Oil & gas macro outlook

The market remains well supplied

Oil & gas

4 October 2013

Oil prices were bid higher in late August by exaggerated fears concerning geopolitical developments in the Middle East and supply disruptions in Libya. The reality, however, is that the market continues to be well supplied while demand growth is subdued. Supply is effectively being comfortably underpinned by rising Saudi and non-OPEC production. In all probability major supply disruptions will be avoided in the coming months and Libyan exports will gradually come back on-stream. This could leave scope for prices to weaken somewhat in the near term. A rapprochement between the US and Iran is a wildcard, but if it happens will be bearish for oil prices.

Supply/demand position: Looking comfortable

Non-OPEC supply growth remains buoyant driven by the US and Canada. In the first half of 2013 production was up year-on-year by around 1.3mmb/d, based on EIA data. Production growth is likely to accelerate in the second half resulting in a gain for 2013 of perhaps 1.8mmb/d, including OPEC natural gas liquids (NGLs). This should comfortably exceed 2013 global demand growth, which we believe is unlikely to exceed 1mmb/d. Admittedly, OPEC production in 2013 will be lower than in 2012, but the prospective drop of 0.7-0.8mmb/d should still leave the market in approximate balance. We expect non-OPEC controlled production to remain buoyant in 2014 with growth once again of around 1.8mmb/d, including OPEC NGLs. This will comfortably exceed demand growth of perhaps 1-1.2mmb/d. Even if we assume a consensus 0.5mmb/d decline in OPEC output, the market could be slightly in surplus in 2014. We see scope for OPEC output above the consensus in 2014 given the potential for recovery in Libya and capacity expansion in Iraq.

WTI-Brent spread: $6-8/bbl WTI structural discount

The WTI discount to Brent narrowed sharply between late in the first quarter and early August 2013. From a recent peak of $23/bbl in mid February the discount at times had virtually evaporated altogether in July and August. Driving the narrowing was expanded takeaway capacity in the US Mid-Continent and Texas and a surge in domestic refinery activity. Both factors reduced inventories at the Cushing tank farm. During late August and September the WTI discount widened reaching around $7/bbl at the end of the latter month. Abstracting from severe dislocations to supply outside the US, we continue to expect WTI to trade at a discount of $6-8/bbl to Brent. Broadly this reflects a blend of pipeline and rail tariffs for shipment from Cushing to the Gulf. Discounts significantly below pipeline costs of $4/bbl are not sustainable for any length of time.

Price forecasts: Raised due to strong Q2/Q3 trends

We look for a softening trend in light crude prices over the balance of 2013 and in 2014, reflecting declining geopolitical tension and our bearish supply-demand balance scenario. However, due to the strong upward trend in the second and third quarters we are raising our forecasts for 2013. Brent rises from $105.3/bbl to $108.6/bbl, while WTI goes up from $93.7/bbl to $99.1/bbl. Positive carryover has also led us to raise our 2014 forecasts from $99.0/bbl to $103/bbl for Brent and from $90.9/bbl to $96.5/bbl for WTI.

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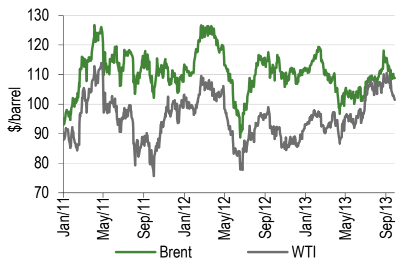
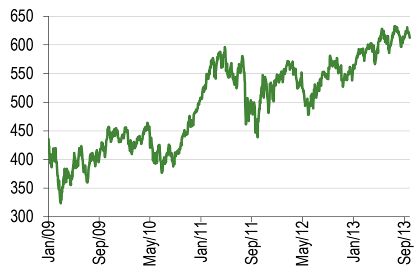
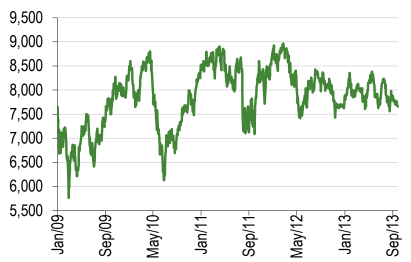




FTSE 350 Oil & Gas Index



Source: Bloomberg

	WTI $/bbl	Brent $/bbl	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	99.1	108.6	3.72
2014e	96.5	103.0	4.01

Note: Prices are yearly averages.

Contents

Highlights

Highlights of this report include:

- Buoyant non-OPEC production growth.
- Very strong production trends in the US and Canada.
- OPEC production supported by Saudi Arabia and the UAE.
- Libyan exports resuming.
- Subdued global oil demand growth.
- Global supply/demand position looks comfortable.
- WTI goes into backwardation.
- WTI discount narrows sharply in 2013.
- Economics of shipping oil by rail from the US Mid-Continent to the seaboards deteriorates.
- 2013 crude oil price forecasts raised due to strong trends in Q2 and Q3.
- Softer price trend expected in the near to medium term.
- An accord with Iran would have significantly bearish oil price implications.
- The US natural gas production and domestic consumption trend is flattening.
- US pipeline gas exports to Mexico surging.
- Exports of NGLs surging.
- US dedicated gas rig count stabilising.
- US gas price forecasts slightly downgraded.
- US dry gas economics remain weak at $3.6/mmBtu.

Executive summary

Recent oil price developments: International light crude prices trended sharply higher between mid April and end August 2013. Benchmark grades rose by about $20/bbl and approached the February 2013 highs of around $120/bbl. Since end August, prices have declined by about $10/bbl reflecting an easing of geopolitical concerns in the Middle East, a partial resumption of Libyan exports and a bearish EIA report for 20 September referring to rising inventories. The easing of Middle Eastern concerns relates to Syria and more recently Iran.

WTI-Brent spread: The historically wide WTI discount to Brent in the first quarter of 2013 narrowed sharply in the second and third quarters to levels not seen since 2010. The average discount in the third quarter was $4/bbl, well down from the mid-February peak of $23/bbl and spot highs of almost $30/bbl in October 2012. At times, the WTI discount almost evaporated completely in July and early August. Post August the discount has widened and in late September was about $7/bbl. The earlier narrowing of the WTI discount reflected increased takeaway capacity in the Mid-Continent and Permian Basin and a surge in refinery activity. Both factors conspired in a sharp reduction in inventories at the Cushing tank farm. The widening discount in September stemmed from the waning impact of rising refinery activity and the bearish EIA 20 September inventory report.

Non-OPEC output: Non-OPEC crude oil output growth has remained buoyant in recent months and looks like continuing to be so over the balance of 2013 and in 2014. According to the EIA, production was up year-on-year by 1.3mmb/d in the first half. For 2013 as a whole, the EIA is forecasting a gain of about 1.6mmb/d, which translates into closer to 1.8mmb/d, including OPEC NGLs, which are not subject to quota. This is one of the larger gains in non-OPEC output over the last 10 years. The EIA is also looking for growth in 2014 of about 1.8mmb/d including OPEC NGLs. The key drivers behind the forecasts continue to be rapid development of US and Canadian shale and tight reservoir reserves and the Athabasca oil sands in Alberta, Canada. Production has recently commenced at the giant Kashagan oilfield in the Caspian Sea. Production here should gather momentum heading into 2014 and indeed through the balance of the decade.

US output: For the four weeks to 24 September 2013, US crude production averaged 7.74mmb/d, a 24-year high and 1.79mmb/d or 30% above a year earlier. Production continues to be driven by intensive development activity in the shale and tight reservoir formations of the Great Plains and Texas. The EIA is forecasting US crude oil output gains of 15% and 13% in 2013 and 2014 respectively. These constitute upgrades compared with earlier in the year and are arguably on the conservative side.

OPEC output: OPEC crude oil production in 2013 has averaged about 30.4mmb/d through August, down a modest 3% on 2012. Production overall has continued to be buoyed primarily by Saudi Arabia but the UAE and Kuwait have also played a part. Rising trends in these three have largely offset the plunge in production in recent months in Libya and lacklustre performance in Nigeria. The trend over the balance of 2013 is likely to be weak reflecting a major planned outage in Iraq for maintenance/upgrading of its Gulf export terminals. Libya also constitutes a potential vulnerability, although production here appears to have rebounded significantly in recent weeks. The EIA is forecasting OPEC crude production in 2013 of 30.0mmb/d, down 0.85mmb/d on 2012. We regard this as on the pessimistic side based on recent trends.

