MEDIUM-TERM OIL & GAS MARKETS

2010

International Energy Agency

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2010

Critical questions persist over the key oil and gas market drivers likely to prevail in coming years. Are economic and energy demand outlooks clearer than in mid-2009? In oil markets, have we seen a genuine structural shift in demand patterns? Will a nascent recovery in upstream spending evident in 2010 be sustained? How long will current levels of OPEC spare capacity persist? And for the gas market, will demand recover from its collapse in 2009? How long will the gas glut last? Will unconventional gas revolutionise gas markets outside North America? And how are China, Russia and the Middle East changing their approach to gas use?

The new combined IEA publication, *Medium-Term Oil and Gas Markets 2010,* tries to answer these questions, presenting a comprehensive, annual outlook for oil and gas market fundamentals for the next few years. The detailed oil market analysis develops two oil demand scenarios, given the ongoing uncertainties about the path of economic recovery after the worldwide slow-down in 2008/2009. Market balances are generated on a bottom-up basis, derived from detailed analysis of upstream investment projects, oil field decline rates, product-by-product demand trends, and refinery investment and operations. The gas market analysis provides a broader overview, assessing prices, unconventional gas, future demand developments, LNG markets as well as investment in all parts of the gas value chain and regional trends. It focuses on key producers, including Russia, the Caspian region, the Middle East and rising LNG exporters like Australia, and looks at the implications for global gas markets.

€ 500

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INTERNATIONAL ENERGY AGENCY

The International Energy Agency (IEA), an autonomous agency, was established in November 1974. Its mandate is two-fold: to promote energy security amongst its member countries through collective response to physical disruptions in oil supply and to advise member countries on sound energy policy.

The IEA carries out a comprehensive programme of energy co-operation among 28 advanced economies, each of which is obliged to hold oil stocks equivalent to 90 days of its net imports. The Agency aims to:

- 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.
- Find solutions to global energy challenges through engagement and dialogue with non-member countries, industry, international organisations and other stakeholders.

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FOREWORD

For the first time, the IEA is presenting a combined publication that sets out to analyse recent and future trends in oil and gas markets. We recognise that these markets are different, but there are areas of convergence. Both, for example, are currently affected by uncertainty about the sustainability of OECD economic recovery, together with the more consensual expectations for sharp growth in emerging countries.

For the next few years, the oil market is marked by more comfortable spare capacity than envisaged last year and the duration of the current gas glut is set to last beyond 2013, at least in some regions. Yet we shouldn't be complacent. Developing new supplies of oil and gas is in general a long-term undertaking. Global oil demand is expected to grow by 2% this year and the gas market is characterised by a strong asymmetry as demand might pick up again, especially in the power sector, much more rapidly than additional supplies. Output from mature oil and gas fields continues to show an inexorable decline, while production growth is increasingly concentrated in a few countries, often distant from consuming regions. Recent tragic events in the US Gulf of Mexico highlight the difficulties companies and regulators face in safely accessing more difficult sources of hydrocarbons. This is why the IEA urges all stakeholders to encourage sound, safe investment along the supply chain to ensure the security of oil and gas supply beyond a more comfortable short and medium term.

Consuming regions also bear a responsibility to encourage energy efficiency in order to smooth the transition towards a low-carbon economy. In our medium-term oil forecast, we present two scenarios depending on the growth of the global economy. These scenarios are also based on different assumptions in terms of energy efficiency progress. For the longer term, governments should strive to encourage a third scenario: one where strong economic growth is possible without excessive tightening of the supply/demand balance. This requires a more systematic encouragement of measures to boost energy efficiency, across all energy forms, starting now.

This report brings together our medium-term overviews of oil and gas markets. Such an approach highlights the significant, and ongoing, progress in oil data transparency over recent years, and the lack of similar progress in gas data. Much more needs to be done in the field of oil data, notably for the developing countries which will soon account for over 50% of the global market. But there is a clear need also for improved breadth, accuracy and timeliness of statistical data on gas markets. These markets are playing an increasing role in energy policy and in the transition towards a low-carbon economy. As we have learnt from oil markets, high quality, timely data are also essential to managing any emergency that may arise, and holds the potential to reduce market volatility borne of uncertainty. The partners in the Joint Oil Data Initiative have recently decided to extend their work to improve the quality, coverage and timeliness of data on gas markets. We urge all stakeholders to contribute to this bold data endeavour.

Despite all their differences, we are seeing increasing interaction between oil, gas and power markets. I thought it would be useful to allow our readers to make their own judgements about the convergence of oil and gas markets by presenting the updates of our medium-term analyses for both together. We hope this new effort will help provide more transparency and understanding of current and future market trends at a time of such great uncertainty.

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

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EXECUTIVE SUMMARY

Oil and gas markets are starting to show important signs of recovery, but the impact of the recession has been different on the two energy sources. Gas demand fell by more than 3% in 2009, double the pace of decline seen for oil. This highlights the use of oil primarily as a transport fuel, where consumption is relatively inelastic. Gas on the other hand, as a major industrial and power generation fuel, was fully exposed to the decline in industrial production seen in the recession. But common to both oil and gas is the dichotomy between OECD and non-OECD markets, with continuing growth in non-OECD regions, notably China, India and the Middle East, contrasting with weaker demand in OECD and FSU countries. Last year's medium-term outlooks for oil and gas markets were written amid apparently contradictory concerns. In the midst of chronic uncertainty about prospects for the global economy, virtually at the nadir of the recession, there were nonetheless serious questions about the adequacy of upstream oil investment to meet an anticipated eventual rebound in oil demand growth. While upstream gas concerns were more muted, owing to the surge in North American unconventional gas output, and the massive expansion of LNG liquefaction plants, uncertainty about the timing and extent of medium-term investments throughout the value chain were still present.

A year later, many uncertainties persist. Regulation of commodity futures markets is still clearly on policy markers' radar and operational regulation in the physical market for both gas and oil could be overhauled, depending on results of the enquiry into the Gulf of Mexico disaster. The European debt crisis has created additional uncertainty over the resilience of the economic recovery there and further afield. Questions persist too over the impact of stimulus withdrawal and potential over-heating in the Chinese economy.

Demand

Although economic recovery has become re-entrenched, in sharp contrast to last year's back-drop, concerns persist about its strength and durability. As a result, two oil demand scenarios are again presented. Using May 2010 *OMR* data as our starting point, we have developed two contrasting views on economic growth, with the lower variant also tempered by weaker assumed efficiency gains. Common features however are the predominance of both the non-OECD countries and the transportation sector in driving demand growth. In the higher GDP and efficiency gains case (the base case for our analysis), oil demand grows by an average of 1.2 mb/d annually (1.4%), reaching close to 92 mb/d by 2015. Oil demand recovers to pre-crisis 2007 levels again by 2010. This presupposes GDP growth around 4.5% per year from 2010 onwards (in line with recent IMF projections) and a reduction in oil use intensity of 3% annually, near the level seen in the last five years.

But many voices still envisage a weaker path for global economic growth, amid world trade imbalances and the weakening impact on activity of aggressive fiscal consolidation. This suggests a lower GDP and efficiency gains case. Here, global GDP grows by a weaker 3% annually, while the progress in oil use efficiency is slowed by the weaker investment environment, pushing anticipated reductions in oil use intensity back to the 15-year average, near 2% per year. In this case, annual oil demand growth averages 840 kb/d (1.0%), taking total global demand to 90 mb/d by 2015, with the reattainment of 2007 demand levels deferred to 2011.

This year for the first time, we have modelled OECD gas demand into the medium term, using the same high case GDP assumptions as for the oil market projections, notwithstanding that gas data are generally less comprehensive than for oil. We see OECD demand returning to 2008 levels by around 2012, but with large regional variations, with Europe especially weak, given its sharp decline in 2009 (nearly 6%) and ongoing concerns about its recovery. OECD Europe does not return to demand levels seen in early 2008 until after 2013. The power sector is a key source of uncertainty in OECD demand, but also in some non-OECD regions, including the Middle East. OECD North America and Pacific gas demand is recovering, and can be expected to surpass 2008 levels as early as 2012, as industrial production recovers, and gas remains the fuel of choice in the power sector. Asian demand is growing strongly; Chinese gas demand doubling between 2007 and 2015 now looks conservative. Hence gas markets seem likely to tighten more quickly in the medium term in some regions, notably the Pacific, in comparison to Europe or North America.

Supply

Some of last year's concerns about medium-term oil supply prospects have eased, with baseline global supply capacity now estimated close to 91 mb/d, around 0.9 mb/d higher than anticipated in the June 2009 *MTOMR*. Stronger crude prices, lower costs and a renewed uptick in spending have helped facilitate this upturn. New project schedules have been advanced, and implied decline from baseload fields looks to have eased slightly (albeit remaining a constant drain on global supplies). Non-OPEC supply continues to grow through the outlook, concentrated on the Americas, the Caspian and biofuels which offset mature field decline, notably in the OECD countries. However OPEC crude and natural gas liquids generate the bulk of expected net growth in production capacity of over 5 mb/d through 2015. Notwithstanding perpetual supply-side risks, the degree to which OPEC is required to control spare capacity over the outlook therefore depends largely on the type of GDP/oil demand picture that emerges.

In gas, the notable expansion of North American gas output has continued apace despite subdued gas prices, adding more than 100 bcm of gas to world output, and making the United States the world's largest gas producer in 2009, and a large virtual gas exporter, as LNG supplies destined for that market are diverted to other consumers. The development of unconventional gas in North America is of global significance. Many countries are seeking to emulate this success, although the time horizons for this suggest major contributions before 2020 are unlikely, for example, in Europe. However, a number of LNG projects based on coal bed methane are advancing towards final investment decisions (FID) in Australia, and China may also be well placed to take advantage of unconventional gas. While LNG capacity has continued to expand, output is lagging, as some upstream supplies are constrained and technical problems plague new plants. But LNG output can be expected to increase by around 120 bcm by 2013, a near 50% increase over 2008.

Notwithstanding these positive developments, extended project lead times are still with us, even more so now that a brief spell of falling upstream costs in 2009 seems to have levelled off. Moreover, ongoing geopolitical and investment risks in countries such as Russia, Nigeria and Iraq affect both oil and gas, and the potential for further deepwater project delays after the recent Gulf of Mexico disaster, suggest that a degree of supply forecast conservatism remains in order.

Of course, depletion from existing fields is an issue in gas just as for oil. Decline rates, estimated at between 5% and 7.5% per year, mean that nearly half of the world's gas production needs to be replaced between now and 2030. Gas output is declining in many OECD countries, and imports from more distant, and harder to develop sources, are inevitable. Investments have to be made right through the gas value chain in a timely way, including long distance pipelines and storage facilities. Indeed these segments of the gas market are most likely to be affected by the current uncertainty.

Moreover, supply-side risks abound in both oil and gas. Firstly, there is an ever-present threat of geopolitical disruption surrounding a number of key OPEC oil producers. Secondly, the potential for the recent *Deepwater Horizon* disaster in the US Gulf of Mexico to delay substantial deepwater developments which underpin much of expected oil and gas supply growth. Efforts to improve safety and environmental standards will understandably be redoubled after the tragedy. Should the impact of those measures be widespread delays to deepwater projects, anything between 100 kb/d and 800 kb/d of new 2015 oil supply currently included in our outlook might be deferred. For gas, domestic market obligations have emerged as a key trend in producing regions, with governments reserving volumes for their own customers.

Exhausting the resource base is not the issue, but instead the ability of the oil and gas industry to respond quickly enough with adequate investment. This will be the case especially if demand should recover more quickly than envisaged here, either through a more broad-based recovery, or in the case of gas, more rapid expansion of gas-fired power generation, which has become the favoured option in many regions. So in the higher GDP base case, and in spite of an assumed ongoing improvement in oil use intensity, effective OPEC spare crude capacity begins to decline again from next year. Although the estimated 2015 level of 3.5 mb/d remains more comfortable than prevailed for much of 2002-2008, the declining trend itself, to well below 5% of global demand, suggests more nervous markets could re-emerge after a prolonged spell of relative price stability in the last year.

Lower economic growth, or perhaps more importantly, a sustained impetus to improve oil and gas end-use efficiency and diversify transportation and electricity energy sources, could maintain oil spare capacity closer to recent levels, and prolong the period of comfortable gas supplies. In both cases however, the call on producers outside OECD will increase.

Prices

Against this backdrop, prices in the two energy commodities have followed different paths. Crude oil prices soared from the trough of $35/bbl in February 2009 to reach $85/bbl in May 2010. In contrast, gas prices have remained subdued, falling to levels at or below one-third of oil prices on an energy content basis over the last year. For oil, comparatively benign prompt market fundamentals following the economic recession look to have been over-ridden by other factors, with crude oil prices having remained within a steady range at a historically high $65-$85/bbl. The macro-economy, currency swings and expectations about longer-term market fundamentals have all helped shape recent oil price trends, over and above the influence of more tradional physical drivers.

However, uncertainties within the physical oil market also persist. Reliable demand and stocks data are lacking for the non-OECD portion of the market that will soon surpass 50% of global demand. Fears of potential renewed supply tightness are offsetting downside demand risks from economic market uncertainty. A common feature for both the physical and financial markets for oil is the relative paucity of reliable, timely, market-wide data and information. Achieving sustainable price stability needs greater visibility for the prompt market, allied to greater clarity about market prospects and policy measures for the future.

Some of these comments apply equally to gas. A little less than half of OECD gas demand is priced directly off oil, with varying time lags and linkages. In 2009, these markets, including Japan, Korea, and most of continental Europe saw prices averaging about $9/MBtu. In North America and the United Kingdom, prices averaged less than half this level, on an energy basis around one-third that of oil. Unsurprisingly, this dichotomy has led to gas buyers, especially in Europe, seeking access to lower priced spot gas, and placed enormous pressure on long-term take-or pay-contracts. For the moment, both these features of the continental market, long-term contracts and oil indexation, remain, although producers have made significant concessions to buyers. Again, and arguably even more so than for oil, data is a real issue, particularly for countries outside the OECD, which already account for more than half of global gas use. Even within the OECD, up-to-date gas data are sadly deficient. A number of parties are working to rectify this, including industry bodies. The IEA is actively working to improve this situation with initiatives such as the recently released European gas map, which shows monthly cross-border gas flows in Europe. Much more remains to be done, however, if markets are not to be subjected to unnecessary uncertainty and volatility.

The individual overviews of oil and gas markets at the beginning of the two sections will provide a more detailed summary of our analysis for both markets.

PART 1

OIL

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OVERVIEW

Plus ça change …

Last year's *MTOMR* was written amid unprecedented uncertainty about prospects for the global economy, and serious concerns about the adequacy of upstream investment to meet an anticipated rebound in oil demand growth. That report also highlighted a fairly dire outlook for OECD oil refiners, and an ongoing debate over the key drivers of crude prices – fundamental and financial.

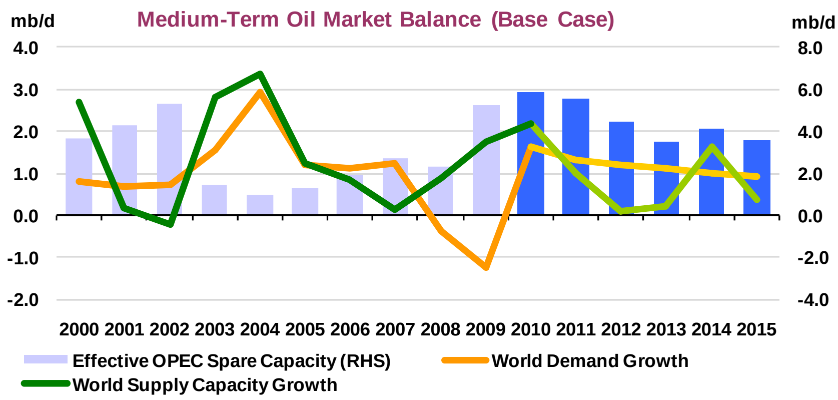
Global Balance Summary (Base Case)

(million barrels per day)

	2009	2010	2011	2012	2013	2014	2015
GDP Growth Assumption (% per year)	**-0.83**	**4.13**	**4.27**	**4.40**	**4.47**	**4.51**	**4.52**
Global Demand	**84.77**	**86.39**	**87.69**	**88.87**	**89.98**	**90.99**	**91.93**
Non-OPEC Supply	51.52	52.22	52.60	52.44	52.11	52.51	52.50
OPEC NGLs, etc.	4.66	5.40	6.25	6.64	6.89	7.11	7.24
Global Supply excluding OPEC Crude	**56.18**	**57.62**	**58.86**	**59.08**	**59.01**	**59.63**	**59.74**
OPEC Crude Capacity	**34.85**	**35.59**	**35.36**	**35.23**	**35.51**	**36.51**	**36.78**
Call on OPEC Crude + Stock Ch.	**28.59**	**28.76**	**28.83**	**29.79**	**30.97**	**31.37**	**32.19**
Implied OPEC Spare Capacity[1]	6.26	6.83	6.53	5.44	4.54	5.15	4.60
Effective OPEC Spare Capacity[2]	5.26	5.83	5.53	4.44	3.54	4.15	3.60
as percentage of global demand	*6.2%*	*6.8%*	*6.3%*	*5.0%*	*3.9%*	*4.6%*	*3.9%*
Changes since December 2009 MTOMR							
Global Demand	**-0.09**	**0.06**	**0.18**	**0.21**	**0.18**	**0.13**	
Non-OPEC Supply	0.25	0.58	0.47	0.32	0.42	1.16	
OPEC NGLs, etc.	-0.20	-0.28	-0.09	-0.01	-0.07	-0.23	
Global Supply excluding OPEC Crude	**0.05**	**0.30**	**0.38**	**0.31**	**0.35**	**0.93**	
OPEC Crude Capacity	**0.03**	**-0.07**	**-0.01**	**0.04**	**-0.25**	**-0.39**	
Call on OPEC Crude + Stock Ch.	**-0.15**	**-0.24**	**-0.20**	**-0.10**	**-0.17**	**-0.80**	
Implied OPEC Spare Capacity[1]	0.18	0.17	0.19	0.14	-0.07	0.41	

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

One year on, many uncertainties persist, even if some clarity has re-emerged concerning the economy, the supply-side and structural shifts in demand. Regulation of commodity futures markets remains centre stage, and OECD refining margins, though better than a year ago, remain weak by historical standards. Uncertainty continues over the resilience of a particularly fragile European economy, although a broader economic recovery is underway, something that last year's projections lacked. Questions persist too over the impact of stimulus withdrawal and potential over-heating in the Chinese economy. For this reason, we again run two oil demand cases based on different economic expectations through 2015, albeit the more optimistic outlook showing 4.4% economic growth for 2010-2015 now



serves as this year's base case. Crucially however, there are signs that an impetus for structural improvements in oil use efficiency has become embedded, under a proviso of continued economic recovery.

This year, as last, we see an upstream sector facing difficulies expanding oil supply rapidly, not least as an estimated 3.1 mb/d of capacity is lost each year due to mature field decline. But last year's widespread concerns over collapsing investment and accelerating decline now look a little jaded. Baseline supply has been revised significantly higher, and around 5.5 mb/d of net supply growth is expected by 2015, even though this still lags demand growth in the base case scenario. However, the industry performed better than expected in 2009, even if renewed supply risks are evident. Physically, Iraq, Russia, Nigeria and Venezuela are capable of higher output volumes than we show here. But extended project lead times are still with us, even more so now that a brief spell of falling upstream costs seems to have levelled off. Moreover, ongoing geopolitical and investment risks in the above countries, and the potential for further deepwater project delays after the recent Gulf of Mexico disaster, suggest that a degree of supply forecast caution remains in order.

Running out of oil is not the issue, rather the ability of the industry to mobilise investment quickly enough to meet the higher of our two demand profiles. So in the base case, and in spite of an assumed 3% annual reduction in oil use intensity, effective OPEC spare capacity begins to decline again from 2011. A broad-based rise in expected OPEC capacity in 2014 pushes spare capacity back above 4 mb/d again, before it dips toward 3.5 mb/d in 2015. That level remains much more comfortable than prevailed for much of 2002-2008, noting also that spare capacity alone does not determine market sentiment. But the declining trend itself, to levels below 5% of global demand, suggests more jittery markets ahead, after a prolonged spell of relative price stability in the last year.

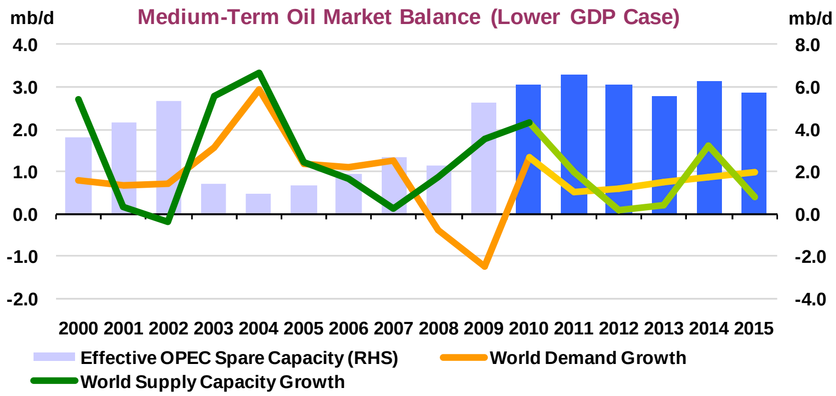
Global Balance Summary (Lower GDP Case)

(million barrels per day)

	2009	2010	2011	2012	2013	2014	2015
GDP Growth Assumption (% per year)	**-0.83**	**3.23**	**2.87**	**2.95**	**2.98**	**2.99**	**2.98**
Global Demand	**84.77**	**86.11**	**86.62**	**87.22**	**87.96**	**88.83**	**89.82**
Non-OPEC Supply	51.52	52.22	52.60	52.44	52.11	52.51	52.50
OPEC NGLs, etc.	4.66	5.40	6.25	6.64	6.89	7.11	7.24
Global Supply excluding OPEC Crude	**56.18**	**57.62**	**58.86**	**59.08**	**59.01**	**59.63**	**59.74**
OPEC Crude Capacity	**34.85**	**35.59**	**35.36**	**35.23**	**35.51**	**36.51**	**36.78**
Call on OPEC Crude + Stock Ch.	**28.59**	**28.48**	**27.76**	**28.14**	**28.96**	**29.20**	**30.07**
Implied OPEC Spare Capacity[1]	6.26	7.11	7.60	7.10	6.55	7.32	6.71
Effective OPEC Spare Capacity[2]	5.26	6.11	6.60	6.10	5.55	6.32	5.71
as percentage of global demand	*6.2%*	*7.1%*	*7.6%*	*7.0%*	*6.3%*	*7.1%*	*6.4%*
Changes since December 2009 MTOMR							
Global Demand	**-0.09**	**0.16**	**0.19**	**0.47**	**1.02**	**1.80**	
Non-OPEC Supply	0.25	0.58	0.47	0.32	0.42	1.16	
OPEC NGLs, etc.	-0.20	-0.28	-0.09	-0.01	-0.07	-0.23	
Global Supply excluding OPEC Crude	**0.05**	**0.30**	**0.38**	**0.31**	**0.35**	**0.93**	
OPEC Crude Capacity	**0.03**	**-0.07**	**-0.01**	**0.04**	**-0.25**	**-0.39**	
Call on OPEC Crude + Stock Ch.	**-0.15**	**-0.52**	**-1.27**	**-1.75**	**-2.19**	**-2.97**	
Implied OPEC Spare Capacity[1]	0.18	0.44	1.26	1.79	1.94	2.57	

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

Once again however, echoing our thoughts of last year, 1 mb/d-plus of annual oil demand growth is by no means inevitable. Lower economic growth (or alternatively high growth allied to an accelerated impetus to improve oil use efficiency and diversify transportation fuel supplies) could maintain spare capacity closer to recent levels of between 5-6 mb/d, while still generating a slow but steady annual rise in demand for OPEC crude. With producers having enjoyed prices within their 'preferred' range of $65-$85/bbl for much of the last year, despite spare capacity remaining at recession-induced levels, such a prospect need not be unduly alarming for producers.



As always, projections like these raise as many questions as they answer. Shifts in assumed oil intensity or decline rates could generate markedly different outcomes. Policy change regarding end-user price subsidies, access to hydrocarbon reserves and oil product quality could also transform these deliberately simplified scenarios. With a revamp of financial market regulation underway, so too could incoming regulation were it to sharply curb liquidity in commodity futures markets and the ability of producers and consumers to hedge future investment, even if this now looks less likely.

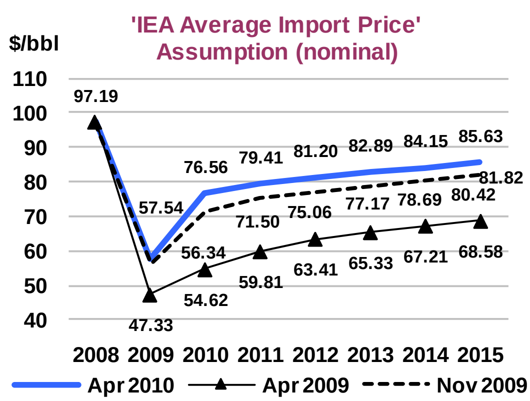
By definition, a five-year outlook takes the world as it is, examining how planned investments match expected demand under the prevailing policy framework. We know that several outcomes are possible, and that sustained investment and actively moderated demand growth can avert tighter oil markets, making increased volatility far from certain for the medium term. The die is largely cast in terms of the policies which will impact upon market fundamentals to 2015, but the importance of clear policy guidelines for the period after that is clear. Extending the recent period of relative market stability requires ongoing efforts to maximise safe and sustainable investment, to broaden access to capital and energy resources, and to promote oil use efficiency and market transparency.

Oil Pricing

In the 12 months since the June 2009 *MTOMR*, debate has continued over the relative contributions of several oil price drivers. At first glance, benign oil market fundamentals following the economic recession look to have been over-ridden by other factors, with crude oil prices having remained within a remarkably steady range at an historically high $65-$85/bbl. Perceptions on the path of economic recovery, equity markets, open interest in commodity futures, fluctuations in the dollar and, more recently, concerns about possible contagion from sovereign debt issues within the Eurozone have all acted to augment the more tradional drivers of prices.

However, uncertainties within the physical oil market also persist, not least concerning the true pace of demand growth in emerging countries. Reliable demand and stocks data are difficult to come by for a portion of the market that will soon surpass 50% of global consumption. Amid uncertainties about the interactions between market contango and supply to the prompt market, and with current levels of OPEC spare capacity arguably only 'comfortable' compared to recent history, fears of potential renewed supply tightness are offsetting downside demand risks deriving from renewed economic market uncertainty. Whether this uneasy 'truce' for price volatility holds is open to question, amid ongoing inelasticity on both the supply and demand sides of the market. However, a common feature for both the physical and financial markets for oil is the relative paucity of reliable, timely, market-wide data and information. Achieving sustainable price stability will partly rest on improvements in visibility for the prompt market, allied to greater clarity about market prospects and policy measures for the future.

For now at least, a period of relative price stability prevails. This is reflected by a futures strip that, although clearly shifted higher since our last two medium-term projections, nonetheless shows a gentle nominal price escalation through mid-decade, with prices rising from $77/bbl to $86/bbl. Based on the futures strip around mid-April, this price assumption (*not a forecast*) underpins the modelling of oil supply and demand through mid-decade undertaken for this report. In the lower GDP case, prices of course could weaken. However this is reflected implicitly via an assumption of slower improvements in oil intensity, rather than through an explicit change in the price strip employed.

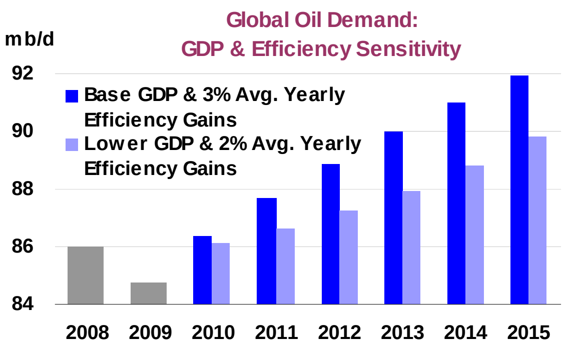


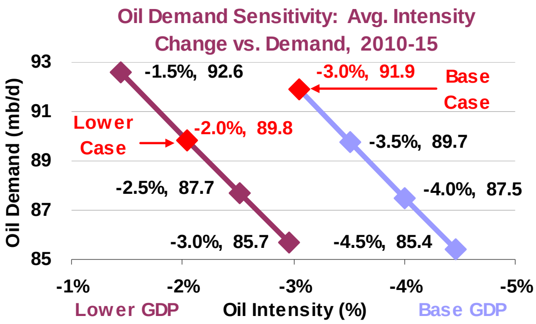
Concerns about a potential return to greater market volatility remain however. These, together with the fall-out from the global financial crisis, are also prompting regulatory changes in commodity futures markets. While proposals vary internationally, with tighter energy commodity position limits one area of divergence, common features nonetheless exist. New regulatory proposals attempt to shed more light onto bilateral OTC markets in particular, and to curb risks within the global financial system. More central clearing of standardised products is likely, alongside reporting of trades to a central repository and increasing collateral. In the end, a desire for globally harmonised standards may temper the more radical proposals for market intervention, ensuring that market liquidity, price discovery and the ability of physical players to hedge risk is maintained.

Demand

As economic uncertainty has persisted beyond the 2008/2009 recession, this year's projections again include two oil demand scenarios. Using May 2010 *OMR* data as our starting point, we have developed two contrasting views on economic growth, with a lower variant also tempered by weaker efficiency gains. In the higher GDP and efficiency gains case (the base case for our analysis), oil demand grows by an average of 1.2 mb/d annually (1.4%), reaching just shy of 92 mb/d by 2015. This presupposes GDP growth of nearly 4.5% per year from 2010 onwards (in line with the IMF) and a reduction in oil use intensity of 3% annually, close to the 2004-2009 average.

The possibility of weaker global economic growth, amid continued world trade imbalances and the challenges of fiscal consolidation and spiralling OECD nation sovereign debt, generates a lower GDP and efficiency gains scenario. Here, global GDP grows by a more muted 3% annually, while the impetus for aggressive oil use efficiency gains is diluted by a weaker investment environment and, by implication, weaker energy prices. This pushes anticipated reductions in oil use intensity back to the 15-year average, near 2% per year. In this case, annual oil demand growth averages 840 kb/d (1.0%), taking total global demand to 90 mb/d by 2015.





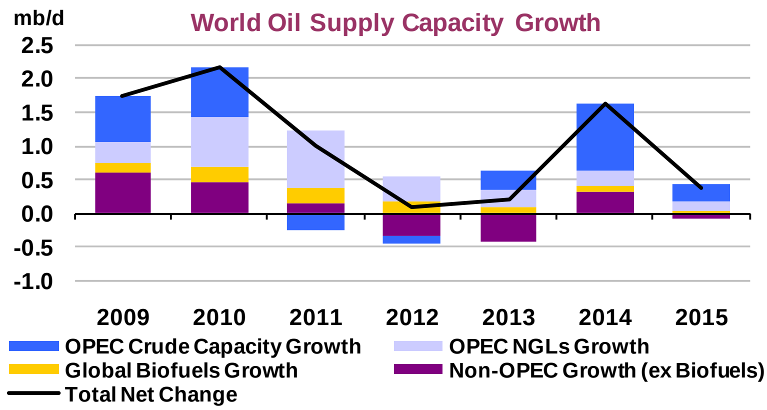
These are merely working assumptions, and global 2015 demand could conceivably lie anywhere within a broad range, depending on the combination of economic growth and intensity reductions that materialises. The implementation of new initiatives involves long lead times, meaning that efficiency gains in excess of those assumed here are unlikely to materialise by 2015. That said, North America is introducing ambitious fuel economy standards from 2012, while vehicle manufacturers, under pressure from stagnating OECD markets, are turning towards innovative new fuel technologies. While unlikely to make huge market inroads before later in the decade, these transformational technologies hold the potential to revitalise car makers' fortunes in the OECD, while also helping them break into more lucrative non-OECD markets and curb those markets' otherwise huge latent oil demand growth potential. In the end, the lower global demand profile could be achieved were higher GDP growth to be accompanied by faster reductions in oil intensity, of around 3.5% per year. Accelerating efficiency gains to that level would be difficult by 2015, but it does illustrate the potential for the longer term if enlightened policy choices are pursued today.

The transport sector and the non-OECD again provide the impetus for demand growth in the next five years. In OECD markets, modest increases in transport fuel demand fail to offset ongoing structural decline in oil use in industry and power generation, exacerbated by potentially weak natural gas prices. OECD oil demand likely peaked in 2005 and falls by between 300-400 kb/d annually through 2015. In contrast, non-OECD demand grows by between 1-1.5 mb/d per year, driven by non-OECD Asia, the Middle East and Latin America. Rising populations within a critical oil demand 'take-off' zone of $3 000-$4 000 per capita income, plus an anticipated persistence of end-user price subsidies, sustains oil demand growth in the face of relatively high crude oil prices. The report highlights ongoing work on the subsidy issue, and the stark statistic that 70% of expected growth in Middle East OPEC crude capacity stands to be absorbed by regional demand growth amid ongoing subsidies. As non-OECD demand reaches 52% of the world total by 2015, so the need for better data on emerging market demand and inventory comes into ever sharper focus.

Supply

Higher prices, lower costs and fledgling signs of increased upstream spending have eased some of last year's concerns about medium-term oil supply prospects. 2009 itself turned out stronger than anticipated, with estimates of total production capacity now close to 91 mb/d, around 0.9 mb/d higher than in the June 2009 report and 0.1 mb/d above our December update. Non-OPEC output in particular survivied lower 2009 spending better than anticipated, and is revised higher, to grow from 51.5 mb/d to 52.5 mb/d by 2015. Latin America, the Canadian oil sands, the Caspian region and biofuels generate most of the growth, offsetting continued decline from the North Sea, the US and Mexico.

The stronger baseline derives in part from higher new project supply, but also lower observed levels of decline at existing fields. The *net decline* proxy for non-OPEC baseline oil supply now stands at closer to 5.1% annually than the near 5.8% which we derived last year, after monitoring decline at mature fields over the course of 2008/2009. Of course, field-specific data are patchy, and our projections for total non-OPEC supply in 2015 would swing sharply subject to a relatively narrow variation in assumed decline rates. In addition, even with more benign decline rate assumptions this year, the global capacity base still loses around 3.1 mb/d each year to mature field decline. The investment challenge to offset this *and* meet global demand growth remains formidable.



That said, the global oil supply outlook is raised by an average 0.3 mb/d each year for the forecast period, with total production capacity now expected to rise from 91.0 mb/d in 2009 to 96.5 mb/d in 2015. Supply growth derives primarily from new OPEC investments, both crude oil and NGL. OPEC crude capacity rises by a net 1.9 mb/d from 2009-2015, to 36.8 mb/d, with notable increments from Iraq (+1.0 mb/d – after the signing of a raft of new contracts with IOCs) and from Saudi Arabia, Angola and the UAE. OPEC NGLs also rise by 2.6 mb/d by 2015 to 7.2 mb/d, playing a key role in the lighter/sweeter feedstock slate anticipated for 2009-2012, even if global supplies then become heavier once again. An extensive review of global NGLs and condensate industry drivers highlights that gas liquids could account for nearly 60% of incremental supply through 2015, with the added impetus for OPEC producers that this production stream is unconstrained by output quotas.

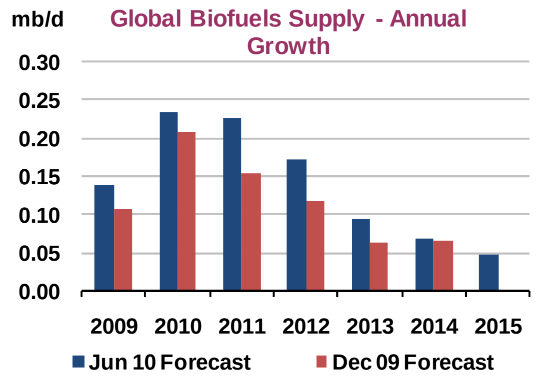
However, supply-side risks abound. Firstly, there is an ever-present threat of geopolitical disruption surrounding a number of key OPEC producers. Secondly, the potential for the recent *Deepwater Horizon* disaster in the US Gulf of Mexico to delay substantial deepwater developments which underpin much of expected supply growth. Efforts to improve safety and environmental standards will understandably be redoubled after the tragedy. Should the impact of those measures be widespread delays to deepwater projects, anything between 300 kb/d and 800 kb/d of new 2015 supply currently included in our outlook might be deferred.

Biofuels

Biofuels production is expected to rise sharply in 2010 and to see continued growth thereafter, with output increasing from 1.6 mb/d in 2009 to 2.4 mb/d in 2015. As such, biofuels remain a marginal source of fuel supply overall, but nonetheless an important offset, together with NGLs and non-conventional oils, for the decline expected in conventional crude oil output from non-OPEC in the forecast period.

By 2015, around 5.7% of gasoline demand on an energy content basis will be met by ethanol, and 1.5% of gaspoil by biodiesel. The economic crisis curtailed growth, but did not completely derail it, as 2009 supply rose by 140 kb/d. Indeed, baseline revisions generate 2009/2010 supply levels that are some 45 kb/d higher than in the December update, largely on the basis of upgrades to North American estimates. Industry rationalisation brought about by economic crisis, lower oil prices and high sugar prices has resulted in a biofuels sector now somewhat stronger and primed for renewed growth, even if questions surrounding environmental sustainability and land use for first generation supplies, and localised over capacity, persist.

On average, forecast production comes in around 135 kb/d higher than December's equivalent, with North America, followed distantly by Latin America and Europe, generating the bulk of this upgrade. Asian project economics, on the other hand, now look more tenuous. As in previous years, the US and Brazil dominate absolute production (together 75% of world supply) and provide 75% of the growth expected for 2009-2015.



Second-generation biofuel activity should increase, notably with a US cellulosic biofuel mandate from 2010 onwards. Current plans imply global potential at 150 kb/d in 2015, with 55% from cellulosic ethanol and 45% from second-generation biodiesel. Yet, challenging economics may keep actual production well below this, and break-even prices near $120/bbl crude may be required for cellulosic ethanol and biomass-to-liquids (BTL) to compete effectively with fossil fuels in the longer term.

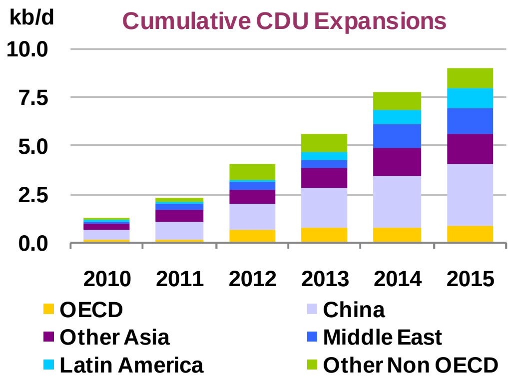
Crude Trade

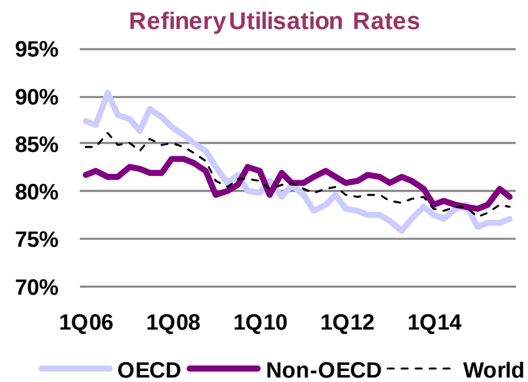
International crude oil trade is expected to increase by 3.2 mb/d from recession-affected lows in 2009 and attain 36.5 mb/d by 2015. Trade is expected to become more long haul, something that may gradually ease short-term pressures on the international tanker industry brought about by vessel over-supply. The Middle East is likely to retain its predominant market share, with around 48% of crude exports, while Africa and Latin America boost their shares of international crude trade, partly at the expense of the FSU. All incremental supplies from the Middle East head towards Asia. Both the FSU and Latin America also increasingly target growth markets in Asia during the outlook, as key export infrastructure projects are brought to fruition. Not surprisingly given declining demand, trade into the OECD countries diminishes, to the tune of 900 kb/d by 2015, although declining domestic production sees OECD Europe imports increase. As elsewhere in this report, expectations for China are impressive, with crude imports increasing by 2.7 mb/d to 6.4 mb/d in 2015, having seemingly been insulated from the global recession, increasing by 600 kb/d in 2009 alone.

Refining and Product Supply

Renewed demand growth, focused in the non-OECD markets, looks to have trumped lagging refining margins to bolster expected refinery capacity additions for the 2009-2015 period. We now envisage net growth of 9.0 mb/d in global distillation capacity, alongside 7.0 mb/d of new upgrading and 8.2 mb/d of desulphurisation capacity through the outlook period, based on firmly committed projects. The outlook includes a modest first wave of capacity closures within the OECD, even if more may be required before OECD refiners can overcome depressed operating rates and sub-optimal economics. Worldwide, surplus refining capacity could reach 7.0 mb/d by 2015 in the absence of further closures.

Given expected trends in demand growth, less competitive OECD capacity will be pressured by new high-complexity facilities and strategic units being built in China, Other Asia, the Middle East and Latin America, even though some retrenchment in Middle Eastern expansion plans has been evident. China has plans to boost capacity by at least 3.3 mb/d by 2015, and the other three regions mentioned collectively add nearly 4 mb/d.





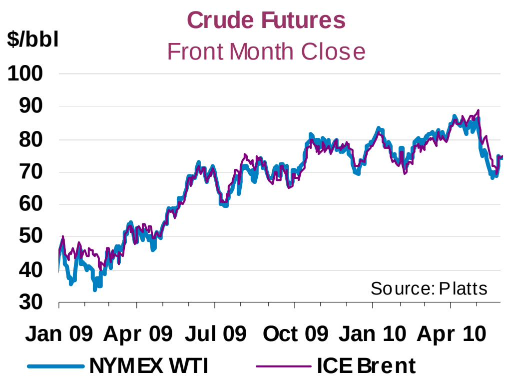
Further undermining some of the more vulnerable downstream facilities will be the sizeable portion of future demand that will be met from rising supplies of biofuels, gas liquids and non-conventional oil, derived from outside the refining system. Moreover, a lighter, sweeter feedstock slate until 2011/2012 could undermine upgrading margins, placing some of the less strategically-oriented new cracking investments into doubt. Longer term, incentives for upgrading may improve as the supply barrel turns heavier and sourer again, amid rising supplies from Canada, Venezuela and Colombia.

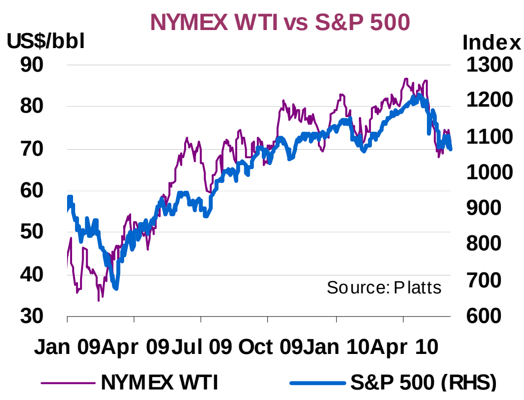
Weaker fuel oil demand and the ultimately heavier crude oil slate eradicate a key feature of last year's projections - tightening fuel oil markets. However, our modelling of likely products supply for light ends and middle distillates still suggest a fundamental imbalance here, with a sharp tightening in markets for middle distillates possible over the forecast period, and a tendency towards surplus in gasoline. Further hydrocracking investment, over and above firm plans, will be required to help resolve this potential imbalance.

OIL PRICING

Benchmark oil futures, while trending higher, have nonetheless traded in a relatively narrow range of $65-85/bbl since last June's *Medium-Term Oil Market Report (MTOMR)*. They have been underpinned variously by prompt physical fundamentals, shifting market sentiment on the pace of the global economic recovery and the ebb and flow in international financial markets. Both WTI and Brent have hovered within a $20/bbl price band for much of the past year, averaging around $75/bbl since June 2009. That compares with the volatile swings that served as the back drop to last year's report, after prices peaked at a high of near $150/bbl in July 2008 and fell to a low of around $35/bbl in February 2009.

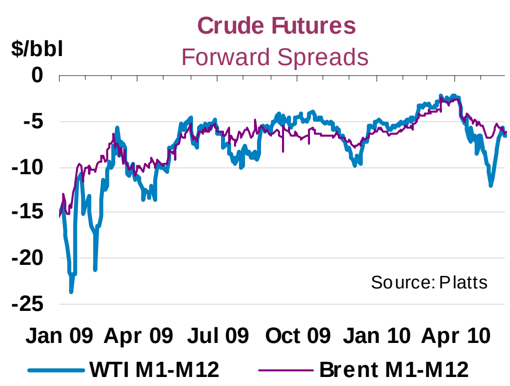
Since the financial crisis broke in mid-2008 a multitude of ever changing macroeconomic developments has underpinned financial and oil market direction, at times exerting a disproportionate influence on oil prices. A shift in market psychology away from a myopic focus on short-term fundamentals and microfinancial positions on the futures market, towards a longer-term view appears to have had something of a stabilising impact on price movements this past year.



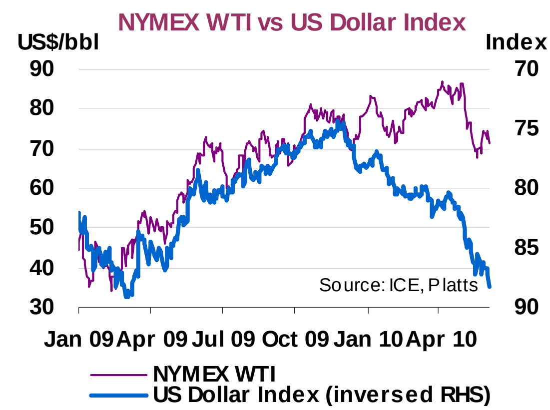


In the wake of the global economic recession, equity and other macrofinancial markets have emerged as critical barometers for future oil demand growth. Perceptions over the pace of demand recovery and the sustainability of growth in China and emerging markets in particular have played a key role in leading oil prices both higher and lower. Oil price moves to the upside more often than not have been accompanied by a multitude of positive macroeconomic developments and bullish financial markets. Swings to the upside frequently defied conventional market thinking, especially given the healthy cushion of oil stocks and spare production capacity over the past 12 months.

That said, OECD stocks represent only a partial picture of market flexibility, meaning that over time, their diagnostic value as regards price might be expected to diminish. Some analysts, moreover, have pointed to the increased use of 'arbitrage for profit' as suggesting that shifts into storage can themselves withdraw oil from the prompt market and therefore push prices higher. Notwithstanding this hypothesis, prevailing weakness in OECD oil demand, and persistent high levels of oil inventories both onshore and held at sea likely exerted



downward pressure on prompt prices relative to forward markets at various points throughout the year. The market contango (whereby prompt prices trade at a discount to forward prices) for WTI M1-M12 contracts in 2009 averaged $8.52/bbl compared with $5.28/bbl through end-May 2010. After widening to $10/bbl at end 2009, the M1-M12 contango has steadily narrowed through much of 2010, to just over $2/bbl at end-March, which the broader market interpreted as a signal that stronger demand was finally starting to make a dent in the global stock overhang. However, the narrowing of the contango reversed course in early April, in part due to a combination of reduced refiner demand during seasonal maintenance as well as rising stock levels at the pivotal Cushing, Oklahoma storage terminals.



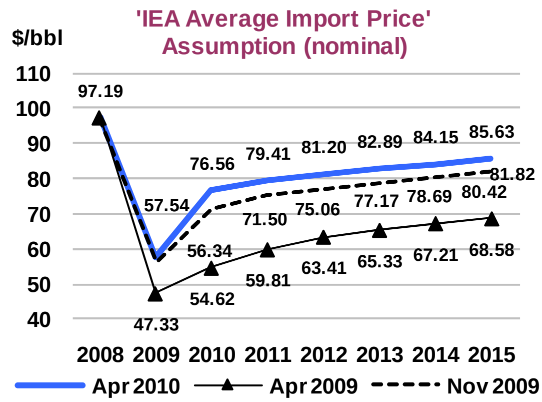
Indeed, volatility returned to the market with a vengeance in May, in large part due to the Eurozone debt crisis and fears that broadening budgetary pressures will undermine global economic recovery and anticipated growth in oil demand. The collapse of the Euro has also triggered a disconnect in the NYMEX WTI inverse relationship with the US Dollar Index, evident through much of 2009. Oil prices broke through the upper and lower limits of their erstwhile range in May. Benchmark prices plummeted by just over $18/bbl by 20 May before partially recovering to around $74/bbl at the end of May, back within the $65-85/bbl range seen for much of the past year.

Global economic issues, especially EU fiscal problems, and broader financial market activity look set to remain key influences on oil price volatility in the short and longer term. These factors have not supplanted a more traditional focus on supply and demand. Indeed, the inelasticity of both supply and demand to price remains arguably the key longstanding contributor to market volatility, off which investor sentiment – both bullish and bearish - tends to feed.

Increasingly, linkages between the physical and paper markets will need to be studied to better understand current and future price dynamics. A joint IEA/IEEJ workshop in Tokyo in February 2010 touched upon some of these issues, (see *'Oil Price Volatility: Causes, Impacts and Potential Remedies')* and will be followed by further work by the IEA and others in months to come.

Methodology for Calculating the 'IEA Average Import Price'

A relatively narrow price range is also seen in the price assumption employed for the forecast period in the *MTOGM*. The IEA does not forecast oil prices, but deploys oil price assumptions for use in our forecasting models. The *MTOGM* price assumption is broadly generated by using a combination of historical NYMEX futures prices for the light, sweet crude contract (WTI) and the forward price curve, which is then benchmarked against the average crude oil import prices for IEA member countries.



For this year's *MTOGM* projections, an average of the last three months' WTI futures strips for respective delivery year was used. This was then converted to an 'IEA average import price' on the basis of the 5.2% discount to crude futures evident in the last five years. This generates a price profile approaching $85/bbl for the latter years of the forecast period, $17-$22/bbl higher than the profile employed in last June's report and around $4/bbl higher than the assumption in the *December 2009 medium-term update*.

Oil Price Volatility: Causes, Impacts and Potential Remedies

Rising crude oil prices through mid-2008, and their subsequent collapse and then recovery, have focused attention on the issue of price formation. An ongoing debate has polarised around the relative roles of fundamentals and financial market speculation in determining crude oil price levels. This polarity, however, may unintentionally mislead financial regulators and policy makers. While the IEA view is that fundamentals are the main determinant of oil prices over time, clearly other factors — ranging from macroeconomic developments, equity and other derivative markets to government policies and geopolitical events — can also play a role in influencing oil price levels in the short term.

The IEA held the third in a series of workshops on oil price formation in February 2010 in Tokyo. Partnered with the Institute of Energy Economics Japan (IEEJ), with the support of Japan's Ministry of Economy, Trade and Industry (METI) this year's workshop focused on the causes, impacts and potential remedies for oil price volatility and involved over 80 participants from industry, government, research bodies, financial institutions, regulators, commodity exchanges and international organisations.

A wide cross-section of views was aired on the many drivers influencing oil prices, the impact of volatility and measures to combat 'excessive' volatility, even if the latter was impossible to quantify. There was near unanimous consensus that attempts to identify and manage a 'fair price' fail to grasp the important role markets play in improving transparency and price discovery. Simplifying the debate between the 'speculation' camp on one side, and 'fundamentals' proponents on the other, may be unhelpful and overly simplistic. If the multiple drivers of price changes are difficult to identify, then policy prescriptions to reduce volatility risk targeting the wrong 'culprits'. Assigning precise price impacts derived from speculation was seen to be inconclusive, even futile.

While entrenched views on the role of speculation and fundamentals were evident, a majority of experts tended to view speculators as playing a secondary role relative to fundamentals, at least over longer periods of time. Almost all speakers appeared to agree that speculation itself is not a bad thing, and is indeed necessary in well functioning markets, providing liquidity, allowing physical market participants to hedge risks and facilitating price discovery. The question is rather whether excessive speculation caused the surge in prices to their mid-2008 peak and continues to distort price levels today.

Proponents of the 'speculative' view acknowledged that today's fundamentals and perceptions of tomorrow's fundamentals are key in setting price expectations. However, they see the shift of oil from being a purely physical commodity to becoming also a financial asset has embedded an excessive degree of volatility. For others, the social damage caused by high volatility in food and energy prices, particularly when the economic recovery is still fragile, means that position limits in energy futures markets are required. The size of these markets is poorly understood (leading some to call for mandatory data reporting), but may be around ten times the size of the physical market. Highly leveraged financial markets were seen by some as accentuating volatility. Passive index investors were singled out by proponents of the 'speculative' view as being different from traditional speculators, since they are not short-term buyers and sellers, but rather buy, hold and roll commodities.

Oil Price Volatility: Causes, Impacts and Potential Remedies (continued)

Most participants across the spectrum acknowledged the key fundamental drivers of prices – rapid, emerging market demand growth driven by subsidised prices and rising incomes, constraints on the ability to expand supply and, more generally, the price inelasticity of both supply and demand. A lack of visibility on both emerging market supply and demand prospects was also seen as contributing to potentially alarmist views about future market balances.

Proponents of the 'physical' market view argued multi-participant markets are more likely to reflect true value – so the question was whether the market can ever be said to provide the 'wrong' price. Price is one of the few accurate, prompt, real-time data points that we have. The market itself, so the argument runs, is more likely to send rational signals to participants than any attempt to artificially control prices.

Data and More Data

From a fundamental point of view, the key to price stability and market transparency is better data on the current state of the market – covering upstream, downstream, inventories and demand, most notably for non-OECD countries – to minimise market uncertainties.

Demand-side uncertainty now is perhaps as great as it has ever been. Expectations for 2010 demand growth were said to range from 0.8 mb/d to 2.5 mb/d. Suggestions to minimise this uncertainty included forecasting agencies providing more detail on the assumptions and uncertainties that underpin projections. Indeed, a common theme throughout the forum was that forecasts are inherently uncertain, and perceived wisdom about future feast or famine often gets over-turned by game-changing developments, which analysts fail to spot in advance.

More generally, speakers saw domestic price subsidies in emerging markets playing a key role in dampening price feed-through to consumers, and effectively increasing volatility in international markets. This has also blunted the traditional view of rising oil prices inevitably having an immediate adverse impact on global economic growth. Although some signs of wage inflation in China due to increased prices were identified, the theme of the global economy's ability to better withstand sharply higher prices was also highlighted.

Improved transparency in the refining sector would also help, given refined products markets have frequently been a driver of rising crude prices in time of tightness, especially diesel markets in 2008. The downstream component is often overlooked, but at its root is relatively straightforward. A mismatch between crude slate, refining complexity and products demand can inflate crude oil demand, something that likely contributed to higher crude prices in 2007/2008.

Although the importance of OECD inventories as a measure of physical market flexibility is diminishing, as non-OECD demand begins to predominate, these, alongside OPEC spare capacity, are seen as key 'shock-absorbers' for the system. Seemingly abundant current spare capacity of around 6 mb/d was nonetheless seen as being a relatively narrow margin, both in comparison with other industries and with historical levels. Some pointed out that a 5% capacity margin may be a 'tipping point' for oil markets, noting that spare capacity was consistently below this level for much of 2003-2008. The fact that IEA member governments also control strategic stocks for use in a supply disruption was identified as a potentially calming feature for markets, and one that is perhaps not highlighted frequently enough.

Moving the Debate Forward

While views varied over the relative contribution of fundamental or speculative factors in shaping the price environment, a consensus emerged that a combination of prompt physical fundamentals, expectations for the future and a complex web of financial and economic drivers underpin shifts in oil prices. Solid statistical correlations frequently prove to be transient, highlighting the observation that

Oil Price Volatility: Causes, Impacts and Potential Remedies (continued)

price drivers are both manifold and tend to ebb and flow in importance over time. More analysis on how macro-economic shifts, including equity and currency fluctuations, affect commodity prices, and vice versa, as well as better data on supply and demand fundamentals, futures trading positions and derivative transactions may be more valuable in assessing how to improve market functioning than merely continuing the polarised debate over the role of speculators versus fundamentals.

Creating more favourable conditions for investment and ensuring that price signals are efficiently passed through to producers and consumers will be equally if not more important than judicious financial regulation in promoting greater stability. A number of key issues were identified which can underpin future policy action aimed at helping markets function better:

- Firstly, volatility is inescapable, and can never be eradicated. But volatility can adversely affect investment planning and import-dependent emerging countries. It can be limited via better functioning markets and improved visibility on current and expected future market fundamentals;
- A combination of prompt physical fundamentals, expectations for the future and a complex web of financial and economic drivers tend to underpin shifts in oil prices. The uncertainties inherent in forecasts, and alternative outcomes need to be more clearly acknowledged by forecasters;
- The issue of data transparency is paramount for improved understanding of market dynamics. Better data on demand, supply and stocks are key, notably for emerging markets poised to account for over 50% of global demand by mid-decade (not least Asia);
- Equally important is greater visibility on participation in financial markets. Recent moves to enhance reporting requirements by the CFTC and other regulators should continue, possibly extending to OTC derivatives markets. Plans to increase financial market oversight can play a critical role in improving market function but efforts to regulate commodity futures markets must take into account liquidity and risk management, which could be impaired if incoming regulation is too heavy handed;
- Finally, well-defined and more consistent international long-term policy signals are required in areas such as promoting access to reserves and investment, the shift towards market pricing and environmental and oil use efficiency targets. A clearer policy framework can help both consumers and producers make optimal investment decisions for the future.

Financial Market Regulation

The financial crisis has prompted global efforts to improve the regulatory framework and proposed changes affect also commodity markets. New legislative proposals target derivative trading in bilateral over-the-counter (OTC) markets, which include also oil swaps, and attempt to impose position limits on futures market energy contracts to prevent market manipulation. A common regulatory push under a G20 umbrella appears to be evident across many of the main markets to ensure the maximum use of clearing, migration to exchanges and more stringent reporting requirements.

Derivatives are financial instruments whose value is derived from the value of an underlying asset. They include futures, options and swaps. Derivatives can be used either to:

- Hedge exposure to the physical asset itself;
- Make speculative profits if prices of the underlying asset move in an expected direction;
- Gain financial exposure to an underlying asset where trade in the asset is restricted; or
- Secure an option to buy or sell an underlying asset if prices hit a specific level.

Derivatives can be standardised and traded on exchanges, or privately negotiated between two parties as OTC derivatives. According to the International Swaps and Derivatives Association, derivatives are used to manage risk by the majority of the largest companies in the world, at least half of medium-sized firms and many small businesses.

An advantage of OTC derivatives is the ability to tailor the contracts to hedge precise risks a company faces due to fluctuations in commodity and other markets. Their disadvantage is a greater level of counterparty, liquidity and operational risk. Counterparty risk (if one party were to fail to meet its financial obligations) is significant and could threaten the stability of the financial system if the defaulting counterparty is a large financial institution. The crisis emphasised also other potential issues, such as lack of transparency and lower capital requirements in comparison with trading in the underlying asset. New regulation aims to mitigate unintended consequences of derivative risks.

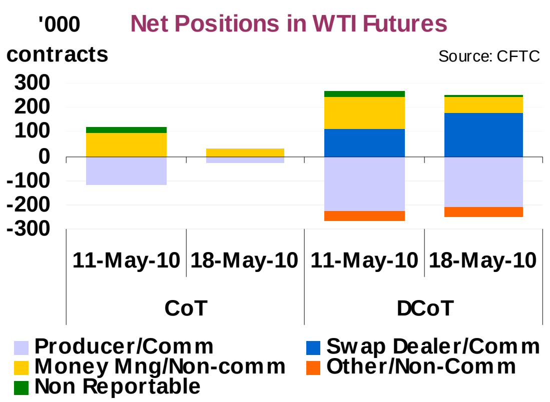
Policy makers' proposals for extensive regulatory overhaul in the OTC derivative markets reflect a commitment to a lower risk financial system from G20 leaders. According to the G20 statement following the meeting in Pittsburgh in September 2009, they would like to see all standardised OTC derivatives contracts traded on exchanges or electronic trading platforms and cleared through central counterparties by end-2012 at the latest. In general, G20 regulatory proposals set out the following key items for regulation of OTC derivatives:

- Clearing of trades through an intermediary company with sufficient capital, such as clearing houses, or central counterparties (CCPs) to eliminate counterparty risk;
- Standardisation of OTC derivative contracts and trading on exchanges to eliminate operational risk;
- Capital requirements for banks to balance their OTC exposure;
- Reporting of OTC derivative contracts to qualified trade repositories to increase transparency;
- Regulation of market participants, greater oversight of exchanges, clearing counterparties and electronic trading platforms and registration of credit rating agencies;
- Non-centrally cleared contracts should be subject to higher capital requirements and;
- Harmonisation of accounting standards.

The US Takes the Lead

US OTC derivatives are largely exempt from the existing regulatory framework. Three legislative texts proposing a new framework for OTC derivatives have been circulating in recent months: a proposal from the Obama administration, the *Wall Street Reform and Consumer Protection Act* passed in the House of Representatives in December 2009 and a draft from the Senate's Banking and Agriculture committees approved in May 2010. The texts diverge in places and are likely to be reconciled in a single rule. The final bill would clarify clearing requirements, exchange trading, trade reporting, regulation of market participants, capital and margin requirements and position limits.

The bill passed by the House of Representatives expands the authority of the Commodities Futures Trading Commission (CFTC) to establish position limits on energy commodities (now limited to agricultural commodities). The CFTC itself came under pressure to strengthen its oversight of the markets after 'excessive' speculation was blamed for much of the record increase in energy prices in 2008. As part of its effort to increase market transparency, the CFTC released three years' of historical Disaggregated Commitments of Traders (DCoT) data. The new format was designed to better highlight the role of investment banks and index traders, among others, in commodity markets. Critics pointed out that the new DCoT report does not fully capture information about the swap dealer's counterparties. That counterparty might be a speculative trader, like an index fund, or alternatively a traditional commercial user managing risk arising from physical market activity.



Despite an earlier CFTC report that concluded there was no clear correlation between speculative positions and rising oil prices, the agency unveiled in January 2010 a proposal to limit the amount of US energy futures contracts that hedge funds, investment banks and other non-physical participants can control. The position caps would affect the WTI, heating oil, RBOB gasoline and natural gas futures contracts.

The suggested rule sets aggregate limits by the number of outstanding contracts. Companies could hold 10% of the first 25 000 contracts of open interest for all trading months combined and then 2.5% of open interest beyond this threshold. The new rule would allow exemptions to companies using the futures contracts to hedge their commercial risks. A 'limited risk management' exemption, where limits are capped at two times the normal limits, would also be granted to swap dealers offsetting their positions underwritten on the OTC markets.

Initially, the proposal was viewed as benign since limits were thought high enough not to divert trades either to OTC markets or outside the US. The CFTC said they believed only ten companies trading in the crude market (of a total around 320) would be affected and that these would be able to ask for exemptions. In the heating oil and gasoline markets, the CFTC estimated that caps would have been imposed on 16 traders in each market over the past two years (of around 160 and 200, respectively).

During the CFTC public comment period on its draft for position limits, the majority of responses supported the regulatory bill. In general, the end-users and producers welcomed the proposal, claiming limits are necessary to curb volatility, with some even saying the rule is too generous in terms of limit levels and exemptions. However, several expressed concerns that position caps might constrain hedging activity of energy companies that engage in swap trading.

On the other hand, representatives of the financial industry (banks, traders and exchanges) criticised the 'limited risk management' exemptions for swap dealers, which they believe in effect limit speculative activity and by implication hedging. Some believe that the introduction of position limits might shift trades to the OTC market or outside the US to countries with less strict legislation. Critical comments also indicated that limits could have greater impact on smaller heating oil and gasoline markets, or that they might drive parties to take physical market risk to avoid regulatory exposure. In addition, the Intercontinental Exchange (ICE) expressed concerns that limits would hurt new or smaller exchanges trying to compete with large players, because it would limit positions not only across exchanges but also on individual exchanges based on open interest seen in the previous year. As it is not always possible to separate hedges and speculative trades and since the agency itself did not identify any evidence of excessive speculation, many recommended the CFTC wait until the finalisation of financial reform by US legislative bodies before proposing a final rule.

Divergent European Approaches

In the EU, the first legislative proposal detailing a new regulation to control derivative trading should be published in June 2010. Legislative changes in the EU require approval from member states' ministers and the European Parliament to become law. The proposal therefore will need to maintain a balance between the calls of mainland Europe for greater regulatory oversight and the more liberal UK approach. Meanwhile, the European Commission set intermediary targets to:

- Reduce operational risk through greater standardisation;
- Curb counterparty risk by promoting the trading on exchanges or through centralised platforms like CCPs, improving collateralisation and raising capital charges for bilaterally-cleared contracts;
- Increase transparency through wider use of trade repositories and record retention of all transactions not cleared by a CCP in trade repositories; and
- Enhance market integrity and oversight by allowing regulators to set position limits in the Markets in Financial Instruments Directive (MiFID) and by clarifying and extending the scope of market manipulation as set out in the Market Abuse Directive (MAD) to derivatives.

The draft, prepared by the Directorate-General for Internal Market and Services, will likely contain mandatory clearing of standardised derivatives, requirements for CCPs and trade repositories, reporting of derivative trades and probably also limits on individual derivative trades by speculators.

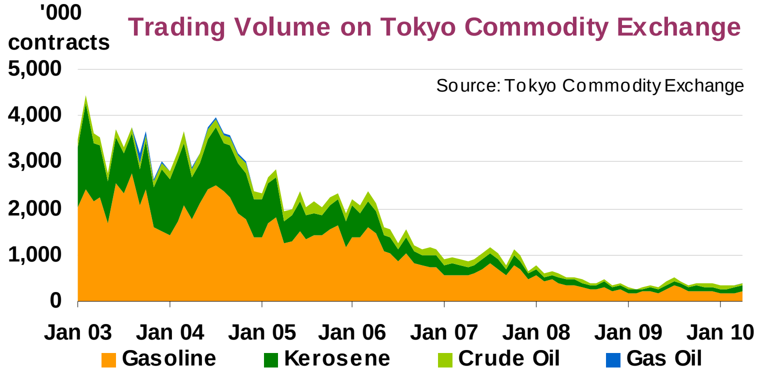
The European Union's Committee of European Securities Regulators (CESR) plans to improve the MiFID for equity markets, investor protection and trade reporting and mandatory reporting of off-exchange derivatives transactions.

The UK Financial Services Authority (FSA) said in December 2009 it is considering greater standardisation of OTC contracts, CCP clearing and more robust collateralisation and capitalisation of transactions not cleared through CCP to manage counterparty risk, high standards for CCPs and registration of relevant OTC derivative trades in a trade repository. However, it does not plan to follow its US counterpart by imposing position limits, as it considers them outside its current remit.

Asian Moves to Clearing

The OTC derivative market in Asia is small in proportion to western markets, but according to the Bank for International Settlements (BIS), the traded volumes are rising fast. Japan, Korea, China, Hong Kong, Taiwan, Singapore and India are all committed to set up clearing operations for the OTC markets, partly as a preventative measure in case of market arbitrage.

Japan faces declining trading volumes in commodity markets, especially decreasing speculative trading, something that could threaten price discovery and the hedging functions of the market. Lower activity in commodity markets is due to excessive and aggressive marketing of Futures Commission Merchants (FCM), the



brokers, directed towards inappropriate investors. The regulators therefore focus on measures to achieve balanced market participation by hedgers and speculators, tighter regulation of the FCMs and higher standards of conduct, rather than position limits. Pre-existing position limits in Japan were deemed very strict for certain commodities and were subsequently diluted.

In relation to the regulation of the OTC markets, Japan is moving forward to control OTC derivatives transactions and to strengthen the transparency of the markets in line with G20 pledges. The Financial Services Agency presented a legislative proposal in March 2010 that introduced mandatory CCP clearing, data storage of trade information and reporting requirements.

In other parts of Asia, India permits OTC derivative trades where at least one counterparty is a regulated entity. The Reserve Bank of India is tasked with supervision and intermediary functions as a reporting platform and CCP for OTC trading. China has set up the Shanghai Clearing House to provide CCP clearing for OTC derivatives and Hong Kong seeks to improve its legal framework for OTC derivatives as the regulation in place is fairly fragmented and covers only specific types of derivatives. The Singapore exchange already clears OTC oil, freight and other commodity derivatives and plans to expand clearing to OTC foreign exchange rates and interest rates products.

The Role of International Organisations

Consistent regulation across jurisdictions is seen by some as critical to ensure efficient functioning of the markets and to prevent regulatory arbitrage. Besides the OTC derivatives regulation, the series of high-level talks among G20 countries discussed measures to rebuild trust in the financial system by strengthening transparency and accountability, enhancing sound regulation, promoting integrity in financial markets and reinforcing international cooperation. The G20 group therefore established a Financial Stability Board (FSB) that is tasked to propose reforms to reach set targets for the derivative markets, to classify standardised derivative products, protect against market manipulation and regularly evaluate the implementation of G20 pledges made in September 2009.

To achieve the tasks, the FSB coordinates a working group consisting of the Committee on Payment and Settlement Systems (CPSS) of BIS, the International Organisation of Securities Commissions (IOSCO) and the International Association of Supervisors (IAIS) aiming to review existing regulation and make recommendations to improve regulation of OTC derivatives trading by October 2010.

Meanwhile, the Basel committee on Banking Supervision (BCBS) of BIS is working on new rules on capital and liquidity requirements to mitigate counterparty risk. It plans to create incentives for banks to use CCPs for derivatives clearings by increasing capital requirements for any bilateral agreement. In addition, legislation to harmonise accounting standards is being prepared.

The new regulatory proposals attempt to shed more light onto the OTC market and prevent potential negative consequences on the global financial system. Policy makers worldwide differ on various parts of the proposals. All, for example, require central clearing of standardised products, reporting of all trades to a central repository or increasing collateralisation of bilateral OTC trades. However, controversial elements need to be carefully negotiated before any globally harmonised legislation will be possible and to ensure the new policies do not restrain the basic functions of tertiary markets, such as liquidity, price discovery, efficiency and risk sharing.

DEMAND

Summary

- **Global oil product demand is projected to increase by 1.4% or 1.2 mb/d per year on average between 2009 and 2015, from 84.8 mb/d to 91.9 mb/d.** This prognosis is based on the International Monetary Fund's economic forecasts (*World Economic Outlook*, April 2010), which see global economic activity expanding by 3.6% per year, and assumes worldwide efficiency gains of 3% per year. By contrast, under an alternative, 'Lower GDP' case, with economic growth averaging 2.5% and efficiency gains of 2% per year, oil demand would grow by 1.0% or 840 kb/d per year on average to 89.8 mb/d by 2015, a difference of 2.1 mb/d versus the base case.

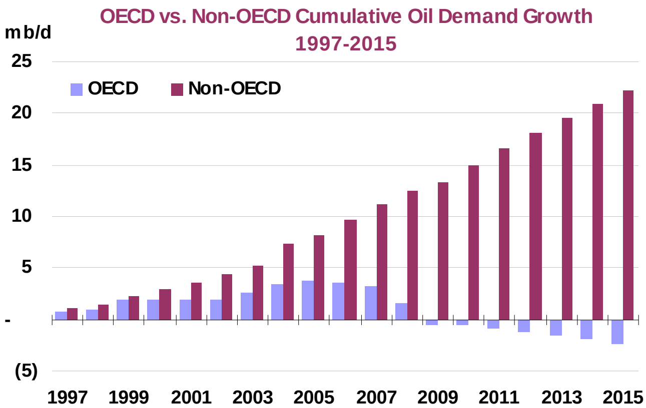
Oil Demand Sensitivity

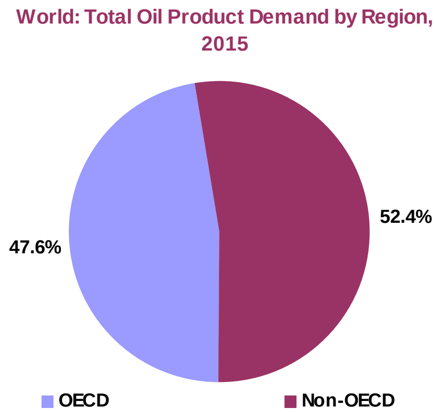
(million barrels per day)

	2009	2010	2011	2012	2013	2014	2015	Avg. Yearly Growth, 2009-2015		Avg. Yearly Growth, 2010-2015	
								%	mb/d	%	mb/d
Base GDP & 3% Avg. Yearly Efficiency Gains											
Global GDP (y-o-y chg)	-0.8%	4.1%	4.3%	4.4%	4.5%	4.5%	4.5%	3.6%		4.4%	
OECD	45.5	45.4	45.2	44.9	44.5	44.1	43.7	-0.7%	-0.29	-0.8%	-0.34
Non-OECD	39.3	40.9	42.5	44.0	45.5	46.9	48.2	3.5%	1.48	3.3%	1.45
World	84.8	86.4	87.7	88.9	90.0	91.0	91.9	1.4%	1.19	1.3%	1.11
Lower GDP & 2% Avg. Yearly Efficiency Gains											
Global GDP (y-o-y chg)	-0.8%	3.2%	2.9%	2.9%	3.0%	3.0%	3.0%	2.5%		3.0%	
OECD	45.5	45.4	44.9	44.4	44.0	43.7	43.4	-0.8%	-0.35	-0.9%	-0.40
Non-OECD	39.3	40.7	41.7	42.8	43.9	45.2	46.5	2.8%	1.19	2.7%	1.14
World	84.8	86.1	86.6	87.2	88.0	88.8	89.8	1.0%	0.84	0.8%	0.74
Lower vs. Base											
Global GDP (% points)	0.00	-0.90	-1.40	-1.45	-1.49	-1.52	-1.54	-1.2		-1.4	
OECD	0.00	-0.07	-0.29	-0.42	-0.47	-0.44	-0.36	-0.1	-0.06	-0.1	-0.06
Non-OECD	0.00	-0.21	-0.79	-1.23	-1.54	-1.72	-1.76	-0.6	-0.29	-0.7	-0.31
World	0.00	-0.28	-1.07	-1.65	-2.02	-2.17	-2.11	-0.4	-0.35	-0.4	-0.37

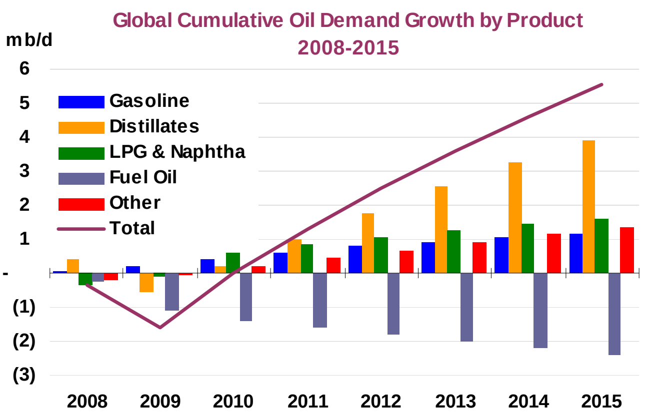
- **Oil demand is not only highly sensitive to economic conditions, but also to efficiency mandates and technological change.** GDP growth greatly influences the pace of oil demand expansion, as witnessed in the recent global recession. More interestingly, efficiency gains (or the decline in oil intensity) could have a greater effect. Seeking to refine our analysis and go beyond a purely GDP-based sensitivity, we have also assessed the effect of different oil intensities. Curbing average GDP growth by a third would slash global oil demand by over 6 mb/d by 2015 if the decline in oil intensity remained at 3% per year under both cases, only slightly higher than in the recent six-year period. However, adopting a 2% yearly oil intensity decline under the lower case, in line with the 15-year average, offsets the fall in oil demand by two-thirds. Subdued economic activity over the medium term could indeed slow down efficiency initiatives – market-based or government-mandated – thus moderating the income effect on oil demand. Moreover, a lesser decline in oil intensity implicitly entails a weaker oil price.

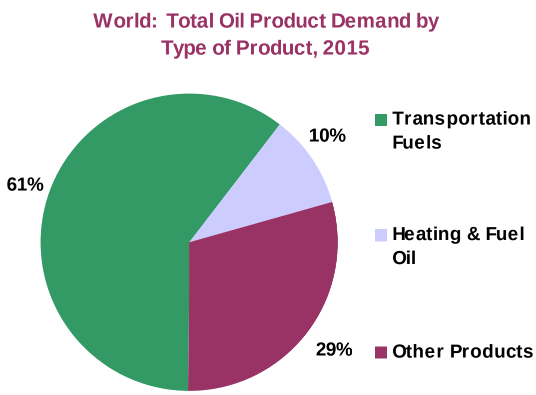
- **In both cases, non-OECD countries will drive global oil demand growth, while consumption will decline in the OECD.** Under the base case, non-OECD oil demand is expected to increase by 3.5% on average per year over 2009-2015, from 39.3 mb/d to 48.2 mb/d, equivalent to almost +1.5 mb/d per year. By contrast, OECD demand is projected to fall annually by 0.7% or 290 kb/d on average, from 45.5 mb/d in 2009 to 43.7 mb/d in 2015. Under the lower case, oil demand would grow by only 2.8% per year in the non-OECD, reflecting the area's high energy intensity, and would decline slightly faster in the OECD (-0.8%). Non-OECD Asia will remain the dominant force behind global oil demand, more distantly followed by the Middle East and Latin America. By 2015, emerging economies will account for over half of global oil demand.



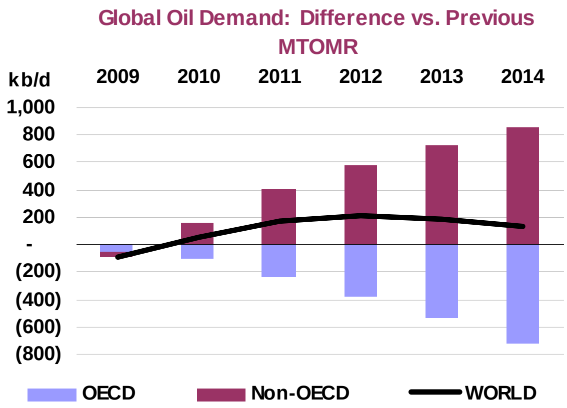


- **A common theme in both OECD and non-OECD countries is the pre-eminence of transportation fuels.** In non-OECD countries, demand for gasoline and distillates (jet fuel/kerosene and gasoil) will accompany the rise in burning fuels (heating and residual fuel oils) and industrial feedstocks (LPG, naphtha and 'other products') consumption. By contrast, growth in transportation fuel demand in the OECD will be modest and insufficient to offset the structural decline in both burning and industrial fuels. Vehicle fleets are reaching saturation point, thus limiting the scope for expansion, while efficiency moves (notably in North America) and older populations who tend to drive less (Europe and the Pacific) are set to significantly curb demand. Meanwhile, most OECD energy intensive industries have relocated to emerging areas, while other sources of energy – natural gas, nuclear and renewables – are overtaking oil for heating or power generation. In the longer term, the adoption of new, disruptive technologies – hybrid or electric vehicles, 'biojet', etc. – may bring further, significant changes for oil use in transportation.





- **Overall, the current prognosis shows marginal differences versus our last medium-term assessment.** Compared with the *December 2009 medium-term update*, the current global oil demand forecast is only 130 kb/d higher by 2014. However, upward revisions in the non-OECD (+850 kb/d) offset downward adjustments in the OECD (-730 kb/d). In the OECD, the pace of decline in North America is expected to be steeper, following a reassessment of efficiency trends in the transportation sector in both the US and Canada. In the non-OECD, meanwhile, baseline revisions following the submission of finalised 2008 data and a reappraisal of Chinese prospects yield a stronger demand prognosis.



- **A customary warning is that this outlook presents several downside and upside risks, which could significantly alter the evolution of global oil demand.** These include: 1) the strength and sustainability of the ongoing global economic recovery; 2) the volatility of commodity prices, particularly oil and its direct substitutes, such as natural gas; 3) the degree to which price subsidies persist in large non-OECD countries; 4) accelerated developments in energy efficiency and alternative technologies; 5) behavioural changes, notably in OECD countries; 6) deviation from 'normal' weather conditions, defined as a ten-year average of observed temperatures; and 7) revisions to data resulting from greater transparency and better reporting.

Global Overview

Global oil product demand is expected to increase by 7.1 mb/d between 2009 (84.8 mb/d) and 2015 (91.9 mb/d), equivalent to an average yearly growth of 1.4% or 1.2 mb/d. The pillars of this outlook are three-fold: 1) the set of economic assumptions provided by the International Monetary Fund (*World Economic Outlook*, April 2010); 2) assumed efficiency gains of +3% per year on average over the forecast period; and 3) an oil price path, derived from forward price curves as of late April/early May, which sees a broadly stable level of $76/bbl in real terms on average.

Global Oil Demand (2009-2015)

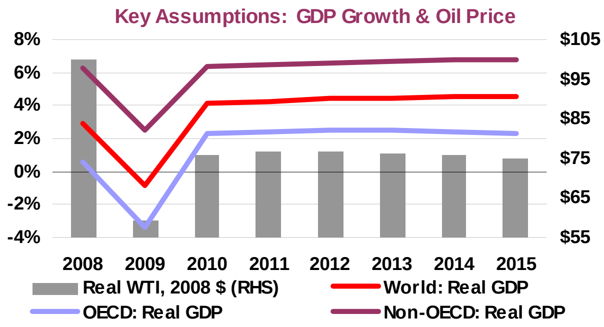
(million barrels per day)

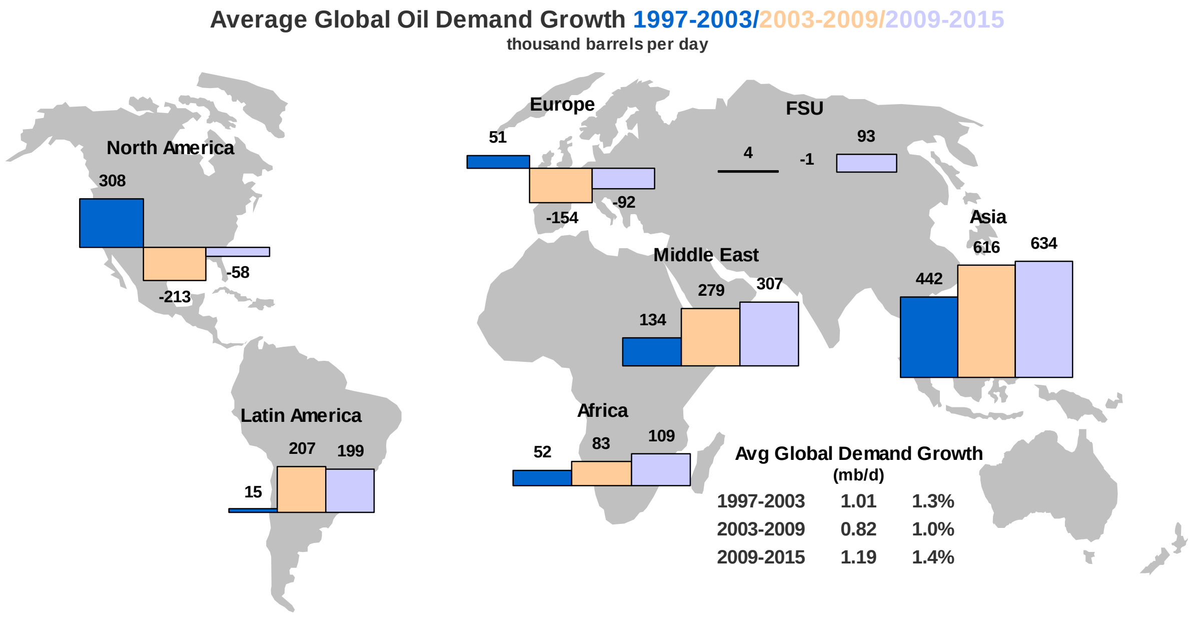
	1Q09	2Q09	3Q09	4Q09	2009	1Q10	2Q10	3Q10	4Q10	2010	2011	2012	2013	2014	2015
Africa	3.2	3.2	3.1	3.1	3.2	3.2	3.3	3.2	3.3	3.3	3.4	3.5	3.6	3.7	3.8
Americas	29.3	28.9	29.4	29.6	29.3	29.6	29.6	29.9	29.8	29.7	29.8	29.9	30.0	30.1	30.2
Asia/Pacific	25.7	25.9	25.9	27.0	26.1	27.3	26.8	26.3	27.3	26.9	27.6	28.2	28.8	29.4	29.9
Europe	15.7	15.0	15.2	15.1	15.2	14.8	14.9	15.3	15.3	15.1	15.1	15.0	14.9	14.8	14.7
FSU	3.9	3.8	4.0	3.9	3.9	4.1	3.9	4.1	4.1	4.1	4.2	4.3	4.3	4.4	4.4
Middle East	6.5	7.1	7.6	7.0	7.1	6.9	7.4	7.9	7.2	7.4	7.7	8.0	8.3	8.6	8.9
World	**84.3**	**83.9**	**85.1**	**85.7**	**84.8**	**85.9**	**85.9**	**86.7**	**87.0**	**86.4**	**87.7**	**88.9**	**90.0**	**91.0**	**91.9**
Annual Chg (%)	-3.3	-2.7	-0.6	0.8	-1.4	2.0	2.3	1.8	1.5	1.9	1.5	1.3	1.2	1.1	1.0
Annual Chg (mb/d)	-2.8	-2.3	-0.5	0.7	-1.2	1.7	1.9	1.6	1.3	1.6	1.3	1.2	1.1	1.0	0.9
Changes from last MTOMR (mb/d)	-0.21	-0.18	-0.17	0.18	-0.09	-0.22	0.25	0.01	0.19	0.06	0.18	0.21	0.18	0.13	

At first glance, the Fund's vision of global economic activity averaging 3.6% per year over the 2009-2015 period (from -0.8% in 2009 to 4.4% over 2010-2015) would suggest that the 2008-2009 recession is genuinely over. Two caveats, however, are in order. First, the recovery has been led by emerging economies, which proved overall to be surprisingly resilient. Not only did non-OECD economies as a whole continue to grow in 2009 (+2.6%), but they are also expected to increase at

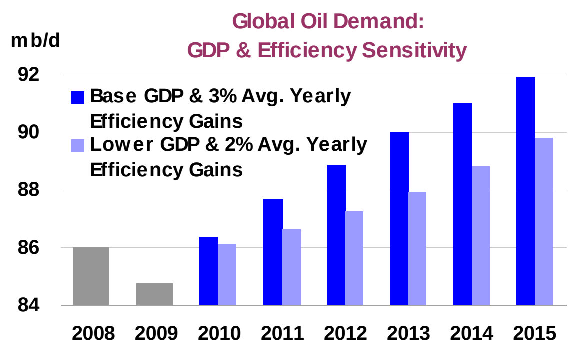
6.6% per year on average from 2009 to 2015. By contrast, OECD countries bore the brunt of the financial and economic turmoil (collectively contracting by 3.4% in 2009), and should expand at roughly a third as fast (+2.4%) as emerging areas. More interestingly, according to the IMF projections, by 2015 the share of global wealth will tilt in favour of non-OECD countries (50.2% versus 49.8% for the OECD) for the first time in the modern era.

Second, as much as the ongoing recovery would appear to conform to a pronounced 'V-shaped' bounce, the risk of an 'L-shaped' or even 'W-shaped' trajectory remains. Greece's financial travails and the resulting turmoil in the Eurozone have made clear that the economic recovery is at risk of drowning in an ocean of public debt. Although attention is currently focusing on the unfolding Greek drama and its potential repercussions on other Mediterranean countries, other large OECD economies – and not only in Europe – face the increasingly pressing challenge of achieving an orderly fiscal consolidation in the next few years without jeopardising long-term economic growth (but arguably at the risk of subdued short- to medium-term performance). As if it were not enough, this challenge is to be overcome amid excessive spare capacity in many industries, a highly indebted private sector and persistent global imbalances. Admittedly, the depreciation of the euro will provide a welcome export boost to European economies, but that will complicate efforts to engineer a gradual appreciation of the renminbi relative to the US dollar in order to cool the overheating Chinese economy. So far, China's moves to restrict bank lending have had limited impact in terms of overall growth (GDP surged by almost 12% year-on-year in 1Q10).

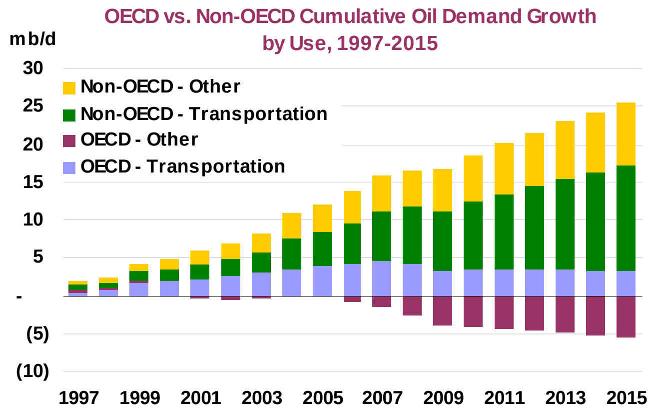




Therefore, an alternative case, whereby global GDP would expand by a lesser 2.5% per year on average over 2009-2015, cannot be discarded. Moreover, subdued economic activity over the medium term could conceivably also slow down efficiency gains, be they market-based or government-mandated, to perhaps only 2% per year. Under such a 'Lower GDP' case, oil demand would grow by 1.0% or 840 kb/d per year on average to 89.8 mb/d, a difference of 2.1 mb/d by 2015 versus the base case.



Largely shadowing economic growth assumptions, oil demand growth will be driven exclusively by non-OECD countries. Non-OECD oil product demand is expected to rise from 39.3 mb/d in 2009 to 48.2 mb/d in 2015, equivalent to +3.5% or +1.5 mb/d per year on average, with growth concentrated in Asia (51%), the Middle East (21%) and Latin America (13%). Only in a few non-OECD areas – Africa, the FSU and Europe – will growth be much more moderate. Demand growth is expected to be strong across all key drivers: transportation fuels (gasoline and distillates) will accompany the rise in burning fuels (heating and residual fuel oils) and industrial feedstocks (LPG, naphtha and 'other products') consumption. Overall, by 2015, non-OECD countries – having accounted for total oil demand growth since 2009 – will dominate global oil demand (53% versus 47% for the OECD). This change is all the more striking when considering that, as recently as in the mid-1990s, non-OECD demand accounted for roughly a third of total global demand.

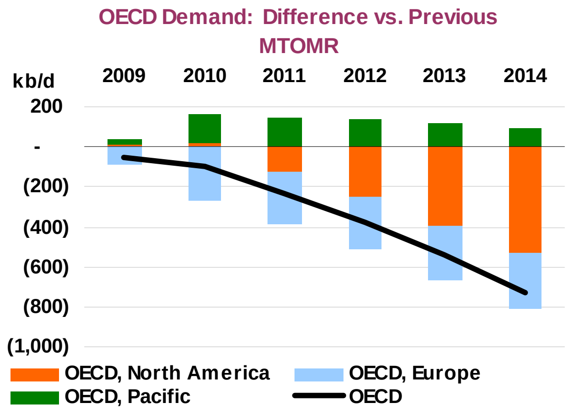


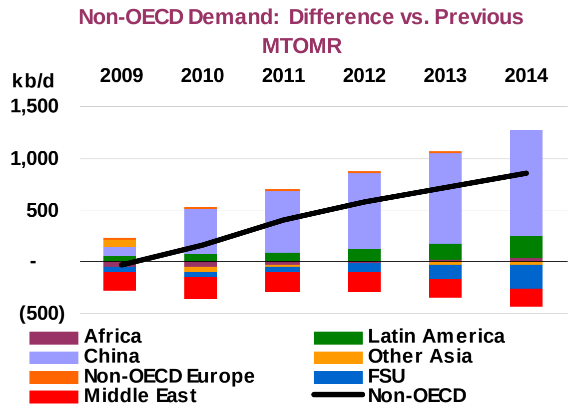
By contrast, OECD oil demand is projected to decrease by 0.7% or 290 kb/d per year on average over the forecast period, from 45.5 mb/d in 2009 to 43.7 mb/d in 2015. Thus, as far as the OECD is concerned, the emergence from the 2008-2009 recession will in practice translate into an 'oil-less' recovery over the forecast period. On the one hand, growth in transportation fuel demand in the OECD will be modest and insufficient to offset the structural decline in both burning and industrial fuels. Vehicle fleets have reached saturation point in most developed economies, thus limiting the scope for expansion.

Moreover, aggressive efficiency moves (notably in North America) and older populations who tend to drive less (Europe and the Pacific) are set to significantly curb demand for gasoline and diesel; only jet fuel demand will post modest growth. Meanwhile, most OECD energy intensive industries have relocated to emerging areas, while other sources of energy – natural gas, nuclear and renewables – are overtaking oil for heating or power generation. On the other hand, expected oil demand growth in North America – albeit modest, given cheaper energy alternatives, efficiency improvements and behavioural changes – will be counterbalanced by structurally declining demand in both Europe and the Pacific.

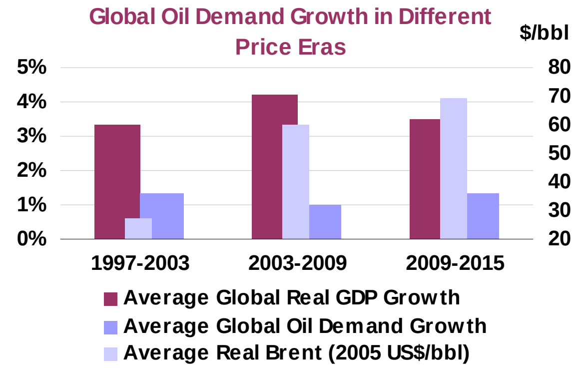
As much as the pre-eminence of transportation fuels is a theme shared by both OECD and non-OECD countries, the adoption of new, disruptive technologies in the longer term, notably in the transportation sector, may bring about further, significant changes in how oil is consumed. Indeed, the push to build new, ultra-efficient vehicles is not only driven by environmental considerations or government legislation, but also by market forces. Although most of these new technological trends, such as a widespread adoption of hybrid or electric vehicles, are unlikely to have an impact on oil demand within this report's timeframe, they could well become discernible by 2020.

Overall, the current prognosis shows marginal differences versus our last assessment. Compared with the *December 2009 medium-term update*, the current global oil demand forecast is only 130 kb/d higher by 2014. However, upward revisions in the non-OECD (+850 kb/d) offset downward adjustments in the OECD (-730 kb/d). In the former, baseline revisions following the submission of finalised 2008 data and a reappraisal of Chinese prospects yield a stronger demand outlook. In the latter, meanwhile, the pace of decline in North America is expected to be steeper, following a reassessment of efficiency trends in the transportation sector in both the US and Canada.



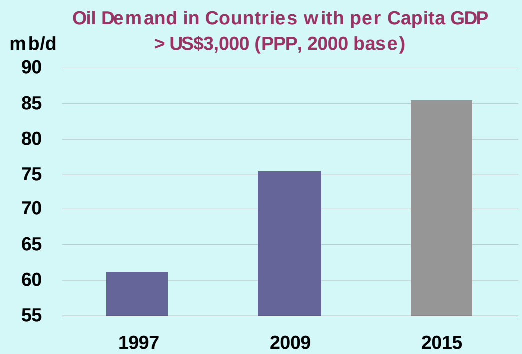


Finally, it is customary to recall that, given the complexity of oil demand drivers, this outlook faces both downside and upside risks. The strength and sustainability of the ongoing global economic recovery is obviously a key one, as is the volatility of commodity prices, particularly oil and its direct substitutes, such as natural gas. Other 'known unknowns' include the persistence of administered price regimes, as well as developments regarding energy efficiency and alternative technologies. The transition to fully market-based prices in regions featuring high subsidies, such as the Middle East, would indeed slow down oil demand growth, but this possibility is not envisaged within the forecast period. More subtle risks include behavioural changes, notably in OECD countries, as well as weather conditions that could deviate from the 'normal' (a ten-year average of observed temperatures). Lastly, any oil demand outlook faces the vexing problem of poor or hard-to-interpret data, an issue bound to become ever more pressing as the centre of gravity of global oil demand moves 'East of Suez' – to the areas where oil data are often incomplete.



Oil Demand Sensitivity: Caught Between Income and Efficiency

Income per capita has repeatedly been found to be the most important variable affecting oil demand, which tends to follow a so-called 'energy ladder'. As its income rises, a typical developing-country household – striving primarily to meet its cooking, heating and lighting needs – will first consume more energy from traditional sources (biomass or solid fuels) and then gradually move to higher quality fuels (oil-based liquid fuels and eventually electricity). Regarding mobility, a similar continuum can be traced: walking -> bicycle -> public transportation -> motorbike -> small car -> large car. At each step of the ladder, energy use tends to increase exponentially before reaching a saturation point, where growth slows down markedly (the so-called 'S curve'), as in many advanced economies. Empirically, the income per capita threshold above which oil demand takes off is around $3,000 (2000 base year). Many emerging countries have or are about to reach that threshold, largely explaining why non-OECD oil demand growth is likely to remain strong in the years ahead.



However, as much as GDP growth is a key oil demand driver, efficiency improvements can also play a major role. Seeking to refine our sensitivity analysis, we have introduced this last variable in order to go beyond a mere GDP-based sensitivity, as in previous editions of this report. The gain in efficiency – or more accurately, the decline in oil intensity – can be defined as the ratio of the change in demand over the change in real income. A change in oil intensity over time is akin to a change in income elasticity – i.e., how much less (or more) oil is required to produce a unit of output at a given point in time compared with previous timeframes. However, determining the precise drivers influencing oil intensity is extremely complex, since many variables are involved, most notably the price of oil, the price of substitutes, and the evolution of technologies and government policies, to name a few.

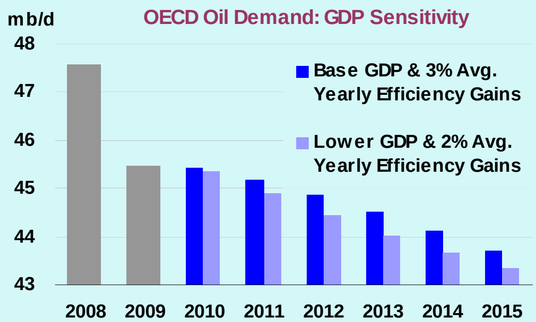
Oil Demand Sensitivity Rationale

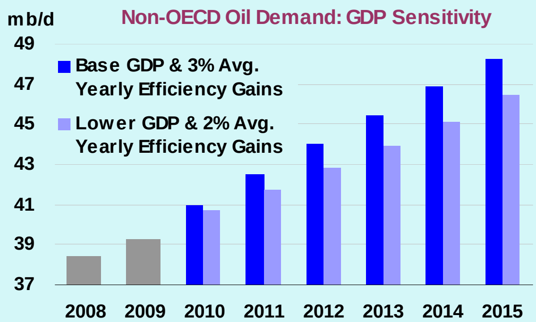
Base GDP & Existing Efficiency Gains	Lower GDP & Subdued Efficiency Gains
• The global economy recovers fully from the 2008-2009 recession, expanding by +3.6% on average over 2009-2015 (+4.4% over 2010-2015) as internal and external imbalances (high public and private leverage, excess capacity, unemployment, current account imbalances, etc.) are gradually eliminated	• The global economy fails to return to pre-crisis levels, burdened by persistent internal and external imbalances, notably among OECD countries; global GDP growth only averages +2.5% over 2009-2015 (+3.0% over 2010-2015)
• Existing efficiency goals are aggressively pursued as oil prices remain high (tighter US CAFE standards, hybrid/electric cars, operational and technological improvements in aircrafts and ships); oil intensity declines by 3% on average over 2010-2015	• Implicitly lower oil prices mean that efficiency improves more slowly, thus reducing market and government incentives to develop cleaner technologies; oil intensity declines by 2% on average over 2010-2015, in line with the 15-year average to 2009
• Annual oil demand grows strongly, by +1.2 mb/d over 2009-2015 (+1.1 mb/d over 2010-2015)	• Annual oil demand grows by only +0.8 mb/d over 2009-2015 (+0.7 mb/d over 2010-2015)

Oil Demand Sensitivity: Caught Between Income and Efficiency (continued)

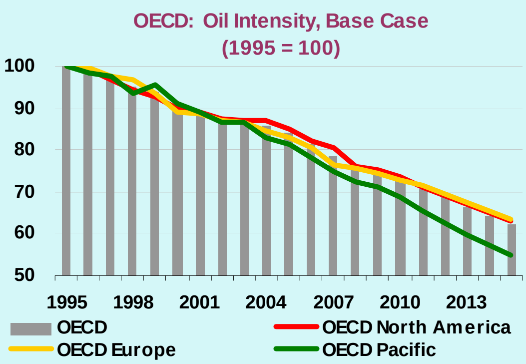
In order to test the oil demand sensitivity to both income and efficiency, we have developed two oil demand cases. The base case, which underpins the trends discussed in this report, assumes that 1) global economic growth averages 3.6% per year, in line with the latest IMF economic outlook, and 2) global oil intensity declines by 3% per year on average over 2010-2015, slightly faster than in the previous 6-year period (-2.7% over 2004-2009), which saw the game-changing emergence of non-OECD oil demand and the sharp rise in oil prices.

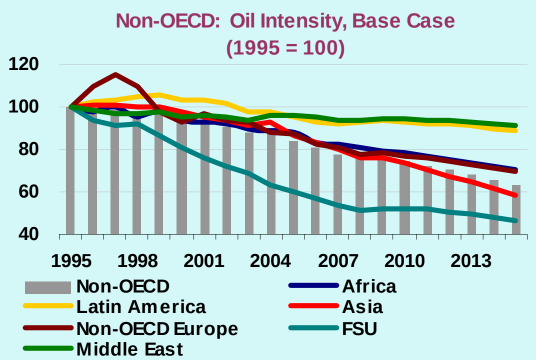
Alternatively, under the 'Lower GDP' case, annual economic growth would average 2.5%, with oil intensity falling by only 2% per year, roughly in line with the 15-year average to 2009 (-2.1%). The more subdued oil intensity assumption implicitly reflects the likelihood that oil prices would be weaker if GDP growth were to be much lower, thus reducing the incentives to rapidly improve efficiency gains. That said, the second case is purely illustrative and does not imply any specific probability of occurrence, or any certainty over the extent to which efficiency gains would be dragged down with weaker economic activity. In other words, we have not attempted to directly model the iterations between GDP growth and the oil price, as such an *scenario* approach goes beyond our *sensitivity* analysis.





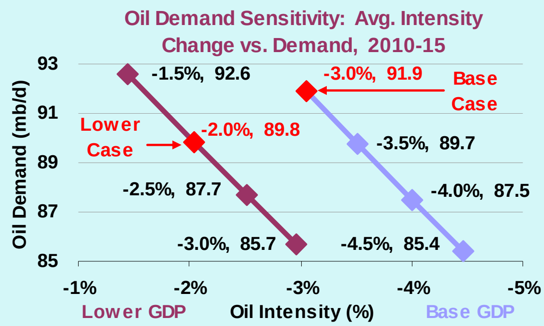
The difference in projected oil demand between the two cases is 2.1 mb/d or 2% by 2015, almost equivalent to the entire current consumption of a large European country such as France or Germany. Unsurprisingly, non-OECD countries are more sensitive to changes in GDP and efficiency than the OECD. As noted earlier, most emerging economies are at the initial steps of the energy ladder, where energy use increases rapidly, and only a few are actively adopting efficiency goals – the Middle East and Latin America, and more recently the FSU, are notorious laggards in this respect. By contrast, OECD countries have already reached the point where income elasticity becomes very low, and have largely adopted aggressive efficiency targets – the Pacific and Europe being the most conspicuous examples, soon to be followed by North America as more stringent standards are adopted in the transportation sector. As such, under the lower case, non-OECD oil demand would be about 1.8 mb/d or 4% lower by 2015 than under the base case, while OECD demand would only be 360 kb/d or 1% lower.





Oil Demand Sensitivity: Caught Between Income and Efficiency (continued)

More interesting, perhaps, is the offsetting effect of more subdued efficiency gains. Indeed, if the decline in oil intensity remained unchanged at 3% per year under both cases, global oil demand would be over 6 mb/d lower by 2015, should average GDP growth be curbed by a third. But if subdued economic activity over the medium term were to also slow down efficiency initiatives – be they market-based or government-mandated – the GDP effect upon oil demand would be relatively limited. Empirically, every 0.5 percentage-point variation in the pace of oil intensity decline would imply a change in oil demand of roughly 2 mb/d by the end of the forecast period. As such, assuming a 2% intensity decline effectively offsets the GDP effect by two-thirds.

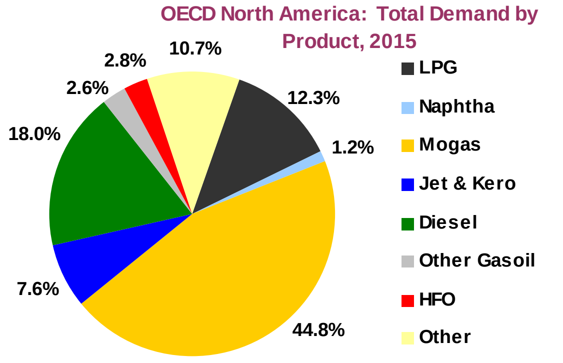


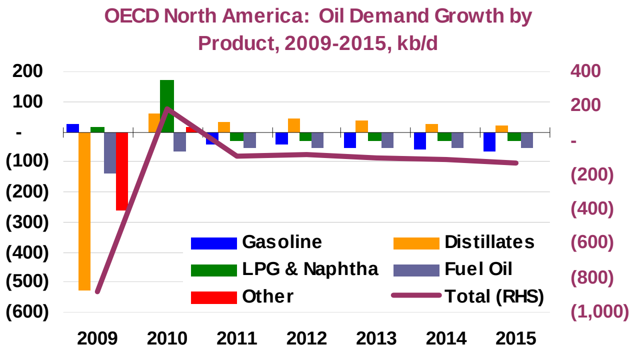
Lastly, this analysis suggests that, thanks in part to rising efficiency, oil demand has arguably peaked in the OECD. Even as these economies recover from the recession and the resultant plunge in oil demand, a large portion of oil demand will have been permanently 'destroyed', rather than temporarily 'suppressed' – and this regardless of oil price levels, as current technologies and operating procedures are unlikely to be rolled back even if prices were to fall sharply. Admittedly, this is not the case in non-OECD countries, although it should be noted that some – more noticeably China – have efficiency goals that are in many respects more ambitious than in most advanced economies. Moreover, emerging countries can leapfrog the less efficient technologies in favour of the most advanced ones – an opportunity dubbed by some analysts as the 'Hummer bypass'. China, for one, is likely to have a greater proportion of highly efficient vehicles in its overall fleet in just a few years than, say, the US, which will take more time to turn over its existing fleet, which is much larger and older. And if new, disruptive technologies come to fruition – such as electric vehicles (EVs) – non-OECD demand could also eventually peak, sooner than many envisage, although arguably not within this report's forecast period.

