Oil & gas macro outlook

Edison investment research

Prices look vulnerable

Prior to the 21 February setback, Brent was close to $120/barrel, the upper end of the trading range and a level that has historically had negative implications for economic activity. We believe that the upward trend in Brent in the early weeks of 2013 was divorced from the fundamentals and reflected unduly bullish expectations for the world economy and the potential for supply disruptions. In the coming months we think that oil prices could trend down in the face of a comfortably balanced market.

Supply/demand position: Looking comfortable

After having been in surplus through the first three quarters of 2012 the oil market was probably in balance in the fourth quarter. Assuming no major unplanned outages, we would expect approximate balance to be achieved in 2013. The key factors are likely to be fairly subdued demand growth reflecting a lacklustre world economy and a robust non-OPEC production backdrop driven by North America. Broadly, we would expect demand growth in 2013 to be around 0.9mmb/d based on consensus world GDP forecasts. Meanwhile, non-OPEC output could increase by about 1.4mmb/d according to the EIA. Admittedly, OPEC output in 2013 will probably be lower than in 2012 but should nevertheless top 30mmb/d buoyed by Iraq. This is likely to be sufficient to keep the market broadly balanced. A supply surplus is looking plausible for 2014 given the EIA's forecast increase in non-OPEC output of 1.7mmb/d.

Brent price: Bogus risk-on excitement

Brent rose 7% between end 2012 and mid-February 2013 pretty much in tandem with a broad 'risk-on' phenomenon in financial markets. The uptrend in early 2013 has been rationalised in terms of positive economic developments in China and falling Saudi production. China, however, is to a large extent offset by weakness in Europe while declining Saudi production is probably largely tracking a seasonal softening in demand. In the light of the strong start to the year we are raising our 2013 Brent price forecast from $99.0 to $108.7/barrel.

WTI-Brent spread: The WTI discount widens again

The trend in WTI, the inland US light crude benchmark, has been weaker than for Brent in recent weeks reflecting the continuing influx of supply in the Mid-Continent and pipeline constraints. As a consequence, the WTI discount to Brent widened from $17 to $23/barrel between mid-January and February. We expect a narrowing in the discount over the next two years as upgraded pipeline capacity lowers transportation costs from the Mid-Continent to the Gulf Coast. However, the shear influx of supply expected probably implies that the near-term discount will remain well above pipeline costs of $4-5/barrel from the Mid-Continent to Houston. In due course we would expect Gulf Coast prices to move to a significant discount to Brent. Reflecting positive carryover from 2012, our 2013 WTI forecast has been increased from $86.5 to $91.8/barrel.

26 February 2013

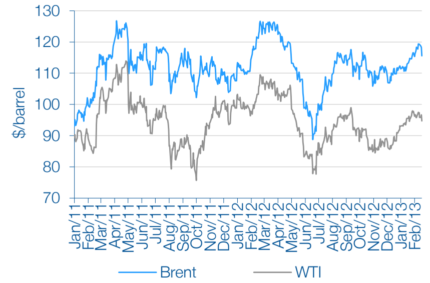
Analysts

Peter J Dupont +44 (0)20 3077 5741
Colin McEnery +44 (0)20 3077 5731
Ian McLelland +44 (0)20 3077 5756
Will Forbes +44 (0)20 3077 5749
Elaine Reynolds +44 (0)20 3077 5700
John Kidd +64 (0)4 894 8555
oilandgas@edisoninvestmentresearch.co.uk

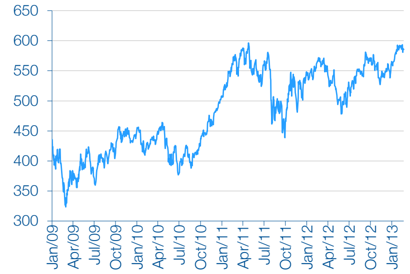
For institutional enquiries please contact:

Gareth Jones +44 (0)20 3077 5704
institutional@edisoninvestmentresearch.co.uk

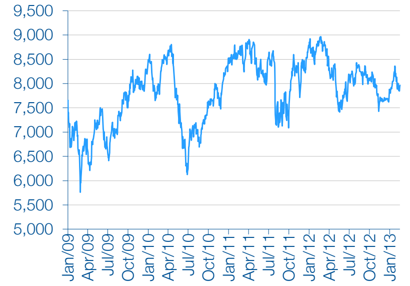
WTI vs Brent



S&P 500 Oil & Gas Index



FTSE 350 Oil & Gas Index



Price trends

	WTI $/barrel	Brent $/barrel	Henry Hub $/mmBtu
2010	79.5	79.7	4.37
2011	94.9	110.0	4.00
2012	94.2	112.0	2.75
2013e	91.8	108.7	3.56
2014e	90.0	100.3	4.00

Note: Prices are yearly averages.

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Crude oil market dynamics

Price overview

Market overview: Brent turns higher in early 2013

Recent months and 2012 in retrospect: The closing months of 2012 and the first two weeks of 2013 were uneventful in international crude oil markets. Essentially prices for key light crude benchmarks such as Brent, Dubai Fateh and Nigerian Bonny were on a high plateau between August/September 2012 and early January 2013. The flat trend of late 2012, of course, contrasted with the sharp swings of the first seven or eight months of the year. During this period Brent collapsed by around 30% between March and June and then promptly rebounded by 30% in the two months to mid-August. For 2012 as a whole, international light crude prices on average were similar to the previous year. Bucking the flat trend of late 2012 was WTI, the US inland benchmark. Post mid-December the trend in WTI firmed noticeably resulting in a narrowing in the discount to Brent from the highs of late October. Despite the firming trend towards year end the average for WTI in 2012 was marginally down on 2011.

During 2012 four key factors tended to drive oil prices. These were the lacklustre economic backdrop in the OECD world in general and the EU in particular, the Iranian nuclear issue, the surge in North American oil production and unplanned non-OPEC production outages. Bearish macro-economic forces tended to keep a lid on prices while geopolitical factors and outages, especially in the North Sea, supported them and arguably prevented a rout at crucial moments in 2012. OPEC led by Saudi Arabia also helped stabilise the market in 2012 by maintaining historically high output levels in the first half and then trimming output in the second half.

Post end 2012, Brent and other international light crudes have firmed noticeably while WTI has shown a more muted development. As of mid-February 2013 Brent was up 7% from end December 2012 and trading at around a nine-month high of $119/barrel. Significantly, this is towards the top end of the trading range over recent years and also a level that has historically had negative implications for world economic activity if sustained.

North America was the key news story in 2012: Arguably the key petroleum industry news story in 2012 was the surge in North American production reflecting the development of the oil sands in Alberta and the shale resources of the Great Plains in both the US and Canada. Oil production (which includes natural gas liquids, ethanol and biodiesel) was up by about 0.94mmb/d (+9%) in the US and 0.28mmb/d (+6%) in Canada and the two combined more than accounted for the net increase of 0.58mmb/d in non-OPEC oil production in 2012. The trend in US production has, in fact, been firming noticeably over the past year or two. Leading industry proponents, such as EOG, have indeed been pointing out for some time the scope for a gain of 2mmb/d between 2011 and 2015. However, the story gained traction when the International Energy Agency (IEA) suggested in its World Energy Outlook last November that the US would become the largest oil producer globally by around 2020. In addition the IEA has alluded to the potential for North America becoming a net oil exporter by 2030.

Certainly on current trends the IEA's prognostications appear plausible. Indeed, US oil production including natural gas liquids, renewables (mainly ethanol) and refinery processing gain is already running at over 11mmb/d. It should be noted that US shale oil development is also generating large volumes of natural gas liquids (NGLs). On a broad definition the US may, in fact, already be the largest producer of oil globally. Surging US oil and indeed gas production is clearly a major plus for the US economy currently and prospectively. It has resulted in internationally low domestic prices, provided a major source of new employment and state taxes and led to a significant decline in petroleum imports. In 2012 US net imports of crude and petroleum products fell from a year previously by 12% to 7.5mmb/d and were 40% down from the 2005 all-time high of 12.5mmb/d, according to the EIA (US Energy Information Agency). The EIA is forecasting further declines of 12% in both 2013 and 8% in 2014. In the latter year this would imply imports falling to roughly the level of the late 1980s.

The big risk now for the US is that the great shale oil revolution could trigger two developments that would undermine industrial competitiveness. The first relates to a trend appreciation in the dollar leading to the so called 'Dutch disease' (currency appreciation resulting in an acute loss of competitiveness in the industrial economy) and the second the imposition of a carbon tax. The former may, however, be headed off by maintaining the prohibition (with the exception of Canada) on exports of hydrocarbons other than in refined form. In the event of falling domestic prices for oil and gas, a carbon tax could become an increasingly attractive course of action for a federal government hungry for large new sources of tax revenues.

US, or at least growing North American, energy independence clearly has major geopolitical implications. What is important here from a strategic perspective is the potential to undermine the power of OPEC as the swing oil producer. Until now, OPEC has taken a sanguine view of US developments in public statements, but the prospect of US light crude imports along the Gulf Coast dropping to practically zero by mid-decade and being sharply reduced along the eastern seaboard must be causing concern.

The key issue now is to what extent the shale oil and gas revolution can be replicated outside North America. We would be positive on this front. As the EIA has noted, there is no shortage of prospective oil and gas shale resources around the globe even if the oilfield services infrastructural backdrop, tax and land mineral right regimes are not as favourable as in the US. Not surprisingly, developments in the US are being eyed increasingly enviously by others around the world which should trigger a response in terms of exploration and development activity. At present those in pole position are probably Argentina, Australia and China. One of the few areas to fail to embrace shale development activity is Western Europe, reflecting opposition to fracking and possibly more broadly to fossil fuels.

Ain Amenas terrorist attack: The al-Qaeda attack on the Ain Amenas gas processing plant in south eastern Algeria in mid-January raises the issue of security at oil and gas installations in North Africa and the Middle East. Clearly, security will have to be stepped-up, although at least as far as Algeria is concerned, the costs will probably have to be borne by the state given the reluctance of the authorities there to allow the intervention of third parties in security matters. In all likelihood the cost of insurance for western and other companies operating in North Africa will also rise. However, we would not expect the Ain Amenas attack to have an adverse impact on development activity in North Africa other than perhaps on a very short-term basis. The key issues here are firstly that energy projects in Algeria and Libya are extremely lucrative for the host governments and secondly that they have few if any alternative development opportunities. We therefore believe that governments may, if necessary, decide to sweeten regulatory terms to maintain oil and gas company interest. Algeria was reputedly considering modifications to its notoriously tough fiscal regime before the Ain Amenas attack.

Non-OPEC output rebounds in Q412: Following the weak performance of the third quarter, mainly reflecting planned and unplanned outages in the North Sea and Brazil, production appears to have rebounded in the fourth quarter of 2012. The gain between the two quarters may have been about 0.6mmb/d according to the IEA and was driven primarily by the strong underlying upward trend in North America and a lesser extent in Russia. Production also increased between the third and fourth quarters in the North Sea but remains here at a low level historically. Based on the IEA's estimate of 0.95mmb/d, UK output in 2012 was down 14% on 2011 and the lowest level since 1977. Brazil's output in 2012 was marginally down on the previous year at 2.62mmb/d reflecting depletion in the Campos Basin fields, the enforced closure of Chevron's Frade field over an environmental/legal dispute and heavy offshore maintenance programmes. This was the first decline for Brazil since 2004.

For 2012 as a whole, non-OPEC production appears to have increased from 2011 by about 0.58mmb/d to 53mmb/d, according to the EIA. This was a significantly stronger performance than seemed likely a few months ago and to a considerable extent reflects the bullish trend in North America. For 2013 both OPEC and the IEA are looking for a robust gain in non-OPEC output of around 1mmb/d while the EIA is forecasting 1.2mmb/d. To these numbers a further 0.2mmb/d can be added for OPEC natural gas liquids which are not subject to quota. The anticipated gain in 2013 non-OPEC output is largely driven by the continuing upward trend in North America and a rebound in Brazil reflecting development activity and a resumption in Frade production. Interestingly, the IEA is anticipating further declines in UK and Norwegian output in 2013 of 7% and 6% respectively.

OPEC production slips in late 2012: OPEC crude output during the first three quarters of 2012 was broadly stable on a quarterly sequential basis and averaged 31.2mmb/d, the highest level since 2008. However, during the fourth quarter output slipped, averaging 30.7mmb/d. Furthermore, the trend weakened during the period with a decline to 30.4mmb/d in December, which has taken output fairly close to OPEC's 30mmb/d target. The average for 2012 was 31.2mmb/d, up 1.4mmb/d or 4.7% on a year previously and similar to the record level in 2008.

The decline in output between November and December of about 0.5mmb/d was driven by Saudi Arabia and to a lesser extent Iraq. The motive for the drop in Saudi production from peak levels of about 10mmb/d in the second quarter to 9.2mmb/d in December has been subject to a great deal of speculation. The explanation appears to be very simple, demand has fallen. It should be noted that Saudi Aramco essentially schedules production based on the incoming order flow. Reflecting domestic power generation needs related to heavy air conditioner usage, plus an increasing weighting in the customer mix towards rapidly growing developing world markets, demand now tends to be strongest for Saudi crude during the third quarter. This contrasts with the situation in an earlier era when Aramco was more orientated to supplying developed world markets and demand was relatively soft during this period.

The dip in Iraqi output of 0.2mmb/d to 3.0mmb/d between November and December was surprising and contrasts with the strong upward trend apparent for many months. The absolute level was also well short of Oil Ministry intimations a few months ago of 3.4mmb/d by end 2012. The explanation appears to largely reflect lower shipments from the Gulf export terminal related to inclement weather conditions. Pipeline exports from the Kurdistan region have also ground to a halt due to the ongoing political dispute between the local and federal governments. Interestingly, Genel Energy has recently indicated that it intends trucking around 20,000b/d from Kurdistan to Turkey. Despite the drop in December, Iraqi production in 2012 still averaged 3mmb/d, the highest annual total since 1979's 3.5mmb/d and up 12% on 2011.