Global demand: Global oil demand remains subdued, reflecting recessionary forces and negative structural influences in the OECD world related to improving vehicle fuel economy and declining miles driven. Based on IEA, EIA and OPEC forecasts, demand is unlikely to grow by more than 1mmb/d (0.9%) in 2013 and possibly 1.2mmb/d (1.3%) in 2014.

Oil supply/demand balance: Non-OPEC controlled output growth looks like comfortably exceeding global demand growth in 2013 and 2014. The surpluses could be about 0.8mmb/d and 0.6mmb/d respectively. Consensus views on declining OPEC crude production, however, imply a market globally that is broadly balanced or possibly slightly in surplus.

Crude oil price forecasts: Due to the strong upward trend in crude prices in the second and third quarters, we are raising our 2013 forecasts for Brent and WTI. Brent rises from $105.3 to $108.6/bbl while WTI increases from $93.7 to $99.1/bbl. Positive carryover has also led us to raise our forecasts for 2014 from $99.0 to $103/bbl for Brent and from $90.9 to $96.5/bbl for WTI. An accord between the US and Iran over the latter's nuclear programme would, in our view, have significantly bearish implications for oil prices both in the near and long term.

US natural gas fundamentals: US production growth has slowed sharply over the past year or so, reflecting scaled back drilling activity and well shut-ins due to poor gas industry profitability. Through the first six months of 2013, US gas production was up 0.5%from 2012. Gas consumption over the same basis was 2% higher but in May and June actually showed year-on-year declines. Demand growth in 2013 has been severely constrained by a significant drop in the power station gas burn rate due to an erosion in gas's competitiveness compared to coal. The upshot is that US demand growth will probably be marginal in 2013.

US natural gas prices: US natural gas prices are well off the lows of the second quarter of 2012 but in recent months the trend has been lacklustre. Towards the end of September 2013 the Henry Hub benchmark quote was around $3.64/mmBtu. For the average dry gas producer this implies a significant cash contribution but in all probability a fully accounted loss after allowing for finding and development costs. Wet gas producers, of course, given their production of NGLs, continue to have considerably more favourable economics and are probably profitable on a fully accounted basis. Reflecting the relatively weak showing in the third quarter and comfortable supplies we are slightly downgrading our 2013 Henry Hub price forecast from $3.86/mmBtu to $3.72/mmBtu. We have also downgraded our 2014 forecast from $4.10/mmBtu to $4.01/mmBtu.

Crude oil market dynamics

Price overview

Market developments: Partial reversal of bullish Q2/Q3 trend in September

Recent months in retrospect: International crude oil prices have trended sharply higher in recent months. Momentum gathered pace in August, resulting in benchmark light crude prices at the end of the month up by about $20/bbl on the April 2013 lows and approaching the February 2013 highs of around $120/bbl.

Oil market bullishness of late has been driven by the familiar themes of rising Middle East political tension associated with the civil war in Syria and a plunge in Libyan production and exports related to factional infighting and strikes in the country. An underlying positive for oil markets in recent months has been buoyant refinery activity following an unusually heavy period of facility maintenance/upgrading. In early September the upward pressure on prices ebbed as the prospect of imminent US military action against Syria in response to an alleged chemical weapons attack receded. This followed an unexpected announcement of a Russian plan to put Syria's chemical weapons stockpile under international control. By late September international benchmark light oil prices were down about $9/bbl from the end August highs to around $109/bbl.

The surge in prices in late August occurred despite a still well-supplied market. By all accounts inventories in the OECD world, at least, appear at adequate levels for the time of year. It might indeed be asked why Syria, which even before the commencement of the civil war was a fairly marginal oil producer with production of less than 0.4mmb/d, should have a major impact on oil prices now. The consensus view relates to the possibility of the war spreading to other countries in the Middle East given that the antagonisms between the different parties to the Syrian conflict are broadly based across the region.

From an oil market perspective the key concern at this stage is the possibility of the Syrian conflict spreading to neighbouring Iraq. As is usually the case when tension increases in the Middle East, the oil market rapidly takes fright and pushes prices higher. The rationale is that the Middle East is the source of approaching 30% of world crude oil production and virtually all global spare capacity, which the EIA (Energy Information Agency, the statistical arm of the US Department of Energy) estimates at a modest 2.5mmb/d. Doubtless, disruption to supplies in say Iraq could be made good by higher production from Saudi Arabia and the UAE but this would be at the expense of eliminating a sizeable amount of the available spare capacity. Effectively, the conflict in Syria and the disruptions to supply in Libya increase uncertainty, although it must be added that market fears concerning Middle East supplies are often grossly exaggerated.

What's happening in Libya In the near term at least, plummeting Libyan oil production in 2013 is arguably of greater significance for oil markets than the ongoing civil war in Syria. Libya, in fact, is particularly influential in European light oil markets given its status as one of the top five suppliers. Following the overthrow of Colonel Gaddafi in October 2011, production recovered strongly and by the fourth quarter of 2012 was back to pre-war levels of 1.5mm-1.6mmb/d with exports of about 1.2mmb/d. Subsequently, production has plummeted and by end-August was running at a trickle with exports ceasing altogether. As of early September production was reported by the government as running at 0.2-0.3mmb/d, but by end-month seems to have rebounded to about 0.7mmb/d based on press reports.

Plummeting production in 2013 reflects a complex situation verging on anarchy. The bottom line is that armed militias in conflict with the central government over a variety of issues relating to pay, jobs, corruption and sovereignty for the eastern provinces have effectively enforced a near cessation of production and exports. How the situation might be resolved is anyone's guess at this stage. Possibly the central government will ultimately have to resort to the use of force. In due course (say within three months) we would expect Libyan production and exports to return to more normal levels given that oil and gas are in effect the country's only significant source of income excluding that obtained from investments.

Non-OPEC supply remains buoyant: Non-OPEC production has remained buoyant in recent months. According to the EIA data, production came in at 53.3mmb/d and 54.2mmb/d in the first and second quarters resulting in year-on-year gains of 0.7mmb/d and 1.9mmb/d. The cumulative year-on-year increase for the first half of 2013 was 1.3mmb/d or 2.5%. Bearing in mind seasonal maintenance issues, the EIA is looking for a robust 0.5mmb/d quarter on quarter gain between the second and third quarters of 2013. On this basis third quarter output will be up 2.3mmb/d or 4.4% on a year earlier.

In the year-to-date non-OPEC production growth has been largely driven by strong underlying gains in the US and Canada and considerably fewer unplanned outages than a year ago. Through the first half of 2013 production was up year-on-year by 10.1% and 5.9% in the US and Canada respectively. US production has continued to be driven by rapid development of the shale and tight reservoir formations of the Great Plains and Texas. Canada's production growth stems from a combination of the Athabasca oil sands, Alberta's tight reservoir formations and the Atlantic offshore oilfields. Key developments in 2013 for the oil sands have been the expansion of Suncor's Firebag project and the start-up of Imperial Oil's Kearl project. According to Imperial, Kearl is currently producing 50,000-60,000b/d and should reach planned capacity of 110,000b/d by end 2013. A further expansion to 145,000b/d is planned to come onstream by 2015. The Athabasca oil sands currently account for over 50% of Canadian production expected to be about 4.25mmb/d in 2013, based on EIA data.

A major constraint on non-OPEC oil production in recent years has been a sharp fall in North Sea oil production reflecting depletion and heavy planned and unplanned maintenance programmes. According to EIA data, production fell between 2009 and 2012 by 1.02mmb/d or 25% to 3.06mmb/d. Out of this total Norway and the UK represented 1.91mmb/d and 0.96mmb/d respectively. Reflecting trends in the year-to-date plus known maintenance schedules in the third quarter, 2013 now looks like being another significant year of weakness with the UK being the key culprit. For the year as a whole the EIA is looking for a decline in North Sea output of 4% to 2.93mmb/d. The drop in the UK looks like being somewhat greater at 8% based on industry indications, which would take production down to about 0.88mmb/d, the lowest level since the late 1970s. Industry forecasts for the UK have recently been downgraded both near and medium term.