OECD North America

Oil product demand in North America is expected to fall by 0.2% per year on average between 2009 and 2015, from 23.3 mb/d to 22.9 mb/d. This outlook stems from structural declines in oil usage for heating and power generation outweighing modest rises in transportation fuel and petrochemical feedstock demand. The US continues to dominate oil consumption, accounting for over 80% of regional demand in 2015. The regional economic outlook envisages real GDP growth returning to levels seen before the economic crisis, with 2010-2015 annual growth averaging 2.7%, similar to the 2002-2006 average. This would seem to suggest a stronger return to oil demand growth, particularly in the more economically sensitive transportation sector. Yet gasoline consumption should actually decline over the forecast period, owing to improved fuel economy and high oil prices.

Indeed, a dichotomy has emerged in North American transportation fuel demand. While transportation fuels should grow by 0.3% annually from 2009-2015, the rise stems from higher diesel, jet fuel/kerosene and Mexican gasoline outweighing structural declines in US and Canadian gasoline. Vehicle efficiency standards issued by the US and Canadian governments portend falling gasoline demand over the medium term, as new light-duty vehicles become increasingly more efficient and less emissions-intensive. The economic crisis and high oil prices have spurred market-driven innovations in middle distillate use as well. Industrial supply chains are employing diesel-based trucking fleets more efficiently, while air carriers are fielding newer and more efficient aircraft, operated at higher passenger load factors. Still, a rebounding economy points to higher middle distillate consumption ahead (as suggested by strong preliminary US data in recent weeks), with efficiency improvements outweighed by activity and capacity gains. Industry restocking provided a boost to petrochemical feedstock in 2010, underpinning overall forecast period growth. However, petrochemical expansions in other, more cost-advantaged regions suggest declines from 2011 onwards. Meanwhile, increased natural gas availability should continue to spur declines in oil-based heating and power generation.





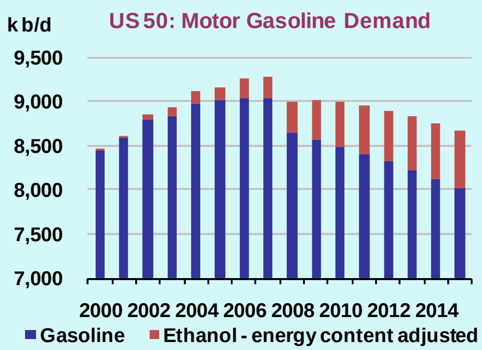
OECD North America: Demand Trends, Main Refined Products

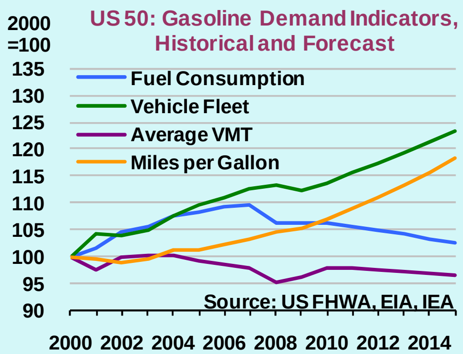
Product	Volume, 2015 (mb/d)	Avg. Yearly Growth, 2009-2015	Comments
Naphtha	0.29	-1.1%	Petrochemical activity boosted by economic recovery in 2010, but declining in the US and Canada from 2011 as more competitive petrochemical producers emerge; growth expected in Mexico, but from a low base
Gasoline (including ethanol)	10.28	-0.4%	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
Jet Fuel & Kerosene	1.75	1.1%	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)	4.72	0.4%	Diesel growing in all three countries, driven by economic activity and offsetting continued displacement of heating oil by natural gas and electricity in the US and Canada
Residual Fuel Oil	0.64	-6.7%	Declining use for power generation in all three countries, as fuel oil is substituted by natural gas or other sources both for price reasons and in a bid to curb carbon emissions
Total Oil Products	**22.94**	**-0.2%**	

Evaporating US Gasoline Demand?

Increasingly stringent fuel efficiency rules for new light duty vehicles in the US have set the stage for falling gasoline demand. Following the Obama administration's initial announcement in 2009, the US government issued final rules in April 2010, setting out efficiency and emissions mandates for new light vehicles at 35.5 miles per gallon (MPG) on average by 2016 (see 'Structural Change in Action', *Oil Market Report* dated 13 April 2010). Medium and heavy trucks will also be subject to future efficiency standards, equally implying an effect on diesel demand. Yet specifics are still forthcoming, and mandates will not start until 2014. As such, this analysis focuses solely on gasoline.

Overall, we expect US motor gasoline demand to decline by 0.6% annually from 2009-2015. Assumptions about the vehicle fleet (number, type and technology), average vehicle-miles travelled (VMT) and average MPG underpin the forecast, with the relationship between these variables and demand growth expressed as follows: %ΔDemand = %ΔFleet + %ΔVMT - %ΔMPG. On this basis, the fuel economy of the existing US gasoline vehicle fleet is set to improve by 1.9% annually between 2009 and 2015, assuming that both fleet size and driving activity expand in line with historical GDP correlations. With US annual GDP growth of 2.6% on average, the fleet is seen growing by 1.2% per year, while average miles per vehicle are projected to rise by 0.1% per year. It should be noted that the increase in average VMT stems wholly from a rebound in 2010, prompted by the economic recovery. Afterwards, VMT are projected to fall by 0.3% annually, in line with the trend observed in the past decade.





While improved vehicle fleet efficiency plays a dominant role, high oil price assumptions and potentially persistent long-term unemployment – in the US, the economic recovery has so far been jobless – put downside cyclical pressure on demand. Work commuting, for example, accounts for over 25% of total vehicle trips. Slower than anticipated GDP growth could also curtail the vehicle fleet's expansion – another key demand driver – but this effect would be partially counteracted by reduced turnover of the fleet and lesser efficiency improvements. Nevertheless, the impact of different cyclical assumptions is limited - US gasoline demand declines by 0.7% annually under our lower GDP case, similar to the 0.6% fall in our base case. Finally, the subtraction of required ethanol blending amounts points to steeper, though still gradual, decreases in oil-based gasoline consumption.

However, the fall in US gasoline demand is not irreversible in the long term. Although moves to achieve greater vehicle efficiency (such as recently announced light-duty vehicle emissions standards for 2017 and beyond) would arguably help, increased efficiency could also paradoxically increase transportation fuel demand, even under higher oil prices. Indeed, higher fuel economy may lower the average cost per mile driven, spurring drivers to increase their average VMT. It may also renew the relative attractiveness of light trucks (when safety and utility factors are taken into account) and thus slow or even reverse an assumed rebalancing of the fleet away from less efficient, larger vehicles towards passenger cars.

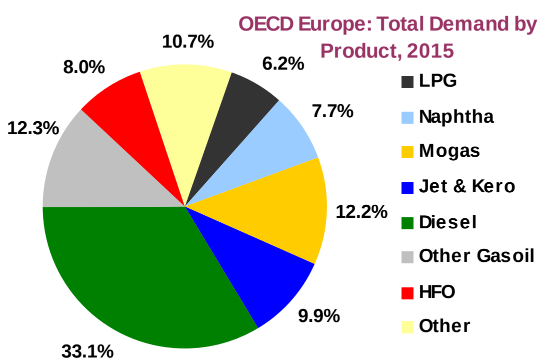
Evaporating US Gasoline Demand? (continued)

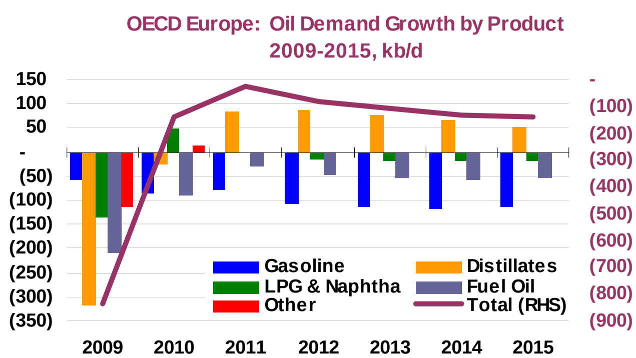
Finally, demographic and technological factors will play a crucial role in shaping the transport demand equation, but arguably their effects will be truly felt beyond the forecast period. The US remains a country designed around the automobile and is characterised by large swathes of suburban sprawl. While public transportation ridership increased during the oil price run-up of 2008, the upside for such alternative forms of mobility remains limited, and government transportation spending is strongly skewed towards roads. Moreover, even though the housing market bust may have curtailed a march away from city centres, dramatic re-urbanisation is unlikely under present incentives, while the lure of bigger, cheaper housing may keep the sprawl momentum. Yet major technological breakthroughs – such as a shift towards ultra-efficient electric vehicles – could help offset these demographic features and reinforce the trend of ever-falling gasoline demand.

OECD Europe

Oil product demand in Europe is seen declining by 0.7% per year on average, from 15.0 mb/d in 2009 to 13.9 mb/d in 2015, largely on developments in its largest economies. Demand in France, Germany, Italy, Spain and the United Kingdom, expected to account for 60% of total regional demand by the end of the forecast period, will continue to decline structurally. Modest economic growth relative to other countries, notably in central and eastern Europe; declining populations, particularly in Germany, Italy and Spain; the progressive 'dieselisation' of vehicle fleets, albeit at a lower pace than in previous years; and further substitution of heating and residual fuel oils by natural gas and renewables are all contributing factors.

Regarding this last point, it should be noted that natural gas substitution is likely to be centred in heating uses rather than power generation, where such transition is largely completed. Moreover, previous worries over natural gas availability following several interruptions of gas supplies from Russia have now given way to expectations of a persistent gas glut. The economic recession curbed gas demand dramatically, albeit temporarily, but also resulted in much idle LNG capacity, built precisely to assuage European concerns over Russian supplies. If anything, gas supply will remain plentiful for the foreseeable future and able to comfortably meet future gas demand growth.





Meanwhile, the steep fall in gasoline consumption, further encouraged by temporary, recession-induced, incentive-based scrapping schemes of older cars in favour of more efficient vehicles (mostly diesel-powered) is now expected to offset modest growth in middle-distillate demand (diesel and jet fuel). Together with vehicle-fleet saturation and behavioural changes, transportation fuels demand

(55% of total consumption on average) should decline by 2% over the forecast period. Nonetheless, whether the share of oil in transportation fuel demand will actually decline will depend on biofuels mandates and government subsidies, which have become more lukewarm on concerns about the environmental sustainability and cost of such alternative supplies.

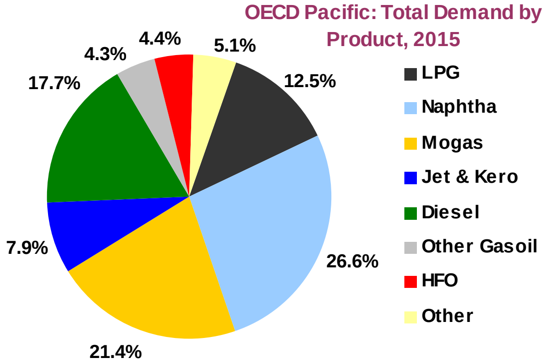
OECD Europe: Demand Trends, Main Refined Products

Product	Volume, 2015 (mb/d)	Avg. Yearly Growth, 2009-2015	Comments
Naphtha	1.07	1.3%	Petrochemical activity stagnating in 'core' countries (France, Germany, Italy, Spain and the United Kingdom) after emerging from the economic recession; moderate growth in several 'peripheral' (eastern) countries
Gasoline (including ethanol)	1.69	-5.0%	Recession-induced, incentive-based scrapping of older gasoline-fuelled cars in favour of more efficient diesel vehicles in core countries; moderate growth in peripheral ones
Jet Fuel & Kerosene	1.37	1.5%	Air travel boosted by 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)	6.30	0.6%	Diesel fleets expanding in peripheral, less saturated countries; continued substitution of heating oil by natural gas and to a lesser extent electricity
Residual Fuel Oil	1.11	-4.3%	Declining use for power generation on substitution by other energy sources (natural gas, renewables and nuclear), although this process has largely been completed in large countries; rising bunker demand in the Netherlands and Belgium as global trade recovers
Total Oil Products	**13.87**	**-0.7%**	

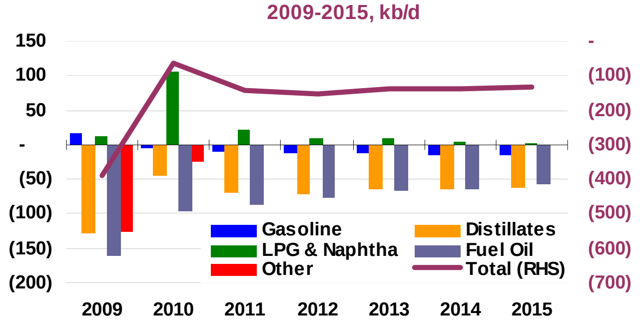
OECD Pacific

The Pacific is expected to feature the most pronounced decline in oil demand in the OECD. Demand is seen falling by 1.8% per year on average, from 7.7 mb/d in 2009 to 6.9 mb/d in 2015, driven mostly by powerful structural developments in Japan. The country faces the unappealing prospect of an ageing population, which could affect long-term economic growth. Moreover, efforts to develop ever more efficient vehicles continue unabated, while the share of electricity-based heating resumes growth on the back of restored nuclear power generation, reversing several years of strong residual fuel oil consumption and direct crude burning following a series of nuclear outages. Meanwhile, the post-recession surge of LPG and naphtha, prompted by the recovery of Japan’s export-oriented petrochemical industry is likely to taper off as more competitive producers emerge elsewhere. Japanese developments should thus weigh heavily on the region’s overall prospects, as this country will account for over half of total regional demand over the forecast period.

OECD Pacific: Total Demand by Product, 2015



OECD Pacific: Oil Demand Growth by Product 2009-2015, kb/d



Korea, the second largest consumer with roughly 30% of regional oil demand, is also facing structural decline, but only in kerosene (used for heating, as in Japan), heating oil and residual fuel oil. Demand for gasoline, diesel and, most importantly, naphtha is seen increasing, albeit moderately. The outlook for naphtha use is particularly critical, given its weight relative to Korea's total oil demand (rising from 42% in 2009 to 48% in 2015). It assumes that the country will successfully fulfil its ambitious petrochemical expansion plans, aimed largely at feeding the vast Chinese market, despite fierce competition from other regions, notably the Middle East (and China itself).

OECD Pacific: Demand Trends, Main Refined Products

Product	Volume, 2015 (mb/d)	Avg. Yearly Growth, 2009-2015	Comments
Naphtha	1.84	1.5%	Growing in Korea but declining rapidly in Japan after a temporary post-recession surge, as other, more competitive petrochemical producers emerge (the Middle East and China)
Gasoline (including ethanol)	1.48	-0.8%	Declining in Japan given demographic, technological and behavioural changes; marginal or stagnant growth in Korea and Australia
Jet Fuel & Kerosene	0.55	-7.0%	Rapidly declining kerosene consumption given sustained switch to electricity-based heating in Japan and Korea, largely offsetting recovery-driven jet fuel growth, notably in Korea and Australia
Gasoil (including biodiesel)	1.52	-0.8%	Sharp structural heating oil decline, notably in Japan and Korea, largely offsetting growing diesel demand in all countries (Australia, Japan, Korea and New Zealand) as economic activity rebounds
Residual Fuel Oil	0.31	-14.0%	Declining across the region, displaced by natural gas and other energy sources, notably nuclear power generation in Japan as shut-in plants resume operations
Total Oil Products	**6.91**	**-1.8%**	

Energy Subsidies: Getting the Price Right

For over a decade, the IEA's *World Energy Outlook* has called for the phasing-out of fossil fuel subsidies as a means to improve energy security, promote economic growth and protect the environment. Since 2003, the rise in energy prices has brought about renewed impetus for reform.

Countries importing energy at international prices and selling it domestically at lower, regulated prices have faced a rising fiscal burden. There is growing recognition that subsidies encourage fuel adulteration and smuggling, and typically benefit wealthier segments of the population rather than the poor. Artificially low energy prices also stifle demand response at times of high international prices. While energy importers have clear incentives to remove subsidies, several energy exporters are also gradually phasing them out or are considering doing so, since they can often lead to rampant domestic demand growth, undermining export revenues. Notably, the Middle East's expected rise in oil demand over 2009-2015 is equivalent to 70% of that period's net increase in regional OPEC crude production capacity.

A key step toward reform was taken in September 2009, when the G-20 committed to 'rationalise and phase out over the medium term inefficient fossil fuel subsidies that encourage wasteful consumption'. This pledge recognised that subsidies distort markets, impede investment in clean energy sources and undermine efforts to deal with climate change. The IEA, OPEC, OECD, and World Bank were called upon to provide an analysis of the scope of energy subsidies and suggestions for implementation of the G-20 initiative. A Joint Report prepared by these four organisations will be reviewed at the G-20 Leaders' Summit in late June 2010.

Energy Subsidies: Getting the Price Right (continued)

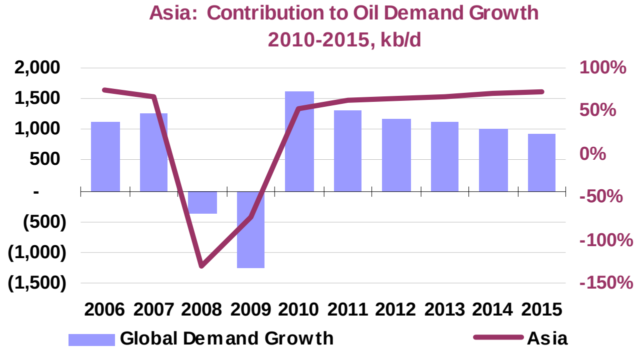
In response to the call from the G-20, the IEA estimates that fossil fuel subsidies amounted to $557 billion in 2008. Iran's subsidy bill, in particular, reached approximately $101 billion (the highest of any country) that year, equivalent to about a third of the country's budget. Chronic under-pricing of domestic energy has caused major economic strains, increased dependence on refined product imports and fostered widespread inefficiency. The government has announced a sweeping plan for energy subsidy reform from September 2010, but many obstacles must be overcome for such a reform to last.

Our projections in this report are based on policies in place, therefore incorporating the encouraging moves a few other large non-OECD countries – such as China, Russia and Indonesia – have taken to bring domestic energy prices in line with international prices. Saudi Arabia, one of the world's largest oil exporters, is currently debating the need to reform its price system, with top officials recently suggesting that domestic energy prices should better reflect market conditions in order to tame runaway demand growth.

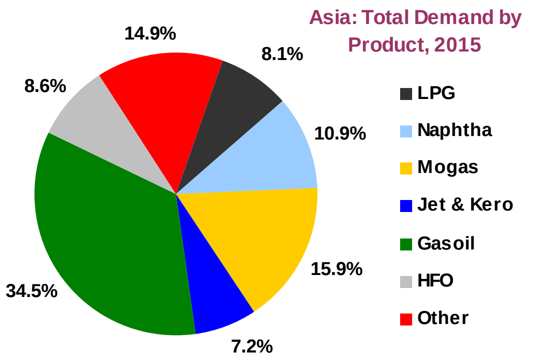
IEA modelling indicates that gradually phasing out fossil-fuel subsidies over the next decade would cut global oil demand by roughly 6.5 mb/d in 2020, compared to a baseline assuming no change from current policies. This equates to roughly one third of current US oil demand. Higher end-user prices would indeed encourage more efficient energy use, notably in the transportation sector, and trigger some switching from fossil fuels to other, less carbon-intensive sources. The *World Energy Outlook 2010* – to be published on 9 November – will include a special focus on energy subsides, building on the findings outlined above.

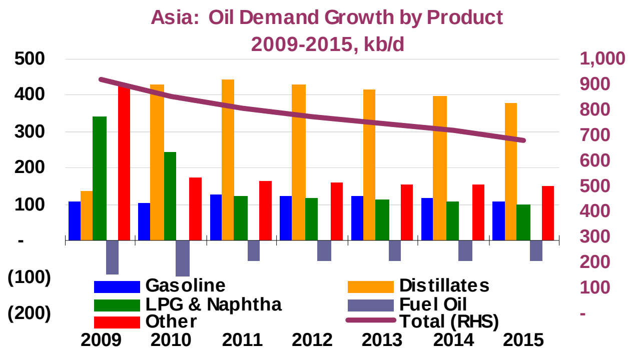
Asia

Oil product demand in non-OECD Asia is expected to rise by 3.8% per year on average, from 18.5 mb/d in 2009 to 23.0 mb/d in 2015 – the most significant regional change to the previous forecast, which foresaw somewhat lower growth. Although not strictly comparable, growth had been assessed at +3.1% over 2009-2014 under the December update. Upward baseline revisions following the submission of finalised 2008 data for most countries have played a role, but the extraordinary resilience of the region's economy in the face of the global recession, supported by massive government-backed stimulus programmes, has been instrumental in improving the outlook, as demand in both 2009 and the early months of 2010 has vastly exceeded expectations. Indeed, the region's largest economies – China, India and Indonesia – and other smaller ones managed to expand robustly in 2009, albeit at a slower pace than in previous years, thus setting the basis for strong GDP growth in 2010.



Looking ahead, Asian economic activity is projected to rise by 8% per year on average over the forecast period – even as stimuli are gradually withdrawn – which is much faster than any other region in the world. As such, demand for all product categories bar residual fuel oil – displaced by rising natural gas penetration – will register strong growth, on the back of strong demand for greater mobility and petrochemical, industrial and agricultural activity. It should be noted that, contrary to earlier expectations, fuel oil demand in China is set to fall over the forecast period, rather than rise. Indeed, the consolidation of the independent refining industry has proceeded at a faster-than-anticipated pace, with the country's overall refinery configuration gradually becoming more complex.





Demand for transportation fuels, fuelled by a huge population and rising income per capita in urban areas, will continue to be the main driver of oil consumption growth, with vehicle and aircraft fleets expanding significantly, particularly in the largest countries. This trend could even accelerate if rising oil prices were to foster a move to maintain or restore end-user subsidies. Since 2009, China – the region's largest oil consumer, with almost half of total demand over the forecast period, as well as the world's largest car market ahead of the US – has put in place a price mechanism that has largely tracked changes in international oil prices, albeit with lags and concerns about hoarding behaviour (which will possibly lead to some fine-tuning in the months ahead). By contrast, India (17% of regional demand) maintains both price subsidies (on LPG and kerosene) and price controls (on gasoline and gasoil), despite several government-commissioned reports recommending the adoption of market prices. The government is understandably concerned to shield the poor segments of the population (who depend heavily on subsidised kerosene, in particular), but capping the price of transportation fuels, while politically useful, has severely distorted demand – and has arguably benefitted higher income-earners.

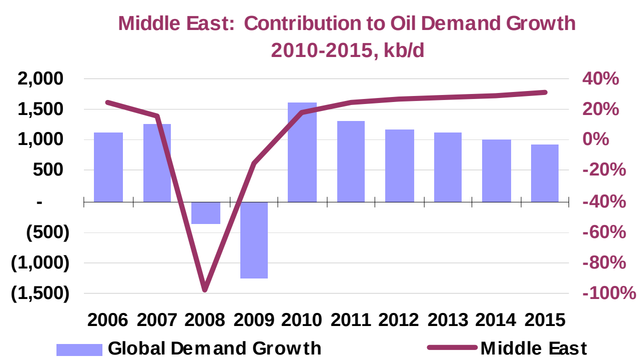
Asia: Demand Trends, Main Refined Products

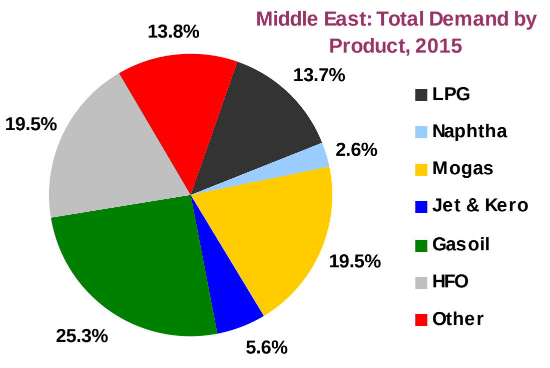
Product	Volume, 2015 (mb/d)	Avg. Yearly Growth, 2009-2015	Comments
Naphtha	2.50	4.8%	Growing in China, Chinese Taipei, Hong Kong, Indonesia, Philippines and Singapore; declining in India given growing supplies of both domestic and imported natural gas for the production of petrochemicals, notably fertilisers
Gasoline (including ethanol)	3.67	3.6%	Surging as vehicle fleets expand, given rising income per capita in urban areas, notably in China, India, Indonesia and Vietnam
Jet Fuel & Kerosene	1.65	4.0%	Growing jet fuel demand with rising air transportation and expanding aircraft fleets in China, Chinese Taipei, Hong Kong, India, Indonesia, Malaysia, Singapore and Thailand; subsidised kerosene to remain the fuel of choice for the poor, notably in India and Indonesia
Gasoil (including biodiesel)	7.94	5.4%	Expanding strongly in all countries, driven by economic activity and gasoil's multiple usages; additional support may be provided by subsidies if prices rise
Residual Fuel Oil	1.97	-2.9%	Declining in the power generation sector because of natural gas substitution, notably in China, Indonesia, Malaysia and Thailand; rising in Hong Kong and Singapore as global trade resumes and bunkers demand picks up
Total Oil Products	**23.03**	**3.8%**	

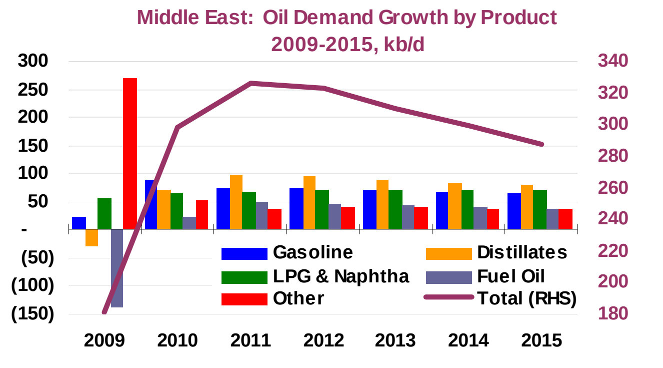
Given its multiple usages (transportation, industry, agriculture and small-scale power generation), gasoil will remain the region's fuel of choice, accounting for almost a third of total demand. Our estimates suggest that transportation will account for the bulk of Asian gasoil use, both in 2010 and in years to come (transportation should account for roughly 44% of total gasoil consumption in 2010, followed by petrochemical and industrial activities, with about 22%, and residential / agriculture / power generation with almost 20%). Aside from the fact that precise sectoral breakdowns are notoriously difficult to achieve given the lack of data, the use of gasoil for power generation sources is clearly an upside risk to the forecast, notably if other sources of electricity such as coal were to falter due to supply and demand imbalances.

Middle East

Oil product demand in the Middle East is seen growing by 3.9% per year on average over the forecast period, from 7.1 mb/d in 2009 to 8.9 mb/d in 2015. As in Asia, this region also had a mild recession, with all countries bar two expanding, albeit at a lower pace than in previous years. GDP in Kuwait and the UAE contracted, but both countries registered only a mild recession, if judged by OECD standards. In the medium term, oil demand looks set to continue growing due to sustained economic expansion (based on oil and gas, petrochemicals, heavy industry and to a lesser extent construction, which felt the brunt of the economic slowdown), demographics (continued urbanisation and a young and growing population) and end-user subsidies, which are unlikely to be dismantled in most countries (currently, fuel prices across the region are among the lowest in the world). However, Iran has announced plans for a gradual subsidy phase-out and some voices have also called for greater reliance on market prices in Saudi Arabia.







As such, yearly demand growth across all oil product categories will be strong, ranging between 2.5% and 6.0% depending on the product. As in Asia, demand for transportation fuels (mainly gasoline and jet fuel) will continue to rise on the back of expanding vehicle and aircraft fleets (the Gulf, moreover, is becoming one of the world's main air travel hubs), relatively unencumbered by efficiency considerations given cheap end-user prices. Demand for petrochemical feedstocks (LPG and naphtha) is also expected to increase sharply, as the region strives to become a major petrochemical hub. Demand for burning fuels (crude for direct burning, residual fuel oil and gasoil) will also rise in order to meet ever growing power and industrial needs, since the development of domestic natural gas resources is likely to be delayed.

Even though Saudi Arabia and Iran will remain the largest regional oil users (40% and 21% of total Middle Eastern demand by 2015, respectively), other countries are projected to contribute significantly to future regional growth. In absolute terms, combined oil demand growth in Iraq and the UAE, in particular, will be roughly equivalent to Iran's, at almost 40 kb/d by 2015. In the long run, as security improves and the country is rebuilt, Iraq could become a major regional power, owing to its relatively well-educated population, large industrial base and vast oil and gas resources. By contrast, the outlook for Iran is clouded with uncertainty and poses a significant downward risk to the forecast. Demand plummeted in 2009 (-6.4% year-on-year), and reported figures for the first few months of 2010 have been inordinately weak, suggesting that economic conditions may be worsening as a result of both external pressures and domestic factors. Moreover, the government is committed to gradually removing onerous fuel subsidies, which could further curb demand for gasoline and diesel.

Middle East: Demand Trends, Main Refined Products

Product	Volume, 2015 (mb/d)	Avg. Yearly Growth, 2009-2015	Comments
Naphtha	0.24	4.6%	Surging as ambitious petrochemical projects are developed across the region, particularly in Saudi Arabia, and given the lack of sufficient natural gas supplies (although LPG/ethane supplies are set to grow sharply)
Gasoline (including ethanol)	1.73	5.0%	Rising rapidly, spurred by expanding vehicle fleets on the back of rising income per capita, urbanisation and extremely low end-user prices, especially in the largest markets; end-user price subsidies expected to continue, with the notable exception of Iran
Jet Fuel & Kerosene	0.50	3.2%	Increasing as air traffic rises across the region, which is becoming a key global hub, with the largest markets being respectively Iran, Saudi Arabia, the UAE and Iraq
Gasoil (including biodiesel)	2.26	3.6%	Rebounding demand as rapid economic activity resumes, notably in the construction sector and, to a lesser extent, the power industry, with Saudi Arabia, Iran, Iraq and the UAE at the forefront
Residual Fuel Oil	1.74	2.5%	Growing to feed power plants as long as alternative sources (mainly domestic natural gas) remain commercially unavailable, notably in Iran, the UAE, Saudi Arabia, Iraq, Syria and Kuwait
Total Oil Products	**8.90**	**3.9%**	

Staring at the Crystal Ball: New Transportation Trends

Since transportation is expected to account for almost two-thirds of global oil demand by 2015, the adoption of new, disruptive technologies and processes could bring about significant and long-lasting changes in how much oil is used globally. The main focus of attention is currently the automotive industry. The push to build new, more efficient vehicles is not only driven by environmental considerations or government legislation, but also by market forces. Although these trends are unlikely to have an impact on oil demand within this report's timeframe, they could well become quite discernible by 2020 and are therefore worth examining.

Industrial Challenges …

As the global recession unfolded, a growing number of car manufacturers were confronted by plunging sales and the threat of bankruptcy. Governments across the world opted either to bailout their car manufacturers or put in place temporary scrappage schemes to support new vehicle sales. Yet, at best, the automotive industry just gained some time amid pressing financial, behavioural and environmental challenges. Indeed, OECD markets are becoming saturated, with sales stagnating, costs rising, profits receding and overcapacity increasing. Post-recession restrictions on credit, improving vehicle reliability and widening options for cheap short-term renting or car-sharing in urban areas will all potentially restrict sales in years to come. Moreover, consumers are increasingly choosing smaller, more fuel efficient models.

Facing a seemingly unsustainable situation in the developed world, the industry has focused on more promising non-OECD markets, where vehicle fleets are still small and rising incomes are encouraging sales. Most car manufacturers are actively pursuing this approach, notably in large countries such as China, India or Russia, frequently through partnerships with local producers. Yet this strategy entails environmental consequences. The industry hopes to sell some 100 million vehicles per year worldwide by 2020, compared to 60 million today. Development of new, much more efficient vehicles and transportation concepts has thus become urgent. Currently, several technologies and new business models are actively competing in the race to build the car of the future.

… New Technologies & Business Models …

One currently available technology is the **hybrid vehicle**. Already commercially produced by several Japanese manufacturers, it combines an internal combustion engine with an electric motor that takes over at low speeds, powered by a nickel-metal battery recharged by the thermal engine or when braking. A hybrid variant has an electric motor that powers the vehicle permanently and a small thermal engine to recharge it if needed (the car can also be plugged into the mains). Although more expensive than a gasoline-based vehicle, a hybrid has a large autonomy range and is more efficient, with broadly similar fuel economy to that of conventional diesel cars. To boost the appeal of hybrids, carmakers are attempting to increase efficiency by combining electricity and other hydrocarbon fuels, such as LPG. Still, hybrids still emit greenhouse gases under any configuration.

Natural gas vehicles have gained ground in various countries (notably Argentina, Bangladesh, Brazil, India, Iran, Pakistan and Thailand) and can be economical if gas is plentiful and cheap. The recent surge of shale gas production in the US has led to renewed calls there to shift towards gas-powered vehicle technology. But despite more efficient combustion than gasoline and diesel engines, gas-powered vehicles face several obstacles. These include small tanks, limited autonomy and concerns about reliability, engine power and the risk of explosion in case of collision. Meanwhile, the conversion of existing gasoline-powered vehicles to gas is relatively expensive, particularly if intended to use LNG (liquefied natural gas) rather than the more widely used CNG (compressed). The establishment of refuelling infrastructure is also costly. Short of further incentives, natural gas vehicles will likely remain a niche market, serving commercial and public fleets in urban areas.

Staring at the Crystal Ball: New Transportation Trends (continued)

Electric vehicles can be very cheap to operate, as well as silent, but face several potential hurdles, notably high battery costs, long charging times and limited driving range. The first problem could be overcome by government subsidies, while 'fast-charging' points and schemes to lease and replace batteries as needed could address the last two issues, albeit with high dedicated infrastructure costs. More importantly, most carmakers would have to agree on battery size and positioning to facilitate quick and easy replacement. The main advantage of this approach is that EVs would be much cheaper to buy, as the cost of the battery would not be borne upfront by the consumer, but would rather become amortised as a running fee. Better Place, a start-up US company in partnership with the Renault/Nissan alliance, is the main proponent of this concept, with pilot projects to be implemented in Denmark, Israel, Australia and Hawaii (aimed at private cars), as well as Japan (taxis).

Better Place's business model, however, could be derailed if major battery technology breakthroughs were to materialise – or if 'range anxiety' proved less than expected, notably in urban areas. Lithium-ion batteries are currently preferred, providing around 150 km average autonomy for small to medium-sized cars, although some companies are working on a cheaper sodium-nickel-chloride variety. A potential hurdle of lithium-ion batteries, though, concerns the supply of their main component. Lithium, a rare and expensive metal, is mostly found in only a handful of countries, notably in Latin America. Chile is currently the largest producer, but Bolivia alone holds half of the world's known reserves. More interestingly, perhaps, than the evolution of batteries *per se*, is altering the design of the car itself in order to expand the range of existing battery technology. Japanese researchers have built an eight-wheel prototype with a small motor in each wheel – as opposed to the centrally located engine found in most hybrids and forthcoming EVs – which can reportedly run for up to 300 km on a single charge, since energy losses are significantly reduced.

In any case, as with plug-in hybrids or hydrogen fuel cells, EVs may not be entirely emission-free if the electricity that feeds them comes from thermal sources, although large thermal power plants are more efficient than internal-combustion engines. EVs could also overload the grid unless they were recharged at off-peak hours. But grids managed with 'smart' technologies, which would supply real-time price data to users and demand and generation information to utilities, could overcome this problem. Furthermore, EVs could eventually become a useful repository of power from renewable sources such as wind, which otherwise could not be stored.

Fuel cells, which are electrochemical devices mixing stored hydrogen with atmospheric oxygen to generate electricity and water vapour, constitute another possibility. A hydrogen-based car produces no emissions directly but, as with electric vehicles, overall emissions depend on the energy used to produce the hydrogen. Natural gas is often the source of choice, although some companies are experimenting with solar energy. Moreover, producing and delivering hydrogen in large quantities is very expensive, in addition to the cost of dedicated refuelling infrastructure. The vehicle itself is also pricey. As such, this technology remains confined to a number of localised pilot projects, such as 'hydrogen highways' in California, Norway and Japan. Nonetheless, some carmakers envision commercial mass-production as early as 2015, arguing that this type of vehicle will flourish in densely populated areas.

In sum, the race to find the transportation game-changer is just beginning, but it remains unclear whether a single technology will prevail or several alternatives will co-exist – for example, hybrid cars in the US and Japan, EVs in Europe, ethanol-powered models in Brazil, natural-gas vehicles in India or hydrogen fuel cells in Norway. Oil companies may adapt to the new environment by adding electric recharging facilities at their service stations (such plans were recently announced by two of China's majors) or becoming fully integrated 'energy' companies to tap the potential offered by future power needs. Similarly, the automotive industry, forced to produce cheaper, smaller and more efficient vehicles to meet stringent mandates and changing tastes, will have to make high-risk technological bets.

Staring at the Crystal Ball: New Transportation Trends (continued)

Those opting for EVs will be wary to let others control a key component – the battery – and may tie in with battery manufacturers in order to secure their technology, as is already happening in Japan. Competition could also come from unexpected quarters. Michelin, for example, has developed an 'Active Wheel', fitted with two electric motors (one to drive and brake the wheel itself and another to control its suspension). The automotive industry will also be reluctant to be reduced to a mere manufacturing role and let the value of the growing 'personal mobility' business be captured by other firms (Daimler and Peugeot have in fact already launched their own services of short-term car rental).

… And Government Intervention …

These technologies have the public-policy advantages of curbing greenhouse gas emissions, enhancing energy supply security and reducing oil import dependence. As such, several countries around the world – most notably China, France, Germany, Japan, Portugal, Spain, the UK and the US – are actively supporting the advent of new transportation trends.

To date, fiscal incentives for 'ultralow emission' vehicles (hybrid or electric) range from roughly $5,000 per unit (France) to $10,000 (Japan), while EV research subsidies vary from $250 million (Spain) to $27 billion (the US). In addition, several governments have signed specific partnerships with carmakers. In France, for example, the central government has promised to purchase at least 100,000 EVs over the next five years in order to kick-start domestic production, and intends to finance battery research in partnership with Renault; the Paris municipality is seeking to introduce short-term EV rental; and state-owned utility EDF plans to build electric infrastructure in partnership with Renault and Peugeot. The European Union, meanwhile, is working on common standards for both EVs and recharging facilities.

Government policies not only encourage the switch to new technologies, but also favour some. For example, after spending some $1.2 billion in fuel cell research, the US DOE concluded that such technology was unlikely to become imminently commercial, and last year slashed its fuel cell budget by 90%. Meanwhile, the US Congress has long debated whether to push decisively for natural gas for heavy-duty vehicles. Similarly, China's programmes – including fleet demonstrations in at least 20 cities and recently announced subsidies for private purchases in five – are expected to put thousands of EVs on the road by end-2010. The country's main carmakers are developing EVs, and at least one (BYD) will soon market one model in the US.

… Equals Much Lower Oil Demand?

Looking ahead, two key questions remain unanswered. What will be the penetration rate of these new transportation technologies and when will they begin to make a significant difference regarding oil demand? Doubts over vehicle costs, range and reliability, as well as refuelling and recharging capabilities, compounded by uncertainty on future government policies, have led to widely divergent forecasts.

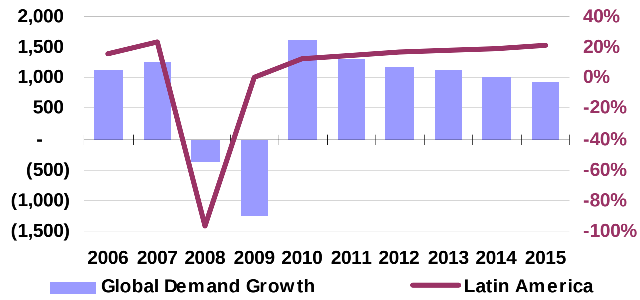
Regarding EVs, for example, carmakers are divided: Renault/Nissan predicts that worldwide sales will represent 10% of the market by 2020 (equivalent to some 6-8 million units per year), while Peugeot puts this share at 5% and Volkswagen at only 1.5%. Combining all technologies, the IEA's *World Energy Outlook* (2009) envisages a global 7% share by 2030 under current government policies, while other analysts predict a 14-18% share. For comparison, current worldwide sales of hybrids are estimated at around 1.3% of the total. In terms of oil demand effects, the range of forecasts also varies significantly, from almost nil to a decline of over 4 mb/d over the next two decades.

In sum, the uncertainty surrounding new transportation trends is huge. In the end, however, the shape of future oil demand will be largely determined by emerging countries, especially if they sidestep conventional technologies in the build-up of their own fleets. As in many other issues concerning oil markets, China will be instrumental in this respect.

Latin America

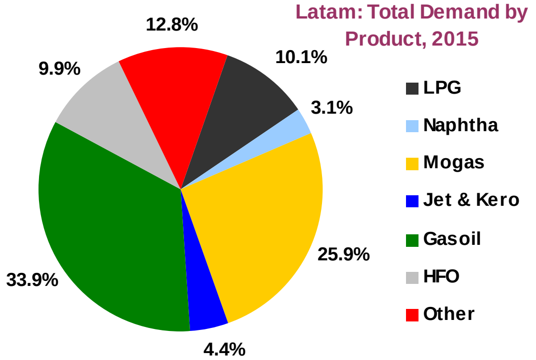
Oil product demand in Latin America is expected to rise by 3.1% per year on average between 2009 and 2015, from 6.0 mb/d to 7.2 mb/d. The economic crisis derailed regional demand growth, but did not cause precipitous falls – oil consumption fell by only 0.1% in 2009 and should rebound by 3.4% in 2010. This is due to only mild slowdowns in Argentina and Brazil, while electricity shortfalls have increased oil-fired generation in Venezuela. With average annual economic growth of 3.9% over 2009-2015, the region should experience a strong rise in middle distillate demand, as agriculture, mining and air travel activities expand in Argentina, Brazil and Chile, but also as smaller economies, such as Colombia and Peru, resume more rapid economic expansion. Petrochemical activity should continue to grow, while usage of heavy fuel oil for power generation should fall slightly as natural gas availability increases. Nevertheless, reliance on hydro sources (about two-thirds of total power generation) leave the region prone to increasing oil – and natural gas – consumption for electricity generation during times of drought, as in 2009-2010.

Latin America: Contribution to Oil Demand Growth 2010-2015, kb/d

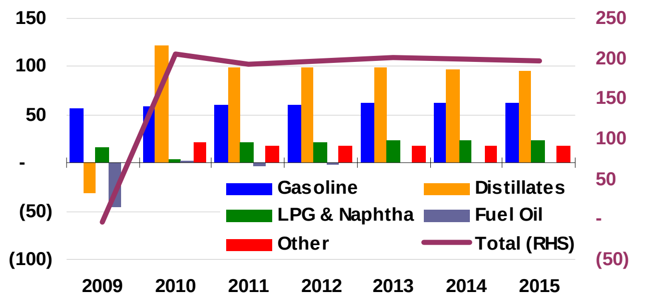


Brazil will continue to dominate overall consumption, accounting for 43.7% of regional demand in 2015, followed by Venezuela (11.5%), Argentina (10.2%), Chile (5.9%) and Colombia (5.0%). Brazil's annual growth of 3.5% should be transportation-led, with smaller increases in petrochemicals. Rapidly expanding road and air travel should underpin strong gasoline and jet fuel/kerosene growth, while increased freight and agricultural activity should spur diesel consumption. Transportation fuel demand, though, will be marked by increased penetration of alternative fuels. With flex-fuel vehicles accounting for over 90% of light vehicle sales, ethanol (adjusted for energy content) may account for over half of motor gasoline growth. Higher blending standards also portend increased biofuels use in Argentina, Colombia, Ecuador and Peru.

Latam: Total Demand by Product, 2015



Latin America: Oil Demand Growth by Product 2009-2015, kb/d



Increased natural gas availability in Brazil and Peru should enhance usage in those countries, while constrained supply in Argentina relative to its needs should increase its reliance on LNG imports and Bolivian gas – but that country is itself prone to slow development due to a difficult investment climate. While natural gas vehicles have increasingly provided an outlet for transportation requirements in Argentina and Brazil, higher gas supplies should go more towards reducing regional heavy fuel oil use in power generation. Nonetheless, Venezuelan oil use in electricity should grow.

Since mid-2009 a power crisis induced by drought and chronic under-investment in transmission infrastructure has led to electricity rationing for industrial customers. The government also plans to construct new thermoelectric plants that will likely run on diesel. While the return of rain may temporarily assuage the situation, creaky infrastructure will make Venezuela prone to diesel demand spikes over the medium term. Moreover, despite a precarious economic outlook over the medium term – with GDP forecast to decline by 2.6% in 2010 and threats of stagflation ahead – the persistence of end-user energy price subsidies should keep total Venezuelan oil product demand increasing by 2.1% per year on average over the forecast period.

Latin America: Demand Trends, Main Refined Products

Product	Volume, 2015 (mb/d)	Avg. Yearly Growth, 2009-2015	Comments
Naphtha	0.22	2.2%	Growing petrochemical activity in Brazil, the largest regional economy, as well as in Argentina, Chile and Colombia (but all from a very small base, with Brazil accounting for the bulk of regional naphtha demand)
Gasoline (including ethanol)	1.87	3.7%	Increasing in all countries as vehicle fleets expand, with strongest absolute growth in Argentina, Brazil, Colombia and Peru; low end-user prices in Venezuela provide further support despite the country's weak economic outlook
Jet Fuel & Kerosene	0.32	4.3%	Growth spurred by expanding airline capacity and increased passenger travel, with the largest increments from Argentina, Brazil, Chile, Colombia, Ecuador and Peru
Gasoil (including biodiesel)	2.44	4.2%	Renewed economic activity boosting diesel use in agriculture, mining and freight in Argentina, Brazil, Chile, Colombia and Peru; increasingly used for power generation given natural gas shortfalls (and potential hydropower disruptions) in Chile and Venezuela
Residual Fuel Oil	0.72	0.0%	Declining slightly overall, replaced by natural gas or gasoil for power generation (both base and peak); only growing in countries such as Venezuela, with under-developed or limited access to gas sources
Total Oil Products	**7.21**	**3.1%**	

Ethylene's Booming Times Ahead

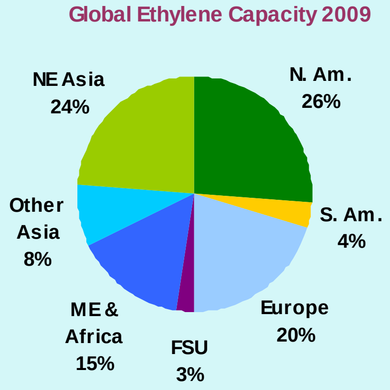
As economic recovery gets underway, the ethylene demand outlook has improved. Expected ethylene production capacity additions in 2009 were delayed, thus supporting currently robust operating rates and production margins. However, massive capacity additions are expected, particularly in 2010, potentially depressing operating rates until the end of the forecast period. Meanwhile, petrochemical demand has rebounded on the back of government stimulus programmes, particularly in China. Ethylene demand should expand by 5.5% per year on average over the forecast period – about 1.25 times GDP growth. These feedstock supply requirements will pose significant challenges to both the oil refining and gas processing sectors.

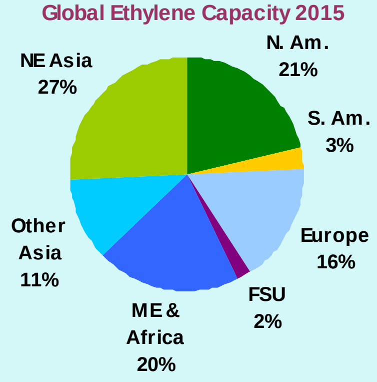
Capacity Trends

On the base of our latest assessment, global ethylene production capacity stood at 135.6 million tonnes per year (mt/y) in 2009, 0.3 mt/y lower than in last year's report. This figure, however, masks upward revisions in 2008 (+1.9 mt/y) and downward adjustments in 2009 (-2.1 mt/y). In particular, Middle Eastern production capacity in 2009 turned out to be 3.9 mt/y lower than expected, while Asian expansions were 1.1 mt/y higher. In North America, 1.0 mt/y of capacity previously slated for closure remained in operation as natural gas prices supported production economics, given breakthroughs in shale gas extraction technology. Capacity additions over 2009-2014 should be 2.2 mt/y lower than last year's expected growth (+35.7 mt/y). As such, projected ethylene production capacity in 2014 is revised down by 0.4 mt/y to 162.6 mt/y. By 2015, capacity should reach 166.2 mt/y.

Ethylene's Booming Times Ahead (continued)

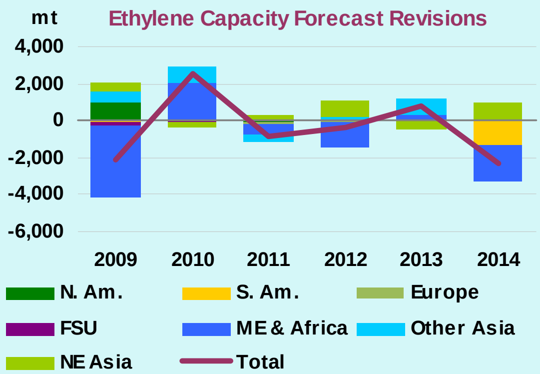
Production capacity additions over 2010-2015 (+30.5 mt/y) will be concentrated in the Middle East and North East Asia, with 11.0 mt/y (36% of total additions) and 10.8 mt/y (35%), respectively. China alone will account for 32% of global additions, expanding capacity by 9.9 mt/y to 23.4 mt/y by 2015. Saudi Arabia will add 5.2 mt/y, reaching 15.6 mt/y by 2015. Yet global production capacity will continue to be concentrated in the US (despite no planned additions), with 17% of the total by 2015; China and Saudi Arabia will follow with 14% and 9%, respectively.

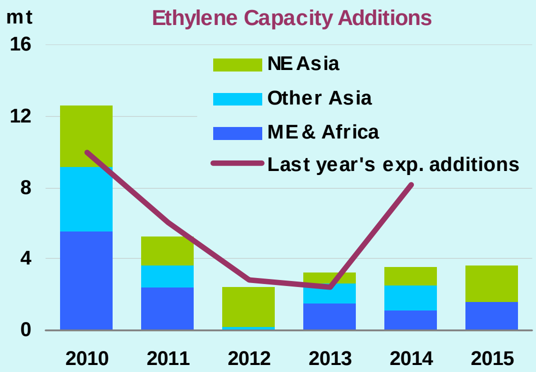




Demand and Operating Trends

GDP projections have improved markedly relative to last year's assessment. In particular, GDP growth in 2010 is expected to top 4.1%, 2.3 percentage points above last year's estimate of 1.8%. Better economic prospects entail higher ethylene demand. Global ethylene demand in 2009 was around 110.5 mt/y, 6.0 mt/y or almost 5.8% higher than estimated last year, rebounding as early as 2Q09 as governments implemented unprecedented stimulus programmes, particularly in China.

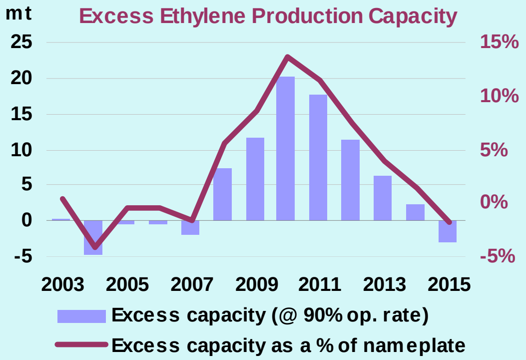




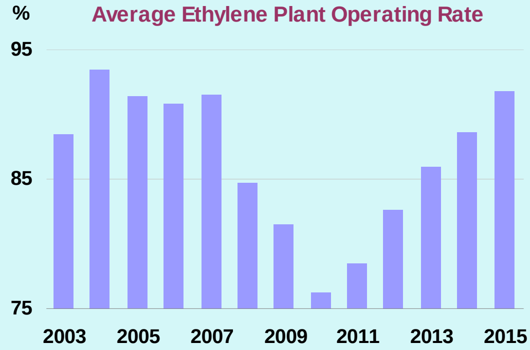
Ethylene demand is now seen growing by 5.5% per year on average, reaching 152.4 mt/y by 2015. This is a hefty increase of 42.0 mt or 38% from 2009, more than offsetting total capacity additions (34.6 mt) over that period. However, out of this total, 36% of the ethylene capacity expansions are expected to take place in 2010, thus weighing heavily on both operating rates and margins in the early stages of the forecast period. Only by 2015 will demand growth catch up and operating rates recover, assuming no further capacity additions take place.

Ethylene's Booming Times Ahead (continued)

As in last year's exercise, excess production capacity can be defined as the difference between nameplate capacity operated at 90% and expected demand. On this basis, excess production capacity could reach 20.3 mt/y in 2010, equivalent to 13.7% of nameplate capacity. Considering the unlikely event of no additional capacity to be announced on top of the current assessment, global operating rates are expected to recover to 92% by 2015. However, over the forecast period, the expected average operating level is a relatively muted 84%.



Source: IEA estimates



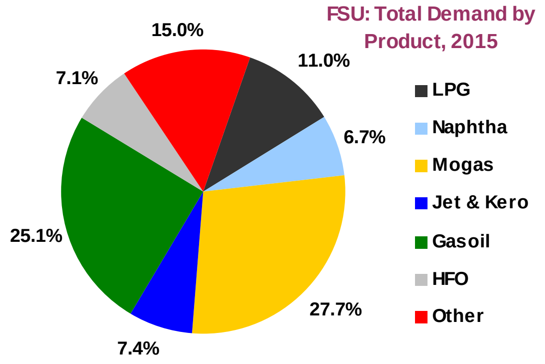
Source: IEA estimates

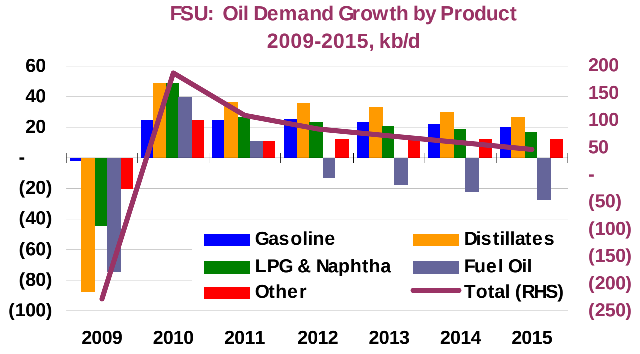
Given the decoupling of natural gas prices from crude oil prices, light feedstocks are becoming more attractive for petrochemicals production. This will support operating rates in North America, where ethane is the main feedstock, suggesting this region could boost exports as much as production economics permit. By contrast, European operating rates are expected to remain suppressed, as approximately 71% of this region's ethylene production is based on naphtha. Furthermore, Europe is prone to face incremental competition from the Middle East, which will remain the most competitive region in terms of production costs as capacity is largely run on ethane.

In Asia, integration of petrochemical complexes with refineries will help them avoid naphtha price swings from the crude market and reduce the feedstock cost gap relative to NGLs, which are driven by natural gas prices. However, the significant production capacity expansions expected in China will decrease the country's ethylene imports and affect operating rates elsewhere in the region, as demand will lag behind capacity.

Former Soviet Union

Oil demand in the Former Soviet Union is forecast to grow by 2.3% per year on average, from 3.9 mb/d in 2009 to 4.4 mb/d in 2015. This weaker prognosis, relative to previous assessments, is related to the sharp economic recession in two of the largest regional economies, Russia and Ukraine (the third, Kazakhstan, experienced a marked slowdown in 2009 but should sustain a strong economic expansion, albeit at a much lower pace than before the recession). Russia's GDP shrank by 7.9% in 2009 as commodity prices fell and industrial activity came to a standstill, while Ukraine's plummeted by 15.1%, recalling the tumultuous years of the early 1990s. Consequently, oil demand in both countries also plunged, thus lowering the baseline and weighing on the average growth rate going forward. Nonetheless, the regional economy is expected to rebound over the medium term as Russian output recovers, given its abundant hydrocarbon resources and growing industrial base.





As such, oil demand should resume growing, largely spurred by demand for transportation fuels, particularly Russian needs. This country, which is set to account for 69% of regional demand by 2015, is projected to become Europe's largest car market in the short term as it surmounts the effects of the global recession. Moreover, Russia will post demand growth in all product categories, with the exception of residual fuel oil. This constitutes a major departure from previous forecasts: the emerging natural gas glut in Europe – Russia's biggest market – has arguably diluted the urgency to displace fuel oil use in power generation in order meet its gas export commitments.

FSU: Demand Trends, Main Refined Products

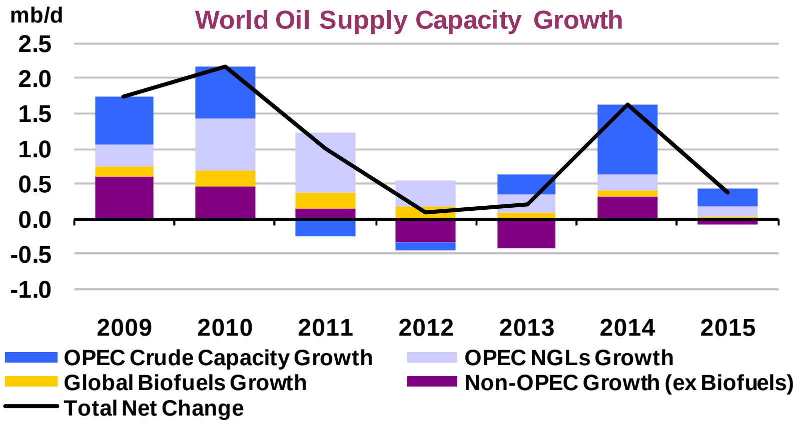
Product	Volume, 2015 (mb/d)	Avg. Yearly Growth, 2009-2015	Comments
Naphtha	0.30	3.3%	Growing Russian petrochemical output (94% of regional naphtha demand), assuming it recovers from its current recession-driven slump
Gasoline (including ethanol)	1.23	2.0%	Growing as vehicle fleets expand on the back of strong economic expansion and rising income per capita, particularly in Russia, the largest regional (and soon European) car market
Jet Fuel & Kerosene	0.33	2.9%	Rising air business and leisure air travel and expanding aircraft fleets in Russia and elsewhere
Gasoil (including biodiesel)	1.11	2.6%	Increasing as economic activity resumes; strong demand growth in Russia, Ukraine, Kazakhstan, Belarus and Azerbaijan
Residual Fuel Oil	0.31	-1.5%	Declining as the recession-induced natural gas glut no longer requires Russia to divert gas supplies away from power generation in order to support exports
Total Oil Products	**4.43**	**2.3%**	

SUPPLY

Summary

- **The 2009-2015 global oil supply outlook is raised by an average 0.3 mb/d**, with total production capacity now forecast to rise from 91.0 mb/d in 2009 to 96.5 mb/d in 2015. Adjustments stem mainly from higher non-OPEC supply, while growth in the forecast period comes largely from OPEC, both in terms of crude and natural gas liquids (NGL) capacity. Renewed spending increases, lower costs and an apparent easing in field decline paint a more optimistic supply picture now than in earlier projections.

- **Non-OPEC supply is projected to grow from 51.5 mb/d in 2009 to 52.5 mb/d by 2015**, an average upward revision of 0.5 mb/d. Growth comes from Latin America, Canadian oil sands, biofuels and the Caspian. With the futures strip suggesting oil prices in a $70-80/bbl range, upstream projects have been reactivated or brought forward. Moreover, *implied* decline rates have slowed since last year. Growth in biofuels, unconventional oil and non-OPEC NGLs more than offset decline in non-OPEC conventional crude. Downside forecast risks include deepwater project delays after the recent *Deepwater Horizon* disaster in the Gulf of Mexico.

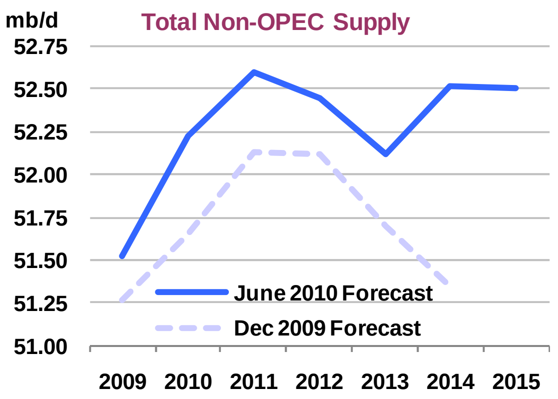


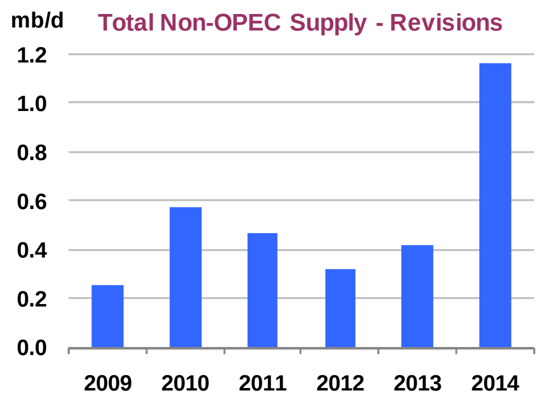
- **OPEC is on course to increase installed crude oil production capacity by a net 1.9 mb/d from 2009-2015, to 36.8 mb/d**. Growth comes mainly from Iraq, Saudi Arabia, Angola and the UAE. While the forecast is largely unchanged from our *December 2009 medium-term update*, the headline number masks significant changes for some individual countries. The outlook for Iraq and Venezuela, in particular, has improved dramatically after both signed new contracts with IOCs, while forecast capacity for Nigeria, Algeria and Angola is revised down sharply as political upheaval and unattractive contract terms conspire to delay previously included projects beyond 2015.

- **OPEC NGLs production is on track to rise by 2.6 mb/d** over the 2009-2015 period. Total condensate, NGLs and non-conventional output is projected to increase from 4.7 mb/d in 2009 to 7.2 mb/d by 2015, with Middle Eastern producers providing 85% of this expected growth. The gas liquids component in OPEC's total supply profile is seen rising from 13% in 2009 to 20% by 2015.

Non-OPEC Supply Overview

The non-OPEC supply projection is revised higher, increasing from 51.5 mb/d to 52.5 mb/d during 2009-2015. At +1.0 mb/d, growth is stronger than in the *December 2009 medium-term update*, which envisaged incremental output of 0.7 mb/d for 2008-2014, and significantly stronger than the 0.4 mb/d *decline* foreseen one year ago. The more optimistic outlook is the result of a combination of factors: Oil prices have remained relatively high in a steady $65-85/bbl range over the past year, spurring renewed upstream investment. At the same time, upstream costs have slipped below highs seen in mid/late-2008. Both these factors have prompted companies to reactivate upstream projects they had delayed, as evidenced in a forecast surge of start-ups in the latter half of the outlook period. Lastly, there is evidence that *implied* decline has slowed compared to last year.





Sources of growth remain largely unchanged. Non-OPEC supply growth is expected to come from Latin America, the FSU and North America, offsetting strong decline in OECD Europe and, to a lesser extent, elsewhere. Regarding the different types of oil output, once again a net decline in conventional non-OPEC crude supply (-1.0 mb/d) is offset by gains in biofuels (+0.8 mb/d), other unconventional sources (+0.7 mb/d), NGLs (+0.4 mb/d) and a small rise in refinery processing gains.

A Brighter Outlook

Compared with a year ago, and with the picture painted in the *December 2009 medium-term update*, the outlook for non-OPEC supply has improved. Estimated 2009 output grew by 0.7 mb/d year-on-year and 2010 is forecast to see a similar increment. The last time yearly growth attained these levels was in the 2000-2004 period and, on average, the 2009-2010 increment is higher than the mean annual increase since 1994. Extensive supply outages in 2005 and 2008, and the impact of weaker prices in 2008/2009, may have exaggerated pessimism over non-OPEC prospects, although it is still possible that supply increments could slip in the future if investment conditions deteriorate or major project delays materialise. 2010 supply could also be affected by strong anticipated Atlantic hurricane activity, even though our projections include a five-year average storm adjustment. Nonetheless, concerns over imminent and irreversible peak oil supply seem to have faded for now, even if a plateauing of conventional non-OPEC crude supply is evident in our outlook.

On average, non-OPEC supply in 2009-2014 is revised up by 535 kb/d. Indeed, this is approximately the level of cumulative 'baseline' revision evident for 2010 non-OPEC supply in monthly *OMRs* published since December 2009.

A combination of the general recovery of the global economy, strong non-OECD oil demand and higher oil prices have stimulated renewed investment in the upstream sector, while costs, although sticky, have nonetheless fallen from mid-2008 highs. Recent surveys put expected 2010 growth in upstream capital expenditure in the 8-12% range, a significant advance on the 10-15% decline now widely estimated for 2009.

Despite fears to the contrary one year ago, the main impact of the upstream spending dip last year was to postpone rather than cancel upstream projects, many of which have been reactivated. This is evident in the revised pattern of project start-ups, postponed into the latter half of the 2009-2015 forecast period, or brought forward into 2013-2015 following reactivation. A good example of this is Canadian oil sands projects, the sector seen last year as being hit hardest by delays and suspensions, but also some Russian oil fields. Recent stronger production performance and better prospects or detailed information on specific investments have prompted upward revisions to other areas, including Colombia, where recent rapid growth and field performance have exceeded expectations.

Non-OPEC Supply

(million barrels per day)

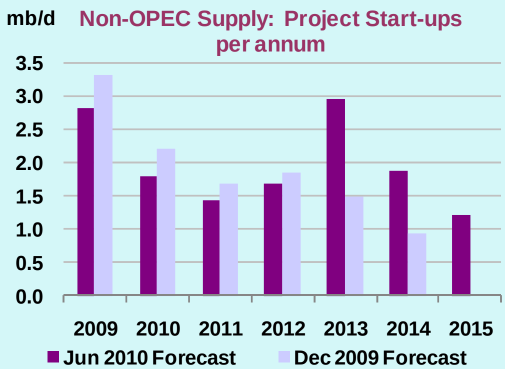
	2009	2010	2011	2012	2013	2014	2015
North America	13.6	13.5	13.4	13.3	13.3	13.4	13.7
Europe	4.5	4.2	4.0	3.8	3.6	3.6	3.3
Pacific	0.6	0.7	0.7	0.7	0.6	0.5	0.5
Total OECD	**18.7**	**18.5**	**18.1**	**17.8**	**17.5**	**17.5**	**17.5**
Former USSR	13.3	13.6	13.7	13.7	13.5	13.7	13.8
Europe	0.1	0.1	0.1	0.1	0.1	0.1	0.1
China	3.8	4.0	3.9	4.0	3.9	3.9	3.7
Other Asia	3.6	3.7	3.7	3.6	3.6	3.6	3.6
Latin America	3.9	4.1	4.4	4.5	4.7	5.0	5.1
Middle East	1.7	1.7	1.7	1.7	1.6	1.5	1.5
Africa	2.5	2.5	2.6	2.6	2.5	2.5	2.4
Total Non-OECD	**28.9**	**29.7**	**30.2**	**30.1**	**30.0**	**30.3**	**30.3**
Processing Gains	2.3	2.2	2.2	2.3	2.3	2.3	2.3
Global Biofuels	1.6	1.8	2.1	2.2	2.3	2.4	2.4
Total Non-OPEC	**51.5**	**52.2**	**52.6**	**52.4**	**52.1**	**52.5**	**52.5**
Annual Chg (mb/d)	0.3	0.7	0.4	-0.2	-0.3	0.4	0.0
Changes from last MTOMR (mb/d)	0.3	0.6	0.5	0.3	0.4	1.2	

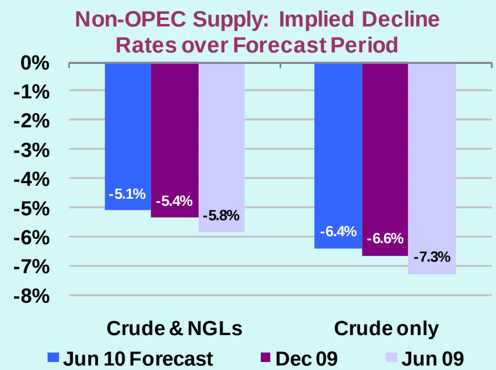
But our calculations also show that *implied* levels of annual decline across the entire production baseline have slowed by between 0.7-0.9% since last year's estimates to around 5%. This would suggest that additional work is also being undertaken on mature assets or simply that evaluations of how long new fields can stay at plateau capacity have lengthened. None of this is to minimise the ongoing, heavy investment burden the industry faces in coming years just to offset mature field decline, which may amount to 1.9 mb/d of lost non-OPEC capacity on an annual basis. But the problem may be a little less acute than looked likely a year ago.

Dissecting the Changes: More Upstream Projects and Slower Decline Rates

Besides the impact of relatively stable oil prices in a $65-85/bbl range in the past year, breaking down the revisions to non-OPEC supply growth reveals a more optimistic picture of project start-ups later in the projection. All told, the 2009 non-OPEC supply baseline has been adjusted up by 250 kb/d since the *December 2009 medium-term update* (and by nearly 1 mb/d at the time of that report, compared to the June 2009 *MTOMR*) on higher reported production. Some projects previously expected to start up in 2009-2011 actually came onstream earlier than anticipated.

Later in the projection period the impact is two-fold. Some project slippage has occurred, moving expected start-up volumes from the first to the second half of the forecast period. In addition, the tail end of the forecast now captures some increments previously deferred to later in the decade. Notably, this includes several Canadian oil sands projects.





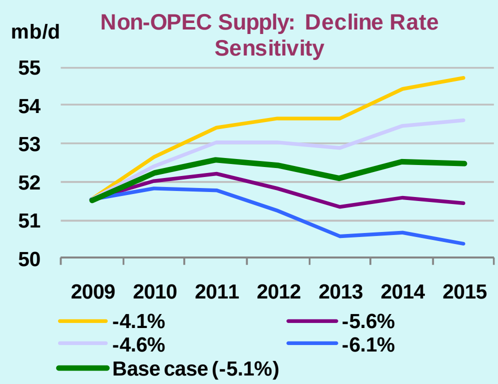
However, not only new fields affect the outlook. Mature, post-plateau oilfields enter production decline as reservoir pressure drops. Individual field decline rates can vary from 1-2% per year onshore to in excess of 30% annually offshore. Through the course of the year, individual field decline rate assumptions for the future are adjusted in *OMR* projections based on observed field performance. We attempt to make allowance for non-geological events such as mechanical outages, unscheduled field stoppages, and prolonged field maintenance. The net result of our individual field decline can be represented in an *implied* decline proxy, calculated by netting off new production from the net growth or decline in total regional production in our forecast. This will tend to be lower than *actual* field decline, as the number reflects *implied* decline for the entire production baseload (fields at plateau or ramping up supply, as well as those in post-peak decline). However it serves as a good at-a-glance proxy for what is happening to the portion of today's production which does not comprise new field start ups.

This *implied* decline proxy came in lower in 2008 and 2009 than we had expected. Established fields have therefore performed better, something reflected in our deployment of lower individual field decline rates within our new projections. For 2009-2015, *implied* decline equates to 5.1% annually, compared with the 5.8% assumed in the June 2009 *MTOMR*. This is not to say mature field decline is no longer an issue. Even at these assumed lower rates, non-OPEC supply still loses the equivalent of 1.9 mb/d of capacity each year (and OPEC supply a further 1.2 mb/d). Rather, it suggests that higher prices, lower costs and revived spending have eased some of the pressures on supply.

Examples of where we have actively adjusted decline rates include Colombia, which has seen a recent surge in growth due to an improved investment regime and better-than-expected performance at some key fields. Russia too, which surprised on the upside in 2009, has been reassessed in light of this and, while production is expected to remain relatively flat overall, this nonetheless implies slightly slower decline at mature assets. The same is true of the UK, Norway and Mexico, where structural decline in output is now seen to be taking place at a slightly slower pace.

Dissecting the Changes: More Upstream Projects and Slower Decline Rates (continued)

To demonstrate the impact of such a shift, a sensitivity exercise shows that each 0.5% incremental shift in implied annual decline has an impact of around 1 m/d on prospective non-OPEC supply by 2015. This illustrates the extreme sensitivity of supply to decline rate assumptions and cautions that recent higher-than-expected spending, while encouraging, nonetheless needs to be sustained in years to come to prevent a renewed sharp downturn in non-OPEC supply. In the now-higher price environment we are assuming for the projection period, we have dispensed with the lower supply sensitivity (of around 0.5 mb/d) which we illustrated last year. That said, huge risks persist on the supply side which could again undermine this more optimistic outlook if investment opportunities again become squeezed.



Turning again to new project assumptions, the forecast includes only those projects already underway or for which detailed investment approval has been granted. Such investments are unlikely to be halted and in any case have usually been planned on the basis of conservative price assumptions well below the recent range. In summary, it would appear that the key causes of recovery in non-OPEC supply in 2009 were several. Firstly, the more rapid than expected realisation of a series of new projects in which investment was begun earlier in the decade. Second, the largely unforeseen turnaround in Russian upstream fortunes, and thirdly an absence of the extensive hurricane-related shut-ins in the US Gulf of Mexico seen in 2008. But the less headline-grabbing impact of widespread incremental spend at mature assets also played an important role.

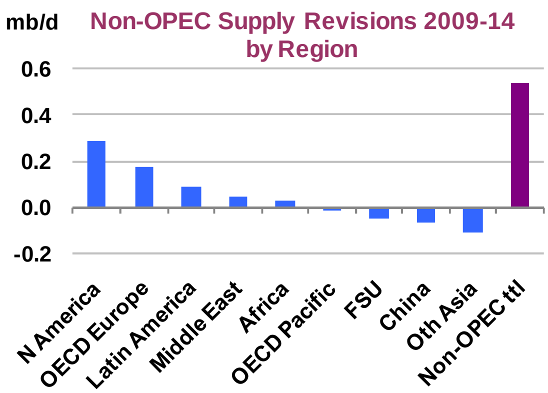
Revisions to Forecast

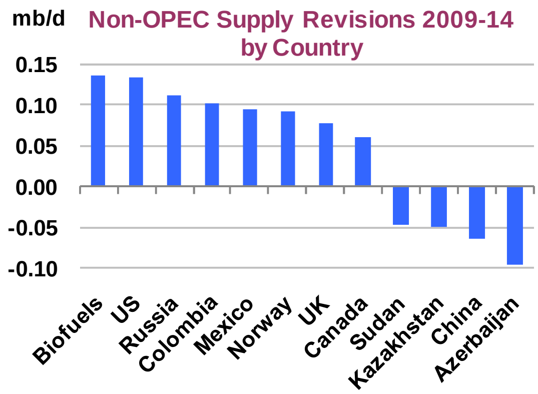
Regionally, the largest upward revisions to forecast compared to the *December 2009 medium-term update* are focused on the OECD, mostly in North America (+290 kb/d on average), but also in Europe (+175 kb/d), while the outlook for the OECD Pacific is left largely unchanged. For North America, this reflects a substantial adjustment to the US, where crude and NGL supplies are seen higher in years to come, while in Canada, reactivated oil sands projects offset downward-revised conventional crude. Mexican crude production is still forecast to decline sharply, but slower than previously assumed.

The non-OECD as a whole is revised down by an average 50 kb/d. Regionally, forecasts for Other Asia, China and the FSU are adjusted by -105 kb/d, -65 kb/d and -50 kb/d respectively, partly offset by upward adjustments to Latin America (+85 kb/d), the Middle East (+45 kb/d) and Africa (+25 kb/d). Global biofuels are revised up by an average 135 kb/d per annum, while processing gains were left broadly unchanged.

For individual countries, the largest upward adjustments made (on average per annum) are to the US (+135 kb/d), Russia (+110 kb/d), Colombia (+105 kb/d) and Canada (+60 kb/d), as well as, perhaps more surprisingly, Mexico (+95 kb/d), Norway (+90 kb/d), Egypt (+90 kb/d), and the UK (+80 kb/d). In Egypt, the adjustment is largely due to a baseline revision to NGLs, while in Mexico, Norway and the UK, erstwhile rapid decline appears to have slowed.

The largest downward revisions are in Azerbaijan (-95 kb/d), China (-65 kb/d), Kazakhstan, Sudan, Malaysia and Indonesia (each around -50 kb/d). For the former three, it is a case of slower assumed growth, while in Malaysia and Indonesia, it is faster decline. In Sudan, a drying up of investment due to political instability, sanctions and possible secession of the south have led to a reassessed profile.

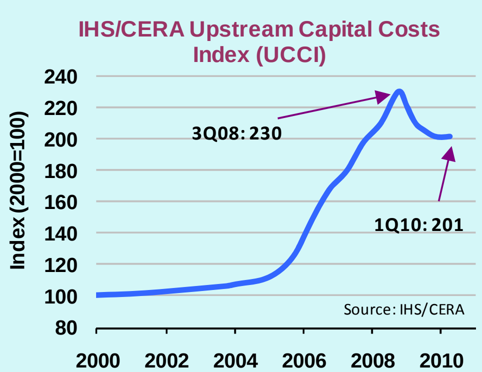


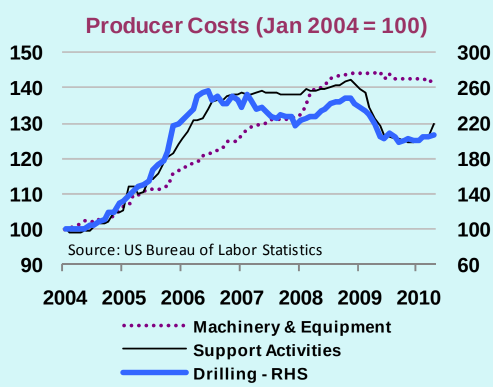


Sustained Spending and Access to Reserves Will Drive Future Prospects

One year ago, IEA research anticipated a decline of 21% in upstream investment in 2009, at a time when oil prices had plummeted and the scope of the credit crunch and subsequent global recession was becoming apparent. The June 2009 *MTOMR* included a feature on how this could potentially impact on non-OPEC supply in the short to medium term (see *Downside Risks to Non-OPEC Supply Due to Lower Investment?* in June 2009 *MTOMR*). The reality proved to be different, as oil prices recovered and subsequently stayed relatively steady in a $65-85/bbl range over the past year.

Upstream investment in 2009 did not fall as sharply as we had anticipated – current estimates range between 10-15%. And, as we have pointed out before, this shortfall was in any case partly offset by a contemporaneous fall in upstream costs in the range of 12% year-on-year, measured at the end of 2009 (according to IHS/CERA's UCCI Index and confirmed by data released by the US Bureau of Labor Statistics). Another offsetting factor in some countries was currency devaluation, e.g. in Russia, which helped cushion the upstream from expected activity declines. Costs for now appear to have stabilised, although new sources of oil are generally becoming more expensive, all the more so if widespread adoption of a price on CO_2 materialises. And in the shorter term, significant increases in international iron ore contract prices may help place a floor under upstream costs.



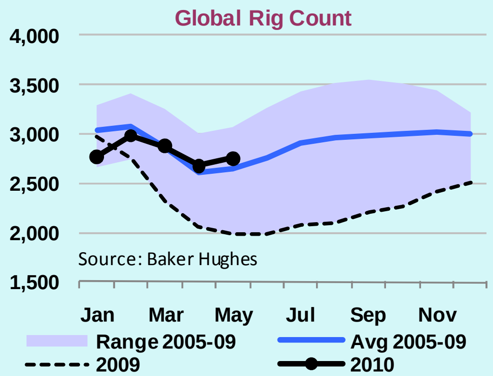


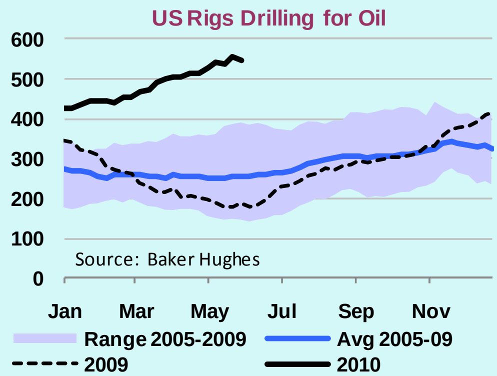
Estimates of 2010 upstream investment currently range between 8-12% growth versus 2009. Rig counts covering exploration and development have recovered globally and in the US have surged to their highest level since early 1991, reflecting a surge in onshore activity in new areas such as the Bakken Shale (albeit offshore drilling activity will be curbed following the Macondo disaster in the Gulf of Mexico – see *Potential Implications of US Gulf Oil Spill*).

Sustained Spending and Access to Reserves Will Drive Future Prospects (continued)

But clearly risks to the downside remain. Based upon the recent futures strip, this report assumes that crude oil prices remain near $72/bbl in real terms throughout the forecast period. But, as our *Lower GDP and Efficiency Scenario* illustrates, we recognise that there are still huge question marks over the global economic recovery and any slowing in demand could rapidly have an impact on an already amply-supplied oil market. As highlighted by the recent oil spill in the US Gulf of Mexico, the regulatory and investment environment could rapidly change – stricter safety requirements and tighter inspections will likely be implemented and are being considered outside the US, even if more extreme calls for a total ban on offshore drilling due to environmental risks are unlikely to be realised.

After oil prices fell from mid-2008 heights, resource nationalism has to some extent ebbed – as evidenced by a rekindled interest in foreign investment in Venezuela and elsewhere. Iraq's opening to foreign investment could prove a source of substantial new supply (see *Iraqi Efforts to Boost Capacity Face Headwinds*). There are a number of key non-OPEC countries where mooted changes to fiscal and investment regimes could make a significant difference. They include Russia, where exemptions to the crude export duty and the Mineral Extraction Tax (MET) have arguably underpinned the recent boost in output for greenfield projects in Eastern Siberia, but uncertainty remains over the duration and expansion of these adjustments. In Brazil, proposed legislation that would regulate the development of the huge, recently-discovered pre-salt reserves is making its way through Congress and will likely determine the speed at which these resources will be brought onstream as well as the degree to which foreign companies become involved.



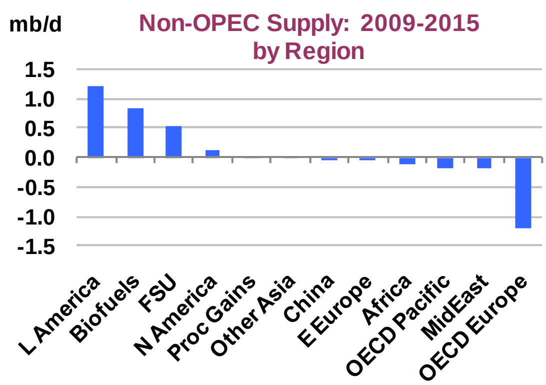


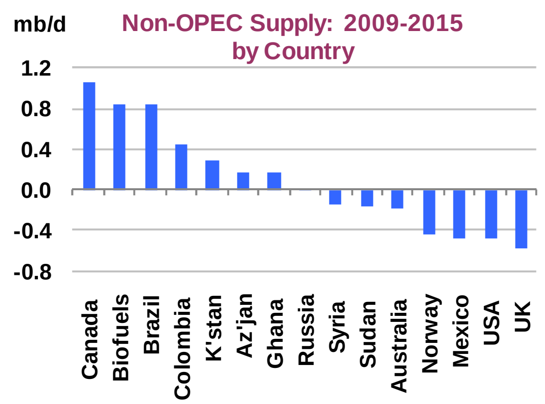
In OECD countries too, where oil production is mostly in steady decline, changes to the investment environment have the potential to regulate that decline. Mexico, which has seen crude output fall rapidly from a high of 3.4 mb/d in 2004 to 2.6 mb/d in 2009 and is constitutionally prevented from allowing direct foreign participation in its upstream sector, has put in place an arrangement whereby service companies can help it to access oil in challenging areas. The UK and Norway, whose era of major discoveries has arguably passed, are keen to set incentives to encourage the development of marginal fields and to maximise recovery from mature assets. And in Australia, a proposed 'supertax' is thought by some to have the potential to significantly curb oil production in years to come.

The degree to which this uptick in non-OPEC supply is sustained beyond mid-decade will depend on ongoing increases in real spending and continued improvements in national investment terms and access to reserves. Again, this brings the importance of the Macondo disaster into sharp focus, suggesting a need for regulation that balances safety and environmental sustainability, with an avoidance of placing large swathes of deepwater resources completely off limits. On a more upbeat note, the assumed strength in prices looking ahead, and the potential for ongoing technological advances, such as have recently transformed the natural gas market, suggest it is premature to dismiss prospects for non-OPEC supply.

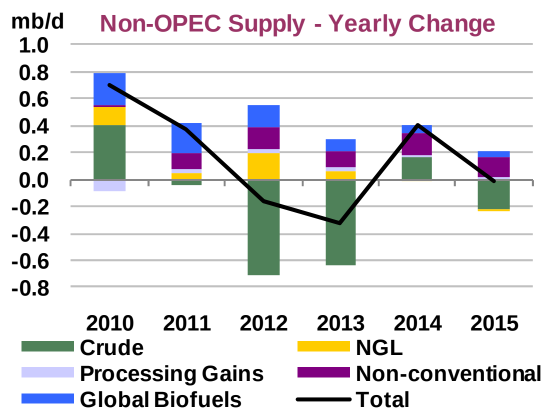
Sources of Non-OPEC Supply Growth

Regionally, sources of growth are largely unchanged from previous reports, with higher output in Latin America making up most of the increment, followed by increases in global biofuels, the FSU and North America. Decline is by far the most pronounced in OECD Europe.





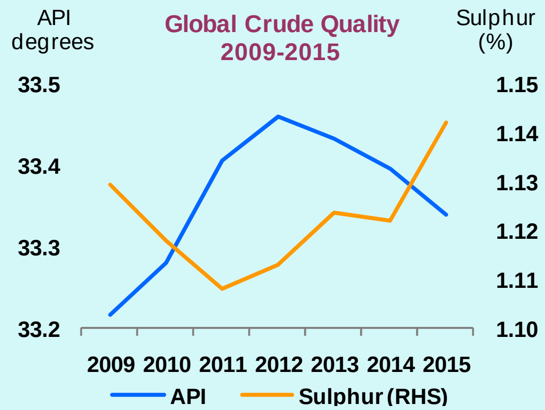
In terms of individual countries, most growth will come from Canada (+1.1 mb/d), followed by global biofuels and Brazil (each +840 kb/d), Colombia (+450 kb/d), Kazakhstan and Azerbaijan (+300 kb/d and +175 kb/d respectively) and Ghana (+170 kb/d). Oil supply will decline most in the UK (-580 kb/d), the US and Mexico (each -480 kb/d), Norway (-445 kb/d), Australia (-180 kb/d), Sudan (-165 kb/d) and Syria (-145 kb/d). Relatively speaking, Colombia's rise to prominence in the growth ranking is perhaps the most noticeable change. Also noteworthy is that Russia's oil production profile is now expected to stay flat over the 2009-2015 forecast period, albeit with a rise in mid-forecast.

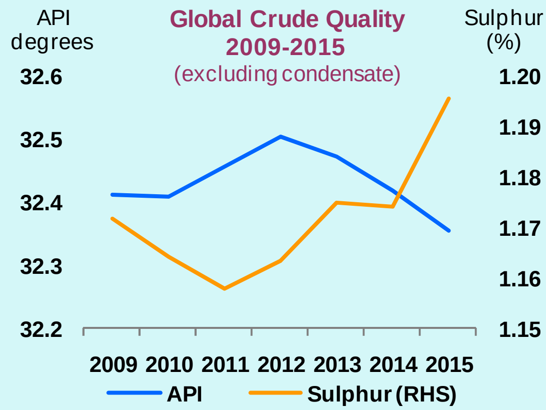


One clear trend is unchanged from previous reports. While non-OPEC conventional crude is projected to decline over the forecast period, to the tune of 1.0 mb/d, this is more than offset by growth in global biofuels of +840 kb/d, other non-conventional oil (+715 kb/d – largely Canadian syncrude), NGLs (+425 kb/d) and a small increment in refinery processing gains (+35 kb/d). But compared to previous forecasts, the crude production decline is noticeably less pronounced, with a small year-on-year increment in 2014, a year in which annual increases in Azerbaijan, Kazakhstan, Brazil and Ghana are particularly pronounced. This can largely be traced to the projected start-up of specific projects, including the West Chirag platform in Azerbaijan, Kashagan in Kazakhstan, the Jack/St Malo and Mad Dog projects in the US GoM, as well as a string of start-ups in Canadian oil sands.

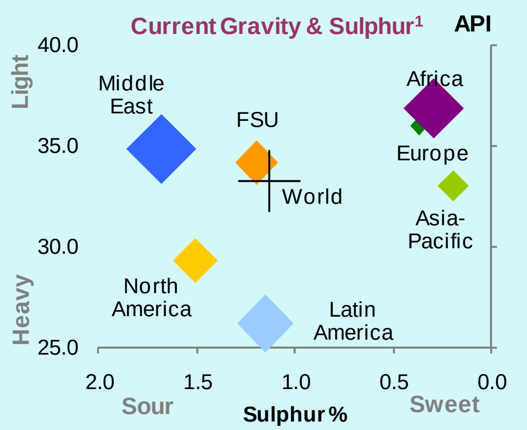
The Evolution of Crude Oil Production by Quality

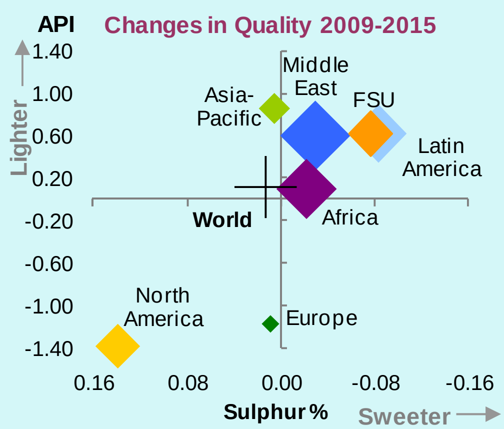
Crude oil supply is set to become sweeter and lighter by the middle of the forecast period as condensate and lighter crude production in the FSU and Middle East increases. However, between 2012 and 2015, declining North Sea output combined with a rise in production of Canadian un-upgraded bitumen and Latin American crudes reverses the trend and on average crude oil becomes heavier and sourer by 2015.





Output will become lighter as weighted average API gravity rises from 33.2° to 33.5° by 2012, with Latin America, the Middle East and FSU contributing to much of the shift. In contrast to our previous forecast of stable API by the end of the period, current projected API gravity falls to 33.3° by 2015, a trend mainly due to developments in North America and Europe. In terms of sulphur content, oil supply becomes sweeter in the earlier years and hits a floor of 1.11% of sulphur in 2011, because of higher condensate output and production capacity of lighter crudes in the Middle East. By 2015, as more barrels from Canadian bitumen production reach the market, available feedstocks become sourer, reaching 1.14%.





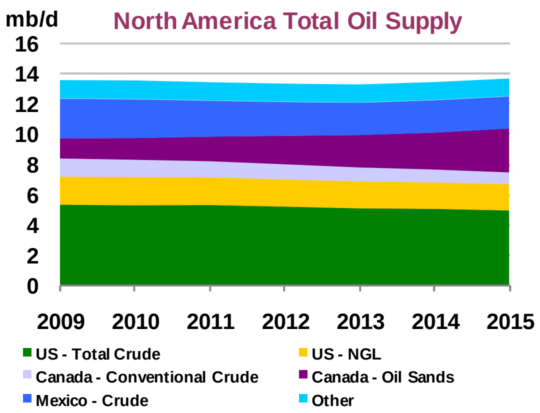
1 Symbols proportionate in size to regional production.

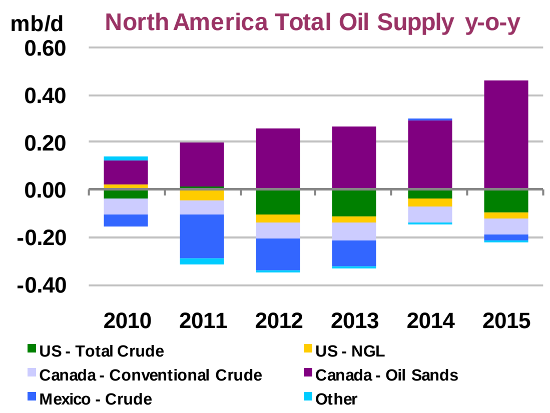
The most significant change in quality in 2009-2015 is seen in North America, where crude becomes heavier and sourer as production of Albertan bitumen picks up in the second half of the forecast period. The projected decrease in North Sea oil production sees European weighted average API falling by one degree. On the other hand, the start of production of light Kashagan crude at the end of 2013 drives overall FSU oil quality higher, while the decline in comparatively heavy Chinese crude oil production causes Asia's API to rise by one degree. Latin American crude, traditionally heavier than the global average, becomes slightly lighter and sweeter due to the addition of Brazil pre-salt crude oil production and despite a ramp-up from the heavy Colombian Rubiales and Castilla fields. All in all, global oil supplied to refiners will become slightly lighter, but sourer by 2015.

Regional Breakdown

North America

North America is the region to see the strongest upward adjustment to forecast, an average 290 kb/d, with revisions to the US (+135 kb/d), Canada (+60 kb/d) and Mexico (+95 kb/d). The region as a whole is now projected to see total supply increase by 110 kb/d by 2015, with strong growth in Canada offset by hefty decline in the US and Mexico. The **US** saw the single largest upward revisions to forecast in this *MTOGM*. Other Lower-48 production is seen stronger on robust recent performance, while Gulf of Mexico output is adjusted slightly lower. Over the forecast period however, only the latter is expected to see incremental crude production, growing by 125 kb/d, thus only partly offsetting a decline in other crude-producing areas. US crude supply will fall by 375 kb/d. NGL supply is expected to decline by 130 kb/d, while other hydrocarbons (excluding fuel ethanol) will rise by 30 kb/d. Total US supply will therefore fall by 480 kb/d to 6.9 mb/d in 2015.





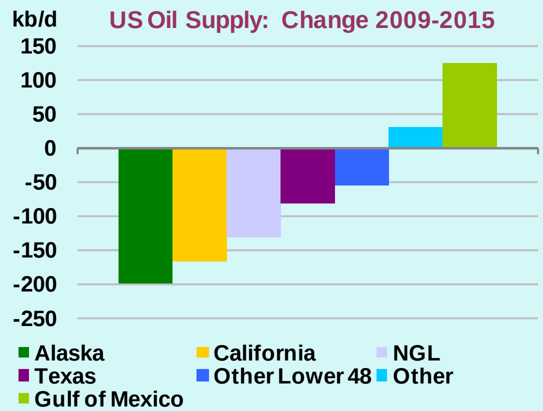
Total oil supply in **Canada** will rise from 3.2 mb/d in 2009 to 4.3 mb/d in 2015, an increment of 1.1 mb/d, with growth in bitumen and mined upgraded synthetic crude of 910 kb/d and 650 kb/d respectively offsetting a decrease in other conventional crude of 410 kb/d and a dip in NGLs of 85 kb/d. Total oil sands production has been reassessed after many projects were reactivated. A year ago, Canadian oil sands were seen as the sector hardest hit by lower oil prices and the projected downturn in investment. In the end, few projects were actually cancelled but instead delayed. Their resuscitation boosts the tail end of the forecast in particular. In addition, oil sands growth has benefited from the decline in the price of natural gas (used extensively in extraction) which, were it to rise again, could impose constraints on incremental supply. Potential future constraints to CO_2 emissions could also slow growth, as could both export infrastructure limitations and a growing need for diluent imports used to aid the flow of otherwise very viscous bitumen.

Oil production in **Mexico** is forecast to drop from 3.0 mb/d in 2009 to 2.5 mb/d in 2015, due to a decline in crude output. In the light of recent, partial success in slowing decline at the Cantarell field, Mexico's production profile has been lifted slightly. Nonetheless, assuming an average decline rate of 20%, Cantarell's output could still fall to only 200 kb/d by 2015 from a current 520 kb/d. Ku-Maloob-Zaap (KMZ) output is seen to increase to a peak of 850 kb/d in 2010-2011 and then to slow to 700 kb/d by 2015. Despite Pemex's best attempts to boost output at the complex onshore Chicontepec field, we assume only 100 kb/d output by 2015. On the other hand, we expect around 250 kb/d of new crude output by 2015 from shallow waters offshore Tabasco state.

Potential Implications of US Gulf Oil Spill

The sinking of the *Deepwater Horizon* offshore drilling rig on 22 April has resulted in the largest oil spill in US history. An estimated 20-40 kb/d of crude oil (earlier estimates were 12-19 kb/d) have been leaking into surrounding waters, amounting to some 0.5-2 mb by 14 June (compared to the 250 kb spilled in the Exxon Valdez incident in 1989). None of BP's attempts so far to completely halt the leak have been successful, including reactivating the failed blowout preventer, mounting a dome or 'top hat' on top of the leak, or an attempt to clog the well using drilling mud ('top kill') and solid waste ('junk shot'). At writing, BP was siphoning off around 15 kb/d through a Lower Marine Riser Package placed on top of the leaking well, and was hopeful it could eventually catch most of the leakage. BP is also drilling two relief wells nearby, to tap the Macondo well beneath the seafloor and cut the flow of oil and gas permanently. However, these wells will likely take until at least August to complete and potentially longer if hurricane disruption occurs.

On 27 May, President Obama extended an earlier moratorium on new deepwater drilling to six months. All wells currently in operation will be allowed to continue production, while drilling in depths less than 500 feet will be unaffected. Exploratory drilling planned for summer 2010 offshore Alaska was postponed. Lease sales planned for the Gulf of Mexico in August and offshore Virginia in 2011/2012 were cancelled. President Obama has established a bipartisan *National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling*. This body will make recommendations how to prevent – and mitigate the impact of – any future spills that result from offshore drilling. The Commission will report within six months. The Minerals Management Service (MMS) is to be broken into three distinct bodies, separating the functions of energy leasing, revenue collection, and safety enforcement.



Regional crude and natural gas production of around 1.7 mb/d and 2.7 tcf/y, respectively, is continuing as normal and no short-term impact upon regional production is expected. Similarly, oil shipment and refining operations are unaffected. US Gulf of Mexico crude oil and gas production make up around 30% and 11% respectively of total US domestic output. June however marked the start of the hurricane season, with 2010 expected to be particularly active. While it is not normally until August/September that storms impact upon offshore operations, early storms this year could affect attempts to deal with the leak and the spread of the oil slick (though they could also help to disperse the oil). Longer-term, the moratorium on drilling new deepwater wells could delay new oil and gas development projects. Existing production might ultimately be affected, as oil fields need regular workover to maintain production, albeit this activity is for now unrestricted.

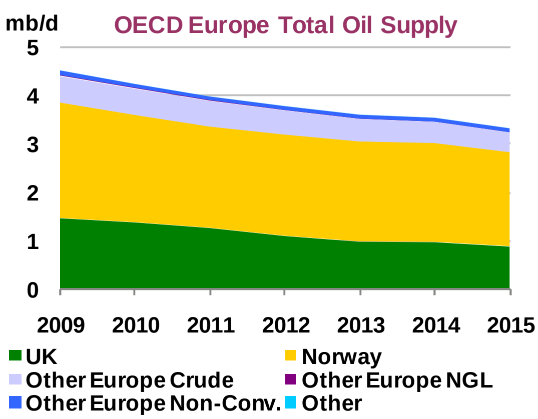
Meanwhile, the impact on the regional economy and environment is highly significant. Despite the scale of the clean-up effort, crude oil has now reached the coastline near Pensacola in Florida's western panhandle, having previously hit Louisiana, Mississippi and Alabama. Large swathes of the local economy have been badly hit, including fishing, shrimping and tourism, the latter of major significance for Florida. Some 35 national wildlife refuges are at risk and several hundred dead birds have been collected. Criticism has targeted BP, the US government and the broader oil industry. The government may try to harness changing public sentiment behind legislation aimed at weaning the US away from oil use, and mitigating climate change. However, moves that adversely affect local oil industry employment carry their own political difficulties.

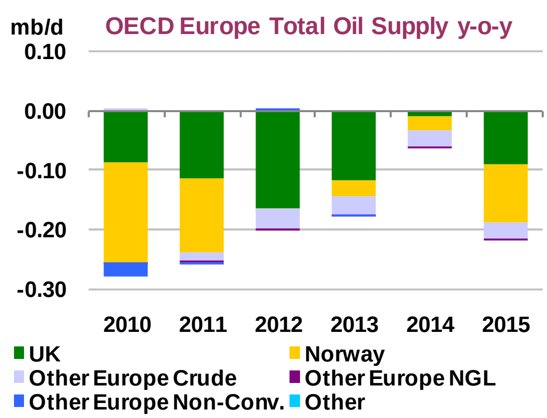
Potential Implications of US Gulf Oil Spill (continued)

At present there is no certainty over specific regulatory and permitting changes that may be implemented in the aftermath of *Deepwater Horizon* and so no certainty over the ultimate impact on regional production. Purely for illustration, assuming 1-2 years of delay for all planned new deepwater oilfield projects implies 2015 production from the US Gulf of Mexico of 100-300 kb/d less than in our working case production forecast. Regulatory procedures and operating conditions differ from country to country, so extrapolating any potential delays in the Gulf to other deepwater regions has limited analytical value. Nonetheless, Canada, the UK, Norway, Brazil and China are all examining existing procedures in light of the disaster. A further 550 kb/d of expected 2009-2015 production growth from deepwater Brazil, Angola and Nigeria could be at risk, albeit there are no current indications that permitting in these countries is likely to be affected.

OECD Europe

As in previous reports, OECD Europe remains the region with the most pronounced decline. Total oil supply is projected to fall from 4.5 mb/d in 2009 to 3.3 mb/d in 2015. The **UK** is anticipated to see the sharpest drop, with output falling from 1.5 mb/d in 2009 to 0.9 mb/d in 2015, as new field start-ups only marginally slow declining output from mature fields. Nonetheless, UK oil supply has been revised up by 80 kb/d on average, with decline having slowed on strenuous efforts to raise recovery rates and extend field life, as for instance tax breaks for certain new field developments announced in 2009 and renewed earlier this year. Compared to an average annual decline of 200 kb/d from 2000-2006, 2008 and 2009 each saw a drop of only 100 kb/d and the average annual decline in output for the 2010-2015 period is forecast to remain at a similar level.

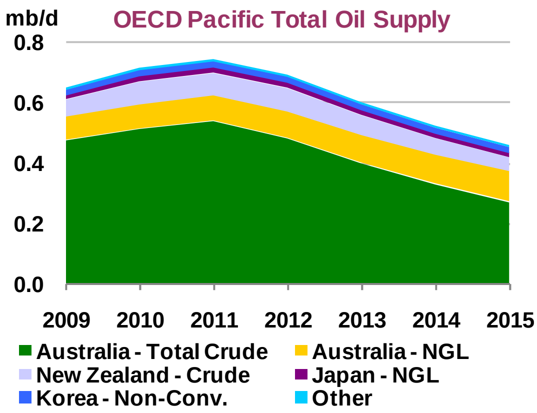


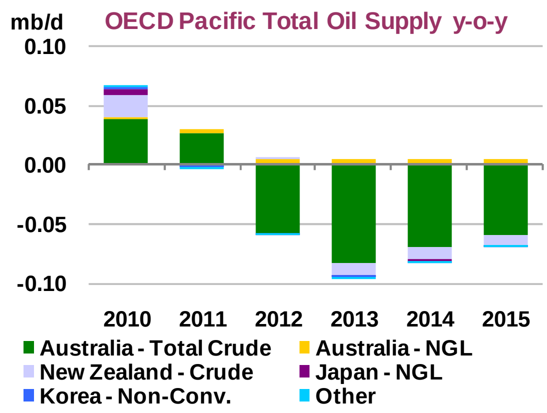


Norway too is revised up an average 90 kb/d on stronger recent performance and efforts to stem decline. Nonetheless, while in comparison to the UK, Norway's remaining reserve base is significantly larger, many mainstays of current production such as the Ekofisk, Gullfaks, Oseberg, Statfjord and Troll complexes are in steady decline. Total Norwegian oil supply is forecast to fall from 2.4 mb/d in 2009 to 1.9 mb/d in 2015. NGL and condensate grow by a collective 50 kb/d while crude oil declines by 500 kb/d by 2015. Meanwhile, the recent US Gulf oil spill has raised concerns about similar leaks in sensitive environments in Norway, for instance making the opening up of acreage offshore the Lofoten islands less likely.

OECD Pacific

Oil production in the OECD Pacific is expected to fall from 650 kb/d in 2009 to 460 kb/d in 2015 as a result of lower **Australian** output. There, oil production is forecast to rise from 550 kb/d in 2009 to 625 kb/d by 2011 as new fields ramp up production, but then to decline again to 375 kb/d by 2015 in the absence of further new projects. A proposed 'supertax' of 40%, to be levied on production of natural resources from mid-2012, could curb upstream investment. A small increment of 25 kb/d in NGLs due to LNG start-ups will slightly offset a decline of 205 kb/d in crude.





Former Soviet Union (FSU)

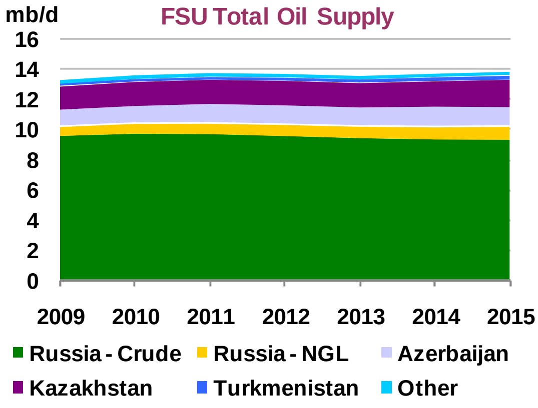
FSU oil production is revised down by an average 50 kb/d, but remains one of the main sources of growth for non-OPEC supply. **Russian** output is adjusted up by 110 kb/d on strong recent performance, with more to come from a number of key fields. Nonetheless, total supply is seen flat overall at 10.2 mb/d over the forecast, albeit with a rise to 10.4 mb/d in 2010-2011. Towards the end of the period, the relative effect of increases at Vankor and other large new fields is more than offset by decline in mature West Siberian and other assets. Russia does however see strong growth of 250 kb/d in NGL output, which is expected to rise from 590 kb/d in 2009 to 840 kb/d in 2015. This offsets a similar decline in crude production. NGLs are seen growing on a greater utilisation of associated gas due to a higher liquids ratio in deeper reservoirs, greater monetisation of these gas liquids as relevant infrastructure is expanded, and due to curbs on flaring.

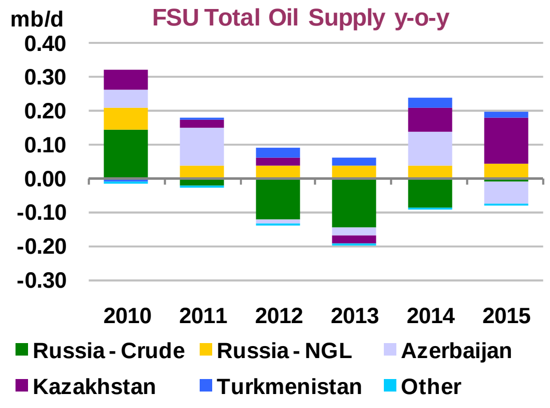
This report assumes today's policies persist, though as argued before, key tax breaks have likely incentivised growth at greenfield projects, especially in Eastern Siberia. These projects were long in conception and other factors such as rouble devaluation also contributed to output growth. The issue of whether these tax breaks remain in place, are extended in time and location, perhaps also to mature basins, or whether they are gradually reduced in order to boost tax revenues, remains one of the larger uncertainties in our forecast. Despite recent upward revisions to the baseline and forecast on the basis of performance in 2009 and in early 2010, we remain cautious in the medium term, still assuming that the weight of Russia's mature base load supply will offset new sources of growth.

