 mb/d in 2010 to a peak of 4.3 mb/d in 2012-2014, then declining again to 4.2 mb/d by 2016. Oil production in **Indonesia** is marred by a worsening investment outlook. Production there is projected to slip from 975 kb/d in 2010 to 800 kb/d by 2016. **India** sees some growth to 920 kb/d in 2011-13, as the Mangala-Bhagyama-Aishwariya field complex in Rajasthan ramps up to capacity, but then national

production declines again to 720 kb/d in 2016. Most other regional producers are expected to see a structural decline in oil production in the medium term.



Latin America

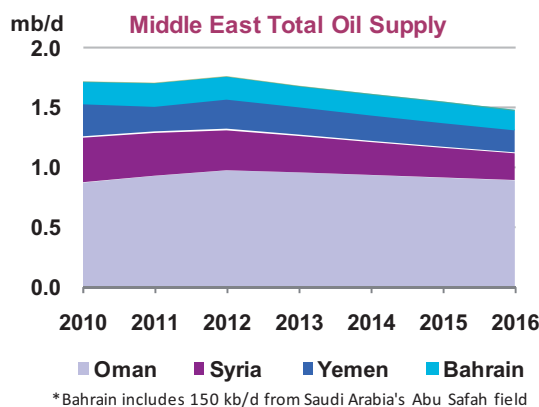
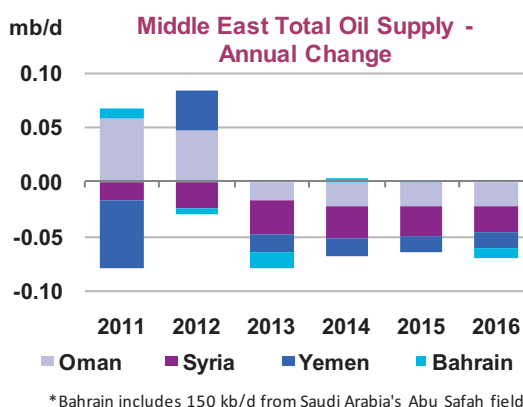
Latin America has slipped from being the first to second-strongest regional source of non-OPEC incremental oil supply – now overtaken by North America. Behind Canada, **Brazil** is the second-largest individual source of growth in non-OPEC, with a string of large-scale deepwater offshore projects due to boost production from 2.1 mb/d in 2010 to 3.1 mb/d in 2016. Around 70% of this incremental supply is to come from the pre-salt strata in the deepwater. A requirement that rigs, drilling ships and other equipment be sourced locally, as well as mandatory operatorship of all pre-salt projects by state-controlled Petrobras, remain downside risks to our outlook in terms of potential logistical and organisational bottlenecks. That said, Petrobras clearly has the financial weight and operational experience to successfully develop challenging deepwater prospects.



Colombia is the second-largest regional source of incremental oil supply. An improvement in its investment climate, the part-privatisation of state oil company Ecopetrol from 2006 and enhanced security have attracted development of a string of new onshore fields, which should raise oil production from 0.8 mb/d in 2010 to 1.1 mb/d by 2015/16.

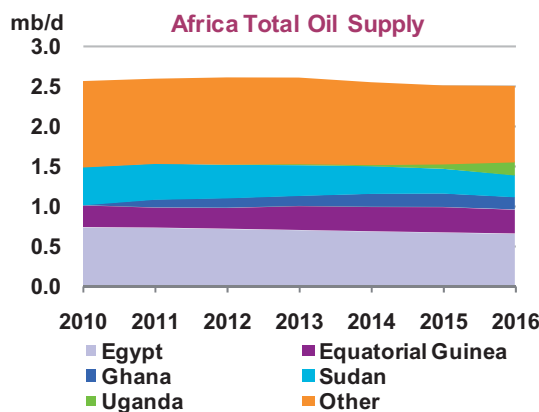
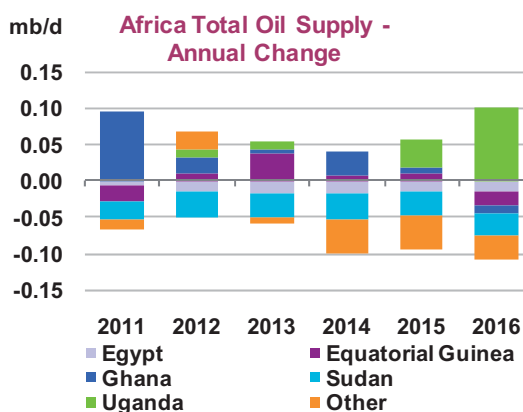
Middle East

Non-OPEC Middle Eastern oil production is projected to decline between 2010 and 2016. Some countries are suffering from the wider unrest seen in the MENA region – in May 2011, as much as two-thirds (or 170 kb/d) of **Yemen's** oil production was briefly shut-in, and political tensions persist in **Bahrain** and **Syria**. Only **Oman** is projected to see a small increment in output in the medium term, boosted by enhanced oil recovery and some new start-ups. Oil production will surge from an average 865 kb/d in 2010 to 970 kb/d in 2012, then decline again to 885 kb/d by 2016.



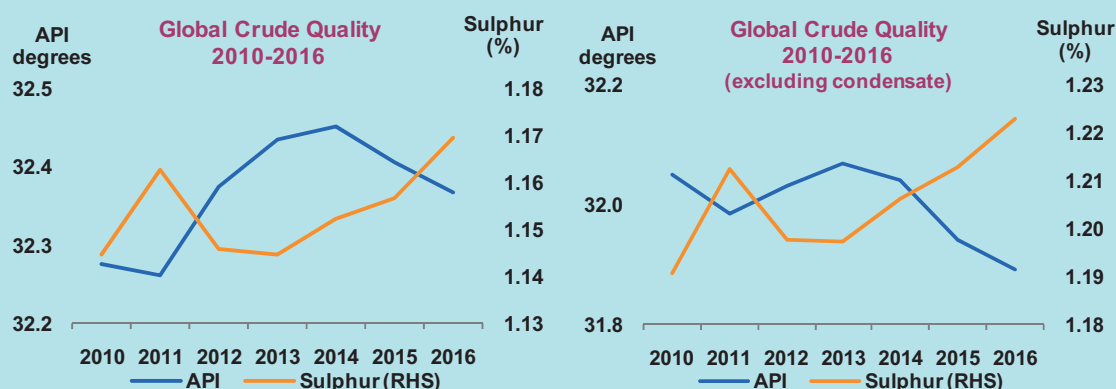
Africa

Africa's oil producers show mixed results by 2016, with overall regional supply expected to decline marginally to 2.5 mb/d. **Ghana** and **Uganda** are newcomers to oil production, but both see output rise to around 150 kb/d by 2016. Older producing countries, such as **Egypt** and, to a lesser degree, **Chad**, **Congo** and **Gabon**, all see production slide. **Sudan**, from which the southern part of the country is expected to secede in July this year, has seen small production shut-ins due to rivalry over disputed oil-producing regions that are close to the border. The unrest could very well continue to fester, putting a question mark on renewed investment in the country, and output is expected to fall by around 470 kb/d to 275 kb/d by 2016.

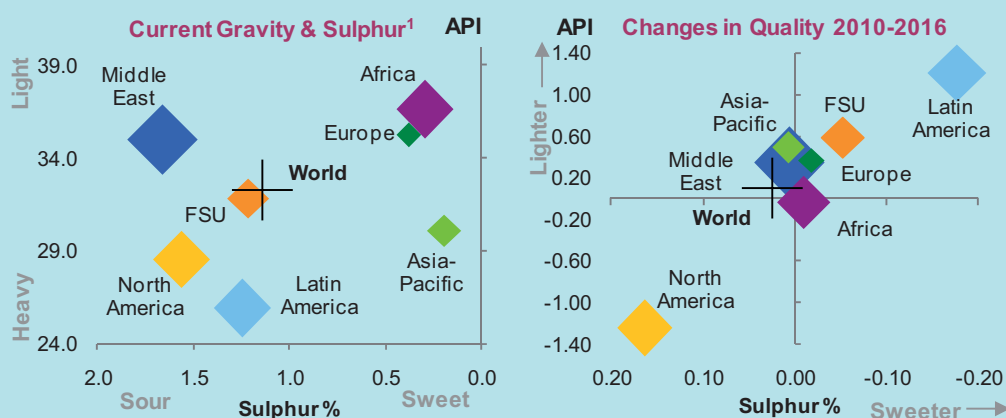


The Evolution of Crude Oil Production by Quality

In line with the June 2010 *MTOGM*, world crude oil supply is projected to become slightly lighter and sourer over the forecast period. However, the outlook has three distinct phases. 2011 is characterised by production becoming marginally heavier and sharply sourer as the light, sweet production from Libya is taken off the market. Secondly, during 2012-2014 supplies become lighter and sourer with increased African, Latin American and Middle Eastern production prospects. Finally, in 2015-2016 supplies once again become heavier and sourer as heavy oil production is ramped up in North America.



The weighted average API gravity is projected to rise modestly from 32.3° to 32.4° over the forecast period driven by higher production in Africa and Latin America. The loss of light, sweet Libyan production in the early part of the forecast sees sulphur content rises sharply to 1.16% in 2011 before falling back and then climbing steadily from 2014, to a high of 1.17% in 2016. This represents a significant increase compared with the June 2010 *MTOGM*, attributable to improved heavy oil supply prospects in North America and rising sour oil production in the Middle East and Asia.



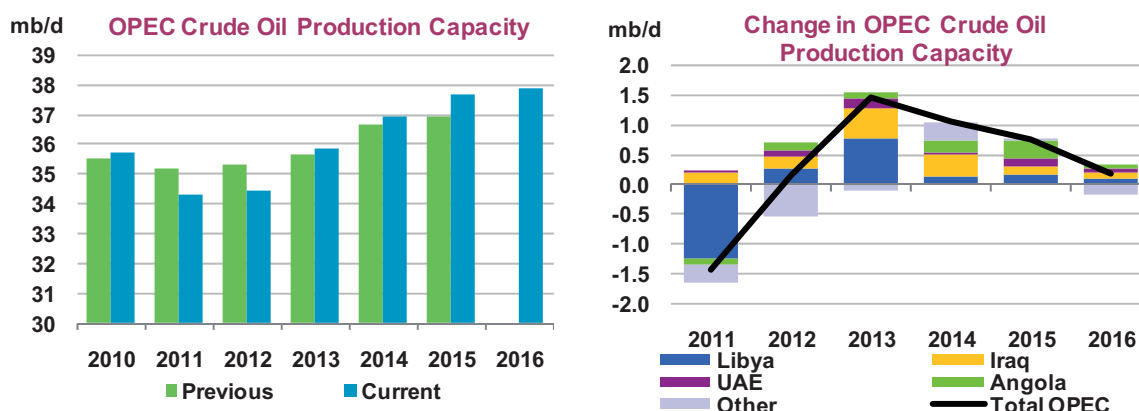
1 Symbols proportionate in size to regional production.

The most significant shift in quality is set to occur within North America where crude becomes progressively heavier and sourer with increasing output of Canadian bitumen, especially towards the end of the forecast. Latin American supply is likely to become lighter and sweeter as Brazilian pre-salt production is ramped up, partially offsetting increased Venezuelan heavy oil. FSU crude is also set to become lighter and sweeter as Kazakh and East Siberian fields come on-stream and mature heavier fields decline. Middle Eastern supply prospects are expected to remain relatively stable with API increasing by 0.3° and sulphur rising by 0.01%, largely due to increased condensate production.

OPEC Crude Oil Capacity Outlook

Markedly higher oil prices over the past six months, shut-in Libyan crude production and anticipated robust growth in global oil demand have had surprisingly little impact on most OPEC members' plans to increase installed production capacity in the medium term. OPEC crude oil production capacity is slated to increase by 2.13 mb/d to 37.85 mb/d over the 2010-2016 period, growth being largely unchanged from our previous outlook in December 2010 and from the June 2010 report.

The near total shut-in of Libyan production since the start of its civil war in February 2011 has significantly altered the group's production profile for the near term. OPEC installed capacity is on track to hit a four-year low in 2011 due to the loss of Libyan supplies, before rebounding in 2013 on expectations of a recovery in the country's output. Libya's capacity is expected to reach pre-crisis levels by 2015 (see *'Libya Faces a Long Haul to Restore Production Capacity'*).



Severely constrained Libyan production through 2012 highlights the lack of light-crude spare capacity held by the majority of OPEC members. Indeed, OPEC's effective spare capacity is expected to average well below 4 mb/d through 2013, hitting a low of 3.15 mb/d in 2011. As expected, the bulk of the spare capacity is held by Saudi Arabia, in large part due to the country's substantial capacity increases of 1.6 mb/d in the 2009-10 period (see *'What is OPEC's Effective Spare Capacity?'*).

Just three of OPEC's 12 members realistically plan significant capacity expansions by 2016, with Iraq providing more than 70% of the net increase. Angola and the UAE are the two other major sources of growth. By contrast, five countries are expected to see capacity decline, with Iran down by more than 20% compared to 2010 levels.

Oil prices have been on an upward trajectory since 3Q10, propelled higher by both a recovering economy and financial sector, and with them, resurgent oil demand growth. Heightened political risk issues in the MENA region fuelled further prices increases since the start of 2011. As a result, our current price assumption, based on the Brent forward curve, shows a fairly narrow range of around \$100-105/bbl for the 2011-16 period. Higher price expectations are a key reason that international oil companies are increasing capital expenditures and fast-tracking upstream projects in non-OPEC countries. By contrast, within OPEC, only Saudi Arabia has moved forward development plans for its

next large project. By and large, a growing number of OPEC producers appear incapable of increasing production capacity in the medium term due to a multitude of reasons, including:

- Uncompetitive contract terms and/or shifting fiscal regimes for IOCs stemming from resource nationalism (Algeria, Libya, Nigeria, Iran, Venezuela, Ecuador);
- Project delays or cancellations due to internal and external political and security constraints (Iran, Nigeria, Libya, Kuwait, Iraq, Ecuador and Venezuela);
- Delays to project developments due to requirements on local sourcing of infrastructure, equipment and workforce (Algeria, Angola, Nigeria, Libya, Iraq, Venezuela, Ecuador);
- Inability to monetise assets in the short term by surging production due to management issues/equipment/expertise constraints (Algeria, Nigeria, Libya, Kuwait, Venezuela, Ecuador); and
- Lack of expertise or access to advanced technology for EOR projects needed for maximising recovery rates (Algeria, Libya, Iran, Kuwait, Venezuela, Ecuador).

New OPEC capacity coming on stream during the forecast period is estimated at a gross 10.6 mb/d at peak, with Iraq accounting for one-third of the increase. However, new capacity will be partially offset by a decline of 8.5 mb/d (1.4 mb/d, or 4.5% annually, from the existing production base) – MTOGM capacity estimates are based on a combination of new project start-ups, and assessed base load supply, net of mature field decline.

A baseline revision to Venezuela's production capacity profile over the 2002-2016 period is also included in this year's update, which results in an upward revision of 300 kb/d on average for the 2005-10 period (see 'Venezuelan Baseline Production Revisions').

Estimated OPEC Sustainable Crude Production Capacity

(In million barrels per day)

	2010	2011	2012	2013	2014	2015	2016	2010-16
Algeria	1.35	1.33	1.34	1.42	1.42	1.37	1.32	-0.03
Angola	1.99	1.89	2.02	2.13	2.32	2.62	2.70	0.71
Ecuador	0.50	0.52	0.53	0.53	0.51	0.48	0.46	-0.04
Iran	3.87	3.70	3.55	3.50	3.35	3.19	3.06	-0.81
Iraq	2.55	2.76	2.95	3.46	3.85	3.99	4.08	1.53
Kuwait	2.58	2.54	2.51	2.59	2.64	2.64	2.61	0.03
Libya	1.67	0.44	0.70	1.46	1.57	1.74	1.84	0.17
Nigeria	2.69	2.72	2.60	2.53	2.62	2.78	2.89	0.20
Qatar	1.02	1.03	1.03	1.02	1.01	0.99	0.98	-0.04
Saudi Arabia	12.07	12.04	11.82	11.64	11.71	11.79	11.82	-0.25
UAE	2.70	2.72	2.82	3.00	3.04	3.17	3.23	0.53
Venezuela	2.71	2.61	2.57	2.63	2.89	2.92	2.84	0.14
OPEC-11*	33.17	31.53	31.49	32.43	33.08	33.68	33.77	0.60
Total OPEC	35.72	34.29	34.44	35.89	36.93	37.67	37.85	2.13
<i>Increment</i>	0.45	-1.44	0.15	1.45	1.04	0.74	0.17	

* Excludes Iraq

What is OPEC's 'Effective' Spare Crude Oil Production Capacity?

The IEA assesses current sustainable OPEC crude production capacity and provides an estimate of 'effective' spare capacity. Sustainable production capacity comprises 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. However, prevailing physical limitations on gas flaring and other technical issues are accounted for, with the result that our numbers aim to represent sustainable output potential, rather than short-term surge capacity. For any given period, nominal spare capacity is simply sustainable capacity minus estimated crude production.

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.

Mixed Supply Outlook for Middle East Producers

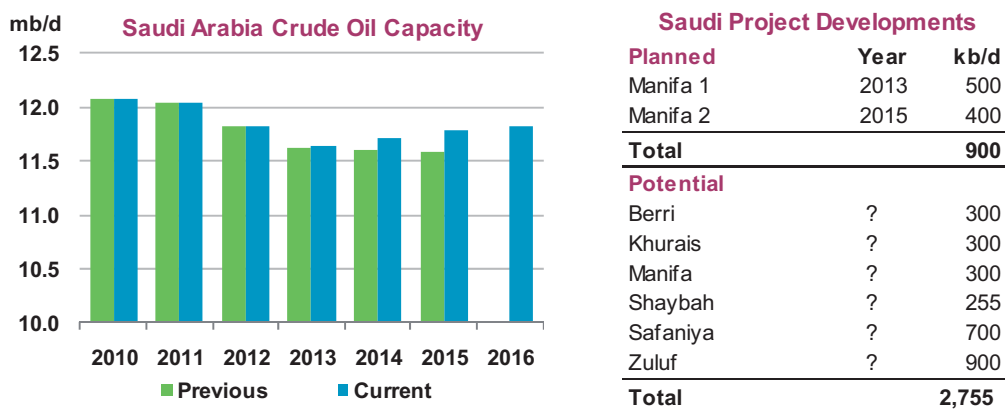
OPEC's Middle East capacity is expected to rise by a net 983 kb/d, to 25.8 mb/d, by 2016, accounting for 46% of OPEC's total increase. Iraq's substantial gains are partially offset by significant capacity losses in Iran. In addition to Iraq, the UAE is the only country in the region to post a major capacity addition in the medium term. However, while Saudi capacity is actually forecast to decline slightly over the forecast period, the kingdom has moved forward the timeline for developing the offshore Manifa field and resurrected a long list of projects if market conditions warrant.

Just over eight years after the fall of Saddam Hussein, Iraq is poised to significantly increase production capacity in the coming years. Its new joint venture partnerships started contributing incremental production increases earlier in 2011 and once some serious operational and logistical export constraints are addressed, development projects should start gathering steam next year (see *'Iraqi Production On a Solid Upward Trend'*).

Saudi Arabia is the one OPEC member to have fast-forwarded plans to develop new crude projects. Nonetheless, the country's installed capacity is expected to remain constrained within an 11.5-12.0 mb/d range through 2016. In response to expectations of stronger demand at home and in key export markets, Saudi Aramco announced in early May that it would bring forward development of the second phase of the 900 kb/d Manifa project to 2014, versus the originally planned 2024. The Manifa development is largely aimed at offsetting lower output due to natural decline rates. The Saudi implied decline rate averages 5.6% annually in our outlook. Most of the heavy oil from the \$16 billion Manifa development is earmarked for internal use at new refineries (Yanbu and Jubail).

Saudi Arabia added an unprecedented 1.6 mb/d to capacity over the 2009-10 period and had largely shifted its development efforts to its natural gas and petrochemical sectors. With no major oil development projects on the horizon as of 2010, Saudi Aramco also embarked on an extensive

rehabilitation of existing infrastructure and a drilling programme for new wells at the world's largest oilfield, Ghawar. Reports emerged that Saudi Aramco will significantly increase rig activity this year, up from around 90 rigs to 120 by end-2011. Part of the work at Ghawar includes plans for a massive CO₂ injection project, slated to start in 2012, which is aimed at sequestering greenhouse gases as well as reducing the amount of natural gas needed for reinjection to maintain oilfield pressure. Production from Ghawar, which has been producing since 1948, is currently estimated at 5 mb/d.



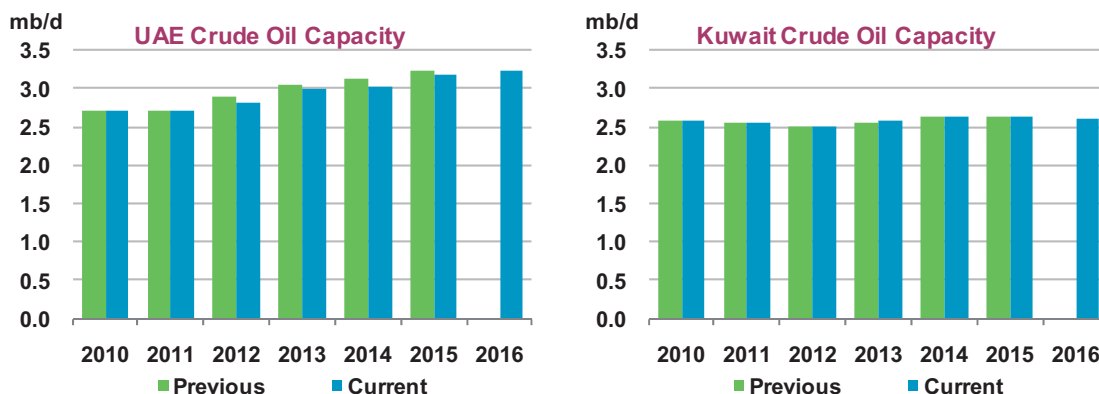
Potential development of six additional projects could add a gross 2.76 mb/d to Saudi Arabia's capacity, with many previously cited as part of a plan to attain 15 mb/d of capacity if market conditions justified. The most likely scenario comprises increments at the recently launched Khurais and the Shaybah fields. Though Saudi Aramco has not formally announced plans to increase production at Shaybah, which produces Arab Extra Light, a contract was awarded at end-2010 to US GE to supply power generation equipment and services for the expansion of the Shaybah gas-oil processing facilities, from 750 kb/d to 1 mb/d.

The 1.2 mb/d Khurais project was inaugurated in 2009 and at the time represented the single largest field development in Saudi Aramco's history. The project's original design capacity was 1.5 mb/d; bringing on the additional 300 kb/d is expected to be relatively straightforward. The Shaybah development, currently capable of producing 750 kb/d of Arab Light, also has a higher design capacity of 1 mb/d.

The **UAE's** crude oil production capacity is forecast to rise by a net 530 kb/d to an average 3.23 mb/d by 2016. The country's current capacity target is 3.5 mb/d by 2019, delayed once again by one year from 2018, and from an original 2015 target.

A programme of seven projects is designed to add a gross 605 kb/d by 2016, with increased volumes from both the Upper Zakum and Lower Zakum fields accounting for half of the addition. Output from the Lower Zakum expansion is slated to start-up in 2012 following re-commissioning of production infrastructure mothballed in the 1980s. The remaining production increases will come from enhanced oil recovery (EOR) projects at mature onshore fields, some involving CO₂ injection.

Contracts have been awarded for the development of the offshore Umm Lulu and Nasr fields, with combined output of 160 kb/d. However, initial output of only 50 kb/d is scheduled to be brought online during our forecast time frame. A second development phase for the remaining production is not now scheduled until 2019.



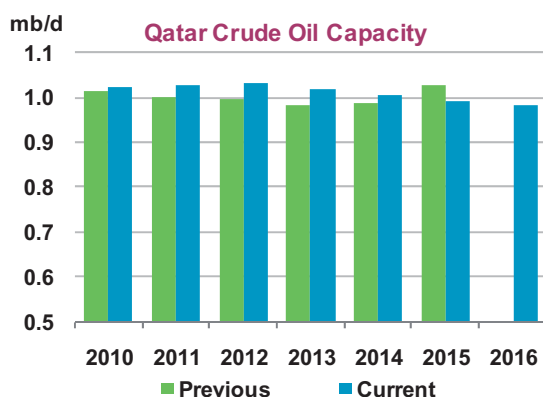
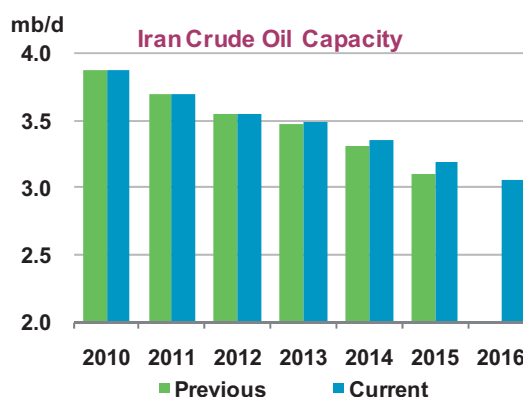
More than 20 years after the invasion by Iraq, **Kuwaiti** production capacity expansion plans remain at a standstill due to chronic political gridlock over the role of foreign investment. Capacity is forecast to rise by a modest 30 kb/d to 2.61 mb/d by 2016, significantly below the Kuwaiti government's 3.5 mb/d capacity target for this time frame. Despite higher production levels cited by officials, there is a lack of supporting information on field development specifics. As such we have not adopted these higher levels in our forecast. Only the small 90 kb/d GC-24 Sabriya field and enhanced oil recovery work at the Burgan field have been factored into our projection.

Kuwait's plans to increase capacity to 4 mb/d by 2020, which would focus on the development of fields in the northern region of the country, including the 270 kb/d Lower Fars heavy oil project, will require IOC involvement. To date it is still unclear if contracts will be offered to IOCs given the deep-seated divide at government level.

Qatar's crude production capacity is expected to hover around 1 mb/d over the forecast period, with most project work aimed at offsetting natural field decline. Expansion plans to 525 kb/d at al-Shaheen in 2010 fell well short of the target due to structural problems encountered with the field, with maximum capacity now seen at 450 kb/d. Instead, Qatar has awarded contracts for enhanced oil recovery projects aimed at maintaining capacity at the 250 kb/d Dukhan field and at the 120 kb/d Idd El Shargi North Dome field (ISND). The EOR projects are expected to maintain production capacity at current levels until about 2015, when a slight decline will set in.

Iran's oil industry is clearly under stress from further wide-ranging sanctions imposed by the international community in mid-2010. Crude oil production capacity is now forecast to decline by 810 kb/d, to 3.1 mb/d by 2016. With the exception of Chinese companies, most international operators have now completely withdrawn from the country. The much broader sanctions targeting financial transactions, including the banking and insurance industry, have largely choked off foreign investment as well as Iranian companies' ability to procure equipment and materials for their oil

projects. There are several projects coming on stream during the forecast period, include the 85 kb/d Yadavaran field in 2012, the 50 kb/d Paranj development in 2013 and the 120 kb/d Darkhovin field in 2016. However, planned additions fall well short of offsetting natural decline, which is conservatively estimated at 8-10% per year.

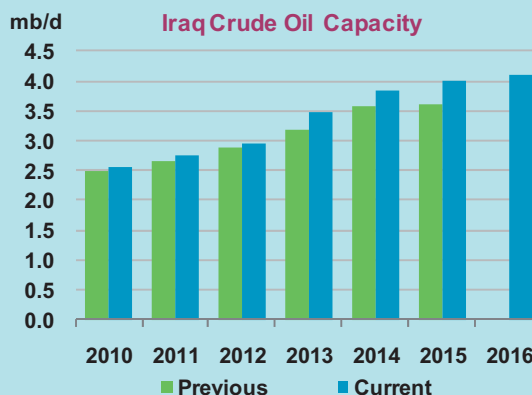


Constant management changes at both the oil ministry and at state oil company NIOC have also left the two key institutions short of experienced industry hands and long on political appointees. Ultimately, a financial imperative to reverse the production decline may emerge but, for now, relatively high oil prices are mitigating the impact of declining output. That said, our projections necessarily assume a continuation of the status quo over the forecast period.

Iraqi Production On a Solid Upward Trend

Iraq's crude oil production capacity is forecast to increase by 1.5 mb/d to 4.1 mb/d by 2016. This year's forecast has been revised up by around 170 kb/d compared with the December 2010 update as progress on a number of the 12 major joint venture projects awarded to IOCs under 20-year service contracts moves apace. In what is likely just the first milestone, first production from three key joint venture projects started flowing between end-2010 and 1Q11. The three upstream mega projects – West Qurna (+1.94 mb/d), Rumaila (+1.85 mb/d) and Zubair (+930 kb/d) – will account for more than 70% of the capacity increase.

At 4.1 mb/d by 2016, our capacity estimates are still below official projections. Industry participants are increasingly sceptical of official targets reaching 6.5 mb/d by 2014 and 12 mb/d by 2017. Indeed, in recent months government and company officials have been downgrading their estimates, with backroom discussions over the need to redraft the federal oil and gas law to include the contracts already awarded, renegotiate contracts to incorporate lower output levels and the working broaden time frames. At the 8 June 2011 OPEC meeting in Vienna Oil Minister Abdul-Kareem Luaibi suggested output targets could be extended to 13 to 14 years from the existing 6 to 7 years set out in the current



Iraqi Production On a Solid Upward Trend (continued)

IOC contracts. Among the many challenges, operating companies report operational problems from everything to chronic bureaucratic red tape in awarding contracts and processing work visas, to logistical import constraints of equipment, to a lack of skilled workers and local opposition to the projects on the grounds that the population is not receiving any benefit. On a broader scale, there are mounting concerns about security as the deadline for the withdraw of US troops nears at the end of 2011. In early June, Iraqi officials reported a rare bomb attack on key southern oil facilities, which included tanks at the Zubair storage facility. Companies have also reported that small acts of sabotage to oil facilities and infrastructure have increased in the past year, largely due to local discontent over the lack of employment opportunities being provided by the projects.

Moreover, while the early success of first production has been encouraging, given the new massive infrastructure requirements needed to support higher production levels, Iraq's outlook will crucially hinge on the corresponding timelines for a number of inter-related factors including refurbishing or building new water injection facilities, internal pipelines and export outlets. Two further, major risks to the forecast are the high costs and uncertain funding for the associated infrastructure. However, with project timelines slipping further and the lack of government financial resources to pay for the projects, the IOCs involved have now stepped in to shoulder costs over and above their contract obligations in order to kick-start progress. Details for key infrastructure projects such as water and gas reinjection facilities and a shared water injection plant, however, have yet to be worked out one year on. Moreover, the infrastructure projects currently under discussion are mostly designed only to support the first tranche of capacity additions.

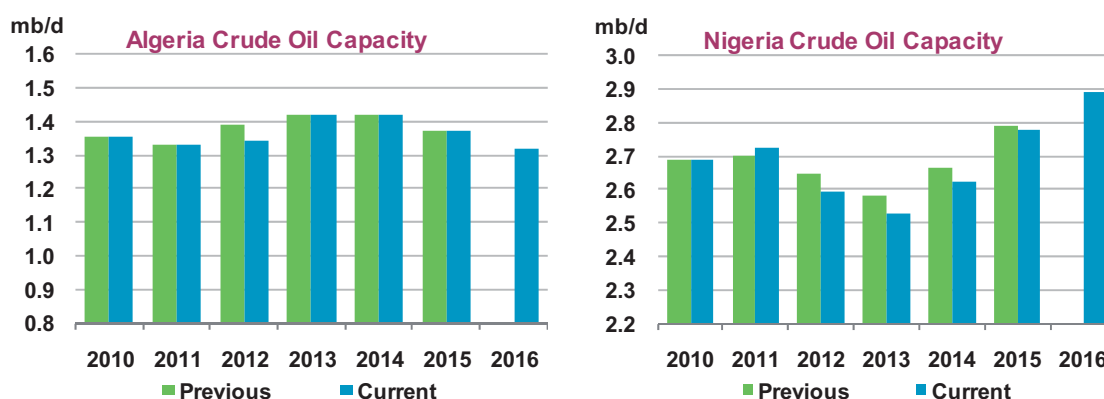
Near term, logistical constraints at the southern ports are expected to cap production increases until early-2012 and it is unlikely a significant increase in exports will be possible until 2013. Four single point mooring buoys (SPM), with a reported nameplate capacity of 900 kb/d each, are key to increasing southern export capacity but the projects have faced several delays. Two SPMs, with a combined capacity of 1.8 mb/d, are now mooted to be ready end-2011/early-2012 but concern centres on timely completion of needed infrastructure such as underwater pipelines linking them to the shoreline, which industry participants say may delay start-up until late 2012. The third SPM is officially slated for launch in 2012 but also appears unlikely until 2013 while contracts for the fourth SPM have yet to be awarded.

The 35-year-old Basrah Oil Terminal (BOT), which on paper can handle 1.4-1.5 mb/d, and the nearby 300 kb/d Khor al-Amaya port, are both regularly plagued by operational problems. As a result of export bottlenecks, near-term production capacity is likely to be constrained below 3 mb/d through 2012, but gradually ramp thereafter by 300 kb/d on average per year to 2016.

In the Kurdistan region, increased production from the Tawke and Taq Taq fields provided a boost to capacity in early 2011, reaching a combined 135 kb/d by April. However, it is still unclear how much the fields will contribute going forward, given the intractable debate over the legal status of contracts awarded by the Kurdistan Regional Government (KRG). The two fields were briefly brought online in mid-2009 but then shut-in after Baghdad said the contracts signed with the KRG were illegal. Since then some modest payments have been made to the companies, essentially just covering the operating costs for the barrels sold, not the market price Baghdad is collecting from buyers. Negotiations between Baghdad and the KRG over production sharing agreements signed with foreign operators are ongoing, but there is still no final deal. Deputy Prime Minister Hussain al-Shahristani has consistently argued that the existing contracts with the KRG would not be recognised by the government and that the production-sharing contracts awarded by the KRG must be converted into service contracts similar to those Baghdad has signed with IOCs.

OPEC's African Producers Challenged by Political Turmoil

OPEC's African member countries are confronted with formidable challenges over the medium term, none more so than Libya. Indeed, Libyan capacity is expected to hit a low point in 2011 before very gradually recovering in 2013, with capacity only reaching pre-crisis levels by 2015 (see '*Libya Faces a Long Haul to Restore Production Capacity*'). At the other end of the spectrum, Angola is on track to significantly ramp up capacity over the forecast period. Capacity for the four countries — Algeria, Angola, Libya and Nigeria — is on track to rise by around 880 kb/d between 2010 to 2016, to 8.8 mb/d. Angola provides more than 80% of this growth and Nigeria just over 20%, while Algeria posts a decline.



Algeria has largely been spared the internal political upheaval plaguing some of its North African neighbours, but the country's oil sector has only partially recovered from the massive corruption scandal that rocked the state oil company, Sonatrach, in January 2010. Crude oil production capacity is forecast to decline by 30 kb/d, to 1.32 mb/d during 2010-2016. Indeed, Algeria's award in March 2011 of only two out of ten permits in its last bidding round has reinforced views that the country may not have enough projects coming online to even maintain current production levels. This was the third bid round under the new law that imposed tougher financial terms, prompting lacklustre interest from IOCs.

The failure of the last round prompted at least one official to publicly recognise that the new tax terms pose a major obstacle for IOCs, which may lead to a review of contracts. Sonatrach has long struggled with IOCs, who argue the existing contract terms are unattractive, especially given the considerable technical challenges embedded in the EOR projects and demands that they use local service and equipment providers. Bureaucratic delays within Sonatrach appear to have become entrenched as new management grapples with institutional inertia, which is further delaying long-planned expansion projects.

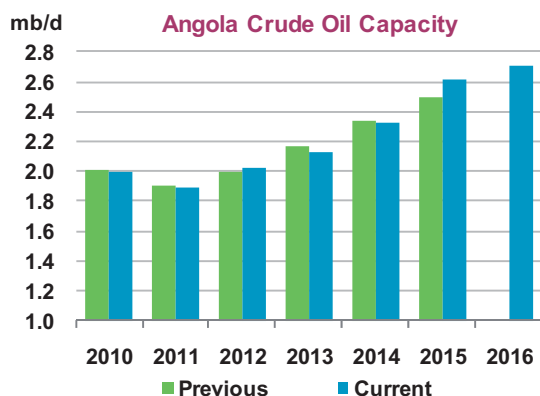
By contrast, **Nigeria's** political outlook has improved with the hard-won ceasefire agreement with the Niger Delta rebel groups holding and following the successful election process in April, which returned President Goodluck Jonathan to office. Nigerian capacity is expected to increase by 200 kb/d, to 2.89 mb/d by 2016. However, a key risk to the current outlook remains: final adoption

of the long, drawn-out and controversial 'Petroleum Industry Bill' (PIB). After endless meetings and reviews, indications are that companies now have a more positive view of the exhaustive legislation. As such, our forecast assumes that a favourable outcome will prevail for the IOCs operating in the country.

Nigeria has half a dozen 100 kb/d-plus projects, and a few smaller ones in the pipeline over the next six years, with a total gross peak capacity addition of 1 mb/d. The first mega project out of the gate is the Total-operated 180 kb/d Usan field, with first oil now scheduled for late 2011. Other major projects include:

- Bonga SW & Aparo fields in 2014 (140 kb/d);
- Egina field in 2014 (150 kb/d);
- Nsiko in 2015 (100 kb/d);
- Bosi fields in 2015 (135 kb/d); and
- Uge field in 2016 (110 kb/d).

Angola is expected to contribute the second-largest increment to OPEC production over the 2011-2016 period. The country's capacity should increase by 710 kb/d, to 2.7 mb/d. The outlook for higher oil prices appears to be a factor in advancing development plans, given the steep costs of deepwater production. However, a key issue that could derail our forecast is the government's requirement that joint ventures source more infrastructure, equipment and workforce locally. Problems finding suitable local partners given the high level of expertise needed for the complex ultra-deepwater projects has forced delays in the past. Nonetheless, although final investment decisions are still awaited on several projects at the tail end of the forecast period, approximately 13 developments are expected to deliver an additional gross 1.7 mb/d of peak capacity over the next six years.



Angola: Crude Oil Production Projects 2011-16

(In thousands barrels per day)

	Capacity	Start	Increment 2011-16
PAZFLOR	220	2011	220
PSVM	150	2012	150
Platino, Chumbo, Cesio	150	2013	150
Terra Miranda, Cordelia, Porti	150	2014	150
Mafumeira Sul	110	2014	110
Cabaca Norte-1	40	2014	40
Negage	50	2014	50
Lucapa	130	2014	100
Gindungo, Canela, Gengibre	200	2015	200
Other	425		425
Total	1735		1620

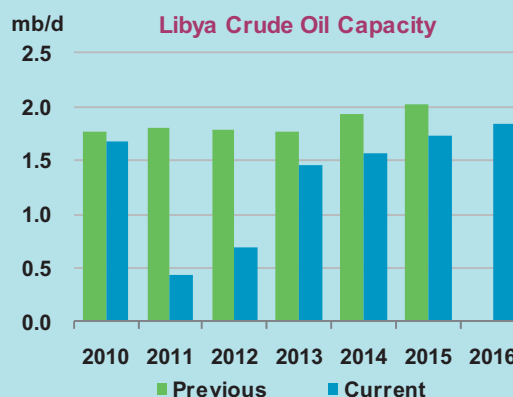
Libya Faces a Long Haul to Restore Production Capacity

The political uprisings across the MENA region have largely sidestepped the oil sector, excepting in Libya, where the oil industry has been profoundly impacted after four months of civil war. Hopes that a quick end to the unrest would leave the oil sector relatively unscathed have faded now. Indeed a long, protracted stoppage is looking increasingly likely.

Libya's crude production has now plummeted to under 200 kb/d from pre-crisis levels of 1.5-1.6 mb/d. Damage to infrastructure has been reported following numerous attacks by government forces on rebel-controlled oil fields and infrastructure, including shipping facilities, in the eastern region of the country. There has been limited information of any damage to oil fields in the western part of the country. However, with exports choked off by the conflict and the threat of punitive sanctions, current production controlled by the regime is likely minimal. Moreover, the haste with which the fields were shut-in will likely result in some longer-term damage to the wells and infrastructure.

For our outlook, we assume that production will be marginal for the rest of 2011, with the rebel-led National Transitional Council, now formally recognised by major international bodies, perhaps able to export some crude in coming months under NATO protection. We expect that more export supplies will become available as the situation at least stabilises in the eastern region, but with a very slow ramp-up in the country's production. By next year, the political dynamics should be settled, one way or another, and by 2013 capacity restored to just below pre-crisis levels, with a full recovery by 2015. That said, the rehabilitation of oil production capacity is expected to be painfully slow over a four-year period, for several reasons:

- The country's oil industry was highly dependent on foreign companies; many will be slow to return until the situation on the ground is completely safe;
- Much of the country's crude oil is waxy, which can cause significant damage to hastily shuttered equipment and wells if shut-in for a long period of time; and
- The existing contracts, which were already considered fairly unattractive by foreign operators, may need to be renegotiated.



Libyan Crude Oil Operations & Exports

Crude Stream	Terminal	Location	2010 Exports (kb/d)*	Operator
Es Sider	Es Sider	South Central	341	ENI/NOC
Amna	Ras Lanuf	Central East	217	NOC/PetroCanada/Wintershall
Bu Attifel/Zuetina	Zuetina	Central East	147	ENI/NOC & OMV Zuetina
Brega/Sirtica	Marsa al Brega	North Central	87	NOC
Sarir	Tabrouk	Central East	45	NOC
Total Eastern region			837	
El Shahara	Zawia	South West	206	Repsol/Total/OMV/Statoil
Al Jurf	Farwah FPSO	North West	28	NOC/Total/Wintershall
Bouri	Bouri	North West	48	NOC/ENI
Mellitah	Mellitah (Al Wafa)	Central West	154	NOC/ENI/KNOC
Total Western Region			436	
TOTAL CRUDE			1,273	

*Source: Lloyds Marine Intelligence

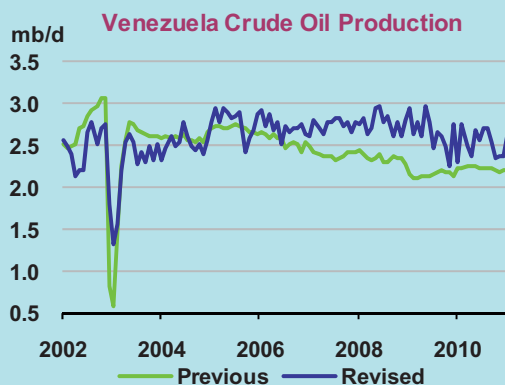
Venezuelan Baseline Supply Revisions

A baseline revision to Venezuela's crude oil production capacity profile over the 2002-2011 period has been included in this year's *MTOGM* projections. Persistent concerns have surrounded the accuracy of production and export data emanating from official sources, following a debilitating strike at Venezuela's state oil company in 2002. With wide divergence between official and third-party indicators, we have undertaken a comprehensive review of data sources and decided to switch from a monthly estimate based on a proxy for wellhead production, to an assessment that combines observed international imports of Venezuelan crude with domestic refinery runs – a proxy for the broader measure of crude oil supply.

The previous production assessment combined industry and government reports on activity levels at the four main Orinoco heavy oil production facilities, with estimates on prevailing trends in wellhead output from conventional assets in the Maracaibo basin and elsewhere. Regular soundings taken with industry, government and analytical sources over broad levels of Venezuelan supply led to observations that export levels were potentially higher than those implied by this wellhead proxy, and prompted our review of methodology.

We now base our monthly assessments on publicly reported Venezuelan crude oil flows into both OECD and non-OECD importing countries, plus refinery throughput data submitted to the Joint Organisations Data Initiative (JODI). OECD data is supplied by member countries to the IEA and non-OECD data for countries such as China come from official government publications. The Venezuelan government supplies monthly refinery throughput rates to JODI. As a result, we have made a baseline revision to data from 2002 to 2011, with supply over the 2002-04 period lowered on average by 100 kb/d and for the 2005-11 period increased on average by 300 kb/d.

Of course, questions over the completeness and veracity of the data for this new supply proxy remain. Official Venezuelan data continue to imply higher export levels than suggested here, but are not backed up by available import data. Moreover, the higher supply assessment we now incorporate for the 2006-2009 period sits in stark contrast to widespread service company reports of significant conventional crude output decline around Lake Maracaibo and in other areas. Nonetheless, we believe there are clear transparency benefits in this new approach to estimating Venezuelan supply.



Venezuela Crude Oil Production

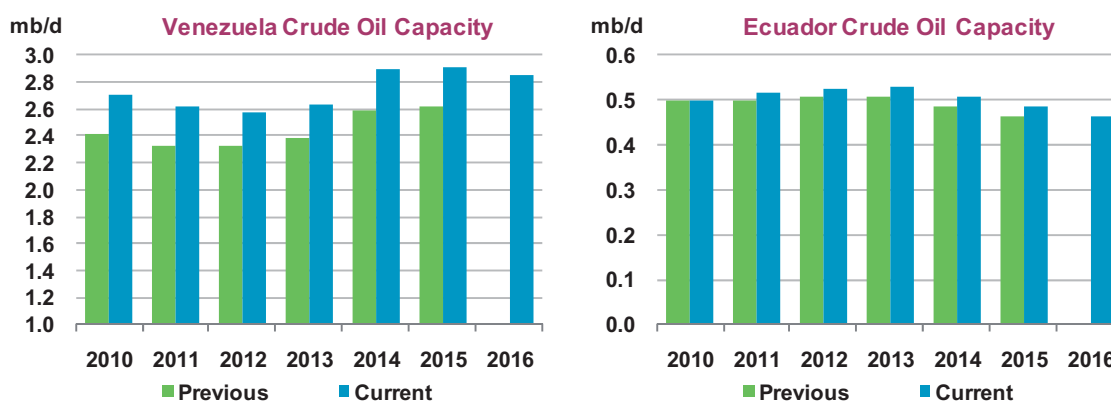
(In million barrels per day)

	2002	2003	2004	2005	2006	2007	2008	2009	2010
New Series									
OECD imports	1,676	1,587	1,738	1,761	1,702	1,699	1,541	1,443	1,293
Non-OECD imports	60	85	67	189	274	255	418	333	473
Refinery Throughputs*	800	651	807	927	807	786	816	892	750
Less Orimulsion	-101	-58	-90	-90	-58	0	0	0	0
Current Total	2,435	2,264	2,522	2,788	2,725	2,740	2,775	2,667	2,516
Previous	2,590	2,358	2,590	2,706	2,562	2,394	2,353	2,154	2,227
Revision	-155	-94	-68	81	163	346	423	513	289

* JODI refinery input data excluding heavy oil upgraders and NGLs

OPEC's Latin America Production Capacity Hit by Nationalisation

Venezuela has made considerable strides in locking in project developments in its massive Orinoco heavy oil belt with its oil-for-loan strategy. Approximately six key contracts, now in place, will eventually deliver a sharp 2 mb/d boost in gross capacity. However, a year after the initial contracts were signed, project timelines are still vague. New projects projected to come online during the forecast period will add 1.24 mb/d when at peak levels. However, with development programmes still in an early stage, we assume that new capacity will slowly start coming on in 2013, and that the bulk of the production will not be fully online until after the end of our forecast period. As a result, Venezuela's crude oil production capacity is forecast to rise by a net 140 kb/d, to 2.84 mb/d by 2016.



Ecuador embarked on yet another contract renegotiation period this past year, with a majority of IOCs now shunning the country altogether following the introduction of a new hydrocarbon law. The country's crude oil production capacity is expected to decline by 40 kb/d to 460 kb/d over the medium term. This is despite state-run Petroecuador having announced plans to increase capital spending to partially offset natural decline rates. In addition, the company late last year offered new service contracts for enhanced oil recovery (EOR) projects at mature fields in a bid to offset decline. By March, the energy ministry said it had received 11 bids and hopes to announce contract awards in July.

OPEC Gas Liquids Supply

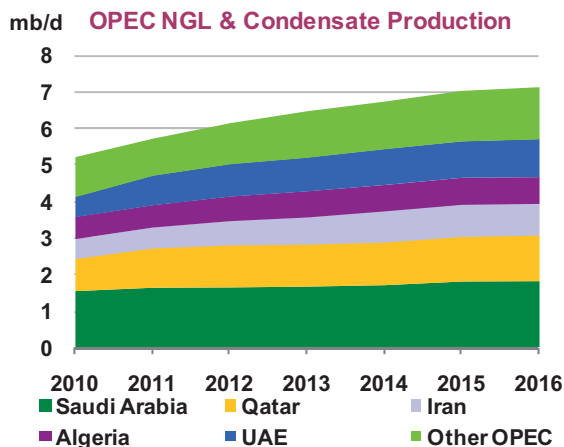
OPEC NGL and condensate production capacity is on course to rise by 1.9 mb/d, to 7.12 mb/d by 2016, largely unchanged from our December forecast. Middle East producers Qatar, Iran and Saudi Arabia and the UAE will provide 75% of the incremental supply. Notably, start-up of several new gas-to-liquids (GTLs) plants will drive non-conventional supplies up by 42%, to 286 kb/d by 2016. Runaway domestic demand for natural gas as a fuel for utilities, water desalination plants and industrial needs in the Middle East is behind the rapid growth in NGLs. Increasing demand for gas to maintain pressure at mature fields, especially in Iraq and the UAE, has also fuelled the NGL boom.

The **UAE** heads expected incremental supply this year due to a number of major start-ups. However Saudi Arabia and Qatar remain the largest producers. The UAE's NGL capacity is forecast to increase by 476 kb/d, to just over 1 mb/d by 2016. The start-up of the Habshan condensate and NGL projects in 2010 will add a combined 240 kb/d to capacity, followed by the 120 kb/d Integrated Gas Development (IGD) project in 2013.

Qatar is on target to increase its condensate and other NGL supply by around a net 350 kb/d to 1.26 mb/d by 2016, following the start-up of its last LNG train earlier this year. Qatargas 4, Train 7 was commissioned in 1Q11 and Qatargas 3, Train 6, was launched in October 2010. Commissioning of the 140 kb/d Pearl 1 GTL project also got underway earlier this year (although this is included in non-conventional oil supply rather than NGL estimates).

Saudi Arabia remains the largest OPEC supplier of NGLs, with growth of around 275 kb/d, to 1.8 mb/d, expected over the 2010-2016 period. About half of the increase will come from projects already in production as they ramp up to peak capacity. The next major increase will be launched in 2014, with the start-up of the massive 264 kb/d Shaybah NGL development. The smaller Hasbah project is also scheduled to come online in 2014, with production capacity around 30 kb/d of natural gas liquids. The Manifa project, expected online starting in 2013-14, will also add 65 kb/d of condensate.

Running counter to the dismal outlook for **Iran's** crude oil production, the country's gas liquids capacity is in on course to post steady increases over the 2011-16 period, largely because projects already long in the pipeline will add to incremental growth. Iranian condensate and NGLs are set to rise by around 340 kb/d to 868 kb/d by 2016. The forecast is about 100 kb/d below last year's equivalent, which had already been adjusted down due to expected delays, following the implementation of tougher sanctions by the international community.



Estimated OPEC Sustainable Condensate & NGL Production Capacity

(In thousand barrels per day)

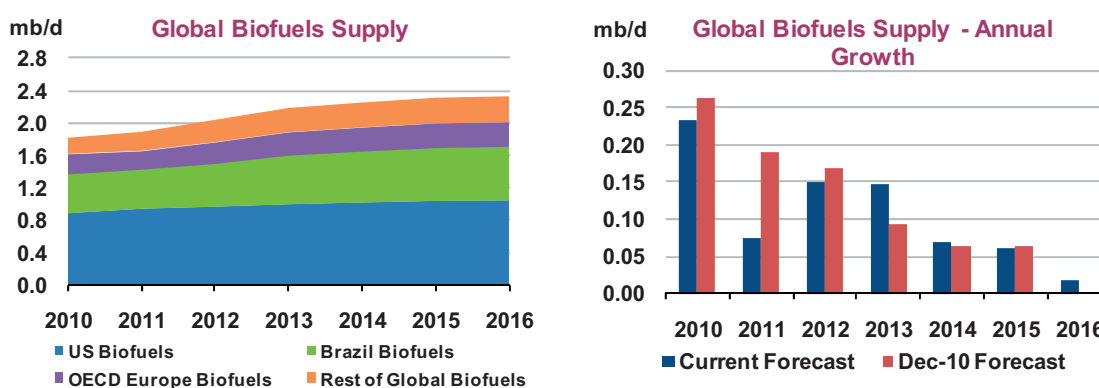
	2010	2011	2012	2013	2014	2015	2016	2010-16
Algeria	610	616	674	718	721	738	733	123
Angola	90	90	125	132	128	130	126	36
Ecuador	2	1	1	1	0	0	0	...
Iran	531	565	658	737	852	878	868	338
Iraq	56	59	64	68	73	79	79	23
Kuwait	200	210	238	328	345	350	345	145
Libya	111	18	25	59	85	152	196	84
Nigeria	412	414	447	461	443	441	451	39
Qatar	902	1,093	1,167	1,166	1,179	1,232	1,255	354
Saudi Arabia	1,550	1,641	1,650	1,672	1,712	1,813	1,824	274
UAE	555	809	886	918	979	992	1,031	476
Venezuela	211	213	213	214	215	216	216	5
Total OPEC NGLs	5,229	5,729	6,148	6,473	6,733	7,022	7,125	1,895
Non-Conventional*	119	152	182	212	238	286	286	167
Total OPEC	5,348	5,881	6,330	6,685	6,971	7,308	7,411	2,062
Increment	418	533	449	356	286	337	102	

* Includes gas-to-liquids (GTLs).

BIOFUELS

Note: Biofuels data in the MTOGM are expressed in volumetric terms. Exceptions will be noted where volumes are adjusted for energy content versus corresponding fossil fuels.

- **Biofuels production is expected to grow by 0.5 mb/d over the medium term**, with volumes rising from 1.8 mb/d in 2010 to 2.3 mb/d in 2016. This growth, while still robust, is slower than the 0.8 mb/d growth for 2009-2015 envisaged in the December 2010 update, partly due to the strength of 2009-2010. Adjusted for *energy content* versus oil, biofuels supply increases from 1.3 mb/d in 2010 to 1.7 mb/d in 2016.
- **Downward revisions, mostly in Latin America and Europe, curb 2011 output by 115 kb/d** versus the December update, while 2010 assessments remain unchanged. Global production from 2012-2015 is seen 95 kb/d lower, mostly due to Brazil and Europe, while upward revisions from North America and other Latin America provide some offset. The US and Brazil still dominate absolute production (together 73% of world supply in 2016), but growth in the latter is increasingly at risk.
- **Advanced biofuel production is projected to increase over the medium term**, with capacity rising from around 20 kb/d in 2010 to potentially 100-130 kb/d in 2016. Despite many projects on the drawing board, the outlook remains highly volatile, with little commercial production expected even in the face of rising US mandates. Nevertheless, advanced biofuels will likely play a crucial role in *long-term* efforts to decarbonise transport fuels.



Despite Strong Growth, Biofuels Supply Assessment Downgraded

Dramatically rising oil prices since our last forecast in December 2010 would seemingly be a boon to biofuels production going forward. Indeed, from 2010-2016, we forecast that biofuels output will rise by 0.5 mb/d, a near 30% increase. This represents slower growth than the 0.8 mb/d increase for 2009-2015 that we envisaged in December. To be sure, part of the difference stems from the omission of 2009-2010's strong growth in the current forecast. Yet, market conditions have also become more challenging – tighter agricultural feedstock supplies and higher costs have reduced competitiveness versus fossil fuels, even with high oil prices, undermining production in Brazil and Europe in particular. Meanwhile, the extension of our forecast to 2016 further highlights limitations in the industry's ability to meet mandates for difficult-to-produce advanced biofuel supplies.

Biofuels will still help satisfy a significant part of oil demand growth, though less than previously. From 2004-2010, biofuels supply growth, *on an energy-adjusted basis*, met 23% of global incremental gasoline and gasoil demand, with ethanol at 48% of gasoline and biodiesel at 10% of gasoil growth. From 2010-2016, with combined gasoline and gasoil demand growing by 4.3 mb/d, biofuels supply growth should meet only 9%, with ethanol constituting 24% of gasoline and biodiesel accounting for 4% of gasoil growth. By 2016, ethanol and biodiesel should displace 5.3% and 1.5% of total global gasoline and gasoil demand, respectively, on an energy content basis.

World Biofuels Production

(thousand barrels per day)

	2010	2011	2012	2013	2014	2015	2016
OECD North America	909	971	999	1,030	1,052	1,073	1,079
United States	882	938	964	994	1,017	1,036	1,042
OECD Europe	246	228	264	286	296	302	303
OECD Pacific	12	12	14	14	16	16	16
Total OECD	1,167	1,211	1,277	1,330	1,364	1,391	1,397
FSU	6	6	9	10	10	10	10
Non-OECD Europe	4	4	4	5	5	5	5
China	47	50	54	57	58	61	61
Other Asia	42	57	75	88	91	93	96
Latin America	550	562	617	693	723	748	757
Brazil	492	492	537	610	638	662	671
Middle East	0	0	0	0	0	0	0
Africa	3	6	8	9	11	14	14
Total Non-OECD	653	685	768	862	898	931	942
Total World	1,820	1,895	2,045	2,192	2,262	2,322	2,340
World - Revision vs Dec 2010	-3	-116	-136	-82	-76	-81	

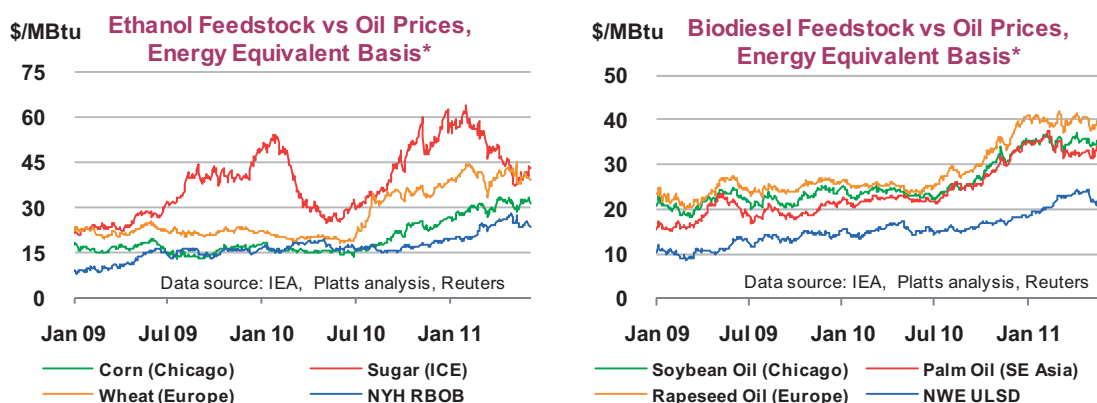
The lower profile for biofuels stems from a 115 kb/d downward revision for 2011. The growth pattern has also changed. Increases in 2011-2012 have slowed due to tough economics, but with potential margin improvements ahead, growth is revised up in 2013 and 2014. Changes stem from less favourable outlooks in Brazil, Europe and Asia, partly offset by higher US and Argentine output.

As in previous updates, forecast revisions stem from a reappraisal of our capacity-driven model and expectations of utilisation rates. Given their small and fragmented nature, biofuels plants are difficult to track. The industry also remains a volatile one, fraught with company exits and consolidations. Still, smaller capital requirements and shorter construction lead times mean biofuels capacity can quickly change in response to market conditions. As such, while we conservatively scrutinise future plants, we err on the side of allowing potential capacity to grow faster than output.

Ever-Present Feedstock Price Risk, Though Policy Support Persists

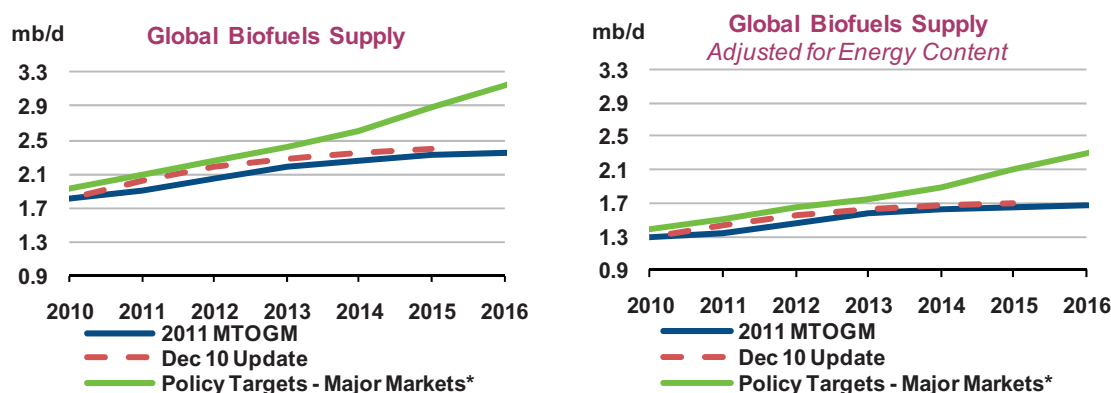
Due to rising agricultural feedstock prices, biofuels production growth is expected to slow in 2011, despite a crude price assumption of \$105/bbl. Difficult weather conditions, strong emerging market demand, usage from the biofuels industry itself and increased energy costs have all tightened balances in many commodities. Translating these higher agricultural prices into energy equivalent volumes of produced liquid fuels shows a wider gap between biofuel and fossil fuel economics from

2H10 onwards. While, these feedstock values are indicative and do not reflect local price or operating cost differentials nor offsetting revenues derived from other sources, they do show a *relative* loss of competitiveness for many processes, particularly sugar cane ethanol.



* Agricultural prices expressed in terms of the energy value of liquid fuels – ethanol or biodiesel – produced. Values do not reflect local price or operating cost differentials nor revenues from co-generation or by-products such as dried distillers grains.

This report does not attempt to forecast agriculture fundamentals or prices. However, it is important to note that agricultural markets have already begun to adjust. High prices have created incentives for farmers to increase plantings, with some market sources pointing to easing sugar and grain markets over the next year. To be sure, weather risks remain, as shown by recent flooding in the US Midwest, drought in Europe and heavy April rains in Brazil, and feedstock prices will likely remain volatile. Nevertheless, we assume that agricultural markets will balance themselves over time and that conversion costs will continue to fall, factors that are supportive of increased biofuels production over the medium term.



*Implied output from national level usage and/or production targets in the US, Canada, Brazil, Argentina, Colombia, Peru, the European Union, Japan, Korea, Australia, China, India, Indonesia, Malaysia and Thailand.

Government policies – blending mandates, production subsidies and blenders' credits – provide another support. In an environment of fiscal austerity, financial incentives are increasingly at risk, particularly in the US. However, mandates/targets continue to rise, with Argentina, Canada, Thailand, Peru, Malaysia and Germany all increasing required blending volumes. Notably, the fulfilment of government usage targets as they currently stand versus our demand forecast suggests production upside. Our 2010-2016 growth of 520 kb/d undershoots by 670 kb/d the potential supply increases,

were national level policy targets in major biofuels markets to be met. Yet, combined with challenging economics, other policy actions – concerning sustainability, domestic pricing, advanced biofuels, food security, technical specifications and infrastructure – limit potential output.

Regional Outlook

OECD North America

Upward revisions in North America stem from a higher US ethanol baseline and a slightly more optimistic US biodiesel assessment, partly offset by slightly lower Canadian ethanol and biodiesel. US ethanol production is expected to average 900 kb/d in 2011, about 10%, by volume, of gasoline demand. The approval of E15 by the EPA for post-2000 vehicles has opened the way for conventional ethanol blending to reach its mandate of 980 kb/d in 2016. In practice, however, nationwide uptake of E15 by retailers is likely to be slow as an array of technical and logistical hurdles are confronted. Still, individual states may speed things up – Iowa is considering a bill that offers misfueling liability protection, as well as an E15 sales tax credit to retailers.

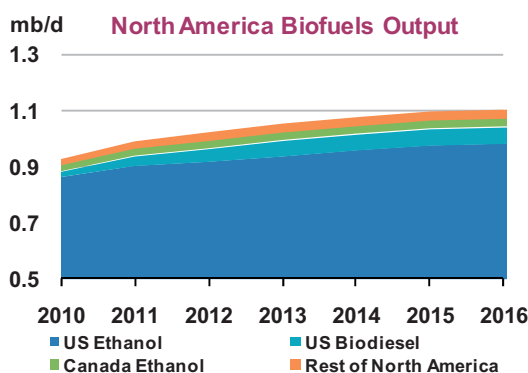
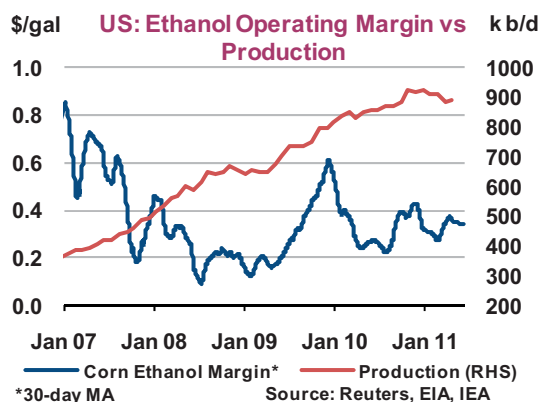
US Renewable Fuel Standard: Mandated Biofuel Volumes

(thousand barrels per day)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Renewable biofuel	585	685	783	822	859	900	939	978	976	978	978	978	976	978	978
Advanced biofuel	0	39	62	88	130	179	245	359	472	587	718	848	976	1,174	1,370
Cellulosic Biofuel	0	0	0	0	33	65	114	196	276	359	457	554	683	881	1,044
Biomass-based Diesel*	0	33	42	52	65	0	0	0	0	0	0	0	0	0	0
Undifferentiated Advanced Biofuel	0	7	19	35	33	114	130	163	195	228	261	294	293	294	326
TOTAL RFS	585	724	845	910	989	1,080	1,184	1,337	1,447	1,566	1,696	1,826	1,952	2,153	2,348

* Biomass-based diesel standard was combined for 2009/2010

Meanwhile, ethanol supply volume increases will likely be exported and absorbed by a growing domestic fleet of flex-fuel vehicles. In 2010, the US – previously a net importer – exported about 25 kb/d, with volumes rising to 50 kb/d in 1Q11. About 30% of exports in 2011 have gone to Canada, where the introduction of an E5 mandate has spurred demand.

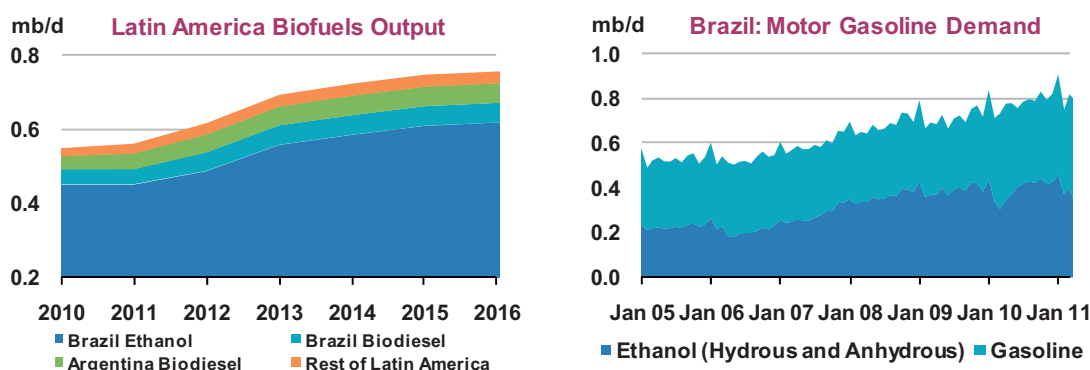


Potential financial incentive changes and the sourcing of advanced biofuels cloud the US production outlook, however. Both the blenders' tax credit (for ethanol and biodiesel) and tariff against imported ethanol are under increasing scrutiny. The current regime will expire at end-2011 and future incentives may be phased out over time. While inducements to produce advanced biofuels look safe, it is unlikely that the US will meet its own blending targets, at 470 kb/d in 2016, for this category. Overall, developments in cellulosic ethanol and advanced biodiesel have proceeded slowly

(see *Advanced Biofuels to Play Important CO₂ Reducing Role... In the Long Run*); US and Canadian capacity in these fuels may reach only 50-70 kb/d by 2016. Meanwhile, Brazilian ethanol imports, categorised as ‘advanced’ under US requirements, may fail to materialise, even without the tariff.

Latin America

Downward revisions to Brazilian ethanol production, averaging -95 kb/d for 2012-2015, represent the largest change in our outlook. With challenging weather and high sugar prices, output is expected to remain flat in 2011, at 450 kb/d. While surging gasoline demand and flex-fuel vehicle sales seemingly bode well for consumption, Brazil’s uneven pricing policy – which limits pass-through of crude prices to retail gasoline prices, while letting ethanol prices move with market conditions – creates demand uncertainty and a disincentive for producer investment. Moreover, it appears that distillery builds and expansions are proceeding slowly, with higher capital costs and increased permitting requirements, reportedly increasing new-build lead times to 3-4 years, from 2-3 years in 2007.

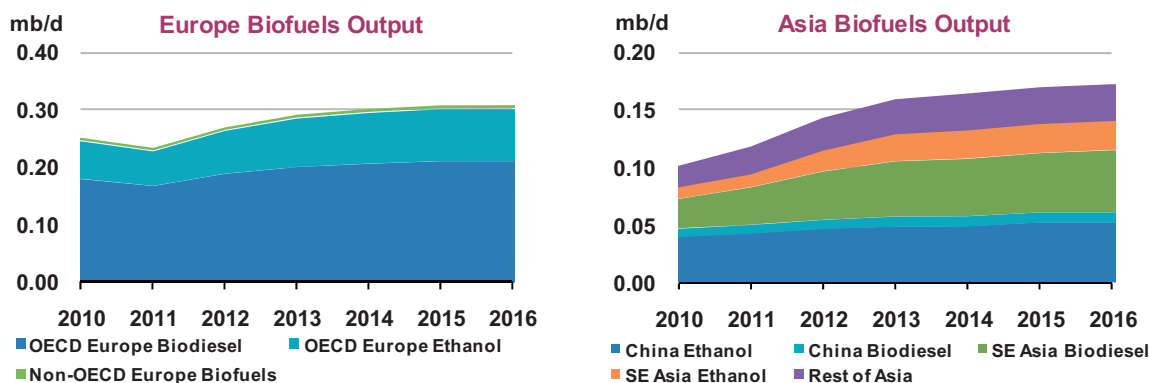


Output should still grow over the medium term, though supply will struggle to keep pace with demand, with shortages potentially emerging. The government is planning to offer subsidised credit lines to encourage the replanting of less productive cane fields, but uncertainty over sugar balances ahead presents a clear downside risk to the production forecast. With the designation of ethanol as a ‘strategic fuel’, ANP, the hydrocarbon sector regulator, may align stock-holding and distribution practices with those of gasoline to reduce supply volatility. In addition, state-run development bank BNDES has announced financing to increase cane production while Petrobras has indicated it will increase distillery capacity, with a production target of 45 kb/d (2.6 bn litres) by 2014. Meanwhile, the wider regional picture looks more optimistic, guided by higher baseline biodiesel production in Argentina and Colombia. Outside of Brazilian ethanol, other Latin American biofuels are expected to grow from 100 kb/d in 2010 to 140 kb/d in 2016.

OECD Europe

With lower-than-anticipated 2011 output (revised down by 35 kb/d), the biofuels outlook for OECD Europe has weakened. The EU maintains a mandate of 10% renewable energy in transport by 2020, but weak economics and sustainability concerns cloud the supply picture. In the near term, surging wheat prices have sapped ethanol production margins and have prompted the idling of Europe’s second largest plant – Ensus’ 7 kb/d (400 ml/y) distillery. The demand boost (~25 kb/d) from Germany’s switch from E5 to an E10 blend has only partially materialised due to consumer aversion to the fuel and the region as a whole maintains an overall declining oil demand profile.

All the while, the industry remains in limbo due to the uneven application of sustainability criteria, which, amongst other environmental restrictions, require biofuels to be certified as generating greenhouse gas savings of at least 35% versus fossil fuels. So far, only Germany, Austria and Sweden have implemented the schemes, but the European Commission (EC) is currently publishing seven certification systems, which should spur adoption by other member states. Nevertheless, sustainability concerns may crowd out production further down the line, with the EC due to tighten criteria based on results of indirect land-use change studies. While advanced biofuels and sugar-based ethanol still look viable on sustainability grounds, less efficient processes of wheat ethanol or biodiesel may be at risk, potentially undermining already sluggish production and investment.



Asia-Pacific

The Asian biofuels outlook has been revised down by 10 kb/d from 2011-2015, with both a lower baseline and a lower capacity assessment going forward. The picture in China has changed little – the country remains Asia’s largest producer, but the government’s strategy to restrict additional production to non-grain sources will keep a limit on growth until commercial breakthroughs are made in advanced biofuels technology.

Meanwhile, Thailand posts the largest downward revisions due to a lower biodiesel capacity assessment and weaker baseline ethanol production. Still, production potential for Thai biofuels remains strong, particularly with higher molasses production expected ahead, steadily increasing blending mandates and preferential pricing at the pump. By comparison, ample capacity and rising mandates are not enough to spur significant growth in India – government allocations of ethanol towards the country’s E5 programme continue to fall short of requirements and price/policy discrepancies between states impede the ability of the market to deliver sufficient volumes.

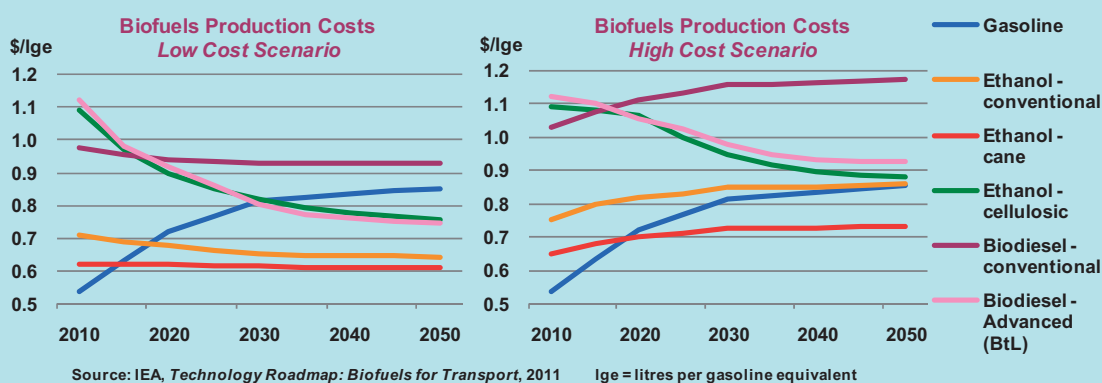
In Malaysia, a 5% biodiesel mandate is making a staggered start, helping to boost domestic demand. The government aims to keep prices competitive at the pump with diesel, which is subsidised, by dropping a biodiesel sales tax. Indonesia will also see increasing production and mandates for both ethanol and biodiesel. Nevertheless, biodiesel utilisation in both countries will remain weak, with strong palm oil prices and still overall tepid regional demand. The start of Neste’s renewable diesel plant (15 kb/d) in Singapore represents a big production addition, yet may also dampen regional margins by tightening feedstocks and crowding out exports to Europe or North America.

Advanced Biofuels to Play Important CO₂ Reducing Role... In the Long Run

In the long-term, augmenting the sustainability of transport fuel will require significant volumes of advanced biofuels³. The IEA's *Technology Roadmap: Biofuels for Transport* sets a biofuels supply target of 750 Mtoe (15+ mb/d or 27% of transport demand), much of it advanced, which would contribute 20% (2.1 Gt) of the CO₂ emissions reductions envisaged for the transport sector by 2050. By 2016, this vision would require some 225 kb/d (gasoline equivalent) of global advanced capacity. The US, itself, has a 2016 volumetric blending obligation of 280 kb/d of cellulosic biofuel. Moreover, the EU's blending incentives have advanced biofuels counting double towards reaching a 2020 target for 10% renewable energy in transport.

Nevertheless, the medium-term outlook remains highly uncertain, notably regarding financing and production economics. With little access to project finance, due to their risky nature, and oil majors and venture capital only partially filling investment needs, many producers depend upon government loan guarantees and grants (the US and EU both play large supportive roles). So far, it appears advanced biofuels have escaped budget cutting initiatives, but fiscal austerity remains a risk.

Moreover, producers face the challenge of reducing capital requirements, improving conversion efficiency and sourcing feedstocks. IEA cost estimates indicate that advanced biofuels such as cellulosic ethanol and biomass-to-liquids (BtL) diesel may reach parity with fossil fuels only by 2030 as scale and efficiency increase. Sustained high oil prices above \$120/bbl (real), corresponding to gasoline at \$0.85/litre in 2050, may help speed this convergence. This low-cost scenario assumes no strong feedback between higher oil prices and biofuels production costs. Yet, under a higher cost scenario, where oil price rises are accompanied with increased agricultural prices (as currently), competitiveness would shift further out.