Barring major political convulsions and/or technical issues, Iraq oil production should regain upward momentum in 2013 driven by field development work in the southern Basra region and greater export capacity. Kurdistan output could also play a part but this is subject to a rapprochement between the federal government and the regional authority over the subject of exports and the split of revenues. In a recent study the IEA has suggested that Iraqi output could be running at 4.2mmb/d by 2015 and 6.1mmb/d (Kurdistan 0.5-0.8mmb/d) by 2020. For 2013 we think output of about 3.5mmb/d is plausible. Interestingly, the Iraqi government is now looking to revamp, with the assistance of BP, its longstanding Kirkuk supergiant oilfield close to the border with Kurdistan. Output here has fallen sharply for a number of years to about 0.25mmb/d. The aim is to roughly double output over an unspecified time period. Heightened sectarian tension of late in Iraq does not appear to have affected Iraqi oil output but could pose a risk in the coming months.

Global demand apparently firms in late 2012: Overall, 2012 was a fairly subdued year for demand globally but there were signs of a firming trend towards year end. For the year as a whole demand, based on EIA data, grew by about 0.9mmb/d or 1% to 89.2mmb/d. Not surprisingly, growth was driven by the non-OECD world where there was a gain in 2012 of about 1.3mmb/d. This was partly offset by a drop in the OECD of 0.4mmb/d led by North America and particularly Europe. The drop in the OECD would have been significantly greater in the absence of Japan's increasing oil usage in power generation following the closure of the bulk of its nuclear capacity. The impact may have been 0.2-0.3mmb/d. In Europe demand dropped in 2012 by about 0.5mmb/d to 13.8mmb/d, which left it 12% below 2007 levels. Clearly, demand in Europe in 2012 was adversely affected by powerful recessionary forces, but record-high refined product prices following swingeing tax hikes in some countries along with efficiency gains in the auto fleet also played a part.

Based on IEA data, world demand was somewhat greater than expected in the fourth quarter of 2012. The key factor appears to have been a more robust than expected trend in China after a relatively weak showing earlier in the year. This reflects a combination of strengthening economic activity and inventory building. Despite the upgrade, demand growth in China in 2012 was probably not much over 3% or 0.3mmb/d in 2012, well down on the 5% to 6% of recent years.

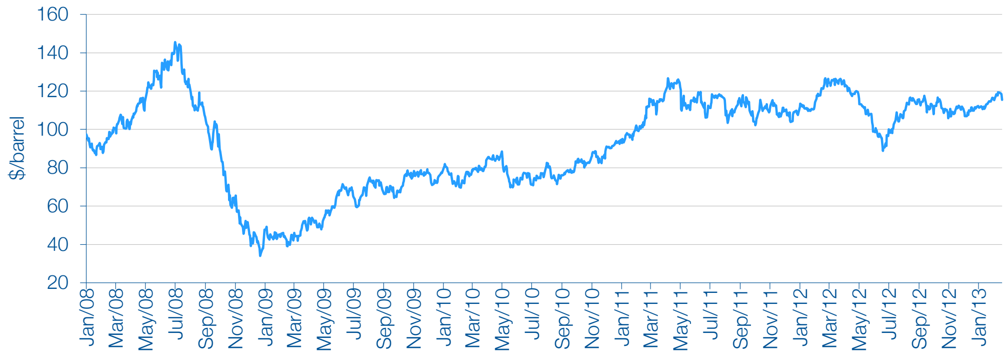
The IEA in its February report revised down its estimate of world demand for 2013 by 90,000b/d to 840,000b/d (full-year forecast of 90.7mmb/d) citing weak economic conditions. OPEC is looking for an identical increase in 2013 but the EIA is forecasting a somewhat larger gain of 1.05mmb/d.

OECD inventories remain comfortable: OECD commercial inventories continue to look comfortable for the time of year on an absolute and particularly a day's supply basis. Inventories declined sequentially in December by 22mm barrels to 2.688mm barrels but the decline was less than suggested by the seasonal pattern. On a day's supply basis in December, inventories were equivalent to 57.2 days, almost 2 days ahead of a year earlier. The day's supply is at the top end of the range for the time of year based on data between 2008 and 2012.

Recent trends in Brent and WTI: Brent has again been outpacing WTI of late

Between November and December 2012, WTI strengthened noticeably relative to Brent, the key international light crude benchmark. This reversed the picture that had been apparent for much of the third quarter and the early part of the fourth quarter of 2012. At the beginning of November 2012 Brent plumbed around a 3½ month low of $105.8/barrel, 10% below the third quarter peak of $117.6/barrel. Brent then proceeded to trend higher over the balance of November hitting $112/barrel at month end propelled by growing optimism concerning the world economy. After a minor relapse in early December which took Brent down to $107/barrel, the trend again firmed over the balance of the month. Brent ended December at $111.9/barrel and averaged $110.9/barrel in the fourth quarter, 1% higher than in the previous three months. For 2012 as a whole Brent averaged $112.0/barrel, up 1.8% on 2011 and a record for a calendar year.

Exhibit 1: Brent crude oil price trend

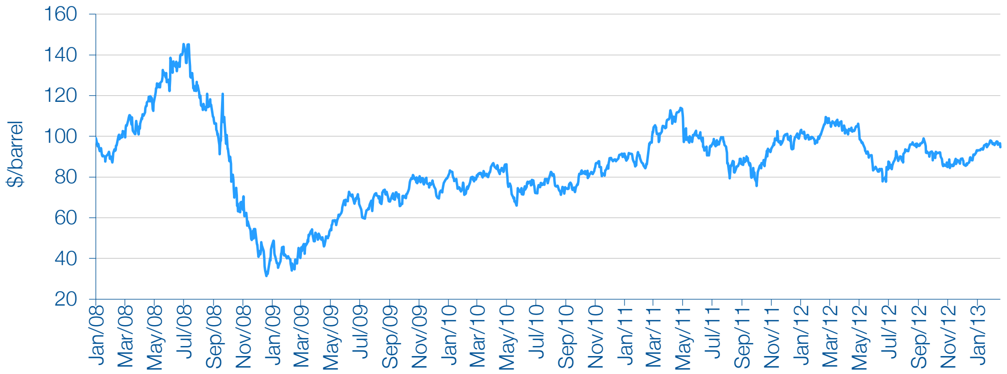


Source: Bloomberg

After trending flat during the first half of January 2013, Brent subsequently regained upward momentum and reached $116.5/barrel at month end. Brent continued to trend higher in February reaching a nine-month high of $119.3/barrel on 15 February. The firm trend in the early weeks of 2013 has tended to mirror stock market activity and post mid-January was buoyed by bullish US and Chinese economic statistics. The Ain Amenas attack also helped buoy Brent during the third week of January.

WTI plunged between mid-September and early November 2012 from $99.0/barrel to $84.4/barrel. This was driven by rapidly growing production in the US, logistical bottlenecks and burgeoning US inventories. Between early November and end December 2012 WTI rebounded strongly with the key factor being market bullishness regarding the direction of the US economy in 2013. Industry specific US data on demand also tended to be more supportive of higher prices in late 2012 than was the case for much of 2012. WTI ended 2012 at $91.8/barrel, up 9% on the early November low. The average for the fourth quarter of 2012 was $88.2/barrel, down 4% on the prior quarter. WTI averaged $94.2/barrel in 2012, down 0.7% on 2011.

Exhibit 2: WTI crude oil price trend



Source: Bloomberg

In the early weeks of 2013 WTI temporarily showed a stronger upward trend than Brent reflecting general market bullishness and optimism that logistical bottlenecks from Cushing, Oklahoma to the Gulf Coast would be alleviated with Seaway pipeline coming fully on-stream. By end January WTI was trading at $97.8/barrel, a 4½ month high. However, contrasting with Brent, WTI, lost momentum during February and by 15 February the price had dipped to $95.6/barrel.

US production developments

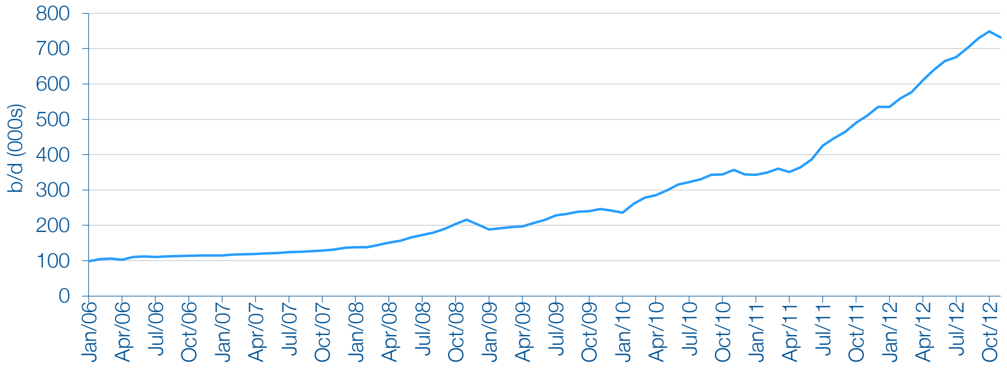
North Dakota : Production rebounds in December, 1mmb/d comes into view by 2015

North Dakota is now the second-largest oil producing state in the US, reflecting rapid development over the past four or five years of the Bakken shale petroleum system utilising horizontal drilling and multi-stage fracking technology. After rising for 20 months, production slipped in November 2012 for the first time in 20 months. During the month production averaged 735,062b/d, down 2.0% on October. The decline was attributed by the North Dakota Department of Mineral Resources (NDDMR) to the impact of winter storm Brutus, which halted development activity for several days. Fracking operations were particularly badly affected due to the disruption to road transportation. November's dip has proved to be an aberration. Production in December came in at 768,853b/d, up 4.6% on the prior month and 44% on a year earlier as 123 new wells were brought on-stream. At 2012 year end the North Dakota Department of Mineral Resources estimated that 413 wells were awaiting completion services. Interestingly, the NDDMR also estimates that 90 new wells are needed monthly currently to maintain production. For 2012 as a whole North Dakota production averaged 664,060b/d, a hefty 59% above a year previously. For perspective, production in the state was running at a mere 218,604b/d in 2009 and 97,741b/d in 2005.

Two leading indicators are pointing to the possibility of slowing production growth in the coming months. These include falling drilling permits and a declining rig count. Permits, for example, have fallen from a recent peak of 370 in October to 154 in December, while the rig count has declined from a second quarter 2012 high of 213 to a low for the year of 183 in December. Against these factors, spuds increased between November and December from 263 to 292 and permitting activity increased in January according to NDDMR. Higher spud rates combined with the declining rig count appears to be pointing to improving drilling efficiency thereby nullifying, at least in part, the falling rig count. As far as the very near term is concerned, it should be noted that weather conditions in North Dakota in early 2013 have been less benign than in 2012. Year-on-year comparisons in the first quarter of 2013 are therefore likely to be more challenging than a year earlier.

In the medium term the key issue for North Dakota's oil production is well decline rates. Typically Bakken wells have an initial production rate of about 1,000b/d and then decline over the next two or three years to about 250b/d. Given this rate of depletion, it is necessary to maintain drilling activity at a very rapid pace in the play to maintain growth or even the level of production. High rates of depletion and the now sizeable inventory of wells at 8,224 suggests that production growth in North Dakota over the next two or three years will inevitably slacken. It should be noted, however, that the latest industry estimates for recoverable reserves in the Bakken petroleum system call for over 20bnboe (Continental Resources [CLR} estimates 24bnboe). Assuming these estimates are broadly correct, there should be ample drilling opportunities to keep production moving ahead, albeit at a less rapid pace, than over the past three or four years. Increasingly, operators in all likelihood will increasingly need to tap the Three Forks formation below the Lower Bakken shale. We believe industry suggestions that North Dakota production will reach 1mmb/d or more by 2015 are plausible. According to the NDDMR, production from the Bakken petroleum system in including the Three Forks and Sanish formations is not expected to peak until 2020 or even 2025.

Exhibit 3: North Dakota crude oil production



Source: EIA

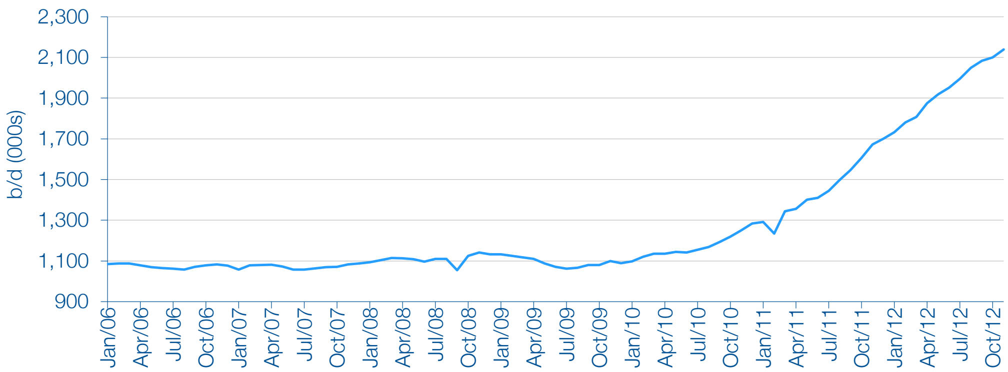
Takeaway capacity: Based on a recent Continental Resources presentation, takeaway capacity from the Williston Basin appears to be at least in line with current rates of production. Furthermore by end 2013 the capacity looks like approaching 1mmb/d, which should be more than adequate. Driving capacity expansion in the Williston Basin of late has been an expansion in rail loading facilities. According to the North Dakota Pipeline Authority, the takeaway mix in the Basin is currently as follows: rail 52%, pipeline 38%, Tesoro's Mundan refinery (Bismark ND) 8% and truck to Canadian pipelines 2%. Rail shipments are mainly made to Midwest refineries, Cushing and the Gulf Coast. In recent months shipments have also built up to refineries on the eastern seaboard and to a lesser extent the west coast. We believe the cost of making such shipments is around $15/barrel. The key advantage of rail shipments is flexibility in terms of serving end markets.