The forecast for **Azerbaijan** is revised down by an average 100 kb/d, but still sees oil supply grow from 1.1 mb/d in 2009 to 1.2 mb/d in 2015. The large Azeri-Chirag-Guneshli (ACG) offshore complex will continue to provide the bulk of Azeri crude, albeit incremental supplies may now be on a slower timeline. Following a gas leak in mid-2008, which shut down some of the platforms, output appears never to have fully recovered to previous levels. Moreover, ACG will see continued growth from the

Guneshli Deep complex, as well as the start-up of the 185 kb/d Chirag Oil Project in late 2013, the next large step in development.

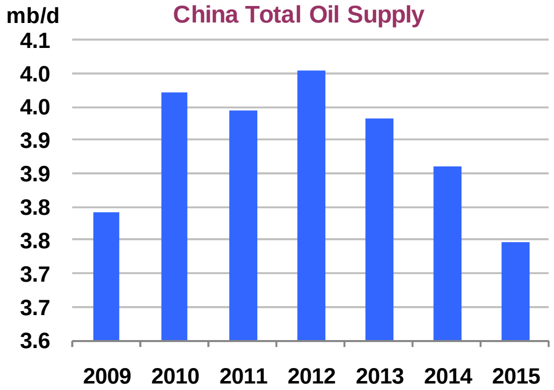
Oil supply in **Kazakhstan** is also adjusted down by an average 50 kb/d on a reassessment of the timing of key projects, including the next stage in the Karachaganak condensate field and most importantly, start-up of the super-giant Kashagan field. Already much delayed, our forecast now assumes first oil from Kashagan at the end of 2013, with increments in 2014 and 2015, by which time we forecast output will have reached 300 kb/d. Total oil production in Kazakhstan is forecast to rise from 1.6 mb/d in 2009 to 1.9 mb/d in 2015.

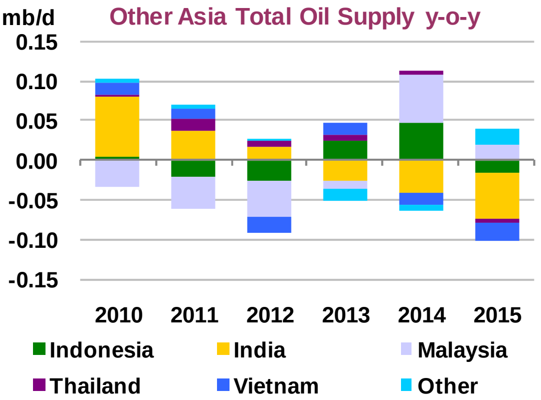




Asia

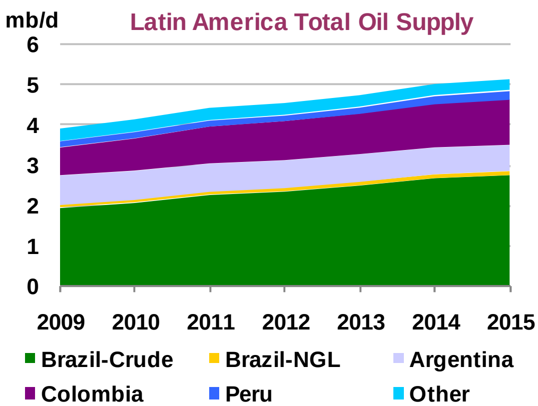
Total non-OPEC Asian production is revised down by 170 kb/d on average and is expected to decline over the forecast period, from 7.4 mb/d in 2009 to 7.3 mb/d in 2015. **China's** production profile is adjusted down by 65 kb/d and is expected to dip from 3.8 mb/d to 3.7 mb/d in 2015, albeit with a surge to 4 mb/d in 2012. While production from new offshore fields and some key onshore areas such as Changqing and Yanchang will continue to rise, some of its large, older fields such as Daqing and Shengli face steady decline. Elsewhere, **Papua New Guinea** and **Thailand** will each see growth around 35 kb/d by 2015, while **Malaysia's** output is set to drop by 45 kb/d. **India** and **Indonesia** are both expected to have a flat production profile. Despite regional crude production slowing, due to rising natural gas supply, regional NGL output will rise from 660 kb/d in 2009 to 830 kb/d by 2015.

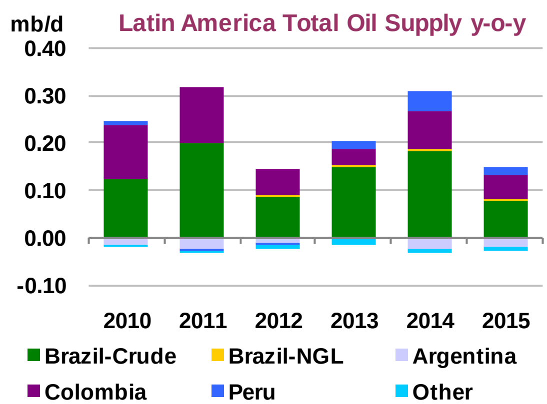




Latin America

Non-OPEC Latin America is forecast to see the strongest regional growth by far, rising from 3.9 mb/d to 5.1 mb/d by 2015, due to robust growth in Brazil and Colombia. In **Brazil**, crude output is expected to grow by 815 kb/d to 2.8 mb/d, all offshore and nearly half of which will stem from production at new pre-salt fields including Guara, Iara, Parque das Baleias and most importantly, Tupi. In the longer term, the pace of development of the huge pre-salt reserves will depend upon a new legislative framework, which is currently making its way through Congress. Existing contracts, including the already-sanctioned projects incorporated in our forecast, would not be affected, but the proposal to mandate Petrobras's operatorship in all new pre-salt developments and an attempt to source most of the related construction, infrastructure and service work domestically could slow production increases. Meanwhile, NGL output will grow a marginal 20 kb/d, hitting 100 kb/d in 2015. Total Brazilian oil supply (excluding fuel ethanol) is forecast to grow from 2.0 mb/d in 2009 to 2.9 mb/d in 2015.

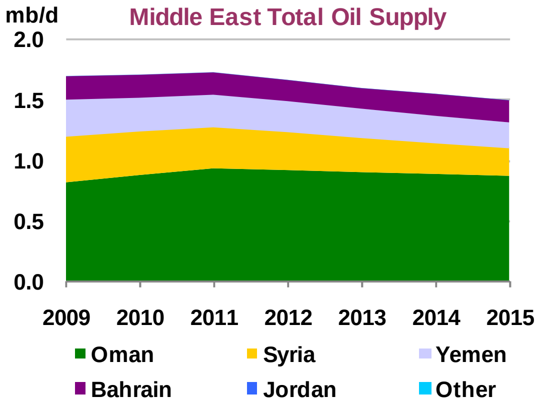


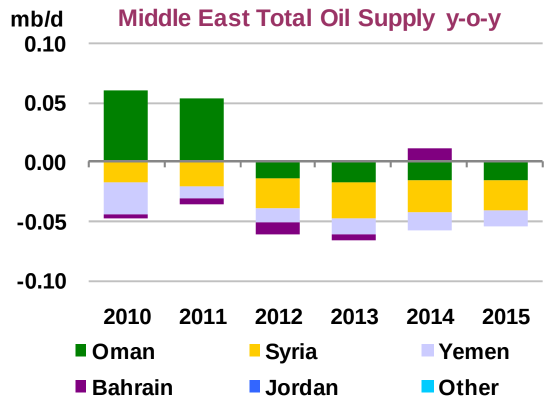


In terms of growth, **Colombia** is the new star on the non-OPEC horizon. Oil production is now forecast to grow from 675 kb/d to 1.1 mb/d by 2015, following an average upward revision of 100 kb/d. Changes to the investment environment such as a more competitive exploration rights bidding framework and large areas made available in licensing rounds in recent years are paying off. Thus growth at some new fields, including Rubiales and Castilla, has been impressive, with those two for instance showing combined year-on-year growth of 70 kb/d alone by February 2010. Their operators have ambitious plans to boost output further, aided by new infrastructure being put in place to bring crude from the Llanos area to coastal export terminals, as well as an improved security environment. **Peru** is forecast to see growth of 75 kb/d by 2015, while in **Argentina**, output is expected to decline by 90 kb/d.

Middle East

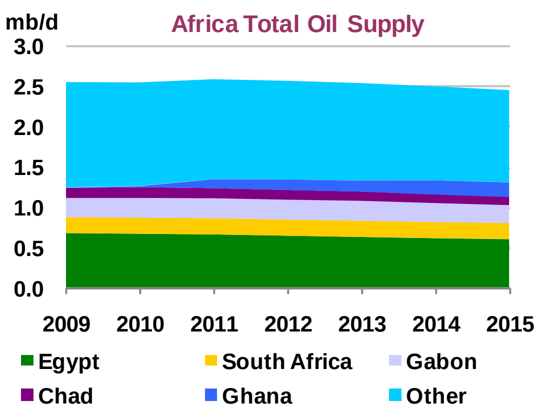
Non-OPEC Middle East oil production is revised up by 45 kb/d on average but is nonetheless forecast to decline from 1.7 mb/d to 1.5 mb/d by 2015. Production in **Syria** is anticipated to fall quite sharply, from 385 kb/d to 240 kb/d by 2015, due to the relative maturity of existing fields. **Yemen** will also see output decline, by 95 kb/d, while in **Oman**, a string of enhanced oil recovery (EOR) projects will boost output from 815 kb/d in 2009 to a high of 930 kb/d in 2011, before production drops off again to 865 kb/d in 2015.

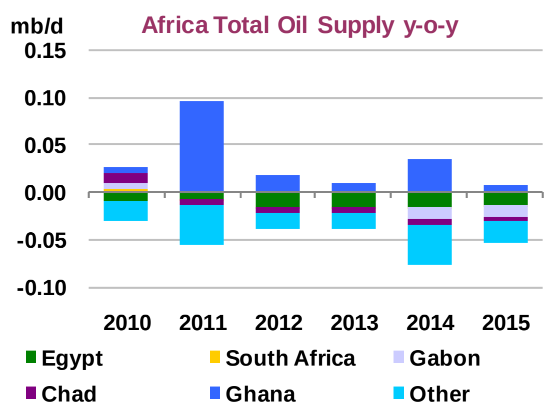




Africa

Non-OPEC African production is revised marginally and is forecast to decline by 100 kb/d to 2.4 mb/d in 2015. **Ghana** will soon see output start at its large Jubilee field, boosting output from near zero in 2009 to 175 kb/d in 2015 and to perhaps 300 kb/d or higher in the latter half of the decade. Exploration indicates that the offshore basin where Jubilee is located may well contain significant reserves, so Ghana and neighbouring countries such as the **Ivory Coast** may yet see more activity and growth in output. **Uganda**, another newcomer to oil, will start output in the Albert Lake area in late 2011 and reach nearly 50 kb/d total output by 2015. Most other producers are forecast to experience a decline in output, including, most significantly, **Sudan**, due to a lack of investment and political instability, and the possibility of secession by the southern region. Output in **Egypt**, **Congo** and **Chad** is also expected to decline over the forecast period.



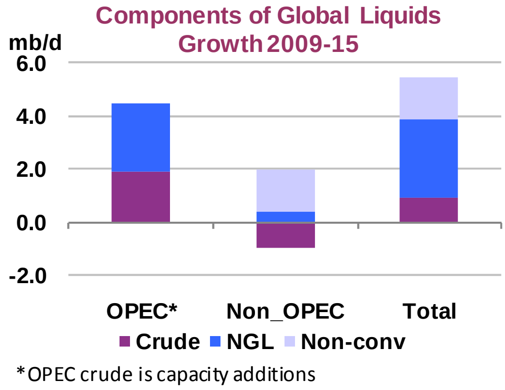


Natural Gas Liquids – Cornerstone of Global Oil Supply Growth

In April 2010, we published *'Natural Gas Liquids Supply Outlook 2008-2015'*. OMR subscribers can access the report at **www.oilmarketreport.org**. Global natural gas liquids (NGL) accounted for 13% of total oil production in 2009 and are forecast to grow by a net 3.0 mb/d during 2009-2015, with 2.6 mb/d of the growth from OPEC and 0.4 mb/d from non-OPEC countries. Incremental NGL production represents 56% of total oil supply growth (5.4 mb/d) from 2009 to 2015 (*see below*).

What are NGLs?

NGLs are light hydrocarbons dissolved in natural gas and produced within the gas stream. They comprise ethane, propane and butane (collectively LPG), pentanes-plus and gas condensates. Here NGLs are taken to exclude refinery-sourced material. Above ground, rich gas is unstable, as heavier components condense and are separated from dry gas in a processing plant (GPP). Condensate and other NGLs' distinct characteristics make it useful to distinguish between the two. NGLs are extracted to meet dry gas sales criteria, and to monetise valuable liquids.



The *OMR* and *MTOGM* report all OPEC condensate and other NGLs separately from crude oil, as OPEC producers customarily set production targets excluding gas liquids. For non-OPEC countries *OMR* NGL estimates generally include only gas plant NGLs. For some countries field condensates are also included, according to official reporting practices and condensate marketing.

Components of LPG are used as a clean-burning heating and cooking fuel, a petrochemical feedstock, a gasoline blending component and an automotive fuel. In Canada condensates are spiked into bitumen to cut viscosity and lighten/sweeten supply.

Realising Investment in the NGL Value Chain

The competitive nature of the petrochemical feedstock market ensures that price elasticity for NGLs demand in that sector is very high. In comparison, LPG demand in the residential sector is relatively inelastic. NGL prices are therefore traditionally more volatile than other oil product prices, making NGL business profitability difficult to predict. Given the uncertainty, planned gas processing projects can often linger in the decision process, while condensate is generally easier to monetise.

NGL extraction and fractionation form the midstream part of the value chain. Midstream investments are difficult to evaluate from a financial viewpoint, as the costs of developing capacity, plus segregated storage and shipment have to be balanced against the value of monetising differentiated products. Infrastructure constraints can also impede midstream development.

Realising a country's NGL potential may be determined in part by the way petroleum investments are planned and regulated. Firstly, large scale gas developments, be they LNG or pipeline export projects or 'country-wide gasification' projects, tend to favour NGL investments. The existence of specialist midstream companies servicing upstream operators has been the preferred model in North America. A gas processing centre that acts as a hub for an entire country or region also creates economics of scale that make NGL investments profitable. Another model that reduces the risk for midstream investments is an integrated system, regulated as a natural monopoly, such as in Norway.

NGLs are often developed as a part of a large-scale gas development aimed at exports, but liquids from smaller-scale developments aimed at flaring reduction also hold the potential to substantially boost local supply and consumption of LPG. In emerging economies, domestic sector use of LPG represents a logical early step away from reliance on traditional biomass fuels and enjoys the initial benefit of acting as a bridge before more costly natural gas distribution infrastructure is developed.

Trends in Natural Gas Production and Implications for NGL Supply

Forecast NGL output increases at a compound annual 4.2%, while marketed natural gas production increases by 2.0% annually. This sees the ratio of NGLs to dry gas rise from 20.6% in 2009 to 23.4% in 2012, stabilising until 2015. The increasing scale of natural gas developments, increased utilisation of associated gas and the trend of wet non-associated gas gradually replacing dry, non-associated gas in some countries (partly due to the development of deeper reservoirs with high pressure and temperature), all contribute to the increasing liquids ratio. However, the replacement of associated gas by dry non-associated gas provides an offset in several countries.

Large gas condensate deposits have been targeted for development by IOCs in recent years, with wet gas reservoirs developed relatively earlier than drier gas deposits as a way of maximising early project returns. The many LNG projects launched in 2008-2011 boost global NGL production by an estimated 550 kb/d, with 380 kb/d related to Qatar LNG developments alone.

Increased utilisation of natural gas is also a result of measures to cut flaring of associated gas. The World Bank estimates that 140 bcm of gas was flared world-wide in 2008. Measures to reduce flaring here underpin a large part of the projected rise in NGLs from Russia, Nigeria and Angola. Assuming a conservative average liquids ratio in flared gas of 20% implies that 0.5 mb/d of NGLs are flared, representing both environmental pollution and a waste of valuable energy resources.

Recent rising gas supplies from deepwater Gulf of Mexico and from tight gas in the Rocky Mountains, have had a liquids content on average two to three times that of gas from shallow water and onshore Texas. The trend of wetter non-associated gas is also evident in the North Sea, where deeper, high temperature and pressure deposits have been developed. Russia too is seen tapping deeper, wetter reservoirs, boosting liquids yields from a current low base. High oil prices, new technology and access restrictions can focus company attention on previously unattractive gas sources.

The rapid development of unconventional gas in North America has transformed perceptions on global gas supply in the next decade. Although unconventional gas tends to be dry, liquids content varies widely, so longer-term NGL supply projections need to better reflect associated liquids potential if unconventional gas development continues apace. The high price spread between natural gas and NGL in the USA prompts companies to target wet strata. Coal bed methane is dry, but coexists in basins with differentiated geological strata and liquids content of more than 30%. Clearly, there is potential for greater liquids exploitation here, but beyond the scope of this projection.

In contrast, Mexico, Egypt, China, India and Australia have large natural gas reserves in drier reservoirs, whose rising gas production in recent years has constrained liquids ratios overall. Long term, global gas supply is expected to become drier. However, rising dry non-associated gas supply in the Middle East has so far been hampered by subsidised local prices. To realise ambitious output targets, these countries will need prices to better reflect marginal production costs.

Global NGL Supply Outlook

Global supply of condensate and other NGLs is forecast to grow by 3.0 mb/d from 2009 to 2015, (+4.2% annually), close to growth seen in 2003-2009. Between 2009 and 2011 growth averages 7.9% per year, equal to 1.8 mb/d in absolute terms. Notably in 2009, the launch of several liquefied natural gas (LNG) projects with high liquids content, contributes to NGL growth. The trend towards drier, non-associated gas in some countries, is overshadowed globally by greater liquids recovery. The global liquids ratio increases from 20.6% in 2009 to 23.4% in 2012, remaining flat to 2015.

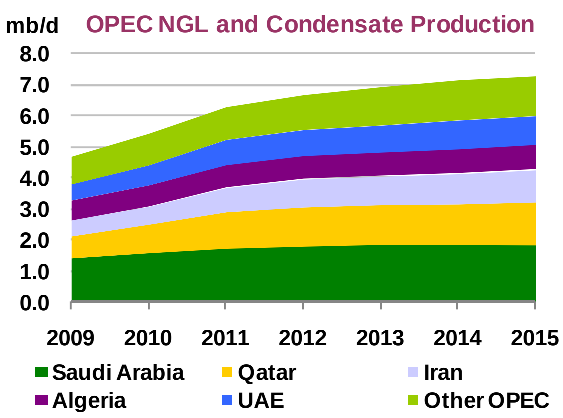
World Supply of Condensate and other NGLs 2009-2015

(thousand barrels per day)

	2009	2010	2011	2012	2013	2014	2015	*Increment 09 - 15*
Non-OPEC								
OECD North America	2,918	2,947	2,870	2,832	2,789	2,750	2,710	(208)
OECD Europe	737	738	742	810	805	787	758	21
OECD Pacific	94	100	104	108	111	115	120	26
Total OECD	3,749	3,785	3,716	3,749	3,706	3,651	3,588	(161)
FSU	1,050	1,117	1,188	1,290	1,337	1,366	1,402	353
Non-OECD Europe	15	14	14	13	12	10	9	(6)
Asia	661	680	716	774	824	831	830	169
Africa	283	280	281	283	286	288	291	9
Middle East	160	175	178	178	179	181	182	23
Latin America	329	329	336	344	352	361	369	41
Total non-OECD	2,497	2,596	2,714	2,883	2,990	3,036	3,085	588
Total non-OPEC	**6,246**	**6,381**	**6,429**	**6,632**	**6,696**	**6,687**	**6,673**	**427**
OPEC								
Middle East OPEC	3,301	3,887	4,680	5,002	5,218	5,377	5,500	2,199
Other OPEC	1,278	1,429	1,489	1,553	1,591	1,652	1,659	381
Total OPEC	**4,579**	**5,316**	**6,169**	**6,555**	**6,809**	**7,029**	**7,159**	**2,580**
Total World Condensate and other NGLs	**10,825**	**11,697**	**12,599**	**13,187**	**13,505**	**13,717**	**13,831**	**3,006**

Non-OPEC NGL production rises by 0.4 mb/d to 6.7 mb/d by 2015, an annual growth rate of 1.1%, well below the 2003-2009 rate of 2.6%. In North America NGL production is seen falling by 1.2% annually with a decline in gas production and the exploitation of drier gas deposits. In Russia, greater flared gas capture and exploitation of wetter gas have a positive impact. Meanwhile in the Asia-Pacific region NGL production grows due to rising gas production, albeit the liquids ratio falls on a growing contribution from drier non-associated gas.

OPEC NGL and condensate capacity growth outpaces that for crude, and is on track to rise by 2.6 mb/d over the 2009-2015 forecast period, increasing from 4.6 mb/d in 2009 to 7.2 mb/d by 2015. Middle East producers will provide 85% of the growth at 2.2 mb/d, attaining production of 5.6 mb/d by the end of the forecast period. The gas liquids component in OPEC's total supply profile is seen rising from 13% in 2009 to 20% by 2015. OPEC's rapid expansion of NGLs in large part is driven by growing domestic demand for gas as a fuel to power utilities, water desalination plants, industrial use as well as for reinjection to maintain pressure at mature oil fields.



Saudi Arabia remains OPEC's single largest producer of NGLs over the forecast period, with production expected to rise by around 425 kb/d to 1.8 mb/d by 2015. Most of the capacity growth will come from projects already launched but scheduled to build up slowly, with both the 310 kb/d Hawiyah NGL project and the 210 kb/d Khursaniyah reaching peak capacity in 2013.

Qatar posts the largest increase, with capacity almost doubling from 720 kb/d to 1.4 mb/d between 2009 and 2015. Developments in the North Field, the world's largest gas field which also straddles the maritime border with Iran (where it is called South Pars), will provide most of the country's growth. Further North Field development beyond currently active projects is uncertain due to a moratorium put in place in 2005 and extended to 2014 to allow time to study the effects of the existing projects on the reservoir. Major capacity additions over the forecast period include Qatargas 2, 3 and 4 which will add 300 kb/d of mostly condensate by 2012 while RasGas 3 will add 100 kb/d of condensate and 45 kb/d of other NGLs by 2012.

Though plagued by project delays, **Iran** is slated to increase NGL capacity by a substantial 525 kb/d, to 1.0 mb/d by 2015. Delays with the start-up of South Pars 7-10 have slowed expected capacity growth at the front of the forecast but output is gradually expected to reach full capacity of 330-370 kb/d by 2012. However, a number of projects have now been temporarily delayed or postponed as several foreign companies opted to abandon their involvement in the country given growing concerns about the prospect of new sanctions on the country's energy industry.

Estimated Average Sustainable OPEC Condensate & NGL Production Capacity

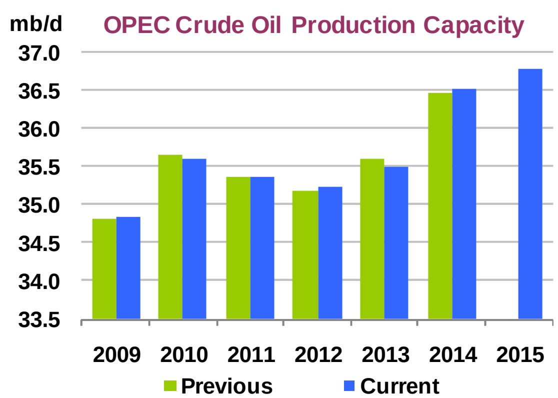
(thousand barrels per day)

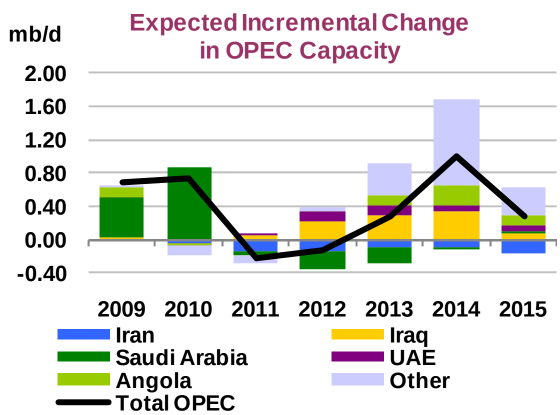
	2009	2010	2011	2012	2013	2014	2015	*Increment 09 - 15*
Algeria	627	667	705	724	742	762	780	*153*
Angola	50	50	50	85	92	86	80	*30*
Ecuador	2	2	1	1	1	0	0	*(2)*
Iran	521	585	788	909	929	985	1,048	*527*
Iraq	42	56	59	64	68	73	74	*32*
Kuwait	190	195	205	223	308	320	320	*130*
Libya	115	111	111	111	122	168	172	*56*
Nigeria	273	388	409	419	420	421	410	*137*
Qatar	718	933	1,190	1,280	1,296	1,326	1,400	*682*
Saudi Arabia	1,394	1,560	1,710	1,775	1,834	1,829	1,820	*426*
UAE	519	643	813	836	868	929	922	*403*
Venezuela	210	211	213	213	214	215	216	*6*
Total OPEC	**4,662**	**5,401**	**6,254**	**6,640**	**6,894**	**7,114**	**7,244**	***2,582***

OPEC Crude Oil Capacity Outlook

An anticipated recovery in oil demand growth in the medium term and stronger oil prices over the past year have spurred a number of OPEC producers to move forward with expansion plans for 2010-2015. OPEC is on course to increase installed crude oil production capacity by a net 1.9 mb/d, reaching 36.8 mb/d by the end of the forecast period. OPEC sees strong growth in capacity in 2010 but declines set in during 2011-2012 before posting a strong recovery in 2014. Capacity additions in 2015 are seen as minimal, in part due to delays in agreeing final investment decisions by several countries, especially Nigeria where projects are in limbo awaiting a new petroleum law.

MTOGM capacity estimates are based on a combination of new project start-ups, and assessed base load supply, net of mature field decline. The implied decline rates for the 2010-2015 period are slightly higher, at -3.9%, than last year's roughly -3%, partly reflecting a shift in OPEC's production slate to offshore production, where decline rates can range from 15-30% compared with 1-3% at onshore fields. New OPEC production capacity coming on stream during the forecast period is estimated at a gross 10.9 mb/d at peak, with offshore production accounting for 38.3% of the increase at 4.2 mb/d. New capacity will be partially offset by a net decline of 7.1 mb/d, or 1.2 mb/d annually.





A year ago, OPEC had slowed or halted some planned projects in the wake of the global economic crisis to reassess demand prospects for its crude and gas liquids, review strategic investment plans or renegotiate contract terms with IOCs, oil service companies and other contractors. The steady increase in oil prices over the past year has leant momentum to get projects back on track. Middle Eastern producers, in particular, are pressing forward following renegotiation of contracts aimed at capturing prevailing lower costs, with capacity additions concentrated in Iraq (50%), Saudi Arabia and Angola (22% each) and the UAE (20%). By contrast, other countries have seen their start-up dates pushed back further due to uncompetitive contract terms, especially African member countries.

Estimated Average Sustainable OPEC Crude Production Capacity

(million barrels per day)

	2009	2010	2011	2012	2013	2014	2015	*Increment 09 - 15*
Algeria	1.39	1.37	1.38	1.45	1.49	1.49	1.45	*0.07*
Angola	2.06	2.03	2.02	2.02	2.12	2.36	2.48	*0.42*
Ecuador	0.49	0.48	0.45	0.46	0.46	0.44	0.42	*(0.07)*
Iran	3.97	3.93	3.79	3.66	3.56	3.46	3.29	*(0.68)*
Iraq	2.49	2.50	2.55	2.77	3.05	3.39	3.46	*0.97*
Kuwait	2.62	2.59	2.55	2.52	2.56	2.67	2.66	*0.04*
Libya	1.77	1.78	1.81	1.78	1.78	1.95	2.03	*0.25*
Nigeria	2.66	2.70	2.70	2.58	2.52	2.49	2.56	*(0.10)*
Qatar	0.93	1.00	1.02	1.00	0.98	0.98	1.03	*0.10*
Saudi Arabia	11.23	12.09	12.04	11.83	11.65	11.63	11.66	*0.43*
UAE	2.72	2.71	2.72	2.84	2.98	3.05	3.12	*0.39*
Venezuela	2.51	2.42	2.33	2.33	2.37	2.60	2.62	*0.11*
OPEC-11	**32.35**	**33.09**	**32.82**	**32.47**	**32.46**	**33.12**	**33.32**	***0.97***
Total OPEC	**34.85**	**35.59**	**35.36**	**35.23**	**35.51**	**36.51**	**36.78**	***1.94***

Indeed, while the overall forecast is largely unchanged from our *December 2009 medium-term update*, the headline number masks significant changes for several individual countries. The production outlook for both Iraq and Venezuela, in particular, has improved dramatically after those countries signed a raft of new contracts with IOCs.

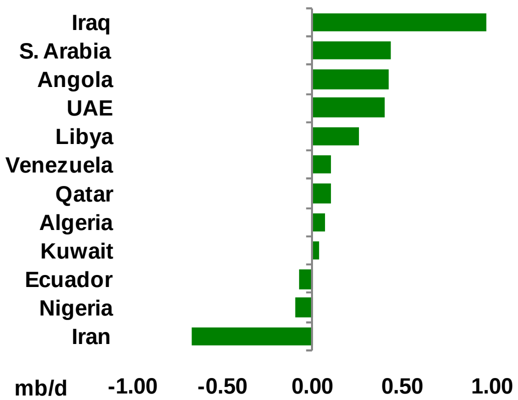
By contrast, forecast capacity for OPEC's African producers has been revised down sharply as political upheaval and unattractive contract changes conspire to delay project developments to beyond our 2015 forecast period. Project cancellations or delays in Algeria, Nigeria and Angola have resulted in a combined 800 kb/d downward revision from the *December 2009 medium term update*.

Middle East Producers Stay the Course

OPEC's Middle East producers, with the exception of Iran, have moved apace with plans to increase production capacity from 2009-2015. Middle East capacity is expected to rise by a net 1.3 mb/d and accounting for 65% of OPEC's total increase. Critically, Iraq is expected to provide 50% of OPEC's total 1.9 mb/d rise in production capacity. Iraq's success with its two major bidding rounds last year is seen by some as capable of raising production to 6.0 mb/d by 2015 but given the considerable logistical, operational and political challenges, we have assumed a more conservative increase to 3.5 mb/d over the forecast period. That said, an increase to 6.0 mb/d now appears to be more a question of when, rather than if *(see 'Iraqi Efforts to Boost Capacity Face Headwinds').*

Iraq, Saudi Arabia, the UAE, Kuwait and Qatar combined are slated to increase capacity by 1.9 mb/d, which will be partly offset by a drop in Iranian capacity of 675 kb/d over the forecast period. For its part, Qatar's crude oil production capacity will be eclipsed by the rapid expansion of NGLs and condensate output *(see 'Natural Gas Liquids – Cornerstone of Global Supply Growth').*

Incremental Change in Crude Production Capacity 2009-15

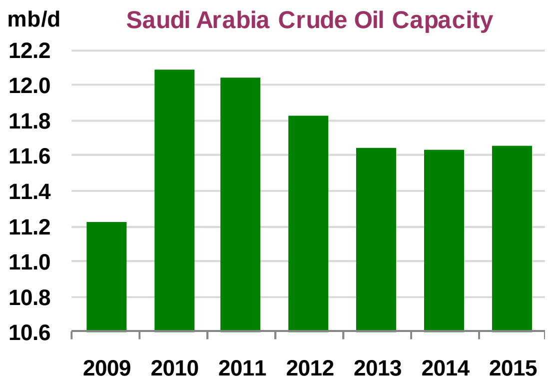


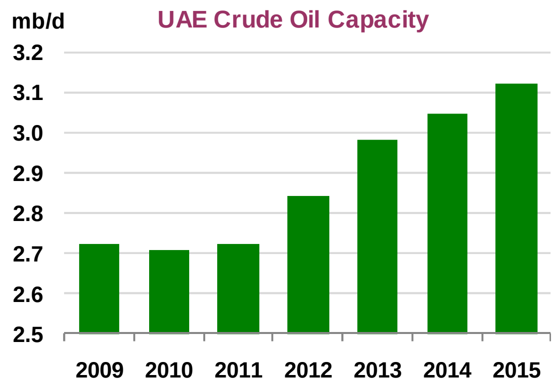
Saudi Arabia's production capacity is expected to average 11.7 mb/d by 2015, a net increase of 433 kb/d from 2009 levels. Saudi Aramco posted a record increase in nameplate capacity in the 2009 -2010 period following the completion of three key projects — Khurais (+1.2 mb/d), Shaybah (+250 kb/d) and Nuayyim (+100 kb/d). The projects, combined, are slated to add 1.6 mb/d to the country's capacity though it is understood that work on associated infrastructure is still ongoing.

Despite the steady improvement in global oil demand over the forecast period, OPEC's effective spare capacity remains at relatively comfortable levels, ranging from a high of 5.85 mb/d in 2010 to a low of 3.5 mb/d in 2013. With history as a guide, Saudi Arabia might be expected to shoulder the burden of curtailing production, so we assume in our forecast that operating levels will be held below nameplate capacity of 12.5 mb/d, in a range of between 11.6 mb/d to 12.1 mb/d.

Saudi Arabia is expected to shut-in some operations for extended periods of time either for purely economic reasons or to perform extensive rehabilitation work. Indeed, extensive overhaul of infrastructure and drilling of new wells is reportedly underway at Ghawar, the world's largest oil field. In addition, Saudi Aramco is laying the groundwork for a massive CO_2 injection plan at Ghawar, which would not only advance plans for sequestering greenhouse gases but also reduce the amount of natural gas needed for reinjection to maintain oil field pressure and enable it to be diverted for domestic use. Initial plans call for gathering and injecting 40 mmcf/d of CO_2 into the reservoir.

Saudi Arabia's next mega project is the 900 kb/d heavy oil Manifa field, which is slated to start up late-2013 or early-2014 and to be brought on in stages, with completion now not expected before end-2015. The cost of developing Manifa is estimated at $16 billion. Manifa is designed to offset declining production elsewhere so will not add to nameplate capacity. Moreover, the timeline for Manifa also critically hinges on planned refinery start-ups, which have also been subject to changing targets due to the surplus in global refining capacity *(see Refining & Product Supply).*





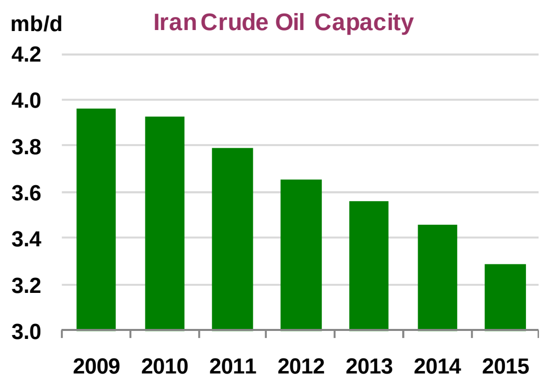
The **UAE** is on course to ramp up production capacity by a net 394 kb/d to an average 3.1 mb/d by 2015. Last year the Emirates deferred plans to increase production capacity to 3.5 mb/d from 2015 to 2018. Expansion of the offshore Upper Zakum field will provide 65% of the UAE's total increase in capacity by 2015. The project's partners, state-owned Adnoc, ExxonMobil and Japan Oil Development Co (JODCO) plan to raise Upper Zakum's production capacity from 500 kb/d to 750 kb/d by 2H15. Japan's Inpex, partnered with JODCO, is also planning a feasibility study for CO_2 injection into the reservoir, which would be a first for an offshore field.

Production increases elsewhere will come from extensive enhanced oil recovery (EOR) at mature fields and recomissioning of production facilities mothballed in the 1980s at Lower Zakum. A planned capacity increase of 100 kb/d at Lower Zakum will be brought on in stages starting in 2012. Incremental production from onshore fields is also slated to start in 2012, with capacity at the Asab, Sahil and Shah by a combined 75 kb/d. Qusahwira capacity of 30 kb/d is expected to come online in 2013.

Also planned is the development of the offshore Nasr field, with contract award for the first phase of construction expected in 2H10. Initial output of 25 kb/d is planned for end-2015. The second phase calls for an increase of 40 kb/d by 2018. Nasr is the first offshore development since the Lower Zakum field came on stream in 1966.

Iran's crude oil production capacity is forecast to decline by 675 kb/d, from just under 4 mb/d to 3.3 mb/d by 2015. Iran has several small projects of 25-50 kb/d coming online during the forecast period plus the 100 kb/d Azadegan II and Yadavaran at 85 kb/d, both with Chinese partners. However, these additions fall short of offsetting decline rates, which officials recently estimated at 8-10%.

The country's escalating isolation from the international oil community in the wake of global opposition to its nuclear programme is just one factor behind the projected capacity decline. Equally, if not more, important are unattractive investment terms, based on a largely discredited buyback programme of service contracts. An ever-changing management team at state oil company NIOC has further clouded the country's production outlook. With investment by IOCs down to a trickle and domestic production initiatives hampered by US sanctions, Iran's targeted increase in capacity to 5.1 mb/d by 2015 looks wholly unrealistic.

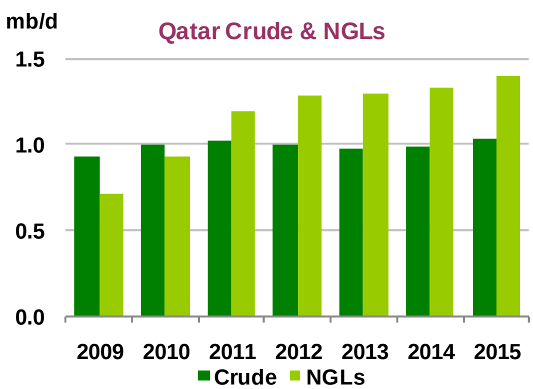


Kuwait's production capacity is forecast to stagnate in the medium term, averaging 2.7 mb/d by 2015. The state oil company recently said it plans to invest around $10.4 billion dollars in upstream developments over the next five years, but that pales in comparison to its neighbouring countries in the Middle East Gulf. Projects underway essentially offset declines elsewhere. The GC-24 project at the northern Sabriya field has been slightly delayed from 2013 to early 2014, with capacity of around 90 kb/d added by the end of the forecast period in 2015. EOR projects at the Burgan field are expected to add incremental capacity over the period, up a total 100 kb/d, to 1.7 mb/d, by 2015.

Divisive internal debate over the future role of foreign investment in the country's oil sector between Parliament, the executive branch and the general public has combined to derail expansion plans for almost two decades. A new Parliament and the appointment of a new oil minister earlier in 2010 may hold some promise for an improved investment climate going forward but the outlook is still very murky. A recent technical service contract signed with Shell for the development of non-associated gas reserves is seen as a step forward. However, crude oil resources are still largely viewed as sacrosanct and industry observers question whether the same, more attractive technical service contract agreed with Shell will be on offer for oil. Further EOR projects, which will require IOC involvement, hang in limbo. Long-standing technical service contracts with Chevron and BP expired last year and so far Kuwait has not pursued alternative partners.

Kuwait's longer-term plans call for increasing capacity to 4 mb/d by 2020, involving resurrection of a modified Project Kuwait, which encompasses the development of fields in the northern region of the country, and the Lower Fars heavy oil project also in the north. Discussions with IOCs on both these projects are at an early stage.

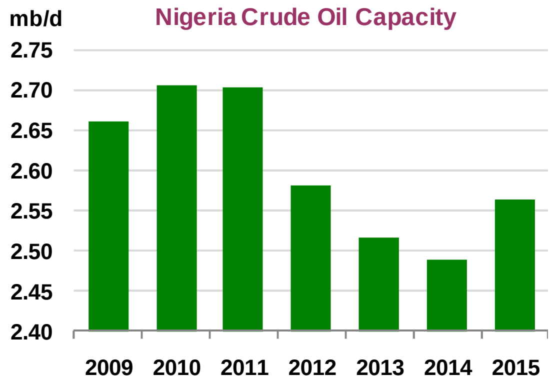
Qatar's production capacity is forecast to breach the 1 mb/d mark in 2010 following expansion of the al-Shaheen field earlier in the year. Increased output at Al Rayyan and several other active EOR projects are designed to maintain and slightly increase production by the end of the forecast period. However, by 2011 production capacity of NGLs and condensate will overtake crude as the country's primary source of liquid fuel supply. *(see OPEC Gas Liquids Supply).*



Reversal of Fortune for OPEC's African Producers

Capacity expansion plans in OPEC's African member have been derailed by increasingly unattractive contract terms, resurgent resource nationalism and domestic political developments. Capacity growth for the four countries—Algeria, Angola, Libya and Nigeria—has been revised lower by a steep 800 kb/d on average since the December 2009 six-year forecast, with production now forecast to rise by 650 kb/d, to 8.5 mb/d.

Nigeria's production outlook is once again marred by renewed militant activity, political turmoil and continued uncertainties about the future commercial operating environment for IOCs given possible new legislation that could negatively impact contract terms. Since the December update, several critical issues have emerged, not least the death of President Umaru Yar'Adua on 5 May. The unsettled political and security situation has led to a slowdown in project development plans, with capacity now seen declining by just under 100 kb/d over the forecast period, from 2.7 mb/d to 2.6 mb/d. That is a downward revision of around 360 kb/d from December's forecast.



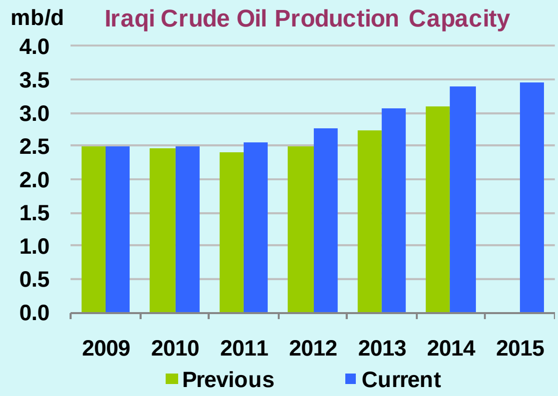
Nigeria's unexpected success last year in agreeing a ceasefire with rebel groups signalled a major shift in the operating environment for IOCs, after years of debilitating attacks on oil operations. The ceasefire period enabled companies to repair damaged infrastructure and boost production closer to 2.0 mb/d. However, the fragile peace accord began fraying at the edges amid political uncertainty resulting from the long absence of the ailing President Umaru Yar'Adua from the country. Militants renewed their campaign of sabotage in early 2010 and, while a brief calm prevailed over the country after Goodluck Jonathan assumed full presidential powers following the death of Yar'Adua, attacks on oil installations have resumed. With contentious presidential elections looming sometime within the next year, the country's operating environment remains highly uncertain.

The proposed 'Petroleum Industry Bill (PIB)' is also casting a cloud over capacity expansion plans. The draft legislation enables the government to renegotiate old contracts and impose higher royalties and taxes. While we assume that ultimately a positive outcome for the government and companies will prevail, the timeline for sanction of new project developments will likely be delayed pending passage of new legislatin—now likely to be after next year's presidential elections. Projects still awaiting final investment decisions and therefore expected beyond our current forecast period include the 140 kb/d Bonga SW & Aparo; the 50 kb/d Bongo NW; the 135 kb/d Bosi; the 110 kb/d Uge. The 100 kb/d Nsiko and 200 kb/d Egina projects are factored in at end-2015 but the fields will not reach full capacity during the forecast period.

Angola's production capacity is forecast to increase by 420 kb/d to 2.5 mb/d over the 2010-2015 period, a downward revision of around 160 kb/d since our last 6-year forecast in December 2009. Delays in final investment decisions are behind the lower production target by the end of the forecast period, with planned increases now moved into the 2016-2017 period. In Block 17 the 160 kb/d CLOV complex now looks likely to come only at the tail-end of 2015. Also expected at end-2015 is the 200 kb/d Cabaca Norte.

Iraqi Efforts to Boost Capacity Face Headwinds

Iraqi production capacity is forecast to rise by just under 1.0 mb/d, to 3.5 mb/d by 2015. That is an upward revision of 290 kb/d from our December forecast based on more detailed development plans being put forward by the joint venture companies. Indeed, project plans envisage an even sharper increase in the medium term, with production capacity, on paper, projected at 6.0 mb/d by 2015 and 10-12 mb/d by 2017, but we expect an array of problems to delay official targets and see a more gradual increase in the medium term.



Near-term maximum production capacity is expected to average around 2.5 mb/d this year and next with a gradual ramp up seen after that. Capacity is forecast to average on an annual basis 2.8 mb/d in 2012, 3.1 mb/d in 2013, 3.4 mb/d in 2014 and 3.5 mb/d in 2015.

The implications for the country's future following the March 2010 elections are still very unclear, with escalating tensions and manoeuvring among politicians still at a critical juncture four months on. The delay in forming a government will push even further into the future the passage of a binding petroleum law, which is seen critical to the companies before they invest the billions of dollars committed so far. The uncertain outcome from the elections has been accompanied by an uptick in violence across the country. As a result, near-term plans to increase production by 600 kb/d by 2011 will likely be delayed.

Iraq's two bid rounds last year resulted in plans for eleven different field development projects. Five mega projects – Rumaila, West Qurna 1 & 2, Majnoon and Zubair – will account for more than 85% of the expected capacity increase. To fast track production gains, the contracts stipulate that companies will only start recovering costs and per barrel fees once production is increased by 10%. The companies are moving apace with joint venture and logistical planning. By late May, more project details emerged for two of the biggest and furthest advanced projects.

At **Rumaila**, joint venture partners BP and CNPC plan to invest $15-20 billion over the 20-year contract. Reservoir pressure and water incursion is a major problem for Rumaila, which has been producing for more than 50 years. Therefore, workover of existing wells and replacing worn out equipment at surface facilities are top priorities. A series of tenders worth more than $500 million have been awarded so far, which entail drilling 56 new wells, purchasing equipment, and installing pipes and other secondary work.

West Qurna 1, the ExxonMobil and Shell JV, is one of the more geologically challenging and expensive projects. Capex is set at $50 billion to boost output from around 250 kb/d to 2.35 mb/d by 2017. Near term, the JV partners plan to drill 8 new wells and overhaul up to 45-50 wells in 2010 to boost output. West Qurna 1 has been pumping since late 1990 and reached a peak of 400 kb/d before the 2003 invasion but output fell by more than 40% since then in large part due to declining pressure. Water for reinjection is also critical to the timing of the project.

There is little dispute that Iraq holds sufficient reserves to enable the attainment of its ambitious production targets. However, while contracts have been awarded for field developments that could produce to those levels eventually, associated contracts needed to support development are not yet in place. Their award will hinge on progress at the political level as well as improved security on the ground. Also, Iraq's basic non-oil infrastructure is in a desperate state of disrepair. Everything from new roads, bridges, and expansions of ports is needed.

Iraqi Efforts to Boost Capacity Face Headwinds (continued)

Iraqi officials and oil company executives are already working on plans to develop the infrastructure needed to support field development, but the challenges are daunting. One critical issue is the shortage of water for field reinjection, especially in the south. Water flows from the Tigris and Euphrates rivers have been declining, in part due to droughts. The problem has been compounded by an increase over the past decade of the number of dams in Turkey and Syria, which have diverted flows. It is still unclear who will shoulder the costs for these massive projects since the original development contract awards did not stipulate the companies' responsibility and the state lacks the financial resources to provide the funding. Final decisions on these issues will crucially depend on the new government currently being formed. Infrastructure projects needed to support oil field developments in the 2009-2015 forecast period include:

- Water and gas reinjection facilities, which are critical to boosting production at many of the projects. Work on a shared water injection plant is reportedly expected to start early in early 2011 and will take 30 months to complete but this timeline appears unrealistic given the lack of progress on contract awards. The projects currently at design will only support production slated for the first tranche of production expansions, with planning for additional facilities still to be determined.

- Export routes have been severely constrained by decades of war, with southern ports and pipelines already near operating at capacity. Logistical obstacles may limit the country's plans to significantly expand exports until 2013-14 at the earliest. Iraq is planning to install single point mooring buoys (SPM) in the Middle East Gulf designed to increase capacity by 1.0 mb/d to relieve the export bottleneck at its southern Basrah ports. Current southern export capacity is limited to the 35 year-old Basrah Oil Terminal (BOT) which at most can handle 1.4-1.5 mb/d and nearby Khor al-Amaya that has a design capacity of 300 kb/d but is frequently plagued by operational problems. Iraq has yet to finalise contracts for the SPMs, meaning plans to ramp-up capacity by 600 kb/d may be delayed.

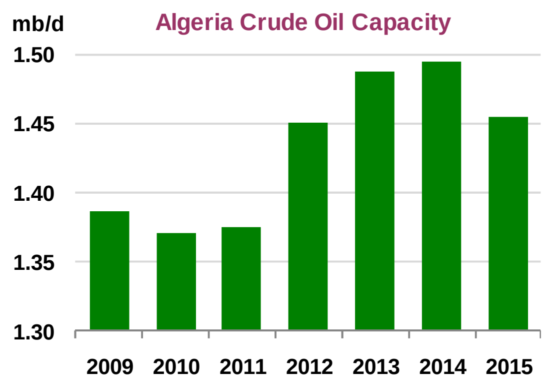
As part of the two licensing rounds Baghdad included several projects in the northern region of the country but there were no bids given the political and legal uncertainty surrounding the fields. The Kurdish Regional Government (KRG) has awarded almost two dozen development contracts but Baghdad disputes the legality of the contracts. New production from the Tawke and Taq Taq fields last year was halted after the oil ministry refused to make payments to the companies on oil shipped through the Kirkuk-Ceyhan pipeline. Government officials have reportedly offered to let exports resume but would agree only to reimburse minimal operating fees and so far the companies have rejected this proposal. It is unlikely progress will be made on the broader complex negotiations over autonomy for the northern region of the country until a new government is functioning in Baghdad.

Iraq's Contract Awards & Planned Production Targets

(thousand barrels per day)

Contract Awards	Current Production	Target Capacity	Production Increment	Companies	Fee Paid	Reserves Billion bbls
Rumaila	1,066	2,850	1,850	BP/CNPC	$2.00	17.0
West Qurna 1	244	2,325	2,065	Exxon/Shell	$1.90	8.7
West Qurna 2	-	1,800	1,800	Lukoil,Statoil	$1.15	12.9
Majnoon	46	1,800	1,754	Shell,Petronas, Missan Oil Co	$1.39	12.6
Zubair	183	1,200	1,017	ENI, Occidental, Kogas	$2.00	6.6
Halfaya	3	535	532	CNPC, Total, Petronas	$1.40	4.1
Garraf	-	230	230	Petronas, Japex	$1.49	0.9
Badra	7	170	163	Gazprom, Kogas, Petronas, TPAO	$5.50	0.1
Qayara	-	120	120	Sonangol	$5.00	0.8
Najmah	-	110	110	Sonangol	$6.00	0.9
Missan	100	450	350	CNOOC, Turkish Petroleum	$2.30	2.5
Total	**1,649**	**11,590**	**9,991**			**67.1**

Algeria's crude production capacity is forecast to increase by around 65 kb/d, to 1.45 mb/d, by 2015. This is a sharp downward revision of some 240 kb/d from the *December 2009 medium-term update*. In March 2010 the country's Oil Minister Khelil—since replaced in a cabinet reshuffle at end May-- announced that the country would maintain production levels at around 1.4 mb/d through 2014 compared with an earlier target of 1.6 mb/d. Meanwhile, a corruption scandal engulfing top executives from state-owned Sonatrach, which came to light at the start of 2010, has paralysed the decision making process. The appointment of Youcef Yousfi, a former diplomat and previous head of Sonatrach in the 1990s, is viewed as a positive development for getting projects back on track. Expansion has been plagued by delays, difficult contract renegotiations and unattractive terms.



However, EOR plans for Hassi Messoud, the country's oldest and largest field, appear delayed beyond the forecast period. Capacity was expected to be increased from a current 400 kb/d to 600 kb/d. However, projects expected to go forward include: El Merk at 135 kb/d starting in 2012; Bir Seba at 36 kb/d starting in 2011; IAN EOR project at 30 kb/d starting in 2012; Menzel Ledjmet East at 8 kb/d starting in 2012; and Takouazet at 50 kb/d starting in 2013.

Libyan crude oil production capacity is down slightly from December's forecast, now seen rising from 1.8 mb/d to 2.0 mb/d by 2015. Government plans to increase production to 2.3 mb/d by 2013 look ambitious, given continued delays in contract awards. Our current forecast sees capacity running 500 kb/d below the government's target level in 2013, at 1.8 mb/d. Several relatively small EOR projects will combine to boost capacity by just over 250 kb/d during 2009-2015.

Mixed Outlook for OPEC's Latin American Producers

Venezuela is moving forward with expansion of its massive Orinoco heavy oil belt. The government has signed six contracts aimed at boosting heavy crude output by 2.1 mb/d. Two contracts cover the Carabobo area and four projects are in the Junin area. Though development timelines for projects in the Orinoco belt are still being finalised, given the technical complexity and lead times necessary for building the accompanying upgraders to process the extra heavy oil, we assume production will start in the later half of our forecast period.

Venezuela Orinoco Projects
(thousand barrels per day)

Orinoco Belt	Company	Est. Start	Capacity
Junin Block 2	Petrovietnam 40%	2013	200
Junin Block 4	CNPC 40%	No date	400
Junin Block 5	ENI 40%	2013	75
Junin Block 5	ENI 40%	2015	165
Junin Block 6	40% shared Rosneft, Gazprom, Lukoil, TNK-BP, Surgutneftegaz	2017	450
Carabobo 1	Repsol/Petronas/ONGC 11% each, Indian Oil and Oil India 3.5% each	2013	400
Carabobo 3	Chevron 34%, Ven Suelopetrol 1%, Mitsubishi/Inpex 5% each	2017	400
Total			**2,090**

Production from the new Venezuelan projects is likely to start in 2013 and build up to 400 kb/d on average in 2015. For 2009-2015, Venezuela production capacity is now forecast to rise on a net basis by just over 100 kb/d, to 2.6 mb/d, an upward revision from the December 2009 six-year forecast of 425 b/d.

Ecuador's punitive contract changes and deteriorating investment climate have combined to undermine future crude oil production capacity levels. Production capacity is forecast to contract by 70 kb/d, from around 500 kb/d on average in 2009 to 425 kb/d by 2015. Further blunting foreign investment, Ecuador announced it plans to renegotiate a number of contracts held by foreign operators by the end of the year, once a new hydrocarbon law is approved.

BIOFUELS

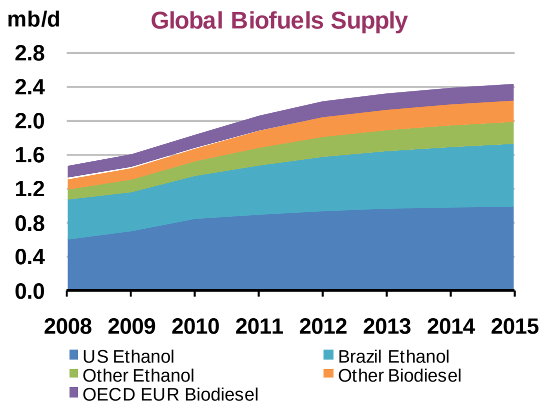
Summary

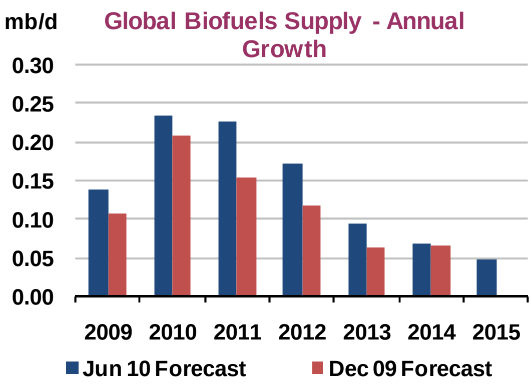
Note: Biofuels data in the MTOGM are expressed in volumetric terms. Exceptions will be noted where volumes are adjusted for energy content versus corresponding fossil fuels.

- **Biofuels production should grow strongly in 2010 and expand over the medium term,** with volumes increasing from 1.6 mb/d in 2009 to 2.4 mb/d in 2015. The economic crisis damped, but did not derail, growth as 2009 supply rose by 140 kb/d. Growth during 2009-2014, at 0.8 mb/d, is seen higher than the 0.6 mb/d envisaged in the *December 2009 medium-term update*. Still, increases remain strongest in 2010 and 2011, with lower annual rises thereafter. Adjusted for *energy content* versus oil, biofuels supply increases from 1.1 mb/d in 2009 to 1.7 mb/d in 2015.

- **While the economic crisis, lower oil prices and high sugar prices** forced capacity rationalisation, improving economics and consolidation have enhanced growth prospects. Sizeable overcapacities remain, particularly in biodiesel, and environmental/feedstock concerns with first-generation biofuels cloud government support. Still, blending targets persist in the OECD and have spread in Latin America. The US outlook has strengthened. Nonetheless, our production estimates there lag those implied by government goals, notably in second-generation biofuels.

- **Upward revisions, mainly in North America, increased 2009 and 2010 annual output** by an average 45 kb/d versus the December update. Global production is seen 185 kb/d higher in 2011-2014 with 70% of the revision from North America. Latin America and Europe also see upward revisions for 2011-2014, while Asian production is slightly lower. The US and Brazil dominate absolute production (together 75% of world supply) and provide 75% of growth from 2009-2015.





- **With 140 kb/d average annual output increases from 2009-2015,** biofuels contribute strongly to the non-OPEC supply growth picture. By 2015, ethanol and biodiesel should displace 5.7% and 1.5% of global gasoline and gasoil demand, respectively, on an energy content basis.

- **Second-generation biofuel activity should increase,** particularly with a US cellulosic biofuel mandate from 2010 onwards. Current plans imply 2015 global capacity potential at 150 kb/d, 55% from second-generation ethanol and 45% from second-generation biodiesel. Yet, technology development delays and difficult economics may keep actual production well below this level.

Biofuels Production Prospects Improve, Though Hurdles Remain

Though hampered by the economic crisis, lower oil prices and challenging sugar market conditions in 2009, the industry's slowdown remained modest and production prospects for global biofuels continue to improve. Higher GDP and oil price assumptions over the 2009-2015 forecast period have raised our outlook for global oil demand somewhat and point to potentially improved biofuels production economics. Over the past year, prices for feedstocks such as corn and wheat have remained steady relative to rising oil prices, benefitting North American and European ethanol producers. Sky-high sugar prices have also retreated somewhat, raising expectations for improved Brazilian ethanol output. Though biodiesel generally bears more challenging production economics, the rise of domestic blending mandates and export opportunities for cost-advantaged producers, such as Argentina, underpin a better outlook in that fuel as well. Industry consolidation and improved access to credit have strengthened the operating and financial position of biofuels on the whole, compared with a year ago. Moreover, some large projects in Europe and Asia – notably in the UK, Netherlands and Singapore – are set to add significant capacity over the next 18 months.

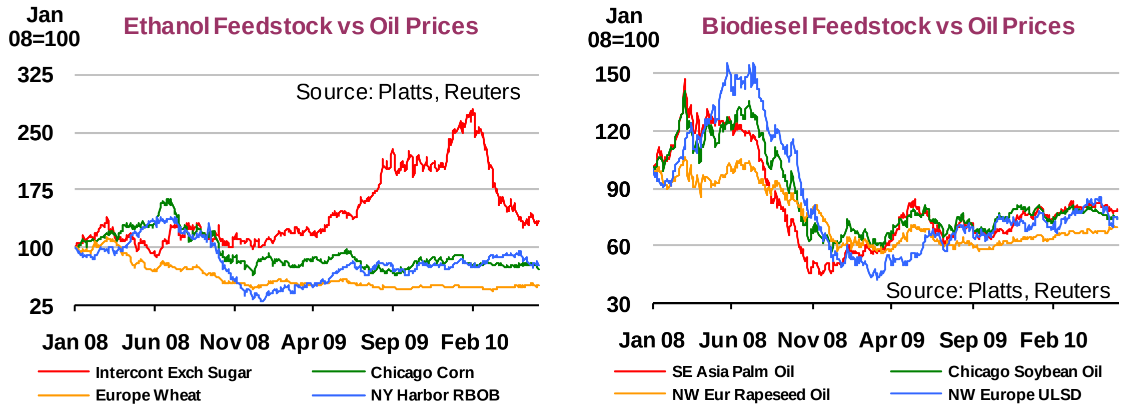
World Biofuels Production

(thousand barrels per day)

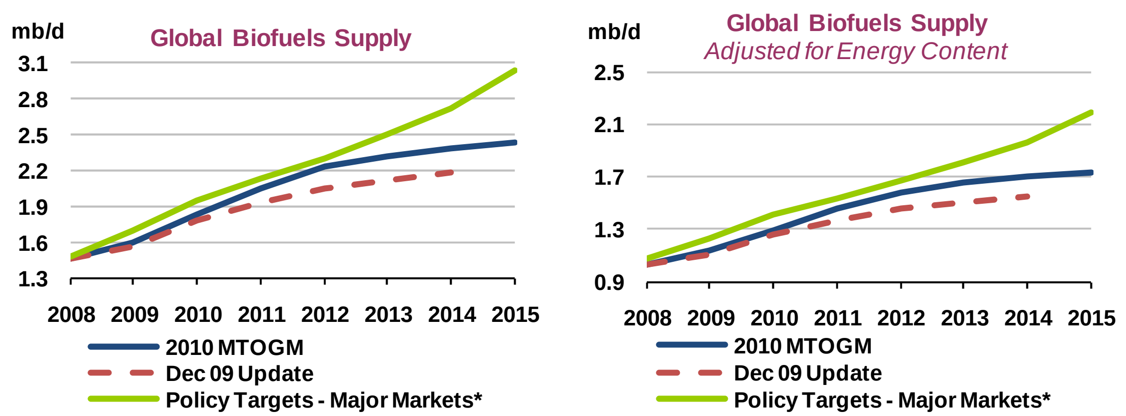
	2009	2010	2011	2012	2013	2014	2015
OECD North America	759	907	980	1,033	1,065	1,089	1,101
United States	738	879	946	995	1,027	1,047	1,059
OECD Europe	210	226	260	280	289	293	295
OECD Pacific	8	9	12	13	15	16	16
Total OECD	**978**	**1,142**	**1,252**	**1,325**	**1,368**	**1,397**	**1,411**
FSU	2	3	9	11	11	11	11
Non-OECD Europe	3	3	3	3	3	3	3
China	42	42	43	45	47	48	48
Other Asia	39	49	68	88	89	91	92
Latin America	532	589	677	749	795	830	859
Brazil	490	543	623	686	727	760	789
Middle East	0	0	0	0	0	0	0
Africa	2	3	6	8	9	11	14
Total Non-OECD	**620**	**689**	**807**	**905**	**956**	**995**	**1,028**
Total World	**1,598**	**1,831**	**2,059**	**2,230**	**2,324**	**2,391**	**2,438**

As such, biofuels will continue to constitute an important component for satisfying oil demand growth. From 2003-2009, biofuels supply growth, *on an energy-adjusted basis*, met about 20% of global incremental gasoline and gasoil demand, with ethanol accounting for 36% of gasoline and biodiesel meeting 9% of gasoil growth. From 2009-2015, with gasoline and gasoil demand growing by 4.8 mb/d collectively, biofuels supply growth, *on an energy-adjusted basis*, should only meet 13% of this. Some of the discrepancy between the two periods stems from the influence of 2009, when global oil, and particularly middle distillate, demand fell while biofuels production rose. Nevertheless, with declining North American gasoline demand over the medium term, ethanol should account for 48% of global gasoline demand growth from 2009-2015. Biodiesel comprises only 4% of rising gasoil demand, due to a resurgence in middle distillate demand growth and a slower biodiesel expansion profile versus the previous decade.

Downside risks remain for the industry. Notably, it remains burdened by overcapacity, particularly in biodiesel, which may weigh upon margins, and thus production, in many regions. Though forecasting agricultural fundamentals and prices is beyond the scope of this report, continued expansion of biofuels production may boost feedstock prices going forward, despite a relative near-term abundance in some commodities, notably corn. Weather patterns add another element of risk. In 2009, the El Niño phenomenon in the Pacific led to simultaneous drought conditions in Asia, while excess rains in Brazil tightened the sugar market and undermined ethanol production there. Moreover, industry consolidation and the fallout from the credit crisis will likely continue to shift capacity in and out of use and raise question marks over the viability of some expansion plans.



Ultimately, much of the industry depends on government support in the form of blending mandates, production subsidies or both. Government policy simultaneously provides a floor for growth and a ceiling to expansion. Notably, the fulfillment of government mandates/targets as they currently stand suggests significant production upside, as graphically depicted in the Policy Targets output trajectory below. Our 2009-2015 production outlook sees 840 kb/d of growth, with 80% from North and Latin America. But this growth undershoots, by 500 kb/d, potential supply increases from meeting national level policy targets in select major biofuels markets.



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

Other government policies, however, act as a potential ceiling. Sustainability criteria in OECD Europe and North America allow blending targets to be met only with biofuels that nominally reduce greenhouse gases (GHGs) relative to fossil fuels. Though curbing greenhouse gas emissions remains a goal in China, biofuels plant approvals there have been low due to food supply concerns. Trade barriers seek to protect the domestic industries of some countries, often on energy security grounds, yet they inhibit rebalancing of supplies towards lower cost producers. Finally, governments play an important role in setting technical specifications and in infrastructure, both of which influence the rise of demand centres, but advances in these areas generally lag production capacity growth.

Future technological and infrastructure developments will guide the industry's ability to meet ambitious usage targets while at the same time fulfilling other policy concerns, with much hope placed on the advancement of second-generation biofuels. Nevertheless, contributions from such biofuels technologies remain small during the forecast period, with capacity potentially only reaching 150 kb/d by 2015.

Key Revisions to the Supply Outlook

An upward revision to 2009 supply of 30 kb/d provides a higher 1.6 mb/d baseline to guide the forecast. The supply growth pattern remains similar to the *December 2009 medium-term updat*e, with the strongest annual increments in 2010 and 2011, followed by declining growth thereafter. We see 2010 production growing to 1.8 mb/d and 2011 supply reaching 2.1 mb/d, on average 90 kb/d higher than predicted in December based on higher than expected production in the US and a capacity reassessment in Brazil.

World Biofuels Production - Changes to December 2009 Forecast

(thousand barrels per day)

	2009	2010	2011	2012	2013	2014
OECD North America	14	60	83	113	145	169
United States	16	59	81	110	141	161
OECD Europe	11	-4	12	19	26	29
OECD Pacific	3	2	1	-1	0	0
Total OECD	**28**	**58**	**97**	**130**	**171**	**198**
FSU	0	0	0	0	0	0
Non-OECD Europe	-2	-1	-1	-2	-2	-2
China	10	7	2	2	3	4
Other Asia	-5	-15	-18	-10	-9	-7
Latin America	1	6	48	58	44	14
Brazil	-12	-3	30	39	22	-10
Middle East	0	0	0	0	0	0
Africa	0	0	1	2	3	4
Total Non-OECD	**4**	**-3**	**32**	**51**	**40**	**13**
Total World	**31**	**55**	**128**	**181**	**211**	**211**

Upward revisions to 2009 stem from higher ethanol output in the US, more favourable estimated biodiesel production in Europe and an upward revision to Chinese ethanol output carried through from 2008. These outweigh somewhat lower Brazilian ethanol production. Other revisions stem from the continued integration of more comprehensive 2008 data from OECD and non-OECD countries alike. We caution that while the quality of biofuels production data continue to improve, with industry data collection and reporting still in its infancy, historical data points remain prone to revision in future.

Revisions pertaining to forward-looking values stem from a reappraisal of our capacity-driven model and expectations of utilisation going forward. Regional forecast revisions are explained in greater detail in the sections ahead. Given their small and fragmented nature compared with oil refineries, biofuels plants remain difficult to track, particularly when they go offline or operate at reduced rates. Though the credit crisis has meant longer time horizons for bringing plants online, smaller overall capital requirements and shorter construction lead times mean biofuels capacity can respond more quickly to changing market conditions. As such, while we conservatively scrutinise future plant assumptions, we may err on the side of allowing potential capacity to grow faster than production.

Regional Outlook and Policies

OECD North America

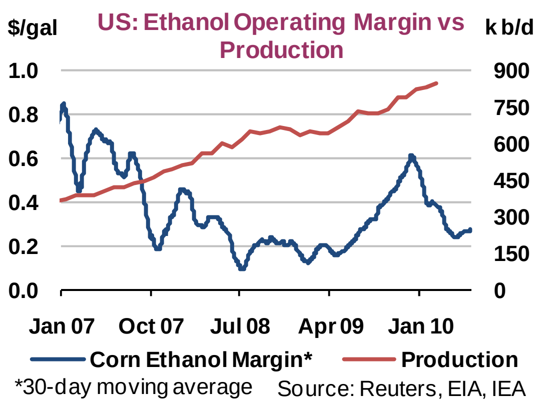
The largest upward revisions to our forecast stem from the US, where ethanol production has consistently exceeded expectations, averaging 700 kb/d in 2009. Steady corn prices, low natural gas prices and increasing ethanol prices allowed producers to enjoy favourable margins in 2009. While the economic crisis caused closures, and industry consolidation continues, overall capacity continues to expand and some idled capacity has been reactivated. Despite low corn prices, margins eroded in 1H10 as ethanol prices fell. Still, ethanol has increased its competitiveness to gasoline, boosting blending incentives - as of late-May, 80% of US conventional gasoline carried some ethanol. Moreover, the industry continues to benefit from a 45 cent/gallon blenders' tax credit.

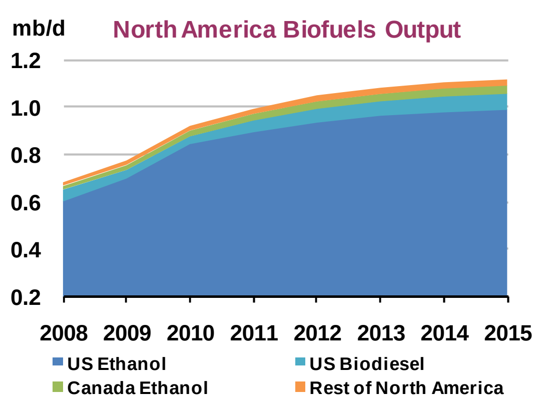
US Renewable Fuel Standard: Mandated Biofuel Volumes
(thousand barrels per day)

	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	16	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	20	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**

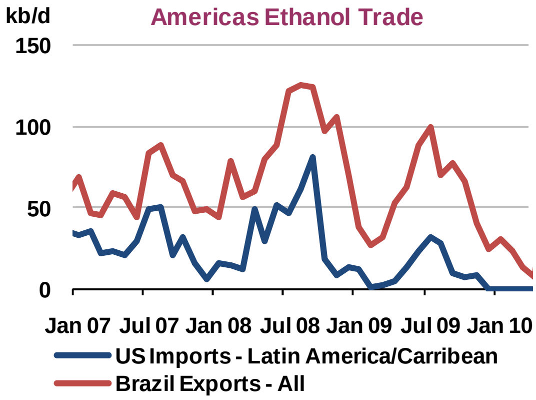
* Biomass-based diesel standard has been combined for 2009/2010

Concerns are growing over how much ethanol can be absorbed into the system as supply growth has outpaced demand. Yet, we forecast higher production over the medium term as prospects for meeting the US Renewable Fuel Standard (RFS) for renewable biofuel (i.e. conventional ethanol) with domestic output have improved. Notably, questions over the viability of most corn ethanol production on environmental grounds have been assuaged. In February, the US Environmental Protection Agency (EPA) issued its final rule on biofuels sustainability under the RFS, acknowledging that dry mill corn ethanol production (bar that using coal power) meets the required 20% GHG reduction compared to petroleum fuel.





The 'blend wall' - the 10% technical limit for ethanol in gasoline for conventional vehicles - represents another barrier. Measured against our US gasoline demand forecast, ethanol production, at 895 kb/d, should reach 10% by volume of gasoline demand in 2011 and the most saturated markets in the Midwest may already be hitting this wall. One relief valve would be for the EPA to approve a 15% blend, a decision on which is expected this summer. While the outcome remains uncertain, we assume for this forecast that the higher blend will be allowed for at least post-2000 vehicles. Any such approval is unlikely to cause a near-term surge in ethanol absorption – subsequent supply chain and air quality issues will still need resolution. Nevertheless, the higher blend and increased export oppportunities should provide enough outlets for supply over the medium term. Moreover, with automakers signalling production increases, a growing US flex-fuel vehicle fleet (which can use 85% ethanol blends) should provide another absorption mechanism, albeit from a low base and limited by E85 fuel pump availability.

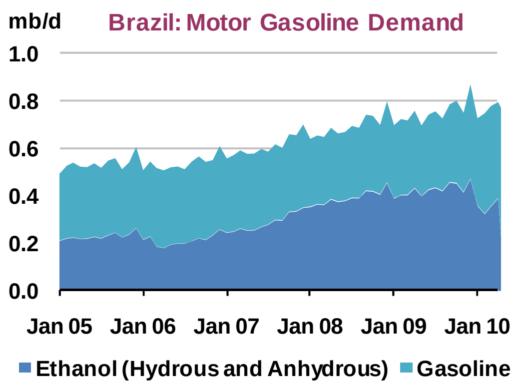


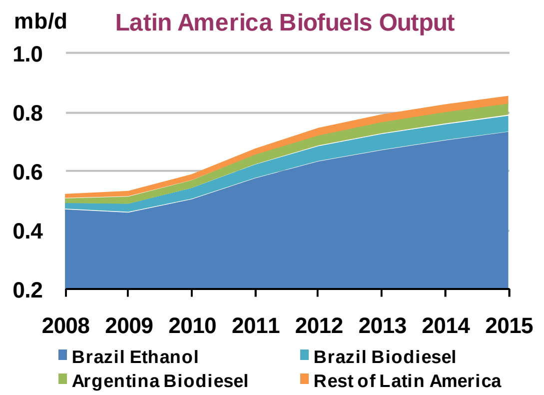
Bigger question marks remain over the Advanced Biofuel portion of the RFS which sees increased biodiesel and cellulosic biofuel, but may also include other biofuels, so long as they achieve at least a 50% reduction of GHGs versus petroleum fuel. For cellulosic ethanol, while prospects have improved, lack of commercially available capacity will plague RFS requirements going forward (see *Second-Generation Biofuels Hold Promise, But Capacity Remains Low*). For biodiesel, the industry remains under duress with reduced export opportunities to Europe and the lapse of a $1.00/gallon blenders' tax credit (though this tax credit may be reinstated per a pending bill in the US Congress). Still, persistence of the blending mandate supports our rising biodiesel production forecast (to 70 kb/d in 2015), given that the capacity is available. Additional advanced biofuel could be sourced from imported sugar cane ethanol, for example, but economics will remain difficult so long as the US maintains a 54 cent/gallon import tariff on most foreign supplies.

Latin America

After a disappointing 2009, Brazilian ethanol prodution should rebound over the medium term. Credit constraints forced producers to sell ethanol to generate cash early in 2009, leaving stocks lean. High sugar prices combined with heavy rains in the Centre-South region to damp production in 2H09 and caused hydrous ethanol prices to climb above energy parity with gasoline in most regions. To stem rising fuel costs, the Brazilian government ordered a reduction in anhydrous ethanol blended in the gasoline pool to 20% in February of this year, reinstating the previous 25% blend in May.

The industry remains fragile in the wake of the credit crisis, but consolidation and investment from larger players such as Petrobras, BP and Shell has helped shore up its financial position. A new government loan scheme aims to help smaller producers cover day-to-day costs and the government has approved inter-mill ethanol trade, both of which should smooth supply. Increased domestic demand will drive production growth in 2010 with continued capacity expansion and exports helping to guide supplies over the medium term. With flex-fuel vehicles comprising over 90% of auto sales, ethanol, on an energy adjusted basis, should satisfy over half of Brazil's gasoline demand growth from 2009-2015 and should rise, on a volumetric basis, to over 60% of the gasoline pool by 2015.

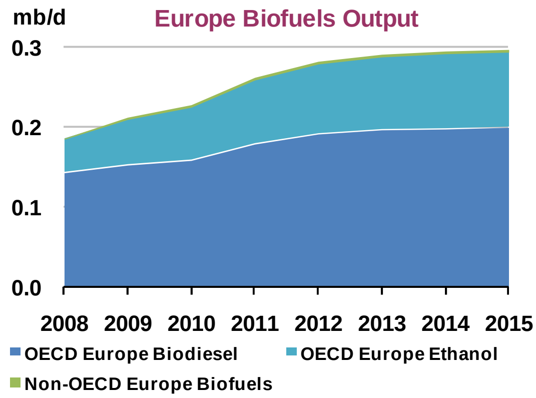


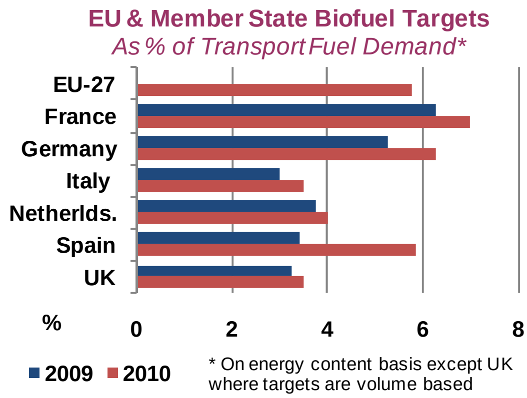


Other Latin American biofuels sectors are poised for growth as well. Increased export opportunities to Europe, the introduction of a 5% domestic blending mandate in 2010 and plans to eventually reach a 10% blend have lifted Argentina's biodiesel production profile. Brazil has also introduced a 5% biodiesel blending mandate and domestic usage should grow based upon rapidly increasing gasoil consumption. Meanwhile, ethanol blending mandates in Colombia, Ecuador and Peru should underpin regional biofuels production growth as well.

OECD Europe

Production prospects in OECD Europe have also improved over the past year, though the region only accounts for 10% of global growth during 2009-2015. The EU maintains a target of 5.75% renewable fuels, by energy content, in the transport pool by 2010 and a 10% renewable energy mandate for 2020. Favourable wheat and sugar beet ethanol margins led to growing regional ethanol output in 2009, with further increases expected in 2010 and beyond. Some large ethanol capacity additions over 2010 and 2011 drive the forecast. Abengoa recently started its 8 kb/d (480 ml/y) plant in the Netherlands; in the UK, Ensus started a 7 kb/d (400 ml/y) distillery in December 2009 while Vivergo plans to bring a 7 kb/d (400 ml/y) plant online by early-2011.



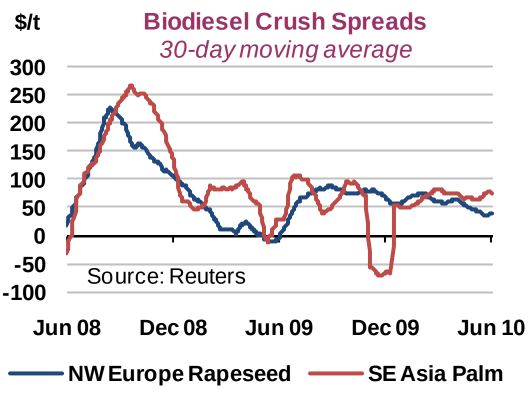


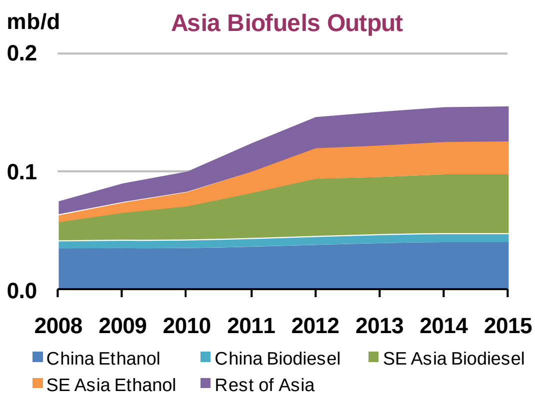
Europe's rapid biodiesel growth slowed in 2009 on overcapacity and faltering economics, particularly in Germany and Italy. Though output grew in Spain, the industry there also remains burdened by overcapacity. Despite Europe's short middle distillate position, with regional refineries unable to meet diesel demand, domestic biodiesel's generally unfavourable price competitiveness versus imports (of both diesel and biodiesel) weighs upon utilisation rates. Still, the regional outlook is better overall versus our last forecast, with the 2009 baseline revised up 10 kb/d and mandates driving growth over the medium term. Yet, the presence of more competitive imports remains a challenge for European producers going forward. In 2009 the EU imposed import duties to stem the practice of foreign supplies emanating from the US and benefitting from a tax credit after blending with a small amount of diesel (so-called 'splash and dash'). In theory, the trade action should have improved the production position of domestic European producers. Rather, more competitive biodiesel from other regions, particularly Argentina, simply filled the gap.

Still, market access for imports remains uncertain over time. The EU's Renewable Energy Directive requires that biofuels must generate GHG savings of at least 35% versus fossil fuels starting at end-2010 to count towards targets; these savings rise to 50% in 2017 and 60% in 2018. Current EU default values put rapeseed biodiesel, which accounts for most European production, above the 35% threshold and soybean and palm based biodiesel, primary sources for imports, below it. Though actual soy and palm biodiesel production may achieve higher GHG savings, such volumes would require certification, which itself may represent a potential hurdle. Moreover, supply challenges for foreign and domestic producers will likely increase when calculations take indirect land use change into account. A recent European Commission-funded study assessed that of the 10% renewable fuels target in 2020, first-generation biofuels (with a significant Brazilian ethanol component) could meet 5.6%, since negative environmental impacts, including indirect land use change, would increase at concentrations above that level. Currently underdeveloped second-generation biofuels would thus be important in filling the gap.

Asia-Pacific

Though benefitting from a higher baseline in 2009, the Asia biofuels production outlook is less optimistic than in the December update. Higher 2009 production stems from an upward revision to Chinese ethanol carried through from 2008 and smaller upward biodiesel revisions in Korea and Indonesia. China continues as Asia's largest producer and as the world's third biggest ethanol source. But its growth is limited over the forecast period given the Chinese government's strategy of restricting additional ethanol production to non-grain sources, such as cassava.





Despite a downward revision to expected output in 2010 and 2011, Thailand holds the region's most promising growth potential, with ethanol – largely from molasses and cassava – and biodiesel – largely from palm oil – increasing over the medium term. Thai government policy for biofuels has been supportive, with 10%, 20% and 85% ethanol blends all on offer and plans to increase the current 2% biodiesel blending mandate to 3% in June 2010 and to 5% by 2012. By comparison, India's support of its biofuels industry remains more fragmented. Despite the nominal implementation of a

5% ethanol blending mandate and a target of 20% for biofuels in transport fuels by 2017, the sector's expansion looks tenuous, stymied by an unfavourable domestic pricing system and recent high sugar prices. The government has proposed an increase to the price of ethanol that refiners pay to sugar mills, which may help boost production, though a market based pricing strategy would better help in balancing supply and demand.

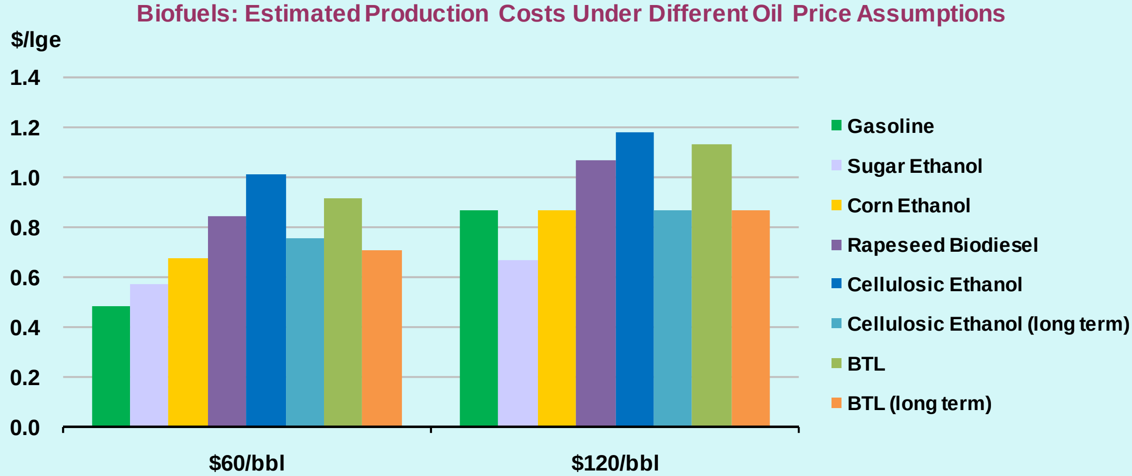
Biodiesel export potential in Indonesia and Malaysia remains strong, but barriers to palm based supplies in Europe suggest that domestic demand must be stimulated. Malaysia has introduced a 5% biodiesel mandate for 2011. Yet, doubts remain over its implementation – consumers there have enjoyed subsidised fuel prices and the programme's success may hinge on the government's ability to pass the higher fuel costs on to oil companies. Indonesia has plans to increase its biodiesel usage over time, from a current 2.5% biodiesel blend in diesel. Yet, a 5% mandate is not envisaged until 2015 and overall plant utilisation remains low. Finally, the startup of Neste's biomass-to-liquids plant by end-2010 should boost Singapore's production. Still, reduced export opportunities for other plants may limit overall capacity utilisation here as well.

Second-Generation Biofuels Hold Promise, But Capacity Remains Low

Meeting OECD targets for greater biofuels use will require increased volumes of second-generation fuel. While in the US this requirement is explicit and rises over time, in Europe it is implied through sustainability criteria with increasing GHG thresholds. Second-generation biofuels generally derive from cellulosic (non-food) sources and provide greater GHG savings than most first generation supplies, which come from food crops. Yet, they face higher technology, feedstock and cost hurdles, which have thus far limited commercial development.

A dramatic investment push may surmount those hurdles. The US government has approved $800 million for funding biomass projects, many of them involving second-generation biofuels. Governments in Canada, Australia and Europe are pushing forward with support measures. Integrated oil companies have also entered the fray, with investment commitments made by players such as BP, Shell and Exxon-Mobil. Still, companies continue to target a variety of outputs, ranging from biobutanol to algae-derived biodiesel. To date, no 'winning' technology, i.e. one that could significantly scale up in a cost-effective manner, has emerged.

Biofuels: Estimated Production Costs Under Different Oil Price Assumptions



Source: IEA Mobility Model
lge = litre of gasoline equivalent

Second-Generation Biofuels Hold Promise, But Capacity Remains Low (continued)

Developments in cellulosic ethanol and Fischer-Tropsch biodiesel, or biomass-to-liquids (BTL), technologies look most promising. In the former, which aims to produce fuel from waste materials, grasses, wood and corn cobs, progress has come from reducing the costs of enzymes for breaking feedstocks into fermentable sugars. Successful demonstration projects have emerged such as DONG Energy's 5 ml/year straw-fed cellulosic ethanol plant in Denmark. POET, a large US ethanol producer developing a 95 ml/year plant, recently announced it had brought cellulosic ethanol costs down to within $1/gallon (~$0.26/litre) of its corn ethanol. On the BTL side, Choren completed a 17 ml/year plant in Germany in 2008, but has still not commenced commercial production.

Overall, commercial production has yet to take hold for second-generation biofuels and is unlikely to significantly do so during the forecast period. Higher oil prices may ultimately provide the most effective route for scaling up over the medium to long term – cost data from the IEA Mobility Model show cellulosic ethanol and BTL approaching fossil fuel competitiveness at $120/bbl (real). Still, even with high fuel prices, considerable difficulty remains in sourcing and moving feedstock.

With a flurry of activity in second-generation, capacity forecasts remain difficult and estimating production presents a greater challenge. To illustrate, the US EPA downgraded its 2010 requirement for cellulosic biofuel blending from 100 to 6.5 million gallons due to delays and cancellations among projects supporting the original standard. Our assessment sees 150 kb/d (about 9 bn litres/year) of potential global second-generation capacity in 2015 based upon announced plans and plants under construction. Second-generation ethanol represents 55% of this, while 45% comes from second-generation biodiesel. However, given the volatile nature of second-generation development many of these facilities will likely experience delays and cancellations beyond those we have assumed. Plants that do come online may operate at rates far below capacity. As such, actual production volumes over the medium term should remain small.

CRUDE TRADE

Summary

- **Global inter-regional crude trade is expected to rise by a robust 3.2 mb/d during 2009–2015**, equating to 1.5% compound annual growth, and taking the 2015 level to 36.5 mb/d. Compared with the June 2009 *MTOMR*, the outlook is brighter, with both annual growth and end-forecast supply estimated significantly higher. This stems from two factors – an inordinately low 2009 baseline and improved demand prospects.

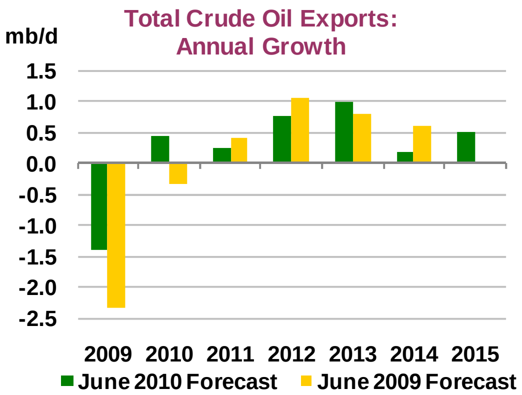
- **The trade in crude oil will become more globalised** as suppliers diversify into new markets. Latin America makes inroads into Other Asia and China, and the FSU will open up new eastward routes into the Pacific Basin. Despite this, the Middle East remains the key crude exporting region, with volumes set to grow from 15.9 mb/d in 2009 to 17.4 mb/d in 2015.

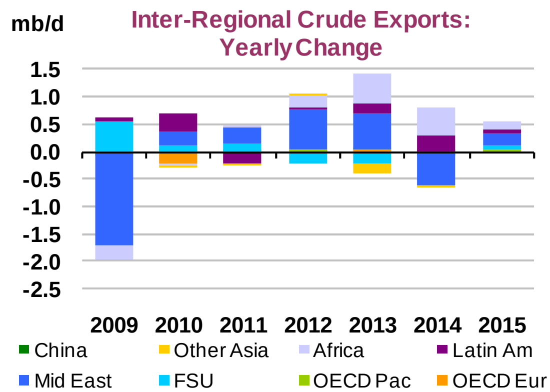
- **The non-OECD is expected to absorb all incremental supply** over the forecast, with annual growth of 5.1%. China and India will drive this trend, with China in particular expected to raise imports by 9.2% annually from 2009 - 2015. In comparison 0.7% annual decline is expected in the OECD, with only OECD Europe set to see growth in response to falling domestic production.

Overview and Methodology

As in previous exercises, crude oil trade has been modelled as a function of oil production capacity and demand growth, incremental supplies being allocated on the basis of projected refinery expansions. On this basis, during 2009–2015 exports of crude oil are estimated to increase by 3.2 mb/d to 36.5 mb/d, equating to 1.5% annual growth. This compares with June 2009 *MTOMR* growth of 0.1% annually. This difference stems from the relatively low 2009 baseline of 33.4 mb/d, characterised by depressed demand and OPEC production cuts, therefore leaving more potential for future export growth. Compared to last year, the short-term outlook is also now seen brighter since the economic recession has proved less long-lasting than initially expected, albeit uncertainties remain. Global crude trade in 2014 is now seen stronger at 36.0 mb/d versus last year's estimate of 35.4 mb/d.

Crude oil trade is expected to become progressively more globalised with new long haul routes growing in importance as swing producers, notably the FSU and Latin America, increasingly turn their attention to diversifying exports towards Asia. The Middle East will remain the key oil exporting region, supplying 17.4 mb/d in 2015 and retaining its existing dominant crude trade position with a 47.6% share. However, a subtle shift is expected, with Africa set to become the second largest supplier on a global level and increasing its market share by 1.8% to account for 23.8% of global exports by 2015. This rise is notably at the expense of the third largest supplier, the FSU, which sees its share of the market cut by 2.0% to 18.3% during 2009 - 2015. Latin America is also expected to increase its market share by 1.8% to 7.1% with other regions accounting for a combined 3.2% (-1.5% over the forecast). In 2010 the bulk of regional export growth is expected to come from Latin America (+ 360 kb/d from 2009) but with increasing growth expected from Middle Eastern and African suppliers thereafter, a notable exception is 2014 where a dip in growth is expected in the Middle East, as the region sees significant new refining capacity commissioned.



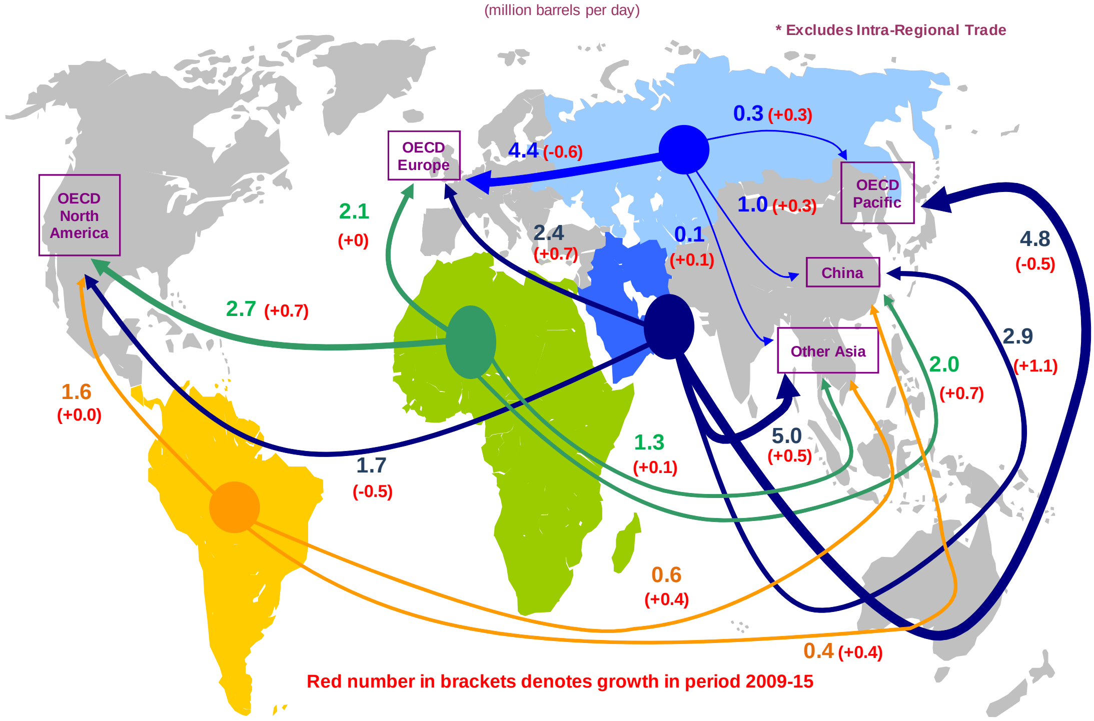


Regional Trade

The Middle East retains its role as swing supplier, with output expected to reach 17.4 mb/d by 2015. This represents a rise of 1.5 mb/d from recessionary 2009 levels, unsurprising given that the region bore the brunt of OPEC production cuts, but a more muted export rise of 200 kb/d versus 2008. All incremental production from the region heads to Asia. Other Asia consolidates its position as the largest buyer of Middle Eastern grades, importing 5.0 mb/d by 2015 (+460 kb/d from 2009). The strongest growth in imports of Middle Eastern grades is expected to come from China, where an extra 1.2 mb/d is projected in 2015. Unlike last year's exercise, OECD Europe imports 730 kb/d more Middle Eastern crude by the end of the forecast, stemming from a need to offset both declining domestic production and lower imports from the FSU. The traditional markets of the OECD Pacific and OECD North America will cut their demand for Middle Eastern grades by 500 kb/d each, although the OECD Pacific remains the Middle East's second largest customer, importing 4.8 mb/d in 2015.

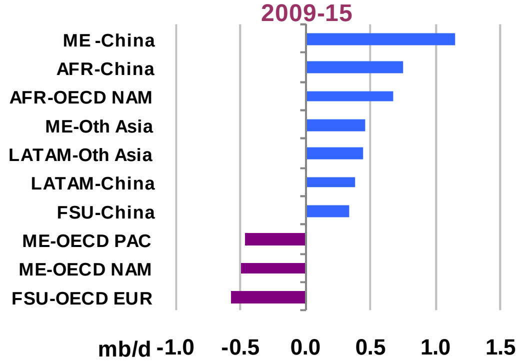
Crude Exports in 2015 and Growth in 2009-15 for Key Trade Routes*

(million barrels per day)

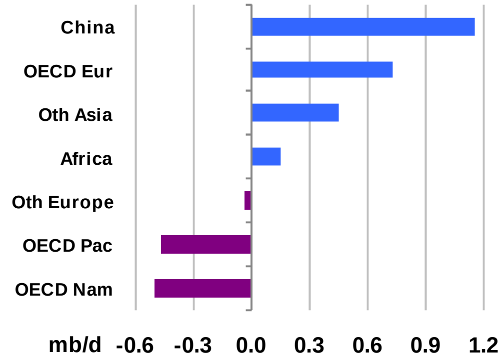


Africa will become an increasingly important swing supplier over the forecast. Compound annual growth of 2.8% and exports of 8.7 mb/d by 2015 are estimated. Incremental production should be absorbed by OECD North America and China, both of whose imports increase by around 700 kb/d during 2009-2015. OECD North America will continue to be the largest customer for African crude with imports set to reach 2.7 mb/d by 2015. In the face of diminishing supplies of US onshore, light, sweet crudes, US Gulf Coast refiners may seek alternative, similar quality African supplies. Exports to OECD Europe are projected to remain static at 2.1 mb/d, with Other Asia set to rise by a modest 100 kb/d.

Inter-Regional Export Growth 2009-15

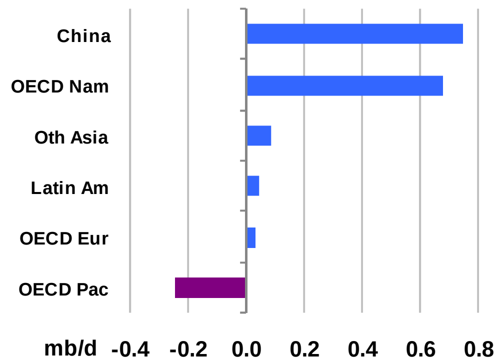


Middle East Export Growth 2009-15

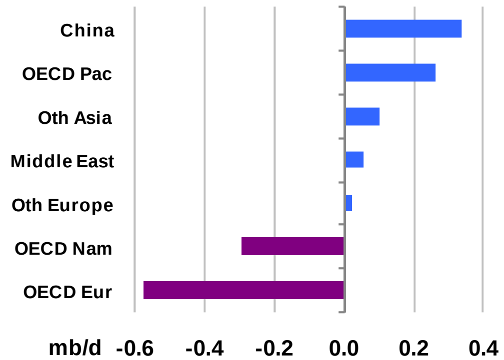


FSU exports are expected to fall by 100 kb/d during 2009 – 2015 overall, despite initially rising during 2009-2011 by 270 kb/d. In contrast to the previous outlook, the FSU will diversify its exports with new eastward routes to Pacific markets. These trades could displace around 0.6 mb/d of existing deliveries into OECD Europe. Although eastbound volumes remain minor compared to those heading west, they fulfil a dual Russian aim of minimising reliance on transit countries and targeting lucrative Asian growth markets. Instrumental in this is the recently inaugurated East Siberia to Pacific Ocean (ESPO) pipeline which also facilitates the development of new east Siberian reserves. Cargoes from the Kozmino leg of the pipeline will likely be sold spot, rather than on a contract basis, allowing flexible sales to a variety of Asian customers and potentially the Americas. Russian exports to China will likely be more stable and sold on a contract basis or through swap deals with 300 kb/d expected via ESPO. Total FSU exports to China are seen at 1.0 mb/d. The Caspian region is also expected to significantly boost exports, notably when the giant Kashagan field starts up in late 2013, with a large proportion likely absorbed by China. Nonetheless, OECD Europe retains its position as the main destination of FSU crudes with 4.4 mb/d anticipated in 2015.

Africa Export Growth 2009-15

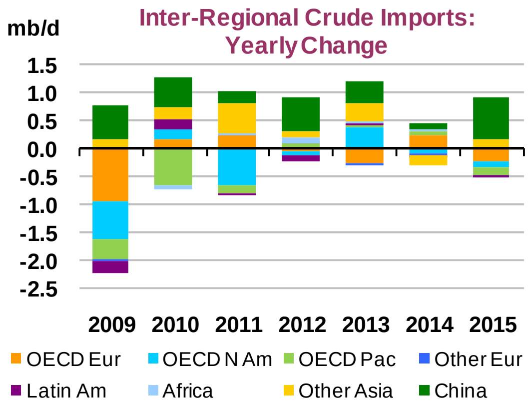


FSU Export Growth 2009-15



Latin America is projected to display the strongest growth globally, at 6.7% annually over the forecast. Total exports should rise from 1.8 mb/d in 2009 to 2.6 mb/d in 2015. All of the incremental production will be absorbed by Asian countries, where the addition of complex refinery capacity will facilitate processing heavy Latin American grades, notably from rising Venezuelan production expected to come on-stream late in the forecast. Other Asia, notably India, has already started to take Latin American cargoes and by 2015 could import 550 kb/d, while China is expected to take regular shipments from 2012, ramping up to 400 kb/d by 2015. The diversification of markets will stem from various factors. Production from Colombia, Brazil and Venezuela is expected to rise over the forecast period and at the same time expansion of the Panama Canal to take larger carriers will reduce shipping times and improve the profitability of cargoes into Asia. Latin American suppliers will also likely have to look further afield since exports to the traditional destination of the US could stagnate at 1.6 mb/d over the medium term. It is anticipated that US refiners will increasingly look to imports of Canadian oil sands which could replace heavy Latin American grades.

Non-OECD importers are forecast to enlarge their share of global imports from 35.1% in 2009 to 43.2% in 2015. Imports grow from 11.7 mb/d in 2009 to 15.8 mb/d in 2015, representing annual growth of 5.1%. China and Other Asia will drive this trend by absorbing incremental production. China's imports should dramatically climb from 3.7 mb/d in 2009 to 6.4 mb/d in 2015, equating to +9.2% on a compound annual basis. On the same basis, Other Asia is projected to have annual growth of 3.1% as imports climb from 5.9 mb/d to 7.1 mb/d. Largely unaffected by the recession, imports into China and India rose by 600 kb/d and 100 kb/d respectively in 2009.



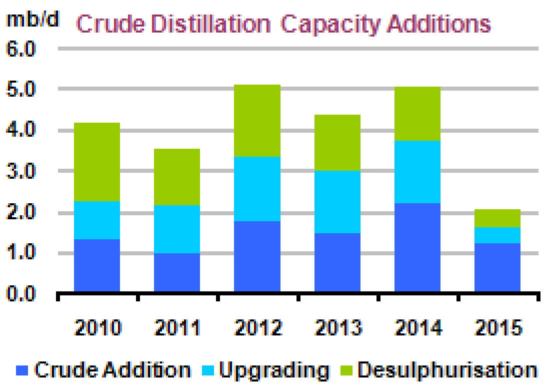
The OECD, in response to falling demand, is expected to reduce its absolute imports over the forecast by an average of 900 kb/d to 20.7 mb/d by 2015, representing annual decline of 0.7%. However, the picture is mixed with the OECD Pacific and OECD North America set to decline by 700 kb/d and 370 kb/d, respectively, while falling domestic production sees import requirements into OECD Europe rise by 170 kb/d during 2009–2015.

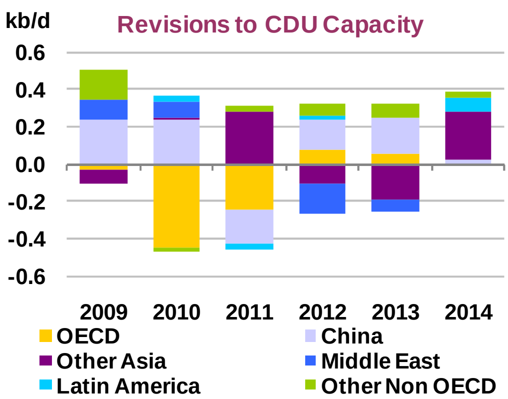
The dirty tanker market is expected to be underpinned by this globalisation over the medium term and partly allay fears of significantly depressed freight rates in the face of a looming oversupply of tankers ordered pre-recession. The trend of increasing long-haul voyages, especially cross-Pacific, is expected to increase average journey times and therefore tie-up tonnage for longer. Additionally, the construction of extra, export-orientated refining capacity in Asia, notably India, is expected to support the clean tanker market over the medium term.

REFINING AND PRODUCT SUPPLY

Summary

- **Global refinery crude distillation (CDU) capacity is expected to increase by 9.0 mb/d from 2009 to 2015**, an average annual addition of 1.5 mb/d, to reach 99.8 mb/d in 2015. The largest increase comes from China, where 3.3 mb/d of distillation additions are likely, followed by Other Asia, the Middle East and Latin America. In the OECD, capacity rationalisation has started, with a total 1.4 mb/d removed over 2009-2011, and we expect this figure to increase as refiners continue to react to poor economics, and further closures are announced.





- **Refinery capacity additions outpace expected demand growth in the 2010-2015 period,** potentially adding 4.8 mb/d of spare capacity to an already large surplus. Refinery throughputs are set to meet only 62% of forecast demand growth (of 7.1 mb/d) for the period, as increased biofuels supplies, NGLs bypassing the refining system and coal- and gas-to-liquids are expected to add a combined 2.6 mb/d to product supplies.

- **Global refinery utilisation rates are seen declining over the medium term, to average 78% of capacity in 2015**, compared to 84% in 2008, and an estimated 81% in 2009. Although OECD refineries sustain higher operating rates than in previous assessments, this in part reflects capacity reductions. Operating levels are nevertheless expected to remain at suppressed levels throughout the forecast period, unless more capacity is removed. Non-OECD refiners will likely sustain higher utilisation rates. Here too, less complex plants face competition for crude and markets from new, more sophisticated or strategically operated facilities.

- **Oil product balances have changed significantly since the June 2009 MTOMR,** but more so due to revised oil product demand and upstream supply side fundamentals than a changed view of the refinery sector. Global balances now point to the potential for a significant, and increasing, surplus of light distillates, tightening middle distillates supplies, and a more balanced fuel oil market in the years ahead.