Individual producers may indeed achieve cost breakthroughs before that, but it is unlikely that major commercial volumes will materialise over the medium term. At the end of 2010, advanced biofuels capacity stood around 20 kb/d, with Neste's BtL plant in Singapore accounting for the bulk of this. Based on announced projects, this report sees the potential for only 100-130 kb/d (6-8 bn litres/year) of global capacity by 2016 – slightly down from our assessment a year ago – with 60% in advanced biodiesel and 40% in cellulosic ethanol. However, given the industry's volatile nature and limited operational history, many of these facilities may experience delays, cancellations or ramp up with very low utilisation rates.

³ Advanced biofuels technologies are conversion technologies still in the research and development, pilot or demonstration phase, commonly referred to as second- or third- generation. This category includes hydrotreated vegetable oil (HVO), which is based on animal fat and plant oil, as well as biofuels based on lignocellulosic biomass, such as cellulosic ethanol, biomass-to-liquids (BtL)-diesel and bio-synthetic gas (bio-SG). This category also includes novel technologies that are mainly in R&D and pilot stage, such as algae-based biofuels and the conversion of sugar into diesel-type biofuels using biological or chemical catalysts.

CRUDE TRADE

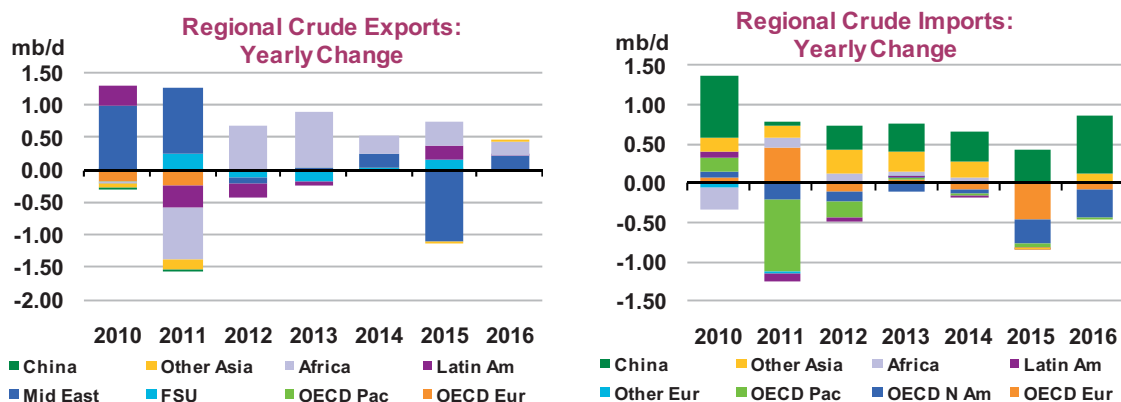
Summary

- **Global inter-regional crude trade is expected to rise by 1.0 mb/d during 2010-2016, to 35.8 mb/d.** Trade volumes are lower than those presented in the June 2010 *MTOGM* with both annual growth and 2015 exports trimmed significantly. This difference stems from a higher proportion of refinery capacity expansions in producing regions, with the assumption that more oil will be refined domestically.
- **However, the trade in crude oil will continue to become more globalised** as net-exporters continue to diversify away from ‘traditional’ OECD markets into lucrative Asian markets. The Middle East will remain the key supplier, accounting for 47% of global exports in 2016.
- **The OECD is expected to reduce its import requirement by 2.6 mb/d over the forecast period,** due to lower demand, refinery closures and slightly higher domestic upstream supply prospects. In contrast, **the non-OECD is anticipated to hike its imports by 3.6 mb/d,** with 63% and 28% of growth accounted for by China and Other Asia, respectively.

Overview and Methodology

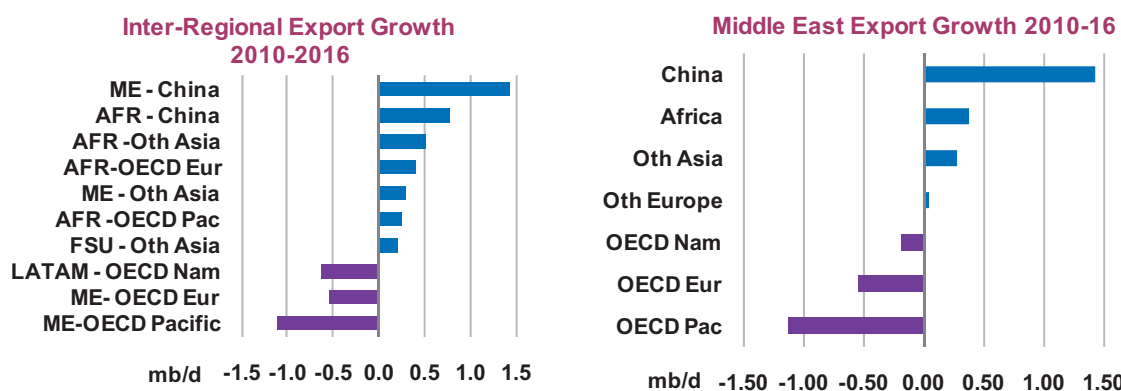
As in previous reports, crude trade has been modelled as a function of projected oil production, demand growth and refinery utilisation rates with incremental supplies being allocated on expectations of refinery capacity expansions. On this basis, inter-regional exports of crude oil have been estimated to rise by 1.0 mb/d from 34.8 mb/d in 2010 to 35.8 mb/d in 2016, equating to 0.4% compounded annual growth. This is significantly weaker than the 1.5% annual growth presented in our previous outlook, albeit that projected from the low recessionary 2009 baseline. Moreover, due to refinery capacity expansions outpacing supply growth across many net crude exporting regions, global crude trade is now seen at 35.4 mb/d in 2015, a downward revision of 1.1 mb/d compared to the 2010 *MTOGM*. It is therefore assumed that these regions will preferentially refine their oil domestically, either to satisfy demand or to export as products. Implicitly this suggests a proportional shift from crude to products trade compared with current patterns.

The Middle East remains the key oil exporting region, supplying 16.7 mb/d, or 47% of global crude trade in 2016. Despite the Libyan conflict, Africa is anticipated to consolidate its role as the world’s second-largest swing supplier over the forecast, with a 25% market share (8.8 mb/d) by 2016. FSU exports are expected to remain between 6.6 mb/d and 6.9 mb/d during 2010-2016; therefore its share of the market is likely to stagnate at approximately 19%. In contrast, shipments from Latin America are seen falling by 400 kb/d as local refinery capacity growth outpaces incremental production. Exports from the region are estimated at 2.6 mb/d in 2016, a 7% market share and a fall of 2% compared to 2010. In 2010 and 2011, the main source of regional crude export growth is the Middle East, but from 2012 onwards Africa takes over as the dominant growth source. Long-haul seaborne routes from the Middle East and Africa into Asia are set to be the main sources of growth, while shipments into the OECD exhibit the largest contractions.



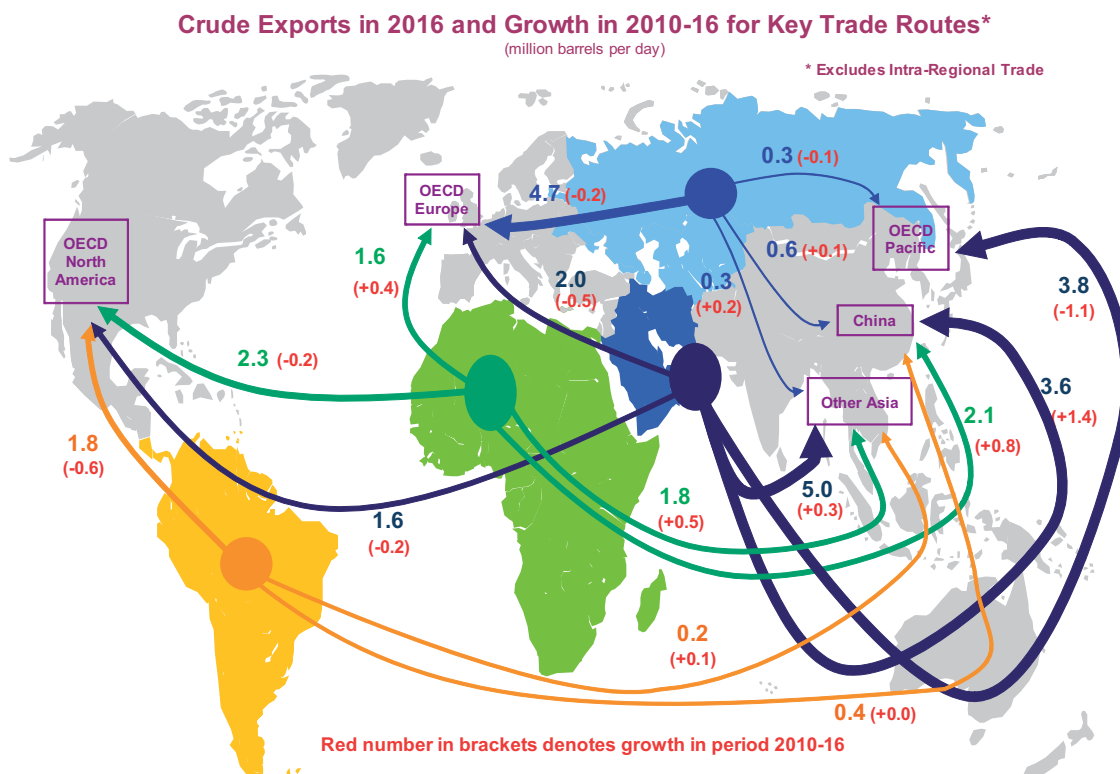
Regional Trade

The Middle East retains its role as swing supplier, with all incremental supplies absorbed by Asia. Exports will rise from 16.4 mb/d in 2010, peaking at 17.6 mb/d in 2014 and then tailing off to 16.7 mb/d by 2016. The post-2014 decline is attributed to the rapid expansion of the Saudi Arabian refining sector, which will likely divert crude otherwise exported. Other Asia is projected to replace the OECD Pacific as the largest buyer of Middle Eastern crudes in 2011, and will import over 5 mb/d by 2016. By contrast, OECD Pacific, OECD Europe and OECD North America are all likely to reduce their imports of Middle Eastern crudes, by 1.1 mb/d, 0.5 mb/d and 0.2 mb/d, respectively. The drivers for this trend differ from region to region, with the OECD Pacific and Europe set to cut refining capacity and import more African supplies, whereas OECD North America should reduce its crude import requirement in response to increasing regional supply. In comparison, China displays the strongest growth in Middle Eastern imports and is expected to augment its intake of these crudes by 1.4 mb/d, reaching 3.6 mb/d in 2016.



Africa is expected to consolidate its position as the number two swing producer over the forecast. Although exports should decline in 2011 due to the Libyan conflict, they are anticipated to rise from 2012 as production in Angola and Nigeria ramps up. The region is projected to have the strongest annual growth (3.0%) of all net exporting regions, and flows are estimated to grow by 1.6 mb/d from 2010 to 8.8 mb/d by 2016. Although OECD North America is seen to remain the region's largest

customer, its imports are projected to fall by 170 kb/d during 2010-2016. The majority of incremental supplies will be absorbed instead by Asia, with 800 kb/d and 500 kb/d extra respectively heading to China and Other Asia in 2016. OECD Europe is also expected to receive an extra 400 kb/d by 2016, as the region seeks to replace its declining domestic production and reliance on Middle Eastern producers.



FSU exports are projected to remain stable, increasing by a modest 100 kb/d over the forecast and reaching 6.7 mb/d by 2016. As with the previous outlook, the FSU is expected to continue to diversify export destinations, with 1.4 mb/d anticipated to head to Pacific Rim countries by 2016, while less oil should go to the traditional destination of OECD Europe. A key driver of this trend is the East Siberian to Pacific Ocean pipeline (ESPO), which Russia has built to facilitate the development of remote fields and its expansion into lucrative Asian markets. Spot ESPO crude has gained a foothold in Pacific Rim markets, and current pipeline capacity of 600 kb/d should increase to 1.0 mb/d upon completion of its Phase-2 expansion in 2013. The mooted Phase-3 expansion to over 1.6 mb/d has not been included, since it likely falls outside the forecast. Following the 2011 start-up of the Skovorodino to Daqing ESPO spur, China currently imports 300 kb/d of Russian ESPO crude and supplements this with supplies from other FSU producers and the occasional ex-Kozmino ESPO spot cargo. By 2016 its imports from the FSU are projected to grow by a modest 100 kb/d, with supplies augmented from its interests in Kazakhstan. Regardless of the FSU's efforts to diversify its customers, OECD Europe is expected to remain the largest taker of FSU crudes, receiving 4.7 mb/d in 2016, a 200 kb/d drop from 2010 levels, with another 400 kb/d being sent to non-OECD Europe.

Latin America is the only net exporting region where shipments are projected to contract over the forecast. Exports are set to fall by 400 kb/d from 3.0 mb/d in 2010 to 2.6 mb/d in 2016. Rising production, notably from Brazil, will be outpaced by rapidly expanding refining capacity as the region strives to become self sufficient and reduce expensive product import bills. Continued sales to Asian customers will be enabled by lower deliveries to OECD North America, which plummet by 600 kb/d by 2016 as local production increases. Regardless, OECD North America will continue to be the region's largest customer, taking an estimated 1.8 mb/d in 2016. China and India are expected to import 400 kb/d and 200 kb/d, respectively, by 2016, partly as complex new refining capacity absorbs incremental heavy/sour Venezuelan barrels from the Orinoco Belt. These flows will also be facilitated by the Panama Canal expansion, currently due to be completed in 2014, decreasing journey times and permitting larger Suezmax sized vessels to pass from the Atlantic to the Pacific basin.

Non-OECD importers are anticipated to increase their share of global crude imports from 36% in 2010 to 45% in 2016, in line with the previous forecast. During 2010-2016 imports will grow from 12.6 mb/d to 16.1 mb/d. Driven by strengthening demand, China and Other Asia account for an impressive 63% and 28% of absolute growth, respectively. China's import requirement is expected to climb from 4.5 mb/d in 2010 to 6.7 mb/d in 2016 while imports into Other Asia rise from 6.6 mb/d in 2010 to 7.6 mb/d in 2016. In contrast, OECD imports contract from 22.2 mb/d in 2010 to 19.7 mb/d in 2016, amid declining demand in all regions. OECD Pacific and OECD North America see the sharpest falls, on refinery closures and higher production respectively. European imports decline less sharply as the region seeks to replace declining domestic production.

The crude freight market will be underpinned by the expected 1.0 mb/d growth in global crude trade, equivalent to 15 extra VLCCs per month in 2016 when compared with 2010. Additionally, the increasing importance of long-haul routes such as trades into Asia from Latin America, the Middle East and Africa, will likely increase journey times and thus the demands on the fleet. With the majority of these trades likely being served by VLCCs, there is some light at the end of the tunnel for currently beleaguered VLCC owners. However, recent data from various shipbrokers suggest that growth of the combined VLCC, Suezmax and Aframax fleet until 2015 (the data do not project 2016) is set to outpace the trade growth presented here. Therefore, the prospect of the fleet becoming even more bloated may yet temper any lasting gains that could come from the trade flows previously outlined.

ASIAN STORAGE EXPANSIONS

Summary

- **Supply security is becoming increasingly important for Asian countries**, which account for two thirds of incremental global oil demand in 2011-2016. A substantial programme of new storage capacity construction for both government strategic and commercial inventory is underway, temporarily boosting crude and product demand at the margin over the next five to six years, with crude volumes over and above the levels implied by our demand projections.
- **China's second phase of its three-phase Strategic Petroleum Reserves (SPR) plan** is under construction. The first phase (103 mb) was filled by April 2009, the second (an additional 169 mb) will be completed by 2013 and the third is expected to boost total storage capacity to approximately 500 mb by 2016.
- **India's first phase SPR programme** envisages 39 mb of capacity, to be completed by 2013. The details of the second phase are as yet unknown, but India aims to establish total strategic storage capacity of 110 mb.
- **Filling of planned SPR facilities in China and India** after completion will increase both countries' demand for crude, albeit phased purchasing may be deployed to minimise market impact. Were the expected reserves to be filled, it would imply a yearly average of around 240 kb/d of incremental crude oil demand over the next five years.
- **Expansions of commercial storage capacity** (crude and products) are also underway in various Asian countries, with the largest additions in China, India, Singapore, Malaysia, Indonesia and South Korea amounting to 320 mb. A similar smoothed pattern of fill would suggest additional demand near 180 kb/d over the next five years, although some of this capacity may not be wholly incremental.

The What and Why of Emergency Stocks

Asian countries, which will account for around two thirds of incremental global oil demand, aim to ensure security of supply via SPR stockbuilding or increases in commercial storage. Plans for new storage facilities are proliferating, given the region's oil import dependency and the logistical and security challenges thrown up by long distances from producing regions. It is worth noting that deliveries to or from crude storage are not counted in our product-based estimates of non-OECD oil demand. By contrast, our demand estimates do implicitly include shifts in oil products storage.

In the case of a crisis, emergency stocks are the most effective line of defence for providing additional oil to an undersupplied market. The most visible form of emergency stocks are government-controlled (referred to as public or strategic stocks, either government-owned or agency-held), but emergency stocks also include obligatory stocks held by industry. In addition to commercial inventories, emergency stocks can be drawn upon, either by the loan or sale of strategic stocks or by the lowering of the industry obligation, to meet short-term demand in a disruption.

Chinese Strategic and Commercial Storage

Locations for Chinese Strategic Petroleum Reserves Phase 1 and Phase 2



To reduce the impact of a supply disruption, the Chinese government established an SPR programme in 2001, which has the potential to create crude oil stocks equivalent to 90 days of net imports by 2020. The first phase (SPR-I) with capacity of 103 mb was filled with crude oil by April 2009. Two out of eight storage facilities for the second phase (SPR-II) are currently under construction and the SPR capacity will increase to 270 mb by 2013. Details of the third phase (SPR-III) are yet to be made public, but it is expected to bring total SPR capacity to approximately 500 mb by 2016.

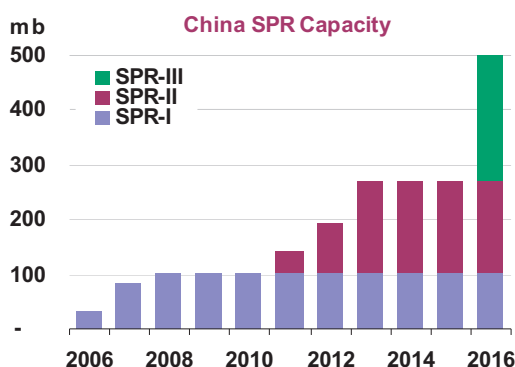
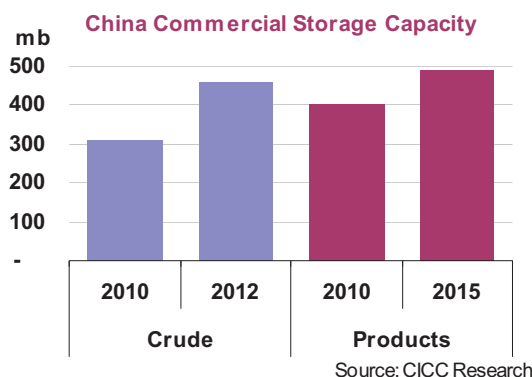
The Chinese National Oil Reserve Centre, under the supervision of the National Energy Administration (NEA), is responsible for SPR construction and oil procurement, while major national oil companies serve as operators of SPR facilities. Under the SPR-I, four storage facilities were built between 2004 and 2008. The storage sites (Zhenhai, Zhoushan, Huangdao and Dalian) are located near refining centres on the eastern coast. Chinese media quoted the former head of the NEA saying that the first phase was filled at an average cost of \$58/bbl, although this has not been confirmed.

Chinese Strategic Petroleum Reserve Sites

million barrels per day

Operator	Location	Capacity	Status	Completion
Sinopec	Zhenhai, Zhejiang	32.7	Filled	3Q06
Sinochem	Zhoushan, Zhejiang	31.4	Filled	4Q07
Sinopec	Huangdao, Shandong	20.1	Filled	4Q07
CNPC	Dalian, Liaoning	18.9	Filled	4Q08
Phase 1		103.2		2008
CNPC	Dushanzi, Xinjiang	18.9	Construction	1H11
CNPC	Lanzhou, Gansu	18.9	Construction	1H11
Sinopec	Tianjin	20.1	Approved	1H12
	Other	111.1		2013
Phase 2		169.0		2013
Phase 3		227.8		2016
Total SPR		500.0		

The SPR-II comprises eight storage facilities with a total capacity of 169 mb. The Dushanzi and Lanzhou sites are under construction, with estimated completion in 2011, while work at the Tianjin facility is expected to start in 2011. The complete list of locations has not been officially disclosed, although other potential facilities are believed to be underground, located inland near refinery centres and important pipelines, or to be expansions of existing storage sites. Chinese officials have already indicated they plan to speed up construction; so, we assume most of the capacity will be completed by end-2013 as scheduled. Filling of the SPR-II facilities may start immediately, but could also depend on crude oil price levels.



While building the SPR, the Chinese government has also encouraged domestic oil companies to increase commercial reserves and is considering placing a minimum stockholding obligation on industry, creating a comprehensive national reserve system – the National Petroleum Reserve (NPR).

According to China International Capital Corporation (CICC), estimated crude oil commercial storage capacity stood at around 310 mb in 2010 and planned projects indicate it could increase by a further 150 mb by end-2012. Refined product storage capacity was estimated at around 400 mb in 2010, and is seen rising to almost 500 mb in 2015.

However, there is much ambiguity surrounding SPR-II and commercial storage expansions, as the distinction between the two is not always clear. There was, for example, an apparently contradictory report in January 2011 from CNPC, citing 178 mb of strategic storage and 168 mb of commercial storage available at end-2010. Either way, China is demonstrating a strong capability to expand its petroleum storage, and is significantly increasing its level of cover.

Indian Strategic and Commercial Storage

India consumed 3.3 mb/d of oil in 2010 and demand is forecast to rise on average by 3.3% annually over 2010-2016. However, its crude demand is likely to grow even more strongly to satisfy not only domestic consumers, but also to supply recently built large export-oriented refineries.



The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

The Indian government decided in 2004 to establish a 110 mb strategic petroleum reserve in two phases. The construction of strategic crude oil storage facilities is managed by Indian Strategic Petroleum Reserves Limited, a special purpose vehicle, wholly-owned by the Oil Industry Development Board. The first phase (SPR-I) envisages three storage sites with a combined 39 mb capacity, to be completed by 2013.

Indian Strategic Petroleum Reserve Sites
million barrels per day

Location	Status	Additions	Completion
Visakhapatnam	Construction	9.5	4Q11
Mangalore	Construction	11.0	4Q12
Padur	Construction	18.3	4Q12
Phase 1		38.8	
Phase 2		71.2	
Total SPR		110.0	

Source: Indian Oil Industry Development Board, Indian Oil & Gas

The details of the second phase are unknown yet, but various options are being considered, including placing a stockholding obligation on industry; inviting foreign oil producing companies to participate in the construction of the strategic petroleum reserves; or becoming a regional storage hub for crude and refined products. Meanwhile, trade journal *Indian Oil & Gas* estimated the country's current commercial storage capacity at around 160 mb at end-2009. Planned SPR-I and commercial crude oil and product storage expansions would add 39 mb and 24 mb by 2013, respectively.

Other Commercial Storage Capacity Developments in Asia

Storage is also likely to increase elsewhere in Asia. Expansions of commercial storage capacity are underway in Singapore, Malaysia, Indonesia and South Korea. All told, the additions itemised below amount to 320 mb, although their completion over a five-year period suggest a modest average fill rate of around 180 kb/d even if these facilities were to be wholly incremental (which is not certain).

A recent lease agreement between Japan and Saudi Aramco augments a trend whereby Middle East producers become de facto short-haul suppliers by leasing storage space in key consuming countries. The shorter distance and rapid delivery time also provides a competitive advantage, for example against growing volumes of Russian ESPO crude. Currently, ESPO crude volumes flowing to Asia are too low to completely crowd-out well-established Middle Eastern contract volumes. Nevertheless, Middle East producers believe the ESPO Blend will become a significant competitor after the completion of ESPO Phase 2 by 2013, which will take pipeline capacity to 1.0 mb/d. For Asian consumers, such leasing arrangements with key oil producers enhance supply security if preferential access to crude at times of crisis can be agreed.

Japan and Saudi Aramco signed a three-year tank lease agreement in December 2010, after almost four years of negotiations. The contract allows Aramco to store up to 3.8 mb of crude oil at a state-owned Okinawa storage terminal, with the first VLCC having arrived in February 2011. The agreement includes a provision allowing Japan primary access to stocks in the case of a supply emergency. This agreement complemented an earlier lease deal between UAE's Abu Dhabi National Oil Company and JX Nippon Oil & Energy for a 3.9 mb storage terminal in Kiire.

Singapore is Asia's leading oil trading hub. According to Singapore's Economic Development Board, storage capacity stood at around 125 mb in 2010, with independent oil storage accounting for 40%. To complement existing storage capacity amid space constraints, the state owned JTC plans to build a very large floating oil storage unit in 3Q11 with almost 2 mb of storage capacity and a further 9.3 mb under the first phase of the giant Jurong Rock Caverns project. This underground oil storage facility will be able to house crude oil, condensate, naphtha and gasoil when completed in 2014. The planned second phase will add further caverns with 8.3 mb capacity, but this will depend on the first phase results.

Largest Commercial Oil Storage Capacity Additions in Asia

million barrels per day

Country	Fuel	Additions	Completion
China	Crude Oil & Products	235.0	2012/2015
South Korea	Crude Oil & Products	36.9	2016
India	Crude Oil & Products	24.1	2012
Malaysia	Crude Oil & Products	13.5	2014
Singapore	Crude Oil & Products	11.1	2014
Indonesia	Oil Products	2.5	2015
Total Largest Additions		323.1	

South Korea aspires to transform its southern coast into an oil trading hub, with a planned 37 mb commercial storage capacity expansion. To enhance its competitive position, the government is reportedly contemplating offering lower fees for use of storage facilities than other locations in the region. In the first phase a new commercial storage facility of 8.9 mb at Yeo-su is under construction and is expected to be completed in 2012. Another 28 mb storage facility near Ulsan is envisaged under the second phase, with completion date in 2016. In addition, Korea National Oil Corporation (KNOC) leases surplus tank capacity (estimated at around 40 mb) under the "International Joint Stockpiling" scheme to industry, reportedly including also foreign oil companies from Norway, France, Algeria, UAE and China; and the scheme in turn gives Korea the pre-emptive rights to purchase the oil in the case of a supply shortage.

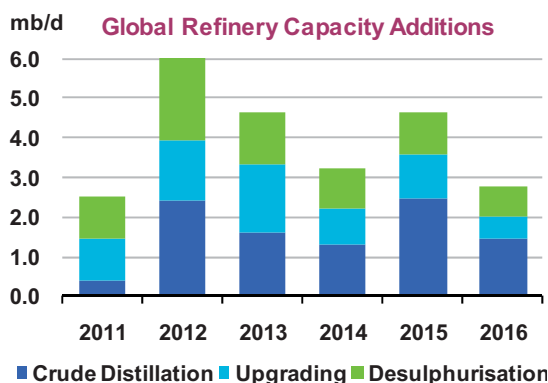
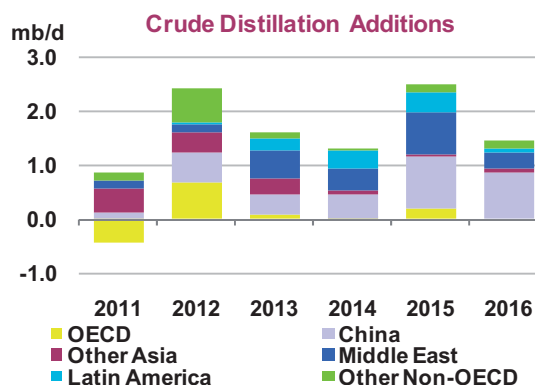
Malaysia plans to construct an oil and chemical hub in Johor near Singapore to benefit from increased regional demand. The government recently announced construction of an 8.2 mb deepwater oil storage terminal in Pengerang, with the first phase to be completed by 2014. In addition to the 2.5 mb oil storage terminal completed in 2010, construction is underway for another 5.3 mb distillate and fuel oil terminal to become operational by 2012.

Meanwhile, **Indonesia's** product storage capacity expanded by 2.5 mb in 2010 as Vopak opened the first independent oil products terminal in Jakarta with storage capacity of 1.6 mb and the country's national oil company Pertamina completed another 0.9 mb storage facility in East Java. Pertamina plans to add a further 2.5 mb of capacity by 2015, while the Vopak terminal may be expanded to 2.8 mb in the future.

REFINING AND PRODUCT SUPPLY

Summary

- **Global refinery crude distillation (CDU) capacity is expected to increase by 9.6 mb/d in the 2011-2016 period**, of which half comes from non-OECD Asia and most notably China. Restructuring of the industry in the OECD continues, with a total of 1.8 mb/d of capacity closed or scheduled to close since the economic downturn in mid-2008. Significant investments in upgrading and desulphurisation capacity are also planned, adding 6.9 mb/d and 7.3 mb/d, respectively.
- **Planned additions are likely to outpace forecast demand growth for the period**, thus increasing spare refining capacity, unless projects are cancelled or more closures are announced. Furthermore, increasing volumes of biofuels, crude for direct burning, gas and coal-to-liquids and NGLs will contribute to meet product demand, sidestepping the refinery system. Of the 7.2 mb/d oil demand growth projected in the period, crude and condensate refinery intake accounts for only some 70%, implying spare capacity could increase by more than 4.0 mb/d.



- **Global refinery utilisation rates are seen declining to 78% on average in 2016, from 82% in the 2006-2010 period.** OECD rates are expected to fall more sharply, to only 77% of capacity, while larger, more sophisticated, refineries in non-OECD demand growth areas are assumed to operate at a higher 79% on average in 2016. For an 82% global utilisation rate to be attained in 2016, an extra 4.4 mb/d of capacity would have to be shut or completion deferred.
- **Oil product supply balances** point to increased tightness in middle distillates towards 2016, as demand growth is heavily skewed towards diesel, gasoil and kerosene. Gasoline markets will remain under pressure, as North America achieves self-sufficiency for the motor fuel and surpluses in Europe, the FSU and Asia remain. Fuel oil markets could also tighten, as the anticipated fall in end-user demand has been slowed, the feedstock slate becomes lighter and refiners upgrade to produce higher-value products.

Refinery Investment Overview

Global refinery expansion plans are seen adding 9.6 mb/d of crude distillation (CDU) capacity post-2010, reaching a total of 102.7 mb/d in 2016. Around 95% of additions are planned in the non-OECD, most notably in Asia. China alone is expected to account for a third of global growth, or 3.3 mb/d, largely in line with demand growth estimates. Other Asia will see a further 1.3 mb/d added in the period, or 13% of global growth, while significant investments are also taking place in the Middle East and Latin America. Completed and committed refinery closures in the OECD fail to offset expansions, resulting in a net 0.5 mb/d capacity increase there for the period. Identified upgrading and desulphurisation projects add 6.9 mb/d and 7.3 mb/d of capacity, respectively.

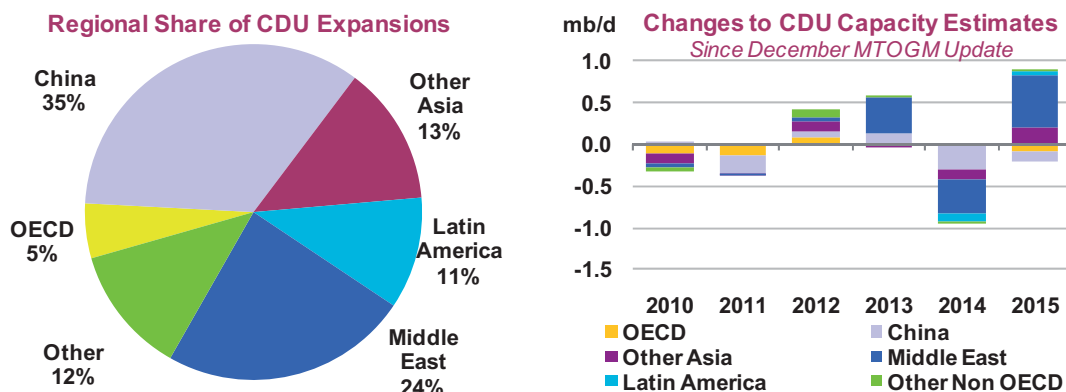
Global Crude Distillation Capacity¹

(million barrels per day)

	2010	2011	2012	2013	2014	2015	2016	2016-2010
OECD North America	21.5	21.4	21.9	22.0	22.0	22.0	22.0	0.6
OECD Europe	15.9	15.7	15.7	15.7	15.7	15.9	15.9	0.0
OECD Pacific	8.6	8.5	8.6	8.6	8.6	8.6	8.6	0.0
FSU	8.1	8.2	8.5	8.6	8.6	8.7	8.8	0.7
China	9.9	10.0	10.6	11.0	11.4	12.3	13.2	3.3
Other Asia	10.7	11.1	11.5	11.8	11.9	11.9	12.0	1.3
Middle East	7.8	8.0	8.1	8.6	9.0	9.8	10.1	2.3
Other Non-OECD	10.6	10.7	11.0	11.3	11.7	12.0	12.2	1.5
World	93.1	93.5	95.9	97.5	98.8	101.3	102.7	9.6

1. Includes Condensate Splitters

Overall, largely unchanged cumulative additions in the 2010-2015 period, compared with the December update, masks significant changes to regional composition and expected completion dates. Recent closures in the OECD and slightly lower growth expected in China and Latin America are offset by additional projects in the Middle East. Several projects have also slipped or advanced by one year or two from the previous update.



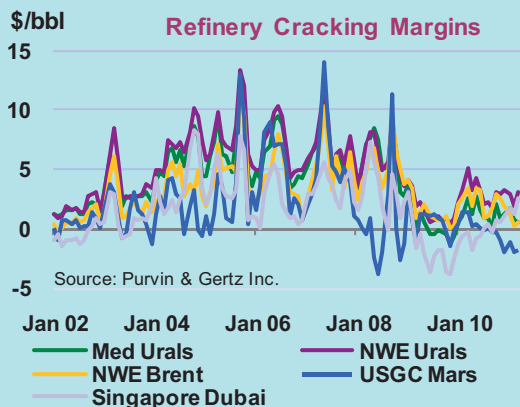
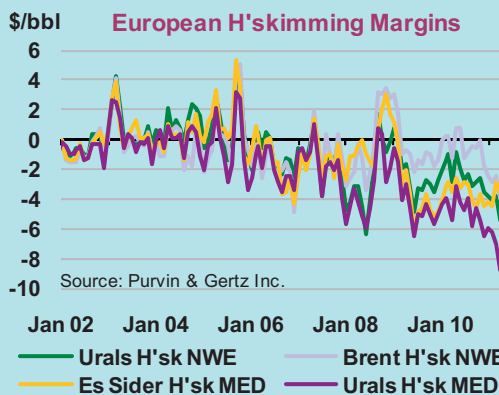
The largest refinery investments will clearly be made in China in the medium term. While uncertainty remains, several key projects are advancing to help meet projected demand growth of some 3.0 mb/d over 2010-2016. The government's strategy seems to be to approve projects needed to meet domestic product demand, balancing concerns over surplus capacity and increased product import requirements. Projects scheduled for the tail-end of the forecast are therefore likely to be managed in line with evolving demand prospects.

In contrast with China, India is expanding its refining industry to establish itself as a key product exporter in the Asia Pacific region. India has already been exporting high-quality products to the US, Latin America and Europe since the start up of Reliance's Jamnagar export plant in 2009, and the country will likely increase product surpluses as refinery capacity is expanded by more than 1 mb/d by 2016. In the Middle East, Saudi Aramco has revived its ambitious refinery expansion plans, temporarily put on hold during the recession, and it seems that three of the four proposed mega-projects will now come to fruition, with two 400 kb/d projects likely before 2016. Regional investments also include UAE's 420 kb/d Ruwais project, expected in 2014. Latin American expansions are dominated by Brazil, which is likely to add 0.7 mb/d of capacity by 2016.

While OECD industry rationalisation continues and a total of 1.8 mb/d of distillation capacity has been shut or is due to shut in the next few years, crude distillation capacity is still seen expanding overall by about 0.5 mb/d in the forecast period. The 740 kb/d closures scheduled for the 2011-2016 period will largely be offset by Motiva's 325 kb/d Port Arthur and Pemex's 150 kb/d Minatitlán expansions, to be completed in 2012, as well as additions in Spain and Turkey.

Record-Low Refining Margins for Simple Refineries So Far in 2011

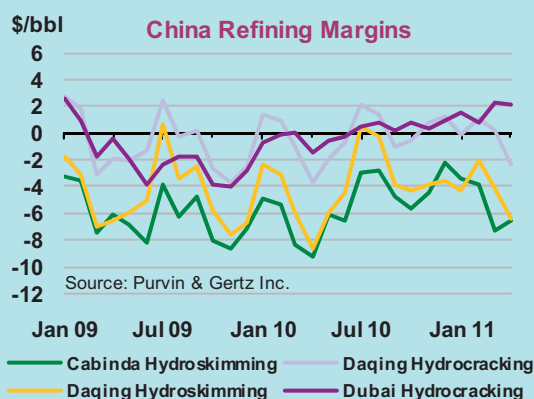
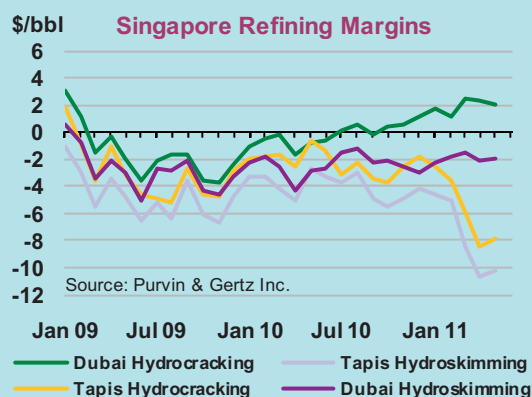
Refinery cracking margins have been relatively stable since mid-2010, after a rebound from the lows seen in 2009. From an historical perspective, however, cracking margins remain very weak in all regions. In the US, Mars cracking margins have hovered around break-even for the last two years, whereas European margins have stabilised in a +\$2-3/bbl range.



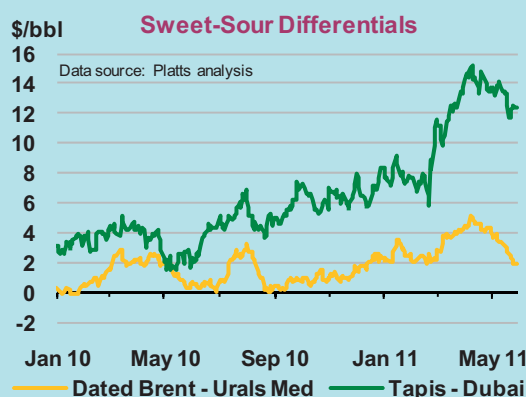
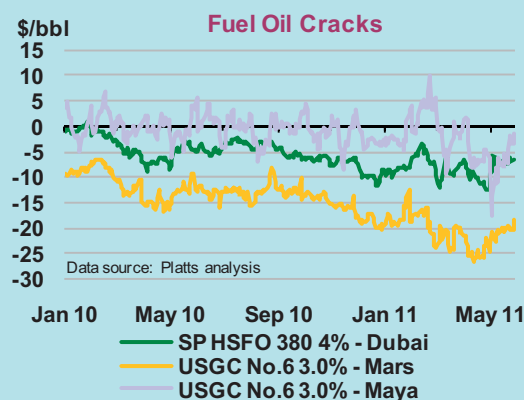
Compared with the weak-but-stable trend for cracking, hydroskimming margins in Europe have gone from bad to worse in recent months. This is also reflected in lower throughput rates for OECD Europe, where the ramp up after 2011 spring maintenance has been muted and run rates throughout 2010 and so far in 2011 have been around 1 mb/d lower than the 5-year average.

Record-Low Refining Margins for Simple Refineries So Far in 2011 (continued)

In China, Dubai hydrocracking margins have been profitable since 4Q10. For the other benchmark crude, Daqing, hydrocracking margins were around break-even, but have posted losses this spring, mainly due to weak fuel oil prices. Simple hydroskimming refineries also showed losses, albeit less than the record-low levels in 2006-2008. In spite of this, utilisation rates for state-owned refineries have been above 90% in the last six months, reflecting the fact that operational decisions are not always guided purely by market price-derived profitability. Under the current Chinese pricing system these refineries are guaranteed a certain margin depending on the price of a basket of crude prices, while throughputs may also be partially mandated by the government to ensure adequate domestic product supply.

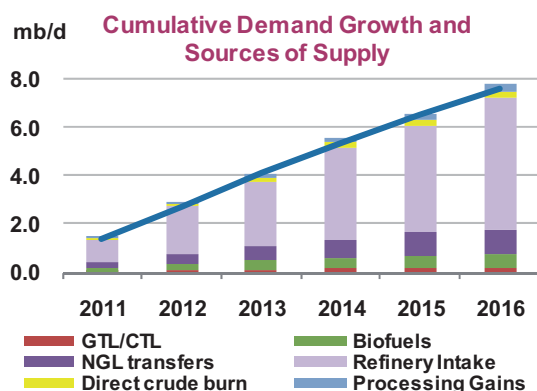
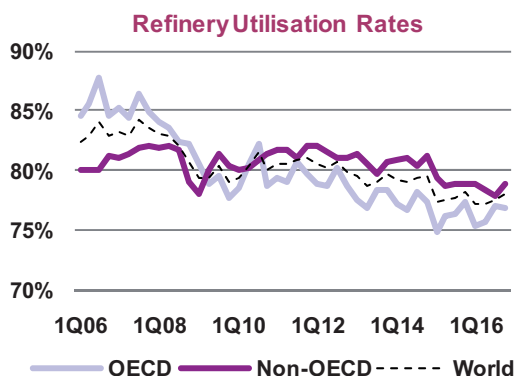


Singapore sour hydrocracking margins have posted an average profit of \$1.40/bbl since October 2010, in contrast to the general trend for refining margins. The Maya coking margin in the US Gulf has also trended upwards in the last six months. The relative advantage for complex plants running heavy-sour crude has become more pronounced in recent months as light-sweet crude premia have ballooned following the loss of Libyan crude supply. Hydroskimming margins have taken a further hit as fuel oil cracks have collapsed, despite some support from incremental Japanese demand and the loss of some Libyan crudes which traditionally act as fuel oil precursor in the Mediterranean. When all is said and done however, throughputs in the non-OECD regions will continue to gain impetus from resilient demand growth, with maturing markets and strained profitability among OECD operators likely to cap rates there for some time to come.



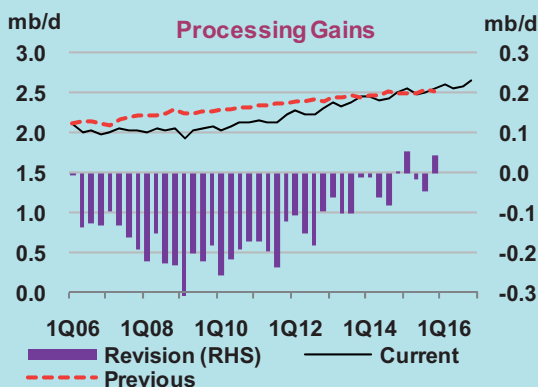
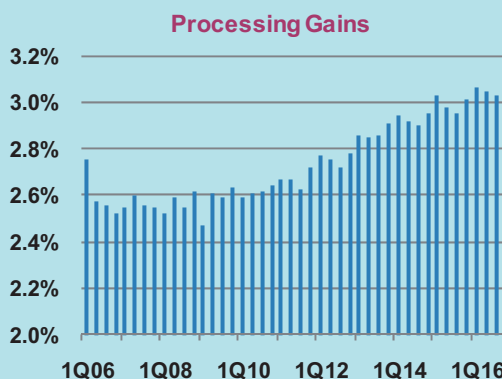
Refinery Utilisation and Throughputs

Global refinery utilisation rates are seen dropping from 82% on average during 2006-2010, to 78% in 2016. Planned CDU additions outpace expected demand growth, and an increasing share of demand is met by oil products bypassing the refinery system. For the six-year period, incremental refinery intake is expected to account for just over 70% of demand growth, while the rest is met by NGLs and crude bypassing the refinery system, biofuels, processing gains and gas and coal-to-liquids. After sliding from 85% in 2006-2008 to 80% in 2010, OECD utilisation rates are expected to fall further, to only 76% in 2016, in line with structurally declining demand and as refiners face competition for export markets. The non-OECD will likely sustain higher rates in the period, to meet surging demand. In all, crude and condensate refinery intake is set to grow from 74.4 mb/d in 2010 to 79.7 mb/d in 2016. A 1.3 mb/d reduction in OECD runs is offset by a 6.6 mb/d increase in the non-OECD.



Refinery Processing Gains

Since the June 2010 MTOGM, we have revised our refinery processing gains calculations based on our Product Supply Model. Processing gains are the volumetric amount by which total refinery output exceeds input for a given period of time. This difference is due to conversion of crude and feedstocks into products with a lower specific gravity via the use of upgrading capacity. Overall, processing gains are revised lower by 130 kb/d on average for the 2006-2015 period, with the largest adjustments in 2008-2010. Global processing gains rise from 2.6% on average in 2006-2010 to 3.1% in 2016, as refiners invest in upgrading capacity and simple refineries are assumed to run at lower rates.



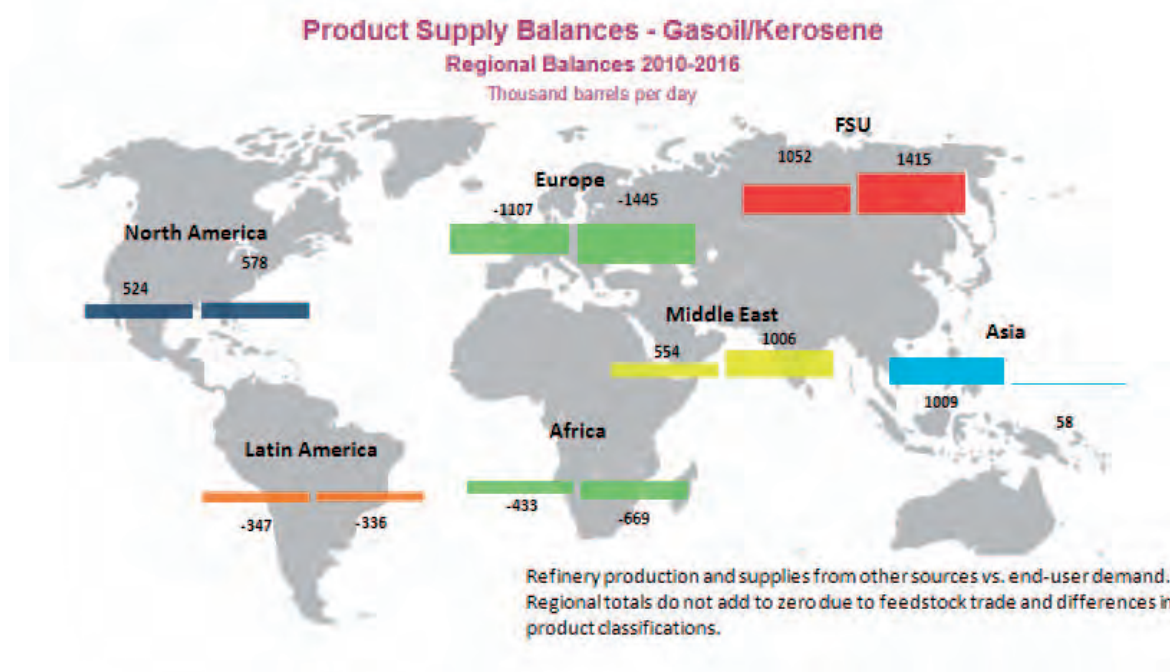
Product Supply Balances

The trends in global product supply balances highlighted in last June's report remain largely unchanged, as demand growth continues to be heavily skewed towards middle distillates. Higher demand overall and proportionally larger upward revisions to fuel oil and other products moderate the product imbalances highlighted previously, but could tighten fuel oil markets. Light distillates are expected to remain adequately supplied, as demand contracts in key regions and availability is boosted by both biofuels supplies and blending components from NGL fractionation.

Products Supply Modelling - Seeking the Pressure Points*

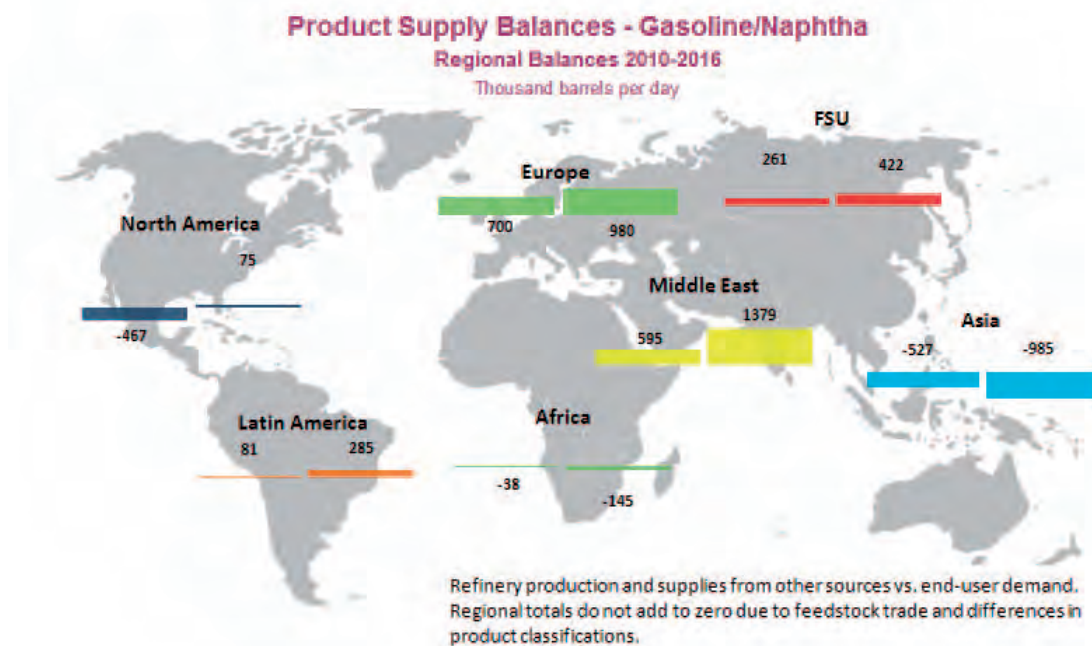
Our approach to modelling refined product supply is not designed to optimise the global/regional system, but rather to highlight where pressures may emerge within that system in the 2011-2016 period. A number of simplifying assumptions underpin the analysis, and as such changes to any one of these would generate a significantly different picture. The aim is to highlight the adequacy, or otherwise, of firmly committed refining capacity and currently prevailing refinery operating regime in meeting the forecast pattern of demand growth, given the expected changes in crude feedstock quality and availability. 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 in filling the gap between this and total oil product demand, while also maximising utilisation of higher-value crude capacity. We also assume an operational 'merit order', with crude preferentially allocated to demand growth regions and to 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.

*Please note that all crude allocation and refinery modelling was done with late-May supply and demand data, which differ marginally from the broader oil balances presented in this report.



Middle distillates supplies, including diesel, gasoil, kerosene and biodiesel, will remain tight in the medium term. While slightly lower than in last year's report, the share of middle distillates in total demand growth remains impressive, at 52%. Middle distillate demand grows in all regions, except for the OECD Pacific where it is unchanged. Europe remains structurally short of diesel, and net imports are expected to increase from the 1.1 mb/d registered in 2010 (including non-OECD Europe) to an estimated 1.4 mb/d in 2016. This excludes gasoil imported as feedstock or to be upgraded further from the Former Soviet Union. The latter is expected to remain the largest regional exporter of gasoil, with most of the products going to Europe for final consumption or further processing.

North America is forecast to retain some export potential in the medium term, close to current net exports of around 0.5 mb/d. These will partly meet Latin American demand, which will likely continue to surpass regional production. The largest change in middle distillate balances is expected to come from Asia, which goes from being a significant net exporter, of more than 1.0 mb/d estimated for 2010, to a more balanced regional market in 2016. China attains a marginal surplus in 2016, offset by import needs in Other Asia and falling exports from the OECD Pacific. Further tightening in middle distillates might be expected going forward if marine diesel progressively displaces fuel oil in the international bunker market (see *Uncharted Waters: The Outlook for Bunker Demand*).

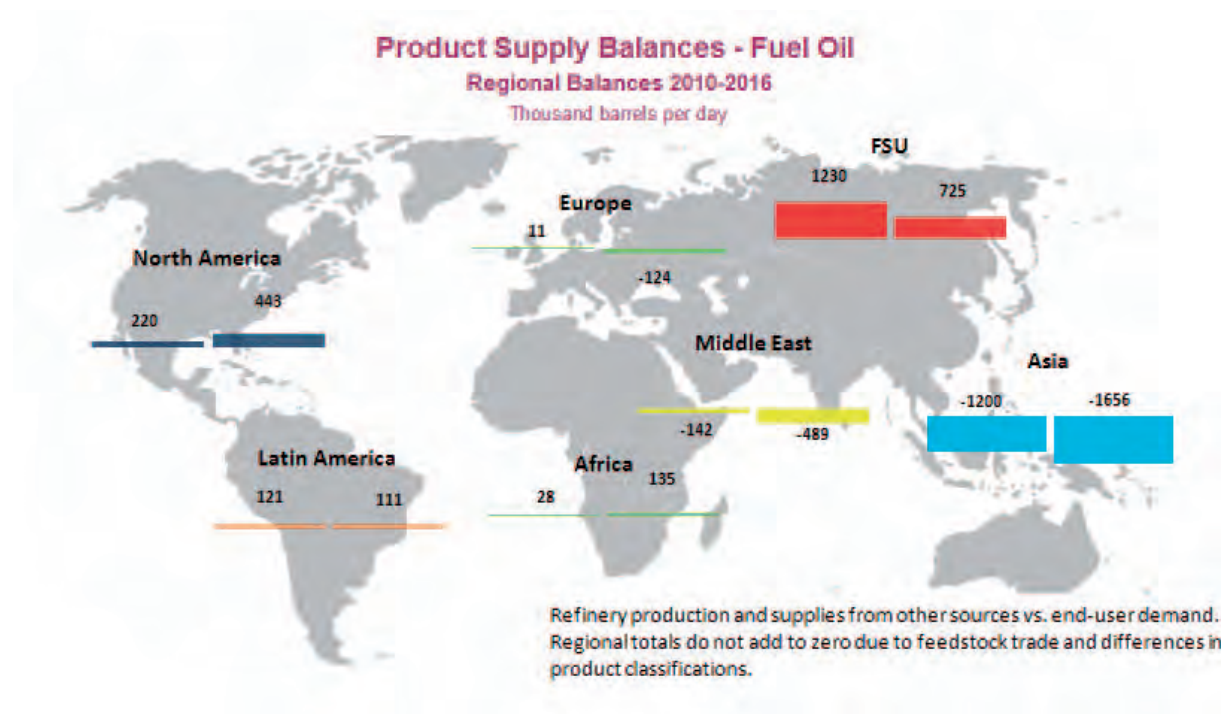


Light distillate markets, here including naphtha, gasoline and ethanol, are expected to remain well supplied in the medium term. North America's import requirements are eradicated in the six-year period, as demand declines in line with more efficient vehicles while an increasing share of demand is met by biofuels. In the meantime, surplus material from Europe is set to increase from current levels as structural demand decline continues. Latin America is also expected to increase exports as ethanol production rises from 470 kb/d to 640 kb/d, whereas refining additions boost crude-based gasoline output largely in line with demand.

African import requirements are likely to increase as few refinery additions are seen completed in the period, while demand continues to grow. Middle Eastern exports could rise sharply, potentially to as much as 1.4 mb/d by 2016, from 600 kb/d currently. Imports of some 200 kb/d of gasoline will only partly offset a 1.6 mb/d surplus of naphtha, coming both from NGL fractionation, condensate splitters and traditional refineries. Middle Eastern naphtha supplies will go almost entirely to Asia, which is net short by a similar amount. OECD Pacific imports are expected to remain stable from 2010 levels, at around 0.9 mb/d of naphtha, while Chinese imports could increase from 50 kb/d in 2010 to around 300 kb/d in 2016 in line with significant expansions in the petrochemical sector.

Fuel oil markets once again look set to tighten over the medium term. While import needs in Asia and the Middle East increase over the period, product supply shrinks as refiners invest in upgrading capacity and the global feedstock slate gets lighter. The FSU remains by far the largest exporter, but Russian volumes are also expected to diminish over the period as several refinery upgrading projects are completed. Middle Eastern import requirements could triple over the six-year period, to almost 0.5 mb/d in 2016, to meet increased power generation needs, while regional fuel oil yields are reduced as new capacity is commissioned and upgrades are completed.

The assumption that OPEC countries will continue to restrict output of heavier crude also plays into this tightening picture, effectively lowering fuel oil production. Asia, mainly its non-OECD Asia and China components, remain large importers of fuel oil, while the OECD Pacific is balanced. Net imports for the three regions combined are seen increasing from an estimated 1.2 mb/d in 2010, to 1.6 mb/d in 2016 as the structural decline in demand, from fuel switching in power generation, is offset by robust bunker demand and falling supplies particularly in the OECD Pacific.



NGLs Add to Product Supplies, but Largely Bypass the Refining System

One of the most important sources of supply growth in the medium term is condensates and gas liquids from gas processing plants (referred to as NGLs in this report), accounting for 2.7 mb/d or 40% of global oil supply growth. The fact that gas-plant NGLs, as distinct from field condensates, help to satisfy final product demand while bypassing the refining system, has important implications for the refinery industry in the medium term.

NGLs can either be fractionated at a fractionation plant or sent to a refinery for further processing. Fractionation is the most common route, and the products of NGL fractionation are typically LPG, ethane (C₂H₆), pentane (C₅H₁₂) and gas plant naphtha. LPG is a common term for propane (C₃H₈), butane (C₄H₁₀), isobutane or any mix of those. In our analysis, product yields from NGL fractionation plants are estimated based on reported data, and represent averages by country.

For 2011, we estimate that around 70% of gas-plant NGLs produced are fractionated before being marketed, and that the remaining 30% are destined for the refinery system. The level of expected growth in NGL supply has important implications for product supply and the global oil refining sector. Of the total gas plant NGL supply growth (2010-2016) of 1.4 mb/d, 1.2 mb/d are likely to be fractionated into ethane, LPG and naphtha while only 200 kb/d will be available as raw feedstock for refineries. The remaining volumes are either used directly as petrochemical feedstock or as a burner fuel.

Product Supply from Gas Plant Fractionated NGLs (kb/d)

	2010	2011	2012	2013	2014	2015	2016
Ethane/LPG	4054	4352	4508	4665	4784	4979	5017
Naphtha	539	602	631	677	719	755	768
Total	4593	4954	5140	5342	5503	5734	5785

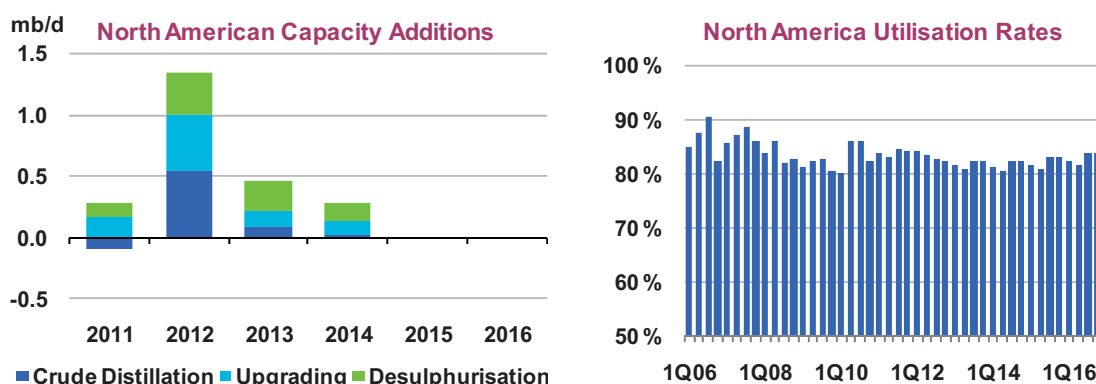
The petrochemical sector is the primary destination for naphtha and ethane, while the residential sector consumes the bulk of LPG. LPG is a clean and efficient fuel, with a relatively low carbon footprint due to its high hydrogen-to-carbon ratio and efficient combustion characteristics. LPG also contains few or no contaminants so that emissions of SO₂ and NO_x gases are negligible. LPG can compete with natural gas as a heating and cooking fuel, but with the advantage of requiring much less expensive infrastructure to distribute it to the residential or commercial market.

Field (or lease) condensates are stable liquids (C₅+), and are the heaviest NGL components. They are similar to very light crudes (API>50°), and they can be transported as crude oil. As condensates consist of only light components, they require special treatment in a refinery, and therefore it is useful to look at these volumes separately. Condensates are currently reported either as crude volumes or as NGL volumes, and are only being reported separately by a few countries. Hence, on a field-by-field basis we have separated out what we think are condensates volumes, either included in the crude or NGL volumes. IEA estimates that 5.5 mb/d of condensates will be available for refineries and condensate splitters in 2011. Condensate splitters are dedicated distillation towers specially designed to distil petroleum products directly from condensates, and are mainly found in the Middle East and Asia. The typical yield for a condensate splitter is 50-70% gasoline and naphtha in addition to LPG, kerosene and gasoil. Total condensate splitter capacity in 2011 is assumed at around 2.3 mb/d, leaving 3.2 mb/d of condensates to be routed to the conventional refining system, often blended with heavier crude to increase light product yields. In the outlook period (2010-2016), condensate splitter capacity increases by 0.8 mb/d to a total of 3 mb/d. With total condensate production expected to increase by 1.2 mb/d, this will leave a substantial volume of light, sweet condensate feedstock to be processed in conventional refining facilities.

Regional Developments

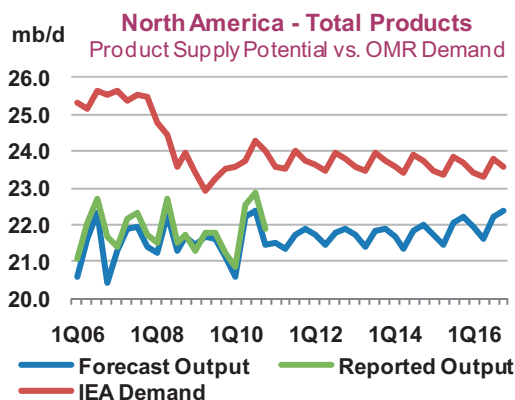
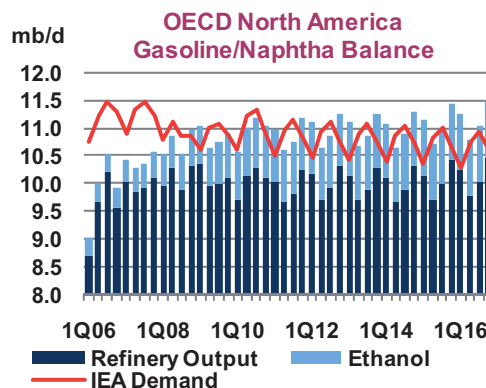
North America

After modest capacity contraction in 2009 and 2010, North American crude distillation capacity is expected to expand by 555 kb/d by 2016. The most notable additions are the expansions of Pemex's Minatitlán and Motiva's Port Arthur plants, both expected in 2012, and capacity increase and upgrade of ConocoPhillips' Wood River in 2011, partly offset by the capacity reduction of Hess' St Croix refinery in the US Virgin Islands. The latter company cut capacity at its 500 kb/d Hovensa refinery by some 30% in 1Q11, in part due to weak refinery margins. This latest capacity cut brings total North American refinery closures to 620 kb/d since 2008, excluding PBF's 210 kb/d Delaware refinery, which was in the process of restarting in early June 2011. The former Valero plant was closed in 2009, but sold to PBF Investments for \$220 million in June 2010. Furthermore, significant investments are being made at US refineries to increase the ability to process heavier crudes coinciding with the rise in Canadian production.



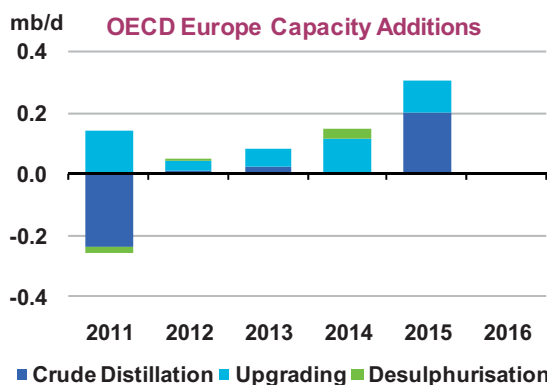
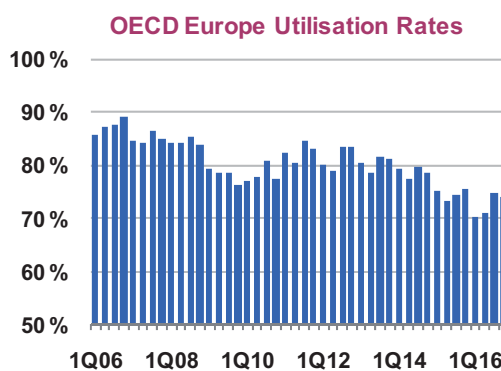
The current overhang of crude supplies at Cushing, Oklahoma, has contributed to a steep discount of WTI prices compared with similar grades and significantly improved refinery margins for those refiners able to process the cheaper crude. As a result, operating rates in the Midwest have outperformed the rest of the US recently, and a few companies have decided to increase capacity to profit fully. Since December's update Tesoro has announced it is adding 10 kb/d at its 58 kb/d Mandan North Dakota refinery by 2Q12 while Valero is planning to bump up intake by 25 kb/d at its McKee refinery within three years.

In the last decade, OECD North America has gone from being a significant net oil product importer (860 kb/d in 2000) to a net exporter in 2010, when it had a surplus of some 250 kb/d. Refined product exports to Latin America, in particular, were exceptionally high in 2010, averaging more than 0.5 mb/d, as natural disasters and technical problems added to an already structurally tight refinery system there. North America became a significant exporter of middle distillates in 2010 to not only Latin America but also Europe. While US gasoline imports from Europe, (at 520 kb/d in 2010) are significantly higher than in 2000, they were about 200 kb/d lower than the 2007 highs. Looking ahead, regional refinery output is expected to largely keep track with demand growth. Augmented by product supplies from NGLs and biofuels, product surpluses will increase, in particular of gasoline and fuel oil.

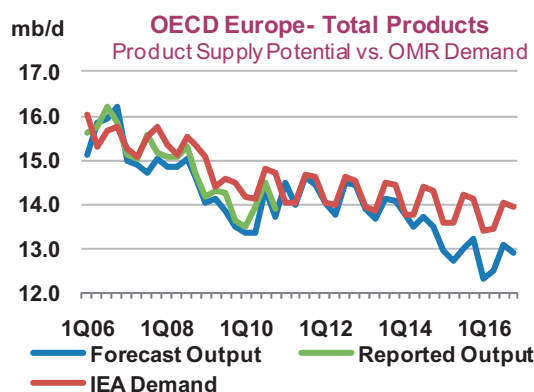
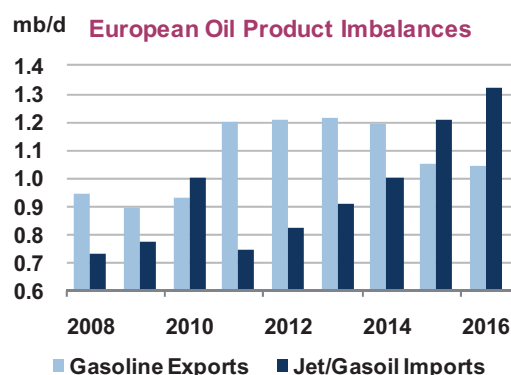


OECD Europe

Despite significant efforts to shed surplus capacity (see *Restructuring of European Refinery Industry Continues*), European refinery capacity is expected to remain unchanged over the 2010-2016 period unless further closures are announced. Offsetting some 380 kb/d of announced capacity reductions from 2011 onwards, Repsol's Cartagena refinery in Spain is on track to augment distillation capacity by 110 kb/d and significantly increase distillate yields by the end of 2011. Our projections also assume that one of the two planned new Turkish refineries – at Aliaga and Ceyhan – gets built in the outlook period, adding around 200 kb/d.



As a result of surplus capacity, European refinery utilisation has been very weak since the downturn of the global economy. Most recently, weak demand, coupled with heavy turnarounds and elevated light/sweet feedstock costs due to the Libyan crisis, has pushed both refinery margins and throughputs to historic lows. We expect the European industry to remain under pressure in the near term, unless further closures are confirmed. In terms of product balances, the region's middle distillate import requirements are expected to increase from some 900 kb/d recorded in 2010, to 1.3 mb/d in 2016, while gasoline exports inch only marginally higher from around 900 kb/d recorded in 2010, as reduced runs offset structurally declining demand.



The Restructuring of Europe's Refinery Industry Continues

The European refining industry is continuing to see major changes due to structurally declining demand, intense export competition from new capacity in emerging countries and resulting poor margins. Since the beginning of 2009, six refineries have announced they will halt operations completely, and several are looking for investors or buyers to avoid shutdown and closure.

Since 2009, European refinery capacity has been cut by some 580 kb/d, including Romania's 70 kb/d Pitești plant (technically non-OECD Europe), and another 110 kb/d has been scheduled for 2012. We include the shutdown of Petroplus' Teesside refinery in the UK in 2009, Total's Dunkirk in 2010 and a Gonfreville crude unit in 2011, Petroplus' Reichstett refinery also in France in 2011 and Tamoil's Cremona refinery in Italy in 2011. Shell has announced that it will convert its Harburg refinery in Germany to an oil terminal by mid-2012. LyondellBasel is currently discussing plans to shut its 105 kb/d Berre L'Étang refinery, but no decision has been taken yet.

Completed and Announced Refinery Closures Europe (kb/d)

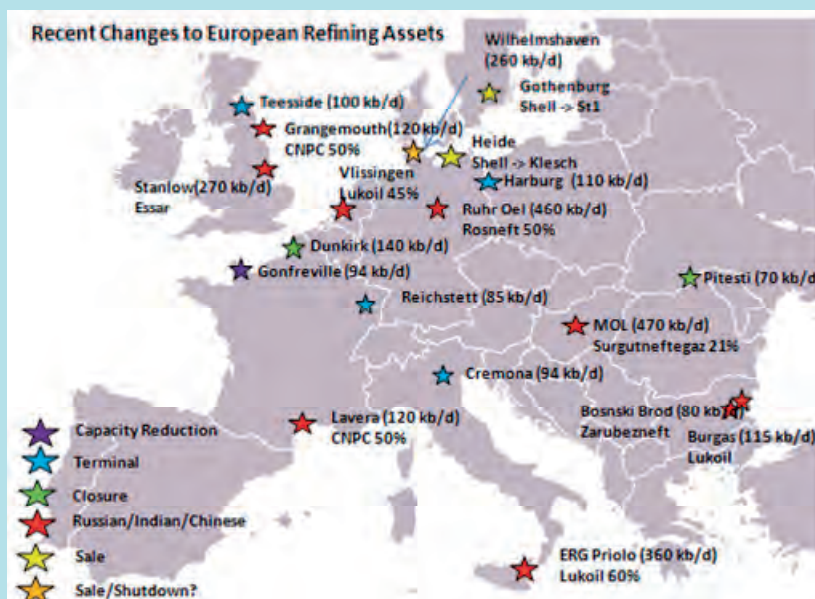
Country	Company	Plant	Capacity	Timing
UK	Petroplus	Teesside	100	2009
France	Total SA	Dunkirk	141	2010
Romania	Arpichem SA	Pitești	70	2010
France	Petroplus	Reichstett	85	2011
France	Total SA	Gonfreville l'Orcher (Capacity Reduction)	94	2011
Italy	Tamoil	Cremona	94	2011
Germany	Shell	Harburg	110	2012
Total Europe			694	
<i>Of which OECD Europe</i>			<i>600</i>	

In addition to the plants already closed or scheduled to close, several refineries are currently officially for sale. Some of these could face shutdown if no buyer is found, although prohibitive site remediation costs encourage operators to continue operating sites for storage rather than shutting them down completely. However, closure is the most likely fate of ConocoPhillips' 260 kb/d Wilhelmshaven refinery which has largely been idle since the end of 2009 due to poor margins. The Libyan Investment Authority/Sovereign Wealth Fund is planning to divest at least 50% of Tamoil, its European refinery and

The Restructuring of Europe's Refinery Industry Continues (continued)

marketing company, and has already closed its Cremona refinery in Italy. The company's Collombey refinery in Switzerland and its Holborn refinery in Germany could also face sale or closure, though a sale is unlikely for the time being, given uncertainty surrounding Libyan assets and sanctions. In the UK, Murphy Oil has decided to exit the refining sector and is looking for a buyer for its Milford Haven plant. The refinery completed a debottlenecking in 1Q10, lifting capacity by 22 kb/d to 130 kb/d. Also in the UK, Total is trying to sell its Lindsey refinery as part of its aim to shed a total of 500 kb/d of refining capacity, after pledging not to close any further sites in France, following industrial action in the wake of the Dunkirk closure.

Several refineries have changed ownership in the last year, and it is particularly noteworthy that largely upstream, cash-rich non-OECD companies are making an entry into the European refining sector, buying plants at distressed prices. On 10 January, China's state-owned PetroChina and UK-based Ineos signed an agreement to form an oil refining and trading joint venture, marking China's first move into the European refining sector. The deal encompasses Ineos' two European refineries: the Grangemouth refinery in Scotland and the Lavera refinery in southern France, both with processing capacity of around 210 kb/d. The cooperation includes the sharing of refining and petrochemical technology and expertise between the respective businesses.



Russian oil giant Rosneft made a similar move in October, when it bought PDVSA's 50% stake in Germany's Ruhr Oel. The company is now a 50/50 downstream joint venture between BP and Rosneft, with stakes in four German refineries, including Gelsenkirchen (100%), Schwedt (37.5%), Bayernoil (25%) and Miro (24%). The four plants have a combined capacity of 1.04 mb/d, of which 460 kb/d belonging to Ruhr Oel. There are now 13 refineries in Europe with Russian equity interest.

Indian-based Essar Energy finally closed the deal to buy Shell's 270 kb/d Stanlow refinery in the UK in April. The deal marks Shell's exit of the UK refining market and allows Essar to enter the European downstream market. Essar might use Stanlow's distribution network to place clean products from its Indian west coast Vadinar refinery. The UK also saw major independent US refiner Valero enter the market recently, as the latter agreed to buy Chevron's 210 kb/d Pembroke refinery, including marketing

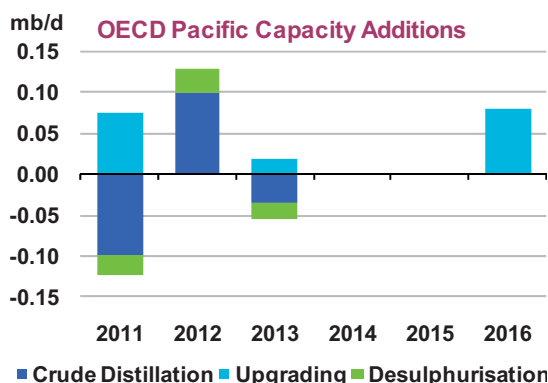
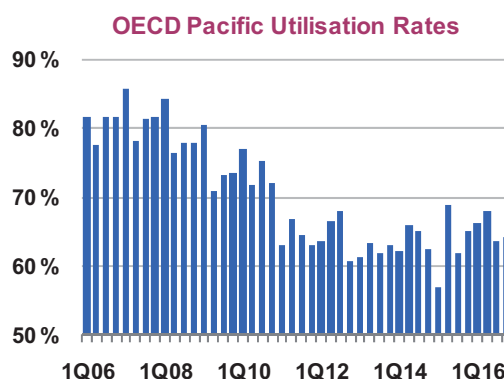
Restructuring of European Refinery Industry Continues (continued)

and logistical assets. Valero, which disposed of two refineries on the US East Coast in 2010, might want to ship products from the UK across the Atlantic to key East Coast product markets. Furthermore, Total recently sold its 49% stake in Spanish CEPSA to Abu Dhabi's state-owned investment fund IPIC. Shell sold its 80 kb/d Gothenburg refinery to St1 (a Finnish energy company with 1,200 retail stations in Finland, Sweden, Norway and Poland and 6 bioethanol plants) in October 2010. While the influx of capital from cash-rich overseas interests sustains local employment and allows for the potential upgrading of mature European capacity, it does little to address a continent-wide problem of surplus refining capacity.