The strong performance in North America continues to underpin the outlook for a highly significant gain in non-OPEC crude output in 2013. In addition to North America, output should receive a modest boost from several other producers such as Russia, the Caspian region, Colombia and Brazil. The EIA is currently the most bullish of the quasi governmental forecasting bodies with forecast output growth of 1.6mmb/d or 3% to 54.3mmb/d. This constitutes a significant upgrade from the 1.1mmb/d of a few months ago. Additionally, OPEC natural gas liquids (NGLs), which are not subject to quota, should contribute another 0.1-0.2mmb/d implying a total increase in supply of approaching 1.8mmb/d. This would be one of the larger increases in non-OPEC controlled supplies over the past 10 years. OPEC and the IEA (International Energy Agency, the energy watchdog for the OECD) are both forecasting output growth in 2013 of 1.1mmb/d or 2%. As far as we are aware, 54mmb/d will be a record level of non-OPEC output. The anticipated growth in 2013 will provide a partial offset to the slump in Libyan output and sanctions depressed Iranian production.

A similar picture in terms of non-OPEC crude oil supply growth seems likely in 2014. The EIA, for example, is forecasting growth in crude oil output of 1.5mmb/d, again driven by North America. OPEC NGLs are expected by the EIA to add another 0.3mmb/d, so the total increase in non-OPEC controlled supplies could again be around 1.8mmb/d.

Kashagan comes on-stream: The much delayed giant Kashagan field in the Kazakhstan sector of the Caspian Sea came on-stream in early September. First discovered in 2000, Kashagan with recoverable reserves of 13bnbbl, is initially scheduled to produce at 180,000b/d. The ENI-led consortium managing the project has previously suggested stepping up production to 380,000b/d during the second half of 2014 and to 1.5mmb/d by 2020. We believe that Kashagan is the largest conventional oil project scheduled to come on-stream in the 2013/14 timeframe. It needs to be remembered, however, that the operating conditions surrounding Kashagan are challenging in terms of the climate and geology. Post 2014 the giant pre-salt fields offshore Brazil should begin making a meaningful contribution to non-OPEC production.

YPF-Chevron deal ratified: The earlier $1.24bn agreement between the Argentine state-controlled oil company YPF and the US major Chevron to develop the Vaca Muerte shale formation in Argentina's Neuquen province has now been ratified at federal and provincial levels. The deal initially calls for a pilot project in the Loma la Lata zone with up to 100 wells. According to a regulatory filing, YPF is looking for production of 50,000b/d of oil and 3mmcm/d of gas by 2017. The full commercialisation of Vaca Muerte could involve drilling up to 2,000 wells at a cost of perhaps $15bn. Assuming well rates similar to the Bakken at 95b/d we could be looking at production of around 200,000b/d of oil plus associated gas. This compares with Argentina's current oil production of about 0.7mmb/d. Given the potential in the deeper Los Molles and Agrio formations there is quite possibly considerable upside to the longer-term production outlook. Remember here that the Vaca Muerte alone is estimated to contain 23bnboe of recoverable reserves based on a Ryder Scott report. According to a recent article in the publication *Upstream*, YPF has recently been producing 11,800b/d from 90 wells in the Vaca Muerte. This compares with around 3,000b/d at the end of 2012. Production per well of 131b/d, it should be noted, compares very favourably with the Bakken.

While current Vaca Muerte production rates are, of course, still distinctly marginal, what is interesting about the shale formation is the upside potential given the scale of the reserve base and the apparent excellent reservoir quality. It should also be noted that Neuquen is a well established hydrocarbons producing province with well established infrastructure and access to oilfield services. Indeed, there is little doubt from our perspective that Vaca Muerte is both a world class shale play and also by far the most advanced major shale play outside North America. Schlumberger has recently said at the World Shale Oil & Gas Latin America Summit in Buenos Aires that Vaca Muerte "is the most active play external to North America today as far as shale is concerned. Things are ramping up nicely". The stock market also appears to be thinking along similar lines given that YPF at end September was up around 120% to $21/share in New York from the low point in November 2012.

OPEC production broadly stable so far in 2013: So far in 2013, OPEC crude output has trended broadly flat but over the last four months of the year there is potentially a significant vulnerability. Based on independent sources OPEC production in 2013 has averaged as follows: Q1 30.2mmb/d, Q2 30.6 mmb/d, and Q3 (July/August) 30.3mmb/d. Compared with a year earlier year-to-date production is off about 3% while August 2013 output was down 4%. Significantly during 2013 OPEC production has been supported by upward trends particularly in Saudi Arabia and to a lesser extent in the UAE and Kuwait. Saudi production in August of around 10.2mmb/d was a 32-year high. To a large extent the strength in Saudi Arabia has offset plummeting production in Libya. Iraq also buoyed the overall trend in August with production up month-on-month by 133,000b/d to 3.14mmb/d, which was close to a post 1990 high. However, the Iraqi trend has been slightly disappointing this year given earlier forecasts by Iraqi officials of 3.5mmb/d by this stage in the year. Key constraints on output have been logistical limitations, terrorist activity against the northern Kirkuk-Ceyhan (Turkey) pipeline and a suspension of exports from Kurdistan using the northern pipeline.

OPEC output looks like dipping in September and quite possibly also in the fourth quarter of 2013. This reflects the continuing turmoil in Libya and maintenance/upgrading activity at Iraq's southern export terminals in the Gulf. The latter is expected by the IEA to cut output by 0.5mmb/d. Iraq has indicated that the work is expected to take 30 to 45 days but the fear is of a much longer shut-down, particularly if both single point mooring terminals are involved. Following completion of the terminal upgrading and expansion work in 2014 Iraq's export capacity from the Gulf is expected to roughly double to 6mmb/d. Interestingly, the Iraqi deputy premier for energy affairs has recently suggested that Iraq's production will increase to 3.6-3.7mmb/d by 2013 year end. To a considerable extent this reflects the revamped Majnoon field coming on-stream.

Theoretically Saudi Arabia has the capacity to compensate for any temporary loss of production in Iraq but given the loss of Libyan output it will temporarily sharply reduce the amount of OPEC spare capacity available. It might also be added that that we really do not know how quickly Saudi output can be boosted to almost 11mmb/d and for how long this level can be sustained. We are in unchartered waters. The EIA is currently looking for OPEC production to average 29.9mmb/d and 29.8mmb/d in the third and fourth quarters of 2013 respectively. This would equate in 2013 to 30.1mmb/d on average down 0.79mmb/d on 2012. Arguably this forecast is on the conservative side given the apparent partial recovery in Libyan output and assuming that the planned outages in Iraq are not longer than scheduled.

Interestingly, the EIA's forecast output levels for these two quarters are broadly in line with the IEA's expected call on OPEC crude. In effect, the call is declining due to the anticipated strong increase in non-OPEC production.

Global demand growth still moderate: There have been no major changes in the demand growth picture for 2013 and 2014 in recent months. The overall outlook is for moderate growth propelled by emerging and developing economies. However, reflecting broader macroeconomic trends there has been a tendency of late for demand to stabilise in the OECD world while slowing elsewhere. Based on EIA data global oil demand in the first half of 2013 was up 1.2mmb/d or 1.3% on a year earlier. A drop in OECD markets of 0.7% was comfortably offset by a gain in the non-OECD area of 3.4%. Significantly global growth accelerated between the first and second quarters from 1.2% to 1.4%. This reflected a sharp deceleration in the rate of contraction in the OECD from 1.1% to 0.2% with Europe being the key factor. According to EIA data, European demand actually rose strongly between the first and second quarters of 2013 leaving the latter period unchanged from a year earlier. For comparison, European demand in the first quarter showed a 4% year-on-year decline following a strong downward trend since 2007. In the first half of 2013 OECD demand was also buoyed by a resumption of modest growth in the US after several years of declines.

Based on EIA data demand growth in China remained strong in the first half of 2013 at 5.9% but a significant slowdown is expected in the second half. For 2013 as a whole, the EIA is looking for growth in China of 4% to 10.7mmb/d. This is half the growth of around 8% in the early to mid 2000s. The slowdown reflects a combination of decelerating economic growth, improvements in fuel efficiency and administrative action encouraging gasoline/diesel fuel conservation and substitution of petroleum products by other fuels, most notably CNG.