Texas: Strong upward trend, production at a 25-year high

Oil production in Texas, the largest producing state in the US, has remained on a strong upward trend in recent months. This has continued to be driven by intensive development activity in the Eagle Ford shale zone of the Western Gulf Basin in the south-west of the state and the tight oil formations of the Permian Basin to the north-west. Based on EIA data, production in November 2012 was 2.14mmb/d, up 1.9% on the previous month and 27.9% on a year previously. Production in November was around a 25-year high and roughly double the 2004 low. For perspective, the all-time high for Texas oil production was 3.45mmb/d in 1972.

Eagle Ford production in November was 358,826b/d, 70% higher than a year earlier. Significantly, the bulk of this output has surfaced over the past three years. Permian Basin production is presently running at about 1.2mmb/d, which compares with around 0.45mmb/d as recently as 2009. The balancing 0.4mmb/d mainly stems from the East Texas Field.

Exhibit 4: Texas crude oil production



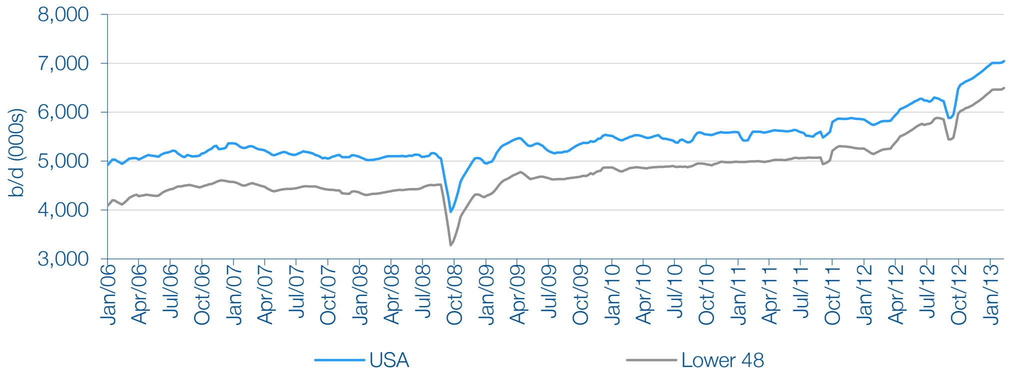
Source: EIA

US: Production at a 20-year high

The trend in US crude oil production has continued on a strong upward path in recent months paced by gains in the shale and tight sands formations of the Great Plains and Texas. Significantly, in the early weeks of 2013 US production has exceeded 7mmb/d for the first time in about 20 years. For the week ended 8 February 2013 production averaged 7.06mmb/d, up 21.4% on a year earlier.

For 2012 as a whole US crude production (excludes NGLs and bio-fuels) averaged 6.43mmb/d, 13.4% or 0.76mmb/d above a year earlier. This was apparently the largest annual increase in the history of US oil production. In the four weeks to 8 February 2013 production was up year-on-year by 21.8% to 7.01mmb/d. In addition to the high-profile states of North Dakota and Texas, production has also been growing strongly in Colorado, Oklahoma and New Mexico. Constraining growth in 2012 was falling production in Alaska and broadly flat output in California the third and fourth largest producing states respectively. The EIA is forecasting growth in US crude output of 13.8% to 7.3mmb/d in 2013 and 8.2% to 7.9mmb/d in 2014. Interestingly, Valero Energy is now suggesting that US shale oil output will reach about 3mmb/d by 2016. This compares with perhaps 1.5mmb/d currently.

Exhibit 5: US crude oil production



Source: EIA

Light crude spreads

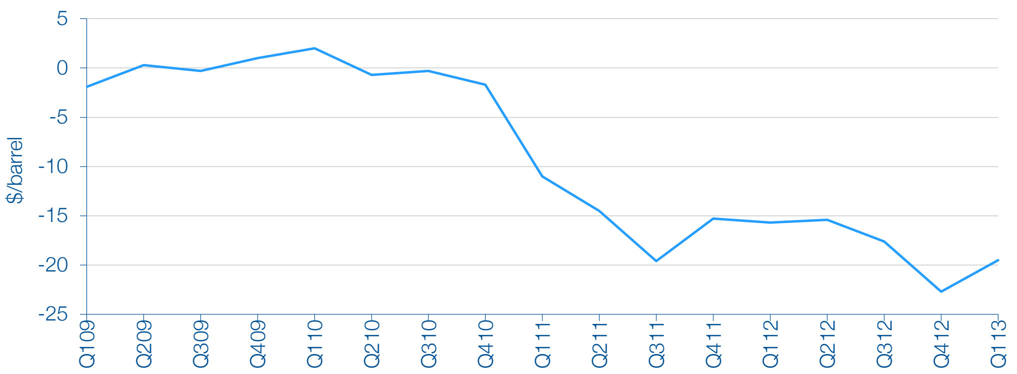
WTI-Brent: The WTI discount has recently widened to $23/barrel

WTI was trading at a discount of almost $25/barrel to Brent in late October 2012. This was a high for the year and approaching the record level of $30/barrel of September 2011. Reflecting the buoyant trend of WTI relative to Brent, the WTI discount narrowed significantly from a high base through mid-January 2013. By end December 2012 the discount was down to $20.1/barrel. The average for the fourth quarter of 2012 of $22.7/barrel was nevertheless well up on the $17.6/barrel of the previous quarter and comfortably the widest quarterly discount of 2012. For 2012 as a whole the WTI discount averaged $17.8/barrel against $15.1/barrel in 2011 and $0.2/barrel in 2010.

By the third week of January 2013 the WTI discount was down to about $17/barrel. Since end January, however, to the surprise of many industry observers, it has widened and on 15 February was at $23/barrel. The recent rebound in the WTI discount was sparked by an announcement on 31January by Enterprise Products. This stated that its Seaway pipeline from the tank farm at Cushing, Oklahoma (NYMEX delivery point for WTI) to the Gulf Coast would be operating at 175,000b/d rather than the full capacity of 400,000b/d until late 2013. The proximate cause of the cutback was the Jones Creek terminal (north of Freeport Texas) at the southern end of the pipeline reaching full capacity reflecting in part the closure for maintenance of Phillips 66's Sweeny refinery to the north-west of Houston. Enterprise has indicated that it expects the bottleneck to be removed when it completes the 65 mile Jones Creek pipeline connection to its ECHO terminal on the Houston Ship Channel. The work is expected to be completed by end 2013. ECHO will be able supply the Houston refining complex and when a further pipeline connection is added in 2014, Port Arthur to the east.

In addition to the decision on the Seaway flow rate, WTI has also continued to be constrained by inventories remaining at near record levels at Cushing in recent weeks together with buoyant Mid-Continent production. Conceptually, improving logistics between Cushing and the Gulf Coast in the form of pipelines, rail and waterways should ultimately lead to a narrowing of the WTI discount. Two further pipeline projects connecting Cushing to the Gulf Coast are expected to come on-stream over the next year or two. The first concerns TransCanada's 700,000b/d Gulf Coast pipeline, which should commence operations by late 2013. The second is Enterprise's 400,000b/d pipeline running parallel to Seaway, which is scheduled for completion in the first quarter of 2014.

Exhibit 6: WTI-Brent spread



Source: Bloomberg

Despite the increasing takeaway capacity, we would not expect to see a sharp narrowing in the WTI discount to Brent in the coming months to the $4-5/barrel level represented by pipeline fees from Cushing the Gulf Coast. Constraints on a narrowing include the shear influx of light crude expected in the Mid-Continent in the coming months, Midwest refinery conversions and the recently announced Seaway capacity cutback. On the refinery conversion front, cases in point are BP's Whiting refinery near Chicago and Marathon's Detroit refinery. The former is in the final stages of being converted to use heavy-sour crude from Canada and at the latter conversion to heavy crude feedstock has recently been completed. Longer term, there is also a question mark as to whether greater pipeline capacity will simply result in a substitution for higher cost rail shipments. If it does, the potential for a narrowing in the WTI discount might be less than currently thought by some observers.

Reflecting the constraints mentioned above we look for the WTI discount to Brent to trend down in 2013 from an average of $21.5/barrel in the first quarter to $14.0/barrel in the fourth quarter. Our average for the year as a whole is $16.9/barrel, slightly lower than in 2012. For 2014 we look for a more pronounced narrowing to $10/barrel. These forecasts assume a broadly unchanged picture geopolitically. In the event of an upsurge in geopolitical tension particularly in the Middle East, WTI could easily move to a much wider discount than currently forecast. The same probably also applies if there is another prolonged period of outages in the North Sea.

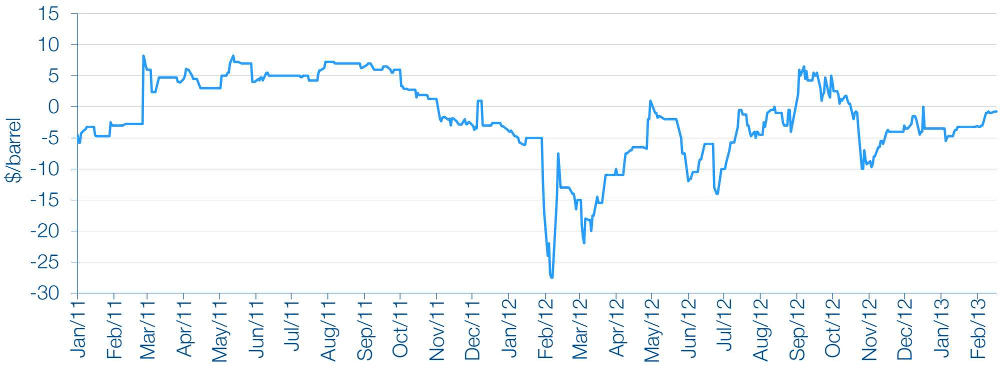
WTI Midland-Cushing spread: There are two pricing points for WTI, Cushing Oklahoma (30 miles west of Tulsa) and Midland, west Texas (300 miles west of Dallas and 400 miles south-west of Cushing), with the former serving the Mid-Continent and the latter the Permian Basin. Historically, WTI Midland has sold at a discount of a dollar or less to WTI Cushing. During 2012 the WTI Midland discount swung sharply reflecting a combination of rapidly rising production in the Permian Basin and occasional transportation bottlenecks. The year started with a discount of about

$2/barrel but by early in the second quarter it had widened to an atypical $9/barrel. This was followed by a narrowing in the third quarter to a typical $1.5/barrel or so. Early in the fourth quarter the discount widened dramatically and by mid-November hit an unprecedented $20/barrel, reflecting transportation bottlenecks and maintenance work at the Phillips 66 refinery at Sweeny. Over the balance of the fourth quarter the discount fluctuated along a volatile path between about $6 and $15/barrel. Since end 2012, the WTI Midland discount has narrowed sharply from almost $15/barrel to around $1/barrel. We believe the sharp narrowing of late reflects rising takeaway capacity.

Bakken and Syncrude spreads: Stable and narrow of late

Contrasting with the situation in the first nine months of 2012 the Bakken (Clearbrook Minnesota hub) and Canadian Syncrude (Edmonton Alberta hub) light crude spreads to WTI have been stable and narrow of late. In the case of Bakken, there has been a discount to WTI of $1-3/barrel since mid-November 2012. This compares with a premium of $6.5/barrel as recently as mid-September 2012 and a discount of $27.5/barrel in February 2012. In mid-February 2013 Syncrude was trading at a small premium of $1.75/barrel to WTI, which contrasts with a discount of about $7/barrel in mid-November, a premium of $15.5/barrel in mid-September 2012 and a discount of $23.0/barrel in February 2012.

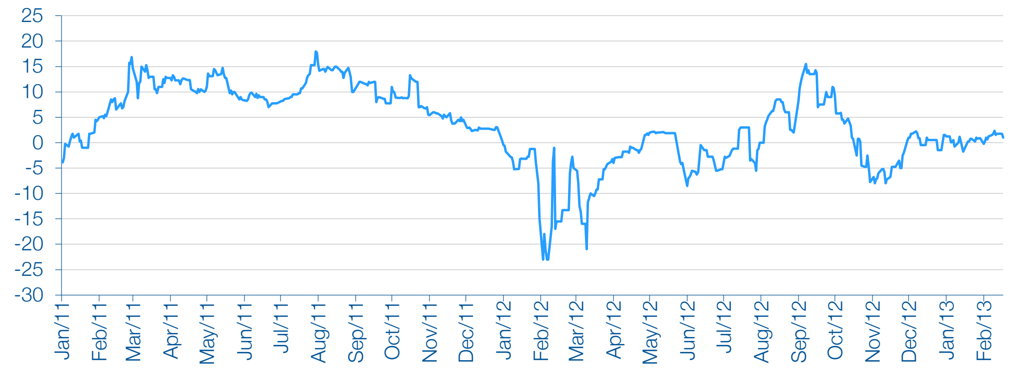
Exhibit 7: Bakken-WTI spread



Source: Bloomberg

The narrowing and then the stabilisation of the Bakken and Syncrude spreads of late reflects the increasing availability of takeaway capacity particularly by rail and production operations that appear to be running smoothly. In the absence of unplanned outages we would normally expect to see Bakken crude selling at a discount of under $10/barrel to WTI Cushing. This reflects the cost of transportation to Cushing from the Williston Basin oilfields assuming rail freight. Both Bakken and Syncrude spreads will be sensitive to refinery utilisation rates in the US Midwest and Alberta. Specifically in the case of Syncrude, spreads will also be highly sensitive to planned and unplanned outages at facilities in the Athabasca oil sands.