Refinery Investment Overview

Global refinery expansion plans are expected to add 9.0 mb/d of crude distillation (CDU) capacity by 2015. More than one third of the growth comes from China, which is adding almost 3.3 mb/d in the forecast period, followed by 1.5 mb/d of new capacity in Other Asia, 1.4 mb/d in the Middle East and just over 1.0 mb/d in Latin America. Refinery investment decisions in the main growth areas often have strategic, rather than purely economic, motivations. The 2009-2014 crude distillation capacity forecast has been revised higher by 670 kb/d since the *December 2009 medium-term update*. Lower estimates for the OECD, where the closure of several refineries has been included, are more than offset by stronger additions expected in the non-OECD, particularly from China and Other Asia. Refiners are also investing to satisfy a lighter, lower sulphur demand barrel. Upgrading capacity and desulphurisation investments add respectively 7.0 mb/d and 8.2 mb/d by 2015. The global upgrading ratio (cracking/distillation) therefore increases from 0.41 to 0.47 over the forecast period.

Global Crude Distillation Capacity

(million barrels per day)

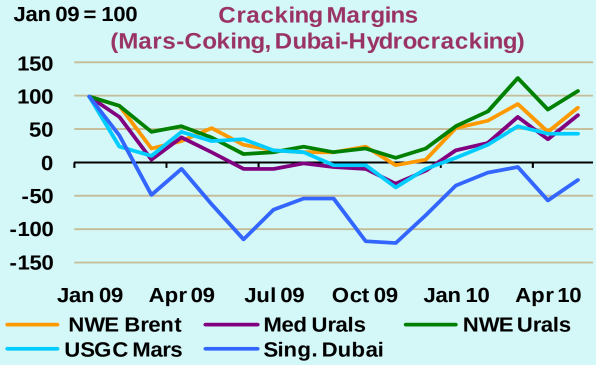
	2009	2010	2011	2012	2013	2014	2015	2015-2009
OECD	45.3	45.4	45.4	45.9	46.0	46.0	46.1	0.8
FSU	7.8	7.9	7.9	8.3	8.4	8.4	8.4	0.6
China	9.1	10.1	10.1	10.5	11.3	11.9	12.4	3.3
Other Asia	10.4	11.1	11.1	11.2	11.5	11.8	11.9	1.5
Middle East	7.8	8.1	8.1	8.2	8.2	9.0	9.2	1.4
Other Non-OECD	10.3	10.5	10.5	10.8	11.0	11.4	11.8	1.5
World	**90.8**	**93.1**	**93.1**	**94.9**	**96.4**	**98.6**	**99.8**	**9.0**

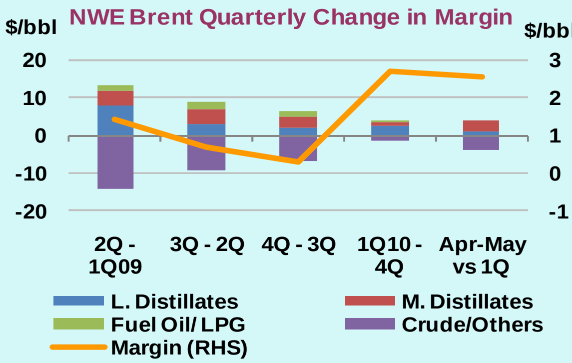
The largest risk to our forecast revolves around our assumption for **Chinese** expansions. Industry estimates for capacity growth vary considerably, with some assessements as high as 5 mb/d, equivalent to a 50% increase in total capacity, by 2015. Visibility on the status of proposed projects remains opaque, and the increased internal competition by main players and new entrants results in a flurry of project proposals competing for government approval and market share. Although it is hard to discern which refineries will be built within the timeframe and which will be delayed or shelved, we assume that Chinese expansions will be motivated by securing product supplies to meet domestic demand growth for distillate products, thereby limiting product imports. Of course, should demand growth prove less strong than currently projected, refinery additions might also be lower.

Other Asian capacity expansions are dominated by growth in India, which account for 71% of regional increases. The Indian government's objective of ensuring that India's oil product demand growth is met at affordable prices over time as well as establishing India as a major global refined product exporter, drive expansions. Other additions come from Vietnam, where two further grassroots refinery projects are now seen likely, although we recognise the risk of these slipping beyond 2015. Growth in **Middle Eastern** refining capacity is heavily biased towards the end of the forecast period, with the expected commissioning of two mega projects, namely Jubail in Saudi Arabia and Ruwais in the UAE, adding some 800 kb/d of capacity in 2014. While substantial capacity is added in **Latin America**, driven by Brazil, the region's oil product import needs will rise as additional supplies fall short of projected product demand growth. The same is true for **Africa** where, although a multitude of refinery projects have been proposed, few make it past planning stage, due to financing, political or other problems.

Refining Margins Trending Higher

Refining margins in 2010 have bounced back from the recessionary lows that prevailed for much of 2009. However, profitability remains strained and well below the comparatively heady levels evident in several years from mid-decade in the run-up to the mid-2008 crash. While utilisation rates in North America, in particular, have recovered in recent months, we envisage OECD margins and throughput remaining under pressure from the impact of major refinery expansions East of Suez and a growing proportion of oil demand growth met from outside the refining system (biofuels, NGL and non-conventional supplies).

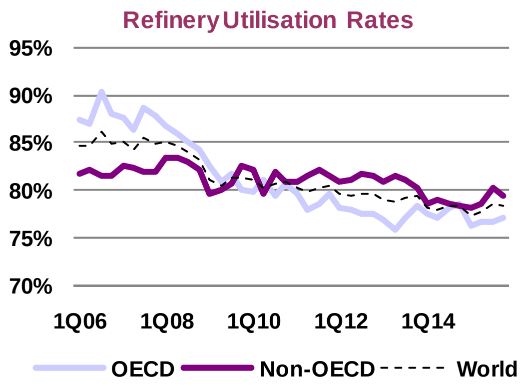


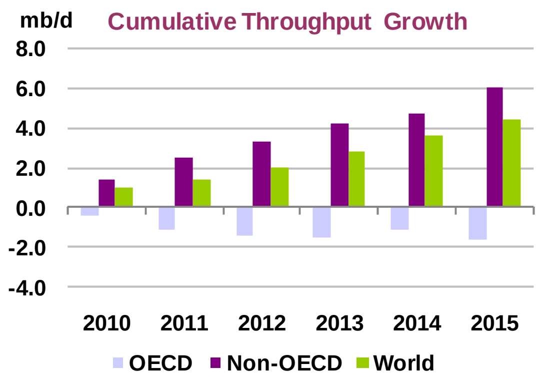


Already very low at the time of the June 2009 *MTOMR*, margins dropped further to a low-point around November 2009, forcing OECD refiners to cut runs to levels around 78% utilisation, 9 percentage points below the 2004-2008 average level. This followed OECD distillate stocks reaching record highs at 38.7 days of cover in August 2009 and gasoline at 27.5 days in September. Since November 2009, however, margins have recovered some lost ground, reaching a high point in March 2010 on revitalised gasoline and distillate markets, as global maintenance activity was it its highest, and before intense Eurozone financial concerns took hold. However, among the benchmark margins, only European Urals cracking has regained January 2009 levels, with the rest still having some ground to recover, particularly in Asia where margins have remained well below earlier levels.

Refinery Utilisation and Global Throughputs

Global refinery utilisation levels are seen declining over the medium term, to average 78% of capacity in 2015, compared to 84% in 2008, the last year for which annual throughput data are available, and 81% in 2009. Crude distillation capacity additions continue to outpace global demand growth, which is also increasingly met by supplies from other sources (such as biofuels, NGL volumes bypassing the refinery system and gas- and coal-to-liquids). Compared with the *June 2009 Medium-Term Oil Market Report*, utilisation rates for the OECD are seen higher overall, while those of the non-OECD generally trend flat at around 80%. The changes are less about different operating levels *per se* and more due to a lower capacity assessment for the OECD, following refinery closures, and significantly higher capacity additions for the non-OECD (partly reflected in the *December 2009 medium-term update,* and discussed above). As before, we assume that utilisation rates in the mature markets of the OECD will remain weak until further capacity is shut, while non-OECD, and in particular the strong demand growth centres of the Middle East, China, and Latin America, manage to keep rates relatively stable. In Other Asia, where significant capacity is added, not always for purely commercial reasons, we assume less complex refiners will struggle to source crude supplies and markets for their output, resulting in slightly lower utilisation rates.





In volumetric terms, however, after contracting by 1.8 mb/d in 2009, global refinery throughputs are expected to grow by 4.5 mb/d from 2009 to 2015. Of this, roughly 30% is expected to come from increased condensate supplies, processed in dedicated splitters or in traditional refineries, blended into the crude feedstock. Throughput growth is wholly accounted for by the non-OECD, with 42% of non-OECD growth stemming from China, 21% in other Asia followed by 17% in the Middle East. OECD throughputs are currently seen contracting by 1.6 mb/d for the forecast period, concentrated at the front-end of the period.

In order to bring global operating rates back to 85% utilisation, the average seen in 2006-2008, and a level widely considered sufficient to support refining margins, more than 7 mb/d of capacity would have to be shut, or not built by the end of the forecast period. The shutdowns are more likely in mature markets, notably the OECD Pacific, OECD Europe and, to a lesser extent, OECD North America. Some closures, or project delays, will also likely be seen in Other Asia. Not explicitly included in this assessment is the assumed closure/mothballing of small independent refiners in China. To increase the competitive position of its refining industry, the Chinese government plans to shut down refineries with capacities below 20 kb/d, mainly in the Shandong region. Independent refiners are estimated to have run only around 20% of capacity in 2009.

Product Supply Balances

Oil product balances look dramatically different from the outcome published in the *June 2009 MTOMR*. The changes stem less from modifications to our assumptions for the global refining system, and more from significant revisions to the supply and demand outlooks from one year ago. The large potential deficit in fuel oil highlighted in last year's report has all but vanished. Gasoline and naphtha look increasingly tended towards over-supply. Meanwhile, despite extensive upgrading capacity additions, middle distillate supply potential again proves to be a bottle-neck compared to the preponderance of demand growth for these products. A degree of mismatch between the types of planned upgrading capacity additions and the evolving demand slate is therefore evident.

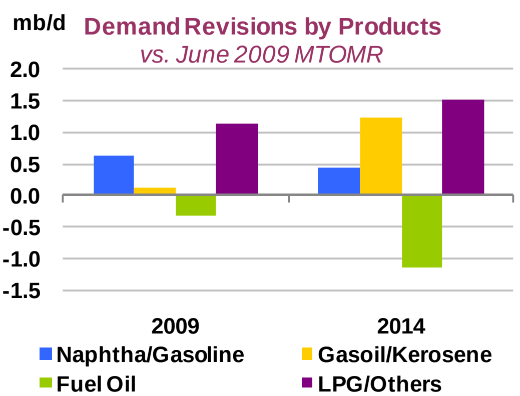
Not only has 2014 global oil products demand estimates been revised up by 2.0 mb/d since last year's *MTOMR*, non-OPEC supplies have also been revised higher by a total of 2.3 mb/d in 2014. Behind the two seemingly offsetting factors, however, changes within demand and supply have significant implications for product supplies. Demand gains are heavily biased towards stronger middle distillates (+1.2 mb/d), while gasoline (partly masked by stronger naphtha) and fuel oil demand are sharply lower towards the end of the forecast period (by -0.6 mb/d and -1.2 mb/d, respectively).

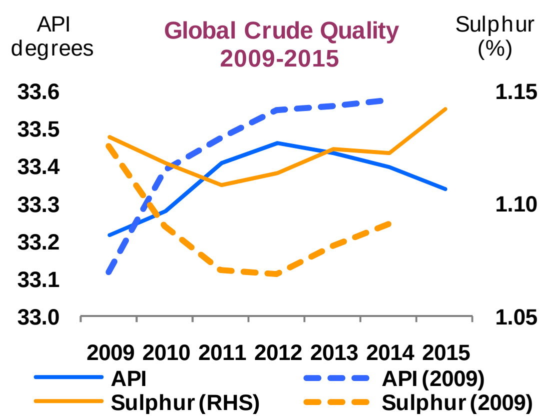
Products Supply Modelling – Seeking the Pressure Points

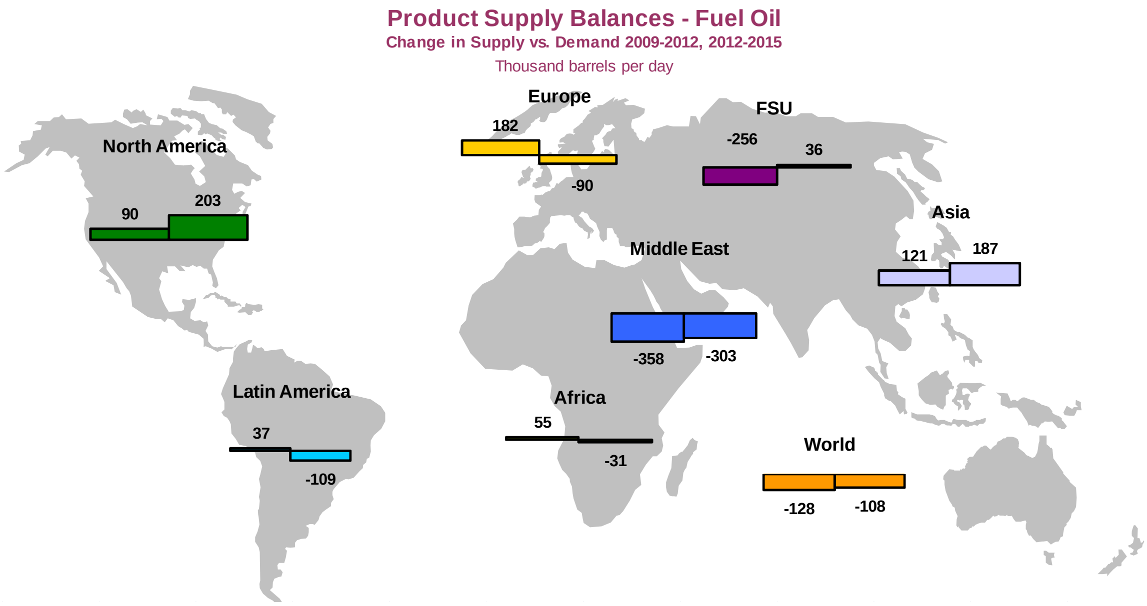
Our approach to modelling refined product supply is not designed to optimise the global/regional system, rather to highlight where pressures may emerge within that system in the 2010-2015 period. A number of simplifying assumptions underpin the analysis, changes to any one of which would generate a significantly 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 expected pattern of demand growth, with expected changes in crude feedstock quality. 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. 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.

Feedstock supply side revisions are dominated by higher Canadian oil sands supplies, these being 430 kb/d higher than last year's 2014 estimate, with further growth of 460 kb/d seen in 2015. Stronger-than-expected Russian crude volumes, as well as the additions of heavier Colombian crudes towards the end of the forecast, further contribute to a heavier, more sour feedstock base for refiners post-2011/2012. A higher Venezuelan upstream capacity assessment from 2014 onwards also translates into more heavy OPEC supplies, as we continue to assume that total OPEC supplies are controlled to balance product demand, and that core producers (Saudi Arabia, Kuwait and the UAE) act as swing suppliers.

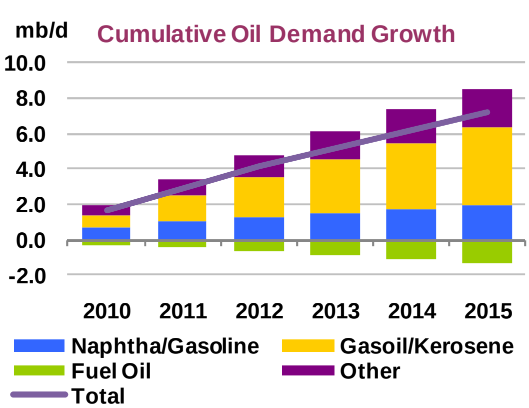
The most significant outcome of the changes above is that the huge potential fuel oil deficit we outlined last year has all but vanished. Fuel oil now looks more balanced, with a tightening in the Middle East mostly offset by increased potential surplus from Asia and North America. The assumption that OPEC will disproportionally restrict the production of heavy/sour crude to balance the market obviously has an impact. The Middle East is shown to generate the largest fuel oil deficit in the medium term, as demand remain robust, while supplies dwindle due to lighter feedstock and significant investment in upgrading capacity. The region is already increasingly replacing fuel oil for power generation with direct crude burning, in part reducing import needs. Fuel oil balances in the Former Soviet Union (FSU) are expected to tighten in the near-medium term (2009-2012), as refinery investments boost light product yields, but then stabilise towards the end of the forecast period.

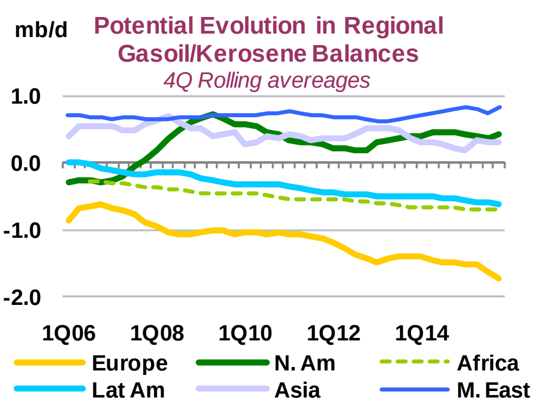


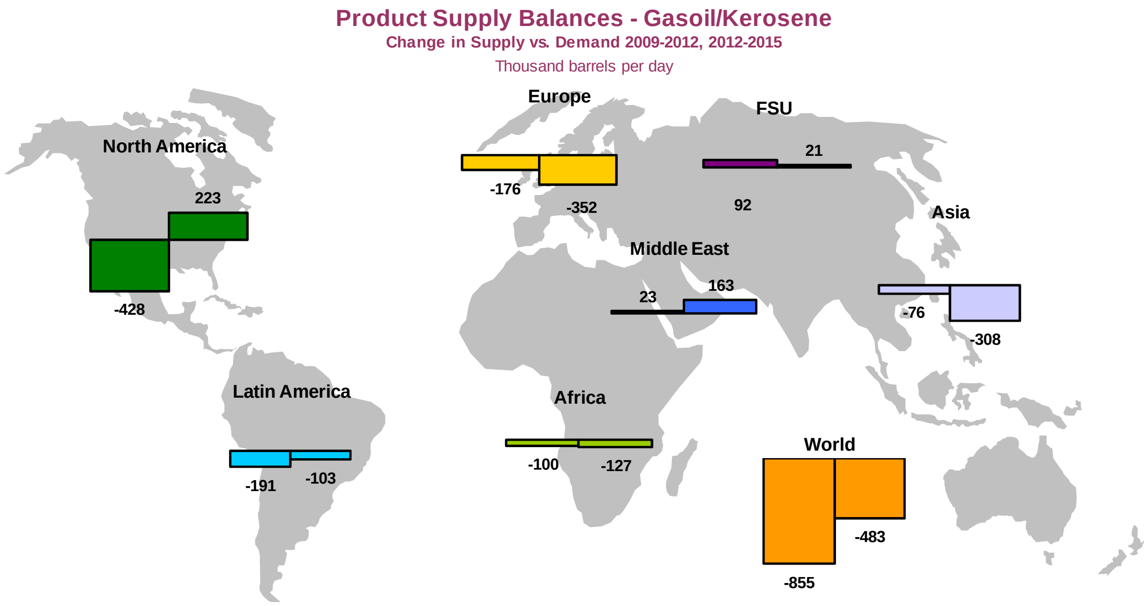




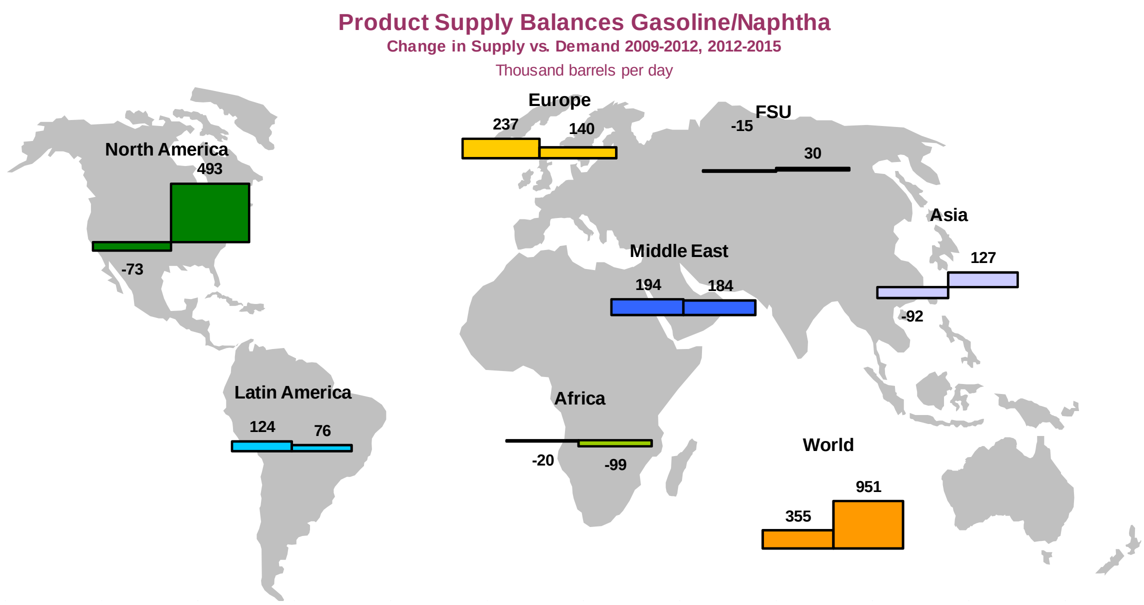
After a period of relatively amply supplied middle distillate markets, strong demand growth is again expected to create a bottleneck for refiners. Of the 7.1 mb/d increase in total demand from 2009 to 2015, gasoil/kerosene account for an impressive 62%. Markets are expected to tighten, notably in North America, in the near-medium term. North American demand dropped from a high of 7.3 mb/d in 1Q07 to 6.0 mb/d in mid-2009, but is now expected to recover alongside economic growth. Despite this tightening through 2012, our assumptions on run rates for North America suggest the region will continue to export distillates throughout the forecast period, providing some relief to Europe, which sees its middle distillate import requirements increase sharply. The Middle East and FSU also see modest surplus middle distillate availability develop, albeit insufficient to meet sharply rising import demand in other regions.







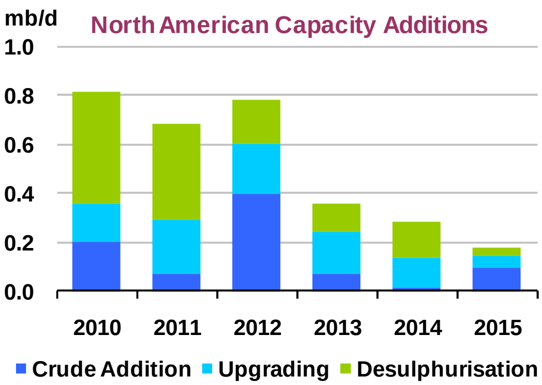
Gasoline and naphtha balances, on the other hand, look set to increasingly tend towards over-supply in the medium term, notably toward the end of the projection. The expected decline in North American gasoline demand, as well as increased availability of biofuels (see *Evaporating US Gasoline Demand?*) has significant implications for global balances. US gasoline demand is expected to fall by 330 kb/d from 2009 to 2015, with regional biofuel supplies growing by 340 kb/d. While Latin America's gasoline supply situation improves in the medium term, due to increased biofuels supplies, Africa's import needs of gasoline will increase, as refinery investments fail to keep up with projected demand growth. This will provide little relief to European refiners, who will struggle to replace the US as an outlet for surplus supplies. European refiners will also meet strong competition for markets from highly sophisticated export refiners in Asia (in particular India and Japan), who see regional markets sufficiently supplied.

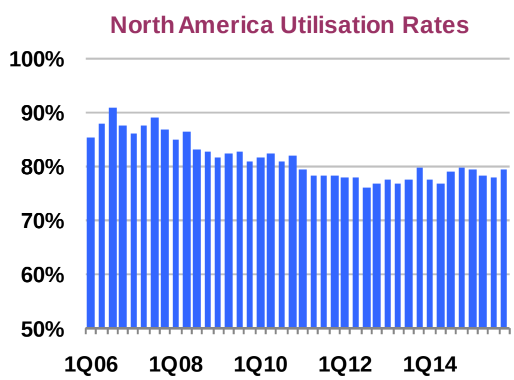


Regional Developments

North America

North American crude oil distillation capacity is expected to grow by 860 kb/d over the 2010-2015 period. Although very similar to the *December 2009 medium-term update*, the headline number masks offsetting changes. Firstly, in the December report we assumed Valero's Delaware refinery would be permanently shut and therefore taken out of capacity assessments. The 190 kb/d refinery has been reinstated, however, following the April sale to the Petroplus-led PBF group. PBF bought the refinery at a bargain price of $170 million (compared to Valero's purchase price of $1.9 billion in 2005), and plan to recommission the plant in 2Q11, after extensive refurbishment.

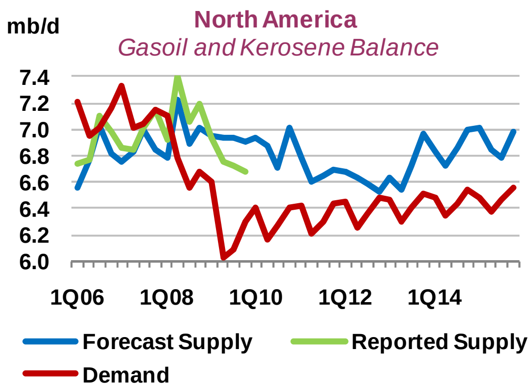


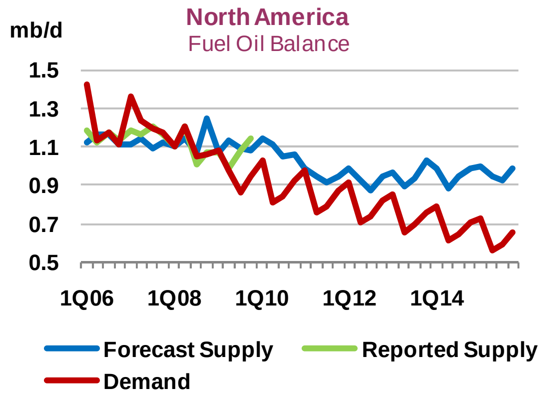


Further changes include the closure of Shell's 130 kb/d Montreal refinery in Canada, which will be turned into an oil terminal at the end of 2010. We have also included the shutdown of Giant Refining's Bloomfield refinery, which was shut at the end of 2009, as well as a 35 kb/d capacity reduction for Holly's two Tulsa refineries. Including Sunoco's Eagle Point refinery, already shut in the December update, total North American shutdowns now amount to 330 kb/d. The commissioning of Marathon's 180 kb/d Garyville expansion in 1Q10 offsets the refinery closures, however, and results in a 200 kb/d net increase to North American crude distillation capacity in 2010. Further planned additions, including Motiva Enterprises' 325 kb/d Port Arthur expansion, seem to be on track, with only minor adjustments made to timings and capacity.

A shortage of domestic refining capacity in Mexico has led the country to increasingly rely on expensive gasoline and other products imports. Pemex imports product at market prices and sells at subsidised retail prices set by the government. To relieve the product shortage, Pemex is planning to build a 250 kb/d refinery in the city of Tula, outside our timeframe. Several expansion/upgrading projects at existing refineries, however, will increase gasoline and diesel production. The 150 kb/d expansion to the Minatitlan plant, including a coker and FCC, should start operation in mid-2010. The Salina Cruz, Salamanca and Tula Hildago refineries are also expected to be upgraded over 2013/2014.

As discussed in the overview section, declining North American gasoline demand and increasing ethanol supplies reduce the region's import needs in the medium term. Furthermore, the region's current middle-distillate surplus is expected to narrow as demand growth resumes, yet the region retains its export potential. Fuel oil balances ease in the period, as relatively cheap natural gas continues to displace fuel oil in power generation, lowering demand. Supplies, on the other hand, are seen declining in the near term as additional upgrading capacity is commissioned, though the increased volumes of heavy Canadian crudes limit the downside potential.

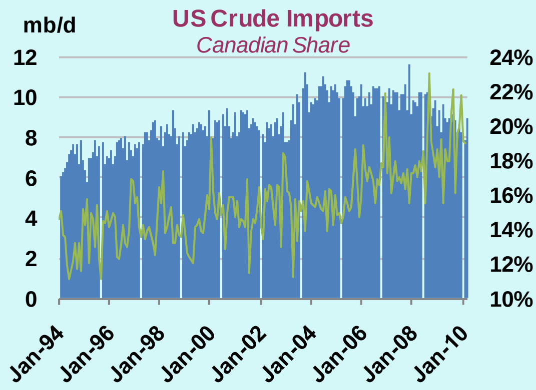




US Refiners Prepare for Increased Canadian Supplies

Increased investments in Canadian oil sands production and pipeline infrastructure are currently a main driver of US refinery investments. Canadian crude imports are taking up a larger share of total US crude imports, and the share is expected to rise significantly over the medium term as Canadian oil production increases, rising by 1.1 mb/d from 2009 to 2015, of which roughly 80% is heavy crude and bitumen.

The US imported 1.65 mb/d of Canadian crude in 2009 (19% of total crude imports), through three main pipeline systems: the Enbridge system, Kinder Morgan's Express and Trans Mountain Pipelines. Current projects to increase pipeline capacity include the TransCanada 435 kb/d Keystone line from Hardisty to Wood River and Patoka by the end of 2010, with an extension to the US Gulf Coast by 2013. A major expansion of Enbridge's main line, the Alberta Clipper Project, is under way from Edmonton to Superior, Wisconsin as well as an extension southwards from Superior to Flanagan, Illinois.



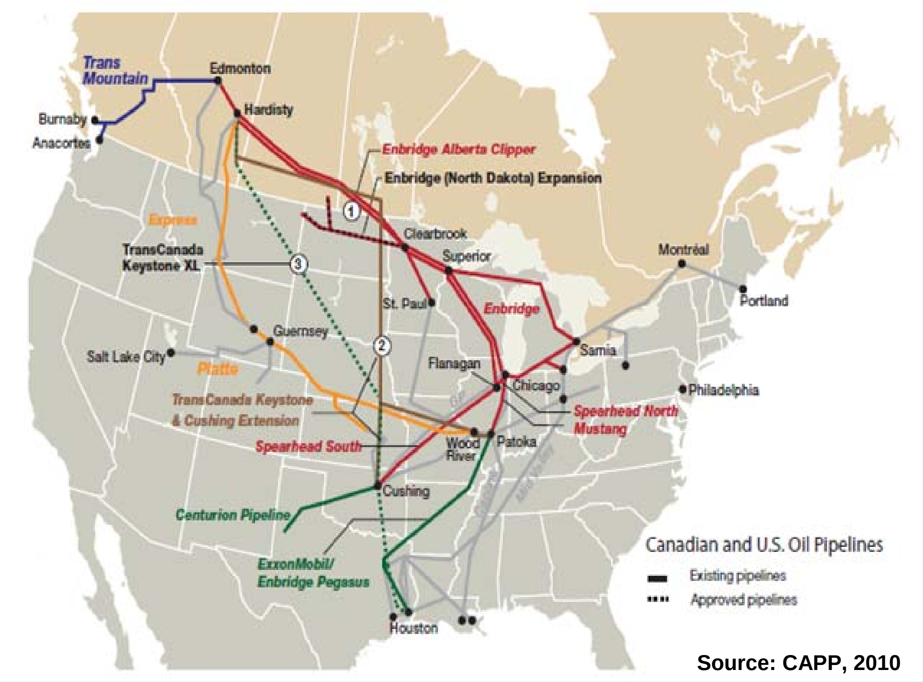
The investments in Canadian production and pipeline capacity have been accompanied by a slew of proposed refinery expansion proposals in the US to process heavy bitumen blends. These feedstocks traditionally require additional coking and vacuum distillation capacity, sulphur recovery and hydrogen production, as well as additional hydro processing units. Among the more advanced projects are:

- Motiva Port Arthur's $7 billion expansion, which will add 325 kb/d processing capacity and capability to process Canadian oil sands crude (by adding a 100 kb/d coker). Completion expected in 3Q12.
- Marathon's Detroit refinery: $2.2 billion Heavy Oil Upgrade Project (HOUP) delayed from 2010 to capture falling costs, 80 kb/d of heavy oil processing capacity expected in 1Q13.
- BP's Whiting, Indiana refinery: the $3.8 billion modernisation project will increase the refinery's capacity to process heavy Canadian crude by 260 kb/d, expected to conclude in early 2012. The expansion will make the refinery the largest refiner of tar sands oil in the US.
- ConocoPhillips Borger/Wood River, Texas refinery: The 2007 ConocoPhillips and EnCana Corp. JV entails plans to expand throughput (+195 kb/d) and heavy oil processing capacity at both refineries between 2011-2015.

US Refiners Prepare for Increased Canadian Supplies (continued)

a. Borger will add 50 kb/d of crude capacity and a 20 kb/d delayed coker, as well as a vacuum distillation unit and a diesel hydrotreater by 2Q13.

b. The Wood River Expansion is scheduled in two phases. The first phase involves a 50 kb/d increase to CDU capacity as well as a new 65 kb/d delayed coker and is expected online in 2011. The second phase includes a 95 kb/d CDU expansion, as well as another 50 kb/d coker, and is expected to be completed in 2015.



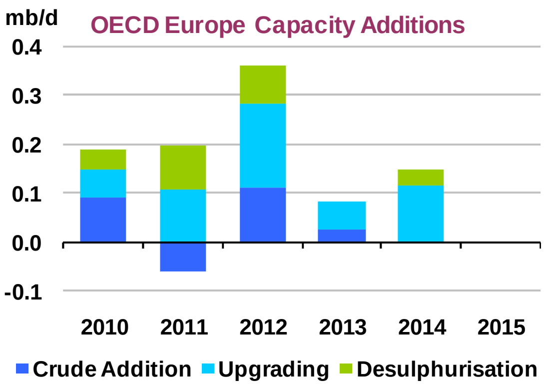
Source: CAPP, 2010

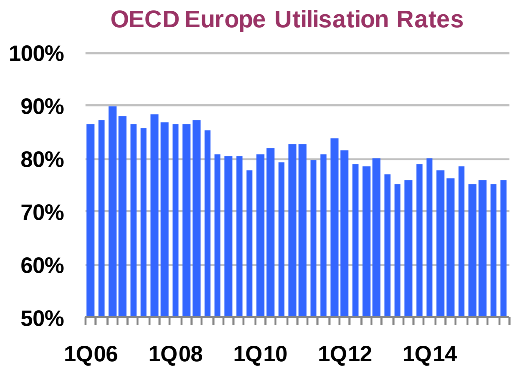
OECD Europe

Since the *December 2009 medium-term update*, **European capacity** estimates have been reduced as refiners react to structurally declining demand and poor economics. In total, 370 kb/d of capacity has been permanently shut, with further capacity idle or for sale. More closures are likely in the years to come, as efforts made to reduce the overhang have been inadequate in keeping operating rates at high levels and supporting economics.

In February 2010, French oil major Total, announced it would permanently close its 140 kb/d Dunkirk plant in response to structurally declining demand. The company had earlier announced plans to shed 500 kb/d of capacity by 2011 due to the extremely tough operating environment, but was met with fierce resistance from workers, unions and politicians, and subsequently pledged not to shut any further refineries in France within a five-year period. The company will nonetheless shut one crude distillation unit at its largest refinery, Gonfreville in Normandy, idle since mid-2009. Speculation has it that Total would dispose of its Lindsey refinery in the UK to fulfil its goal of total capacity reductions, and independent refiner Petroplus reportedly put in an offer for the plant at the end of April. Also in the UK, Petroplus suspended refining operations at its 100 kb/d Teesside refinery at the end of 2009, and the site has been converted into a storage terminal.

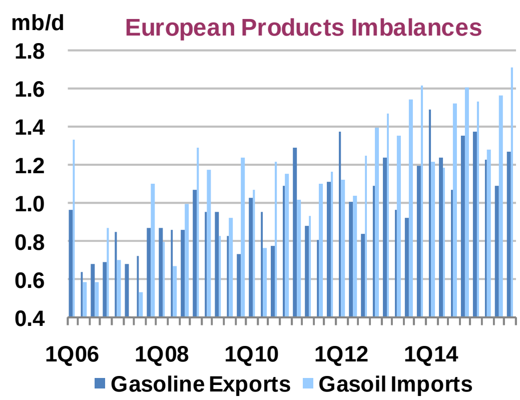
In addition to the refineries already closed, several plants have been identified as closure candidates or are up for sale. In the UK, Shell's Stanlow and Chevron's Pembroke refineries are looking for buyers, while in Germany Shell's Heide and Hamburg refineries are also for sale. ConocoPhillips' Wilhelmshaven refinery (260 kb/d) could also still be closed or sold, even though the refinery resumed operations at the tail-end of April, after having been shut for six months due to poor economics. Its much delayed upgrading project has been officially cancelled, though. In Italy, industry association Unione Petrolifera said earlier this year that the oil refining sector was in crisis and that up to five refineries, or almost a third of the total could face closure. The association named Livorno (Eni), Falconara (API), Taranto (Eni) and Gela (Eni) refineries as possible candidates for closure. While several Indian, Chinese and Russian companies have been listed as potential buyers of the distressed plants, even in the event of a sale the plants could still face closure, with the sites turned into import terminals and a market entry point for foreign crudes and products.





Despite efforts to reduce the capacity surplus in the region, total crude distillation capacity is currently seen growing by 170 kb/d over 2010-2015. Expansion and upgrading of Grupa Lotos' Gdansk refinery is adding 90 kb/d in 2010/2011, while expansions at Spain's, Cartagena, Huelva and Puertollano refineries add a combined 215 kb/d over 2010-2012.

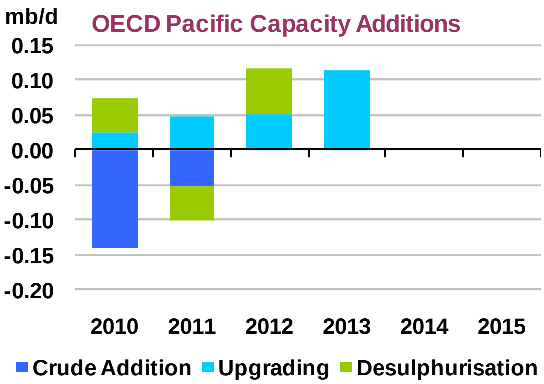
European refiners face the twin challenge of meeting regional middle-distillate demand while reducing surplus gasoline. As discussed above, with US gasoline import requirements dwindling, and new players adding light distillate volumes to the market, Europe will struggle to find buyers for surplus supplies. However, middle distillate import requirements will increase significantly over the period. Total's move to shut an FCC unit at its Gonfreville refinery, while adding hydrocracking, is a step in the right direction to augment diesel production while lowering gasoline output, but comes at a high capital cost.

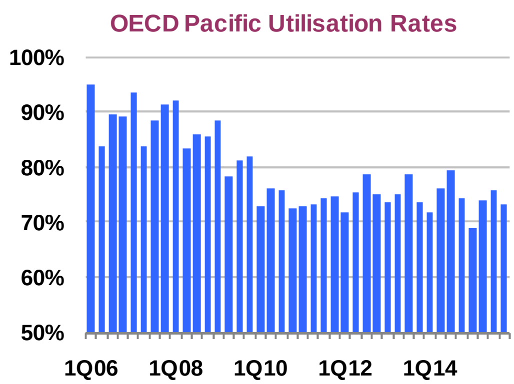


OECD Pacific

The **OECD Pacific**, dominated by Japan, is the region where surplus refinery capacity is the most acute, and where most announcements of capacity rationalisation and refinery closures have been made. Since the *December 2009 medium-term update*, nearly 400 kb/d of capacity has either been shut or scheduled to close before 2011 and a further 740 kb/d reduction has been announced. Total Pacific crude distillation capacity is now seen shrinking by 190 kb/d over the 2010-2015 period.

Despite the weak regional refinery outlook, investments in upgrading and desulphurisation capacity in South Korea proceed as planned. GS-Caltex is installing a 113 kb/d residue hydrocracker at it Yosu refinery in 2013, Hyundai is planning RFCC and residue hydro treating additions for 2012, while S-Oil Corp will invest in a reformer and naphtha reforming for 2011. SK Corps planned investments at its Incheon refinery however has been delayed for at least five years due to the worsening outlook.





Japan – Talking Refinery Consolidation, Major Reductions Yet to Come

Japan's refining industry is facing tougher times than most. Domestic demand is dwindling, from 5.5 mb/d in 2000 to only 4.4 mb/d in 2009, and is expected to shrink by a further 0.8 mb/d by 2015, as energy efficiency and demographic shifts continue. Up until now, Japanese refiners have remained competitive by exporting surplus product to energy-hungry, developing neighbours. Japanese product exports peaked in August 2008, but have since seen steady declines as the global recession and slump in oil demand coincided with a glut of new regional refining capacity. Japanese refiners had to drastically cut runs to sustain profitability and have announced closures and capacity reductions.

Announced Japanese Capacity Cuts

(thousand barrels per day)

Company	Plant	Capacity Cuts		Closure date	Notes
		Announced	Included		
JX Holdings	Negishi	70	70	Oct-10	Mothball 70 kb/d No. 2 CDU
	Osaka	115		Mar-11	Turn into export refinery JV CNPC
	Mizushima	110	110	Jun-10	Mothball110 kb/d No. 2 CDU
	Oita	24	24	May-10	Mothball No 1 CDU
	Toyama	60	60	Mar-09	Turned into an oil terminal
	Kashima	21	-	May-10	Cut nameplate cap. of No. 1 CDU by 10 %
	TBC	200	-	Mar-14	
	TBC	200		Mar-21	Refinery closure
Cosmo Oil	Chiba	20	-	Feb-10	Company not physically removing capacity
	Yokkaichi	50	-	Feb-10	Company not physically removing capacity
	Sakaide	30	-	Feb-10	Company not physically removing capacity
Show a Shell	Ohgishima	120	120	Sep-11	End refining business, continue oil terminal
Idemitsu Kosan	TBC	100		2013-2014	
Total		**1120**	**384**		

Japan – Talking Refinery Consolidation, Major Reductions Yet to Come (continued)

Over the last year, more than 1.1 mb/d of refinery capacity reductions have been announced in Japan. However, due to the high cost of closing a refinery, companies, although clearly recognising their predicament, have been reluctant so far to definitively shut capacity. Of the total 1.1 mb/d announced figure, we have identified less than 400 kb/d as permanently shut, mothballed or dismantled, all before the end of 2011. In the absence of firm closure details we retain capacity in our model, but compensate with low utilisation rates.

JX Holdings, formed on 1 April as the holding company for Nippon Oil (Japan's largest refiner) and Nippon Mining Holdings, has a combined capacity of 1.7 mb/d at eight refineries. The two companies had previously announced they would shed 400 kb/d by 2011 and a further 200 kb/d by 2015. That timetable may now have been brought forward. The company also now plans an additional 200 kb/d refinery closure by 2020/2021. As detailed in the table on the previous page, the company has already started its closures. The 60 kb/d Toyama refinery was closed in March 2009, and is now operating only as an oil terminal. The company further closed its 24 kb/d Number 1 CDU at Oita refinery in May and will mothball the 110 kb/d CDU no. 2 at Mizushima in June followed by a 70 kb/d CDU at Negishi in October of this year. The 115 kb/d Osaka refinery, although shed from the company's refining portfolio, will not close but rather be turned into an export refinery, through a potential JV with CNPC. We have yet to include the 200 kb/d reduction by March 2014 and the additional 200 kb/d by 2021, as no firm details have been made available.

Showa Shell, announced, also in February, closure of the Toa Keihin Refinery (Ohgimachi Factory) by September 2011. Toa Oil will continue to operate the crude oil loading facility and the terminal.

Cosmo Oil stated it would reduce crude processing capacity at four refineries by 100 kb/d, but add a 20 kb/d coker at one plant, effectively only cutting capacity by 80 kb/d. The company is not intending to mothball or dismantle the CDU's however, rather reducing nameplate capacity, as a "message to markets of the company's intention to balance its refining capacity", a company official said in early February. The company will examine ways to physically remove capacity as part of its three year fiscal plan from fiscal year 2010-2011.

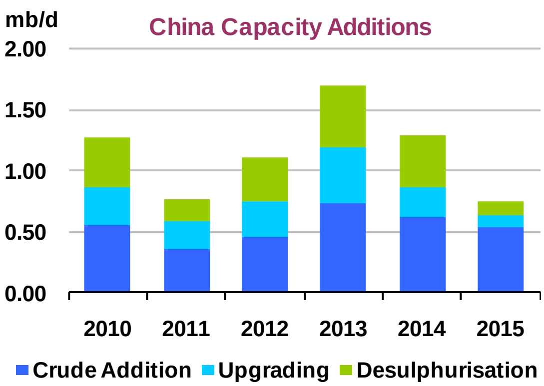
Idemitsu Kosan joined the list of Japanese refiners to slash refining capacity at the end of April, announcing it will cut crude distillation capacity by 100 kb/d over the next three to four years. Idemitsu currently operates a nameplate capacity of 640 kb/d, spread across four refineries. It is unclear where, and in what form, the capacity cuts will take place.

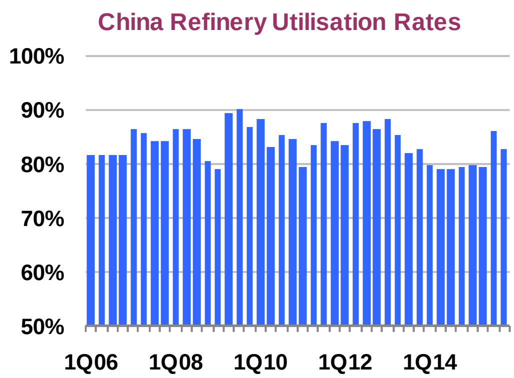
China

China will clearly provide the largest capacity additions in the medium term, adding almost 3.3 mb/d by 2015 or an average of 545 kb/d per year over the forecast period. Chinese crude distillation capacity already increased significantly in 2009 (by 850 kb/d), and news of record high Chinese crude runs are now almost a monthly occurrence. 1Q10 throughputs averaged 8.1 mb/d, an impressive 1.6 mb/d above 1Q09, which admittedly was exceptionally weak. 2010 growth is coming from Sinopec's Tianjin refinery, which started operations earlier this year and CNPC's 200 kb/d Quinzhou refinery, which is slated to start commercial operations in 3Q10.

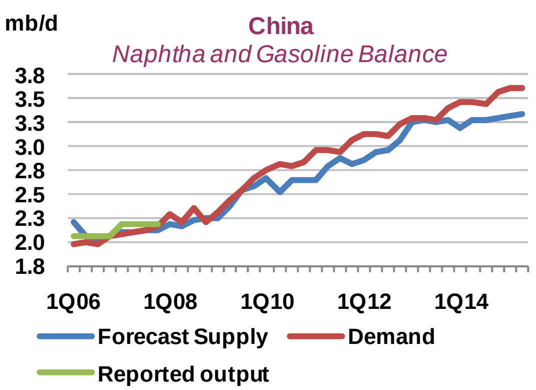
Chinese efforts to team up with foreign partners to expand the refining industry seems to have been successful, with several projects now deemed firm and likely for completion before 2016. The joint ventures are mutually beneficial as Chinese companies secure crude supplies for the refineries, and producers secure a steady crude off-take while getting a share of Chinese product markets. We now include the joint ventures of CNPC/Rosneft for a 200 kb/d refinery in Tianjin for 2013, the CNPC/PDVSA 400 kb/d Jieyang refinery for 2013, Sinopec/KPC's 300 kb/d Zhanjiang refinery for 2014 as well as Sinochem's 240 kb/d Quanzhou refinery in 2014. The proposed 400 kb/d project by CNPC/Qatar Petroleum and Shell in Taizhou and Sinopec/Saudi Aramco/ExxonMobil's 240 kb/d project are for the moment expected to be completed after 2015.

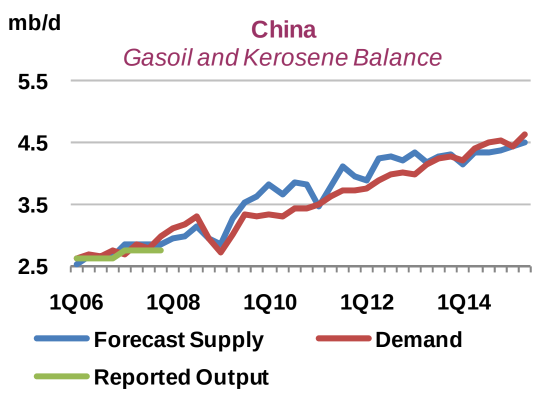
The assumption that refinery additions and throughput levels will keep up with domestic demand provides a key risk to the forecast. The lack of visibility on project status makes it difficult to ascertain progress and expected completion for proposed projects. In the near term, however, the significant capacity additions, coinciding with a drop off in middle distillate demand, provides surplus supplies before the balance tightens towards the end of the forecast.





Not explicitly included in this assessment is the assumed closure/mothballing of small independent refiners in China. To increase the competitive position of its refining industry, the Chinese government plans to shut down refineries with capacities below 20 kb/d, mainly in the Shandong region. While our own capacity database includes about 1 mb/d of capacity at independent refineries, some other estimates double that. Independent refiners are estimated to have run only around 20% of capacity in 2009.

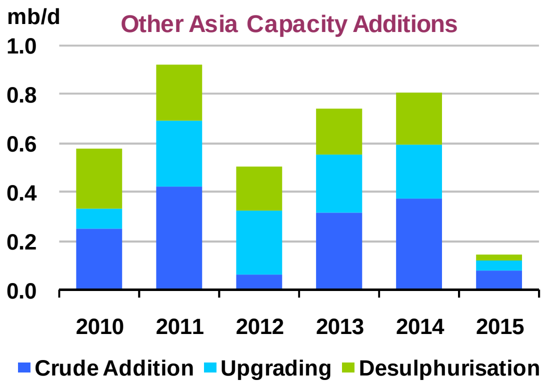


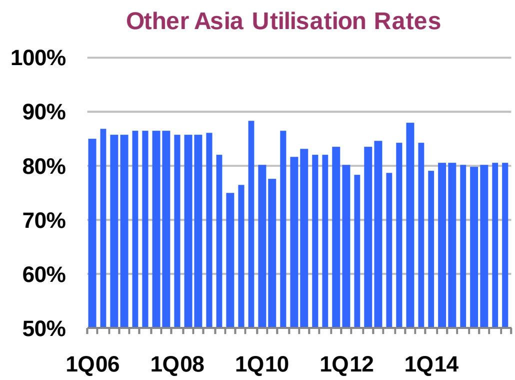


Other Asia

Other Asian refinery projects sum up to 1.5 mb/d of additional capacity over the 2010-2015 period, the bulk of which stems from **India.** The Indian government's policy of ensuring that domestic oil product demand is met at affordable prices and establishing the country as a net product exporter has led to massive refinery expansions (See *Indian Downstream Petroleum Sector*). A total of

1.1 mb/d of crude distillation capacity additions is scheduled by 2015 and further investment is aimed at meeting new fuel standards. The Auto Fuels Policy mandated that major cities moved towards Euro 4 fuel specifications by April 2010, and the remainder of the country towards Euro 3 standards, but as it became evident that refiners would not be able to complete upgrading projects before the deadline, the nationwide Euro 3 target has been delayed.



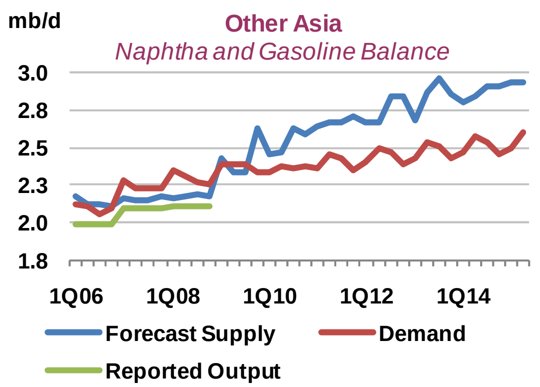


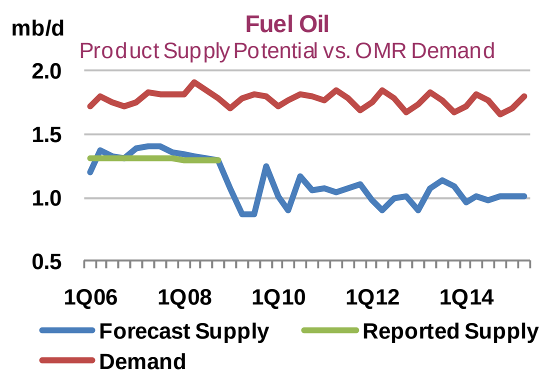
Outside of India, **Vietnam** accounts for the second largest share of additions. Vietnam's first refinery, the 140 kb/d Dung Quat refinery, started operations in early 2009. Three other refinery projects have been proposed, two of which we have included in this report. The first, at Nghi Son, will have a processing capacity of 195 kb/d and is a JV between PetroVietnam (25.1%), Kuwait Petroleum Corp. (35.1%), Idemitsu (35.1%) and Mitsui Chemicals (4.7%). We expect the refinery to be completed by early 2014, at a cost of $8 billion. The refinery will run Kuwaiti crude.

Work is also proceeding at the Vung Ro refinery, to be built in the Phu Yen Province. Construction is set to begin as early as June or July this year, after having been delayed for several years due to land clearing problems. The project is being jointly funded by UK's Technostar and Russia's TellOil, and is scheduled for completion in 2014. We foresee some delays and have included it for 2015, but recognise the risk of the project slipping beyond the timeframe of this report. PetroVietnam is further looking to finalise agreements with foreign investors for the construction of a fourth refinery, Long Son, and has reportedly been seeking Saudi Aramco's participation in the $7 billion project. Although the project is scheduled for completion in 2015, we do not see it at an advanced enough stage to be completed within the report's timeframe.

We continue to discount **Indonesia's** ambitious plans of adding at least 500 kb/d of refining capacity to deal with increasingly expensive product imports. Project financing remains difficult, and foreign investors are hesitant to join the projects as long as incentives are unclear. Indonesia's state-owned Pertamina and Japan's Mitsui have further shelved plans to build a $1.5 billion RFCC at the Cilacap refinery in Central Java, after failing to set up the Joint Venture for the project. Pertamina is now planning to go ahead with the project alone, but we don't see completion likely before 2016.

Regional distillation capacity additions are more or less in line with expected demand growth. Middle distillate supplies are expected to more or less keep pace with demand growth, despite this taking an increasingly large share of total demand. Over the 2010-2015 period, middle distillates account for 65% of regional demand growth, while gasoline grows more modestly and fuel oil contracts. As highlighted in previous reports, lighter feedstocks and upgrading capacity significantly reduce fuel oil supplies. Naphtha and gasoline availabilities on the other hand will grow faster than demand, considerably increasing the region's export potential.





India's Downstream Petroleum Sector[1]

India is expected to become the world's fourth largest crude consumer by 2020. India currently imports almost 80% of its crude oil demand and the share will increase further. Two key objectives motivate the Indian government's policy in the downstream petroleum sector: (a) ensuring India's growing refined product demand is met at affordable prices over time; and (b) establishing India as a major global refined product exporter.

India liberalised the petroleum sector in 2002 but maintained *de facto* price controls on four 'sensitive' petroleum products to insulate consumers against high global crude oil prices: petrol and diesel as transport fuels and LPG and kerosene as cooking fuels. India's government-owned Oil Marketing Companies (OMCs) are mandated to sell these products in retail markets at centrally-determined, fixed prices. As crude prices began structural appreciation from 2005, OMCs began recording significant 'under-recoveries' on the sale of these four products. Under-recoveries are a notional measure representing the difference between the trade-parity refinery-gate cost of refined product paid by OMCs and their managed sale price. As a consequence, the government has been forced to issue hundreds of billions of rupees to maintain the solvency of the OMCs. This has increasingly occurred via the extension of off-budget 'oil bonds' – debt securities issued to OMCs to be traded by these companies for liquid cash, or to be used as collateral for borrowing in financial markets. The Government issued close to US$20 billion in oil bond debt to OMCs in FY2008-2009.[2]

Off-budget debt issuance has led a fiscal overflow in India. India's fiscal deficit more than-doubled in nominal terms, from 5.7% of GDP in FY2007-2008, to 11.4% in FY2008-2009. In an effort to further deal with the under-recoveries, the government also cut the various tax rates on petroleum products. This, however, has been done in an unbalanced fashion, with the central government taking a larger fiscal hit than local authorities. Cutting taxes on petroleum products has provided short-term relief but also undermined a key, inelastic source of revenue and weakened an important element for future demand-side management while failing to address the root problem of controlled pricing.

The current pricing practices have made public-sector OMCs *de facto* reliant on the government for working capital. During the height of the oil price rise Indian OMCs lost between 25 and 43% of their net worth from April and December 2008. Despite this, OMCs have invested strongly in refinery capacity in recent years. Between 2007 and 2012, OMCs will have added over 900 kb/d in refining capacity, more than matching India's rapidly growing product demand over this period. The OMC sector is therefore defined by heavy-handed regulation and lacklustre commercial performance, yet robust capacity investment.

[1] The IEA recently published a working paper on India's Downstream Petroleum Sector. The paper can be downloaded free under: http://www.iea.org/publications/free_new_Desc.asp?PUBS_ID=2238

[2] A US dollar conversions are based on the average dollar-rupee exchange rate for fiscal year 2008-2009 of 45.53Rs/$. Note, the India fiscal year runs from 1 April to 31 March.

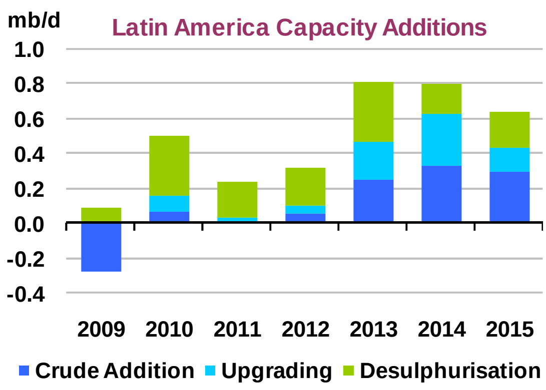
India's Downstream Petroleum Sector (continued)

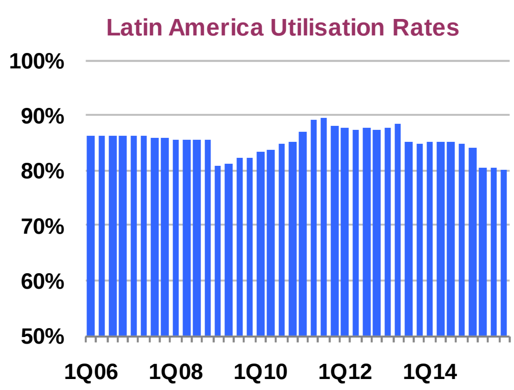
Private-sector refinery investment in India, too, is shown to be robust in both the recent past and in the near future. From the commissioning of Reliance Industry Limited's (RIL) Jamnagar II refinery in late-2008 to Essar Oil's Vadinar II refinery scheduled in 2011, private-sector refiners will have added around 0.8 mb/d of new capacity. This has been driven by: (a) private-sector refiners' scope to profitably supply domestic Indian markets by selling wholesale to OMCs, avoiding exposure to managed prices; and (b) India's significant comparative advantages as a base for export-oriented refining operations. The country's present refining base of 3.7 mb/d is expected to increase to nearly 4.8 mb/d by 2015. India is expected to surpass Japan as the world's fourth largest refiner by 2013, given current firm expansions and refinery shutdowns.

Despite strong demand growth, India's excess refining capacity could total 1.0 mb/d by 2015, allowing the country to increase product exports by more than 0.5 mb/d from 2009 and provide greater breadth to high quality regional oil product supplies. This is further evidence of a shift whereby refining hubs in Asia and the Middle East increasingly become the source of incremental world refined product supply. Moves to consolidate India's role as a major exporter will require sustained investment, ideally by the private sector and through a process of market reform, leaving OMC investment increasingly based on market signals and retained earnings. The fiscal burden from unofficial price subsidies needs to be lessened, allowing more direct pass-through of international price signals to consumers and consequent incentives to conserve or substitute. Market based pricing reform, while simultaneously targeting graduated subsidies to the poorest consumers, will likely be required.

Latin America

Latin America is expected to see strong growth in crude distillation capacity towards the end of the forecast period, but additions fail to offset demand growth. Just over 1.0 mb/d of refinery capacity will be added, of which 87% from 2013 onwards. Regional oil demand, however, is expected to grow by 1.2 mb/d from 2009, to reach 7.2 mb/d in 2015, leading to increased regional product import requirements. Refinery additions stem almost exclusively from new refineries and expansions in **Brazil.** The downstream expansions are aimed at meeting growing demand and to increase exports of refined products by processing the bulk of pre-salt crude production at home. The government's aim is to further develop the industry and create jobs in the underdeveloped northern states.

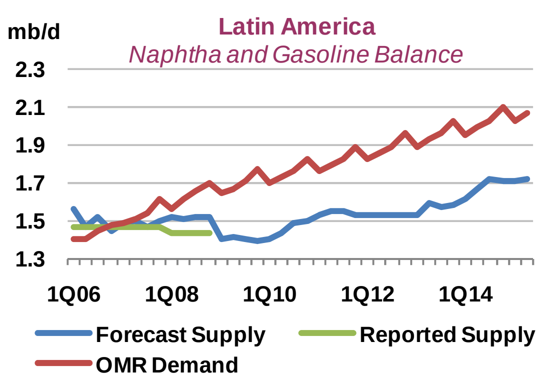


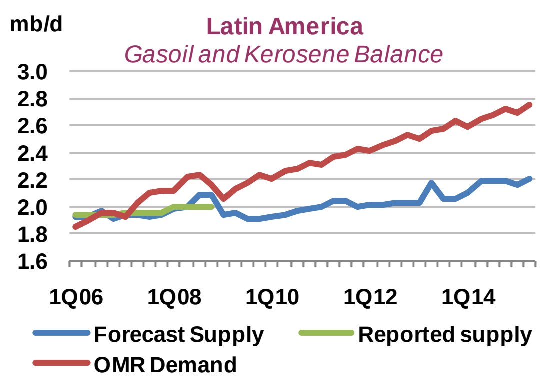


State-controlled oil company Petrobras outlined plans to increase refining capacity from 1.8 mb/d to 3.0 mb/d by 2020 in its recent strategic plan. The plan, although currently under review, is to build five new refineries, and upgrade existing facilities to produce more diesel. Petrobras announced earlier this year that work had started at the 600 kb/d export refinery, located in Sao Luis in the northern state of Maranhao. The refinery is expected to process light crudes from the giant pre-salt fields currently being developed offshore Rio de Janeiro and Sao Paulo, and we expect the first phase (300 kb/d) to be completed in early 2015. The second phase, which will double capacity, as well as a second 300 kb/d refinery planned in Ceara state, are expected to be completed after 2015.

In addition to the Sao Luis refinery, two other refineries are under construction, dedicated to process heavy crude oil from the Campos Basin. The 230 kb/d Abreu e Lima plant in Pernambuco state was to be built as a JV with Venezuelan PDVSA. Petrobras may be stuck with paying for the project by itself, however, as PDVSA has yet to sign the agreement giving it 40% of the refinery or put up any of its promised share of investment. Petrobras is building a second heavy oil refinery, Comperj, near Rio de Janeiro and recent plans include doubling the complex's capacity, to include two identical 165 kb/d refining trains instead of one. The first is expected to start operations in early-2014, the second two or three years later.

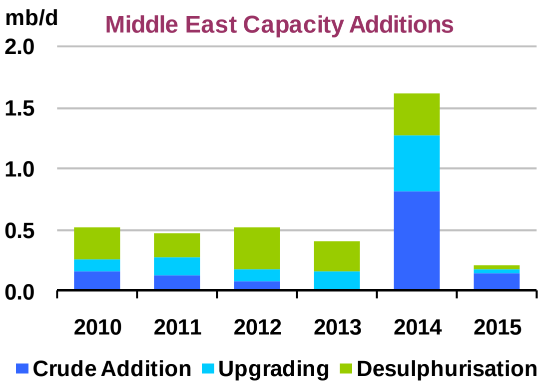
Outside of Brazil, smaller expansion projects in Colombia, Costa Rica and Venezuela add to capacities. We continue to exclude Petroecuador and PDVSA's planned 300 kb/d refinery on Ecuador's Pacific coast, despite company reports of progress in securing parts of the required $10-12 billion financing. The joint oil refinery project between Venezuela and Nicaragua to build a 200 kb/d unit (100 kb/d by 2015) to process heavy Venezuelan crude and export products is also excluded. We are also waiting for more details before including plans to expand refining capacity in the Dominican Republic.

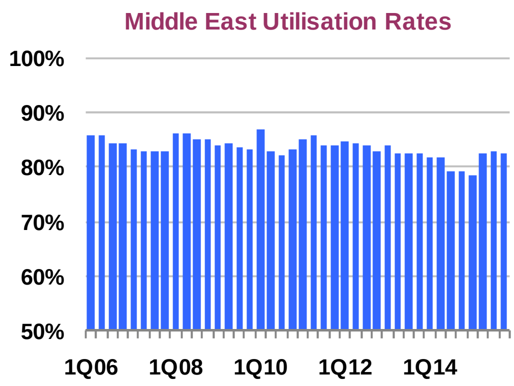




Middle East

The Middle East will make a significant contribution to global crude distillation growth over the next five years, adding close to 1.4 mb/d of capacity by 2015. The largest contributors to growth are Saudi Arabia's Jubail refinery, due for start up early-2014 and UAE's Ruwais refinery, also slated for 2014. The doubling of capacity at the recently commissioned Qatari condensate splitter at Ras Laffan further boosts capacity in 2015. Smaller additions are seen in Iran and Iraq, although the major plans for grassroots expansions are not seen within the timeframe of this report due to financing concerns.





Saudi Arabia's Mega Projects Slip Again?

The withdrawal of ConocoPhillips from the 400 kb/d, $10 billion Yanbu refinery project at the end of April is another blow to Saudi Arabia's ambitious refinery expansion programme. The programme, launched in 2006 in response to product supply bottlenecks and spiralling prices, included four major refinery projects and plans for doubling domestic and international refinery capacity by 2015. The subsequent downturn in the global market has seen plans revised. Of the four mega projects proposed, we only include one refinery to be completed within the 2015 timeframe.

Work on Saudi Aramco Total Refining and Petrochemical Company's (SATORP) 400 kb/d **Jubail** refinery is progressing as planned and we expect the refinery to start up in early 2014. The project was postponed from its original March 2013 start, as construction and procurement contract awards were delayed to capture declining project costs. The company is estimated to have saved 20% by the delay and reduced costs from an original $12 billion to $9.6 billion. The refinery, which is to process 100% Arab Heavy crude, was planned as an export unit, but the scope seems to have shifted due to the changing global refinery outlook. Recent indications that the planned Dow-Chemical –Saudi Aramco JV petrochemical project (which was also delayed to capture falling costs) will be relocated from Ras Tanura to Jubail mean that Jubail could be more domestically focused supplying the petrochemical plant with feedstock instead.

The relocation of the petrochemical plant also makes the **Ras Tanura** refinery expansion project less likely. Saudi Aramco is reported to have effectively shelved the 400 kb/d project, letting design and project management contractor, Worley Parsons, send the project staff home. Although not officially cancelled, the project has been postponed for five years or more, and might only be brought back on the table once refining economics improve.

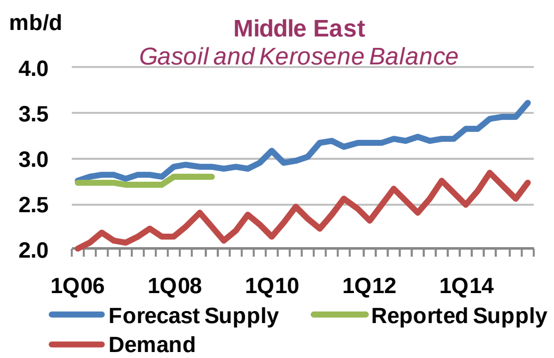
The ConocoPhillips Saudi Aramco JV **Yanbu** refinery was to be almost identical to the Jubail refinery. Although Aramco is currently looking for new partners for the project, and is adamant it will continue alone if it fails to secure a partner, we see the project slipping from its original planned start up in 2014 to beyond 2015. Saudi Aramco has extended bidding deadlines for a solid handling unit again in May, making it the third time the deadline has been delayed. The complex refinery is slated to process heavy oil from the Manifa field, which has also been delayed from its planned start-up.

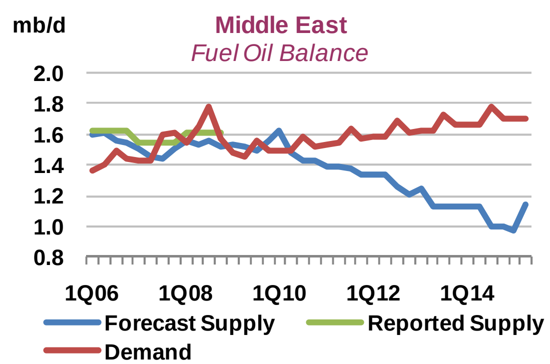
The last proposed mega project is the **Jazan** refinery, in the country's southwest region. This is planned as a 250/400 kb/d semi/full conversion export refinery with a targeted start up in 2015. It was supposed to be the Kingdom's first private sector refinery but, due to lack of interest, King Abdullah reportedly asked Aramco to proceed with the project alone.

Elsewhere in the region, **Qatar's** 250 kb/d Al Shaheen refinery project has been indefinitely postponed. It was put in hold in early 2009, due to rising costs, and is still considered too expensive. Instead, the country will double capacity at the recently commissioned 146 kb/d Ras Laffan condensate refinery, to deal with increasing associated liquids stripped out from gas produced to feed Qatar's LNG industry, the country's two gas-to-liquids plants and domestic consumption.

Iraq is planning massive refining investments over the coming years, and has outlined plans to increase distillation capacity to 1.45 mb/d by 2015. FEED contracts have been awarded to four grassroots refinery projects, with a joint capacity of 740 kb/d, in Nassiriya, Karbala, Missan and Kirkuk. With Baghdad yet to secure foreign investors however, none is included in our projections. Some smaller expansion projects are underway however, including a 70 kb/d addition of SOMO's Basrah plant in 2011. A smaller refinery in Erbil also started operations at the tail-end of 2009, and its capacity is expected to double, to 40 kb/d, by early next year. The refinery is expected to process oil from the Khurmala Dome oil field.

We continue to exclude **Kuwait's** proposed Al-Zour refinery, despite recent reports that the project will be retendered this year. The refinery has been delayed numerous times, first due to surging cost estimates; secondly due to political disputes. Political and financial problems equally continue to hamper progress on **Iran's** impressive refinery expansion plans. The country aims to double current refining capacity of 1.6 mb/d, through seven new grassroots refineries. The only active project however is the Persian Gulf Star project, designed to process 360 kb/d of condensate from the South Pars field. The refinery would produce some 220 kb/d of gasoline, significantly alleviating the country's current gasoline deficit, and is scheduled for 2012. Although construction is reportedly more than one-third complete, work has apparently stalled due to lack of funds, and is thus excluded from capacity assessments. Work seems to be progressing at some of the expansion projects however, aimed at reducing the country's gasoline import requirements as well as meeting targets to meet Euro-IV gasoline environmental standards by 2012.





The addition of upgrading capacity, as well as the assumption that OPEC producers will preferentially curb output of heavy/sour crude to balance the market, play out in the region's fuel oil balance. While supplies are severly curtailed, demand growth feeds increased power generation needs. Increased direct burning of crude oil is to an extent reducing import needs, though fuel oil markets are set to tighten sharply.

Africa

African refinery capacity is largely unchanged from the *December 2009 medium-term update*, with crude distillation additions amounting to a mere 340 kb/d over the 2010-2015 period. While there is no lack of proposed projects, and sound reasons to expand capacity, funding problems seem to hinder projects being brought to completion. Of the proposed projects, the ones funded by Chinese investors are so far dominating the refinery investment outlook.

China – Investing also in the African Downstream

In exchange for access to upstream projects, China has been investing in infrastructure developments in oil producing African countries. (For an overview of Chinese upstream overseas investments, see *Chinese NOCs Active Abroad* in June 10 OMR). Currently, CNPC is constructing refineries both in Chad and Niger, and plans are being drawn up for investments in Sudan, Egypt and most recently, potentially in Nigeria. In total, more than 1.3 mb/d of refining capacity could be built on the continent if, however unlikely, all the projects were to materialise.

In **Chad**, CNPC has started the construction of a 20 kb/d refinery, expected to start up in early 2012. According to CNPC, the refinery will include a CDU, heavy oil catalytic cracker, a hydro-treating unit and a reforming facility. The plan includes raising the plant's capacity by a further 30 kb/d in 2015. CNPC also started construction of a 20 kb/d refinery in Zinder, **Niger**, in 2008. The refinery is also expected to start operations in 2012.

The government of **Sudan,** CNPC and Petronas signed a memorandum of understanding (MoU) on 17 November 2009 to expand the Khartoum refinery by 50 kb/d by 2013 and a further 50 kb/d at a later stage. According to the MoU, CNPC and Petronas are to upgrade the refinery in exchange for greater stake in upstream projects in the country. CNPC is currently operating 7 upstream projects in Sudan. The Khartoum refinery, in which CNPC and the Sudanese government has a 50/50 share, was built in 2000 and has a capacity of 100 kb/d. Sudan's crude exports to China rose 16% to 245 kb/d in 2009, becoming the fifth-largest Chinese crude supplier.

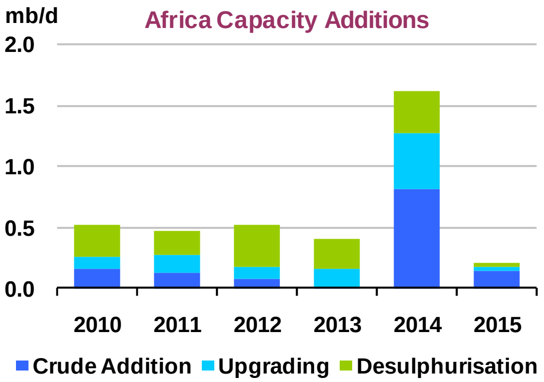
China is also planning to invest in a $2billion refinery project in **Egypt.** With a distillation capacity of 300 kb/d, the refinery will be Egypt's largest. The refinery will be constructed by Chinese companies, Rongsheng Petrochemicals and CNPC, and will be operated by the Chinese firms for 25 years, before ownership is gradually transferred to Egypt. The project will provide products including jet fuel and diesel for the domestic market and naphtha exports to China.

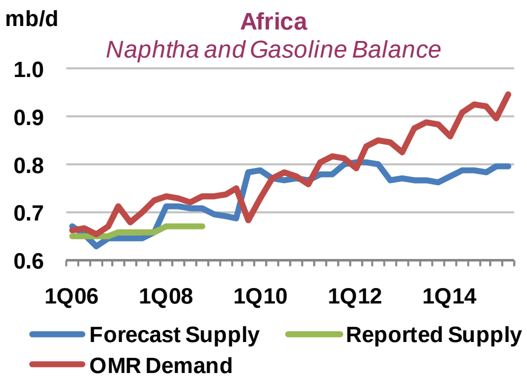
State-owned Nigerian National Petroleum Corporation (NNPC) signed a memorandum of understanding (MoU) on 13 May with the China State Construction Engineering Corporation (CSCEC) for the construction of 3 new refineries, with a combined capacity of 750 kb/d, in **Nigeria**. The investment of some $23 billion is to be contractor-financed with funding coming from the China Export and Credit Insurance Corporation and a consortium of Chinese banks. The Nigerian and Egyptian projects will only be included in our capacity estimates, once, and if, they reach a more advanced stage. ONGC Mittal Energy and ONGC Videsh have also signed MoUs to build refineries in Nigeria in exchange for increased involvement in Nigeria's upstream sector, but so far progress on the projects seem to have stalled.

Uganda, which is preparing for its first oil production, is undertaking a feasibility study to build a 150 kb/d refinery. The project has yet to secure the $2 billion estimated cost and there has been talk of possible Chinese involvement.

Aside from Chinese sponsored projects, progress elsewhere has been less successful. In **South Africa**, for example, the government is determined to build nearly 500 kb/d of capacity to reduce product imports and meet growing domestic demand, but has encountered problems securing the financing.

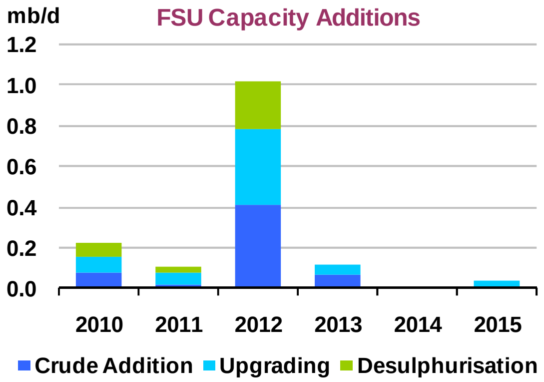
National oil company PetroSA has proposed to spend $9-10 billion on a 400 kb/d refinery in Coega, but is looking to finance as much as 62.5% of the project cost through private investors. The government has said it is open to the idea, given its fiscal challenges and the need to fund power and pipeline infrastructure. Final investment decision is not expected until 2012, with an eventual commissioning in 2016. In **Angola**, Sonangol's 200 kb/d Lobito refinery project was delayed from its original 2012 completion target as China's state-owned Sinopec withdrew due to a marketing dispute. As financing concerns remain, we have excluded the project from completion within our timeframe.

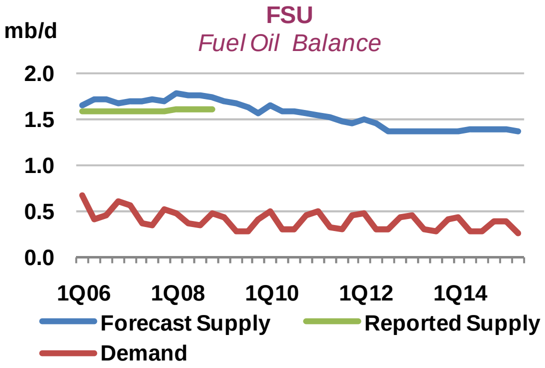




Former Soviet Union

The Former Soviet Union is expected to add 585 kb/d of crude distillation capacity before the end of 2015. The expansion is some 300 kb/d higher than in the *December 2009 medium-term update*, as we have included several smaller expansion projects, in addition to Rosneft's Tuapse and Tatneft's Nizhnekamsk 140 kb/d expansions included previously. Included amongst others, is a 54 kb/d expansion to the Mari El refinery in the Mari Republic, a 20 kb/d addition at Rosneft's Komsomolsk, a 20 kb/d addition to Alliance's Khabarovsk plant, as well as a 50 kb/d expansion the Antipinsky refinery in 2010, followed by a further 70 kb/d expanison in 2013 which will include a hydrocracker and add units to produce Euro-5 fuels. Interestingly, regional fuel oil balances tighten over the period despite likely increased domestic gas availability. The latter could dilute a previous policy aimed at maximising domestic fuel oil burn for power generation to free up gas for export. In addition to increased upgrading capacity, the refinery feedstock slate becomes slighly lighter over the period due to increased regional condensate production.





TABLES

Table 1

WORLD OIL SUPPLY AND DEMAND

(million barrels per day)

	1Q09	2Q09	3Q09	4Q09	2009	1Q10	2Q10	3Q10	4Q10	2010	2011	2012	2013	2014	2015
OECD DEMAND															
North America	23.5	22.9	23.2	23.5	23.3	23.5	23.3	23.6	23.4	23.5	23.4	23.3	23.2	23.1	22.9
Europe	14.9	14.2	14.5	14.4	14.5	14.1	14.2	14.6	14.5	14.4	14.3	14.2	14.1	14.0	13.9
Pacific	8.1	7.3	7.3	8.0	7.7	8.2	7.2	7.2	7.9	7.6	7.5	7.3	7.2	7.0	6.9
Total OECD	46.6	44.4	45.0	45.9	45.5	45.8	44.7	45.3	45.9	45.4	45.2	44.9	44.5	44.1	43.7
NON-OECD DEMAND															
FSU	3.9	3.8	4.0	3.9	3.9	4.1	3.9	4.1	4.1	4.1	4.2	4.3	4.3	4.4	4.4
Europe	0.8	0.8	0.7	0.7	0.7	0.7	0.8	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8
China	7.7	8.6	8.8	8.9	8.5	9.1	9.3	9.1	9.1	9.2	9.7	10.2	10.7	11.2	11.6
Other Asia	9.9	10.0	9.8	10.1	9.9	10.0	10.2	10.0	10.3	10.1	10.4	10.7	10.9	11.2	11.4
Latin America	5.8	6.0	6.1	6.2	6.0	6.0	6.2	6.3	6.3	6.2	6.4	6.6	6.8	7.0	7.2
Middle East	6.5	7.1	7.6	7.0	7.1	6.9	7.4	7.9	7.2	7.4	7.7	8.0	8.3	8.6	8.9
Africa	3.2	3.2	3.1	3.1	3.2	3.2	3.3	3.2	3.3	3.3	3.4	3.5	3.6	3.7	3.8
Total Non-OECD	37.7	39.5	40.2	39.8	39.3	40.1	41.1	41.4	41.2	40.9	42.5	44.0	45.5	46.9	48.2
Total Demand[1]	84.3	83.9	85.1	85.7	84.8	85.9	85.9	86.7	87.0	86.4	87.7	88.9	90.0	91.0	91.9
OECD SUPPLY															
North America	13.5	13.4	13.5	13.7	13.6	13.8	13.6	13.2	13.5	13.5	13.4	13.3	13.3	13.4	13.7
Europe	4.9	4.5	4.2	4.5	4.5	4.5	4.1	4.1	4.3	4.2	4.0	3.8	3.6	3.6	3.3
Pacific	0.7	0.6	0.7	0.6	0.6	0.6	0.7	0.7	0.8	0.7	0.7	0.7	0.6	0.5	0.5
Total OECD	19.1	18.5	18.5	18.9	18.7	18.8	18.5	18.1	18.6	18.5	18.1	17.8	17.5	17.5	17.5
NON-OECD SUPPLY															
FSU	13.0	13.2	13.4	13.5	13.3	13.5	13.6	13.5	13.8	13.6	13.7	13.7	13.5	13.7	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	3.7	3.8	3.8	3.8	3.8	4.0	4.0	4.0	4.0	4.0	3.9	4.0	3.9	3.9	3.7
Other Asia	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.7	3.7	3.7	3.7	3.6	3.6	3.6	3.6
Latin America	3.8	3.9	3.9	4.0	3.9	4.0	4.1	4.1	4.2	4.1	4.4	4.5	4.7	5.0	5.1
Middle East	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.6	1.5	1.5
Africa	2.6	2.5	2.5	2.5	2.5	2.6	2.5	2.5	2.5	2.5	2.6	2.6	2.5	2.5	2.4
Total Non-OECD	28.5	28.8	29.0	29.2	28.9	29.5	29.6	29.6	30.0	29.7	30.2	30.1	30.0	30.3	30.3
Processing Gains[2]	2.3	2.3	2.3	2.3	2.3	2.2	2.2	2.2	2.2	2.2	2.2	2.3	2.3	2.3	2.3
Global Biofuels[3]	1.5	1.6	1.6	1.7	1.6	1.8	1.8	1.9	1.9	1.8	2.1	2.2	2.3	2.4	2.4
Total Non-OPEC[4]	51.4	51.1	51.4	52.1	51.5	52.3	52.1	51.8	52.6	52.2	52.6	52.4	52.1	52.5	52.5
OPEC															
Crude[5]	28.6	28.5	28.8	29.0	28.7	29.1									
OPEC NGLs	4.6	4.5	4.7	4.8	4.7	5.1	5.2	5.5	5.8	5.4	6.3	6.6	6.9	7.1	7.2
Total OPEC	33.2	33.0	33.5	33.8	33.4	34.2									
Total Supply	84.6	84.2	84.9	85.9	84.9	86.5									
Memo items:															
Call on OPEC crude + Stock ch.[6]	28.3	28.2	29.0	28.8	28.6	28.5	28.5	29.4	28.6	28.8	28.8	29.8	31.0	31.4	32.2

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

2 Net volumetric gains and losses in the refining process (excludes net gain/loss in China and non-OECD Europe) 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, ethanol and MTBE.

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

6 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)

	1Q09	2Q09	3Q09	4Q09	2009	1Q10	2Q10	3Q10	4Q10	2010	2011	2012	2013	2014	2015
OECD DEMAND															
North America	0.0	0.0	-0.1	0.1	0.0	0.1	0.2	0.0	-0.2	0.0	-0.1	-0.3	-0.4	-0.5	
Europe	0.0	0.0	0.0	-0.4	-0.1	-0.7	-0.1	0.0	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	
Pacific	0.0	0.0	0.0	0.1	0.0	0.2	0.1	0.0	0.2	0.1	0.2	0.1	0.1	0.1	
Total OECD	0.0	0.0	-0.1	-0.1	-0.1	-0.4	0.2	0.0	-0.2	-0.1	-0.2	-0.4	-0.5	-0.7	
NON-OECD DEMAND															
FSU	0.0	0.0	0.0	-0.1	0.0	0.0	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-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	0.4	0.1	0.6	0.4	0.3	0.4	0.4	0.6	0.7	0.9	1.0	
Other Asia	0.0	0.0	0.1	0.2	0.1	-0.2	-0.1	0.0	0.2	0.0	0.0	0.0	0.0	0.0	
Latin America	0.0	0.0	0.0	0.1	0.1	0.1	0.0	0.0	0.1	0.1	0.1	0.1	0.2	0.2	
Middle East	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.3	-0.2	-0.2	-0.2	-0.2	-0.2	
Africa	0.0	0.0	0.0	-0.2	-0.1	-0.1	0.0	0.0	0.0	-0.1	0.0	0.0	0.0	0.0	
Total Non-OECD	-0.2	-0.2	-0.1	0.3	0.0	0.2	0.1	0.0	0.4	0.2	0.4	0.6	0.7	0.9	
Total Demand	-0.2	-0.2	-0.2	0.2	-0.1	-0.2	0.2	0.0	0.2	0.1	0.2	0.2	0.2	0.1	
OECD SUPPLY															
North America	0.0	0.2	0.1	0.2	0.1	0.3	0.5	0.5	0.4	0.4	0.3	0.2	0.2	0.5	
Europe	0.0	0.0	0.0	0.3	0.1	0.2	0.2	0.3	0.3	0.2	0.2	0.2	0.1	0.1	
Pacific	0.0	0.0	0.0	0.0	0.0	-0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Total OECD	0.0	0.2	0.1	0.4	0.2	0.4	0.7	0.8	0.7	0.6	0.5	0.4	0.4	0.6	
NON-OECD SUPPLY															
FSU	0.0	0.0	0.0	-0.1	0.0	-0.2	-0.3	-0.2	-0.1	-0.2	-0.1	-0.1	0.0	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	-0.1	-0.1	-0.1	-0.1	-0.1	
Other Asia	0.0	0.0	0.0	0.0	0.0	-0.1	-0.1	-0.1	-0.1	-0.1	-0.2	-0.2	-0.2	0.0	
Latin America	0.0	0.0	0.0	0.1	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.1	
Middle East	0.0	0.0	0.0	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.1	
Africa	0.0	0.0	0.0	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	
Total Non-OECD	0.1	0.1	0.1	0.0	0.1	-0.1	-0.2	-0.1	-0.1	-0.1	-0.2	-0.2	-0.2	0.3	
Processing Gains	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Global Biofuels	0.0	0.0	0.0	0.1	0.0	0.1	0.1	0.0	0.0	0.1	0.1	0.2	0.2	0.2	
Total Non-OPEC	0.1	0.3	0.2	0.4	0.3	0.4	0.6	0.7	0.6	0.6	0.5	0.3	0.4	1.2	
OPEC NGLs	0.0	-0.1	-0.4	-0.3	-0.2	-0.3	-0.3	-0.3	-0.2	-0.3	-0.1	0.0	-0.1	-0.2	
Memo items:															
Call on OPEC crude + Stock ch.	-0.3	-0.3	-0.1	0.0	-0.2	-0.3	0.0	-0.4	-0.3	-0.2	-0.2	-0.1	-0.2	-0.8	

Table 2
SUMMARY OF GLOBAL OIL DEMAND

	1Q09	2Q09	3Q09	4Q09	2009	1Q10	2Q10	3Q10	4Q10	2010	2011	2012	2013	2014	2015
Demand (mb/d)															
North America	23.52	22.91	23.25	23.48	23.29	23.53	23.33	23.57	23.45	23.47	23.37	23.29	23.19	23.07	22.94
Europe	14.90	14.24	14.46	14.39	14.50	14.11	14.19	14.57	14.55	14.36	14.33	14.25	14.14	14.01	13.87
Pacific	8.14	7.30	7.27	8.01	7.68	8.19	7.22	7.17	7.88	7.61	7.47	7.32	7.18	7.04	6.91
Total OECD	46.56	44.45	44.98	45.88	45.46	45.83	44.74	45.31	45.88	45.44	45.17	44.85	44.50	44.12	43.72
Asia	17.53	18.65	18.62	18.99	18.45	19.10	19.54	19.11	19.47	19.31	20.11	20.88	21.63	22.35	23.03
Middle East	6.54	7.12	7.59	6.96	7.06	6.91	7.40	7.87	7.23	7.35	7.68	8.00	8.31	8.61	8.90
Latin America	5.81	5.99	6.11	6.17	6.02	6.05	6.22	6.29	6.34	6.23	6.42	6.62	6.82	7.02	7.21
FSU	3.85	3.75	3.97	3.92	3.87	4.09	3.93	4.13	4.09	4.06	4.17	4.25	4.33	4.39	4.43
Africa	3.22	3.19	3.14	3.09	3.16	3.20	3.29	3.25	3.31	3.26	3.38	3.49	3.59	3.70	3.81
Europe	0.76	0.76	0.74	0.73	0.75	0.73	0.75	0.74	0.73	0.74	0.75	0.77	0.79	0.81	0.82
Total Non-OECD	37.71	39.48	40.16	39.84	39.31	40.08	41.14	41.39	41.16	40.95	42.52	44.02	45.47	46.87	48.21
World	84.27	83.92	85.14	85.72	84.77	85.91	85.88	86.70	87.04	86.39	87.69	88.87	89.98	90.99	91.93
of which:															
US50	*18.96*	*18.54*	*18.70*	*18.86*	*18.77*	*18.91*	*18.90*	*18.90*	*18.77*	*18.87*	*18.77*	*18.68*	*18.58*	*18.47*	*18.35*
Euro5	*9.41*	*8.85*	*8.92*	*8.88*	*9.01*	*8.78*	*8.72*	*8.90*	*8.92*	*8.83*	*8.77*	*8.68*	*8.57*	*8.44*	*8.32*
China	*7.65*	*8.61*	*8.84*	*8.92*	*8.51*	*9.09*	*9.31*	*9.12*	*9.12*	*9.16*	*9.69*	*10.20*	*10.69*	*11.17*	*11.63*
Japan	*4.72*	*4.03*	*4.10*	*4.59*	*4.36*	*4.77*	*3.92*	*3.98*	*4.44*	*4.28*	*4.12*	*3.96*	*3.83*	*3.69*	*3.55*
India	*3.36*	*3.30*	*3.09*	*3.30*	*3.26*	*3.36*	*3.37*	*3.17*	*3.42*	*3.33*	*3.44*	*3.53*	*3.63*	*3.72*	*3.81*
Russia	*2.64*	*2.60*	*2.80*	*2.73*	*2.69*	*2.85*	*2.75*	*2.95*	*2.87*	*2.85*	*2.91*	*2.97*	*3.01*	*3.05*	*3.08*
Brazil	*2.43*	*2.53*	*2.62*	*2.68*	*2.57*	*2.59*	*2.65*	*2.71*	*2.77*	*2.68*	*2.78*	*2.87*	*2.96*	*3.06*	*3.15*
Saudi Arabia	*2.15*	*2.70*	*2.92*	*2.41*	*2.54*	*2.42*	*2.83*	*3.05*	*2.55*	*2.71*	*2.87*	*3.03*	*3.20*	*3.36*	*3.52*
Canada	*2.20*	*2.08*	*2.16*	*2.16*	*2.15*	*2.16*	*2.11*	*2.25*	*2.22*	*2.19*	*2.17*	*2.15*	*2.13*	*2.12*	*2.10*
Korea	*2.34*	*2.17*	*2.07*	*2.29*	*2.22*	*2.34*	*2.18*	*2.07*	*2.30*	*2.22*	*2.22*	*2.22*	*2.21*	*2.21*	*2.20*
Mexico	*2.05*	*2.01*	*2.10*	*2.14*	*2.08*	*2.14*	*2.05*	*2.13*	*2.15*	*2.12*	*2.13*	*2.15*	*2.17*	*2.18*	*2.18*
Iran	*1.68*	*1.64*	*1.63*	*1.66*	*1.65*	*1.66*	*1.67*	*1.69*	*1.70*	*1.68*	*1.73*	*1.78*	*1.83*	*1.87*	*1.91*
Total	*59.59*	*59.05*	*59.94*	*60.63*	*59.81*	*61.07*	*60.46*	*60.92*	*61.22*	*60.92*	*61.61*	*62.23*	*62.81*	*63.33*	*63.80*
% of World	*70.72*	*70.37*	*70.41*	*70.73*	*70.56*	*71.09*	*70.40*	*70.26*	*70.34*	*70.52*	*70.25*	*70.03*	*69.81*	*69.60*	*69.40*
Annual Change (% per annum)															
North America	-5.1	-6.2	-1.4	-1.9	-3.7	0.0	1.8	1.4	-0.1	0.8	-0.4	-0.4	-0.4	-0.5	-0.6
Europe	-2.5	-5.6	-6.8	-6.8	-5.4	-5.3	-0.3	0.7	1.1	-1.0	-0.2	-0.6	-0.8	-0.9	-1.0
Pacific	-8.6	-7.2	-3.5	0.5	-4.8	0.6	-1.1	-1.3	-1.6	-0.9	-1.9	-2.0	-1.9	-1.9	-1.9
Total OECD	-4.9	-6.1	-3.5	-3.1	-4.4	-1.6	0.7	0.7	0.0	-0.1	-0.6	-0.7	-0.8	-0.9	-0.9
Asia	-1.6	4.0	6.7	12.1	5.3	9.0	4.8	2.7	2.5	4.6	4.2	3.8	3.6	3.3	3.1
Middle East	0.9	2.9	3.1	3.4	2.6	5.7	3.9	3.7	3.9	4.2	4.4	4.2	3.9	3.6	3.3
Latin America	-0.3	-1.4	-0.8	2.2	-0.1	4.1	3.8	3.0	2.8	3.4	3.1	3.1	3.0	2.9	2.8
FSU	-5.2	-6.7	-6.7	-3.6	-5.6	6.1	4.7	4.2	4.5	4.8	2.7	2.0	1.7	1.4	1.1
Africa	2.1	1.5	1.3	-2.6	0.5	-0.4	3.0	3.6	7.0	3.3	3.6	3.1	3.1	3.1	3.0
Europe	-4.5	-1.1	-0.9	-6.4	-3.2	-4.4	-1.3	-0.3	0.2	-1.5	2.4	2.7	2.3	1.9	1.6
Total Non-OECD	-1.1	1.5	2.8	5.7	2.2	6.3	4.2	3.1	3.3	4.2	3.8	3.5	3.3	3.1	2.9
World	-3.3	-2.7	-0.6	0.8	-1.4	1.9	2.3	1.8	1.5	1.9	1.5	1.3	1.2	1.1	1.0
Annual Change (mb/d)															
North America	-1.25	-1.51	-0.33	-0.46	-0.88	0.01	0.42	0.32	-0.03	0.18	-0.10	-0.08	-0.10	-0.12	-0.13
Europe	-0.39	-0.84	-1.06	-1.05	-0.83	-0.79	-0.04	0.11	0.16	-0.14	-0.03	-0.08	-0.11	-0.13	-0.14
Pacific	-0.77	-0.56	-0.26	0.04	-0.39	0.05	-0.08	-0.10	-0.13	-0.07	-0.14	-0.15	-0.14	-0.14	-0.13
Total OECD	-2.40	-2.91	-1.65	-1.46	-2.11	-0.73	0.30	0.33	0.00	-0.02	-0.27	-0.32	-0.35	-0.39	-0.40
Asia	-0.29	0.72	1.18	2.06	0.92	1.57	0.90	0.49	0.48	0.86	0.81	0.77	0.75	0.72	0.68
Middle East	0.06	0.20	0.23	0.23	0.18	0.37	0.28	0.28	0.27	0.30	0.33	0.32	0.31	0.30	0.29
Latin America	-0.02	-0.09	-0.05	0.13	0.00	0.24	0.23	0.18	0.18	0.21	0.19	0.20	0.20	0.20	0.20
FSU	-0.21	-0.27	-0.29	-0.15	-0.23	0.24	0.18	0.17	0.17	0.19	0.11	0.08	0.07	0.06	0.05
Africa	0.07	0.05	0.04	-0.08	0.02	-0.01	0.09	0.11	0.22	0.10	0.12	0.11	0.11	0.11	0.11
Europe	-0.04	-0.01	-0.01	-0.05	-0.02	-0.03	-0.01	0.00	0.00	-0.01	0.02	0.02	0.02	0.02	0.01
Total Non-OECD	-0.43	0.60	1.10	2.14	0.86	2.37	1.66	1.23	1.32	1.64	1.57	1.50	1.45	1.40	1.34
World	-2.84	-2.31	-0.55	0.68	-1.24	1.64	1.96	1.56	1.32	1.62	1.30	1.18	1.10	1.02	0.94
Revisions to Oil Demand from Last Medium Term Report (mb/d)															
North America	0.00	0.00	-0.06	0.10	0.01	0.08	0.20	-0.02	-0.18	0.02	-0.13	-0.25	-0.39	-0.53	
Europe	-0.01	0.00	-0.01	-0.36	-0.09	-0.70	-0.09	-0.04	-0.25	-0.27	-0.26	-0.26	-0.27	-0.28	
Pacific	0.00	0.00	0.00	0.11	0.03	0.24	0.09	0.03	0.25	0.15	0.15	0.14	0.12	0.09	
Total OECD	-0.01	0.00	-0.08	-0.14	-0.06	-0.38	0.19	-0.03	-0.19	-0.10	-0.23	-0.38	-0.54	-0.73	
Asia	-0.05	-0.02	0.07	0.59	0.15	0.40	0.29	0.26	0.64	0.40	0.57	0.72	0.85	0.99	
Middle East	-0.17	-0.19	-0.17	-0.18	-0.18	-0.16	-0.20	-0.18	-0.27	-0.21	-0.19	-0.18	-0.18	-0.18	
Latin America	0.04	0.04	0.02	0.12	0.05	0.09	0.05	0.01	0.13	0.07	0.10	0.12	0.16	0.20	
FSU	-0.04	-0.03	-0.04	-0.07	-0.05	-0.03	-0.07	-0.07	-0.09	-0.06	-0.05	-0.09	-0.14	-0.22	
Africa	-0.02	-0.02	-0.02	-0.16	-0.05	-0.14	-0.03	-0.01	-0.04	-0.05	-0.02	0.00	0.02	0.05	
Europe	0.04	0.04	0.03	0.01	0.03	-0.01	0.01	0.02	0.00	0.01	0.01	0.01	0.01	0.01	
Total Non-OECD	-0.20	-0.18	-0.10	0.33	-0.04	0.16	0.05	0.04	0.38	0.16	0.41	0.59	0.72	0.85	
World	-0.21	-0.18	-0.17	0.18	-0.09	-0.22	0.25	0.01	0.19	0.06	0.18	0.21	0.18	0.13	
Revisions to Oil Demand Growth from Last Medium Term Report (mb/d)															
World	0.13	-0.13	-0.03	0.47	0.11	-0.01	0.43	0.18	0.00	0.15	0.12	0.03	-0.03	-0.05	

Table 3
WORLD OIL PRODUCTION
(million barrels per day)

	1Q09	2Q09	3Q09	4Q09	2009	1Q10	2Q10	3Q10	4Q10	2010	2011	2012	2013	2014	2015
OPEC															
Total NGLs[1]	4.59	4.53	4.69	4.83	4.66	5.09	5.21	5.53	5.76	5.40	6.25	6.64	6.89	7.11	7.25
NON-OPEC[2]															
OECD															
North America	13.55	13.38	13.55	13.74	13.55	13.75	13.64	13.23	13.53	13.54	13.42	13.33	13.27	13.43	13.66
United States	7.21	7.30	7.40	7.55	7.37	7.57	7.42	7.16	7.28	7.36	7.33	7.20	7.07	7.01	6.89
Mexico	3.04	2.97	2.94	2.95	2.97	2.99	2.97	2.90	2.87	2.93	2.75	2.61	2.51	2.52	2.49
Canada	3.31	3.12	3.21	3.24	3.22	3.19	3.25	3.17	3.38	3.25	3.34	3.51	3.69	3.90	4.28
Europe	4.88	4.46	4.24	4.52	4.52	4.45	4.14	4.12	4.28	4.25	3.99	3.79	3.62	3.55	3.34
UK	1.62	1.56	1.26	1.46	1.47	1.46	1.38	1.31	1.40	1.39	1.27	1.11	0.99	0.98	0.89
Norway	2.56	2.25	2.32	2.42	2.39	2.35	2.11	2.16	2.24	2.21	2.09	2.09	2.06	2.04	1.94
Others	0.69	0.66	0.66	0.64	0.66	0.64	0.65	0.65	0.64	0.64	0.63	0.60	0.56	0.53	0.51
Pacific	0.65	0.64	0.67	0.65	0.65	0.63	0.73	0.74	0.76	0.72	0.74	0.69	0.60	0.53	0.46
Australia	0.56	0.54	0.57	0.55	0.55	0.53	0.60	0.61	0.63	0.59	0.62	0.57	0.49	0.43	0.37
Others	0.09	0.09	0.10	0.10	0.10	0.10	0.13	0.13	0.13	0.12	0.12	0.12	0.11	0.10	0.09
Total OECD	19.07	18.48	18.45	18.91	18.73	18.83	18.51	18.09	18.57	18.50	18.15	17.82	17.49	17.51	17.46
NON-OECD															
Former USSR	13.02	13.24	13.37	13.47	13.28	13.50	13.62	13.46	13.75	13.58	13.73	13.68	13.54	13.69	13.81
Russia	10.06	10.16	10.26	10.36	10.21	10.39	10.43	10.39	10.45	10.42	10.43	10.34	10.23	10.18	10.22
Others	2.96	3.09	3.11	3.11	3.07	3.10	3.19	3.07	3.30	3.16	3.30	3.34	3.31	3.50	3.59
Asia	7.31	7.36	7.41	7.41	7.37	7.61	7.60	7.66	7.63	7.62	7.61	7.60	7.53	7.50	7.33
China	3.73	3.80	3.83	3.81	3.79	3.97	3.97	3.98	3.96	3.97	3.94	4.00	3.93	3.86	3.75
Malaysia	0.76	0.74	0.74	0.72	0.74	0.74	0.70	0.69	0.69	0.71	0.67	0.62	0.61	0.67	0.69
India	0.79	0.79	0.80	0.81	0.80	0.83	0.86	0.90	0.90	0.87	0.91	0.93	0.90	0.86	0.80
Indonesia	0.99	0.98	0.98	0.98	0.98	0.99	0.99	0.98	0.99	0.99	0.96	0.94	0.96	1.01	0.99
Others	1.05	1.05	1.07	1.08	1.06	1.08	1.08	1.09	1.09	1.08	1.12	1.11	1.12	1.10	1.09
Europe	0.14	0.13	0.14	0.14	0.14	0.13	0.13	0.13	0.13	0.13	0.13	0.11	0.10	0.09	0.09
Latin America	3.84	3.86	3.85	3.98	3.88	4.02	4.06	4.12	4.23	4.11	4.40	4.52	4.71	4.99	5.11
Brazil	2.00	2.01	2.03	2.07	2.03	2.09	2.11	2.16	2.25	2.15	2.36	2.44	2.60	2.78	2.87
Argentina	0.74	0.73	0.70	0.72	0.72	0.71	0.72	0.71	0.70	0.71	0.69	0.68	0.67	0.65	0.63
Colombia	0.64	0.66	0.67	0.73	0.67	0.76	0.77	0.80	0.83	0.79	0.91	0.96	1.00	1.08	1.13
Others	0.46	0.45	0.45	0.46	0.45	0.46	0.46	0.46	0.45	0.46	0.45	0.43	0.44	0.48	0.48
Middle East	1.67	1.69	1.71	1.70	1.69	1.70	1.70	1.71	1.71	1.70	1.72	1.66	1.60	1.55	1.50
Oman	0.79	0.80	0.83	0.83	0.81	0.86	0.86	0.88	0.89	0.87	0.93	0.91	0.90	0.88	0.87
Syria	0.39	0.39	0.38	0.38	0.38	0.37	0.37	0.37	0.36	0.37	0.35	0.32	0.29	0.26	0.24
Yemen	0.30	0.31	0.30	0.29	0.30	0.28	0.28	0.27	0.27	0.27	0.27	0.25	0.24	0.22	0.21
Others	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.18	0.17	0.17	0.18	0.18
Africa	2.55	2.55	2.55	2.54	2.55	2.56	2.53	2.53	2.54	2.54	2.58	2.56	2.53	2.49	2.45
Egypt	0.70	0.69	0.68	0.67	0.69	0.68	0.68	0.68	0.68	0.68	0.67	0.65	0.64	0.62	0.61
Equatorial Guinea	0.32	0.31	0.30	0.29	0.31	0.29	0.28	0.27	0.26	0.27	0.25	0.25	0.28	0.31	0.33
Sudan	0.46	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.45	0.41	0.38	0.34	0.31
Others	1.08	1.07	1.09	1.10	1.08	1.13	1.11	1.12	1.14	1.12	1.21	1.25	1.24	1.22	1.20
Total Non-OECD	28.54	28.82	29.03	29.23	28.91	29.52	29.64	29.62	30.00	29.69	30.16	30.14	30.01	30.32	30.27
Processing Gains[3]	2.29	2.29	2.29	2.29	2.29	2.20	2.20	2.20	2.20	2.20	2.23	2.26	2.29	2.30	2.32
Global Biofuels[4]	1.49	1.56	1.65	1.70	1.60	1.79	1.80	1.86	1.88	1.83	2.06	2.23	2.32	2.39	2.44
TOTAL NON-OPEC	51.39	51.15	51.42	52.12	51.52	52.34	52.15	51.76	52.65	52.22	52.60	52.44	52.11	52.51	52.50