The EIA, IEA and OPEC are all pointing to similar conclusions on global oil demand for 2013 and 2014. There have also been no major forecast revisions since our last report in June. The IEA and OPEC are forecasting growth for 2013 of 0.90mmb/d and 0.82mmb/d respectively, while the EIA is looking for a somewhat greater 1.11mmb/d. Broadly these forecasts translate into growth of about 1% and imply demand of a little over 90mmb/d. Regionally, the picture is broadly growth in the non-OECD world of 1.3mmb/d (China 0.4mmb/d, Middle East 0.3mmb/d, Latin America 0.2mmb/d, other Asia 0.2mmb/d, Former Soviet Union 0.1mmb/d, other 0.1mmb/d), partly offset by a drop in the OECD of 0.2mmb/d (Europe -0.2mmb/d, North America +0.2mmb/d, Japan -0.2mmb/d). Demand growth globally in 2013 of 1% considerably lags the IMF's forecast for world GDP growth in 2013 of

3.1%. Given year-to-date demand trends and the near-term economic outlook we believe 2013 oil demand growth of about 1% is plausible.

The IEA, EIA and OPEC are all anticipating a moderate strengthening in global oil demand between 2013 and 2014, reflecting the assumption of a firming economy. Cognisant of the IMF's 3.8% GDP growth forecast the three forecasting bodies are looking for increases in demand in 2014 of 1.0mmb/d to 1.2mmb/d, which translates into 1.2-1.3%. Demand in 2014 is again expected to be driven by the non-OECD world, where broadly speaking a gain of 1.3-1.4mmb/d is forecast. The key contributors will once again be China, the Middle East, Latin America and other Asia. OECD demand in 2014 is expected by the forecasting bodies to slip by another 0.2-0.3mmb/d with the key factor being Europe. This reflects not only a weak economic backdrop but also intensive fuel conservation measures and significant advances in the fuel efficiency of the highway transportation fleet. A decline in Japanese consumption also seems distinctly possible given the likely restart of nuclear electricity generating capacity and ongoing fuel substitution trends in thermal power stations from oil-based products to coal and LNG.

Assuming economic growth of 3.8%, an increase in global oil demand of 1mmb/d or so in 2014 appears plausible. A potential vulnerability relates to intensifying economic difficulties in parts of the developing world where major balance of payments deficits have emerged along with downward currency pressure. Key examples are some of the larger developing economies including Brazil, India, South Africa and Indonesia.

OECD inventories adequate: OECD commercial inventories (crude and refined products) have shown a weak seasonal trend in recent months but appear perfectly adequate particularly from a days outstanding perspective. The weak trend has been principally manifested in terms of crude oil and appears to mainly reflect a surge in refinery activity in the second quarter following widespread and unusually heavy maintenance/upgrading programmes. Contributing to the weak trend, particularly in Europe, was plummeting Libyan crude oil production. At the end of July 2013 OECD commercial inventories stood at 2,668mmbbl, 49.1mm below a year earlier and 55.5mm under the five-year average. This left inventories towards the lower end of the five-year range. According to the IEA, there was a 14.2mmbbl draw in August against the seasonal trend. July's inventories were equivalent to 58.5 days of forward demand, which was 0.3 days above the five-year average and a very comfortable level by historical standards. It should also be noted that we are now entering the shoulder refining season when facilities undergo conversion for a switch from gasoline to heating oil. This should temporarily, at least, temper the demand for crude.

Recent trends in Brent and WTI: WTI has outperformed Brent for much of 2013

During the six months or so to early August 2013, WTI performed strongly relative to Brent, thereby breaking the pattern of the past three years or so. Between mid-February and August 2013 WTI rose by around 13% to $108/bbl while Brent actually fell over the same period by 8% to $109/bbl. In the first half of 2013 both WTI and Brent plumbed lows in mid April, of $96.8/bbl and $86.7/bbl respectively.

WTI's strength relative to Brent through much of the first seven months of 2013 was not entirely unexpected. Key factors were stepped-up refinery activity in the US as facilities came back on-stream following maintenance/upgrading programmes and falling inventories at the Cushing Oklahoma tank farm. The latter was a function both of rising refining activity and an increase and re-engineering of pipeline capacity that has re-directed burgeoning Mid-Continent and Permian Basin (Texas) production to the refining centres of the Gulf Coast. Key examples of upgraded pipeline capacity include the first stage of the Enterprise Seaway reversal from Houston to Cushing, Magellan Midstream Partners' Longhorn reversal from El Paso to Houston and the first stage of Sunoco's Permian Express that links Wichita Falls and Port Arthur. Brent's weakness both absolutely and relatively in the five or six months to early August reflected a combination of rising supplies of crude in the eastern Atlantic Basin and lacklustre demand in Europe. The former stemmed from both rising North Sea production and most significantly displaced exports of light crude to the US.

Since early August, WTI has once again weakened relative to Brent. Between 1 August and 16 September, for example, WTI slipped by 1.3% to $106.5/bbl while Brent rose by 1.4% to $110.9/bbl. Both WTI and Brent were lifted in late August by the threat of military action against Syria following the earlier alleged chemical weapons attack and the virtual cessation of exports from Libya. Brent's understandable greater sensitivity to events in the Middle East and North Africa nevertheless buoyed its relative performance.

Exhibit 1: Brent crude oil price trend

Source: Bloomberg

In late August Brent was trading close to a six-month high of $118.1/bbl, while WTI at $110/bbl was the highest level in about 28 months. Both Brent and WTI slipped in early to mid September as fears concerning Syria waned as the risk of imminent military action dissipated following a US/Russia plan to put Syria's chemical weapons stockpile under international control. Towards month end WTI also tended to be depressed by general economic concerns in the US and a bearish EIA inventory report for the week ending 20 September. Compared with a year ago, prices on 27 September were up 12% to $102.9/bbl for WTI and down 4% to $109.2/bbl for Brent.

Exhibit 2: WTI crude oil price trend

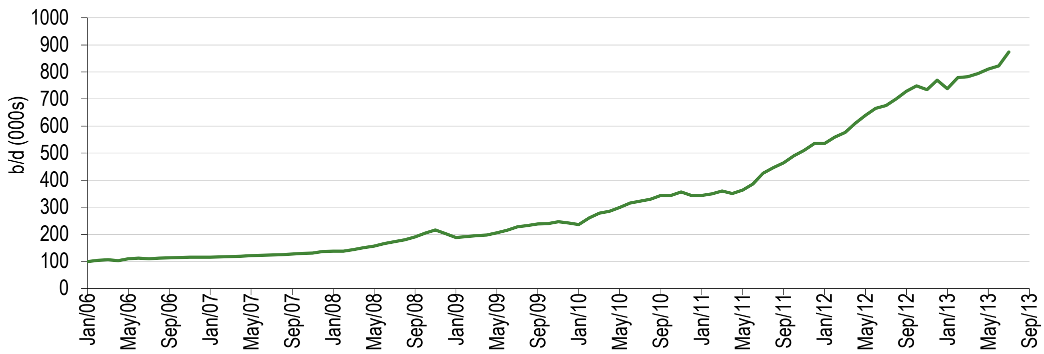
Source: Bloomberg

US production developments

North Dakota: Stunning gain in July

North Dakota, crude oil production continues to hit new records, which confirm the state as the number two producer in the union. According to the North Dakota Department of Mineral Resources, production in July 2013 was 874,681b/d a hefty 52,875b/d or 6.4% up on the prior month and 29% on a year previously. For the seven months to July, production averaged 801,024b/d, a gain of 31% from 2012. The stunning month-on-month increase between June and July reflects a very high rate of well completion activity in the Bakken/Three Forks formations, which resulted in producing wells climbing by 223 to 9,329 between June and July. Compared with a year earlier, producing wells in July were 25% higher than a year earlier. Significantly, production per well has also been trending up and in July was 97b/d against 92b/d a year ago and 93b/d in the prior month.

Exhibit 3: North Dakota crude oil production



Source: EIA

Completion activity has probably been buoyed of late by a strong recovery following disruption by hostile weather conditions earlier in the year. The Department of Mineral Resources has suggested that further 'steady' production increases are expected in the coming months but not on the scale of July. Spud and permitting activity continues to point to a buoyant production trend. July's 198 spuds were 25% above a year earlier, while drilling permits of 276 were up 50% from a year ago. The North Dakota rig count continues to decline moderately, reflecting the increasing use of pad drilling whereby several horizontal wells are drilled from one location. The advent pad drilling is resulting in efficiency gains and consequent savings in drilling costs.