OECD Pacific

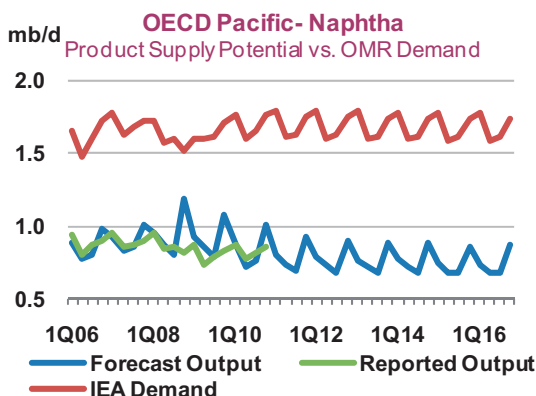
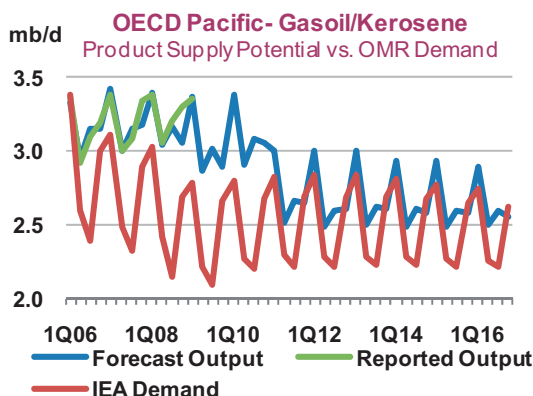
OECD Pacific refinery consolidation plans have been altered by the earthquake and tsunami that devastated **Japan** in March this year. Three refineries, with a combined capacity of some 600 kb/d, remain shut after the disaster, of which two might remain closed for some time due to sustained damage. JX Nippon was planning to restart the 250 kb/d Kashima refinery in June, while the 145 kb/d Sendai refinery will only likely start production in the summer of 2012. Cosmo Oil's 220 kb/d Chiba refinery also remains shut, with no announced restart date.

Japan had previously announced plans to cut capacity by over 1 mb/d, though we had only counted some 400 kb/d of this as firmly committed and allocated to specific plants (see *Japan - Talking Refinery Consolidation – Major Reductions Yet to Come* in *MTOGM 2010*). Following the devastating earthquake, Cosmo Oil reversed already-completed capacity cuts at both its Yokkaichi (50 kb/d) and Sakaide (30 kb/d) refineries in a matter of days, though we had not counted these in our shutdown assessments. JX Nippon announced in late March it had restarted capacity at its Mizushima plant, raising capacity by 50 kb/d to 400 kb/d to help ease fuel shortages. Mizushima's rationalisation had been part of the company's plan to cut a third of its capacity. Showa Shell, however, announced it remains committed to mothball its 120 kb/d Ohgimachi Factory by September. Rationalisation efforts are expected to be revived, once the damaged capacity is reinstalled and supply disruptions ease.



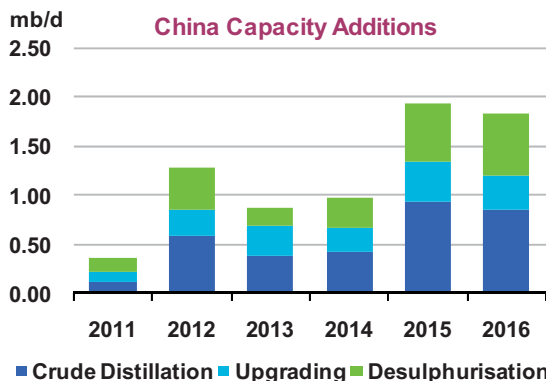
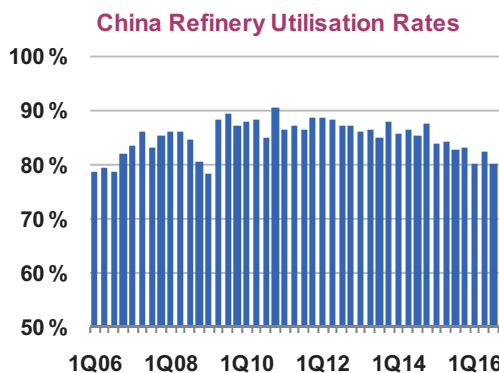
Australia is also having to reconsider the viability of some of its aging refineries in the face of competition from sophisticated, large facilities constructed in Asia. Shell is looking to convert its 75 kb/d Clyde refinery into an oil terminal by mid-2013 at the latest, when the plant would otherwise require significant investment in order to continue operations. Some investments are nonetheless taking place in **South Korea**, where both Hyundai Oil and GS Caltex are expanding heavy oil upgrading facilities.

OECD Pacific refinery throughputs are expected to fall sharply over the medium term. An aging and shrinking population, coupled with increased energy efficiency, will likely cut demand for key products such as gasoline and fuel oil over the period. Middle distillate demand is expected to largely trend sideways to 2016, but from the already reduced levels of 2009/2010. Naphtha will remain the region's key import, averaging around 0.9 mb/d in the entire forecast period, to fuel the large petrochemical industry. Most naphtha imports are sourced from the Middle East to South Korea.



China

China remains the single largest contributor to refinery capacity growth in the medium term. After adding some 900 kb/d and 660 kb/d of CDU capacity in 2009 and 2010, respectively, total Chinese distillation capacity is assessed at 10 mb/d in early 2011. Few additions are seen completed in 2011, but from 2012 onwards we expect several large projects to come to completion, with a total of 3.3 mb/d of net CDU capacity additions by 2016.



Upstream Heavyweights Move Downstream in China

Over the last year, Middle East producers have increased their presence in the Chinese downstream sector. In March 2011, Saudi Aramco signed a memorandum of understanding (MoU) with PetroChina to build a 200 kb/d refinery in the Yunnan Province, representing the company's third project targeted in China. Aramco was the first Mideast producer to invest in a Chinese refinery, through its 240 kb/d Fujian refinery, developed jointly with Sinopec and ExxonMobil, started in 2009. A third proposed joint venture between Aramco and Sinopec in Quindao fell through over differences on investment returns; Sinopec completed the project on its own in 2008.

The Yunnan project is strategically important to China as it will be complemented by a 400 kb/d pipeline from Myanmar to Kunming in Yunnan province, allowing crude deliveries to bypass the Malacca Strait, enhancing security of supply for a part of China's seaborne oil imports. Construction of the pipeline started last year and the goal is to complete it by 2013. The Middle East accounted for 47% of China's crude imports in 2010 (2.26 mb/d), of which Saudi Arabia supplied some 900 kb/d.

Kuwait Petroleum Corp. (KPC) finally received approval from China's National Development and Reform Commission (NDRC) in May to build a 300 kb/d refinery and petrochemical plant at Zhanjiang to start up by 2015. The approval puts an end to almost six years of waiting. KPC has been trying to strengthen ties with China as a means to secure markets for its crude. KPC is also looking to participate in a 240 kb/d refinery project in Fujian led by Sinochem, further increasing Kuwait's market share in China, which stood at a modest 200 kb/d, or 4% of Chinese crude imports, in 2010.

Qatar Petroleum is waiting for approval from the NDRC for its proposed Taizhou refinery and petrochemical project (with Royal Dutch Shell and PetroChina). The project would provide an outlet for Qatar's rapidly increasing condensate production and provide strong naphtha yields to feed China's burgeoning petrochemical sector.

Chinese-Middle East investment flows are not simply one-way: PetroChina signed a deal in March to take 37.5% stake of Saudi Aramco's 400 kb/d Yanbu refinery, after ConocoPhillips pulled out in 2010, further enhancing the strategic alliances between key producer and consumer countries.

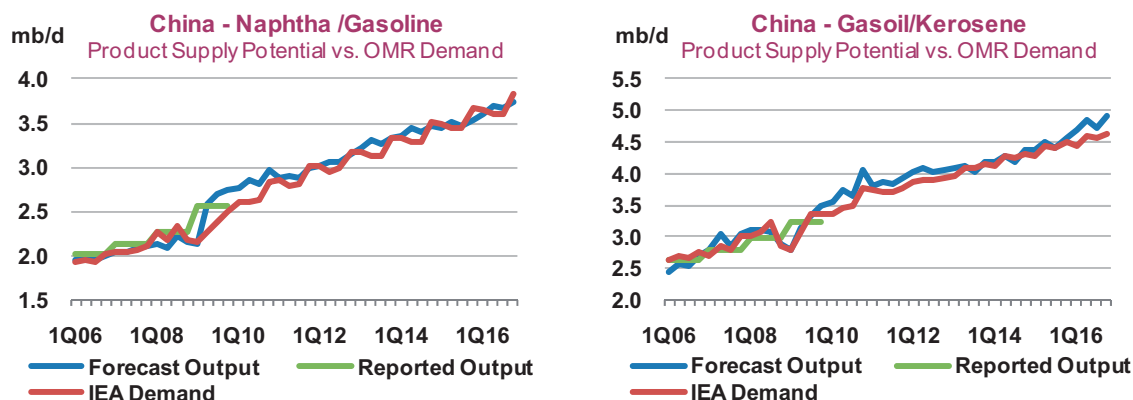
Russia is also moving to enhance energy cooperation with its large neighbour. Rosneft and CNPC have established a JV (Chinese-Russian Eastern Petrochemical Company) to build a refinery in Tianjin and develop a network of retail stations in China. According to a feasibility study prepared by the East-China Petroleum and Natural Gas Exploration and Design Institute, the 260 kb/d refinery with a light product yield of over 80%, is planned to be completed by 2015. The refinery will also have integrated petrochemical operations.

On 6 January 2011, China's Ministry of Environmental Protection gave its preliminary clearance for the proposed Guangdong Province refinery to be built by PetroChina and PDVSA, following NDRC project approval last year. The \$8.7 bn refinery, which is to be located in Jieyang, will have the capacity to refine 400 kb/d of heavy Venezuelan crude. The move is part of an attempt by China to enhance ties with the OPEC producer and secure and diversify crude supplies. The project is expected to be completed by 2016.

As in previous reports, we highlight the large uncertainty in the pace of Chinese refinery expansions. The sheer number of proposed projects means that some projects likely compete against each other and could be delayed or cancelled altogether. In the end, the pace of expansion will probably depend on oil demand growth. We think that China's National Development and Reform Commission (NDRC)

will control the speed at which more domestic refinery capacity is brought on line, in order to avoid creating surplus capacity. We retain our assumption that NDRC will make sure supplies are adequate but not excessive by controlling project approvals.

Since our December update, we have included the shutdown of some local refineries in the overall capacity assessment. Small, unsophisticated domestic refiners remain under pressure to close plants and many are currently idle due to lack of access to feedstock. The latest regulations issued by the NDRC aim at shutting small refineries with a capacity of less than 40 kb/d by 2013 and halting construction of plants smaller than 200 kb/d. The previous plan had set minimum capacity of small refineries at 20 kb/d. The newest guidelines also state that catalytic crackers and hydrocrackers should have capacity of more than 30 kb/d. We have thus reduced local refinery capacity by 100 kb/d per year from 2010-2015, and 50 kb/d in 2016.



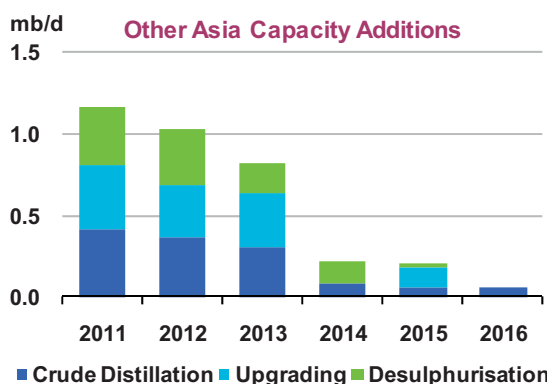
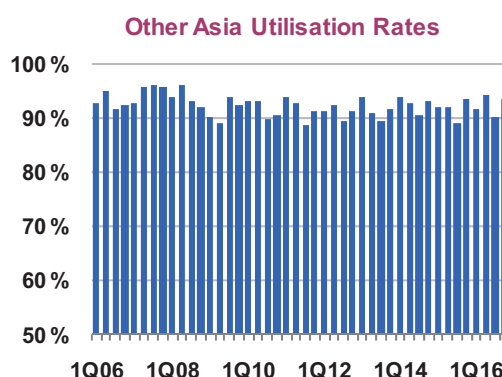
As highlighted above, a key assumption regarding the Chinese refining industry is that expansions and runs keep pace with demand growth for key products. By 2016, both light and middle distillates remain mostly balanced (a 100-200 kb/d swing in either direction could materialise), while fuel oil imports are seen steady at around current 200-300 kb/d levels.

Other Asia

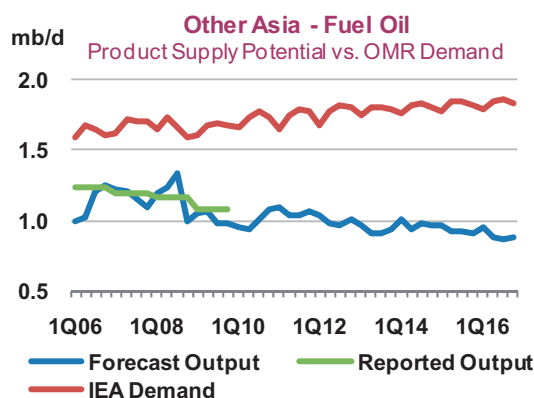
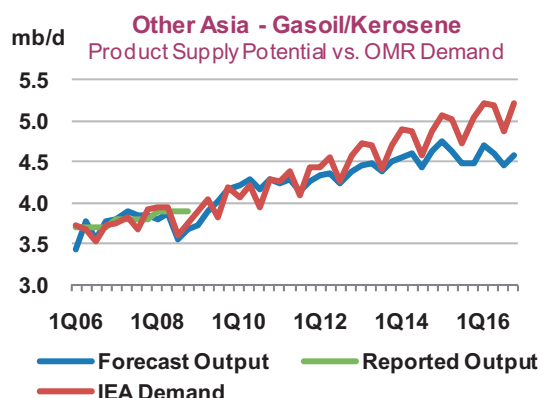
Refinery additions in **Other Asia** in the medium term continue to be dominated by **India**. After expanding crude distillation capacity by a massive 0.8 mb/d over 2009-2010, reaching 4.0 mb/d by early 2011, the country is expected to account for almost 80% of the region's 1.3 mb/d firm and likely additions by 2016. Key projects include Bharat Oman Refinery Ltd.'s 120 kb/d Bina refinery and Hindustan Mittal Energy Ltd.'s 180 kb/d Bhatinda grassroots projects, both slated to start commercial operations this year, augmented by expansions of IOC's Koyali and Essar's Vadinar plants. Next year, we expect the completion of the Cuddalore refinery before Indian Oil's 300 kb/d Paradip refinery starts operations in 2013.

Other regional projects likely to be completed in the forecast period include **Vietnam's** 195 kb/d Nghi Son refinery, now expected in 2015. PetroVietnam is also planning to expand capacity of its Dung Quat plant from 130 kb/d to 200 kb/d, potentially with PDVSA as a partner, though likely only after the timeframe of this report. Byco Petroleum seems to be progressing with the expansion of its

30 kb/d Balochistan refinery in **Pakistan**, where it is installing a 120 kb/d unit relocated from the UK, and we expect this to be completed in early 2012.



We continue to include the planned decommissioning of **Taiwan's** 205 kb/d Kaohsiung refinery in 2015, even though this looks less firm than previously expected. The company reportedly started decommissioning units in 2010, making good on a promise made to local residents 20 years ago to shut the plant by 2015, in exchange for allowing the firm to build a new ethylene plant on the site. Lack of progress on the proposed greenfield refinery by Kuokuang Petrochemical Technology Corp. could potentially delay the mothballing, however.

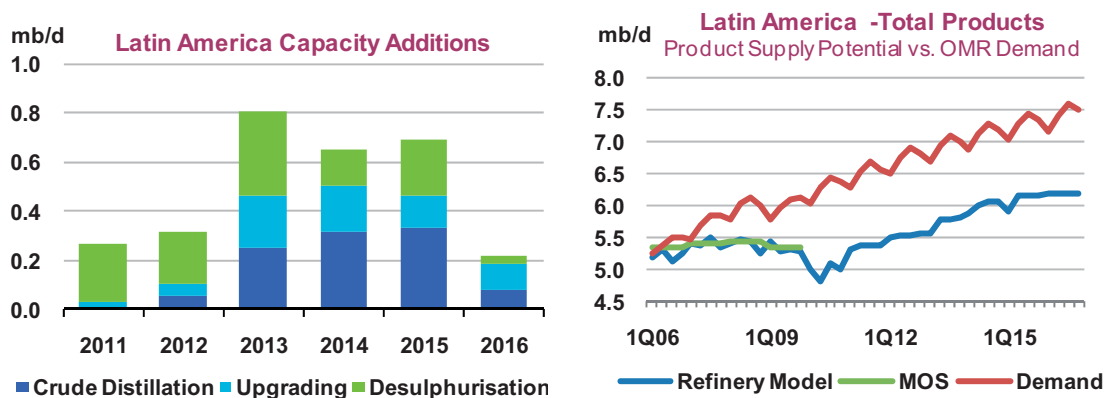


Firm refinery expansions in 'Other Asia' fail to keep track with expected demand growth in the forecast period. Middle distillates import requirements could rise sharply, from a slight surplus currently, to 0.5 mb/d in 2016. Fuel oil import requirements will also rise slightly, from around an estimated 0.9 mb/d in 2010 to 1.2 mb/d in 2016 to meet increased regional bunker demand.

Latin America

Latin American investments are motivated by increasing crude production, strong regional demand growth and tighter fuel specifications as well as a way to develop industry and create jobs. Projects remain focused on **Brazil**, where Petrobras is planning to increase refining capacity by 75% from 2010 to 2020, through several large grassroots projects. Total regional crude distillation additions amount to 1.0 mb/d over the forecast period, of which Brazil accounts for almost 70%. We expect the

230 kb/d Abreu e Lima refinery to be completed in 2012, the first 165 kb/d phase of the Comperj project in 2013 and the first phase of Premium 1 in 2015. Because of the scale of the expansion programme, the second phase of Premium 1 could be delayed beyond the 2016 target. The second phase of Comperj, as well as the proposed Premium 2, are scheduled to add another 465 kb/d, but after 2016.



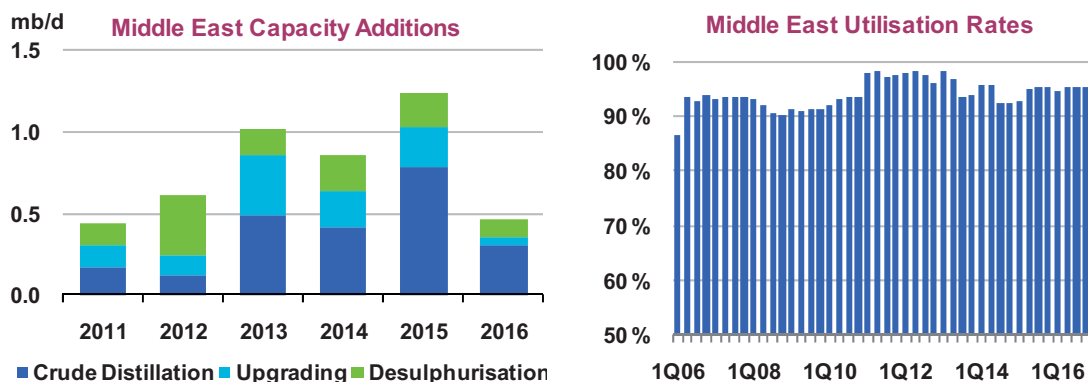
Elsewhere in the region, **Colombia** is reportedly moving ahead with the expansion of its Cartagena and Barrancabermeja refineries. Together with foreign partners, national oil company Ecopetrol is spending more than \$7 bn to upgrade the two refineries, in order to handle the country's rapidly increasing production of heavy crude oil. Other projects include **Cuba's** expansion of Cienfuegos in 2014. PDVSA and ENI's planned 240 kb/d refinery in **Venezuela** and **Ecuador's** 300 kb/d Manabi project are not yet included. The 235 kb/d **Aruba** refinery, which we had excluded from our capacity estimates from 2009 when it was shut, has been reinstated following its restart early this year.

Latin America's import requirements shrink over the forecast period, as gasoline and ethanol production rise faster than demand growth and middle distillate import requirements remain relatively stable, around an estimated 350 kb/d currently. If regional refinery utilisation rates are raised in line with the commissioning of new capacity, at the expense of crude exports, the region could become a net product exporter by 2016.

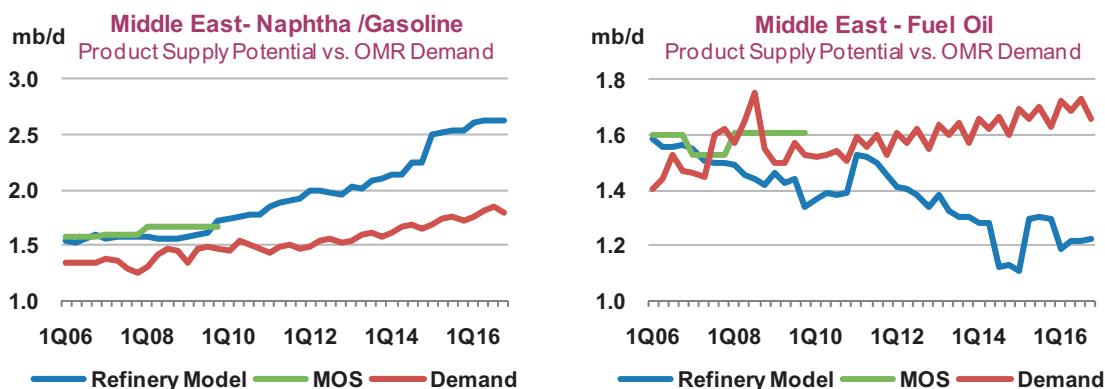
Middle East

The most significant changes to our medium term investment outlook since December's update have been made for the **Middle East**, and most notably for **Saudi Arabia**. State-owned Saudi Aramco seems to be pushing ahead with three major refinery constructions under its current investment plan; six months ago, only one project looked firm in the timeframe. In addition to the 400 kb/d Aramco/Total Jubail joint venture, which we see commissioned in 2013, a year earlier than in our last update, we also include the proposed Yanbu project completed within the timeframe of this report. Aramco recently confirmed that it plans to bring the 400 kb/d plant online by 2014 and has already awarded several engineering, procurement and construction contracts through its Red Sea Refining Company. In March, the company signed an initial deal with Sinopec for the Chinese state-company to take a 37.5% share. The refinery, which originally was to be built jointly by Aramco and ConocoPhillips, before the latter pulled out of the project in early 2010, will process heavy crude from the Manifa field. While the third project, the Jizan refinery, looks more firm than previously, the

complexity of the project, which includes large infrastructure investments, might delay it beyond 2016.



In the **United Arab Emirates**, the Ruwais refinery project seems to be progressing according to plan and we keep the 420 kb/d project in for 2014, one year after the announced completion date. Also in the UAE, IPIC, the Abu Dhabi sovereign wealth fund, announced in April it was moving forward with the proposed 200 kb/d refinery at Fujairah. While FEED contracts have been awarded, and the project is scheduled to be completed by mid-2016, we see likely delays and exclude this project from the timeframe of this report.

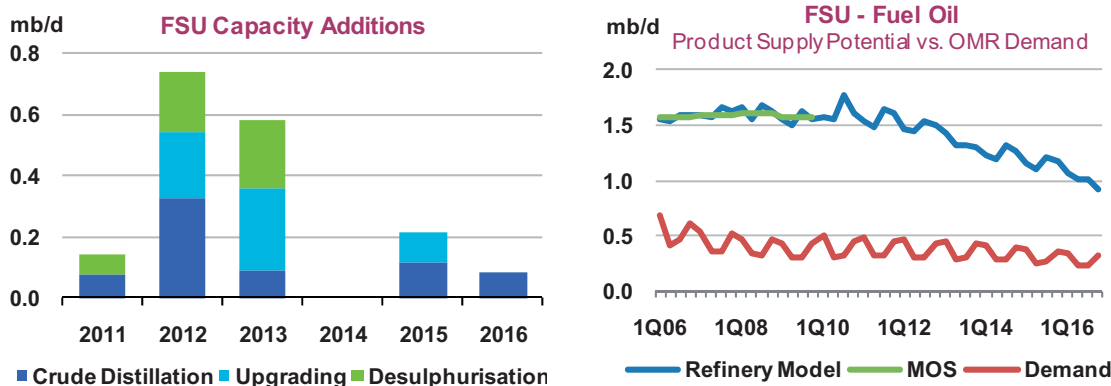


In **Iraq**, the government has ambitious plans to triple refining capacity to almost 1.5 mb/d through four new grassroots refineries and several upgrades to existing plants. The grassroots projects include Karbala (140 kb/d), Misan (150 kb/d), Kirkuk (150 kb/d) and Nasiriya (300 kb/d). The government stated in November last year that the Karbala refinery is the priority, due to high oil consumption in the region, and announced its willingness to pay for the project itself. Technip is close to completing the front end engineering and design on the \$4 billion project, and we see completion as likely by 2016. While progress is also being made on the Nasiriya and Misan projects, financing has not been secured and we do not assume completion within this outlook's timeframe. Financing remains a concern also in **Iran**, which after current international sanctions were stepped up has had to stall several projects due to lack of funds. In all, we see the Middle East add 2.3 mb/d of crude distillation capacity by 2016, heavily skewed towards the second half of the period.

The region potentially sees a striking tightening in its residual fuel oil balance, as power and desalination demand increases, while regional upgrading capacity limits supply. In reality, this may lead to a realignment of crude supply preference, with greater output of heavier grades to ensure more adequate supply.

Former Soviet Union

The refinery industry in the **Former Soviet Union** is expected to see significant investments in the medium term, as companies expand distillation capacity to increase product export potential and upgrade existing plants to meet more stringent domestic fuel specifications. While the current tax structure favours product exports over crude, recent fuel shortages in **Russia** have already forced the government to rebalance export duties to secure adequate domestic supplies. Even though regulatory uncertainty is a key issue for the region, we expect CDU capacity to increase by almost 700 kb/d by 2016. Upgrading and desulphurisation capacity investments are also impressive, as refiners strive to meet Euro 4 and Euro 5 fuel standards.



Key projects include Tatneft's new 140 kb/d Nizhnekamsk refinery, which was completed in 2010, but which started commercial operations 2011. Rosneft is reportedly on track to expand capacity of its Tuapse refinery to 240 kb/d by next year. While the crude distillation unit could be installed already by December or January of next year, it will likely only reach capacity once the second stage, including hydrocracking, isomerisation and desulphurisation units, is completed in 2013. Rosneft will also upgrade its Komsomolsk and Achinsk refineries by 2013. Gazprom is constructing a 120 kb/d crude unit at its Salavat refinery as part of a \$230 million modernisation project this year. Lukoil plans to increase crude distillation capacity at its Ukhta refinery by 70 kb/d sometime late this year or by early 2012, and the Atinpinsky refinery is due for a 70 kb/d expansion in 2013. West Siberian Oil Refinery has announced plans to invest \$600 million in a 60 kb/d oil refinery in Tomsk.

Elsewhere in the region, a feasibility study for the expansion of **Kazakhstan's** Pavlodar refinery has reportedly been completed, though the results are not yet known. If favourable, construction of a new 50 kb/d CDU and desulphurisation units could start in 2012. **Turkmenistan** is also planning to build a new refinery at Okarem on the Caspian Sea to replace the aging Seide plant. However, these plans are not yet advanced enough to be included in this forecast.

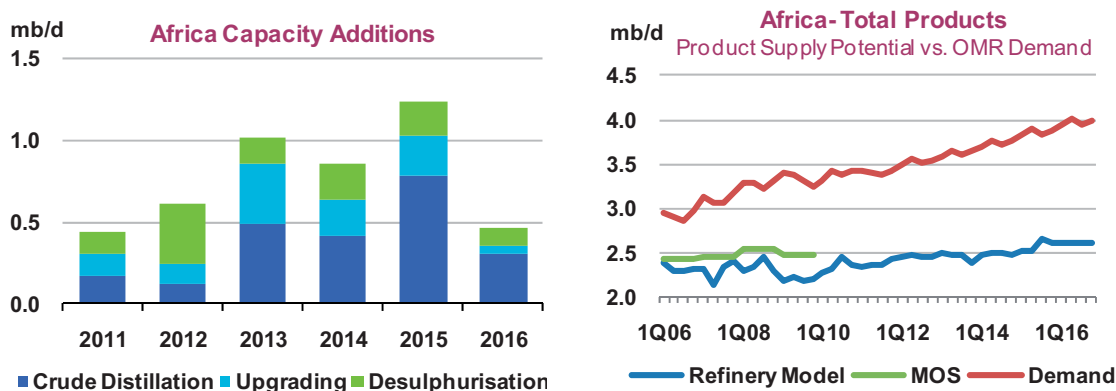
The investments mentioned above could keep oil product exports steady at today's levels, assuming tax structures remain favourable to process crude at home and export products. Upgrading additions will reduce fuel oil production, however, potentially cutting exports from today's 1.2 mb/d to 0.7 mb/d in 2016. Increased motor gasoline and middle distillate supplies will, nonetheless, offset the decline in heavy fuel oil.

Africa

While there is no lack of proposed refinery projects in **Africa**, and the region's import dependence on refined products continues to increase, little progress has been made to date. Financing problems have stalled projects in **Angola** and **South Africa** and, so far, no advance seems to have been made on Chinese investor's pledge to build three refineries in **Nigeria**. The recent uprising and change of governments in **Egypt** and **Tunisia** could furthermore stall or delay projects in those countries, including Egypt's proposed grassroots projects in Mostorod and El-Sokhna. While early work is continuing on the Egyptian Refining Co.'s (ERC) Mostorod site, the project is now awaiting approval from the new government and we expect the commissioning to be delayed to after 2016.

Major projects like Angola's 200 kb/d Lobito refinery and South Africa's proposed 200-400 kb/d Coega refinery are still seen as unlikely to be completed within the next five years. Financing is a major concern for both projects, and the energy ministry has delayed approving the Coega plans until financing and a lead shareholder have been secured. The latest from Angola is also that construction of the plant has been slowed as Sonangol seeks a partner for the \$8 billion project.

The expected ramp-up of oil production in the Lake Albertine Rift Basin in **Uganda**, to 160 kb/d by 2016, has led us to include a small refinery in that country by that date. While producer Tullow and its new partners Total and CNPC seem to favour a crude export pipeline through Kenya, the Ugandan government prefers supplying the domestic market with locally refined products. The capacity of the plant is not yet determined, and proposals vary from a 10 kb/d mini-refinery to a 200 kb/d plant. We think a 60 kb/d facility unveiled by local officials earlier this year, could be completed by 2016.



Unless progress is made on at least one of the proposed refinery projects, African oil product imports will rise significantly in the period. Both gasoline and middle distillate requirements will increase, as demand for transportation fuels continues to grow.

TABLES

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

	1Q10	2Q10	3Q10	4Q10	2010	1Q11	2Q11	3Q11	4Q11	2011	2012	2013	2014	2015	2016
OECD DEMAND															
North America	23.6	23.8	24.3	24.0	23.9	23.9	23.7	24.0	23.8	23.8	23.8	23.7	23.6	23.5	23.3
Europe	14.2	14.1	14.8	14.7	14.4	14.0	13.8	14.6	14.5	14.3	14.2	14.1	14.0	13.9	13.7
Pacific	8.2	7.3	7.6	8.0	7.8	8.3	7.3	7.6	8.1	7.8	7.7	7.7	7.7	7.6	7.6
Total OECD	45.9	45.2	46.7	46.8	46.1	46.2	44.8	46.2	46.5	45.9	45.7	45.5	45.3	44.9	44.6
NON-OECD DEMAND															
FSU	4.2	4.1	4.4	4.4	4.3	4.3	4.2	4.5	4.5	4.3	4.5	4.5	4.5	4.5	4.5
Europe	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	0.8	0.8
China	8.6	9.1	8.9	9.7	9.1	9.5	9.7	9.7	9.9	9.7	10.2	10.7	11.1	11.6	12.1
Other Asia	10.4	10.6	10.2	10.6	10.4	10.7	10.9	10.5	10.9	10.8	11.1	11.5	11.8	12.2	12.5
Latin America	6.0	6.3	6.4	6.4	6.3	6.3	6.5	6.7	6.6	6.5	6.7	6.9	7.1	7.2	7.3
Middle East	7.4	7.8	8.2	7.7	7.8	7.6	7.9	8.5	7.8	7.9	8.2	8.5	8.8	9.2	9.5
Africa	3.3	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.5	3.6	3.8	3.9	4.0
Total Non-OECD	40.6	41.9	42.2	42.8	41.9	42.5	43.3	43.8	43.8	43.4	44.9	46.4	47.9	49.3	50.7
Total Demand¹	86.5	87.1	88.8	89.6	88.0	88.7	88.1	90.0	90.3	89.3	90.6	91.9	93.1	94.2	95.3
OECD SUPPLY															
North America	13.9	14.1	14.1	14.4	14.1	14.4	14.0	14.0	14.3	14.2	14.4	14.5	14.6	15.1	15.6
Europe	4.5	4.2	3.8	4.2	4.2	4.1	4.0	4.0	4.3	4.1	4.1	3.9	3.7	3.7	3.5
Pacific	0.6	0.6	0.6	0.6	0.6	0.5	0.6	0.7	0.7	0.6	0.7	0.6	0.6	0.6	0.6
Total OECD	19.1	18.9	18.5	19.2	18.9	19.0	18.6	18.6	19.3	18.9	19.2	19.0	18.9	19.4	19.7
NON-OECD SUPPLY															
FSU	13.5	13.5	13.5	13.7	13.6	13.7	13.7	13.6	13.7	13.7	13.7	13.6	13.7	13.8	13.8
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	4.0	4.1	4.1	4.2	4.1	4.2	4.1	4.3	4.3	4.2	4.3	4.3	4.3	4.3	4.2
Other Asia	3.7	3.7	3.8	3.7	3.7	3.7	3.7	3.6	3.6	3.6	3.5	3.6	3.6	3.5	3.3
Latin America	4.0	4.1	4.1	4.1	4.1	4.2	4.2	4.4	4.5	4.3	4.6	4.7	4.8	5.1	5.3
Middle East	1.7	1.7	1.7	1.7	1.7	1.7	1.6	1.7	1.8	1.7	1.8	1.7	1.6	1.6	1.5
Africa	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.5	2.5
Total Non-OECD	29.7	29.8	30.0	30.1	29.9	30.2	30.0	30.4	30.6	30.3	30.7	30.6	30.7	30.9	30.7
Processing Gains ²	2.0	2.1	2.1	2.1	2.1	2.2	2.1	2.1	2.2	2.2	2.3	2.4	2.5	2.5	2.6
Global Biofuels ³	1.4	2.0	2.1	1.8	1.8	1.5	1.9	2.2	2.0	1.9	2.0	2.2	2.3	2.3	2.3
Total Non-OPEC ⁴	52.2	52.7	52.7	53.2	52.7	52.9	52.6	53.4	54.2	53.3	54.2	54.2	54.3	55.1	55.4
OPEC															
Crude ⁵	29.3	29.3	29.7	29.6	29.5	29.9									
OPEC NGLs	5.2	5.2	5.5	5.6	5.3	5.8	5.8	5.9	6.0	5.9	6.3	6.7	7.0	7.3	7.4
Total OPEC	34.5	34.5	35.1	35.2	34.8	35.7									
Total Supply	86.7	87.2	87.8	88.4	87.5	88.6									

Memo items:

Call on OPEC crude + Stock ch.⁶ 29.2 29.2 30.7 30.7 30.0 30.0 29.7 30.7 30.1 30.1 30.1 31.0 31.8 31.8 32.5

1 Measured as deliveries from refineries and primary stocks, comprises inland deliveries, international marine bunkers, refinery fuel, crude for direct burning, oil from non-conventional sources and other sources of supply.

2 Net volumetric gains and losses in the refining process and marine transportation losses.

3 As of the June 2010 MTOGM, Global Biofuels comprise all world biofuel production including fuel ethanol from the US and Brazil.

4 Non-OPEC supplies include crude oil, condensates, NGL and non-conventional sources of supply such as synthetic crude, coal-to-liquids (CTL), gas-to-liquids (GTL) and refinery additives.

5 As of the March 2006 OMR, Venezuelan Orinoco heavy crude production is included within Venezuelan crude estimates. Orimulsion fuel remains within the OPEC NGL & non-conventional category, but Orimulsion production reportedly ceased from January 2007.

6 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)

	1Q10	2Q10	3Q10	4Q10	2010	1Q11	2Q11	3Q11	4Q11	2011	2012	2013	2014	2015	2016
OECD DEMAND															
North America	0.0	0.0	0.0	0.2	0.1	0.2	0.0	-0.1	-0.2	0.0	-0.1	-0.1	-0.1	-0.1	
Europe	0.0	0.0	0.0	0.3	0.1	-0.1	-0.2	0.0	0.2	0.0	0.0	0.1	0.1	0.1	
Pacific	0.0	0.0	0.0	0.3	0.1	0.2	0.0	0.3	0.5	0.3	0.3	0.3	0.4	0.4	
Total OECD	0.0	0.0	0.0	0.8	0.2	0.4	-0.1	0.2	0.5	0.2	0.2	0.3	0.4	0.4	
NON-OECD DEMAND															
FSU	0.0	0.0	-0.1	0.1	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.1	0.1	0.1	
Europe	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
China	-0.3	-0.3	-0.3	0.2	-0.2	0.1	-0.1	0.0	0.1	0.0	0.0	0.0	-0.1	-0.1	
Other Asia	0.2	0.2	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.4	0.5	
Latin America	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	
Middle East	0.2	0.2	0.3	0.3	0.3	0.1	0.0	0.1	0.2	0.1	0.0	0.0	-0.1	-0.1	
Africa	0.1	0.1	0.1	0.2	0.1	0.1	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	
Total Non-OECD	0.2	0.2	0.2	1.0	0.4	0.4	0.1	0.3	0.5	0.3	0.4	0.4	0.4	0.4	
Total Demand	0.2	0.2	0.2	1.8	0.6	0.7	-0.1	0.4	1.0	0.5	0.6	0.7	0.8	0.9	
OECD SUPPLY															
North America	0.0	0.0	0.0	0.3	0.1	0.4	0.3	0.2	0.3	0.3	0.5	0.7	0.9	1.1	
Europe	0.0	0.0	0.0	0.1	0.0	-0.1	0.0	0.1	0.2	0.0	0.2	0.1	0.0	0.2	
Pacific	0.0	0.0	0.0	-0.1	0.0	-0.1	-0.1	0.0	0.0	-0.1	0.0	0.0	0.1	0.1	
Total OECD	0.0	0.0	0.1	0.3	0.1	0.1	0.2	0.3	0.5	0.3	0.6	0.8	1.1	1.4	
NON-OECD SUPPLY															
FSU	0.0	0.0	0.0	-0.1	0.0	-0.1	-0.1	0.0	-0.1	-0.1	-0.2	-0.2	-0.2	-0.2	
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	0.1	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.1	0.1	0.1	
Other Asia	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	-0.1	0.0	0.0	-0.1	
Latin America	0.0	0.0	0.0	0.0	0.0	0.0	-0.1	0.0	0.1	0.0	0.2	0.0	-0.1	0.0	
Middle East	0.0	0.0	0.0	0.0	0.0	0.0	-0.1	0.0	0.1	0.0	0.1	0.1	0.1	0.1	
Africa	0.0	0.0	0.0	0.0	0.0	0.0	-0.1	0.0	-0.1	0.0	0.0	0.0	0.0	0.0	
Total Non-OECD	0.0	0.1	0.1	0.0	0.0	-0.2	-0.3	0.0	0.1	-0.1	0.0	0.0	-0.2	-0.1	
Processing Gains	-0.3	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.1	-0.2	-0.1	-0.1	0.0	0.0	
Global Biofuels	0.0	0.0	0.0	0.0	0.0	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	
Total Non-OPEC	-0.2	-0.1	-0.1	0.1	-0.1	-0.3	-0.5	0.0	0.3	-0.1	0.4	0.7	0.7	1.1	
OPEC															
Crude	0.2	0.3	0.4												
OPEC NGLs	0.0	0.0	0.1	0.1	0.1	0.1	0.0	0.0	0.1	0.0	0.1	0.1	0.1	0.2	
Total OPEC	0.3	0.3	0.5												
Total Supply	0.1	0.2	0.5												
Memo items:															
Call on OPEC crude + Stock ch.	0.3	0.3	0.2	1.6	0.6	0.9	0.4	0.5	0.7	0.6	0.1	0.0	0.0	-0.5	

Table 2
SUMMARY OF GLOBAL OIL DEMAND

	1Q10	2Q10	3Q10	4Q10	2010	1Q11	2Q11	3Q11	4Q11	2011	2012	2013	2014	2015	2016
Demand (mb/d)															
North America	23.58	23.76	24.26	24.03	23.91	23.88	23.68	24.01	23.79	23.84	23.77	23.68	23.58	23.45	23.31
Europe	14.18	14.12	14.79	14.69	14.45	14.05	13.85	14.58	14.55	14.26	14.23	14.14	14.02	13.88	13.71
Pacific	8.19	7.32	7.60	8.04	7.79	8.32	7.25	7.61	8.14	7.83	7.71	7.68	7.65	7.62	7.58
Total OECD	45.95	45.20	46.65	46.76	46.14	46.25	44.78	46.20	46.48	45.93	45.71	45.51	45.25	44.95	44.60
Asia	19.04	19.63	19.09	20.26	19.51	20.25	20.62	20.16	20.81	20.46	21.28	22.13	22.95	23.75	24.52
Middle East	7.35	7.77	8.22	7.65	7.75	7.59	7.91	8.46	7.81	7.94	8.22	8.49	8.82	9.17	9.51
Latin America	6.03	6.28	6.45	6.37	6.29	6.27	6.50	6.65	6.57	6.50	6.71	6.89	7.06	7.21	7.34
FSU	4.17	4.12	4.35	4.37	4.26	4.27	4.20	4.46	4.47	4.35	4.46	4.51	4.53	4.53	4.51
Africa	3.32	3.42	3.37	3.42	3.38	3.41	3.39	3.39	3.42	3.40	3.52	3.64	3.75	3.88	4.00
Europe	0.69	0.69	0.69	0.72	0.70	0.69	0.71	0.71	0.73	0.71	0.73	0.75	0.76	0.77	0.77
Total Non-OECD	40.60	41.92	42.18	42.80	41.88	42.48	43.32	43.83	43.80	43.37	44.92	46.42	47.88	49.29	50.66
World	86.55	87.11	88.83	89.56	88.02	88.73	88.10	90.04	90.29	89.30	90.63	91.92	93.13	94.24	95.26
of which:															
US50	18.93	19.10	19.57	19.31	19.23	19.20	19.07	19.39	19.12	19.20	19.15	19.09	19.01	18.91	18.81
Euro5*	8.80	8.68	9.08	8.93	8.87	8.65	8.44	8.88	8.80	8.69	8.60	8.51	8.39	8.26	8.12
China	8.63	9.06	8.92	9.67	9.07	9.53	9.73	9.65	9.89	9.70	10.18	10.65	11.13	11.59	12.05
Japan	4.79	4.04	4.33	4.54	4.42	4.83	4.00	4.34	4.64	4.45	4.32	4.30	4.28	4.26	4.23
India	3.38	3.44	3.13	3.38	3.33	3.50	3.57	3.26	3.51	3.46	3.59	3.71	3.83	3.95	4.05
Russia	2.94	2.95	3.19	3.14	3.06	2.99	2.98	3.25	3.21	3.11	3.18	3.21	3.21	3.20	3.18
Brazil	2.60	2.71	2.82	2.80	2.73	2.68	2.78	2.88	2.88	2.81	2.89	2.97	3.04	3.10	3.15
Saudi Arabia	2.33	2.73	3.02	2.54	2.66	2.47	2.82	3.19	2.67	2.79	2.90	3.02	3.18	3.34	3.51
Korea	2.31	2.18	2.15	2.35	2.25	2.35	2.13	2.14	2.33	2.24	2.24	2.23	2.21	2.19	2.16
Canada	2.19	2.21	2.29	2.27	2.24	2.27	2.19	2.23	2.23	2.23	2.21	2.19	2.17	2.15	2.12
Mexico	2.14	2.17	2.12	2.14	2.14	2.10	2.14	2.09	2.13	2.11	2.11	2.10	2.09	2.08	2.07
Iran	2.10	2.08	2.08	2.09	2.09	2.09	2.01	2.03	2.00	2.03	2.06	2.09	2.12	2.16	2.19
Total	61.14	61.35	62.71	63.17	62.10	62.66	61.86	63.33	63.42	62.82	63.43	64.06	64.65	65.18	65.65
% of World	70.64	70.43	70.59	70.54	70.55	70.62	70.22	70.34	70.24	70.35	69.99	69.69	69.42	69.16	68.91
Annual Change (mb/d)															
North America	0.15	0.82	0.99	0.49	0.61	0.31	-0.08	-0.25	-0.23	-0.07	-0.07	-0.09	-0.11	-0.12	-0.14
Europe	-0.88	-0.28	0.23	0.19	-0.18	-0.13	-0.27	-0.21	-0.15	-0.19	-0.03	-0.09	-0.12	-0.14	-0.16
Pacific	0.07	0.04	0.35	0.06	0.13	0.13	-0.06	0.02	0.10	0.05	-0.12	-0.02	-0.03	-0.03	-0.04
Total OECD	-0.67	0.58	1.57	0.73	0.56	0.30	-0.42	-0.45	-0.28	-0.21	-0.22	-0.20	-0.25	-0.30	-0.34
Asia	1.95	1.28	0.69	1.38	1.32	1.22	0.98	1.07	0.54	0.95	0.82	0.85	0.82	0.79	0.78
Middle East	0.34	0.25	0.26	0.30	0.29	0.24	0.14	0.24	0.15	0.19	0.27	0.28	0.33	0.34	0.35
Latin America	0.25	0.29	0.35	0.26	0.29	0.23	0.22	0.21	0.20	0.21	0.21	0.18	0.17	0.15	0.14
FSU	0.33	0.27	0.23	0.32	0.29	0.09	0.07	0.11	0.10	0.09	0.11	0.06	0.02	0.00	-0.02
Africa	-0.08	0.05	0.06	0.18	0.05	0.10	-0.03	0.02	0.01	0.02	0.12	0.11	0.12	0.12	0.12
Europe	-0.05	-0.05	-0.02	0.01	-0.03	0.00	0.02	0.01	0.01	0.01	0.03	0.02	0.01	0.01	0.00
Total Non-OECD	2.75	2.09	1.56	2.45	2.21	1.88	1.41	1.66	1.01	1.49	1.55	1.50	1.46	1.41	1.37
World	2.09	2.67	3.13	3.19	2.77	2.18	0.99	1.21	0.73	1.27	1.33	1.29	1.21	1.11	1.02
Revisions to Oil Demand from Last Medium Term Report (mb/d)															
North America	0.00	-0.02	0.05	0.20	0.06	0.21	0.00	-0.12	-0.21	-0.03	-0.06	-0.09	-0.11	-0.15	
Europe	0.01	-0.01	-0.01	0.31	0.08	-0.09	-0.18	-0.02	0.22	-0.02	0.04	0.08	0.11	0.12	
Pacific	0.00	0.00	0.00	0.25	0.06	0.24	0.05	0.30	0.45	0.26	0.26	0.33	0.39	0.44	
Total OECD	0.01	-0.02	0.03	0.77	0.20	0.36	-0.13	0.16	0.47	0.21	0.24	0.33	0.39	0.41	
Asia	-0.14	-0.14	-0.16	0.38	-0.01	0.26	0.15	0.16	0.24	0.20	0.24	0.30	0.33	0.35	
Middle East	0.21	0.22	0.25	0.34	0.25	0.10	-0.01	0.12	0.16	0.09	0.03	-0.04	-0.08	-0.13	
Latin America	-0.02	-0.02	0.00	-0.02	-0.01	-0.01	-0.03	-0.01	-0.04	-0.02	-0.01	-0.01	-0.02	-0.03	
FSU	-0.01	-0.01	-0.06	0.13	0.01	-0.04	-0.02	-0.04	0.09	0.00	0.04	0.07	0.09	0.10	
Africa	0.14	0.14	0.13	0.19	0.15	0.09	0.00	0.04	0.10	0.06	0.06	0.08	0.10	0.12	
Europe	-0.01	-0.01	-0.02	0.01	-0.01	-0.02	-0.01	-0.02	0.00	-0.01	0.00	0.01	0.02	0.02	
Total Non-OECD	0.16	0.18	0.15	1.02	0.38	0.38	0.06	0.25	0.55	0.31	0.36	0.41	0.44	0.44	
World	0.17	0.15	0.18	1.79	0.58	0.74	-0.06	0.41	1.01	0.53	0.60	0.74	0.83	0.85	
Revisions to Oil Demand Growth from Last Medium Term Report (mb/d)															
World	0.14	-0.12	-0.14	1.33	0.30	0.57	-0.22	0.22	-0.78	-0.05	0.08	0.13	0.09	0.03	

* France, Germany, Italy, Spain and UK

Table 3
WORLD OIL PRODUCTION

(million barrels per day)

	1Q10	2Q10	3Q10	4Q10	2010	1Q11	2Q11	3Q11	4Q11	2011	2012	2013	2014	2015	2016
OPEC															
Crude Oil															
Saudi Arabia	7.96	8.07	8.18	8.30	8.13	8.55									
Iran	3.71	3.75	3.69	3.67	3.70	3.63									
Iraq	2.38	2.31	2.34	2.43	2.36	2.66									
UAE	2.28	2.30	2.33	2.33	2.31	2.48									
Kuwait	2.03	2.03	2.03	2.03	2.03	2.08									
Neutral Zone	0.51	0.54	0.54	0.54	0.53	0.56									
Qatar	0.80	0.79	0.80	0.81	0.80	0.82									
Angola	1.88	1.77	1.67	1.61	1.73	1.61									
Nigeria	2.00	1.96	2.15	2.21	2.08	2.14									
Libya	1.53	1.56	1.56	1.56	1.55	1.13									
Algeria	1.25	1.24	1.26	1.27	1.25	1.27									
Ecuador	0.47	0.46	0.46	0.47	0.47	0.50									
Venezuela	2.50	2.54	2.66	2.36	2.52	2.52									
Total Crude Oil	29.29	29.32	29.65	29.60	29.47	29.95									
Total NGLs ¹	5.18	5.18	5.45	5.58	5.35	5.80	5.78	5.92	6.02	5.88	6.33	6.69	6.97	7.31	7.41
Total OPEC	34.47	34.50	35.10	35.18	34.81	35.75									
NON-OPEC²															
OECD															
North America	13.93	14.05	14.10	14.44	14.13	14.42	13.96	13.97	14.33	14.17	14.39	14.53	14.57	15.07	15.63
United States	7.67	7.74	7.80	8.00	7.80	7.92	7.87	7.69	7.84	7.83	7.89	7.99	7.90	8.05	8.35
Mexico	2.99	2.97	2.95	2.93	2.96	2.97	2.93	2.88	2.88	2.92	2.86	2.75	2.67	2.69	2.58
Canada	3.27	3.34	3.35	3.51	3.37	3.53	3.16	3.40	3.61	3.43	3.64	3.78	4.00	4.33	4.70
Europe	4.53	4.20	3.79	4.22	4.18	4.10	4.01	4.00	4.29	4.10	4.07	3.85	3.70	3.65	3.47
UK	1.52	1.40	1.21	1.35	1.37	1.26	1.25	1.22	1.38	1.28	1.29	1.21	1.17	1.13	1.03
Norway	2.36	2.16	1.96	2.21	2.17	2.17	2.08	2.11	2.25	2.15	2.14	2.04	1.96	1.99	1.93
Others	0.65	0.64	0.62	0.66	0.64	0.67	0.68	0.67	0.66	0.67	0.63	0.60	0.57	0.54	0.51
Pacific	0.63	0.62	0.61	0.58	0.61	0.52	0.59	0.67	0.69	0.62	0.70	0.65	0.63	0.64	0.62
Australia	0.53	0.52	0.52	0.49	0.51	0.42	0.50	0.58	0.60	0.53	0.61	0.57	0.56	0.58	0.56
Others	0.10	0.10	0.10	0.09	0.10	0.09	0.09	0.09	0.09	0.09	0.08	0.08	0.07	0.06	0.06
Total OECD	19.10	18.86	18.50	19.24	18.92	19.04	18.56	18.64	19.31	18.89	19.16	19.03	18.89	19.37	19.72
NON-OECD															
Former USSR	13.48	13.53	13.55	13.66	13.55	13.68	13.72	13.57	13.73	13.67	13.71	13.60	13.65	13.82	13.77
Russia	10.40	10.43	10.44	10.54	10.45	10.52	10.55	10.54	10.55	10.54	10.57	10.45	10.32	10.33	10.32
Others	3.09	3.10	3.11	3.12	3.10	3.16	3.16	3.04	3.18	3.13	3.13	3.14	3.34	3.49	3.45
Asia	7.71	7.76	7.90	7.92	7.82	7.90	7.80	7.92	7.86	7.87	7.86	7.94	7.98	7.78	7.52
China	3.99	4.06	4.14	4.22	4.10	4.21	4.15	4.31	4.29	4.24	4.31	4.35	4.35	4.29	4.21
Malaysia	0.74	0.72	0.70	0.71	0.72	0.70	0.65	0.63	0.63	0.65	0.61	0.65	0.74	0.71	0.68
India	0.83	0.84	0.88	0.91	0.86	0.91	0.93	0.92	0.91	0.92	0.92	0.91	0.86	0.79	0.72
Indonesia	0.98	1.00	0.98	0.94	0.97	0.94	0.93	0.92	0.89	0.92	0.87	0.87	0.89	0.86	0.81
Others	1.17	1.15	1.19	1.15	1.17	1.14	1.14	1.15	1.15	1.14	1.14	1.16	1.15	1.13	1.11
Europe	0.14	0.14	0.14	0.13	0.14	0.14	0.14	0.13	0.13	0.14	0.13	0.12	0.11	0.10	0.09
Latin America	4.03	4.10	4.09	4.10	4.08	4.19	4.20	4.44	4.55	4.34	4.65	4.67	4.81	5.12	5.33
Brazil	2.09	2.15	2.13	2.18	2.14	2.18	2.20	2.33	2.42	2.28	2.48	2.50	2.61	2.85	3.09
Argentina	0.71	0.71	0.71	0.66	0.70	0.70	0.63	0.71	0.71	0.69	0.70	0.69	0.67	0.66	0.64
Colombia	0.76	0.78	0.79	0.82	0.79	0.87	0.92	0.96	0.98	0.93	1.02	1.05	1.09	1.11	1.09
Others	0.46	0.46	0.46	0.44	0.45	0.45	0.44	0.44	0.44	0.44	0.44	0.43	0.44	0.51	0.50
Middle East	1.72	1.71	1.72	1.72	1.72	1.72	1.61	1.72	1.77	1.71	1.76	1.68	1.61	1.55	1.48
Oman	0.86	0.86	0.87	0.88	0.86	0.89	0.91	0.94	0.95	0.92	0.97	0.95	0.93	0.91	0.88
Syria	0.39	0.39	0.39	0.39	0.39	0.38	0.37	0.37	0.36	0.37	0.34	0.31	0.28	0.26	0.23
Yemen	0.29	0.28	0.27	0.27	0.28	0.26	0.13	0.22	0.25	0.21	0.25	0.24	0.22	0.21	0.19
Others	0.19	0.19	0.19	0.19	0.19	0.20	0.20	0.20	0.20	0.20	0.19	0.18	0.18	0.18	0.17
Africa	2.58	2.55	2.57	2.56	2.56	2.59	2.58	2.61	2.60	2.59	2.61	2.61	2.55	2.51	2.51
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	0.66
Equatorial Guinea	0.29	0.28	0.27	0.26	0.27	0.26	0.25	0.25	0.24	0.25	0.26	0.30	0.31	0.32	0.30
Sudan	0.47	0.46	0.48	0.47	0.47	0.46	0.44	0.44	0.43	0.44	0.41	0.37	0.34	0.30	0.27
Others	1.09	1.07	1.08	1.08	1.08	1.12	1.15	1.19	1.20	1.16	1.22	1.23	1.22	1.22	1.27
Total Non-OECD	29.66	29.79	29.96	30.09	29.88	30.22	30.03	30.41	30.64	30.33	30.71	30.62	30.72	30.89	30.70
Processing Gains ³	2.03	2.07	2.14	2.14	2.10	2.16	2.14	2.14	2.23	2.17	2.26	2.38	2.45	2.52	2.60
Global Biofuels ⁴	1.40	1.96	2.14	1.78	1.82	1.47	1.87	2.25	1.99	1.90	2.04	2.19	2.26	2.32	2.34
TOTAL NON-OPEC	52.19	52.69	52.73	53.25	52.71	52.89	52.60	53.43	54.17	53.28	54.18	54.22	54.33	55.11	55.36
TOTAL SUPPLY	86.65	87.19	87.83	88.42	87.53	88.63									

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 Non-OPEC supplies include crude oil, condensates, NGL and non-conventional sources of supply such as synthetic crude, coal-to-liquids (CTL), gas-to-liquids (GTL) and refinery additives.

³ Net volumetric gains and losses in refining (excludes net gain/loss China and non-OECD Europe) and marine transportation losses.

⁴ As of the June 2010 MTOGM, Global Biofuels comprise all world biofuel production including fuel ethanol from the US and Brazil.

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

Country	Project	Start Year	Peak Capacity (kbbd)	Country	Project	Start Year	Peak Capacity (kbbd)	Country	Project	Start Year	Peak Capacity (kbbd)
OECD North America											
USA	Great White, Silver Tip & Tobago	2010	100	Norway	Osølv	2012	13	Asia			
USA	Chinook & Cascade	2011	80	Norway	Visund South	2012	10	India	Bhagiyama	2011	50
USA	Nikaitchuq	2011	30	Norway	Fossekall/Dompa	2013	10	India	Aishwariya	2012	40
USA	Clipper	2011	12	Norway	Vigdis Northeast	2013	10	Indonesia	North Duri steam flood phases 2 & 3	2013	45
USA	Santa Cruz/Isabela	2012	50	Norway	Gollat	2014	60	Indonesia	Bukit Tua	2013	20
USA	Caesar	2012	40	Norway	Gudrun	2014	65	Malaysia	Sepat	2012	20
USA	Liberty	2013	40	Norway	Froy redevelopment	2014	35	Malaysia	Gumutut	2013	130
USA	Big Foot	2014	75	Norway	Ekofisk extension	2015	50	Malaysia	Malik	2013	50
USA	Jack/Sk Malo	2015	170	Norway	Edfisk extension	2015	25	Malaysia	Kebabangan/Kamunsu	2013	45
USA	Mad Dog tie-backs	2015	100	UK	Athena	2011	20	Papua N Guinea	Papua New Guinea LNG	2014	60
USA	Tubular Bells	2015	100	UK	Solan	2011	20	Papua N Guinea	Port Moresby LNG	2014	30
USA	Mars B	2015	65	UK	Bachus	2011	10	Thailand	Platong gas II	2011	20
USA	Kaskida	2016	140	UK	Causeway	2011	10	Thailand	Bongkot South gas	2012	50
Canada	Athabasca 2 - Jackpine 1A	2010	100	UK	Huntington	2012	30	Vietnam	Te Giac Trang/White Rhino	2011	40
Canada	Firebag 3	2011	68	UK	Bentley	2012	10	Vietnam	Hai Su Den/Hai Su Trang	2011	35
Canada	Christina Lake 1C	2011	40	UK	Perth	2013	15	Vietnam	Chim Sao	2011	25
Canada	Jackfish 2	2011	35	UK	Golden Eagle	2014	35	Latin America			
Canada	Kearl 1	2012	110	UK	Cheviot	2014	30	Brazil	Jubarte 2 P-57	2010	150
Canada	Long Lake 2	2012	72	UK	Fyre & Dandy	2014	20	Brazil	Albacore expansion	2010	100
Canada	Firebag 4	2013	68	UK	Clair expansion	2015	35	Brazil	Cachalote	2010	100
Canada	Christina Lake 1D	2013	40	OECD Pacific				Brazil	Lula (ex-Tup) pilot (phase 1)	2010	100
Canada	Kirby	2013	40	Australia	Pyrenes	2010	90	Brazil	Chinook/Peregrino	2011	100
Canada	Great Divide expansion	2013	24	Australia	Van Gogh	2010	40	Brazil	Marlim Sul 3 P-56	2011	100
Canada	Tamarack 1	2013	20	Australia	Montara	2011	35	Brazil	Waimea	2011	50
Canada	Horizon 2/3	2013	120	Australia	Kitan	2011	20	Brazil	Baleia Azul	2011	100
Canada	Sumrise 1	2014	60	Australia	West Seahorse	2012	20	Brazil	Guara South	2012	120
Canada	Sumrise 2	2014	50	Australia	Comiston	2013	25	Brazil	Papa Terra BC-20	2013	120
Canada	Carmon Creek 1	2014	40	Australia	North Rankin 2	2014	40	Brazil	Sidon/Tiro	2013	100
Canada	Christina Lake 1E	2014	40	Australia	Balraives	2014	25	Brazil	Roncador P-55	2013	150
Canada	Hangingsstone 1	2014	12	Australia	Wheatstone/LAGO LNG	2016	20	Brazil	Lula (ex-Tup) phase 2	2014	120
Canada	MacKay River 1	2014	35	FSU				Brazil	Aruaña	2014	100
Canada	Foster Creek 1F	2014	30	Russia	Yuri Korchagin	2010	50	Brazil	Parque das Baleias P-58	2015	150
Canada	Kearl 2	2015	110	Russia	Probskoye expansion	2011	100	Brazil	Roncador P-62	2015	150
Canada	Summont 2	2015	83	Russia	Yarakinskoye	2011	40	Brazil	Carioca	2015	50
Canada	Dover 1	2015	50	Russia	Kolvinskoye Increment	2011	30	Brazil	Gulama	2016	100
Canada	Jackfish 3	2015	35	Russia	Prirazdnoye	2012	120	Brazil	Iara	2016	80
Canada	Cold Lake - Nabye expansion	2015	30	Russia	Novoportovskoye	2012	30	Colombia	Rubiales expansion	2010	100
Canada	Taiga	2015	30	Russia	Bolsheketysky	2013	100	Colombia	Castilla expansion	2011	100
Canada	Fort Hills 1	2016	165	Russia	Kharyaga expansion	2013	20	Peru	Block 67 Amazon	2014	100
Canada	Aurora South 1	2016	100	Russia	Vladimir Flanovsky	2014	150	Middle East			
Canada	Long Lake 3	2016	72	Russia	Trebs & Titov	2014	120	Bahrain	Awail EOR	2013	35
Canada	Grouse	2016	60	Russia	Arktun-Daginskoye	2014	90	Oman	Harweel and other PDO EOR	2011	40
Canada	Sumrise 3	2016	50	Russia	Russkoye	2015	150	Oman	Qam Alam EOR	2011	40
Canada	Christina Lake 1F	2016	40	Russia	Yurubcheno-Tokhomskoye	2015	150	Oman	Mukhalna EOR	2012	50
Canada	Foster Creek 1G	2016	30	Russia	Tsentralnoye	2015	100	Oman	Amal East/West expansion	2012	25
Canada	Hangingsstone 2	2016	25	Russia	Tagul	2016	100	Oman	Daleel expansion	2012	15
Mexico	Ayatsil	2016	100	Russia	Shokman	2016	100	Oman	Nimr-Karim	2012	15
Mexico	Tsimin	2016	100	Russia	Chirag Oil Project	2016	15	Oman	M'boundi expansion	2011	35
OECD Europe											
Norway	Gjoa	2010	50	Azerbaijan	Kashagan phase 1a	2013	185	Congo	Moho North	2016	100
Norway	Skarv	2010	35	Kazakhstan	Kashagan phase 1b	2013	150	Congo	Belinda	2012	100
Norway	Yme	2011	80	Kazakhstan	Kashagan phase 1c	2014	70	Congo	Jubilee phase 1	2010	120
Norway	Trym	2011	10	Kazakhstan	Karachaganak expansion (phase 3)	2015	100	Uganda	Kasamene/Kingfisher	2012	20
				Kazakhstan				Uganda	Albert Basin	2015	180

Table 3B: SELECTED OPEC UPSTREAM PROJECT START-UPS

Country	Project	Peak Capacity (kbbd)	Start Year	Country	Project	Peak Capacity (kbbd)	Start Year	Country	Project	Peak Capacity (kbbd)	Start Year
Crude Oil Projects											
Algeria	IAN/IEOR	30	2012	Iraq	Majnoon Phase 1	200	2013	Algeria	MLE (Condensate)	10	2012
Algeria	El Merk	135	2012	Iraq	Badra	170	2014	Algeria	MLE (NGLs)	14	2012
Algeria	Takouzet Est & Ouest	50	2012	Iraq	Charaf	230	2012	Algeria	El Merk (Condensate)	30	2012
Algeria	Menzel Ledjinet East (MLE Block 4-05b)	32	2012	Iraq	Al Ahdab	50	2012	Algeria	El Merk (NGLs)	30	2012
Algeria	Br Seba (Blocks 433a/416b)	36	2013	Kuwait	Burgan (Water treatment)	120	2013	Algeria	Tisselt Nord (Condensate)	10	2012
Algeria	PAZFLO (Block 17)	220	2011	Kuwait	Sabriya CC-24	160	2014	Algeria	Gassi Touil (NGLs)	10	2014
Algeria	PSVM (Block 31)	150	2012	Libya	Amal	90	2014	Algeria	Hassi Messaoud (LPG)	50	2012
Algeria	Kizomba D-Satellites (Block 15)	140	2012	Libya	WAHA Development	60	2015	Iran	Pars 9&10 (Condensate)	80	2010
Algeria	CLOV (Block 17)	160	2013	Libya	Gialo Expansion	100	2015	Iran	Pars 9&10 (NGLs)	80	2010
Algeria	Platino, Chumbo, Cesio (Block 18W)	150	2013	Libya	Area 47 Chadames Basin	50	2015	Iran	Khang (NGLs)	50	2013
Algeria	Sangos/N Goma (Block 15)	85	2013	Libya	Nafoora expansion	130	2015	Iran	Bidboland (NGLs)	120	2014
Algeria	SE PAU (Block 31)	150	2013	Libya	Zuetina expansion	50	2015	Iran	Bidboland (Condensate)	20	2014
Algeria	Cabaca Norte-1 (Block 15)	200	2014	Nigeria	Ofon 2	60	2010	Iran	S. Par 12 (NGLs)	6	2014
Algeria	Matumeira Sul	110	2014	Nigeria	Ebok	35	2011	Iran	S. Par 12 (Condensate)	60	2014
Algeria	Terra Miranda, Cordella, Portia (Block 31)	150	2014	Nigeria	Usan	180	2012	Libya	NC-98	95	2015
Algeria	Lucapa (Block 14)	130	2014	Nigeria	Erha North	50	2013	Nigeria	Charan/Ubie 2 & 3	90	2016
Algeria	Negage (Block 14)	50	2014	Nigeria	Bonga SW & Aparo	140	2014	Nigeria	OKLING	30	2015
Algeria	Gindungo, Canela, Gengibre (Block 32)	200	2015	Nigeria	Bonga NW	50	2014	Qatar	Qatargas 3, Train 6 (Condensate)	45	2010
Ecuador	Pungarayacu field-Phase 1	30	2012	Nigeria	Egina	200	2014	Qatar	Qatargas 3, Train 7 (NGLs)	7	2010
Ecuador	Pungarayacu field-Phase 2	25	2013	Nigeria	Nsiko	100	2015	Qatar	Qatargas 4, Train 7 (Condensate)	48	2011
Iran	Yadawaran I	85	2012	Nigeria	Bosi	135	2015	Qatar	Pearl GTL - 1	70	2011
Iran	Foroozan	65	2012	Nigeria	Uge	110	2016	Qatar	Pearl GTL - 2	70	2014
Iran	Paranj	50	2013	Saudi Arabia	Manifa 1	500	2013	Qatar	Oryx GTL Expansion	65	2012
Iran	South Pars	35	2013	Saudi Arabia	Manifa 2	400	2015	Qatar	Barzan	25	2015
Iran	Darkhovin	120	2016	UAE	Umm Shaif expansion	75	2011	Saudi Arabia	Khursaniyah (Condensate)	80	2010
Iraq	Rumaila Phase 1	200	2010	UAE	Lower Zakum expansion	125	2012	Saudi Arabia	Khursaniyah (NGLs)	210	2010
Iraq	Rumaila Phase 2	200	2012	UAE	Upper Zakum expansion	250	2015	Saudi Arabia	Khurais (Condensate)	70	2010
Iraq	Rumaila Phase 3	1450	2016	UAE	ADCO Onshore-Sahil, Asab, Shah	75	2012	Saudi Arabia	Manifa 1 (Condensate)	65	2013
Iraq	Zubair Phase 1	100	2011	UAE	ADCO Onshore Quawirah/Bidah al Qenzan	65	2012	Saudi Arabia	Hasbah NGLs	30	2014
Iraq	Zubair Phase 2	100	2012	UAE	Bab Co 2	80	2012	Saudi Arabia	Shaybah (NGLs)	210	2014
Iraq	W. Qurna 1 Phase 1	200	2011	UAE	Bab Rumailah/Al-Dabbija (NE)	75	2013	UAE	OGD 3 Habshan (Condensate)	120	2010
Iraq	W. Qurna 2 Phase 1	175	2013	Venezuela	Junin Block 2-PetroVietnam	200	2012	UAE	OGD 3 Habshan (NGLs)	120	2010
Iraq	W. Qurna 2 Phase 3	200	2014	Venezuela	Junin Block 4-CNPC	400	2013	UAE	IGD-Integrated Gas Dev. (Condensate)	30	2013
Iraq	Taq Taq	90	2011	Venezuela	Carabobo 1	400	2013	UAE	IGD-Integrated Gas Dev. (NGLs)	110	2013
Iraq	Tawke	140	2011	Venezuela	Junin Block 5-ENI	240	2013	UAE	Shah Sour Gas	35	2015

Table 4
WORLD ETHANOL PRODUCTION¹

(thousand barrels per day)

	2010	2011	2012	2013	2014	2015	2016
OECD North America	889	933	949	969	991	1,010	1,016
United States	864	904	919	938	960	977	983
Canada	23	28	29	30	30	31	31
OECD Europe	66	60	75	85	89	91	91
Austria	2	2	2	2	2	2	2
Belgium	4	4	4	4	4	4	4
France	12	11	14	15	16	17	17
Germany	16	15	18	19	20	20	20
Italy	1	1	2	3	3	3	3
Netherlands	3	2	4	4	4	5	5
Poland	5	4	4	5	6	6	6
Spain	7	6	7	9	9	9	9
UK	6	5	7	10	10	10	10
OECD Pacific	5	4	4	5	6	6	6
Australia	5	4	4	5	5	5	5
Total OECD	959	997	1,028	1,059	1,086	1,107	1,113
FSU	2	3	6	6	6	6	6
Non-OECD Europe	2	2	2	2	2	2	2
China	40	43	47	49	49	52	52
Other Asia	16	23	31	37	39	40	40
India	4	9	9	9	9	9	9
Indonesia	1	1	1	2	3	3	3
Malaysia	0	0	0	0	0	0	0
Philippines	2	2	5	6	6	7	7
Singapore	1	1	1	1	1	1	1
Thailand	7	8	12	15	15	15	15
Latin America	466	469	508	579	607	631	640
Argentina	2	3	4	4	4	4	4
Brazil	450	451	487	557	584	609	618
Colombia	5	6	8	9	10	10	10
Middle East	0	0	0	0	0	0	0
Africa	3	5	6	8	8	8	8
Total Non-OECD	529	545	600	681	711	739	748
Total World	1,488	1,541	1,628	1,740	1,797	1,846	1,861

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

Table 4A
WORLD BIODIESEL PRODUCTION¹

(thousand barrels per day)

	2010	2011	2012	2013	2014	2015	2016
OECD North America	20	38	50	61	61	63	63
United States	18	34	46	56	57	59	59
Canada	2	3	4	5	5	5	5
OECD Europe	180	168	190	201	207	212	212
Austria	3	3	4	4	4	4	4
Belgium	6	6	7	7	7	7	7
France	44	38	41	44	45	46	46
Germany	48	37	44	46	46	46	46
Italy	14	16	17	17	17	17	17
Netherlands	6	10	13	14	16	17	17
Poland	5	4	4	5	6	6	6
Spain	19	19	21	25	25	25	25
UK	6	7	8	8	8	9	9
OECD Pacific	8	8	9	9	9	9	9
Australia	3	3	4	4	4	4	4
Total OECD	208	214	249	271	278	284	284
FSU	3	3	3	3	3	3	3
Non-OECD Europe	3	3	3	3	3	3	3
China	7	7	8	9	9	9	9
Other Asia	26	33	44	50	52	54	56
India	1	1	2	2	2	2	2
Indonesia	7	7	8	9	10	10	11
Malaysia	2	4	5	6	7	8	9
Philippines	2	2	3	4	4	4	4
Singapore	4	9	14	16	16	16	16
Thailand	11	11	12	13	13	13	13
Latin America	85	93	109	114	117	117	117
Argentina	36	43	49	51	53	53	53
Brazil	41	41	50	53	53	53	53
Colombia	5	6	7	7	7	7	7
Middle East	0	0	0	0	0	0	0
Africa	0	0	1	1	3	6	6
Total Non-OECD	124	140	168	181	187	192	194
Total World	332	354	417	452	465	476	478

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

Table 4B: SELECTED BIOFUEL PROJECT START-UPS

Country	Project	Output	Peak Capacity (kbd)	Peak Capacity (mly)	Start Year
OECD North America					
USA	Aventine Renewable Energy - Aurora, Nebraska	ethanol	7	428	2011
USA	Aventine Renewable Energy - Mt Vernon, Indiana	ethanol	7	428	2011
USA	Abengoa - Hugoton, Kansas	cellulosic ethanol	7	379	2014e
USA	Dynamic Fuels - Geismar, Louisiana	biodiesel (BTL)	5	290	2011
USA	AE Biofuels - Keyes, California	ethanol	4	208	2011
USA	Coskata - Green County, Alabama	cellulosic ethanol	4	208	2015e
USA	Vercipia (Verenium/BP) - Highlands County, Florida	cellulosic ethanol	2	136	2014e
USA	POET - Emmetsburg, Iowa	cellulosic ethanol	2	95	2012
Canada	Lignol - Vancouver, British Columbia	cellulosic ethanol	1	76	2015e
Canada	Enerkem - Edmonton, Alberta	cellulosic ethanol	1	38	2012
OECD Europe					
Netherlands	Neste Oil - Rotterdam	biodiesel (BTL)	15	899	2011
UK	Vivergo - Hull	ethanol	7	400	2012
Netherlands	Mercuria / Vesta - Amsterdam	biodiesel	4	225	2011
Hungary	Pannonia Ethanol - Dunafoldvar	ethanol	3	200	2012
Sweden	Chemrec - Ornskoldsvik	bioDME	2	112	2014e
Italy	Mossi & Ghisolf / Novazymes - Piedmont	cellulosic ethanol	1	50	2012
Asia					
Singapore	Neste Oil - Singapore	biodiesel (BTL)	15	899	2010
China	China Integrated Energy - Lin Gao, Hainan	biodiesel	6	337	2013e
Latin America					
Argentina	Louis Dreyfus Commodities - Bahia Blanca	biodiesel	6	337	2011
Argentina	Patagonia Bioenergia - San Lorenzo	biodiesel	5	281	2013e
Argentina	Cargill - San Martin	biodiesel	5	281	2011
Argentina	Unitec Bio SA - Puerto San Martin	biodiesel	4	247	2011
Brazil	Petrobras - Candeias	biodiesel	3	152	2013e

Table 5
WORLD REFINERY CAPACITY ADDITIONS
(thousand barrels per day)

	2011	2012	2013	2014	2015	2016	Total
Crude Distillation Additions and Expansions¹							
OECD North America	-95	550	85	15			555
OECD Europe	-240		26		200		-13
OECD Pacific	-98	100	-35				-33
FSU	80	323	90		120	85	698
Non-OECD Europe	10	110					120
China	130	586	380	420	940	860	3,316
Other Asia	420	366	300	82	60	60	1,287
Latin America		55	250	315	335	83	1,038
Middle East	165	124	493	417	786	310	2,295
Africa	40	174	20	46	30	60	370
Total World	412	2,388	1,609	1,295	2,471	1,458	9,632
Upgrading Capacity Additions²							
OECD North America	160	445	131	125			861
OECD Europe	142	35	55	115	106		453
OECD Pacific	75		18			80	173
FSU		217	267		95		578
Non-OECD Europe	26	59		43			128
China	94	266	315	250	399	338	1,663
Other Asia	381	320	337		125		1,163
Latin America	30	49	213	190	130	104	716
Middle East	146	119	366	217	245	40	1,133
Africa	8	20	5				33
Total World	1,062	1,530	1,707	940	1,100	562	6,901
Desulphurisation Capacity Additions³							
OECD North America	126	351	240	145			862
OECD Europe	-19	4		35			20
OECD Pacific	-26	30	-20				-16
FSU	65	196	220				481
Non-OECD Europe	8	85					93
China	136	424	190	316	607	628	2,302
Other Asia	363	339	185	139	25		1,050
Latin America	240	213	347	151	230	30	1,211
Middle East	123	366	160	220	201	116	1,186
Africa		95	5				100
Total World	1,016	2,102	1,328	1,006	1,063	774	7,289

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

² Comprises gross capacity additions to coking, hydrocracking, residue hydrocracking, visbreaking, FCC or RFCC capacity.