1 Includes condensates reported by OPEC countries, oil from non-conventional sources, e.g. Venezuelan Orimulsion (but not Orinoco extra-heavy oil), and non-oil inputs to Saudi Arabian MTBE. Orimulsion production reportedly ceased from January 2007.
2 Comprises crude oil, condensates, NGLs and oil from non-conventional sources.
3 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	Peak Capacity (kbd)	Start Year
OECD North America			
USA	Shenzi	100	2009
USA	Tahiti	125	2009
USA	Thunder Hawk	45	2009
USA	Chinook & Cascade	80	2010
USA	Clipper	12	2010
USA	Droshky	45	2010
USA	Great White, Silver Tip & Tobago	100	2010
USA	Phoenix	30	2010
USA	Telemark	25	2010
USA	Caesar	40	2011
USA	Liberty	40	2011
USA	Nikaitchuq	60	2011
USA	Santa Cruz/Isabela	50	2011
USA	Kaskida	140	2013
USA	Big Foot	55	2014
USA	Jack/St Malo	150	2014
USA	Mad Dog tie-backs	50	2014
USA	Point Thomson	10	2014
USA	Tubular Bells	100	2014
Canada	Horizon 1	110	2009
Canada	Hibernia AA expansion	25	2010
Canada	North Amethyst, South White Rose	35	2010
Canada	Scotford phase 2	100	2010
Canada	Algar (Great Divide)	10	2011
Canada	Athabasca 2 - Jackpine 1A	100	2011
Canada	Athabasca 3 - Muskeg River expansion	100	2011
Canada	Christina Lake 1C (Cenovus)	40	2011
Canada	Firebag 3	68	2011
Canada	Jackfish 2	35	2011
Canada	Leismer	10	2011
Canada	Poplar Creek 1	10	2011
Canada	Black Gold 1	10	2012
Canada	Carmon Creek 1	50	2012
Canada	Firebag 4	68	2012
Canada	Great Divide exp	24	2012
Canada	Kearl 1	100	2012
Canada	May River	10	2012
Canada	McKay River	12	2012
Canada	Terre de Grace pilot	10	2012
Canada	Christina Lake 1D (Cenovus)	40	2013
Canada	CHRISTINA LAKE 2B (MEG)	35	2013
Canada	Saleski	10	2013
Canada	Scotford phase 3	100	2013
Canada	Voyageur	120	2013
Canada	Athabasca 4 - Jackpine 1B	100	2014
Canada	Borealis 1	50	2014
Canada	Chard 1	40	2014
Canada	CHRISTINA LAKE 3A (MEG)	50	2014
Canada	Firebag 5	68	2014
Canada	Grouse	60	2014
Canada	Horizon 2/3	120	2014
Canada	Kirby	45	2014
Canada	MacKay River 1	50	2014
Canada	Sunrise 1	50	2014
Canada	Tamarack 1	20	2014
Canada	Joslyn North	100	2015

Country	Project	Peak Capacity (kbd)	Start Year
Canada	Kearl 2	100	2015
Canada	Surmont 2	83	2015
Canada	Taiga	35	2015
Mexico	Chicontepec expansion	100	2008
Mexico	Kuil	10	2010
Mexico	Ayatsil	125	2013
Mexico	Tsimin	125	2013
OECD Europe			
Norway	Gjoa	10	2010
Norway	Morvin	20	2010
Norway	Trym	10	2010
Norway	Vega complex (North, Central, South)	10	2010
Norway	Oselvar	13	2011
Norway	Skarv	80	2011
Norway	Froy redevelopment	35	2012
Norway	Goliat	90	2013
Norway	Trestakk	50	2013
Norway	Gudrun	65	2014
Norway	Ekofisk extension	50	2015
Norway	Eldfisk extension	20	2015
UK	Lochranza	10	2010
UK	Alder	9	2011
UK	Athena	20	2011
UK	Bentley	10	2011
UK	Causeway	10	2011
UK	Perth	15	2011
UK	Cheviot	30	2012
UK	Clair expansion	35	2013
UK	Huntington	30	2013
UK	Jasmine	85	2013
UK	Kessog	25	2013
UK	Laggan-Tormore	15	2014
OECD Pacific			
Australia	Pyrenees	90	2010
Australia	Van Gogh	40	2010
Australia	Crux	25	2011
Australia	Kipper & Turrum	20	2011
Australia	Montara (and Skua & Swift)	35	2011
Australia	Gorgon gas	15	2014
FSU			
Russia	Uvat expansion	120	2009
Russia	Vankor	500	2009
Russia	Yuzhno Khylchuyuskoye	150	2009
Russia	Odoptu	30	2010
Russia	Yuri Korchagin	50	2010
Russia	Priobskoye exp	100	2011
Russia	Kharyaga expansion	20	2012
Russia	Prirazlomnoye	120	2012
Russia	Bolshekhetsky	100	2013
Russia	Yurubcheno-Tokhomskoye	200	2013
Russia	Vladimir Filanovsky	120	2014
Russia	Arkutun-Daginskoye	90	2015
Russia	Russkoye	175	2015
Azerbaijan	Chirag Oil Project	185	2013
Kazakhstan	Karachaganak expansion (phase 3)	100	2012
Kazakhstan	Kashagan phase 1	450	2013

Country	Project	Peak Capacity (kbd)	Start Year
Asia			
China	Jidong Nanpu	200	2009
China	Penglai-3	75	2009
China	Changqing expansion	100	2010
East Timor	Kitan	20	2011
India	Mangala	150	2009
India	Aishwariya	40	2010
India	B-22 cluster	15	2012
India	Bhagyama	50	2012
Indonesia	Tuban expansion	10	2010
Indonesia	North Duri steam flood phases 2 & 3	45	2012
Indonesia	Aster	30	2013
Indonesia	Bukit Tua	20	2013
Indonesia	Gendalo/Gehem	25	2014
Vietnam	Doi Moi	75	2010
Vietnam	Chim Sao	25	2011
Vietnam	Hai Su Den/Hai Su Trang	35	2011
Vietnam	Te Giac Trang	40	2011
Malaysia	Gumusut	135	2013
Malaysia	Ubah	50	2014
Malaysia	Malikai	50	2015
Latin America			
Brazil	Frade	90	2009
Brazil	Jabuti	100	2009
Brazil	Marlim Sul 2 - P-51	150	2009
Brazil	Parque das Conchas - BC-10	100	2009
Brazil	Albacore expansion	100	2010
Brazil	Cachalote	100	2010
Brazil	Tupi pilot (Tupi phase 1)	100	2010
Brazil	Urugua/Tambau	35	2010
Brazil	Chinook/Peregrino	100	2011
Brazil	Marlim Sul 3 - P-56	100	2011
Brazil	Baleia Azul	100	2012
Brazil	Jubarte 2 P-57	180	2012
Brazil	Tupi phase 2	100	2012
Brazil	Espadarte module 3	100	2013
Brazil	Guara	100	2013
Brazil	Papa Terra - BC-20	140	2013
Brazil	Sidon/Tiro	60	2013
Brazil	Roncador P-55	150	2014
Brazil	Roncador P-62	150	2014
Brazil	Iara	100	2015
Brazil	Parque das Baleias	150	2015
Colombia	Rubiales expansion 2	80	2010
Colombia	Castilla expansion	100	2011
Colombia	Quifa	30	2013
Middle East			
Oman	Harweel and other PDO EOR	40	2010
Oman	Amal East/West expansion	40	2012
Oman	Mukhaizna EOR	50	2012
Africa			
Equatorial Guinea	Aseng	50	2012
Equatorial Guinea	Belinda	50	2014
Ghana	Jubilee phase 1	120	2010
Uganda	Kasamene/Kingfisher	10	2011
Uganda	Albert Basin	100	2015

Table 3B: SELECTED OPEC UPSTREAM PROJECT START-UPS

Country	Project	Peak Capacity (kbd)	Start Year	Country	Project	Peak Capacity (kbd)	Start Year	Country	Project	Peak Capacity (kbd)	Start Year
Crude Oil Projects								*NGL & Condensate Projects*			
Algeria	ROM Integrated	20	2010	Iraq	Al Ahdab	50	2012	Algeria	MLE (Condensate)	10	2012
Algeria	Bir Seba (Blocks 433a/416b)	36	2011	Iraq	Gharaf	230	2014	Algeria	MLE (NGLs)	14	2012
Algeria	IAN/EOR	30	2012	Iraq	Badra	170	2014	Algeria	El Merk (Condensate)	55	2012
Algeria	Menzel Ledjmet East (MLE Block 405b)	8	2012	Iraq	Tawke	50	2011	Algeria	El Merk (NGLs)	30	2012
Algeria	Takouazet	50	2012	Iraq	Taq Taq	60	2011	Algeria	Tisselit Nord Condensate	10	2012
Algeria	El Merk	135	2012	Kuwait	Burgan (Water treatment)	120	2013	Iran	Pars 6-8 (Condensate)	152	2009
Angola	Tombua-Landana (Block 14)	100	2009	Kuwait	Sabriya GC-24	160	2014	Iran	Pars 6-8 (NGLs)	50	2009
Angola	Sangos/N'Goma (Block 15)	85	2013	Kuwait	Offshore Eocene (Khafji/Hout)	40	2010	Iran	Bidboland NGLs	120	2011
Angola	PAZFLOR (Block 17)	200	2011	Libya	Amal	90	2010	Iran	Bidboland Condesate	20	2011
Angola	PSVM (Block 31)	150	2012	Libya	WAHA Deveolpment	60	2011	Iran	Pars 9&10 Condensate	80	2010
Angola	Kizomba D--Satellites (Block 15) Clochas & Mav	140	2012	Libya	Gialo Expansion	100	2013	Iran	Pars 9&10 NGLs	80	2010
Angola	Platino, Chumbo, Cesio (Block 18W)	150	2013	Libya	NC186 expansion	35	2013	Iran	S. Par 12 NGLS	6	2014
Angola	SE PAJ (Block 31)	150	2013	Libya	Area 47 Ghadames Basin	50	2013	Iran	S. Par 12 Condensate	60	2014
Angola	Terra Miranda, Cordelia, Portia (Block 31)	150	2013	Libya	Zuetina expansion	50	2014	Iran	Kharg NGLs	50	2013
Angola	Gindungo, Canela, Gengibre (Block 32)	200	2013	Libya	Nafoora expansion	130	2014	Kuwait	Sabriyah & Umm Niqa II	115	2012
Angola	Cabaca Norte-1 (Block 15)	200	2014	Nigeria	EA Field	115	2009	Libya	NC-98	60	2013
Angola	Negage (Block 14)	50	2014	Nigeria	Ofon 2	60	2010	Nigeria	Akpo	175	2009
Angola	Lucapa (Block 14)	130	2014	Nigeria	Usan	180	2013	Nigeria	Gbaran/Ubie	70	2010
Angola	CLOV (Block 17)	160	2014	Nigeria	Oyo	29	2010	Qatar	Qatargas II Train 4 & 5	140	2009
Ecuador	Pungarayacu field--Phase 1	30	2013	Nigeria	Nsiko	100	2015	Qatar	RasGas Train 6 & 7 (NGL)	45	2009
Ecuador	Other	25	2013	Nigeria	Egina	200	2014	Qatar	RasGas Train 6 (condensate)	100	2009
Iran	Aghajari	30	2009	Qatar	Al Shaheen increments	100	2010	Qatar	Qatargas II Train 5 & 6 (NGL)	21	2009
Iran	Azadegan II	100	2014	Qatar	Al Rayyan	50	2010	Qatar	Qatargas 6-7 (condensate)	140	2010
Iran	Cheshmeh Kosh	44	2009	Saudi Arabia	Shaybah 2	250	2009	Qatar	Al Khaleej 2 (Condensate)	40	2009
Iran	Jufeyr	25	2010	Saudi Arabia	Nuayyim	100	2009	Qatar	Al Khaleej 2 (NGLs)	72	2009
Iran	South Pars	35	2011	Saudi Arabia	Khurais (incl Abu Jifan & Mazalij)	1200	2009	Qatar	Pearl GTL - 1	70	2011
Iran	Khesht	35	2010	Saudi Arabia	Manifa	900	2014	Qatar	Pearl GTL - 2	70	2014
Iran	Foroozan	65	2012	Saudi Arabia	Offshore Eocene (Khafji/Hout)	40	2010	Qatar	Oryx GTL	65	2012
Iran	Yadavaran I	85	2013	UAE	Umm Shaif Expansion	75	2011	S. Arabia	Khursaniyah (condensate)	80	2010
Iran	Paranj	50	2013	UAE	Lower Zakum expansion	100	2012	S. Arabia	Khursaniyah (NGLs)	210	2010
Iraq	Nassiriyah	25	2009	UAE	Upper Zakum expansion	250	2013	S. Arabia	Hawiyah NGL Complex	310	2009
Iraq	Rumaila Phase 1	200	2011	UAE	Nasr	25	2015	S. Arabia	Khurais (Condensate)	70	2010
Iraq	Rumaila Phase 2	200	2012	UAE	ADCO Onshore-Sahil, Asab, Shah	75	2012	S. Arabia	Manifa (Condensate)	65	2014
Iraq	W. Qurna 1 Phase 1	200	2011	UAE	ADCO Onshore Qusawirah\Bidah al Qemzan	65	2013	S. Arabia	Hasbah	30	2014
Iraq	W. Qurna 2 Phase 1	150	2012	UAE	Bab Rumaitha/Al-Dabbiya (NE)	75	2013	S. Arabia	Shaybah (NGLs)	40	2014
Iraq	W. Qurna 2 Phase 2	200	2014	Venezuela	Corocoro	100	2010	UAE	OGD 3 Habshan (Condensate)	120	2010
Iraq	Majnoon Phase 1	200	2013	Venezuela	Junin Block 2-PetroVietnam	200	2012	UAE	OGD 3 Habshan (NGLs)	120	2010
Iraq	Zubair Phase 1	100	2012	Venezuela	Junin Block 4--CNPC	400	2013	UAE	Asab 2 NGL	80	2009
Iraq	Zubair Phase 2	100	2013	Venezuela	Junin Block 5--ENI	240	2013	UAE	IGD--Integrated Gas Dev. (Condensate)	30	2013
Iraq	Halfaya	100	2014	Venezuela	Carabobo 1	400	2013	UAE	IGD--Integrated Gas Dev. (NGLs)	110	2013

Table 4
WORLD ETHANOL PRODUCTION[1]

(thousand barrels per day)

	2009	2010	2011	2012	2013	2014	2015
OECD North America	723	872	925	969	998	1,015	1,026
United States	702	846	895	936	965	979	989
Canada	20	24	28	31	32	35	35
OECD Europe	57	67	80	88	91	94	94
Austria	2	2	2	2	2	2	2
Belgium	3	3	3	3	3	3	3
France	15	15	17	17	18	18	18
Germany	14	15	16	17	17	17	17
Italy	1	2	2	2	3	3	3
Netherlands	1	3	6	7	7	7	7
Poland	2	4	5	5	6	7	7
Spain	7	8	10	10	10	10	10
UK	3	4	8	8	9	9	9
OECD Pacific	4	4	6	6	7	8	8
Australia	4	4	5	6	7	7	7
Total OECD	**784**	**943**	**1,011**	**1,062**	**1,097**	**1,118**	**1,129**
FSU	1	2	6	8	8	8	8
Non-OECD Europe	1	1	1	1	1	1	1
China	36	36	37	39	40	41	41
Other Asia	14	18	26	36	38	38	39
India	4	4	5	5	5	5	5
Indonesia	1	2	2	3	4	4	4
Malaysia	0	0	0	0	0	0	0
Philippines	0	0	1	2	2	3	3
Singapore	1	1	1	1	1	1	1
Thailand	7	9	14	20	20	20	20
Latin America	476	523	594	654	693	726	755
Argentina	1	1	1	1	1	1	1
Brazil	462	507	578	636	674	707	736
Colombia	6	7	7	9	9	9	9
Middle East	0	0	0	0	0	0	0
Africa	2	3	5	6	8	8	8
Total Non-OECD	**529**	**582**	**670**	**745**	**788**	**822**	**852**
Total World	**1,313**	**1,525**	**1,681**	**1,807**	**1,884**	**1,940**	**1,981**

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 PRODUCTION[1]

(thousand barrels per day)

	2009	2010	2011	2012	2013	2014	2015
OECD North America	36	35	54	64	67	73	74
United States	36	33	50	59	62	68	69
Canada	0	2	4	5	5	5	5
OECD Europe	153	159	179	192	197	198	200
Austria	4	4	4	4	4	4	4
Belgium	5	7	7	7	7	7	7
France	46	47	47	49	49	49	49
Germany	44	44	48	49	49	49	49
Italy	7	7	13	16	16	16	16
Netherlands	1	3	11	15	19	19	19
Poland	2	4	5	5	6	7	7
Spain	10	12	14	15	16	16	16
UK	8	8	8	8	8	9	10
OECD Pacific	4	5	7	7	7	7	7
Australia	1	2	3	3	3	3	3
Total OECD	**194**	**199**	**241**	**263**	**271**	**279**	**282**
FSU	1	1	3	3	3	3	3
Non-OECD Europe	2	2	2	2	2	2	2
China	6	6	6	7	7	7	7
Other Asia	26	31	42	52	52	53	53
India	2	2	3	3	3	3	3
Indonesia	5	7	7	7	7	7	7
Malaysia	5	6	8	8	8	8	8
Philippines	2	2	2	3	3	4	4
Singapore	2	4	11	16	16	16	16
Thailand	10	10	10	14	14	14	14
Latin America	56	66	83	95	103	104	104
Argentina	24	26	34	37	42	43	43
Brazil	28	37	45	50	53	53	53
Colombia	3	3	3	4	4	4	4
Middle East	0	0	0	0	0	0	0
Africa	0	0	0	1	1	3	6
Total Non-OECD	**92**	**107**	**136**	**160**	**168**	**173**	**176**
Total World	**286**	**306**	**377**	**423**	**439**	**451**	**458**

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	Capacity (kbd)	Capacity (mly)	Start Year
OECD North America					
USA	Aventine Renewable Energy - Aurora, Nebraska	ethanol	7	428	2010
USA	Aventine Renewable Energy - Mt Vernon, Indiana	ethanol	7	428	2010
USA	Metro Energy - New York, New York	biodiesel	7	416	2010
USA	Homeland Energy Solution - New Hampton, Iowa	ethanol	7	379	2010
USA	Abengoa - Mt Vernon, Indiana	ethanol	6	333	2010
USA	Abengoa - Madison, Illinois	ethanol	6	333	2010
USA	Dynamic Fuels - Geismar, Louisiana	biodiesel (BTL)	5	284	2010
USA	Biodiesel of Las Vegas - Las Vegas, Nevada	biodiesel	7	379	2011
USA	AltAir/Tesoro - Anacortes, Washington	biodiesel/biojet	7	379	2012
USA	Vercipia (Verenium/BP) - Highlands County, Florida	cellulosic ethanol	2	136	2012
USA	POET - Emmetsburg, Iowa	cellulosic ethanol	2	95	2012
OECD Europe					
Netherlands	Abengoa - Rotterdam	ethanol	8	480	2010
Netherlands	Neste Oil - Rotterdam	biodiesel (BTL)	15	899	2011
Portugal	Greencyber - Sines	biodiesel	5	281	2013
UK	Ensus - Teeside	ethanol	7	400	2009
UK	Vivergo - Hull	ethanol	7	400	2011
Asia					
Singapore	Neste Oil - Singapore	biodiesel (BTL)	15	899	2010
Latin America					
Argentina	Louis Dreyfus Commodities - Bahia Blanca	biodiesel	6	337	2011
Argentina	Patagonia Bioenergia - San Lorenzo	biodiesel	5	281	2013
Brazil	Petrobras - Parana	biodiesel	5	298	2012

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

	2010	2011	2012	2013	2014	2015	Total
Crude Distillation Additions and Expansions[1]							
OECD North America	207	70	400	75	15	95	862
OECD Europe	91	-61	110	26			166
OECD Pacific	-139	-51					-190
FSU	80	20	414	70			584
Non-OECD Europe			50			50	100
China	560	366	450	730	620	540	3,266
Other Asia	252	426	64	315	375	80	1,512
Latin America	73		55	250	335	300	1,013
Middle East	160	130	80	21	817	146	1,354
Africa	35	100	144		28	30	337
Total World	1,320	999	1,767	1,487	2,190	1,241	9,004
Upgrading Capacity Additions[2]							
OECD North America	152	227	205	168	125	50	927
OECD Europe	57	107	175	55	115		510
OECD Pacific	25	48	52	113			238
FSU	79	55	370	45		37	586
Non-OECD Europe		26	50	43			119
China	297	214	295	462	250	95	1,612
Other Asia	82	270	262	240	220	40	1,114
Latin America	85	30	49	215	294	130	803
Middle East	105	146	94	135	457	25	962
Africa	45	8	25		57		135
Total World	928	1,130	1,577	1,477	1,518	377	7,006
Desulphurisation Capacity Additions[3]							
OECD North America	456	386	175	115	145	30	1,307
OECD Europe	41	89	76		35		241
OECD Pacific	49	-49	66				66
FSU	65	30	235				330
Non-OECD Europe	3	8	65				77
China	407	192	358	510	418	115	2,000
Other Asia	243	223	180	185	214	26	1,071
Latin America	345	210	213	347	165	205	1,485
Middle East	255	190	346	256	335	40	1,422
Africa	55	95	5		42		197
Total World	1,919	1,374	1,719	1,413	1,354	416	8,195

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)

	2009	2010	2011	2012	2013	2014	Total
Crude Distillation Additions and Expansions[1]							
OECD North America	121	-203		75	60		54
OECD Europe	-100	-74	-139				-313
OECD Pacific	-57	-174	-101				-332
FSU	60	80	20	74	70		304
Non-OECD Europe							
China	239	240	-190	160	190	20	659
Other Asia	-70	8	276	-111	-196	255	163
Latin America		30	-25	25		85	115
Middle East	107	90		-157	-60		-20
Africa	100	-100	20	-10		28	38
Total World	400	-102	-140	56	65	388	667
Upgrading Capacity Additions[2]							
OECD North America	121	-87	-28	25	30	40	102
OECD Europe		-1	-15	-18	20	50	37
OECD Pacific		25	-25				
FSU				-15	45		30
Non-OECD Europe					43		43
China	-26	149	-26	175	152	-61	363
Other Asia	-5	-60	131	117	-102	201	282
Latin America			-29	29		60	60
Middle East		25	35	-10			50
Africa				5			5
Total World	90	52	44	308	188	290	972
Desulphurisation Capacity Additions[3]							
OECD North America	112	-73		25	-80	85	69
OECD Europe	-24	-34	35	-25		15	-33
OECD Pacific		49	-134				-85
FSU							
Non-OECD Europe							
China	48	92	-6	262	96	-91	401
Other Asia	-20	40	81	70	-110	160	221
Latin America			-78	58	20	70	70
Middle East	49	-25	-11	158			171
Africa		35	15	5		42	97
Total World	165	83	-98	553	-74	281	910

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 DISTILATION PROJECT LIST

Country	Project	Capacity (kbd)[1]	Start Year	Country	Project	Capacity (kbd)[1]	Start Year
OECD North America				China	Sinopec - Yangzi	60	2013
Canada	Shell Canada Ltd. - Montreal	-130	2010	China	Sinopec/KPC - Zhanjiang	300	2014
Canada	Consumers' Cooperative Refineries Ltd. - Regina	30	2012	China	Sinochem - Quanzhou	240	2014
Mexico	PEMEX - Minititlan	150	2010	China	CNOOC/Shangdong Haihua - Haihua	80	2014
United States	Marathon - Garyville	180	2010	China	Sinopec - Zhenhai	300	2015
United States	Holly Corp. - Tulsa	-35	2010	China	Sinopec - Caofeidian	200	2015
United States	ConocoPhillips - Wood River	50	2011	***Other Asia***			
United States	Motiva Enterprises LLC - Port Arthur	325	2012	India	Indian Oil Co. Ltd. - Panipat	60	2010
United States	Valero - St Charles	45	2012	India	HPCL - Mumbai	48	2010
United States	ConocoPhillips - Borger	50	2013	India	BPCL - Kochi	40	2010
United States	ConocoPhillips - Wood River	95	2015	India	Essar Oil - Vadinar	151	2011
OECD Europe				India	Bharat Oman Co. Ltd. - Bina	120	2011
France	Total SA - Dunkirk	-141	2010	India	Indian Oil Co. Ltd. - Gujarat	40	2011
France	Total SA - Gonfreville	-94	2011	India	ONGC - Mangalore	64	2012
Greece	Motor Oil (Hellas) Corinth Refineries SA - Aghii Theodori	60	2010	India	Indian Oil Co. Ltd. - Paradeep	300	2013
Poland	Grupa Lotos SA - Gdansk	90	2010/2011	India	HPCL/MITTAL - Bathinda	180	2014
Spain	Cia. Espanola de Petroles SA - Huelva	75	2010	Pakistan	Byco Petroleum Pakistan Ltd. - Karachi	115	2011
Spain	Repsol YPF SA - Puertollano	30	2010	Vietnam	Petro vietnam/KPC/Idemitsu - Nghi Son	195	2014
Spain	Repsol YPF SA - Cartagena Murcia	110	2012	Vietnam	Vung Ro - Phu Yen	80	2015
OECD Pacific				***Latin America***			
Japan	Cosmo Oil Co. Ltd. - Sakai	30	2010	Brazil	Petrobras - Paulina	33	2010
Japan	JX Holdings - Oita	-24	2010	Brazil	Petrobras (Clara Camarao)	30	2010
Japan	JX Holdings - Negishi	-70	2010	Brazil	Petrobras - Abreu e Lima	230	2013
Japan	JX Holdings - Mizushima	-110	2010	Brazil	Petrobras - Comperj	165	2014
Japan	Showa Shell/Toa Oil Co. Ltd. Ohgimachi Factory	-120	2011	Brazil	Petrobras - Maranhao	300	2015
New Zealand	New Zealand Refining Co. Ltd. - Marsden Point	35	2010	Colombia	ENAP - Cartagena	70	2014
South Korea	S-Oil Corp. Onsan	50	2011	Colombia	ENAP- Barrancabermeja	65	2014
Non-OECD Europe				Costa Rica	Recope/CNPC - Limon	35	2014
Bulgaria	Lukoil - Bourgas	50	2015	Jamaica	Petrojam Ltd. - Kingston	20	2013
Romania	Petrobrazi SA - Ploisti	50	2012	Venezuela	PDV - Santa Inés	30	2012
FSU				***Middle East***			
Belarus	P.O. Naftan Refinery - Novopolotsk	60	2012	Iran	National Iranian Oil Co. Arak	80	2012
Russia	Antipinsky Refinery - Antipinsky	50	2010	Iran	National Iranian Oil Co. -Lavan Island	21	2013
Russia	Rosneft - Tuapse	140	2012	Iraq	SOMO - Daura	70	2010
Russia	Tatneft - Nizhnekamsk	140	2012	Iraq	Kurdistan Govn. -Erbil	20	2010
Russia	Mari El refinery - Mari Republic	54	2012	Iraq	SOMO/TGE Addax - Taq Taq	20	2010
Russia	Antipinsky Refinery - Antipinsky	70	2013	Iraq	SOMO -Basra	70	2011
China				Israel	ORL - Haifa	60	2011
China	CNPC - Quinzhou	200	2010	Qatar	QatarPetroleum - Ras Laffan 2	146	2015
China	Sinopec - Tianjin	200	2010	Saudi Arabia	Saudi Aramco - Rabigh	50	2010
China	Sinopec - Qilu	50	2010	Saudi Arabia	SATORP - Jubail	400	2014
China	Dongming Petrochemical - Dongming	60	2010	UAE-Abu Dhabi	Abu Dhabi National Oil Co. - Ruwais 2	417	2014
China	Sinopec - Qingdao	50	2010	***Africa***			
China	CNPC - Fushun	110	2011	Algeria	Naftec SPA - Skikda	32	2012
China	CNPC - Yinchuan	100	2011	Algeria	Naftec SPA - Arzew	22	2012
China	Sinopec - Zhanjiang Dongxing	66	2011	Angola	Sonangol - Luanda	35	2010
China	CNPC - Pengzhou	200	2012	Cameroon	SONARA - Cape Limboh	28	2014
China	Sinopec - Maoming	90	2012	Chad	CNPC - N'Djamena	20/30	2012/2015
China	Sinopec - Wuhan	60	2012	Ghana	Tema Oil Refinery Co. Ltd.	60	2011
China	CNPC/PDVSA - Jieyang	400	2013	Morocco	SAMIR - Mohammedia	40	2011
China	CNPC/Rosneft - Tianjin	200	2013	Niger	CNPC - Ganaram	20	2012
China	CNPC - Huhhot Petchem	70	2013	Sudan	CNPC - Khartoum	50	2012

PART 2

GAS

Overview

Recent Global Market Trends

Short-Term Demand Forecasts

Market Trends in the LNG Business

Unconventional Gas

Prices and Trading Developments

Investments Overview

Investments in Production

Investment in LNG

Investments in Pipelines and Regasification Terminals

OVERVIEW

World gas demand dropped sharply in 2009 as a result of the economic crisis, with strong variations between regions. While gas demand declined in all OECD regions, by on average 3.3%, disparities were wider among non-OECD countries. It plummeted in Former Soviet Union (FSU) countries, but increased strongly in China, India and Middle East and North African (MENA) countries. In the OECD, Europe was by far the most affected: seasonally adjusted data show demand in late 2008 falling back to early 2004 levels. The drop was concentrated in two sectors, industry and power. Interestingly, gas consumption in power generation has evolved very differently depending on the prevailing regional price differentials: consumption declined in several European countries where gas-fired plants are at the margin; gas actually displaced coal in the power mix in the United States.

OECD gas demand will recover slowly, with an expected return to 2008 levels by about 2012 but with large regional variations. In 2013, gas demand will reach 1,578 bcm, 2% above 2008. The end of 2009 and early 2010 started to show some relative improvement with the tide turning. Gas consumption in 2010 seems to have already showed signs of recovery, but th is is largely due to a colder than average first quarter so that demand, in particular in the residential/commercial sector, is estimated to be 10 bcm higher than in a normal winter. Looking forward, the main driver is obviously the economy and what shape the nascent economic recovery will have over the coming four years. OECD North America and OECD Pacific show the strongest recoveries; the recovery is anticipated to be more sluggish in Europe. European gas demand will recover to 2007 levels only by 2013 but that level will still be below that prevailing in the first half of 2008. While residential/commercial gas demand can be expected to be relatively stable (assuming normal weather), industrial gas demand will not come back to 2008 levels before 2013: across the OECD, growth in North America and Pacific will compensate for the drop in Europe. The key sector – and by far the biggest uncertainty regarding the pace of future gas demand – is the power generation sector: the year 2009 has proved that every country evolves differently according to its generation mix. Depending on the evolution of the economic recovery, prevailing prices and the success or failure of continuing to build renewables, gas input in the power generation sector can vary considerably.

Two revolutions took place on the supply side: the much-anticipated one was the growth of liquefied natural gas (LNG) capacity which will see liquefaction capacity growing by 50% over 2009-13. The revolution is well underway, as 60 bcm already started operating in 2009, followed by another 20 bcm during the first half of 2010. A further 50 bcm is expected to come on line by the end of 2013. However, this capacity growth was not matched by supply: LNG production increased only by 5% in 2009. Supply issues are now common not only for existing plants, but also for the recent ones due to feedgas and technical issues. The relentless growth of LNG supply happens in a market with much less appetite than anticipated when those projects were sanctioned, generally earlier in the decade. In particular, the North American market has absorbed limited volumes of LNG, leaving a surplus which has been redirected to other markets such as Europe and China. More LNG markets are emerging around the world – in Asia, Middle East and Latin America – taking advantage of the upcoming wave of new LNG supply. The actual increase of LNG supply is expected to take place later in 2010 and 2011, which will test the resilience of LNG markets in regions where demand will increase at a slow pace.

The second, less expected, supply revolution is unconventional gas. Starting only in about 2006-07, the continued rise of North American unconventional gas has had regional and global consequences; in particular it aggravated the global oversupply and significantly reduced US import needs. It also raises the question of whether such a revolution is possible in other regions, where companies and governments are already investigating this potential, and if so, how quickly can significant volumes reach markets. Prospects look quite good in Asia, where Australia, China and India already produce small volumes of unconventional gas. The effective development of unconventional gas in Europe, MENA or Latin America will face some challenges. The IEA does not anticipate unconventional gas playing a major role in Europe before the end of the decade. Among the challenges faced by unconventional gas resources are the need to more systematically appraise resources, as well as environmental issues and local opposition. The ongoing discussions about the impact of unconventional gas drilling on water reservoirs – well founded or not – are likely to play a role in Europe. Finally, a different ownership structure of subsoil resources in countries outside the United States could make landowners less accepting of production. Similarly to conventional gas, pricing and fiscal conditions, the availability of gas transport infrastructure, as well as of specific completion methods, such as horizontal drilling and hydraulic fracturing, will be determining factors.

The most daunting question faced by the gas industry is the duration of the gas glut. As supply matches demand, some producers had to curtail their production in 2009: this was particularly the case in FSU countries, but also in Canada, Nigeria, and Algeria. Similar to the demand side, a handful of producers, notably Qatar, still saw their output increasing. Looking forward, the duration of the oversupply will depend on many factors, including the growth of regional gas markets, the actual increase of LNG supply, and the sustainability of unconventional gas given low price levels. More importantly, the glut will play out differently in different markets. In the Atlantic basin, and in Europe in particular, it is hard to see tight supplies before 2015, despite the rapid decline of European domestic production. The situation is less clear in Asia and in the Pacific. For example, Chinese and Indian demand growth could really bite into LNG supply: within a few years, both countries combined will be capable of importing around 65 bcm, roughly the LNG imports of OECD Europe in 2009.

The result of the oversupply is that, in the OECD, two different price systems now co-exist with a large and unprecedented gap between them. Henry Hub (HH) and National Balancing Point (NBP) gas prices averaged $4/MBtu and $5/MBtu respectively in 2009, compared to around $9/MBtu in Japan and Continental Europe. This sustained decoupling between low spot prices in the United States and the United Kingdom and oil-linked gas prices prevailing in Continental Europe and OECD Pacific, is having far reaching consequences for buyers and sellers in the three OECD traditional markets, as well as in emerging LNG importers. Gas buyers, mostly in Europe, are caught between their long-term contractual obligations and pressure from their customers, in particular industrial, to supply gas at more competitive prices. Importers have in turn pressed their suppliers for more flexibility on price and volumes. Already a few key suppliers to Europe have granted some important concessions on these two items. This additional volume flexibility, that was agreed in several long-term contracts, not only eased the situation of oversupply in 2009, but will also alter the European supply/demand balance in 2010 and beyond. Pricing flexibility has also been important, with price falls in important users such as Germany, but as a corollary, a closing of the gap between spot and contract prices in Europe. A second interesting pricing development has been the remarkable convergence between HH and NBP prices over one year; the latest evolution in the spring of 2010 suggests, however, that this trend may not be sustainable.

Arguably, the second most important question faced by the gas industry is whether the traditional oil linkage on European continental and Asian markets will continue. The growth of trading in Continental Europe proves market players' increased confidence. Further improvements in transport, regulation, and services are expected to enhance liquidity growth. This question finds some answers in the other key question stated above: the duration of the gas glut. Indeed, the concessions granted giving a partial spot indexation in some European contracts, are temporary. Whether such spot indexation remains beyond the three years, and is extended to other contracts or traditional oil indexation fully returns will depend first on the global supply/demand balance and then on the evolution of the gap between the different spot and oil-linked prices. Again, regional differences will matter, so that a persistent regional oversupply in North America could leave HH prices below other regional prices.

The past two years will have profound consequences for future investments as markets moved from tightness to a global oversupply. Despite the comforting Final Investment Decisions (FID) for two LNG liquefaction projects late in 2009, uncertainties prevail and investments along the gas value chain slowed down during 2009. Investors now face the double-whammy on the supply side combined with increased uncertainty on future demand growth, fuelled by the uncertainties regarding the economic recovery, and have unsurprisingly adopted a cautious wait-and-see approach. The question is raised on where and when incremental gas volumes or supply infrastructure would be needed and where to invest in the gas value chain. A few projects are still moving forward but these are targeting those markets where the economic crisis has not affected a growing appetite for gas – predominantly Asia. Australia has emerged as a major focus for new LNG investments and many projects, including coalbed methane (CBM)-to-LNG projects in Queensland, are competing to secure market shares and limited project resources. It is reasonable to anticipate at least one or two new FIDs over 2010-11. It is difficult to see any FID being taken in the Atlantic basin in the current market circumstances. Globally, floating LNG is gaining momentum, but the technology remains to be tested.

While import requirements will be less than they were expected to be two years ago and investments in the upstream sector will not be as pressing as then, gas demand is still planned to increase in any scenario in the longer term. Even if demand were flat, production from existing declining fields would have to be replaced. Experience shows that at least a decade is needed to develop a greenfield deposit; a liquefaction plant now requires five years on average once the FID is taken. Producers are consequently adapting their strategies, focussing on key projects and shifting towards the growing markets. In particular, Russia faced a tough year in 2009, with increasing uncertainty in its main export market, Europe. Consequently, its strategy slightly shifted towards Asian markets, but it remains to be seen whether it will be translated into concrete outcomes, as the development of the fields in Eastern Siberia and the Far East is more challenging than the ongoing development of the Yamal Peninsula. In MENA countries, only Qatar seems to be able to meet confidently rising domestic demand and fuel its export targets in the medium term. Developing more difficult and expensive non-associated gas fields (frequently tight gas or sour) is the new challenge for MENA countries. Despite campaigns to attract exploration and production (E&P) investors, rapidly rising domestic demand and the continuing requirements for gas reinjection may leave very little gas for exports, unless CO_2 reinjection projects gain popularity in the region. Indeed domestic market obligations have emerged as a new trend across producing regions, with governments reserving volumes for their own customers, by law or by contract. However, usually low local market gas prices fail to attract foreign investors.

Among all parts of the gas value chain, inter-regional transport is likely to be the most affected by the global oversupply now and in the medium term. Indeed, a surplus of capacity is resulting from the current and future wave of new projects while demand remains weak. This will lead to competition between pipelines and regasification terminals whose outcome will depend on regional dynamics, especially in Europe. Looking forward, the race will continue between these different delivery modes which are still at the planning stage. Across regions, LNG regasification terminals seem to be making more progress than pipelines. In 2009, the only significant inter-regional pipeline that commenced operations was the first part of the Turkmenistan-China pipeline, which incidentally marks a fundamental change in the relationships between Central Asia and its potential markets. Interestingly, some regions such as the Middle East, Latin America, and Southeast Asia are now turning to LNG imports, sometimes to mitigate the failure of regional pipelines. The floating regasification and storage units (FRSU) and LNG regasification vessels (LNGRV) which are quicker to build have been very successful in these regions. Looking ahead, regasification terminals are advancing faster than pipelines – when projects move ahead. Global regasification capacity will increase by at least 20% by 2013, exacerbating the excess of regasification capacity compared to liquefaction but allowing LNG to be moved around the world. Meanwhile, only one major new inter-regional pipeline project advances – the much-awaited Nord Stream pipeline between Russia and Germany, now under construction.

The last part of the gas value chain, underground gas storage, faces the very same market issues as the other parts: demand uncertainties, as well as cost and regulatory difficulties. Even in mature markets, many projects are still planned as the role of storage is changing. The increasing use of gas to compensate for the intermittency of wind generation implies that more flexibility will be needed, and therefore more fast-cycling storage facilities. Storage also remains a key component for security of supply in regions that are becoming increasingly import dependent. Meanwhile, fast-growing markets such as China and Iran are looking to expand storage capacity.

RECENT GLOBAL MARKET TRENDS

Summary

- **World gas demand is estimated to have dropped by 3% in 2009, the biggest decline observed since the 1970s. Demand dropped sharply in almost all OECD countries, but with strong variations among the regions: Europe has been by far the most affected as seasonally adjusted demand levels dropped in late 2008 to the levels of early 2004. Demand disparities are wider for non-OECD countries, some of which observed remarkable growth.** Such a demand fall is unprecedented: according to IEA's annual gas statistics, world gas demand has fallen only twice, in 1975 and 1992, and never by more than 1%. OECD gas demand fell by 3.3%, while some non-OECD countries such as Russia, Ukraine and Brazil also saw their demand receding, but others such as China and India have witnessed a strong growth by 10% or as much as 20%. The end of 2009 and early 2010 started to show some relative improvement, notably in the OECD region, with the tide turning as the economy recovers. The gas industry also benefited from an extreme winter 2009/10, which was not only cold but lingered well into March.

- **Two sectors make the difference: industry and power generation**. **While demand plummeted in the industrial sector, the outcome for the power sector varies across regions: gas managed to increase its share in the power mix in a handful of countries.** The economic recession has affected the industrial sector as many factories closed or reduced output. This had two consequences on gas demand: a direct one – diminished need for gas – and an indirect one through reduced power demand, which subsequently impacted the use of gas-fired power plants.

- **While economic activity remains the main driver of gas demand, price levels can considerably change the outcome in the power sector**. The economic recession is one of the major factors contributing to the overall drop of energy demand. Relatively high oil-linked gas prices in some regions, such as Europe or OECD Pacific, also impacted gas demand in particular in the power generation sector, pricing gas out of the mix; in regions where gas was priced at market levels, notably the United States, gas-fired power actually increased in 2009 in absolute terms.

- **Two supply revolutions took place in 2009: the start of the much expected but still unprecedented rise of LNG liquefaction capacity and the continued growth of US unconventional gas production.** The first one was clearly anticipated by markets, but the growth of unconventional gas really began to accelerate in 2006 and 2007. This additional supply added to weak demand, resulting in global oversupply. As a result, many suppliers had to curtail their production while a few, such as Qatar or Yemen, increased production. As LNG supply increased, **albeit** modestly, the entire demand drop had to be borne by pipeline trade.

- **The daunting question faced by the gas industry is how long the gas glut will last. The exact duration of the current gas glut will depend on many factors, the two most important being economic recovery and the growth of gas demand in the power generation sector.** It will play out differently in different markets. While it is hard to see a tightening situation in Europe before 2015 despite the decline of domestic production, much uncertainty lies in Asia and in MENA. In particular China's gas demand continues to grow at an impressive 10% per year. As gas markets are globalising, tightening markets in the Pacific region could spill over into other regions.

The Worst Decline Ever

OECD Demand Trends

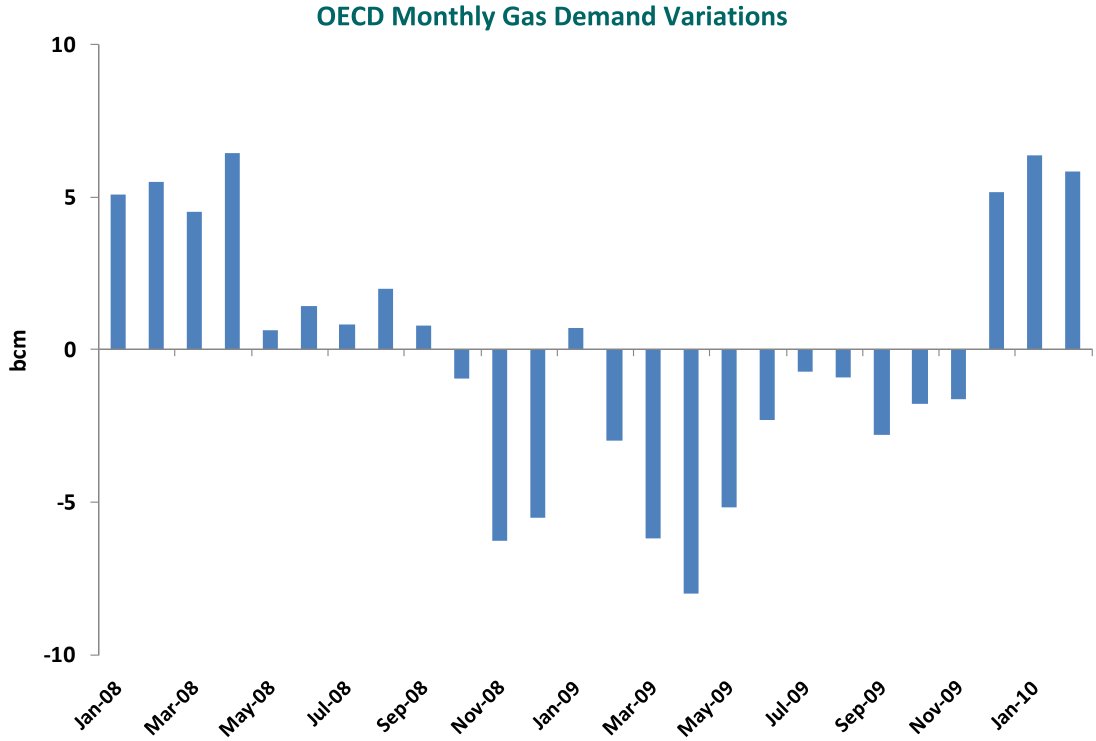
OECD gas demand, which represents just under half of global gas demand – estimated at around 3,050 billion cubic meters (bcm) –declined by 3.3% in 2009, from 1,545 bcm in 2008 to 1,495 bcm. This represents a 50 bcm drop, more than France's annual gas demand. Historically, the OECD region has seen higher relative declines – 4.5% in 1982, but the absolute decline was lower and less than half of the countries actually saw their demand declining. As in past years, the analysis reveals some wide variations across regions and countries: OECD Europe was the worst affected among OECD regions with 5.6% decline. The drop was less significant in OECD Pacific at 3.4% due to a recovery during the last months of 2009. Among the largest relative declines in demand are Greece (-16%), Hungary (-14%), Spain (-11%) and the United Kingdom down nearly 8%. There have been countries where demand increased though: Sweden witnessed a 30% increase (on a very small base) and the Netherlands saw demand increasing slightly, due to the effect of low gas spot prices in the power sector.

Gas Demand in OECD Countries: 2008 versus 2009 (bcm)

	2008	2009		2008	2009
Australia	31.8	31.0	Korea	35.8	34.0
Austria	8.7	8.8	Luxembourg	1.3	1.3
Belgium	17.5	17.2	Mexico	60.3	60.9
Canada	95.1	92.7	Netherlands	48.5	48.8
Czech Republic	8.7	8.2	New Zealand	4.2	4.2
Denmark	4.6	4.4	Norway	5.8	6.0
Finland	4.7	4.3	Poland	16.3	16.4
France	46.1	44.5	Portugal	4.7	4.8
Germany	98.0	92.6	Slovakia	6.3	6.1
Greece	4.2	3.5	Spain	38.2	33.9
Hungary	13.1	11.3	Sweden	0.9	1.2
Iceland	0	0	Switzerland	3.4	3.3
Ireland	5.2	5.0	Turkey	36.6	35.1
Italy	84.9	78.1	United Kingdom	99.0	90.8
Japan	103.5	100.1	United States	657.8	646.6

Source: IEA statistics.

The effects of the economic crisis were particularly felt during the first half of 2009, during which OECD gas demand dropped substantially: the decline eased thereafter. During the first half of 2009, OECD demand fell by over 5% with the most dramatic declines in Europe (8%) and Pacific (6%). Over the second half of 2009, demand continued to decline over the previous year despite what seemed an improvement in terms of relative decline; only the month of December 2009 showed incremental gas demand growth. The two first months of 2010 seemed to continue this trend, with demand 8% higher than the same period the previous year. This increase has to be viewed with caution due to the exceptionally cold weather in most OECD countries.



Source: IEA, Monthly Gas Statistics.

Looking at the year-on-year differences can sometimes be misleading as seasonality (higher demand during winter months and therefore higher year-on-year differences) can mask the real trend. Thus, in order to analyse trends, one has to look at demand corrected for seasonal effects such as weather and number of working days.

Seasonally Adjusted Demand Trends

In order to improve the identification of turning points in demand, year-on-year comparisons of widely oscillating series are often accompanied by the analysis of seasonally adjusted values. When the regular seasonal variations and large deviations from average weather are taken into account, additional insight into the recent developments in demand can be gained.

Accounting for Seasonal Effects

Natural gas demand in the majority of OECD countries varies significantly from month to month, exhibiting seasonality. This is a common phenomenon and can arise from natural factors such as the weather, length of the day, but it is also affected by administrative (*e.g.* school year), cultural (*e.g.* holiday periods) and calendar effects (*e.g.* the number of working days in a given month). Temperature is clearly the main contributor to seasonality in gas demand, but the size of other effects is also significant according to this analysis. Seasonality complicates the interpretation of trend dynamics for gas demand by making it impossible to compare directly the values of adjacent months. The conventional solution is year-on-year analysis but this method does not take into account demand in the 11 months between the compared times and has been criticised for producing delayed identification of turning points. Turning points in gas demand are of particular interest at times of dramatic changes in the market; when noticed, they can feed into policy decisions and business planning.

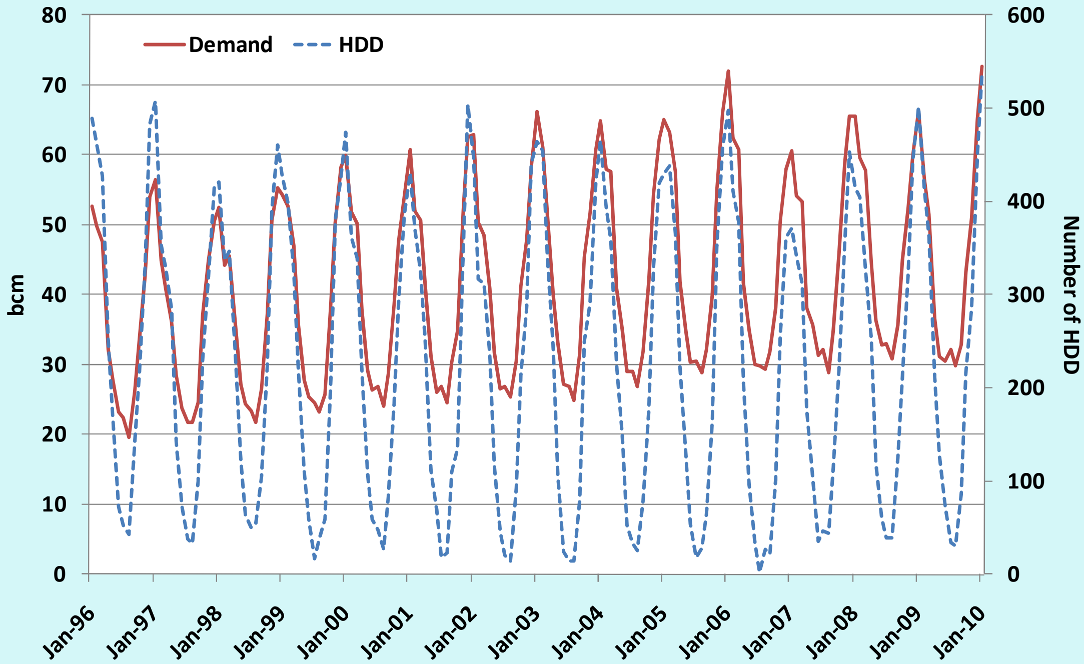
Accounting for Seasonal Effects (continued)

A well-established way of identifying turning points and trends, which often complements year-on-year comparisons, is seasonal adjustment. The approach is based on the decomposition of raw values into trend, seasonal effect and an irregular component:

*Demand = Trend * Seasonal * Irregular*

In this calculation, the trend and the seasonal components are evaluated by an Auto-Regressive Integrated Moving Average (ARIMA)-based method of estimating unobserved components, based on maximising the variation of the irregular component.[3] Dividing the original demand by the estimated seasonal effects produces seasonally adjusted values which contain the noise and are not as smooth as the fitted trend.

Correlation of Demand and Heating Degree-Days in OECD Europe



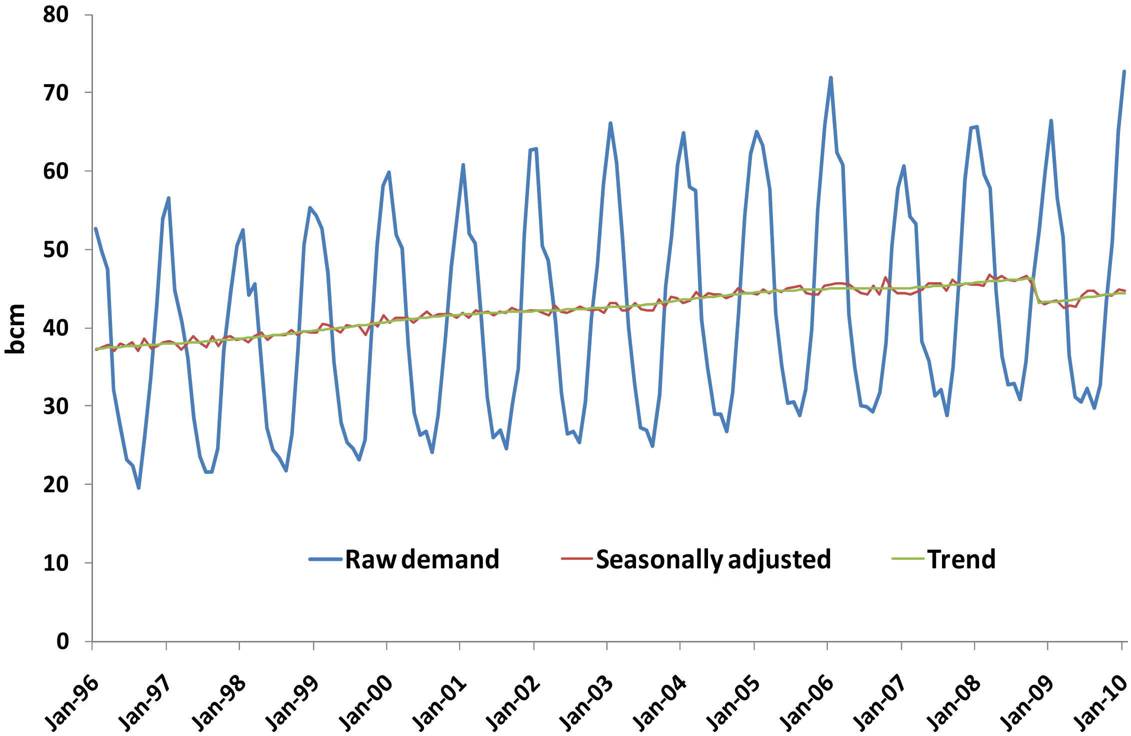
Source: IEA.

Analysis focuses on the trend because it drives the total value. For instance, a 5% increase in the trend, results in the same 5% increase in the total. One has to be aware though that trend dynamics are an indicator of the next, not current, year growth rate. For example, if the monthly trend grew (very linearly) by 1% between January and December of Year 2, it does not follow that the annual consumption in Year 2 is 1% higher than in Year 1, because in the intermediate months, it was somewhere between the start and the end level. However, it does imply that if the trend continues at the same rate during all the months of Year 3, the annual demand will grow by 1% as well. This is assuming stable seasonality which seems to be a reasonable assumption for gas demand. For this analysis, a 'pre-adjustment' procedure to remove the effect of large deviations from the average temperature has been used for the following reason: if one seasonally adjusts the raw demand values, the method will identify the average seasonal pattern, but then the trend will be affected by large deviations from the 'normal' weather. For the purpose of this analysis, the interest is mainly in the longer-term prospects of demand than short-lived peaks due to fluctuations in temperature.

[3] European Statistical System Guidelines on Seasonal Adjustment, Eurostat, 2009.

Gas demand in OECD Europe has been steadily increasing over the period 1996-2008. This trend abruptly stopped mid-2008 when gas demand fell sharply between September 2008 and November 2008, roughly to the level of early 2004, but then quickly returned to the previous long-term growth path. One interpretation is that the economic crisis exposed the system to a shock, which brought demand down significantly. However, the fundamentals, which had been historically driving gas demand up, are still present or recovered so that gas demand has resumed its growth. Since fuel demand is often considered to depend on the level of economic activity, it is interesting to note gross domestic product (GDP) in EU-27 (also seasonally adjusted) started growing from the third quarter of 2009, albeit at very slow quarterly rates of 0.3%, 0.1% and 0.2% during the two last quarters of 2009 and first quarter of 2010.[4] The fitted trend indicates that monthly demand grew 2.6% from January 2009 to January 2010, which suggests that recovery of annual demand could potentially happen quicker than most observers suggest.

OECD Europe Raw Demand, Seasonally Adjusted Demand and Trend



Source: IEA.

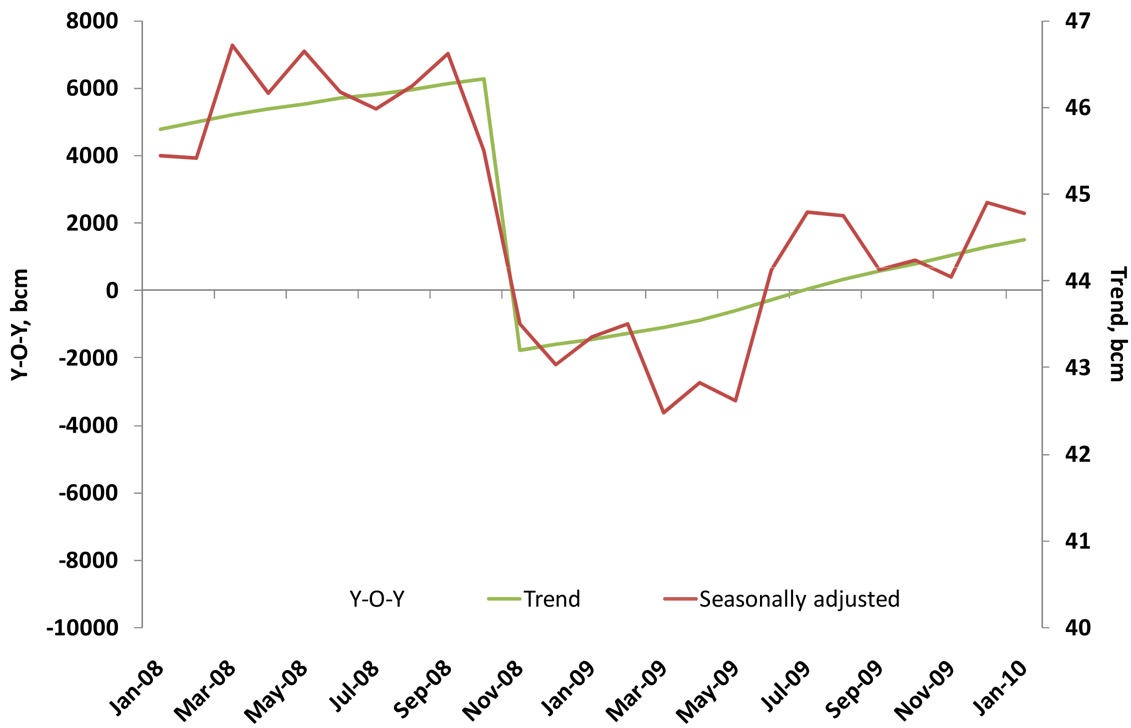
Looking more closely at the dynamics of the seasonally adjusted demand in 2009, it appears that spring 2009 saw the lowest level of gas demand over the period mid-2008 to early 2010. Several factors can explain that gas demand bottomed during that period: industrial production also bottomed in several countries in spring 2009 and that period is generally recognised as the nadir of the recession in many IEA countries, while both NBP prices and oil-linked gas prices were still relatively high. The line also points to June 2009 as the first month of substantial increase in demand. Interestingly, the high consumption in January 2010 in Europe does not appear to be as extreme

[4] Eurostat data.

when the very cold temperature is taken into account by the model. Consumption has effectively not been growing between July 2009 and January 2010.

Thus, the overall demand trend and the seasonally adjusted values point to somewhat different paths of recovery, differing by region, reflecting a hesitant recovery. This uncertainty will probably become gradually resolved as more data become available.

Trend of the Last Two Years in OECD Europe



Source: IEA.

Industrial Sector

Gas demand collapsed in the industry with some differences across regions. Estimates of sectoral gas demand trends are not yet available for all countries, but the evolution of industrial production can give an insight on how industrial gas demand has evolved during 2009. Switching from refined products to gas is structurally limited, and not encouraged by recent price developments, so that industrial production remains one of the best indicators. Based on OECD indices for total industry production, all OECD countries saw their total industry production decline abruptly by 11.9%[5] in 2009 compared to 2008, the worst decline in over 40 years. The most extreme was in Japan (-22%). Major economies such as Germany, Italy, and Spain also saw a sharp drop, between 15% and 20%; production in the United States and the United Kingdom dropped by around 10%.

[5] Based on OECD indices on total industry production, which take 2005 as the reference year (100).

This translated almost directly into gas demand falls from industry in 2009, mostly during the first half of the year. Although the second half started to show some slight improvements, one has to remember that the crisis was well engaged during the second half of 2008. Thus it is not surprising when making month-on-month comparisons, the decline rates seem to be levelling out. Despite the lack of a complete OECD picture, preliminary data indicate that OECD industrial gas demand has declined by around 10%. In the United States, industrial demand dropped by 8% and despite some improving economic perspectives, industrial gas use was still well below 2008 levels up to December 2009. This is in line with the still declining production indices. Starting from December 2009, an improvement in industrial gas demand is evident. In the United Kingdom, industrial demand plummeted by 22%, continuing a trend started last decade: 2009 industrial gas demand was 32% lower than that in 2005 and 44% lower than 2000. Germany's industrial gas demand is estimated to have collapsed by 10%, while French industrial and power consumption declined by 2%.[6] Dutch industrial gas demand declined by 7% mostly during the first half of 2009. Spain's conventional gas demand (excluding power generation) declined by 17% in line with a similar drop in industry output.

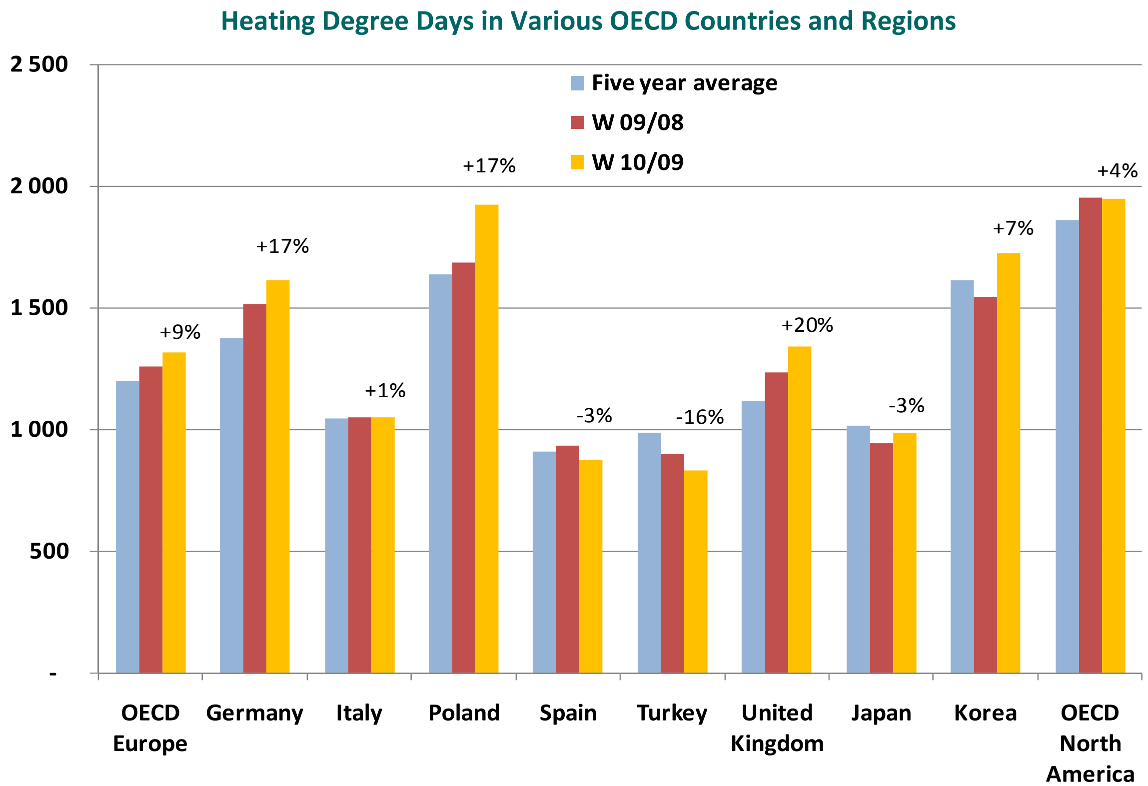
The situation seems to be reversing in a number of countries according to the OECD indices on total industry production, suggesting a partial recovery in this sector in 2010. Still, permanent demand destructions are likely to be seen in this sector due to factory closures; this will leave short-term industrial gas demand at lower levels than in 2007-08.

Residential Sector

Residential demand is mostly influenced by the temperature; winter 2009/10 was certainly one of the coldest in most OECD countries. The graphic below shows the sum of heating degree days (HDD) for the key winter months, December to February, for three periods: winter 2009/10, winter 2008/09 and the average of the five previous winters.

As shown, winter 2009/10 was colder than the previous year, except for Spain, Turkey and North America. Even in North America, some regions were heavily affected by colder weather well into 2010. Crucially, winter has been colder than the five-year average for most countries, except Spain, Turkey and Japan. In Spain and Japan, residential gas demand represents however a very small share of total demand, around 10%. The increase in HDD is astonishing for Germany, Poland and the United Kingdom. Germany and the United Kingdom have a high share of residential demand which represents around 36% and 33% respectively, so any variation in this sector has major implications for total gas demand. Peak daily gas demand broke records in the United Kingdom in January 2010 reaching an unprecedented 470 Mcm/d (equal to an annual rate of 172 bcm per year (bcm/y)). US residential gas demand declined by 2%. French gas demand from residential, commercial and small users declined by 5% on the back of annual HDD decline by 2% and high gas prices. Temperature corrected consumption for these sectors shows demand declining by 6.7%. German residential gas demand is estimated to have increased by 3%.

[6] Sources :United Kingdom - Department of Energy and Climate Change; Germany - Ag-energiebilanzen; France - Ministry of Ecology, Energy, Sustainable Development and the Sea.



Source: IEA.

It seems that the residential sector was less affected by the economic crisis. There were, nevertheless, some strong indirect effects: consumers saw their incomes declining or faced unemployment while their energy bills increased. This was particularly the case during winter 2008/09 during which residential gas prices were high. Prices declined in most OECD countries starting in the second or third quarter 2009. The high price level is likely to have resulted in residential users starting their boilers later in the fall or switching them off earlier in April, and lowering the thermostat during the whole heating season.

Power Generation Sector

One sector attracts everyone's attention: the power generation sector. This sector has the potential to provide the biggest variations from one year to another, and is the biggest uncertainty for future gas demand. Gas use in the power generation sector in OECD countries in 2009 has been affected, first of all by the 4.2% decline in electricity production induced by the economic crisis, a demand decline unprecedented since the Second World War. Indeed, fossil-fuel generation, which represents two-thirds of total generation, accounted for 420 TWh of the 450 TWh decline in power generation. This is more than UK electricity demand and slightly less than Korea's. Meanwhile hydro and nuclear declined by only 2% and 1.5% respectively, reflecting their low short-term marginal cost. Only renewable generation increased, by 18%, on the back of growth of wind capacity. However, this still represents a small share of total electricity generation.

Fossil fuels are usually dispatched after nuclear, hydro and renewable which are 'must-run' capacity. In 2009, gas had to compete against coal for a shrinking part of total electricity generation. In most countries, high gas prices did not allow gas to hold its ground versus coal: coal prices plummeted from above $200 per tonne mid-late 2008 to around $60 per tonne by mid-2009 (although they have since risen back to around $90 per tonne) while oil-linked gas prices continued to increase up to end 2008 and remained above $7/MBtu in 2009 with an increasing trend since then. This usually puts gas-fired power at a disadvantage in the merit order, especially in Continental Europe for companies that do not have access to cheap spot gas supplies.

The two extreme examples of how fuel prices and non fossil-fuel generation can affect gas demand can be found in the United States and Spain. In the United States, gas won market share from coal due to the extremely low Henry Hub prices (HH) during most of 2009, which supported the preferential dispatch of gas versus coal in some regions during much of 2009. Gas demand in this sector increased by 3% as a result. Low spot prices, however, did not help gas use in the United Kingdom as electricity consumption declined while nuclear and wind generation increased. The 17.5% drop in coal generation did not prevent gas generation from also dropping by 8.2%. The other extreme case is Spain where gas use by power generators plummeted by 15% in 2009, but this partally reversed a 33% increase seen the previous year due to extremely low hydro levels. As highlighted in the *Natural Gas Market Review (NGMR) 2009*, Spanish gas demand for power is extremely variable: despite the massive build of gas-fired capacity since 2000, gas is dispatched after hydro, wind and nuclear which represent around 40% of total generation. The strong seasonal variations of wind generation require significant flexibility from the gas-fired plants, leading to wide daily and annual demand swings. Furthermore gas is imported under long-term contracts, some of which have oil-indexed formulae.

Non-OECD Demand Trends

The demand picture in non-OECD countries is a study in contrasts to say the least. On the one side, some countries have been similarly affected as OECD countries by negative economic growth, falling industrial production or specific country conditions such as renewables availability. Among the most noticeable drops, Russia – the world's second largest market – saw its gas demand fall by an estimated 6% on the back of falling industrial demand. Brazilian gas consumption had been increasing rapidly over the past decade but nevertheless fell by 22% due to high hydro production. Ukraine's economic decline was among the worst globally of any major country, and its consumption dropped substantially. The economic crisis has also particularly affected demand in non-OECD European countries, where consumption is estimated to have plummeted by 15%.

There are nevertheless some exceptions to this trend: some non-OECD countries have seen positive economic growth or increasing supply. In particular, Chinese gas demand increased by 9 bcm to 87.5 bcm, an 11% increase. In China, more and more residential customers are using gas as a heating fuel, even in the south of the country. This created some supply issues when peak demand jumped above available supply late in 2009. Indian consumption is estimated to have increased by 10 bcm to 53 bcm.[7] The Indian story is a bit different: the country has always been supply constrained and the start of the giant Krishna Godavari field enabled more supplies to be available to the Indian market. In particular, fertiliser producers and power generators have been using more gas, reducing sharply oil products use.

[7] Source: Petroleum Planning and Analysis Cell (PPAC) and statistics from the Ministry of Energy. Consumption is based on the fiscal year (1 April–31 March).

Supply Trends: the Boom and the Bust

Two supply revolutions took place in 2009: the start of the much-awaited and unprecedented rise of LNG liquefaction capacity and the continuation of the growth of unconventional gas. The first one was clearly anticipated by markets; despite delays and technical issues, the construction of LNG plants is difficult to miss. The growth of unconventional gas was the continuation of a phenomenon that started long ago, but really began to accelerate in 2006 and 2007, catching many industry observers off guard by both its volume over the past three years. The fact that unconventional US gas production was booming despite all odds while the new LNG liquefaction capacity was arriving slowly but surely onto markets put another layer of supply on world production capacity, which was already much higher than demand. These three trends have caused weak prices and the current oversupply, the gas glut.

The Gas Glut

As world gas demand declined by over 3% in 2009, inevitably, supply had to adjust. Beyond the natural decline of gas production in Continental Europe and in the United Kingdom (UK gas output fell more than 15% in 2009), some gas producers had to curtail their gas production: despite their higher production potential, they were unable to find demand for their gas in their traditional markets and could not find alternative markets. Russia, Turkmenistan and Canada are examples of countries that were forced to curtail production. Meanwhile, some producers maintained their market share, if not the volumes supplied, and a few reinforced their position or entered the market. Globally, LNG supply increased – albeit modestly – by 5.3% (around 12 bcm), while US gas production increased by 3.3% (19 bcm). In the importing regions or countries, pipeline exporters (especially those exporting at oil-linked gas prices) confronted not only weaker demand because of the economy but also stiff competition from cheaper sources of suply: in Europe, pipeline supplies from Russia and Algeria were displaced by LNG or Norwegian pipeline gas; in North America, LNG and Canada were the victims of the production growth.

However, the capacity to produce more was there: the surplus capacity on the production side is estimated to be over 200 bcm in 2009. The upside was limited in OECD countries to around 30 bcm as only a few countries, such as Canada, Australia and the Netherlands, could have produced more. The upside comes mainly from non-OECD producers. A few countries had planned to increase their production but could not due to lack of buyers. This group includes Russia and Turkmenistan whose combined production dropped by around 115 bcm and a few Latin American countries. Others faced technical issues, such as Algeria or Nigeria whose production dropped by an estimated 13 bcm.

The daunting question faced by the gas industry is how long the gas glut will last, knowing that up to 110 bcm of LNG supply will arrive by the end of 2013, based on plants currently under construction and those recently completed. The duration of the current gas oversupply depends on several factors, but the two most important ones are economic growth over the upcoming years and the evolution of the role of gas in the power mix (as well as relative fuel prices in the different regional markets). The gas glut will play out differently in different markets, with supply/demand balance expected to tighten faster in the Asia-Pacific region compared to the Atlantic region.

The global gas glut consists of some parts of supply that are fungible (such as flexible LNG) and some parts that are not, such as large scale pipeline capacity from Russia to Europe. In Europe, it is hard to see tight supplies before 2015, despite the continuous decline in UK gas production (only partly compensated by Norwegian growth). But the situation is less clear in Asia and the Pacific. For example, Chinese and Indian LNG demand growth could really bite into LNG supply: indeed, within a few years, both countries combined will be capable of importing around 65 bcm annually, while they started importing LNG only in 2006 and 2005, respectively. This level would be similar to that imported in 2009 by OECD Europe. Other Asian countries such as Thailand and Pakistan are also seeing their demand increase quickly while gas demand in MENA is expected to increase by 100 bcm between 2008 and 2015.[8]

The IEA foresees a weak recovery in European gas demand, on the back of a feeble economic recovery, and increasing renewable power into the European grid. Therefore, the underutilisation of these pipelines is likely to continue for some time, likely well into this decade while some additional pipeline and LNG capacity will be added over the 2010-15 period. Abundant gas is already putting strong downward pressure on gas prices in markets where prices are generally oil-linked. North America, with plentiful unconventional gas plus underutilised Canadian pipeline and production capacity, seems likely to be well supplied without the need for the large scale LNG imports that were anticipated, even as recently as five years ago. US LNG terminals have been utilised at only 10% over the past two years. However, a key question is whether prices will stay at the current $4-5/MBtu, which is very low, especially compared to oil. As noted earlier, such low price levels have helped gas to displace some coal-fired power in 2009, notably in the summer, thus raising demand in the power sector, and to rebalance markets.

In Asia and the Pacific, it is clear that Chinese and Indian gas demand is growing fast, and that many players are willing to invest in new supply infrastructure for those markets. The large commitment to the Gorgon project in Australia in 2009, for delivery in 2015, as well as the high interest in other Australian LNG projects, is evidence of that. More Qatari LNG seems likely to head east too. China has proved its ability to rapidly ramp up energy demand in oil, and in imported coal too. The same is quite possible for gas; in any event, China will, by well before 2015, use more gas than any OECD country except the United States. Therefore, gas supplies in the Pacific seem likely to tighten more quickly than in Europe.

As mentioned before, there is a high potential that gas demand could recover more quickly than expected, particularly in the power generation sector, even in the OECD region. There is around 800 GW of gas-fired power in the OECD, which is used at around a capacity factor of 35%. If these plants were used to meet a 1% increase in OECD power demand (100 TWh), gas demand could be expected to increase by around 25 bcm. To put these numbers in context, hydro generation can vary by 50 TWh from one year to another, a 1.6 GW nuclear power plant running base-load will produce up to 13 TWh. Furthermore, if the power demand drop seen in 2009 of 450 TWh was entirely met by reducing gas-fired power, it would represent more than 100 bcm of reduced gas demand.

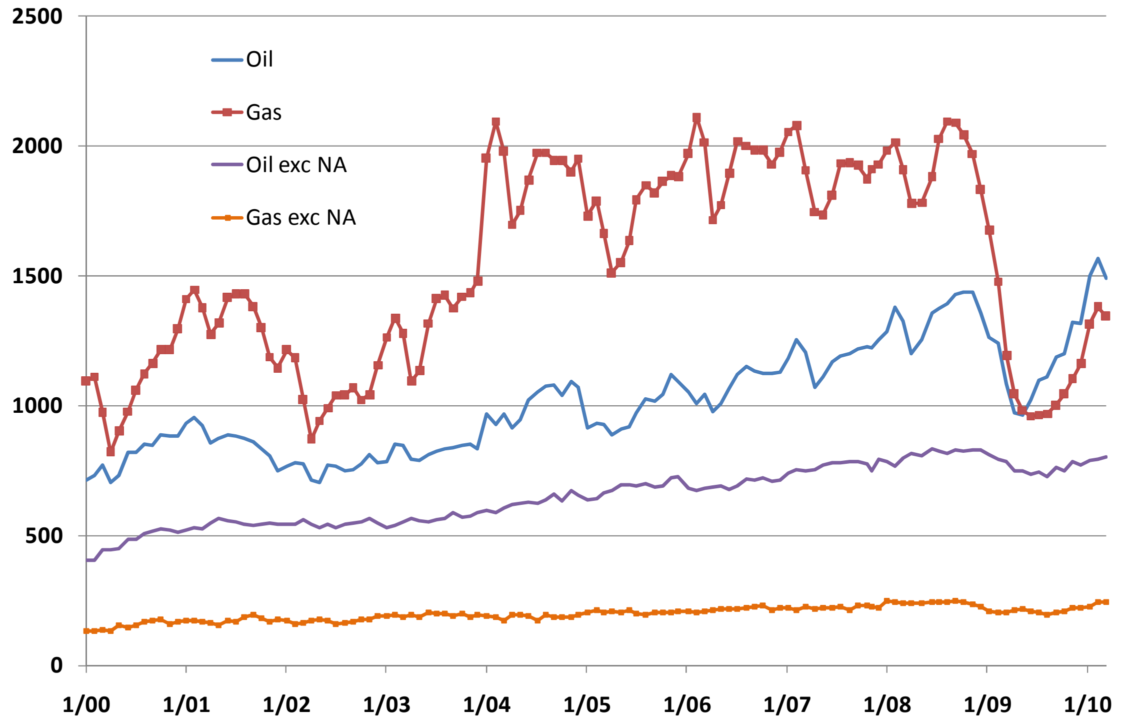
Oil Versus Gas Drilling

Another factor is at work on the production side: the preference for oil over gas. With oil prices at $70-80 and spot gas prices at $4/MBtu (or around $25 oil equivalent), some producers may tend to drill more oil than gas wells, which may then have an impact on future gas production. However, this phenomenon has happened mostly in North America as can be seen on the graphic below, which shows the oil and gas rigs internationally, as given by Baker Hughes (Europe, Middle East, Africa, Latin America, Asia and North America). While the number of gas rigs does not seem to have recovered as much as oil rigs, the exclusion of the United States and Canada from this count shows a different trend with both oil and gas rigs coming back to the levels seen mid-2008. The strongest declines took place in Europe, Asia and Latin America. This can be explained by the price mechanisms

[8] *World Energy Outlook* (WEO) 2009, Reference scenario.

prevailing in each region. Obviously, the North American market, where spot indexation prevails and where gas prices have plummeted, sees a direct, rapid reaction to the spot price collapse. Europe, where spot indexation is gaining ground, also saw an effect of lower spot prices on gas drilling. In other regions, prices are regulated so that the spot gas price movements have less impact than government decisions.

Oil and Gas Rigs in the World



Source: Baker Hughes.

OECD Regions

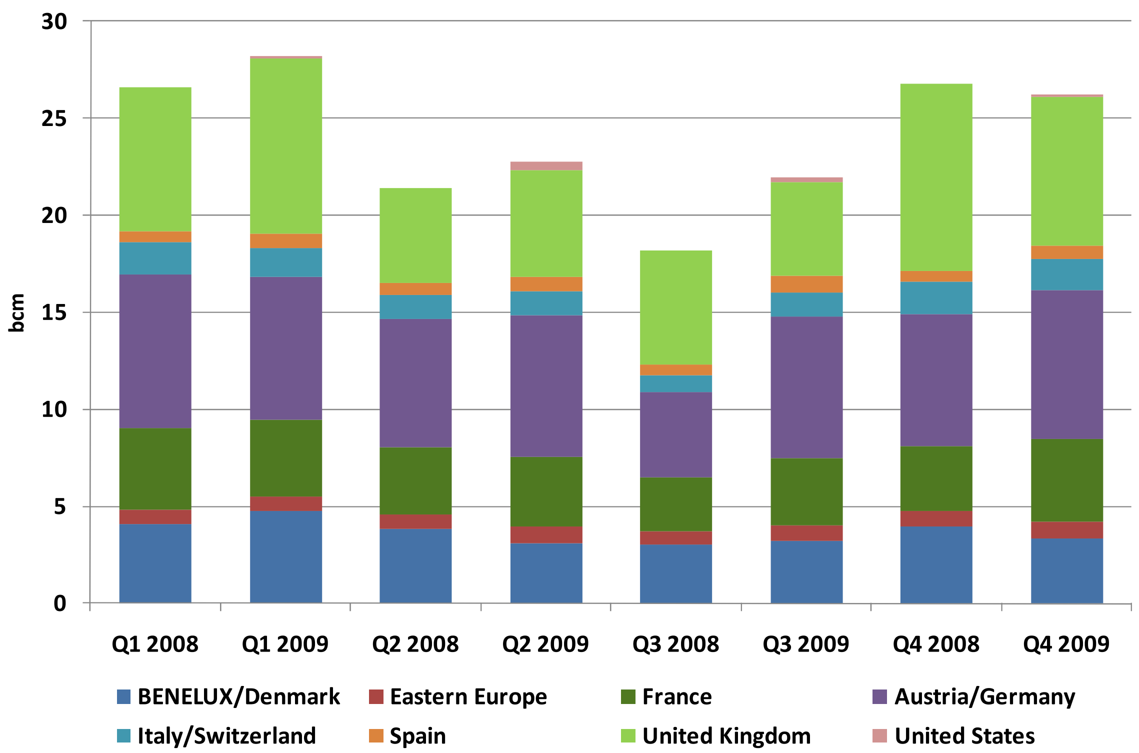
The three OECD regions are net gas importers: their total production represented just below 40% of global gas production while they consumed just under half of total demand in 2008. In 2009, OECD production declined slightly by 0.7% or around 8 bcm, much less than the 50 bcm demand drop in the OECD. This means that most of the supply reduction was borne by non-OECD producers; some faced not only lower demand in their domestic market but also reduced export requirements.

Production increased both in OECD Pacific (5.1%) and OECD North America (0.7%) but declined sharply in OECD Europe (5.4%). US domestic production increased by 19 bcm, after some revisions from the Energy Information Administration (EIA) which had initially overestimated unconventional gas production from small producers. This does not diminish the fact that unconventional gas production increased in the United States, despite a decline in the number of rigs and prices falling sharply. Production falls in Canada partly offset these US production gains. North America produced more than its actual consumption (803 bcm versus 800 bcm), the balance going to build record gas storage levels. The key question for the following years is how much North America will need to import (via LNG), and whether, and how much LNG can displace the most expensive conventional non-associated gas and unconventional gas.

OECD Europe's production declined by 5.4%, a 16 bcm drop, which stems from the continuous sharp decline of UK gas production (11 bcm), a small decline by the swing Dutch supplier (5 bcm) and some limited drops (around 1 bcm) in Germany, Italy and Denmark. These declines were partly offset by an increase in Norway of 4 bcm. Norwegian production grew less than in 2008 (10 bcm) due to the European gas market conditions. Production from major fields such as Troll and Sleipner dropped. Ormen Lange's production continued to increase and reached its plateau of 20 bcm in 2009.

The fact that Norway managed to increase production and deliveries to a declining market probably reflects the country's marketing and price strategy. Indeed Norway exports almost entirely to Western Europe with the largest volumes sold to the United Kingdom and to the Germany/Austria region. Sales to the United Kingdom declined slightly (by less than 1 bcm) from 2008 to 2009. Although they increased by 18% during the first half of 2009, they also declined by 20% during the second half, displaced by new LNG arriving at South Hook and Dragon. Sales to Germany/Austria increased by 5 bcm, mostly at the expense of Russian imports. Sales to France, the United States, Spain and Eastern Europe increased as well. This suggests that Norwegian gas has been sold at lower prices on the spot market and displaced more expensive gas such as Russian or Algerian deliveries.

Norwegian Exports in 2008 and 2009 by Quarter



Source: IEA statistics.

In OECD Pacific, Australian domestic production increased by 2.5 bcm, which translated into increased LNG exports as supplies to the domestic market dropped by 1 bcm. Although a large part of the production is currently consumed in the country, Australia is already a significant LNG exporter with over 24 bcm/y. Its global role is set to increase as two new LNG liquefaction plants, Pluto and Gorgon, will start late 2010/early 2011 and 2015. Australia has the highest additional LNG export potential with well over 100 bcm of planned liquefaction capacity. Final investment decision (FID) on new LNG projects seems likely in 2010 and 2011.

Non-OECD Regions

Supply in non-OECD regions is estimated to have declined by around 100 bcm, but global numbers mask many disparities. The largest share of this decline has been borne by Russia whose production declined by 12% or around 82 bcm. Turkmen gas production also declined as its exports to Russia (over 40 bcm/y in 2007 and 2008) were cut over a nine-month period. Turkmen gas production is estimated to have declined from 71 bcm in 2008 to around 35-42 bcm in 2009 due to lower exports and less gas used for compression. Other countries have seen more limited declines. Brazilian domestic gas production declined by 19% while imports plummeted by 29%. Production also declined in Bolivia, due to lower exports to Brazil and in Argentina. Despite the global increase of LNG trade in 2009, some LNG suppliers such as Nigeria saw their exports declining mostly due to upstream or political issues. There were also some limited export declines (less than 1 bcm) from Indonesia, Abu Dhabi, Egypt, and Brunei –due to the drop of demand in their traditional markets.

But as observed with demand, the declining trend is not happening in all markets. Some growing markets witnessed an increase of production: China, and particularly India with the start of Krishna Godavari field in April 2009. Qatar saw a significant jump of its production with the start of three LNG trains in 2009, while Yemen commenced exporting.

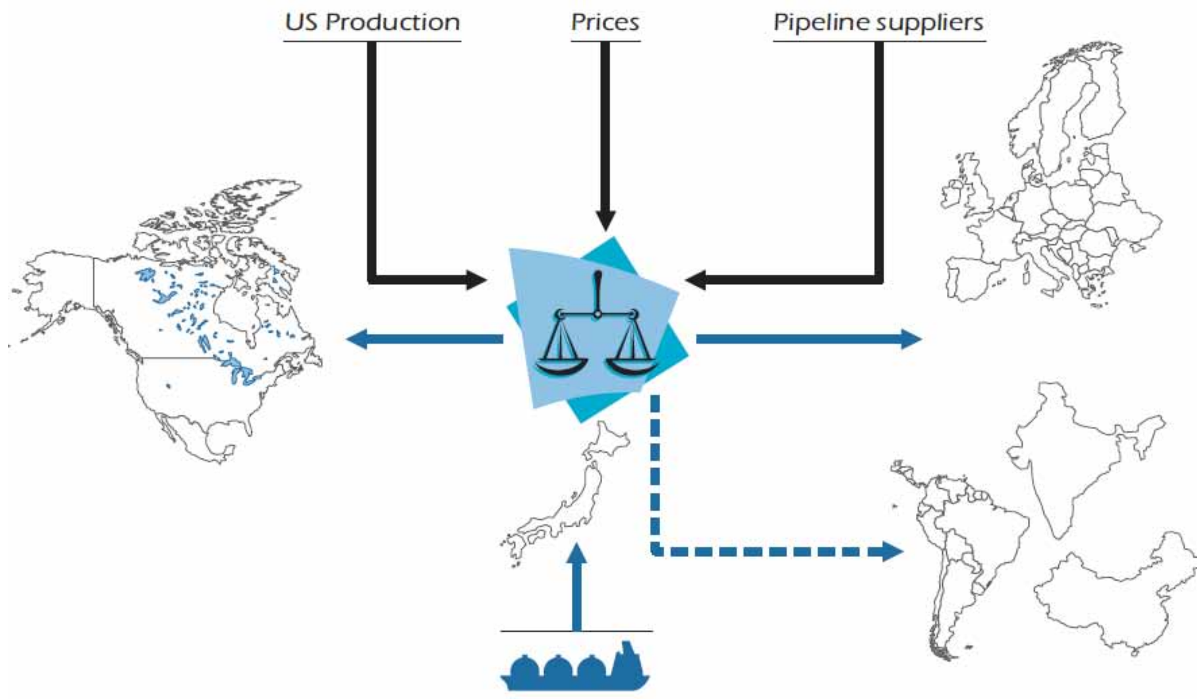
Are Gas Markets Globalising?

The answer to this question is yes, they are globalising and the use of the present progressive tense in this sentence is deliberate. Markets are not globalised yet: two-thirds of global gas is still consumed in the country where it is produced and parts of the world are relatively exempt from global market influences. LNG is the glue linking different parts of the world together.

Recently, China became physically linked by pipeline to the Caspian region and thus to Russia and Europe. Other parts of the world are becoming newly connected: Latin America through its new LNG terminals, China due to its growing appetite for LNG (and to a lesser extent India) and the Middle East which started operating its first LNG import terminal in Kuwait in July 2009. As LNG trade resumed its growth in 2009 and more LNG is set to come on line over the next years, gas markets will increasingly interact with each other. Two of the three traditional regional markets are increasingly connected: the price convergence that many analysts had been anticipating can be clearly seen in the links between the United Kingdom and the United States hub prices since spring 2009.

The United States has currently almost withdrawn from the LNG trading picture; this does not mask the fact that they remain the residual market where LNG will compete against the most expensive conventional and unconventional gas production. In Europe, some uncontracted or flexible LNG will compete against pipeline supply. Europe, whether it has noticed it or not, is now effectively competing with China for LNG supplies and also for Caspian gas. Indeed, growing and flexible LNG production from the Middle East means that these suppliers can equally target Asian, European and North American markets, or the Chinese market, which has recently proven that it was willing to pay higher prices (over $6/MBtu) than those in Europe or in the United States.

Globalisation of Gas Markets



Source: IEA.

Globalisation can be also examined through the investment prism: developments in one part of the world now have widespread consequences. The reversing of the supply situation in North America not only drove away producing countries that had been looking at this market, but also had regional consequences for import terminal projects. One import terminal project in Canada was even transformed into an export project.

Despite the globalisation, there is a high geographical concentration in terms of resources. In 2008, more than half of total gas supply was produced in five countries and more than half of gas exports were from five countries. This compares to a lower concentration of crude oil production and exports of 43% to top five countries. Concentration is even higher in LNG: 62% was exported from five countries. These figures were higher in 1990: 68% of gas production, 80% of gas exports, and 92% of LNG exports were from five countries. In 2009, the ranking changed: the United States overtook Russia owing to US production increase and the collapse of Russian production. Qatar overtook both Algeria and the Netherlands while Indonesia dropped below China. Among the exporters, Russia remains the largest despite its weaker performance in 2009, while Qatar jumped from the fifth to the third rank. Turkmenistan has probably observed the biggest fall among these exporters as exports are estimated to have been around 20 bcm.

But gas demand is also highly concentrated. While some main consumers such as the United States, Russia, and Iran are also large producers, many differences arise when one looks at countries below the third rank. Finding the largest developed countries (from a population and industry point of view) in this list is not a surprise. More surprising is Ukraine's 10th position, which is largely due to the inefficiency of its gas sector. China's rank will be higher in 2009 as it overtook Italy and is set to overtake Germany and the United Kingdom and possibly Japan by 2010: that would put China at the fifth, potentially fourth position among gas consumers – a dramatic change from the 28 bcm consumed in 2000.

Concentration in Gas Production, Export and LNG Export in 2008 (bcm)

	Production		Export		LNG Export	
1	Russia	665	Russia	195	Qatar	39
2	United States	575	Canada	103	Malaysia	31
3	Canada	175	Norway	96	Indonesia	28
4	Iran	130	Netherlands	62	Australia	21
5	Norway	102	Qatar	58	Nigeria	21
6	Netherlands	84	Algeria	57	Algeria	20
7	Algeria	82	Turkmenistan	54	Trinidad and Tobago	17
8	Qatar	78	Indonesia	37	Egypt	13
9	Indonesia	74	Malaysia	28	Oman	11
10	China	72	United States	28	Brunei	10
Total		**3 149**		**942**		**226**
Top 5		**52%**		**55%**		**62%**

Source: Natural Gas Information 2009, IEA.

Concentration in Gas Demand, Imports and LNG Imports in 2008 (bcm)

	Consumption		Imports		LNG imports	
1	United States	658	United States	113	Japan	95
2	Russia	460	Japan	95	Korea	37
3	Iran	132	Germany	92	Spain	28
4	Japan	103	Italy	77	Taipei	12
5	United Kingdom	99	Ukraine	53	France	10
6	Germany	98	France	46	India	10
7	Canada	95	Spain	39	United States	10
8	Italy	85	United Kingdom	37	Turkey	5
9	China	78	Turkey	37	China	4
10	Ukraine	67	Korea	37	Mexico	4
Total		**3 154**		**937**		**226**
Top 5		**46%**		**46%**		**81%**

Source: Natural Gas Information 2009, IEA.

SHORT-TERM DEMAND FORECASTS

Summary

- **In the OECD, after the 3.3% drop in 2009, gas demand is expected to recover to 2008 levels by 2012.** In 2013, gas demand will reach 1,578 bcm, 2% above 2008. Gas consumption in 2010 seems to have already rebounded, but this is largely due to a colder than average first quarter: demand, particularly in the residential/commercial sector, is estimated to be 10 bcm higher than in a normal winter.
- **The pace of growth will differ widely among regions, with OECD Europe clearly lagging behind.** OECD North America and OECD Pacific show the strongest recoveries. European gas demand will recover to 2007 levels only by 2013 but that level will still be below that prevailing in the first half of 2008.
- **The power generation sector is the primary driver behind demand growth.** Gas demand in this sector is expected to grow in all regions, despite competition from increasing renewables generation, nuclear (particularly in OECD Pacific) and coal. Residential/commercial demand is expected to stabilise, while industrial gas demand will return to 2008 levels in 2013.

Recent demand developments underline the need to understand the possible future demand developments in the short to medium term. As noted earlier, two main factors or uncertainties exist for future gas demand: the economy – how fast and by how much will the economy recover in different countries – and the evolution in the power generation sector. Gas demand levels in any given country are the result of the historical evolution of different sectors: residential/commercial, industry, power generation and uses in the energy sector (such as oil and gas production, LNG liquefaction or regasification). The use of gas as raw material (fertiliser) is included in the industrial sector for this particular exercise. Gas demand has always been and remains influenced by various factors such as the development of the gas grid, the number of residential and industrial customers opting for gas, temperature influencing heating demand levels, behaviour towards energy efficiency, policy and regulatory decisions leading to a particular evolution of the power generation mix (*e.g.* nuclear, wind) as well as prices or taxes, and the availability of domestic energy resources.

Economic activity is the primary determinant of natural gas demand. It influences industrial production and therefore its energy consumption (particularly gas and electricity) as well as household incomes, commercial activity and to some extent price levels. There is still considerable uncertainty on the pace and extent of the economic recovery (if any) across regions. In fact, recent developments in the European region are adding a new level of uncertainty. Assumptions on GDP are based on the latest International Monetary Fund (IMF) outlook, which foresees a recovery of the global economy by 2010 with the world's GDP increasing by 4.1% in 2010 and then 4.3% (2011), 4.4% (2012) and 4.5% (2013). The recovery will be more sluggish in Europe with the economy expected to increase by 1.3% in 2010 but with stronger growth in the following years at 1.9%, 2.2% and 2.3%. In OECD North America and OECD Pacific, economic growth will be stronger: North American economies will recover in 2010 (+3.2%) and the economic growth will remain strong over the following three years at around 2.7%. Meanwhile OECD Pacific economies are projected to grow at around 2.6% per year over 2010-13.

Another key parameter is fuel prices. Assumptions on crude prices are similar to those in the *Part 1: Oil* of this report. These prices are assumptions based on the prevailing future strip and serve as an input in the model but do not represent forecasts. Nominal crude prices will increase from $77/bbl in 2010 to $79 (2011), $81 (2012) and $83 (2013). Coal price assumptions in Europe and in the United States are also based on the current curve: they will continue on the increasing trend that started mid-2009. In Europe, coal prices will increase progressively from $90 per tonne to $122 per tonne in 2013 while in the United States, coal prices increase from $62 per tonne in 2010 to $80 per tonne in 2013. Regarding gas prices, assumptions differ across regions. Assumptions on Henry Hub prices are based on the forward curve: they are expected to increase from $4/MBtu in 2009 to $4.5/MBtu in 2010 and then progressively reach $6/MBtu by 2013. In OECD Pacific, gas prices will remain strongly linked to oil prices: in this case, price assumptions are based on the historical relationship between oil prices and Japanese import prices. In this region, gas prices are assumed to increase from $9.1/MBtu in 2009 to $11.8/MBtu in 2013, reflecting the increase in oil prices with a time lag. Assumptions regarding European gas prices reflect the inclusion of a spot element in some contract formulas: prices will increase from $8/MBtu in 2010 to $9.4/MBtu by 2013.

Methodology

For these short-term forecasts, consumption is divided into 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' (Other Sectors).
- The industrial sector includes what is usually categorised as industry (such as iron and steel, chemicals and non-ferrous metals) and non-energy use from fertiliser producers.
- The transformation sector corresponds essentially to the power generation sector and includes categories such as 'Main Activity Producer Electricity Plants', 'Autoproducer Electricity Plants', 'Main Activity Producer combined heat and power (CHP) Plants', 'Autoproducer CHP plants'.
- Other uses include the energy sector, distribution losses and the transport sector (use in pipelines or in road transport).

As noted earlier, economic growth is the single most important assumption for the forecasts. It is used as a primary input in the industrial sector and for electricity demand. It does have an impact in the residential sector but a more indirect one. Indeed, the residential sector has a certain inertia as consumers will generally change their heating systems only after more than a decade. However, their consumption patterns evolve over time as they react to external changes such as climate change awareness, but also increasing energy prices, lower incomes or as their social behaviour changes (more houses with fewer people). As weather remains the single most important factor behind the yearly changes in this sector, it is important to take out the influence of HDD and to look instead at the evolution of consumption per consumer per HDD for the different countries (or at the evolution per HDD when no reliable data on consumers was available). The resulting trend has been used for the forecasts. HDD for the upcoming years 2011 to 2013 are based on the five-year average. For 2010, real data for the months January to April have been used and the five-year average for the remaining eight months.

In the industrial sector, production (therefore GDP) and prices are two essential components used to determine the historical relationship between gas demand, production and prices, and therefore future demand path. For gas demand from fertiliser producers, the production forecasts of the International Fertiliser Industry Association (IFA) and the European Fertiliser Manufacturers Association (EFMA) has been used as an input for demand forecasts. The transport sector groups both transport by pipeline and road transport. For road transport, assumptions on fleet growth for different countries have been based on the historical evolution of natural gas vehicles (NGVs).

The most complex sector is, unsurprisingly, the power generation sector as final gas consumption is the end result of many iterations. First, one needs to look at the evolution of electricity demand, for which economic growth is a major driver. Then generation of renewables, hydro and nuclear must be subtracted as they are 'must-run' generation. For most countries, historical utilisation rates of these different generation types have been used to forecast electricity generated for the years 2010 to 2013, based on power capacity and taking into account new plants or decommissioning of older plants. It is important to recognise that a rainy or a dry year can have a significant impact on gas demand in the power generation sector: the drop of Brazilian gas demand in 2009 and the increase in Spanish gas demand in 2008 reflect these two factors. Finally, the balance between electricity demand and these items represents generation by fossil fuels: gas, coal and refined oil products.

Short-Term Gas Demand Forecasts by Sector

According to this analysis, OECD gas demand is expected to recover to 2008 levels by 2012. OECD North America and OECD Pacific show the strongest and fastest recoveries. The recovery will be more sluggish in Europe due to lower GDP. Gas consumption in 2010 seems to have already rebounded, but this is largely due to a colder than average first quarter so that demand, in particular in the residential/commercial sector, shows an estimated 10 bcm surplus compared to a normal winter. Europe gas demand will recover to 2007 levels only by 2013.

OECD Gas Demand by Region (bcm)

	2000	2005	2008	2009	2010	2011	2012	2013
Europe	472	546	557	527	544	533	540	548
North America	791	763	814	800	804	803	820	835
Pacific	131	151	175	169	180	182	149	195
Total	**1,394**	**1,459**	**1,546**	**1,495**	**1,528**	**1,517**	**1,549**	**1,578**

Source: IEA.

OECD Gas Demand by Sector (bcm)

	2000	2005	2008	2009	2010	2011	2012	2013
Res/com	486	518	524	522	532	513	513	514
Industry	391	344	343	306	310	320	331	342
Power generation	382	463	529	516	532	529	548	563
Others	135	134	152	152	153	155	157	159
Total	**1,394**	**1,459**	**1,546**	**1,495**	**1,528**	**1,517**	**1,549**	**1,578**

Note: Others include energy, transport and distribution losses.
Source: IEA.

The major driver behind this gas demand growth is the power generation sector, with around 35 bcm of gas demand growth over the period 2008-13. There will also be growth in the energy and transport sectors, but other sectors, such as industry or residential/commercial, will show an absolute decline. Again, most of the uncertainty is concentrated on the power generation sector, in which gas demand evolution depends not only on how electricity demand recovers, but also on the evolution of the power mix in each country and on the evolution of trade between countries.

Residential/Commercial Sector

OECD residential gas demand has been growing over recent years, but the main driver has been relatively colder weather rather than a structural growth. Although the number of gas users has been growing relentlessly over past years, individual consumption has been falling progressively due to progress in insulation, use of new boilers, and use of alternative heating sources such as solar panels. In Europe, the Energy Performance in Buildings Directive was passed in 2002 and implemented in most member countries.[9] The impact of the Directive was estimated as insufficient, so that the Directive was recast in May 2010; however, new measures will take time to be implemented. Most countries show declining trends in terms of individual consumption per household per HDD.

As a result, residential/commercial gas demand will remain relatively stable in the OECD region over the period 2008-13. While this sector's demand will be higher in 2009 and 2010 as a result of colder weather during these two years, it will recede again in 2011 due to assumptions for HDD based on the five-year average. It will therefore increase from 524 bcm in 2008 to 532 bcm in 2010 and reach 514 bcm in 2013. Demand is expected to show a slightly positive trend in OECD Pacific while the trend will be negative in North America and OECD Europe (excluding Turkey).

Industry

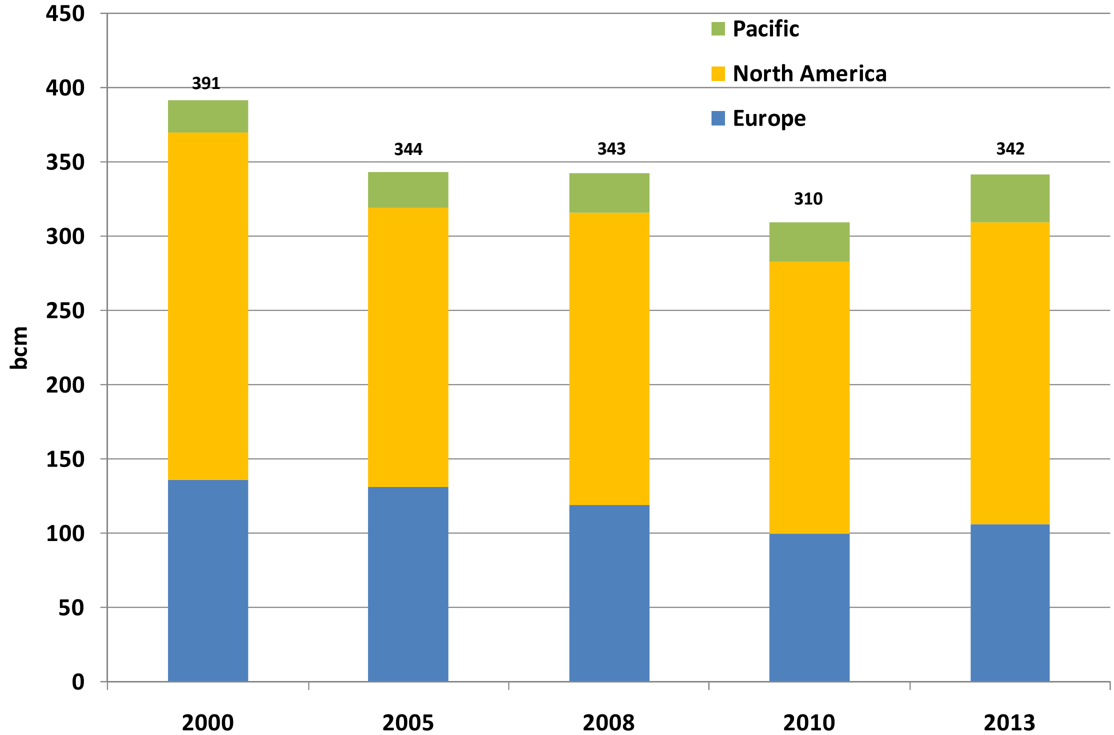
OECD industrial gas demand has been hit by the economic crisis, more than any other sector.[10] But it was already affected by trends inherent to that sector such as a shift to light industry or even services as heavy industry moves offshore, and more energy efficient processes triggered by rising energy prices over the past decade. A clear proof is the decline of industrial gas demand over the period 2000-08 from 391 bcm to 344 bcm. In most countries, industrial gas demand has been on a declining trend when reported relative to industrial production. Industrial gas demand will not reach 2008 levels before 2013. Again, the trends will be different depending on the region: both OECD North America and OECD Pacific will see demand increasing by 5 bcm each over 2008-13, while OECD Europe will see demand actually decline by 12 bcm.

Demand from fertilisers amounted to 37 bcm in 2008. World fertiliser consumption has been strongly affected by the financial and economic downturn. According to IFA, aggregate fertiliser consumption in 2008/09 dropped by an estimated 6.7%, although nitrogen (ammonia, urea) dropped only by 1.5%. Demand for fertiliser declined in all OECD regions. IFA anticipates a full recovery of global nitrogen consumption in 2010 and further increases by 1.9%/y over the period 2010-13, with the strongest demand growth in Asia and Latin America. Meanwhile, production of ammonia was stable and urea increasing slightly, resulting in inventory build-up. Looking forward, there will be a continued increase of capacity in Asia, Africa and Latin America.

[9] The Directive did not fix concrete levels but required setting minimum energy performance requirements for new buildings, as well as for the large existing ones being renovated, so that it lowered energy consumption in new buildings.
[10] This includes demand from fertilisers which represents about 11% of total industry demand.

Therefore, gas use in this sector in OECD countries will regain 2008 levels by 2011-12 on the back of increased fertiliser demand, and relatively low prices in North America and continue to increase further, but the increase will be limited as the bulk of additional fertiliser production will come from non-OECD countries driven by their higher demand, production capacity and lower gas prices. In the OECD region, most of the incremental gas use in this sector will come from North America, while gas demand in Europe will not recover even by 2013 despite the fact that some fertilisers are supplied at spot prices.

OECD Industrial Gas Demand by Region



Source: IEA.