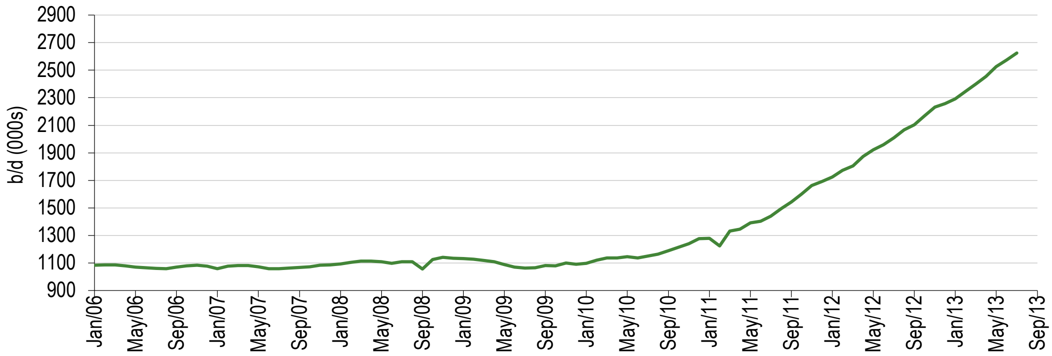
Given the strong year-to-date trend and the positive backdrop in terms of spuds and permitting, we believe North Dakota crude oil production could exceed 950,000b/d by end 2013. The caveat is no major disruptions due to inclement weather. By end 2014 production of over 1mmb/d looks to be on the cards, which is a year ahead of industry expectations of just a few months ago.

As we have noted before, North Dakota's production growth particularly in percentage terms is likely to slow over the medium term. This reflects high rates of depletion and the now sizeable number of wells in existence. In all probability the key to maintaining production at a high rate will be development of the Three Forks formations below the Lower Bakken shale zone. Development of the Three Forks is at an early stage. Initial results from work undertaken by the leading Bakken operator and pioneer in the Three Forks (18 wells to date), Continental Resources (CLR), have been positive.

Texas: Strong upward trend maintained, early 1970s peak coming into view

The renaissance in Texas crude oil production continues. Based on EIA data, production in June came in at 2.575mmb/d, up 31% on a year previously and the highest level since the first half of 1981. Cumulatively in 2013, Texas production has increased by 32% from 2012. Significantly, production in June 2013 was 2.4x the recent low in 2009.

Exhibit 4: Texas crude oil production



Source: EIA

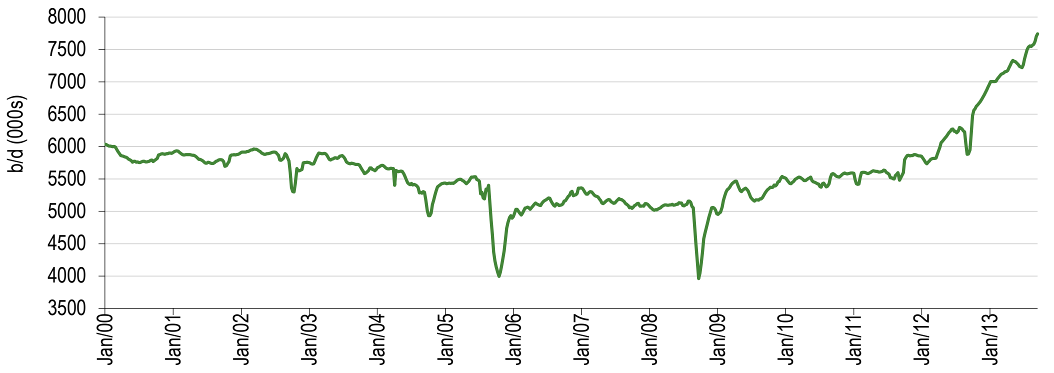
Surging Texas production continues to be driven by the rapid development of the tight carbonate and sandstone reservoir formations of the Permian Basin in the north-west and the Eagle Ford shale formation located in the Western Gulf Basin in the south-west of the state. According to the Texas Railroad Commission, production in June 2013 was 621,000b/d, up 60% from a year previously, but slightly down from the prior month. Cumulatively Eagle Ford production in 2013 is running 51% higher than a year ago. It should be noted that Eagle Ford production has only been underway since 2010 when it averaged 15,163b/d. Based on recent trends Eagle Ford production could exceed 1mmb/d by the third quarter of 2014, while industry expectations for 1.4mmb/d by 2016 look entirely realistic. Permian Basin production is significantly higher than the Eagle Ford at around 900,000b/d. Industry expectations suggest that the Permian Basin could exceed 2mmb/d within five years. All told, we believe there is a very real possibility that Texas oil production will surpass the early 1970s peak of about 3.5mmb/d over the next few years.

US: Production is running at around a 24-year high

The underlying trend in US crude oil production remains impressively upward. The driver remains rapid development in the tight reservoir and shale formations of the Great Plains and Texas.

Based on EIA data, US production in the four weeks to 6 September averaged 7.62mmb/d, around a 24-year high. Compared with a year ago there was a gain of 1.74mmb/d or 30%, while relative to the lows in 2005 and 2009 production is up by a hefty 3.7mmb/d. Year-to-date, production in the US has climbed 20.9% from 2012. Outside of North Dakota and Texas the key areas of strength in 2013 among the larger producing states have been Oklahoma, New Mexico and Colorado. Cumulative year-on-year gains in 2013 in these three have been 28%, 21% and 26% respectively. Elsewhere, there have been gains of 15% in Montana, 9% in Wyoming and 7% in Kansas. As has been the case for some time the overall growth trend has been constrained by flat or declining production in Alaska, California and the offshore waters of the Gulf of Mexico.

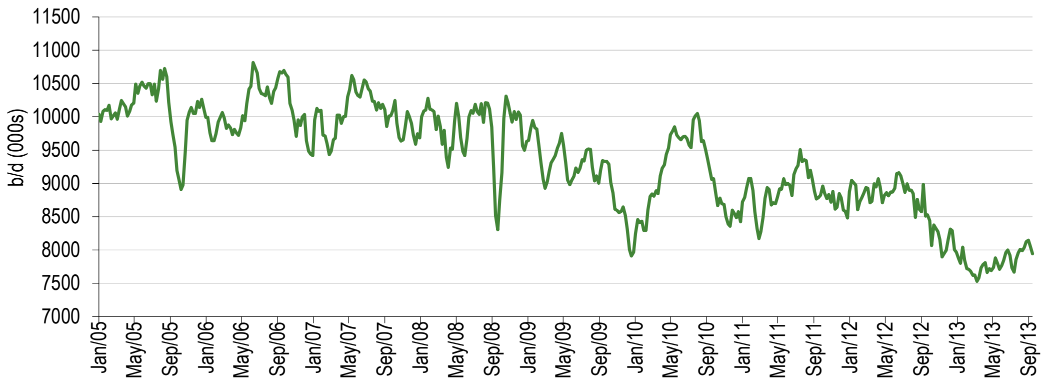
Exhibit 5: US crude oil production



Source: EIA. Note: Data relate to four-week averages

The EIA is forecasting growth in US crude oil production of 15.1% to 7.47mmb/d in 2013 and 12.9% to 8.43mmb/d in 2014. The former would be the highest annual production rate since 1989 and the latter since 1986. The EIA's latest forecasts constitute upgrades compared with those given earlier in 2013. Based on underlying trends we believe the forecasts are conservative. Total oil supply, including renewable and natural gas liquids, is forecast by the EIA at 12.2mmb/d (+9.6%) and 13.2mmb/d (+8.2%) for 2013 and 2014 respectively.

Exhibit 6: US crude oil imports



Source: EIA. Note data relate to four-week averages.

Imports: Reflecting rising domestic production, US crude imports have continued to trend down. Taking the four weeks to 6 September 2013 crude imports have averaged 8.15mmb/d, down a modest 5.2% on a year earlier. Cumulatively, however, in 2013 crude imports have declined by 1.02mmb/d and are now off by about 2.3mmb/d from the 2010 record of 10.1mmb/d. The EIA is forecasting declines in US crude imports of about 1mmb/d in 2013 and 0.9mmb/d in 2014. It should also be noted that the balance of trade on refined products has swung from deficit to surplus over the past two years, so the overall picture on trade is far stronger than suggested by crude alone. The surplus on products is currently running at about 1mmb/d.