³ Comprises additions to hydrotreating and hydrodesulphurisation capacity.

Table 5A
WORLD REFINERY CAPACITY ADDITIONS:
Changes from Last Medium-Term Report
(thousand barrels per day)

	2010	2011	2012	2013	2014	2015	Total
Crude Distillation Additions and Expansions¹							
OECD North America	-150	-145	130	10		-95	-250
OECD Europe		-5	-110				-115
OECD Pacific	31	22	50	-35			68
FSU		50	49	20	-40	60	139
Non-OECD Europe		10	-12			-50	-52
China	30	-216	76	140	-300	-100	-370
Other Asia	-120	-10	130	-15	-134	195	47
Latin America					-105	35	-70
Middle East	-50	-35	30	422	-400	640	607
Africa	-35	-60	50		18		-27
Total World	-294	-389	393	542	-961	685	-23
Upgrading Capacity Additions²							
OECD North America	-42	4	170	-88	-50	-50	-56
OECD Europe	-45	105	-120				-60
OECD Pacific			-53	18			-35
FSU	-39	-55	-103	185		58	45
Non-OECD Europe			-50	-43	43		-50
China	20	-36	-84	190	-110	-33	-53
Other Asia	-110	60	50	60	-150	110	20
Latin America				-2	-104		-106
Middle East	-80	-25	25	306	-240	220	206
Africa	11					-57	-46
Total World	-285	53	-165	627	-611	248	-134
Desulphurisation Capacity Additions³							
OECD North America	-119	30	6	125		-30	13
OECD Europe	20		-72				-52
OECD Pacific				-20			-20
FSU	-51	35	27	220	-40		191
Non-OECD Europe							
China	40	-20	6	146	-123	-181	-132
Other Asia	-81	116	22		-35	104	126
Latin America	27	30			-14	25	68
Middle East	-55			115	-115	161	106
Africa	-55	-95	95			-42	-97
Total World	-274	96	83	586	-327	37	202

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

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

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

Table 5B: SELECTED REFINERY CRUDE DISTILLATION PROJECT LIST

Country	Project	Peak Capacity (kbd)	Start Year	Country	Project	Peak Capacity (kbd)	Start Year
OECD North America							
Canada	Consumers' Cooperative Refineries Ltd. - Regina	30	2012	China	China National Petroleum Corp. - Renqui	100	2013
Mexico	PEMEX - Minatitlan	150	2012	China	Local Refineries -	100	2014
United States	ConocoPhillips - Wood River	300	2011	China	Sinopec/Zhenhai	300	2015
United States	Motiva Enterprises LLC - Port Arthur	325	2012	China	Sinopec/KPC - Zhanjiang	300	2015
United States	BP PLC - Whiting	20	2012	China	PetroChina Huludao (Jinx) Local - Liaoning	200	2015
United States	ConocoPhillips - Barger	50	2013	China	Local Refineries -	100	2015
United States	Valero Energy Corp. - Sunray	25	2013	China	CNPC/PDPSA - Jieyang	400	2016
Virgin Islands	Hovensa LLC - St. Croix	150	2011	China	CNPC/Rosneft - Tianjin	260	2016
OECD Europe							
France	Petroplus - Reichstett	85	2011	China	CNOOC/Zhongjie - Hebei	160	2016
France	Total SA - Contrefeville l'Orcher	94	2011	China	Sinopec - Yangzi	90	2016
Germany	Shell - Harburg	110	2012	China	Local Refineries -	50	2016
Hungary	MOL Hungarian Oil & Gas Co. - Szazhalombatta	26	2013	Other Asia			
Italy	Tamoli Raffinazione SPA - Cremona	94	2011	Bangladesh	Eastern Refinery Ltd. - Chittagong	70	2015
Poland	Grupa Lotos SA - Gdansk	45	2011	China, Taiwan	Chinese Petroleum Corp. - Kaohsiung	205	2015
Spain	Repsol YPF SA - Cartagena Murcia	110	2012	India	HPCL/MITTAL (HMEL) - Bathinda	180	2011
Turkey	Turcas Petrol SOCAR - Alaga	200	2015	India	Bharat Oman Co. Ltd. - Bina	120	2011
OECD Pacific							
Australia	Darwin clean fuels - Darwin	50	2013	India	Essar Oil - Vadinar	80/40	2011/2012
Australia	Shell Refinery - Clyde	85	2013	India	Indian Oil Co. Ltd. - Koyali, Gujarat	40	2011
Japan	Showa Shell/Toa Oil Co. Ltd. - Ohgimachi Factory	120	2011	India	Nagarjuna oil Co - Cuddalore	120	2012
South Korea	Samsung - Onsan	50	2012	India	ONGC - Mangalore	64	2012
South Korea	S-Oil Corp. - Ulsan	50	2012	India	Indian Oil Co. Ltd. - Paradip	300	2013
Non-OECD Europe							
Bosnia	Zarubezhneft - Brod	60	2012	Myanmar	Chennai Refinery - Madras	60	2016
Romania	Petrolbraz SA - Floresti	50	2012	Pakistan	CNPC/Myanmar - Mandalay	50	2014
Belarus	P.O. Naftan Refinery - Novopolotsk	60	2012	Vietnam	Byco Petroleum Pakistan Ltd. - Karachi	120	2012
Russia	Lukoil - Uktika	70	2011	Vietnam	Petro Vietnam/KPC/Idemitsu Kosan - Nghi Son	195	2015
Russia	Rosneft - Tuapse	140	2012	Middle East			
Russia	GAZPROMNEFT - Salavat	120	2012	Iran	National Iranian Oil Co. - Arak	80	2012
Russia	Mari El refinery - Mari Republic	63	2012	Iran	National Iranian Oil Co. - Lavan Island	21	2013
Russia	GAZPROMNEFT - Salavat	80	2012	Iraq	National Iranian Oil Co. - Persian Gulf Star Refinery	240/120	2015/2016
Russia	Antipinsky Refinery - Antipinsky	70	2013	Iraq	SOMO - Daura, Bagdad	70	2011
Russia	Rosneft - Komsomolsk	20	2013	Iraq	SOMO - Basra	70	2011
Russia	Verkhoturys - Sverdlovsk	60	2015	Oman	INOCORA - Karbala	140	2016
Russia	West Siberian Oil Refinery - Tomsk	60	2015	Qatar	Sohar Bitumen Refinery - Sohar	30	2012
Russia	Lukoil - Kstovo, Nizhny Novgorod	85	2016	Qatar	Oman Refinery Co. - Sohar	715	2013
China							
China	Huaxing Petrochemical - Huaxing	120	2011	Saudi Arabia	Qatar Petroleum - Ras Laffan 2	146	2015
China	CNPC - Yinchuan	100	2011	Saudi Arabia	Saudi Arabian Oil Co. (Saudi Aramco) Total - Jubail	400	2013
China	CNPC - Fushun	70	2011	Saudi Arabia	Aramco Sinopec - Yanbu	400	2015
China	Local Refineries -	100	2012	UAE-Abu Dhabi	Abu Dhabi National Oil Co. - Ruwais 2	417	2014
China	CNPC - Pengzhou	200	2012	Yemen	Reliance Petroleum Ltd./RRC - Ras Issa	50	2016
China	Sinopec - Beihai Tiandong	188	2012	Latin America			
China	Sinopec - Jinling Nanjing	160	2012	Brazil	Petrobras/PDVS2 - Abreu e Lima	230	2013
China	Sinopec - Shijiazhuang	60	2012	Brazil	Petrobras - COMPERJ	165	2014
China	Sinopec - Anqing	50	2012	Colombia	Petrobras (Premium I) - Maranhao	300	2015
China	Local Refineries -	100	2012	Colombia	Ecopetrol - Cartagena, Bolivar	65	2014
China	Sinopec - Maoming	240	2013	Costa Rica	Ecopetrol - Barrancabermeja-Santander	50	2016
China	CNPC - Renqui	100	2013	Peru	Recopa/CNPC - Limon	35	2015
China	CNPC - Huohot Petchem	70	2013	Venezuela	Cuba Petroleos - Cienfuegos	85	2014
China	Sinopec - Jujiang	70	2013	Venezuela	Petroperu SA - Talara, Piura	33	2016
China	Local Refineries -	100	2013	Africa	Petroleos de Venezuela SA - Santa Inés (Barinas)	30	2012
China	Sinochem KPC - Qanzhou Fujang	240	2014	Algeria	Naftec SPA - Skikda	32	2012
China	CNPC - Kuming/Anning	200	2014	Algeria	Naftec SPA - Arzew	22	2012
China	CNOOC/Shangdong Haihua - Haihua	80	2014	Cameroon	SONARA - Cape Limboh Limbe	28	2014
				Chad	CNPC - N'Djamena	20/30	2013/2015
				Morocco	SAMIR - Mohammedia	40	2011
				Niger	CNPC - Ganaram	20	2012
				Sudan	CNPC - Khartoum	100	2012
				Uganda	Tullow - JV - Albertine Graben	60	2016

GAS

Overview

Recent Global Market Trends

Power Generation

Medium-Term Supply and Demand Forecasts

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Investments in Major Producing Regions

Investments in LNG

Investments in Pipelines and Regasification Terminals

OVERVIEW

World gas demand climbed to an estimated 3,284 billion cubic meters (bcm) in 2010, rebounding a surprising 7.4% from its 2009 level, one of the highest growth rates recorded over the past 40 years. This growth overshadows the 2.5% drop in gas demand experienced in 2009 and puts natural gas demand back on its pre-crisis track. Demand in most non-OECD regions was driven by economic growth and increasing needs in both the power and industrial sectors. Although OECD gas demand grew by 5.9% in 2010, this recovery is artificially inflated, as half of the increase was driven by abnormal weather reflecting very cold winter months across Europe and a hot summer in the Pacific region. Seasonally adjusted figures show that European gas demand is just back to 2007 levels. By comparison, China's gas demand increased 22%, reaching 107 bcm, making it the fourth-largest gas user behind the United States, Russia and Iran. Gas markets grew strongly in Asia, Latin America and the Middle East, and more moderately in Africa. Demand growth in Russia was also partially driven by exceptional weather.

Abundant gas supplies were available to meet the incremental demand of 227 bcm. Production increased in all regions, including across the OECD. A 60 bcm liquefied natural gas (LNG) wave hit the markets due to the completion of projects launched around the middle of the decade, bringing the increase of LNG production capacity to 100 bcm in 2009-10. Although some experts predicted a slower increase in unconventional gas production in 2010, US shale gas production jumped by an estimated 50 bcm in 2010. The largest incremental gas supplies came from the Middle East and the Former Soviet Union (FSU), driven by a strong recovery in Russian gas production. Additional supplies in the Middle East came in large part from new Qatari LNG trains. Historical LNG consumers in Asia and new markets in the Middle East and Latin America, combined with a growing appetite for LNG in Europe, contributed to absorb these new LNG volumes. The continued rise of shale gas in the United States discouraged LNG imports, which dropped even further.

Power generation remains the main driver behind gas demand growth; use in this sector is estimated to have increased by 5% in 2010. Both gas turbines and renewables (including wind and photovoltaic) continue to dominate the investment picture for power generation across the OECD. But the strong growth of wind and solar generation tends to reduce the share of combustible fuels; as a result, gas must increasingly compete against coal at the margin. The use of gas by power generators depends not only on relative fuel prices, but also on country-specific factors such as electricity capacity mix, market structure and fuel supply arrangements, as well as the existence of carbon pricing. Additionally, the increasing deployment of variable renewable energy sources impacts the relative attractiveness of future technologies, favouring gas-fired plants compared to capital-intensive options such as coal and nuclear power plants.

The surplus of gas, which materialised in 2009 with depressed demand and the increased supplies of both LNG and unconventional gas, was partly absorbed in 2010 by resurgent demand. Similarly to last year, energy buyers and producers wonder how long the surplus gas situation will last. The answer hinges on four factors. On the demand side, the main factors include economic growth, relative fuel prices and energy policy developments regarding nuclear, renewables and energy efficiency. The fourth factor – unrest in the Middle East – is more directly linked to supply. Much

uncertainty remains on the future gas demand path, as economic recovery is still fragile, particularly in Europe. Meanwhile, the recent gas price increases in OECD Europe and OECD Pacific may impact the growth in the power sector. Additionally, multiple unexpected events affecting gas markets took place during early 2011. Replacing nuclear capacity in Japan and Germany is likely to have a positive effect on gas demand. Finally, unrest in the Middle East could affect supply beyond Libya, the gas exports of which have been easily replaced thus far. The combination of such factors could result in tightness happening earlier than expected.

Demand for natural gas is expected to increase strongly over 2010-16, reaching around 3,800 bcm by 2016. The bulk of the incremental gas demand originates from the non-OECD regions, especially the Middle East and Asia, while the growth of gas consumption in most OECD countries will be dampened by high gas prices. There are ample supplies to meet this demand, coming mostly from non-OECD producing countries. China will be one of the fastest-growing and largest gas consumers; its gas demand is projected to double over the forecast period to 260 bcm. Meanwhile, the Middle East will represent 20% of additional gas use. New supply volumes will come mostly from the existing largest non-OECD producers, FSU and the Middle East. The FSU region will be by far the most important producing region by 2016 and will help meet demand in Asia. OECD gas production should also increase, as additional output from Australia and North America compensates for rapidly declining European gas production.

Gas markets saw the results of the first wave of LNG liquefaction plants being brought online as LNG trade increased by 25% in 2010 to reach 299 bcm, the largest percentage increase ever seen. Global LNG trade now represents 9% of global gas demand. Qatar was the largest contributor to additional LNG supplies and now represents one-quarter of global LNG supplies, twice as much as Indonesia, the second-largest LNG supplier. Growth of LNG trade is set to continue over 2011-16 as new plants come on stream. On the export side, the gap is closing between the Middle East region (34%) and Asia-Pacific (38%) as the two largest global LNG exporters as of 2010. LNG imports continue to gain market shares in most regions, but declined in the United States and India, due to growth of domestic production. Asia retains the lion's share with 60% of global LNG imports, while Europe now represents 29%. Other regions, such as Latin America and the Middle East, are turning increasingly to LNG to compensate for insufficient production or the failure of pipeline supplies, but they represent only 4% of total LNG imports. The coming five years will see continuing growth in LNG trade as another 80 bcm (or +21%) of liquefaction capacity is expected to come online by 2016. LNG supplies are expected to grow by one-third over 2010-16. Most new LNG supplies are already contracted, particularly to Japan and China.

Unconventional gas continues to impact gas markets. Not only have these resources doubled the estimated recoverable gas resources compared to recoverable conventional gas resources, they are also more evenly distributed across regions. The bulk of unconventional gas production is currently located in North America. Interest in unconventional gas is now spreading all over the world, but with very different outcomes. While most countries are seriously looking at shale gas, coalbed methane (CBM) is also attracting attention in a number of others. The obstacles to developing unconventional gas are diverse though, and environmental concerns are increasingly in the spotlight and have deterred exploration in a few countries. The first step toward exploiting

unconventional gas is to evaluate resource potentials; until recently, these had been largely disregarded, even in producing regions. Countries then need to tackle issues ranging from regulatory and fiscal frameworks to establishing the required infrastructure and attracting companies with the necessary expertise. Asia/Oceania is becoming active in unconventional gas, with countries such as Australia and China taking the lead. Both are initially focusing on CBM, but China is pursuing shale gas development as well. European countries show a range of attitudes: Poland is actively supporting shale gas, while France banned hydraulic fracturing due to local opposition. In the Middle East, Africa and Latin America, tight gas and shale gas resources could complement existing conventional gas, especially in countries facing dwindling conventional gas output.

Different supply and demand balances, coupled with market dynamics, have caused regional market prices to drift further apart. Unlike 2009, when US and UK spot prices converged towards \$4/MBtu, creating a sustained gap with much higher oil-linked gas prices, European spot and contract prices converged in 2010. Market prices nevertheless represent around 60% of wholesale gas prices in the world, while one-third of global prices is still subject to regulation. As global inter- and intra-regional trade increases, more countries could be exposed to oil-indexation or spot prices as they turn to imports. European gas prices have ranged between \$8/MBtu and \$10/MBtu as of early 2011, below Asian oil-linked gas prices at \$12/MBtu, but well above US Henry Hub (HH) gas prices at \$5/MBtu. HH gas prices are kept low by the abundance of supplies in North America. In Europe, National Balancing Point (NBP) prices increased as a result of tightening of global gas markets, convergence with continental prices (due to more efficient continental markets) and increased competition between coal- and gas-fired plants. In addition, the United Kingdom has become a transit country to Continental Europe. Despite the partial indexation to spot prices, prices in Continental Europe continued to increase over 2010, driven by oil prices moving towards \$100/bbl and price increases at NBP. Delinking gas prices from oil prices in long-term contracts remains a topical issue in Europe, very much illustrated by the number of contract renegotiations underway. As markets tighten due to recent events, the benefits of spot indexation, albeit still present, are decreasing. Some uncertainty remains on whether full spot indexation would actually lead to lower gas prices. The question remains whether one of the Continental European spot markets could provide an alternative marker to NBP in long-term contracts, should buyers and sellers agree to increase spot indexation. Despite the strong growth in trading in Continental Europe, especially in Germany and in the Netherlands, market liquidity remains much lower than in the UK market.

Assessing investment needs is as difficult as ever. The past two years have seen a wide boom-and-bust cycle as demand recovered by 7.4% in 2010 after declining 2.5% the year before. This global picture hides wide regional disparities that will translate into different requirements in terms of new production and transport infrastructure. Unconventional gas prospects are adding another layer of uncertainty: while producers could benefit from these new resources, they could also threaten some conventional exports.

On the production side, Russia is advancing major projects such as Yamal Peninsula, but it has yet to take final investment decisions (FIDs) on the next projects. Strategically positioned between Russia, Iran, China and Europe, the Caspian region will play a critical role. The Middle East and Africa offer a contrasting picture as new production will be more costly to develop but is needed to

sustain economic development and fulfil export commitments. Only Qatar can meet comfortably both increasing domestic needs and export commitments. For Russia, uncertainties persist regarding Europe, its main export market; exports did not recover in 2010 due to competition from LNG supplies. Russia is turning to China, hoping to secure a slice of the pie in this huge and rapidly growing market. New projects, often based on LNG exports, will be challenging to develop. In the Northwest, Shtokman will face competition from Yamal LNG; both projects have some common foreign investors. The interest in developing greenfields in the Far East and Eastern Siberia is mounting after the Fukushima accident, which is expected to lead to higher gas demand in Japan. In the Middle East and Africa, a few countries have domestic market obligations (DMOs) in place to limit exports. Iran, the second-largest holder of proven gas reserves in the world, is a net importer and most LNG export projects are stalled. Oman is struggling to develop new tight gas fields to keep pace with its rising demand. Meanwhile, Iraq – and, more surprisingly, Israel and the East African coast – could emerge as gas exporters in the long term, although there are still many obstacles to tackle.

The mood in the LNG business seems to be quite positive with six FIDs taken over the past two years. Therefore, a second wave of investment is forming to bring new projects on line by the middle of the decade. These new projects will not be low cost; construction costs are anticipated to be twice as high as those for plants that recently came online. All recently approved projects come from the Pacific region and target growing Asian markets. In this context, Australia – with five plants currently under construction or committed and a few others close to reaching FID – seems set to become the new Qatar. It will become the first country with CBM-to-LNG projects and a floating LNG plant. However, these new LNG supplies will partially replace LNG exports coming from historical regional suppliers. Uncertainty prevails regarding new plants in the Atlantic basin and the Middle East. Both the United States and Canada are considering the export of LNG. For the 550 bcm of LNG production capacity planned in the world, competition will be stiff to secure markets, not only between LNG projects, but also against pipeline projects.

Expanding inter- and intra-regional transport capacity is crucial to enable higher gas consumption levels, particularly in Asia, which is currently attracting most investments. Globally, LNG regasification terminals are advancing slightly faster than inter-regional pipelines. Inter-regional developments depend not only on future demand developments, but also on unconventional gas supplies. Regasification terminals are usually smaller and require less capital than pipelines, and also benefit from the rapid development of LNG production. Floating regasification terminals enable rapid relief to countries with increasing import needs, especially in the Middle East, Southeast Asia and Latin America. Looking ahead, over 100 bcm of regasification capacity is currently under construction, while only three inter-regional pipelines are being constructed or expanded. Intra-regional capacity is moving ahead, albeit for different reasons: in Europe, the focus is on security of supply; North America is keen to bring new gas production to markets (primarily within North America). Finally, many importer/exporter countries are emerging. LNG exporters in Asia are turning to imports, while continuing to export LNG. Canada and the United States, both LNG importers, are planning liquefaction capacity to export their production.

RECENT GLOBAL MARKET TRENDS

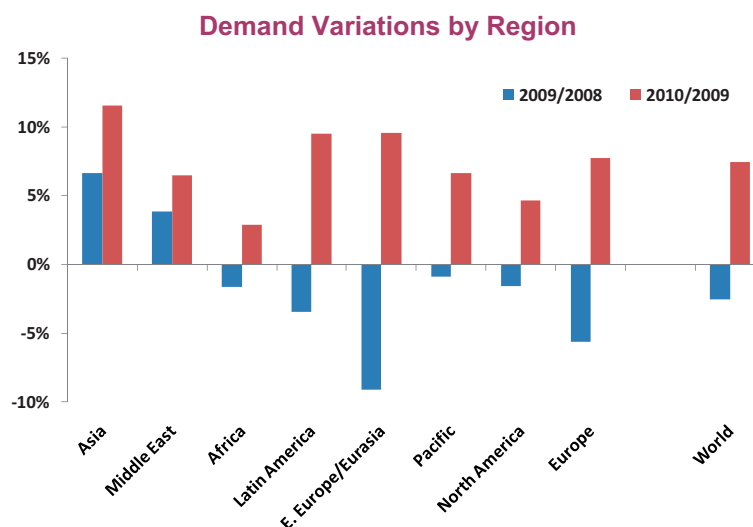
Summary

- **World gas demand in 2010 witnessed an amazing rebound, with growth estimated at 7.4% (or 227 bcm), one of the highest increases recorded in over 40 years. This more than erased the 2.5% decline observed in 2009 and puts natural gas demand back on its pre-crisis path.**
- **However, the weather-adjusted recovery in the OECD region was much lower.** Indeed, OECD gas demand recovery of 5.9% was to a large extent driven by cold winters exacerbating residential demand and hot summers in Asia translating into high needs in the power generation sector. The correction in 2011 may be abrupt in some countries, particularly in Europe, where the weather from January to April was extremely mild.
- **Unlike the OECD region, natural gas demand growth in most non-OECD countries is essentially driven by higher needs in the power generation and industry sectors.** China continues to break records, reaching 107 bcm in 2010, representing a 22% increase over 2009. While China may be an extreme case, strong growth has been observed in other Asian countries, as well as in Latin America and across the Middle East. Demand growth in Russia was largely driven by exceptional weather conditions.
- **The power sector remains extremely sensitive to price variations in the OECD region as well as in some key non-OECD countries.** As gas-fired plants are competing at the margin with coal-fired plants, they react very rapidly to price changes, particularly in countries with spot indexation. The tragic nuclear accident of Fukushima is likely to translate into additional gas demand in Japan; subsequent decisions to decommission nuclear power plants in Germany have so far had limited impact on gas demand.
- **Abundant supplies were available to meet this incremental 227 bcm demand. A 60 bcm LNG wave, a result of the addition of 100 bcm of liquefaction capacity since early 2009, has hit the markets. While expert may have predicted a slower increase of unconventional gas production in 2010, US shale gas production remained buoyant and broke production records, jumping by an estimated 50 bcm in 2010.** The LNG wave has been smoothly absorbed due to the rebound of Asian markets and increased appetite for LNG in Europe, Latin America and the Middle East, while US LNG needs remain limited.
- **Continuing from last year, energy buyers and producers wonder how long the gas oversupply will last. The cushion that existed in 2009 has certainly diminished, but much uncertainty remains on future gas demand.** While the economy rebounded, the recovery remains fragile, and the recent gas price increase may also weaken gas demand growth in the OECD's power sector. The tightening of markets will play out differently regionally: Asia's gas demand, particularly in China, is growing extremely fast and is increasingly interacting with global gas markets. Tightness in this region could spread rapidly into other regions.

World Supply and Demand Trends: Magic Number Seven

Gas demand increased by over 7.4% in 2010, returning to its previous growth path and erasing the dark year of 2009. World gas demand in 2010 reached an estimated 3,284 bcm, reflecting an increase of around 227 bcm – equivalent to three-quarters of total LNG trade or the combined demand of Germany, Spain and the United Kingdom. Demand increased in all regions, by over 20% in some

countries. On the supply side, all regions contributed to meeting this incremental demand. OECD⁴ gas production, which accounts for 37% of global gas supply, increased marginally by around 3%. The bulk of the increase was therefore borne by non-OECD countries, where production increased by 11%. Eastern Europe/Eurasia and the Middle East were the biggest contributors. In the Middle East, incremental supplies came mostly from the new Qatari LNG plants which started operating in early 2009. Russia also recovered from the “*annus horribilis*” and regained its position as the world’s largest producer.



Note: 2010 numbers are estimates.

Russia and the United States continue to be both the biggest gas producers and consumers, but while Russia is exporting a significant share of its production, the United States remains a net importer. Six of the top ten consuming countries are from the OECD region. In 2009, Ukraine was replaced by Saudi Arabia as a major gas consumer due to the dramatic effect of the economic crisis on the Ukrainian economy and its energy consumption. In 2009, China’s ranking was still below that of the largest European consumers and Japan; in 2010, Chinese gas demand exceeded that of all OECD countries except the United States. Among the top ten consumers, only three are self-sufficient (Russia, Canada and Saudi Arabia); three need to import a small part of their consumption (the United States, Iran and China), while the others depend extensively or completely on imports.

In 2010, Russia regained its position as the largest producer after losing it to the United States in 2009. Each country’s gas production (above 600 bcm) dwarfs that of any other producer. Canada, the third-ranking country, has an output four times smaller. Iran ranks fourth, but its production is still insufficient to meet its demand. Compared to the previous years, two countries are gaining momentum: Qatar on the back of its new LNG plants (this is actually more visible with 2010 estimates), and China, which is emerging as a significant producer with 95 bcm produced in 2010, although this remains insufficient to meet an even faster-growing consumption. All ten top producers export gas, but unlike the others, the United States, Iran and China are not net exporters. Canada, Iran, the Netherlands and China export only by pipeline.

⁴ In this report, the OECD region does not include Chile, Estonia, Israel and Slovenia, although they now belong to the OECD.

Top Ten Producers and Consumers in 2009 (2010 estimates) (bcm) (Ranking based on 2009)

	Consumption	2009	2010	Production	2009	2010
1	United States	647	683	United States	583	613
2	Russia	429	472	Russia	572	651
3	Iran	136	143	Canada	164	160
4	Japan	103	105	Iran	137	na
5	Canada	97	96	Norway	106	107
6	Germany	94	97	Qatar	89	118
7	United Kingdom	91	98	China	85	95
8	China	87	107	Netherlands	79	89
9	Italy	78	83	Algeria	78	85
10	Saudi Arabia	75	80	Indonesia	77	na

Gas Demand: a Hidden Two-speed Recovery**OECD Gas Demand: the Illusion of Growth**

OECD gas demand is estimated to have rebounded by 5.9% in 2010 to 1,594 bcm. This represents a 2.8% increase over the pre-crisis levels of 2008 and puts OECD demand at exactly the same level as if it had followed the same trend evident from 2000 to 2008. But abnormal weather contributed to half of the incremental demand, while economic recovery, higher industrial production and increased gas use in power production accounted for the other half.

OECD Gas Demand by Country, 2010 vs. 2009

	2009	2010		2009	2010
Australia	31.4	32.3	Korea	34.4	42.9
Austria	8.3	9.5	Luxembourg	1.3	1.4
Belgium	17.7	20.3	Mexico	60.4	61.6
Canada	97.0	96.4	Netherlands	49.0	54.7
Czech Republic	8.2	9.3	New Zealand	4.1	4.2
Denmark	4.4	4.9	Norway	6.0	6.1
Finland	4.3	4.7	Poland	15.8	17.2
France	44.5	49.8	Portugal	4.7	5.2
Germany	93.5	97.3	Slovakia	5.4	6.3
Greece	3.5	3.8	Spain	36.0	35.8
Hungary	11.3	12.1	Sweden	1.2	1.7
Iceland	0	0	Switzerland	3.3	3.7
Ireland	5.1	5.7	Turkey	35.1	38.1
Italy	78.0	83.0	United Kingdom	90.8	98.0
Japan	103.3	105.3	United States	646.8	683.4

Most countries saw a positive demand growth, with Spain and Canada being the exceptions. The highest relative increases were in Sweden (35%), driven by new gas-fired generation, and Korea (25%), and the largest in volumes in the United States (37 bcm). After plummeting by 5.6% in 2009, gas consumption in OECD Europe reached historical levels of 568 bcm in 2010 (7.7% higher). The growth was slightly lower in OECD Pacific with gas use reaching 185 bcm (+6.6%), but the recovery was particularly impressive in Korea, driven by both the power and industrial sectors. North America's growth was 4.6%, reflecting the fact that its demand decline in 2009 was less pronounced than in other OECD regions. This region still benefits from low gas prices and strong gross domestic product (GDP) recovery, so that gas demand increased from 804 bcm in 2009 to 841 bcm in 2010.

Unexpected Events: the Impact of Fukushima on Gas Demand

On 11 March 2011, a magnitude 9 earthquake followed by a tsunami struck the north-eastern coast of Japan. Energy supply, including power, oil, and gas, was severely disrupted. The 9 gigawatts (GW) Fukushima nuclear power complexes were severely damaged, particularly four units of Fukushima Daiichi. Other nuclear power plant units representing 4.4 GW were also shutdown by the earthquake. In early May, at the request of the Japanese government, Chubu Electric Power shut down three reactors (3.6 GW) at the Hamaoka nuclear power plant. Including three units of Kashiwazaki-Kariwa still in outage (recovering from the previous earthquake in 2007), 20.3 GW of nuclear capacity was unavailable as of June 2011.

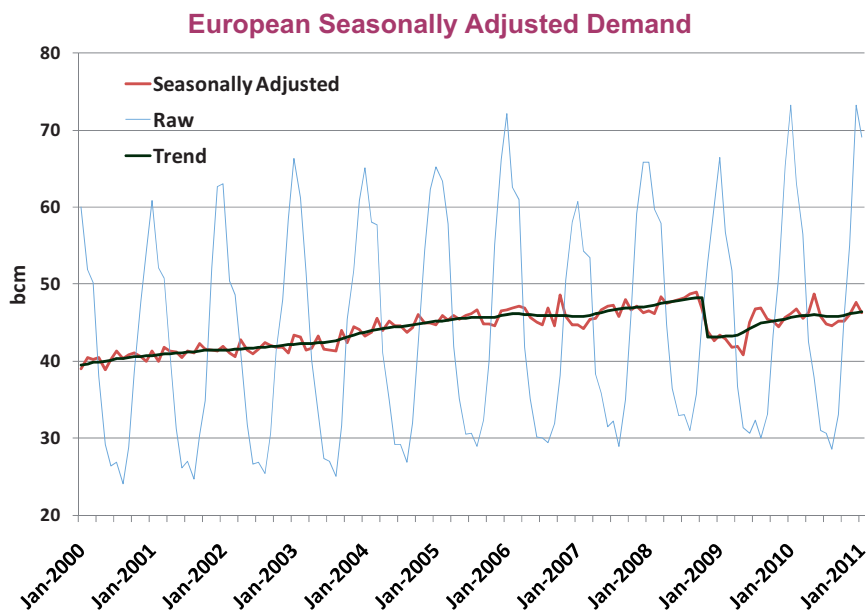
Additional fossil fuel consumption resulting of these events depends on many factors, including power demand evolution and on how the missing shortfall of base-load nuclear and coal power capacity is replaced by oil- and gas-fired generation, as well as demand rationing, if necessary. There is still great uncertainty around the recovery of power demand, which declined in the past months due to the macroeconomic impact of the earthquake, disruptions in industrial production and conservation measures (also seasonal shoulder period for power demand). A key issue is the capacity shortfall during the summer. Last year's summer-peak demand for TEPCO was around 60 GW, but it was an unusually hot summer. In a mild summer, it would be around 55 GW, while TEPCO expects to have 55.2 GW running by the end of July and 56.2 GW by the end of August. Forced load shedding will therefore depend on the ongoing macroeconomic impact on demand, as well as on the success of conservation and weather conditions.

Of the total capacities that could potentially be available for summer 2011, 23% is expected to be oil and 45% is expected to be gas. It is likely that most of the burden will be on gas-fired plants as these are newer, more reliable and can be used at higher load factors, while their operating costs are below the costs of oil-fired units. This would translate into over 11 bcm of additional gas consumption (see chapter on medium-term supply and demand forecasts).

There are various options to deliver LNG cargoes. Historical suppliers such as Qatar, Indonesia, and Malaysia, as well as Russia, are working to make additional cargoes available for Japan. Neighbouring countries, including Taiwan and Korea, have offered LNG cargoes based on time swaps; additional diversions could come from other markets (such as Europe), depending on shipping availability. Within Japan, several companies have offered cargoes to TEPCO based on time swaps. In 2011, a key issue will be to evaluate the timing and extent of additional gas demand and whether LNG cargoes can be diverted without bringing too much tightness into the markets. There is certainly a lot of LNG available — with the capacity recently coming online and provided that no unexpected event reduces LNG supply — but shipping is getting tighter. The increasing appetite for LNG over the past months (not only from Japan) has already had an impact on the daily rates of LNG tankers, which increased from \$40,000 in the summer of 2010 to \$60,000 in the winter 2010/11 and jumped to \$80,000 in April 2011.

There are significant differences between unadjusted demand and the seasonally adjusted trend in Europe. The economic crisis in 2008 resulted in a sharp decline in the existing trend, which went back to late 2003 levels. Seasonally adjusted data indicate that demand did not recover before July 2009. This recovery was essentially driven by the National Balancing Point (NBP) price collapse as prices halved from \$8.8/MBtu in January 2009 to \$4.3/MBtu in April 2009 and remained below \$3.8/MBtu over the July to September period that year, spurring a strong recovery in the power generation sector and in the industrial sector. Since then, the recovery of seasonally adjusted gas demand has been slower, experiencing sporadic hiccups. The trend has actually been receding between April and

October 2010 due to increasing NBP prices impacting gas demand for power generation. As of early 2011, the trend level is just back to mid-2007 levels and remains 3.7% below the peak in 2008.



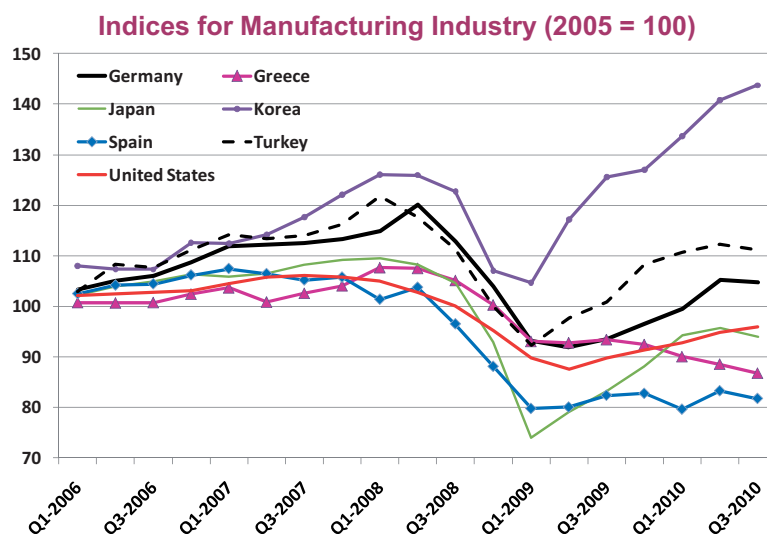
Industrial Sector

While newspapers discuss the strength, or lack thereof, of the economic recovery, when one looks at indices of industrial production, the picture is less than rosy. Among OECD countries, only Korea, Ireland and Poland's indices are above pre-crisis levels (end-2010 versus the second quarter of 2008). All other countries have indices well below that level, and major countries such as Germany and the United States are still 10% below their peak level in 2008. Lagging performers include Spain, Greece and Italy.

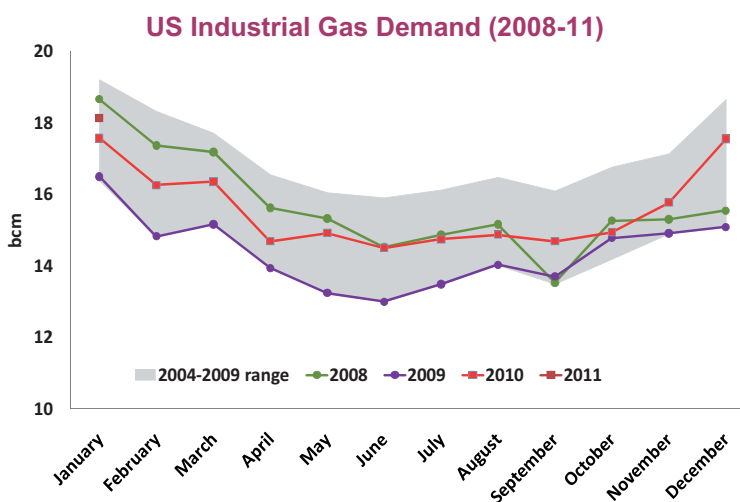
As a result, despite some recovery between 2009 and 2010, industrial gas demand lags behind earlier levels. Nonetheless, lower gas prices during the first half of the year 2010 boosted European industrial gas demand, but the effect quickly disappeared during the second half of 2010 as spot prices increased. Despite the lack of a complete OECD picture, preliminary data indicates that OECD industrial gas demand has recovered by an estimated 7% compared to the 8% drop in 2009.

In Europe, the picture is uneven. While industrial gas demand has certainly increased in all countries, only a few have actually recovered to pre-crisis levels. In the United Kingdom, industrial gas demand recovered by 8.9% in 2010, with a strong increase (+43%) in gas demand for iron and steel that rose well above the pre-crisis levels, although total industrial gas demand in 2010 remains 10% below 2008 levels. This picture also reflects the fact that most of the incremental gas demand happened in the first quarter and the subsequent quarterly increases have been much weaker during the second half of the year due to much higher gas prices. Similarly, in Italy, the 7% growth only partially compensates for the 14.6% drop from the previous year. French industrial and power consumption increased by 13% in 2010 and was actually 4.7% above 2008 levels. Since the statistics regroup all

users connected to the transmission system, this increase may also be partly due to new power plants. Dutch industrial gas demand recovered by 9%, mostly during the first quarter of 2010. Similar trends can be observed in Eastern Europe, for example in Poland; PGNiG's sales to industrial users increased by 7%.



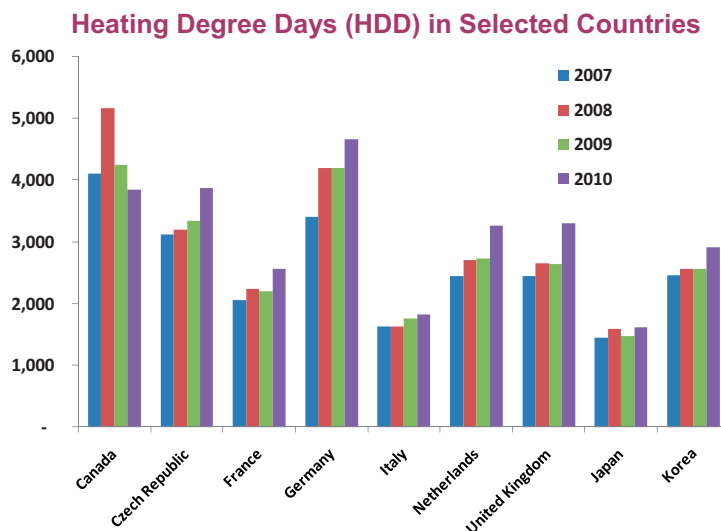
In the United States, industrial demand recovered by 7% in 2010, following a 7.4% drop in 2009. US industrial gas demand is still below what it was in 2008. Although industrial gas demand has rebounded, it seems only partially driven by recovery in the economy and therefore in industrial production, but also by relatively low gas prices (Henry Hub averaged \$4/MBtu in 2010) compared to other prices (in particular, refined oil products). Incremental industrial gas consumption represented half of the incremental primary energy consumed in the industrial sector, which increased by 6.3%. By contrast, the recovery of petroleum products consumption was only 2.5%.



Source: EIA.

Residential Sector

The levels of residential and commercial gas demand are largely influenced by temperature on a short-term basis. After the cold winter 2008/09, several records were broken again in 2010 in Europe as temperatures dropped considerably below normal. Not only did the cold winter in 2009/10 linger well into April, but the year ended with extreme cold and heavy snowfalls in most northern European countries. Temperatures were also below average in Japan and Korea. However, this trend was not present everywhere, as Canada experienced a relatively warm winter. As a result, residential gas demand surged in many European countries and OECD residential gas demand reached an estimated 549 bcm in 2010. Additional demand growth due to colder weather in 2010 in OECD Europe (compared to “normal” weather) is estimated at around 23 bcm, 80% of which occurred during January, February and December. This means that without the weather effect, incremental demand growth in Europe in 2010 would have been only half of that experienced. The United Kingdom saw residential demand increase by 15% in 2010, with gas demand during the last quarter of 2010 30% higher than in the same period in 2009. In France, gas demand from small users increased by 10% in 2010, while in Italy, residential/commercial gas demand increased by 7.1%.



Power Generation Sector

The power sector remains the most variable as far as gas demand is concerned (see chapter on power generation). Gas use for power across the OECD in 2010 increased by 5%: this was to some extent driven by the 3.7% recovery of electricity generation. The aggregate fuel mix did not change substantially between 2009 and 2010: the share of combustible fuels remained almost the same as in 2009 (60.3% instead of 60.1%), while renewables (excluding hydro) increased from 5.1% to 5.5% and nuclear declined slightly from 21.7% to 21.3%. It is obvious that the recent earthquake and the resulting Fukushima accident as well as the decommissioning of 7 GW of nuclear in Germany, will have an impact on nuclear generation in 2011 (see chapter on medium-term forecasts).

The year 2010, with rapid changes in European spot prices, illustrated how sensitive this sector is to relative coal and gas prices. This sensitivity is most pronounced in those countries with a well

developed spot gas market, such as the United Kingdom, the United States, Belgium and the Netherlands. The output from UK gas-fired generators increased strongly over January-June 2010, with an incremental 22 terawatt-hours (TWh) generated compared to the same period in 2009, while the output from coal-fired plants declined by 2 TWh. But as NBP prices increased progressively over 2010, gas-fired plants' generation costs increased to the same or higher levels than coal-fired plants and their output actually dropped by 1 TWh in the second half of 2010, while coal-fired plants output increased by 17 TWh. In the United States, increasing power demand was met 59% by coal-fired plants and one-third by gas-fired plants. Unlike 2009, when gas-fired plants pushed coal-fired plants out of the mix in the Eastern part of the country, both gas and coal benefited from the recovery in electricity demand.

Non-OECD Gas Demand: Quo Non Ascendet?

The demand picture in non-OECD countries shows robust growth in all regions. Unlike the OECD, this growth was not due to abnormal weather (Russia being the exception). Rising demand was driven by economic growth and growing requirements for industrial production and power. The fastest-growing country by far was China, where demand reached 106.6 bcm in 2010, representing a 22% year-over-year increase. China now consumes more gas than any OECD country except the United States and ranks as the fourth-largest gas user in the world. Indian gas demand increased moderately from 59 bcm to an estimated 63 bcm in 2010, as production did not grow as much as anticipated and LNG imports fell.

Asia recorded the largest relative growth, with demand increasing 12%, followed by Eastern Europe/Eurasia and Latin America at 10% each. In Asia, incremental consumption was driven by China and India, as well as by many Southeast Asian countries, such as Indonesia, Thailand and Vietnam. In Latin America, most of the incremental growth was driven by Brazil: gas demand increased by around 38%, recovering from a 20% drop in 2009 due to high hydro levels impacting gas-fired generation. Peru, due to the start of the new liquefaction plant in June 2011, Bolivia, and Colombia, boosted by healthy gas production, also saw their demand increase substantially. But the two major consumers, Argentina and Venezuela, both faced gas shortages, which limited consumption increases to about 1%.

The Former Soviet Union (FSU) region saw its gas consumption surge from the lows of 2009. The 10% growth erased the 8% drop of the previous year. This increase, essentially from Russia, was partly driven by exceptionally cold months of January and December and a hot summer, which led to a surge of power demand for air conditioning. But a portion of the growth reflects a partial rebound in production from Russian industry. Nevertheless, although Russia's indices for production of manufacturing industry increased by 13% from the lows of the recession, they remain at early 2007 levels. In Ukraine and Belarus, the recovery boosted gas consumption respectively by an estimated 11% and 23%. Meanwhile, Turkmenistan, Azerbaijan and Uzbekistan gas consumption remained flat.

Demand in the Middle East increased by 6%, or around 20 bcm, on the back of strong consumption in Kuwait, Oman, and Saudi Arabia. Africa's gas demand growth was moderate with 3%: neither Algeria nor Egypt, which together represent three-quarters of African gas demand, showed exceptional growth.

Supply Trends: the Boom and the Bust

The year 2009 left gas consumers around the world with a comfortable surplus of supply capacity. This surplus supply was partially used in 2010, as the impressive gas demand rebound swallowed large shares of previously unused productive capacity. Production grew in every region – even in Europe where domestic production had been declining. The ranking changed as Eastern Europe/Eurasia's production exceeded North American production, driven by the recovery of domestic and export markets for Russia. The largest additional supplies came from Eastern Europe/Eurasia and the Middle East. Production in Eastern Europe/Eurasia jumped by over 70 bcm; Middle East gas production continued its relentless climb, growing by an estimated 50 bcm, mostly from Qatar. Asia also saw strong production growth, driven not only by China and India, but also by Indonesia and Thailand.

The two supply revolutions that took hold in 2009 continue to influence the markets: a first LNG wave hit the markets, providing an additional 60 bcm, while North American production increased by 26 bcm (3%), driven by the surge in US shale gas output. Most of the additional LNG came from the Middle East (Qatar and Yemen), as well as from Russia and Peru. This LNG wave is expected to continue in 2011 on the back of plants recently started. The next LNG wave will only come by the middle of this decade.

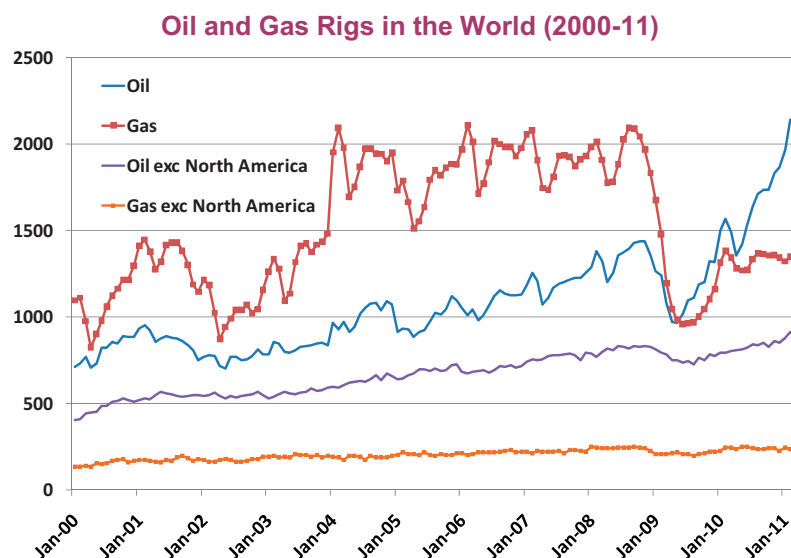
OECD: Surprisingly, Gas Output Increases in all Three Regions

OECD gas production maintained its share in total gas production at around 37% and increased in all three OECD regions. This is not so surprising in OECD Pacific where Australia is slowly building up gas production before the surge of LNG production by the middle of the decade. The increase of production in Europe was quite unexpected and was uncertain in North America.

OECD Europe's gas production increased marginally from 292 bcm in 2009 to 298 bcm in 2010, a 2% increase that largely reflects a 10 bcm increase from the Netherlands. As the Netherlands often acts as the swing supplier in Northern Europe, this increase is relatively normal and is more a catching up to normal levels. After a 4 bcm growth in 2009, Norwegian gas production increased by only 1 bcm in 2010, despite the recovery in European gas demand, its main export market. Many Norwegian fields such as Sleipner Øst have declining gas output, while Ormen Lange reached its plateau of 20 bcm in 2009. Only a couple of fields, including Gjøa, have recently started. Production continued to decline in most other European countries – Germany's output dropped by 12% and the United Kingdom's by 4%. No European countries, except for Norway and Ireland (with the expected start of the Corrib field), are expected to have growing production in the medium term.

Production in North America is a study in contrasts. The growth of US gas production continues to be strong despite relatively low prices, limited opportunities to hedge production at higher prices, and strong divergence between oil and gas prices. US gas production nevertheless increased by 30 bcm in 2010, and reflects a growth of 100 bcm over the past five years. In the integrated North American market, one supplier's loss is another's gain. More expensive Canadian gas imports are struggling to compete against cheaper shale gas production (which is also displacing the most expensive US conventional gas). Canada's gas production continued to fall, dropping 4 bcm in 2010, after having already plummeted by 20 bcm between 2007 and 2009. The growing gap in prices between oil and

gas provides more incentive to drill for oil, and the number of oil rigs in North America has more than doubled within two years. With elevated oil prices, above \$100 for several months now, and US spot gas prices remaining around \$4/MBtu (around \$25/bbl oil equivalent), producers have a clear preference to drill for oil. In fact, they are increasingly turning towards liquid-rich shale plays in order to increase revenues from the liquids as gas prices remain too close to break-even costs. This has, however, turned into a virtuous circle, with the liquids driving the growth of gas production.



Source: Baker Hughes.

In OECD Pacific, Australian domestic production increased by 2.2 bcm, which translated into slightly higher LNG exports and supplies to the domestic market. The new LNG plant, Pluto, failed to arrive as scheduled by end-2010, and will only start by August 2011. A more significant increase of Australian production is now expected by 2012 and then later in the decade, when three other committed LNG plants come online.

Non-OECD: Bearing most of the 230 bcm Recovery

Supply in non-OECD regions is characterised by a recovery of FSU (mostly Russian), African and Latin American gas production, and a continuing rise in Asian and Middle East production. Despite its strong rebound by 13%, FSU gas production stayed well below 2008 levels. Meanwhile, both African and Latin American gas production exceeded 2008 levels notwithstanding the weakness of some key producers.

Russian gas production is estimated to have increased from 572 bcm to 651 bcm, but still remains below its 2008 level of 662 bcm. There is little doubt that Russia can produce much more, but it is constrained by the absence of recovery in exports to Europe, so that the increase is entirely driven by domestic demand and exports to other FSU countries. The output of independent gas producers jumped by 20 bcm (see chapter on investments in major producing regions). Production also recovered in Turkmenistan, due to the new exports to China (4 bcm) and a slight recovery of exports to Russia, but it declined in Ukraine and Uzbekistan.

Middle East production increased by 13%, driven by rising domestic needs and growing LNG exports in Qatar, where production increased by one-third. In 2008, the country became the second-largest Middle East producer behind Iran. In Africa, Nigerian gas production nearly returned to 2008 levels after plummeting by one-third in 2009, due to unrest and sabotage. The recovery in export markets, combined with growing domestic demand, facilitated increasing production in Algeria. Egypt faced production issues affecting operation of its LNG trains, leaving them largely under-utilised at 60%.

Asian countries are increasing their output to meet their rising gas demand, and, in some cases, export commitments. China, with 95 bcm produced in 2010, has emerged as a key producer. A relatively high proportion of its output is tight gas (between 15% and 20%) and around 6 bcm comes from both coalbed methane (CBM) and coal mine methane (CMM). Indian gas production continued to increase, albeit less than anticipated, as the giant Krishna Godavari experienced reservoir difficulties limiting its production. India sees a growing share of its output now produced offshore and by private companies and/or joint ventures. Production grew strongly in Thailand, on the back of growing production from the Arthit field and the start of new fields in the Joint Development Area with Malaysia. New production feeding Indonesia's Tangguh LNG plant largely compensated for the decline in production from mature fields.

Latin American production growth was mostly driven by Brazil and Peru (where a new LNG liquefaction plant started in 2010). Colombia also increased its output by around 10%, but major producers such as Argentina and Venezuela are struggling to increase production and have *de facto* turned into net importers of gas, despite their significant reserves.

What Happened to the Gas Glut?

In 2009, the 2.5% decline in gas demand occurred at a time when ample new supplies were being placed on the market, creating a situation of oversupply and overcapacity in the transportation of gas to markets. This situation was often referred to as the “gas glut”, measured by the excess of inter-regional transportation capacity (pipeline and LNG) versus trade. Demand dropped heavily in the OECD region as well as in most non-OECD regions. Only a few countries, such as China and India, saw increased demand in 2009.

This slowing in demand happened just as the anticipated wave of supply from new LNG plants was reaching the markets. The unexpected boom of US unconventional gas production worsened the situation as North America effectively withdrew from global markets. Some LNG exporters with new plants commissioned in 2009 delayed their operational start dates, while others faced upstream issues. Some LNG producers that had targeted the North American market had to find alternative outlets, mostly in Asia and in Europe. LNG trade nevertheless increased in 2009 as competition between LNG and pipeline suppliers intensified. Due to the excess of gas, spot prices in the United States and in the United Kingdom plummeted by two-thirds from \$13/MBtu to \$4/MBtu, at levels twice lower than oil-linked gas prices in Continental Europe and Japan. This created some tensions between buyers and suppliers, particularly in Europe. Those with long-term, oil-indexed contracts saw their customers taking volumes sometimes lower than what contractual flexibility would allow, as buyers tried to take advantage of lower spot indexed gas supplies. The excess of

production led some suppliers to curtail output in 2009. This affected primarily pipeline suppliers such as Russia, Canada and Turkmenistan.

In 2010, the strong rebound of gas demand worldwide, particularly across historically importing regions (OECD Europe and Pacific) and growing importers (Asia and Latin America) partly absorbed the excess of supply. The daunting question facing the gas industry is whether the rebound is short-lived (demand growth in OECD regions was exacerbated by abnormal weather) or whether demand will continue on the same path, driven by Asian countries. The biggest uncertainties remain the strength of the global economic recovery and the evolving role of gas in the power mix. The latter issue hinges critically on relative coal and gas prices as well as on future decisions on both nuclear power and renewables policy. If the stated objectives of the 12th Five-Year Plan in China were to be met, this would result in a dramatic increase in gas demand to 260 bcm from 107 bcm today. This eventuality would quickly erode the excess global supply capacity as Chinese imports would need to increase to over 100 bcm to cover that demand increase.

The gas glut is likely to play out differently in different markets, with supply and demand expected to tighten faster in the Asia-Pacific region compared to the Atlantic basin. In *World Energy Outlook (WEO) 2010*, the excess supply capacity was estimated to disappear only by 2020; were demand to grow at a faster pace, the excess of supply would dissipate more quickly. In the GAS scenario in the *WEO 2011* excerpt *Are We Entering Golden Age of Gas?*,⁵ in which gas demand increases to 3,685 bcm by 2015 (150 bcm more than in the New Policies Scenario of *WEO 2010*), the utilisation rate of inter-regional capacity would recover to pre-crisis levels of around 80% by 2015.

Additionally, unforeseen events that affect supply could lead to the same result. In early 2011, the world experienced a series of events that collectively eroded the excess of supply on the markets. Libya's disruption resulted in a reduction of 9 bcm of pipeline exports (going only to Italy) and around 0.5 bcm of LNG, which was easily manageable for global markets. Pipeline supplies to Italy have been replaced by additional Russian and Algerian gas deliveries. The closure of nuclear power plants in Germany is likely to translate into additional gas demand. Markets are not yet tight and spot prices have not increased in an excessive manner, but pressure remains and market prices in Europe and OECD Pacific continue their upward trajectory (see chapter on prices and trading development).

⁵ This report was issued on 6 June 2011.

POWER GENERATION

Summary

- **OECD electricity generation largely recovered in 2010 after the sharp 3.8% fall in 2009. The recovery occurred at differing paces, due to varying degrees of economic growth.** Still, OECD power output in 2010 was 0.3% lower than in 2008. Some countries, such as Korea and Turkey, showed a quick rebound of power demand. Europe's electricity demand increase was slower due to a sluggish recovery; in some countries, electricity generation was also affected by changes in trade patterns.
- **The share of gas in total generation increased slightly in 2010, benefitting from the recovery and, to some extent, from lower spot prices in the United States and in Europe.** In the United States, although the gas-to-coal price ratio grew in 2010, the share of gas still rose slightly, reflecting a “one-sided elasticity” of gas share in thermal generation. In most electricity systems, gas is a marginal generator; consequently, gas-fired generation reacts disproportionately to changes in power demand even when relative prices remain unchanged.
- **The relationship between the price of fossil fuel and their use for power generation varies significantly among OECD countries.** Analysis of the United States and Japan shows that the degree of responsiveness to relative price changes varies depending on power plant fleet, market structure and fuel supply arrangements.
- **Plans for new power generation capacity in the OECD show that renewables and gas will dominate.** In Europe, the increase in gas-fired capacity over 2011-15 is expected to be between 8% and 21% depending on fuel prices and policy decisions, compared to between 34% to 55% for renewables. In the United States, gas represents half of all additions, ahead of coal and wind.
- **Increasing deployment of variable renewable energy sources such as wind and photovoltaic (PV) strongly impacts the relative attractiveness of future investments in different generation technologies, favouring natural gas compared to both coal and nuclear power.** Indeed, the increasing share of variable electricity sources strongly decreases the capacity factor at which other types of generation will run. Generation technologies with relatively low investment costs (such as gas) become more attractive at lower capacity factors. However, changes in load factors of the existing capacities are likely to affect disproportionately gas capacities (which are often at the margin) and thus gas demand.

OECD Electricity Generation and Demand in 2010

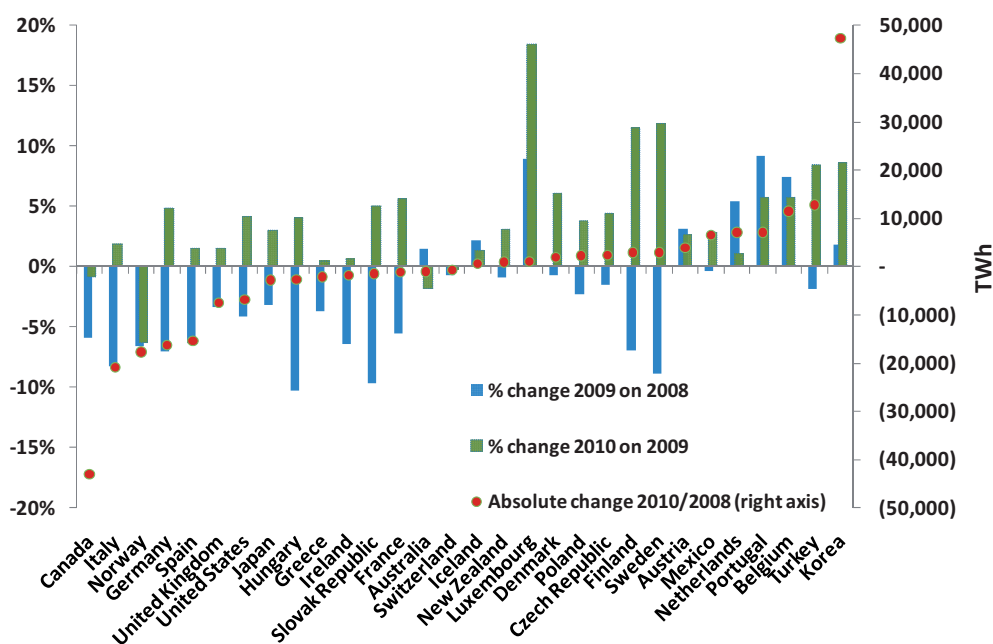
Electricity generation increased by an estimated 3.7% in 2010, after plummeting by 3.8% in 2009, so that the aggregated OECD power output was only 0.3% lower in 2010 than in 2008. Yet, the aggregated number masks significant differences between the countries' changes in production. Although most countries saw generation growing in 2010 (green bars in the following graphic), the 2008 power generation levels were exceeded only by roughly half of the OECD countries, with the other half was still lagging behind 2008 levels to a varying degree.

At the top of the spectrum is Korea with 8.7% growth in 2010: the country stands out as its GDP did not go down even in the middle of the 2009 recession and increased by an impressive 6.3% in 2010,

thanks to robust manufacturing exports and the largest financial stimulus among OECD countries.⁶ After a relatively small dip in 2009, Turkey's electricity generation rebounded by 8% and returned to the previous trend of being the fastest-growing power consumer among OECD countries. Turkey's per-capita electricity consumption remains still well below the OECD average level. Strong economic growth and a very hot summer were key contributing factors driving up demand in 2010.

Parts of Europe with active cross-border trade could appear as defying the general trend in changes in generation, whereas some differences in growth are explained by a geographic redistribution of generation in the last two years. In the Netherlands, power generation increased in both 2009 and 2010: although the country was hit by the recession, availability of cheaper gas from late 2008 and more efficient power generation assets made locally produced electricity more competitive. Imports from Germany fell (affecting power generation in Germany as well) and so net imports to the Netherlands shrunk by about 10 TWh in 2009, then by further 2 TWh in 2010. The same line of arguments applies to Belgium, albeit the country was also less affected by the recession.

Changes in Total Power Generation 2008-10



In a few countries, power generation remains below the pre-crisis level. For a number of them, this is explained by slower rates of economic recovery, notably for Italy, Spain and Greece. Although the United States benefitted from strong economic growth and a very hot 2010 summer, US power generation in 2010 was 0.2% lower than in 2008. Another factor contributing to US growth of electricity demand and generation was a very hot 2010 summer: cooling degree days were at an all-time high, 18% higher than in 2009; total power generation over June-August 2010 was 8% higher than during the same period in 2009.

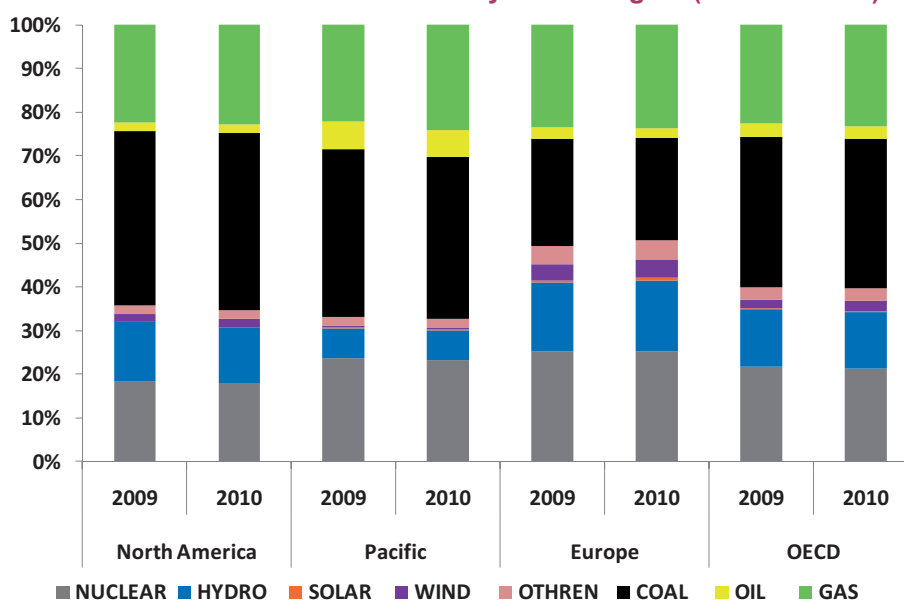
⁶ OECD, (2010). Economic Survey of Korea.

Latest Trends in Fuels Use in the OECD

Over the past decade, gas has steadily increased its share in the OECD generation mix from 16% to 22%. All OECD regions show the same trend: the proportion of gas in total generation in OECD North America grew from 15% to 22%, in OECD Europe from 16% to 23%, and in OECD Pacific from 19% to 22%. This trend continued to some extent even in the middle of the recession in 2009. In the United States, where gas was relatively cheap in 2009, the output from gas-fired plants increased despite a drop in electricity demand resulting in a bigger drop in the output from coal-fired plants. However, in Europe, the share of gas declined by 0.6% in 2009. First, the share of renewables (excluding hydro) increased by 1.3%, reducing the share of combustible fuels. Additionally, in a few European countries such as Italy, gas remained relatively expensive versus coal so that its share declined more substantially in 2009 as demand fell.

Output from gas-fired plants increased by 6% in 2010, versus 3% for coal-fired plants, 16% for wind and 43% for solar. In the United States, despite the fact that gas share in the generation mix only grew by 0.5% in 2010 compared to 2% in 2009, a month-by-month analysis reveals a more subtle story. Gas prices and gas-to-coal relative prices both rose in 2010, which could have triggered some switching back to coal compared to 2009. The potential price incentive to switch to coal was significant at times: during the summer 2010, the gas-to-coal price rose by as much as 15% but switching to coal did not occur (see chapter on prices and trading development). In contrast, following the hot summer, gas prices declined in the autumn below the 2009 level and generators started switching further away from coal in those months. This phenomenon of “one-way elasticity” is probably explained by gas prices being higher than in 2009 but still too low for coal to effectively compete across all US power markets. This seems to suggest that very low gas prices, when they increase, do not trigger a switching back to coal, but that gas price decreases cause further displacement of coal.

Fuel Shares in Power Generation by OECD Region (2010 vs. 2009)



In Europe, gas had to maintain its share against growing renewables and compete against coal at the margin, resulting in widely diverse outcomes on a country basis. Total renewables generation in OECD Europe grew strongly in 2010, by an estimated 9%. Hydro accounted for half of the growth, wind and other renewable for one-sixth each. Gas benefitted from lower gas prices relative to coal prices in some countries, particularly during the first half of the year (see chapter on prices and trading development). In the United Kingdom, where gas prices were low during the first half of 2010, gas-fired generation increased by 6%, benefitting also from nuclear outages. In Spain, however, gas was squeezed by growing output from nuclear, hydro, and renewables, reducing the share of combustible fuels from 43% to 33% between 2009 and 2010, and that of gas from 30% to 24%. Although generation from gas-fired plants declined by 14%, it did gain substantial market share from coal in the competitive segment of the electricity market as the strong growth in wind (+16%) and solar (+10%) took place in the framework of feed-in tariffs.

Inter-fuel Substitution/Competition and Fuel Prices

Considering the importance of the power sector for the future demand for natural gas, it is crucial to understand how factors such as renewables integration and relative fuel prices will impact the dispatch of power plants and, therefore, use of gas-fired plants. Based on two contrasting examples,⁷ the following analysis focuses on fossil fuels and extends the once dominant notion of “fuel switching” in multi-firing units to a system-wide view where substitution occurs between plants.

Fuel prices are not the only factor affecting the dispatch of power plants. Actually, there are many others such as the range of plant efficiencies and ramping rates, the wholesale market design and operational factors, regulation on retail price formation, emission standards, air quality, and maintenance schedules. These factors can weaken or strengthen the effect of fuel prices on fuel use, and the cumulative effect results in a particular pattern of price influence on fuel use in a given power market. In other words, while spark spreads send a signal to the market, how the market participants react is a different matter. The presented approach captures the strength of this response by calculating fuel demand elasticity,⁸ and can be used for projecting the future generation mix under given assumptions.

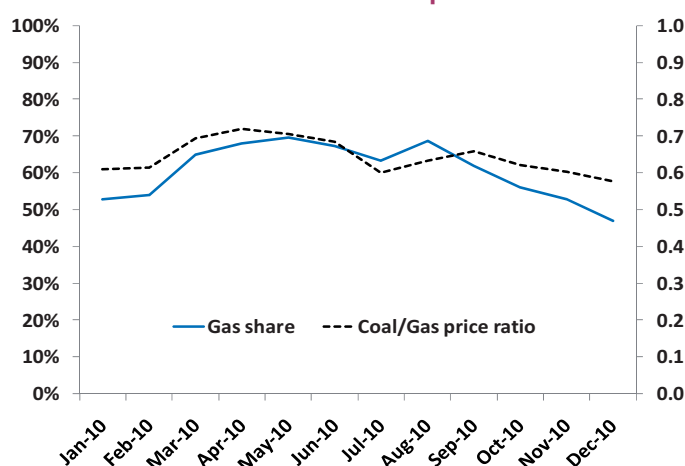
In the United Kingdom, the estimated coal price elasticity of gas demand, which is the ratio of the percentage change of gas use to the percentage change in coal price, is relatively high at around 0.4. This number indicates that, when the price of *coal* goes up by, for example, 10%, and other factors stay fixed, the use of *gas* for power generation increases on average by 4% ($0.1 \times 0.4 = 0.04$). The figure below shows the share of generation from gas-fired plants in total combustible fuel generation plotted against the movements of relative coal-to-gas prices. This high responsiveness is explained by the healthy competition between the players on the UK wholesale market, a well diversified fleet of plants, sufficient surplus capacity, and the availability of a liquid gas spot market allowing for quick adjustment in fuel supplies. The results of this analysis also show that a higher carbon price or relative coal-to-gas price is likely to lead to gas gaining a larger share in the UK generation sector as there is ample gas-fired capacity.

⁷ A Working Paper on the subject with more substantive analysis will be published in late 2011.

⁸ For more details of the methodology see IEA, (2011). Annual Carbon and Electricity Report.

In contrast to the United Kingdom, Japan's power market appears much slower to respond to relative fuel price movements. Indeed, the coal price elasticity of gas demand is only 0.05. The generation from oil products is still significant in Japan (8.6% in 2009) but the oil price elasticity of gas demand is also similarly small at -0.08. Minus indicates that the use of gas decreases slightly when the price of oil goes up, reflecting the fact that gas and oil prices are linked. Additionally, the market is split into ten areas, each dominated by a vertically integrated utility. This market arrangement together with regulated power prices, where the cost of fuel is almost fully passed on to the consumer, potentially reduces the incentive to cut power generation costs. However, although the liberalisation of Japan's electricity market slowed down and was officially stopped in 2008, there is still political pressure on utilities to reduce electricity prices. As a result, electricity prices have declined significantly in the past several years.

Use of Gas in the UK Power Sector in Response to Relative Fuel Prices



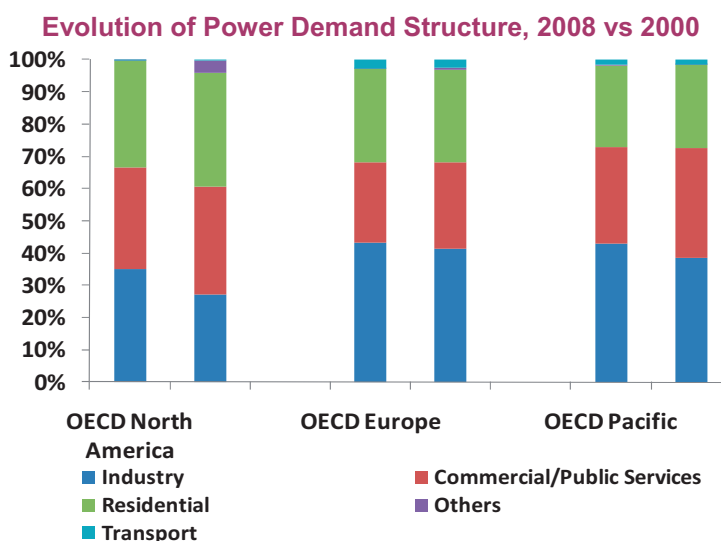
Note: the gas share is the percentage of electricity produced from gas of the total generation from combustible fuels; gas price are NBP, coal prices are Northwest Europe.

Thus, while there are incentives for Japan's generators to reduce costs, the extent to which the industry can respond to price signals is likely to be limited by the prominence of long-term, take-or-pay gas supply contracts. Even though relative oil-to-gas import prices can change substantially in a particular month because of the lag in gas contracts, in the longer term, it might be challenging to reduce fuel costs by taking into account changes in the relative price on a monthly basis as contracted gas still has to be used. The result is the low responsiveness of gas use to other fuels' prices as reflected in the low estimated elasticity. Of course, recent events will change the situation as Japan tries to replace missing nuclear capacity. Additionally, estimates of fuel price elasticity can also be combined with the analysis of reserve capacity in order to assess power systems' security. For example, the likely response of the power market to a fuel supply disruption will be estimated in a future IEA working paper.

Investment Outlook

Several factors have contributed to the high number of gas-fired plants being built in OECD countries as well as in many non-OECD countries. Among these factors are gas-fired plants' lower capital costs

and construction times, a higher flexibility better suited to meet variable power demand as well as backing variable renewables generation (see section below), the ability to hedge higher fuel prices, as well as the introduction of emissions trading schemes which would favour gas over coal. Additionally, gas-fired plants are less subject to “not-in-my-back-yard” (NIMBY) issues than coal, nuclear power plants or wind mills. There have also been changes on the demand side requiring more flexible generation. Indeed, the share of industrial electricity demand (which is usually base-load) was roughly the same in OECD Europe and OECD Pacific, and was somewhat lower in OECD North America in 2000. Since then, the share of industry’s consumption has fallen in all regions (especially in North America), prompting a call for more load-following and peaking units.



Investments in the OECD Region

In Europe, gas and renewables will contribute most to new capacity additions in the next five years according to the forecasts of the European Network of Electricity Transmission System Operators (ENTSO-E). Additions of coal-fired plants, hydro and nuclear will be limited in comparison. Only four nuclear power plants are under construction and expected to start during that period: one in Finland, one in France and two in Slovakia. ENTSOE’s forecasts foresee European gas-fired capacity to be at least 8% higher in 2015 in comparison to the level expected in 2011. This estimate is based on 36 European TSOs information on approved projects,⁹ and is the most conservative forecast based on projects considered as sure and for which the commissioning decision can no longer be cancelled.

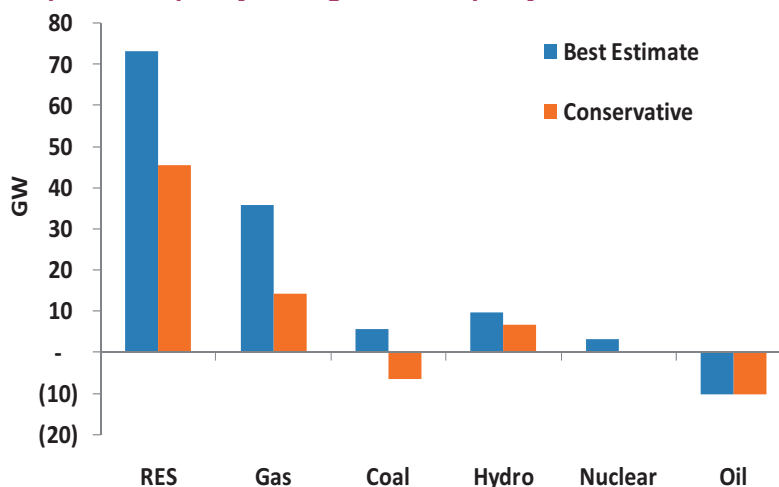
The growth of gas-fired capacity is likely to be significantly higher, depending on many factors such as fuel and carbon prices. Another forecast is given by the TSOs “best estimate” scenario, which was compiled with the other scenario at the end of 2010, and therefore does not take into account the effect of Germany’s measures on nuclear energy after the earthquake in Japan in March 2011. Under this scenario, the expected level of gas generation capacity will be significantly higher than under the conservative scenario (206 GW vs 184 GW in the conservative scenario in 2015, compared to 170 GW in 2011). In the best estimate scenario, the additions of renewables are higher than in the

⁹ ENTSO-E, (2011). Scenario Outlook and System Adequacy Forecast 2011-2025.

conservative case. The graph below shows changes in absolute terms and implies a 21% growth of gas capacity and a 55% growth in renewables (other than hydro) in the best estimate scenario. How this additional capacity will translate into generation is another matter. Renewable energy sources have relatively low load factors: 20% to 30% for wind onshore, 35% to 55% for wind offshore and around 10% for PV. Gas-fired plants load factors will depend on the share of must-run technologies (nuclear, hydro, and renewables) in a given market and on how gas competes against other technologies or imports from other markets. Therefore, significant additions of gas-fired capacity do not automatically translate into higher gas demand, as demonstrated by the example of Spain where combined-cycled gas turbines (CCGTs) were used at a capacity factor of 30% in 2010.