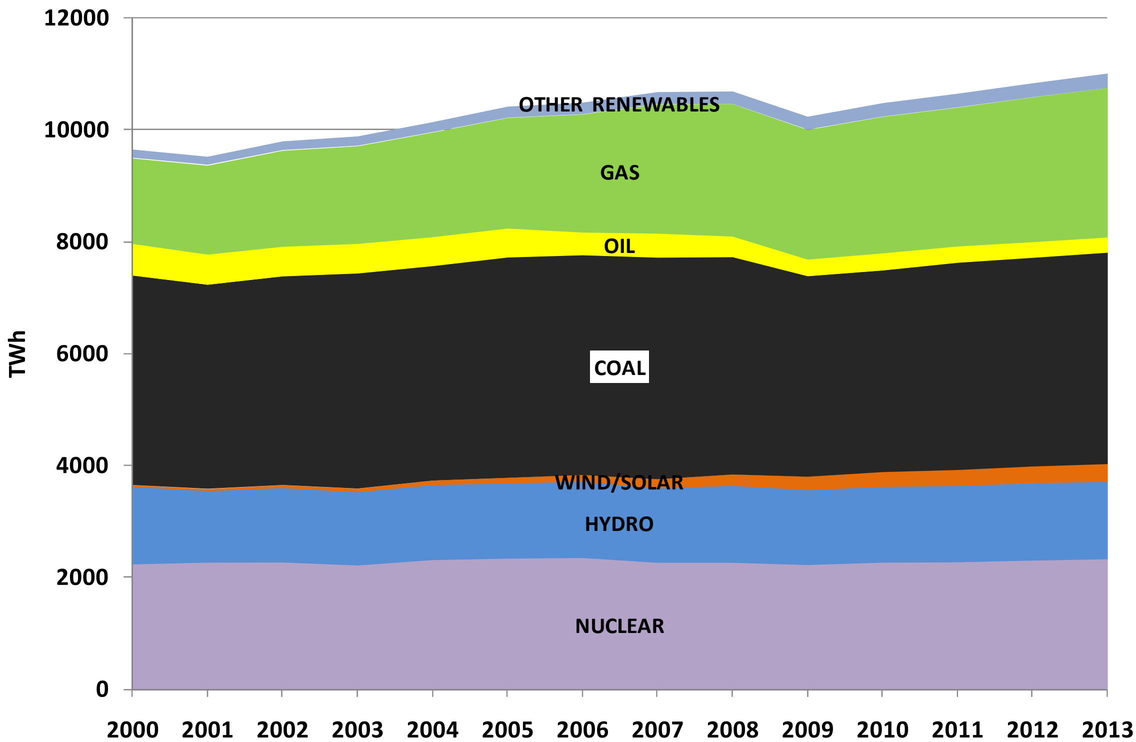
Power Generation Sector

Power demand will recover slowly from the economic crisis, largely because the industrial sector has been particularly hit and represents over one-third of total electricity consumed. Power generation in OECD countries is anticipated to come back to 2008 levels between 2011 and 2012. By 2013, power generation will be 2.7% above 2008 levels. North America and Pacific will be back to 2008 levels by 2011 but Europe only by 2013.

Generation from hydro is expected to be relatively stable over the period 2008-13 as only a few new hydro plants will come on line, for example in Turkey, Canada, Portugal, Spain and Japan. Generation from nuclear will increase by 3% over 2008-13 due to new plants coming on line in Korea (5.5 GW), Finland (1.6 GW), France (1.6 GW), Japan (1.3 GW) and the United States (1.3 GW), and some capacity increases in Sweden and Mexico. This will compensate for decommissioning of older plants in countries such as the United Kingdom. Nuclear output in Japan is expected to increase in 2010 with blocks of Kashiwazaki-Kariwa starting again.

Although wind and solar will still represent a small share (3%) of total OECD generation, their output will increase by 55% over the period 2008-13 on the back of increasing wind capacity. Output from wind and solar will reach 308 TWh by 2013 up from 199 TWh in 2008. The United States, Spain and Germany will be the biggest contributors to that increase, while half of the increase will happen in Europe as the region tries to reach the 20:20 targets (requiring renewables to represent 20% of final energy consumption by 2020). Other renewables will also show strong, albeit lower growth, as their output will increase by 16% over the 2008-13 period. They also represent a small part of total generation, just above 2%.

Evolution of Power Generation for the OECD Region



Source: IEA.

After a strong decline in 2009, generation by fossil fuels (gas, coal and oil) will recover over the period 2010-13, with total generation reaching 2008 levels (6,409 TWh) between 2012 and 2013. Again, the growth will be stronger in Pacific and North America, where fossil-fuel generation will increase back to 2008 levels between 2011 and 2012; in Europe it will lag below 2008 levels.

Refined oil products face structural decline in the power generation sector, apart from peak load or in regions such as islands without any gas grid. In most OECD countries, oil use to generate electricity is limited to 1% to 3% of total generation. The exceptions are Mexico (18%), Greece (14%), Italy (10%), Japan (9%), Spain (6%) and Poland (5%).[11] Oil use in the power generation sector has declined by 41% over the 2005-09 period, owing to higher oil prices and decommissioning of old oil-fired plants in countries such as Italy, where they were replaced by new combined-cycle gas turbines

[11] Shares in total generation capacity as of 2009.

(CCGTs). The decline is anticipated to continue albeit at slower rates: by 2013, oil-fired plants output will be 26% lower than in 2008; in 2009, their output had already declined by 18% compared to 2008.

Competition between coal- and gas-fired plants will continue in all OECD regions: gas-fired plants output will increase by 8% over the 2008-13 period while coal-fired plants output will marginally decline by 1%. But regional disparities are very strong: generation from coal-fired plants will increase in OECD Pacific and decline in Europe: the decline in Europe will be relatively strong (-11%) when one looks at the period 2008-13, but not if one compares 2009 and 2013 as coal-fired plants output will only decline by 3%. Gas-fired plants output will increase strongly in North America (+7%), Pacific (+10%) but more modestly in OECD Europe (+4%).

Others

In the transport sector, demand is expected to slightly increase from 28 bcm to 30 bcm over 2008-13, with the incremental demand coming half from pipeline transport and half from road transport. Gas use for NGVs is particularly interesting and has been attracting attention from leaders and market players, although most of the growth is actually happening in non-OECD countries such as Argentina, Iran, or India.

For the moment, it is a niche market and will undoubtely remain so during the period considered. There were an estimated 700,000 NGVs in OECD countries in 2008, of which over 500,000 were in Italy. From the government perspective, there can be several reasons to promote NGVs such as making the transport sector contribute to national CO_2 reduction targets, improving public health by reducing pollution from traffic in cities or increasing energy security of transport fuels through domestic production or by diversifying supply. Looking at the period 2009-13, the total number of NGVs increases at much lower growth rates than the period 2005-08 suggests (10%/y) with an average growth of 4%, driving demand from 2.6 bcm in 2008 to 3.7 bcm in 2013.

OECD gas demand in the energy sector amounted to 120 bcm in 2008. Two-thirds of this consumption comes from oil and gas extraction, while input in oil refineries represents 26%, and the rest from use in liquefaction, regasification and coal mines. Demand in this sector has been growing steadily over the past four years and this trend is expected to continue with demand reaching 125 bcm in 2013. Consumption related to oil and gas extraction will globally increase by around 2 bcm, while input in oil refineries will increase by another 2 bcm as natural gas will be required to produce hydrogen by steam reforming. In most OECD countries, consumption linked to oil and gas extraction will decline with the most important drop in the United Kingdom. A few countries will see remarkable growth, notably Canada due to the doubling of oil sands production from 1.2 million barrels per day (mb/d) in 2008 to 2.1 mb/d in 2013. Lower increases will take place in Norway and Australia. Hydrogen requirements will increase due to desulfurisation of gasoline: requirements will increase in particular in North America and Europe but remain stable in OECD Pacific. Fuel requirements for LNG liquefaction will increase in Australia.

Distribution losses account for around 3 bcm and are expected to stay at that level.

MARKET TRENDS IN THE LNG BUSINESS

Summary

- **Global LNG trade grew by 5.3% to 245 bcm (180 mtpa) in 2009,**[12] thanks to the massive expansion of LNG liquefaction capacity, mainly from Qatar, as well as switching from Russian pipeline gas to LNG in Northwest Europe.
- **This trend is gaining even greater momentum in 2010, in a market with much less appetite than anticipated when those projects were sanctioned earlier in the decade.** Increased LNG trade is applying further downward pressure on spot prices, but at the same time giving more confidence to buyers from OECD countries and emerging markets that additional LNG supplies would be available.
- **The start of the dramatic expansion of liquefaction capacity, which will see a 50% increase over 2009-13 has nevertheless been partially offset by the sluggish performance of some existing LNG exporters.** Technical difficulties have become the norm rather than the exception, including unplanned outages, feedgas issues in Algeria and Nigeria, long ramp-up periods at new production facilities, which were noted in the previous *NGMRs*. Most LNG is still to hit the market.
- **Despite the downturn in demand, major new FIDs were taken late in 2009.** Other FIDs are expected in 2010, notably in Australia.
- **More LNG markets are emerging around the world**, taking advantage of expected incremental availability of LNG supply in coming years, and quick-start floating LNG is seeing more interest. Plenty of new LNG terminals are planned. China is quickly expanding LNG imports: after starting importing LNG only in 2006, 2009 saw commercial operations at two new LNG receiving terminals (Fujian and Shanghai) and long-term contract delivery from Indonesia, Malaysia and Qatar.

Stronger LNG Growth Buoyed by Liquefaction Expansion

Global LNG trade grew by 5.3% to 245 bcm (180 mtpa) in 2009,[10] thanks to the massive expansion of LNG liquefaction capacity, mainly from Qatar. The shares of the Middle East in global LNG exports and Europe and Asia in the LNG imports increased slightly. In Europe, LNG along with other sources of cheaper spot gas displaced some Russian gas supplies. While the trend of liquefaction expansion is set to continue in 2010, the LNG market environment has altered markedly: the appetite for LNG in the United States is much less than previously anticipated by LNG exporters that were originally targeting this market several years ago. Buyers in other markets are trying to take advantage of these new volumes. At the same time, supply problems continue in certain LNG exporting countries.

The global LNG market expanded by around 50% in five years from 2002 to 2007, followed by almost no growth in 2008 and early 2009 due to upstream issues in major producing countries, particularly Nigeria and Algeria. The market then returned to a relatively strong growth in the second half of 2009 even as the global gas market contracted. Another 50% liquefaction capacity expansion is well under way within the 2009-13 period. Whether this will directly lead to a comparative expansion of global LNG trade is another question. Indeed many delays have been observed for the start of these new LNG plants, as well as unplanned outages requiring these new plants as well as existing ones to

[12] Preliminary figure.

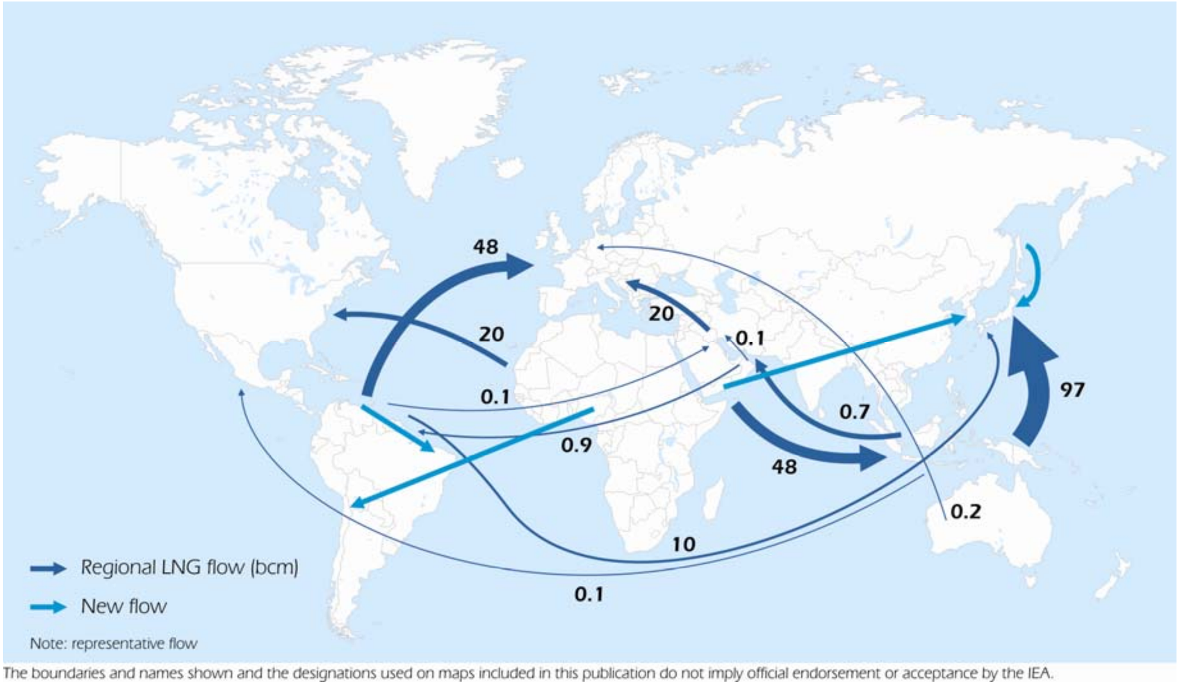
go into prolonged maintenance. It usually takes these plants several months and sometimes up to one year to ramp up to full production. Therefore a more gradual is anticipated but still very significant increase in LNG trade during the period 2010-15.

LNG Trades in 2009 (preliminary figures in bcm)

		Exporter				
		Asia Pacific	Middle East	Atlantic	Total	Share (%)
Importer	Asia	97	48	10	155	63
	Middle East	0.7	0.1	0.1	1	0.4
	Europe	0.2	20	48	69	29
	Americas	0.1	0.9	20	21	8
	World Total	**98**	**70**	**78**	**245**	
	Share (%)	**40**	**28**	**32**		

Source: Preliminary estimates based on custom statistics in countries, company information, GIIGNL, and industry journals.

LNG Trade Flows in 2009



Note: Flows indicated on the map represent flows between the regions and correspond to the table 'LNG Trades in 2009'.
Source: IEA.

China became the market of choice during 2009 for some LNG exporters. The country is quickly expanding LNG imports, after the start of commercial operations of the new LNG receiving terminal at Shanghai and the start of long-term contract delivery from Indonesia, Malaysia and Qatar in 2009. Meanwhile, traditional Asian importing countries were showing some signs of revived LNG appetites at the end of 2009, after a marked slump over most of the year.

From 2006 to 2008, higher gas prices and tighter market balances accelerated some global exchanges of LNG cargoes, notably from the Atlantic to the Asia-Pacific markets. These inter-regional movements of LNG underpin the globalising trends of gas markets described earlier. Some observers and industry experts have predicted that the next few years will see a return to regional markets despite an expected significant increase in both liquefaction and regasification capacity around the world. This assumes that any extra regional requirements should be met by extra output within the regions. Particularly, the increase in North American production from shale gas sources has apparently eliminated the need for imports of LNG, which were anticipated as recently as 2006.

However, the recent trend towards globalisation of markets has already transformed the business to an irreversible extent: a number of players are clearly working to secure multiple supply sources to support deals in multiple market outlets in different regions. Trading patterns are constantly evolving. Although the Atlantic-to-Pacific trades reduced in 2009, certain cargoes are still being transported in the same patterns as some transactions are under short- and medium-term contracts, rather than one-off spot trading. In 2009, flows from the Middle East to Northwest Europe increased. Some increases into the Middle East and South America, both relatively new LNG importing regions, were also observed. Finally, some importing countries are now able to export LNG: LNG has been re-exported from Belgium since 2008 and the US Sabine Pass terminal started to re-export LNG in 2009.

Issues in the LNG Markets in 2009-10

	2009 Developments	2010 Issues
Short-Term Trends	Sluggish demand in traditional big LNG markets (Japan, Korea and Spain). Significant increase of LNG imports into Northwest Europe led by Qatar into the United Kingdom. Other markets expand. The largest ever expansion of liquefaction capacity starts.	Demand recovery is still uncertain. While the US market is the residual market, how much LNG it will import is a major unknown. While liquefaction expansion continues, uncertainty persists on the supply side, too.
Long-Term trends	Concrete steps in Pacific for next generation (FIDs and long-term sales). Uncertainty in Atlantic projects continues.	Focus shifts to projects for second half of 2010s Most projects from Australia
Emerging Markets	Latin American LNG markets expand. Southeast Asia emerges as a future consuming centre. New terminals open in both OECD and non-OECD countries.	New terminal plans in Europe and North America slowly advance with supply uncertainty. China and India expand gas and LNG markets. Price reforms in some countries are needed and expected.

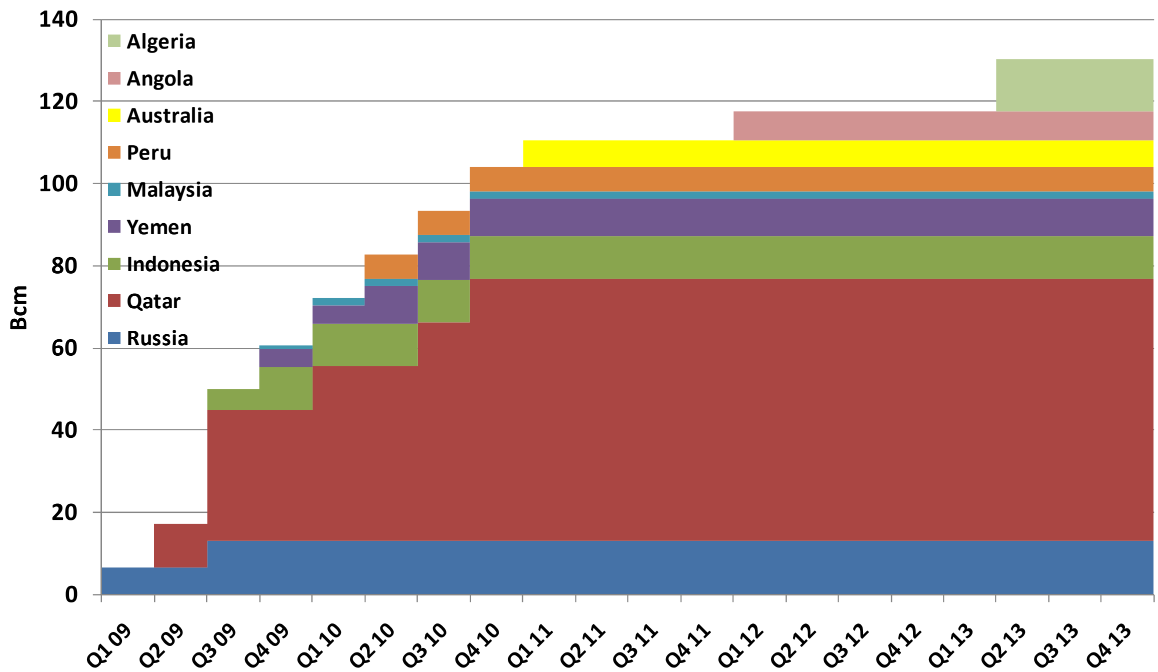
Source: IEA.

Current Expansion of Liquefaction and its Consequences

In 2009, 60 bcm of liquefaction capacity started operating. The year marked the entry of Russia and Yemen as new LNG exporters while Qatar achieved unprecedented growth – by over 30 bcm in a six month period and Indonesia started production at its first new liquefaction plant in almost 25 years. A large part of this new capacity started in the second half of 2009 – apart from Sakhalin and Qatargas II train 4 – due to construction and commissioning delays. Most projects experienced initial operational problems requiring long maintenance periods. Combined with problems at existing liquefaction plants, this led to limited growth in LNG trade in 2009.

All LNG export projects that started incremental and new production in 2009 have supply commitments to multiple markets. As the new projects ramp up to capacity and some additional projects come online, the resilience and flexibility of global markets will be tested later in 2010. In 2010, an additional 15 bcm started over January-April with RasGas II Train 7 and the second Yemeni train. The first Latin American plant in Peru started in June. Two other Qatari plants are expected to start before the end of 2010. Over 2009-10, over 105 bcm will have started – the largest increase ever seen in LNG capacity in such a timeframe. Over the upcoming three years (2011 to 2013), there will be fewer plants starting – 26 bcm. Half of the incremental capacity starting during the 2009-13 period will be located in Qatar (63 bcm) and will be able to easily target Asian, European or North American gas markets. Two additional plants are under construction, Gorgon and Papua New Guinea (PNG). FIDs were taken in 2009, and they are scheduled to start by 2014-15.

LNG Liquefaction Starting over 2009-13



Source: IEA after companies' press releases.

Qatargas and RasGas Mega-Trains, Qatar

Qatar exported 50 bcm (37 mtpa) of LNG in 2009, setting a new record for LNG export volume by a single country, after surpassing Indonesia as the largest LNG exporting country in the world in 2006. The previous record was Indonesia's 40 bcm in 1999. After the commissioning of Qatargas II Train 4&5 and RasGas III Train 6, the Middle East emirate is expected to double this amount fairly quickly after completing the remaining mega-trains in 2010.[13] Qatargas II Train 4 was officially inaugurated on 6 April 2009, with initial LNG production starting on 14 March, and shutting down on 1 April 2009. LNG production resumed at the end of May. After fixing the initial teething problems,

[13] Qatargas chief executive Faisal Al-Suwaidi forecast in March 2010 that his company will complete its last two remaining mega-trains by the end of 2010, enabling Qatar to reach its targeted production capacity of 77 mtpa (105 bcm) in 2011. The company plans to start up Train 6 in June and Train 7 in September 2010.

Train 4 had ramped up to 80% of capacity by the end of June and 100% by September. Qatargas II Train 5 started producing LNG in September 2009. RasGas III Train 6 started exporting in September. The fourth mega-train (RasGas III Train 7) started in February 2010 but has been encountering difficulties. Qatargas III and IV (Trains 6 and 7) will follow late in 2010. Those six mega-trains represent the biggest expansion of liquefaction capacity in the world over 2009-11, from 41 bcm at the end of 2008 to 105 bcm (77 mtpa, one quarter of total liquefaction capacity) in 2010-11.

Qatar already produces 22 bcf/d of gas (at the wellhead, equivalent to 227 bcm/y). Gas has become very important for Qatar: gas overtook oil in 2009 as the largest contributor to Qatar's economy, accounting for 32% of GDP, compared with 28% for oil. The increase of Qatar's production directly contributed to additional LNG imports into Northwest Europe in 2009, notably into the United Kingdom, Belgium and Italy, where Qatar has long-term supply commitments through either direct investment in LNG receiving infrastructure or long-term sale deals.

Partly due to the sheer size of the trains and the expansion as a whole, the Qatargas and RasGas projects were not immune to the delays and cost overruns. The original start-up schedule for those trains was from 2007 to 2010 when FIDs were made in 2004 and 2005. Ramping up to the plateau capacity production was also expected to take more time than originally planned, but is now apparently running smoothly, as operators learn from the experiences of the earlier mega-trains.

The unprecedented scale of expansion has begun to have significant impacts on the balance of the global LNG market, and subsequently on Qatar's own LNG marketing strategy. Whether this will result in changes in its LNG pricing and regional allocation of volumes is to be seen in the next couple of years. The initial strategy of having an equally spread geographical distribution between Asia, Europe and North America has clearly evolved towards Asia, away from North America. Indeed, Qatar has been expanding and diversifying its market reach since it started exporting LNG in 1997 to Japan. The current massive expansion phase was originally proposed to target markets in the United Kingdom and United States. The United Kingdom imported some 10 bcm of LNG, ramping up sharply in the latter half of 2009. But from 2006, the Qataris started to market some of the expected mega-train output to other regional markets on medium- and long-term basis, notably to China and to a lesser extent to new LNG markets in Europe. As the Qatari marketers have different pricing strategies into different markets and insist near oil price parity in the North Asian markets, Japanese buyers have not made additional long-term purchase commitments beyond the original Qatargas 1 contracts.

While the Qatargas mega-trains have a basic destination coming online at the same time as the liquefaction project, RasGas III's default destination, the Golden Pass terminal in the Gulf of Mexico has been delayed until the middle of 2010 by the damage caused by Hurricane Ike in 2008, highlighting again the issue of supply security surrounding energy production and infrastructure assets in the Gulf of Mexico. While waiting for the start-up of Golden Pass, RasGas III arranged interim 18-month sale deals with Chevron, Sempra, and Statoil from the second half of 2009 to 2010.

The global gas market has changed dramatically in recent years as a result of lower demand in the United States for LNG. In turn, Asian countries such as China and India, as well as some European and South American countries, would absorb more volumes. Soon after the start of the long-term contract delivery to China National Offshore Oil Corporation (CNOOC) in October 2009, Qatargas signed memoranda of understanding (MOUs) with CNOOC and PetroChina in November 2009 to double the contracted amount of LNG to those companies to a combined 14 bcm (10 mtpa) in the first half of the 2010s. In December 2009, RasGas began supplying an additional 3.4 bcm (2.5 mtpa) of LNG to India's Petronet LNG, increasing the total LNG term contract quantities between the two firms to 10 bcm (7.5 mtpa). These deliveries could be increased by up to 5.4 bcm (4 mtpa) by 2014.

Poland signed an agreement with Qatar in June 2009 for the supply of 1.5 bcm (1.1 mtpa) of LNG for Poland's planned terminal in Swinoujscie. This LNG is said to be quite expensive compared to current market prices. Qatar is also looking at other Eastern European markets including Greece and Bulgaria; the latter does not yet have any terminals but could import via Greece. Turkey and Qatar signed an agreement to potentially cooperate on proposed oil and gas projects in August 2009, which could include LNG sales to Turkey, as well as potential pipeline gas.

Sakhalin II, Russia

The 13 bcm Sakhalin project started production in early 2009 and exported the first LNG cargo to Japan in March following an off spec LNG cargo to India. The two trains were near full capacity by the end of September 2009. Sakhalin exported 81 LNG cargoes (5 mtpa or 6.8 bcm) along with 59 shipments of crude oil, which exceeded its previous targets for 2009. More than half of the LNG went to Japan, and the rest to Korea, India, China, Chinese Taipei and Kuwait. Russian gas could also target the Energia Costa Azul terminal in Baja California, in which Shell owns capacity.

Tangguh, Indonesia

Indonesia's Tangguh project was the first liquefaction train commissioned in that country since the late 1980s. It started in July 2009 and exported its first cargoes to Korea, for Posco and K-Power, and Fujian, China. Sempra Energy's Costa Azul LNG terminal in Baja California, Mexico received its first Tangguh cargo in August 2009. The cargo was the first delivered to the Mexican terminal since September 2008.

Despite the start-up of the Tangguh project, the country's overall LNG production in 2009 was below 27 bcm (20 mtpa) for the first time since 1989. The project exported only around 20 cargoes in 2009, much lower than the anticipated 56 cargoes, due to initial production problems and delays in the second train's start up. The Tangguh venture has original long-term sales contracts to customers in China, Korea, and Mexico. Half of the 5 bcm (3.7 mtpa) contract to Mexico can be diverted to other markets with compensating fees to the original buyer and some has already been diverted to customers in Asia. The country's Bontang LNG plant shipped out several replacement cargoes to fulfill contractual obligations to Chinese and Korean customers in the interim period from May to July, partly thanks to the reduced lifting by the long-term buyers from the Bontang venture in 2009. In addition, two Korean buyers have been supplied from other sources, notably from Egypt, since 2006 for their Tangguh contracts.

Yemen LNG, Yemen

The 9.2 bcm Yemen LNG project began production in October 2009 and exported its first cargo to Korea in early November, following several start-up delays. The project is the largest industrial undertaking in the country and the consortium is led by Total. The first train began operating in late June, with the first cargo scheduled by the end of August. Due to technical glitches, Yemen LNG exported only six cargoes in 2009. The project came on-line about one year later than planned and at a little over $4 billion, about 15% above planned cost. The second train, which was planned to arrive one year after the first, started operating in April 2010. About one-third of Yemen’s LNG is planned to go to Korea under a long-term contract. The remainder is contracted by Total and GDF Suez, which can benefit from using arbitrage opportunities. Both companies have multiple outlets in North America, Europe and Asia (India) for LNG, but are currently selling significant quantities of LNG to China where prices are comparatively higher than in Europe.

Peru LNG, Peru

The 6 bcm Peru LNG is started producing in June 2010. The 400 km trans-Andes pipeline from the Camisea fields to Pampa Melchorita was completed at the end of January. The project will be the first in Pacific South America and was the only project that made an FID in 2006. Due to its location, access to the global LNG market is currently relatively limited. The majority of the planned LNG volume is contracted to Mexico's Manzanillo terminal under construction on the Pacific Coast through Repsol. Some volumes may be sold to Asian LNG buyers. The planned expansion of the Panama Canal after 2014 would increase flexibility in marketing from the project, if additional LNG is available. As the Mexican terminal is due to become operational only in July 2012, the initial volumes are expected to go to other destinations, including the Canaport terminal on Canada's Atlantic Coast, which is operated by Repsol and opened in 2009.

The Peru LNG project features a unique combination of promoters as an LNG project without supermajors: Hunt Oil of the United States (50%); SK of Korea (20%); Repsol of Spain (20%); Marubeni of Japan (10%), and a relative newcomer in LNG liquefaction engineering: Chicago Bridge & Iron (CB&I). Feed gas will come from the Camisea fields. The government is facing pressure to prioritise domestic users, as many critics insist that the country lacks sufficient reserves to supply both local demand and LNG export commitment.

Pluto, Western Australia

As of the end of 2009, the first phase of Pluto was 83% complete and the commissioning of the offshore production platform was already under way, according to the project majority owner Woodside. Onshore, more than 90% of the 264 modules that comprise the first train had been delivered, including the plant's main liquefaction unit. There was nevertheless concern about project delays, triggered by a labour dispute at the construction site in January and February 2010. Woodside says it has started discussions with its Japanese buyers (and minority shareholders), Tokyo Gas and Kansai Electric, to implement risk mitigation measures in case of potential further industrial actions. The project is expected to start by the end of 2010, but may be delayed to 2011.

Woodside raised the cost estimate for the project by A$1.1 billion ($1 billion), citing a shortage of skilled labour as the main cause. The estimated cost stood at A$12 billion, including upstream development when the FID was made in August 2007, already almost doubling the original estimate made in 2005. To mitigate cost pressures and utilise the skilled labour force mobilised for Train 1, the company seeks to implement Trains 2 and 3 sequentially. However, the company's own exploration activities and talks with third-party gas suppliers for the expansion trains have not yet led to sufficient gas reserves. Woodside is targeting a FID on Pluto Train 2 by the end of 2010 and Train 3 by the end of 2011 if it can gain access to enough gas reserves.

Angola LNG, Angola

Although Angola LNG is still on target to start exporting LNG from its 7 bcm plant in the first quarter of 2012, the estimated cost of the project as of January 2010 has doubled to reach $9 billion compared to 2006 estimates. The remote location of the facility and rising construction costs over the 2007-08 period have been pinpointed as reasons for rising cost.

The project's FID was made in December 2007, after being postponed several times; one foreign partner, ExxonMobil, was replaced by Italy's Eni. The Angola LNG project is owned by Chevron (36%), state-owned Sonangol (Sociedade Nacional de Combustíveis de Angola, 23%), Total, BP and Eni (14%

each). The venture's preferred outlet has been the Gulf LNG'S Clean Energy terminal under construction in Pascagoula, Mississippi, in which Sonangol has a 20% interest along with El Paso Corporation (50%) and Crest Group (30%). The terminal is due to open in late 2011, just before the liquefaction venture. As US LNG needs are less than expected, the partners are considering diversion mechanisms elsewhere in the Atlantic basin while keeping the US terminal as the base destination.

Skikda and Gassi Touil, Algeria

The start of the two liquefaction projects in Algeria, the 6.4 bcm Gassi Touil and the 6.1 bcm Skikda replacing the plant destroyed in 2004, has been delayed to 2013. Gassi Touil was initially planned to come onstream in 2009 and Skikda in 2011. Gassi Touil suffered from significant delays during the first development phase by Spain’s Repsol and Gas Natural. This led Sonatrach to assume responsibility for full management of the project after arbitration. None of the plants have dedicated long-term supply contracts and most of Algeria’s traditional LNG markets, Spain, Italy, France, are well-supplied to oversupplied. Algeria has been in discussion with several Indian companies but no agreement has emerged from these discussions yet.

Sluggish Performance of Existing LNG Plants

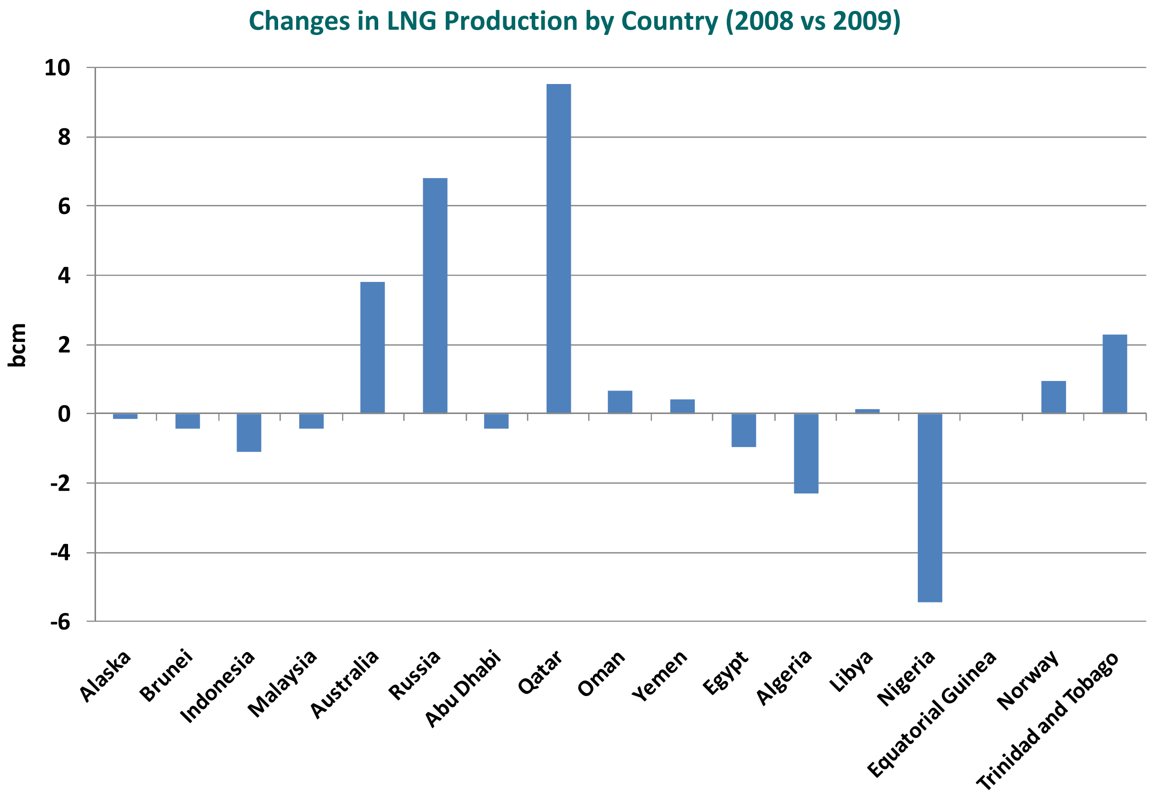
Increases in production from new liquefaction trains were to some extent offset by sluggish performance at some of the existing producers in 2009. Reductions in the Asia-Pacific LNG producers were mostly caused by depressed demand from their long-term buyers and can be classified as planned reductions, although feedgas shortages and upstream problems led to significant decreases in LNG production in Nigeria, Algeria and Indonesia.

Bontang and Arun, Indonesia

Indonesia's LNG export was down an estimated 4% in 2009, despite the delayed start up of the new Tangguh project. The existing Arun plant is expected to ship 36 cargoes of LNG in 2010, down from 42 in 2009. The Bontang LNG plant will export the equivalent of 279.5 standard-sized LNG cargoes in 2010, also down from the equivalent of 302.6 cargoes in 2009, due to lower feedgas supply. Upstream regulator BP Migas said that Tangguh is expected to ship 116 LNG cargoes (around 7 mtpa) in 2010 depending on market demand and if the plant performs as planned. In total, Indonesia could export 432 cargoes in 2010, compared to about 360 in 2009.

For Bontang, the feedgas supply from the main Mahakam fields is declining further, the question is whether to mothball the oldest Trains A and B with a combined capacity of 6 bcm (4.5 mtpa), or to maintain these trains in a ready state at a cost, in anticipation of future increases in gas supply from coalbed methane (CBM) and deepwater fields, as it would be expensive to bring back capacity once mothballed. In late November 2009, BP-Eni joint venture Vico was awarded a new CBM production sharing contract (PSC) in the Sanga-Sanga block in East Kalimantan that could provide feedstock for Bontang. Vico produced conventional gas for more than 40 years from that block. Preliminary studies show that this block, which covers 1 700 km^2, has a CBM resource potential of more than 4 tcf (113 bcm, 83 mtpa LNG equivalent).

The Arun liquefaction plant could be converted into a storage and regasification terminal over a period of just two years. The terminal would be modified to meet domestic demand, but also to serve as an LNG ‘hub’ in the area. There is still a major question of gaps between international LNG prices and domestic gas prices. The upstream regulator BPMigas said in March 2010 that Arun would stop LNG exports in 2014, and Bontang will divert its entire supply to the domestic market by 2020.



Source: Preliminary estimates based on custom statistics in countries, company information, industry journals.

Nigeria LNG, Nigeria

Nigeria's LNG production in 2009 was almost 30% lower than that in 2008, equating to about 6.3 bcm reduction, due to continued troubles in feedgas supply caused by civil strike and vandalism and civil strike to its condensate and feedgas pipelines. Nigeria LNG continues facing feedstock shortages because the Soku gas processing plant in Rivers State, which typically provides 40% of the feedgas to the LNG plant, has yet to be brought back to stable full capacity since it was shut again on 15 December 2009 after operating for only three months. A joint investigation team comprising regulatory and security personnel determined a leak had been caused by 'third-party illegal tampering'.

Malaysia LNG, Malaysia

Malaysia's overall LNG output in 2009 was slightly down 0.1% year on year to 30 bcm (22 mtpa). This resulted from a combination of reductions in contractual delivery to customers in Japan, Korea and Chinese Taipei and start of the long-term contract delivery to China, not necessarily related to feedgas shortage. Only half of the 1.6 bcm (1.2 mtpa) of the extra capacity associated with the debottlenecking of Malaysia LNG Dua was on-line by the end of 2009 and Petronas put off completion of the remaining 50% until the second quarter 2010 in order to avoid disrupting winter loadings.

There has been some enhancement in feedgas supply. Petronas signed an agreement with Sarawak Shell and Petronas Carigali in March 2010 to buy gas from three fields in block SK308 200 km offshore Sarawak. Shell and Petronas Carigali would supply gas from fields F28, F14 and E6 to Petronas' liquefaction complex in Bintulu. The F28 field would be the first to be developed and first gas is expected in April 2012, Petronas said. Shell and Petronas Carigali each hold a 50% stake in the block.

North West Shelf (NWS), Western Australia

Australia's LNG production in 2009 was around 19% more than that of 2008, mainly due to the ramping up of production from the fifth train of the North West Shelf (NWS) that started up in September 2008.[14] The train actually was operating at reduced capacity in 2009 due to a problem with the plant's cryogenic heat exchanger. The train was shut down for nearly a month in May 2009 for repairs. The venture also conducted maintenance for other trains in the second half of the year, taking advantage of the reduced demand from its existing customers in Asia.

Reflecting the reduced contract volumes to the historical buyers in Japan from April 2009,[15] further reduced demand from those buyers, and some incremental production capacity, the NWS venture increased spot sales significantly in 2009 to around 10% in total from just 1% in 2008, mainly to its new markets in the Asia-Pacific region, but also to Europe on a couple of occasions.

Flood of New Terminals

There could be more than a dozen quick-built terminals using either LNG regasification vessels (LNGRV) or floating storage and regasification units (FSRU) throughout Southeast Asia, the Middle East, South America, the Caribbean and the Mediterranean by the middle of this decade, particularly encouraged by recent successes in South America of those applications. FSRUs are typically chartered on a long-term basis while LNGRVs are often used to meet demand peaks.

Terminals in Europe – Notably in the United Kingdom, Italy and France

Four new LNG receiving terminals started importing LNG in Europe, two in the United Kingdom – South Hook and Dragon LNG, the first since the Isle of Grain terminal in Kent, England was completed in July 2005 and the Teesside Dockside Gasport in 2007. There were also one in Italy – Adriatic LNG offshore Rovigo, and one in France – Fos Cavaou on the Mediterranean coast. Those capacity increases coincided with the major expansion of LNG availability from Qatar. The United Kingdom and Belgium have become the largest buyers of Qatari LNG in Europe, importing 12 bcm in 2009.

The United Kingdom's LNG import capacity increased from 17 bcm to 34 bcm with the addition of the two new import terminals. The capacity is set to increase to 50 bcm by winter 2010/11 – equivalent to more than half of UK annual demand. The second phase of South Hook is completed. LNG imports grew exponentially to 10 bcm in 2009, from 1 bcm in 2008. 55% was supplied from Qatar, including long-term supply under the vertically integrated arrangement from Qatargas 2 to the South Hook terminal in Wales and occasionally spot cargoes into the expanded Isle of Grain terminal. While another terminal in Wales, Dragon LNG, received its commissioning cargo in July 2009, the terminal has not been as utilised as the other two.

The 8 bcm Adriatic LNG terminal in the northern Adriatic offshore Rovigo, Italy's second LNG terminal and the world's first gravity-based LNG structure, received its first cargo from Qatar in August 2009. The terminal's main supply source is Qatar's RasGas, although 1 bcm capacity is allocated to BP, which is expected to bring in Egyptian cargoes.

[14] With the fifth train, the venture now has a total production capacity of 16.3 mtpa (22.2 bcm/y), out of which the venture has flexibility volumes of as much as 1.7 mtpa (2.3 bcm/y).

[15] The original sales contracts amounting to 7.33 mtpa (10 bcm/y) from the Trains 1-3 with Japanese foundation buyers expired in March 2009. Some of the foundation customers were forced to receive smaller volumes than they previously imported. The renewal terms only last from six to 12 years, compared to 20 years for all the original deals, which were made in the early 1980s and started in 1989.

The Fos Cavaou terminal in southern France received its first cargo in late October 2009 after repeated delays from the original target date of 2007. The operational rate is likely to be restricted to 20% of nameplate capacity until the operator's reapplication to operate it at full capacity is accepted by the local authority. In the meantime, a valuable source of potential downward pressure on increasing French gas prices is not being utilised.

Elsewhere in Europe, the Gate terminal in the Netherlands and OLT Offshore LNG Toscana in Italy are under construction for targeted completion in 2011. Construction at Spain's El Musel greenfield LNG terminal in Gijon on the north coast is about to begin following months of delays. The terminal had been planned to start in 2011, although this now looks unlikely. Capacity expansion works are underway at some terminals in Spain and the United Kingdom. Apart from those expansion plans at existing sites, securing long-term LNG supply commitment is key to advancing projects.

New Terminals in China

China seems set to become increasingly import dependent and in the medium term, the additional sources of import will be LNG and pipeline gas from Turkmenistan. The country imported 7.5 bcm (5.5 mt) of LNG in 2009, up from 4.5 bcm (3.3 mt) in 2008. Long-term contract delivery started from Indonesia, Malaysia and Qatar in 2009, in addition to long-term contract cargoes from Australia and spot cargoes from other sources. First cargoes from Belgium and Yemen arrived in January 2010.

Three terminals are under construction: CNOOC has confirmed the start of construction of its LNG terminal project in Zhejiang in January 2010, expected to be on-stream by 2012. PetroChina is constructing its own terminals in Rudong, Jiangsu and Dalian, Liaoning, in the north of the country for its contract purchases from 2011 from Australia and Qatar. It received its first LNG cargo, from Russia's Sakhalin II project, in January 2010 at the Shanghai terminal in which it is leasing capacity, in order to meet gas shortages caused by record-low temperatures and high snowfall. The National Development and Reform Commission (NDRC) signed off on Sinopec's application to construct a new LNG terminal in Qingdao, Shandong shortly after Sinopec signed a binding 20-year sale and purchase agreement with PNG LNG in Papua New Guinea in early December 2009. The terminal could be online by 2013.

Latin America Expands

Chile received its first LNG cargo at the GNL Quintero terminal in the central region from Trinidad and Tobago in July 2009. The second terminal in the north of the country, GNL Mejillones, in February 2010, also received its first LNG from Trinidad and Tobago. The country imported about 0.5 bcm of LNG in 2009.

Both terminals adopted quick implementation schemes and are supplied by global LNG players' portfolios of LNG – BG for GNL Quintero and GDF Suez for GNL Mejillones. GNL Quintero's fast-track phase discharges LNG directly from the ship into the onshore vaporisers with only a very small 10,000 m^3 storage tank available as buffer. Two larger 160,000 m^3 tanks will be operational in 2010. The first stage of GNL Mejillones uses a LNG vessel for storage, as well as a jetty and onshore regasification plant. Second cargo arrived at the terminal in May 2010 from Egypt.

Argentina is expected to use its Bahía Blanca GasPort, 687 km south of Buenos Aires, for three winters (April-October) in a row from 2010, with an onboard regasification ship provided by Excelerate Energy, after importing 1 bcm of LNG in 2009. A second floating terminal is also considered to be located near Zarate in the north-east of Buenos Aires province in 2010.

Brazil started importing LNG in early 2009 with FSRUs located in Pecém, Ceará, in the north, and Guanabara Bay, off the Rio de Janeiro state. The Pecém terminal is the first FSRU LNG terminal in the world.

Middle East Emerges

Kuwait started importing LNG in August 2009 with an onboard regasification vessel moored at Kuwait Petroleum Corporation's (KPC) Mina Al-Ahmadi refinery. Sources were from Shell's global portfolio, including Sakhalin, Oman, Malaysia and Australia. Cargoes also came from Trinidad and Tobago. KPC wants to expand LNG procurement beyond Shell in 2010. The Dubai Supply Authority (Dusup) is accelerating its LNG import project for commissioning in September or October 2010 after postponing the project until the middle of 2011. DP World put its Jebel Ali port expansion on hold in 2009 as a result of the economic downturn, delaying a large breakwater. But Dusup moved the location of the FSRU slightly to put the plan back on track.

Portfolio LNG Players are Thriving

These days, players with multiple options, such as international oil and gas companies (IOGCs) and portfolio mid-stream players, lead the global gas business. They are expected to increase their share of LNG for at least the medium term. The strategy is to have a portfolio of LNG assets in multiple locations, in upstream, liquefaction, regasification and marketing. Companies with more options have a better chance to win business opportunities, further expanding options for potential business. The Appendices in *Part 3, Gas Supplement*, give details on LNG and other activities by company.

Supermajors and International Oil and Gas Companies (IOGCs)

Many supermajors and other international oil and gas companies (IOGCs) have in recent years expanded LNG upstream positions, as well as market reach. Some of them have also bought into unconventional gas production in North America, further diversifying their portfolios, partly aiming at mitigating risks as the earlier LNG initiatives were targeting markets in the United States. After effective completion of the mega project waves in Qatar and its long-term sale drive to China, their focus of those companies is now shifting to the Pacific, notably to Australia. Competition there is now fierce in marketing and resulting project decisions.

BG

BG Group is the prime mover in several areas of the global LNG business including firm capacity holding in the United States, portfolio supply building with flexible destinations, and secondary marketing of LNG. Taking advantage of its large regasification capacity position and LNG supply portfolio, the company is expanding from the Atlantic into Pacific LNG marketing, not only by diverting short-term cargoes from the former to the latter, but also by establishing long-term market access in Chile, Singapore and China, as well as developing supply sources in Eastern Australia from CBM.

GDF Suez

GDF Suez formed an even stronger group in LNG after the merger in summer 2008, now holding significant receiving capacities on both sides of the Atlantic, American Continent and even footholds in Asia (India's Petronet and the planned LNG project off Australia). Start-up of the Yemen LNG project is now giving the company an opportunity for further expanding market reach, including Chile and Pakistan, as well as its base destinations in North America and Europe.

Gas Natural/Repsol

The Gas Natural/Repsol duo of Spain has mainly focussed on Latin American and Southern European countries. Now that Repsol opened a receiving terminal in eastern Canada in 2009, the two companies have more flexible market access on both sides of the Atlantic. Repsol has committed to buy all the planned output from Peru LNG in which the company also has 20% equity. The company will supply most of its Peru LNG to the planned Manzanillo terminal on the Pacific central coast of Mexico. The company is considering directing a smaller portion of Peruvian LNG production to Asia, subject to pricing arrangements.

Asian Utility Buyers and Trading Houses

Some utility buyers from traditional LNG markets in Japan and Korea have become active in acquiring upstream and liquefaction stakes in exchange with long-term purchasing commitments. Recent examples include LNG purchase contracts from the Pluto and Gorgon projects in Australia to Japanese buyers. In December 2009 Tokyo Electric Power (Tepco) bought an 11.25% stake in Chevron's Wheatstone project in Australia along with nearly half of the output from the project for 20 years starting 2016.

In February 2010, Korea Gas Corporation (Kogas) agreed a joint-venture deal with Canadian gas producer EnCana to develop prospects in the province of British Columbia that could supply 20% of the planned LNG export project in Kitimat. In March 2010, Tokyo Gas announced its intention to acquire a 25% interest in a relatively small-scale gas field and LNG development project in South Sulawesi, Indonesia, led by Energy World Corporation (EWC) of Australia. In May 2010, another Japanese utility Osaka Gas announced the purchase of a 20% stake of Sagunto LNG terminal in Spain from Endesa.

UNCONVENTIONAL GAS

Summary

- **The rise of unconventional gas in North America has had regional and global consequences, and raises the question of whether such a revolution is possible outside the United States.** Many countries, including Australia, China, India, Indonesia, European and Latin American countries, are investigating their unconventional gas potential. While prospects look quite good in Australia, which already produces some unconventional gas, and Asia, the effective development of unconventional gas in Europe, MENA or Latin America will face more challenges.

- **Among the challenges that developers of unconventional gas resources face are the need for more systematic appraisals of resources, as well as environmental issues and local opposition.** Unconventional gas resources have been only roughly estimated outside North America and a deeper, more detailed study of the geological potential and the best plays is necessary. Furthermore, questions about the impact of unconventional gas drilling on water reservoirs – well founded or not – have been raised by many observers and politicians. This is likely to play a role in Europe where experience with the hydrocarbon industry is less than in the United States. Finally, different ownership of subsoil resources in countries outside the United States could fail to attract landowners' acceptance of production.

- **Unconventional gas development will also face challenges similar to conventional gas.** The prevailing pricing and fiscal conditions, the presence of infrastructure to transport the gas, availability of drilling rigs and of a qualified workforce as well as the availability of specific completion methods (hydraulic fracturing) will be determining factors.

What a difference five years makes. In 2005, significant unconventional gas production was a relatively distant prospect in most countries outside North America. Paradoxically it was already contributing to over 30% of US gas production – the second largest gas producer globally – mainly through tight gas and CBM. But it was not so widely discussed as it had not impacted global gas markets, and the surge of shale gas production had not started. While a few countries, such as Australia, Indonesia, China, India, were already looking at this potential, unconventional gas was still relatively unheard of outside North America. Studies of worldwide unconventional gas potential were relatively few. Mostly geologists were discussing the issues related to horizontal drilling, hydraulic fracturing and the permeability of rocks that are now widely publicised in the press.

At that time, the United States was still expected to become a large importer of LNG by the end of the decade (2010) and companies were actively pursuing regasification terminal projects. The EIA in its Annual Energy Outlook (AEO) 2005 expected LNG imports to reach around 50 bcm in 2008 and 2009 and increase to 70 bcm by 2010. But by 2008, the unconventional revolution had already changed the US supply picture reducing LNG import needs. As US production increased by 29 bcm in 2008 and again by 19 bcm in 2009, LNG imports were reduced to 9 bcm and 13 bcm respectively, implying a 10% utilisation of the US regasification capacity. In 2009, the effect of increasing US production combined with rising global LNG production and the economic crisis had spill-over effects on both regional and global gas markets, the latter often described as a 'gas glut'.

To some extent one can wonder if these resources should be called 'unconventional'; in fact the EIA now includes tight gas in the conventional category in their latest AEO, while estimates of the share of unconventional gas in US production vary for the very same reason. China and other countries also count tight gas as conventional gas. Now that North America has become almost self-sufficient in gas, many countries are examining unconventional gas production as a potential means of reducing their import needs (or increasing their ability to export). The United States remains the unchallenged leader of unconventional gas production with around 300 bcm in 2008, followed by Canada with 60 bcm. A few other countries, such as Australia, also produce unconventional gas, but quantities remain limited so far. The gas industry faces the following questions:

- What will be the short-term evolution of the US supply/demand balance as unconventional gas faces increasing competition from the new wave of LNG? Are the current production levels sustainable at $4-5/MBtu?
- What challenges does unconventional gas production face in the United States and in other countries?
- How likely is an unconventional gas revolution in other parts of the world and how long will it take to come about?

Unconventional Gas Types

There are three types of unconventional gas, not taking into account the more distant methane hydrates: tight gas, coalbed methane (CBM) and shale gas. Tight gas is contained in a very tight formation, trapped in unusually impermeable, hard rock, in a sandstone or limestone formation that has a low permeability and cannot be developed profitably with conventional vertical wells. CBM is gas contained in coal beds, which are usually too deep or too poor to be profitable. It has been known for a long time due to the danger of explosions in coal mines. Shale gas is natural gas, primarily methane, which is trapped is the Earth's most common sedimentary rock, shale. Shale generally has a very low permeability, but the gas is usually clean and dry. Most producers have ignored shale for a long time and it can sometimes occur far from the traditional production areas, so that many areas are unexplored.

Two technologies have helped the development of unconventional gas: hydraulic fracturing and horizontal drilling. Hydraulic fracturing (or fracking) is created by pumping water, solid propping material (proppants, usually sand) into the well. The water opens the cracks, and the sand or the other proppants maintain them open. The key to increase production is to have as many fractures as possible and maintain them open allowing the gas to be extracted. A well drilled in an unconventional gas reservoir will usually produce less gas over a longer period of time than a well in a conventional reservoir, with often sharp early depletion rates. This requires more wells with smaller well spacing to be drilled.

A Slow Evolution

Unconventional gas is not new. Tight gas has been produced for over 40 years in the United States: CBM production started in the 1990s although CBM has been known for as long as coal has been exploited and was often considered as a risk. Shale gas was the last one to be developed due to the very low permeability of the host rock. What made this revolution possible was the combination of:

- better knowledge of best resource potential, with entrepreneurs the driving force
- improved drilling and completing (fracking) technologies and
- rising HH prices to $6-8/MBtu over 2005-08.

A long E&P history, a meshed gas grid, and the need to replace declining gas resources and meet increasing demand led US geologists to seek better knowledge of the underground geology and improve progressively the drilling technology, notably horizontal drilling and improved fracturing. Unconventional gas also benefitted from regular technical progress in the E&P sector. For example, CBM is adsorbed at the coal surface and pressure must be reduced to extract gas; furthermore CBM often contains significant amounts of water which must be removed and disposed of in an environmentally sound manner as well. Better understanding of CBM resources in place and technology for dewatering coal seams enabled US CBM developments in the 1990s.

The fracking methods applied before 1998 for shale gas used massive amounts of sand, while the development of light sand fracturing (water fracture treatment) improved the efficiency and reduced the cost of wells. The price factor was also an important element for shale gas development. Until 2008, the conventional wisdom was that shale gas needed prices around $6-8/MBtu to be economic. Now the range of gas prices is estimated at around $3-6/MBtu. Shale gas is expected to represent an increasing share of US unconventional gas production, growing from 34 bcm and 57 bcm in 2007 and 2008 respectively to 109 bcm by 2015 and 128 bcm by 2020 (one quarter of total US production). One important fact is that the development of these resources seems to have been systematically underestimated as can be seen in the table below. Gas production forecasts were often 30 bcm to 60 bcm lower than actual production.

Evolution of Unconventional Gas Production Forecasts (EIA) (bcm)

	1995	2000	2005	2010	2015
AEO 1996	76	66			
AEO 1998	86	98	106	122	144
AEO 2000		n.a.	141	150	184
AEO 2002		131	165	202	229
AEO 2004			n.a.	206	246
AEO 2006			n.a.	218	230
AEO 2008			224	256	268
AEO 2009				301	310

Note: underlined data indicate actual production. This data represents only unconventional gas production, not total gas production.
Source: Annual Energy Outlooks from 1996 to 2009, EIA.

Not only is future production difficult to forecast, but the actual production is difficult to estimate. In April 2010, the EIA announced upcoming revisions in gas production data due to a potential overestimation. Indeed the sum of monthly balancing items[16] in the US supply and demand balance amounted to 20 bcm for 2009 according to first estimates, a level much higher than the previous years (3.8 bcm in 2008 and 5.9 bcm in 2007). US production has been reevaluated at 594 bcm, 5 bcm lower than the original estimates. The reason for the change of methodology is that the EIA only surveys top producers (which account for the bulk of US gas production), as small producers change rapidly and are difficult to track.

[16] Supply and demand of natural gas cannot always be measured exactly. When physical and statistical measurements of natural gas supply and disposition activities do not match, the difference is called the balancing item. (Source: EIA).

What Price is Needed for Unconventional Gas?

There is no single answer to that question, much to the dismay of analysts, or rather the answer is: 'it depends'. Like for conventional gas, a wide range of prices can make unconventional gas economic, depending among others on the quality and productivity of the play, on water management, on the specific fiscal conditions and environmental regulation in the region. In the *WEO-2009*, Barnett Shale wells were analysed. The threshold price (at the well head) needed to get a 10% return on capital ranged from $4/MBtu to over $13/MBtu. So far, most wells have been drilled in those productive areas of the Barnett shale close to the $4/MBtu threshold. However, this value is an average for all operators, and does not take into account the learning curve and better experience of some producers against less experienced or smaller players. Some companies have even reduced the average threshold to $2.5/MBtu. There is a strong belief among the US gas industry that the most economic unconventional gas can reach lower prices than conventional gas plays, the question is how much unconventional gas can be produced at these low prices.

Again one of the key factors driving prices downwards will be the technology, which will undoubtedly favour the most experienced players. Spacing between wells, length of the wells are some of the techniques to improve the productivity of the wells, while others look at improving the current low recovery from reservoirs. The learning curve is also faster: it took over 25 years for the Barnett play to reach a daily production of 50 Mcm/d and 5 years for Fayetteville. However, in other countries, with less qualified workforces and equipment, higher service costs and higher environmental costs (water treatment), the threshold price is very likely to be higher. The price per acre as well as the royalties and other taxes will also be key parameters for investors to look at. From the national point of view, there will be a balance between a higher security of supply through increased domestic production and these prices, that could be attained through, for example, preferential fiscal regimes. In the longer term, recoverable unconventional gas resources can be produced at prices between $2.7/MBtu and $9/MBtu.

But in the short term, the price question is whether the current $4-5/MBtu at which HH has been since mid March 2010 (and the relatively weaker HH prices since March 2009) will support US production at similar levels as 2009's. So far, production has been stable in early 2010 compared to the same period in 2009, just 0.1% up over the first two months. Meanwhile the number of US gas rigs has been declining again since mid April in response to declining prices. Some players may want to continue to drill due to expiring leases, even more if they had hedged contracts locking in higher prices. Furthermore, many players have entered into joint-ventures with foreign players or International oil companies (IOCs), some of which will be willing to pay for continued drilling or leases in return for experience. But while some may be drilling at a loss, they may still have difficulties funding the new wells. Also a considerable amount of the drilling being done for gas this year in the US is for lease commitments (rather than to add economical production today).

Unconventional Gas Outside the US, a Dream or a Reality?

There will be challenges to overcome to reproduce the unconventional gas revolution outside the United States. These issues can be categorised as follows:

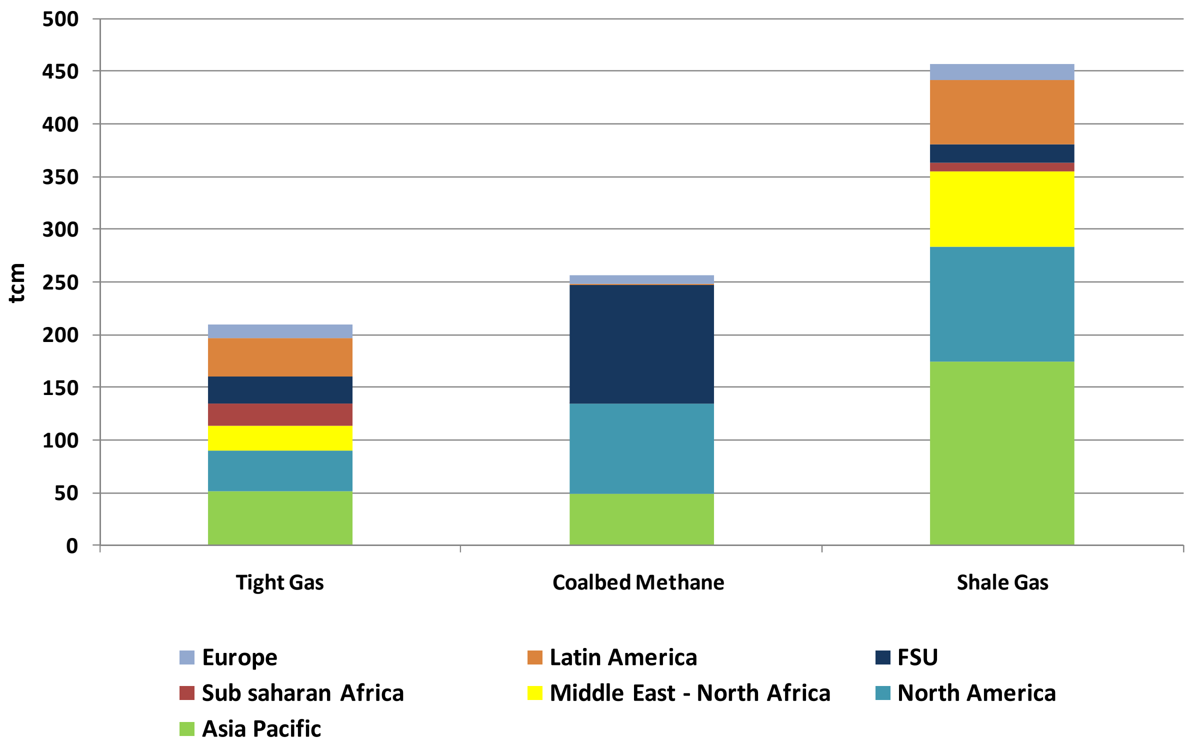
- Still limited studies on the unconventional gas potential, including sufficient geological information,
- Resolving water management issues (and potential leakages into drinking water reservoirs)
- Fiscal conditions
- Acceptance by landowners and the local population

- Interference from local authorities
- Proximity of a pipeline system
- Availability of suitable rigs and of skilled workforce in Europe and many other regions
- Gas players' experience

Limited Studies on the Potential

The first uncertainty is: how much potential is there? Despite some estimates outside North America, major work is still needed to refine and expand these data. Even in the United States, gas reserves are constantly reappraised; proven gas reserves increased from 4.7 tcm to 7.5 tcm between 2000 and 2009, mainly because of reevaluation of unconventional gas resources. In the *WEO-2009*, the unconventional gas potential has been analysed based on various studies available:[17] total resources in place are estimated at 921 tcm, a large part of which is not recoverable.

Unconventional Gas Resources in Place



Source: World Energy Outlook 2009, IEA.

Looking at regional estimates of unconventional gas potential, Asia Pacific and North America have the highest with 274 tcm and 233 tcm respectively followed by FSU with 155 tcm, Latin America 98 tcm and MENA 95 tcm. Although there is much discussion about unconventional gas in Europe, the resources are so far estimated at only 35 tcm. Shale gas represents half of this global potential and is especially present in Asia and North America while CBM is mainly in FSU and tight gas is quite evenly distributed between the regions. Again, these numbers should be considered with caution.

[17] Rogner, Kawata & Fujita, Holditch. This excludes methane hydrates.

First, with a few exceptions, unconventional gas resources have largely been overlooked and understudied. They are usually more viewed as a potential long-term resource and have not been appraised in any systematic way. Furthermore, not all of this gas will be recoverable; the IEA estimated that around 380 tcm would be recoverable based on current data and knowledge: this compares with 405 tcm of recoverable conventional reserves, and 182 tcm of proven gas reserves.

Many initiatives are underway such as the Gas Shales in Europe ('GASH'), coordinated by the German GeoForschungsZentrum (GFZ) and The Institut Français du Pétrole (IFP). In other regions, IOCs and National Oil Companies (NOCs) have been carrying out exploratory work, the results of which will not always be available. Once the potential has been established, companies need to find the best areas.

Population Density

In addition, there will be many 'above-ground' issues making it difficult to realise the potential in some regions, in particular environmental concerns and interaction with the local population. North America has benefitted from a quite low population density as both Canada and the United States have very low population density in most production areas. However, many European countries have a population density above 100 hab/km^2 or even 200 hab/km^2 compared to around 30 hab/km^2 in the United States and 3 hab/km^2 in Canada. A higher population density implies more interaction with the local population who may in general be less ready to accept disturbances. It may also be more difficult to drill many wells in one place.

Environmental Concerns

In the United States, there have been some increasing concerns about the impact of fracking and chemicals contained in the fracking liquids on the environment, and how this might affect water quality, quantity and supply infrastructure. CBM production produces water as a byproduct, which is not always suitable for irrigation; meanwhile water is used for shale gas production. Several million litres of water (2-3 million gallons) containing 1-2% chemicals are used per well. A study reported that 3% of the groundwater in the Barnett shale area was used for shale gas production in 2005. Unconventional gas development could compete with other groundwater uses, in particular in regions with scarce water supplies.

Early in 2010, the EPA (Environmental Protection Agency) launched a study to determine whether fracking could contaminate water supplies. In a previous EPA study in 2004, it had not found any evidence of contamination. The EPA is likely to try to regulate fracking under the Safe Water Drinking Act. This study is expected to take two years, during which shale gas production is likely to blossom in the United States. Major gas producers are concerned about the possible consequences of the EPA study. Exxon Mobil included a fracking-related escape clause in its $41 billion takeover of XTO Energy (but the deal is expected to close in 2010, before the study is completed). The findings of this study could also be significant on a global scale as some regions, in particular Europe, are particularly attentive to environmental issues and are likely to raise more objections to drilling.

Meanwhile some congressional Democrats launched a probe into the chemicals used by companies, which are commercial intellectual property. Policymakers are looking at ways to force companies to disclose information on chemicals. This may however clash with intellectual property rights, since producers are using chemicals designed by service companies. There are nevertheless two counter-arguments that could postpone federal regulation for some time: the potential to be self sufficient in gas and the lower CO_2 emissions of gas. In the meantime, these concerns have led New York state to impose a moratorium on shale gas drilling near the water sources supplying New York city. Concerns about water management will be particularly acute in densely populated areas such as Europe or some Asian regions and where water resources would be an issue.

Finally the long-term management of intensive drilling and multiplication of holes and cracks, their influence on existing natural fractures and faults, and their long-term development, is so far unknown.

Gas Grid

Another advantage of the United States is the extremely developed and highly meshed gas grid and the long existence of E&P activities which fits very well the fragmented character of unconventional gas resources.

Gas Grid Density

	United States	Australia	Italy	Sweden	United Kingdom	India
Gas grid (km) /area (1000 km^2)	62	3	110	1	45	3

Source: IEA country reviews, based on length of the transmission grid.

Landowners' Acceptance

The United States has specific legislation regarding underground resources: owners of above ground land also frequently own underground resources. Therefore landowners have received up to $25 000 per acre, and sometimes up to 25% royalty; even those who got only $5 000 per acre and 20% royalty did not prevent drilling from happening; on the contrary, such ongoing incentives are a powerful stimulus for open land access, drilling and production.

The mineral rights are however different in many other countries where landowners do not own underground resources; rather they are generally owned by the State, either regional or national. Usually, US landowners tolerate the invasion of trucks, rigs and workers as they receive ongoing revenues from this activity. In almost every other country, the state owns mineral rights, so that local inhabitants will mainly feel the downside of E&P activities but can only hope to be compensated for the use of their property.

Access to Technology

To develop unconventional gas resources, access to specific technology for drilling (hydraulic fracturing and horizontal wells) and for evaluating the potential is key. The fact that major IOCs have now acquired mid-size unconventional gas players will enable them to export the expertise worldwide so that the learning experience gained in North America can be applied relatively quickly.

Unconventional Gas Developments Outside North America

While unconventional gas is a reality in North America, its development at a comparable scale is still to be proven in other countries. As in the United States, it is important to note that the three types of unconventional gas can be developed but the rate and extent will differ by region. Unlike the United States, all three types could be developed in the short-term if the potential and the players are there, the technology is relatively readily available, having been developed to maturity in North America.

By any account, Australia ranks first among the countries with high short-term unconventional gas potential. The interest – and the potential – is very high in Asia: China and India both have existing activities and Indonesia is looking actively at shale gas. Russia's potential lies primarily in CBM, but the country has extensive conventional resources that are likely to be developed first if the economics are right.

The major question is on the European market as countries would like to reduce import dependency, but the development would face many challenges. Lastly Argentina has been looking actively at unconventional gas. In all these countries, except maybe Australia, players are at the stage of acquiring large areas of land, participating in bidding rounds and starting exploration.

Australia

CBM has been at the mature market stage in Australia for some time, but shale gas is still in its infancy.

CBM has been produced in Australia since 1996 and more is to come with six LNG liquefaction projects based on CBM (also called coal seam gas (CSG)) in the Gladstone basin. It is uncertain whether all projects will move forward (their prospects are discussed in the LNG investments section). Around 20 companies are active on CBM, including Arrow Energy, Santos or Queensland Gas Company. The distinction is made between CBM, also known as Coal Seam Methane (CSM) and Coal Seam Gas (CSG), and Coal Mine Methane (CMM), which is methane associated with coal mining operations. Legislation on CBM and CMM resources depends on the State and Territory Governments: in New South Wales and Queensland, petroleum resources legislation is applied on CBM while mineral resources legislation is relevant for CMM. In Victoria, CBM resources are administered under the legislation for mineral resources development. As water resources are particularly scarce in Australia, the State government is funding a study on coal seam gas mining impacts on underground water.

Some companies such as Santos, Beach Petroleum, New Standard Energy and Exoma Energy Limited are also looking at shale gas, in particular in the Cooper Basin, but such a development seems less likely than CBM. One of the major challenges would be higher costs that would make shale gas uncompetitive on the domestic market, while Australia still has ample conventional gas resources.

China

China has important unconventional gas resources of the three types and the US revolution has inspired Chinese energy policy makers as the country is expected to be increasingly import dependent. There has been historically a large focus on CBM, but now the country is looking at shale gas as well while tight gas is already produced. In November 2009, the United States signed a MOU with China to develop shale gas resources by helping to assess the potential, conducting joint studies and promoting investments. In any case, assessing the potential will be a key success factor as well as acquiring the technology. This is the reason why Chinese NOCs have been engaged in takeovers or cooperation agreements with foreign companies such as Shell, and Fortune Oil, over the past year. Furthermore, reform of pricing policies may be necessary if prices are kept at low levels. Finally, developing the infrastructure to transport this gas to the markets will also be a challenge.

There is already tight gas production in China, that is in fact classified with conventional resources. The Changbei tight gas field in the Ordos Basin, that Shell and CNPC are operating, produces 3 bcm/y. Both companies plan to jointly develop tight gas deposits in Sichuan under a 30-year PSA. Meanwhile Total has a PSC with PetroChina, signed in 2006, to develop the Sulige South field.

CBM 'geological resources' were estimated at 37 tcm and proven resources at 134 bcm in 2009, but progress has been relatively slow over the past 15 years. Indeed, the China United Coalbed Methane

(CUCBM) was formally established in March 1996 by approval of the State Council and was granted the exclusive right of the exploration, development, and production of CBM in cooperation with foreign companies through PSCs. It was restructured in 2008, and CNPC was left to produce CBM by itself. PSCs have been signed between either CUCBM or CNPC and companies such as Arrow Energy, Fortune Oil, ConocoPhillips, Greka, and TerraWest. Chevron however quit its three CBM blocks in 2009. The government plans to produce 40 bcm of CBM by 2020, from only 0.7 bcm in 2009.

Most of CBM currently produced comes from CBM extraction in coal mines and very little from CBM wells. CNPC started producing CBM gas from the Fanzhuang block, which has an annual production capacity of 0.6 bcm/y and is also developing CBM in Shanxi province. They have built a dedicated pipeline from Qinshui to the East-West pipeline. They expect to produce 10 bcm/y by 2020, including 5 bcm from the Qinshui basin. Most of the resources are concentrated in 13 coal basins with the largest potential located in Shanxi and Ordos. One of the potential challenges though is the competition between coal and CBM production so that agreements have to be found with local coal producers. Part of the CBM produced is transported in compressed form by trucks, liquefied or consumed locally at power stations. Increased transport infrastructure – in particular the West – East pipeline – will be needed to move this gas to consuming regions. CBM benefits from government subsidies: RMB 0.20/m^3 for CBM produced and RMB 0.25/kWh of electricity produced by CBM-fuelled power projects. Current production costs are said to lie around RMB 0.8-1.2/m^3, making CBM more competitive than LNG or Turkmen gas. The Chinese Government has deregulated CBM natural gas such that producers have the right to negotiate their own contracts and sell produced gas directly to end users.

China is estimated to have 26 tcm of shale gas, and the Ministry of Land and Resources (MLR) has announced a strategic goal of reaching a production target of 15-30 bcm by 2020. MLR will also allocate RMB 33 million to appraise its shale gas reserves: it will be the first time China has assessed these reserves. Again, it will be crucial for Chinese NOCs to acquire technology. In this regard, Sinopec has been in talks with BP.

India

India has been focusing more on CBM but is now turning to shale gas as well. There will be three key issues for the development of such resources: low domestic prices, lack of domestic infrastructure except in the North-West and expertise.

India had been organising CBM licensing rounds and the 4th licensing round took place in 2009, but so far CBM production, which started in 2007, is very limited. CBM resources are estimated at 4.6 tcm most of which are located in the North-East and North-West of the country. Indian as well as foreign companies are active including Oil and Natural Gas Corporation (ONGC), BP, Reliance Industries Ltd (RIL), Essar Oil, Arrow Energy, Gas Authority of India Ltd (GAIL), and GEECL. So far only 26 blocks representing 13,600 km^2 have been auctioned. CBM is often sold as compressed natural gas (CNG), but RIL has been looking at using it for a power plant. ONGC and Arrow Energy signed a MOU on cooperation in early 2009.

Shale gas exploration is relatively new in India but rapidly gaining the attention of industry players with ONGC launching a pilot project in 2011. The fact that RIL invested $1.7 billion in the US shale play Marcellus in April 2010 shows the interest of Indian companies in acquiring the expertise and technology. However, two obstacles remain: the lack of clarity regarding the upstream regulation for shale gas – *i.e*. does the New Exploration and Licensing Policy (NELP) apply? – and the lack of data as most of India remains underexplored.

Indonesia

Despite its position as a net exporter, Indonesia feels the need to increase domestic production to meet increasing demand and reverse the decline of conventional gas. Indonesia has nevertheless been relatively slow to develop unconventional gas compared to India or Australia. One of the main reasons may have been the regulatory and legal uncertainty, making foreign companies reluctant to invest, but the situation has improved since 2007.

Indonesia has significant CBM reserves (12.7 tcm) mainly located in Southern Sumatra and East Kalimantan, and is thought to hold large shale gas resources as well. The government aims at producing 10 bcm of CBM by 2025. So far, 20 CBM PSCs have been signed between the Directorate General of Oil and Gas (Migas) and the CBM contractors. The government simplified legislation and offered incentives to contractors, which get a 45% share.[18] Late 2009, Migas launched the first CBM round: three blocks were awarded to three companies. The investment commitment for these blocks would consist of geological and geophysical studies, drilling of exploration and exploration wells amounting to a total commitment of $53 million. Additionally, two CBM blocks have been proposed from the existing Petroleum Working Area and Coal Mining Area. The government expects first CBM production in 2011.

Indonesia plans to launch a tender of shale gas fields in 2010; shale gas potential is estimated at around 30 tcm.

Europe: An Evolution Rather Than a Revolution

Looking at the US example, many importing European countries have become very interested about the potential of unconventional gas production. As noted earlier, there are many challenges that could prevent an unconventional gas boom happening in Europe. However, there has been a lot of activity recently, in particular on shale gas or CBM, in Austria, Bulgaria, France, Germany, Italy, Poland, Romania, Spain, Sweden and the United Kingdom. There are also some tight gas prospects in Central Europe (Poland, Hungary, and Germany).

IOCs, which had been largely absent from the first steps in the United States, are keen to be on board sooner rather than later: ExxonMobil, Shell, Chevron, ConocoPhillips Marathon, and Total are present in one to several countries. European upstream players such as Statoil, OMV, Eni are also looking into this potential. But there are also smaller players such as European Gas, Falcon, Schueppbach, Aurelian Oil & Gas, FX Energy to quote a few.

Europe, at least, benefits from good geological documentation but needs to appraise the quality of the potential shale plays. In most countries, unconventional gas is at the very early stages of acquiring seismic data, looking to drill wells in 2010-12. Only a few European countries are actually producing unconventional gas, and then only in small quantities.

[18] This compares with much lower share for conventional oil (15%) and gas (30%).

Unconventional Gas Activities in Europe

	CBM	Tight gas	Shale
Austria			OMV
Belgium	European Gas, Transcor Astra Group		
Bulgaria	CBM Energy		
France	European Gas Ltd		Total, Egdon Resources, Mouvoil, Schueppbach Energy LLC, Dale Gas Partners, Eagle Energy Ltd, Bridgeoil Ltd., Diamoco Energy
Germany	Exxon Mobil	Wintershall	ExxonMobil,
Hungary		MOL, Falcon, Exxon Mobil	Exxon Mobil
Italy	Ind. Resources plc		
Poland	Composite Energy, EurEnergy	Aurelian	ExxonMobil, ConocoPhilips, Lane Energy, Talisman, Chevron, Aurelian, FX Energy
		FX Energy	
Romania	Falcon, Galaxy		Aurelian, FX Energy
Sweden			Shell
UK	Island gas, Composite Energy		
	BG, Nexen, Marathon		
Turkey			TransAtlantic Petroleum, TPAO
	Preliminary work, exploration, assessment of seismic data		
	Wells drilled		
	Production		

Note: the list of companies is not exhaustive.
Source: IEA, based on press releases, news reports.

Poland

Poland is a large coal producer, so that CBM resources could be expected, but shale gas seems to have got more attention. Unconventional gas has attracted not only IOCs such as Chevron, Exxon Mobil, ConocoPhillips, Marathon but also smaller companies such as Lane Energy, a subsidiary of 3 Legs resources, Aurelian Oil & Gas, EurEnergy.

Poland has approved around 45 exploration licenses for shale gas. ExxonMobil has five concessions in the Podlasie and Lublin basins representing 1.3 million acres and is quite advanced in seismic data analysis. ConocoPhillips signed an agreement with Lane Energy, which owns six exploration licences covering around 1 million acres, located in Northern Poland, in the Baltic Basin region. ConocoPhillips funded an initial shale gas exploration programme of seismic and drilling and Lane expects to start drilling in June 2010. Chevron also acquired rights to explore for natural gas in Poland and expects to start drilling in 2011. It was awarded three five-year exploration licenses in December 2009 (Zwierzyniec, Kransnik and Frampol) and another one (Grabowiec) in February 2010. They represent together around 1.1 million acres. Talisman has a 60% interest in two concessions in Poland, as well as a third one. Talisman is conducting seismic in 2010, and also expects drilling to start in 2011 or 2012. It has also signed a farm agreement with San Leon Energy.

Despite the discussions around shale gas, there is also development on tight gas, with Aurelian Oil & Gas expecting to start drilling in its Sierkeki discovery in June 2010. Areas in eastern and southern Poland are thought to hold CBM resources. Composite Energy, EurEnergy and smaller companies are investigating this potential which failed to attract IOCs.

France

France has attracted a lot of interest recently, in particular on shale gas, and the government has awarded several licenses in March 2010. In 2009, the area of exploration licenses increased from 28,882 km^2 to 42,666 km^2, due to 12 additional permits. Small companies such as European Gas Ltd had been active for several years, particularly in CBM E&P with several permits, notably in the North (Nord-Pas de Calais, Lorraine). European Gas started producing small amounts of CBM (10 Mcm) from Gazonor in the last quarter of 2009. This gas was sold to Total on an oil-linked price, but starting March 2010, the price would be flat for 13 months at €15.4/MWh. The company is explorating in other regions (Lorraine, Jura). There is also a focus on shale gas: early 2010, Total obtained a permit for 75% of the Bassin d'Ales in Southern France. Many small companies such as Egdon Resources, Eagle Energy Limited, Mouvoil, Schuepbach Energy LLC, Bridgeoil Ltd. and Diamoco Energy are also actively looking for unconventional gas in France.

Hungary

Historically, the attention has focused on tight gas, in particular on the Mako Trough area. In January 2005, the Canadian Falcon Oil & Gas Company acquired licenses to explore and drill in this area in southeastern Hungary. A complete 3D seismic program was acquired and wells drilled up to 6,000 m deep. First estimates indicated reserves higher than 600 bcm (P90), approved by the Hungarian Geological Survey end 2006. Mol and Exxon Mobil moved in, bringing their experience. But they gave up in 2009 after disappointing drilling results, including water penetration. Exxon is also looking at shale gas.

Germany

ExxonMobil is active in both shale gas and CBM. They have a large acreage position, very long holding period and so far have drilled three wells for shale gas and are evaluating seismic data. Exxon Mobil also has a long-term multi-year program in place to assess the potential of CBM. Wintershall has been active on the tight gas development of Leer, Lower Saxony, since 2007.

Other Regions Have Still to Appear on the Radar Screen

Other regions or countries are also looking at unconventional gas. Ukraine has attracted a lot of interest, both on CBM, mostly in the Donetsk basin (EuroGas, TNK-BP) and on shale gas (EuroGas). In South Africa, Shell, Statoil, Chesapeake and Sasol are conducting studies on shale gas potential of the Karoo Basin. Apache will drill as many as 48 wells in two fields in the Argentinean Neuquen basin in the next four years. Gas would be sold at $5/MBtu. There are also activities in tight gas prospects in MENA countries. While conventional resources may be developed earlier, such resources can effectively change the supply picture as it is the case for Oman, where tight gas fields seem likely to enable the country to remain a gas exporter.

Unconventional Gas Global Players

For a long time, unconventional gas, in particular CBM and shale gas, was a matter of interest for medium to small E&P companies. Over the past two years, it has attracted increasing interest from majors IOCs and from many NOCs eager to participate in this new development. Technology is the key to developing unconventional gas and this is not something that can be developed in a couple of years. To overcome this, energy companies have focused or combined the following strategies: acquisitions of acreage, take over, or partnership with existing companies.

The New Prize

One of the largest takeovers in 2009 was Exxon Mobil buying XTO Energy, an unconventional gas player and one of the largest US gas producers with around 30 bcm/y. This event was just the tip of an iceberg as IOCs as well as NOCs have become increasingly interested in shale gas, after realising they missed the boat two years ago. IOCs have also been looking at tight gas fields for some time, even though these deposits were often left behind due to the lack of proper drilling techniques.

Exxon Mobil has spread its presence in three regions and in many countries and is looking actively at all three unconventional gas types. By buying XTO, Exxon Mobil acquired not only the technology experience but also 390 bcm of reserves (85% gas) and operations in the Barnett, Haynesville Bakken, Woodford, and Fayetteville shales, and planned drilling for the Marcellus shale, all in the United States. Exxon Mobil is also present in Hungary (tight), Indonesia, Poland and Germany (CBM), Germany, Poland and Canada (Horn River Play, shale).

BP has a strong position and has been very active in all three types. BP started shale gas operations with the Amoco takeover a decade ago, but continued to expand its position by spending $1.75 billion to acquire shale interests (Woodford, Fayetteville, Haynesville) from Chesapeake in 2008 and acquired additional acreage in the Eagle Ford Shale play in Texas from Lewis Energy in 2009. As of end 2009, BP has 1.2 tcm of proven gas reserves in North America, 80% of which is unconventional. The combined position in the four shale plays mentioned earlier amounts to around 280 bcm. It also has tight gas and CBM positions with San Juan and Wamsutter. BP is also increasing its CBM resources in Indonesia with the Sanga-Sanga project. In addition, BP is evaluating CBM and shale gas opportunities with CNPC and Sinopec in China. Regarding tight gas, BP has a very strong position in North America, since half of its production comes from tight gas. BP is now applying its experience to its growing international assets in MENA countries: Amenas, In Salah and Tiguentourine fields in Algeria, the Khazzan and Makarem fields in Oman

ConocoPhilips pioneered large-scale CBM production in the United States and has started looking at shale gas production and even researching gas hydrates. In 2006, they acquired Burlington resources, enabling them to get access to the San Juan tight gas basin and CBM production and also have positions in Haynesville, Eagle Ford and Barnett shale gas areas. In 2009, they acquired acreage in Canada (Horn River) and signed exploration agreements in Poland. In terms of CBM, ConocoPhilips plans to use its experience in the CBM Australia Pacific LNG (APLNG) with Origin Energy in Queensland as well as in projects in China.

Total has developed experience in tight gas reservoirs some time ago, for example in Indonesia, allowing it to win a competitive tender for China's South Sulige reserves in 2006 and be chosen later for the development of the field. More recently, Total has moved to shale gas but is activities are currently very limited: early 2010, it formed a joint-venture (JV) with Chesapeake to acquire 25% of the Chesapeake's holdings in the Barnett Shale (representing around 2 bcm of production and 20 bcm of reserves). Total was also awarded permits for shale gas exploration in France.

Shell has decades of experience in developing tight gas – in Canada (Foothills, Alberta deep basin), the United States (Pinedale, Haynesville as well as Marcellus and Eagle Ford through the recent acquisition of East Resources for $4.7 billion in May 2010), Oman, UK North sea and China (Changbei) and is looking at North Africa. Shell produced around 6 bcm in 2008, of which China and the United States contributed 40% and Canada the rest. In 2010, Shell and PetroChina decided to acquire the Australian CBM specialist Arrow Energy. Shell has proposed a CBM LNG project in Australia, near Gladstone.

BG acquired Exco in 2009, giving it access to US shale (Haynesville) and tight gas (Cotton Valley) resources. So far, the shale experience has been limited to the United States, while they already had tight gas plans in Oman with Abu Butabul discovery. BG is also behind the large proposed CBM based Queensland Curtis LNG project: in 2009, they acquired Pure Energy enlarging their Queensland gas resources to around 500 bcm.

Statoil has been quite actively strengthening its shale gas position, and starting in 2008 by acquiring 32.5% of Chesapeake's position in Marcellus. Statoil plans cooperation on unconventional gas with Chesapeake in a certain number of countries; the companies have identified 14 projects in India, Poland, Hungary, Australia, China or South Africa. Statoil has some experience with tight gas reservoirs, for example in Algeria.

What is the Rationale?

There are several reasons driving the new quest for unconventional gas. Acquiring technology, in particular for shale gas as IOCs have quite strong positions in tight gas, is one of the key drivers. Expanding their acreage, increasing their reserves (or keeping a reserve-replacement ratio higher than 100%), expanding their global presence, or being in a position to be selected by governments to develop future unconventional prospects are also important drivers.

Most companies have started in the United States, and apart from a few exceptions, there had been limited moves abroad until 2009. But this is quickly changing with the sudden interest of countries for this new resource. Based on the analysis above, two companies have a global presence and strong position in all three types of unconventional gas: Exxon Mobil and BP. Others are limited to one or two types, having minor positions in the third, and/or regional presence.

NOCs or smaller non-US companies are moving as well as is illustrated by the interest of Chinese NOCS in CBM and shale gas or by RIL's entry in the United States. For them, the rationale appears mainly to acquire experience to be able to export the know-how to their home markets or in producing countries that would supply their domestic market in the future. Finally, there are many small to medium-size companies active in what is still a niche market at the country scale: it remains to be seen whether they will be able to keep their independence or be absorbed in the next M&A wave.

PRICES AND TRADING DEVELOPMENTS

Summary

- **Two different price systems in OECD countries coexist with a large and unprecedented gap between them**. The decoupling between low spot prices and oil-linked gas prices is having far reaching consequences for buyers and sellers in the three OECD traditional markets as well as in emerging LNG importers. Gas importing companies, essentially in Europe, are caught between their long-term contractual obligations and the pressure from their customers, in particular industrials, to supply gas at more competitive prices. Importers have in turn pressed their suppliers for contract renegotiations on price and volumes. Those producers supplying at oil-linked gas prices have seen a more rapid erosion of their sales than that implied by the recession and a few key suppliers have granted some concessions. The additional volume flexibility that was agreed in several long-term contracts not only eased the situation of oversupply in 2009, but will also alter the European supply/demand balance in 2010 and beyond.

- **Arguably, the most important question faced by the gas industry over the coming three years is whether the traditional oil linkage on European continental and Asian markets will continue or not.** The concessions granted giving a partial spot indexation in some European contracts are only temporary. Whether such spot indexation remains beyond the three years or traditional oil indexation returns will depend on the global supply/demand balance and the evolution of the gap between spot and oil-linked prices.

- **Trading in Continental Europe has continued to progress**. The growth of the Dutch and German spot markets over the past two years has been remarkable. New hub services, improvements in interconnections between countries, increased transportation capacity, regulatory improvements, merging of market areas and improvements of balancing regimes will provide a stimulus for further development of liquidity in European gas markets in the near future.

Two Different Price Systems: is a $5/MBtu Gap Sustainable?

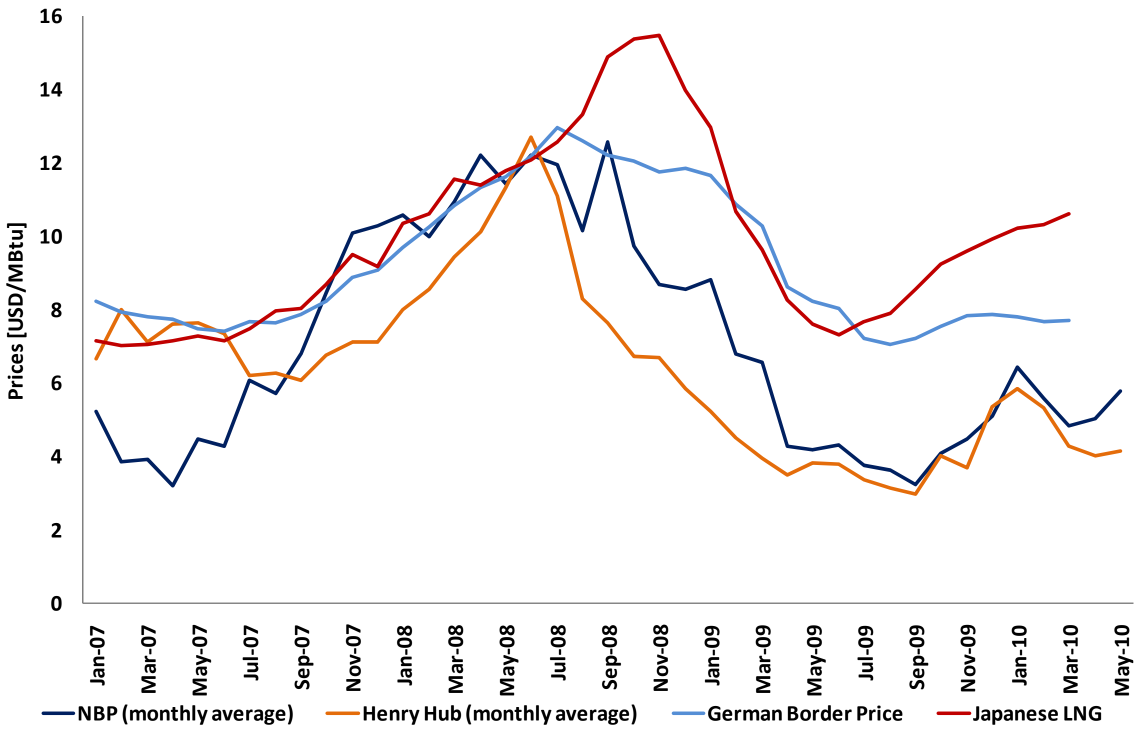
Since the beginning of 2009, two distinct gas price regimes have emerged: the high oil-linked gas prices that prevail in long-term Continental European contracts and Japan/Korea and the much lower spot prices that can be found in North America, the United Kingdom and on Continental European spot markets. The collapse of spot prices, a direct consequence of the gas glut, put these prices as low as one-third of the energy equivalent of oil. The price divergence between the oil-linked and the spot based gas price systems is unprecedented – $5.2/MBtu between the Henry Hub (HH) in the United States and the Japanese import price over 2009. Such a gap has profound consequences for both buyers and sellers: buyers asked for renegotiations of the contracts' formulas while some sellers, who retained their long-term oil-linked gas prices, suffered from a lack of competitiveness in some markets and consequently lost market shares. Such high prices have contributed to demand destruction. Furthermore, the much awaited convergence between spot prices on both sides of the Atlantic – HH prices and the UK National Balancing Point (NBP) – is now a fact. Between March 2009 and March 2010, the monthly difference between NBP and HH has been around $0.5/MBtu and has only rarely exceeded $1/MBtu with HH generally (and unsurprisingly) at a discount to the NBP. Since April 2010, the difference has however grown wider.

Looking forward, the main question facing the gas industry is how long such a gap could persist until major changes occur. This has already launched a heated debate about the delinkage between gas and oil prices, a principle which has been the backbone of many long-term contracts in Europe and OECD Pacific (although on different bases). One should not forget that oil price indexation represents only 20% of total global gas sold while pricing based on gas-to-gas competition represents one-third and regulated gas pricing close to 40%.[19] And that on many occasions, spot prices have been more volatile and higher than oil-linked gas prices and have spiked occasionally to record levels in 2005 and 2006, driven by shortages (notably hurricanes in the United States).

Gas Price Evolution: a Look Back at 2008-10

The fall in spot gas prices that started mid-2008 continued well into 2009, reflecting the economic downturn that resulted in lower gas consumption in combination with abundant supply. The world's two major spot markets both saw extremely low prices in 2009: $4/MBtu and $5/MBtu at the HH and NBP respectively. HH prices occasionally dropped to a low of $1.8/MBtu, a first since 2002. Prices have recovered to some extent since these levels occurred in September 2009 due to the seasonality and the cold winter season.

International Gas Prices (2007-10)



Source: German ministry of Economics, ICE, Japanese Customs and Tariff Bureau.

It is remarkable though that despite the records in daily demand in both the United Kingdom and the United States, day-ahead prices never exceeded $8/MBtu. Lower spring demand levels triggered a return to $4-5/MBtu so that they are now well below their five-year averages of approximately $7-7.5/MBtu. While prices have indeed already fallen below $4/MBtu in March and April 2010, it is

[19] *WEO-2009*, based on International Gas Union (IGU) (2009). Other formulations include bilateral monopoly and netback from final product.

unlikely that they will fall significantly and sustainably below $3.5/MBtu in 2010, even in summer, as coal-to-gas switching in the power sector would start to drive gas demand back up again. Supply will also be affected at some point until only the most economical marginal supply sources remain.

The time-lag of three to nine months caused oil-linked gas prices in Japan and continental Europe to start falling later in 2008 than spot gas prices and they recovered earlier on the back of rising oil prices in 2009, thereby increasing the gap between oil-based prices and spot gas prices. It is worthwhile to note a very interesting change in the evolution of the German border price. This price, reported by the German ministry of economy (BMWI), was known to be the best representative of oil-linked contract gas prices in north-western Europe. Over the past ten years, until summer 2008, the German border price and the Japanese LNG import price had been following each other, if not in terms of levels, at least in their evolution. But this stopped mid-2008: the German border prices never exceeded $12/MBtu and started to drop mid-2008 at the same time as oil prices collapsed, although the time lags in the formulas should have led to a continued increase over at least the third quarter of 2008, if not longer. Meanwhile, Japanese LNG prices followed a different pattern: they continued to increase over the end of 2008 reflecting the increase of JCC to over $130 during summer 2008 and consequently fell later in early 2009. Although both German and Japanese prices showed similar levels during the first half of 2009, Japanese prices recovered earlier in summer 2009 and more strongly, reaching $10/MBtu early 2010. Since the beginning of 2010, there has been a $2.5/MBtu gap between both oil-linked gas prices, which seems to imply that the German border prices are no longer purely reflecting an oil linkage, but also incorporating spot gas supplies.

Convergence: Henry Hub and NBP

The convergence of HH and NBP that started early in 2009 continued throughout the year and into 2010. The NBP premium to HH mostly moved in an unprecedented tight band of $0.5-1/MBtu, averaging $0.75/MBtu. The premium exceeded $1/MBtu only briefly, and Henry Hub traded at a premium to the NBP rarely, for example in December 2009, when cold weather in North America drove up HH prices.

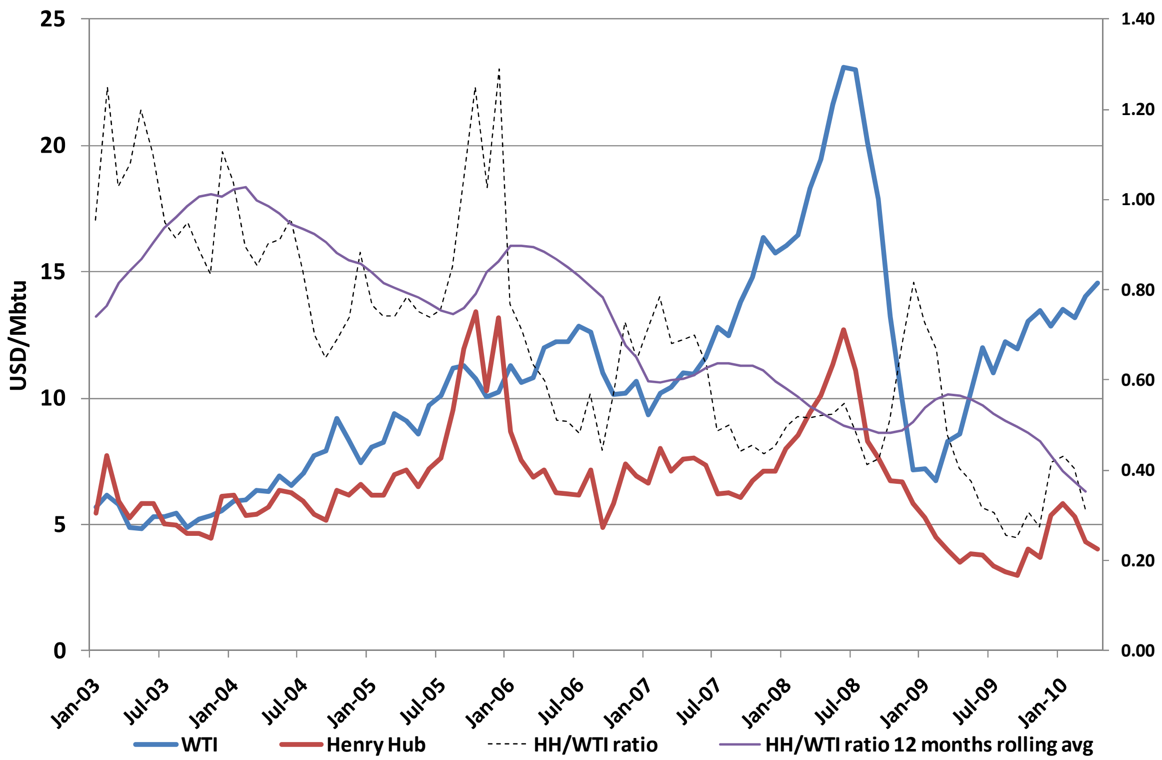
The question is how this convergence came about and whether it is here to stay with NBP at a premium over HH. In other words: which factors will cause these markets to continue to converge or start to (structurally) diverge again? Indeed, in recent months, the gap increased again with HH staying close to $4/MBtu while NBP set off on a rise to $5-6/MBtu. The fundamentals behind this recent development – temperatures below seasonal averages, volatility in flows from Norway and increased continental power demand – seem to be mostly short-term in nature compared to the factors driving convergence. This illustrates that occasionally some short-term regional factors can weaken the convergence.

So let's take a closer look at what's fundamentally driving convergence. The rise of unconventional gas production and the drop in domestic demand in North America mean that one of the world's largest markets is now less dependent on imports and has more options in optimising natural gas sourcing. Some unconventional gas producers have proven to be resilient to prices as low as $3/MBtu and most producers appear to be comfortable with prices ranging around $4-5/MBtu. Furthermore, Qatari LNG can be delivered profitably to the United States at around $3/MBtu due to low feedstock costs and the value of associated condensates. High oil-linked prices in Continental Europe provided buyers with an incentive to maximise the offtake of lower priced spot LNG and created lucrative opportunities for LNG suppliers to divert cargos from the United States to Europe. This would not have been possible in a world with disconnected regional markets or without the current oversupply. Past investments in liquefaction and regasification capacity have created a potential for arbitrage on a global scale. An analysis of the LNG contracts in the Atlantic basin suggests that 60% of the current volumes are flexible, enabling gas suppliers to ship their gas to the market that offers the highest netback. As a result of this, North America is effectively emerging as a price setter for short-term markets in Western Europe. As they are also the residual market, their price is set to remain at a discount against European spot prices. The United Kingdom is indeed importing increasing amounts of LNG and this trend will only continue with the recent growth of LNG capacity.

Divergence: Oil-indexed Gas Prices and Gas-to-Gas Competition

From the start of 2009, the difference between spot prices for oil and gas (WTI versus Henry Hub in energy equivalents) started to widen again. While oil and gas prices fell almost simultaneously in mid-2008, oil prices started rising again from February 2009 onwards while gas has only recovered slightly in recent months. The current absolute difference of around $8/MBtu is certainly not unprecedented (and was even higher in 2007 and 2008), but still remarkable on the horizon of the past decade. The rolling average ratio between Henry Hub and WTI oil prices (expressed in energy equivalent) has been continuously declining over the past seven years from 1 to well below 0.4.

WTI and HH Prices

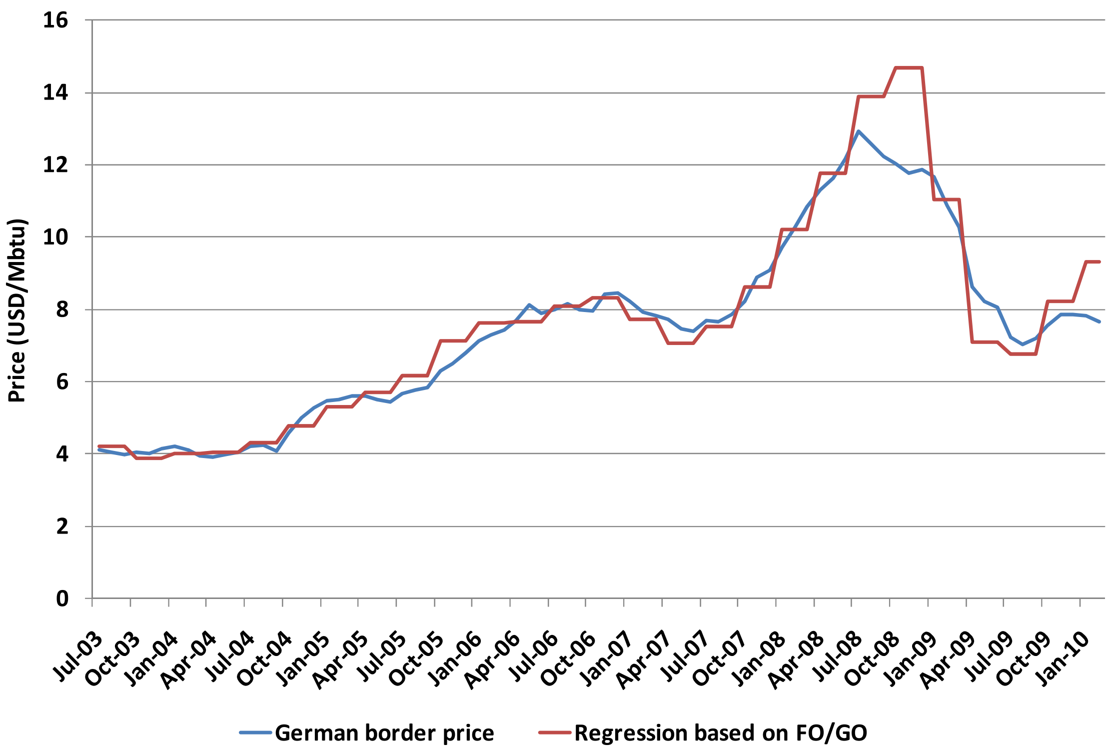


Sources: IEA, ICE, EIA.

Several factors have contributed to the divergence of spot gas prices versus oil-indexed prices or more generally between the gas and the oil markets. On the supply side, the gas market has experienced a double supply 'shock' from relentless unconventional gas production in North America and large scale additional LNG, whereas oil supply has not had such paradigm changes. On the demand side, gas markets have been hit harder than oil markets with world demand declining 3-4% versus 1% respectively. This is because of the relative inelasticity of oil demand, especially in the transport sector, versus the high level of gas use in the hard hit industry sector.

Gas prices under long-term, oil-indexed contracts have generally been higher than spot gas prices for three years now, but the gap has widened significantly since mid-2008. Differences between the German border price and NBP averaged $3.6/MBtu (around €10/MWh) in 2009. As noted earlier, the German border price has somewhat decoupled from what could be expected from an oil-linked gas price. The graphic below shows the difference between the actual German border price and an oil-linked gas price based on a regression over a five-year period between the German border price and Rotterdam's fuel oil and gasoil prices. Meanwhile the Japanese import price continued to reflect more closely the oil price changes.

Actual and Expected German Border Price



Source: BAFA, IEA analysis.

Neither the wide variations of exchange rates between the US dollar and the Euro, nor the variations of the Rotterdam fuel oil and gasoil prices can explain such behaviour. One possible explanation is that although most of the gas imported into Germany is still based on contracts with an oil linkage, there is now increasing spot based gas entering Germany. As explained later in the section on market developments, trading on the Title Transfer Facility (TTF) in the Netherlands and Net Connect Germany (NGC) in Germany has increased significantly: traded and physical volumes increased from 86 bcm and 31 bcm in 2008 to 130 bcm and 50 bcm in 2009 respectively. Clearly these two markets, whose prices closely follow NBP, provide sellers with more opportunities to market their gas at spot prices. Therefore it would not be surprising to see spot gas entering Germany directly or through cross-border trade with the Netherlands. However, entry capacity from the Netherlands into Germany is very limited, particularly on a short-term basis. Naturally, ways to swap volumes at the border exist and Trac-x also provides market participants with a way to buy capacity on the secondary market, but cross-border trade with the Netherlands could not explain such a development. Therefore, this explanation can only partially explain such a change.

There are other explanations for the German border price leaving its oil-based path. One factor that is likely to be part of the answer is ceilings in the price formulae that dampen the impact of extremely high oil prices on the gas price under long-term contracts. Such ceilings could involve linkages to coal spot prices, which collapsed from a peak of $220 per tonne to around $80 per tonne between July 2008 and December 2009. This would explain why the German border price did not increase after July 2008. Another reason might be that German importers chose to increase their off-take under the contracts which have a longer time-lag and thus a lower price in this period of increasing oil prices. The recent changes resulting from the negotiation on long-term contracts will also affect the German wholesale price.