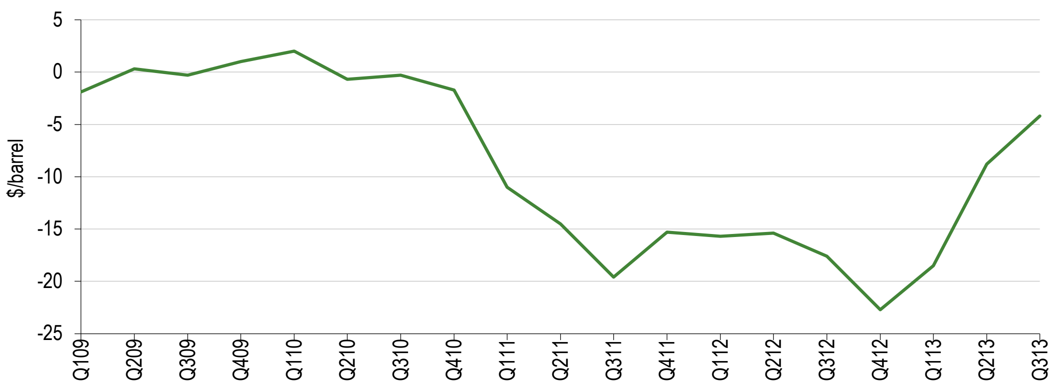
Light crude spreads

WTI-Brent: WTI discount has recently widened, but remains well below early 2013 highs; economics of shipping to the seaboards deteriorates

WTI traded at an unprecedented discount to Brent of $10/bbl or more for most of the period between the fourth quarter of 2010 and the first quarter of 2013. The picture changed radically in the second quarter of 2013. This reflected the factors mentioned previously surrounding a surge in refinery activity and an increase in takeaway capacity from the Cushing tank farm and the Permian

Basin and Eagle Ford oilfields. During the second quarter of 2013 the WTI discount to Brent averaged $8.8/bbl, well down on the $18.6/bbl of the first quarter and spot highs of almost $30/bbl in October 2012. The average for the third quarter through end September was $4.2/bbl. Significantly, in early August the WTI discount narrowed and at times on an intra-day basis there was on occasion a swing to approximate parity to Brent. Discounts of under $2/bbl had not been seen since the fourth quarter of 2010. During August, however, the discount once again widened as Brent was boosted by developments in Syria and Libya. At the end of August WTI was trading at an $8.5/dollar discount to Brent. The easing of tension over Syria in early September resulted in a narrowing in the WTI discount to about $4/bbl. Towards the end of the month there was a widening to $6-7/bbl as general US economic concerns and the bearish EIA inventory report for 20 September depressed WTI relative to Brent.

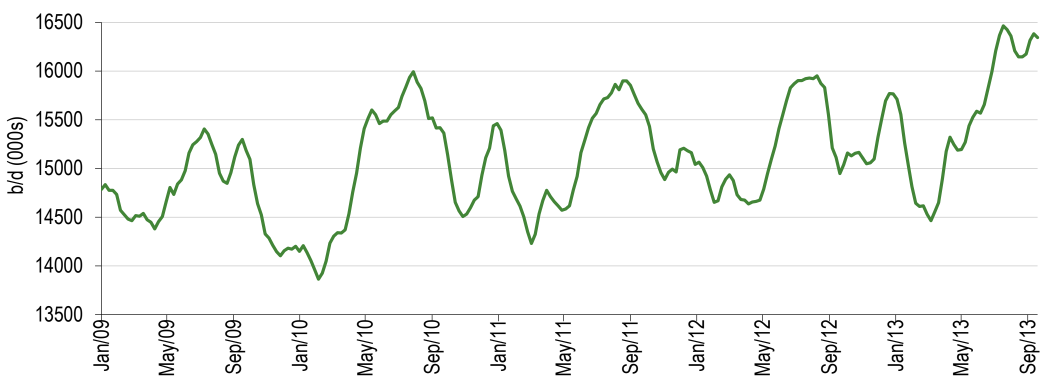
Exhibit 7: WTI-Brent spread



Source: Bloomberg

Interestingly, the mid-September WTI discount of around $4/bbl is close to the Seaway pipeline tariff of $3.8/bbl for uncommitted shipments of light crude from Cushing to the Gulf Coast. It is, however, well under the costs of $10-15/bbl and $20/bbl for shipping the 500 miles between the two locations by rail and truck respectively. Conceptually, given the above pipeline tariff, it might be thought that a WTI discount no lower than $4/bbl would emerge over time. A discount significantly below this level would discourage the flow from Cushing potentially resulting in an inventory build. Recent WTI discounts of less than $5/bbl clearly led to a sharp deterioration in the economics of shipping oil by rail from the Mid-Continent to either the eastern or western seaboards.

Exhibit 8: US refinery runs



Source: EIA

Exhibit 9: WTI 2009-14 quarterly prices, $/bbl

	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
2013	94.3	94.1	105.9	102.0	99.1
2014e	98.0	97.0	96.0	95.0	96.5

Source: Bloomberg and Edison Investment Research. Note: 2013 quarters 1-3 are actuals.

Exhibit 10: Brent 2009-14 quarterly prices, $/bbl

	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
2013	112.8	102.9	110.0	108.5	108.6
2014e	105.0	104.0	102.0	101.0	103.0

Source: Bloomberg and Edison Investment Research. Note: 2013 quarters 1-3 are actuals.

In the near term we are looking for the WTI discount to widen from recent September lows. Key factors we believe will be uncertainty over exports from Libya, which will probably tend to support Brent; the continuing build-up of supply in the Mid-Continent, which could exceed pipeline capacity; rising Canadian oil sands production, which will have to move south to find a market; and lower requirements for light crude refinery feedstock in the fourth quarter of 2013 than in recent months. The last mentioned point stems both from seasonal factors as refineries go into the shoulder maintenance season and a switch in feedstock requirements from light to heavy crudes for BP's giant 415,000b/d Whiting, Indiana, refinery following the completion of a major facility upgrading programme. Given the potential build-up of supply in the Mid-Continent we would expect WTI to trade at a discount of perhaps $6-8/bbl over the next two or three years. This effectively reflects a blend of pipeline and rail tariffs for shipment from Cushing to the Gulf Coast.

For 2013 we look for the quarterly WTI-Brent spread to be as follows: Q1 $18.5, Q2 $8.8, Q3 $4.1, and Q4 $6.5. The average for the year of $9.5/bbl is down from our previous forecast of $11.6/bbl, mainly reflecting the sharp narrowing in the discount in the third quarter. For 2014 we look for a discount of $6.5/bbl against the $8/bbl forecast previously.

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). The former serves 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. Since early in the first quarter of 2013, when the discount was as much as $14/bbl, WTI Midland has mainly been trading at a modest discount in line with the historical picture. On 27 September the Midland discount was $0.55/bbl. The sharp narrowing of the discount since late 2012 and early 2013 is symptomatic of upgraded pipeline and rail logistics from the Permian Basin to the Gulf Coast.

Bakken and Syncrude spreads: Significant discounts to WTI have recently emerged

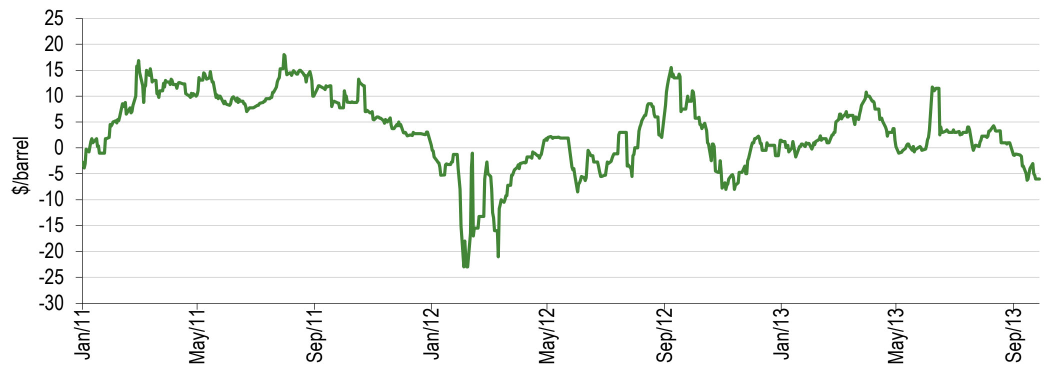
Bakken (Clearbrook Minnesota hub) and Syncrude (Edmonton Alberta hub) grades have broadly similar specifications to WTI. Prices for the two grades tend to be highly volatile resulting in wide swings in spreads. This reflects the potential for outages particularly at oil sands and syncrude upgrading facilities and what has historically been a narrowly focused group of customer refineries. Essentially outages upstream tend to drive prices to premiums to WTI, while outages downstream can result in substantial discounts. Surging production and lagging transportation infrastructure at times resulted in very wide discounts of $25/bbl for both Syncrude and Bakken grade oil in 2012. This clearly burdened profitability. Through the first six or seven months of 2013 the pricing picture for Syncrude and Bakken grade oil tended to normalise with both trading on average close to WTI. The normalisation reflected the absence of major outages and radically upgraded rail and to some extent pipeline takeaway capacity. Effectively, the improved logistics, particularly by rail, allowed Bakken and Syncrude producers to capture high-priced markets along the coasts of North America.