Additionally, the EU Large Combustion Plant Directive stipulates that plants over 50 MW capacity, which do not comply with specified reductions in NO_x and SO_x, will have to shut down at the end of 2015 at the latest. The Directive is not expected to have a great impact on installed capacity in Europe since most companies have invested in retrofitting, except in the United Kingdom where the industry expects several coal-fired plant closures before 2016.

Expected Capacity Changes in Europe by Fuel 2015 vs. 2011



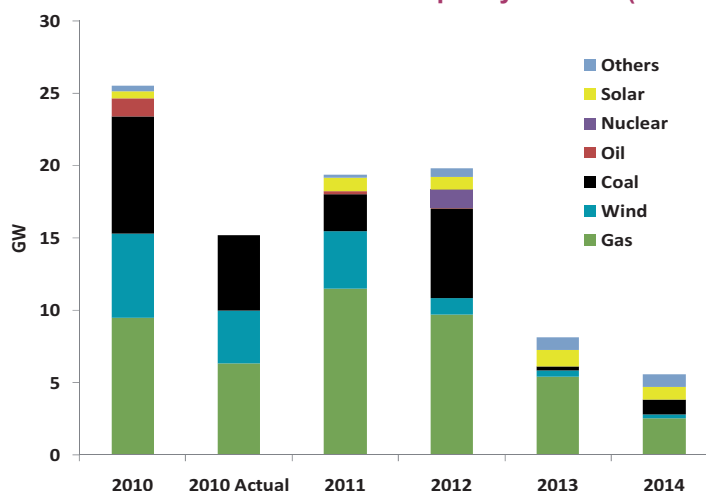
Source: ENTSO-E.

Note: RES: Renewable Energy Sources. Europe includes EU27, Iceland, Norway, Switzerland, Albania, Bosnia Herzegovina, Montenegro, Serbia, FYROM and Cyprus.

The North American power market consists of several regional markets with different fuel prices, regulation and infrastructure and so all-country results are likely to conceal wide local deviations from this average. For example, cheap coal in the Powder River Basin reduces the attractiveness of gas-fired plants in this region. Looking at the planned investments in power capacity over 2010-14, 49% of the 78 GW planned over that period would be gas-fired plants, followed by 23% of coal-fired plants and 15% of wind. First estimates from EIA regarding new additions in 2010 show that less capacity came online in 2010 than planned, but the ratio between fuels remains the same. Despite the relatively large coal additions in 2010-12, very few would take place post-2012. As these plants have longer construction times, their absence at the planning stage means it is unlikely more will be built over 2013-14. Coal plants coming online by 2012 received their final investment decision before the “shale gas revolution”.

By contrast, as wind and solar have shorter planning horizons and can be built in one or two years, wind capacity additions post-2011 are likely to be higher. Similarly, more gas-fired plants could be built in this time frame. An important element to take into account is the retirement of coal and gas-fired plants. In 2009, 7.9 GW were retired, of which 5.9 GW were gas-fired and only 0.5 GW were coal-fired. The growing share of renewables reduces the share of demand left for thermal generation. The existing state-level renewable portfolio certificates (RPS) schemes and federal level legislation already provide a strong impetus for investment in renewables despite the absence of a federal RPS scheme. According to a recent study by the North American Electric Reliability Corporation (NERC),¹⁰ which covers both the United States and Canada, an additional 180 GW of new wind and solar capacity could come online over the next ten years, of which 53 GW with high certainty. The study stresses the distinction between “nameplate” and “on-peak” capacity (available for seasonal maximum load) for variable generation resources, and finds that out of 41 GW of planned wind capacity, only 8 GW will be available on-peak (on average, in North America on-peak is 14% of wind nameplate capacity). This reinforces the need for reserve capacity (often gas-fired) to be available to cover peak power demand.

Planned Investments in Power Capacity 2010-14 (United States)



Source: EIA. The forecasts are for the 2010-14 period and are updated annually. 2010 actual represent EIA's estimates of capacity coming online in 2010. Data on solar, oil and others are missing.

Focus on Russia

There are major events unfolding in the Russian power market with potentially significant consequences for the country's gas balance: after several years of restructuring and gradual liberalisation, the wholesale power market moved to 100% market-based prices from 1 January 2011. This section outlines the state of affairs in the power sector, its interplay with gas and coal markets, and assesses the mid-term outlook for generation and capacity mixes.

Russia's power sector is one of the largest in the world, with 229 GW of installed capacity, and is characterised by being closely intertwined with heat production. Generation from coal and gas

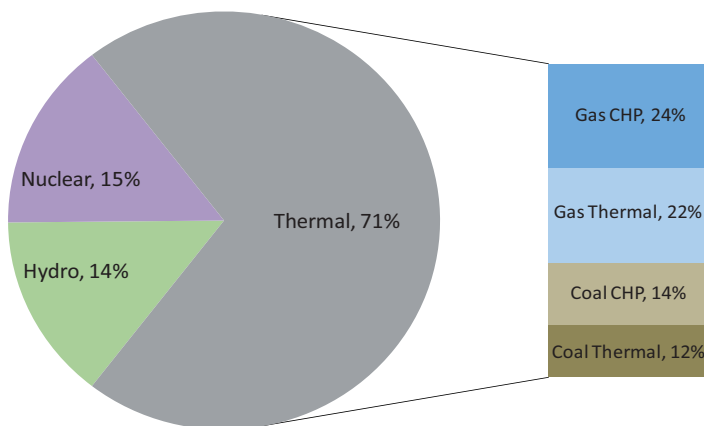
¹⁰ NERC, (2010). Long-term Reliability Assessment.

combined heat and power (CHP) plants accounts for 53% of thermal production which in turn has a high proportion (71%) in total generation. Gas represents a significant share of power generation (46%), with significant variations by region. In the European part, which is also a separate price zone in the wholesale market, gas capacity is dominant, whereas in the Siberian price zone, capacity and generation are largely based on coal and hydro. Apart from pricing reasons, this geographical separation will keep gas-to-coal competition limited.

The current market structure intended by the reform is to ensure that power plant ownership is fairly evenly spread by technology, location and size. However, benefits of such market structure may only be fully realised if ownership is balanced as well. The wholesale market appears to be functioning properly in a sense that price formation follows changes in the supply-demand balance. Although it came under much political criticism over high price spikes last winter, the market reacted properly to the reduction of demand in the middle of the recession and electricity prices fell.

Concerns expressed by some stakeholders about access to gas in the wake of the winter 2010/11 shortages highlight emerging infrastructure constraints and other rigidities in the domestic gas system. Gas has an important ongoing role to play in the efficient development of the electricity sector. Critical infrastructure bottlenecks and rigidities need to be identified and resolved to ensure that the electricity sector can develop in a timely and efficient manner, consistent with achieving the government's modernisation agenda and wider economic reforms. This suggests the need for further reforms of the domestic gas sector.

Generation by Fuel in Russia (2009)



Source: Russia's Energy Forecasting Agency, IEA estimates.

The key factor determining future gas demand is the extent to which the reform will succeed in attracting investment to modernise the aging Russian generation fleet. Replacing all gas-fired generation by state-of-the-art CCGT plants would cut gas demand by around 100 bcm, equivalent to the production from a West Siberian super-giant field. In addition, fuel prices are becoming an important factor in determining future use of gas. While coal has been traded at market prices, the

situation with gas is in limbo. Internal gas prices have been kept at very low levels for decades and are now set to increase significantly, the uncertainty being to what level and how quickly. The government postponed previous plans of reaching “export price parity” during the crisis; the current target is 2015. However, the target is increasingly challenging to achieve as export prices are both volatile, driven by the current high oil prices. The annual 15% increases are likely to be implemented though, which should drive an increase in incentives to move away from gas in generation.

In the longer term, domestic gas prices will probably move gradually to be set by gas-to-gas competition for several reasons: the gas exchange is resuming in summer 2011. There is growing political pressure on Gazprom to give more access to the pipeline system (see chapter on investment in production). Additionally, the industry foresees a quicker development of the financial market to facilitate gas trading in the medium term. Also, when gas prices become more cost-reflective, price changes will be uneven geographically as the fixed prices currently do not take into account transportation costs. Regions further away from the West Siberian gas production area are likely to see higher rises.

The dominant position of gas in the power sector originated with the 1980s Russian version of the “bridge fuel” concept, the so-called “gas pause”. It was intended as a temporary period of intensive gas use before developing clean coal and safer nuclear technologies. In the previous versions of Electricity Strategy papers, the Russian government expressed determination to increase the use of coal in power generation and to phase out the “gas pause”. However, during the economic crisis, gas export prospects worsened and difficulties in deploying more coal supplies became apparent. Thus, the 2010 version of the Electricity Strategy projects only a very slight reduction (3%) of the gas share in thermal generation by 2030.

Integration of Renewables¹¹

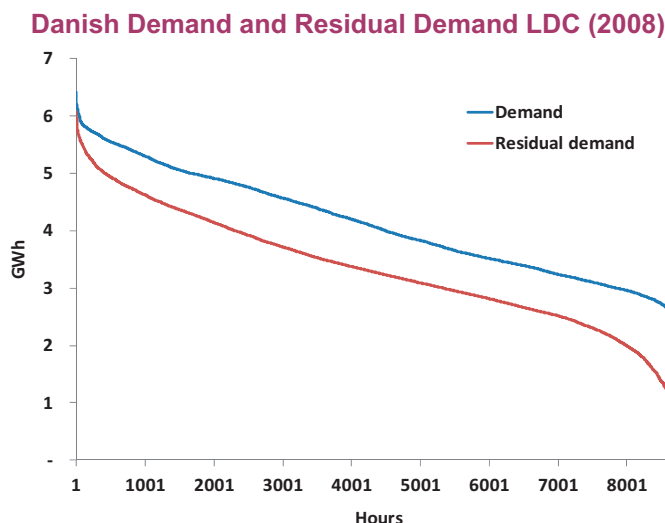
Over the past decade, growing concerns about climate change, air quality and security of gas supply, coupled with considerable advances in low-carbon generation technologies, have led to an increased interest in less carbon-intensive and more sustainable generation technologies (such as wind or solar). As a result, both wind and solar capacity installed around the globe has strongly increased and this trend shows no signs of slowing. In 2010, 37.6 GW of wind capacity was installed worldwide, an increase only surpassed by the 2009 capacity additions.

Several renewable technologies, such as solar PV and wind, demonstrate both intermittency and variable output. Therefore, an increasing share of these types of renewables in power generation strongly affects the way in which other types of generation capacity, like gas and coal, are employed, changing both the demand patterns for these fuels in the power sector and the relative economic attractiveness of investments in these generation technologies. Although the following analysis was mostly based on the effect of an increasing wind market share, other variable renewable electricity sources, such as solar PV, would have similar effects.

¹¹ The results shown here are from an IEA Working Paper on “the effects of an increasing share of wind on gas markets in Europe”, which will be published later in 2011 on IEA’s website.

The effect of an increasing market share of renewables is best shown by comparing the Load Duration Curve (LDC) of total demand and of demand without wind or “residual demand”. This is the demand that has to be filled by other types of generation capacity assuming a preferred dispatch of wind output. The figure below shows the 2008 LDC’s of demand and residual demand of the Danish system, which in 2008 had a wind market share of 19%. Wind significantly decreases the average capacity factor of residual demand; the amount of capacity that runs at high capacity factor (70%-100%) decreases, while the amount of capacity which runs at a low or very low capacity factors (30%-0%) increases.

The capacity factor at which generation units are expected to run strongly influences the relative attractiveness of different types of generation technologies.¹² At lower capacity factors, generation technologies that have low capital investment costs become more attractive. As natural gas-fired technologies have relatively low investment costs (compared, for example, to nuclear or coal-fired capacity), a rising share of renewables increases the relative attractiveness of investments in gas-fired capacity. The investment costs of gas-fired capacity are estimated to be around €800/kWh, compared to €1,300/kWh for coal or €3,000/kWh for nuclear.¹³



Wind not only influences new investment decisions in the power sector, but also the way in which existing generating units are utilised. Due to its variable character, an increasing market share of wind strongly increases the need for flexible supply and demand instruments that can support this intermittency. These instruments include energy storage, regional electricity interconnection and trade, demand-side response and of course supply-side response with other forms of electricity generation ramping up or down in response to wind.

Comparing the technical capability of different fuels, gas-fired capacity seems to be well positioned to support wind flexibility, but it does not have to supply all of the additional flexibility required. Natural gas-fired capacity has the shortest start-up time, lower start-up costs and highest ramp speeds. This makes gas very suitable to support short-term changes in residual demand. But both

¹² IEA, *Harnessing variable energy*, 2011, OECD/IEA, Paris.

¹³ IEA, *Projected Costs of Generating Electricity*, 2010 edition, OECD/IEA, Paris.

nuclear and coal-fired generation units can flex their output in response to changes in electricity demand.

Technical Measures of Plant Flexibility

Technical measure of plant flexibility	Natural gas		Coal	Nuclear
	<i>OCGT</i>	<i>CCGT</i>	<i>Boiler</i>	<i>Boiler</i>
Start-up time	++	++	-	--
Start-up costs	++	+	-	--
Ramp rate	++	+	-	-
Part load efficiency	--	-	+	?
Minimum stable generation	++	+	-	--

Note: ++ is the most flexible, + is second most flexible, - is the third most flexible and -- is the least flexible.

Due to the relatively limited possibilities for expansion within Europe, this study does not include hydro (either pumped storage or hydro reservoirs). Hydro technologies have even shorter start-up times and higher ramping rates than gas-fired technologies, and can play an important role in supporting wind power in regions where expansion possibilities exist.

Exactly what fuel will respond to demand changes will strongly depend on the actual marginal costs of electricity production. Nuclear power, which has relatively low marginal costs, will produce as much at base load as possible, but the response of coal or natural gas-fired units depends very much on actual fuel and CO₂ prices. It seems likely that both coal- and gas-fired generation will be used to support wind.

If indeed gas-fired generation capacity is used to react to changes in wind demand, which seems extremely likely, then increasing wind market share significantly affects the characteristics of gas demand in the power sector. Due to the high variability and limited predictability of wind, residual demand will become even more variable and less predictable than power demand. As a result, natural gas demand would also become more variable and more unpredictable.¹⁴

This would have implications for investments along the gas value chain (such as storage and transport), as well as on costs associated with using gas in a more intermittent way. For example, extra transportation costs occur when gas is used much more intermittently, so that the price per unit transported increases. The role of gas storage would change from smoothing seasonal fluctuations in heating demand to reacting to much more rapid changes in power sector gas use.

¹⁴ How this impacts the market for natural gas is discussed in more detail in the earlier mentioned working paper.

MEDIUM-TERM SUPPLY AND DEMAND FORECASTS

Summary

- **World gas demand is anticipated to grow at a rapid pace (2.4%/y) during 2010-16, albeit lower than in 2010, reaching around 3,800 bcm by 2016.** Around 85% of the incremental consumption of 510 bcm will come from the non-OECD region, particularly from Asia and the Middle East. Growth from “mature markets” such as the OECD and the FSU will be more moderate. The most impressive relative increase will take place in China, where gas demand could reach around 260 bcm by 2016, 2.5 times its level in 2010.
- **The power sector will remain the main driver of gas demand in most regions. In the OECD region, gas demand growth in this sector depends notably on the relative fuel prices, as well as on the expansion of renewables and policy decisions on nuclear.** In the non-OECD region, the power generation sector will continue as the main driver, but gas demand is also anticipated to grow strongly in the industry, energy industry own use and, in some countries, in the residential sector. The rapid expansion of renewables in OECD countries means that combustible fuels’ share in the generation mix will decline somewhat between 2010 and 2016. In the early years of the forecast period, however, combustible fuels will benefit from a drop in nuclear generation. As gas competes against coal, these factors constrain but do not prevent gas demand growth in the OECD power sector.
- **While gas demand expands in all regions over the medium term, additional supply will come mostly from existing non-OECD suppliers with significant market shares, including the FSU and the Middle East.** OECD gas production will increase only marginally, with additional output in Australia compensating for the fast-declining European gas production. The FSU is by far the most important producing region by 2016, boosted by increasing exports to Asia through the Central-Asia Gas Pipeline from Turkmenistan to China. The Middle East region is the second-largest contributor in terms of additional supplies, more to meet internal demand than to feed export projects. Incremental output in Asia, Latin America and China is more limited and to a large extent dedicated to meet incremental indigenous consumption. In the OECD region, Australia, as the fastest-growing producer, will become the second-largest LNG exporter by 2016.
- **Global trade is accelerating rapidly, spurred by rapid increase in liquefaction capacity (by one-quarter between end-2010 and end-2016) and a few additional inter-regional pipelines.** The 2010-16 period will see a rise in gas trade between the regions, although North America remains disconnected from global gas markets. The FSU region remains the largest exporter of gas, but exports from the Middle East and, towards the end of period, from Australia, are also growing quickly. Unsurprisingly, OECD Pacific imports increase markedly, which is also the case for Europe. China emerges as a major importer of both pipeline gas and LNG. LNG imports rise markedly in other Asian countries, as well as in Latin America and the Middle East.

Assumptions

After the impressive 7.4% growth of gas consumption in 2010, one hanging question is whether such growth will continue. Indeed, this will prompt or defer investments decisions along the gas value chain. Recent demand developments and abrupt changes in demand paths underline the importance of understanding the possible future demand developments in the medium term. It should

nevertheless be kept in mind that demand will depend crucially on the economy and relative fuel price movements and can be affected by unexpected events such as the earthquake in Japan in March 2011. Economic assumptions impact gas consumption in all sectors, mainly through industrial production and electricity demand.

Despite positive signs over the past two years, there is still uncertainty on how the economy will recover by region. Recent developments in the European region are adding a new level of uncertainty. Our economic forecasts are based on the latest International Monetary Fund (IMF) outlook from April 2011, which foresees the global economy increasing by more than 4% per annum over the outlook period (for more details, see chapter on oil demand in Part I).

Fuel price assumptions usually derive from the respective forward curves and serve as an input in the model, but do not represent IEA forecasts. Oil price assumptions are the same as for the oil forecasts, with nominal oil prices staying over \$105/bbl in 2011-12 but declining progressively towards \$101/bbl in 2016. Coal prices¹⁵ are critical for the power generation sector: US Appalachian nominal coal prices are anticipated to increase from \$66/t in 2010 to \$97/t in 2016. In Continental Europe, steam coal prices are set to progressively increase from \$124/t in 2010 to \$160 by 2016, while Japanese coal prices increasing from \$114/t to \$149/t over the forecast period. Chinese coal prices increase progressively from \$80/t to \$116. CO₂ prices have been assumed to increase from €16/ton as of mid 2011 to €25/ton, and apply only in European countries.

Fuel Price Assumptions (nominal prices)

	2010	2011	2012	2013	2014	2015	2016
Oil (\$/bbl)	78.1	106.8	105.2	102.8	101.3	100.7	100.9
Coal (\$/ton)							
US (East)	66	78	86	92	95	96	97
Cont. Europe	124	141	153	156	159	161	161
Japan	114	138	142	144	147	149	149
China	84	89	95	100	105	110	116
Gas (\$/MBtu)							
HH	4.4	4.5	5.1	5.4	5.7	6.0	6.3
NBP	6.6	9.8	11.1	11.4	11.6	11.9	12.1
Cont. Europe	8.0	11.4	12.6	12.5	12.4	12.4	12.4
Japan	11.0	13.1	14.4	14.2	13.9	13.8	13.8

Regarding gas prices, regional price assumptions show prices diverging greatly. Assumptions on Henry Hub (HH) prices are based on the forward curve. Reflecting the disconnection between the US gas market and other regions, HH gas prices are expected to stay relatively low, despite a progressive increase. Nominal gas prices are projected to increase from \$4.4/MBtu in 2010 to \$6.3/MBtu by 2016. For the OECD Pacific region, import prices are based on the historical relationship between oil prices and Japanese LNG import prices and incorporate a modest time lag between the two. These prices are expected to remain relatively high, particularly in the short term, due to high oil prices.

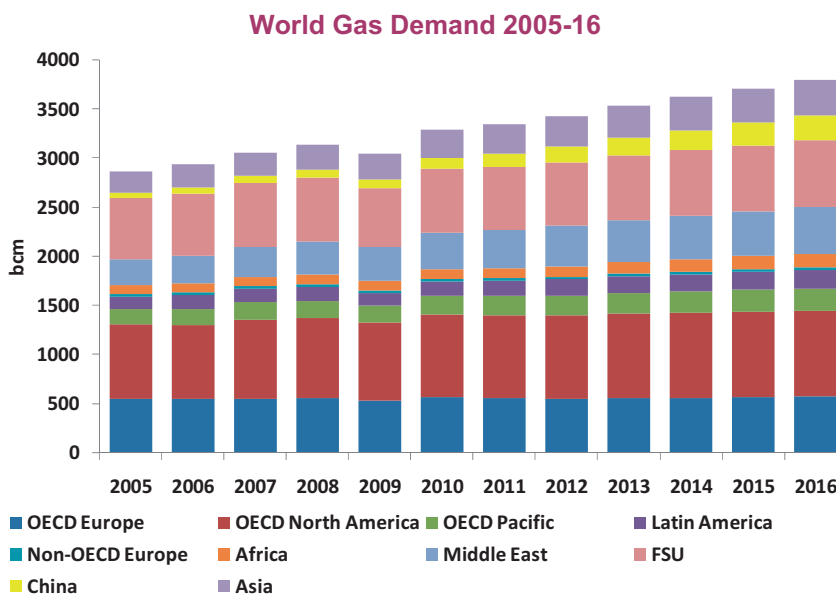
¹⁵ Coal prices are prices for delivery at power plants for steam coal 6,000 kcal/ton.

They would stay above \$14/MBtu in 2012 and 2013, declining slightly by 2016. NBP gas prices will remain largely disconnected from HH gas prices at around \$11.5/MBtu on average, reflecting the current forward curve. European gas prices reflect the inclusion of a spot element in contract formulas (based on NBP prices): they will remain high over the coming six years, declining slightly towards 2016, mostly due to the decline in oil prices.

The modelling has been done on a country-by-country basis, looking at four main sectors, based on the IEA's annual statistics (Natural Gas Information). The residential/commercial sector includes residential, commercial and public services, agriculture and "not elsewhere specified"; industry includes all industrial subsectors such as iron and steel, chemicals, non-ferrous metals as well as non-energy use from fertiliser producers, which has been looked at separately. The transformation sector corresponds to the power generation sector, while "Others" includes the energy sector, distribution losses and the transport sector (use in pipelines or in road transport).

World Gas Demand

Demand for natural gas is expected to rise from 3,284 bcm in 2010 to 3,795 bcm in 2016, adding almost 510 bcm incremental gas demand. This growth is equivalent to current annual gas consumption of the European Union. Gas demand growth will slow down to 2.4%/y, slightly lower than the 2.7%/y observed during the past decade. Gas consumption is set to grow in all regions, even in the OECD, albeit with significant regional differences in terms of drivers and relative gas demand increase.



The bulk of the incremental gas consumption comes from the non-OECD countries, particularly from the Middle East and China. China becomes the third-largest gas consumer, still well below the United States and Russia. It is driven by a strong economic growth of 6.7%/y on average, reflecting additional energy needs from the industrial sector and increased gas use in the power generation

sector. The evolution over the forecast period is radically different between the OECD and non-OECD regions. Demand for natural gas will grow every year in all non-OECD regions, except in 2011 in the FSU region due to a return to normal weather conditions. OECD gas demand is expected to follow a bumpier road: in Europe gas consumption drops in 2011 and 2012 due to a return to “normal” weather conditions, a sharp increase of European oil-linked and spot gas prices and still sluggish economic growth in 2011 in Europe. Demand in OECD Pacific will increase as Japan compensates for lost nuclear production and Korea’s gas demand is boosted by strong economic growth. North American gas use increases, reflecting the impact of low gas prices in the industrial and power generation sectors.

World Gas Demand (bcm)

	2000	2010	2012	2014	2016
OECD	1,391	1,594	1,600	1,641	1,671
Non-OECD	1,119	1,689	1,826	1,978	2,124
Total	2,510	3,284	3,427	3,619	3,795

Note: 2010 are estimates. Numbers may not add up due to rounding.

OECD Demand Developments

In 2010, OECD gas demand recovered by 5.9% to 1,594 bcm, well above 2008 levels. Assuming normal weather conditions, OECD gas demand is expected to increase by only 5% over the forecast period. The OECD regions will also show different patterns, with North America benefitting from stronger economic growth at around 2.8%/y, compared to 2.2%/y in Europe, and gas prices twice lower than in the other OECD regions. Demand will also grow strongly in OECD Pacific, due to the effects of the Fukushima disaster requiring increased use of gas-fired generation to replace missing nuclear power capacity. In Europe, unplanned decommissioning of nuclear power plants up to 2016 is expected to remain limited to Germany, while other countries such as the United Kingdom decommission nuclear capacity as previously planned based on plants’ lifetime. The power sector represents the main driver behind gas demand growth, while the residential/commercial sector shows a marginal growth limited to a few countries.

OECD Gas Demand by Region (bcm)

	2000	2010	2012	2014	2016
Europe	473	568	545	557	570
North America	788	841	856	871	873
Pacific	131	185	200	214	228
Total	1,391	1,594	1,600	1,641	1,671

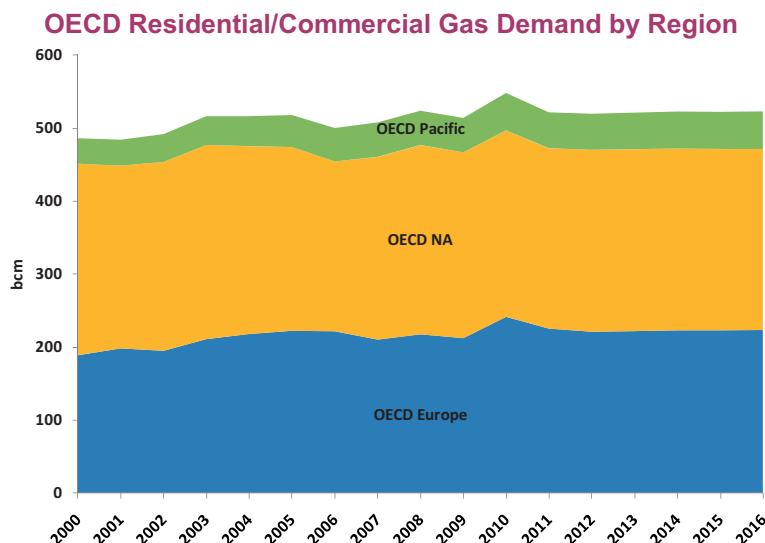
OECD Gas Demand by Sector (bcm)

	2000	2010	2012	2014	2016
Res/com	486	549	520	523	523
Industry	390	341	347	365	376
Power generation	381	550	579	594	602
Others	134	152	154	159	170
Total	1,391	1,594	1,600	1,641	1,671

Note: 2010 are estimates. Numbers may not add up due to rounding. Others include transport sector, energy use and losses.

Consumption in the Residential/Commercial Sector Stagnates

OECD residential/commercial gas demand increased from 486 bcm in 2000 to 514 bcm in 2009, but with annual variations resulting from changes in heating degree days (HDD). While some countries saw their demand increasing along with the number of connected residential users, the effect of maturing markets can be observed in almost every country: potential growth from new connections is quite limited, except for a few countries, including Greece, Turkey, and Korea. Furthermore, households' individual gas consumption is on a declining trend in most OECD countries due to energy efficiency, higher prices, social effects (more divorces leading to an increasing number of houses but with a lower number of inhabitants) and the coupling of gas with renewable energy (solar panels). In most European and North American countries, consumption per household per HDD has declined over time.

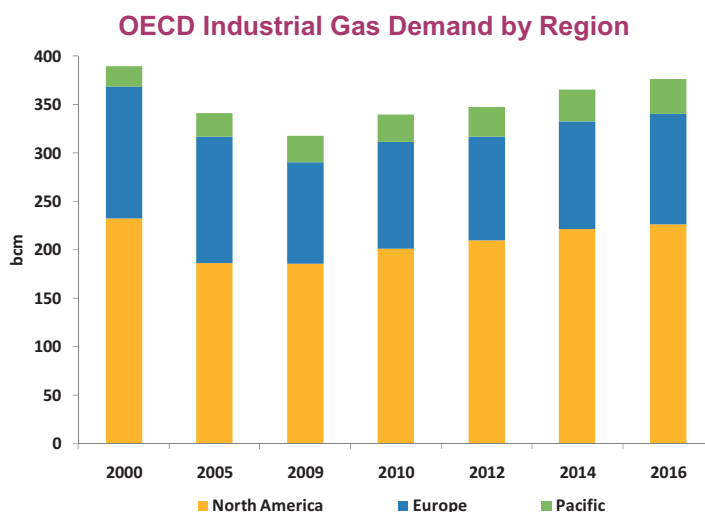


OECD residential gas demand in 2010 was extremely high, reaching an estimated 549 bcm. This demand is set to decline in 2011 towards 520 bcm based on normal weather conditions, and then to slowly increase over the 2012-16 period to 523 bcm. All regions show different behaviours: gas consumption will increase in OECD Pacific as new users are connected, particularly in Korea. In Europe, residential gas use in mature markets (such as Germany, the United Kingdom and the Netherlands) will decline, whereas less mature markets (such as Turkey and Greece) are still expected to see booming gas demand. Declining residential use trends were also observed in the United States and Canada. For the period 2011-16, HDD have been based on the five-year average (2005-09), except for 2011, for which data for the first quarter were already available. Obviously the choice of the five-year average for HDD based on 2005-09 has a large influence on the results. If the modelling had been based on the 2006-10 five-year average, gas demand forecasts would show residential/commercial gas demand increasing to 531 bcm. Without the temperature effect in 2010 (HDD for OECD were 11% higher than in 2009), OECD residential gas demand was estimated at 518 bcm, 31 bcm lower than its actual level. The most important difference (23 bcm) comes from Europe.

Industry

OECD industrial¹⁶ gas demand has only slightly recovered after the 8% drop in 2009. In some regions, lower gas prices helped the recovery, but in general, industrial output remains lower than the pre-crisis levels (see chapter on recent market trends). Additionally, industrial gas demand was already on a declining trend in North America and Europe, where industrial gas demand dropped by 12% and 15%, respectively, over 2000-08. In contrast, demand increased by 29% in OECD Pacific, where all countries except New Zealand showed positive demand growth.

In 2010, OECD industrial gas demand increased by 7%. This recovery should continue to this general trend over the next six years, but with very strong regional disparities. Increasing gas prices will impact European gas consumption in this sector over the years 2011-16, as both Continental and UK gas prices increase sharply. By contrast, North American industrial gas demand is expected to increase by 25 bcm (+13%), driven by low gas prices and relatively strong economic growth. OECD Pacific gas demand will also increase by over 7 bcm (+30%), especially in Korea and Australia, but industrial gas use in Europe will increase by a mere 3 bcm (3%) as high gas prices will largely offset the effect of the economic recovery. European industrial gas use fails to return to 2008 levels, while the other OECD regions will exceed 2008 demand. European industrial gas consumption is likely to drop further in 2011 and 2012 before recovering slightly over the four following years. In North America, the increase will be continuous, mostly driven by the United States, but Canada and Mexico will also contribute. In OECD Pacific, industrial gas demand recovery will be sluggish in 2011, as the effects of the earthquake will not dissipate until 2012.



The use of gas by fertiliser producers will increase by 11% (4 bcm), mostly in North America. The vast majority of new urea plants expected to start over 2010-14 will be located in Asia and to a lesser extent in Latin America and Africa, but very few in the OECD region, according to the production forecasts of the International Fertiliser Industry Association (IFA). Supply capacity is expected to remain broadly the same in the OECD region, so that gas prices and environmental regulations will be key factors influencing the output in these regions. Therefore, around 90% of the additional gas use

¹⁶ Including fertilisers.

will take place in North America. Gas use by European fertiliser companies is expected to decline on the back of rising gas prices.

Transport and Energy Sectors

The transport sector covers two areas: transport by pipeline and road transport. Incremental gas demand growth will come partly from the increase in road transport and partly from pipeline transport, which depends crucially upon gas demand and trade between countries. Gas demand is set to increase from 25 bcm in 2009 to 30 bcm by 2016 and will overcome the 2 bcm drop in gas use for transport by pipeline which occurred in 2009. Around 1.6 bcm of the incremental gas demand over 2009-16 is anticipated to come from the road sector.

Gas demand in the energy sector reached 121 bcm in 2009, 18 bcm higher than in 2000. Oil and gas extraction represents around two-thirds (or around 80 bcm) of gas demand in this sector. Gas use is projected to grow strongly over the next six years, increasing to 137 bcm. Most of the incremental consumption comes from Australia and Canada. Consumption related to oil and gas extraction will be boosted by the increase of Australian gas production and new LNG liquefaction plants and by oil sands in Canada. Some countries will see their consumption drop sharply, particularly the United Kingdom, and marginally in some European gas countries.

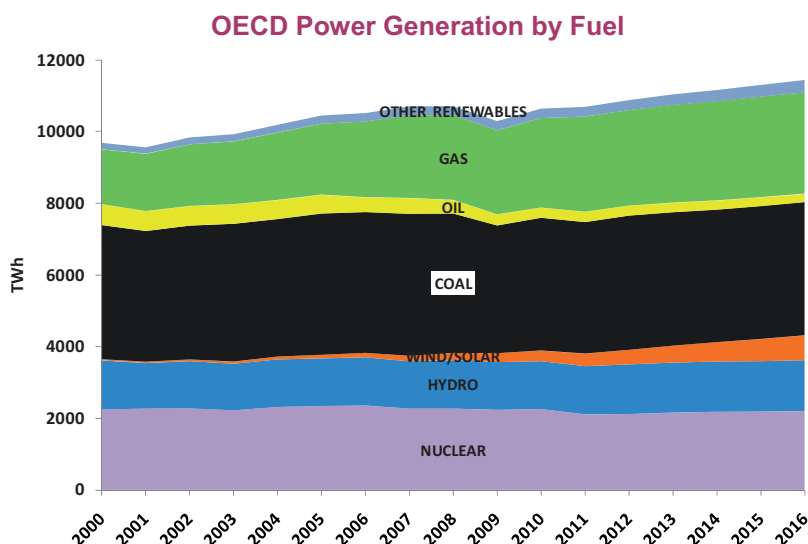
Power Generation Sector

Gas demand in the power sector is expected to increase by 9% over the forecast period. Power generation from gas will likely see its share in total OECD gas consumption rise from 34% to 36%. This growth happens despite increasing gas prices in Europe and Pacific, competition from renewables generation and limited power demand growth over the period. However, Fukushima and the non-availability of some 20 GW of nuclear power plants will have a direct impact on Japanese gas demand, which is expected to increase by 11 bcm in 2011. The decommissioning of 7 GW of nuclear power in Germany, which was assumed to be permanent in multiple forecasts, results in a limited increase in gas demand in the short term, although the lost generation is mostly compensated for by the growth of renewables in Germany (+50 TWh) by 2016. No further unplanned decommissioning has been assumed in the forecasts during the 2011-16 period. The drop in OECD nuclear generation (7%) is quite significant in 2011, but as new nuclear capacity comes online in Korea, France, Finland, Slovakia and Japan (with delays), the drop over 2010-16 is limited to 3%.

The most impressive development over the 2010-16 period is the increase in renewable generation: wind and solar combined output climbs by a factor of 2.4 to reach 694 TWh by 2016. Hydro increases marginally by 6% and reaches 1,428 TWh, accounting for 12.3% of total generation. Taking into account the other renewables, the share of renewables in the OECD electricity mix increases from 18% in 2010 to over 22% in 2016. Incremental production from renewables is 567 TWh, roughly equal to Germany's annual electricity demand.

As a consequence, the share of combustible fuels declines from 61% to 59%. If the share of combustible fuels had remained constant at 61%, it would have been over 200 TWh higher, which equates to some 40 bcm of gas demand. However, during 2011-13, the share of combustible fuels actually increases as renewables cannot grow rapidly enough to replace nuclear generation.

Furthermore, within the combustible fuels, oil-fired plant generation will decline by roughly 20%. Oil-fired plants are being used less frequently and are relatively expensive, given the oil price assumptions. As explained in the chapter on power, fuel prices are not the only consideration in determining the dispatch of power plants, but they are critical for short-run cost optimisation by utilities. Given the price assumptions, gas-fired plants will be challenged to gain market share from coal over 2011-13 in Europe, and become more competitive towards the end.



Non-OECD Demand Developments

Regional Trends: China is the Fastest Growing Market

Demand for natural gas in the non-OECD region expands by 3.9%/y over the 2010-16 period, slightly higher than during the 2005-10 period (3.7%). The fastest growing region by far is China, with over 15%/y growth over the period. Anticipated incremental demand for China is more than 150 bcm over the forecast period. Their 12th Five-Year Plan aims to develop a path for more sustainable economic growth and to use cleaner sources of energy, including renewables, nuclear and gas. The objective is to double the share of gas in the primary energy demand to 8.3% by 2015, which implies an annual consumption of around 260 bcm. In the forecasts, this level is actually reached one year later, in 2016. Chinese demand quickly expands in all sectors, including the rapidly expanding residential/commercial sector, which had been growing by 29%/y over 2005-09. This reflects the priority given to gas use by residential and commercial users in the government's policy. One of the key obstacles recently dampening Chinese gas demand growth was the limited import capacity; new infrastructure investments would enable China to meet much higher gas demand levels (see chapter on investments in pipelines and regasification terminals).

Other non-OECD regions show more moderate growth rates. Excluding China, gas demand in other non-OECD regions will grow at "only" 2.8%/y over 2010-16 against the 3.1%/y growth rate from 2005-10. The Middle East is the second fastest growing region in absolute terms, as its consumption will increase from an estimated 370 bcm in 2010 to 473 bcm by 2016, reflecting strong demand

growth in power, industry (fertiliser) and domestic primary energy production. Iran remains the largest consumer in the region, but is also reliant on Turkmen supplies to meet demand in the North of the country. Iraq manages to use part of the gas flared in the South of the country and to develop some of the gas fields by 2016.

As demand in other Asian countries is increasing very quickly at 3.8%/y, some now face a situation in which supply capacity is the limiting factor. This is the case for Bangladesh and Pakistan, which rely entirely on their domestic production over the 2010-16 period. Indian gas demand increases from an estimated 63 bcm in 2010 to 88 bcm by 2016, benefitting from growing gas production and increasing LNG imports. Demand in Association of Southeast Asian Nations (ASEAN) countries also increases strongly, by 26% over the forecast period. Many of these countries are turning to LNG in order to meet their rapidly increasing demand, as domestic production or imports from neighbouring countries by pipeline are not expanding fast enough. LNG regasification terminals are already under construction in many ASEAN countries (see chapter on investments in pipelines and regasification terminals for more details on infrastructure developments). Africa expands its gas demand by 39%: Algeria and Egypt, which already account for 70% of African gas demand, will contribute to half of this increase. In terms of relative growth, Nigeria and Angola see their demand doubling over the period. Gas consumption recovers in Nigeria, driven by the Gas Master Plan, while Angola benefits from the start of the new liquefaction plant in 2012.

The rapid expansion of gas use in Latin America is mostly driven by Brazil, where demand doubles to reach 59 bcm. Other countries such as Venezuela, Colombia, and Argentina see their demand limited by supply. Argentina will source alternative supply through LNG. A new LNG terminal jointly planned with Uruguay will benefit both countries. Peru is an exception, as the country benefits to some extent from the recent upstream developments feeding its new liquefaction plant. Demand increases are more limited in the FSU and non-OECD Europe regions. FSU gas demand was high in 2010 due to abnormal weather: as in Europe, there is therefore the effect of a return to normal weather conditions in the early part of the forecast period.

Non-OECD Gas Demand by Region (bcm)

	2000	2010	2012	2014	2016
Latin America	101	145	164	175	184
Non-OECD Europe	27	24	25	27	28
Africa	59	102	107	126	141
Middle East	179	369	410	439	473
FSU	572	653	650	668	677
China*	28	110	160	207	260
Asia	153	286	310	337	359
Total	1,119	1,689	1,826	1,978	2,124

Note: China refers to the China region and includes Hong Kong.

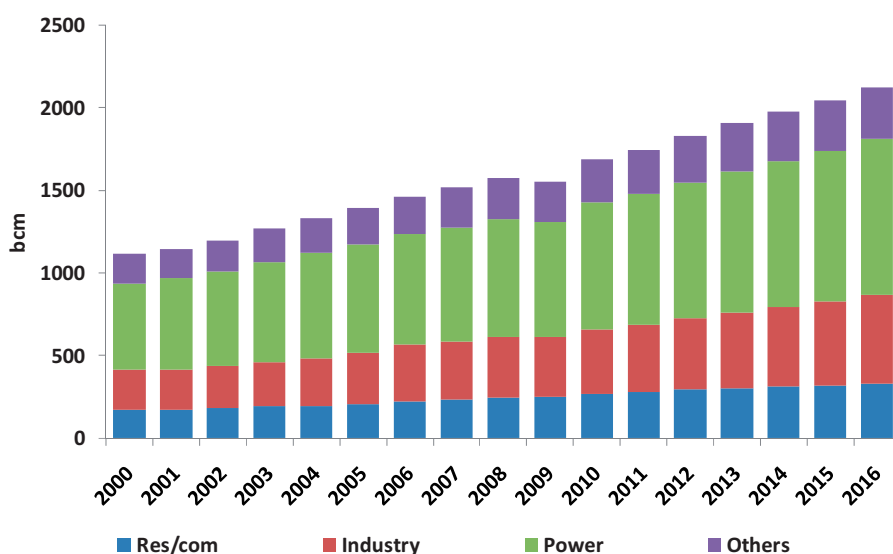
Sectoral Trends: All Sectors Are Growing

Looking at the sectoral trends, an increase in gas use is observed across all sectors. But there are already strong variations between the regions which have already led to very wide differences in terms of gas use. The share of the residential/commercial sector in total gas use is currently above

20% in China, FSU and non-OECD Europe, but extremely low (6%) in Africa for obvious climatic reasons. The share of gas use for fertilisers has been traditionally higher in the Middle East, China and Asia (especially India) at around 10%, as these directly benefit from low gas prices, although prices doubled in India in 2010.¹⁷ The share of gas in the power sector varies between 44% and 53% in the Middle East, Asia, FSU and Africa, but is much lower in China, Latin America or non-OECD Europe. Depending on policy decisions concerning the allocation of gas across sectors, competitiveness of gas versus coal in the power generation, the development of a gas grid or the need of gas for heating purposes, gas use will expand at different rates by region.

The power sector is set to continue to dominate the demand picture, and the incremental growth of gas is the largest, reflecting both increasing electricity demand and the lower environmental footprint of gas compared to coal. This does not mean that gas becomes the most important fuel in the generation mix. Despite its remarkable growth in China, gas remains as a marginal fuel behind coal in the total power generation mix. The gas input to power generation reaches 943 bcm or 44% of total non-OECD demand by the end of the forecast period. The largest increases take place in Africa, the Middle East and China.

Non-OECD Sectoral Gas Demand 2000-16



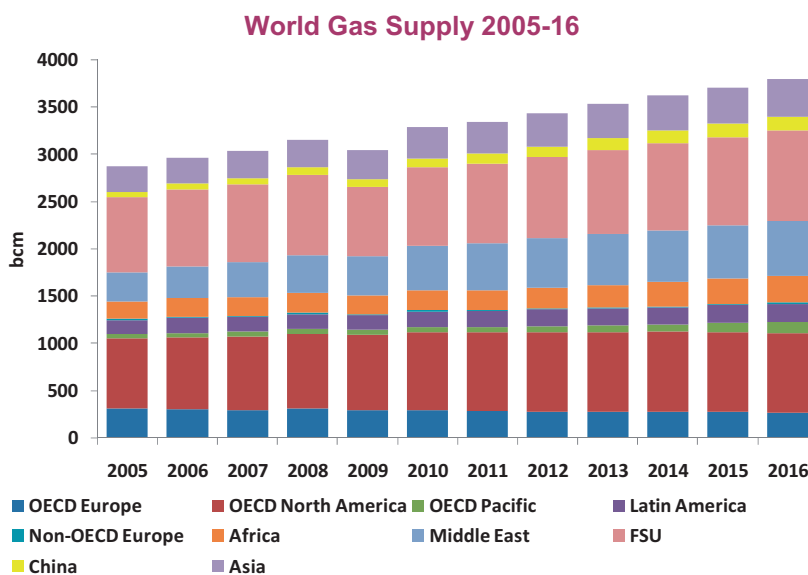
Industrial demand should expand rapidly as many countries need gas to develop industrial activities at home to enhance their economic growth. Natural gas use by industry is projected to grow by almost 150 bcm over the forecast period, particularly China, the Middle East, Africa and more moderate increases in Latin America and Asia. By contrast, residential/commercial gas consumption is projected to grow by only 60 bcm over 2010-16, and its share to marginally decline from 16% to 15.5%. The bulk of the increase is to take place in China, where the potential in the residential and commercial sector is very large.

¹⁷ IEA; Natural gas in India, 2010, OECD/IEA Paris.

Growth in demand for gas is also high in other sectors, including the transport sector (road transport and use for pipelines), losses and energy industry own use (mostly use for oil and gas production or as an input in oil refineries). Energy use increases by 19%, reflecting growing production in most regions (see below), while gas use in the transport sector increases by 26%. Additional demand in the transport sector comes from increasing use of Natural Gas Vehicles, which are more widely used in non-OECD countries. Losses represent less than 2% of non-OECD use and increase moderately by 13%.

World Gas Supply: Non-OECD Contributes to 90% of Supply Growth

Despite this relatively rapid increase of gas use, there is ample supply coming to the market to meet these needs. In most cases, new supply projects have already been sanctioned by FID, especially when there is a need to build pipelines or LNG liquefaction plants. Production is set to increase in all regions except OECD Europe and non-OECD Europe. Natural gas production in non-OECD countries increases more than non-OECD gas demand over the forecast period, where it reaches around 2,570 bcm by 2016, providing an additional 457 bcm to the markets over 2010-16. Production in the OECD increases slightly by around 50 bcm, coming from North America and Australia. Consequently, the share of non-OECD producers in global gas supply increases over 2010-16 from 64% to 68%.



Demand will be constrained by the lack of supply in some developing countries. The reasons range from domestic production failing to increase rapidly enough, the absence of import infrastructure and the difficulty of attracting more expensive gas supply from the global gas markets. In some cases, arbitrage must be made between domestic market needs and export commitments. Examples where supply constraint occurs include: India, Bangladesh and Pakistan in Asia; Argentina, Venezuela or Uruguay in Latin America; Egypt and Algeria in Africa; Israel, Oman, and Iraq in the Middle East.

The FSU region will be the largest producer and is the largest contributor to incremental gas supplies over the forecast period, with a 16% increase of production. Gas production grows by around

130 bcm to reach around 960 bcm in 2016. A large portion will come from Russia, where major upstream projects such as Yamal are expected to come online after 2012 (see chapter on investments in producing countries). None of the LNG projects currently planned are expected to be operational by that time. Turkmenistan also provides additional supply as production goes back to pre-2009 levels and increases further to meet growing import requirements from China. Azerbaijan's upstream project Shah Deniz II is scheduled to start only in 2017, and has not been included in the forecasts.

The Middle East is the second-largest contributor behind FSU. Qatar expands its production rapidly, not only to bring its recently started LNG plants to plateau, but also to meet its growing internal demand, notably from the Pearl project. By 2016, Qatar's gas production exceeds Iranian gas production, as economic sanctions, coupled with flaring and reinjection needs, limit the growth of marketable Iranian gas. Iraqi gas production increases over time as flaring issues are tackled in the south and some fields recently tendered come on stream at the end of the forecast period. Africa increases its gas production by over 70 bcm, albeit over a half is dedicated to the internal market. Algeria, Nigeria, Angola and Egypt represent over 85% of the additional supplies. Production grows in Angola and Algeria as new LNG liquefaction capacity comes online in 2012 and 2013, respectively.

In Latin America, while the bulk of new supplies is directed towards the domestic market, this will be insufficient to meet rapidly increasing demand. Most of the additional volumes come from Brazil, while other countries, including Venezuela and Bolivia, fail to significantly increase their gas production as planned. China also expands its gas production by around 60%, although this covers just half of its incremental needs. Despite this increase in indigenous production, China's import dependence grows quickly. Asia (excluding China) sees its production growing by 17%. Indian gas production grows relatively fast over the forecast period to reach above 70 bcm.

In the OECD, gas production increases mostly from one country, Australia, as it expands its LNG productive capacity with four LNG plants under construction and another committed, but starting in 2017. Consequently, Australia emerges as the second-largest global LNG producer by 2016, behind Qatar. Most of this gas is contracted by the Asian markets. Unconventional gas production is driving a continuous, albeit slower, increase of North American gas production. Notably, Canada's gas production recovers on the back of increasing gas demand and higher gas prices. Meanwhile, Europe sees a sharp decline of 31 bcm to 262 bcm by 2016. This implies that gas imports increase over 2010-16 by 30 bcm. Norway is expected to increase its gas production, while the United Kingdom and the Netherlands will see sharp falls in their domestic gas output.

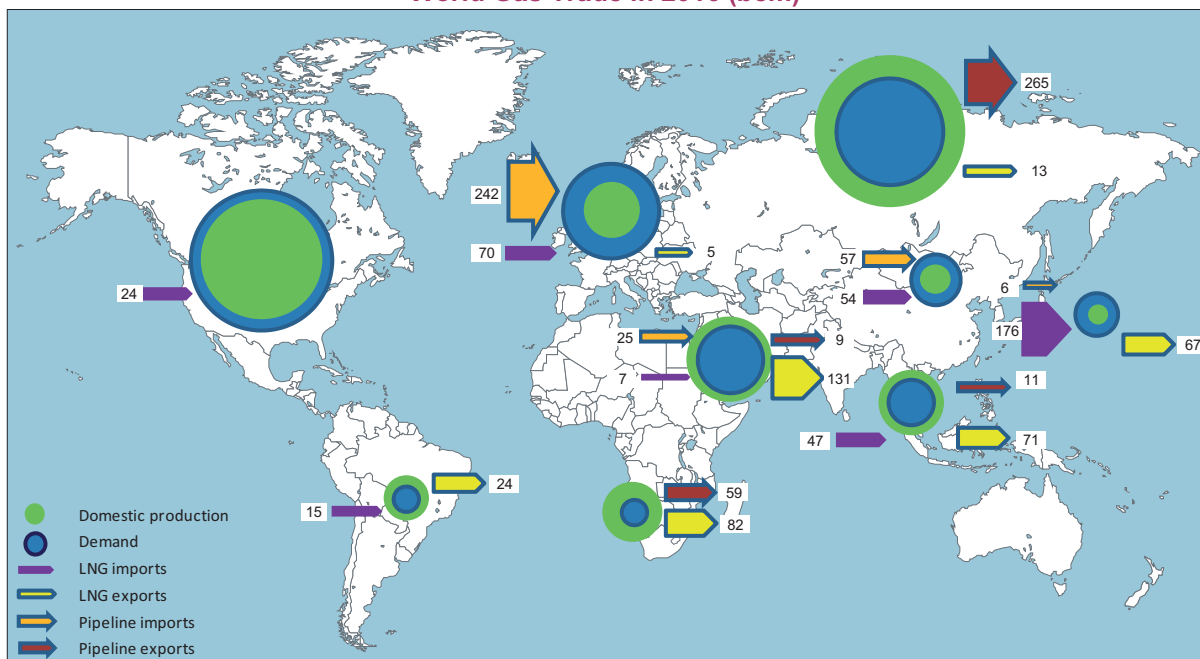
Global Trade is Expanding Quickly

As demand increases by over 500 bcm over the forecast period, import requirements in many regions are growing as well. Global trade benefits from the rapid expansion of LNG production capacity, but trade by pipeline also increases fast. On a regional basis, the Former Soviet Union, Middle East, Africa, Asia and Latin America remain net exporters in 2016. However, some countries in the Middle East, Asia and Latin America have to import in order to meet regional imbalances. Asia and Latin America import exclusively LNG, while the Middle East imports both pipeline gas and LNG. For geographic reasons, Latin America is connected to the global gas market solely through LNG and

LNG exports still exceed imports by the end of the forecast period. The Former Soviet Union remains by far the largest exporter by 2016, and the bulk of its exports are by pipeline to Europe, China and the Middle East. LNG exports are limited to the Sakhalin plant. Exports from the Middle East, however, are essentially supported by LNG, coming from Qatar, which holds a 105 bcm liquefaction capacity. Africa has more diversified exports consisting of both pipeline exports (to Europe and the Middle East) and LNG exports. LNG exports increase over time as new liquefaction plants come online in Angola and Algeria. Asian countries see a slight progressive decline of the LNG exports over 2010-14, but these recover in 2014 as two new liquefaction plants start operations in Papua New Guinea and Indonesia. The region becomes a growing importer of LNG as many ASEAN countries turn to LNG imports.

The other regions, OECD Europe, Pacific and North America, as well as non-OECD Europe and China, are all net importers. OECD Pacific and Europe, however, also export LNG, although European volumes are limited to the single Norwegian LNG plant. By contrast, LNG exports from Australia are set to expand markedly towards the end of the period as three new liquefaction plants representing over 40 bcm of export capacity come online. Meanwhile, China sees its imports growing fast, reaching over 110 bcm by 2016; these consist of both LNG and pipeline imports from FSU and Asia. OECD Europe also becomes more import dependent as its domestic production declines fast, but this is limited, as demand increases marginally. Imports are also set to increase rapidly in OECD Pacific, due to the additional gas demand in Japan and Korea. North American LNG imports expand over the period, reflecting regional disparities and growing demand from Mexico and Canada.

World Gas Trade in 2016 (bcm)



This map is for illustrative purposes and is without prejudice to the status of or sovereignty over any territory covered by this map.
Note: LNG imports in North America are net imports.

MARKET TRENDS IN THE LNG BUSINESS

Summary

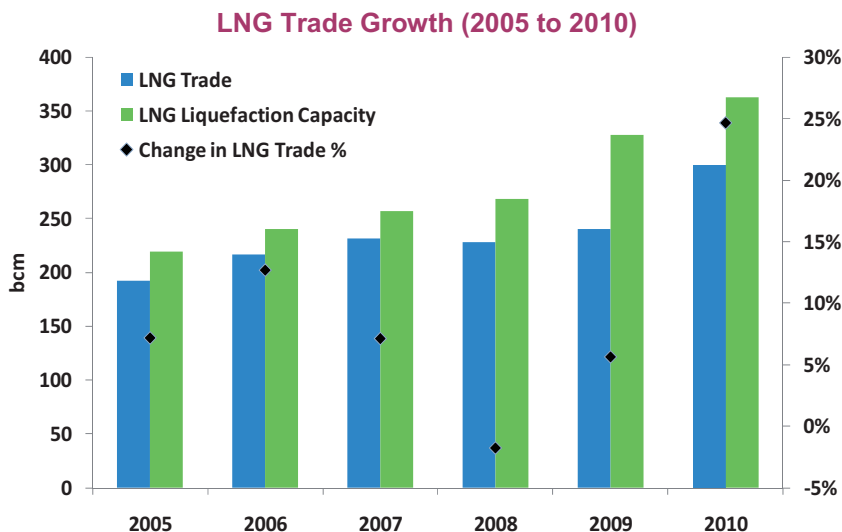
- **Global LNG trade jumped by a substantial 25% in 2010 to reach an estimated 299 bcm, and now accounts for 9% of global gas demand. This has been driven mostly by the massive expansion of LNG liquefaction capacity that has come online since early 2009 and is now progressively reaching plateau.** LNG continues to gain market share in most regions, with the notable exceptions of the United States and India, due to their growing domestic gas production. In 2010, LNG imports rebounded strongly in traditional Asia-Pacific LNG markets; they also increased in Europe, especially in the United Kingdom, which has become a transit country towards the Continent. Other regions, such as Latin America and the Middle East, are turning increasingly to LNG to compensate for insufficient domestic production or failure of pipeline supplies.
- **The most impressive growth in LNG supplies in 2010 occurred in Qatar, which now represents one-quarter of global LNG supplies, twice as much as the second-largest LNG supplier, Indonesia.** With its central geographical position and ability to supply significant volumes, Qatar has a unique opportunity to arbitrage between regions. Additionally, a few new LNG suppliers emerged, including Yemen, Russia and Peru. Despite significant investment decisions taken recently, the rise of Australian LNG, the “next Qatar”, will not happen before 2015.
- **The coming six years will see continuing growth of LNG trade as another 85 bcm of liquefaction capacity is expected to come online by 2017, which will raise LNG capacity by almost 25%. Most of these new LNG supplies are already contracted, with half going to Japan and China.** While China clearly needs to feed its growing market, Japan is looking to replace expiring contracts from traditional Asia-Pacific LNG exporters. New importers are also expected to emerge in South Asia.
- **The production surplus in the United States has led the country to re-export LNG to other markets.** This trend could drive the country to become a true LNG exporter.

Global LNG Demand Hits Historical High

Global LNG demand in 2010 reached an historical high of 299 bcm (220 million tonnes per annum [mtpa]), which was 25% higher than in 2009. LNG trade now represents 9% of global gas demand compared to 5.5% a decade ago, an impressive growth considering that gas demand increased by 30% over the same period. The year 2010 sets a record, as annual growth had not previously exceeded 13%. Such a surge in LNG supplies is the direct result of the remarkable increase in LNG productive capacity over the past two years, during which over 100 bcm of new capacity came online. As new liquefaction plants need usually one year to reach plateau production, the result of the capacity increase in 2009 was only fully visible in 2010.

While the year 2010 was a significant turnaround for the global gas industry, it was even more so for the LNG industry. In 2009, a combination of declining global gas demand, low gas prices and the surge in US unconventional gas production led LNG to fight for markets against pipeline gas. In 2010, global gas demand rebounded by an estimated 7.4%, prices increased in all markets but North America and historical LNG markets recovered strongly. Competition with pipeline supplies still

exists, particularly in Europe, but actually turned out in favour of LNG due to price differentials. During 2010, most LNG demand growth came from Asia, especially historical LNG buyers such as Japan, Korea and Taiwan, but also from Europe, particularly the United Kingdom and Italy. LNG demand also increased in China, Latin America and the Middle East. In the latter two regions, LNG imports remain limited despite the remarkable relative growth from 2009 to 2010, as these regions have only 25 bcm of regasification capacity, which is often only used during a few months to meet peak gas demand.



Note: LNG liquefaction capacity at the end of the year.

Growing demand for LNG was well supported by new production capacity coming online. The first LNG wave is mostly completed, with over 100 bcm of LNG production capacity added between early 2009 and mid-2011. In 2009, three mega-trains in Qatar, Sakhalin II, Tangguh and Yemen LNG Train 1 were completed, contributing to the rapid increase in global LNG production capacity. Throughout 2010, another 34 bcm of new LNG production capacity came on stream, representing the second-largest addition over the last six years, after the one that took place in 2009.

LNG supplies grew on the back of the capacity which came online in 2009, mostly late in the year, due to unfavourable market conditions. New projects usually reach plateau one year later. This explains why the growth in LNG trade in 2009 and 2010 seems to be lagging behind that of LNG liquefaction capacity. Russia's Sakhalin reached plateau in 2010, as did Indonesia's Tangguh and the first train of Yemen LNG. Three Qatari trains also started in 2009, but went under heavy maintenance from spring to summer 2010, resulting in lower LNG supplies during that time.

The trains which started in 2010 have not yet reached plateau. The Malaysia Dua (II) project may be an exception with the successful completion of debottlenecking an additional 2 bcm (1.5 mtpa). Qatargas III Train 6, which started in February 2011, experienced technical difficulties, while RasGas III Train 7 started only late in the year. With the newly added capacity, global LNG production capacity reached 363 bcm as of end-2010 and 373 bcm (275 mtpa) as of mid-2011.

LNG Projects Completed in 2010 and up to mid-2011

Country	Project	Capacity (bcm)	Online date
Qatar	Qatargas III Train 6	10.6	Feb 2010
Qatar	Rasgas III Train 7	10.6	Nov 2010
Yemen	Yemen LNG Train 2	4.6	Apr 2010
Malaysia	Malaysia LNG Dua(II)	2.0	Apr 2010
Peru	Peru LNG	6.1	June 2010
Norway	Nordic LNG	0.4	Nov 2010
Qatar	Qatargas IV Train 7	10.6	Feb 2011
Total		44.9	

Source: IEA and companies' websites.

Qatar is now by far the largest LNG exporter in the world, with a combined capacity of 105 bcm (77 mtpa of LNG), or 28% of global liquefaction capacity, based on two LNG production projects at the single site of Ras Laffan: Qatargas and RasGas. Each project has seven LNG production trains, which have capacity ranging from 6.4 bcm to 10.6 bcm per year. The trains have different owners, but the primary owner of all trains is Qatar Petroleum, the Qatari national oil company. Six massive 10.6 bcm/y trains have come online in the last two years.

Globalisation of LNG Flows is Increasing

Gas trade is globalising and LNG effectively links the markets together. Globalisation is not only measured by the ratio between LNG trade and total demand, but also by the number of countries (or regions) involved. Since early 2009, three new countries have emerged as LNG exporters – Russia and Yemen in 2009, and Peru in 2010. Meanwhile, Canada, Chile, and Kuwait started importing LNG in 2009, and Dubai followed in 2010. Looking forward, Southeast Asia will emerge as an LNG importing region in the next five years, while Angola and Papua New Guinea will start LNG exports by 2012 and 2014, respectively. But the globalisation of gas markets stops at the doors of the United States where LNG imports actually dropped, due to the continuous growth in US domestic production.

LNG Trade in 2010 (Physical Flow, Preliminary Figures in bcm)

2010		Exporter (by basin)				
		Asia-Pacific	Middle East	Atlantic	Total	Share
Importer	Asia	110	58	11	179	60%
	Middle East	0.3	1.4	1.2	2.9	1%
	Europe	1.4	36	50	88	29%
	Latin America	0.3	1	6	8	3%
	North America	3	4	15	21	7%
	Total	115	101	84	299	
	Share	38%	34%	28%		

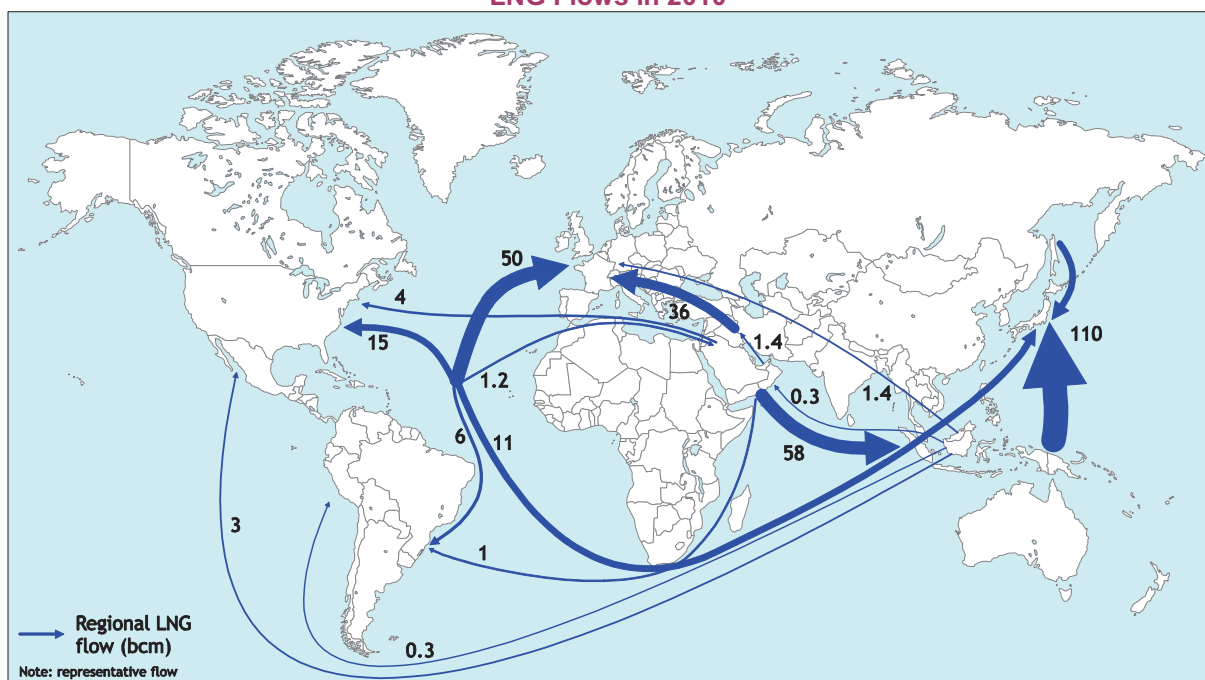
Note: Asia-Pacific exporters include Australia, Brunei, Indonesia, Malaysia, Peru, Russia and the United States (Alaska). The Middle East includes Abu Dhabi, Oman, Qatar, and Yemen. The Atlantic basin includes Algeria, Egypt, Equatorial Guinea, Libya, Nigeria, and Norway.

Looking at the regional LNG trade, Asia continues to represent the bulk of LNG imports with 179 bcm, with 60% of its imports coming from the Asia-Pacific region and one-third from the Middle East. The

growth of European LNG imports from 61.5 bcm to 88 bcm has been quite remarkable. Africa and The Middle East remain very important LNG supply sources for Europe. Political unrest in the region in early 2011 may have encouraged European countries to reconsider their security of supply and dependency on LNG imports from the region. However, there was no major supply disruption of LNG to Europe and missing Libyan exports were replaced by pipeline or LNG supply from other sources. Latin American LNG imports more than tripled in 2010, although their share in total LNG trade is only 3%. LNG is mostly coming from the regional producer Trinidad and Tobago, and also from Peru. While the United States significantly reduced their LNG imports, Canada imported 1.8 bcm of LNG, a 90% increase from 2009, due to the remoteness of producing gas fields and growing East coast demand.

Exports have increased across all regions. Asia-Pacific represents 38% of world LNG trade: its LNG exports increased by 17 bcm (+15.7%) to reach 115 bcm, driven by exports from countries with new export plants: Indonesia (Tangguh), Russia (Sakhalin) and Peru. The Middle East region is closing the gap with the Asia-Pacific region as an LNG exporter, due to the rise of Qatar and new volumes from Yemen. Middle East exporters have rapidly increased their production capacity and are diversifying their export markets. Most of the 30 bcm increase came from Qatar and half of it was delivered to Europe. Particularly Qatar, with the largest production capacity along with its huge LNG tanker fleet, can deliver LNG to all regions in a very efficient manner. In contrast, the increase of Atlantic exports was rather modest, mostly due to the recovery of production in Nigeria. It is interesting to note that one cargo from the United States was re-exported to the United Kingdom for the first time in the last few decades, while another cargo was re-exported from Belgium to Korea. The travelling distance of the LNG fleet is increasing, which is also a sign of LNG market globalisation.

LNG Flows in 2010



This map is for illustrative purposes and is without prejudice to the status of or sovereignty over any territory covered by this map.

Regional Review: Recent and Future Trends on the Importers' Side

Apart from the United States and India, all importing countries have seen their LNG imports increasing. Most countries, apart from Spain and Portugal, have recovered to the pre-crisis LNG imports levels of 2008. Some important distinctions between countries should be highlighted:

- LNG benefited from gas demand recovery (and therefore drove up LNG imports) in many countries including Japan, Korea, Taiwan, Greece, Turkey, Belgium and Mexico.
- LNG demand was driven by new regasification terminals. As a result, its share in the import mix increased versus pipeline gas. The most impressive case is the United Kingdom, where LNG imports almost doubled on the back of 42 bcm capacity expansions between 2008 and 2010. Italy and France also benefitted from the start of the 8 bcm Rovigo terminal late in 2009 and 8 bcm Fos Cavaou terminal early in 2010. China saw a new terminal in Shanghai and the expansion of Guangdong Dapeng adding 8 bcm of capacity. Canada, Mexico, Chile, Brazil and Kuwait increased their imports on the back of terminals starting over the past two years. A newcomer, Dubai, became an LNG importer in 2010.
- LNG held its ground in Spain and Portugal.
- LNG imports declined in both the United States and India, reflecting rising domestic production, thereby limiting the needs for LNG imports.

The strong increase in LNG imports has been quite uneven at the country level, not only in terms of growth but also in terms of cargo origin and whether the gas was contracted or spot purchased.

Asia-Pacific: Historical Importers Recover, New Importers Look for Supplies

LNG demand has been growing strongly in Japan following the economic recovery. Japan's LNG imports in 2010 increased from 93 bcm to 96 bcm, higher than 2008 LNG imports. The dramatic earthquake in March 2011 shut down significant nuclear capacity and is likely to result in increasing LNG demand in the coming years. There is much uncertainty around which power plants will be operational and how much of peak demand will be offset through energy conservation efforts of industry, commercial and residential sectors. However, Japan is likely to heavily depend upon gas-fired power plants to supplement the lost nuclear power capacity. Taking into account the recent voluntary shutdown of Chubu Electric's 3.6 GW Hamaoka nuclear power plants, Japan would need additional LNG supplies on top of its existing long-term contracts for the coming years to offset the lost nuclear generation (see chapter on medium-term supply and demand forecasts). Both domestic utilities and utilities in neighbouring countries, as well as LNG producers, are diverting supplies to offset this loss

In Korea, LNG demand increased from 33 bcm to 44 bcm, driven by heating demand and growth in power generation. In December 2010, the Korean government issued its 10th Natural Gas Long-term Supply/Demand Plan, forecasting 3.5%/y growth over the 2008-13 period. To meet these incremental needs, KOGAS signed short-term deals with Tangguh LNG in 2010 for 1.2 bcm (14 cargoes) through 2012; with Repsol for 1.9 bcm (21 cargoes) for 15 months from January 2011; and with GDF Suez to purchase 3.4 bcm (41 cargoes) from its global portfolio from the fourth quarter of 2010 until the end of 2013. KOGAS is also in negotiation with Russia to increase LNG supplies to

Korea. Total annual imports in Chinese Taipei, including spot cargoes, reached 15 bcm, 27% higher than in 2009. Given the region's rapid economic recovery and high power demand, Chinese Taipei's CPC had to procure several spot cargoes from spring 2010 onwards.

While LNG demand from traditional Asian Pacific LNG importers is poised to increase, new importers are set to emerge over the four coming years. Thailand's first LNG terminal, with a capacity of 6.8 bcm/y, received a commissioning cargo in June 2011. Thailand's PTT secured 1.4 bcm/y of LNG supply from Qatar for 15 years and is pursuing other supply sources based on a combination of both long-term contracts and spot market purchases. Singapore is also building a 4.8 bcm/y LNG receiving terminal, which will be operational by 2013. The capacity is expandable to 8.2 bcm/y. Singapore signed an agreement to purchase 4.1 bcm of LNG from Queensland Curtis LNG, BG's CBM-to-LNG project, from 2015 for 20 years. Negotiations are ongoing with other suppliers, such as Qatar and Indonesia. Malaysia is advancing the construction of its regasification terminal, expected to be online in 2012. Petronas signed a 42-month contract with GDF Suez for 3.4 bcm/y. Other countries, such as Vietnam, are looking for LNG to meet growing needs in the power sector. PetroVietnam Gas (PV Gas) is considering building an LNG terminal and opted for a 1.4 bcm floating terminal. In July 2010, PV Gas signed a memorandum of understanding (MOU) for supply of LNG to the power plant in Ho Chi Minh City for 20 years.

Continental Asia: Set to Become a Major LNG Demand Centre

In 2010, Chinese LNG imports increased by 70% to reach 12.7 bcm. China has currently four LNG terminals in operation and six terminals under construction. Total capacity of receiving terminals is set to reach over 50 bcm by 2013, while several terminals are still under consideration. If all these terminals come online, total LNG import capacity could reach 87 bcm/y before 2020. These terminals would help satisfy China's growing thirst for LNG. China is obviously one of the fastest growing markets of LNG in the world and producers worldwide are attempting to widen their share in the Chinese market. Currently LNG import prices range from \$3/MBtu (Australia) to \$13/MBtu (Qatar), resulting in a weighted average of roughly \$6/MBtu. However, the price of imported LNG needs to be competitive not only with coal, but also with other sources of supply, such as unconventional gas production and pipeline supplies.

Indian LNG imports, however, declined from 12.3 bcm to 11.3 bcm between 2009 and 2010, due to an increase in domestic production from the giant field KG-D6 and probably also due to increasing prices on global gas markets. This trend may change in the future if the field's production does not increase as planned. Meanwhile, a third LNG terminal at Dabhol should become operational in 2011. Although it was originally planned to start in early 2010, the cool down of the terminal is now postponed until November 2011 due to delays in dredging activity at the port. GAIL and Marubeni agreed on an LNG supply deal of 0.7 bcm for three years from 2011. Until Dabhol becomes operational, LNG cargoes will be delivered to Dahej terminal. Interestingly, Shell and Total opened the Hazira LNG terminal to third parties for the first time in 2010 and Gujarat State Petroleum Corp (GSPC), which also owned capacity at Dahej, imported a spot cargo in July. Indian companies are actively looking for additional LNG supplies: Petronet signed an agreement to purchase 2 bcm from Gorgon, while GSPC also signed an agreement with Gazprom Marketing & Trading to purchase 0.4 bcm, starting in the second half of 2011 for two years.

Europe: Key Markets are Growing

UK LNG imports jumped by 85% in 2010, reaching 18.8 bcm. The United Kingdom received many Qatari cargoes throughout 2010 which would otherwise have been directed to the US market if there had been no unconventional gas revolution. The country is now playing a very important role as an intake point of LNG to Continental Europe. As NBP prices were higher than HH prices in 2010, they attracted LNG producers worldwide. In particular, Qatar Petroleum utilised South Hook as a strategic outlet for the LNG from its mega-trains. UK's Dragon LNG terminal also received a cargo from Qatar for the first time in August 2010. The Isle of Grain terminal received a first cargo from US Sabine Pass in November 2010, which was re-exported in order to take advantage of arbitrage opportunities. In early 2011, Centrica signed an agreement with Qatargas to supply 3.3 bcm (2.4 mtpa) of LNG for three years to the Isle of Grain terminal.

Italy's LNG imports tripled in 2010 to 9 bcm. Italy has two LNG terminals: Panigaglia LNG and Adriatic LNG, where Qatar has regasification capacity. Adriatic LNG started operation in 2009 and received 7 bcm, mostly from Qatar in 2010. The Adriatic LNG terminal appears also as one of the LNG terminals used by Qatar as an outlet for its production, like South Hook in the United Kingdom.

The long-awaited Gate LNG terminal in Rotterdam was under commissioning in June 2011 and is set to commence operations in September. Gate will be another LNG hub terminal in Northwest Europe similar to Zeebrugge in Belgium. Several major European players have already secured capacity at the terminal and LNG trade in Northwest Europe will be encouraged through these new imports, swap arrangements or increasing competition. RWE, Eneco, EconGas, E.ON Ruhrgas, and DONG have reserved together a terminal capacity of 12 bcm. These companies can be considered as relatively new entrants in the LNG business. Merrill Lynch is also believed to have secured 1 bcm capacity.

Middle East: A Surprising New LNG Importer

Kuwait started importing in 2009 due to rapidly increasing domestic gas demand, and LNG imports tripled over 2010 to reach 2.7 bcm. Abu Dhabi has been an LNG producer for over 30 years, exporting primarily to Asia. To face rising domestic demand, the Dubai Supply Authority has chartered a 5.1 bcm/y LNG floating terminal with capacity from Golar LNG under a 10-year contract and started importing LNG from December 2010. The first LNG cargo was shipped from Qatargas IV Train 7 late 2010 for commissioning. The supply period is currently limited to May-October.

The Americas: Oscillating between Fullness and Dire Needs

In North America, the United States did not need to import much LNG in 2010 and remained the residual market. The United States imported 12 bcm in 2010, a 5% decline from 2009 levels. Still, new terminals are coming online, as illustrated by the Golden Pass terminal in Texas, which received two commissioning cargoes from Qatar in 2010 and commenced commercial operations in February 2011. Qatar Petroleum, as well as its strategic partners Exxon Mobil and ConocoPhillips own this terminal. The terminal could play an important role as an outlet for Qatari LNG into the US market, if there is still LNG available on the global market. Likewise, the Gulf LNG terminal in the Gulf of Mexico is expected to be completed by October 2011. It remains to be seen whether this terminal, in which Sonangol owns 20% capacity, will indeed receive LNG cargoes from Angola LNG after 2012 or whether LNG cargoes will be diverted to other markets.