Exhibit 8: Syncrude-WTI spread



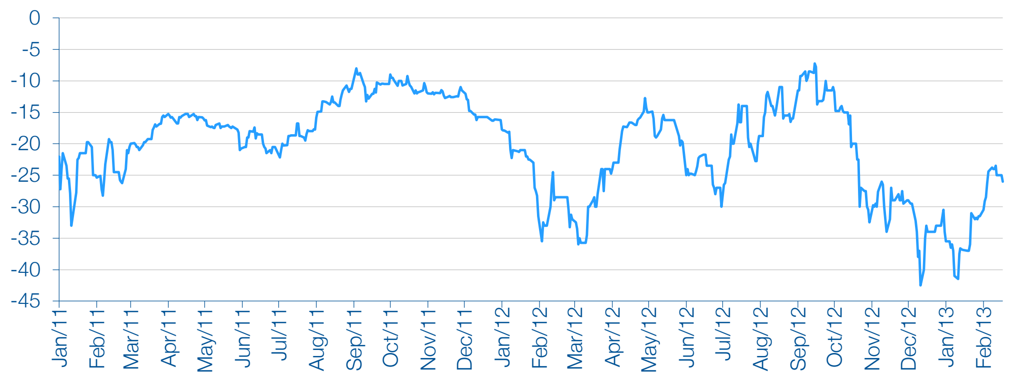
Source: Bloomberg

Western Canada Select (WCS) discount

WCS, a heavy sour Canadian blended grade with an API of 20.5%, is among the cheapest crudes available in the world. During December 2012 and early January 2013 WCS was at times trading at discounts to WTI of over $40/barrel against $7/barrel or so as recently as September 2012. Since early January the discount to WTI has narrowed but as of mid-February was still around $25/barrel resulting in a price of about $70/barrel. The earlier widening in the WCS discount appears to reflect two factors. Firstly, pipeline constraints in Alberta and secondly the partial outage at BP's Whiting refinery. Given the imminent start-up of Imperial Oil's 110,000b/d Kearl oil sands project in Alberta and delays in completing the Whiting changeover to heavy crude, the WCS discount may remain wide in the coming months. The wide WCS discount clearly has an adverse impact on the profitability of Alberta oil sands projects (excluding those that convert oil sands to syncrude), which, if sustained, could slow the pace of development.

A key factor for both the Syncrude and WCS spreads over the medium term will be the upcoming decision on whether or not to allow the 700,000b/d Keystone XL pipeline to be built from Hardisty Alberta to Steele City Nebraska and then to Cushing. A decision is expected in the first quarter of 2013 by the president/State Department.

Exhibit 9: WCS-WTI spread

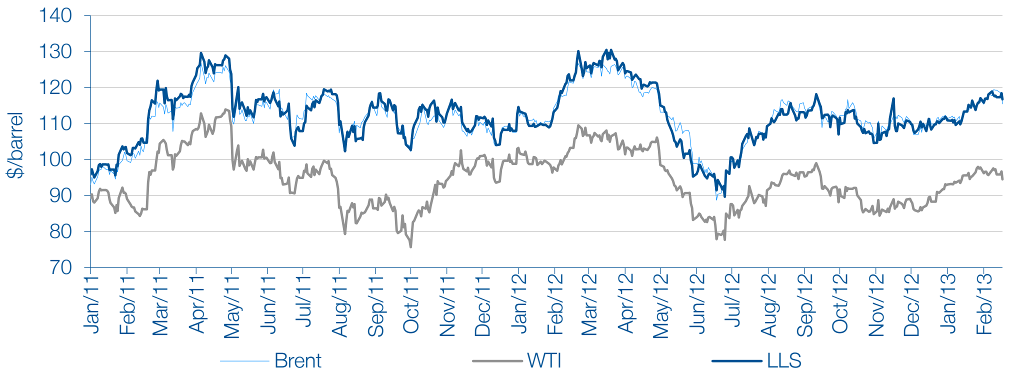


Source: Bloomberg

LLS-WTI and LLS-Brent: LLS is moving to a structural discount to Brent

Light Louisiana Sweet (LLS) is a Gulf of Mexico-sourced light crude comparable in specification to WTI and Brent. It competes with waterborne imports at Gulf Coast refineries and has traditionally traded at a $2 to $3/barrel premium to Brent. Given Gulf sourcing, LLS naturally tracks Brent rather than WTI. As a consequence, a hefty premium to WTI of $21/barrel or so has opened up over the past two or so years.

Exhibit 10: Recent trends in WTI, LLS and Brent



Source: Bloomberg

Importantly, between 2011 and 2012 LLS swung on average from a premium of $4.8/barrel to a discount of $0.2/barrel to Brent. This was a reflection of the supply build-up on the Gulf Coast of inland US-sourced light crudes. Effectively, these inland supplies are displacing imports at a rapid rate. In mid-February 2013 LLS was trading at a discount to Brent of $1.3/barrel. In the longer term we would expect to see a discount of at least $2/barrel and possibly closer to $5/barrel open up. This reflects both the underlying tight supply of Brent and the continuing influx of new supply from the Mid-Continent, Texas and Canada as new high volume pipeline capacity comes on-stream. The availability of low cost feedstock will provide refineries located along the Gulf Coast with a structural cost advantage in an Atlantic Basin context.

Exhibit 11: WTI 2009-14 quarterly prices ($/barrel)

	Q1	Q2	Q3	Q4	Average
2009	43.2	59.7	68.1	76.0	62.0
2010	78.8	77.9	76.1	85.2	79.5
2011	93.9	102.3	89.5	94.0	94.9
2012	103.0	93.3	92.2	88.2	94.2
2013e	95.5	91.7	90.0	90.0	91.8
2014e	89.0	90.0	90.0	91.0	90.0

Source: Bloomberg and Edison Investment Research

Exhibit 12: Brent 2009-14 quarterly prices ($/barrel)

	Q1	Q2	Q3	Q4	Average
2009	45.1	59.4	68.4	75.0	62.0
2010	76.8	78.6	76.4	86.9	79.7
2011	104.9	116.8	109.1	109.3	110.0
2012	118.7	108.7	109.8	110.9	112.0
2013e	117.0	108.6	105.0	104.0	108.7
2014e	102.0	100.0	99.0	100.0	100.3

Source: Bloomberg and Edison Investment Research

Other key light crude benchmarks: Urals discount normal, Dubai discount historically high, Bonny premium possibly in secular decline and Tapis premium widens.

Brent-Urals Mediterranean: Urals is a Russia-sourced medium-sour export blend that is shipped either from the Black Sea or Baltic ports. Reflecting its inferior quality in terms of gravity and sulphur Urals has typically sold at a discount of $1-3/barrel to Brent. Urals is nevertheless well suited to producing middle distillates such as diesel and can be easily shipped to the refining centres of the Mediterranean.

During the fourth quarter of 2012 the Urals discount to Brent widened significantly from the unusually low level of the third quarter when Urals was boosted by strong demand in the wake of the EU embargo on Iranian oil imports. The discount for the fourth quarter averaged $1.9/barrel against $0.66/barrel in the prior quarter. In mid-February 2013 the Urals discount was about $1.8/barrel or well within the historical range.

Brent-Dubai: Dubai Fateh is a Gulf-sourced light but relatively sour crude popular with Far Eastern refineries. Historically, Dubai has traded at a discount of about $2/barrel to the higher-grade Brent. During the second half of 2012 the Dubai discount, however, ran at a significantly higher $3.5/barrel reflecting strong demand in the Far East for grades with a high middle distillate yield and a plentiful supply of sour grades. In the first month and a half of 2013 the Dubai discount has widened still further to a historically high $5.4/barrel. Strong demand for middle distillates in the Far East appears to have been driven at least in part by colder than average winter temperatures in the region, which has boosted diesel and heating oil usage.

Brent-Bonny: Nigeria sourced Bonny is a key eastern Atlantic ultra-low sulphur light crude. Normally it trades at a premium of $1 to $2.5/barrel to Brent. After averaging $1.6/barrel in the first half of 2012, the Bonny premium slipped to an historically low $0.06/barrel in the third quarter. This was followed by a widening to $0.86/barrel in the fourth quarter and about $1/barrel in early 2013. Despite this recent widening the premium remains towards the low end of the historical range. Abstracting from supply interruptions in Nigeria, we believe that the Bonny premium to Brent may be in secular decline given the actual and potential loss of markets in the Atlantic Basin due to the increasing availability of US light crude along both the Gulf Coast and eastern seaboard.

Tapis-Dubai: Tapis is a high-quality low-sulphur Malaysia-sourced crude popular with refineries in the Far East. The spread to Dubai Fateh crude is one of the key sweet-sour crude price relationships. The Tapis premium to Dubai fell sharply during the course of 2012 from $11.9/barrel in the first quarter to $6.1/barrel in the fourth. Subsequently in early 2013 the premium has widened to about $10.8/barrel. The sharp narrowing of the Tapis premium in the second half of 2012 seems to have reflected the growing availability of West African light crudes in the Far East largely stemming from their displacement in US markets. The widening premium in early 2013 probably reflects strong demand in the Far East presently for grades with a very high middle distillates yield. As for Bonny, the Tapis premium may be lower in the future due to the US factor.

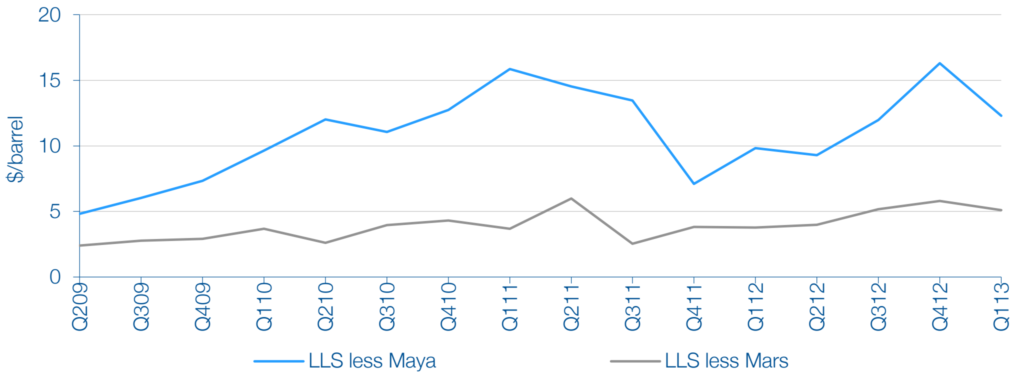
US Gulf heavy crude spreads: Heavy crude discounts narrow from H212 highs

US heavy crude discounts widened significantly in the second half of 2012. For example, the discount of Mars, a medium-sour grade sourced from the Gulf of Mexico, to LLS climbed from $2.9/barrel in June to an average $5.8/barrel in the fourth quarter. Similarly for Maya, a Mexican heavy-sour grade, the discount to LLS rose from about $7/barrel in May/June to $16.3/barrel. During the early weeks of 2013 the Mars and Maya discounts have narrowed and as of mid-February were about $5/barrel and $10/barrel respectively. US heavy crude discounts have been running at high levels of late from the perspective of the past four years or so and have provided a useful competitive advantage for those refineries with the ability to process heavy crudes.

Widening heavy discounts in earlier months reflected a combination of the increasing availability of South American heavy crudes reflecting several outages or partial outages at major refineries. These have included PDVSA's Amuay refinery in Venezuela, Motiva Enterprises (Shell/Aramco) Port Arthur refinery and Pemex's Salina Cruz facility. While PDVSA appears to be struggling to restore output at Amuay after a devastating fire last August, Motiva is about to commission a new crude distillation unit after a number of teething issues.

We would expect the demand in the Gulf/Caribbean region for heavy crudes to increase in the coming months resulting in a possible further narrowing of discounts from recent relatively lofty levels. Key factors could be the Motiva Port Arthur start-up and the commissioning of the new hydrocrackers at Valero's Port Arthur and St Charles facilities (both the Valero facilities are designed to use heavy crude). PDVSA might also have some success in restoring output at Amuay.

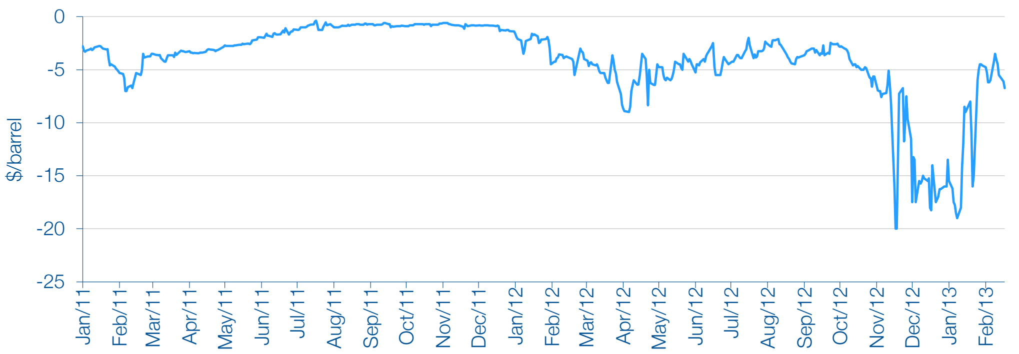
Exhibit 13: US medium and heavy discounts



Source: Bloomberg

WTS-WTI Cushing spread US: WTS (West Texas Sour) is an inland medium gravity sour grade with a specification similar to Mars and a delivery point of Midland, West Texas. In retrospect the WTS discount to WTI trended broadly flat at around $4/barrel through the first nine months of 2012, although there was a significant widening for a short period in early April to about $9/barrel. During the fourth quarter of 2012 the WTS discount widened dramatically to unprecedented levels. The average for the quarter was $9.4/barrel, but in mid-November actually reached $20/barrel at one stage. The WTS discount remained historically very high in December and early January probably reflecting transportation bottlenecks and refinery outages. Towards the end of January and in February there was a marked narrowing and by 15 February the discount was back to a reasonably normal $5.5/barrel.