Contracts' Renegotiation: the Beginning of the End?

The outcome of this disparity was minimum off-take under oil-based gas contracts and renegotiations of long-term contracts. European buyers realised as early as the third quarter of 2008 that the crisis was affecting their demand much more than expected and that it was likely that they would not be able to respect minimum take-or-pay quantities. Criticism over the oil-linkage was vociferous among European buyers while Asian buyers called for more flexibility and competitive prices. Both volumes and prices, which are interlinked, were at stake: a high price is less likely to encourage a recovery of demand in particular in the industrial and power generation sectors.

Adjustments of long-term oil-based contracts have already occurred. Surprisingly, Gazprom agreed, publicly, to some concessions on both the volume and the price with some of the major consumers, including ENI and E.ON Ruhrgas. Gazprom and E.ON Ruhrgas agreed on linking 15% of the volume to spot prices for a three-year period. GasTerra made it known that in the 2009 negotiations concerning the extension of long-term contracts with GDF Suez, Distrigas and Swissgas, partial decoupling from oil-based pricing has been incorporated. Contracts from Turkish utility Botas apparently received even greater flexibility in its Russian deliveries. Early 2010, Statoil accommodated some changes in long-term contracts by introducing separate contracts and the company recently announced that it is looking for buyers, power generators in particular, to engage in long-term commitments based on price indices other than oil (*e.g.* power, gas). Energy companies that managed to renegotiate conditions either generally have direct access to LNG supplies or face competition from new entrants which could source volumes on spot markets themselves and outbid them, particularly in competition for supply contracts to industrial buyers.

Such adjustments to the price formula are not too much of a surprise: given the volume losses experienced by sellers and the difficulties encountered by buyers selling this gas to their own customers. Indeed, while some large European importers may be able to pass through the gas import price increases to small users with predictable reactions from gas users associations and governments, some industrial consumers and power generators see the spot price and demand this price. Furthermore, both buyers and sellers have an interest helping gas demand recover in the industrial and power generation sectors by improving its competitiveness versus coal and other generating technologies. Finally, sellers want to protect their share of the market in particular in a context of declining gas demand.

E.ON Ruhrgas for instance made a strong plea for adapting long-term contracts to the changed circumstances, saying: "…[long-term import contracts] must be carefully adapted flexibly to major market changes. This is urgently needed at present" and adding that "In Europe, [gas] has increasingly gained the image of an insecure imported energy that is problematic in geopolitical terms and is also expensive and subject to price volatility".[20] GDF Suez voiced similar concerns and the Japan Gas Association urged dialogue between gas exporting and importing countries to "reduce exposure to oil price fluctuations" and reach an agreement on a "reasonable and acceptable price level" to create sustainable growth for both parties. While some companies have been relatively vocal about the changes obtained, the confidentiality of long-term contracts makes it difficult to get a comprehensive picture of the size of the market that has been affected by the changes. Even a market without LNG terminals like Germany sees some influence from cheap supplies available through its interconnections to other countries and the growth of trading. Meanwhile, Eastern European countries have limited access to spot gas and the geographical constraints on the transmission system make it unlikely that true competition from spot gas will be seen in that region.

Which Way Forward?

Even if a change towards spot pricing were to happen at the margin, that would not be the end of the long-term contracts which have underpinned major upstream and infrastructure investments for years. Also, there are many roads that lead to Rome: adjustments in oil-indexed long-term contracts to (partially) close the gap can either be made by adjusting the oil based formula[21] or by introducing spot market indexation for a certain part of the volume (*e.g.* all volumes above minimum bill levels).

The continued gap between spot gas prices and oil-based prices will naturally induce buyers to exert pressure on suppliers for the introduction or expansion of gas-to-gas pricing in new and existing contracts, particularly if they sell gas to, or operate, gas-fired power plants. It would, however, be unrealistic to expect a sudden turnaround of oil-based pricing. But, first of all, what are the arguments in favour or against decoupling?

Buyers would argue that the growth of LNG supplies and unconventional gas leading to the current oversupply has made considerable quantities of cheap gas available to the market. Furthermore, oil indexation is not adequate as a reference for most sectors, in particular for the fastest growing sector – power generation, where oil plays at best a very minor role in all but a few IEA countries. Oil's role in the power sector of IEA countries has been declining over the last decades. According to an IEA study completed in 2002, fuel-switching from oil to an alternative fuel in case of supply disruption represented around 1.2 mb/d with 80% concentrated in the United States, Japan, Italy, Korea and Spain. Nine countries were able to reduce their national total oil consumption by more than 5% through fuel-switching out of oil. Fuel-switching from gas into oil represents roughly 3.5 mb/d for the IEA as a whole, again concentrated in the United States, Japan, Italy, Germany and Korea. Since that study, oil use has declined further in OECD countries to just over half the levels of 2000, accounting for around 2 mb/d, or 4% of total power use and has fallen sharply in the last two years. An indexation to spot, which would lead to lower prices in the current market conditions, would also improve the competitiveness of gas, accelerate demand recovery and also give some short-term gains to buyers. Where gas is priced on fundamentals, it has held or even increased market share against other energy sources, such as coal, as has been seen in the United States. Finally oil prices have proven to be very volatile over the past years and their evolution is largely independent from the price evolution of gas.

[20] IGU World Gas Conference, Buenos Aires 5 – 9 October 2009.

[21] Price formulae in long-term contracts usually take the general form of $P_0 + x_1$ * Gas-oil + x_2 * Fuel-oil. Adjusting the P_0 is the most straightforward way to tune the formula to a new level.

Suppliers will argue that liquidity of spot gas markets is insufficient, which means that – contrary to the global oil market – demand and supply may be subject to manipulation and that volatility is too high for large scale, long term indexation. In doing so, they will not only attempt to protect their revenues, but also secure incentives for future up-stream investments. There is also the problem of choosing the appropriate marker: would the NBP market be sufficiently representative given their own market conditions differ fundamentally from the United States? It is already used in a certain number of long-term contracts, in particular from Norway and the Netherlands. Some European or Pacific suppliers might consider HH inappropriate as a marker.

The next three years will be a test for the oil linkage of gas prices but also for the convergence between NBP and HH gas prices. Oil linkage and the convergence between NBP and HH are in fact closely interlinked. The key parameters that will decide the outcome will be when global gas markets recover, how the demand and supply balance in each of the three regional markets will evolve (*i.e.* where tightness emerges) and the prevailing oil price level.

If demand recovers only gradually so that the oversupply is only progressively eroded towards 2015 and if weak demand in North America persists, then the delinkage of spot gas prices from oil prices is likely to continue and even increase while HH and NBP will show a strong convergence. The pressure will come from two sides: on the supply side, the availability of increased flexible LNG volumes combined with increased LNG import capacity will improve players' capacity to import cheap gas. On the demand side, industrials supplied under oil-linked prices will be put at a disadvantage against their competitors having access to spot gas (directly or through their suppliers) and such industrial consumers are likely to increase pressure on their suppliers (reduced offtake and demand for price concessions). On European gas markets, buyers will renegotiate a share of spot indexation depending on their ability to source additional supplies on global LNG markets or on the Continental spot market. On Asian markets, buyers may ask for more flexibility in their contracts in order to be able to source part of their supplies on spot markets. Chinese buyers are likely to be particularly attentive to price conditions, notwithstanding a clear willingness to pay higher prices than previously. Japanese buyers are likely to be more prudent as they prefer stability of long-term relationships, and are less likely to deviate from their current model, but an expansion of upward and downward quantity tolerances and a gentler slope could be part of renegotiations. Unexpected events, such as failure in other parts of their power sector, could see Japan buying more spot gas.

However the current oversupply could also be eroded swiftly if demand rebounds rapidly driven by strong economic growth and the power generation sector within the coming five years. Demand in non-OECD countries is set to increase but could increase more rapidly than expected, in particular in China which is becoming a serious competitor to Europe for LNG supplies. Also a rapid gas demand increase in producing countries could take away volumes previously earmarked for exports. In that case two possibilities arise depending on whether the United States remains disconnected from international markets in terms of supply and demand.

- In a first case, the US market would remain physically disconnected due to abundant domestic supply resulting in limited LNG imports needs and still relatively low HH prices. In that case, HH and NBP prices would diverge as NBP prices would be determined by the marginal supplier – global LNG or European gas. Asian markets would remain predominantly oil-linked. The market would be a seller's market giving limited concessions to buyers.
- In the second scenario, demand increases would make the North American gas balance tighten again and HH prices would increase accordingly, closing part of the gap with oil-linked gas prices.

Regional Price Evolution

Continental European Spot Price

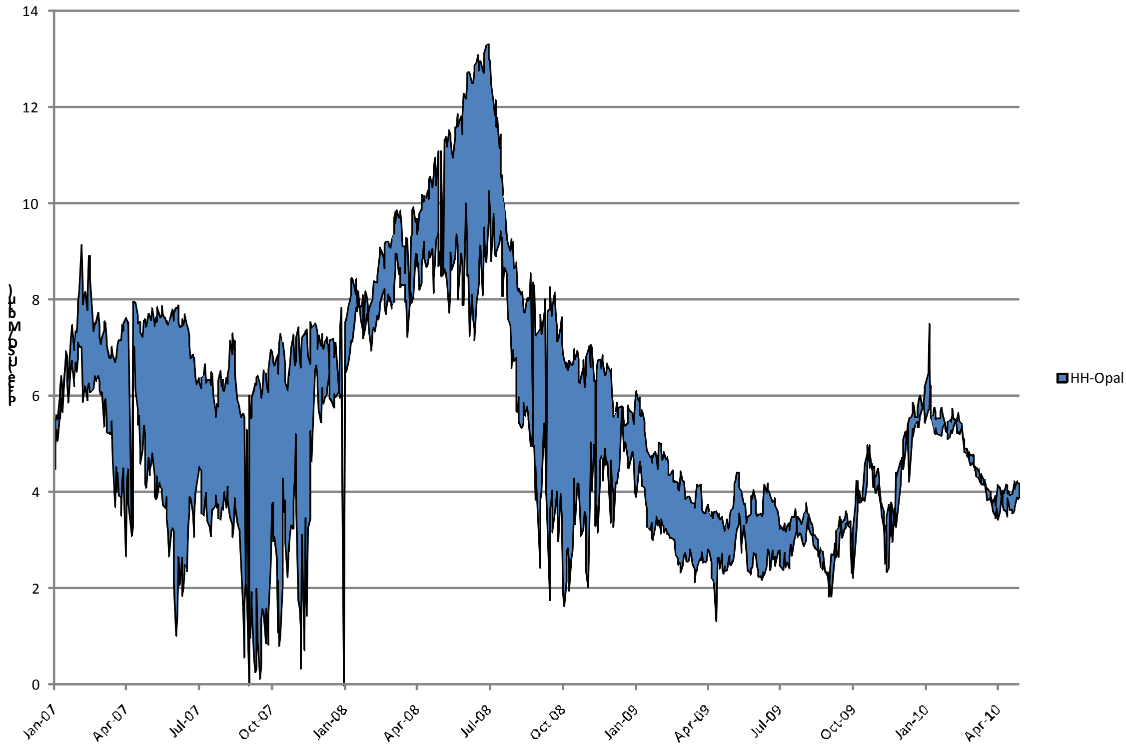
Prices on the Continental European spot markets continued to follow NBP prices ever more closely. The delta between Zeebrugge (ZBH) and TTF usually moved within \$0.4/MBtu either way. Unlike in recent years, TTF tended to be higher than ZBH and NBP in 2009. A possible explanation for this is that while ZBH and NBP are directly influenced by global price development through LNG trade, transport constraints for gas flowing from the UK and Belgium to The Netherlands (*i.e*. no reverse flow through BBL) cause these price changes to seep through more slowly and imperfectly to the Dutch market. The United Kingdom was clearly well supplied during winter 09/10. It was only late November 2009 that Interconnector United Kingdom (IUK) flows turned to the United Kingdom and net flows over the winter 09/10 were close to 0 bcm. This also confirms the role of the United Kingdom as a transit country for LNG and Norwegian gas for Western Europe. Gas flows to the United Kingdom through the IUK will be stimulated by the July 2009 decision of Fluxys and Interconnector to bring Wobbe index requirements for gas through the IUK in line with the level in the United Kingdom.

North-American Prices

Prices in North-America have been severely depressed as a result of two cheap supply options that drastically changed the market: unconventional gas and LNG. Both can be commercially produced and sold at prices below \$4/MBtu and sometimes even \$3/MBtu, due to technological improvements, economies of scale and valuable associated NGLs. Since European buyers are struggling to meet take-or-pay obligations, it is likely that some of the global increase in LNG supplies will continue to end up in North-America – the residual market, which means that prices are unlikely to rise in the near future. This is illustrated by a recent trend in the United States for sellers and buyers to commit to long-term contracts. Such producers fear that prices may plummet even further and buyers are willing to lock-in current prices and avoid speculating on a further decline of prices and the risk and volatility that come with that strategy. This demonstrates that producers are able to sell substantial volumes at current prices of \$4/MBtu and still make a satisfactory profit and secondly, they are not expecting higher prices any time soon.

Another development in pricing in North-America is the convergence of regional prices. The traditional premium of gas in the consuming Eastern regions compared to the producing Western regions has almost disappeared as a result of East-West transportation capacity coming online (*e.g.* the Rockies Express Pipeline) and increased Eastern supplies from unconventional gas production (*e.g*. Marcellus) and LNG terminals along the Atlantic coast (Excelerate and Canaport). Canadian AECO prices, that used to move parallel to HH, have over the course of 2009 and early 2010 also converged to HH. The AECO discount that averaged \$1/MBtu in 2007 and 2008 is currently less than half that difference, reflecting the shift in the North-American supply balance. Considering the rather permanent nature of these changes and expected future increases in transportation capacity from the West to the East, it is likely that the convergence is here to stay. The graphic below illustrates the convergence between the Opal Hub in Wyoming, where REX starts, and the Henry Hub (the upper limit of the area is the price at the Henry Hub, the lower limit is the price at the Opal Hub, and the coloured area is the difference).

Day-Ahead Prices at the Henry Hub and Opal Hub (Wyoming)[22]



Source: ICE.

Asian Price Developments

Japan, Korea and Taiwan have been the traditional LNG markets in Asia for a long time, four decades in the case of Japan, the world's largest LNG user, with China and India emerging as relatively new markets as their economies grow and their energy consumption, in particular gas, rises. Although ASEAN countries have bilateral gas pipelines and gas trade has been encouraged over the last few decades, the Asian gas market is dominated by the trade in LNG due to its dependence on energy resources that are geologically remote from the home markets. In order to secure stable gas supplies, Asian markets rely mostly on marine transportation such as LNG tankers. Only one intercontinental or cross-border pipelines has been built in this region, the Turkmenistan-China pipeline. Although Asian markets are mutually independent in physical terms, they are significantly influenced by each other in terms of trading prices since they tend to procure the majority of LNG from common producers in the Asia-Pacific region (Australia, Indonesia, Malaysia, Brunei) or the Middle East (Qatar, Oman). Due to these characteristics, the Asian gas price has been through a unique development.

Asian gas prices have some remarkable properties, which distinguish them from European oil-linked gas prices. The first is linked to the historical dependency of Japan and Korea on LNG. As LNG liquefaction plants require massive long lead time capital investments, particularly in the early stage of projects, LNG producers have sought long-term commitments (often up to 20 years) from buyers to make their projects economically feasible. Asian buyers have also preferred long-term contracts to secure access to gas in times when less LNG projects were operational globally. Furthermore, as

[22] Opal Hub is generally lower than HH.

noted earlier, the price formula of Asian LNG is closely linked to Japanese Crude Cocktail (JCC) prices and, as a result, Asian gas prices follow oil price fluctuations. The formula also contains the so-called S-Curve mechanism, which provides protection for both buyers and sellers at times of high and low oil prices respectively.[23]

However, due to the high crude oil prices since 2004 and the widened disparity between oil and gas prices in energy equivalent terms, there has been some debate concerning the price formula between LNG buyers and sellers although the slope of price formulae has been evolving forward around 85% crude oil linkage. Contractual commitments sometimes prevent them from switching to other supply sources that become more favourable as the market changes. It is also one of the unique characteristics of LNG trade that delivery schedules of LNG cargoes are agreed well in advance between a buyer and a seller so that the buyer and seller can plan an efficient demand/supply program respectively. It is particularly important for the buyers to know when the cargoes are scheduled to arrive at their terminals in order to manage the reception of various LNG cargoes from different projects, taking into account the volume of LNG in their tanks. These delivery schedules obviously limit flexibility in supply and demand.

Furthermore, the destination clause in LNG purchase agreements limits Asian buyers in their flexibility of replacing expensive cargoes by procuring cheaper spot cargoes available in the market. It is noticeable that spot cargoes which represented around 10% of Japanese supplies during late 2007-early 2008, when LNG prices were well below oil on an energy basis have collapsed to around 3% during most of 2009. Unavailability of key nuclear plants was also a driving factor behind high spot LNG imports in 2007-08. Although Japanese buyers used downward quantity tolerances in their contracts, the low demand did not allow them to benefit from cheap LNG supplies.

Finally, Japanese and Korean buyers pay a premium on their LNG purchases. For instance, the average imported price of Japanese LNG for the last 3 years (early 2007 until early 2010) is \$9.9/MBtu whereas the equivalent prices at the German Border and the Henry Hub are \$9.3/MBtu and \$6.5/MBtu respectively. The higher average of Japanese LNG prices is driven by high crude oil prices through indexation, shipping costs from remote exporting countries and a lack of competitive domestic production. The difference in indexation between Asian markets on the one hand and European/North-American prices on the other may play an important role in global gas price development. As the LNG market globalises and traded volumes increase, more diversified price arrangements or formulas could be developed and much more sophisticated deals emerge, using financial instruments to take advantage of different price indexation formulae. Such developments would serve the various needs of new producers and customers not only in Asia but globally.

European Market Development

In 2009, once again, annual traded volumes on Continental hubs rose markedly. There are now seven Continental hubs for which data are reported: Zeebrugge in Belgium, TTF in the Netherlands, Point d'Echange Gaz (PEG) in France, Punto di Scambio Virtuale (PSV) in Italy, NetConnect Germany (NGC) and Gaspool in Germany and Central European Gas Hub (CEGH) in Austria. The 56% growth, which nearly equals 2008's unprecedented growth, drove traded volumes to 292 bcm and physical volumes are estimated to have reached over 100 bcm – almost one quarter of total European gas demand. All

[23] The idea behind this is that crude oil had been the predominant energy source in the power sector in major consuming Asian countries such as Japan and that, in contrast with European and North American markets, no substantial volumes of natural gas were produced domestically. Therefore, the comparative advantage of natural gas as an alternative energy source to crude oil was the key issue for gas importing industries and consumers.

continental hubs experienced double digit growth, which was the result of both improved functioning of markets and the global situation of oversupply. Improvements in the transportation system, or abolishing different gas qualities, were some of the reasons for improvement. On most hubs, with the notable exception of TTF, trading concentrates on the spot market rather than on the curve.[24]

Traded and Physical Volumes

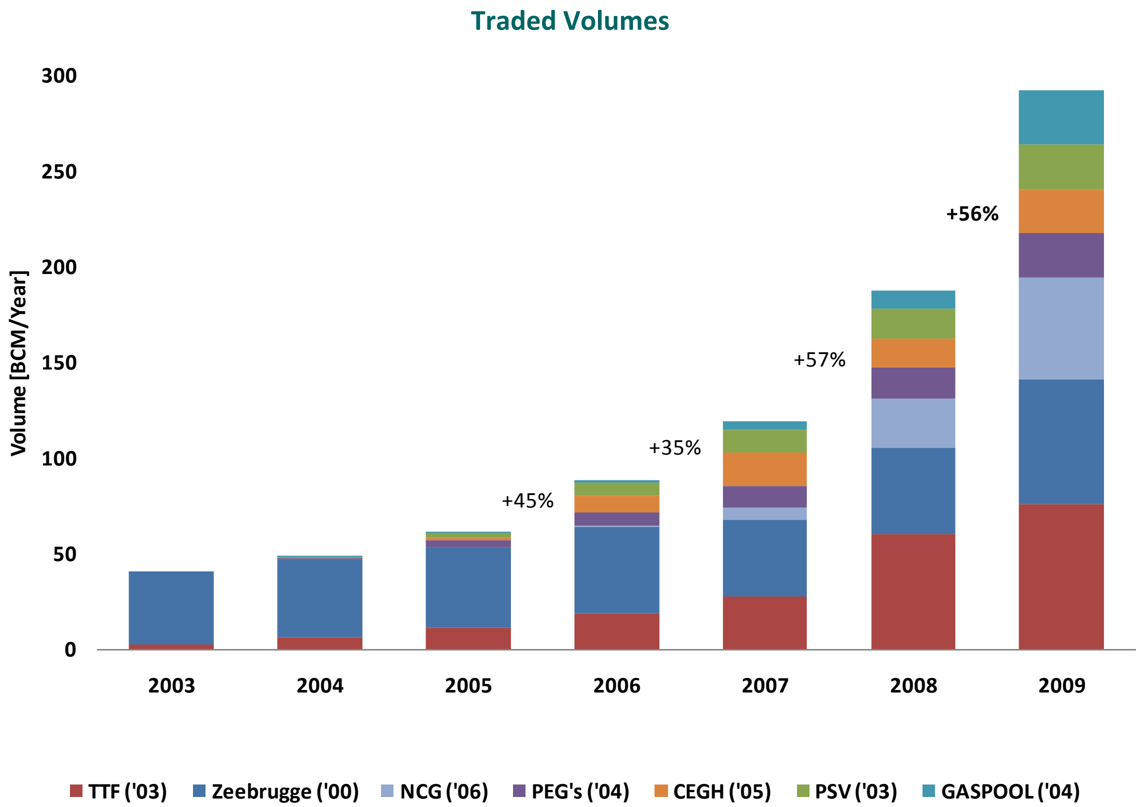
bcm per year		NBP (96)	ZBH (00)	TTF (03)	PSV (03)	PEGs (04)	GASPOOL (04/09)	CEGH (05)	NCG (06/09)
Traded volume	2003	611.0	38.6	2.3	0.1				
	2004	551.9	41.1	6.2	1.1	0.3	0.0		
	2005	500.1	41.7	11.6	2.6	4.0	0.4	0.8	
	2006	615.2	45.1	19.1	7.1	7.0	1.2	8.9	0.2
	2007	902.6	40.2	27.3	11.5	11.1	4.8	17.7	6.6
	2008	960.8	45.4	60.2	15.6	16.5	9.7	14.9	25.3
	2009	1051.3	64.9	76.1	23.5	23.7	28.6	22.8	53.5
Physical volume	2003	52.5	10.2	1.3	n/a	n/a	n/a		
	2004	53.2	10.6	2.3	n/a	n/a	n/a		
	2005	53.7	8.4	3.8	n/a	n/a	n/a	n/a	
	2006	60.6	8.6	5.9	n/a	n/a	n/a	n/a	0.1
	2007	66.8	7.9	7.4	6.8	1.4	n/a	6.9	4.1
	2008	66.6	9.1	18.7	7.7	4.5	n/a	5.2	14.4
	2009	n/a	12.9	25.0	11.0	11.6	n/a	7.6	25.0

Source: National Grid, Gas Transport Services, Huberator, GRTgaz, TIGF, CRE, Gashub, Gaspool, Aequamus, Net Connect Germany, SNAM Rete Gas.

More work still has to be done regarding the simplification of balancing rules and the development of trading platforms. In Germany and France, the growth of traded volumes was heavily influenced by the mergers of market areas. ZBH, which was once the leading continental hub, is now clearly behind TTF. NGC is likely to overtake ZBH in coming years and the combined traded volume of NGC and GASPOOL already exceeds TTF.

The volatility of prices on the three main hubs NBP, ZBH and TTF has increased substantially from 2008 to 2009 and is back to 2007 levels. For NBP and ZBH the volatility has more than doubled, for TTF it has tripled. The indicator used (standard deviation of closing prices / average closing price) measures the variation in prices relative to the price level itself. The variation itself remained more or less constant for NBP and Zeebrugge, but increased dramatically for TTF. For all three markets the average decreased to more than half 2008's value. The resulting volatility is more or less equal to the five year average for NBP and ZBH, but much higher for TTF. Other indicators measure the volatility of price changes rather than the price itself, which leads to a slightly different conclusion: volatility has indeed increased in 2009 to a level close to that in 2007, but the increase is less dramatic than the other indicator suggests and TTF has the lowest volatility of the three markets.

[24] In financial and commodity markets, the prompt or spot market refers to the transactions where delivery is immediately or at a point in the relatively near future, whereas 'the curve' represents trading of products on the futures market, with delivery at a specified time in the future. In gas markets, the curve is loosely defined as a point in time in or beyond the month following the month of the trading day (month-ahead), which makes every contract with delivery before the end of the month of the trading day part of 'the prompt'. The most commonly traded contract on the prompt is Day-Ahead.



Sources: National Grid, Gas Transport Services, Huberator, GRTgaz, TIGF, CRE, Gashub, Gaspool, Aequamus, Net Connect Germany, SNAM Rete Gas.

Looking at the near future, most of the European hubs can be expected to continue their growth paths of recent years as market functioning continues to improve. While not all hubs are developing at the same pace, each country is at least working on improvements that will over time boost liquidity. These include more import/export capacity through pipelines or LNG terminals, domestic transportation capacity, trading services offered at the virtual exchange point, transmission system operator (TSO) or regulatory policy related to balancing regimes and access to capacity in pipelines or storage. The recent Link4Hub initiative, a joint project of TSOs Gasunie Deutschland, Energinet.dk and Dutch GTS, provides a good example of what is needed. Starting with a pilot in June 2010, this application will enable shippers to link their portfolios in the three grids on a day-ahead basis to facilitate trading at the VEPs.

All these factors have a positive impact on hub liquidity as they facilitate the access of volumes to a hub, decrease uncertainty for market participants, lower transaction costs and enable them to profit from arbitrage opportunities. The recent trend of suppliers 'dumping' volumes on spot markets when faced with a lack of demand is one important factor in increasing liquidity in 2009. This could reverse when economic growth drives gas demand upwards, which may have a depressing effect on physical and probably also on traded volumes.

United Kingdom

Traded volumes on NBP grew 7% to 1 053 bcm in 2009, for the first time ever exceeding 1 tcm. The first quarter of 2010 saw a considerably (around 10%) lower volume traded than in the previous two years, an opposite trend compared to TTF and ZBH where traded volumes increased by 17 % and 6% respectively. UK numbers from October 2009 onwards have to be interpreted with some caution though, since the reporting standard changed when National Grid implemented the Network Code modification. Unfortunately, with the implementation of this change, data on the physical volumes on NBP have become unavailable. This represents a major step back in transparency of Europe's largest gas hub that needs to be resolved.

The Netherlands

Substantial growth helped TTF to maintain its position as the Continent's leading hub. There are currently 68 parties registered by GTS for trading at the TTF as of April 2010. Traded volumes grew 26% to 76 bcm while physical volumes grew 34% to 25 bcm, causing the churn rate to decline further to 3.0 (compared to 3.2 in 2008). In principle, one would expect a developing spot market to increase its churn rate as more players enter the market and set up mutual contracts enabling them to trade with more and more counterparties. Established markets such as NBP and HH have churn rates around 10-15 and around 30 respectively. The drop in growth in the churn rate may be only a temporary hiccup in TTF's growth, due to the limited activity of financial players as a result of the financial crisis. However, the question needs to be asked whether the churn rate of TTF is limited by a more structural cause.

Substantial progress had been achieved in facilitating trading by abolishing quality differences from the traders' point of view. In 2009 the Dutch TSO Gastransport Services (GTS) implemented important changes to quality conversion (QC). Prior to this, trading at the Dutch TTF was separated for high calorific gas (Wobbe 51.6) and G+ gas (Wobbe 44.4)[25] and shippers needed to book the QC service when the quality of their gas that they entered into the system differed from the quality of the gas that exited the system. Now that QC is a system service, only one gas quality is traded at TTF, separate fees for QC service have been replaced by a mark-up on all entry and exit fees and booking of QC is no longer necessary. At this point, there is no apparent reason for TTF not to resume its path to maturity as the economy recovers. Three factors could help further improve liquidity: increased transport capacity, new trading services and a new balancing regime.

- More import and export capacity is planned to come online as a result of Open Season projects. The Integrated Open Season of Gasunie NL and Deutschland revealed a substantial demand for additional capacity, 7% in the Netherlands and 40% in Germany. The FID is to be taken in the second half of 2010; whether the required investments of €1-2 billion will be made depends to a large extent on the German regulatory regime regarding transportation tariffs.
- Another step in enhancing liquidity in the short term is expected to come from the Intercontinental Exchange (ICE) offering TTF futures trading since 15 March 2010 and thereby adding another trading platform which also provides access to the NBP. Trades in the first week amounted to over 1 million MWh (>100 Mcm).
- Implementation of the new balancing regime has been delayed and is now to be introduced in 2011. The key word in this new regime is 'market balancing', which means that market players

[25] In principle, two more qualities (43.8 and 46.5) were tradable but these were never used in practice. Liquidity on G+ was also very low compared to H-gas.

collectively are to keep the system in balance. To enable them to do this, GTS sends near-time information on the position of their portfolio and the system as a whole. When the system exceeds linepack limits a residual balance procedure starts, where market participants can offer short-term capacity on the bid price ladder at the expense of participants that caused the system to be out of balance and rewarding participants that helped the system move towards balance. The aim is to stimulate the within-day market and improve access to the market.

Balgzand-Bacton Line (BBL) Company undertook a market consultation to gauge interest for non-physical interruptible reverse flow (IRF) services. After this consultation, discussions with regulatory bodies have taken place and BBL Company recently received Ofgem's approval for its auction methodology, developed in cooperation with APX-Endex. Approval of the Dutch regulator Energiekamer is now the only requirement left for the delayed implementation of this important service, which would stimulate further development of the Western European gas market, the Dutch 'gas roundabout' and TTF in particular. When implemented, it is likely that IUK will see a decline of flows from the UK as currently gas takes a 'detour' through BBL, the United Kingdom and back though the IUK to Continental Europe when NBP is at a discount to Continental hubs. From December 2010, the installation of a fourth compressor will increase BBL's technical forward flow capacity by more than 3 bcm/y (to 18 bcm/y), which also increases the potential volume for virtual IRF.

Germany

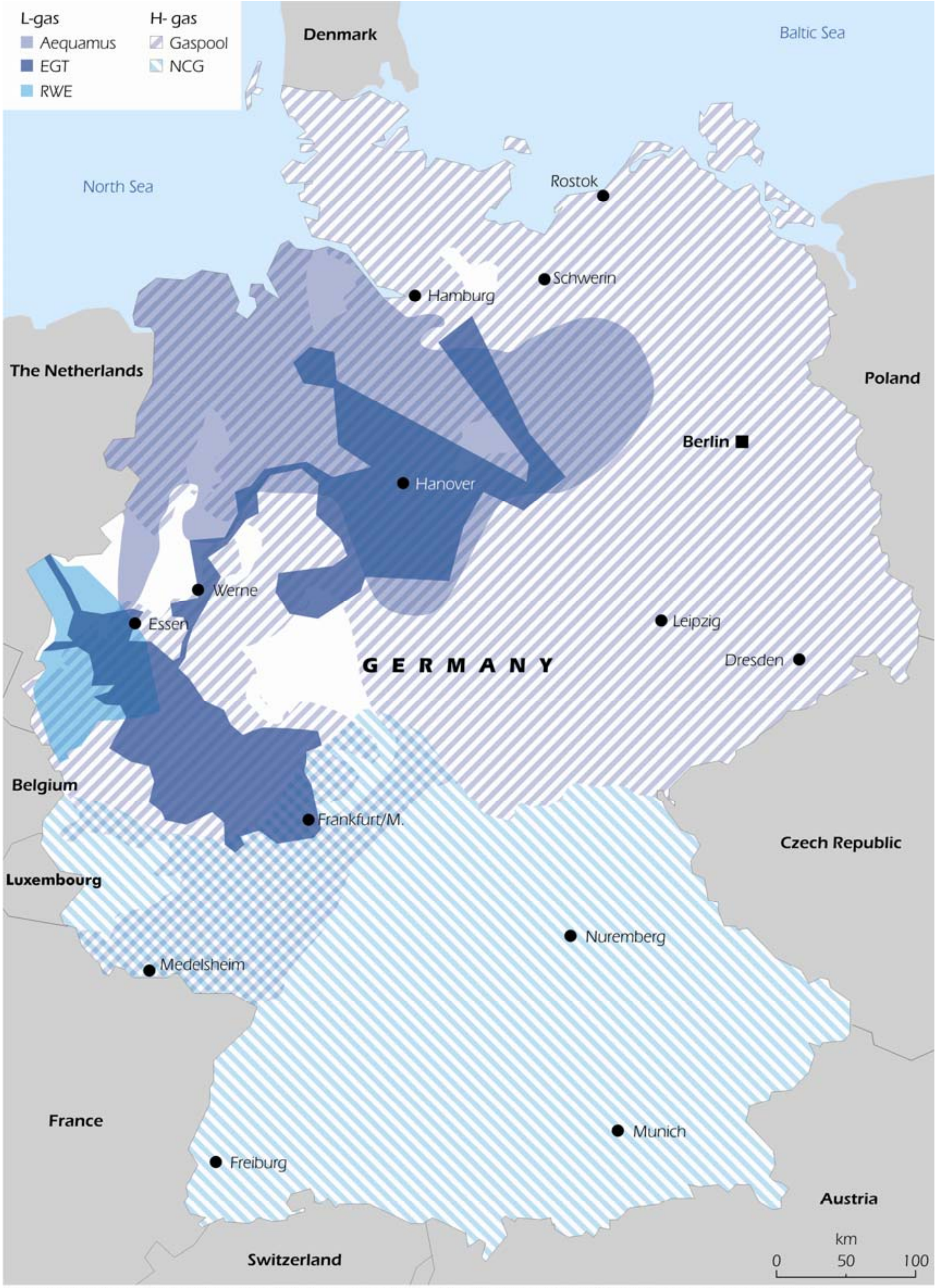
In Germany, 2009 brought yet more mergers of market areas. The five market areas of Gasunie Deutschland, ONTRAS (VNG Gastransport), WINGAS transport, StatoilHydro Deutschland and DONG Energy Pipelines merged into one single market area called GASPOOL, creating a trade area for more than half of the transported H-Gas in Germany. Furthermore, the Net Connect Germany (NCG) area was expanded with ENI Gas Transport Deutschland, GRTgaz Deutschland and GVS Netz joining in October 2009.

The German Bundeskartellamt recently indicated that further merging of market areas is desirable, adding that NCG's L and H gas areas are likely candidates for a merger. Another possibility would be to merge the different L gas zones. A government decree that is expected to enter force in September 2010 would enforce further mergers until eventually only one H-gas zone and one L-gas zone remain. The decree is also designed to make grid operators pool their entry and exit capacity into one platform and ensure that 20 percent of the transport capacity is reserved for bookings in the short term (less than two years) and 15 percent will be reserved for the medium term (under four years).

In this respect, E.ON cutting its long-term contracted import capacity to 54% and making the balance available to the market by October 2015, under pressure of the European Commission, is also worth mentioning. In combination with the introduction of UIOLI,[26] these developments will put an end to the traditional long-term contracting of transport capacity, which was capable of effectively closing market areas to gas from other areas or across the border.

[26] Use it or lose it: a policy whereby it is mandatory to offer unused capacity on the secondary market.

Market Areas in Germany



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.

Source: IEA.

Since October 2009 traded volumes in all formerly separated market areas are included in the volumes for GASPOOL and NCG, making a comparison with previous volumes traded in the BEB area and the EGT area impossible. It is clear though that volumes traded at both markets have shown substantial growth since their establishment/expansion on October 1, 2009. Traded volumes amounted to 29 bcm for the GASPOOL area and 54 bcm for the NCG area; when combined these volumes exceed traded volumes in 2009 at the Dutch TTF by 6 bcm. The German exchange EEX introduced an intra-day auction in 2009 that enables trading in NCG and Gaspool prompt products (day-ahead, 2-DA and weekend). Although the volumes exchanged have been very limited so far, they are growing and it might prove to be another stimulus for liquidity. A gas balancing platform may follow in a later stage.

Belgium

The Belgian Zeebrugge Hub (ZBH) maintained the growth path of the previous year by growing 43% to 65 bcm traded volume and 42% to 13 bcm physical volume. While the growth of its churn rate has come to a halt as it has for other markets, the drop is less than the one observed for TTF and the 2009 churn rate of 5.0 still makes ZBH the most liquid hub of the Continent in this respect. The first quarter of 2010 saw a modest increase (6%) compared to the same quarter in 2009.

The LNG terminal supplied the Belgian market with 6 bcm of natural gas from 78 ships in 2009 (37 ships in 2008) and the reloading option that was added in 2008 has been used four times in 2009. This year should see additional East-West capacity between Opwijk and Eynatten coming online and virtual storage services are to be introduced. Other more long-term plans for infrastructure investments include a higher capacity on the French border (possibly both ways), the Luxembourg border (binding open season held), and possibly doubling of capacity for the Zeebrugge LNG terminal. The Belgian ambition to play a pivotal role in the Western-European gas market would certainly benefit if these plans become reality.

France

The total volumes traded at the French hubs (PEGs) rose 43% to 24bcm and physical volumes more than doubled to almost 12 bcm, accompanied by a further decline in the churn rate. Both the GRT area in the north and the TIGF area in the south contributed to the growth although volumes in the southern market area remain quite limited. It's worth noting that the French regulator CRE has started publishing data about volumes at the French PEGs in 2009, distinguishing between volumes *négocié*, *livré* and *total livré*. The first category includes all trades made through exchanges and brokers, while the last category includes nominations from all OTC trades. To make comparisons with other hubs consistent, the category *total livré* is regarded as the traded volumes. The volumes *négocié* amount to 13 bcm in 2009, but unfortunately there are no data available from other hubs with which to compare this.

The market consultation that regulator CRE carried out in 2009 revealed that market participants desire more transparency in terms of information on wholesale trading and the availability of capacity. Respondents also indicated an interest in CRE analysis of the behaviour of market participants near the borders in relation to wholesale market activity and prices relative to the neighbouring markets, *e.g.* Belgium or Germany. CRE has announced the publication of a set of indicators to monitor these aspects of markets and indeed followed up on this in its December 2009 review of the wholesale markets. CRE uses the Herfindahl-Hirschmann index (HHI[27]) to measure the market concentration on the PEGs and found that for PEG Nord, there is little market concentration on the sellers' side (HHI below 1,000 for spot and close to 1,000 for the futures market) and on the buyers' side for the futures market (below 1,000), but the buyers' side of the spot market is fairly concentrated (HHI between 1,000 and 1,800). The other PEGs are more concentrated, particularly PEG Sud Ouest which is highly concentrated on both sides and on both the spot and futures market. PEG Sud is most concentrated on the buyers' side of the futures market (HHI ~2,200). It must be noted that the first half of 2009 shows a clear improvement for the southern PEGs compared with 2008.

The picture that emerges from this analysis is that the French wholesale market is definitely developing but currently is less mature than its counterparts in The Netherlands and Belgium. The outlook can certainly be improved if interconnections with Spain and Germany improve, LNG volumes increase and the zones are merged into one common market.

Austria

The Austrian market is progressing very well, as illustrated by the significant growth that the hub CEGH experienced during 2009. Benefiting from the operational balancing agreement that was put in place early 2009, traded and physical volumes grew by 53% to 23 bcm and 47% to 8 bcm respectively in 2009. The introduction of the Integrated Trading Area Baumgarten (ITAB) provided a further boost to liquidity and helped the year 2010 start out successfully with an 8% higher traded volume in the first quarter of 2010 compared to the fourth quarter of 2009. The churn factor increased slightly from 2.9 in 2008 to 3.0 in 2009. The number of registered users increased from 84 members of which 68 were active in December 2008 to currently 102 members of which 87 are active.

The dominant role of Gazprom at the CEGH through its long-term contracts in combination with the proposed transfer of shares from OMV to Gazprom and its subsidiary Centrex Europe Energy & Gas has led to concerns from the Austrian regulator E-control. The share transfer, which follows from a cooperation agreement signed between OMV and Gazprom in January 2008, is subject to prior approval by the European Commission under European Union (EU) merger control law.

Since 11 December 2009, the hub not only offers OTC trading but also a gas exchange in cooperation with Wiener Börse and European Commodity Clearing AG (ECC). The current spot trading services are expected to be followed by futures trading in 2010, subject to Financial Market Authority approval. These developments fit in with CEGH's ambition to become the Continent's biggest gas hub and thereby provide short-term trading services to market participants in the area of Central Eastern Europe that is currently dominated by traditional long-term gas supply agreements at the Baumgarten node.

The CEGH is very well-placed to fulfil a pivotal role between the growing gas flows in Central Eastern Europe and Western Europe. Whether it has the potential to outgrow the current Continental hubs remains to be seen, as the other hubs also benefit from improved market functioning, higher transported volumes and investments in transmission capacity, LNG and storage.

[27] The HHI measures market concentration by calculating the sum of the squared market shares of market participants. A market with a HHI under 1,000 is considered to show little concentration and a HHI above 1,800 indicates a highly concentrated market.

Italy

The Italian Punto di Scambio Virtuale (PSV) benefited from increased pipeline capacity through the TAG and Transmed pipelines (+13 bcm) and the new 8 bcm offshore Adriatic LNG terminal. The traded volume grew by 50% to 24 bcm, making it slightly bigger than the CEGH and the PEG. Physical volumes also grew by a substantial 42% to 11 bcm, 2 bcm less than Zeebrugge. Nevertheless, this remains quite low considering the size of the market and the diversity of supply sources.

The obligation since October 2008 to auction a certain volume of non-EU entry contracts on the PSV resulted in several gas releases, the main one being a 5 bcm release by ENI in September 2009 for Gas Year 2009. This auction was not met with much enthusiasm in the market for various reasons including timing, risks concerning price changes and a general lack of demand as Italian demand dropped by nearly 9% in 2009, despite recovering somewhat in the last quarter. Also the minimum price is likely to have contributed to the rather disappointing result of less than one quarter of the volume being assigned. The regulator sets a minimum price which determines the revenue for the seller; additional revenues from the auction are redistributed among the Italian industry.

The new gas exchange that is to be launched is still progressing although at a rather slow pace. From 10 May 2010, onwards, a preliminary gas import trading platform called P-GAS has been available as a prelude to the launch of the exchange in October 2010. This exchange is to be managed by GME (Gestore Mercati Energetici), the organisation that is currently managing the electricity exchange. P-GAS quotes second month-ahead and gas-year-ahead contracts. Although the platform has so far seen only one transaction, it represents a positive development in a country where gas consumers still miss out on lower gas prices seen elsewhere in Europe. It is possible to turn Italy's gas future around, but for this many factors contributing to a lack of competition need to be addressed firmly by the regulator, including a discouraging balancing regime and limited access to import and storage capacity.

Czech Republic

The Czech electricity market operator OTE launched the country's first spot gas market as of January 2010, adding intraday trading in the second quarter. The number of deals and the traded volumes in the auction-based Day-Ahead market have been quite limited so far (2,557 MWh or 0.23 Mcm in the first quarter). The first month of the intra-day market got off to a good start with 1,685 MWh traded. OTE currently has registered 47 participants for the spot gas market, including both Czech and Western European utilities.

This development represents a promising initiative to improve liquidity on Central European gas markets. Combined with the possibilities of daily nomination and secondary trading of border capacity, it enhances the integration of the Czech Republic to Western European markets. Hopefully the recently established taskforce of the European Federation for Energy Traders (EFET) for Eastern Europe will also succeed in stimulating the liquidity and transparency of markets in this region. The taskforce will focus on Hungary, the Czech Republic and Slovakia initially and address Poland and Romania in a later stage. Indeed improvement of markets would be very welcome as it enhances security of supply in this region as well.

INVESTMENTS OVERVIEW

The years 2008 and 2009 will leave profound marks on the investment side. Despite the comforting and much-awaited FID for two LNG liquefaction projects late 2009, uncertainties prevail and investments slowed down during 2009. In two years, markets have moved from tightness to a global oversupply – the 'gas glut'. Gas saw demand destroyed sharply in 2009, notably in Europe, while the supply side has witnessed a half-expected boom. The US unconventional gas revolution was unexpected by its scale, and continued to increase production despite sharply lower prices; however its potential to spread to other continents by 2020 is difficult to assess. Meanwhile, the dramatic ramp-up of LNG output until 2014 has been on the cards for a number of years.

This double-whammy, coupled with continuing uncertainty about the pace and location of economic recovery, has created new uncertainties on where and when incremental gas volumes would be needed and where to invest in the gas value chain. An unsurprisingly cautious wait-and-see approach has therefore been adopted by many investors: projects are postponed, reappraised based on new demand and price estimates, when not cancelled outright due to the perception of a lack of timely market demand. The few projects which are moving forward are targeting those markets where the economic crisis has not affected a growing appetite for gas.

One question is in the mind of all investors. How long will the global oversupply last and where should they invest? To answer that question, one needs to look at global developments of supply and demand as the potential to move gas across oceans to demanding markets has become a reality, but also at the regional trends as the inter-regional transport or even transmission infrastructure is not always sufficiently developed, or in the case of large transcontinental pipelines, is relatively inflexible.

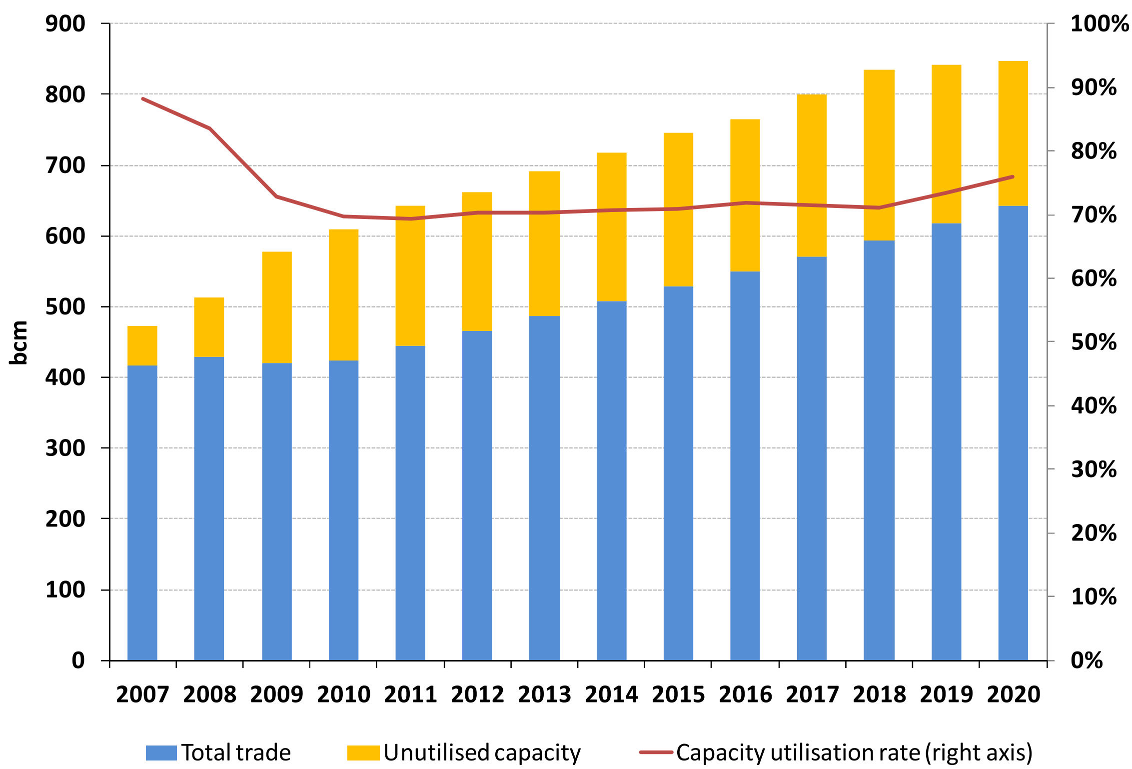
On the supply side, much of the investments to 2015 have a high degree of certainty, in particular the new LNG capacity, as they are characterised by long lead times. Unconventional gas is more uncertain, both in terms of volumes and timing: it has a proven capability to answer rapidly price and demand signals in North America but remains to be developed in other continents. Additionally, above-ground risks such as conflicts, regulatory issues, royalties and tax changes, can affect supply developments and are less predictable.

A more significant uncertainty comes from the demand side, due to two major factors: the economic recovery and future investments in the power generation sector. In the World Energy Outlook 2009, the IEA concluded that gas demand would increase in all scenarios, even a greener scenario, reaching between 3 560 bcm and 4 313 bcm by 2030 from 2007's level of 3 049 bcm. The Reference Scenario portrays that a recovery to 2015 would be slow and sluggish in the OECD countries, coming back to the 2007 levels by 2014-15, but quite healthy in non-OECD countries with an incremental increase of 350 bcm between 2007 and 2015.

Ironically, the biggest upside risks are also likely to be in large non-OECD countries, in particular China, India and MENA countries. In China and India, the appetite for gas is growing as new supply becomes available. Given China's track record of exceeding energy demand forecasts, a gas demand level of 142 bcm by 2015 (a 9 bcm/y increase) could very well be exceeded. Middle East gas demand is projected to jump by 30% fuelled by low domestic prices, while some countries struggle to achieve production increases that keep up with demand growth. In mature OECD countries, besides the economic recovery, the uncertainty comes more from greening the power sector – for example the 20/20 targets in Europe. If less renewables capacity is built, energy efficiency gains do not appear, or power demand recovers quickly, gas demand in the power sector is likely to grow more and faster than expected, as gas is and remains the fuel of choice. Hoewever, if high levels of renewable power are achieved in the 2020 timeframe, gas demand growth in the EU would be a modest 7% between 2007 and 2020.

Uncertainties on the supply and demand balance ripple through into investments in transport capacity, both LNG and pipeline. For the coming ten years, unutilised capacity in inter-regional transport will grow from 70 bcm in 2007 – which was too tight, to over 200 bcm by the middle of the next decade. Some may argue that a volume of 200 bcm compared to total demand around 3400 bcm is a relatively low reserve margin indeed – 6%. However, on a global scale, most gas is still consumed where it is produced, so that imported volumes represent only one-third of global demand and volumes transported between regions only 14% – around 400 bcm, growing to around 650 bcm by the end of the decade. As inter-regional capacity will continue to increase, this means that its capacity utilisation will drop from 88% in 2007 to 69% in 2011, then recover slowly to 71% in 2015 and 76% by 2020. Therefore the surplus in transport capacity will be quite significant.

Utilisation of Inter-regional Transport Capacity



Source: IEA.

In the mind of some investors, the current situation may not call for more investments in upstream or in inter-regional transport capacity. While this attitude is understandable based on the facts explained above, the observed delay in investments could result in a supply crunch. One has to keep in mind the long lead times on the upstream side: liquefaction plants projects approved today will come on stream in 2015, at the earliest, and more likely with one or two years delay based on recent experience. The current surge on the LNG side comes from FIDs taken before 2005. During the following years, there was a shortage of investments across the gas value chain driven by increasing costs and market uncertainties. All parts of the gas value chain must be developed in a coordinated manner: upstream reserves that feed both domestic and export markets; the liquefaction plants, regasification terminals and pipelines to transport gas, and finally the transmission and storage infrastructure to meet annual and seasonal demand. Tightness in one part of the value chain could have global or regional/national consequences.

Furthermore this situation is likely to show a geographical disparity as well as differences between pipelines and LNG. As noted earlier, Asia is expected to be the fastest growing market: in 2009, India and China grew by around 10 bcm each despite the recession. Supplies are therefore likely to be tighter in Asia Pacific, relative to the Atlantic Basin. Moreover, some countries currently exporting may reduce their future exports due to fields' depletion or domestic market obligations (DMO). Most of the surplus capacity can be expected to be found in the pipelines due to their limited flexibility, while much of the LNG oversupply can and will be moved around between regions. Firstly, the regasification capacity is double that of liquefaction, allowing gas to be redirected to demanding markets. Second, a large chunk of this LNG will come from Qatar with the ability to move easily between Atlantic and Pacific markets responding to price signals. Finally, part of the LNG is likely to be priced based on gas fundamentals, while much pipeline gas in Europe and certain parts of Asia seems likely to remain on an oil-priced basis. Thus it seems likely that pipeline suppliers will likely bear the brunt of volume cutbacks, while LNG suppliers may not receive the prices they might have hoped for.

Despite the current gloomy picture, new gas supplies will be needed beyond 2020, not only to meet demand, but also to replace existing supplies. Globally the decline rate of existing fields after their peak is 5.3%, so that even with stable demand, ongoing upstream investments are necessary. Furthermore, producing countries focus increasingly on their own markets, sometimes giving them priority over export markets even if the latter bring more revenues. Such decisions are becoming a trend in most producing countries and could reduce their capability to use even existing infrastructure.

The previous year has reminded us that supply shortages can happen due to many causes – transit issues (Russia-Ukraine), or upstream issues in Norway or Thailand. Therefore, some excess capacity in the import infrastructure, with diversification of supply routes, is often desirable as well as better interconnections between markets. In some regions, the depletion of traditional sources of supply will also require new investments as historical flows are impacted.

Similarly one should not forget the seasonal character of gas demand and the need to invest in sufficient transport and storage capacity to meet peak demand. Even an apparently very well supplied market like the United Kingdom had difficulties meeting peak demand in January 2010; China also faced shortages in some undersupplied regions while El Niño caused peak demand to surge in Colombia. Such requirements will become increasingly important if gas-fired plants are used to balance wind generation.

INVESTMENTS IN PRODUCTION

Summary

- **The current oversupply has led to many questions on how much additional supply will be needed, where and when**. While import requirements will be less than they were expected to be a few years ago due to the demand drop in 2009, gas demand is still planned to increase in any scenario, while production from existing declining fields will have to be replaced. There is however a strong asymmetry between demand and supply evolution: demand has the potential to increase at faster rates, in particular in the power generation sector, than new additional supply can be brought to the markets. At least a decade is needed to develop a greenfield, while it will take five years to put a LNG plant on stream once the FID is taken. Investments in the upstream sector need to be based on a longer view rather than on the short-term environment.

- **Russia faced a particularly tough year in 2009, with increased uncertainty on its main export market, Europe, not only on volumes but also on prices**. The new Energy Strategy to 2030 released in November 2009 remains ambitious in terms of production targets including LNG, and new regions to be developed. There has also been a slight shift of strategy towards Asian markets, but it remains to be seen whether this will be translated into concrete outcomes as the development of these fields is even more challenging than the ongoing development of the Yamal Peninsula.

- **Despite the large scale of proven gas reserves in the MENA area, only one country, Qatar, can be confident of meeting both its domestic needs and its export ambitions in the medium term**. In recent years, a number of campaigns have been launched to attract foreign E&P investors, to tackle challenging, and more expensive, non-associated gas deposits (frequently tight gas or sour) and to explore for new deposits in areas hitherto overlooked. Gas now seems likely to attract a significant proportion, if not the majority, of medium-term investment in the hydrocarbon sector. But given rapidly rising domestic demand and the continuing requirements for gas reinjection in oil fields, it is still uncertain how much additional gas will be available for world markets.

- **With its 8 tcm of proven gas reserves, the Caspian region has emerged as a key supplier strategically placed between different existing and potential importers: Russia, Iran, China and Europe. The commissioning of the Turkmenistan-China pipeline in December 2009 represents a major shift in the politics and economics of East Caspian gas.** Turkmenistan has been the centre of much interest due to the huge South Yolotan field, and has ambitious targets to increase its production from 70 bcm in 2008 to 250 bcm by 2030, but there is still considerable uncertainty that sufficient upstream investment will be forthcoming and that markets for such large incremental gas volumes will be available.

- **Across the world, domestic market obligations are becoming more apparent among producers, which are now giving increasing priority to their domestic markets.** Gas demand in many of these markets is often rising fast, so that producing countries are choosing to limit the volumes destined for export. These countries face a difficult choice between losing potential export revenues and meeting a rapidly growing energy demand with a lower environmental impact. As domestic gas prices are often low, they face the risk of deterring foreign investment, while the decision to increase energy prices is a tough political one, particularly in the current economic environment.

Introduction

The upstream part of the gas market is probably the most visible part of the gas value chain, due to the size of some projects and the amount of investments under discussion. Failure to invest enough globally will spread to all markets as these become increasingly interconnected through LNG. Until mid-2008, the biggest worry of gas users was indeed whether producing countries were investing enough in a timely way, and would be in a position to meet their demand and contractual obligations. The economic and financial crisis has completely reversed the picture as countries and companies face two radical changes: the gas glut and, for some exporting countries, a decline in the gas export price. Many producers have seen not only their sales falling in their core export markets since mid-2008, but also weaker cash flows and now face much tougher financing conditions to build new producing and delivery infrastructure. Since 2009, a new investment framework has emerged as some countries or companies adopt a wait-and-see approach. The only major projects moving forward are in the Pacific basin. Meanwhile, domestic market obligations are becoming a more widespread trend.

Domestic Market Obligations (DMO)

A trend, that one could have thought to be limited to a handful of countries, is spreading among producing countries as these want to use the more environmental friendly fuel to replace more polluting (and sometimes imported) refined oil products. The DMO can have various forms, either a limitation in the share of gas exported, a moratorium on exports, the cancellation of export projects or obligations given to companies finding gas to help develop the domestic market. The dilemma is a difficult one though: while such a decision benefits the country by helping it to meet a rapidly growing energy demand with a lower environmental impact, it also has a cost. The country loses potential export revenues, which are not compensated by low domestic prices, and risks deterring foreign investments, particularly in risky exploration. Increasing domestic prices or removing subsidies is a political decision that many governments will struggle to implement in the current social and economic context, so that meeting contractual obligations and rising domestic demand will prove to be increasingly difficult.

Egypt was one of the first countries to allocate gas for its domestic market and has used various methods to meet its growing gas demand: in 2000, the government decided to allocate one-third of the then proven reserves for domestic gas demand for 25 years, one-third for strategic purposes, and one-third plus upcoming gas discoveries to exports. Being a regional and an LNG exporter, this decision affects many countries. In June 2008, Egypt decided to put new gas contracts on hold due to concerns that gas (LNG) was sold under the market price, triggering renegotiations with buyers. This also led to the interruption of exports to Israel in November 2008, until the Egyptian supreme administrative court decided in February 2010 that the contract with Israel was legal, under the condition that prices would be closely monitored. Egypt is a textbook example of the export versus domestic market dilemma: in 2008, it agreed to raise prices at which producers could sell gas on the domestic market. This allowed some needed upstream projects from BP and RWE Dea to move forward. Removing subsidies and increasing prices could be a way to dampen domestic demand growth. This seems to be the solution chosen by the Ministry of Petroleum with the new post-production investment model with BP on the North Alexandria field. It gives BP full production rights but gives the General Petroleum Authority first purchasing rights at a price linked to oil prices. But this might not be sufficient as Egypt had been trying to renegotiate export volumes downwards. Given the current market conditions, buyers will probably be happy to do so, but this will considerably reduce export revenues.

Domestic Market Obligations (DMO) (continued)

Qatar has opted for a moratorium on gas exports, which has been extended to 2015. While the country also desires to keep some gas for its growing market, the main driver is to get a better understanding of the impact of the rapid increase in gas output from the North Field.

Several countries are reconsidering their export plans in the light of growing domestic demand. Peru has renegotiated the agreement with the consortium operating the Camisea field to make sure its rising domestic demand would be met. The consortium has the obligation to cover domestic demand for 20 years and may reduce LNG output accordingly. Indonesia has been facing regional imbalances, due to the country's size, which have been threatening not only new export projects such as Donggi Senoro but existing ones as well. Fears that Indonesia may soon slip into deficit have prompted BPMigas, the country's upstream regulator, to state that LNG plant Arun would stop exports in 2014, and Bontang would supply the domestic market by 2020. BPMigas expects also to free up between 2.5 and 3 mtpa when some of its Japanese contracts expire in 2011. They will supply planned domestic LNG import terminals. This would remove around 30 bcm of inter-regional capacity by 2020. Nigeria has set out a master plan prioritising the domestic market (along with addressing the huge flaring issue), which could further delay LNG plants under discussion. This first requires the Petroleum Industry Bill to become law.

Middle East and Former Soviet Union (FSU) countries hold 41% and 30% of proven global gas reserves respectively. Both are expected to be the source of most incremental gas production until 2030. In both regions, gas represents already an important part of the primary energy supply, just below 50%, and gas is sold at cheap to very cheap prices on the domestic market and exported at higher prices to other countries. But the similarities between them stop there: Middle Eastern countries' gas demand and gas share in TPES have been growing sharply over the past two decades. Demand will continue to grow at a healthy pace as governments take advantage of the cleaner fuel, especially in the power sector where gas-fired output can be expected to grow 50% by 2015. Incremental gas use between 2007 and 2015 is estimated at 300 bcm. Gas use in Russia has been quite dynamic over the past two decades and despite the substantial increase, Russian gas demand is not expected to recover from the recession before 2015.

Russia

The global economic crisis created many uncertainties for the Russian gas industry at a time when the Russian government was releasing a new energy strategy to 2030. Before the economic crisis changed the outlook for Russia, as well as for many gas industry players, Russia had been pressed to invest in new upstream projects: over 2006-08, voices among European consumers, Russian politicians and the IEA expressed concerns that Russia would not be able to meet its increasing demand (+30 bcm between 2005 and 2008) and its export commitments. While both were expected to continue to grow, Russia's three super giant fields (Yamburg, Medvezhe, and Urengoy), which were the backbone of its production until 2000, were declining sharply at an estimated 20-25 bcm/y. The start of new fields, particularly Zapolyarnoye in 2000, helped to stabilise production up to 2010. But post 2010, Russia would have to invest into the next generation of large Russian fields, Yamal and Shtokman, for the Western market. These new projects are capital intensive, located in remote areas and technologically challenging. The Eastern Siberia and Far East regions, which have drawn a lot of attention recently, are even more challenging due to the absence of existing gas infrastructure, and the need to settle a legal dispute on one of the major fields (Kovykta) while negotiating a price agreement with China. The global economic crisis has had a major impact on the way Russia regards its short- and long-term strategy on production and exports, at a time when Russian gas exports have dropped and its own demand fallen, and consequently Russia now has to accommodate a surplus of gas for a number of years.

The Year 2009: The Outcome

If any country has seen its gas industry affected by the financial and economic crisis, then it is Russia. Even without the January crisis, the year 2009 will certainly go down in the annals of the Russian gas industry as '*annus horribilis*'.

Key Numbers for Russia Supply, Demand and Investments

	2009	**2008**
Russian production	582.9	664.9
Of which Gazprom	*462.3*	*550.9*
Domestic demand	430.6	459.7
Gazprom sales to Russia	*273.5*	*292.2*
Total exports	202.8	247.5
Exports to Europe	*145.0*	*166.7*
	2010	**2009**
Investments priorities	3 axes • Yamal • Eastern gas • Others including Shtokman, Prirazlomnoye, Nord Stream, Pochinki Gryazovets	2 axes • Zapolyarnoye, Yamal, Urengoy, Shtokman, Severo-Kamennomisskoye • Pochinki-Gryazovets, Nord Stream, Yamal and Murmansk-Volkhov
Investments	RUB 753 billion, Capex RUB 614 bln	RUB 920 bln, Capex RUB 700 bln RUB 762 bln, Capex RUB 484 bln (rev. April 2009)

Source: Minenergo, Gazprom, Central Dispatch Unit 2009 annual report

Russian domestic demand started to drop as early as the beginning of Winter 2008/09, while a similar trend was observed in all export markets as well. For example, German gas imports fell by 16% from August to December 2008 compared with the same period a year earlier. Looking back at 2009, all elements of the supply and demand balance have therefore contracted in 2009. Russia even lost its position as the world's largest gas producer to the United States, whose 3% production growth contrasted with Russia's 12% decline. Russian domestic demand declined by over 6% due to lower demand from industry and the power generation sector.

Exports took a sharp fall: to European markets[28] down by 13.7% and to Former Soviet Union by 37%.[29] All FSU countries' economies have been badly affected and most reduced their gas imports accordingly, the worst by far being Ukraine (-49%). European countries, Russia's main customer and traditional source of revenues, have also imported less gas and even less Russian gas: Russian exports to Europe (including Baltic countries) plummeted from 166.7 bcm in 2008 to 145 bcm.[30] While this

[28] Excluding the three Baltic countries.

[29] Data on domestic demand are from Minenergo, data on exports are reported by Central Dispatch Unit.

[30] This is data as reported by the Russians, but the bcm are measured at a different temperature (20°C versus 15°C) and are not comparable one to one to what Europeans would report. Exports to Europe excluding Baltics have declined from 162 to 141 bcm.

partly reflected weakening western economies, it was also driven by the high price of oil-indexed gas. In early 2009, oil-indexed gas prices incorporated oil prices from the first half of 2008 which were more than $100. Because of this pricing formula, Russian gas has proven to be too expensive, especially compared to spot gas. When the Russian import price was still at $10/MBtu early in 2009, NBP had already dropped to $7/MBtu, and when Russian prices declined to $7-8/MBtu during summer 2009, NBP was half these levels at $3-4/MBtu. The gap continues with Russian oil-indexed gas priced at $10/MBtu against $5/MBtu in spring 2010. Despite the take-or-pay (TOP) obligations in their long-term contracts, many European gas buyers tried to replace their expensive Russian gas imports by cheaper spot gas. As a result, many failed to meet their TOP obligations at the end of 2009, pressing Gazprom for renegotiations on the volumes and pricing conditions as the end of 2009 approached. Early in 2010, Gazprom agreed to more flexibility over the next few years to come.

The economic downturn was also particularly severe for Russia with a 9% drop, the worst among major economies. A 6.2% decline during the fourth quarter 2009 shows that Russia is not out of the woods yet, although the IMF expects the economy to rebound by 3.6% in 2010. On the positive side, an improvement was clearly noticeable in the fourth quarter of 2009 with exports to Europe and FSU, and domestic sales all increasing. Gazprom's gas production then returned to levels comparable to 2007. Russian companies also benefitted from the cold winter 09/10.

In common with many companies, Gazprom's financial situation is certainly much less bright than in 2008, when the company launched a big acquisition campaign. This could affect future debt financing terms, and again, unsurprisingly, has impacted on the investment program and forced the company to prioritise and reassess investment projects. During 2009, Gazprom's sales revenues dropped by 10% to RUB 2,991 billion ($94 billion).[31] The operating profit plummeted by 32% to RUB 857 billion ($27 billion). Meanwhile Gazprom's total debt increased by 19%. Moreover, most debt is in US Dollars or Euros, and the rouble has depreciated heavily against these currencies since early 2008. This situation clearly called for measures to be taken on the financial and operational sides. On the financial side, Gazprom is looking at cost-cutting measures and possible improvements in debt management. On the operational side, there have been substantial revisions to the investment program. Gazprom revised downwards their initial investment program for 2009 from RUB 920 billion (announced in December 2008) to RUB 762 billion[32] with Capex cut from RUB 700 billion to RUB 484 billion. Investments for 2010 are planned at RUB 753 billion, with an increase of Capex to RUB 614 billion. Gazprom has announced quite radical changes in terms of priority investments:[33] these are now on three axes compared to two axes in 2009. What remains a clear priority is the Yamal development along with the associated upgrade of the transmission network such as Pochinki-Gryazovets.[34] Nord Stream is committed and construction started in April 2010.

Independent gas producers, the most prominent of which are Novatek, and Itera, and vertically integrated oil companies, including Surgutneftegaz, Lukoil, Rosneft and TNK-BP, have suffered less than Gazprom over 2009. The proportion of oil companies and independent producers in total gas production in Russia has been growing since 2002. Despite the crisis, they were even able to boost production by 5.8% to 120 bcm while their share in total gas production increased to 21% against 17% in 2008.

[31] Source: Gazprom, consolidated financial results under FIRS, April 2010. Sales net of VAT, excise tax and custom duties.
[32] This includes RUB 138.5 billion for the purchase of 20% of Gazprom Neft.
[33] Based on Investment day presentations in February 2009 and February 2010.
[34] Pochinki-Gryazovets will link the Central and Northern transmission networks and allow gas from the Central line to be transported to Nord Stream and later gas from Yamal to be re-routed to the South.

Novatek occupies second place in Russia in terms of reserves and gas production after Gazprom. It produced 32.8 bcm in 2009, a 6.2% increase over 2008, due to the launch of the second phase of the Yurkharovskoye field, the company's largest field, in the Yamal-Nenets Autonomous Region, above the Arctic Circle. In the first quarter of 2010, gas output was up 21% over 2009, with liquids (mainly condensates) up 22%. Novatek intends to continue the development of this field with the phases 3 and 4. TNK-BP and Rosneft also increased their production while Lukoil and Surguneftegaz both saw a decline. One of the reasons why independent and oil companies have been less affected than Gazprom may lie in their business optimisation between dry gas and wet gas. Companies with wet gas resources will maximise this production and sell the liquid content, even if this means reducing dry gas production. But these companies were also affected by reduced demand from their customers and potentially by difficulties accessing the gas grid. Many companies such as Surguneftegaz, Rosneft, TNK-BP are investing to increase the use of associated gas in their fields, in line with a government decree passed in 2008 to ensure the enforcement of license terms (95% use of associated gas) by January 2011.

Independent Gas Producers and Oil Companies

	2008	2009	Plans
Novatek	30.9	32.8	60-65 bcm by 2015
Other independents	17.7	14.1	
PSA operators	8.5	18.1	
Lukoil	14.2	12.4	
Surgutneftegaz	14.1	13.6	
Rosneft	13.0	13.2	55 bcm by 2020
TNK-BP	11.7	12.4	
Russneft	1.3	1.3	
Bashneft	0.4	0.4	
Slavneft	0.9	0.9	
Oil companies	**57.0**	**55.8**	
Independents and oil companies	**114.0**	**120.6**	

Source: companies' websites and annual reports, Central Dispatch Unit 2009 annual report.

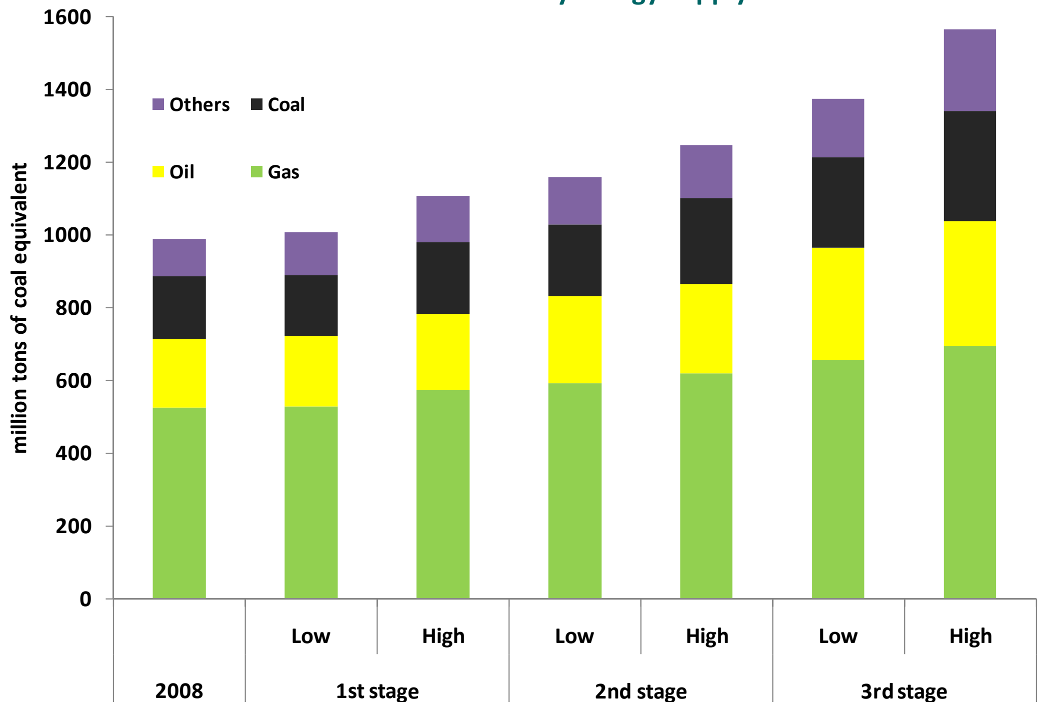
Another key change in 2009 was a partial strategic and political refocus on Asia, which finds its roots in Europe as well as in central Asia with the deals Turkmenistan has with China. As Russia's traditional main export market, Europe saw double digit demand growth in the first months of 2008 rapidly reversed with a 7% demand drop in the balance of 2008, and by a further 6% demand drop in 2009. Such volatility of demand will, inevitably, spill out to Europe's gas suppliers. Moreover, some European consumers bought less than the minimum TOP quantities, which were thought to provide a safeguard on the export side. In the short term, Russia had to lower some prices and agree to volume revisions to its main customers, hoping that they would be limited in time. In the longer term, the question is how and at what pace European gas markets will recover from the recession and what will be the impact of the 20/20 targets.

Long-Term Energy Strategy to 2030: Taking into Account the New Signs?

A New Russian Energy Strategy to 2030

In November 2009, the Russian government approved a new Energy Strategy (ES) to 2030, replacing the previous one to 2020, which had been approved in 2003. Its adoption had been postponed several times during 2009 due to the uncertainties of the economic crisis. This document, which determines the aims and priorities for different stages of the national energy policy, has to be seen as a geopolitical document rather than the blueprint of Russia's future energy balance. It remains however a key document to understand how Russia approaches the post-crisis challenges and adapts its internal and external strategy. It looks at the economic implications of the energy strategy as energy and the economy are particularly intertwined in Russia (as is the case for many energy producers). Among the general objectives of the ES are reducing the economy's dependency on energy (whose share in GDP and in exports is set to decline from 30% and 64% in 2008 to 18% and 34% in 2030 respectively), lowering energy intensity, helping to strengthen its foreign economic positions and reducing the share of gas in favour of other fuels, in particular renewables and nuclear.

Russia's Total Primary Energy Supply



Source: Energy Strategy of Russia.

The ES foresees three stages or periods, with no clear starts or ending reflecting the possible shifts:

- 2009-12/15: post crisis development, a recognition of the medium-term effects of the crisis. For gas, this period includes the development of Yamal, preparatory work in the Far East and Eastern Siberia, construction of North Stream, and guided liberalisation on the domestic market.
- 2013/15-20/22: energy efficiency development, during which the necessary steps to reduce the waste of energy would be taken. Regarding gas, the fields in the Ob and Taz bays, Shtokman, Krasnoyarsk and Irkutsk gas-extracting centres start with the export network being enhanced.

- 2021/23-30: innovative development with more focus given to renewables and nuclear. The regional gas network will be nevertheless developed to the East, while use of natural gas in the chemistry sector and synthetic liquid fuels production will be encouraged.

Despite the efforts during the second stage, Russian total energy demand is expected to grow between 39% and 58% over 2008-30, whereas the IEA foresees TPES increasing by only 22% over 2007-30. The major differences are the more optimistic economic assumptions with an annual GDP growth of 7% compared to 3.4% for the IEA. As of 2007, Russian TPES/capita consumption was at 4.75 toe/capita, slightly higher than the OECD average and much higher than OECD Europe's average of 3.4 toe/capita. Furthermore, the ES foresees electricity demand jumping from 1,021 TWh to 1,740-2,164 TWh by 2030 compared to 1,424 TWh in IEA's reference scenario. If the population declines as forecast by the United Nations from 142 million in 2007 to 129 million in 2030, this would imply a significant jump in energy consumption per capita at levels higher than the OECD average and even higher electricity demand per capita. Furthermore, the ES assumes that nuclear generating capacity would more than double to 52-62 GW by 2030, noting that nearly 7.7 GW of new nuclear capacity is under construction. In the Alternative Innovation Scenario developed in the ES 2030, foreseeing more energy efficiency and stronger environmental focus, TPES could be 1,195 mtce, 13% to 24% lower than the low and high estimates by 2030.

Focus on the Gas Part of the Energy Strategy

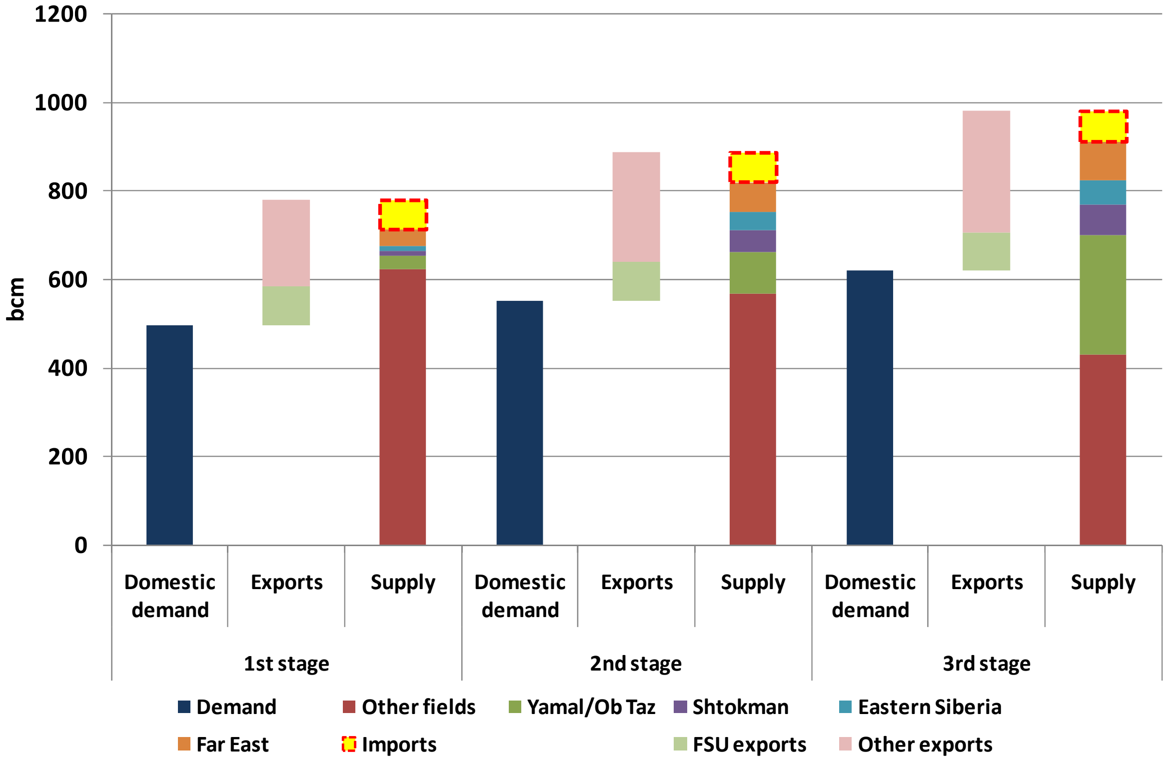
The gas strategy has to be viewed through the prism of the supply/demand balance. Previously based on six elements (Gazprom's production, independents' production, Caspian imports, domestic Russian demand, exports to Europe and to FSU), it now incorporates LNG exports and exports to China. Russia's (and Gazprom's) upstream strategy uses all elements. The flexible LNG element appeared in 2009 with the start of exports from Sakhalin while exports to Asia (by pipeline) are for the post-2015 period. Turkmenistan, previously considered as a source of cheap gas, is now paid at prices closer to global levels and Russia's import strategy has evolved accordingly, although Russia seeks to import more from other Caspian countries such as Azerbaijan, Uzbekistan and Kazakstan.

Again the ES is one part of the story to be compared to the signs on the ground. Regarding upstream gas developments and gas exports, the following trends can be observed:

- **Diversifying exports**. Although Europe is and remains the main export market, Russia looks at diversifying exports and at 'lower(ing) the risk of the Russian energy sector's mono-dependence'.[35] European exports are still expected to increase from 140 bcm to over 200 bcm by 2030, but by then, Asia would account for 20% of total exports (around 70 bcm) while LNG would contribute to 15% of this volume (around 52-55 bcm).[36] Far East and Eastern Siberian production and exports to China had always been present in Gazprom's export strategy but in general at the bottom of the projects list. These projects, a combination of LNG and pipeline exports coupled with the development of the Far East region, have been gaining momentum since mid 2009. Following a visit of Prime Minister Putin in October, first agreements have been signed that foresee exports up to 70 bcm to China. Also gas would gain importance economically with its share in energy exports increasing from 32% in 2008 to 43% by 2030. It remains to be seen how quickly the geopolitical shift towards the East will be followed by concrete steps on the ground. The critical issue will be negotiating an adequate price with the Chinese.

[35] Energy Strategy 2030.
[36] Asia will be China but also Japan and Korea, three countries to which Russia already exports gas from Sakhalin.

Russia's Supply and Demand Balance According to the ES



Source: Russian Energy Strategy, IEA.

- **Postponing projects**. In the medium-term, both Yamal and Shtokman have been postponed to 2012 and 2016 respectively. As highlighted in the *NGMR 2009*, the dates previously announced were considered to be too optimistic; this shows a more realistic approach to new market uncertainties. The assumption that Shtokman could start in the first stage of the Energy Strategy seems also unrealistic and not in line with Gazprom's strategy. In the long term, 39% of natural gas production (345-367 bcm) would come from new regions such as Eastern Siberia, the Far East, Shtokman, while the share of independent gas producers would increase from 21% in 2009 to 27% by 2030 (113 bcm to 150-160 bcm). The development of the Far East and Eastern Siberian fields is particularly challenging. Eastern Siberian fields are located in remote areas where most infrastructure (railroads, roads, pipeline) is absent requiring huge investments to be made, notwithstanding a very low population density and a difficult climate. Furthermore, there is still no agreement on prices, although the positions of Russia and China are getting closer. Finally, there is still a legal dispute over Kovykta. Production starting during the first stage seems optimistic. One could argue that more emphasis could possibly be put on independent producers sitting on huge natural gas reserves nearer to existing infrastructure. This would seem much more economic and would be much less risky, especially during this time of uncertainty on the demand side.
- **Wait-and-see approach**. If Yamal gas were to start in 2011 as previously planned, it would just add a layer of unwanted gas to an already oversupplied market. This gas, being oil-linked and delivered by pipeline, is likely to be less competitive than spot gas at least for the medium term. It would not be surprising to see the start of these projects delayed further if market conditions are not right, but as explained earlier, Gazprom has many elements to play with, such as its own

production, independents' production, and Caspian imports. Serious investments have already been done on Yamal with the most difficult part completed, allowing the ability for a staged approach and start-up in a couple of years. Shtokman, which combines technical difficulties with existing market uncertainties, may well be further delayed.

- **Caspian imports – carrot and stick**. Russia continues to have a strong relationship with the Caspian countries, but this differs according to the country. Russia is looking to increase imports from Azerbaijan, a way to pre-empt Shah Deniz phase II gas that has been mooted for Nabucco, and also from Uzbekistan. But at the same time, import volumes from Turkmenistan have been revised downward from a level above 40 bcm in 2008 to a maximum of 30 bcm from 2010 onwards, although actual volumes in 2010 are likely to be closer to 10 bcm. According to the previous long-term agreement, Russia was supposed to import up to 80-90 bcm from Turkmenistan by 2010. The Russian projection of imports of around 70 bcm assume either an increase of Turkmen deliveries and/or deliveries from other Caspian countries.

There are additional unknown factors in Russia: the future of the Russian domestic market and the role of independent gas producers and vertically integrated oil companies.

The evolution of the Russian domestic gas market itself is quite uncertain. According to the ES 2030, gas demand increases in volume to 605-641 bcm (growth of 32% to 40%) but its share in the total energy mix declines from 53% to 44-48%. The domestic Russian gas market is characterised by two aspects: electricity and gas are intertwined, and it is energy inefficient. Around 60% of total gas demand is used in the transformation sector while 48% of the power generated comes from gas, creating a significant interdependency. Gas-fired power is especially prominent in large urban centres, often associated with CHP.

One could argue that Yamal gas could more easily come from effective implementation of Russia's newly passed Energy Efficiency Law. In the Alternative Innovation Scenario, gas demand would be 10%-15% lower, saving 60-90 bcm by 2030. Gazprom estimated in 2009 that more efficient gas generating plants could easily save 20 bcm/y while better insulation in the residential and commercial sector could save another 70 bcm/y. Gains could be achieved by using more efficient gas plants in the power and industrial sector, rationalising energy use in the industry sector, moving from central heating to direct heating, or improving insulation in the residential sector. But, as elsewhere, the crisis is likely to have an adverse effect on energy saving as users cannot afford to invest in more efficient equipment. More changes can also be expected from structural shifts similar to those that happened in developed countries during the last decade with a progressive move from heavy industry to light industry or services.

At the final implementation stage of the Energy Strategy, the Russian economy is expected to boost the utilisation of natural gas not only as an energy source but also as a valuable chemical product. High-tech gas chemistry and production of synthetic liquid fuels from natural gas will develop extensively.

What could trigger such changes would be the planned price rises, but these are especially difficult to pursue, given the economic and social impacts of the current recession. In theory, Russia aims at gas export parity pricing between the domestic market and exports to Europe; in practice, this measure has repeatedly been pushed back, either due to the dramatic increase of oil prices (and therefore export prices) or the recession. The Federal Tariff Service is working on a new pricing formula to be proposed to the government. In ES 2030, prices are expected to be at parity by 2013-15, but Gazprom does not expect this before at least 2014: gas prices would have to reach RUB 4,800/1,000 m^3 from 2009 levels of RUB 1,970/1,000 m^3, implying an annual increase of 20%, well above the official 15%. The key uncertainties are the oil price,[37] the exchange rate between the Rouble and the US Dollar and future European export prices if the inclusion of a spot element is extended into the medium term.

The second open question is the role of the independents as well as private and foreign companies in the future Energy Strategy. Investments in the gas sector over the period 2009-30 are estimated at $565-590 billion (2007), split as follows: one-third in production, half in transport and the rest in treatment, and storage. By comparison, oil investments would amount to $609-625 billion (2007). Although there is an overall target of increasing the share of foreign investment in the energy sector to at least 5%, 8% and 12% over the three stages, there is no specific details about gas. Before and during the crisis, the government has always supported state companies through financial, political and regulatory measures. Independent gas producers and oil companies are rapidly increasing their production. These companies have a keen interest in LNG and production of liquids rich gas. However, despite their important gas production potential, one potential difficulty is access to the grid. Moreover, the target is well below what these companies plan for the short and medium term. Novatek expects its production to increase from 32 bcm in 2009 to 60-65 bcm in 2015, while Lukoil expects its production to increase from 12 bcm to 50-70 bcm by 2017.

The relationship between the Russian government and IOCs is more complex: after some difficult episodes, the government is again interested in IOC participation in the Russian upstream sector due to their know-how and their access to capital markets. It is obvious that Gazprom alone will be very hard pressed to support all this investment and that financial help of foreign companies will be needed. According to the new legislation being drafted by the Ministry of Natural Resources, foreign companies could get up to 49% ownership of offshore Russian oil and gas projects, a change from the 2008 decision to restrict access to offshore deposits. But their involvement would still be limited to joint-ventures with Rosneft and Gazprom for technologically challenging projects such as Shtokman, Yamal LNG, the Eastern Siberia development, or the expansion of Sakhalin. It remains to be seen whether IOCs or foreign NOCs will accept these conditions. Chinese NOCs could be particularly keen to help on the development of the Far East and Siberian fields, if the gas is for their market, replicating what has been done with Turkmenistan. But Russian views on an important Chinese presence in this region have yet to be tested.

New Projects

Over the coming years, Gazprom expects its production to increase from 462 bcm in 2009 to 507.5 bcm in 2010 and 523.8 bcm by 2012. The production increase would come from deposits surrounding the super-giants: first Achimovsk (Urengoy) in 2009; Valanginian (Zapolyarnoye), Zapadnoe (Urengoy), Yareyskaya (Yamsoveyskoye) in 2010, Nydinskaya (Medvezhye) in 2011 and finally the start of the Yamal peninsula production with Bovanenkovo in 2012.

Yamal Peninsula and the Ob-Taz Bay

Despite the one year delay for the starting date, the Yamal Peninsula project remains one of the two priority projects for Gazprom. As noted above, this project is critical to replace declining production from the major existing fields: Urengoy, Medvezhye, and Yamburg whose production is declining by 20-25 bcm/y since 2000. Yamal and the Ob-Taz Bay include 26 fields, and the production areas can be divided into three groups: Bovanenkovo, Kharasavey and Kruzenshternskoye in the centre of the peninsula, the southern production zone of the Ob-Taz Bay and six fields in the Tambey group

[37] The ministry's forecasts is $76 for Urals crude.

located in the north-east part of the peninsula.[38] Production from Yamal is expected to increase to 12-44 bcm by 2015, to 72-76 bcm by 2020, to reach 185-220 bcm by 2030, more than one quarter of Russian production. Production from the Ob-Taz bay would reach 68 bcm by 2030. By 2012 (instead of 2011 previously), Bovanenkovo is expected to produce 8 bcm per year. Given the delays in the start, a production range of 12-44 bcm appears realistic by 2015.

The challenge in the development of the two fields has been above all logistical: the construction material has to be transported to the Yamal Peninsula, the pipelines to bring the gas to the unified gas supply system (UGSS) have to be built. Transporting the material has been performed mostly during summer at the Kharasavey port. Early 2010, the Obskaya-Bovanenkovo railroad was commissioned and the construction of the Bovanenkovo-Karskaya railroad section should be completed later in 2010, allowing all year transport. Bovanenkovo holds 4.9 tcm of gas reserves and was chosen to be developed first. This approach necessitated a difficult route, crossing the Baidaratskaya Bay, rather than linking the fields to the existing infrastructure surrounding the three super-giant fields. Gazprom has already spent significant sums on Bovanenkovo: $4 billion in 2008, $3.4 billion in 2009 and a planned $6.8 billion in 2010. The most difficult technical part, laying the pipeline across the Baidaratskaya Bay, has been half completed as of early 2010. Most of the infrastructure has been completed while the first production wells have been drilled. The development of the southern zone would start in 2015, with the fields linked to Yamburg.[39]

Gazprom has set out plans for the development of the Ob-Taz bay – the fields located to the south of the Yamal Peninsula. The development of these fields has also been postponed due to the recession. The company is still waiting to receive offshore licenses. The first to be developed would be the Severo-Kamennomysskoye offshore field that could start by 2018. Kamennomysskoye could start three years later. The advantage is that these fields are close to Yamburg and can be relatively easily tied to existing infrastructure, replacing declining production from Yamburg.

A new stage has been reached with more serious discussions around the 15-16 mtpa Yamal LNG project, basically the development of the Northern zone well above the Arctic Circle. Novatek, which owns 51% of the Yuzhno-Tambeiskoye field, can be considered as a prime mover. In September 2009, Prime Minister Putin invited CEOs from international companies for discussions on this new project. Tenders have been organised by Novatek to find a partner and were closed in March 2010. The project is nevertheless much less advanced than Bovanenkovo, and would present more challenges than the southern zone. To some extent, this project is a competitor to Yamal if not in terms of the markets targeted, at least in terms of domestic workforce, material and cash resources. There was first an agreement between Gazprom and India's ONGC to cooperate on the project. Recently, Moscow has been trying to get Qatari companies' participation in the project, while companies such as Shell, Total or Wintershall have also expressed interest. In any case, this commercially and technically complex project would depend on the market outlook but may require at least a decade to complete, based on international experience with greenfields.

[38] Gazprom holds the development licenses for Bovanenkovo, Kharasavey, Novoportovskoye, Kruzenshternskoye, Severo-Tambey, Zapadno-Tambey, Tasiyskoye and Malyginskoye fields.
[39] Jonathan Stern, Oxford Energy Institute: Future Gas Production in Russia: is the concern about lack of investment justified?, October 2009.

Russian Gas Infrastructure

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.

Source: IEA

The Eastern Siberia Program

Developments in the Eastern and Far East regions have become the second priority of Gazprom under the name 'Eastern Siberia Program'. The project appeared firmly on Gazprom's strategy in June 2009, after years of discussions and the September 2007 Order. This order calls for a parallel development of production, transmission, gas processing and chemical industries in Eastern Siberia and the Far East, with potential gas exports to China and other Asian countries. Gazprom was appointed as the Program execution coordinator. These projects are even more challenging as the region is largely undeveloped and poorly explored, apart from Sakhalin 2. One should distinguish the fields located in the Far East (Sakhalin, Kamchatka) from the other fields in Eastern Siberia.

The Eastern Siberia program would develop fields such as Kovykta and Chayandinorskoye both for local consumption and export. These fields could either be linked to the Eastern pipeline system and possibly then to China or to the Western system entering the North-west of China. The Kovykta field is owned by RUSIA Petroleum, in which TNK-BP holds 63%. In 2007, TNK-BP agreed to cede its share to Gazprom after failing to fulfil the license terms: TNK-BP could not bring output to the levels stipulated due to low local demand and because Gazprom has a monopoly on Russian gas exports. However, the deal was never completed: talks between TNK-BP and Gazprom over the sale of the assets had previously broken down as the companies were unable to agree on a price. The fact that Gazprom may not have sufficient financing to develop all projects (on top of Yamal and Shtokman) may well play in the favour of a positive decision being taken for a strong IOC partner to develop the Eastern fields, given the geopolitical interest to develop this region sooner rather than later.

Production from Sakhalin 2 started in early 2009, and production from Sakhalin 3 is expected for 2014. The ES 2030 is rather optimistic regarding this region with production reaching 35-40 bcm by the end of the first stage and rising progressively to around 85 bcm by 2030. Gazprom is currently developing the gas transmission system from Sakhalin to Khabarovsk and Vladivostok, and started building a new gas pipeline to link Sakhalin Island with Khabarovsk and Vladivostok in July 2009. The onshore pipeline is expected to be part of an export route to the Pacific Rim later. The 1,350 km pipeline system will have an initial capacity of 6 bcm to be increased to 30 bcm and be commissioned in the third quarter of 2011. Then, in a second stage, the pipeline would be extended to 1,800 km and reach a capacity of 30 bcm (22 mtpa). A liquefaction plant at Vladivostok has been proposed to supply Asian markets. This would give the potential to either link the pipeline system to the one in northern China or to export LNG to the Pacific market.

Sakhalin could be the first step of a more important liquefaction centre in Far East, depending on future resources. Although "It is very important for us to set up new centres of gas production in the Far East and East Siberia", as Russian Prime Minister Vladimir Putin said at a ceremony marking the welding of the pipeline's first segment in Khabarovsk, the supply sources to this pipeline and the potential liquefaction project at Vladivostok are not certain. The development of Sakhalin III and IV led by Gazprom, potentially involving Shell, Mitsui, and Mitsubishi, could be a future source, although Sakhalin I cannot be ruled out. Customers, notably in Korea, are already showing signs of interest.

Shtokman

The Shtokman project appears to have been put on the back burner. Discovered in 1988, the field is estimated to contain 3.9 tcm of gas. It represents the first major offshore development for the Russian gas industry and is probably one of the most challenging due to the difficult arctic conditions. The field's output is to be developed in three phases of 23 bcm each, split between LNG and pipeline. The Shtokman Development Company (Gazprom 51%, Total 25% and StatoilHydro 24%) is developing the first phase. The gas would be transported to Murmansk, and then either by pipeline to Europe through the Nord Stream pipeline or by LNG to the Atlantic region. In February 2010, the Shtokman Development Company announced that the start-up of the project would be delayed by three years. The first pipeline gas would be in 2016 and first LNG production in 2017. FEED was completed end 2009. According to the latest plans, the Shtokman Development Company is currently conducting a study on market potential (in particular shale gas) and plans to take a decision on pipeline gas in March 2011 and on LNG end 2011. More than any other project, Shtokman requires demand certainty, which at the moment is simply lacking. The uncertainties regarding European gas markets and the rise of unconventional gas in the United States make exports to these markets less certain. Depending on the technical difficulties, it may even be ranked after Yamal LNG if market conditions in the Atlantic become favourable again.

The Caspian Region

The Caspian region is strategically placed to supply different regions or countries: Asia, Russia, Europe or Iran. The four countries, Turkmenistan, Azerbaijan, Kazakhstan and Uzbekistan hold around 8 tcm of proven reserves together, but the medium-term perspective to increase gas exports comes mainly from two – Turkmenistan and Azerbaijan.

Turkmenistan

Turkmenistan is the major gas exporting country in the Caspian region and it has recovered well from the difficult short-term outlook that it faced in mid-2009. At that time, gas trade with Gazprom – Turkmenistan's main gas export partner – had broken down following an explosion in April on the main Central Asia-Centre export pipeline. Discussions on the price and volume terms under which trade could resume were not promising quick results and continued for much of the year. Given the demand declines in Russia's main European markets, Gazprom had few commercial incentives to take extra volumes from Turkmenistan. For Ashgabat, the only short-term alternative route to market was a relatively small-capacity connection southwards along the Caspian Sea to Iran. The breakdown of Turkmenistan exports would have had a major impact on production; there is for the moment no official confirmation of the amount of gas produced in 2009, but the IEA estimates that it was in the range of 35-42 bcm, only just over half the 71 bcm produced in 2008. Likewise, the decline in export must have had a major effect on government revenues, although the scale of this impact is difficult to discern from official figures.

It may take more than one year to return to the production levels of 70 bcm, but the situation in 2010 is undeniably brighter for Turkmenistan than it was in mid-2009. Two new routes to market, a large-capacity link to China and a second cross-border line to Iran, were commissioned in December 2009; negotiations with Russia were concluded successfully and northward exports were resumed from the end of the year (albeit at lower volumes than before). Moreover, the Turkmenistan authorities moved ahead with contracts for development of the super-giant South Yolotan field in the southeast of the country, which is the cornerstone of Turkmenistan's plans to increase output over the coming years. The official production target is to reach 250 bcm per year by 2030. While the resource base could conceivably support an expansion of this magnitude, there is considerable uncertainty that sufficient investment will be forthcoming and that markets for such large incremental gas volumes will be available.

Turkmenistan policy on upstream developments is that international companies are welcome to invest in offshore developments, but that onshore, where the bulk of gas reserves are located, their role is limited to providing assistance on a contractual basis to state-owned Turkmengaz. Offshore gas output in the Caspian Sea, primarily associated gas produced by Malaysia's Petronas, could easily reach 10 bcm per year by 2015. This gas could potentially be directed to Europe along a new 'southern gas corridor' on the condition that a way is found to bring gas across the Caspian Sea to Baku.

Russia's Itera and Germany's RWE both took the first steps towards joining the offshore producers in 2009, signing production-sharing agreements (PSAs) on different offshore blocks (21 and 23 respectively). A less encouraging medium-term sign of Turkmenistan's offshore gas potential was the decision by Wintershall/Maersk/OMEL to surrender rights to blocks 11-12 after concluding that the results of initial drilling were not sufficient to proceed with further exploration.

A number of companies are looking at larger resources available onshore. Burren Energy, which was bought by Italy's ENI in 2007, has onshore operations near the Caspian Sea under a PSA concluded back in 1996. But the only international company that has been granted direct access to the major inland resources so far is China's CNPC, which has a PSA for gas development on the right bank of the Amu Darya river, near the border with Uzbekistan. Given the reluctance of the Turkmenistan authorities to countenance other onshore PSAs, some international oil companies are looking at how onshore service contracts can be structured to include an element of longer-term risk and reward, but it is not yet clear whether this approach will find favour from the Turkmenistan side. One way or another, though, the Turkmenistan authorities will need to harness international expertise and technology to support new gas developments: the next generation of Turkmenistan onshore gas will be more expensive and complex to develop than gas produced up until now because it is deeper, at higher pressure and temperature, and has higher concentrations of hydrogen sulphide and carbon dioxide. For the moment, as the example of the South Yolotan field suggests (see below), the Turkmenistan authorities expect that their policy of relying on classical service contracts for onshore gas developments will deliver the necessary results.

Caspian Region Gas Infrastructure

Only major trunk lines (mostly trans-national) are shown.
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.

Source: IEA

South Yolotan

Appraisal work conducted by the UK's Gaffney Cline at the South Yolotan field, in southeast Turkmenistan, has estimated gas-initially-in-place at 6-14 tcm; the Turkmenistan government has recently gone further with a high figure of 16 tcm. Even taking a figure at the lower end of this range and then applying a pessimistic assumption about the level of recoverable resources, South Yolotan is still one of the largest discoveries ever made. Once it starts production, South Yolotan is likely to be the mainstay of Turkmenistan production for many years to come as production from the Shatlyk and Dauletabad fields decline.

With the assistance of at least $3 billion in loans from China, the Turkmenistan authorities awarded a series of contracts in 2009 for the first phase of field development at South Yolotan. This first phase should produce 30 bcm/y, with first gas expected in 2012. The contracts came to a total value of $9.7 billion and were awarded to United Arab Emirates's Petrofac and Gulf Oil & Gas, South Korea's LG and Hyundai, and China's CNPC. These contracts cover drilling, sub-surface development and surface handling and construction, with Turkmengaz retaining overall project management. Developing such a large and complex field will involve huge technical challenges (including an average non-hydrocarbon gas content of around 8%); given the pattern of delays experienced by other large investment projects in the Caspian region, the announced schedule for field development – with first gas expected already in 2012 – could well slip. The success and speed with which South

Yolotan is developed will be the key variable in determining Turkmenistan's ability to supply significant volumes to multiple export markets. Since the field is being developed with Chinese money and Turkmenistan needs to deliver 40 bcm/y to China once the second string of the Turkmenistan-China pipeline is completed, it is likely that first gas from South Yolotan will be earmarked for the Chinese market.

Azerbaijan

After a major increase in 2008 as production from Phase I of the Shah Deniz field ramped up, Azerbaijan's gas output rose only slightly in 2009. The rise from 16 bcm to around 16.6 bcm was mainly due to an increase in associated gas delivered to SOCAR from the Azeri-Chirag-Guneshli (ACG) oil complex. Azerbaijan gas production comes from three main sources: the Shah Deniz field and SOCAR's own production (each contributing over one-third in 2009), with the remainder being associated gas from ACG. Most Shah Deniz gas is exported, mainly to Turkey along the South Caucasus Pipeline (also known as the Baku-Tbilisi-Erzurum pipeline). Since 2010, a separate portion of SOCAR's own gas is exported to Russia according to an agreement signed in October 2009 between Gazprom and SOCAR. The initial amount of 0.5 bcm/y was doubled in early 2010 to 1 bcm increasing to 2 bcm in 2011. The rest of SOCAR's own production and ACG gas is used for the domestic market.

There is significant potential to increase output from 2009 levels. The main incremental source of gas in the period to 2020 is Phase II development of the Shah Deniz field. This could bring an additional 14-16 bcm/y and had been initially foreseen as starting in 2014. Additional gas output is also possible from the Absheron field, where Total will drill a first exploratory well in 2010, and from deep horizons under currently producing reservoirs at Shah Deniz and the oil-producing ACG complex. Following on from their PSA in the Turkmenistan sector of the Caspian, RWE concluded in 2009 a Memorandum on the Nakhichevan offshore field and expects to conclude an exploration, development and production-sharing agreement (EDPSA) before the end of 2010.

Uncertainty over the timing, direction and marketing arrangements for future gas export from Azerbaijan has held back some upstream developments. Although Azerbaijan has been looking at a variety of options for gas export, including trans-Black Sea LNG and CNG, and sales to Russia and Iran, Azerbaijan's expressed preference is to sell its gas on European markets via pipeline to and through Turkey. However, delays in agreeing the terms for gas trade along this 'southern gas corridor' to Europe meant that a decision to sanction Shah Deniz Phase II has been delayed so that first gas could arrive only by 2016 or even 2017.

The conclusion of an Inter-Governmental Agreement among the transit countries for the Nabucco project in July 2009 helped to clarify the arrangements for a southern corridor, as did the memoranda agreed in June 2010 between Turkey and Azerbaijan on the price of gas delivered from Shah Deniz Phase I, and price and transit arrangements for Phase II. These developments should help to clear the way for specific commercial negotiations to begin between the members of the Shah Deniz consortium and the different pipelines and purchasers interested in Azerbaijan gas exports. Evidence that a functioning southern gas corridor is in place will be essential to encourage further upstream developments in the Caspian region, not only in Azerbaijan but also in other countries with potential access to this corridor, such as Iraq and also (offshore) Turkmenistan.

Middle East and North Africa

Qatar will shortly be exporting 77 mtpa (105 bcm) of LNG, in addition to pipeline exports to the United Arab Emirates (via Dolphin) of 20 bcm/y and domestic sales of 28 bcm for power and industry. By 2013, Qatar should also have developed the substantial Barzan off-shore gas field (15 bcm/y) as well as benefiting from the exports of Shell's pioneering Pearl GTL venture (16.5 bcm/y) – a total annual production of sales gas of 185 bcm.

All other major gas producers in the Gulf and Mediterranean areas are struggling. Saudi Aramco has not made an allocation of gas to industry since 2006. The United Arab Emirates has to consider alternatives to gas for power generation, and indeed, has recently awarded a major contract for nuclear power plant construction. Kuwait is already importing LNG to cover summer peak power demand and Dubai is expected to follow suit in 2011. Oman is limiting its LNG exports to 80% of capacity, while Egypt has denied foreign investors the authorisation to add further LNG export capacity at Damietta, giving priority to domestic demand. Algeria has sufficient gas at present, but is planning an extra 20 bcm of pipe (Medgaz) and LNG export capacity (Skikda and Gassi Touil), for which the gas supplies need to be developed. While Iran produces about 160 bcm/y of raw gas, increasing quantities are used for oil field injection and other internal uses; so despite its massive reserves, Iran is a net gas importer. Meanwhile, for lack of foreign partners, National Iranian Oil Company (NIOC) has failed to develop any LNG capacity to enable exports from their South Pars production. The recent increase in supply capacity from Turkmenistan (to 14 bcm/y) will make it easier to cover northern Iran's winter demand peaks; but with volumes exported to Turkey still very variable, it seems likely to extend the period when Iran remains a net importer of gas well into the medium term.

For both environmental and technical reasons, gas remains the fuel of choice for both power generation and petrochemicals, as well as for enhanced oil recovery in this region. The race is therefore on to identify additional quantities of non-associated gas. An early step in this direction, the Saudi Gas Initiative in the late 1990s, proved unsatisfactory. While companies like Shell, Lukoil and Repsol were pleased to be invited into the Kingdom, it proved impossible to develop any reserves at a cost anywhere near the Saudi domestic selling price of $0.75/MBtu. Today, there is a greater realisation that additional gas deposits are going to come in at costs much higher than in the past, and that if domestic prices are going to remain artificially low, a way must be found for the government or the NOC to bridge the gap. More logically, prices should be allowed to rise to levels that encourage viable exploration and production, at the same time encouraging efficient utilisation in applications such as power generation, and water production and use.