On the other hand all other North and South American countries need LNG supplies due to regional supply/demand imbalances. The Canaport LNG terminal, the only terminal operational in Eastern Canada, received 1.9 bcm of LNG in 2010 – twice the amount in 2009. In October 2010, Repsol, which owns Canaport LNG's capacity, agreed to purchase LNG from Qatar in a multi-year contract. Qatari LNG exports to Canada are therefore likely to increase significantly from 0.3 bcm in 2010. Mexico has been increasing LNG imports, which represent around 10% of national demand and are expected to increase further when the third LNG terminal in Manzanillo comes online in September 2011.

LNG imports in Latin America rose from 2 bcm in 2009 to 7.5 bcm in 2010. Argentina suffered from critical shortages during the summer of 2010 and increased its LNG imports, which still did not prevent industrial customers from being interrupted. Chile's second LNG receiving terminal, GNL Mejillones, commenced operation in 2010 and received an initial cargo from Trinidad and Tobago. While Chile currently use a vessel for storage, the country is also planning to build an onshore storage tank by 2013. Brazil is in talks with Qatar over LNG supply and expects to receive an LNG cargo from Rasgas for the first time in summer 2011.

Regional LNG Development From the Producers' Side

On the supply side, problems in Indonesia, Egypt, Oman, Norway and Algeria have resulted in only an 88% utilisation of the liquefaction plants. Oman and Egypt are faced with competition between rising demand and export commitments, while Norway struggled with upstream issues. Algerian exports declined by an estimated 6%, although the reasons for the decrease are unclear. One possible explanation is that with disappointing spot prices, the country preferred to hold shipping until the market tightens. However, some analysts also suggest that there could be serious technical issues. The recovery of spot prices should help clarify the situation. Indonesia saw diverging trends between Tangguh reaching plateau and a drop in exports at Arun and Bontang. Nevertheless, these difficulties were more than compensated for by the recent start of new liquefaction plants over 2009-10 in Qatar, Russia, Yemen and Peru, as well as recovery in Nigeria, where LNG exports had dropped dramatically in 2009 due to unrest and sabotage.

Asia-Pacific

Trends in Asia-Pacific region diverge, with increasing LNG exports in Australia and stagnating exports from other countries. Brunei has major term contracts expiring by 2013 and it seems that the negotiation for their renewal is underway with the buyers. With continuing concern over gas reserves, it is not clear how long the supply from Brunei will last, even if the contracts are extended. In Malaysia, domestic demand for gas is increasing, while domestic production is unable to satisfy it due to regulatory limitations for domestic gas production. However, this limitation does not apply to LNG exports.

In Indonesia, despite the recent FID for the 2.7 bcm Donggi Senoro LNG project, a policy dispute has raged over how much of the gas fields' production should be reserved for domestic use. The stakeholders finally agreed that 70% to 75% of the produced gas would be designated for LNG exports. As the Arun plants are aging and their exports are declining, they could cease exports in 2014. In comparison, Bontang terminals are playing an important role in supporting the country's long-term commitment to existing buyers. New fields are also being developed to supply raw gas to

the terminals. Australian LNG supplies have been increasing slightly in 2010, with extra cargoes available from North West Shelf and Darwin LNG projects, but the real increase will likely take place in 2011-12 with the 6.5 bcm LNG project Pluto scheduled to begin operations in August 2011.

Middle East: The Unchallenged Rise of Qatar

From spring to summer 2010, Qatar undertook sequential maintenance on its LNG trains. Meanwhile, three mega-trains, 10.6 bcm each, started operation in the last 18 months and Qatar became by far the largest LNG producer in the world with 105 bcm (77 mtpa) production capacity. Nakilat, a Qatari marine transport company, received the last Q-Max tankers in July to form a gigantic fleet of 54 LNG tankers (14 Q-Max, 31 Q-Flex and the rest conventional) and is now capable of transporting Qatar's LNG worldwide.

After the start of its second 4.6 bcm/y train in April 2010, following the first train's commissioning in 2009, Yemen LNG now has a production capacity of 9.2 bcm/y. Yemen LNG has a sale contract with KOGAS, while GDF Suez and Total use their equity LNG to supply markets using arbitrage opportunities. Exports going to Asia, Europe and the United States reached 5.6 bcm in 2010. Meanwhile, Oman could reduce LNG exports to meet growing domestic gas demand.

Africa: Can Unrest Threaten LNG Exports?

Political unrest in Egypt, which started in January 2011, has had a minimum impact on the operation of Idku and Damietta LNG plants and LNG trade through the Suez Canal. Egyptian LNG exports are nevertheless down, due to fast growing demand and relatively low LNG plant utilisation rates of some 60%, well below the world's average. Around 40 bcm of LNG transited through the Canal in 2010, mostly from Qatar. Issues with transit through the Canal would result in additional shipping time of 15 days to reach Europe, probably leading to higher spot prices. Political unrest in Libya resulted in a disruption of LNG exports, but these were very limited, at below 1 bcm/y. Spain, the main importer of Libyan LNG, has not experienced gas shortages.

Disruption of Algerian exports, albeit unlikely, would be more problematic, as global LNG markets would be deprived of around 20 bcm of LNG and over 30 bcm of pipeline gas exports, mostly to Italy and Spain. Spain would need to replace around 7 bcm of pipeline gas with LNG, resulting in a further tightening of LNG markets. Italy, which already faces disruption of 9 bcm of Libyan pipeline gas, would suffer unprecedented tightness. Two trains under construction in Algeria are expected by 2013. It is not clear whether these trains will result in incremental capacity or replace older plants.

Nigeria suffered from political unrest and sabotage in 2009, which resulted in LNG exports plummeting by one-third. In 2010, the situation improved significantly and LNG exports came back to 2008 levels although two trains remain shut down. The country experienced a power supply problem in December 2010 which reduced LNG production significantly. Nigeria has several LNG plants under consideration, including Brass LNG, Olokola LNG and Nigeria LNG Train 7, but little progress was made in 2010, so these projects are unlikely to start producing before 2016.

Americas: One Plant Opens, Another Shuts Down

In Alaska, ConocoPhillips and Marathon have decided to close down the 2 bcm Kenai LNG before summer 2011 after over 40 years of operation. As LNG exports to Japan had been declining over the last years due to limited reserves, it was no longer economic to maintain the operation for the small volume of exports although the operators had requested a two-year extension of the export license until 2013.

Peru LNG, led by Repsol, started exporting LNG in June 2010. It is the first LNG export project in Latin America. The first cargo went to Semptra's Energia Costa Azul terminal in Mexico. During the ramp-up to full contractual volume (5.2 bcm from 2014) of 15 years LNG supply to CFE's Manzanillo terminal in Mexico, Peru LNG can market spot cargoes or short-term supply to South America, Asia, Europe or North America, particularly Canada, where Repsol has 100% capacity of the Canaport LNG terminal. Repsol signed an agreement with the Dutch trading company Gunvor to provide 14 spot cargoes from November 2010 to December 2011.

Russia: Reaching Full Export Potential

Russia joined the club of LNG exporters in February 2009, when the 13 bcm Sakhalin II started operation. The plant reached full production in 2010. The primary market for the project is Asia-Pacific. Russia has an ambitious target of expanding its market share in the region with massive new LNG projects, while attempting to increase gas exports to Europe and Asia via pipeline.

New Contractual Agreements

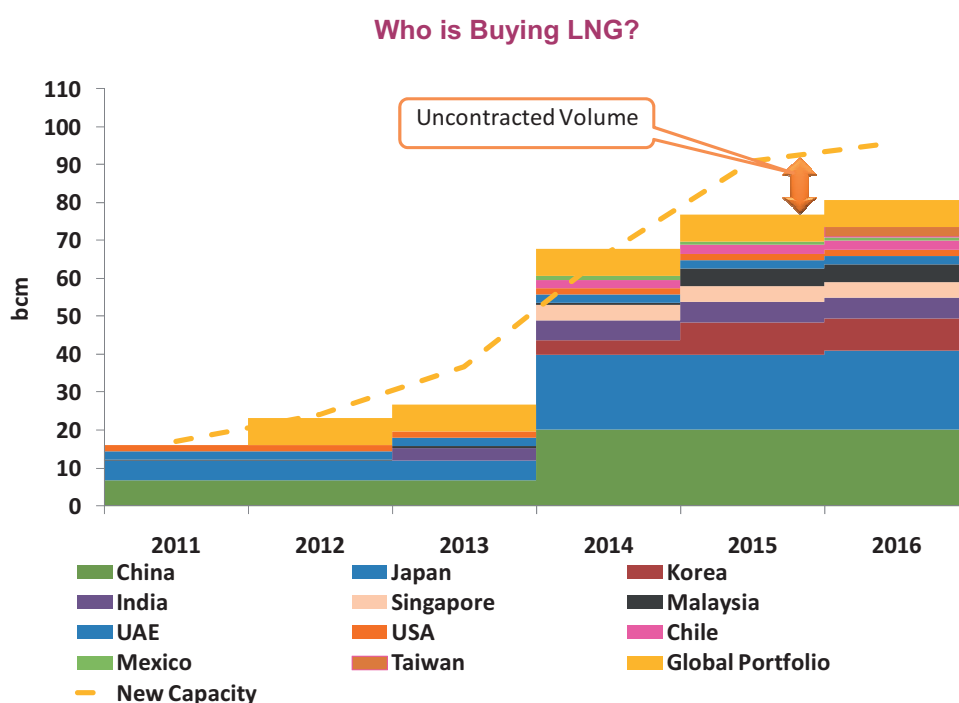
Who is Thirsty for LNG?

Over the next five years, several LNG production projects, either under construction or recently sanctioned, will be completed. As a result, an additional 96 bcm of capacity will come online between early 2011 and the end of 2017. Of all LNG produced annually from these projects, 20 bcm/y is contracted to go to Japan, another 20 bcm/y to China and another 8.5 bcm/y to Korea. Japan's new contracts reflect the needs to replace other supply sources and growth related to the power and industrial sectors. More contracts, short- or mid-term, are expected to be concluded shortly as a result of the lost nuclear capacity in the Fukushima accident. China's new contracts are coming purely from demand related to rapid economic growth. New contracts with Korea are to meet booming gas demand and replace contracts set to expire over the next five years. Roughly 5 bcm will go to both India and Malaysia while lower volumes will go to Chile, Mexico and the United States, although the latter is doubtful due to the current low demand for LNG.

Around 7 bcm of "global portfolio" from Angola could serve any market, as the gas was previously expected to serve the US market. Additionally, there is still a fair amount of uncontracted volume, mostly from Algeria (9 bcm) and Australia (5 bcm), in the range of 10 bcm to 15 bcm before 2016. Remaining volumes are expected to be marketed prior to the commissioning date or will be sold on a spot basis/short-term sales arrangements to Asia, Middle East or Europe.

It is not clear how much of new Qatari production is contracted on a long-term basis. Some of the contracts are agreed with project partners, such as Shell and ConocoPhillips. These contracts are

viable under circumstances where the US market would still be the primary market of LNG. Market changes led Qatar and its project partners to reconsider their marketing strategy and business portfolio. They have secured the capacity of receiving terminals worldwide, such as in the United Kingdom or Italy, as an outlet for their LNG. However, secured capacity does not seem to be absorbing all the new production. As a result, Qatar could become a swing producer in order to take advantage of the highest market at a given point in time, diverting cargoes rather than filling the global market with unwanted Qatari LNG under long-term commitments. It is still unclear how this strategy will play out in their project economics.



Japanese Companies Looking for New LNG Supplies

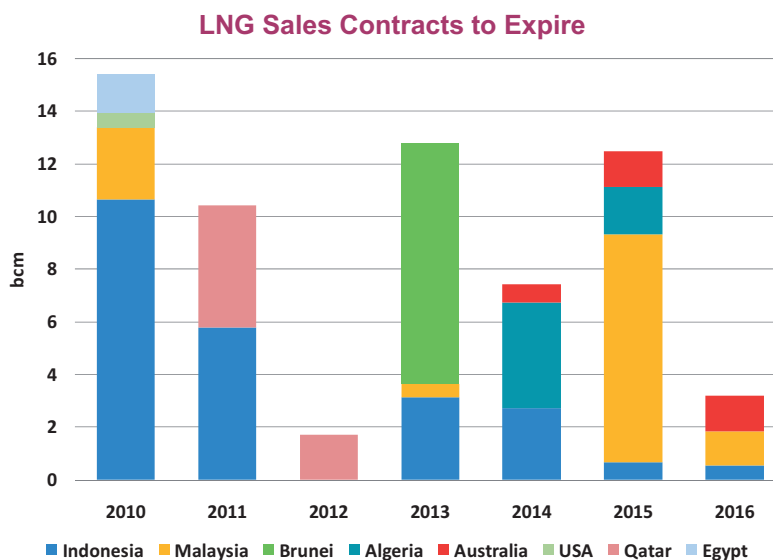
Throughout 2010, there were a few agreements reached among Japanese utilities regarding LNG supply. Long-term LNG deals with foreign suppliers were becoming increasingly larger (beyond 1 bcm/y) and relatively smaller deals under 1 bcm/y were getting more difficult to conclude. Indeed, the rapidly growing LNG demand in Asia-Pacific pushed up the minimum requirement of long-term LNG purchase. Smaller demand had to find a spot deal or short/mid-term deals in a very volatile market. Under these circumstances, some of the large utilities, which could still import several bcm of LNG annually, explored business opportunities with smaller domestic utilities.

In June 2010, Shizuoka Gas signed the agreement for 0.4 bcm of LNG from Osaka Gas for 20 years from 2014 and another agreement for 0.35 bcm from TEPCO for 20 years from 2015. In July, Osaka Gas signed an agreement with Shell for the purchase of 1 bcm LNG from 2012 for 25 years. Shell is expected to supply LNG from its global gas portfolio in the medium term, but after 2017, the LNG would come from Prelude in Australia, which just recently took a FID, as of late May 2011. Late 2010, Shizuoka Gas inked a deal with Mitsubishi on LNG supply of 4 bcm over six years until 2016 and Tokyo Gas also agreed to supply LNG to Hokkaido Gas for 11 years from 2012, but the volume and price are still under discussion.

Major Long-Term Contracts to Expire

The comforting picture of new LNG supply contracts actually hides the fact that some LNG contracts will expire and not be extended. In 2010, 15 bcm-worth of LNG sales contracts, mostly from Indonesia, expired and another 10 bcm are expected to expire in 2011. Interestingly, for the next five years, a rather high share of the historical LNG supply contracts is also expected to expire.

Most Indonesian long-term contracts will end before 2016. An additional 13 bcm of natural gas on top of the 10.7 bcm which expired in 2010 may no longer be exported via LNG, as Indonesia expressed its strategy to divert gas production to satisfy growing domestic demand. At the same time, Indonesia plans to import LNG if domestic production is not sufficient to meet domestic demand to increase supply flexibility. While Indonesia will continue to be an LNG exporter from its recently completed Tangguh and upcoming Donggi Senoro, volumes from the existing Arun are expected to drastically decline. Similarly, Malaysia has growing needs from its domestic market and will start importing LNG within a few years. The country has a considerable number of long-term contracts with Japan, Korea and Taiwan, and 10.4 bcm of contracted gas all together is set to expire before 2016 on top of the 2.7 bcm that expired in 2010. More urgently, 9 bcm of contracted gas from Brunei to Japan and Korea will expire in 2013, although a number of these contracts are being renegotiated.



There is an increasing need in Indonesia to secure natural gas supply sources as domestic gas demand increases. To satisfy growing national demand, Indonesia is reducing LNG exports while further exploring natural gas reserves, and it also has plans to install LNG receiving terminals along its coast. One of the proposed projects is to install a floating terminal in West Java with 2 bcm receiving capacity. It is expected to be operational before end-2012. Meanwhile, liquefaction projects Tangguh Train 3 and Masela LNG (6.1 bcm/year) are still under consideration.

Malaysia and Brunei both have a long history of stable LNG supply so that they have comparative advantages against new projects in terms of supply reliability and depreciated assets. However, given the number of new projects coming online or being examined, traditional producers could be challenged in negotiating renewal unless they can provide added value on top of stable supply since there is an emerging trend among LNG buyers to take an upstream stake in exchange for a firm commitment to purchase LNG. LNG buyers are ready to share risks associated with plant construction and project management as well as profit arising from green field projects.

Some short- and mid-term contracts from Qatar are also expiring, including a 4.6 bcm commitment with Belgium in 2011 and another 1.7 bcm commitment with Spain in 2012. It is unclear whether they would be extended.

LNG Re-export Business: A new Trend?

Due to the ample domestic gas supply supported by unconventional gas production and low prices, US LNG imports in 2010 were down from 2009 to 12.2 bcm. US LNG imports are expected to remain low for years to come and some of the receiving terminals in the United States have reconsidered their business portfolio and LNG strategy in the light of low utilisation rates of the facilities. In order to maintain operations at the LNG regasification terminals while benefitting from the arbitrage between the US and other markets, the owners of three regasification terminals applied for and obtained licences to re-export foreign oriented LNG from the US Department of Energy (DOE) and the Federal Energy Regulatory Commission (FERC). These facilities include Sabine Pass (Cheniere), Freeport (Freeport LNG) and Cameron (Semptra) terminals. The Cove Point terminal (Dominion) is also considering re-exporting LNG.

LNG is imported in the United States at around \$5/Mbtu under the current market. With marginal operation costs of storage and re-loading into LNG tankers, most of the additional cost would be for freight to the new destination. Assuming the freight estimate to the Asian market, where the LNG price is about \$10-11/Mbtu, is around \$3/Mbtu, LNG re-export appears profitable. Those in the re-export business claim that they own the sole title to the LNG being re-exported. As a result, some of the LNG exporting countries to the US market are not enthusiastic about this new business, since there are no schemes to share profit arising from such business.

In 2010, the Sabine Pass and Freeport terminals, respectively, re-exported over 0.6 bcm and 0.3 bcm of LNG to Europe, Asia and Brazil. Considering that US re-export in 2009 was as low as 0.07 bcm, the re-export volume grew more than 12 times compared to 2009. Such a strategy is not limited to the United States. Zeebrugge, the Belgian LNG terminal, also re-exported single cargoes to Korea and China in 2010. With the increasing demand for LNG in Asia and Europe, where LNG has higher market value than in the United States, re-export could well become an expanding and profitable business opportunity.

UNCONVENTIONAL GAS

Summary

- **Unconventional gas resources have not only doubled the amount of estimated recoverable gas, they have also shown that gas resources are more evenly between regions than previously acknowledged. The unconventional gas revolution in North America is now driving many countries into an unconventional gas race.** Until recently, such resources had been largely disregarded, even in producing regions. Many countries have now embarked on studies to estimate their resource potential and are taking the first steps to put in place the adequate regulatory framework. They are also seeking to acquire the necessary technology through acquisitions, mergers or joint-ventures, or to attract foreign investments.
- **Beyond North America, Asia is the most advanced region in terms of unconventional gas development, Australia and China taking the lead. The focus on the specific type of unconventional gas differs by country, with most would-be producers looking at shale gas.** China is already producing tight gas and coalbed methane (CBM), but is turning to shale gas as well. Indonesia and India are also taking the first steps towards CBM production. European countries reflect a rainbow of approaches: while Poland is actively supporting shale gas, France banned hydraulic fracturing due to local opposition. In the Middle East, Africa and Latin America, tight and shale gas resources could complement existing conventional gas, particularly in countries facing dwindling conventional gas output.
- **The effective development of unconventional gas still faces challenges, primarily due to concerns about the environmental impact of its production, especially shale gas.** As opposition from local populations is mounting against potential exploration and production, industry is very much awaiting the results of a study conducted by the US Environmental Protection Agency (EPA) on the impact of shale gas production on ground water. Several countries have effectively banned drilling, due to local opposition.

Over the past few years, the world had realised the astonishing potential of these new resources through the revolution taking place in the United States. Driven by shale gas, US unconventional gas output has increased by almost 40% over the 2007-10 period. Gas analysts focus on answering two questions: to what extent and how rapidly can the US experience be replicated in other regions; and what are the implications in terms of investment and governments' policies on gas and prices?

As of 2010, unconventional gas production reached an estimated 15% of global gas production. The largest part comes from North America, with around 420 bcm produced in 2010, half of which is still tight gas.¹⁸ Coalbed methane (CBM) production and tight gas in the rest of the world are estimated to around 10 bcm and 60 bcm, respectively. Shale gas output increased by a factor of 11 over the last decade, to reach just under one-third of total unconventional gas production in 2010. However, as of 2010, shale output is still concentrated in the United States. Such an exponential growth naturally spurs interest in many other countries, raising the questions as to whether such growth could be replicated elsewhere and what would be the implications for the energy mix and trade.

¹⁸ In some countries tight gas is considered as conventional gas and is not separated in official statistics resulting in differences on unconventional gas production or resources.

Unconventional Gas Production in the World, 2010



This map is for illustrative purposes and is without prejudice to the status of or sovereignty over any territory covered by this map.
Source: EIA, National Energy Board, Total, Gazprom, Abare, BP, Shell, CNPC.

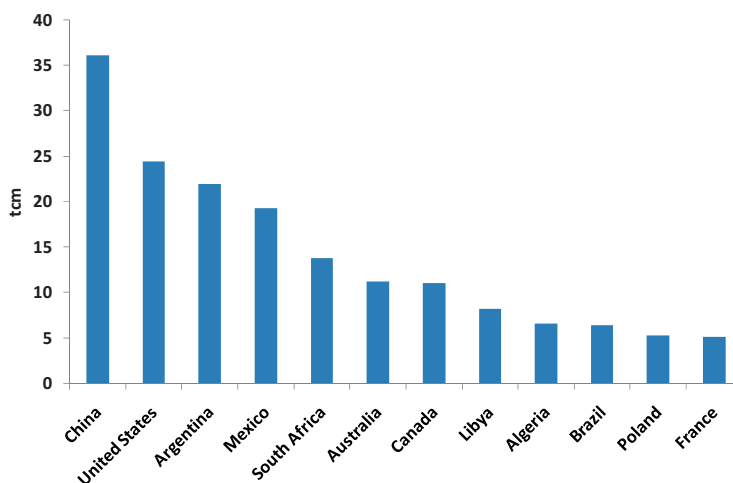
Abundant Resources

Petroleum geologists have been aware of the presence of unconventional gas resources for many years: tight gas has actually often been considered as a continuation of conventional gas, albeit more difficult to produce due to its lower permeability; CBM has been known since the beginning of coal production, while shale gas was known, but considered a “nuisance” and too expensive to produce. Over the past three years, the US success has spurred interest in both producing and importing countries, which are now investigating more closely their unconventional gas resources.

Initial estimates from 1996 (Rogner), 2001 (Kawata and Fujita) and 2006 (Holditch) put total gas resources in place at 920 trillion cubic meters (tcm), but the amount of recoverable unconventional gas resources is obviously much lower. For shale gas, recovery factors are usually between 20% and 30%, depending on the quality of the resource base. A few countries may actually discover a potential they had ignored or not been aware of before: some due to large existing conventional gas resources or others due to the lack of any production. Algerian Energy Minister Youcef Yousfi announced in March 2011 that his country had significant shale gas resources. In April 2011, the US Energy Information Administration (EIA) released a study (*“Shale Gas is a Global Phenomenon”*) with estimates of recoverable shale gas resources in 32 countries based on 48 shale gas basins. Resources in these countries and the United States were estimated to be 185 tcm, close to total proven gas reserves (190 tcm, according to Cedigaz). China was estimated to have the largest shale gas resources at 36 tcm, higher than the already prolific United States (24 tcm), followed by Argentina (22 tcm) and Mexico (19 tcm), where limited activities exist so far. This study did not include many regions, particularly the Middle East, so that global recoverable shale gas resources are certainly

larger. In the IEA's special report *Are we Entering a Golden Age of Gas?*, the IEA estimates total recoverable unconventional gas resources worldwide to be 406 tcm (125 years of current consumption), with shale gas at 204 tcm, CBM resources at 118 tcm and tight gas at 84 tcm.

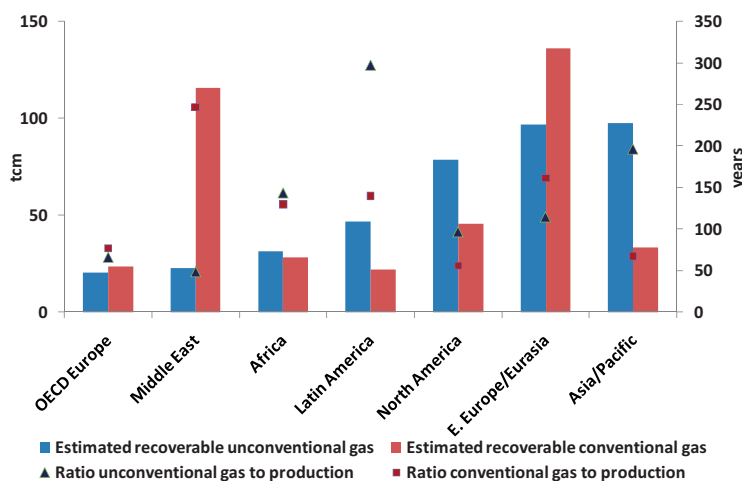
Estimated Recoverable Shale Gas Resources in Selected Countries



Source: EIA, Shale gas is a Global Phenomenon, April 2011.

The world seems endowed with large resources of both conventional and unconventional gas. Proven gas reserves represent 57 years of current demand, a number increasing to 120 years when taking into account total recoverable conventional gas resources. Adding recoverable unconventional gas resources, this number doubles to around 240 years of current consumption. More importantly, unconventional gas resources are evenly distributed in geographic terms and are particularly important in North America, Latin America and Asia/Pacific, where they are estimated to be two times more than conventional resources. Both types of resources are roughly the same in Europe and Africa, while conventional gas resources dominate in the Middle East and Eurasia.

Estimated Unconventional and Conventional Recoverable Gas Resources by Region

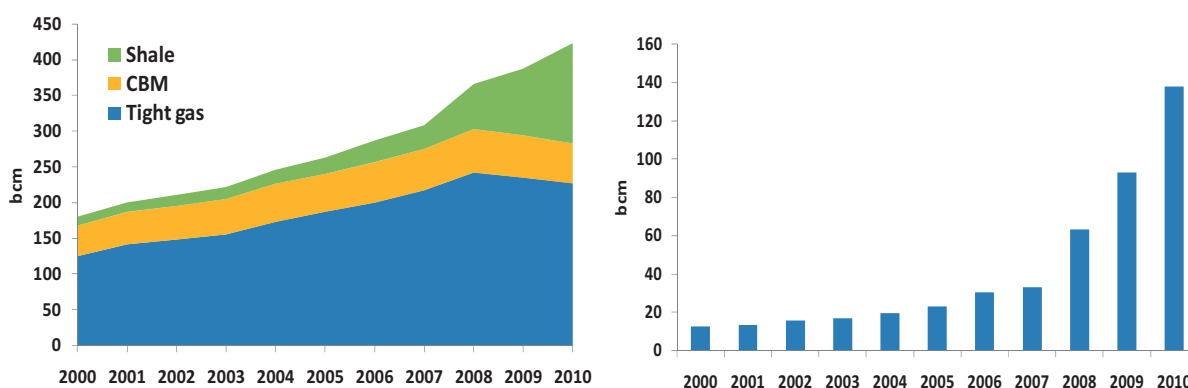


An Increasing Impact on Markets

One single country, the United States, not only represents the majority of unconventional gas production, but is also driving its growth. Despite tough market conditions and rising environmental concerns, US total gas output increased by 5% to 613 bcm during 2010. The main contributor to this incremental production is without any doubt unconventional gas, which now represents an estimated 60% of US gas output. However, there are very diverging trends below the surface: while US shale gas production increased from 90 bcm in 2009 to an estimated 138 bcm in 2010, tight gas and CBM, which had until now represented the backbone of US unconventional gas production, are estimated to have slightly declined. This tremendous growth of shale gas explains why, among the three different types of unconventional gas, it is attracting the most attention, in the United States, but also worldwide.

The market consequences, visible in 2009, have become more marked. The United States is the second largest world gas producer, and has *de facto* withdrawn from global LNG markets with only 12 bcm of LNG imports in 2010. The utilisation of US regasification terminals is at a record low (7%). The country even re-exported 1 bcm of LNG in 2010 to Asia, Europe or Latin America, as several terminals (notably Sabine Pass and Freeport) acquired licenses to re-export. Meanwhile, other regions such as Asia and Europe had to absorb the mounting wave of LNG reaching the market (+25% growth in 2010 as LNG trade reached around 300 bcm). Significantly, companies are now seriously considering LNG exports based on Texas shale gas. This initiative would be a complete reversal for the United States; from a policy point of view, it would support LNG exports from non-stranded resources (unlike Alaska), and sets exports before domestic use. From a market viewpoint, the United States needs a lasting premium market, which can only be Asia or Europe. In any case, North America has become a much less attractive market for existing or would-be LNG exporters, not to mention anybody planning to build LNG regasification terminals.

Unconventional Gas Production in North America/ US Shale Gas



Source: EIA, IEA, National Energy Board, 2010 data are estimates.

The most visible impact of US success in developing unconventional gas is the broad interest generated in other regions. Unconventional gas, especially shale gas, has become the latest phenomenon, although some experts have questioned whether it will be short-lived. The question is longer whether it will be replicated, but to what extent and at which speed. Countries (outside North

America) are divided into three groups (not including countries, which are not yet engaged in any unconventional gas activity):

- **Leaders** are already proceeding with large-scale projects: among these are Australia and China.
- **Followers** have identified specific fields or areas. In some cases, they have initiated limited production, or have launched tenders, started drilling and may be moving towards production: Indonesia, Argentina and Poland – as well as MENA countries such as Oman – belong to this group.
- **Circumspect countries** are investigating their potential or the pros and cons for exploitation. They have not yet reached the drilling phase (apart from tight gas prospects): this broad category includes many European countries (such as Poland, Germany or the United Kingdom) as well as South Africa, and France (despite the ban in place on hydraulic fracturing).

Ongoing Challenges

There is little doubt that some countries will move towards becoming unconventional gas producers, but they face four challenges: geological, costs, country and company factors. Some countries will face one or two, while others may face all of them, in which case, future unconventional gas production could be doubtful, or at least slow to be developed. It is worth noting that it took the United States several decades to reach a point where CBM production could start and reach significant levels; the same occurred for shale gas almost two decades later. This entailed decades of research to develop and improve technologies. Hydraulic fracturing and horizontal drilling – albeit not particularly new – have been perfected over the years. These technologies give an advantage to would-be producing countries, as they are now available (although still being perfected): the question for producers is whether to gain access to these technologies by inviting foreign companies to invest, encouraging partnerships or joint-ventures between National Oil Companies (NOCs) and these experienced companies, or through the acquisition of foreign shale or CBM assets to get expertise.

Geological Factors

While data on unconventional gas are improving, there is still major work needed to refine and expand the range of information available. Obtaining reliable geological data will be critical, but this information may not be consistent on a country-by-country basis, depending on petroleum production history. The lack of exploration and production (E&P) implies that time and investment is needed to learn the subsurface and define the most prospective areas for potential future wells. Beyond this, there is great uncertainty regarding recovery factors. In the EIA study, recovery factors ranged between 20% and 30%, while 15% or 35% were used in some cases. Taking one of the major shale plays, Haynesville, as an example for which resources in place are estimated between 13.8 tcm and 23 tcm and applying the range of recovery factors, there would be a 2.9 tcm difference between the lowest and highest estimates for technically recoverable resources. This is equal to the current world gas consumption. Analysts also tend to look at the resources from today's perspective, but as technology improves, recoverable resources often improve over time. Besides identifying the location, there is a general lack of public data on gas composition for major unconventional gas plays. For example, gas "wetness" varies significantly among major unconventional gas plays. It could be an

issue because of significant gas liquids processing requirements, but it could also serve as an advantage, as US producers currently favour liquids production due to the current high oil prices.

Assessing unconventional gas potential is the priority, before drilling takes place. This can be performed by different stakeholders, provided they have access to geological data – preferably coming from more than one source so that some double-checking can be performed. In addition to the studies led by governmental agencies such as the EIA, and consultants such as Intek and IHS, some producing and service companies have their own estimates, probably not global, as they are linked to their E&P work and not always publicly available. There are also some industry-led initiatives, such as GASH, or inter-government-led initiatives, such as the Global Shale Gas Initiative (GSGI). GASH is a European shale gas research initiative which started in 2009 for an initial 3-year phase. It is sponsored by companies such as Statoil, ExxonMobil, GDF SUEZ and Total, and managed by the German Research Centre for Geosciences (GFZ) in co-operation with other institutes and universities. Meanwhile, GSGI was launched by the US Department of State in April 2010 to help countries identify and develop shale gas resources; it focuses, among other things, on shale gas resource assessments. So far, partnerships have been announced with China, India, Jordan and Poland, while potential bilateral agreements with other countries are being discussed. There is more need for such initiatives to give countries with little E&P experience a chance to develop their potential. It is interesting to see that most studies focus exclusively on shale gas – again a consequence of the recent and impressive boom.

Costs

While it may be convenient to put a price tag on unconventional gas production, there is not such a thing. As with conventional gas, production costs would vary significantly within one region and *a fortiori* within a country. Costs will depend on geological factors such as the quality of the play, the presence of liquids, and on country-specific factors – the fiscal framework, licensing or leasing costs, costs due to environmental regulations, including water recycling and treatment, rigs costs, as well as labour costs. For vast countries with under-developed infrastructure, building pipelines to bring gas to markets adds to these costs. In the United States, costs of around \$4-5/MBtu seem to be accepted as a benchmark, but costs as low as \$2/MBtu have also been quoted. For the very liquid-rich plays, gas production costs would tend towards 0. Costs are likely to be higher in some countries where working labour costs are higher, rigs are not readily available or there are environmental concerns leading to additional regulation. Recent studies have put the break-even prices in Europe between \$8/MBtu and \$14/MBtu, considerably higher than US costs. However, with current import prices at around \$9-10/MBtu, the lower range of these estimates would make unconventional gas competitive with imported gas for the years to come. So the question is not the price, but what would be the volume of gas that could be produced at or below imported gas or conventional gas costs. Governments' incentives, regulatory and tax frameworks, could be crucial to getting gas off the ground, and making it competitive in the first years of production.

Company factors

While the US shale gas revolution has been mostly driven by “entrepreneurs”, International Oil Companies (IOCs) have realised, albeit later, the potential of shale gas resources and have been catching up ever since. In order to acquire positions in the United States, they acquired shale gas

assets together with technology and *savoir faire* through mergers and acquisitions. While the acquisition of XTO by ExxonMobil in 2009 broke the record with \$41 billion, there has been a continuous stream of acquisition since 2008, first from IOCs and more recently from Asian companies eager to get access to resources or experience. Acquisition of shale gas resources in North America is also a way for IOCs to improve the reserves base in countries where the access to gas is not limited by government policies, and potentially to be able to use their experience in less-open countries. Actually experience and technology also play a fundamental role for tight gas or CBM assets. It is their experience which enables companies such as Shell, Total, or BP to be selected to develop tight gas assets in countries such as China or Oman.

Asian Companies' Foreign Investments in Unconventional Gas

Asian companies have entered the unconventional gas world by acquiring foreign assets. While most focus on North America and on shale gas, there are some key differences in terms of strategy and type of investments. In many cases, these new investors provide a relief to cash-trapped companies by covering drilling costs. Two Chinese NOCs, PetroChina and CNOOC, have been investing in foreign unconventional gas assets, mostly in North America and Australia. They have a similar strategy, aiming first at gaining experience in shale gas exploration with a possible longer-term view of supplying China with LNG. In February 2011, PetroChina signed a \$5.5 billion (CAD 5.4 billion) deal with EnCana for a 50% stake in its assets in British Columbia and Alberta to develop Horn River and Montney shale plays, following a head of agreements (HoA) in 2010. In 2010, the company, together with Shell, also acquired Australian CBM producer Arrow for \$3 billion, aiming to supply China with a CBM-to-LNG project. In January 2011, CNOOC acquired one-third of Chesapeake's stake in its assets in Denver-Julesburg and Powder River basins for \$570 million. CNOOC would fund two-thirds of drilling costs, up to \$697 million. This follows a previous acquisition by CNOOC in October 2010 of one-third of Chesapeake's Eagle Ford assets for \$1.1 billion. CNOOC also invested in Australia with the acquisition of 35% of Exoma's exploration permits in the Galilee Basin. The Canadian assets could also feed the LNG export project Kitimat. It is less clear whether the US assets would also serve an export purpose. Sinopec has been less proactive but has recently taken a 15% in one of the planned CBM-to-LNG projects led by ConocoPhillips and Origin Energy.

India's Reliance has also been investing in North America, with the aim to acquire expertise. In 2010, it bought a 40% stake in Atlas Energy's Marcellus share acreage for \$1.7 billion, a 45% stake in Pioneer Natural Resources' Eagle Ford assets for \$1.36 billion, and a 60% stake of Carrizo Oil and Gas's Marcellus assets for \$340 million. In all cases, RIL will pay drilling costs. Other Asian companies are moving to gain a foothold, in North America, looking to supply their respective countries with LNG. Japan's Mitsui acquired 32.5% of Anadarko's holdings in Marcellus and bear \$1.4 billion of Anadarko's future development costs, while Mitsubishi acquired assets from Canada's Penn West Energy Trust for \$237 million. This acquisition led to the establishment in May 2011 of a consortium of Japanese gas companies and utilities (Mitsubishi, JOGMEC, Chubu Electric Tokyo Gas Osaka Gas) which would collaborate on shale gas projects in British Colombia. The CAD 1 billion (\$1 billion) funding will be provided by the Japan Bank for International Cooperation (JBIC), making it a public-private sector initiative. Sumitomo and Korea's KOGAS are also engaged in the shale gas race through acquisitions.

Country factors

Local factors are probably the greatest challenge, once the resources have been identified. Most countries have neither the regulatory framework in place to deal with unconventional gas nor a framework to establish guidelines for gas production at all. Each country must decide whether or not

to open the upstream sector to foreign companies and, if so, under which terms – terms which are deemed to be acceptable for said foreign players. Then arises the question of the future supply/demand balance. Turning a country from an importer to an exporter looks attractive on paper but requires investment in the transmission network to bring new production to markets, in potential export infrastructure and can jeopardise the economics of existing import infrastructure. The United States, with 180 bcm of regasification capacity under-used and massive investments in inter-state pipelines, is an obvious example. Developing these resources also depends on the size of the resource vis-à-vis the gas market and how easily it can replace existing imports or compensate/enhance existing production. Additionally, unconventional gas can trigger a complete change of policy regarding gas use in some sectors as illustrated by President Obama's backing of natural gas use in the transport sector. Looking at Poland, a key question would be whether shale gas would replace imports or be more actively used in the power generation sector (or a combination of both). The question of ownership is also important: in the United States landowners receive revenues from shale gas production, which is not the case in many other countries. Finally, pipeline infrastructure will be needed to transport the gas: while third-party access exists in Europe, it does not apply in many other countries, raising the question of how multiple producers would be able to transport their gas.

Increased Opposition to Unconventional Gas

In the United States, a new source of uncertainty could come from the current study (expected to be issued in 2012) by the Environmental Protection Agency (EPA) on the effects of shale gas production on water. Concerns about quantities of water used and potential contamination of freshwater due to chemicals used for hydraulic fracturing will be the focus. As the 2005 Federal Energy Policy Act exempted hydraulic fracturing from regulation under the Safe Drinking Water Act, shale gas producers do not have to disclose the chemicals used in hydraulic fracturing. Some states have already taken a tougher stance on shale gas, particularly those close to the Marcellus play. Pennsylvania's governor issued a moratorium in October 2010 protecting sensitive forest land, although the measure was lifted by his successor in March 2011. That month, the New York State Assembly voted a moratorium until May 2011 on exploration combining hydraulic fracturing with horizontal drilling. In March 2011, Maryland's House of Representatives passed the Maryland Shale Safe Drilling Act to restrict shale gas development using hydraulic fracturing until 2013 and the completion of a major two-year drinking water and environmental impact assessment. If additional measures would be required to limit the environmental footprint, this may impact gas production costs and future shale gas developments, as well as prevent shale gas drilling in sensitive areas.

Opposition is mounting in other countries as well, despite the lack of production. In France, a ban on shale gas drilling was voted by the Assemblée Nationale on 11 May 2011 following a temporary moratorium by Prime Minister François Fillon in February. The ban has still to be approved by the Sénat. In Quebec, opposition is increasing to place a moratorium on shale gas. Even in South Africa, the government put a moratorium on hydraulic fracturing in the Karoo Basin. In many cases, countries must balance public opposition with other imperatives such as security of supply or possibly energy costs. Local production benefitting the surrounding population directly may be a way to approach the opposition in addition to transparent and efficient drilling. In Australia, the government of the eastern Australian state of New South Wales has introduced a 60-day moratorium on granting new CBM and petroleum exploration licenses. The state government wishes to find a balance between agricultural, energy and mining activities.

Increased Opposition to Unconventional Gas *(continued)*

Acceptance by the population critically hinges on dealing with environmental concerns. Proper and safe environmental standards must be put in place. Recent events in France, Canada (Quebec) and even in the United States prove that popular opposition can stall exploration activities. EU Directive Natura 2000¹⁹ could also make drilling (or obtaining drilling permits) quite complicated in Europe, especially with the relatively high numbers of wells needing to be drilled. The time required will also depend whether (or not) the authorisation process includes multiple levels from national to local communities. The current wave of opposition finds its roots in the United States and spread, but with different outcomes. The film *Gasland*, featuring shale gas production in the United States and its alleged impact on the environment and population, has increased the debate around unconventional gas. Public concerns focus on the effects of hydraulically fracturing on water in terms of quantities used, use of chemical products and potential contamination of freshwater aquifers. The yearly consumption of one well is up to 5 million gallons (18,000 m³) but can also be half this amount. In order to minimise the quantities of water used, the flowback water could be reused and recycled. It is necessary that environmental agencies have access approve the chemicals used.

Regional Developments

North America: Where Everything Started

There is still a great deal of uncertainty regarding the growth of unconventional gas production. Despite the boom of US shale gas, tight gas production has actually been slightly declining since 2008, while CBM output is flat. Between growing production and worries about the environmental impact, shale gas developments have become a hot policy issue. President Obama highlighted natural gas as the first new source of energy, provided that “we’re extracting natural gas safely, without polluting our water supply”. The results of the EPA study expected in 2012 will be crucial for future shale gas production. Many questions are raised on the sustainability of production levels at \$4/MBtu to \$5/MBtu. Some producers quote break-even costs at \$2/MBtu while others are much higher, up to \$6/MBtu. The US gas-producing industry has already proven to be quite reactive to low price signals over the past years, particularly to the divergence between oil and gas prices (see chapter on prices). The number of gas rigs sharply dropped in 2008 and never recovered, while at the same time, well recovery factors greatly improved and break-even prices dropped. Leaders in shale gas production (such as Chesapeake) have been selling their shale gas assets to newcomers, and reacted to the oil-gas price disparity by refocusing on liquid-rich plays. For example, with the acreage sold to Plains Exploration, Statoil, Total and CNOOC since 2008, Chesapeake created over \$12 billion of immediate direct value (including \$5.3 billion in direct cash payments and the rest in drilling carry) but also plans to increase liquids production by 190% over 2010-12 while gas production would increase only by 6%. After entrepreneurs initiated shale gas production, IOCs have become quite interested in shale gas from 2008, and now Asian companies are acquiring assets in North America.

Developments in Canada depend very much on US market developments and on future prices. Canada has seen its production dropping substantially – by more than 20% – over the past four years as exports to the United States have been constrained. Canada produces around 50 bcm of tight gas, mostly from Alberta and 8 bcm of CBM, but almost no shale gas. Shale gas developments in the medium term will be concentrated around the Horn River shale basin and could increase

¹⁹ Natura 2000 is an ecological network of protected areas in the European Union.

significantly, to over 10 bcm within a few years. A possible outlet for this production could be LNG exports. Some shale gas potential also exists in Quebec, but as in the United States, pressure is increasing to put a moratorium on shale gas production.

Australia: A Leader in CBM-to-LNG Development

If anything, Australia has become one of the leading countries for unconventional gas prospects, but unlike many others, the focus is almost exclusively on CBM. Demonstrated gas resources are estimated at 3.8 tcm, including around 400 bcm of CBM (also called coal seam gas [CSG]). CBM has been produced since 2003. In FY 2009/10, around 5 bcm of CSG was produced (almost 10% of total production). Australian CBM production is driven more by LNG exports projects than by domestic market needs: Australia is set to become the first CSG-based LNG exporter, with two projects sanctioned and other CBM-to-LNG projects (see chapter on investments in LNG for more details).

CBM represents a major change for Australia as production is shifting from the northwest offshore to the east onshore. This shift is important as the existing Petroleum Resource Rent Tax (PRRT) is being extended to apply also to onshore oil and gas projects from July 2012. PRRT is a profit-based tax that was until 2011 levied on oil and gas projects in Commonwealth offshore waters. However, CBM has been facing farmers' opposition in Queensland due to competition regarding water usage. Australia is also said to have significant resources of shale gas (around 10 tcm), especially in the Canning and Cooper basins. Santos is preparing to drill in the Cooper basin, while Beach Energy is already ahead and plans some fracturing tests. New Standard Energy, Buru Energy and Green Rock Energy are also planning to drill wells in the Canning Basin before the end of 2011. Infrastructure could be an issue in the Canning basin; some analysts think that these resources might be too far away on the cost curve to be developed in the medium term compared to conventional or CBM, notwithstanding the issue of water management.

Asia

In response to rapid demand growth in the region, a few countries have turned their attention to unconventional gas resources, notably China, India and Indonesia. On a regional basis, CBM development is ahead and expected to move faster, while shale gas developments would potentially arrive later this decade. China is investigating all types of unconventional gas, while India and Indonesia focus more on CBM and shale. Unconventional gas activities in China are led by NOCs, often in partnership with IOCs and smaller companies. IOCs are not yet engaged in India, while Indonesia has attracted a diversified mix of IOCs, local companies and small players through Production Sharing Contracts (PSCs). It will be necessary to tackle issues of pipeline infrastructure development, as well as upstream prices and competition between coal and gas resources.

China: How Significant will be the Contribution of Unconventional Gas?

Unconventional gas production benefits from the Chinese government's strategy to increase the share of gas in the energy mix from 4% to 8% by 2015, which would translate into additional demand of over 150 bcm over five years (from 107 bcm in 2010). Obviously, part of this additional supply has to come from domestic resources. This includes unconventional gas, which should not be systematically regarded as competing against, but rather as complementing, imports. The actual

production costs will play a role in this equation, and transport costs should be added to compare with imported LNG or pipeline gas delivered at the city gate. Apart from CBM, unconventional gas resources have not been assessed systematically. CBM resources were estimated at 36.8 tcm by the Ministry of Land and Resources in 2006, and tight gas resources are said to be above 12 tcm. The EIA estimated technically recoverable shale gas at 36 tcm. Some 70% of CBM resources are located in eight basins, with an estimated 9.8 tcm in the Ordos basin. CBM resources are very unevenly distributed on different coal ranks and at different depths. Tight gas is mostly located in the Ordos and the Sichuan basin.

China is addressing challenges that could prevent the development of such production: prices for domestic gas increased by 25% in June 2010; pipeline infrastructure is being developed, albeit slowly; and Chinese companies are either setting up joint ventures with IOCs or investing abroad to gain expertise. CBM gets preferential treatment as companies conducting surface mining can apply for reduction or exemption of mineral royalty and prospective fees before 2020, and the central government offers a subsidy to mining companies while the price for domestically used CBM is determined by negotiation. The Ministry of Land and Resources set the goal of producing 15 to 30 bcm of shale gas (equivalent to 8% to 12% of domestic output) by 2020, as well as 30 bcm of CBM by 2015 and 50 bcm by 2020, which are quite aggressive targets. NOCs' objectives are more modest: Sinopec aims for 2.5 bcm of CBM by 2015 (5 bcm by 2020); CNPC for 4 bcm of CBM and 0.5 bcm of shale gas by 2015; and China United Coal Bed Methane (CUCBM) for 10 bcm of CBM by 2020.

Tight gas is already produced in China, although it is sometimes considered as conventional gas so that precise data are difficult to get. Tight gas cumulative proven geological reserves over 2000-08 amount to 1.66 tcm, more than half of the total reserves proven during that period. Tight gas output is estimated at almost 20 bcm (13.1 bcm in 2008). Shell's Changbei field has been producing since 2007 and reached over 3 bcm in 2010. The Sulige gas field which started in 2007 should reach its plateau of 23 bcm/y in 2014. The South Sulige field developed by Total and CNPC is expected by 2013. Meanwhile, CBM has become a major focus, as recoverable resources are estimated at around 11 tcm (against 37 tcm of geological resources), mostly in the Ordos, Juggar, Qingshui basins. Commercial exploitation started in 2005 in the Qingshui basin. Around 6 bcm is already produced (mostly from coal mine extraction). In addition to coal producers such as the Shanxi Coal Group, active companies include CUCBM, PetroChina and Sinopec, while foreign investors (such as Far East Energy, Greka Energy, Sinop American Energy) have been engaged through partnerships with CUCBM whereas others (such as Chevron, Shell, Far East Energy, or Asian American Gas) are working with PetroChina. Shell may spend \$1 billion in shale gas development over the next five years, drilling 17 wells. Shell drilled its first well in the Sichuan basin in April 2011.

In early 2011, China decided to auction exploration rights for eight shale gas blocks, which was later than expected as the government decided to revise the conditions to include other Chinese companies such as Sinochem, Xinjiang Guanghui and Zhenhua in addition to PetroChina, Sinopec, and CNOOC. IOCs have been looking at shale gas's potential with great interest, but so far have not been allowed to participate in that round. They are therefore trying to circumvent this obstacle through partnerships with Chinese companies: Shell and Statoil are working with PetroChina; Hess with Sinochem; and BP with Sinopec.

India: First Steps in CBM Development

India is promoting unconventional gas potential with a fifth CBM licensing round and a shale gas licensing round scheduled for 2012. Despite several licensing rounds, CBM production started only in 2007 in India and is still negligible (<1 bcm), but is expected to increase to 2 bcm to 3 bcm by 2014. The last CBM licensing round has attracted more interest than the one for conventional gas. Still, India is having a hard time getting over obstacles to increase domestic production. The doubling of administrative price mechanisms (APM) in mid-2010 is a step in the right direction. Government interference on pricing and allocation, the omnipresence of incumbents and insufficient transport infrastructure still need to be tackled, while a proper regulatory framework for shale gas needs to be put in place. So far India has failed to attract many IOCs to its upstream sector: companies such as Essar Oil, Dart Energy and Great Eastern Energy are active in CBM, while the NOCs such as ONGC and OIL, as well as the private player RIL, are looking at shale gas prospects.

Indonesia: Can Unconventional Gas Reverse the Trend?

Indonesia hopes that its large CBM resources (estimated at 12.8 tcm) will compensate for the dwindling conventional gas output. CBM resources are located in the South Sumatra and Kutai basins. Over 20 CBM PSC have been signed as of end-2010 and the government is organising new tenders. Four CBM blocks were awarded in early 2011 to BP and Total, and the government plans to award a total of ten in 2011. IOCs such as Total, ExxonMobil or BP are now present in the CBM race. CBM could potentially be exported through the Bontang LNG plant, thereby solving the issue of dwindling production feeding the terminal. Indonesia should start producing CBM mid-2011. Initial production will come from the West Sangatta in the East Kalimantan province; initial output will be around 0.4 bcm, but CBM is expected to reach 5 bcm by 2020. Development of shale gas is clearly lagging, with rules being developed and contracts expected to be signed in 2012 at the earliest.

Europe: Solving Environmental Issues is Crucial

In Europe, exploration and drilling has started, focussing primarily on shale gas (unlike Asia). The leading country is Poland, but activities are under way in Germany and the United Kingdom. However, shale gas activities in France have been stopped, even before drilling started, due to local opposition. No significant production is expected in Europe before 2020 due to public opposition, as well as environmental and regulatory issues. Gaining access to land could prove more difficult due to worries about the need for large volumes of water.

Poland has attracted a lot of interest, with as many as 86 concessions granted for exploration of unconventional gas and five exploratory wells completed as of mid-2011. Another 15 are to follow in 2011. The focus is on shale gas resources estimated to range between 1.4 tcm and 5.3 tcm, while some tight gas prospects are also being developed. Curiously, despite Poland's coal resources, CBM seems less attractive. Major international oil and gas companies such as ExxonMobil, ConocoPhillips, along with smaller players such as 3Legs Resources and Polish companies (PGNiG) are active in shale gas exploration.

France has been looking at both shale gas and CBM, but now the future of shale gas is compromised by the recent ban on shale gas decided in May 2011. There had been previously, however, quite a lot

of activity, even before the EIA's estimates of 5 tcm of shale gas were published. The three shale gas exploration permits in southern France (Drôme and Hérault) for up to five years given by the ministry to Total and Schuepbach Energy are likely to be withdrawn. Small players such as Egdon Resources, Schuepbach Energy LLC, Bridgeoil Ltd. and Diamoco Energy had been actively looking for unconventional gas. Small companies such as European Gas Ltd. had been active for several years, particularly in CBM. In 2006 and 2008, drilling took place in Lorraine, but without any significant results. European Gas started producing small amounts of CBM from Gazonor in the last quarter of 2009; volumes reached 30 mcm by end-2010.

In the United Kingdom, shale gas and CBM could add 50% to remaining recoverable conventional gas resources. While some information on coal seams is available, there is an important need for data on shale gas. Several companies are exploring CBM including Centrica, Composite Energy, Igas Energy and Green Energy; so far, only Cuadrilla is exploring for shale gas. Shale gas resources are thought to be harder to exploit as basins are more fragmented. Although CBM is ahead, significant production is not expected before 2015. Licenses to exploit are provided by the Crown, which owns the mineral rights. Although the Supreme Court ruled that a producer could get the right to perform horizontal drilling underneath the land of neighbouring landowners, there are doubts about how this could work in practice.

Unconventional gas E&P has been very modest in Germany, which may be the sleeping giant with CBM, shale gas and tight gas resources. North-Rhine Westphalia awarded 10 exploration licenses to ExxonMobil and other companies in November 2010. ExxonMobil is active in both shale gas and CBM, while Shell and Realm Energy are looking for shale gas. Wintershall has been active on the tight gas development of Leer, Lower Saxony, since 2007. However, local opposition is also mounting against shale gas exploration, so that North Rhine-Westphalia has imposed a moratorium on new shale gas drilling.

In Hungary, companies such as MOL, ExxonMobil and Falcon are involved in unconventional gas exploration, for example in the Makó Trough and the Békés Basin. However, most activities are at a very preliminary stage.

Middle East and Africa

Unconventional gas seems to have taken a back seat in the Middle East and Africa due to the region's plentiful reserves of conventional gas. This may actually be a misleading image as the region may have important resources in terms of tight and shale gas, albeit well below conventional gas resources. These are sometimes located in countries actually facing gas shortages when gas production is non-existent. Tight gas potential is particularly high in these regions, especially in Saudi Arabia, Oman, Jordan, Algeria and Tunisia, where the development of such fields will very much depend on each country's conventional sources and needs for additional resources to meet fuel demand.

Despite some issues on prices, Oman is probably the most advanced, with BP taking the lead on the Khazzan and Makarem fields; the company is also active in developing Jordan's Risha field. In North Africa, the bulk of tight gas is coming from Algeria; more recently some exploration took place in

Morocco and Tunisia as well. Low regulated prices will be an issue, as production costs are likely to be above regulated prices, which are often below \$2/MBtu. Shale gas could play an important role in Africa, as technically recoverable resources amount to 30 tcm according to the EIA's study (300 times current demand). Three countries have a particularly high potential – South Africa, Algeria and Libya. South Africa is taking its first steps in shale gas, led by Shell, Falcon Oil, Sasol with Statoil and Chesapeake, but the regulatory framework is not in place and worries about use and contamination of groundwater resulted in a moratorium (enforced in April 2011) on gas drilling in the Karoo basin.

Latin America

There is already some limited tight gas production in Latin America with fields such as Aguada Pichana in Argentina or Yucal Placer in Venezuela. In the medium term, all activity is centred around Argentina, which has the most promising potential with its Neuquen basin, while Colombia could emerge as a producer through its CBM and shale gas resources. The EIA estimated shale gas resources at 19 tcm, ranking Argentina at the third place in terms of resources, while the federal Energy Secretariat estimated Neuquen's resources at 7 tcm, highlighting again the uncertainties about such resources. So far, Argentina has been focussing more on tight than shale gas, but the government is keen to develop any unconventional resources to reverse the current declining production trend (-10% over 2004-09). It launched the Gas Plus programme, which allows companies to charge \$4.50/MBtu to \$7.50/MBtu for such resources (compared to a set wellhead price of \$2.50/MBtu), although it remains to be seen whether such prices would effectively cover production costs. This, combined with three recent licensing rounds, has nevertheless attracted companies that have invested \$250 million in E&P so far. Repsol's subsidiary YPF, Total, Exxon Mobil and Petrobras are active in tight gas developments and YPF announced in December 2010 a 127 bcm tight gas discovery in Patagonia. Meanwhile, Repsol drilled its first shale gas well, while Total acquired stakes in four shale gas blocks in partnership with YPF. Tight gas and shale gas production could triple to around 3 bcm compared to less than 1 bcm in 2009.

Other countries in Latin America could hold unconventional gas resources, but are just taking first steps towards exploration. Colombia, a large coal producer, is believed to have substantial CBM resources in the Guajira and Cesar basins as well, as shale gas potential. The National Planning Department (El Departamento Nacional de Planeación) has appointed a consultant to prepare the regulatory framework and technical regulation. Drummond has CBM licenses and Nexen a shale gas contract. However, authorities fear a potential conflict between coal and CBM resources. Another issue for Colombia is the lack of pipeline transport capacity and relatively low price (\$4/Mbtu at Bogota's city gate). UK Maple Energy is looking for shale gas in Peru's Ucayali basin. Brazil has also potential for unconventional oil and gas, since resources of shale gas are estimated at over 6 tcm according to the EIA's study. But it is likely that they will not focus on it before the development of pre-salt resources.

PRICES AND TRADING DEVELOPMENT

Summary

- **In 2010, regional gas market prices drifted further apart. Moreover, regional price developments showed very different patterns compared to 2009, including the end of the divergence between low gas spot prices on both sides of the Atlantic and oil-linked gas prices in Continental Europe and OECD Pacific.** European gas prices converged in 2010, well below Asian oil-linked gas prices, while US gas prices remained at about half of those in Europe. This divergence reflected abundant supplies in North America, still-dominant oil indexation in Europe and Asia, and tightening of the global gas markets, coupled with increased competition between coal- and gas-fired plants.
- **Delinking gas prices from oil prices in long-term contracts remains a topical issue, illustrated by the number of long-term contract renegotiations in Europe.** However, as markets tighten due to increasing demand in Asia, much uncertainty remains as to whether full spot indexation would actually lead to lower prices.
- **Market prices nevertheless represent just over half of the world's wholesale gas prices, as more than one-third is still regulated.** As global inter- and intra-regional trade increases, more countries will be exposed to market prices as they turn to imports to cover their increasing demand.
- **Trading in Continental Europe is increasing strongly — particularly in Germany and the Netherlands — although liquidity is still much lower than in the UK market.** Most of the trading is still concentrated in Western Europe. The question remains whether one of the Continental European prices could provide an alternative marker to the National Balancing Point (NBP) in long-term contracts, should companies agree to have increased spot indexation.

Gas prices: The Key Parameters

Looking at prices, one tends to see only the tip of the iceberg: that is, at market prices in Europe, North America and OECD Pacific. These three regions actually represent only half of global gas consumption and therefore half of the currently existing pricing mechanisms. Price mechanisms in the gas trade on a wholesale level (hub prices, border prices, city-gate) range from the well-known – and currently highly debated – oil indexation present mostly in long-term supply contracts, to gas-to-gas competition-based prices (spot prices). In addition, they also include less well-reported and commented on mechanisms such as bilateral monopoly, in which prices are agreed upon in bilateral agreements between countries, or price regulation. Regulated prices can be below costs, indicating subsidies, set at cost of service, or be determined politically, reflecting perceived public needs.

Price levels vary widely, with large spreads between them, including within the different categories. Oil-linked gas prices depend on both the oil price (or in some cases on the price of oil products such as fuel oil and gasoil) and the pass-through factor in the formula of the long-term contract that determines the slope on which the gas price responds to the oil price. In March 2011, the highest oil-indexed gas prices could be found in OECD Asia, with \$12.7/MBtu, compared to around \$10.1/MBtu for European oil-indexed gas. Spot-price levels were between \$4/Mtbu in the United States and \$9.8/MBtu in Continental Europe. While the current high oil prices exacerbate the spread between

the different prices, the relationship between the different mechanisms has varied greatly over time; for example, between 2003 and 2006, the US Henry Hub (HH) price was higher than the European oil-linked price.

Regulated wholesale prices tend to be lower than the prices based on other mechanisms discussed above, sometimes even below \$1/MBtu. They often reflect gas consumed in the country where it is produced, for example, in the Middle East and Africa. Low regulated gas prices are increasingly an issue in regions where new fields are or will be more expensive to develop (see chapter on investments in major producing regions), deterring investments. Prices based on a bilateral monopoly are mostly found in the Former Soviet Union (FSU) States. These prices have increased dramatically lately, while some countries, such as Ukraine, have moved to oil-indexed mechanisms.

In 2010, global demand was around 3,300 bcm. Over one-third of total world volumes is estimated to be sold at regulated prices, largely in the Middle East, Africa, some Latin American countries and in many Asian countries, including China and India. Another one-third is priced on the basis of gas-to-gas competition, mainly in North America and the United Kingdom. At least 25% of the gas in Continental Europe and most of the LNG imported into Latin America are also priced on the basis of gas-to-gas competition. Only one-fifth of global gas prices is actually linked to oil, through oil indexation, mostly in OECD Asia, Europe, Brazil (production) and imports in some Asian countries. The oil indexation mechanisms have recently come under attack from buyers, due to the wide gap between oil indexed and gas-to-gas indexed prices, even though, in Europe, this spread has largely collapsed during 2010 (see figure below). Only a small share of global prices is based on bilateral monopoly.

Looking forward, volumes based on oil indexation and gas-to-gas competition are expected to increase as more countries become more and more import dependent. New resources are unlikely to be cheap to develop and transport to markets (see chapter on investments in LNG). How gas is priced has a significant impact on investments along the whole gas value chain, from upstream, to transport capacity and the demand in different sectors (see chapter on power). Rapid changes in demand and supply fundamentals have led to sharp changes in price levels and in the relationships between regional prices. Looking ahead, there are four crucial questions for all stakeholders, including producers, energy companies, end-users or governments:

- How will the price relation between regions evolve?
- How will gas prices evolve relative to oil prices? There are already large regional disparities between North America, where this linkage seems to be broken, Europe, where it has strongly weakened and Asia, where the linkage is still strong. A persistent disconnection between gas and oil prices could open up opportunities for gas in the transport sector.
- How will gas prices evolve relative to coal prices (including carbon in certain regions)? This is a crucial determinant for gas market share in the power sector.
- And finally, what will be the absolute level of gas prices in different regions?

A discussion about future price formation cannot take place without taking into account recent gas price developments. In the following sections, the evolution of gas price is analysed, looking

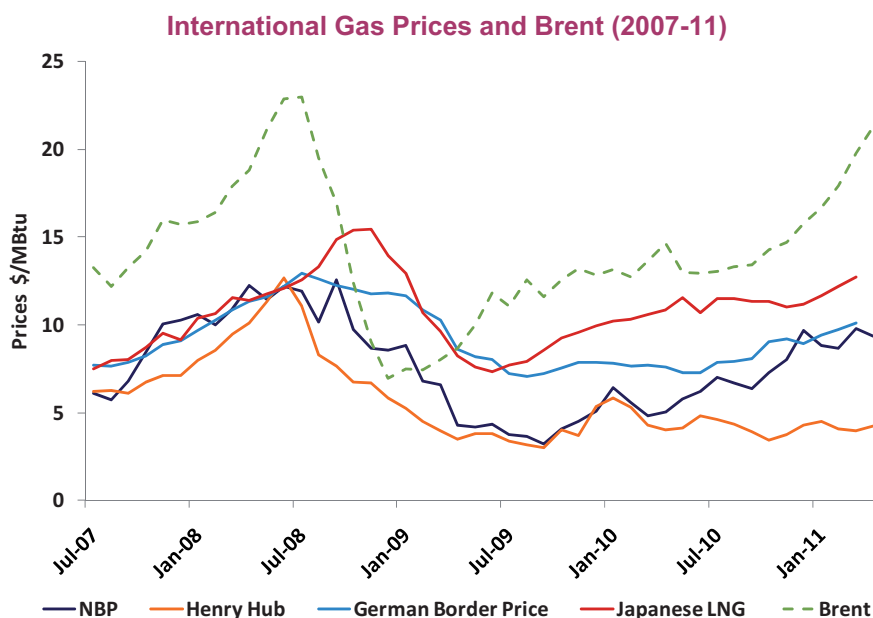
specifically at the relationship between regions, the linkage to oil prices and the evolution of gas prices relative to coal prices.

Gas Price Development: Looking Back

The last three years can be viewed as three distinct stages. The first stage ran from mid-2007 until mid-2008, a period in which gas market prices, along with other fuel prices, were increasing and where regional prices increasingly converged, reflecting tightening gas markets.

In the second stage – which ran up to April 2010 – all regional gas prices decreased strongly in the second half of 2008 up to mid-2009. This trend was visible in all three large gas trading regions, albeit with some key differences. In the fourth quarter of 2009 gas prices started to increase again both in the European and the US spot markets, for a large part driven by the cold winter of 2009-10. Prices in the OECD Asian market started an upward movement earlier that year, strongly following the oil price development with often a three-month time lag. Asia had been paying a significant mark-up on LNG imports compared to both the US and the UK markets, due to the continued use of oil indexation in their long-term contracts.

The second stage also is the period in which a wide gap opened up between spot prices and oil-indexed prices, reflecting the strong drop in gas demand and robust growth in supply (both LNG and unconventional gas). The gap put pressure on the existing long-term European contract prices. The German border price, reported by the German Ministry of Economy (BMWi) was, until 2009, recognised as the best representative of oil-linked contract prices in Northwest Europe. But from mid-2009, it failed to follow increasing oil prices and diverged from the Japanese price, reflecting a higher inflow of spot gas into the German market and the renegotiation of long-term contracts.



Data sources: ICE, German Ministry of Economy and Japanese customs.

The third stage started in the second quarter of 2010 when HH and NBP spot prices started to diverge. NBP prices increased rapidly towards the German Border Price level. This price rise was, initially, all the more unexpected as markets were to be oversupplied by new LNG volumes (see chapter on market trends in the LNG business) and the increase happened during late spring/summer, when UK gas demand usually is low. Still, NBP prices in summer 2010 were, on average, 70% higher than in the same period of 2009. The supply/demand balances were changing dramatically: in 2010, the United Kingdom saw imports increasing by one-third to 54 bcm, and depended increasingly on LNG and Norwegian gas. In late spring 2010, Norway experienced some production problems, while Qatar was undergoing heavy maintenance of its plants during summer, pushing up NBP prices. Secondly, the United Kingdom had, in this period, effectively become a transit country for LNG and Norwegian gas (net Interconnector flows to the Continent were 7 bcm in 2010), making the UK market dependent on Continental prices.²⁰ During summer 2010, net Interconnector flows were at 74% of maximum capacity over May-August 2010, more than twice as high as the same period in 2009. Lastly, the NBP price increase was also caused by a tightening of the global gas market due to the strong growth in LNG demand in Asia, slow industrial recovery in Europe and by a switching from coal to gas in the European power sector. The NBP monthly average day-ahead price in April 2011 was 85% higher than in the same month of 2010, and more than twice as high as HH. As of June 2011, European gas prices are back to the level of October 2008.

Within Europe, spot prices remained very closely connected, with Continental prices following NBP. In 2010, prices at the Dutch spot market TTF were on average \$0.08/MBtu higher than Zeebrugge. The difference between the German hub NCG and TTF was on average only \$0.06/MBtu with NCG on average slightly higher. These small differences were caused by transport constraints for gas flowing from Belgium and the United Kingdom into the Netherlands and Germany.

The cold weather at the beginning of winter 2010/11 led NBP spot prices to increase above the German Border Price for the first time in more than two years. The monthly average NBP price of December 2010 was \$0.7/MBtu higher than the German border price. This convergence of the two prices had two main drivers. First, a higher spot price, which was partly caused by the extremely cold weather of end-2010, but also showed a tightening of the global gas markets. The second was the above-mentioned increased spot indexation reflected in the German Border Price. The German border price had also been rising during 2010, due to the higher oil prices (Brent increased from \$11/MBtu mid-2009 to \$16/MBtu end-2010). It seems the advantage of spot indexation has worn off dramatically compared to mid-2009.

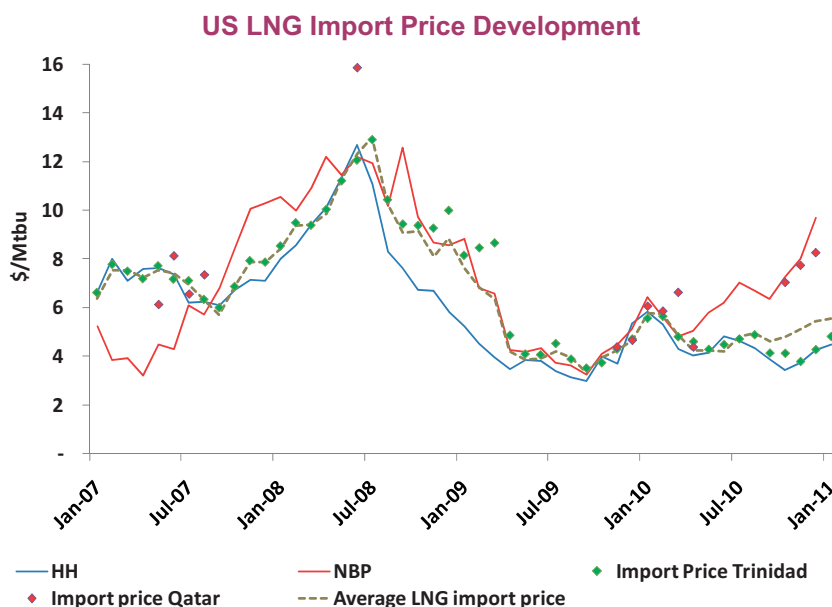
HH prices have not followed the upward trend in the European and Asian prices. The US prices actually showed a declining trend in 2010, even though US natural gas demand increased by 6% during 2010, as domestic production increased as well. The January 2011 price was 23% lower than the January 2010 price. The divergence between the US and UK market increased strongly during 2010 to an unprecedented price difference of \$5.8/MBtu in March 2011. Meanwhile, the spread between the Asian LNG price and the HH increased further during 2010. In March 2011, it was above \$8/MBtu, giving a spread between the Asian LNG price and the UK NBP price of more than \$3/MBtu.

²⁰ Since October 2010 it has been possible for shippers to nominate gas flows from the United Kingdom to the Netherlands. This is not a physical gas flow, more an administrative one, deducting the capacity booked from the physical gas flow from the Netherlands to the United Kingdom.

Divergence: US Market is Moving Away

While the European and Asian markets have faced rising natural gas prices in the past year, in the United States gas prices have declined further. An unprecedented spread emerged between HH and NBP, increasing to an average \$4.7/MBtu in Winter 2010/11 and reaching \$5.8/MBtu in March 2011. The 2010 *Medium-Term Oil and Gas Markets Report (MTOGM)* discussed how LNG arbitrage created a convergence between the two markets; the question now is what happened to end this convergence? As the link between the different markets was and remains LNG, this analysis has to include the evolution of LNG import prices.

In 2007 the average US LNG import price was \$0.1/MBtu higher than the Henry Hub price; this difference increased to more than \$1/MBtu in 2008 as some LNG prices followed the higher priced NBP. Between 2007 and 2008, US LNG imports dropped more than 50%, from 22 bcm to 10 bcm. In mid-2009 the NBP and HH prices converged, the difference between the HH price and the US LNG import price decreased and LNG imports increased slightly, to around 13 bcm. This situation continued up to the beginning of 2010, but with the NBP and HH price diverging again, the US LNG import price moved significantly above the HH again.

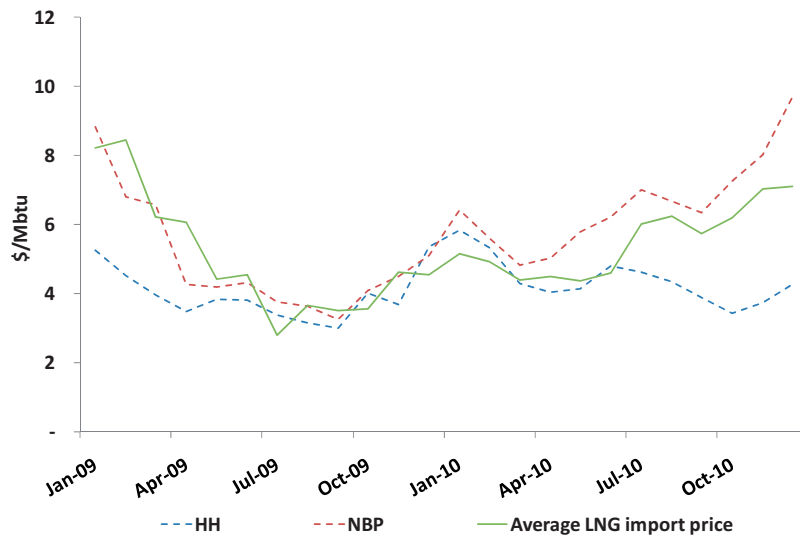


Source: ICE, EIA and IEA.

Looking at the different LNG import prices, several countries export their LNG to the United States at a price strongly linked to HH, such as Trinidad and Tobago and Egypt (together responsible for 60% of total US LNG imports). At the same time, for other countries, such as Qatar and Nigeria responsible for 21% of US LNG imports, prices are more linked to NBP. As a result, the average US LNG import price lies between the level of HH and NBP, depending on the import volumes from the respective sources. The delta between the LNG import price and the market price is an indication that the current US LNG imports, which in 2010 were 12 bcm, are at their minimum and that any cargos that could be rerouted have already been rerouted. The only LNG imported would be contracted LNG that

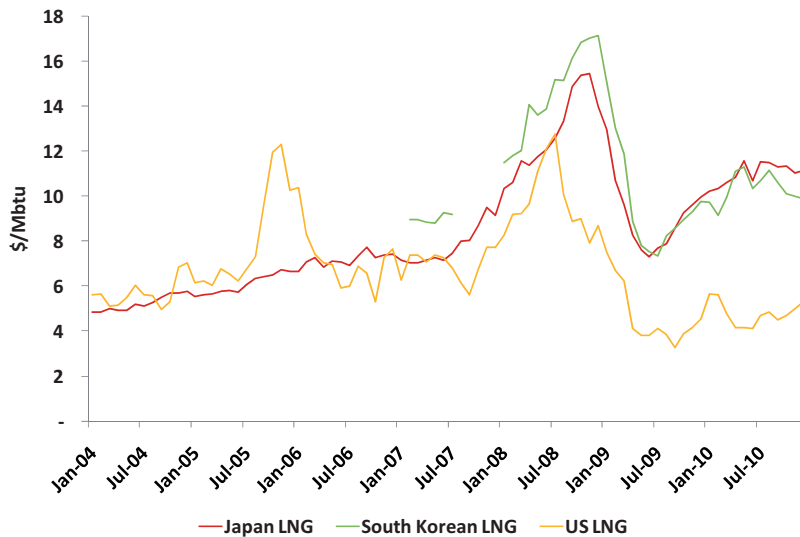
cannot be rerouted or LNG which is necessary to avoid shutting down existing terminals. LNG is no longer a price setter in the United States; and the US market has become almost immune from global price developments. Whether this price divergence remains in the future depends on both the sustainability of US unconventional production and the possible development of re-export capacity. Already 1 bcm was re-exported in 2010. A comparison of the UK LNG import price and the UK market price (NBP) shows that the LNG price in 2010 was significantly lower than the market price. A comparison of the import prices per country shows that the Qatari prices were relatively low, depressing the average price.

UK LNG Price Development



Source: IEA, ICE and UK Trade Info.