Exhibit 11: Bakken-WTI spread

Source: Bloomberg

Since July, however, significant discounts have again started to resurface. Syncrude, for example, has dropped from an average premium to WTI of $5/bbl in July to a discount of $6/bbl in late September, while Bakken on the same basis has seen the discount to WTI widen from $3.4/bbl to $10/bbl. The proximate cause appears to be a lagged response to the earlier narrowing of the WTI-Brent discount. Given rail transport costs of $10-15/bbl from either North Dakota or Alberta to the eastern seaboard or Gulf Coast, Syncrude and Bakken prices have had to decline to maintain competitiveness. Assuming WTI and Brent were to move to parity, Syncrude and Bakken prices would conceptually, to maintain competitiveness in coastal markets, need to stand at discounts to WTI at least equivalent to transport costs. In practice, this might be too bleak a picture as Syncrude and Bakken suppliers also have the option of selling to inland refineries.

Exhibit 12: Syncrude-WTI spread

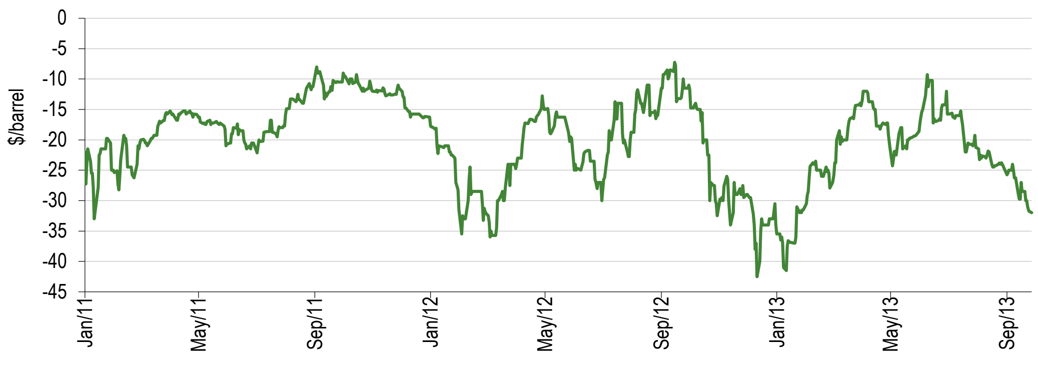


Source: Bloomberg

Western Canada Select (WCS) discount: Hefty $30 plus discount to WTI

WCS is a heavy-sour Canadian blended grade with an API of 20.5° and is one of the world's lowest-priced crude grades. A combination of burgeoning supplies, a lack of pipeline capacity and the delay in commencing operations at BP's Whiting new coking and hydrocracking facilities depressed WCS in late 2012 and early 2013 resulting in a discount to WTI exceeding $40/bbl. However, the apparent surplus of heavy oil eased during the first half of 2013, resulting in a sharp reduction in the discount to $9/bbl by June. Since then the discount has again widened and in late September 2013 was $31.8/bbl, which implied a price of $71/bbl. The widening trend of late reflects rising oil sands production, renewed logistical constraints and further delays in commencing operations at the new Whiting facilities capable of handling heavy oil. Once these come on-stream the WCS market backdrop should improve markedly given that it will have the ability to process 0.35mmb/d of heavy crude against 0.08mmb/d previously.

Exhibit 13: WCS-WTI spread

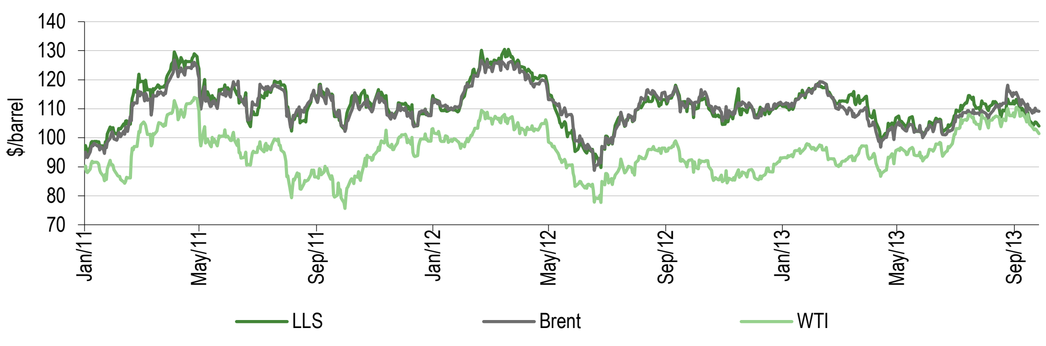


Source: Bloomberg

LLS-WTI and LLS-Brent spreads: LLS has swung to a $3-4 discount to Brent of late

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 sold at a $2-$3/bbl premium to Brent. Given Gulf sourcing, LLS has historically tracked Brent rather than WTI. Consequently LLS traded at substantial premiums to WTI of over $20/bbl on occasion between late 2010 and early 2013. In late March 2013 the premium was around $23/bbl, but subsequently has narrowed sharply in tandem with the WTI-Brent spread. By mid September 2013 the LLS-WTI premium was down to $1.0/bbl, the lowest level in more than three years. At end September the premium was $2.4/bbl.

Exhibit 14: Recent trends in WTI, LLS and Brent



Source: Bloomberg

Given the substantial increase in pipeline and rail capacity linking the Mid-Continent and Permian Basin with the Gulf Coast, a reversal of the historical LLS premium to Brent might be expected. This indeed occurred on occasion in 2012 and the tendency, belatedly, has become more pronounced of late. After trading at premiums of $1.05/bbl and $1.87/bbl in the first and second quarters of 2013 respectively, more or less in line with the historical experience, there was a narrowing to 4 cents/bbl on average in the third quarter. During late August LLS, in fact, swung to a highly significant discount to Brent of $4.76/bbl reflecting the build-up of supply along the Gulf Coast. In September the discount averaged $3.3/bbl and was $4.2/bbl at end month. Reflecting the anticipated continuing influx of supply along the Gulf Coast, we would expect LLS to trade at a discount to Brent of $2/bbl or more on a sustained basis for the foreseeable future. The supply surplus is in effect in the throes of being shifted from Cushing to the Gulf Coast. The beneficiaries will be those Gulf refineries tooled to use light feedstock. The drawback for many refineries is that they are more geared to using heavy oil.

Brent-Dubai: Dubai discount around normal levels

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/bbl to Brent. Dubai grade crude performed relatively weakly in the first quarter of 2013 reflecting the strength of Brent at the time and a plentiful supply of sour grades. On average Dubai traded at a discount of $4.0/bbl to Brent with a high on 20 February of $5.6/bbl. The discount narrowed sharply in the second quarter as Brent softened, the supply of sour grades tightened stemming from declining availability from Kirkuk in northern Iraq and attractive refinery crack spreads in Asia. At the low point in late April the Dubai discount was down to $1.1/bbl. The average for the second quarter of $2.44/bbl was, however, pretty well in line with the longer-term picture. Through end August the Dubai discount widened hitting $4.08/bbl late in the month as Brent rapidly firmed in price. As the factors previously supporting Brent ebbed the Dubai discount returned to normal levels of about $2/bbl by mid September. At the end of the month the discount was $3.1/bbl.