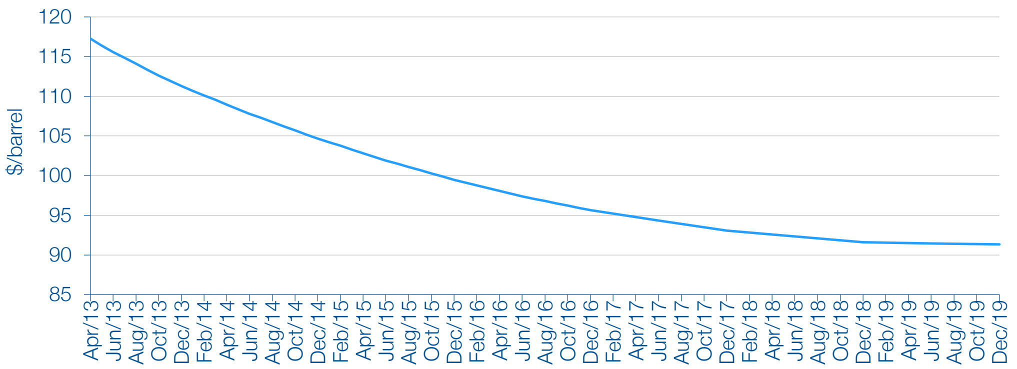
Exhibit 14: WTS-WTI spread



Source: Bloomberg

Forward curves: Brent backwardation and WTI contango remain

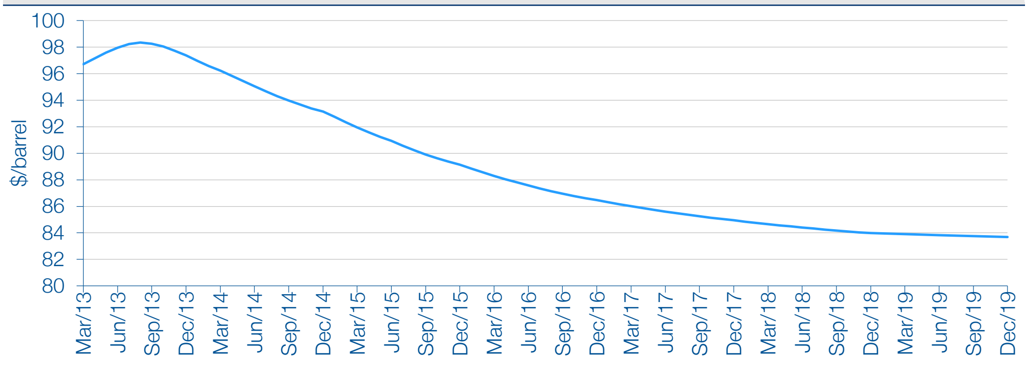
Exhibit 15: Brent forward curve



Source: Bloomberg

The forward curves for Brent and WTI have essentially retained the same profiles in recent months. WTI remains in mild contango (near-term prices lower than for the forward dates) for all dates between March and August, with a peak in the latter month of $98.3/barrel, around $2/barrel above mid-February spot prices. The contango continues to reflect the abundance of near-term supplies at Cushing. Post the third quarter of 2013, the WTI curve goes into backwardation (near-term prices higher than for the forward dates) over the next five years or so, reaching $84.8/barrel by early 2018. Over the subsequent period to end 2021 the curve flattens and terminates at $83.5/barrel.

Exhibit 16: WTI forward curve



Source: Bloomberg

The Brent forward curve remains in significant backwardation through late 2017, reflecting pronounced near-term supply constraints and indeed the expectation that these might persist. From an April 2013 forward price of $117.3/barrel the curve dips to $111.3/barrel by end 2013 and $95.6/barrel by end 2017. By end December 2019 the curve terminates at $83.7/barrel. The two forward curves imply a narrowing of the WTI discount to Brent from $13.9/barrel in December 2013 to $8.1/barrel in December 2017 and $7.6/barrel in December 2019.

Global supply/demand balance:

2012: Sizeable surplus

Globally, oil supply appears to have comfortably covered demand in 2012. There was, however, a tightening tendency between the first and second halves. Based on IEA data the market was in supply surplus to the tune of 1.7mmb/d in both the first and second quarters. In the third quarter the surplus dipped to around 0.8mmb/d while in the fourth quarter the market may have been in approximate balance. For 2012 as a whole there appears to have been a supply surplus of about 1.1mmb/d.

2013/14: Strong increase in non-OPEC production scheduled, demand relatively subdued

At first glance, at least, the backdrop to the global oil supply/demand balance in 2013 looks fairly benign. The IEA and OPEC are both forecasting demand growth of 0.84mmb/d (1.0%), while the EIA is looking for a larger gain of 1.05mmb/d (+1.2%). These forecasts are broadly similar to the estimated outcome for 2012 and appear reasonable assuming the IMF's world GDP growth forecast of 3.5%. As in 2012, a decline in demand in the OECD world will probably be moderately offset by a gain in developing countries led by China, the Middle East and Latin America. Non-OPEC controlled supply growth in 2013 should be robust. OPEC is looking for a gain (including OPEC NGLs) of about 1.2mmb/d while the IEA and EIA are forecasting growth of 1.3mmb/d and 1.4mmb/d respectively. Therefore 2013 could show one of the larger increases in non-OPEC supply over the past 10 years and with the US and Canada being the key drivers. These two sources, in fact, are expected to account for about 80% of non-OPEC controlled supply growth.

Assuming non-OPEC controlled supply growth of about 1.4mmb/d and a gain in global demand of say 0.9mmb/d, the implied surplus would be a comfortable 0.5mmb/d in 2013. OPEC, however, is unlikely to maintain crude output in 2013 at prior year levels of 31.2mmb/d in the absence of major supply interruptions. As always, therefore, OPEC production is a wild card for the overall supply/demand balance in 2013. In the event that OPEC crude production remains moderately ahead of the official target of 30mmb/d, which we think is likely given the likelihood of expansion in Iraq and maybe some other OPEC members such as Angola and Nigeria, the market overall might be broadly balanced. There are, of course, other potentially negative wild cards surrounding the supply outlook in 2013. These include US and EU sanctions on Iran and the possibility of further major unplanned outages in the North Sea and maybe elsewhere.

The outlook for non-OPEC controlled supply in 2014 appears highly positive. This reflects burgeoning North American production growth, pre-salt development activity offshore-Brazil and the giant Kashagan field in the Caspian Sea hopefully coming on-stream after a lengthy development programme. The EIA is forecasting growth in global non-OPEC crude supply and OPEC NGLs in 2014 of 1.7mmb/d, up 0.3mmb/d on 2013. Demand growth globally in 2014 is forecast by the EIA at 1.41mmb/d, reflecting the assumption of strengthening economic activity. Abstracting from the recovery from the 2008/09 dip in 2010, this would be one of the strongest gains in demand since the mid-2000s. The anticipated growth in output in 2014 would nevertheless still imply a modest surplus before allowing for any changes in OPEC production.

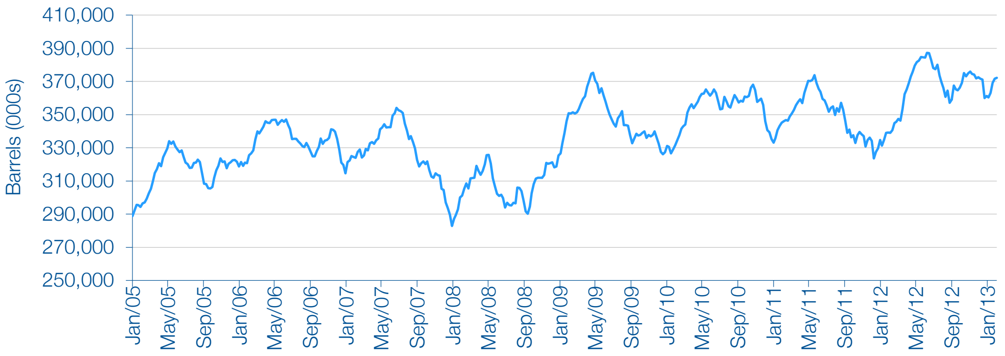
At this stage we would be sceptical that global oil demand growth in 2014 will be as strong as suggested by the EIA. We would make three points. Firstly, we believe it is based on a GDP growth forecast of over 4% (the IMF is looking for 4.1%), which may be optimistic given the structural challenges surrounding the world economy. Factors such as balance sheet deleveraging, tightening banking and environmental regulation and an overhang of commercial and residential property will in our view conspire to constrain economic growth for the foreseeable future. Secondly, advances in automotive technology imply a highly significant enhancement in the fuel economy of the vehicle fleet over the balance of this decade and beyond. Thirdly, demand growth of significantly over 1mmb/d may result in a surge in refined product prices, which, given the fragile state of the world economy, would probably trigger a rapid slowdown in economic growth. We suspect that in practice the world may be incapable of boosting petroleum supply on a trend basis by much more than 1mmb/d per year net of depletion, even allowing for the shale revolution.

US inventories

Crude oil: Rarely been higher

US commercial crude oil inventories, although slipping from the recent 2012 fourth quarter highs, have remained at elevated levels by historical standards in early 2013. In fact, inventories have rarely been higher over the past 30 years. Based on EIA data inventories reached a fourth quarter 2012 high of 375.9mm barrels on 9 November. In the period to end year there was a seasonal decline to 359.9mm barrel but subsequently inventories have risen. On 8 February 2013 they stood at 372.2mmb/d, up 33mm on a year previously and about 35mm above the upper end of the five-year range for the time of year.

Exhibit 17: US crude oil inventory



Source: EIA

On a days' supply basis inventories also remain seasonally high. For the week ending 8 February 2013 inventories were the equivalent of 25.9 days, against 23.5 days a year previously. The days' supply of late have returned to peak levels during the second quarter of 2012 and are close to a 20-year high. Including the strategic petroleum reserve crude inventories on 8 February 2013 were 1,068mm barrels, equivalent to about 74 days' supply.

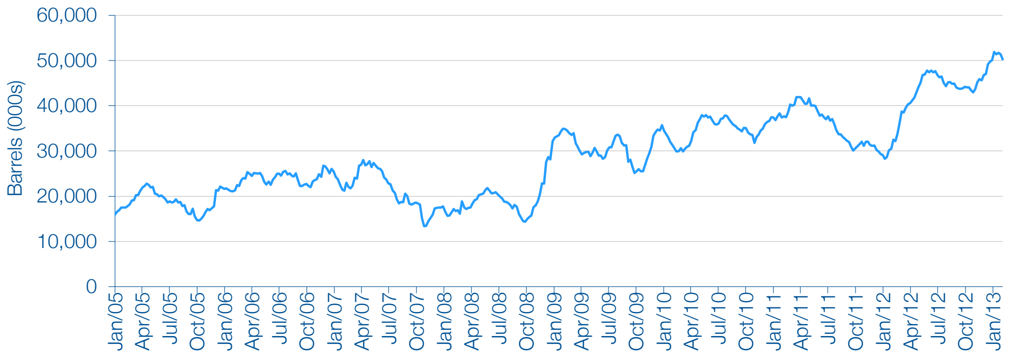
Historically high crude oil inventories continue to reflect buoyant US Mid-Continent production and export transportation bottlenecks surrounding the Cushing hub. Refinery runs and utilisation rates have actually been running at seasonally high levels of late. The former, for example, averaged 14.76mmb/d during January against 14.51mmb/d a year earlier while the refinery utilisation rate was 86.4% against 83.3%. It should be noted in this context that refinery runs and utilisation normally dip in January and February for maintenance and reconfiguration ahead of the changeover from heating oil to gasoline. Refinery runs and utilisation in December were, in fact, the highest since 2007 and 2006 respectively. Both variables have been supported by rising net exports of refined products.

Cushing: Close to record levels

Crude oil inventories at Cushing, Oklahoma, the world's largest tank farm and the delivery point for Nymex crude, reached record levels of 51.9mm barrels on 11 January 2013. Compared with end November and a year earlier there were hefty gains of 6mm and 23.6mm barrels respectively. In the week to 8 February inventories were only slightly lower at 50.2mm barrels and up 17.7mm barrels on a year earlier. Cushing's inventories have been propelled by a continuing build-up of Mid-Continent production and increasing supplies from Canada following earlier upgraded pipeline connections. In addition, in the month or so to early January Cushing's inventories probably received an extra boost from the temporary closure of the Seaway pipeline while the final measures were being taken to raise capacity from 150,000b/d to 400,000b/d.

Now that Seaway is back on-line, albeit at less than full capacity, inventories at Cushing may at least stabilise in the coming weeks. Over the next few months the inventory build-up at Cushing may also be alleviated to some degree by new and expanded pipeline capacity linking the Permian Basin with the Gulf Coast directly. Near term, at least, any dip is not expected to be dramatic given the buoyancy of Mid-Continent production, increasing Canadian supplies and the issue of refinery conversions, notably at BP Whiting and Marathon Detroit, which will reduce demand for crude grades related to WTI.