US and Asian LNG Import Prices



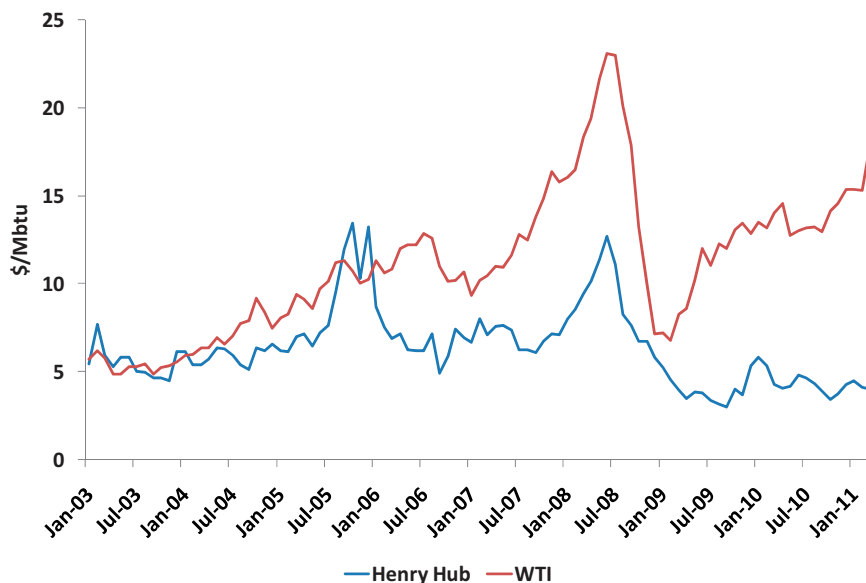
Source: IEA, Japanese customs and KITA.

The spread between US and Asian LNG prices was even wider. Only a few of Asia's traditional LNG suppliers (mostly the Middle East and Africa) can arbitrage between the two markets. As a result, Asian LNG import prices were almost three times higher than US import prices. A comparison of LNG prices within the Asian market shows a very similar development in the Japanese and South Korean LNG import price. Both were clearly linked to the oil prices, with a three-month time lag. Small differences occurred; up to the third quarter of 2009 South Korean LNG prices were often higher than Japanese prices. Since then, South Korean prices have been lower than the Japanese prices.

Testing Oil Linkage Across Regions

Currently about one-fifth of global gas prices is based on oil indexation, through the existence of oil linkage in long-term contracts, particularly in Europe and Asia-Pacific. In the past, even in the markets where oil and gas were not linked through contracts, oil and gas prices were still connected due to the physical possibilities to switch from oil to gas or vice versa. Switching is possible not only on the demand side, but also on the supply side. The large price gap between gas and oil could have either positive or negative effects on gas production. On one hand, it will lead to investments in production capacity to be switched to the product with the highest return, and also deter or postpone investments to produce gas that is reinjected to enhance oil production. However, high oil prices will encourage oil and NGLs production, and therefore the production of the gas associated with it, as revenues from oil and NGLs will largely compensate for the lower gas prices.

Henry Hub and WTI Price Development



Source: ICE and EIA.

In North America, oil and gas prices have been strongly linked together in the past. Although there have been periods of price decoupling due to extreme supply and demand situations, general price trends of gas and oil have been highly correlated. In the past decades, the physical connection between oil and gas on the demand side has eroded, as the share of oil in the markets where gas and

oil compete has strongly decreased. The market share of oil in the US power sector has fallen during the past decade to less than 1%. Since January 2009, gas and oil prices have moved away from each other, with natural gas trading significantly below the oil price. In April 2011, the price difference between HH and WTI reached an unprecedented \$14.7/MBtu.

There are currently no signals that the large price difference is leading to strong switching in any of the demand sectors, but on the supply side there are signs of switching from gas to oil. The number of exploratory and development wells drilled for gas has significantly decreased in the past two years, while the number of oil wells drilled has increased. Furthermore, shale gas producers have been moving towards liquid-rich shale plays. However, it must be added that increased drilling in these areas would also lead to increasing gas production. The long-term persistence of this price difference can lead to the creation of new markets where oil and gas compete, for example, in the transport sector.

In Europe, gas and oil prices were strongly interconnected, not only due to the physical switching possibilities, but also due to the use of oil indexation in long-term contracts. Just as in the US market, the possibilities for physical substitution have decreased; notably market share of oil in the power sector has dropped to 4%, down from more than 50% in the 1970's. At end-2008 a gap opened up between the European oil-linked contract prices and the European hub prices, which were significantly cheaper (up to \$6/MBtu difference). This spread created a call in Europe for contract forms more based on gas-to-gas pricing. As a result many large natural gas sellers altered their price formulas to include an amount of hub indexation. Gazprom has indicated that about 7% of its current European sales are spot-related, while it is estimated that Norwegian gas flowing into the Continent has about 15% spot indexation.

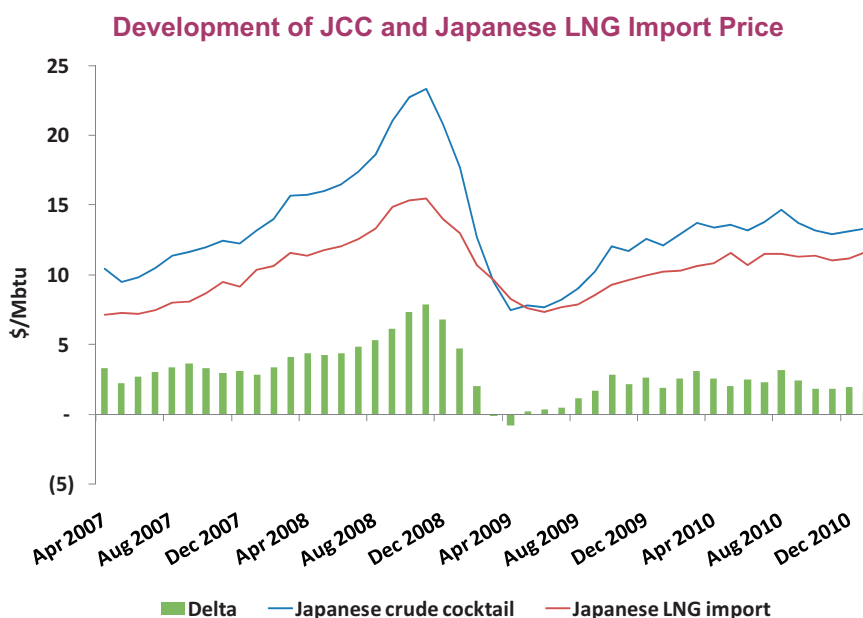
The German Border Price has since mid-2009 significantly decoupled from the Japanese oil-linked import prices. This decoupling has been caused by increasing amounts of spot price-based gas entering the German market, for example, volumes flowing from TTF or Zeebrugge onto the German market and by partial (but temporary) spot indexation in long-term contracts. Whether spot indexation is here to stay will very much depend on the development of the existing gap between spot prices and long-term contract prices and the future availability of cheap LNG in Europe.

In the traditional LNG importing countries such as Japan and South Korea, the gas price is still strongly linked to the oil price – Japanese Crude Cocktail (JCC), with a time lag of around three months – through long-term LNG import contracts. The oil indexation was the preference of both the sellers, who sought long-term financial security to cover the large investments needed to build LNG liquefaction capacity and of the buyers, who very much valued security of supply. A comparison of the development of the JCC (with a three-month time lag) and the Japanese LNG import price shows the very strong relation between the two.

In the first months of 2009 the LNG price followed the drop in the oil price, but bottomed out at a higher price level. Since then, the delta between the oil and the gas price has been significantly lower than before, although the correlation between the oil price and the gas price is still very high. This changed proportion between the two prices can be caused by a change in the contract, for example,

a higher P_0 or pass through factor; which changes the height or the steepness of the slope on which the gas price responds to the oil price.

Japan, Korea and Taiwan still depend largely on oil-indexed long-term contracts for their supplies. China has a variety of long-term contracts; some have a fixed price, but most are based on oil-indexation, although with different pass-through factors than the traditional contracts. With Chinese imports growing and Singapore, Thailand and other Asian Pacific countries becoming LNG importers, and with some contracts of the traditional LNG importers ending and needing to be replaced, a question arises: what will be the share and the price of spot cargoes (if any are available) compared to the contracted volumes?



Source: Japanese customs

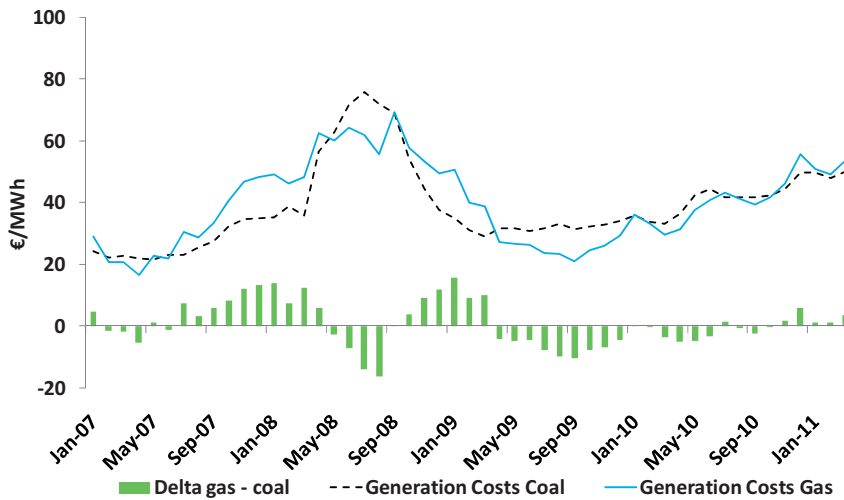
Coal Prices Impact on Gas

In the power sector, there is currently strong competition between coal and gas, especially in the European and US markets. Coal prices have therefore become an important price marker in both markets. Especially in the United States — but also in Europe — significant amounts of electricity production can be switched from coal-fired units to gas-fired units in reaction to the relative coal and gas prices (see chapter on power generation), leading to changes in demand. Of course there is no single switching point, as the efficiency, and thus the generation costs, vary per plant. Instead, there is a range within which different power plants switch at different relative price levels.

In the European market the generation costs of both coal- and gas-fired generation capacity is determined not only by the coal and gas prices, but also by the CO_2 price. In the figure below, the generation costs of coal are calculated assuming an efficiency of coal-fired generation of 36% and a CO_2 emission per MWh of electricity produced of 0.9 tons. The generation costs of natural gas are calculated assuming an efficiency of 50% and an emission of 0.4 tons per MWh. In 2009, generation

costs of gas were significantly below the costs of coal, leading to switching from coal to gas in the power sector. During 2010, the coal price seems to have acted as a ceiling for the gas price. Only at the end of 2010 did the gas price push through this ceiling, with gas becoming more expensive than coal in the power sector in reaction to the cold weather and a tightening of the gas market.

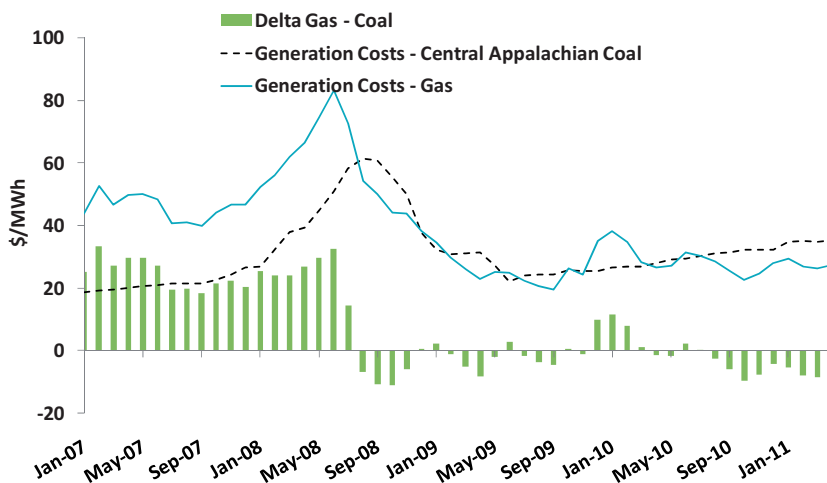
European Generation Costs of Coal and Gas



Source: IEA and McCloskey.

In the United States, CO₂ does not yet have a market price and thus does not have to be taken into account when calculating generation costs. In addition, coal prices differ strongly between regions; the figure below shows generation prices based on the Central Appalachia Coal price, which can be seen as representative of coal prices on the US East Coast. Transport costs of \$5/ton have been added to the price.

US Generation Costs of (Central Appalachian) Coal and Gas



Source: ICE and IEA.

In the United States until mid-2008, the generation costs of coal-fired capacity were significantly lower than those of gas. With the strong drop in gas prices in 2008 and 2009, gas has become strongly competitive with coal. Just as in Europe, this has led to significant switching from coal to gas in the power sector. Since the beginning of 2010 the costs of gas-fired generation have continuously been significantly lower than those of coal.

In the Asian market, coal-fired generation is still significantly cheaper than gas-fired generation due to the relatively high Asian gas import prices.

Development of Trading and Liquidity

In 2010, annual traded volumes on Continental hubs increased further by 43%, from 295 bcm in 2009 to a staggering 423 bcm. There are now seven Continental hubs for which data is reported: Zeebrugge in Belgium, TTF in the Netherlands, Points d'Echange de Gaz (PEG) in France, Punto di Scambio Virtuale (PSV) in Italy, NetConnect Germany (NCG) and Gaspool in Germany and the Central European Gas Hub (CEGH) in Austria. Traded volumes on these seven hubs increased by 43%, less than in 2009 and 2008, but the volume added was unprecedented.

Traded and Physical Volumes

Traded - bcm	NBP	Zeebrugge	TTF	PSV	PEG	GASPOOL	CEGH	NCG
2003	611.0	38.6	2.3	-	-	-	-	-
2004	551.9	41.1	6.2	1.1	0.3	0.0	-	-
2005	500.1	41.7	11.6	2.6	4.0	0.4	0.8	-
2006	615.2	45.1	19.1	7.1	7.0	1.2	8.9	0.2
2007	902.6	40.2	27.3	11.5	11.1	4.8	17.7	6.6
2008	960.8	45.4	60.2	15.6	16.5	9.7	14.9	25.3
2009	1,016.1	64.9	76.1	23.5	23.1	28.6	22.8	56.0
2010	1,236.9	65.2	106.5	43.1	27.8	62.1	34.1	84.1
Physical – bcm								
2003	52.5	10.2	1.3	0.1	-	-	-	-
2004	53.2	10.6	2.3	1.0	0.2	-	-	-
2005	53.7	8.4	3.8	2.0	2.7	0.3	0.7	-
2006	60.6	8.6	5.9	4.8	3.8	0.8	4.7	0.1
2007	66.8	7.9	7.4	6.8	5.1	2.2	6.9	4.1
2008	66.6	9.1	18.7	7.7	6.6	4.4	5.2	14.4
2009	74.6	12.9	25.0	11.0	8.1	12.9	7.6	25.0
2010	106.7	12.9	31.3	21.5	8.7	25.3	10.9	31.3

Sources: National Grid, Gas Transport Services, Huberator, GRTgaz, TIGF, CRE, Gashub, Gaspool, Aequamus, Net Connect Germany, SNAM Rete Gas

Physical volumes in Continental Europe increased as well, albeit less than traded volumes. The physical volumes that flow through the seven spot markets increased with 39% in 2010 to 142 bcm, compared to a 55% growth in 2009. Physical volumes of 140 bcm indicate that now more than one-quarter of gas volumes consumed in OECD Europe flows through one of these seven spot markets.

However, one must take into account that some of these volumes flows between spot markets and thus is counted twice.

The hub's traded and physical volumes are indications of the liquidity of the market but should not be seen as conclusive. In countries like the Netherlands and Germany, the spot market is a virtual point on the transportation network where the ownership of the gas changes; it is not the actual market exchange. In the Netherlands, the actual exchange is the APX ENDEX, while in Germany, gas is traded on the exchange on the European Energy Exchange (EEX). To assess the liquidity of the trade at the hub, it is important to look at more than just the flows.

Spot Market Liquidity

Traded and physical spot volumes are not the only indications of spot-market liquidity. Other indicators are the churn rate of the market, the time horizon for trading gas on an exchange the variety of the products sold on the exchange and the liquidity of individual products. To estimate the liquidity of individual products, the bid-offer spread of the product is usually considered.

The churn rate is calculated by dividing the traded volumes by the physical volumes. This shows how many times, on average, gas changes ownership on the market. The churn is an indication of a market's liquidity and trading depth; a churn rate of ten is often seen as the minimum benchmark for a market to be considered liquid. Established markets have relatively high churn rates. The churn rate of the HH is around 30, while the churn rate on the NBP, although it has decreased in the past years, is still almost 12. In comparison, the churn rates of the Continental markets are relatively low, although slowly increasing for many markets. The Zeebrugge hub is the Continental market with the highest churn rate; it has been stable at around 5 for several years. The churn rate of TTF increased again after two years of decline to 3.4. Other Continental markets have churn rates of between 2 and 3.

A second indicator of market liquidity is the time horizon over which gas can be traded on the exchange. A long trading horizon is important for the development of a spot market as it enables traders to hedge their future deliveries more in advance. Also important is the product variety. Comparing the variety of products sold and the time horizon over which gas can be traded, TTF is the Continental market with both the largest time horizon, with products being traded up to three years in advance, and the largest product variation. Products include monthly, quarterly, year, gas year and seasonal products. The product diversity and product horizon are significantly more limited at the Zeebrugge and NCG hubs; at both markets, products are traded only up to two years in advance.

A final indication of market liquidity is the bid-offer spread. Liquid markets are characterised by narrow bid/ask spreads. A comparison of the different Continental markets shows us that in all analysed markets (Zeebrugge, NCG and TTF) the bid-offer spread of short-term products (day ahead) is small, indicating a high liquidity. The spread on NCG and Zeebrugge significantly increases as the product is traded more in advance, indicating a limited liquidity of the future products. On TTF, the bid-offer spread also increases, but this increase is more limited.

Regulatory Stimulation

Regulators see a liquid hub as one of the important criteria for attaining a well functioning and competitive market and much is done to stimulate the flows through the hubs. In the past years, the German spot markets have seen the fastest increase in both traded volumes and physical volumes of all Continental hubs. The liquidity of the German hub markets has risen significantly since the introduction of the new balancing rules (GABi gas) and the further consolidation of the market areas. In October 2009, the five market areas of Gasunie Deutschland, ONTRAS, WINGAS transport, StatoilHydro Deutschland and DONG Energy Pipelines merged into one single market area called GASPOOL. Between September and October 2009, both physical and traded volumes on the GASPOOL hub increased by almost 250%. In the same month, the market area of NetConnect Germany was merged with the market area of ENI Gas Transport Deutschland, GRTgaz Deutschland and GSV Netz, boosting NCG market volumes by almost 50%.

In April 2011 the number of market areas in Germany further decreased from six to three. On April 1st the Open Grid Europe L-Gas, Thyssengas H-gas and Thyssengas L-gas were merged with the NetConnect Germany market area, making NetConnect Germany the largest market area in Germany and the first cross-quality market area in Germany.

A further increase in spot-market liquidity can be expected due to new regulation in other countries. In Austria the new Natural Gas Act, currently planned for October 2012, will transform the physical CEGH hub into a virtual trading point, which should further increase liquidity of this trading point. At a physical trading point volumes are limited by the transport capacity to and from the hub. By changing the hub into a virtual point, transport capacities will no longer be limiting for trade.

Italy hopes to increase spot-market liquidity by introducing a new, more market-based balancing system in which shippers now themselves become responsible for staying balanced; currently Snam Rete Gas balances the system. The new daily balancing system is planned to be launched in early July 2011. This should significantly increase the liquidity of the short-term trade, as shippers will have to buy or sell volumes to stay balanced. As a result of these market changes, the liquidity of the Continental trading hubs is likely to increase.

INVESTMENTS IN MAJOR PRODUCING REGIONS

Summary

- A fundamental asymmetry exists between the slow pace at which new production can be put in operation and the speed and extent at which demand can grow or rebound. As markets are not yet globalised, sufficient production at the global level does not prevent regional and national tightness if investments do not proceed in a timely manner. Nevertheless, investments in upstream are increasing, with an estimated 10% growth in both 2010 and 2011. The past two years have seen a wide bust-and-boom cycle: demand is estimated to have recovered by 7.4% in 2010 after a 2.5% drop the year before. This global picture hides wide regional disparities that will translate into different requirements in terms of new production. Besides the technical challenges of bringing some new fields online, greenfields also depend on new transport capacity (LNG or pipelines) to transport that gas to markets. The surge in unconventional gas production has also fundamentally affected regional production and export prospects.
- Russia has not entirely recovered from the year 2009: production rebounded but uncertainties persist in European demand, its main export market. Investments into new production are very advanced on the Yamal Peninsula, but none of the other big projects has made a decisive step towards FID. In the northwest, the technically challenging Shtokman is now competing against the equally challenging Yamal LNG, with both projects attracting the same foreign investors. Despite increased interest in greenfields in the Far East and Eastern Siberia, those fields will be even more challenging and costly to develop than the current projects.
- The Caspian region is endowed with significant gas resources and is well-positioned geographically to reach various markets, but production and transportation remain a challenge. Turkmenistan has managed to replace the much-diminished exports to and via Russia with sales to China and Iran. The outlook for further increases in exports is good but hinges on the next generation of fields, which will be more complex to develop. Azerbaijan is on the verge of unleashing its full gas export potential as talks on sales and transit progress, while also working to diversify its export routes.
- The Middle East and Africa offer a contrasted picture, with incremental production needed both to cover rising demand as to feed LNG or pipeline export projects. While still a net exporter, the Middle East region also imports gas by pipeline and, since 2009, by LNG. Only Qatar can comfortably meet both increasing domestic needs and export commitments. The picture is even more contrasted at the national level: domestic market obligations (DMOs) have emerged in a few countries to limit exports. Iran, the second-largest holder of proven gas reserves in the world, is a net importer and most of its LNG export projects are stalled. Oman is struggling to develop new tight gas fields to keep pace with its rising demand. Iraq – and more surprisingly, Israel and the East African coast – could emerge as gas exporters in the longer term.

Russia

Coming Out of the Crisis

Although a year has passed, the cracks below the surface remain open as challenges remain for future Russian production. In last year's *MTOGM*, we described 2009, the year when Russia's

production, consumption and exports plummeted, as an “*annus horribilis*”. In 2010, the Russian gas industry largely recovered from the deep depression but did not emerge entirely unscathed. Although total production bounced back 11.4% to 651 bcm in 2010, sales to Europe, a major export market and source of revenue, fell slightly. Although the reduction was negligible, from 148.3 bcm to 148.1 bcm, given the demand recovery in Europe in 2010, it means an eroded market share of Russian gas on the continent. The rise in Russia’s gas production in 2010 was driven mostly by domestic demand and exports to FSU countries. Gas consumption in Russia went up by an estimated 11% in 2010 on the back of a colder than average winter (January and December 2010 were the coldest in eight years) and an extremely hot summer which broke several historic temperature records. Such extreme weather resulted in higher demand for heating and for electricity demand, which grew by 4% in the European part of Russia; about half of electricity is generated from gas.

Exports to Europe and FSU, 2010 vs. 2009 (bcm)

Destination	2010	2009	Destination	2010	2009
Total Exports	218.3	205.0	Central Europe	44.5	38.5
Western Europe	103.6	109.8	FSU	70.2	56.7
<i>Germany</i>	35.3	33.5	<i>Ukraine</i>	36.6	26.8
<i>Italy</i>	13.1	19.1	<i>Belarus</i>	21.6	17.6
<i>Turkey</i>	18.0	20.0	<i>Kazakhstan</i>	7.7	7.9

Source: Gazprom’s 2010 databook.

This erosion of sales to Europe is largely due to the continued difference in prices between Russian oil-linked contracts and spot trading; Russian gas became significantly more expensive since the beginning of the crisis in late 2008.²¹ As a result, European buyers managed to negotiate a partial linkage to lower spot price components in contracts and a greater flexibility in contracted volumes, presumably with a view to making up the volumes in the coming years.²² The price gap started to narrow from the second quarter of 2010, and during the coldest days of winter 2010/11, Russian exports became cheaper than UK spot prices. At that time, Russian export gas prices were based on oil at \$70 to \$80/bbl, but they will increase in 2011, reflecting the recent higher oil prices. A positive note is the booming LNG exports from Sakhalin reaching plateau with 13 bcm exported. However, Exports to Japan seem to be cheaper than a pure oil linkage would suggest: the average Russian import price in 2010 was \$8.61/MBtu versus \$11/MBtu for all Japanese LNG imports.

In 2010, Gazprom renewed and renegotiated a few high profile export contracts. At the very end of the previous contract’s expiry date, Poland signed a new 12-year contract for the delivery of 10.3 bcm/y. In April 2010, Ukraine, trying to lower the import price set in January 2009, managed to get a 30% discount from Russia (with a ceiling of \$100/1,000 m³), while the take-or-pay volume increased slightly from the crisis level to 36.5 bcm. In exchange, the new deal extended the stay of the Russian fleet in Crimea. For Gazprom, the discount was offset by an exemption from export duty, but this still translates into lower revenues for Russia. In June 2010, a payment crisis with Belarus resulted in a partial cut-off of gas supplies. The debts were soon repaid, but Belarus did not get any further discount on the “European” price in the contract ending in December 2011.

²¹ Oxford Institute for Energy Studies, (2011), *The Transition to Hub-Based Gas Pricing in Continental Europe*.

²² According to Gazprom export, their contracts usually allow to make up volumes up to 5 years ahead.

At the Company Level: The Rise of the Independents

The sharp fall and subsequent recovery of demand in Europe and Russia during the period 2008-10 mainly affected the Yamal-Nenets autonomous region, where production decreased by 90 bcm in 2009, of which only 55 bcm was brought back in 2010. At a company level, Gazprom, the owner of the majority of assets in this region, came back from the lows of 462 bcm in 2009 to 509 bcm in 2010, still below the pre-crisis level of 548 bcm in 2007. Gazprom's revenues grew from RUB 2,991 billion in 2009 to RUB 3,597 billion in 2010 (\$94 billion to \$118 billion), driven by the recovery of domestic and FSU sales and by the delayed effect of the oil price rally since mid-2009 on export prices to Europe. With this increased cash flow and the signs of recovering demand domestically and abroad, investment in 2010 grew by 12%. However, investments in long-term transportation projects are declining naturally towards their completion and in 2011, with an expected decline of \$12 billion in investment in the ongoing projects.

In contrast to Gazprom, independent gas producers and oil companies further increased their output by 17%, reaching 140 bcm in 2010, following another production increase in the midst of the crisis in 2009. Unlike the previous years, the 20 bcm growth in 2010 is mainly attributed to smaller independents (9 bcm), followed by Novatek (5 bcm) and projects in Sakhalin (5 bcm). Oil companies had diverging gas production trends, *e.g.* Lukoil increased production in Yamal-Nenets in response to a higher uptake from Gazprom, while Rosneft's output fell (the company's largest gas field Hrampurovskoe is not connected to the Unified Gas Supply System (UGSS)). Among the lesser-known producers contributing to the growth in 2010 were Itera, whose main assets in Yamal-Nenets are operated by Sibneftegaz and Purgaz, which increased production by 6.4 bcm. However, in late 2010, 51% of Sibneftegaz was bought by Novatek. Itera is also active in gas distribution and benefitted from Russian industrial customers' recovery. Higher production in Sakhalin was driven by LNG exports from Sakhalin-II having reached full capacity in 2010.

Independents' Production 2010 vs. 2009 (in bcm)		
	2010	2009
Novatek	37.7	32.6
Lukoil	15.3	12.4
Surgutneftegaz	13.4	13.6
Itera	12.7	6.3
TNK-BP	11.6	11.1
Rosneft	11.4	13.2

Source: companies' websites.

Novatek, the second-largest gas producer in Russia after Gazprom, is still the main independent producer to watch in the Russian gas sector. It brought gas processing capacity of its main Yurkharovskoe Arctic field to 33 bcm of gas and 3 million tons of condensate in 2010 in the second phase of the field development. In 2010, the company's gas output went up from 32.6 bcm to reach 37.7 bcm, along with a 19% increase in condensate production. Novatek also started operating a methanol plant for its gas from the Yurkharovskoe field, which resulted in significant cost reductions. Potential further production increases in Yurkharovskoe are probably limited in the medium term, although gas processing and transport capacity is around 33 bcm.

The key obstacle for a substantial further production increase from non-state owned gas producers in Russia has been for years the lack of access to Gazprom's pipeline system. There seems to be mounting pressure on Gazprom to give third-party access to other companies. In late 2010, the Russian government published standards for third-party access to the UGSS which require Gazprom to disclose information on spare capacity and tariffs. In early 2011, Prime Minister Putin urged Gazprom to "address efficiently" the current lack of transportation capacity for non-state producers. Failure to do so would result in legislation changes regarding pipeline access. This was followed a month later by a statement by the Federal Antimonopoly Service that a government decree was being prepared. At the same time, some producers have managed to secure additional transportation capacity: TNK-BP is to increase its volumes from 3 bcm to 13 bcm over the next six years and Rosneft is to get unspecified extra access within three years.

The issue of pipeline access is intertwined with another government decree stipulating a 95% utilisation of associated gas to reduce flaring by 2012. Oil companies point out that they cannot meet the target without sufficient access to the UGSS. Gas flaring and the related issue of pipeline access have been a contentious issue for many years. According to the World Bank's estimates, in 2010 as much as 35.2 bcm was flared in Russia, comparable to Spain's total gas demand. The target of a 95% utilisation rate of associated gas has been put forward a few times and is now set for 2012. It is doubtful, as of early 2011, that it can be met on time. In 2010, 19 oil companies were fined for gas flaring; the fines being modest but set to increase significantly in 2011 if the target is not reached. Effective implementation will be critical to seeing an impact on gas flaring in Russia. Although action is being taken towards the implementation, monitoring flaring is difficult and full completion is likely to come after 2012: investments in associated gas utilisation (power stations, gas processing and transportation) are set to increase from RUB 50 billion (\$1.6 billion) in 2010 to RUB 82 billion (\$2.6 billion) in 2011. The above-mentioned anticipated decree on pipeline access will probably contribute significantly towards reducing gas flaring in the next five years.

Update on Energy Strategy 2030

The Energy Strategy 2030 issued in 2009 states that it does not aim to forecast energy balances and that its timeframe is not concrete as it depends on many external factors. Therefore we will not discuss the timeliness of its implementation but briefly go through relevant recent developments. In the gas part of the strategy, diversifying exports and developing Eastern Siberia/Far East were featured prominently, and there seems to be some progress on this front. One of the main projects in the region is the 30 bcm Sakhalin-Habarovsk-Vladivostok pipeline, which is set to be completed by the end of 2011. As of May 2011, the 1,350 km pipeline was over 90% complete. The capacity will be 6 bcm in a first stage. The project is central for the gasification of the Far East and to release the future use of gas resources of the Sakhalin-I project where large volumes of gas are currently reinjected. Apart from using this gas domestically, it also opens possibilities of building an LNG plant near Vladivostok or a pipeline to export to China.

Russia and China have been discussing exports to China for years, always falling short of finding an agreement on prices. This led China to turn to other suppliers – Turkmenistan, Myanmar and now Kazakhstan and Uzbekistan – so that the country is now in a stronger bargaining position *vis-à-vis* Gazprom. In September 2010, Gazprom and China's CNPC signed a detailed, legally binding

agreement “Extended Major Terms of Gas Supply from Russia to China” for gas deliveries. There are still ongoing negotiations on prices, which are expected to be completed in June 2011.²³ The agreement specifies an export starting date of 2015 for 30 years, with a plateau volume of 30 bcm/y. In the absence of a signed contract, this looks relatively optimistic. As the “eastern route” crossing the border with China east of Mongolia is conspicuously absent in the agreement, it is not clear what the prospects for exports to China from this route would be. On the one hand, the Russian government appears to be committed to bolstering the socio-economic development and population growth in the region. On the other hand, there seem to be extra resources available for exports in the mid term. The new gas strategy 2030 due to be released in late 2011 may clarify the matter; the Ministry of Energy passed the final draft to the government in late 2010.

Projects Update

The long-term Russian production prospects depend largely on the future development of super-giant fields, which have been under study for years. As a new decade starts, new fields are necessary to compensate for the decline in the current main producing area, Nadym Pur Taz in the south-east of the Yamal peninsula. In the last ten years, the production decline in the oldest giant fields Urengoy, Yamburg and Medvezhye has been partly offset by bringing to production other fields such as Zapolyarnoe (plateau production of 100 bcm/y) and Yuzhno-Russkoe (25 bcm/y), and by performing extra drilling at old fields. In recent years, there has been an increase in investment in production from deeper, wet and technologically more challenging deposits in Nadym Pur Taz.

To reach the Energy Strategy’s ambitious targets of 885 bcm to 940 bcm production by 2030, the development of new greenfields will be necessary. But market uncertainty has risen over the past years; while additional exports to Europe hinge on European policy decisions on the future role of gas versus renewables or nuclear, the North American market is fully satisfied and Russia missed a first window of opportunity in China. Developing new production assets also closely depends on the export solution being chosen, be it pipeline or LNG, as well as on the evolution of imports from the Caspian region. LNG projects have been attracting mounting interest over the past years and Gazprom sees its LNG exports based on Russian projects increasing from 29 bcm by 2020 to 60 bcm by 2030.²⁴ While Russian companies, including Gazprom, Novatek or Rosneft, remain the leaders in the mega projects, foreign companies are getting involved as partners bringing investments and in some cases expertise. Significant investment will be required not only to bring these new fields on stream but also to build and upgrade the transport system. Gazprom’s annual CAPEX over 2011-30 would be RUB 700-900 bn (\$23-30 bn), half of which is dedicated to Yamal (29%), Shtokman (14%) and the Far East and Eastern Siberia (8%).

Advancing Yamal

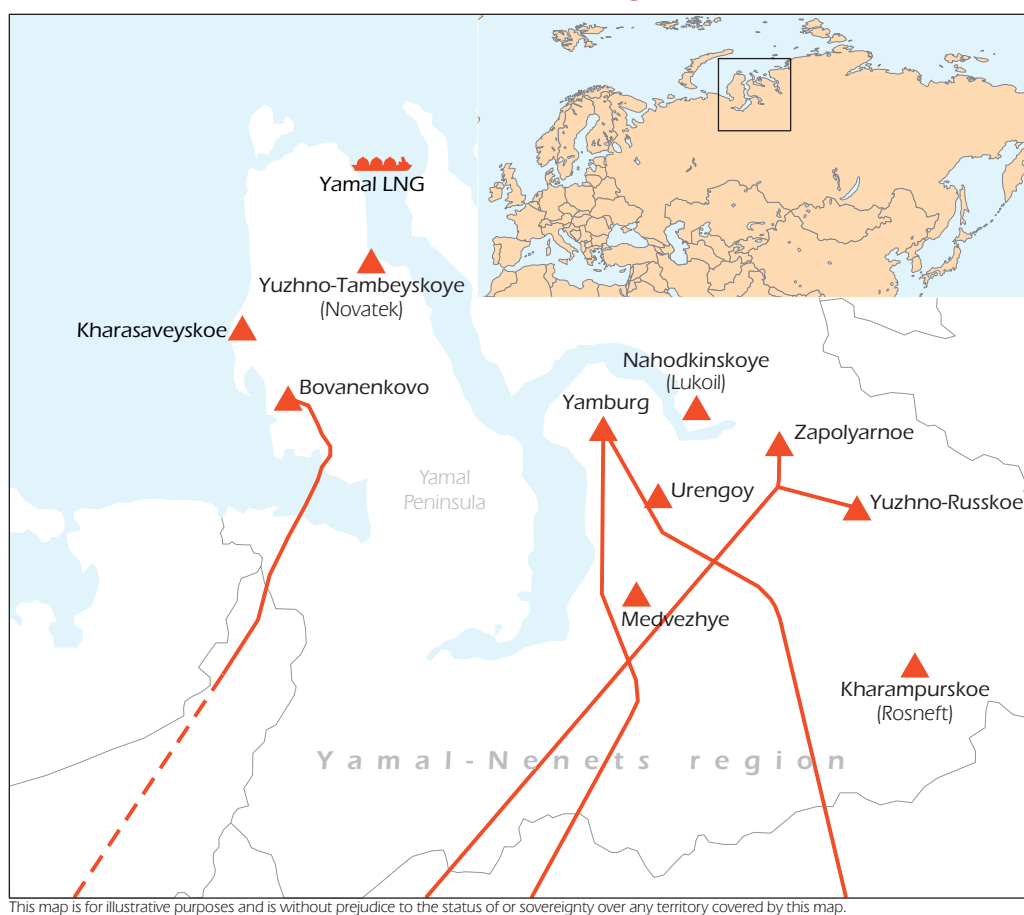
The Yamal Peninsula contains 11.7 tcm of reserves and could reach gas production levels of 350 bcm according to Gazprom, albeit the Energy Strategy sees Yamal production only reaching 185-220 bcm by 2030. The first stage of developing the Yamal Peninsula focuses on the Bovanenkovo and Kharasavey fields. Although work on Bovanenkovo slowed down significantly during the recession in 2009, efforts intensified during 2010, as demand showed signs of recovery, and bar any unexpected

²³ As of going to press, a new round of negotiations was about to get underway, and a deal may be concluded by the time this report is released.

²⁴ Gazprom’s Investor Day, February 2011.

difficulty, the project seems on track to start by end-2012. On the transmission side, the first line of the pipeline to connect the field to the UGSS, Bovanenkovo-Ukhta, is 60% complete as of February 2011, having earlier passed the challenging Baydaratskaya Bay. The Obskaya-Bovanenkovo railway line was completed in 2010, allowing for cheaper and uninterrupted delivery of cargo and personnel. It seems likely that the long-awaited production at Bovanenkovo could finally start in late 2012 and reach 55 bcm by 2016, in line with the full capacity of the first trunk of the pipeline. Gazprom's plans suggest higher production levels around 80 bcm by 2015 reaching 140 bcm by 2020, and requiring the second 55 bcm line to be completed. Kharasavey could start by 2014-15, and would reach production levels of 32 bcm.

The Yamal-Nenets Region



Mounting interest has been given to the northern fields of the Yamal Peninsula, especially the Yamal LNG project. The choice of the LNG option, rather than linking the field to the pipelines being built to Bovanenkovo, which would have to be expanded, reflects probably a desire from Novatek to have diversified export options, such as Asia, and avoid depending on Gazprom's transport system and on European export markets. Total acquired 12% of Novatek shares in early 2011, in line with a more general recent trend of stepping up activities in Russia, and is expected to become a 20% partner in Novatek's Yamal LNG project later in 2011. This challenging project beyond the Arctic circle, where

nuclear ice breakers are planned to assist LNG cargos, received a 12-year exemption from the mineral extraction tax. Statoil is also in discussions to join it. A front-end engineering and design (FEED) study for Yamal LNG is scheduled to be completed only in the first quarter of 2012. Production is unlikely to commence before 2018. However, the earthquake in Japan in March 2011 and resulting uncertainty about the future of nuclear power globally, might add incentive for the project to move forward without further delay. The project's CAPEX is estimated at \$23 billion including a 300 km pipeline but excluding construction of LNG carriers.

Could Shtokman Start before the End of the Decade?

The very same two foreign companies, Total and Statoil, might become the main partners in both LNG projects, Yamal and Shtokman, if Statoil joins Yamal LNG. Shtokman's project equity is split as follows: Gazprom (51%), Total (25%), and Statoil (24%). Although the FEED study for the LNG part of Shtokman has started and is expected by the end of 2011, the project is not yet exempt from the extraction tax (although export duty does not apply to LNG sales). Both the pipeline and the LNG parts of the project are expected to be decided upon at the same time later in 2011. Project sponsors have chosen a "two-phase" technological concept, which is more expensive but more environmentally sound. This technical solution involves two pipes to shore, to avoid long transport by LNG cargo through the Barents Sea, as is the case for Yamal LNG, and also avoids storage of condensate in harsh conditions. Pipeline deliveries would start in 2016 and LNG production in 2017. Particular dates at this stage are probably less relevant; the future of the project will probably be decided by the outcome of FEED on the two-phase concept and the subsequent government's reaction to it (political support and tax breaks). Due to the uniquely difficult conditions, risks of slippage exist.

The Eastern Challenge: East Siberia and Far East

In 2007, Gazprom was appointed as coordinator of the "Eastern Gas Program" in order to develop production, transmission, gas processing and chemical industries in East Siberia and the Far East ("the East of Russia"). The energy strategy in the region is also linked to a wider socio-economic programme for the area. The programme plans to use largely untapped vast resources in the region for both domestic use and export to Asia. The strategy envisages the creation of several production centres connected to one system, similar to the UGSS in the European part: the centres would be in Sakhalin, Yakutia (Chayanda field), the Irkutsk region (Kovykta field) and the Krasnoyarsk region.

Russia's resolve to expand east is not new; the previous energy strategy 2020 issued in 2003 envisaged production reaching 50 bcm in the East of Russia by 2010. In 2010, gross production was only 33 bcm, with about 8 bcm reinjected. Most gas production came from Sakhalin. Delays in the development of the programme are related to the remoteness of some fields and lack of infrastructure, as well as issues around high concentration of helium and NGLs in the eastern fields: Kovykta and Chayanda contain 70% of Russia's helium resources and the geology is not suited for reinjection and conservation of this valuable product. Thus the strategy involves the development of gas processing and chemical industries in parallel to production, which requires more investment and is more challenging logistically. Among the options considered is the delivery of helium together with gas to Khabarovsk or Vladivostok. Liquefaction in Vladivostok could make helium separation cheaper, but plants for further processing are optimally placed in Khabarovsk. Judging from the successfully

progressing mega-project of the East Siberia-Pacific Ocean oil pipeline, ambitious gas projects in the East can be carried out once a decision to go forward has been made. There are also plans to construct a gas pipeline from Chayanda, the Yakutia-Khabarovsk-Vladivostok pipeline, which could use part of the infrastructure of the oil pipeline. The Kovykta field was actually acquired by Gazprom in early 2011. One of the implications of the deal is avoiding higher pressure on the government to remove Gazprom's export monopoly if the other bidder for the field, Rosneftgaz, had won the auction. Now Gazprom has significantly increased its resource base for potential exports, which probably increases the likelihood of striking a deal with China.

The development of Sakhalin-III has been speeded up to start production in 2011 rather than 2014, as previously planned. Extraction will start with the Kirinskoye offshore field, owned by Gazprom, using underwater production units and is going to feed the 1,800 km Sakhalin-Khabarovsk-Vladivostok pipeline (92% completed as of mid 2011). Production from the Kirinskoye field (100 bcm proven reserves) is not sufficient to fill the pipeline to full capacity; the three blocks in Sakhalin-III contain much more gas (1.4 tcm). One bloc is owned by Rosneft and Sinopec, and the others by Gazprom, but the company will probably find it challenging to develop them on its own at this stage. The significance of the pipeline project probably goes beyond pure economics as the final 30 bcm capacity far exceeds future domestic demand and liquefaction at the proposed Vladivostok LNG plant after 1,800 km of transportation is not cost efficient. Another factor putting pressure on timing of the project is the need for quick gasification of the Vladivostok area in time for the Asia-Pacific Economic Cooperation (APEC) Summit in September 2012. This LNG liquefaction plant could give Russia the possibility of increasing LNG exports to Japan following the earthquake in March 2011.

Limited Prospects from the Caspian Shelf and the “Caspian Lowland”

Russia's energy strategy 2030 mentions the “Near-Caspian” region separately from other producing areas; it includes an onshore plain between the north Caucasus and Kazakhstan and the shallow north Caspian shelf. The strategy specifies gas production in the area to go from zero to 8-20 bcm by the middle of the decade, reaching 22 bcm even in the longer term. However, production prospects appear very limited in the medium term, as the onshore Astrahan field has high sulphur content requiring gas processing. Shell has not advanced the development of the deep fields in Kalmykia. Recent legislative changes regarding the Caspian Shelf have reduced the number of companies meeting the requirements to Gazprom and Rosneft. Overall, it seems only possible to extract 2.2 bcm from Lukoil's Korchagin and Filanovsky fields.

Turkmenistan: At the Gas Exporting Crossroads

Turkmenistan's proven reserves are estimated at 7.9 tcm and ultimately recoverable resources at 14.2 tcm, boosted by the recently discovered South Yolotan field in the southeast of the country. Production levels had been rising steadily since the late 1990s until 2009, when the explosion of the main exporting pipeline to Russia resulted in the reduction of output from 71 bcm to 39 bcm in 2009 as exports to Russia plummeted to 10 bcm versus previous levels of 40-50 bcm. After the pipeline was repaired and exports to Russia partially resumed in 2010, production recovered to an estimated 47 bcm in 2010. Turkmenistan's official target is to produce 230 bcm of gas by 2030. Although the resource base could conceivably support such a level of output, it is far from clear whether investment will be forthcoming to bring Turkmenistan close to this level. The country's current policy

is that international companies are welcome to invest in offshore production, but their role onshore should be limited to providing assistance to the state-owned company Turkmengaz. This reduced access could hamper development of the next generation of Turkmenistan's fields which will be more complex, expensive and technically challenging to develop. The main exception to this policy is China's CNPC, whose production area in eastern Turkmenistan is expected to provide up to 15 bcm/y for the Turkmenistan-China pipeline. There is some uncertainty regarding sufficient investment and technology availability to develop the country's vast gas resources.

The traditional export direction to Russia (with re-export further on to Europe) has been reoriented towards China. Russia has pulled out of pipeline projects in Turkmenistan which could have increased export capacity northwards on top of the pre-explosion levels. Additionally, Russia is unlikely to resume imports at the previous level of up to 50 bcm, given the high price of Turkmen gas compared to what it was before, its own export uncertainties and projects such as Yamal moving forward (see section on Russia). In contrast, China is set to become Turkmenistan's main export market by 2015, as it not only presents a growing gas market, but also loans to develop resources. As a result, the targeted level of Turkmenistan exports to China has consistently increased, from an initial 30 bcm in 2007, to 40 bcm the following year. In 2011, export levels of 60 bcm were announced. It is doubtful that Turkmenistan could reach such a target in the medium term without depriving other export routes or drastically increasing production, so this export level seems more a longer term objective. This is probably what drove China to give a \$4.1 bn loan in early 2011 to develop the South Yolotan. Exports to China reached around 4 bcm in 2010, but are expected to swiftly ramp up in the coming years as the Central Asia Gas Pipeline is expanded. Exports to Iran have grown to 14 bcm in 2010 and could potentially go up to 20 bcm now that another 12 bcm pipeline was completed in early 2010. Despite the large excess of export capacity, in the short term, production is sufficient to cover exports as demand from Russia is likely to be limited, but will need to increase in line with exports to China.

Apart from the projects and their extensions described above, Turkmenistan has recently made ambitious moves to expand exports to other countries, although it is not clear how quickly these alternatives will move ahead. An intra-governmental agreement and a gas pipeline framework agreement were signed in December 2010 to build the 30 bcm Turkmenistan-Afghanistan-Pakistan-India (TAPI) pipeline by 2015. It was approved by the Afghanistan Parliament in May 2011, while India is considering signing a PSA by July 2011. This does not remove the security and financing issues, on top of finding enough supplies to meet all these export commitments. Turkmenistan announced that it can deliver up to 40 bcm to Europe via the southern corridor (accompanied by intentions to build the internal East-West pipeline for further exports westwards). This would require the construction of a connection either across or around the Caspian. Either option would be problematic, and there seems little prospect of a project being initiated anytime soon. The pipeline would be the ideal outlet for stranded offshore gas though, as Petronas had to delay production from Block 1 due to the absence of market for it. Such ambitious plans will require a change of approach to developing resources in the medium to long term, while the fast recovery of production after the accident in 2009 means that current export commitments can be met in the short term.

Azerbaijan is Poised to Ramp up Production

Azerbaijan is endowed with significant gas resources and is becoming a major player in inter-regional gas trade. The complication regarding increasing production and opening up the country's gas export potential further is the uncertainty around the marketing and transportation arrangements. Despite the significant size of its gas reserves, Azerbaijan cannot supply enough gas in the mid term for the larger of the possible transport routes to Europe, the Nabucco pipeline, and therefore Azerbaijan's own gas exports depend on external issues surrounding the choice of and the source for pipelines to Europe for Caspian and Middle Eastern gas. This section provides a brief update on the two key areas affecting the future of Azerbaijan's gas trade: resources and transit.

Azerbaijan's proven reserves are estimated to be 1.4 tcm, and although the majority of these reserves is located in Shah Deniz, there is more to the country's gas potential than just this large field, not least because Azerbaijan has been expanding its resource base very actively. A major recent development is the ratification by the parliament of a new PSA with BP in May 2011 to develop the Shafag-Asiman field. Another promising field, Absheron, with estimated reserves of 300 bcm, is being developed by Total which is expecting to finish a 7-km deep drilling this year. In November 2010, the 200 bcm field (Umid) was found close to an older field, Babek, which implies a potential doubling of Babek's resources to 400 bcm. There are also deeper structures of the Azeri-Chirag-Guneshli (ACG) block with ongoing oil and associated gas production which contain 200-250 bcm of gas but the area is not covered by the current PSA. However, a new PSA could be signed by the end of 2011. Despite the promising outlook for reserves, the bottleneck in the production-transport-marketing equation for Azerbaijan is transport.

Some progress on securing transportation of Azeri gas to European markets was made when the Nabucco Intergovernmental Agreement was signed. This agreement also implied moving away from the notion of a "hub", promoted by Turkey to gain the ability to resell gas with a mark-up. It provided safeguards for Turkey's energy security different from the previously proposed 15% lift-off at a discount from gas transported by Nabucco. Further steps followed and in June 2010 Turkey and Azerbaijan signed a general inter-governmental agreement covering three areas: pricing of Azeri gas sales to Turkey, transit to Greece, and direct access for Azerbaijan to customers in Turkey. The agreement allows for 8.5 bcm of Azerbaijan's exports to be transited via Turkey. In February 2011, SOCAR signed a contract with Greece's DEPA for sales of 0.7 bcm/year, although the volumes are not extra, but reassigned exports from Shah Deniz I to Turkey. Work on the June 2010 agreement continued, with progress made on the sale contract side, but some issues still need to be tackled regarding transit. The final contracts are expected to be completed in 2011.

There is still uncertainty as to which pipeline will be used for exports beyond Turkey: Nabucco, ITGI or TAP. But transportation issues could be resolved in 2011 to take FID for Shah Deniz Phase II, enabling the start of production in 2017. Apart from the export routes going via Turkey, Azerbaijan is also looking at diversifying its options for exporting and minimising the number of transit countries with projects such as the Azerbaijan-Georgia-Romania Interconnector (AGRI) project, which involves building a liquefaction terminal on the Georgian coast with Ukraine and Romania as possible destinations, or transporting CNG across the Black Sea.

Middle East and Africa

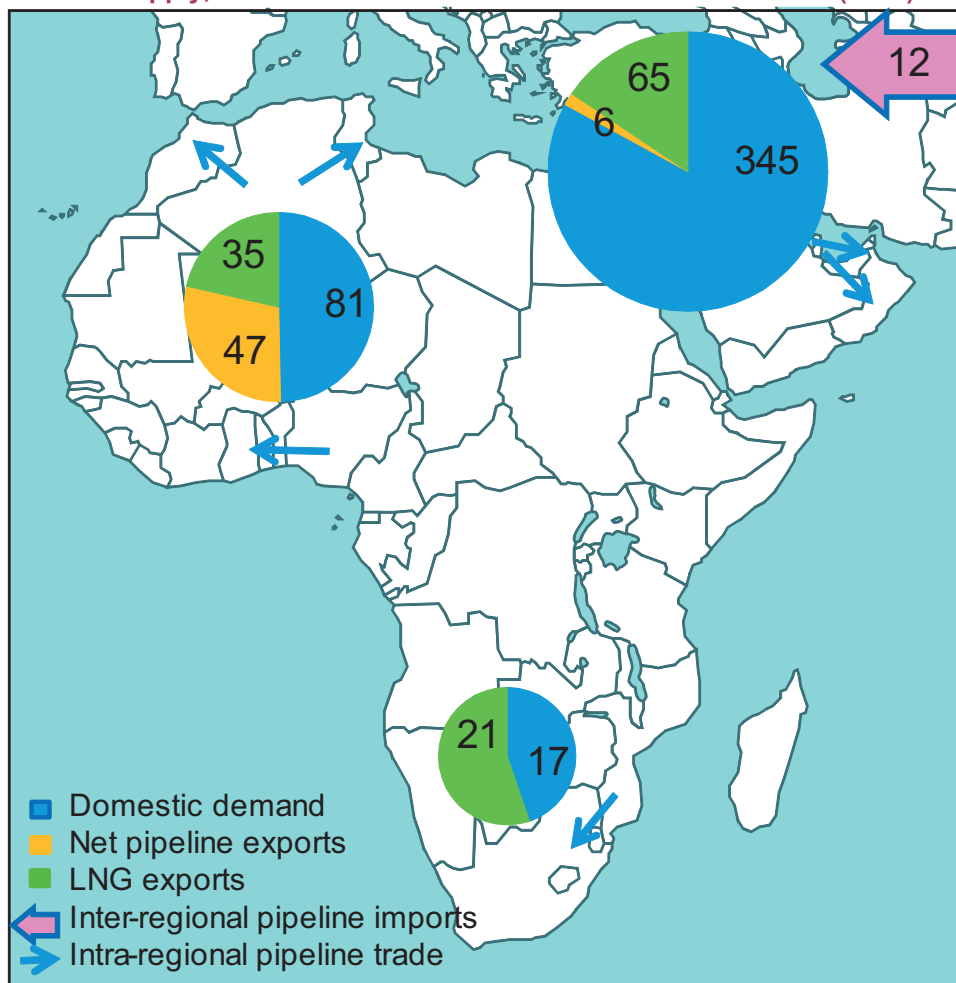
The Middle East and Africa are expected to be the largest contributors in terms of incremental production in the medium term, with their production expected to increase by 111 bcm and 73 bcm, respectively, over the period 2010-16. Increasing production sufficiently is a common challenge in all countries, except Qatar. Despite their huge proven reserves (90 tcm or 48% of global proven reserves), most countries struggled to keep pace with their rapidly increasing demand (7.6%/y over 2005-09 in the Middle East and 3.2%/y in Africa). Incremental output is needed not only to meet rapidly increasing domestic demand, but also to support additional exports by LNG and pipelines.

The two regions contrast significantly in several aspects. The Middle East holds five times more proven gas reserves than Africa and consumes three times more. Unlike Africa, most of the gas produced in the Middle East is consumed in the region, despite the rapid expansion of LNG exports in 2010 to 103 bcm due to Qatar. Besides its 127 bcm of LNG export capacity in four countries, the Middle East has actually only one exporting pipeline from Iran to Turkey, but very little development of export capacity is expected over the medium term. In fact, the region has been developing its import capacity with pipelines from Turkmenistan to Iran, LNG import terminals in Kuwait and Dubai and interregional pipelines from Qatar to Oman and the Emirates. In comparison, Africa exports half of its production, half by pipeline and half by LNG. Gas developments are very uneven also within Africa; despite significant reserves, the Sub-Saharan region remains undeveloped and is poorly interconnected with global markets, with only Nigeria and Equatorial Guinea exporting LNG (in 2012, Angola will start as well). In North Africa, pipeline trade with Europe and Middle East is more important than LNG. Finally, internal pipeline interconnections are very limited, as only a few countries export to their neighbours, Algeria, Zimbabwe, Qatar, Nigeria and Egypt (to the Middle East).

High demand growth is partly driven by high economic growth (over 4%/y over the period 2000-09), although this growth is very volatile, reflecting oil production and prices; needs from the power and petrochemicals sectors; and is exacerbated by very low domestic gas prices, which can be less than a tenth of European or Asian wholesale gas prices (sometimes below \$1/MBtu). Gas shortages have become more visible, particularly in the Middle East, where all countries besides Qatar, Iraq, Saudi Arabia, Bahrain and Yemen import up to 80% of their demand. Meanwhile, some LNG exporters have had to reduce their LNG exports (Egypt, Oman) and to renegotiate the schedule of such deliveries to be able to meet peak summer demand. Such supply constraints could have a direct impact on the power and industrial sectors, and thus on the economy.

On the other side, the development of new production is more challenging, due to multiple factors. Output of associated gas is likely to be constrained by limits to the increases in crude production. Apart from Iraq, few countries in the Middle East or Africa expect to be able to increase oil production significantly. Much of the associated gas which is available will continue to be needed for re-injection and some will continue to be vented or flared. On the positive side, the increasing attractiveness of NGLs in meeting demand for liquid hydrocarbons will help a number of projects move forward.

Gas Supply, Demand and Trade in the Middle East and Africa (2009)



This map is for illustrative purposes and is without prejudice to the status of or sovereignty over any territory covered by this map.

Nevertheless, countries will have to turn to non-associated gas; such resources are more challenging (tight gas, sour gas fields), often do not offer the benefit of liquids revenues, and may require significant additional infrastructure. The pricing issue is pertinent here, as those countries' regulated prices are often below cost of production.²⁵ There is a perceived need for most Middle Eastern and African countries to raise domestic gas prices to at least cost of service, which is going to prove difficult in the current political climate. Existing governments are naturally unwilling to add fuel to public opposition, while new governments will avoid unpopular measures. However, the failure to increase prices will directly impact financial deficits of gas companies and consequently the states' finances, as the companies are often state-owned. Countries would also fail to attract foreign players with the technical expertise needed to develop the most challenging fields, as these would be deterred by the financial conditions, unless the gas is mostly to be exported – which again does not solve the issue of meeting domestic demand. This could, in the medium term, create more shortages or force countries to turn to Domestic Market Obligations (DMO). DMOs have become increasingly

²⁵ IGU PGC B report, October 2009.

apparent over the past decade. For example, After Egypt decided to limit exports to one-third of the resource base, a planned LNG facility did not proceed and existing facilities remain under-utilised.

Qatar is one exception to this trend. Qatar has already become the largest LNG exporter in the world, with future additional production dedicated to domestic projects (Pearl GTL, Khazan). It is unlikely that additional export capacity will be added before the moratorium is lifted in 2015. Two other countries could change their destinies. So far, Iraq produces little marketable gas, and most is actually flared, but it has the potential to become a major producer and potentially, an exporter. Meanwhile, Israel could perform a perfect U-turn from that of an importer to a would-be LNG exporter, due to the unexpected discovery of two major offshore fields. Of course, the scale is not comparable to Qatar's. In the section below, we will analyse the developments of key countries which illustrate the challenges faced by this region.

Saudi Arabia: Meeting Domestic Demand is Key

Saudi Arabia is neither exporting nor importing, a situation likely to remain the status quo, at least for the medium term. Being an importer would be politically unacceptable, as the country holds significant gas reserves (7.9 tcm, half of which is non-associated, but often tight or sour or poorly located offshore); incremental production will be absorbed by the domestic market, where prices are below cost at \$0.75/MBtu. Increasing gas production has proven a challenge, forcing the country to continue to burn oil in power generation. Indeed, a decree issued in 2006 states that coastal power plants would burn fuel oil priced at \$0.46/MBtu. Gas is essential not only for power generation but also for desalination, petrochemicals, refineries and industries. Moreover, the Kingdom has been trying to reduce the economy's oil dependency by developing export-oriented industries, such as SABIC, so the key role of cheap gas must be seen in a wider economic context. An estimated 10 bcm is currently used in gas processing facilities to produce 1,485 kb/d of NGLs.

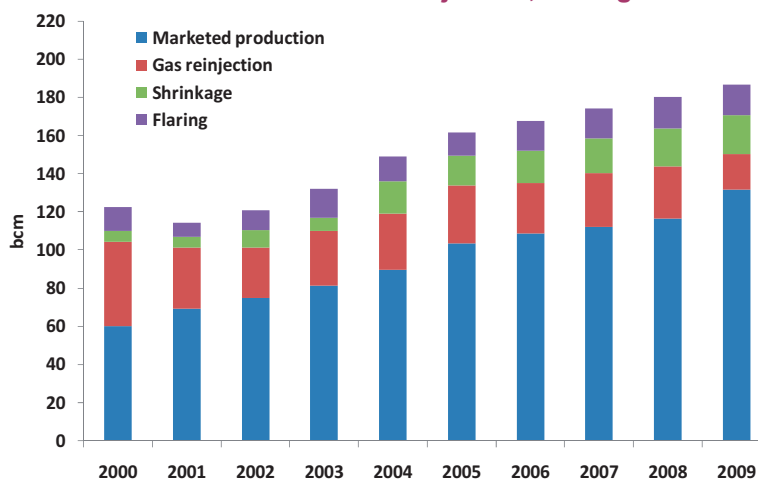
Around 45% of current gas production is associated gas, with two-thirds from the giant Ghawar oil field. Recent gas production additions were nevertheless largely based on associated gas, such as the Khurais increment, which started in June 2009, with facilities treating 3.3 bcm/y and 70,000 bpd of condensate. Saudi Arabia is now looking at two major non-associated gas developments expected to start by the middle of this decade (2013 at the earliest), which could add around 46 bcm of raw gas (38 bcm/y of sales gas) to current production (71 bcm of sales gas in 2009) and help the Kingdom to reach the target of 160 bcm/y by 2015 (against 90 bcm of raw gas in 2009). The 18.6 bcm/y Karan field would be the first non-associated offshore field expected to start by 2013. Meanwhile, the Wasit Gas Program is moving forward, with plans to process 25.8 bcm/y from the Arabiyah and Hasbah non-associated offshore fields and produce approximately 18 bcm/y of sales gas. These fields are high sulphur and offshore, making them more expensive to develop (estimated costs of \$3.5/MBtu and \$5.5/MBtu, respectively). In early 2011 Saudi Aramco awarded contracts for onshore works worth a total of \$2.36 billion to SK Engineering & Construction and Samsung Engineering, and Saipem was awarded a contract to develop the fields.

Iran: LNG Export Dreams are Fading Away

Iran is the second-largest holder of gas reserves, with 29.6 tcm, but ironically, the country is a net importer which increasingly relies on Turkmen imports to meet its winter demand peaks. Around

86% of Iran's gas resources are non-associated, coming mostly from the offshore South Pars field. Iran holds significant undeveloped fields, such as North Pars and Kish with 1.4 tcm of reserves each, and a few significant fields have been discovered over the past three years. Gas field developments have been hampered by political issues driven by concern over Iran's nuclear power and uranium enrichment programme and the resulting EU, US and UN sanctions. A fourth round of sanctions was passed by the United Nations in 2010. US sanctions are tougher, looking specifically at investments in the petroleum sector and exports of sensitive items to Iran, while EU sanctions included a ban on certain investments and provision of certain services in the oil and gas sector, and on financial assistance to the government of Iran. IOCs and many NOCs have effectively withdrawn from Iran, depriving the country of large-scale foreign investment and technology, albeit some foreign companies retain a presence in Iran in order to fulfil outstanding contractual commitments. Marketed production represents only two-thirds of raw gas production, as Iran is estimated to reinject around 19 bcm, and either flare or vent around 16 bcm according to OPEC data. While reinjection has been dropping in recent years, flaring and venting have been increasing in line with raw gas production. Additionally, gas shrinkage had been increasing fast, from 6 bcm in 2000 to 20 bcm in 2009, reflecting the increase of NGLs production from 75 kb/d to 505 kb/d during the same time period. Iran is expected to continue to see its NGLs production increasing rapidly, to 868 kb/d by 2016.

Iran's Marketed Production versus Reinjection, Flaring and Shrinkage



Source: OPEC Annual Statistical Bulletin, Cedigaz.

The focus remains on South Pars' 24 phase development scheme managed by Pars Oil & Gas Company (POGC), a subsidiary of NIOC. Each phase has a combination of natural gas with condensate and/or NGLs production. So far, Phases 1-8 have been brought online, the first in 2003 and the last late 2009, while Phases 9-10 are being brought on stream and expected to start in 2011. All the gas is allocated to the Iranian domestic market. Phases 11 to 18 are at different stages of development. The most advanced is Phase 12, which is expected to be fully online in 2013. Due to the sanctions, IOCs which were considered for the next phases' development have withdrawn (Total and Petronas for Phase 11, Shell and Repsol for Phases 13-14). The only exception is CNPC, which was awarded Phase 11 development for \$4.7 billion in 2009. The development of the other phases is now in the hands of

Iranian companies such as Petropars, Iran Offshore Engineering Construction Company (IOEC), Oil Industries Engineering and Construction (OIEC). These companies face the very same problem of funding, as foreign investment has become scarce. The South Pars Phase 12 received \$1.8 billion funding in order to accelerate its development; whereas India's ONGC, which was planning a 40% stake in Phase 12 faces difficulties securing funding from the banks due to sanctions. Among the other fields, the Kish project appears the most advanced with a first phase expected by 2014.

Development of Iranian Fields

Field/Phase	Gas (bcm/y)	Gas condensates (barrels/d)	Developers	Online date
South Pars				
Ph. 1	9.5	40,000	Petropars	2003
Ph. 2-3	20.4	80,000	Total, Gazprom, Petronas	2002
Ph. 4-5	18.8	80,000	Eni, Petropars, NIOC	2005
Ph. 6-8	34	158,000	Petropars	2008-09
<i>Ph. 9-10</i>	<i>20</i>	<i>80,000</i>	<i>OIEC, IOEC, LG Engineering</i>	<i>2011</i>
<i>Ph. 11 (Pars LNG)</i>	<i>18</i>	<i>80,000</i>	<i>CNPC</i>	<i>Na</i>
<i>Ph. 12 (Iran LNG)</i>	<i>29</i>	<i>110,000</i>	<i>Petropars (ONGC?)</i>	<i>2012-13</i>
<i>Ph. 13 (Persian LNG)</i>	<i>18</i>	<i>77,000</i>	<i>Mapna, SADRA, Petro Paydar</i>	<i>2013</i>
<i>Ph. 14 (Persian LNG)</i>	<i>18</i>	<i>77,000</i>	<i>IDRO, NIDC, IOEC</i>	<i>Na</i>
<i>Ph. 15-16</i>	<i>20</i>	<i>80,000</i>	<i>IOEC, Saff, ISOICO</i>	<i>2014</i>
<i>Ph. 17-18</i>	<i>18</i>	<i>80,000</i>	<i>IOEC, OIEC, IDRO</i>	<i>2014</i>
<i>Ph. 19</i>	<i>18</i>	<i>77,000</i>	<i>Petropars, IOEC</i>	<i>Na</i>
<i>Ph. 20-21</i>	<i>18</i>	<i>75,000</i>	<i>OIEC, IOEC</i>	<i>Na</i>
<i>Ph. 22-24</i>	<i>18</i>	<i>77,000</i>	<i>Petro Sina Aria, SADRA</i>	<i>Na</i>
Other fields				
Golshan, Ferdowsi	26	110,000	SKS	Na
North Pars	27	Na	OSCO	Na
<i>Kish phase 1</i>	<i>10</i>	<i>30,000</i>	<i>PEDEC</i>	<i>2014</i>
<i>Kish phase 2</i>	<i>20</i>		<i>PEDEC</i>	<i>Na</i>

Source: Petropars, IOEC, Oxford Energy Institute, OGEM, POGC.

Note: **Bold**: existing ; *Italics*: under construction ; normal: planned.

Industrial Development and Renovation Organization (IDRO), National Iranian Drilling Company (NIDC) and Iran Offshore Engineering Construction Company (IOEC), Iran Shipbuilding & Offshore Industries Complex Company (ISOICO), Oil Industries Engineering and Construction (OIEC).

The expected online dates are as given by project sponsors and do not reflect the IEA's opinion.

Several LNG export projects had been considered, based on the next phases of South Pars: Iran LNG (South Pars Phase 12), Pars LNG (South Pars Phase 11), and Persian LNG (South Pars Phase 13-14). But Iran's LNG dreams have been fading away due to sanctions and the Pars and Persian LNG projects are reported as "delayed", while Iran LNG is still "ongoing". While Iran LNG is the only project where progress has been made, Iran and the few foreign companies still present a lack of experience in liquefaction technology that would enable this plant to be completed. Furthermore, there is no final sales agreement to support this project despite preliminary sales agreements with Sinopec and OMV. It is therefore likely that the gas will be diverted to the Iranian market once it comes on stream by 2013. Other projects such as North Pars LNG, Qeshm LNG, Golsham LNG or Lavan LNG, together accounting for 36 mtpa, have made no progress. It will not be difficult to find domestic uses for any gas from South Pars projects once it has landed at Assaluyeh. If in significant enough quantities, it could, in theory, also provide the necessary supply for the long-planned export

pipeline to Pakistan (and possibly India) though this still awaits a decision on price, and a political decision about the involvement of India.

Oman: The Challenge of Developing Tight Gas Fields

Oman illustrates many of the issues mentioned above. Oman has 610 bcm of proven gas reserves, with a large share of tight gas. Production reached 28.7 bcm in 2009, with an additional 2.4 bcm reinjected and 1.4 bcm flared. Even though gas has become a cornerstone of the government's plans for industry and power sectors, Oman is facing gas shortages and is struggling to meet the export commitments of the Qalhat and Oman LNG export plants. It has been importing gas from the Dolphin project in Qatar since 2008. Shifting exports to domestic demand is difficult in practice as LNG projects have been developed with international partners unlikely to accept revenue losses.

Petroleum Development Oman (PDO, 60% owned by Oman's government and 34% by Shell) currently produces most Omani gas and is planning to increase production by 10 bcm/y over the medium term, based on more efficient associated gas production and reduced reinjection and flaring. The government has been keen to open upstream to foreign companies to develop tight gas resources, such as BG's Abu Butabul and BP's Khazzan and Makarem fields. Nevertheless, the technical challenges added to cost issues led BG to pull out of Abu Butabul in 2010. As the field has little associated liquids, BG had to rely on revenues from the domestic market, at a price first set at \$1/MBtu – a level that would probably make it very hard to monetise the tight gas. Although BG renegotiated the price late 2009 to \$2.5-3/MBtu, it was apparently still not high enough to justify the necessary investments. Oman Oil Co. (OOC) is now considering taking over the field, but it is not clear whether the company would have to bid for it and whether it would have the technical competencies to develop Abu Butabul alone. In the medium term, all hopes are on BP's fields. The company is likely to put pressure in order to obtain a price that would justify its investments in Khazzan and Makarem, which are expected to produce 15 bcm by 2017.

Iraq: Between High Domestic Needs and Legislative Uncertainty

With its 3.2 tcm of proven gas reserves, Iraq has the potential to become a significant gas producer – and potentially exporter, but the road is paved with much uncertainty. Among the biggest challenges are the delays to passing the oil and gas law, disagreements between the Iraqi government and the Kurdish Regional Government (KRG) and lack of infrastructure, from roads, bridges to gas transmission network and gas-fired plants. Most of the gas resources are associated (80%) and located in the South Eastern Basrah province; there are also gas fields in the North and the West, most of them non-associated. Unlike Iran or Saudi Arabia, Iraq has never attempted to develop its gas resources – either associated or non-associated. This backwardness has been amplified by years of sanctions, war and political uncertainties. Only 2 bcm is currently used in the domestic market, while an estimated 7 bcm is flared or vented due to the lack of transport infrastructure or absence of any other big gas user nearby, 1 bcm is reinjected and 7 bcm goes to shrinkage. A clear regulatory framework is required in the energy sector, but the new oil and gas law has been stalled since 2007, delaying the development of several projects. In any case, electricity generation has first claim on domestic gas and would pre-empt gas exports entirely in the medium term. Furthermore, for a part of gas production to be eventually exported, the law needs to be amended to allow for exports; so far, only the State Oil Marketing Organization (SOMO) is entitled to export oil or gas.

However, there could be light at the end of the tunnel, provided that the issues above are settled. Three different oil and gas licensing rounds organised by the Ministry of Oil have taken place since 2008, offering 11 oil fields and 3 gas fields. Although gas fields had been offered in the first and second, they found bidders only in the third, reflecting uncertainties of companies on future gas developments. Incidentally, as far as scale is concerned, it is worth noting that the total plateau production of the three non-associated gas fields is only fractionally more than that of gas currently flared. Contacts to develop these fields were signed in late May/early June 2011. Meanwhile, KRG signed PSCs for gas fields with small IOCs such as OMV, MOL and Crescent. That the focus is first of all on oil fields is not automatically a negative point, given the amount of associated gas, but as a valuable national resource, it should be utilised. In June 2010, the Iraqi cabinet approved a \$12 billion project to capture gas flared from the Rumaila, Zubair and West Qurna-1 oil fields and Shell agreed to operate the project through the Basra Gas Company (BGC, including Iraq's South Gas Company (51%); Shell (44%) and Mitsubishi (5%)). But so far, Shell has struggled to get the final approval and contracts specificities. This could represent a challenge for the IOCs which won the bids to develop the oil fields – BP, ExxonMobil and Eni – as they may end up having to develop specific gas infrastructure to use the gas, something which was not included in the original contracts. While reducing flaring is the easiest step, companies may want to develop gas fields based on a combination of domestic supplies and exports. But export plans remain controversial due to the urgent needs to generate electricity. Three export possibilities have been envisaged so far – the Nabucco pipeline, the Arab gas pipeline and an LNG project in the Basrah region.

Gas fields under Development in Iraq

Licensing Round	Field	Plateau (mcf/d)	Company
Ministry of Oil			
1	Rumaila, Zubair, West Qurna	700 (currently flared) Up to 3000 later	South Gas Company (51%); Shell (44%) and Mitsubishi (5%)
3	Akkas	400	Kogas
3	Mansouriya	320	Kuwait Energy/TPAO/Kogas
3	Siba	100	Kuwait Energy/TPAO
Kurdistan Regional Government			
	Khor Mor	300*	Crescent (40%), Dana (40%), MOL,
	Chemchemical	200*	OMV (10% each)

Source: IEA based on companies' information.

Note: * Production of Khor Mor and Chemchemical could reach up to 30 bcm/y.

Israel: A surprising Potential Exporter

Israel's emergence as a potential gas exporter is one of the most surprising developments in recent years. In 2009, Noble Energy discovered the offshore Tamar field and then, in 2010 the Leviathan field: total reserves are estimated at around 700 bcm, 200 times Israel's current consumption. However, such developments could be jeopardised by new tax decisions: in March 2011, the Knesset finance committee passed legislation to approve a new tax regime for gas fields, under which a progressive profit tax of between 20% to 50% would be created on top of the existing 12.5% royalties on oil and gas revenues, putting the government share of earnings up to 62% from the current 30%. The country currently relies on one single field, Mari B, with a production of 2.8 bcm expected to decline sharply by 2013. As demand increases, Israel had been looking at imports. Pipeline gas from

Egypt started flowing in 2008 based on a 1.7 bcm/y, 15-year contract, but these exports are highly political on both sides. In Egypt, the initial low export price (\$1.5/MBtu) had been criticised by the opposition, which went to Court. After a ruling in favour of continuing exports, the price increased to \$4/MBtu in 2010. In Israel, concerns have risen about depending on Egypt while at the same time the Tamar discovery was made. But during the debate on increasing taxes for oil and gas production, Israel Corp signed an additional contract with Egypt for 1.4 bcm due to uncertainties on when Tamar would come online.

The recent events in Egypt and the reported attack on the pipeline section running from Egypt to Jordan in February 2011 could change this situation (the Israeli section was untouched but closed for safety reasons and took six weeks to restart and supplies were subsequently cut again). First, the deal has come under further scrutiny and Egypt would like to renegotiate prices upwards, and there are investigations regarding commissions received by the Mubarak family. Second, Israel is likely to want to accelerate the development of Tamar and Leviathan, which could give it import independency and even turn the country into an LNG exporter. But in the short term, before it can even become an exporter, Israel will face shortages if insufficient gas supplies come from Egypt as many oil-fired power plants were planned to switch to gas in 2011. Meanwhile, Tamar could start by 2013 at the earliest with a production of 2-2.5 bcm/y, which could help the country meet demand requirements from the power generation sector. Leviathan, with its potential 20 bcm/y production, could turn the country into an exporter in the longer term.

Sub-Saharan Africa: the New Frontier

While most incremental production in the Sub-Saharan region will come from Nigeria, new countries have appeared at the horizon: Angola, but also the Eastern African region. Angola will start exporting LNG in 2012 from its 7.1 bcm plant,²⁶ albeit the destination of these exports is uncertain. Supplies were originally intended to go to the United States, but the current oversupplied situation makes this doubtful. They are likely to target the strongly growing Asian market, especially as the earthquake in Japan will translate into additional LNG supplies for the coming years.

The most interesting prospective area appears to be Eastern Africa, where several promising discoveries have been made. Anadarko made its fourth deepwater discovery off the Mozambique coast – Tubarão in February 2011, after three discoveries in 2010. Based on the expected resource potential, Anadarko is considering an appraisal program and evaluating LNG commercialisation options. These discoveries are actually located off the Northern coast of Mozambique, relatively far away from the only neighbouring market, South Africa. Anadarko is the operator of the Offshore Area 1 with a 36.5%, while Mitsui E&P Mozambique has 20%, BPRL Ventures Mozambique, Videocon Mozambique Rovuma 10% each and Cove Energy Mozambique Rovuma Offshore 8.5%. While Mitsui and BRRL may want to send the gas to their respective domestic market, an open question remains about the quantity of gas that could be earmarked to the domestic market. At the same time, Ophyr made three gas discoveries in Tanzania, close to the Mozambique's discoveries. Ophyr introduced BG as a joint-venture partner for 60% and signed in May 2010 PSCs with the government enabling not only transport and liquefaction for export purposes, but also a provision for the supply of domestic markets.