Saudi Arabia

Thus in Saudi Arabia, while Saudi Aramco is still expecting to benefit from some large additional associated gas volumes from the 500,000 b/d Khursaniyyah oilfield development, which came on stream in early 2009, and from the 900,000 b/d offshore Manifa field, which is to be developed by 2014, the main additional volumes of gas in the medium term are expected to come from non-associated gas projects where costs are much higher. The offshore Karan field, which should produce 18 bcm/y of sour gas when it comes on stream in 2012, may deliver gas at a production cost of $3.50/MBtu. Gas from the additional fields at Arabiyyah and Hawiyyah, which should add nearly 10.3 bcm/y to supplies for the Wasit gas processing facility, may cost as much as $5.50/MBtu. There are also plans to develop an extra 400 mcf/d of ethane for the petrochemical industry from the 750,000 b/d expansion of the Shaybah oilfield in the Empty Quarter. This might be linked to developing the sour gas deposits at Kidan identified by Shell, which currently represent stranded assets. LUKoil are also sounding more optimistic about being able to develop their discoveries in the Empty Quarter (perhaps 70 bcm of the 300 bcm gas in place), but this will not be before 2015.

While most Saudi gas has historically come as associated gas, there are already substantial supplies of non-associated gas, though insufficient for all current needs. It is estimated that the proportion of associated to non-associated gas in Saudi Arabia's supply varies between 40% and 60%, depending in part on the level of oil production. When, as at present, Saudi Arabia is producing just over 8 mb/d (of its installed capacity of 12.5 mb/d), the proportion of associated gas – as quoted by the Oil Minister Ali al-Naimi in mid-2009 – is 42%. The 58% of non-associated gas in the supply system represents already therefore a huge investment in non-associated gas supply.

Longer-term, the Saudis have said that they hope to expand raw gas production from the current 90 bcm/y (8.8 bcf/d) to 134 bcm/y (13 bcf/d) by 2020. With proven reserves already raised to 7.6 tcm at the end of 2009, the Saudis say they hope to increase these reserves by about 140 bcm each year, matching output. They have just launched a fresh five-year seismic survey of the Empty Quarter. Late 2009, Saudi Aramco also let a $400 million contract for seismic work in the Red Sea; and in early 2010, Khalid al-Faleh, CEO of Saudi Aramco, said that the inland areas north and north-west of Riyadh would also be explored. If gas in sufficient quantities is located in the Jalamid area, for example, there is a proposal to develop it as part of the Maaden phosphate and fertiliser project. Overall, this amounts to a massive upstream development programme.

United Arab Emirates

In the United Arab Emirates, which has 6.1 tcm of proven gas reserves, ADNOC has had to take a similarly realistic approach on costs. They have three major gas development projects currently under way, which are mainly aimed at increasing volumes of gas for use in reinjection, while profiting from the significant quantities of NGL by-products. Onshore Gas Development III is designed to provide 12 bcm/y for reinjection into the Bab oil field. Asab Gas Development II should treat about 7.8 bcm/y of raw gas for reinjection into the Asab reservoir. The recently launched Habshan 5 project will produce 10.3 bcm/y for reinjection and another 10.3 bcm/y for industry and power by 2013. These projects will also produce 11 mtpa of NGLs, much of which will be allocated to the rapidly developing petrochemical industry.

Less obviously profitable is the ambitious Shah sour gas field development which, until very recently, was expected to be taken forward in partnership with ConocoPhillips. ADNOC are now said to be looking for new partners, possibly either Shell or Total, which originally bid, or Occidental Petroleum. The Shah project is to take 10.3 bcm/y of onshore non-associated sour gas and produce 5.6 bcm/y of sales gas for the domestic market along with lucrative quantities of condensates and NGLs. But the production cost of the gas is estimated at $5.0/MBtu and the waste sulphur from the treatment process has proved difficult to dispose of in an over-supplied world market. Nevertheless, the United Arab Emirates' need for additional gas is likely to tempt ADNOC to proceed anyway. As will also be seen below in the case of Oman and Kuwait, these technically challenging gas projects are often the point of entry for the western majors into upstream reserves hitherto closed off. They also provide large scale and lucrative contracts for the European, North American and Far Eastern engineering and project management industries.

One last, relatively small-scale, initiative in the United Arab Emirates, is to take some 2 bcm/y of additional offshore gas and pipe it onshore for the domestic market instead of adding it to the longstanding Das Island gas-liquefaction facility. Like Oman and Egypt, the United Arab Emirates shows no inclination to expand its LNG export capacity as long as it has to address the demands of oilfield injection, local industry and power generation. But at the same time, it is devoting significant investment and cutting-edge technology to developing additional gas supplies.

Iran

While gas strategy on the Arab side of the Gulf is mainly constrained by geology and economics, on the Iranian side, political issues play a dominant role. Iran has the world's second-largest proven gas reserves (29 tcm), and consumes currently about 160 bcm/y of raw gas (of which about 120 bcm of sales gas). In the context of international concern over Iran's nuclear power and uranium enrichment programme, bilateral US sanctions and successive UN Security Council resolutions, while so far not directly impacting import or export of gas, crude oil or oil products, have effectively discouraged the large-scale foreign investment and technology which the Iranian government was hoping could contribute to upstream gas development. This particularly applies to phases 11 and 13-14 of South Pars gas production which were intended to bring in Total and Petronas in the first case and Shell with Repsol in the second. On the other hand, phase 12 of South Pars is being developed by the National Iranian Gas Liquefaction Company using German technology under licence. But progress has been slow and the Iranians are said to have offered ONGC-Videsh of India and the Hinduja company 40% of the project, possibly as a way of attracting more funding. The Iranians have also invited CNPC of China to farm in to the Pars LNG project (South Pars phase 11) in place of Total (at a price of $4.7 billion). But the lack of proprietary technology and project management skills will be a handicap. Meanwhile, the development rights for South Pars phase 13-14 was granted to Iranian group Khatam-ol-Osea in place of Shell and Repsol for $5 billion.

The threat of sanctions is not the only problem. The Iranian oil and gas sector has been subject to strong political influence. Massoud Mirkazemi, appointed Oil Minister after the last presidential elections, is a political ally of President Ahmedinejad rather than a technocrat. The selection of Javad Owji to be Deputy Minister for gas affairs and to head the National Iranian Gas Company (NIGC) and the recent appointment of Ahmed Ghalebani as Deputy Minister and head of NIOC are both seen as political. The politicisation of projects has caused problems for foreign participants: StatoilHydro, which was key to develop South Pars phases 6-8 and provided 27 bcm/y of gas for reinjection, found it very difficult to work with designated Iranian national companies such as Petropars. The allocation of contracts for largely political reasons has continued. Khatam al-Anbiya, a company owned and run by the Iranian Revolutionary Guard Corps, was awarded South Pars phases 15-16 (18.2 bcm/y) on the withdrawal of Kvaerner: they will also take over South Pars phases 22-24 (14.5 bcm/y), which had been intended to be developed by TPAO for export through Turkey to Europe.

There is also a general problem of funding. In February, the outgoing head of NIOC, Seifollah Jashnsaz, regretted that Iran had only attracted $8 billion of foreign investment in the 2009/10 financial year. The new Minister, Mirkazemi, stated in January that while $19 billion was needed this year to sustain gas development projects, the national budget only allocated $3 billion. This has incidentally prompted a determination on his part to ratchet up domestic gas prices sharply, something long overdue. Not all off-shore gas developments need to be linked to LNG, but funding is still necessary. South Pars phase 15-16 now in the hands of Khatam al-Anbiya was recently awarded $2 billion of funding from the foreign exchange fund, from the Oil Ministry's own budget and from domestic banks. Similarly phase 17-18 (18.2 bcm/y) which has recently been taken forward by the Industrial Development and Renovation Organisation (under Ahmed Ghalebani), was said to be

$750 million short of funding this year and has just been allocated €350 million from a recent issue of Eurobonds. Both these projects may now have a chance of starting by the middle of the decade.

Another source of new gas deliveries will be the Salman gas field in the Lower Gulf. The subject of a protracted dispute with Dana Gas of Sharjah, its original export customer, over delivery prices, it has now been linked up to Iran's own on-shore network and should be providing 5.1-5.6 bcm/y this year. (The overall cost of this will be a small fraction of the cost to Abu Dhabi of developing a similar quantity of gas from the Shah gas field). Last autumn, the outgoing head of NIGC, Azizollah Ramezani, said that even if they succeed in restraining domestic demand, overall gas consumption was likely to increase from the present 160 bcm/y to about 200 bcm/y by 2014 (including continuing increases in demand for gas reinjection in oilfields). All these projects will be essential for that target to be met.

Further down the road, there is the prospect of developing the giant 31 bcm/y Kish field, also in the lower Gulf. But recent attempts to persuade the Omanis to jointly fund the project in return for 10.3 bcm/y to supply Oman's own underused LNG export capacity have not borne fruit. A fortiori, any plans to develop the Durra field in the Upper Gulf which straddles the Iranian/Saudi/Kuwaiti maritime border will need to await a significant improvement in the regional political situation. Iran continues to explore onshore for new gas resources. The new Minister announced an assessment of the recently discovered Halegan gas field, with the capacity to produce 18 bcm/y for about 20 years.

Oman

Oman has a modest 690 bcm of proven gas reserves but, like the United Arab Emirates and Iran, has a growing need for gas to enhance oil production. In 2009, gas used in the oilfields increased by 35% over the previous year. At the same time, it sees electricity and water demand rising strongly over the medium term. There are 1,650 MW of gas-fired power capacity coming on line by 2012-13 (and 55 m gallons/day of water). Oman's 10 mtpa of gas liquefaction trains are being run at 80% capacity.

Petroleum Development Oman (Shell/Total) which hold the major concessions, are concentrating on maximising oil and gas recovery rates, and where they can develop fresh gas supplies hope to capitalise on associated condensates and NGLs. Their recent tight gas discovery at Khulud offers the prospect of 10.3 bcm/y in the medium term, though the upstream investment costs will be considerable.

Likewise, both BP and BG Group have promising tight gas concessions held on an EDPSA basis since 2006. They hope to declare commerciality in the near future (on the basis of an agreement on higher sales prices). In the case of BP, this will require a further appraisal investment of $650 million over two years. BP's current estimate of their reserves ranges between 0.6 tcm and 1.7 tcm, and of ultimate full production using hydrofracking, between 10.3 bcm/y and 20.6 bcm/y. They hope to establish early production at about 2 bcm/y by the end of 2011. If all three of these tight gas prospects are confirmed, Oman's gas reserves position will be significantly enhanced and it would open the way for much greater upstream investment over the medium and long term.

INVESTMENT IN LNG

Summary

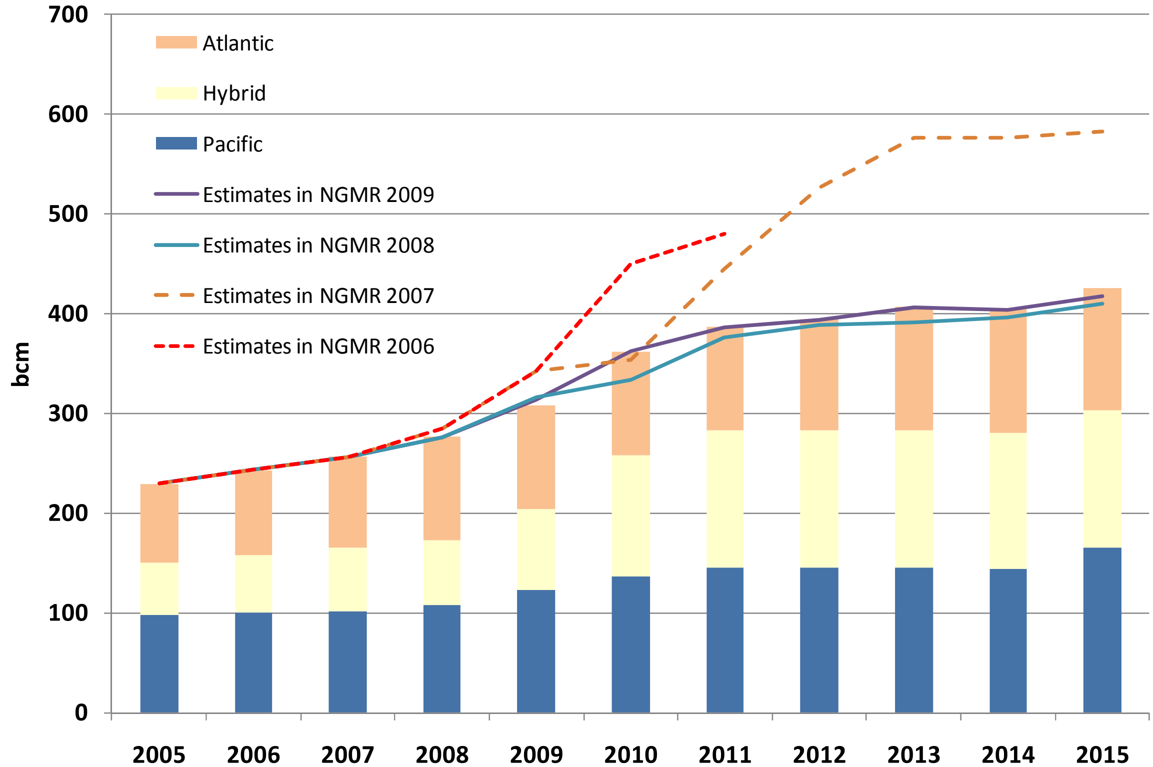
- **The year 2009 saw a sharp contrast between the Pacific and Atlantic LNG markets**, especially in long-term marketing and liquefaction investment: significant progress was achieved in the Pacific basin while uncertainty continued in the Atlantic and in the Middle East where progress on future projects is less clear. The focus of marketing and investment activities in these regions is already shifting to the latter half of the decade.
- **Two projects have made final investment decisions (FIDs) since *the NGMR 2009* – Gorgon and Papua New Guinea LNG (PNG LNG) – and some others have seen significant progress in marketing their planned volumes in the Pacific region**. Long-term and vertically integrated value-chain arrangements have proven to be key to advance projects. Australia has become a major focus for new investments: several projects in Western Australia and CBM-to-LNG projects in Queensland are competing for marketing windows and limited project resources. It is reasonable to anticipate at least one or two new FIDs over 2010-11.
- **Floating LNG production is gaining momentum although no projects have yet been sanctioned.** Those projects sponsored by companies with established track records in LNG business seem more likely to proceed.
- **Traditional LNG supply regions are becoming major consuming centres of LNG as well as pipeline gas, in particular the Middle East and Southeast Asia**. While these regions will remain globally net exporters of gas, regional disparities between, or even within countries have resulted in new LNG import infrastructure being built or planned.

After four years during which only five FIDs were taken, the trend was broken: two projects in the Pacific made final investment decisions (FIDs) in the second half of 2009 – Gorgon and Papua New Guinea LNG (PNG LNG). A key success factor for these two projects was the long-term sales agreements to both growing and more mature markets seeking to meet either incremental demand or replace expiring contracts. Some other projects have seen significant progress in marketing their planned volumes and seem likely to take FID in 2010 or 2011.

Estimates on new LNG liquefaction capacity by region were more bullish in 2006 before engineering, procurement and construction contract (EPC) costs started to increase rapidly. In the *NGMR 2009,* the IEA looked at seven projects with potential FID in 2009 and 2010: two are effectively moving forward but the others, Brass LNG, Nigeria Train 7, Donggi-Senoro, Shtokman and Ichthys seem far from FID. The ones located in the Atlantic basin suffer from the current regional oversupply, while factors such as the regional instability, technological challenges and allocation of domestic gas have added to the difficulties. Now Australia, strategically placed in the Pacific, has emerged as the major new production centre.

The challenges highlighted in the *NGMR 2009* are still very much present. First, market uncertainty remains a concern and projects with sales agreements have a clear advantage. Furthermore, the material and engineering costs of liquefaction plants coming on line over 2009-13 remain relatively high at $830 per tonne/year of capacity compared to those completed over 2005-08 ($430). The fact that most projects which are likely to take FID over 2009-11 would be located in Australia may cause some issues in terms of labour shortage.

Expected LNG Export by Region



Note: annual capacity is adjusted depending on expectations on starting date. In the NGMR 2007 and 2008, it was assumed that Indonesia's Arun would cease in 2009 and that exports from Indonesia would progressively decline as export contracts are not extended.

Source: IEA, previous NGMRs.

Delays and difficulties seem to have become a common trait among existing and new plants; additionally most of them have come on line later than expected. With the two new FIDs on Gorgon and PNG, there are still 79 bcm of capacity under construction and planned to come on line by 2015. Liquefaction capacity at that time will reach 439 bcm, although around 10 bcm of capacity could be decommissioned by then. In addition, there is 500 bcm of capacity currently proposed. Four countries, Australia, Nigeria, Iran and Russia, represent 77% of this planned capacity, but Australian projects looks the most likely in the current circumstances.

As of June 2010, there is around 360 bcm of existing liquefaction capacity, 37% in the Pacific basin, 33% hybrid and 30% in the Atlantic basin. Qatar now has close to one quarter of global liquefaction capacity, well ahead of Indonesia. Some 82 bcm started operating since the start of 2009, but most projects were plagued with technical difficulties requiring shut down and maintenance.

The following section will look at projects recently approved as well as at the projects currently under consideration. The Appendices in *Part 3: Gas Supplement* give details on LNG liquefaction plants existing, under construction and planned.

FIDs Taken Over the Past Ten Years

Project	Capacity (bcm)	FID	Start
Darwin	4.4	2002	2006
Snøhvit	5.6	2002	2007
Sakhalin	13.6	2003	2009
Equitorial Guinea	4.6	2004	2007
RasGas II Train 5	6.4	2005	2007
NWS Train 5	6	2005	2008
Qatargas Trains 4&5	10.5 x 2	2005	2009
RasGas Trains 6&7	10.5 x 2	2005	2009-10
Qatargas Trains 6&7	10.5 x 2	2005	2010
Tangguh	10.3	2005	2009
Yemen	9.2	2005	2009-10
Peru	6.0	2006	2010
Pluto	6.5	2007	2011
Skikda	6.1	2007	2013
Angola	7.2	2007	2012
Gassi Touil	6.4	2008	2013
Gorgon	20.4	2009	2014-15
PNG	9.0	2009	2014-15

Source: IEA based on companies' information.

Pacific Advances two Major Projects: Gorgon and Papua New Guinea

When one looks at where LNG liquefaction plants could be built in the next decade, Australia has the potential to become the new Qatar. With 27 bcm in operation, it has two plants under construction, Pluto and Gorgon, and a number at advanced stages of planning. Its geographical position close to booming Asian markets will also prove an advantage compared to other countries. There are two particular aspects to Australian projects: six are CBM-projects while three are floating liquefaction plants in addition to the planned conventional LNG projects. Australia has not only a great potential as an exporting country but could be the theatre of major technological breakthroughs. Among all these plants, the Queensland Curtis LNG project from BG and Wheatstone from Chevron are probably the most advanced. Papua New Guinea has also seen one of its projects sanctioned in 2009.

Australia continues to face the same challenges that have made past developments difficult. Gas is frequently located in very remote locations, where infrastructure is lacking, and labour costs high. The weak impact of the recession means that cost pressures may emerge again quickly. However, the central Queensland CBM-LNG projects are better located, so infrastructure issues, while still present, may be less pressing. The Australian government is currently negotiating key parameters of the proposed new 40% tax on resource profits with mining groups. Until these are agreed, it is difficult to assess the impact of the tax on new investment decisions.

Gorgon, Western Australia

On 14 September 2009, development proposals for the 20 bcm per annum Gorgon project were approved and production licenses granted by the Western Australian State and Australian Governments. The FID was then announced by the three joint venture partners: Chevron, Shell, and ExxonMobil. Located on Barrow Island off the northwest coast of Western Australia, Gorgon will have with its three trains a capacity close to the five trains of the North West Shelf project. There is also a domestic angle to the project. Under an agreement with the Western Australian state government, the project partners are required to reserve 50 bcm from the Gorgon fields for delivery to domestic customers, subject to supply being commercially viable. Domestic deliveries are also planned to begin 2015. Considerable attention has been given to environmental aspects: the plant is to be constructed in modules offsite and then assembled onsite to minimise the environmental impact on the plant site. The partners have also committed to capture and store around 3.5 million tonnes per year of CO_2, in a host geological storage structure known as the Dupuy formation, at least 2 km beneath the island's surface. This will be one of the largest integrated CCS projects when Gorgon enters operation. One of the key success factors for the project was the sale agreements signed, as well as Japanese buyers taking equity stakes in Gorgon. According to these agreements, Japan would take 5.2 mtpa, China 4 mtpa, India 1.5 mtpa and Korea 2.7 mtpa.

Sales Deals from the Gorgon LNG Project (as of June 2010)

Seller	Buyer	Volume (mtpa (bcm))	Details
Chevron		**6.52 (8.93)**	
	Tokyo Gas	1.1 (1.5)	SPA in September 2009
	Chubu Electric	1.44 (1.96)	SPA in December 2009
	Osaka Gas	1.375 (1.87)	SPA in September 2009
	Nippon Oil	0.3 (0.41)	HOA in January 2010
	Kyushu Electric	0.3 (0.41)	HOA in January 2010
	GS Caltex	0.5 (0.68)*	SPA in September 2009
	Korea Gas	1.5 (2.04)	HOA in September 2009
	CNOOC	n.a.	SPA pending as of September 2009
ExxonMobil		**3.75 (5.06)**	
	Petronet LNG	1.5 (2.0)	SPA in August 2009
	PetroChina	2.25 (3.06)	SPA in August 2009
Shell		**2.0 (2.8)**	
	PetroChina	2.0 (2.8)**	SPA in November 2008

Notes: Chevron's sales to GS Caltex could include other sources of Chevron's global portfolio. Shell's sales to PetroChina could include other sources of Shell's global portfolio. Shell also has a MOU for 0.7 mtpa destined for Mexico and India, which is not counted as a sale agreement.
Source: IEA.

PNG, Papua New Guinea

ExxonMobil announced on 8 December 2009 that the partners (Oil Search, Santos, AGL, Nippon Oil, MRDC) had agreed to proceed with the development of the 9 bcm Papua New Guinea LNG (PNG LNG), pending completion of SPAs with LNG buyers and finalisation of financing arrangements with lenders. By the time of this conditional FID, long-term SPAs were in place with three buyers: Tepco, Osaka Gas, and Sinopec. Sinopec's purchase represented its first long-term import deal, enabling the company to advance the construction of its Qingdao regasification terminal. FID was taken after the final SPA with CPC Corporation (Taiwan) in March 2010. Construction started in April 2010.

The PNG project has clearly indicated an increasing role for export credit agencies (ECAs) in the LNG industry. Financing includes $8.3 billion of loans from key ECAs in the United States, Japan, China, Italy and Australia. The rest of the financing package comprises $3.75 billion of co-lending from

ExxonMobil and $1.95 billion from a syndicate of 17 commercial banks such as Sumitomo Mitsui Banking (SMBC), Mizuho Corporate Bank and the Bank of Tokyo-Mitsubishi UFJ. Japan Bank for International Cooperation (JBIC) would provide financing of as much as $1.8 billion.

Sales Deals from the PNG LNG Project (as of June 2010)

Buyer	Volume (mtpa (bcm))	Remarks
Tokyo Electric Power (Tepco)	1.5 (2.0)	SPA in December 2009
Osaka Gas	1.5 (2.0)	SPA in December 2009
Sinopec	2.0 (2.7)	SPA in December 2009
CPC Corporation, Taiwan	1.2 (1.6)	SPA in March 2010
Total	6.2 (8.3)	

Source: IEA.

Another LNG proposal in the country by the joint venture Liquid Nuigini Gas between InterOil, Merrill Lynch and the Swiss private equity find, Clarion Finanz, is less advanced. Despite a government approval in March 2009, enough reserves have not been proven up in the Elk and Antelope fields.

CBM-to-LNG Race is Heating Up in Australian State of Queensland

There are currently six projects based on CBM[40] reserves in Australia, all located in the Central Queensland region which holds around 380 bcm of proven and probable CBM reserves.

Australia's CBM (CSG) to LNG Projects (as of June 2010)

Project	Sponsors	Capacity (mtpa (bcm))	Timeline	Markets
Queensland Curtis LNG (QC LNG)	BG Group	8.5 (11.6)	FID 2010 Start 2014	Singapore, China (PetroChina), Chile
Gladstone LNG (GLNG)	Santos, Petronas	3.5 (4.8)	FID 2010 Start 2014	Malaysia (Peninsula), Japan
Australia Pacific LNG (AP LNG)	Origin Energy, ConocoPhillips	7.0 (9.5)	FID 2010 Start 2014	
Fisherman's Landing	LNG Limited (Arrow Energy)	1.5 (2.0)	FID 2010 Start 2014	Japan (Toyota Tsusho)*
Curtis Island LNG	Shell, PetroChina	8 (11)	FID 2012 Start 2014-15	China (PetroChina)
Southern Cross LNG	Galveston LNG	1.0 (1.4)		

*The deal has expired.
Note: starting dates are those given by the operators and do not represent IEA's views.
Source: IEA.

Currently the region produces 3.5 bcm/y of CBM.[41] Among them, the Queensland Curtis LNG project by BG Group and the Gladstone LNG project by Santos and Petronas have advanced to critical stages nearing FID in late 2010 or early 2011. As skilled labour sources and logistical capability are expected

[40] The term 'coal seam gas (CSG)' is more often used in Australia.
[41] The Australian Atlas of Mineral Resources, Mines, and Processing Centres.

to be limited, more than two projects are unlikely to be constructed simultaneously. Thus timely marketing arrangements and engineering works are critical.

BG plans to produce 8.5 mtpa (12 bcm) at QC LNG, up from the previously planned output of 7.4 mtpa (10 bcm). The increased output would be underpinned by combined sales of 9.5 mtpa under agreements with China, Japan, Singapore and Chile. In March 2010, BG Group entered a binding SPA with CNOOC and a HOA with Tokyo Gas. CNOOC will buy a 10% stake in Train 1 and Tokyo Gas will acquire a 2.5% stake in Train 2. In February 2010, BG awarded Bechtel more than $3 billion for the EPC for the project and was issued an initial notice to proceed and order equipment including storage tanks and compressors. In March 2010, BG selected Baosteel to build the pipeline from the CBM fields to Gladstone. BG is now waiting for final regulatory and environmental approvals from the Queensland Government.

Marketing Arrangements from the Queensland Curtis LNG (QC LNG) Project (as of June 2010)

Buyer	Volume (mtpa (bcm))	Details
CNOOC	3.6 (4.9)	SPA in March 2010 following a PDA in May 2009
Tokyo Gas	1.2 (1.6)	HOA in March 2010
Chile	1.7 (2.3)	BG Group as an aggregator is to supply LNG
Singapore	3 (4.1)	to the terminals from its global portfolio.
Total	9.5 (12.9)	
Plant capacity	8.5 (11.6)	

Source: IEA.

Santos, with partner Petronas, plans to build the 3.6 mtpa Gladstone LNG plant (GLNG), whose output could eventually be raised to 20 mtpa (five trains). The partners are planning to take FID by late 2010 for the first train to start in 2014 and wants to sanction a doubling of the plant size to two trains (7.2 mtpa) by the middle of 2011. This will require securing additional gas reserves to support the expansion and more LNG off-takers. However, before Santos can give the green light, the project's environmental impact statements (EIS) need to be approved.

The Australia Pacific LNG (APLNG) venture pairing Origin Energy and ConocoPhillips is lagging behind these two projects in terms of marketing and approval processes, although it is advancing upstream CBM development. The project includes a first 3.5 mtpa train to start by 2014, another by 2015 and ultimately increasing the capacity to 14 mtpa. FID for the first train is expected by late 2010.

Initially, Arrow Energy was involved in two CBM projects: the 1.5 mtpa Fisherman's Landing (FLLNG) with LNGL ltd (51:45 interest) and the 8 mtpa Curtis Island LNG (CILNG) project at Gladstone through Shell's 30% interest in Arrow's CBM reserves. In March 2010, Arrow Energy agreed to a takeover bid by Shell and PetroChina. The takeover will enhance the prospects of Shell's CILNG project by increasing available gas reserves and introducing a big Chinese buyer into the picture while giving it additional CBM production experience. At the same time, the deal will force the smaller FLLNG project, which was to be sanctioned in April 2010, to find alternative gas sources. Shell and PetroChina plan to make a FID on the CILNG project in 2012, with first gas targeted for 2015. The partners would each take half of the project's output. PetroChina would send its share of the output to China and is negotiating to buy Shell's output. The offer has to be sanctioned by Arrow shareholders in July 2010.

Western Australian Race is also Hot

In addition to Gorgon and the CBM-to-LNG projects described above, there are several other LNG project proposals in Australia, mostly in Western Australia and in the Northern Territory.

Wheatstone

Chevron intends to go ahead with the 8.6 mtpa Wheatstone project as a stand alone LNG plant at Onslow immediately after sanctioning the Gorgon project. Based on drilling success at the Iago field and agreements with Apache and Kuwait Foreign Petroleum Exploration (Kufpec) to include the Julimar and Brunello fields, Chevron is considering a two-train development at the first stage starting in 2016. It would take the FID in 2011. Several factors favour this project. First, Apache and Kufpec joined in October 2009 Wheatstone LNG instead of Woodside's Pluto, bringing additional gas resources to the project in exchange for stakes in the project. To address the potential shortage of skilled labour, the company's intention is to utilise project resources mobilised for the Gorgon project sequentially after completing the first phase of that project. In addition, Chevron has signed a HOA with Tepco for 20 years covering almost half of Wheatstone's initial capacity. Furthermore, Tepco will purchase 15% of Chevron's holdings in the Wheatstone field equal to about 11.25% of the project, while Kyushu Electric Power signed an initial deal in January 2010 to buy LNG from Chevron's projects.

Sales Deals from the Wheatstone LNG Project (as of June 2010)

Buyer	Volume (mtpa (bcm))	Remarks
Tokyo Electric Power (Tepco)	4 (5.44)	HOA in December 2009
Kyushu Electric Power	0.7 (0.95)	HOA in January 2010
Total initial capacity	8.6 (11.7)	

Source: IEA.

Browse

In addition to second and third trains at the Pluto project, Woodside is leading two other projects in Australia: Browse LNG in Western Australia and Greater Sunrise (via a floating plant).

One of the difficulties regarding the Browse LNG project has been to find a solution to develop the gas resources, which meets environmental requirements and to reach an agreement with Traditional Owners of land in the Kimberley. In December 2008, the Western Australian state government selected a site for an LNG hub in the Kimberley region to receive gas from the Browse basin – James Price Point, 60 km from Broome, with no settlements within 20 km – as it could meet environmental requirements and accommodate several projects. Late December 2009, the Browse joint venture accepted the Australian federal and Western Australian state governments' offers to renew the retention leases for their offshore gas reserves, including a 120-day deadline to agree on a development concept. In February 2010, the partners in Browse LNG agreed to process the gas at the proposed LNG hub. Woodside claims the agreement paves the way for FID by the middle of 2012. It immediately awarded design contracts for both the onshore and offshore components of the project; this will be followed by FEED in 2011.

Prelude

Prelude is one of Australia's three floating LNG (FLNG) proposals. Sponsored by Shell, it will have a 3.5 mtpa (4.8 bcm) capacity and be able to resist poor weather and ocean conditions. No sale contract is yet in place to underpin the project. This FLNG is one of the projects that Shell may develop following an agreement between Shell, Technip and Samsung Heavy Industries (SHI) in July 2009. The two companies won a 15-year contract to design, produce and install FLNG facilities for Shell as well as handle FEED for Shell's FLNG facilities. Shell signed two contracts in March 2010 with a consortium of Technip and SHI for the Prelude floating LNG project off the coast of Western Australia. The first contract covers the FEED elements specific to the Prelude project, taking into account the composition of the gas, local weather and other site specific factors. The second contract details the terms under which the FLNG facility would be built, if the FID for the Prelude project is made.

Bonaparte

GDF Suez finalised a deal with Santos to buy into three offshore fields to supply the proposed 2 mtpa Bonaparte FLNG project in January 2010. The company has paid about $200 million to Santos for 60% of the Petrel, Tern and Frigate fields in the Timor Sea. GDF Suez will lead the project. It will spend the next three years working on development plans and expects the plant to start by 2018. GDF Suez will also be responsible for off-take of the LNG and its marketing.

Sunrise

Woodside has selected a FLNG project for the Greater Sunrise field rather than the alternative of piping the gas 500km to Darwin for processing at a new production train, to be built at the existing Darwin LNG plant operated by ConocoPhillips.

Ichthys

The Ichthys project, sponsored by Japan's Inpex, will produce 10.9 bcm (8 Mtpa) of LNG, 1.6 Mtpa of LPG, and 100 000 b/d of condensate. The facility will be located in Darwin, northern Australia, and feedgas will come from the Ichthys field in the Browse Basin via an 850 km subsea pipeline to Darwin, one of the longest undersea pipelines in the world. FID has been postponed from late 2008 to late 2011, although offshore FEED is expected to be completed in October 2010. Inpex started building its Naoetsu LNG terminal in Joetsu, Niigata, Japan, in July 2009, with a planned start-up in 2014, to provide an outlet for Ichthys LNG. However the project's starting date has been postponed to 2016.

Indonesia: Domestic Market Versus Exports

The second LNG exporter (based on liquefaction capacity) may not expand its liquefaction capacity further due to its rising domestic demand and there are proposals to stop exports from Arun by 2014 and Bontang by 2020. Three projects are nonetheless under consideration: Donggi-Senoro, Sengkang and Masela, which could potentially supply the geographically spread Indonesian market.

The relatively small size of Donggi-Senoro LNG project in Central Sulawesi, 2 mtpa, was designed to give some advantages to the sponsors in terms of marketing and finance – the operator Mitsubishi (51%), state Pertamina (29%), and the privately owned Indonesian company Medco Energi (20%). The three companies finalised a shareholders' agreement in December 2007 for the proposed LNG project and FID was expected to be taken in 2009 for a start in 2013. In January 2009, the liquefaction venture signed 15-year contracts with Pertamina and Medco Energi, partly owned by

Mitsubishi, for the feedgas gas supply to the plant, from Pertamina's wholly owned Matindok block and the Senoro area, which is jointly held by Pertamina and Medco. The blocks are estimated to have 68 bcm of gas. However a major obstacle appeared with discussion over the allocation of gas to the domestic market, so that the initial LNG sales agreements with Japanese buyers expired in August 2009 and the prospects of the project are now uncertain. Pertamina wants local companies interested in purchasing output from the Senoro and Matindok fields to make firm long-term commitments.

In February 2010, Japan's Inpex postponed awarding of a contract for FEED for its 3 mtpa Masela LNG to mid 2010. However, Inpex still plans to make a FID in 2011 and bring it online in 2016. Indonesia's upstream regulator BPMigas has approved Inpex's initial development plan for Abadi, located on the Masela production sharing contract 100 km south of the Tanimbar Islands. The company claims that it has found enough gas in the block's Abadi fields to support the liquefaction plant.

Uncertainty Continues in the Atlantic

After the Angola LNG and two projects in Algeria were sanctioned in 2007-08, no FIDs have been made for LNG liquefaction projects in the Atlantic region. Due to uncertainty over market developments, particularly the need for LNG with the huge increase in shale gas production in the United States, LNG project promoters in the Atlantic basin may have a few more tough years to establish integrated value chains that are absolutely necessary to finance LNG projects. On top of gloomy market perspectives, some projects suffer from technological challenges, or political instability which make FID difficult. Thus, in stark contrast to the Pacific, few, if any, FIDs seem likely in the Atlantic before 2012 at the earliest.

Shtokman and Yamal LNG, Russia

Russia is considering several Arctic LNG export projects destined for the Atlantic: Shtokman and Yamal LNG. Several options have been considered for Shtokman, either only pipeline, only LNG or a mix of both. As this LNG was designed to target primarily the now oversupplied North American gas market, perspectives look difficult. The FID on LNG production has been delayed by at least a year, from 2010 to end 2011 and the start-up of the project has been delayed by three years, with first LNG in 2017, 'acknowledging changes in the market situation and particularly in the LNG market.' The project may go ahead with the pipeline phase even if LNG production is delayed or rejected due to unsatisfactory market conditions. In the latter case, phase one of the project would be fulfilled in the form of supplies of pipeline gas and condensate.

The second project is the 15 mtpa Yamal LNG that Russian independent gas producer Novatek is considering building in the North of the Yamal Peninsula. It would have two trains of 7.5 mtpa each. Novatek and Gazprom (which owns 19.4% of Novatek) are planning to use the Tambei fields in the Yamal Peninsula. Indeed, Novatek expects production from the Yuzhno-Tambeiskoye gas field in the Yamal region to begin between 2015 and 2017. When Novatek bought a controlling 51% stake in Yuzhno-Tambeiskoye in May 2009, it signed an option to buy an additional 23.9% for $450 million within three years. The company has not decided when to use the option. Project promoters in Arctic Russia are eyeing Asia-Pacific LNG markets in the midst of uncertainty in the Atlantic markets. As Novatek plans to send a test LNG tanker from its fields on the Yamal Peninsula to Asia via the Northern Sea Route in July 2010, which will cut 4 000 nautical miles off the usual 11 000-mile journey through the Suez Canal. The success of this test could be a major boost to Yamal LNG, but it would still face strong competition from the Australian projects.

Nigeria

Several projects have been planned in Nigeria, a few for some time. The two most advanced, Nigeria LNG Train 7 (NLNG Seven Plus) and Brass LNG, have seen their FID slip. Other projects, including OK LNG whose FID was initially planned in 2006, are less advanced. Nigerian projects suffer from the instability and insecurity in the Niger Delta which has affected the output of existing plants. Furthermore, uncertainty regarding the Atlantic markets' outlook prevails, although most Nigerian projects are sponsored by portfolio players which could use this gas to take advantage of arbitrage opportunities. Finally, the Nigerian government announced in 2008 that international oil and gas companies working in the country would face suspension of LNG export projects if adequate gas is not supplied to the domestic market. Project sponsors do not question the legitimacy of domestic gas supply but highlight the need to meet these needs with gas exports in order to earn the necessary revenues to support the development of the infrastructure. Nigeria LNG called for the government to give equal priority to domestic and export-oriented projects in February 2010 and for a legal, fiscal and regulatory framework to attract investment in the domestic sector to satisfy both domestic demand and export demand.

In March 2009 the Nigerian government chose 15 companies as core investors for its Gas Master Plan (GMP), designed to develop the country's gas industry, in line with the government's estimates that domestic demand will grow from 12 bcm in 2007 to around 65 bcm in 2011. The immediate focus has been on three gas gathering and processing facilities. In October 2009, the Nigerian government selected seven consortiums to bid for three main gas gathering and processing hubs: in Warri-Forcados in the west, Obiafu in the central and Akwa Ibom-Calabar in the east. However, it emerged in March 2010 that bids for the GMP infrastructure projects were fewer and costlier than anticipated.

Nigeria LNG and Brass LNG, Nigeria

Both FIDs on Nigeria LNG Train 7 (NLNG Seven Plus) and Brass LNG have slipped from 2006 and 2008 and no timeline is in sight for the moment. Partners still hope that these projects will make FID during 2010, but this looks unlikely given the current market uncertainty and instability in Nigeria.

Prospects for NLNG Seven Plus improved when a new inlet gas price for the entire NLNG complex was agreed with state Nigerian National Petroleum Corporation (NNPC) in April 2009. A super mega-train of 8 mtpa (10.9 bcm) – even larger than the Qatari 'mega-trains' – is envisaged for this project. Offtakers would include global portfolio players including BG, Shell, Total and Eni. The partners of NLNG include NNPC (49%), Shell (25.6%), Total (15%) and Eni (10.4%). Securing enough feedstock gas remains a major hurdle for the project, especially in the midst of repeated feedgas supply disruptions to the existing trains.

The Brass LNG project in the Niger Delta state of Bayelsa has also secured marketing agreements with global portfolio players including BG, GDF Suez, BP, ConocoPhillips, and Eni for more than four years and partners are eager to start the project as soon as possible. Total replaced Chevron in 2006 in the project, which plans to have capacity of 10 mtpa (13.6 bcm) from two trains. The project is owned by NNPC (49%), ConocoPhillips (17%), Eni (17%) and Total (17%). Bechtel was awarded the FEED contract in November 2004 and the construction contract in June 2007. One of the major obstacles to the project is the instability in the Niger Delta.

Other Projects in Nigeria

While project officials claim that Olokola LNG (OK LNG) has sufficient gas reserves to bring it on stream in 2014, it is unlikely that OK LNG would come online by that time, in particular due to administrative and cost-related delays. Flex LNG, Mitsubishi and Peak Petroleum Industries Limited of Nigeria agreed in June 2008 to construct the 1.5 mtpa (2 bcm) floating liquefaction plant with an expected starting date of 2011 and Mitsubishi as the sole offtaker. Despite the approval of the Nigerian Department of Petroleum Resources (DPR), the industry regulator, the FID was postponed late 2008. Centrica, StatoilHydro and Greece's infrastructure company Consolidated Contractors (CCC) signed a MOU in 2007 to conduct a feasibility study for an LNG project on Tom Schott Island. Construction is targeted to begin in 2010, with production starting in 2013, which looks unrealistic. Addax Petroleum, Chrome Oil Services and Kogas were planning a 10 mtpa (13.6 bcm) LNG project in Bayelsa state to come onstream in 2013, which also looks unlikely. The project also includes a much needed power generation plant and supply to local petrochemical facilities.

Equatorial Guinea

With the successful operation of the first LNG project (EGLNG) since 2007, Equatorial Guinea hopes to establish itself as a hub for the aggregation of gas in the area to export as LNG. In January 2009, an MOU was signed between the national gas company Sociedad Nacional de Gas de Guinea Ecuatorial (Sonagas), E.ON Ruhrgas, Union Fenósa Gas and Galp Energia for the creation of a company that will act as the owner of a gas gathering system which will utilise gas that is currently being flared. In July 2009, Gasol and Sonagas formed a joint venture to develop associated gas from the Zafiro offshore oil field. Equatorial Guinea initially thought of piping gas from neighbouring Nigeria or Cameroon, which now looks unlikely. However, the country recently upgraded its reserves to 127 bcm, which would be enough to support a 3 mtpa train by 2016.

Cameroon

GDF Suez changed plans to develop its Cameroon liquefaction project from offshore to onshore after lining up enough reserves to support a larger onshore plant. More feedstock available than first expected swings the economics in favour of a traditional plant of at least 3 mtpa (4.1 bcm). Pre-FEED for the new plant is expected to start in 2010. In 2008, GDF Suez conducted a feasibility study under its strategic partnership with Société Nationale des Hydrocarbures (SNH) into the use of gas as feedstock for LNG. This work focused on the south-western Kribi and southern Limbe coastal areas.

Venezuela

Three LNG trains are planned in Venezuela, but all have been on the cards for years and still look uncertain due to lack of progress on the upstream side and increasing domestic demand. Petroleos de Venezuela (PdVSA) will retain a 60% interest in each of the three trains, but each will have a different shareholding. The first two 4.7 mtpa trains are scheduled to be operational by 2014, though little progress has been made since the plan was announced in 2008. Different holding structures of the three trains, combined with the separate different project structures of the upstream elements, complicate the negotiations further in this difficult country.

Output from Deltana Block 2 is earmarked for the first of Venezuela's three planned LNG trains. PdVSA has paid an undisclosed sum for ConocoPhillips' stake in the Deltana Platform gas project offshore Venezuela. PdVSA now holds a 61% stake in Block 2 of the project, estimated to contain 7 tcf (198 bcm) of gas reserves, while Chevron owns the remaining 39%. It is expected to produce about 7-8 bcm per year. PdVSA will hold a 60% stake in the first train with Portugal's Galp Energia (15%), Chevron (10%), Qatar Petroleum (10%) and Mitsubishi (5%).

The second train, to be supplied by the Mariscal Sucre field, includes Galp (15%), Argentina's Enarsa (10%), Japan's Itochu (10%), Mitsubishi (5%) and Mitsui (5%). PdVSA announced in July 2009 that 11 companies were pre-selected as potential minority partners in the Mariscal Sucre natural gas offshore exploration-and-production project. The finalists are Japanese Marubeni, Mitsui, Mitsubishi and Itochu; Algeria's Sonatrach; Kogas; Malaysia's Petronas; Norway's Statoil; Portugal's Galp Energia; Russia's Gazprom and Italy's Eni. The four offshore deposits to be developed are Dragón, Patao, Mejillones and Rio Caribe, located north of the Paria Peninsula, offshore Eastern Venezuela's Sucre state.

The third train includes Gazprom (15%) and Petronas (10%), Eni (10%) and Portugal's EDP (6%) and will be supplied by the Blanquilla and Tortuga offshore blocks north of Margarita Island. The project partners will each hold an interest in the upstream element of the project.

Iran and Iraq Are Yet to Emerge in the Middle East

Iran

Among the three major LNG projects based on the South Pars gas reserves, only Iran LNG claims some progress. The initial phase of the project is to produce 5 mtpa (6.8 bcm) of LNG from gas produced at Phase 12 of the South Pars field. Some 2 000 people are working at the site at Bandar Tombak, north-west of Bandar Assaluyeh on the Persian Gulf coast and the project is claimed to be 24% complete. While marine facilities and foundations for LNG storage tanks are under construction for Iran LNG, none of the core liquefaction facilities are being built. As most technology for large-scale LNG projects is not available for Iran because of the economic sanctions, it is unlikely that any LNG will be exported from Iran in the near future.

In the meantime, the Pars LNG project received a fresh boost in February 2010 as CNPC finalised appraisal drilling plans at Phase 11 of the South Pars gas field. The project used to be part of an integrated LNG project by a Total-Petronas partnership until 2009.

Iran also has a proposed project to export gas from Kish island to Oman for liquefaction at the latter's under-utilised Qalhat LNG plant. The project is cited as one of four regional gas export schemes that Tehran would like to see implemented. However, as is often the case for any regional gas export plans, gas pricing has been a difficult issue for the project and no mutually acceptable solution has emerged yet. The deal with Oman would involve construction of a pipeline from the Kish gas field located 200 km off the Omani coast. Oman held talks with Iran for nearly two years over possible supplies of gas but in 2009 declared it was temporarily shelving the scheme because of changed economic circumstances.

Iraq

Although Iraq hardly produces any marketable gas, it has the potential to become a major producer. Out of the current production of more than 10 bcm/y, mostly associated with oil, barely about 1 bcm is marketed with the rest flared in the Basra region or vented because of a lack of infrastructure to process and transport the gas to market. Most of the country's proven reserves of gas, which total 3.2 tcm, are located in the main oilfields – the Kirkuk and Bai Hassan fields in the north and the Rumaila and Zubair fields in the south. The only non-associated gas production comes from the Anfal field, which supplies about half of all the gas consumed in Iraq. Commercial gas production could be expanded considerably if flaring was reduced: Shell has already invested in gas installations in southern Iraq, contributing to a reduction in flaring.

Shell's plan to develop associated gas in southern Iraq through the planned joint venture Basra Gas Company (BGC) (Mitsubishi (5%); state South Gas Company (51%); and Shell (44%)) may include an LNG export component. But progress has been slow, partly due to political developments. The project scope includes gas from the Rumaila, West Qurnah-1 and Zubair fields which were awarded in the first oil licensing round in 2009. The deadline to sign a development agreement has been extended to September 2010 from the original plan of September 2009. Funding may be a problem for the estimated $8-10 billion project.

In addition to coping with its unused associated gas, the Iraqi Government is also looking ahead to investment in major non-associated gas fields. A fresh licensing round was opened in early May for three gas fields with total reserves of just over 6 tcf and prospective production capacity of about 800 mcf/day. Some of this also may in due course be available for export. But until at least the middle of the decade priority is most likely to be given to using any available volumes of gas for power generation and industry where Iraq needs to reconstitute virtually its entire domestic infrastructure.

North American LNG Exports?

While LNG has been exported from Alaska to Japan since 1969 and a few cargoes have been re-exported from the Gulf of Mexico LNG receiving terminals to global markets, due to the ripple effects of rising domestic gas production, gas producers in Alaska and Western Canada may eventually need alternative markets in the Pacific, or may need more flexibility in choosing markets by having LNG shipping capabilities. There have been suggestions that LNG export plants could be built in the United States (lower 48). This would require marketers sourcing gas close to HH-based prices (depending on the location of the terminal) to find premium buyers to market their gas while using the United States as a residual market. In June 2010, Cheniere announced it would add liquefaction technology to its Sabine Pass terminal to export from shale gas by 2015.

While Canada started importing LNG in 2009 on its eastern coast, the country may become the fourth LNG exporting country among the OECD members, following the United States, Australia and Norway. Kitimat LNG is planning a 5 mtpa onshore LNG export plant in British Columbia on the Pacific Coast. Ironically, the project was once an import project but market conditions have reversed these plans. While the project has received all necessary federal and provincial permits for its proposed Pacific Trail pipeline to ship gas to the liquefaction plant from producing areas in British Columbia, Canada's National Energy Board (NEB) has yet to receive an application from Kitimat seeking permission to export LNG. The project has secured initial offtake agreements based on MoUs with Kogas and Gas Natural (GN), as well as a non-binding feedgas supply agreement from EOG Resources Canada (1-2 bcm) and Apache (2-3 bcm). In February 2010, Kogas struck a joint-venture deal with Canadian gas producer EnCana to develop Montney tight gas and Horn River shale gas, from where it hopes to produce 1.4 bcm/y over 40 years, starting in 2017. In January 2010, Apache bought a 51% stake of the project.

INVESTMENTS IN PIPELINES AND REGASIFICATION TERMINALS

Summary

- **Among all parts of the gas value chain, the transport between regions or within a given region is probably the one most affected by the global oversupply now and in the medium term.** How pipelines and regasification terminals will be used will not only depend on the regional supply/demand balance dynamics but also on the competition between these different delivery modes.

- **Across regions, LNG regasification terminals seem to be making more progress than pipelines.** In 2009, regasification capacity increased by 90 bcm. Meanwhile the only significant new inter-regional pipeline was the first part of the Turkmenistan-China pipeline, which started operating in late December. This pipeline nevertheless marks a fundamental change in the role of Central Asia in supplying surrounding regions.

- **Although some regions such as the Middle East, Latin America, and Southeast Asia remain net exporters, they are turning to LNG imports, sometimes to mitigate the failure of regional pipelines or to meet seasonal needs**. Middle East and Latin America are looking at floating regasification and storage units (FRSU) and LNG regasification vessels (LNGRV), which are quicker to build.

- **Looking ahead, regasification terminals are expanding faster than pipelines – when projects move ahead**. Capacity will increase by at least 20% by 2013, conserving the excess of regasification capacity compared to liquefaction. Meanwhile, only one major new pipeline project advances – the much-awaited Nord Stream pipeline between Russia and Germany, now under construction.

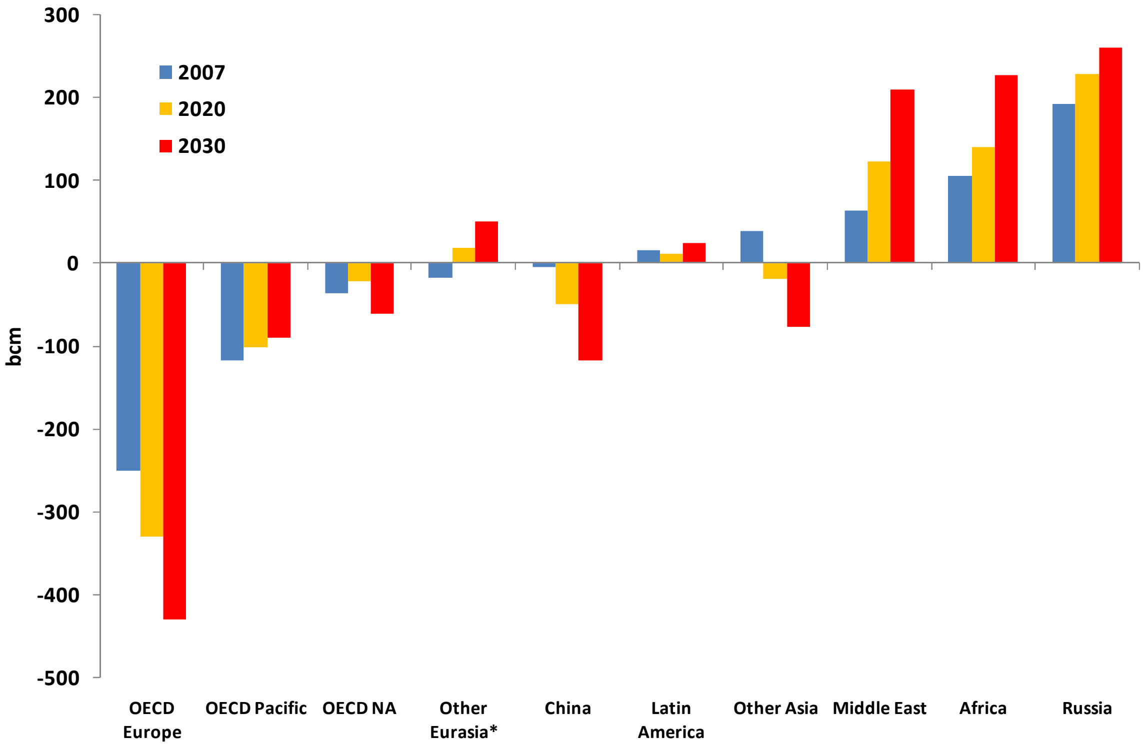
Global Trends

There is great uncertainty on when, how much and where new inter-regional transport infrastructure will be needed to face increasing import requirements. The evolution of regions' import dependency over 2007-30, based on the latest *WEO-2009* forecasts, shows that the import dependency of Europe, North America, China and other Asian countries will increase – quite dramatically in OECD Europe. But again, two uncertainties persist: the first regarding gas demand evolution, which again depends on economic recovery and growth, plus the evolution of the power sector, and on domestic production including how unconventional gas might change regional supply pictures. Suppliers therefore hesitate between LNG and pipeline options, sometimes choosing both. Meanwhile markets are now increasingly competing for the same upstream resources, be it LNG or pipeline gas.

What will make the difference between the pipeline and the regasification terminal option? This will depend on many factors: flexibility and absence of transit countries will play in favour of the regasification terminal; the difficulty of diverting gas away from the pipeline compared to many diversion possibilities for LNG will favour pipelines. It also depends on how the project is integrated in the value chain: combined with a specific field/producing region or not, and on who the players sponsoring the project are. Beyond the market needs and the development of the upstream resources, several development models exist. While finance is the key aspect, the main differences between these development models are as follows:

- Infrastructure sponsors: number of sponsors, characteristics including size, ownership, financing capacity, presence of producers or buyers,
- Ownership of the gas and production capacity,
- Sale structure: underpinned by the buyer's sales, market liquidity, and the presence or absence of long-term contracts.

Evolution of Import Dependency by Region



Source: IEA, *WEO-2009*.

There are three main structures for pipelines: firstly those underpinned by long-term contracts that would help raise debt finance (like Nord Stream), secondly financed by buyers up-front like the Turkmenistan-China pipeline, or thirdly virtual pipelines where shippers raise finance on their own balance sheets to buy 'virtual shares of the pipeline'. This later option can be taken in deep and liquid markets which enable shippers to manage their volume risk with contracts with big commercial or distribution buyers. The European or Latin American markets do not have such liquidity (none at all for Latin America) and require some long-term contracts. Meanwhile, the Chinese companies are certainly underpinned to some extent by booming domestic energy demand and therefore much lower volume uncertainty.

The era for LNG supplies dedicated to one market/terminal is reaching its end, replaced by an era with a mixture of relatively inflexible LNG (in particular in OECD Pacific due to high dependency on LNG imports) and flexible LNG destined for liquid markets or held by aggregators. Regasification terminals are different from pipelines as there is no one-to-one relation with the source of supply, but rather a multiple-to-one relation – global regasification capacity is more than twice the liquefaction capacity, a ratio expected to continue. Their flexibility is their main advantage but could also prove a drawback as illustrated by the 10% utilisation rate of the US terminals in 2009. Financing, or even the construction of regasification terminals, depends on how sponsors are integrated in the LNG value chain and how they plan to utilise this capacity.

The first case is the historical one of an LNG terminal built by the buyer and underpinned by a long-term contract and by the buyer's demand. That would be the case of LNG terminals in emerging markets such as China, but also in Japan or Europe (Rovigo), or even some of the seasonal terminals in Latin America and Middle East. The buyer can have a share in the liquefaction project to help it move forward (Japanese buyers in Gorgon). The second case would be the terminal built by an aggregator (such as ExxonMobil, Shell, Total, BP, BG, GDF Suez, Repsol or Gas Natural) to take advantage of arbitrage opportunities – ideally such terminals would be in different regions. So far they are essentially spread between Europe, the United States and India. Such terminals would be built typically in the most liquid markets; however those cannot absorb unlimited volumes. The last case is a company – usually the unbundled TSO – building a terminal and funding it, underpinned by long-term binding agreements with users: GATE in the Netherlands or Isle of Grain are examples of such terminals.

Regulation on tariffs and access will be key to decide between these options or even the threshold decision whether to build a terminal. Some LNG terminals in the United Kingdom would not have seen daylight without third parties access (TPA) exemptions while Rovigo and Fos-Cavaou had to give a share to third parties. In mature markets (except Japan), the trend is towards the second or third option, while emerging markets tend to favour the first.

An interesting development is that of floating regasification and storage units (FRSU) and LNG regasification vessels (LNGRV). There could be more than a dozen terminals using either of both options throughout Southeast Asia, the Middle East, South America, the Caribbean and the Mediterranean by the middle of this decade, particularly encouraged by recent successes of those applications in South America: they have short lead times, relatively low cost and flexibility. FSRUs are typically chartered on a long-term basis while LNGRVs are often used to meet seasonal demand peaks.

Global regasification capacity reached 772 bcm as of June 2010. This represents 2.5 times the liquefaction capacity. The highest capacity increase in 2009 was observed, ironically, in North America, where the regasification capacity increased to 165 bcm, despite low utilisation rates. Capacity also increased by around 25 bcm in Asia, not only in China but also in mature markets such as Korea and Japan, and in Europe. Latin America doubled its regasification capacity although it remains very small at a global scale (2%), while Middle East entered the group of LNG importing countries. World regasification capacity is expected to increase by another 20% (154 bcm) over 2010-14 (16 bcm already started in the first half of 2010), with the terminals under construction spread as follows: 42% in Asia, 32% in North America and 23% in Europe and the remaining 4% in Middle East and Latin America. It is likely that the upcoming terminals in North America will remain underutilised. The Appendices in *Part 3: Gas Supplement* give details on regasification capacity existing, under construction and planned by country.

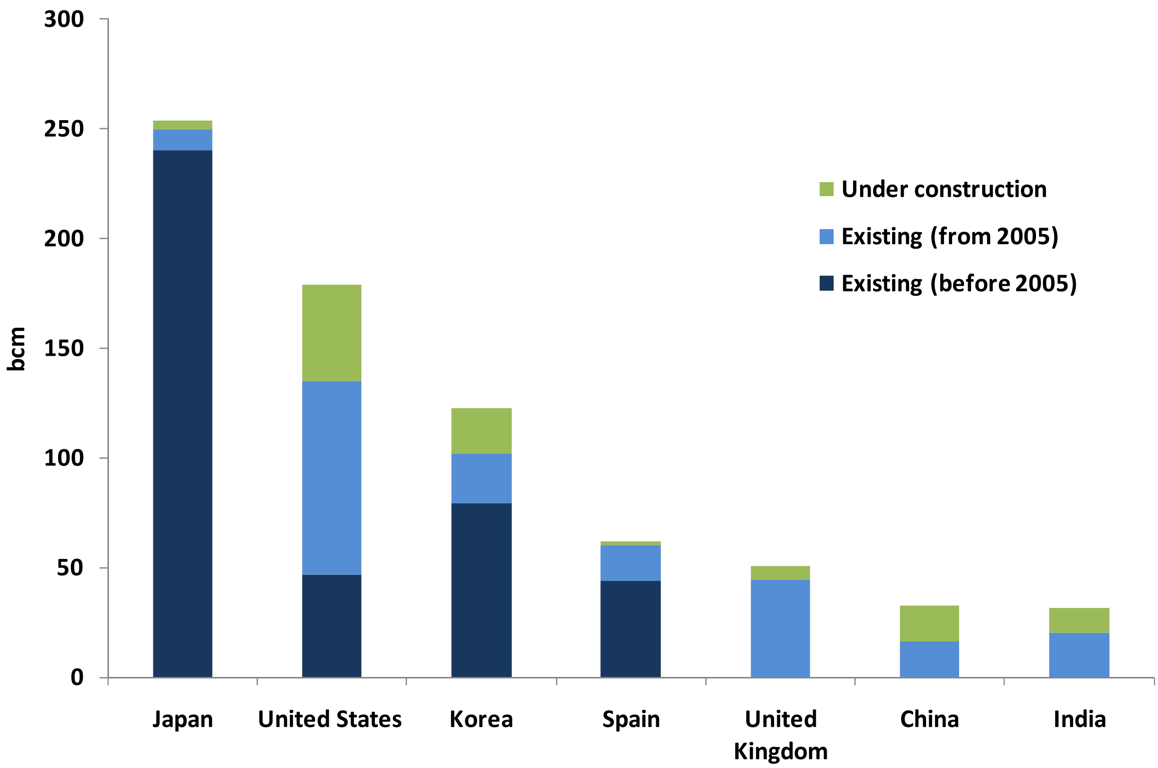
By 2013, Japan, Korea and the United States will hold over 60% of total regasification capacity. Spain and the United Kingdom will hold the fourth and fifth position with 62 bcm and 51 bcm respectively followed by China and India at 33 bcm. But the utilisation rate will vary greatly depending on the region. The graphic below shows how the regasification capacity has evolved and will evolve over the coming years. Before 2005, both Japan and Korea dominated the LNG import picture, while the United States and Spain had around 45 bcm of LNG import capacity each. The picture drastically changed in the last five years with the United States moving very quickly to become the second holder of LNG import capacity, in anticipation of large scale demand for LNG imports yet to appear, while new LNG importing countries appeared.

LNG Regasification Terminals by Region (as of June 2010)

Region	Operation	Construction	Planned
Asia	418	59	131
Europe	173	24	244
Middle East-Africa	3	4	11
North America	165	49	282
Latin America	14	2	8
Grand Total	**772**	**137**	**674**

Source: IEA.

Top Seven Holders of LNG Regasification Capacity



Source: IEA.

Pipeline Projects by Region

Source	Name	Start	Capacity (bcm)	Length (km)	Sponsors	Estimated cost (bn)
Europe						
Russia	**Nord Stream 1**	End 2011	27.5	1,200	Gazprom 51%, BASF, E.ON 20% each, Gasunie, GDF Suez 9% each (tbc)	7.4 (€)
	Nord Stream 2	End 2012	27.5	1,200		
	South Stream	2015	63	3,192	Gazprom, Eni 40% each, EDF 20% (tbc)	19-24 (€)
Caspian/ Middle East	Nabucco	2014	25.5-31	3,296	Botas, Bulgargaz, MOL, Transgaz, OMV, RWE	7.9 (€)
	IGI	2015	8+	800	Depa/Edison	0.95 (€)
	TAP	n.a.	10 (20)	520	EGL/Statoil 42.5% each, E.ON 15%	1.5 (€)
Algeria	Galsi	2014-15	8	1,470	Sonatrach 41.6%, Edison 20.8%, Enel 15.6%, Sfirs 11.6%, Hera: 10.4%	2 (€)
North America						
Alaska	Alaska Pipeline (option 1)	n.a.	46	2,720	TransCanada, ExxonMobil	32-41 ($)
	(option 2)		31	1,280		19-24 ($)
	Denali	2020	47	2,800-3,200	BP/ConocoPhilips	35 ($)
Latin America						
Bolivia	GNEA	n.a.	10.1	1,461	Enarsa	1.8 ($)
Bolivia	Urupabol	n.a.	n.a.	n.a.	n.a.	3 ($)
Middle East- Africa						
East Mediterranean	**Syria-Turkey (Arab Gas Pipeline Extension)**	2011	10	248	Syrian Gas Company/ BOTAS	0.2 ($)
Iraq	Iraq-Syria	2015+	n.a.	120	Syrian Gas Company/NOC	n.a.
Caspian	Turkmenistan-Iran	2010-11	6 (12)	n.a.	Turkmengaz/NIGC	n.a.
Nigeria	Trans Sahara Gas Pipeline	2015+	30	4,128	Gazprom, Total interested	12 ($)

Pipeline Projects by Region (continued)

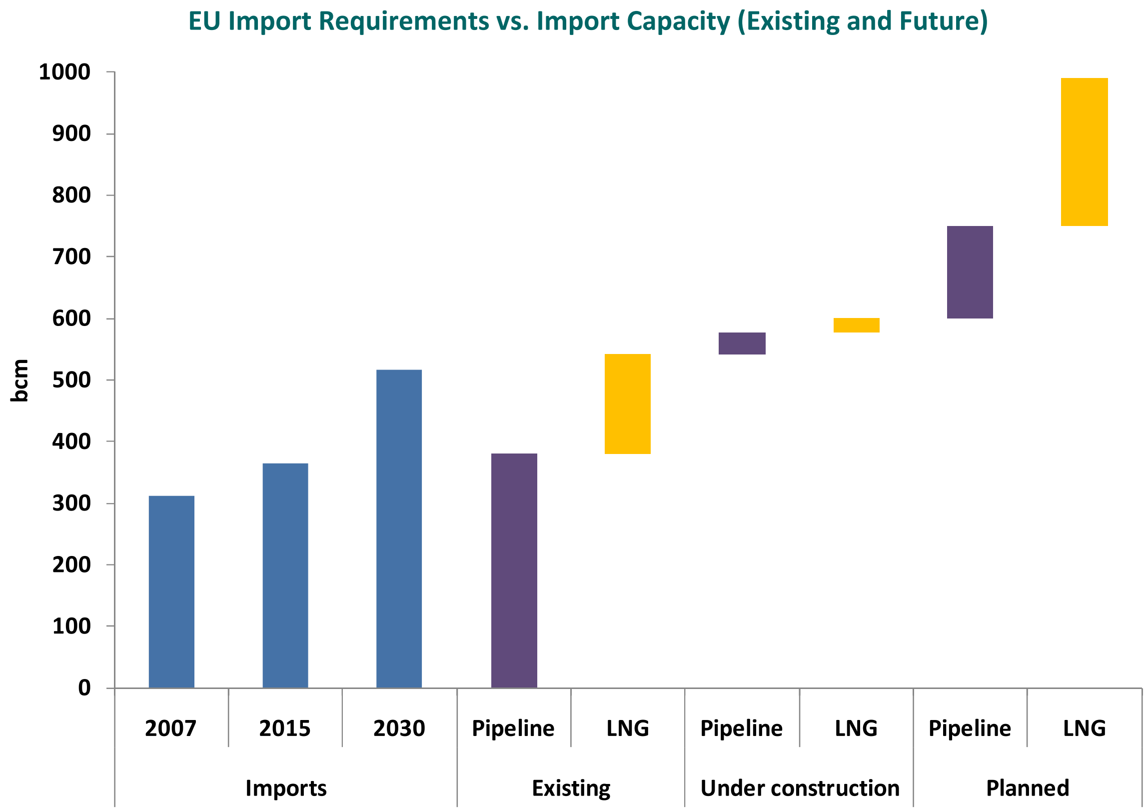
Asia						
Caspian	**Turkmenistan-China**	End 2009	10	7,000	CNPC, China Development Bank	15 ($)
		2012	40			
	TAPI	2015+	30	1,680	ADB, other investors tbd	7.6 ($)
Myanmar	**Myanmar-China**	2012	12	793	CNPC	n.a.
Iran	Iran-Pakistan (India)	2015+	7.5 (22)	900 (2,700)	Inter-State Gas Systems, NIOC	7.5 ($)
Southeast Asia						
Indonesia	East Natuna–Thailand	2015+	n.a.	1,500	Sponsors tbd	7 ($)
Indonesia	East Natuna-Malaysia	2015+	n.a.	600		
Indonesia	East Natuna-Java	2015+	n.a.	1,400		
Indonesia	East Natuna - Vietnam	2015+	n.a.	900		
Indonesia	East Natuna – Brunei-Sabah-Palawan	2015+	n.a.	1,340		

Note: Pipelines in bold and grey shading are under construction.
Source: IEA, press releases, companies' websites.

Europe

Europe is definitely the region which has been attracting most import projects, both pipelines and LNG import terminals. Over the past year, four LNG terminals started in Europe, but no new pipeline entered service as Medgaz was further delayed to mid 2010 due to the current oversupply in the Iberian market. No FID was taken regarding new LNG regasification terminals, while the construction of the first part of the Nord Stream pipeline between Russia and Germany started in April 2010. The race between pipelines and LNG terminals to supply the uncertain gap between future European demand and declining domestic production in Europe continues.

There is already 173 bcm of LNG terminal capacity and 406 bcm of pipeline capacity (including those from Norway), while 35.5 bcm of pipeline and 24 bcm of LNG are under construction. Moreover, planned capacity amounts to around 150 bcm for pipelines and 240 bcm of LNG regasification terminals. While Europe is already the biggest importing region, it is expected to see the gap between demand and domestic production continuing to increase. Even if demand increases modestly between now and 2015, domestic production will decline, especially in the United Kingdom, and therefore imports will increase as well. Net imports are expected to increase by 178 bcm for OECD Europe between 2007 and 2030 reaching 428 bcm. Meanwhile, they would increase by 204 bcm for the European Union from 312 bcm in 2007 to 425 bcm in 2020 and 516 bcm in 2030.



Source: IEA.

One Pipeline Advances

Nord Stream Pipeline

One of the most awaited events of 2010 was the start of the construction of the Nord Stream pipeline linking Vyborg in Russia to Greifswald in Germany, which took place in April 2010. Project shareholders are currently Gazprom (51%), E.ON Ruhrgas and Wintershall holding (20% each) and Gasunie (9%). However, GDF Suez and Gazprom signed a memorandum to give a 9% share to GDF Suez. Both E.ON Rurhgas and Wintershall would give 4.5% to GDF Suez, while Gazprom retains the majority. Over 2009, Nord Stream secured all the permits from the five countries whose territorial waters and/or Exclusive Economic Zones (EEZs) are crossed – Russia, Finland, Sweden, Germany and Denmark – which was quite a lengthy process. The pipeline will ultimately consist of two strings of 27.5 bcm each, but only the first one is currently under construction and expected to come onstream by winter 2011/12. The FID on the second string has not been taken yet but the pipeline would be commissioned as soon as end 2012.

Costs have increased substantially to reach €7.4 billion. The pipeline is financed through a 70/30 debt/equity ratio. In March 2010, Nord Stream finalised the agreements with 26 banks for a €3.9 billion loan for the first string. The company needs to raise an additional €2.5 billion for the second line. There are many questions whether the second line is necessary in the current context of oversupply. So far 22 bcm have been contracted, almost all on the first stream: Wingas (9 bcm/y), E.ON Ruhrgas (4 bcm/y), GDF Suez (2.5 bcm/y to be increased to 4 bcm/y after 2015), Gazprom Marketing & Trading (4 bcm/y), DONG Energy (1 bcm/y first with an option for another 1 bcm/y subject to the completion of the second string).

It remains to be seen how this pipeline will affect the flows though Ukraine and Belarus and therefore through Slovakia, the Czech Republic and Poland. If demand does not recover, especially in the Northwest European market, it is likely that gas flows will be displaced from the existing pipelines to Nord Stream, affecting the revenues of TSOs such as Eustream and RWE Transgas. The new interconnections, OPAL to the Czech-German border and the planned Gazelle pipeline through the Czech Republic, would allow part of the gas previously flowing to Waidhaus to take that route.

Galsi Pipeline

Originally planned to start in 2008, the Galsi pipeline linking Algeria to Italy through Sardinia got the go-ahead at the signing of an inter-governmental agreement by Rome and Algiers at the end of 2007. Since then, the FID has been continuously postponed although it is still planned for 30 June 2010, implying a later start in 2014. Galsi would be owned by Sonatrach (41.6%), Edison (20.8%), Enel (15.6%) and Hera Trading (10.4%), the rest being held by the Sardinian authorities. There were suggestions made by French President Sarkozy early in 2010 about linking the pipeline to Corsica, which does not have any gas supply and hence uses oil products in many stationary energy uses. It has to be seen whether this announcement during the regional election campaign will be translated into agreements and contracts and what impact it would have on the pipeline route and shareholding. This could further delay the FID. Finally, Algeria will put on stream 13.5 bcm of liquefaction capacity and the 8 bcm Medgaz pipeline while its domestic demand continues to increase. Hence, the success of Galsi also depends on upstream developments and transport infrastructure in Algeria as well as on the progress in any of the other supply projects (LNG terminals, Interconnector Greece-Italy, Trans-Adriatic-Pipeline) competing to supply Italy.

Nabucco

There has been some progress over 2009 in clarifying the regulatory framework for the operation of the Nabucco pipeline, with the signing of the inter-governmental agreement in July 2009 between the five countries crossed – Turkey, Bulgaria, Romania, Hungary and Austria. There was also a commitment of €200 million funding for this project from the European Union as part of the stimulus plan announced in April 2009. However, the project has not found any solution yet to its main challenge: securing gas supplies. Possible supply sources remain unchanged: Azerbaijan, Iran, Turkmenistan, Kazakhstan, Iraq, Egypt or Russia. While Azerbaijan has long been expected to be the first and main source of gas, Iraq and Turkmenistan have emerged recently as other main sources expected for the initial phases of pipeline operation, but there are doubts on whether and when gas supplies from these three countries will be available.

The second phase of Shah Deniz was expected to provide first gas supplies in the short term, but this has been postponed to 2016 because of uncertainty over the marketing arrangements. Some of this uncertainty has now been removed because of the Nabucco Inter-Governmental Agreement and the memoranda signed in June 2010 between Azerbaijan and Turkey on pricing of existing gas deliveries under Shah Deniz Phase I – and pricing and transit terms for Phase II. These developments help to clear the way for specific commercial negotiations on marketing gas from Shah Deniz Phase II, but the fact remains that Nabucco still faces some serious competition from other importers and pipeline projects for this gas. Azerbaijan's strategic priority is to sell gas on European markets, but Azerbaijan also has an interest in diversified sales to neighbouring markets. Georgia, and particularly Turkey, will look for supplies from Azerbaijan to their domestic markets; likewise, both Iran and Russia are interested in Azeri supplies and Gazprom has already agreed to buy volumes from SOCAR (although not from the Shah Deniz field) over the next years for supply to the Russian North Caucasus. Aside from pipeline options through Turkey, Azerbaijan has also been investigating options for trans-Black Sea transportation, including agreements with Bulgaria to look at CNG shipments and with Romania to look at LNG. Furthermore, there is tough competition between several other pipelines to get this gas including the Italy-Greece-Interconnector and the Trans-Adriatic-Pipeline. Given likely commitments to the Azerbaijan domestic market and transit markets in Georgia and Turkey, a reasonable assumption is that Shah Deniz Phase II could plausibly supply around 8-12 bcm/y for Nabucco if this route becomes the preferred choice for export.

Iraq is a potential supplier either from the Kurdish region or from the South via Syria and the Arab Gas Pipeline, and has indicated a political willingness to commit gas exports to the Nabucco pipeline. The resources are undoubtedly sufficient to support an increase in production and export, but the question is over timing. Given the current instability of the region, and disagreements between the central administration and the Kurdistan Regional Government (KRG) regarding control over oil and gas developments, it seems unlikely that significant volumes of Iraqi gas will be available for export before the end of the decade. Although significant quantities of associated gas are likely to arise from the increase in oil production in the South of Iraq which is currently planned, much if not all of this gas in the initial period will be required for reinjection or for domestic electricity generation. However, Iraq has also included the Akkas gas field in western Iraq in its third licensing round to be decided later this year. If satisfactory development terms can be agreed, Akkas might reach production of about 3.6 bcm/y well before the end of the decade, and given its location close to the Syrian domestic pipeline network, this gas might sensibly be earmarked for export.

Supplies from Turkmenistan are still widely discussed, not least since RWE Dea was awarded an offshore exploration licence (Block 23) located in the Caspian Sea in 2009. Offshore associated gas appears the most likely early option for Nabucco, particularly from the Petronas field (Block 1). However, there are a number of difficulties that still need to be resolved before Turkmenistan gas can flow along a southern corridor. The main one is the lack of export infrastructure: Turkmenistan insists on selling gas at its border and anything beyond has to be taken care of by buyers. This implies either the construction of a Trans-Caspian or at least a mid-Caspian pipeline (on which there are different views as to political feasibility), or the technically unproven option of CNG transportation, or a politically difficult pipeline or swap arrangement through Iran.

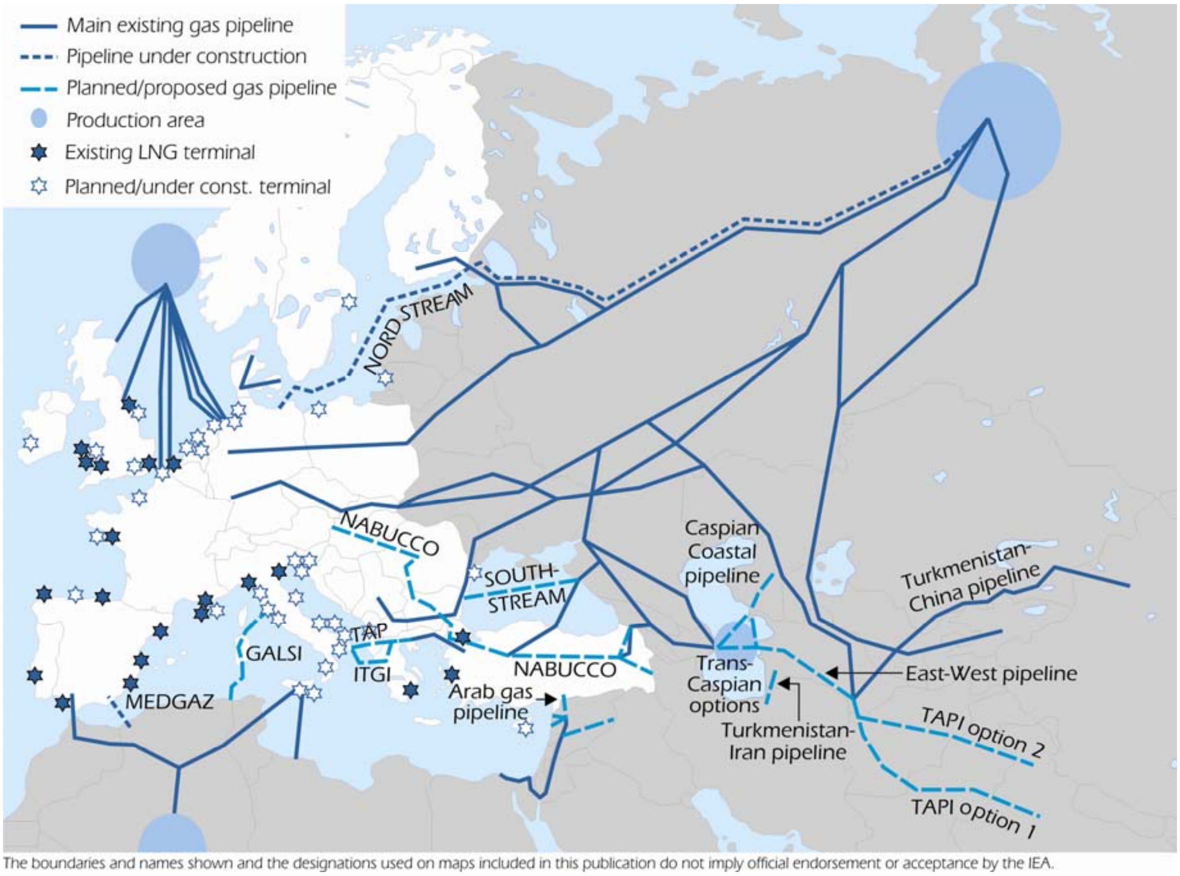
The Nabucco consortium (RWE, OMV, BOTAS, MOL, Transgaz, and Bulgargaz) is anticipating FID but it is hard to see this happening without firm gas supplies. Nevertheless, late April 2010, the consortium launched an initial tender for the long lead time items with the real tender expected in July 2010. These items, notably the pipelines, will represent most of the cost as the investments to increase the pipeline capacity from the initial capacity of 8 bcm to 31 bcm are understood to represent a relatively small part of the total. If Azeri gas comes first, Azerbaijan may be reluctant to have to support most of the pipeline cost for future suppliers.

South Stream

Despite the current uncertainties on European gas market's needs and the financial crisis, the size of the planned South Stream pipeline has expanded from an initially announced capacity of 31 bcm to 63 bcm. Several inter-governmental agreements have been signed with different European countries – Bulgaria, Serbia, Greece and Hungary in 2008, Slovenia in 2009 and Austria in 2010. The pipeline consists of three main parts: the offshore part to Bulgaria which would cost over €4 billion, and two subsections amounting to €15-20 billion. Several options exist for both the offshore and the onshore sections. The onshore pipeline would cross Bulgaria East-West and then divide into the two parts at

Pleven, one going to Greece (Thessaloniki) and then to southern Italy (Oranto and Brindisi) and the other to Serbia (Belgrade), Hungary, splitting to serve Austria and Slovenia. In December 2009, Gazprom and Eni Gazprom signed a MOU fixing their support to EDF's participation in the project. EDF has now agreed to take 20% of the pipeline, with the formal agreement to be signed in June 2010. EDF would take either 20% from Eni or 10% from Gazprom and Eni, putting Gazprom's share at 40%, which would be the first time Gazprom has agreed to take a minority stake in such a major new infrastructure project. Unlike Nord Stream, no long-term contract has been signed yet, which raises the question on how the pipeline will be financed. The question on how much offtake each company is planning to take is also not settled.

European Import Infrastructure



Source: IEA.

Interconnector Greece Italy (IGI)

The Interconnector Turkey-Greece-Italy also competes for Caspian gas. The first part, the Turkey-Greece-Interconnector was completed in 2007 enabling gas to flow from Turkey to Greece; but the second part from Greece to Italy (IGI), also called the Poseidon project, is still awaiting FID, which is expected by end 2010 or early 2011. The IGI will be built by Poseidon, a JV between Depa and Edison and will have a minimum capacity of 8 bcm (6.4 bcm for Edison and 1.6 bcm for Depa). It is expected to be operational by 2015, although it was originally planned for 2012; the last authorisations and detail engineering are expected to be completed by the end of 2010.

In July 2009, the IGI has been included in the list of projects eligible to get funds under the EC stimulus plan and has been awarded a €100 million grant. In November 2009, the Preliminary Environmental Assessment Study for the Greek section was submitted to the Greek Ministry for the Environment, Energy and Climate Change. Furthermore an MOU between Bulgarian Energy Holding (BEH), Depa and Edison was signed in July 2009 to build an additional link – the Interconnector-Greece-Bulgaria (IGB). It will be a 160 km link of 3 to 5 bcm between Komotini and Stara Zagora in the central part of southern Bulgaria. The IGB, expected to cost €120 million (with a €45 million grant to be provided by the EU), will have a capacity of 3-5 bcm and will provide valuable diversity to the Bulgarian gas market. It is expected to start operating by 2013. Further interconnections between Bulgaria and Romania as well as Serbia are also foreseen and expected by 2013.

Trans Adriatic Pipeline (TAP)

Originally backed by Swiss EGL, the project got a boost when Statoil decided to join; both companies created a 50/50 joint-venture in February 2008. In May 2010, E.ON decided to take a 15% equity in the project, leaving both Statoil and EGL with 42.5% each. EGL provides a market for the gas due to its power plants in Italy where E.ON also sells gas, while Statoil is a partner in Azeri upstream projects (notably Shah Deniz). The 520 km pipeline will link Thessaloniki in Greece to Brindisi in Italy through Albania and have a capacity of 10 bcm. EGL signed a contract with Iran’s NIGEC for 5.5 bcm starting in 2012, but it is doubtful that this gas will be available as Iran is currently a net importer.

North America

As noted earlier, North America has plenty of regasification capacity, which is largely under-utilised. The region holds also large reserves of gas in Alaska, which still have to be brought to markets. Gas has been historically exported from Alaska by LNG tankers, but two projects aim at bringing larger volumes to the United States and Canada by pipeline. The future of both projects will depend on the results of open seasons in 2010.

Two Pipelines from the North

The two options to transport gas from the North Slope to markets have been under discussion for almost 40 years. They are now both advancing at the same pace with their open seasons launched early 2010. The key questions are whether and when this gas will be needed in the current environment of rising unconventional gas production and plenty of LNG import capacity, and what delivered costs are likely to be.

In February 2010, TransCanada and ExxonMobil filed plans for an open season for pipeline plans to transport gas from the North Slope reserves with the Federal Energy Regulatory Commission (FERC). There are two mutually exclusive options as there are not enough reserves to satisfy both: 46 bcm (34 mtpa) via a 2,720 km pipeline from North Slope to Alberta connecting with existing networks serving North America or 31 bcm (23 mtpa) via a 1,280 km line to Valdez where an LNG liquefaction plant would be located. Two concurrent open seasons will be held in Canada and the United States between April and July 2010. The choices are restricted. Construction is scheduled to begin in 2014 with the pipeline to be operational by 2020. Costs will depend on which option customers choose. Piping to Alberta will cost $32-41 billion while routing to Valdez would cost $19-24 billion.

The Denali project has been launched by BP and ConocoPhilips in 2008. It is a 46 bcm pipeline between the North Slope where both companies are producers and Alberta in Canada. There is a possibility to extend the pipeline to Chicago. The open season plan was filed with the FERC, two months after the competing project of TransCanada and ExxonMobil. The project would cost $35 billion (based on the main line) and be completed by 2020. It will be regulated by the National Energy Board in Canada and by FERC in the United States.

A Multitude of LNG Terminals – is There Room or Need for Others?

There are currently 14 LNG terminals in North America (as of June 2010), representing a capacity of 165 bcm. Another 49 bcm are under construction, so that total LNG import capacity will increase to 214 bcm by 2013 which is already more than three times the total net import requirements by 2030 (61 bcm) expected by the IEA in its *WEO-2009*. That said, regional imbalances have to be taken into account, for example import needs in Mexico. Many companies target isolated regions, where they could benefit from higher prices, but the boom of unconventional gas is also having an effect on these expected premiums. Due to its liquidity, the US market is effectively used as a residual importer where excess LNG can be sold, but the sheer capacity compared to forecast needs means that LNG import capacity is likely to remain much less utilised than the world average. There are 15 projects (new ones or expansions), mainly in the Gulf of Mexico, which have been approved by the FERC and are awaiting FID. Given the current excess capacity, local opposition, delays and the development of unconventional gas in that region, these projects are unlikely to move forward. Some projects such as the Bradwood LNG project and the Clearwater Port from Northern Start, both on the West Coast, have already been cancelled.

South America

For a long time, Latin America has remained a self sufficient regional market, except for the Dominican Republic which started importing LNG in 2003. In the 1990s, the continental part of Latin America had based its gas exchanges on pipeline trade between the resource rich countries – Bolivia, Argentina – and the others. But failures to boost production in many countries, a surge in resource nationalism and significant supply shortages since 2004 have prompted three countries to look for additional/replacement external supply sources. In 2008, Argentina, despite its abundant gas resources, started importing LNG, followed in 2009 by Brazil and Chile. This brought pipeline additions to a standstill. While Argentina, Trinidad and Tobago and Venezuela represent over 70% of the production, only Trinidad and Tobago exports significant volumes. Argentinean exports have been dwindling over recent years and Venezuela imports gas. Bolivia, which consumes very little gas, and Colombia are the two other exporters in the region. Most new pipeline projects seem now to have been abandoned or to have lost political support, while LNG import projects multiply, in particular on the Islands which do not have access to gas yet.

New LNG Terminals – any Hope for a Regional LNG Market?

There are currently six LNG terminals in Latin America: the 2.4 bcm Punta Caucedo in the Dominican Republic, the 1.5 bcm Bahía Blanca GasPort in Argentina, the 2 bcm Pécem and 4.8 bcm Guanabara Bay in Brazil and the 3.6 bcm GNL Quintero and the recently commissioned 2 bcm Mejillones in Chile. Interestingly, apart from GNL Quintero and Punta Caucedo, all projects are FSRU, which made their construction times quite short compared to traditional regasification terminals. Argentina plans to build another FSRU north of Buenos Aires, which could be ready by 2011, and is also looking at the possibility to import LNG through Uruguay. A third terminal planned in Brazil would be onshore: the 2.2 bcm Tergás terminal (Terminal de Recebimento e Regaseificação de Gás Natural) is being developed by Gas Energy. The plant would supply two-thirds to the 1.18 GW UTE Rio Grande gas-fired power plant and the rest would be sold to the market. Petrobras is also looking at building two additional LNG terminals by 2013 and 2014 respectively and possibly expanding Guanabara Bay. Although nothing concrete had been decided, these terminals could be ready if they are also FSRU.

Latin America Import Infrastructure

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.

Source: IEA.

Furthermore, Petrobras also plans to build a floating liquefaction plant based on its large offshore fields, which could therefore supply its own LNG terminals as well as others in South America. This first floating LNG production vessel is expected to be in place by the end of 2014 to start deliveries in early 2015. LNG import terminals are also planned in El Salvador, Cuba, Jamaica, but there has been very little progress so far. The gradual expansion of the Panama Canal, with the August 2014 target for completion – in time to commemorate the Canal's 100th anniversary – will give cross-ocean access to new Latin American markets. Panama is only three days sailing time from Peru, four days from the Manzanillo terminal on the West Coast of mainland Mexico, and six days from Chile. According to shipping experts, currently less than 10% of the world's LNG fleet can use the Panama Canal. Once work is completed, 80% of LNG vessels will be able to fit through the Canal.

Pipeline Projects – Mostly on Hold

Despite uncertainties on the Bolivian side, in March 2010, Argentina and Bolivia signed the expansion of their gas agreement. A new pipeline will be built enabling an increase of gas deliveries from an initial 3 bcm/y to 10 bcm/y by 2017. The pipeline is 50 km long and is expected to be completed in May 2011. There are also discussions regarding the GNEA (North-eastern Argentina Gas Pipeline) to Argentina. A call for bids for the engineering was launched in February 2009. The total capacity of this 1,465 km pipeline would amount to 10.1 bcm and the total investment costs are estimated at $1.8 billion. Enarsa nevertheless announced that the construction would start in 2010, which looks doubtful with the other pipeline being built. In 2009, Bolivia, Uruguay and Paraguay also revived Urupabol, a pipeline project born in 1963 to link the three countries. It would start in Tarija in Bolivia, cross either Brazil or Argentina to reach Paraguay, and then Uruguay. The three countries are in talks with the World Bank to finance the pipeline, which is estimated to cost $3 billion. Other projects such as the Gran Gasoducto del Sur (Venezuela-Argentina Gas Line) seem to have been abandoned.

Middle East-Africa

A Small Revolution – LNG Import Projects

Kuwait started importing LNG in 2009 and another terminal is planned in Abu Dhabi, formalising the entry of Middle East in the club of LNG importers, despite the region's huge reserves and potential of regional pipelines. One of the first shipments came from Sakhalin. These LNG terminals are essentially designed to meet the peak demand during summer. An offshore permanent LNG terminal has yet to be seen.

Pipeline Developments – Small Interconnections Move Forward

There are only a few pipeline projects in the region, either to supply neighbouring countries with insufficient gas resources or to export to more distant regions. The small ones – the Arab Gas Pipeline and West African Gas Pipeline (WAGP) – have moved forward despite the difficulties. WAGP, which runs from Nigeria to Ghana, started full commercial operations in 2010 after some sporadic supplies since 2008. Despite Iran's huge reserves, there are both projects to export and to import as the country is still a net importer: in the short term, projects aim at enhancing its import capacity, while some projects still exist to export gas by pipeline to Asia.

Arab Gas Pipeline

The Arab Gas Pipeline transports gas from Egypt, through Jordan into Syria and Lebanon. Egypt exported an estimated 5.5 bcm through this pipeline in 2009. The pipeline is planned to be extended to Turkey by 2011 with a 186 km section to be built between Homs and Alep and a 62 km section to be built between Alep and Kalas on the Turkish border. There are increasing concerns about rising Egyptian gas demand so that Egypt is now looking at the possibility of importing gas from Iraq through this pipeline. Iraq has also expressed a wish to participate in the Arab Gas Pipeline project. The pipeline would therefore be bi-directional, enabling Syria to import gas from Azerbaijan according to the MOU signed in March 2010 for 1-1.5 bcm/y and to export Egyptian or Iraqi gas to Turkey. Egypt also exports gas to Israel, after signing a contract for delivering 1.7 bcm/y.

Trans-Sahara-Gas Pipeline (TSGP)

TSGP would carry Nigerian gas for 4,128 km through Niger and Algeria to the southern Mediterranean coast. Although it has been presented as an option for Europe to diversify its gas supplies, this pipeline faces many hurdles including Nigeria's own needs, and the risks of sabotage on the pipeline whose length makes it difficult to protect during construction and afterwards. Algeria is also interested in this project as an additional source of gas either for its own market or for exports and an incentive to develop its southern fields. In July 2009, Algeria, Nigeria and Niger signed an inter-governmental agreement for its development. The project is estimated to cost $12 billion. Many companies including Gazprom, Sonatrach, Total, Eni and Shell have expressed interest. There are doubts, however, on whether this export option would be cheaper than direct LNG exports. If the gas is to be exported by pipeline from Algeria, it would face competition in the oversupplied Italian and Iberian market. If it is to be exported by LNG, there is no logic building the pipeline.

Asia

Many pipeline projects targeting Asia (mainly China and India) source their gas in Turkmenistan. The commissioning of the Turkmenistan-China pipeline in December 2009 represents a major shift in the politics and economics of East Caspian gas. It marks the end of Russia's monopsony on large-volume gas purchases from the Central Asian producers, not only for Turkmenistan, but also for Uzbekistan and Kazakhstan, which are the transit countries for the pipeline. It also means that these producers can, to some extent, make discretionary choices in the future about shipping their gas either to European markets (via Russia) or to China. Both China and India have turned into gas importers over the past few years (as recently as 2006 for China). As their demand for gas increases, they are looking at different sources of imports, both LNG and pipeline. LNG has been the preferred option in India while China has opted for a mix of LNG and pipeline imports.

Pipeline Projects: Mostly Looking West

Pipeline gas will come from the West – the Caspian region or even Middle East. There are also projects for China to import gas from Russia, which are discussed in the Russian section.

Turkmenistan-China

The pipeline was formally opened mid December 2009, with first gas in January 2010. The capacity of the pipeline is scheduled to rise from the current 10 bcm to around 40 bcm by 2012 with the completion of a second string and additional compression, and the whole project has been implemented with impressive speed. The initial framework agreement on gas cooperation between Turkmenistan and China was concluded only in 2006 and construction began in the latter part of 2007. The entire pipeline stretches for close to 7,000 km, consisting of under 200 km within Turkmenistan itself, around 500 km through Uzbekistan, 1,300 km through Kazakhstan, and then the remainder within China itself (including a second West-East pipeline) to bring gas from the Western border to the main gas consumption areas. Gas deliveries to China in 2010 are foreseen at around 3-5 bcm and Turkmengaz is supplying most of the early volumes for the pipeline from the Malai field in southeast Turkmenistan, although there is no single source of gas for the initial volumes. It is not yet clear how quickly Turkmenistan will be able to ramp up exports to the full contractual volumes; this will depend on the speed of development of the fields within the CNPC production area near the Uzbekistan border, together with the South Yolotan field.

Turkmenistan-Afghanistan-Pakistan-India

This proposed pipeline along a 1,680 km route aims to deliver 30 bcm of gas to consumers in Afghanistan, Pakistan and India. Capital cost is estimated at $8 billion. In April 2009, the governments of the four countries signed a framework agreement to construct TAPI. However, the project has been pending for more than ten years. It is backed by the United States, but from the Indian perspective, the security situation in Afghanistan makes it a more distant prospect than the IPI pipeline (see below). Security of the TAPI route through Afghanistan is an impediment, although the Afghan government made in 2008 several pledges to address these concerns. The framework agreement states that the TAPI pipeline would be built by a consortium of national oil companies from the four nations by 2011-12. The draft of Gas Pipeline Framework Agreement provides for payment of transit fee to Afghanistan and Pakista, based on internationally accepted cost-of-service tariff methodology. The IP pipeline (see later) would also undermine the participation of Pakistan in the TAPI pipeline. Another question is about resources. Although its reserves have been reevaluated upwards, Turkmenistan has already committed significant volumes to China, Russia, and is increasing deliveries to Iran, while Europe is also looking at Turkmen gas.

Iran-Pakistan-India Pipeline

The Iran-Pakistan-India pipeline is a project launched in the 1990's that envisaged initial export volumes of around 22 bcm/y, rising to around 50 bcm/y. After long years of negotiations between the neighbouring countries concerning pricing and delivery terms, from which India has virtually withdrawn since the terror attacks in Mumbai in November 2008, Iran and Pakistan agreed finally on 5 June 2009 to develop an Iran-Pakistan (IP) pipeline, moving ahead with the first part of what is still intended to be a trilateral project, the so-called 'Peace Pipeline'. Iran and Pakistan signed in March 2010 an agreement to build the $7.5 billion IP pipeline between Assaluyeh and Iranshahr at the Pakistani border. In 2009, the two countries had signed an agreement for Iran to supply Pakistan with 7.5 bcm/y for 25 years, with an extension of an additional five years in case of mutual agreement. Both countries expressed their interest in a future Indian participation. There are still many hurdles to be overcome by this pipeline. First, despite its large reserves, Iran is still a net importer of gas. Sufficient gas might become available by the middle of the decade, but pipeline projects compete against LNG liquefaction plants. Second, discussions on prices have been difficult as Iran proposed a price formula similar to that for Japanese LNG (S-curve). This added to the transit fees through Pakistan would result in prices around $7/MBtu; this is higher than India is prepared to pay, despite the recent changes in their domestic pricing policy. Finally, geopolitical issues hampering the pipeline are diverse and wide ranging.

Myanmar-China

The construction of the 793 km gas pipeline from Myanmar to the southern part of China started early June 2010. Gas will come from blocks A-1 and A-3 in Myanmar and is expected to start in 2013, following an SPA for 10 bcm/y signed in December 2008. This project advanced despite opposition from NGOs. It is running alongside an oil pipeline for which CNPC received exclusive rights to build and operate in December 2009. Myanmar is located in a unique position since it can provide natural gas directly to southern China by pipeline.

LNG Regasification Terminals: Two Major Players on the Rise

Both China and India have started relatively recently to look at LNG and their LNG imports only started a few years ago. But with 7.5 bcm and 12 bcm respectively in 2009, they are already significant players, conveniently located near two major sources of LNG: Qatar and Australia. There is a total of 27 bcm terminal capacity under construction in both countries, which will increase their combined LNG import capacity to 64 bcm. The Dabhol terminal is India is expected to be completed in 2010 while Kochi should start operating in 2012. Three additional terminals are under construction in China: the 4.1 bcm Dalian and the 4.8 bcm Rudong, both from PetroChina and expected to start in 2011, and CNOOC’s fourth terminal, the 4.1 bcm Zhejiang. An additional 90 bcm of LNG terminal capacity (on top of the 64 bcm mentioned before) is planned for both countries: the Chinese terminals are quite likely to proceed if gas demand continues to increase at an astonishing 10 bcm/y, which seems likely. Other Asian countries are also looking at LNG imports, notably Pakistan, for which additional gas supplies are critical to avoid a major power crisis. 4Gas is planning to build a 3.5 mtpa FRSU at Port Qasim, near Karachi. GDF-Suez won the first tender to supply the terminal but this tender has been cancelled. Interestingly, this LNG would have been priced on a mix of oil-linked, NBP and HH prices.

Southeast Asia

Southeast Asia is historically an energy producer but is also facing import requirements issues: rapidly growing energy consumption is outpacing regional gas production. The region will remain a net exporter of gas for the next few decades with proven gas reserves of 6.6 tcm, but due to increasing regional gas demand, each country has now to review its energy (and gas) strategy to diversify energy sources, secure energy supply and support economic growth. This requires significantly increasing investments in gas import infrastructure, notably in long-distance pipelines and/or LNG import terminals.

Pipeline Development

Currently, nine interconnecting gas pipelines are operating on long-term contracts to deliver natural gas from gas producers in one country to customers in another. They all are bilateral interconnections with a neighbouring country: there are still no multilateral ones across the region. One of the pipelines started as early as 1991 with relatively short distance (5 km) and the longest is 660 km long and started operation in 2001. The latest one to be commissioned was the 325 km pipeline between Malaysia and Vietnam.

In 1997, ASEAN member countries launched the 'ASEAN VISION 2020' calling for cooperation between countries to establish gas interconnections within the ASEAN region through the Trans ASEAN Gas Pipeline (TAGP). The same applied for the power sector. A series of political agreements and a review of the plan followed, and accelerated the construction of regional pipelines. In 2002, ASEAN countries signed the ASEAN MOU on the TAGP to further pursue efforts to construct a regional gas pipeline network and it came into force in 2004. According to the latest TAGP Master plan, five more pipeline projects are under consideration involving 4,500 km worth of $7 billion. The origin of these pipelines is the same: the Indonesian offshore gas field, Natuna D-Alpha. It is estimated to contain 1.3 tcm of recoverable gas reserves, but has a very high CO_2 content. Pertamina has been looking for partners since Exxon Mobil left in 2007. This technical difficulty added to the commercial uncertainties resulted in the pipelines being deferred. The five pipelines would link the field to Thailand, Malaysia, Indonesia, Java, Brunei, Malaysia and the Philippines. They would come online approximately seven years after an FID on Natuna is taken. Meanwhile, even if the pipelines are physically interconnected and bilateral gas trading is encouraged, regional market integration is another issue. Each ASEAN country is at a different stage in terms of economic growth and their market maturity differs. In this regard, if ASEAN wishes to pursue the integration of the regional market, it could usefully study the development of European gas market integration.

Existing Pipelines in the South-Asian Region

Current interconnections	Distance	Commissioning date
Peninsular Malaysia - Singapore	5 km via Johore Straits	1991
Yadana (Myanmar) - Ratchaburi (Thailand),	470 km	1999
Yetagun (Myanmar) - Ratchaburi (Thailand)	340 km	2000
West Natuna (Indonesia) - Singapore	660 km	2001
West Natuna (Indonesia) - Duyong (Malaysia)	100 km	2001
South Sumatra (Indonesia) - Singapore	470 km	2003
Malaysia - Thailand 'Joint Development Area' (JDA)	270 km	2005
Malaysia - Singapore	4 km	2006
Malaysia - Vietnam	325 km	2007

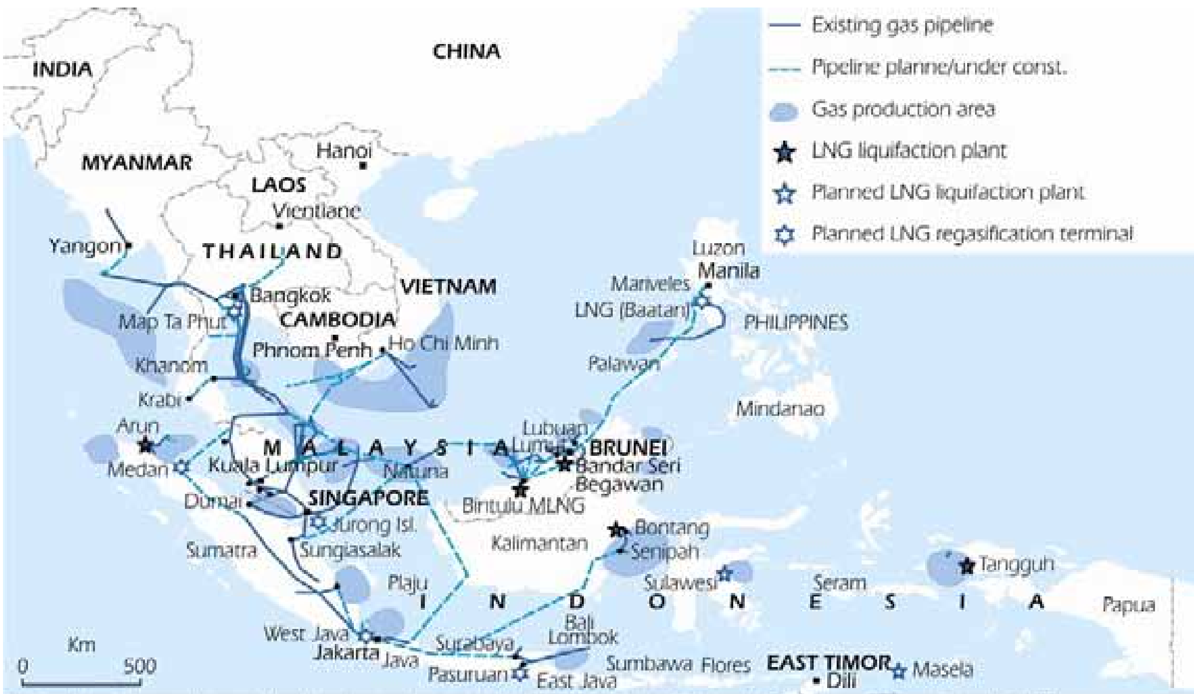
Source: *WEO-2009*.

Regasification Terminals

Some ASEAN countries, notably, Thailand, Indonesia, Philippines, Singapore and Malaysia are considering building LNG regasification terminals in order to supplement growing gas demand, recognising that interconnecting pipeline development in the region is not fast enough to satisfy their growing regional gas demand. In this regard, Thailand and Singapore are progressing ahead of their neighbouring states with their terminals under construction whereas the others are still at the planning phase. Total capacity of the regasification terminals in the region is expected to surpass 26 bcm (20 mtpa) by 2013 (equivalent to Spanish annual LNG imports) if all the planned terminals proceed. The construction of LNG regasification terminals is a way to enhance gas security in parallel with the installation of regional gas pipelines, just as Europe is doing. Interestingly, two of the major LNG exporting countries in the world, Indonesia and Malaysia are planning to build their own regasification terminals. Indonesia has liquefaction plants in remote locations that they plan to use to supply the regasification terminals close to demand centres, notably Java. It would give the country flexibility in terms of supply sources: they can either deliver an LNG cargo to a domestic terminal as well as procure ones from external sources.

However, uncertainty still remains around the economic viability of these projects and firm supply sources. LNG regasification terminals require capital, and efficient operation of the terminals is a very important factor to recoup the capital invested. Unless terminals planned/under construction find firm LNG supply sources around the world, they may end up having low capacity utilisation and undermine the economics of the projects. Stakeholders may then have to pay higher prices for enhancement of their energy security than they originally expected.

Gas Infrastructure in the South-Asian Region



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Source: IEA.

Regasification Terminals in the South-Asian Region

Planned/Under construction LNG regasification terminals	Capacity (mt (bcm))	Commissioning date
Thailand (Map Ta Phut)	5 (6.8)	2011
Indonesia (East Java)	1.5 (2)	2011
Indonesia (North Sumatra)	1.5 (2)	2011
Indonesia (West Java)	1.5 (2)	2012
Philippines (Quezon)	1.0 (1.4)	2011
Philippines (Bataan)	1.4 (1.9)	2012
Singapore(Jurong Island)	3 (4.6)	2013
Malaysia (Port Dickson)	5 (6.8)	2013

Note: Names of terminals in bold and underlined indicates that the terminal is under construction.
Source: IEA.

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