Exhibit 18: Cushing crude inventories



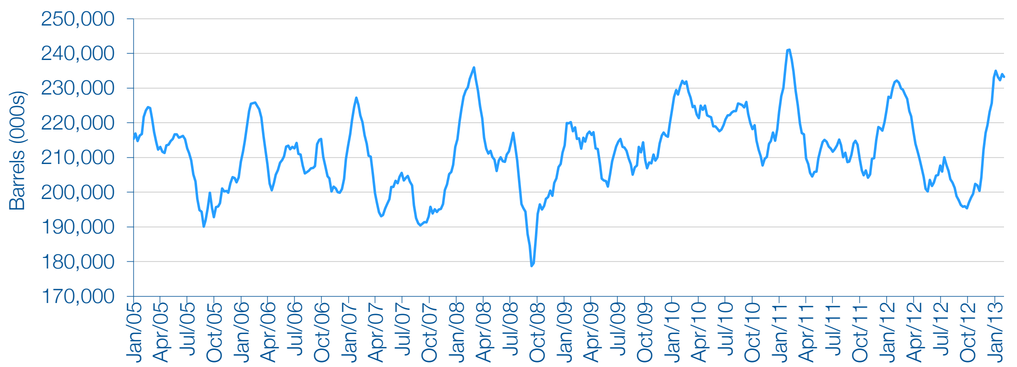
Source: EIA

Gasoline: Seasonally high

After showing seasonally strong declines in the second and third quarters of 2012, gasoline inventories regained strong upward momentum in the closing months of the year and in early 2013. This in part reflects seasonal trends as refiners build inventory ahead of the late first quarter and early second quarter maintenance season. Inventory building has, however, been seasonally strong of late, reflecting buoyant refinery runs in response to attractive crack spreads and lacklustre domestic demand. Gasoline inventories on 8 February at 233.2mm barrels were 1.0mm above a year earlier and at the high end of the range for the time of year.

On a days' supply basis gasoline inventories are also historically high. In the week ending 8 February inventories were equivalent to 27.6 days. This was slightly down on a year previously but at a relatively high level historically.

Exhibit 19: US gasoline inventories



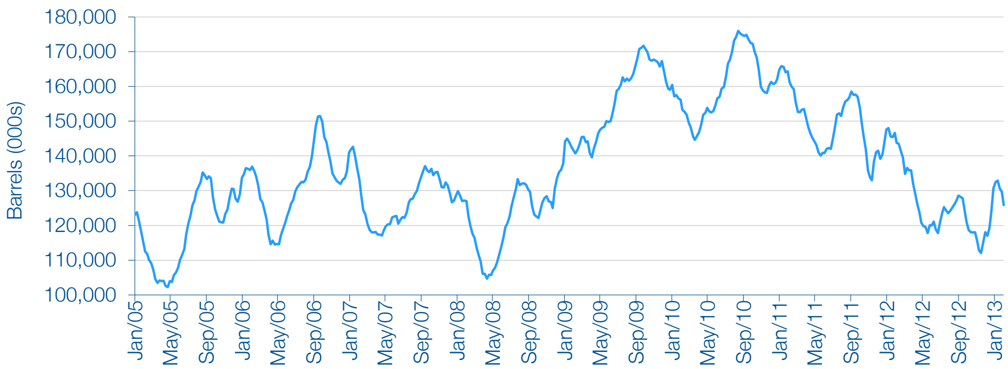
Source: EIA

Distillates: Seasonally low probably driven by surging exports

Contrasting with gasoline, US distillate inventories trended flat to down for most of 2012, which left them at or below the lower level of the seasonal range by end year. Subsequently, there has been a rebound that has taken inventories to slightly above the lower end of the seasonal range. For the week ending 8 February distillate inventories stood at 125.9mm barrels, down 17.8mm barrels on a year earlier. The latest reading was equivalent 34.4 days' supply against 38.7 days in 2012. Although significantly down from the highs in recent years of about 50 days, reported days' supply in recent weeks are not out of line with longer-term trends.

We believe the downward trend in distillate inventories has been very much driven by the ongoing surge in US distillate net exports. These increased in 2012 by about 22% to around1mmb/d. Importantly, crack spreads tend to be higher on export than on domestic shipments so there is a natural tendency to prioritise the former.

Exhibit 20: US distillate inventories

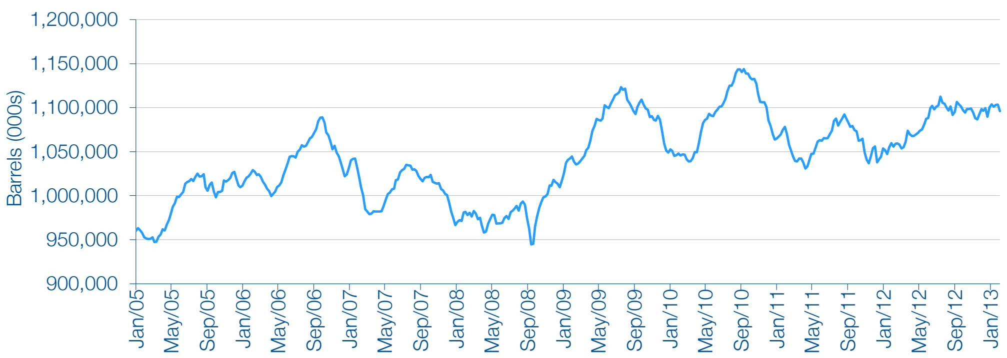


Source: EIA

All petroleum product inventories: Remaining close to 2010 high

We believe the soundest basis for assessing the adequacy of petroleum inventories is on the all-encompassing definition. Based on EIA data for 8 February 2013, US commercial crude and refined product inventories were 1,095.9mm barrels, up 40.3mm barrels or 4% on a year earlier. Total commercial inventories on 8 February were close to the July third-quarter high of 1,112.6mm and within about 4% of the post 2000 high of 1,143.5mm barrels recorded in September 2010. There is little doubt about commercial inventories running at historically high levels.

Exhibit 21: US all petroleum product inventories



Source: EIA

US petroleum product demand

2012: Down by almost 2%

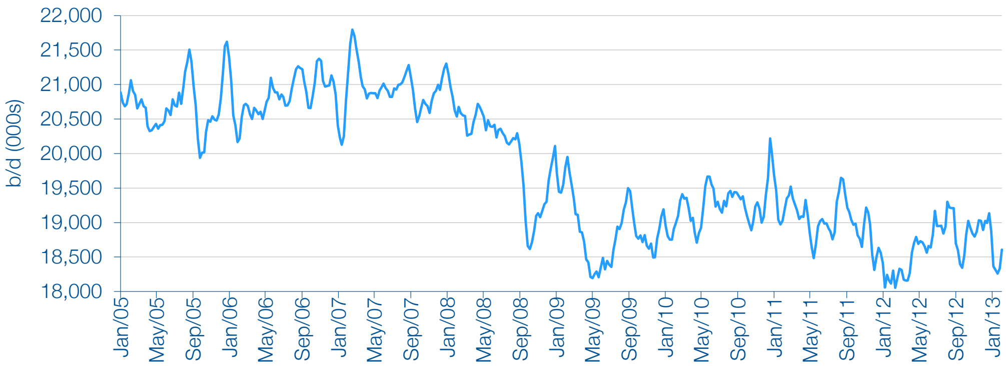
According to EIA data for products supplied, US petroleum demand fell by 1.8% to 18.60mmb/d in 2012. This was the second consecutive year of decline and was part of a longer-term trend that has seen demand drop 10% from the all-time annual peak of 20.8mmb/d in 2005. On a weekly basis, product supplied reached an all-time high of 22.2mmb/d in December 2005. During 2012 the trend in the early months reflected carryover weakness from 2011, but in the second half there was a firming tendency.

All major product groups showed year-on-year declines in 2012. Gasoline, the largest, reflected a decline of 0.3% to 8.72mmb/d, which left a shortfall of 6% compared with the 2007 peak of 9.29mmb/d. The improving fuel economy of the vehicle fleet and declining miles driven continued to weigh on gasoline consumption in 2012. Distillate consumption in 2012 was off 3.8%, while kerosene and a residual miscellaneous group dropped by 0.2% and 3.1% respectively. The decline in distillates may appear surprising. The drivers were the mild winter of 2012/13, which cut heating oil usage, and lower railroad activity due to declining grain and coal shipments. Partly offsetting these areas of weakness was increasing diesel usage in highway trucks.

2013/14: Demand continues to show signs of firming

The firming trend in US demand noted in the closing months of 2012 has continued in early 2013. Based on EIA data for products supplied, demand in the four weeks to 8 February averaged 18.61mmb/d, up 1.6% from a year previously. In terms of the product mix the year-on-year movements in the four weeks to 8 February were as follows: gasoline +4.4%, distillates -1.4%, kerosene +2.2%, fuel oil 38.5%, propane/propylene +14.9% and miscellaneous -2.0%. The strong showing by gasoline was a little surprising and probably reflects a more buoyant economy along with an easy year ago comparison when the trend was very weak. The continuing weakness in distillates probably reflects similar factors to 2012. In the case of propane/propylene the strong gain is likely to have been driven by the rapidly increasing supply of natural gas liquids and expansion programmes in the petro-chemicals sector.

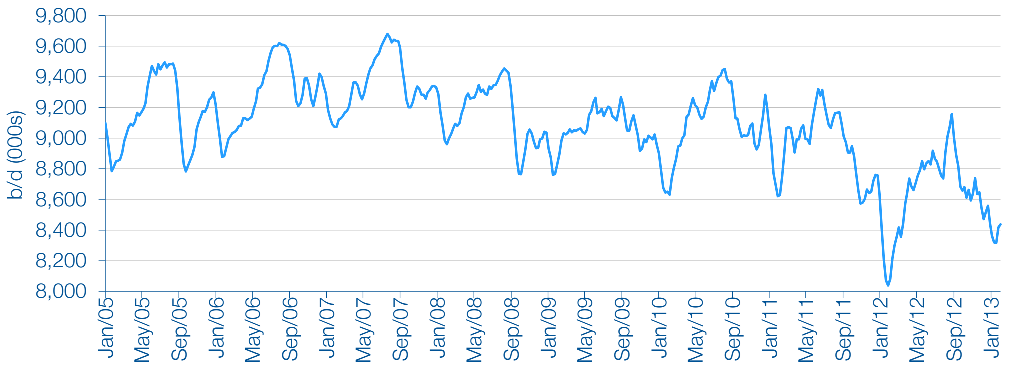
Exhibit 22: US petroleum products supplied



Source: EIA. Note: Data are four-week averages

The EIA is looking for a slight firming in US petroleum product demand over the next two years. For 2013 and 2014 marginal growth is expected with gains of 0.3% to 18.65 and 0.4% to 18.72mmb/d respectively. Demand for gasoline and kerosene is forecast to be flat over the two years, but modest gains are anticipated for distillates and miscellaneous. The key positives are expected to be a return to normal winter weather and heating oil demand and a continuing upward trend in the usage of natural gas liquids in petro-chemicals. In the case of gasoline, ongoing improvements in vehicle fuel economy and possibly further declines in miles driven are expected to constrain the growth in consumption despite the prospect of a more buoyant economy. The EIA's GDP growth assumptions are 1.7% for 2013 and 2.6% for 2014. Given these and bearing in mind the structural factors tending to depress demand in the transportation sector, we believe the EIA forecasts of modest growth for petroleum products demand growth in 2013/14 are entirely plausible.

Exhibit 23: US gasoline supplied



Source: EIA. Note: Data are four-week averages.

Crude oil price outlook: Less than bullish supply/demand influences should gradually take hold in 2013

International crude oil prices in early 2013 have been running at substantially higher levels than might have been expected based on the fundamentals. After all, non-OPEC production appears to be trending higher, OPEC production has been holding up as well as could be expected, global demand remains fairly subdued and inventories generally are historically high in the OECD. The market overall, in fact, is pretty well balanced while in the US it is clearly in surplus. The key question then becomes why Brent was trading in early to mid-February 2013 at a nine-month high and indeed, historically high levels. The explanation appears to reflect in large part correlated markets. Since end 2012, equity and commodity markets in general have all moved in tandem driven by growing optimism concerning the outlook for the world economy. The avoidance, at least for now, of a hard landing for the Chinese economy and the apparent rolling back of the European sovereign debt crisis has been particularly influential in this regard.

Our view is that international crude oil prices may continue to be buoyed over the balance of the first quarter of 2013 by the new-found bullishness in financial and commodity markets as part of a broader 'risk-on' phenomenon. A spot high of over $120/barrel for Brent would not be surprising. Much will depend on the news flow out of China and the US. However, by early in the second quarter we believe that international prices could start to reverse some of the gains of the year-to-date. Assuming the world economy develops in 2013 much as anticipated by the IMF, we would then expect to see prices move around a flat to declining trend over the balance of the year as less than bullish supply/demand influences take hold. Our quarterly scenario for Brent in 2013 is as follows: Q1 $117.0, Q2 $108.6, Q3 $105.0, Q4 $104.0. This would imply a full-year average of $108.7/barrel, which constitutes a significant upgrade from the $99.0/barrel forecast previously. The key factor behind the upgrade constitutes the very strong start to the year driven by euphoria in financial markets and bullish China influences.

For 2014 we look for Brent to average $100.3/barrel with the decline from 2013 reflecting the anticipated upward trend in non-OPEC and quite possibly OPEC supplies driven by Iraq. Note here that increasing North American supplies should have a positive impact on oil supplies overall by displacing imports from OPEC and elsewhere. This should help depress prices internationally.

Clearly, the market dynamics driving WTI are substantially different than those affecting Brent, reflecting strong upward supply influences and transportation bottlenecks in the US. These factors, we believe, will keep WTI at a highly significant discount to Brent of about $17/barrel on average in 2013. Our quarterly scenario for WTI is as follows: Q1 $95.5, Q2 $91.7, Q3 $90.0, Q4 $90.0. This would imply an average price for the year of $91.8/barrel, up $5.3/barrel on the earlier forecast but down $2.4/barrel on 2012. For 2014 we look for a narrowing of the WTI discount reflecting increasing pipeline capacity between Cushing and the Gulf Coast. However, as noted previously, we think it likely that the discount will remain comfortably above pipeline tariffs of $4-5/barrel due to the shear influx of the supplies expected in the Mid-Continent and considerably higher rail transportation freight rates. Refinery conversions to heavy oil may also tend to subdue demand for light crude in the Mid-Continent. On average, we are looking for WTI to average $90.0/barrel in 2014 with a broadly flat trend between the first and fourth quarters.