²⁶ Chevron (36.4%); Sonangol (22.8%); Eni (13.6%); Total (13.6%), BP (13.6%).

INVESTMENT IN LNG

Summary

- **A first wave of new liquefaction capacity has been completed between early 2009 and mid-2011; a second wave is expected to arrive by the middle of the decade. Between early 2011 and end-2016, LNG productive capacity will have increased by at least 20%. Long-term supply contracts have been key to advancing these new capital-intensive projects, for which construction costs are typically twice as high as those that recently came online.** Six final investment decisions (FIDs) were taken over the past two years, despite many market uncertainties; these new projects will essentially target the growing Asian markets.
- **New liquefaction will come predominantly from the Pacific region.** In particular, Australia seems set to become the new Qatar, with five plants currently under construction and a few others close to FID. Australia will be the first country to see CBM-to-LNG projects coming online, with two projects sanctioned; it could also see the first floating LNG liquefaction plant. Part of the new LNG supplies in the Pacific basin will actually replace declining LNG exports coming from traditional suppliers such as Indonesia and Malaysia. Meanwhile, uncertainty prevails regarding new plants in the Atlantic basin and the Middle East.
- **The next decade may see substantial changes as traditional LNG supply regions in Southeast Asia and the Middle East turn into gas importers, while North America may see some LNG plants projects come online.** Growing demand for gas, as well as unconventional gas resources, has profoundly affected future regional gas balances, so that uncertainty remains high on the import needs of the different regional markets. Competition for a larger market share is therefore tough, not only among the 550 bcm of LNG projects planned worldwide, but also between pipeline projects and LNG.

Four LNG Projects have Reached FID since Early 2010

Since early 2010, four projects have reached FID, following two FIDs in 2009 for Gorgon in Australia and PNG in Papua, New Guinea. Three of these four projects are in Australia. Two of them are CBM-to-LNG (or Coal Seam Gas [CSG]) projects in Queensland, Australia, namely Queensland Curtis LNG (QCLNG), led by BG and Gladstone LNG (GLNG), led by Santos, one of the leading oil and gas producers in Australia. They are both planning to build two trains each and have secured sales mostly to Asia. In May 2011, Shell took FID on the first floating liquefaction project in the world, the 4.9 bcm/y Prelude LNG in northwest Australia. Shell is a pioneer of floating LNG production vessels and the FID has been awaited by the industry because this state-of-the-art technology could potentially explore the possibility to develop many stranded gas fields.

Donggi Senoro LNG in Indonesia reached FID in January 2011; this is a relatively small project with production capacity of 2.7 bcm led by the Japanese trading house Mitsubishi. Mitsubishi has been a minor shareholder in various LNG projects for a long time, but has never taken an operatorship before. Similarly, Gladstone is the first operatorship project for Santos. As operatorship is new for both companies, construction and management of capital-intensive LNG projects will be very challenging. They have limited human and capital resources compared to traditional oil and gas majors, but the whole industry should welcome this movement of newcomers for further

development of the LNG industry, since it does open a door to other stakeholders interested in LNG operation. They consider that getting experience as an LNG operator would strengthen their business portfolio and contribute to their long-term growth. In this regard, Gladstone and Donggi Senoro are just a beginning for their ambitious future plans in LNG business.

LNG Capacity to 2016: a Second LNG Wave is Coming

The first wave of new LNG production capacity is almost completed, with over 100 bcm of LNG production capacity added between early 2009 and mid-2011. Total capacity now stands at 373 bcm as of mid-2011, compared to 268 bcm as of end-2008 (see chapter on market trends in the LNG business). This rapid expansion of LNG production capacity is in contrast with the limited LNG production capacity added between 2005 and 2008, which averaged 18 bcm/y.

LNG Projects under Construction and Committed (as of June 2011)

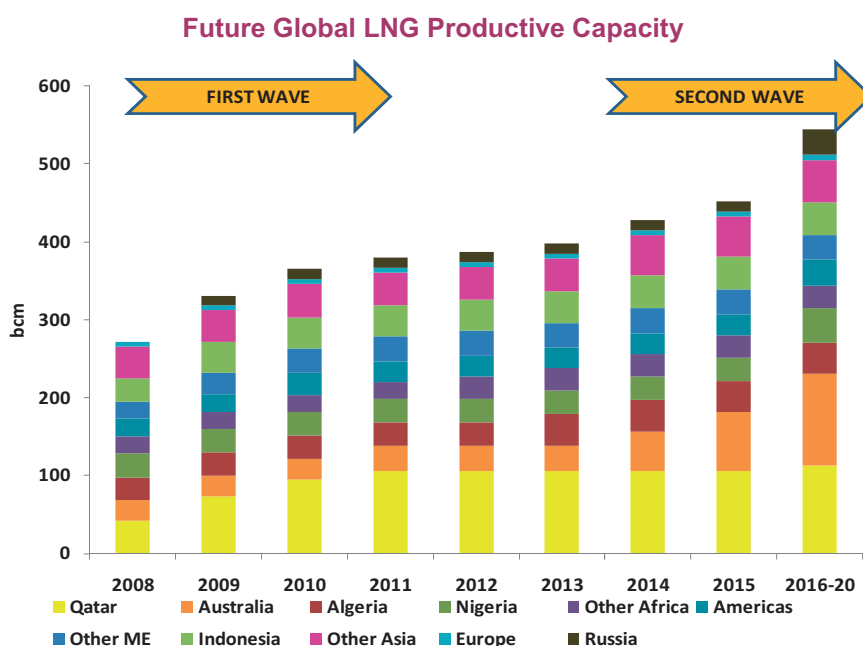
Country	Project	Capacity (bcm)	Major Stakeholders	Online date
Australia	Pluto LNG	6.5	Woodside, Kansai Electric, Tokyo Gas	2011 Aug
Angola	Angola LNG	7.1	Chevron, Sonangol, Eni, Total, BP	Q1 2012
Algeria	Gassi Touil LNG	6.4	Sonatrach	2013
Algeria	Skikda new train	6.1	Sonatrach	2013
Australia	Gorgon LNG	6.8 (20.4)	Chevron, Shell, Exxon Mobil	2014 (2015)
Papua New Guinea	PNG LNG	9.0	Exxon Mobil, Oil Search	2014
Australia	Queensland Curtis LNG	11.6	BG, CNOOC, Tokyo Gas	2014
Indonesia	Donggi Senoro LNG	2.7	Mitsubishi, Pertamina, Kogas	2014
Australia	Gladstone LNG	10.6	Santos, Petronas, Total, Kogas	2015
Australia	Prelude LNG	4.9	Shell	2017
Total		85.3		

Source: IEA and companies' websites.

The expected online dates are as given by project sponsors and do not reflect the IEA's opinion.

There are currently ten LNG projects that are either very close to completion, under construction, or that have reached FID recently, representing 85 bcm, so that total liquefaction capacity will reach at least 458 bcm by 2017. There will be more limited additions over 2011-13, with 37 bcm expected to start operations, representing the smooth end of the first LNG wave. In the first half of 2011, Qatar IV Train 7 is the only train that came online, in spite of a little delay. Pluto LNG was originally expected to be completed by late 2010, but now the completion has been postponed to August 2011. Angola LNG, led by Chevron, is the first LNG project in Angola and will be completed by early 2012, with a production capacity of 7.1 bcm/y. Most of its LNG was expected to be delivered to the US Gulf LNG terminal opening in 2011, where Sonangol holds 20% capacity. But some of the LNG may actually be diverted to Europe, South America or Asia due to the higher demand in these regions compared to the oversupplied US market and higher revenues, as US prices stand twice as low as both OECD Pacific and European prices. Two projects from Algeria are also expected to be completed by 2013: the 6.4 bcm Gassi Touil LNG and the 6.1 bcm Skikda. Skikda's new train is a supplemental train to compensate for the lost capacity due to the plant's explosion in 2004.

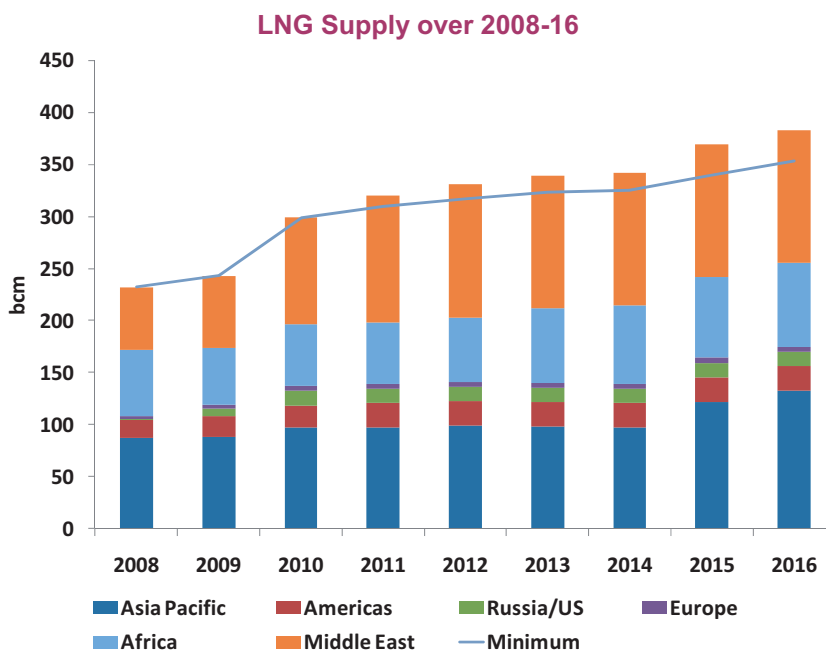
Beyond 2014, a second wave of LNG capacity is coming on the back of the six projects which took FID since late 2009. At least 59 bcm of new production capacity is expected to be completed globally over 2014-17 if all projects are completed on time. While half of the first LNG wave came from Qatar (63 bcm), 80% of the second wave comes from Australia based on projects approved over the past two years. The mega project, Australia's Gorgon LNG, is based on three trains with 6.8 bcm (5 mtpa) each. Their target completion year is currently set for 2014-15 for all three trains, with the first train arriving in late 2014, the second in the first half of 2015 and the third later that year. Papua New Guinea (PNG) LNG, Queensland Curtis LNG (QCLNG) and Donggi Senoro LNG are also slated to be completed in 2014. If all these projects start as scheduled in 2014, the global LNG production capacity will significantly increase by 30 bcm from the previous year of 2013. Then in 2015, Gladstone LNG (GLNG) will be completed along with Gorgon's two trains, adding another 24 bcm production capacity. Some delay of construction is likely due to skilled labour shortage or cost overrun. The trend from 2014 onwards represents the start of the second LNG wave, as many projects, notably in Australia, are close to reaching FID. Based on currently proposed projects, we anticipate global LNG production capacity to reach 540 bcm by 2020.



Note: Projects up to 2015 are under construction; 2020 projections are IEA estimates of projects committed, currently planned or awaiting investment decision.

LNG capacity differs from LNG supply delivered to the markets. Based on future LNG plants and export commitments, global LNG supply is set to continue to increase by one-third during 2010-16, assuming that LNG plants start as expected. The increase over the next two years would be rather moderate, as it will mostly be driven by LNG plants which started in 2010 and early 2011 reaching plateau and by the start of Pluto in mid-2011 and Angola LNG in early 2012, adding some 14 bcm of liquefaction capacity. A more substantial increase would take place in 2015-16, when new LNG plants in Australia and Papua New Guinea start and ramp up production to plateau. This can actually be the

beginning on a second LNG wave, depending on how many plants would take FID to start by 2016-17. At the same time, LNG production from some historical suppliers will increasingly face competition from rising domestic market obligations, reducing volumes available for exports.



Nevertheless, a substantial risk of slippage of new LNG plants exists. The past years have proven that LNG plants can be delayed by one to two years, compared to planned starting dates, even if they are already under construction. Pluto is the most recent example, with an expected start in August 2011 compared to the initial planned starting date of late 2010. Algerian LNG plants, as well as Australian LNG plants, could be delayed, especially if workforce shortages delay the start of Australian LNG plants. Additionally, some historical producers may have to curtail LNG exports even further if their domestic demand increases faster than expected; this is likely to happen in Middle East, Africa and Asia-Pacific countries. In that case, increase in LNG supplies would happen more slowly.

Project Cost Comparison: New Projects will be More Expensive

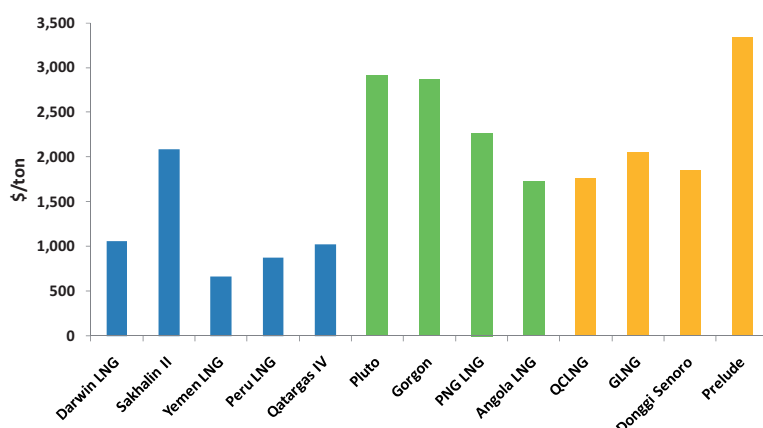
The project costs represent the size and difficulties of developing an LNG project and vary depending on several factors, such as design of the plant, environmental conditions of the plant site, the location and the technical or regulatory challenges of the gas fields, availability of the skilled labour, and construction period before operation. The timing of the project development also plays an important factor and economies of scale do not always help to reduce the project cost.

Among the LNG projects currently operational (blue column in the figure LNG Projects Construction Cost), Sakhalin II in Russia has an outstandingly high cost of construction per ton of annual LNG production, at over \$2,000/ton, whereas construction costs of Yemen LNG, Peru LNG and Qatargas IV were kept relatively low, at just about \$1,000/ton or even lower. Pluto, Gorgon and PNG LNG, which

are currently under construction or close to completion (green column), have higher cost profile ranging from \$1,700 to \$2,900/ton than those operational or having just reached FID (orange column).

With the exception of Prelude LNG, a floating production vessel for which capacity is not easily expanded, the four expensive projects of Sakhalin II, Pluto, Gorgon and PNG LNG have very strong incentives to expand the production capacity by building another train or two after securing firm supply sources of feedgas in order to improve their project economics. In fact, there have been rumours about a third or even a fourth train for those particular projects. Once they secure reliable reserves and commitment from potential LNG buyers, the construction of additional train(s) could be completed by 2016, making the best use of existing infrastructure. However, there is a rising concern about growing competition over skilled labour and raw materials necessary to build LNG plants worldwide, particularly in Australia, where various stakeholders are vigorously aiming to launch their own projects. It could possibly result in project delay or cost overruns.

LNG Projects Construction Costs (\$/ton LNG)



On top of the high construction costs of LNG plants, LNG delivery costs have been increasing as well, which has an impact on the final delivery cost of LNG to markets. The daily rate of LNG tankers was over \$60,000 in April 2010. The rate was quite moderate through the summer around \$40,000 but increased again to \$60,000 towards the high season of winter 2010/11 in Europe and Asia. Increasing demand for LNG combined with the Japanese earthquake and urgent need for additional LNG in the Asian market pushed the rate up to over \$80,000 in April 2011. This trend could invite further investment in the shipping business and end up adding a few dozen new LNG tankers to the current fleet of over 360 tankers available worldwide.

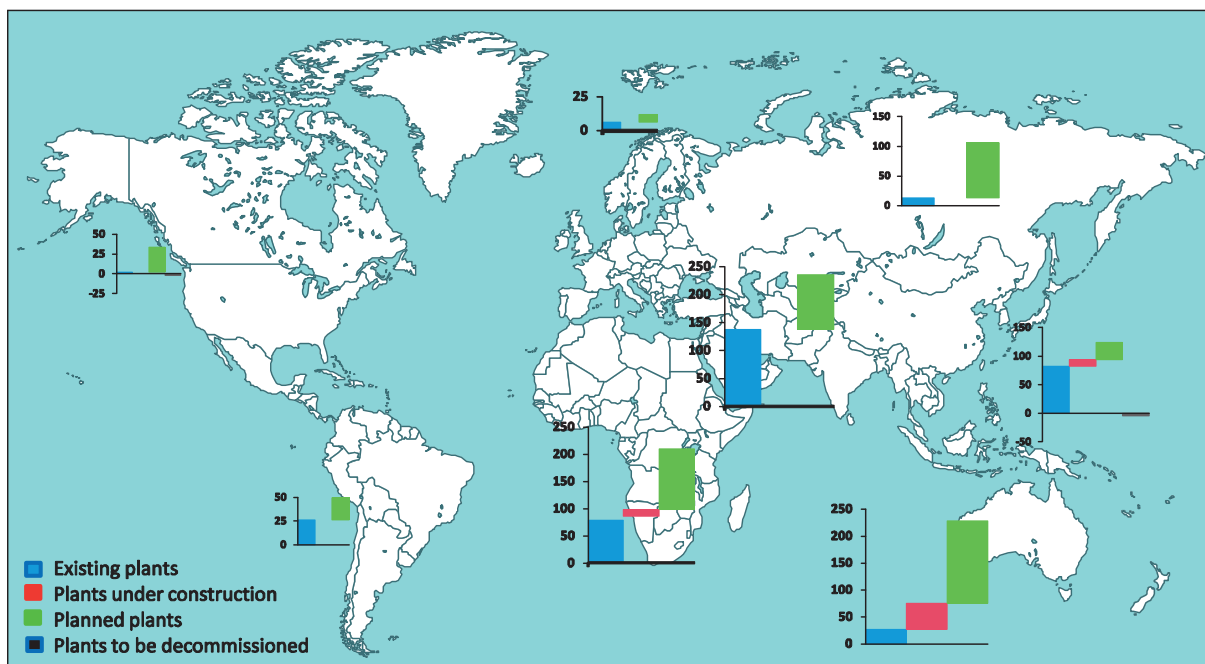
Many Other Potential Projects to Come

A growing mismatch between new consuming regions and producers calls for additional inter-regional (and sometimes intra-regional) transport capacity to be built to feed the new demand centres, notably in Asia. But the past two years have also fundamentally changed global gas markets, with certainties fading away as some countries in North America are expected to turn from potential importers to exporters. As noted before, this has not deterred the LNG project sponsors, and six

consortiums took FID over the past two years. But competition for a larger market share among the 550 bcm of LNG projects currently under consideration is likely to be fierce, not only among the LNG plants, but also against pipelines projects aiming at the same markets.

These LNG projects are all at different stages of progress. Some of them have secured reliable reserves but no firm buyers of LNG; others are still at a preliminary stage or have just embarked on FEED. There is no guarantee that all projects will materialise. In fact, three-quarters of the planned capacity is in four countries – Australia, Russia, Iran and Nigeria. These projects can potentially underpin the growing global LNG demand post-2015 or, depending on market conditions and uncertainties, take longer to be approved and arrive only towards the end of the decade.

LNG Liquefaction Plants Existing, Under Construction and Planned



This map is for illustrative purposes and is without prejudice to the status of or sovereignty over any territory covered by this map.

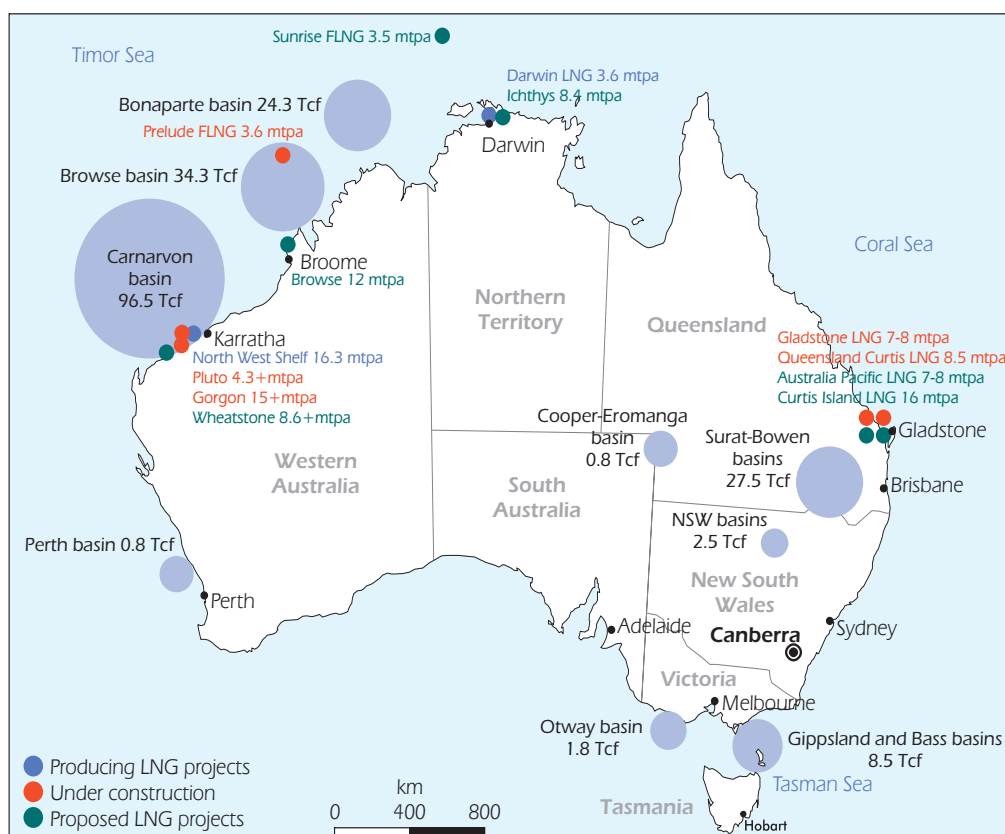
Australia: A New Qatar?

Australia is without doubt the most rapidly growing LNG producer in the world. By 2016, Australia's LNG production capacity should reach 75.8 bcm/y (55.7 mtpa) of LNG,²⁷ making it the world's second-largest LNG exporter after Qatar. There are also a dozen LNG projects, some of which are close to FID within a few years. In addition to huge gas reserve potential, Australia is geologically close to the growing LNG market of Asia, and its political and economical stability has been attracting foreign investment to develop capital-intensive LNG projects. Australia will also see "first of a kind" projects, with two CBM-to-LNG projects approved and a floating liquefaction terminal having reached FID.

²⁷ This does not include Prelude, which is expected to start operations in 2017.

The North West Shelf LNG and Darwin LNG are the two existing LNG projects with a combined production capacity of 26.7 bcm (19.6 mtpa). Meanwhile, Pluto LNG and Gorgon LNG reached FID in 2007 and 2009, respectively. The Pluto LNG Train 1 (6.5 bcm) will start commercial operation in August 2011. The project operator Woodside is now very keen to secure sufficient gas reserves to develop a second train. Gorgon is also expected to complete one train (6.8 bcm) by 2014 and two other trains (13.6 bcm) during 2015. Gorgon's operator, Chevron, is eager to develop a fourth train and to explore additional gas reserves to support this future development.

Australian LNG Projects



This map is for illustrative purposes and is without prejudice to the status of or sovereignty over any territory covered by this map.

Source: ABARE.

Three Projects Reached FID Despite Uncertain Environment

In early 2010, a new tax regime, the Resource Super Profits Tax (RSPT), was proposed by the Rudd administration and it was faced with strong opposition from the petroleum and mining industry due to the adverse impact on project economics. There was a growing concern that some of the proposed LNG projects could be potentially delayed or even cancelled, but after the new administration took over, Premier Gillard withdrew the unpopular new tax regime and declared that the existing tax regime would prevail for the petroleum industry. This provided sufficient comfort to the petroleum industry to go forward with their original plans.

Two projects accelerated their project development and finally reached FID in late 2010 and early 2011, QCLNG (11.6 bcm) and GLNG (10.6 bcm), both in Queensland. Prelude LNG (4.9 bcm), off the coast of Western Australia, also reached FID in May 2011. BG's QCLNG project was granted a state environmental approval in June 2010 but was waiting for the details on the RSPT before reaching FID later in 2010. After the tax had been withdrawn, Federal approval was granted on 22 October 2010 and then the project reached FID in end-October. Likewise, the GLNG project was also granted a state environmental approval in June 2010 and the Federal approval followed in October. FID was taken in January 2011. Korea's KOGAS agreed to take a 15% stake in the project, but is now considering to sell down to 5%.

Prelude LNG, the world's first floating LNG production terminal (4.9 bcm) led by Shell, reached FID in May 2011, with operations expected to start by 2017. The project gained environmental approval from the Federal government in late 2010. Shell has secured an offtake agreement with Osaka for 1.1 bcm and Taiwan's CPC for 2.7 bcm for 20 years, and can either secure additional firm buyers going forward or choose to add the remaining volumes to its global production portfolio and market it globally on a spot or short-term basis. If Shell can prove that floating LNG is economically viable and operationally reliable, it would create new possibilities for the LNG business. Indeed, floating LNG would open the door to quite a few LNG projects, large and small, which have been stranded due to lack of appropriate onshore plant sites or high costs of pipeline transportation from offshore gas fields. Meanwhile, there is still an intense debate regarding the proposed introduction of a carbon pricing regime in Australia by 2012 before a trading regime starts later, and the petroleum industry is worried about its potential impact on the competitiveness of the local LNG industry against foreign producers.

Developing Floating Liquefaction

Floating Production, Storage, Offloading (FPSO) of LNG has been attracting much attention recently due to the rapidly growing LNG demand. FPSO is another type of LNG tanker with gas liquefaction facilities equipped on top of the tanker. This is the most advanced technology currently being tested in the LNG industry. It is also the most suitable for stranded gas fields because this technology opens the door for projects deemed uneconomical due to the remoteness from land or insufficient reserves (generally less than 2 tcf proven reserves). Although there is no FPSO currently under operation, several companies are keen to develop this technology to materialise their LNG projects. In fact, this technology would enable development of many stranded gas fields and contribute to the LNG capacity expansion worldwide.

There are several FPSO projects under consideration and one recently reached FID. Shell has been a strong supporter of FPSO for a long time and is currently developing the Prelude LNG project in Australia, hoping to start operation by 2017. Another Australian FPSO project is the Sunrise LNG project led by Woodside. InterOil is planning an FPSO project in Papua, New Guinea and it could potentially precede Shell's Prelude, aiming to reach FID in 2011 and to start by 2014. Inpex of Japan and Petrobras of Brazil also have ambitions to develop FPSO projects in Indonesia and Brazil, respectively. However, there are still some challenges to overcome. It is still questionable if this new technology can provide a stable supply of LNG, sufficient safety and satisfactory project economics over the long term. In this regard, the industry will be closely watching the development of those potential projects for years to come.

Two More Projects with Secured Buyers Aim to Take FID in 2011

Wheatstone LNG, led by Chevron, has already secured 80% sales of the project's production to Japanese and Korean customers. Chevron also found new gas reserves in the Carnarvon basin to underpin the project. In addition to Tokyo Electric and Kyushu Electric agreements to purchase LNG from the project, KOGAS signed an agreement in July 2010 to purchase 2.7 bcm from Wheatstone LNG. All the buyers have also agreed to take a stake in the project.

Australia Pacific LNG, another CBM-to-LNG, is also planning to reach FID in 2011. The project gained a state approval and the Federal approval on environmental assessment by February 2011. Sinopec signed an agreement to purchase 5.8 bcm/y of LNG over 20 years from 2015 along with a 15% project stake after FID has been reached. The project could expand to have up to four trains and marketing is underway.

Pluto's Expansion and Ichthys: Can they Take FID in 2011?

Both projects still lack committed buyers. The FID for Pluto's expansion (train 2) also remains contingent on the discovery of sufficient gas reserves. In fact, Woodside seems to have found additional gas potential, but further study is required before FID. Meanwhile, Ichthys LNG, led by Japan's Inpex, has now selected the city of Darwin in Northern Territory for the onshore plant site after intensive study and various discussions with stakeholders over the most appropriate plant site. The progress of the project development has been relatively slow as compared to other fast track projects in Australia. Inpex has gained a state approval in May 2011 but is awaiting the Federal environmental approval. The project has not secured a single buyer for the LNG produced, but it is believed that most of marketing activity has been focused on Japanese buyers.

The Next Wave of Australian LNG Projects

A few other projects are planned and aim at taking FID in 2012 or later. Among them, some have also secured buyers and are advancing to get the required approvals. Among all projects, Woodside's Browse LNG is in intensive talks with Asian customers over LNG supply and aims to finalise the primary terms. The state environmental approval was granted in December 2010 and is now proceeding to the Federal government approval process. Meanwhile, Shell and PetroChina are jointly developing the CS CSG project, whose takeover bid was approved by Arrow Energy's board of directors and shareholders in 2010. Shell and PetroChina are offtaking the produced LNG from the first two trains, but the environmental approvals from the state and the federal government are yet to be granted.

GDF Suez aims to take FID for its 2.7 bcm floating LNG project Bonaparte in 2014. Bonaparte is jointly owned by GDF Suez (60%) and Santos (40%). The pre-FEED was awarded to Granherne (upstream) and DORIS Engineering (midstream) in early 2011. This project would reinforce GDF Suez's position in the Pacific region after signing short-term LNG contracts with Kogas and CNOOC. Another Woodside's project, Greater Sunrise, is facing tough problems. East Timor still insists on having the project plant built on East Timor's national territory, although the project partners are seeking a floating option because of its economics. It could potentially significantly delay the project development unless this political disagreement is solved.

Potential Australian LNG Projects (as of June 2011)

Project	Partners (share)	Expected FID	Capacity (bcm)	LNG Buyers	Sales Volume (bcm)	Start-up
Wheatstone	Chevron 80%, Apache 13%, Kufpec 7%	2011	11.7	Tokyo Electric, KOGAS, Kyushu Electric	5.6 2.7 1.1	2016
Australia Pacific LNG	ConocoPhillips 50%, Origin 50%,	2011	6.1 plus	Sinopec	5.8	2015+
Pluto Train2	Woodside 100%	2011	6.5	None yet	NA	2016
Ichthys	Inpex 76% Total 24%	2011	10.9	None yet	NA	2016+
Browse	Woodside 50%, Chevron 16.7%, BP 16.7%, BHP and Shell 8.3% each	2012	16.3 plus	Osaka Gas CPC	1.6 4.1	2016+
CS CSG	Shell 50% PetroChina 50%	2012	10.8 plus	PetroChina Shell	5.4 5.4	2016+
Greater Sunrise	Woodside (33.4%); Shell (26.6%); ConocoPhillips (30%); OG (20%)	2012	6.8	None yet	NA	2016+
Bonaparte	GDF Suez (60%) Santos (40%)	2014	2.7	None yet	NA	2018

Source: IEA and companies' websites.

The expected online dates are as given by project sponsors and do not reflect the IEA's opinion.

Americas: Could North America Export before 2015?

The new LNG export projects reinforce the complete change of perspective from the North American gas industry. The US producers are looking at exporting LNG to benefit from the large price gaps between Henry Hub prices and other regions, while Canada is in search of new export markets. In Latin America, Venezuelan projects are not advancing, despite plentiful supplies. The oversupply in North America closes markets for these projects.

Canada: Finding New Export Markets

Canada has been relying on one single export market, the United States, where import needs for pipeline gas collapsed by 15% over the years 2007-10, in particular, due to the economic crisis and the rapid increase of domestic gas production. Canada is in search of an outlet for its gas, and LNG liquefaction could significantly expand its business opportunity to growing Asian markets or even to Latin America or beyond. The 7 bcm/y Kitimat LNG, owned by Apache, EOG Resources and Encana, is the most advanced on the coast of British Columbia. Other projects that could export LNG are still at a preliminary stage. Shell, as well as Asian companies such as Mitsubishi, PetroChina, Kogas, Chubu Electric, Tokyo Gas and Osaka Gas, has been quite active in acquiring shale gas assets and has ambitions to eventually develop LNG projects (see chapter on unconventional gas). Being on the Western coast, these projects have a geographical advantage over US projects based in Texas when it comes to reaching Asian markets, as they do not have to transit the Panama Canal.

USA: Exporting Shale Gas

While ConocoPhillips and Marathon are shutting down their Alaskan exporting terminal Kenai after 40 years of operation, Cheniere Energy is attempting to build a liquefaction plant at Sabine Pass

terminal to export LNG, in addition to currently re-exporting LNG. It would take advantage of the cheap, domestically produced natural gas in the United States. Cheniere has gained approval from the US Department of Energy in May 2011 and is still awaiting approval from the Federal Energy Regulatory Commission to build a 26.8 bcm liquefaction plant, while Freeport LNG (ConocoPhillips, Cheniere and others) also aims to build a 14.5 bcm liquefaction plant of natural gas at its LNG import terminal.

In addition, the Lake Charles terminal (Southern Union and BG) filed an application in May 2011 to build a liquefaction plant to export 20.7 bcm of LNG. Cheniere has been quite active in materialising this liquefaction project by finding partners such as Morgan Stanley, Gas Natural, EDF Trading and Asian companies, and signing a MOU with them over bidirectional capacity (imports and exports). Such terminals are likely to look at Asia or Europe. Although these terminals would benefit from the expansion of the Panama Canal by 2014, they are further away from the booming Asian markets than Australian or even British Columbian projects. Serving Europe would depend on its future import needs and advancement of other Atlantic-based projects.

Venezuela

Despite declining production over the past decade, Venezuela's resource potential is large, with 5.2 tcm proven reserves that could turn the country into an LNG exporter. The recent discovery of the (estimated) 450 bcm Perla field in 2009 is particularly promising. Three trains (6.4 bcm each) of Delta Caribe Oriental LNG project are under consideration. Each train has a different stakeholder portfolio, with the NOC Petroleos de Venezuela (PDVSA) as the only one in common for all three trains, holding a 60% stake of each. However, projects have been considered for a decade, and there was not much progress in 2010. It is still uncertain which trains will go forward, if any, as the nearby US market is no longer thirsty for LNG. There were also plans to link the gas fields considered for these LNG trains to the existing trains in Trinidad and Tobago.

Potential LNG Projects in the Americas

Country	Project	Capacity (bcm)	Major Stakeholders	Online date
USA	Sabine Pass	26.8	Cheniere Energy	2015+
USA	Freeport	14.5	Freeport LNG Investment	2015+
USA	Lake Charles	20.7	Southern Union	2015+
Canada	Kitimat	7.2	Apache, EOG Resources, Encana	2015+
	Delta Caribe Oriental LNG 1	6.4	PDVSA, Galp, Chevron, QP, MIMI	2015+
Venezuela	Delta Caribe Oriental LNG 2	6.4	PDVSA, Galp, Enarsa, Itochu, MIMI	2015+
	Delta Caribe Oriental LNG 3	6.4	PDVSA, Gazprom, Eni, Petronas, EDP, Blanquilla Este and Tortuga	2015+

Source: IEA and companies' websites.

The expected online dates are as given by project sponsors and do not reflect the IEA's opinion.

Asia

Indonesia

Although Indonesia is reducing future LNG exports from traditional LNG trains due to growing domestic demand for gas, the Tangguh partners are currently in talks about building a third train.

Masela, with 14 tcf (400 bcm) estimated reserves, has been granted a project approval from the Indonesian government in December 2010 for two phases of 3.4 bcm and 2.7 bcm, respectively. But Inpex delayed FID from 2011 to 2013 and the start-up date of the first phase from 2016 to 2018 accordingly. Total and Inpex plan to develop the Mahakam gas block in East Kalimantan in order to supplement depleting gas supply to existing Bontang LNG, which has extended supply contracts (25 bcm in total) with Japan until 2020.

Papua New Guinea

In Papua, New Guinea, there is one LNG project currently under construction, PNG LNG Train 1 and 2, led by Exxon Mobil. Exxon Mobil and its partner Oil Search have the ambitious plan to expand the project by building two more trains of equal capacity to Train 1 and 2 (9 bcm). In addition, InterOil is also developing an LNG project and the governmental approval was granted in December 2009. The project has selected Bechtel for FEED and construction work and will be developed in two phases of 2.7 bcm and 1.36 bcm, respectively. It has a very ambitious completion target of 2013, but it is very likely to be delayed since there is no firm agreement with any LNG buyer yet.

Potential LNG Projects in Asia

Country	Project	Capacity (bcm)	Major Stakeholders	Online date
Papua New Guinea	Liquid Niugini Gas	2.7+ 1.36	InterOil, Pacific LNG	2015+
	PNG LNG Train 3&4	9	Exxon Mobil, Oil Search	2017+
	Tangguh Train 3	5.2	BP, CNOOC, MI Berau	2014+
Indonesia	Masela LNG Train 1	3.4	Inpex, Energy Mega	2018+
	Masela LNG Train 2	2.7	Persada	2018+
	Mahakam block (to Bontang LNG)	NA	Total, Inpex	2017+

Source: IEA and companies' websites.

The expected online dates are as given by project sponsors and do not reflect the IEA's opinion.

Middle East

After the recent wave of LNG projects from Qatar, new projects in the Middle East look challenging. In the medium term, only Qatar could be in a position to increase its capacity by around 12 bcm through debottlenecking, but this depends crucially on the moratorium on new developments being lifted. Iran has much potential, but the United Nations' sanctions made LNG dreams fade away. Meanwhile, the discovery of the Tamar and Leviathan gas fields came as a surprise to Israel.

Iran

Iran is having difficulty developing its three LNG projects: Iran LNG, Persian LNG and Pars LNG (see chapter on investments in major producing regions). Due to economic sanctions from the United Nations, the United States and the European Union over its nuclear program, Iran's access to advanced technologies of liquefying natural gas is very limited. Without the advanced technologies of LNG, all Iranian LNG liquefaction projects are likely to be delayed for a long time until the sanctions are lifted, but they still have the option to develop their gas fields through pipeline exports to neighbouring countries or to consume the gas domestically.

Israel

The US's Noble Energy and Israeli Delek Energy are keen to develop their own LNG project after finding sufficient natural gas in the Tamar and Leviathan fields offshore Israel's coast (see chapter on investments in major producing regions). As the estimated reserves of both fields are ample enough (240 bcm (8.4 tcf) and 450 bcm (16 tcf), respectively) to meet the growing gas demand (mostly from the power sector), it would even be possible for Israel to become an LNG exporter for decades to come. The gas supply disruption from Egypt in early 2011 encouraged the Israeli government to expedite the process of approval and support the construction of an LNG plant, but the government is also attempting to levy a heavy tax on the gas production. The partners are discussing various options to develop the project, including building an LNG liquefaction plant in Cyprus.

Russia: Where Will the Next LNG Project Be?

Several projects are under consideration in Russia, in the North West (Shtokman and Yamal LNG) and in the Far East. A few projects are supported by the Russian federal government, which has the ambitious target of becoming a major LNG exporting country, particularly to the Asia-Pacific region. Gazprom and Novatek agreed in June 2010 to cooperate for the Yamal LNG project based on the South Tambayskoye gas field, with estimated gas reserves of 44.5 tcf (1.25 tcm). Novatek has so far selected Total as foreign investor and is in talks with Statoil to expedite the project development.

The Russian federal government is strongly supporting the Yamal LNG project and has proposed a tax exemption for whichever comes earlier – the first 12 years of production or 250 bcm production of gas. Gazprom's Shtokman LNG project has also the strong support from the government and could potentially be developed if firm buyers of LNG are found. Nevertheless, both greenfields of the Yamal and Shtokman projects have great technical challenges, due to the severe cold environment of the plant sites and gas fields and to the remoteness from major LNG markets compared to other projects. An efficient project cost management and competitive freight cost arrangement would be primary keys for success of these projects in a highly competitive market environment. As it has an existing infrastructure in place and a successful record of two years' operation, Sakhalin II Train 2 has a comparative advantage to the other projects in Russia. Negotiations with Sakhalin I and III partners could provide sufficient gas reserves to materialise a second train or even more. Japan and Russia agreed to advance the study of building an LNG plant in Vladivostok to start exporting 6.8 bcm of LNG from 2017.

Potential LNG Projects in Russia

Project	Capacity (bcm)	Major Stakeholders	Online date
Sakhalin II Train 2	6.5	Gazprom, Shell, Mitsubishi, Mitsui	2015+
Sakhalin I	7.5	Exxon Neftegaz	2015+
Sakhalin III	7.5	Gazprom	2015+
Vladivostok LNG	6.8	Gazprom, Japanese Government	2017+
Yamal LNG	20.4	Novatek, Total	2017+
Shtokman LNG	10.2 plus	Gazprom, Total, Statoil	2018+

Source: IEA and companies' websites.

The expected online dates are as given by project sponsors and do not reflect the IEA's opinion.

Sub Sahara

Nigeria

Although Nigeria has great potential to develop several LNG projects, progress has been very slow due to the lack of a stable financial and tax regime and political uncertainty. President Goodluck Jonathan would be a strong driver to push some LNG projects going forward. Another issue is the Petroleum Industry Bill (PIB) that is currently in legislative consideration at the National Assembly and is to be approved by the President. The PIB is to provide legal reform and transparency to the country's petroleum industry, including privatisation of the Nigerian National Petroleum Corporation (NNPC). If the PIB is enacted, there will be a growing expectation that Nigeria become a much larger LNG supplier than ever before and it could support the development of future Nigerian LNG projects in a more transparent manner. Meanwhile, Brass LNG's major stakeholder NNPC has diluted a small portion of its project stake to LNG Japan, Itochu and Semptra. This movement is obviously an attempt to strengthen marketing activities in the Asian Pacific LNG market for the outlet of Brass LNG. Brass LNG is said to be reaching FID before the end of 2011 for a start in 2016. Olokola LNG (OK LNG) is also currently under project review by investors, but it would start later.

Angola, Equatorial Guinea and Cameroon

Both Equatorial Guinea and Angola are considering a second train; Equatorial Guinea has had one since 2007, while Angola's first train would start in 2012. But there is not much progress confirmed. However, with a first train already operational or soon to be operational, a second train for Angola LNG and EG LNG would have geological and economic advantages against other traditional producers to exploit the growing demand for LNG in the Middle East, Africa and South America towards 2020. Meanwhile, GDF Suez is looking at investing into a 4.8 bcm LNG plant near Kribi in Cameroon.

Potential LNG Projects in the Sub-Sahara

Country	Project	Capacity (bcm)	Major Stakeholders	Online date
Angola	Angola LNG Train 2	7.1	Chevron, Sonangol, Eni, Total, BP	2015+
Equatorial Guinea	EG LNG Train 2	6.0	Marathon, GEPetrol, Mitsui	2016+
Cameroon	Cameroon LNG	4.8	SNH, GDF Suez	2017+
	Brass LNG	13.6	NNPC, Total, ConocoPhillips, Eni	2016+
Nigeria	Olokola (OK) LNG	15	NNPC, Chevron, Shell, BG	2018+
	NLNG Train 7	11.4	NNPC, Shell, Total, Eni	2018+

Source: IEA and companies' websites.

The expected online dates are as given by project sponsors and do not reflect the IEA's opinion.

INVESTMENTS IN PIPELINES AND REGASIFICATION TERMINALS

Summary

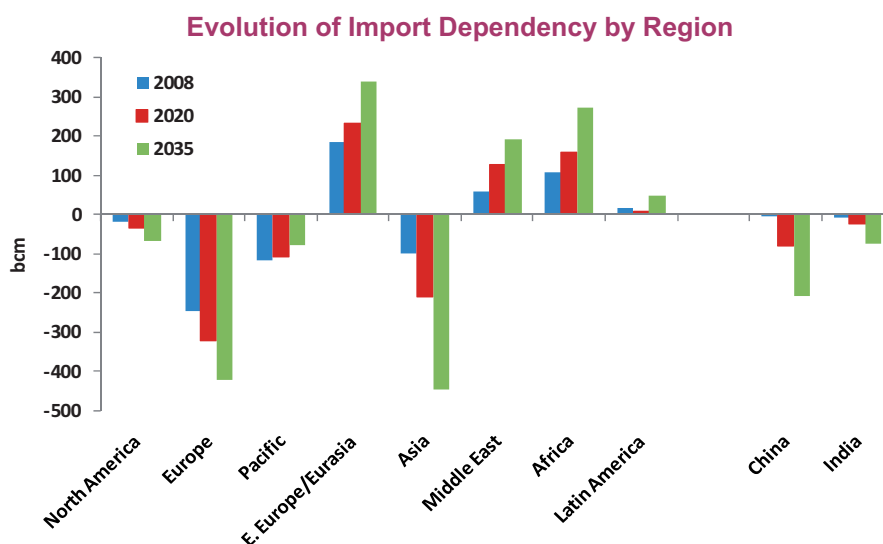
- **Expansion of inter-regional and intra-regional pipeline capacity is crucial to enable higher gas consumption levels, particularly in Asia. But this part of the gas value chain is especially sensitive to abrupt market changes.** Inter-regional transport was particularly affected by the 2009 economic crisis and much uncertainty remains on how the future regional import dependency will evolve. This depends not only on future demand developments, but also on whether, and to what extent, the unconventional gas revolution will spread throughout the world.
- **LNG regasification terminals are advancing slightly faster than inter-regional pipelines. Not only do they benefit from the recent wave of LNG liquefaction plants, but the new floating regasification terminals can rapidly provide relief to countries, particularly in the Middle East, Southeast Asia and Latin America.** Around 110 bcm of regasification capacity is currently under construction, while only three inter-regional pipelines are under construction or being expanded.
- **Expansion of intra-regional capacity is moving ahead, particularly in Europe and North America, but the motives are different.** Europe's primary concern is to enhance security of gas supplies by reinforcing the interconnections between countries, while pipeline expansion in North America aims to bring shale gas production to markets. In Southeast Asia, some intra-regional LNG trade could emerge, as planned pipeline interconnections are not making much progress.
- **Asia is attracting most investments, both in new regasification terminals, and inter-regional pipelines.** Two of the pipelines under construction, from Turkmenistan and Myanmar respectively, are targeting China, aiming to bring an additional 40 bcm of capacity by 2013. Meanwhile, around 70 bcm of regasification capacity is under construction in Asia, targeting not only the fast-growing markets in China and India, but in Southeast Asia as well.
- **The emergence of importer/exporter countries will further complicate international trade.** Some LNG exporters in the Middle East and Asia will increasingly have to turn to LNG or pipeline imports to be able to meet their growing demand and export commitments. Meanwhile, Canada and the United States are moving in the opposite direction by planning liquefaction capacity to export their production.

Global Trends

The developments in the natural gas markets during the past years have strongly affected both intra- and inter-regional gas flows. The US unconventional revolution has strongly reduced US import needs, while on the other side of the globe, Asian gas demand is growing more rapidly than indigenous production, creating new infrastructure needs. In 2009, the economic crisis strongly impacted gas, and thus, import demand, in almost all world regions. Despite an impressive recovery in 2010, uncertainties about how regional demand will continue to grow, the future role of gas in the power mix, and how fast development of unconventional gas production will spread into other regions, make it unclear how regional demand and supply balances will evolve, and thus how inter-

regional trade will develop in the future. This creates uncertainty about whether and when additional transport capacity might be needed, in some situations stalling investment decisions. Then again, growing uncertainty creates a need for both supplying and consuming countries to diversify their export and import possibilities, creating new incentives for infrastructure investment.

In some regions, investments are still very much aimed at filling a growing import dependency, while in others, investments are mainly aimed at diversifying supply options. The evolution of regions' import dependency over the period 2008-35, based on *WEO 2010* forecasts, shows that the import dependency of both Europe and Asia will strongly increase in the coming years, reaching over 400 bcm by 2035. In Asia, India and China are driving this increasing demand, which will need to be filled by Russia, the Caspian region, the Middle East and Africa.



In 2010, two inter-regional pipelines came on stream: the Central-Asia-China gas pipeline (CAGP), which has currently the capacity to bring around 10 bcm of Caspian gas to the Chinese market, and the Dauletabad-Sarakhs-Khangiran pipeline, bringing around 8 bcm of Turkmen gas to Iran. This reinforces the pivotal role of Turkmenistan as a supplier of Asia, Russia and Iran, with the possibility to send at least 20 bcm in every direction by the end of 2011 (except directly to Europe). Also in 2010, more than 40 bcm of LNG regasification capacity came on stream, bringing total global regasification capacity up to more than 800 bcm, and several terminals in China, Argentina, and the United States were commissioned during the first five months of 2011.

The highest LNG regasification capacity increase in 2010 was observed in Europe, with the United Kingdom increasing its capacity. Despite the low US utilisation rates, two new terminals came on stream in North America, as FID was taken well before the shale gas revolution happened. Capacity also increased in Asia, not in China and India, but in the more mature markets of Japan and Korea. In the Middle East, a second terminal came on stream, with Dubai also becoming a LNG importer. Currently another 109 bcm of regasification capacity is under construction and planned to come online before 2015. These terminals are spread as follows: 61% in Asia (half of which in China and India), 23% in Europe, and 17% in North America. Many Asian countries will start being LNG

importers – Thailand in 2011, Singapore in 2013, but also traditional LNG exporters such as Malaysia and Indonesia are planning to import LNG starting in 2012.

At the same time, there are currently only a few large-scale, inter-regional pipeline projects under construction: the 27.5 bcm Nord Stream from Russia to Europe, the 12 bcm Myanmar-China pipeline, and the Kazakhstan-China pipeline, which will connect to the Central-Asia-China Gas pipeline currently being expanded. It is clear from both the capacity which came on stream in 2010 and currently under construction that LNG projects are moving forward faster than pipeline projects, although in several regions both pipelines and LNG projects are being developed simultaneously to keep up with a growing import dependency.

LNG Regasification Capacity (bcm) by Region (as of June 2011)

Region	Operation	Construction	Planned
Asia	434	66	141
<i>Japan & Korea</i>	353	13	8
<i>China & India</i>	45	35	89
Europe	180	25	246
<i>United Kingdom</i>	51	0	34
<i>Italy</i>	25	0	27
<i>France</i>	12		77
Middle East- Africa	7	0	10
North America	208	18	262
<i>United States</i>	179	13	223
Latin America	25	0	34
Total	854	109	694

Stopping at the development of inter-regional trade and infrastructure fails to look at the far more complex intra-regional trade picture. A large part of current infrastructure investments is aimed at increasing transport capacity within the region. There are various reasons for such capacity expansions: to expand the existing network, to enhance security of supply, to link gas-rich areas to areas of growing demand or to decrease price differences between different regions. Interestingly, difficulty of regional interconnection can lead countries to invest in inter-regional transport capacity. In many exporting regions, individual countries have become importers, not relying any more on their gas-rich neighbours, but importing LNG from other regions. This development, which so far has mostly appeared in Latin America and the Middle East, illustrates the failure of regional integration, often due to political or pricing issues.

Another interesting phenomenon is the emergence of the importer/exporter, whereby two categories exist. First are exporting countries which are having increasing difficulty meeting growing demand, *e.g.* at moments of peak demand, and which, while still exporting, have (or will soon have) to start importing – Oman, the United Arab Emirates, Indonesia and Malaysia are examples. And second are countries such as the United States, Canada and Iran, with plentiful gas resources and production, which need to import gas to supply certain areas due to transport bottlenecks between producing and consuming regions.

Europe

Inter-regional Interconnection: Diversifying Supplies

While Europe is very likely to become more import dependent in the coming years due to declining domestic production, there is little certainty on how big future import needs may be. Europe has nevertheless attracted a large number of import projects, both pipeline and LNG. In March 2011, after over two years of delays, the 8 bcm Medgaz pipeline linking Algeria to Spain has come on stream and the 27.5 bcm capacity Nord Stream is currently under construction and planned to come on stream later this year, further increasing Europe's interconnection with Russia. In addition, two new LNG terminals and several terminal expansions are expected to come on stream in 2011, further increasing European LNG regasification capacity.

Inter-regional Pipeline Projects in Europe

Source	Name	Expected date of completion	Status	Capacity (bcm)	Length (km)	Sponsors	Estimated Costs (Bn)
Russia	Nord Stream I*	End 2011	Under Construction	27.5	1,200	Gazprom: 51%, BASF, EON: 20% each, Gasunie, GDF Suez: 9% each	7.4 (€)
	Nord Stream II	End 2012	Planned	27.5	1,200		
	South Stream	End 2015 to End 2018	Planned	15.75x4**	3,463		15.5 (€)
Caspian Region	Nabucco	2017	Planned	25.5-31	3,296	Botas, Bulgargaz, MOL, Transgas, OMV, RWE	7.9 (€)
	ITGI	2017	Planned	12	800	Depa/Edison	0.8 (€)
	TAP	2016-2017	Planned	10 (+10)	520	EGL, Statoil: 42.5% each, E.ON: 15%	1.5 (€)
Algeria	GALSI	2014	Planned	8	1,470	Sonatrach: 41.6%, Edison: 20.8%, Enel: 15.6%, Sfors: 11.6%, Hera: 10.4%	2 (€)
Egypt	Arab Gas Pipeline Expansion	na	Planned	10	70		
Iran	Iran Gas Trunkline 9	na	Planned	37	1,047	NIGEC	na

Source: IEA, companies' websites.

Note: Nord Stream is sometimes called North Stream. South Stream will be developed in four phases of 15.75 bcm each, coming one after another. The expected online dates are as given by project sponsors and do not reflect the IEA's opinion.

Besides projects currently under construction, there is around 230 bcm of pipeline capacity and 245 bcm of LNG regasification capacity planned. Most pipeline projects seem to be stalled. The second string of Nord Stream has apparently secured financing and could start construction in mid-2011 to start operations by end-2012. However, it is uncertain if Nord Stream would really translate into additional gas supplies in the medium term. The different South Corridor pipelines – Nabucco, the Interconnector Greece Italy (IGI) or the Trans-Adriatic Pipeline (TAP) – are still competing, but none has made the decisive step towards investment. These projects depend crucially on Shah Deniz gas supplies, which will not be available before 2017 (see chapter on investments in major producing regions); accordingly, the starting dates of the projects have been postponed. FID on Galsi linking Algeria to Italy through Sardinia has been postponed once more. The Arab gas pipeline linking Egypt

to Jordan, Lebanon and Syria was to be linked to Turkey, but this expansion may be threatened by Egypt's Domestic Market Obligation (DMO), the explosion of the pipeline in February 2011, and recent unrest in the region. LNG regasification terminals seem to proceed more rapidly than pipelines, but only a few are likely to move forward in the medium term. The main difficulty is to find LNG supplies, as most new and committed LNG liquefaction plants are targeting Asian markets.

Europe is already strongly interconnected with its suppliers; pipeline interconnection between Europe and other regions (including Norway) has a total capacity of around 425 bcm and the region has 180 bcm of regasification capacity. Even though European import dependency is expected to increase in the coming years, Europe already has enough import capacity to cover its growing import needs. The question is more whether projects are to fulfil increasing import needs (such as in Turkey) or whether they would satisfy the imperative of supply diversification. Due to Europe's 20:20 targets, there is some policy uncertainty regarding future gas demand. Alternatively, a decision to prematurely close some nuclear power plants could have a positive impact on gas demand. Meanwhile, diversification presents difficulties of financing. Almost 65% of existing transport capacity (including LNG) connects Europe with one of its three large suppliers (Russia, Norway and Algeria), while around 75% of infrastructure projects come from other suppliers, especially from the Caspian region and the Middle East.

Focus on Improving Intra-regional Interconnections

One of the targets of the European Commission is to create a well functioning, single European energy market. Although progress has been made in recent years towards this objective, there are still several obstacles in place. One of them is the limited interconnection between various member states or regions. Two of the main bottlenecks, as determined by the European Commission in the Second Strategic Energy Review in 2008, are the transit capacity from West to East Europe and the limited interconnection between the Iberian Peninsula and the rest of Europe.

In most European Union member states, the intra-regional transport projects progressing from the planning to the building stage very much depend on the interest from the market for additional transport capacity. In some member states, investment decisions are made by the government or regulator via national planning. In most countries, the transmission and distribution activities are unbundled. The Transmission System Operator (TSO) needs to determine which projects are economically viable via an open season. In the open season, shippers with an interest in capacity will bid for long-term rights to use the capacity, promising a long-term financial commitment to the project. In this phase, bids are not yet binding. The open season allows a TSO to consult the market about infrastructure needed and the terms under which it would like this infrastructure to be marketed. The final FID will depend on the results of this process.

A review of current transport projects planned within Europe shows that many projects that have already reached FID are aimed at increasing interconnection in Western Europe, both within the region and with the other regions. Several projects that already have an FID will increase interconnection with the Iberian Peninsula, both entry and exit capacity. Other projects moving forward include interconnections between Belgium France and the Netherlands and between Germany, the Netherlands and Austria.

Intra-regional Europe Infrastructure Expansion Plans

Mcm/d	North		British		West		East		South		Iberian	
	FID	Total	FID	Total	FID	Total	FID	Total	FID	Total	FID	Total
North to	5	20	-	-	7	31	-	25	-	-	-	-
British to	-	-	35	35	-	-	-	-	-	-	-	-
West to	17	17	-	2	224	409	34	125	-	9	48	68
East to	-	24	-	-	6	6	67	108	20	30	-	-
South to	-	-	-	-	-	5	-	10	-	25	-	-
Iberian to	-	-	-	-	69	85	-	-	-	-	25	40
Total to	22	61	35	37	305	536	101	268	20	64	73	108

Source: ENTSG, Ten-Year Network Development Plan 2011-20.

A second market area with many infrastructure projects is Eastern Europe, for example, between Romania, Bulgaria, Hungary and Slovakia, most projects concern expanding existing pipelines or creating reverse flow possibilities, efforts following on the Russia-Ukraine crises. There are still many projects which have not yet reached an FID; in most cases these projects still need to go through the open season process. There are many transport projects in the planning stage aimed at increasing gas flow from Western to Eastern Europe, the second bottleneck determined by the European Commission, but only a limited number has already reached FID. Often there is no particular need for dedicated pipelines, but rather more a need for reverse flow capacity or backhaul transportation. This includes interconnections from Germany and Austria into the Czech Republic, Slovakia, Hungary and Poland.

North America

A Massive Expansion of LNG Capacity has Occurred, but What for?

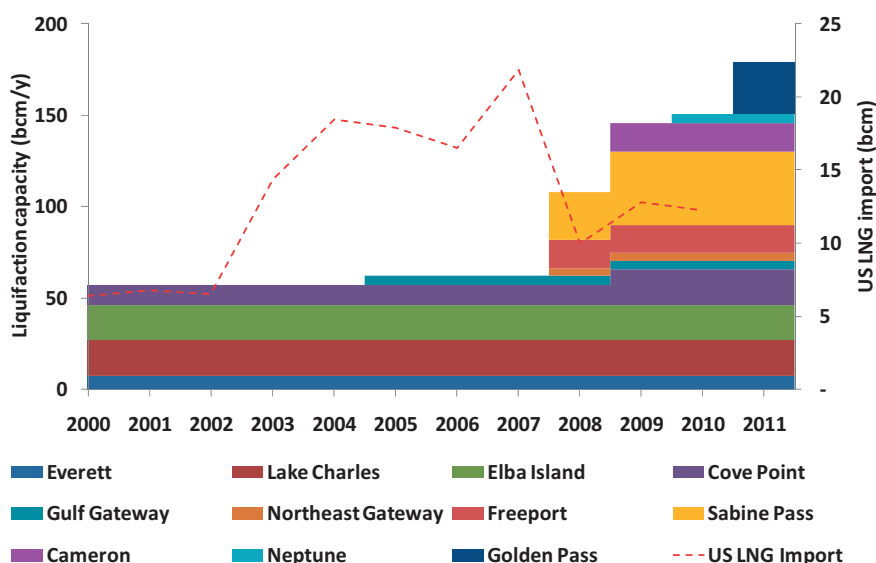
As mentioned previously, the US unconventional gas revolution has significantly decreased the need for LNG imports into the North American market, albeit with some strong regional disparities. Between 2004 and 2009, OECD North America LNG imports dropped by almost 25%, while in the same period, the installed LNG regasification capacity in this region increased by more than 100 bcm to reach 208 bcm. This trend was most visible in the United States, where the regasification capacity on the East coast doubled over the years 2005-11 to reach 179 bcm, while LNG imports decreased by one-third, implying a utilisation rate of 7%.

Assuming that, in the coming years, LNG imports stay at the current level and, based on the world's average utilisation rate of one-third, this means that around 150 bcm (the equivalent of an estimated \$20-25 billion investment) will stay idle in the short to medium term. Meanwhile, Canada and Mexico have become LNG importers, with some of the volumes being delivered through terminals in the United States, in the North East and California respectively. Just as Europe, North America has already enough existing import capacity to cover expected future import needs. Projections in the *WEO 2010* expected North American net import requirements to increase to 67 bcm by 2035; implying an utilisation rate of existing capacity of around 33%.

Even so, there are still plans to build more than 20 new regasification terminals in the region, some of them being a legacy of the pre-shale gas period. There were even more planned projects, but several have already been suspended or cancelled. Seeing the current low utilisation of the existing

LNG capacity and the expected development of future import demand, it seems unlikely that the planned terminals will be built in the near future.

Development of US LNG Regasification Capacity and LNG Imports



Unconventional Gas Drives Intra-regional Interconnections

The North American region is very well interconnected, both between the three countries and within the United States and Canada. The United States has about 50 transit points where natural gas can be exported or imported from or to Canada or Mexico, with a total capacity of almost 200 bcm/y. There are currently no large projects underway aiming at increasing the interconnection between the three countries, but much transport capacity is under construction or planned within Canada, Mexico and the United States. The large increase in unconventional gas production has significantly changed the gas flows within the United States; many of the currently planned infrastructure projects are aimed at increasing the connections between the large shale gas areas in Texas and demand areas in the North or to make use of price differences currently existing between local markets.

Just as in Europe, most pipeline projects in the United States go through an open season process. The results of the open season show whether there is interest in the capacity that will be built and if shippers are willing to pay a high enough price to make the project economically viable. On the basis of the results of the open season, the Federal Energy Regulatory Commission (FERC) will approve the project or not.

Since 2009, the FERC has approved three pipeline projects with a capacity of 20 bcm/y or more. They represent 65 bcm of capacity and are already operational. Two projects approved in 2009 were the Fayetteville Express Pipeline and the Fayetteville Shale Compression Project, with a total length of 300 km and a total capacity of 44.5 bcm/y. Both projects link the Fayetteville shale plays in Arkansas and the growing demand markets in the South East. The Tiger Pipeline, a 282 km pipeline with a capacity of 20.7 bcm/y, linking the Haynesville shale in Texas-Louisiana and the Midwest and

Northeast markets, was approved in 2010. Meanwhile, two large projects to transport gas from the North Slope in Alaska to the US market (the Alaska Pipeline Project and the Denali Project) that have been under discussion for almost 40 years went through an open season in 2010. On the basis of the results of the open season, the Denali Project has been halted due to too little customer interest. The second project, the Alaska Pipeline Project, has not yet been approved by the FERC. In Canada and Mexico, pipeline projects do not go through an open season process. In Canada, the National Energy Board (NEB) determines if there is a need in the market and, on the basis of this, will decide to approve the project or not. The Mackenzie Gas Project, a 1,196 km pipeline that will connect northern onshore gas fields with the Canadian and US markets, was approved by the NEB in 2010.

Southeast Asia: LNG Is the Only Option

Southeast Asia is historically a large gas-producing region, but demand has been growing fast over the past decade (on average, 6% a year) to reach 160 bcm in 2009 – more than Japan and Korea together. Although the region is expected to remain a net exporter, many countries will need import infrastructure due to growing demand and dwindling production in the major exporters. Several countries are considering LNG regasification terminals as an instrument to cover their increasing natural gas demand: Indonesia, Vietnam, Thailand, Sri Lanka, the Philippines and Singapore. In both Thailand and Singapore, LNG terminals are already under construction to come on stream in respectively 2011 and 2013; with one terminal in Indonesia and one in Malaysia, also under construction and planned to come on stream in 2012. In the other countries, the terminals are only in the planning phase. Interestingly, even Indonesia and Malaysia, two large natural gas exporting countries, are currently building regasification capacity, mainly to increase gas flows to high demand regions. Most of the planned terminals are Floating Storage and Regasification Units (FSRU). The great advantage of the FSRU over the conventional onshore system is its shorter building time, which can be further shortened by converting an existing LNG vessel into an FSRU. For countries facing a fast increasing import demand, the shorter building time makes choosing for a FSRU over a conventional onshore facility very attractive. No inter-regional pipeline project is planned in this region.

Developing a Regional LNG Hub

There are currently nine intra-regional pipelines in Southeast Asia connecting the natural gas producing countries Indonesia, Myanmar and Malaysia with demand countries Singapore, Malaysia²⁸ and Thailand. All currently existing connections are bilateral connections. Only one expansion of these bilateral connections is currently planned: the 500 km-long Malaysia–Philippines pipeline. One of the key programme areas under the ASEAN Plan of Action for Energy Cooperation (APEAC) has been the construction of the Trans-ASEAN pipeline (TAGP) connecting Thailand, Malaysia, Indonesia, Brunei and the Philippines to the Indonesian Natuna D-Alpha gas field. The Trans-ASEAN pipeline would be the first multilateral pipeline in the region. Although the project idea of the TAGP was launched in 1997, the outlook for pipeline interconnections in the region is constrained as the big exporters face declining production. TAGP depends largely, though not exclusively, on the East Natuna field, which is technically difficult to develop due to its high CO₂ content.

²⁸ Malaysia imports from Indonesia.



The large differences of economic development among the Southeast Asian countries, seems to limit intra-regional pipeline trade and thus the development of intra-regional interconnections. However, there is the potential to develop intra-regional LNG trade based on small-scale LNG, in order to supply isolated and remote areas with small LNG vessels. Gas could be used to complement variable power sources such as hydropower in regions not connected to existing electricity networks. LNG could also be sourced from FLNG based on stranded gas fields. Furthermore, Singapore is considering the idea of becoming a regional LNG hub, using its future LNG terminal and potentially offering LNG storage to third parties. This could enable the development of a regional gas price, similar to spot prices in the United States and the United Kingdom.

India and China

Bringing gas to consuming regions is key. Just as in Europe, natural gas imports are expected to increase strongly in the coming years in both India and China. The first natural gas pipeline capable of bringing Caspian gas to China came online end-2009; the CAGP has a current capacity of around 10 bcm. This pipeline is currently the only pipeline bringing gas from outside the region to China. China started importing LNG in 2006 and it now has four LNG terminals operational with a total regasification capacity of around 21 bcm. India currently has no pipelines capable of importing gas from outside the region, but does have two regasification facilities with a total capacity of 20 bcm.

Inter-regional Pipeline Projects in China and India

Source	Name	Expected date of completion	Status	Capacity (bcm)	Length (km)	Costs \$ Bn.	Sponsors
Russia	Altai Pipeline	2014-15	Planned	30	2800	14	Gazprom, CNPC
	Russia – Asian Pacific Pipeline	2015-17	Planned	10	Na	3	Gazprom
Caspian Region	CAGP expansion; Kazakhstan – China Pipeline	2014	Under Construction	+30	1480	2.75-3	CNPC, Turkmenogas, KMG
	CAGP expansion phase II		Planned	+20			CNPC, Turkmenogas, KMG
	TAPI Pipeline	2015+	Planned	30	1680	7.6	ADB, et al.
Iran	Iran – Pakistan (-India) pipeline	2015+	Planned	8	900 (2700)	7.5	Inter-State Gas systems, NIOC
Myanmar	Myanmar-China pipeline	2013	Under Construction	13	2806	2.5	CNPC, MOGE

Note: The expected online dates are as given by project sponsors and do not reflect the IEA's opinion.

Both India and China do not have enough import capacity to cover their expected future demand; both countries have several projects under construction or planned to increase their interconnections, in the form of LNG regasification capacity and pipeline capacity. For further pipeline capacity expansion, China and India mainly look north or west – to Russia, the Caspian region and the Middle East. For both the Caspian region and Russia, expansion eastward is an interesting way to diversify their exports. The Caspian region was very much dependent on Russia for its exports, but this is changing with the new CAGP opening a door to China. Meanwhile, Russia exports primarily to Europe and the CIS countries. These pipeline projects would permanently affect flows and relationships not only for Russia and the Caspian region, but also between these two regions.

China and India are not only expanding their pipeline capacity, but also their LNG regasification capacity. Currently eight LNG terminals are under construction, six in China and two in India, three of which are planned to come on stream in 2011. A further 13 plants and several expansions of existing terminals are in the planning phase. If all the planned terminals are constructed, total LNG regasification capacity in China and India would increase from the current 41 bcm to 170 bcm.

Intra-regional Pipelines: Bringing Gas to China is Key

Not only are China and India increasing their interconnections with other regions, both countries are also strongly expanding their inland gas infrastructure, connecting indigenous gas production regions and import entry points to areas of growing demand and expanding their network into locations that are not yet connected. Good examples of pipeline projects that fall in this first category are the Chinese West-East pipelines, phase I up to IV. The first phase has already been completed, connecting the Tarim Basin with the Yangtze delta and has a capacity of 12 bcm. As the inflow of natural gas from the Caspian region increases, transport capacity between West and East will need to be increased. Phases II and III of the West East pipeline, which will expand the pipeline in the direction of the power hungry Hong Kong and Guangzhou region, are currently under construction, while a fourth phase is currently in the planning phase.

India's pipeline network has been developed mostly in the north-west of the country. In 2008, the East-West pipeline was built by RGTIL to link Krishna Godavari KG-D6 field in the East to the existing network. Despite the 11,900 km pipeline network (with a capacity of over 100 bcm/y), many cities in the South, the North and the East do not have access to gas due to the lack of transport infrastructure. Encouraged by the government, which also wants to develop city gas distribution, the pipeline network is to be expanded dramatically. GAIL, the main transport company, will expand its 8,000 km network by 5,500 km over the period 2011-2014, enabling cities such as Kochi or Bangalore to get gas. RGTIL has over 2,600 km of pipeline connections planned along the East coast and in the South, towards Chennai, Tuticorin and Mangalore.

Africa and Middle East

Inter-regional Interconnection

Both Africa and the Middle East are currently natural gas exporting regions; The *WEO 2010* predicts both regions to significantly increase their LNG and pipeline exports in the future, filling growing demand in both Europe and the Asian regions (see investments in production and investments in LNG). African pipeline projects focus mainly on expanding export capacity to the European market, via the Mediterranean Sea or Turkey.

The Middle East inter-regional pipeline projects are aimed at expanding both to Asia and to Europe. At present, there seems to be little progress made on projects in both regions. The 10 bcm Arab Gas Pipeline currently supplies Jordan, Lebanon and Syria, as well as Israel, through a specific line; it was planned to be extended into Turkey in 2011, but there currently are no signals that construction has commenced on this pipeline track. Meanwhile, the 8 bcm GALSI, linking Algeria directly to northern Italy through Sardinia, has also not taken FID, although it is still planned for 2014. Iran is also increasing its connections to Turkmenistan with the recent addition of the 8 bcm Dauletabad-Sarakhs-Khangiran pipeline in 2010. The interconnection could be expanded to 13 bcm/y despite the absence of firm plans. The main issue for Iran is the lack of capacity to bring Iranian gas produced in the South to the North, where winter demand is particularly high.

Interestingly two Middle East countries, Kuwait and Dubai, have started to import LNG through two LNG regasification facilities in 2009 and 2010, respectively, despite the region's large natural gas

reserves. These LNG terminals are mainly constructed to meet high peak demand in summer. Both terminals are FSRU. The short building times made the FSRU an interesting option for both Kuwait and Dubai, which were struggling with short-term natural gas shortages. A third terminal, also offshore, is planned to be constructed in Bahrain.

The Success of FSRU

It usually takes about three years to build an on-shore LNG receiving terminal (4 to 5 bcm/y capacity) costing \$800 to 900 million, although the construction costs and timeframe can vary significantly depending on the size of the terminal, geological condition, safety regulations, etc. However, some countries with urgent import needs due to rapidly growing gas demand chose to build an alternative terminal, called a floating regasification terminal, which can be erected much faster and is less expensive than an on-shore terminal. There are two types of floating regasification terminals in the market. One is a floating storage and regasification unit (FSRU) and the other is an LNG regasification vessel (LNGRV). FSRU and LNGRV are very similar in terms of their functions; In although they are both essentially LNG tankers equipped with regasification facilities, the FSRU receives LNG from another LNG tanker shipped out from the LNG production terminal and regasifies the LNG into gas pipeline grids while LNGRV can transport, store and regasify LNG into gas grid all by itself. There are currently three FSRUs operating in Brazil and Dubai and ten LNGRVs worldwide.

Generally, newly built FSRUs or LNGRVs, as well as associated facilities to accommodate a floating terminal and transport gas to pipeline grid, cost around \$450 million/tanker, roughly half of an on-shore terminal, and take less than two and half years to build. It would be even less expensive and quicker to convert a used LNG tanker into a floating terminal. One can even charter an FSRU or LNGRV for a certain period while building a minimum facility to transport regasified LNG to an on-shore gas grid. The primary disadvantage of floating terminals is the difficulty to expand the capacity to more than 5 bcm/y, as compared to on-shore terminals. However, it is also feasible to start importing with inexpensive floating terminals and build larger on-shore terminals for a longer-term importing strategy. The United States, Kuwait and Argentina currently hold the facilities to accommodate LNGRVs. There is also growing interest for floating regasification terminals worldwide, particularly in Asia and Latin America, due to growing gas demand. Thailand will start importing LNG at its floating terminal by mid-2011 and other Southeast Asian countries are to follow in 2012.

Slow Progress of Intra-regional Interconnections

Within Africa and the Middle East there are pipeline projects of various sizes under way. The small projects are often aimed at increasing transport capacity within countries or between member states. Just as with the larger inter-regional interconnections, pipeline projects within the region have seen little progress in the past year. In 2010 the West African Gas Pipeline (WAGP), which supplies Nigerian gas to industries and power stations in Benin, Togo and Ghana, came on stream, but this pipeline has experienced several problems in its first months of operation and gas flows are still limited. Other projects currently in the planning phase are the Iraq-Syria pipeline, and the Kish field pipeline, to bring Iranian gas to Oman. The limited interconnection in the Middle Eastern region has led several countries to invest in LNG capacity in order to cover peak demand.

Another more large-scale project in this region is the Trans-Saharan pipeline, which could connect Nigeria with existing Algerian infrastructure, creating the opportunity for Nigeria to export natural gas to Europe via existing pipelines. Although many companies, including Gazprom, Sonatrach, Total,

ENI and Shell, have expressed interest in the project, its fruition seems uncertain. There are doubts about whether expanding Nigeria's LNG export would not be a cheaper option and whether Nigeria will be able to produce enough natural gas to make the pipeline economically viable, notwithstanding the fact that the pipeline would traverse a quite instable region.

South America

A Small but Growing LNG Importer

South America has been a self sufficient market for a long time, with little interconnection with other regions apart from LNG exports from Trinidad and Tobago. Interestingly, just as in the Middle East, several countries in South America have started investing in infrastructure capable of importing gas from other regions. These investments are in part driven by previous supply disruptions between neighbouring countries. Failures to boost indigenous supply in the beginning of the century led some countries to restrict their exports in an attempt to address a domestic gas shortage. This, added to resource nationalism, has caused countries to invest in supply diversification options. Since 2003, seven LNG regasification installations have therefore become operational in South America, increasing natural gas import capacity to 25 bcm. The installations are located in Brazil, Argentina, Chile and the Dominican Republic.

As in the Middle East, the short building time of the FSRU compared to the onshore facility, made this option interesting for the South American countries struggling with natural gas shortages. Around ten LNG terminals, five of which will be FSRU terminals, are currently planned to come on stream in the period up to 2015. Due to the shorter build time of the FSRU, LNG regasification capacity could increase relatively quickly in Latin America. The floating terminal in Argentina/Uruguay got the green light from both government and could start construction very soon; however, little development has been seen on the ones currently in the planning phase.

Intra-regional Interconnection Projects are Stalled

Interconnection within the South American region currently exists, mainly bilaterally, between the resource rich countries, Bolivia, Argentina and Colombia, and their neighbouring countries. Several expansions of these interconnections have been proposed due to rapidly increasing demand, but currently there are no projects under construction. One project, the Gasoducto del Noreste Argentino (GNEA) is in the bidding stage. It is a \$1 billion, 1,465 km pipeline project aimed at increasing interconnection between Bolivia and Argentina. This pipeline aims at supplying gas to Argentina, where demand now exceeds domestic production.

Other planned projects have been stalled, postponed or just do not seem to reach the construction phase. In the 1990's, integration of the gas markets was seen as a major goal in South America. The topic has lost much of its political interest in the past years and, due to poor energy policies, interest from investors decreased as well. As previously mentioned, several countries in the South American region have started to import LNG from outside the region, reducing the need for additional interconnection within the region.

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