What about geo-political issues and outages? As of early 2013, geo-political tension was relatively subdued in major oil producing regions with the possible exception of Iran. The price forecasts assume that geo-political tension does not change significantly from current levels. We also assume that there is no repeat of 2012's extreme intensity of unplanned outages. In the event that geo-political tension intensifies substantially or we see a recurrence of the 2012 outages, prices would probably be significantly higher than indicated. In this event there would also be a reverse feedback loop to demand, particularly in Europe and North America. We have seen the implications for demand destruction in the US once retail gasoline prices approach $4/US gallon ($1.06/litre) and we are seeing the impact now in Europe at prices of approaching $9/US gallon ($2.40/litre).

Exhibit 24: Brent and WTI price scenarios

$/bbl	2005	2006	2007	2008	2009	2010	2011	2012	2013e	2014e
WTI	56.6	66.1	72.2	99.8	62.0	79.5	94.9	94.2	91.8	90.0
Brent	54.5	65.4	72.7	97.7	62.0	79.7	110.0	112.0	108.7	100.3

Source: Bloomberg and Edison Investment Research. Note: Prices are averages.

US natural gas market

Production and consumption: Production continues to level-off, January consumption robust

Recent trends

The trend in US gas production was broadly flat between end 2011 and end 2012. During 2012 year-on-year rates of change ebbed from 10% and 15% in January and February respectively to 1.8% in November, the most recent month for which data is available. The hefty gains at the beginning of year reflected favourable comparisons due to adverse weather conditions in early 2011. For 2012 as a whole US marketed natural gas production rose by about 5.3% to a record 25.3tcf reflecting the strength of the early months. Regionally, production in 2012 was very much driven by Appalachia, reflecting rapid development of the Marcellus formation. Based on EIA data, 'other' states, which include areas covered by the Marcellus formation (Pennsylvania and West Virginia), showed a year-on-year gain of 22% to 7.1tcf through the 11 months to November. 'Other' states are now comfortably the largest source of gas in the US. Another strong performer in 2012 was Oklahoma with a gain of 7%. Texas, traditionally the number one producer, showed an increase of about 2.5% in 2012. Contrasting with these areas of strength was the Gulf of Mexico, where production continued to fall sharply. For the year as a whole we estimate a decline of about 17%.

The flattening trend in US natural gas production during the course of 2012 reflected a combination of declining dry gas drilling activity and well shut-ins as gas industry economics deteriorated. Helping support production has been by-product gas output in the shale oil plays. Significantly, the net import balance continued to decline and for the year was probably down by about 20% to 1.5tcf. Net imports are now about 40% of peak levels of 3.8tcf in 2007. Gross imports largely consist of pipeline gas from Canada. LNG imports have fallen to nominal amounts of about 170bcf with the remaining quantity probably reflecting residual long-term contracts.

US natural gas consumption is estimated to have risen by about 4% to a record 25.4tcf in 2012. After running at relatively depressed levels in the early months of the year due to mild weather in the Northeast and Midwest cutting commercial and home heating usage (roughly 50% of households use gas for space heating), consumption strengthened in the subsequent months driven by an increasing gas burn rate in power generation. For 2012 as a whole, power related gas consumption surged by around 23% to 9tcf making this easily the largest gas consuming sector. In 2012 gas usage in power generation was also comfortably a record. According to EIA data, between 2011 and 2012 natural gas's share of the power generation market increased from 25% to 31%, while that of coal fell from 43% to 37%. The rising share of gas reflected sharply enhanced competitiveness compared to coal in the first half of the year driven by the collapse in gas prices.

Industrial, the second largest market for natural gas, showed a gain of 3% in 2012, driven by rising activity in the process industries where gas is often used as a furnace fuel. Partially offsetting the gains in power generation and industrial in 2012 were declines in usage in residential and commercial markets of 13% and 9% respectively.

Outlook

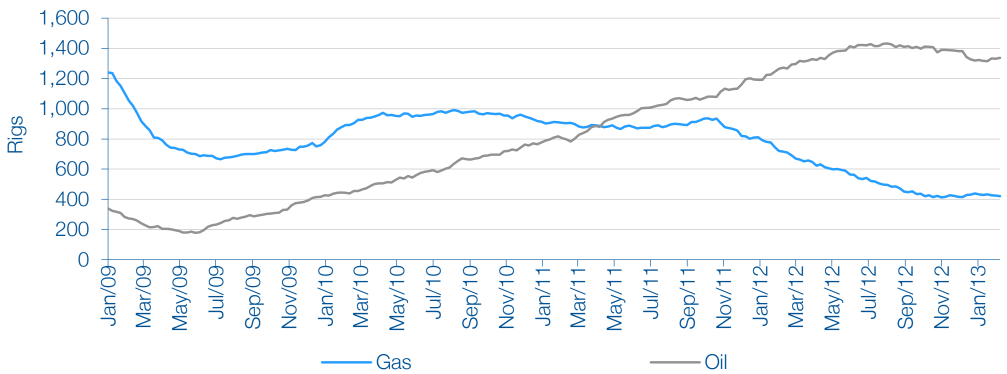
Given the decline in the gas orientated rig count over the past year, the days of surging US gas production would seem to be over in the near term. Drilling activity in the liquids-rich Marcellus zone nevertheless remains buoyant and near-term production here is likely to continue to be buoyed by by-product gas output from shale oil plays. The EIA is looking for a 1.2% gain in 2013 and unchanged output in 2014.

The early indications for 2013 point to significantly stronger US natural gas consumption in residential and commercial markets than a year earlier. According to Bentek Energy LLC, an Evergreen, Colorado energy research/consultancy concern, consumption in these markets in January was 12.4% above a year earlier. The reason was simply a return to more normal winter temperatures in the US. A cursory observation of the weather so far in February in the Northeast and Midwest suggests that there should be a further significant year-on-year gain in February. The key issue now concerning the consumption outlook for 2013 relates to power station gas usage. The EIA is suggesting a decline in the gas burn rate between 2012 and 2013 from 30.3% to 27.6%. This is due to an assumed partial reversal of 2012's gain in price competiveness against coal stemming from an anticipated firming in natural gas prices. Currently, the EIA is forecasting a 7.5% drop in power station gas usage in 2013 and a further 2.3% decline in 2014. Overall, the EIA is looking for a modest 1.2% gain in US gas consumption in 2013 and a decline of 2.3% in 2014. Essentially growth in commercial, residential and industrial usage in 2013 is expected to be largely outweighed by the anticipated decline in power station usage.

Drilling activity and rig count: Unless the rig count rises in 2013/14 production could dip in 2015

After trending down between early and late 2012, the US rotary rig count appears to have stabilised in recent weeks. According to Baker Hughes, the rig count overall on 8 February 2013 was 1,759, down 12% from a year earlier and 13% under the all-time high of 2,026 reported in November 2011. The earlier slide in the rig count was very much gas driven. In the year to 8 February the gas focused rig count fell by 41% to 425. Interestingly, the gas rig count is up 12 from the recent November low. Given that the oil rig count did not peak until August 2012, the series is still showing year-on-year gains. In the year to 8 February there was for example a gain of 5.3% to 1,330 but compared with the August peak of 1.432 there was a decline of 7%. The oil rig count therefore remains at a historically very high level and massively above the June 2009 low of 179.

Exhibit 25: Baker Hughes US rig count



Source: Baker Hughes, Bloomberg

The decline in the US gas rig count in 2012 pretty well paralleled the slump in gas prices. Clearly at the sub $3/mmBtu Henry Hub prices prevailing for much of 2012 it would have been virtually impossible to justify drilling for dry gas given that finding and development costs are typically in the region of $2/mcf. We continue to believe that the bulk of gas rigs are currently devoted to either meeting lease commitments or focused on liquids rich plays notably, the Marcellus and Utica and the Eagle Ford in Texas. Oil drilling, of course, remains lucrative at the early February WTI price of around $96/barrel.

We believe that the gas rig count is unlikely to show a sustained upward move from current levels until benchmark gas prices rise decisively above $4/mcf. Unless the rig count rises during 2013/14 US gas production could dip in 2015.

Inventories: Seasonally high

US natural gas inventories remain at a historically high level seasonally but the situation is not quite as extreme as in 2012. Based on EIA data, inventories for 1 February 2013 were 2,684 bcf which was 226 bcf below year ago levels but 351 bcf above the five-year average for the time of year of 2,333 bcf. Inventories, indeed, remain towards the high end of the seasonal range. Winter weather conditions in 2012/13 have clearly be more conducive to withdrawals from storage than a year earlier with temperatures in the Lower 48 in early February 3.7 degrees lower. This, however, still left them 5.1 degrees above the 30-year norm. In the absence of some extremely severe weather over the next few weeks inventories are likely to remain above average as the injection season starts at the beginning of April. They are nevertheless likely to be somewhat lower than the exceptionally high levels a year earlier.

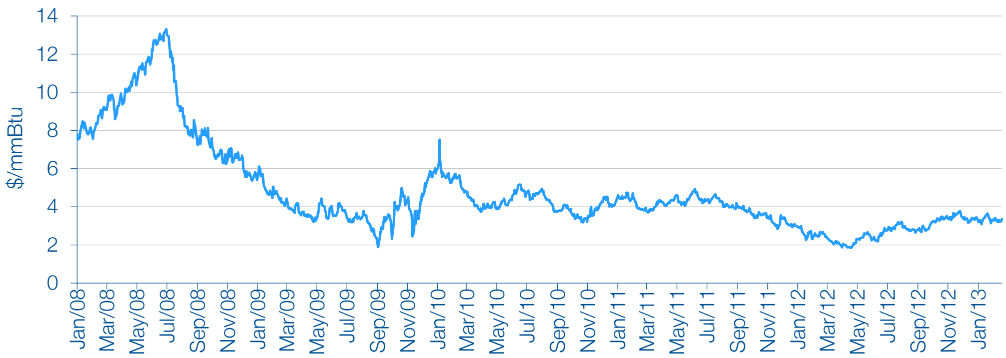
Recent price developments: In recent weeks gas trend weak, ethane broadly flat

Dry gas: The Henry Hub, Louisiana benchmark natural gas quote strengthened noticeably between the third and fourth quarters of 2012 and reached a 15-month high last November of $3.77/mmBtu. Overall, however, the trend in recent months has tended to disappoint the bulls such as Boone Pickens, the legendary former oil man and now fund manager, who expected the Henry Hub price to hit $4.00/mmBtu by end 2012. It actually closed 2012 at $3.43/mmBtu. Since then, the trend has been moderately down with the price at $3.28/mmBtu on 13 February. This was nevertheless up 36% on a year earlier and 80% on the April 2012 low of $1.82/mmBtu. At the other major hubs in the Gulf Coast and Western regions gas was trading on 13 February at similar levels to the Henry Hub. By contrast, at North-eastern hubs such as Algonquin City Gate, prices have recently been in excess of $30/mmBtu due to infrastructural constraints at a time of heavy demand. The subdued trend of recent months at major Gulf Coast and Western hubs has tended to reflect a combination of still historically high inventories, no sustained extreme weather conditions and continuing gains in US natural gas production, albeit at a considerably slower pace than hitherto.

In the absence of severe weather in the Midwest and Northeast we would expect the Henry Hub quote to trade within the recent range of $3.153.55/mmBtu over the balance of the first quarter. We think readily available supplies will prevent a breakout to the upside, while on the downside prices should be supported by relatively cool weather conditions and a modestly firming trend in US economic activity. After firming moderately in the second quarter to $3.40/mmBtu, we look for a more pronounced upward movement in the third quarter to $4.00/mmBtu, driven by seasonal influences associated with strong demand for electricity associated with heavy air conditioner usage during the summer months. This factor has tended to become more pronounced in recent years. In the fourth quarter of 2012 we look for a dip to $3.55/mmBtu on the basis that mild weather conditions tend to prevail in the fall. The average for 2013 on this scenario would be $3.58/mmBtu, which is slightly higher than our earlier forecast of $3.40/mmBtu and up 30% on 2012.

For 2014 we are anticipating that the Henry Hub quote will trend significantly higher. The expectation is that as production growth tails off and maybe even turns negative the market will tighten, thereby allowing a firming of prices. We believe this tendency will become more pronounced in the second half of 2014 as market participants discount a possibly significant drop in output in 2015. Boone Pickens was probably just a little too early in his late 2012 call. On average for 2014 we look for the Henry Hub to average $4.00/mmBtu.

Exhibit 26: Henry Hub price trend



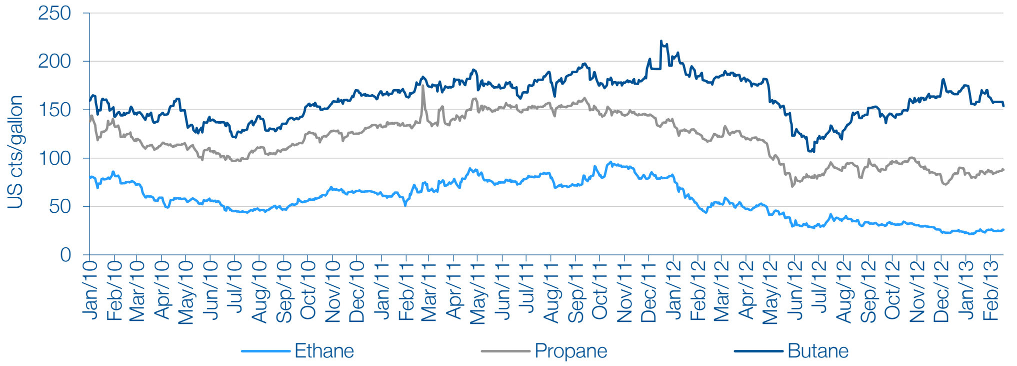
Source: Bloomberg

NGLs: Natural gas liquids such as ethane, propane and butane are important petrochemical feed stocks, gasoline blending agents and fuels, and are valuable by-products of natural gas production. US production of NGLs has been growing rapidly in recent years in tandem with the development of liquids-rich natural gas reserves. In 2012 production, according to the EIA, was 2.41b/d, up 8.6% on 2011.

Prices of US NGLs collapsed in late 2011 and the first half of 2012. Between the high point in late 2011 and end June 2012 ethane, propane and butane fell by roughly 75%, 46% and 48% respectively. Particularly in the case of ethane, a key use of which is in the production of ethylene, prices fell to historically depressed levels. The heavy pressure on prices reflected the lagged impact of an influx of supply combined with a near-term inability to step up domestic demand or exports. Since the June 2012 low, ethane has trended essentially flat and in mid-February 2013 was trading at about $0.24/gallon, Mont Belvieu Texas. Propane and butane, however, have turned in stronger performances in recent months. The price of the former, for example, is up from the June 2012 by about 23% to $0.86/gallon, while the latter has risen on the same basis by 50% to $1.58 /gallon. Both prices are ex Mont Belvieu. Compared with a year ago, ethane, propane and butane prices are currently down by 36%, 28% and 12% respectively.

By providing internationally low cost feedstock, the 2011/12 slump in NGLs has provided a tremendous boost to the US petro-chemical sector. Based on industry estimates ethylene (a key building block for a wide range of plastics), for example, can now be produced in the US at about $250/tonne, which is more in line with costs in Saudi Arabia. The boost to competiveness from low-cost feedstock and also natural gas is now stimulating interest in capital investment in the US petrochemical sector. Major projects are planned by the likes of Exxon, Dow, Formosa Plastics, Lyondell Basell and Sasol. This will potentially boost demand between now and 2020 substantially. Meanwhile, NGL production growth will probably slow significantly over at least the next two years as investment in the natural gas sector is scaled back. The EIA is forecasting growth of 2.6% in 2013 and 0.4% in 2014.

Exhibit 27: Recent trends in US NGL prices



Source: Bloomberg. Note: Prices are ex Mont Belvieu, Texas.

The upshot of the above is that we have probably seen the low point in NGL prices and that a firming trend is likely over the next two years as the supply/demand balance tightens. We would, however, still expect NGL prices to be internationally competitive over at least the next two years.

Economics: $3.30/mmBtu implies only a cash contribution, NGLs enhance the picture

At a price of $3.30/mmBtu we believe that a typical US dry gas producer is probably able to generate a reasonably comfortable cash contribution. This assumes operating costs of $1.5/mcf (including lifting costs, production taxes and royalties), $0.9/mcf for SG&A and $0.2/mcf for processing and pipeline tie-in. Including finding and development costs, however, of perhaps $1.5-2.0/mcf, a significant loss would be implied.

For wet gas producers the picture is potentially considerably more attractive, depending on the price and quantity of NGLs available. Particularly in the liquids-rich gas from shale formations in the Eagle Ford and Marcellus formations, NGLs can boost realisations by a further $2/mcfe or more to approaching perhaps $5.5/mcfe. This would probably imply a comfortable fully accounted profit at current prices even after allowing for greater processing costs.

Exhibit 28: Henry Hub quarterly price scenario

$/mmBtu	Q1	Q2	Q3	Q4	Average
2008	8.66	11.37	9.06	6.45	8.89
2009	4.54	3.70	3.17	4.37	3.94
2010	5.15	4.15	4.32	3.86	4.37
2011	4.18	4.37	4.12	3.33	4.00
2012	2.43	2.29	2.88	3.40	2.75
2013e	3.35	3.40	4.00	3.55	3.58

Source: Bloomberg, Edison Investment Research

Exhibit 29: Henry Hub natural gas price trend

	2005	2006	2007	2008	2009	2010	2011	2012	2013e	2014e
$/mmBtu	8.79	6.72	6.96	8.89	3.94	4.37	4.00	2.75	3.56	4.00

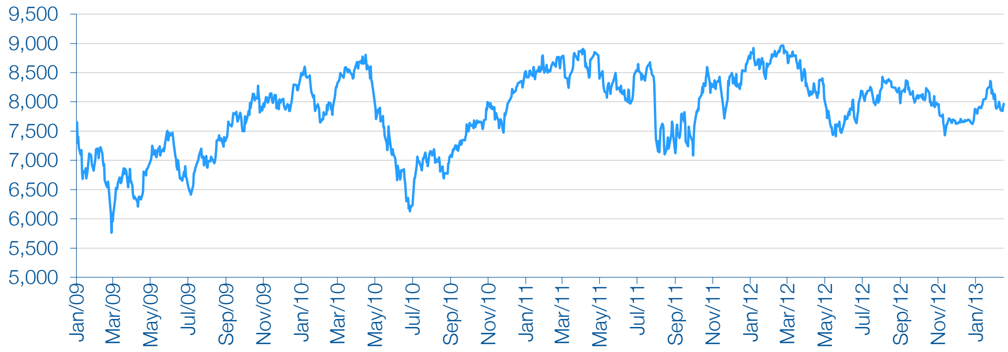
Source: Bloomberg, Edison Investment Research

Oil and gas sector performance

UK: Generally lacklustre showing in 2012, relatively weak upturn in early 2013

Despite the generally favourable oil price backdrop the FTSE 350 Oil & Gas Index, an index of medium and large capitalisation stocks dominated by BP and Shell, performed in a lacklustre fashion both absolutely and relatively in 2012. Between end 2011 and end 2012 the index fell 12% while the FTSE 100 gained 6%. The FTSE 350 Oil & Gas Index was buoyed in the early months of 2012 by the powerful upward trend in Brent related to the Iranian nuclear issue and the tightening of the US and EU sanctions regime on the country. As geopolitical concerns eased and Brent rapidly lost ground, the FTSE 350 simultaneously came under heavy pressure in the second quarter. Although there was a modest recovery in the third quarter, the index once again weakened in the fourth quarter. This left the underlying trend in the FTSE 350 Oil & Gas Index between the end of the second and fourth quarters broadly flat.

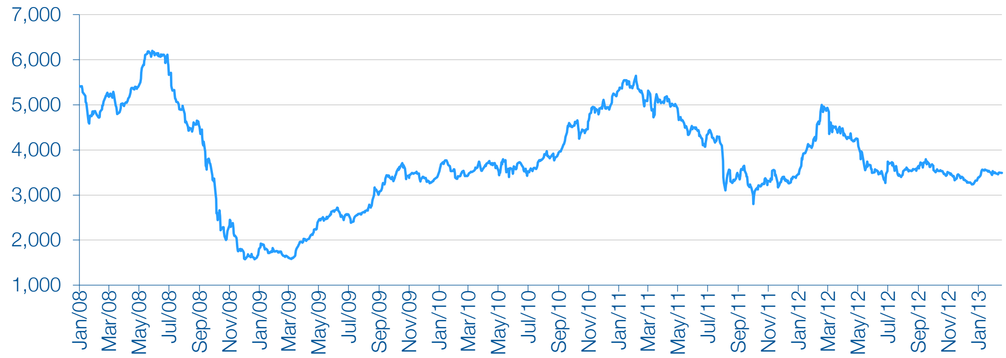
Exhibit 30: FTSE 350 Oil & Gas Index



Source: Bloomberg

The FTSE 350 Oil & Gas Index turned strongly upward in the early weeks of 2013 swept along by general market bullishness and the firming price of Brent. At the high point on 29 January the index was up 10% on the end December close and around a six-month high. Subsequently, however, there has been a significant reversal driven by BP and Shell in the wake of what the market considered disappointing 2012 earnings plus in the case of the former lingering legal and compensation issues surrounding the Macondo debacle. By 14 February the FTSE 350 Oil & Gas Index was up 3.5% from end 2012, while the FTSE 100 was 7.3% higher. Compared with the 2008 high the FTSE 350 Oil & Gas Index is down about 16%.

Exhibit 31: AIM Oil & Gas Index



Source: Bloomberg

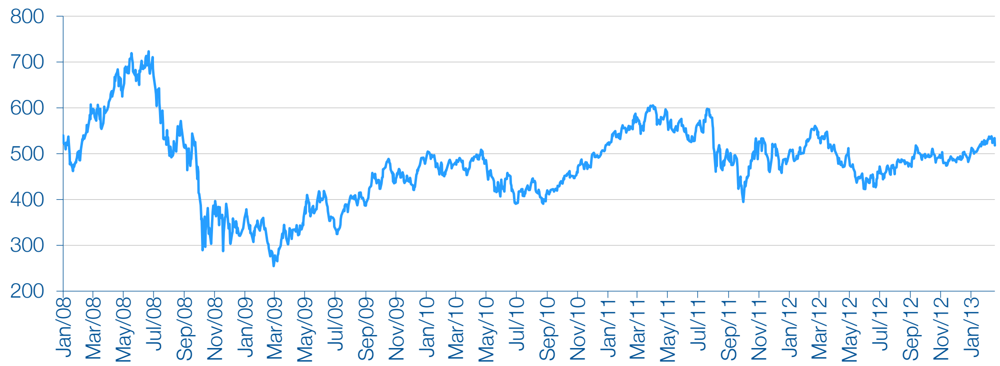
The oil and gas juniors also performed less than robustly in 2012, but they nevertheless managed to outperform the medium and large capitalisation stocks. Between end 2011 and end 2012 the AIM Oil & Gas Index declined by 3%, a modest underperformance compared with the 2% gain in the AIM All Share Index. Since end December, the AIM Oil & Gas Index has risen 5.3%, a slight underperformance compared to the 6% gain in the broader AIM Index. Looked at from a longer-term perspective, the performance of the AIM juniors has been decidedly weak with a drop of 44% between the 2008 high and mid-February 2013.

US: Large caps approaching a five-year high, strong upturn in large cap E&P stocks in early 2013

Key US oil and gas equity indices turned in stronger performances than their UK counterparts in 2012, but nevertheless underperformed the S&P 500. The S&P 500 Oil & Gas Exploration and Production Index (an index of large capitalisation oil and gas independents) was pretty well unchanged between end 2011 and end 2012, while the S&P 500 was up 13.4% over the same period. Significantly, between 2012 year end and mid-February the S&P 500 Oil & Gas Exploration Index has climbed 11%, thereby comfortably outpacing the 7% gain in the S&P 500. From a longer-term perspective, the S&P 500 Oil & Gas Exploration and Production is still lagging the early 2011 highs by about 11% and the 2008 highs by around 25%.

The more broadly based S&P 500 Oil & Gas Index (which includes the majors Exxon, Chevron and ConocoPhillips as well as the large independents and refinery groups such as Valero) moderately outpaced the Exploration and Production Index in 2012 with a gain of 2.8%. It nevertheless underperformed the S&P 500. Since end December 2012, the S&P Oil & Gas Index has performed strongly both absolutely and relatively with a gain of 8%. This Index is now approaching a five-year high.

Exhibit 32: S&P Oil & Gas Exploration and Production Index

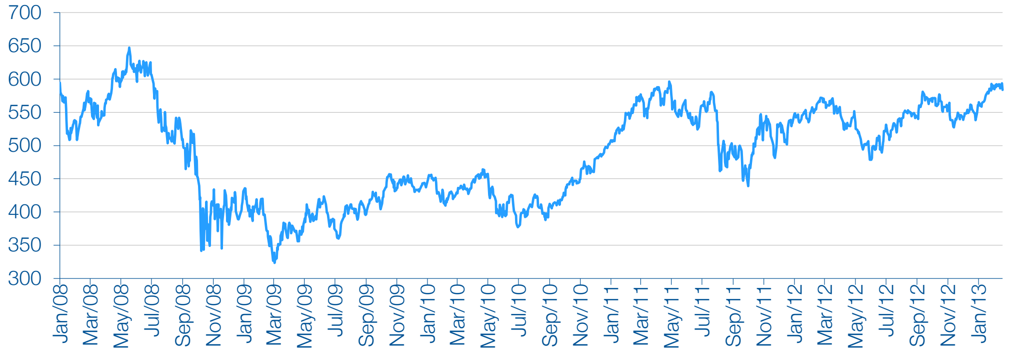


Source: Bloomberg

Activist investors take aim: Over the past year or so the US oil and gas sector has increasingly attracted the attention of activist investors such as Carl Icahn, Paul Singer (Elliott Associates) and Dan Loeb (Third Point LLC). Fundamentally, the interest reflects the value offered by the sector[1] and its tendency to underperform booming conditions in the US oil patch. A key example of activism has been Carl Icahn's boardroom coup at Chesapeake Energy, which has recently led to the removal of Aubrey McClendon, the co-founder of the company, from the CEO's position. Similarly Elliott Associates has been active in forcing Hess to divest its refining interests and now appears to be arguing in favour of greater focus on the US E&P interests. Significantly Hess is one of the larger players in the Bakken formation.

[1] Based on Bloomberg data the S&P 500 Oil & Gas Index is selling on a 2013 EV/EBITDA ratio of 6.0x and a yield of 2.4%. By comparison the S&P 500 is selling on a EV/EBITDA ratio of 9.6x and a yield of 2.1%.

Exhibit 33: S&P 500 Oil & Gas Index



Source: Bloomberg

London +44 (0)20 3077 5700
Lincoln House, 296-302 High Holborn London, WC1V 7JH, UK

New York +1 646 653 7026
245 Park Avenue, 24th Floor 10167, New York, US

Wellington +64 4894 8555
Level 15 HP Tower, 171 Featherston St, Wellington 6011, NZ

Sydney +61 (0)2 9258 1162
Level 33, Australia Square, 264 George St, Sydney, NSW 2000, Australia