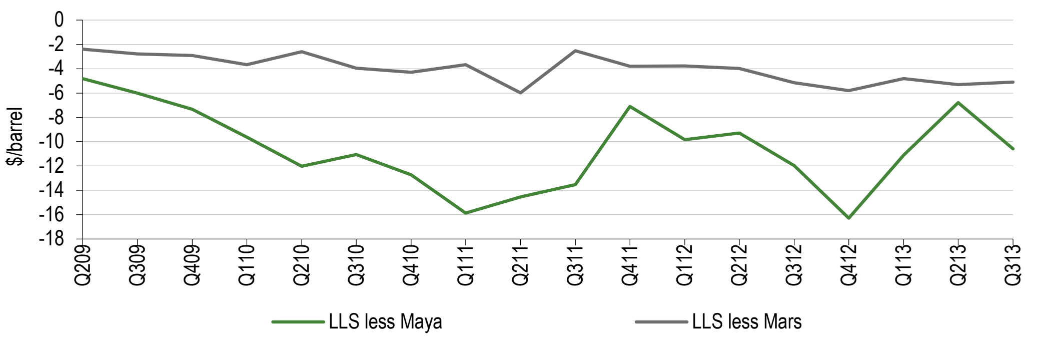
Tapis-Dubai: Tapis premium appears normal but could be vulnerable in the longer term

Tapis is a low-sulphur Malaysia-sourced light crude popular with refineries in the Far East. The spread to Dubai Fateh is one of the key sweet-sour crude price relationships. Typically Tapis trades at a significant premium of $7-10/bbl, reflecting its premium specification. In the first quarter of 2013 the Tapis premium stood at an above average $13.4/bbl driven by strong Far Eastern demand for grades with high light and middle distillates yields. The premium narrowed markedly in the second quarter reflecting the improving availability of light crudes and the tightening supply/demand balance for sour grades. The average Tapis premium for the quarter was $8.0/bbl. During the third quarter there was a modest widening of the premium to $9.7/bbl on average. This was consistent with a general tightening in light crude availability and a pronounced firming in the prices of international light crude grades. By mid-September, however, the Tapis premium had narrowed to $8.4/bbl and at end month was at $9/bbl. We continue to believe that in the medium to long term the Tapis premium over Dubai could be vulnerable to increasing supplies of light crude in the Atlantic Basin and Caspian (Kashagan oilfield) region.

US Gulf heavy crude spreads: Mars and Maya discount normal

LLS-Mars: Mars is a medium-sour grade sourced from the Gulf of Mexico that normally trades at a discount of $2-6/bbl to LLS. So far in 2013 Mars has traded on average at about $5/bbl and has been fairly stable at around this level. After averaging $4.8/bbl in the first quarter there was a slight widening in the discount to $5.3/bbl in the second quarter. The discount in the third quarter has been much the same on average. At end September Mars was trading at a $4.8/bbl discount to LLS. Abstracting from refinery outages we would expect the Mars discount to continue to trend broadly flat in the near term. Given the build-up of light crude supplies along the Gulf Coast and the heavy crude configuration of many refineries in the locality, we believe that the Mars discount could narrow from historical levels in the longer term.

Exhibit 15: US medium and heavy discounts



Source: Bloomberg, Edison Investment Research

LLS-Maya: Maya is a Mexico-sourced heavy-sour grade with a specification similar to WCS. It normally trades at discount to LLS in the range $5-12/bbl. The Maya discount narrowed sharply between the first and second quarters of 2013 from $11.1/bbl to $6.8/bbl, possibly reflecting the restart of PDVSA's Amuay refinery in Venezuela after a major fire in 2012 and increasing requirements for heavy crude post the bringing on-stream of a new hydrocracker at Valero's Port Arthur refinery. The Maya discount widened in the third quarter to $10.7/bbl as light crude prices firmed through end August. The subsequent ebbing in light crude prices left the Maya discount at $8.7/bbl in late September.

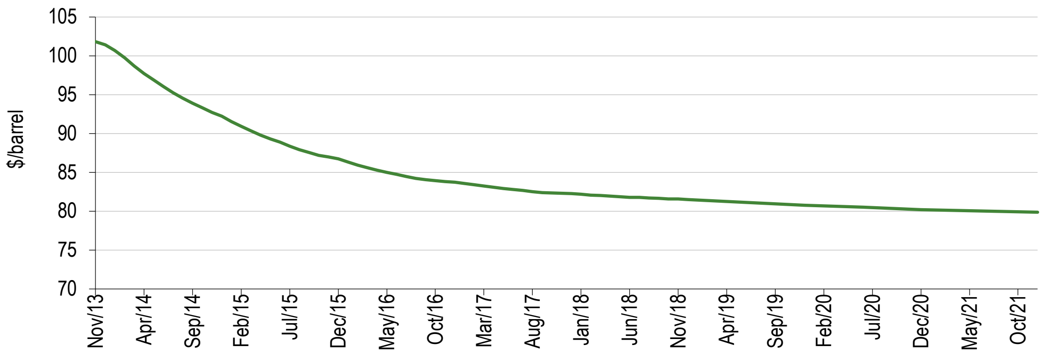
WTS-WTI: West Texas Sour (WTS) is a US inland medium-gravity sour grade with a specification similar to Mars and a delivery point of Midland, West Texas. Historically WTS has generally traded at a discount to WTI of $1-3/bbl. In late 2012, however, the discount fluctuated sharply and on occasion stood at an unprecedented $15-20/bbl due to logistical constraints in the Permian Basin and an outage at the Phillips 66 Sweeny refinery in Texas. The WTS discount narrowed markedly during the first quarter as the logistical constraints eased and towards the end of March 2013 had been virtually eliminated. The average discount for the first quarter was $6.2/bbl. In the second quarter WTS traded close to parity with WTI and from time to time was actually at a premium for the first time in 25 years. On average for the period WTS traded at a discount to WTI of 5 cents/bbl.

The picture was broadly the same in the third quarter with an average discount of 30 cents/bbl. In late September, however, there was a pronounced widening in the WTS discount to $1.1/bbl. Buoying WTS in 2013 has been a generally tight supply/demand relationship for heavy sour grades at Gulf Coast refineries. Note, the influx of supply along the Gulf littoral has mainly comprised light grades while many refineries are configured for heavy feedstock. A key event in terms of the easing of logistical constraints for WTS in recent months was the opening in June of Sunoco's Permian Express pipeline from Wichita Falls to Houston.

Forward curves: WTI goes into pronounced backwardation

Compared with earlier in 2013 there has been a significant change in the shape of the WTI forward curve in recent months. Rather than being in moderate contango (near-term prices lower than for the forward dates) at the front end, the curve is now in backwardation (near-term prices higher than for the forward dates) for all months through 2021. The WTI curve starts at $103/bbl for November 2013 deliveries and then drops sharply through early 2016 to $86/bbl. Subsequently it flattens, terminating at $79.8/bbl in 2021.

Exhibit 16: WTI forward curve

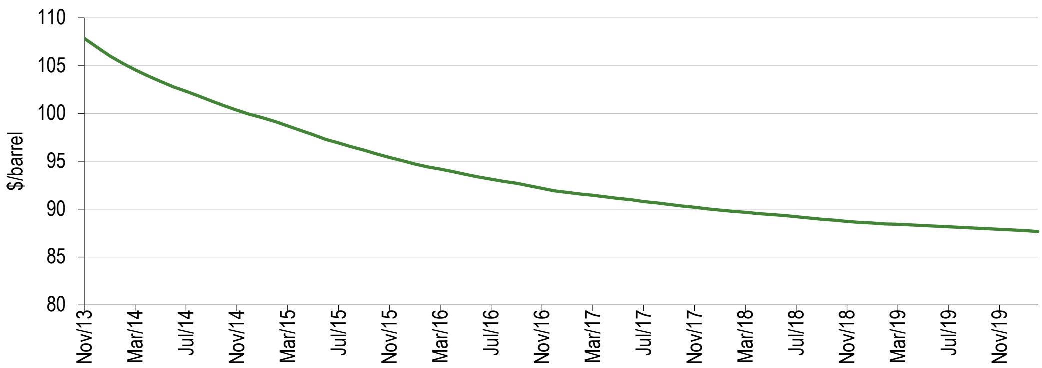


Source: Bloomberg

A swing from contango to pronounced backwardation is typically associated with a major tightening in the availability of near-term supplies. The recent such swing in the WTI curve is indeed consistent with the sharp drop in inventories at Cushing, the delivery point for NYMEX crude. In addition to this factor, it can be argued that hedging activity by US oil companies is putting downward pressure on futures prices. The issue here is that shale oil development activity is to a significant extent being financed with debt rather than equity. Oil companies are being forced by lenders to lock in futures prices through derivative instruments to remove pricing risk. The drawback is that sharp downward price pressure two or three years along the curve has a severe impact on project economics and potentially detracts from viability.

The Brent forward curve has been in backwardation for some time, reflecting tight supplies of the underlying North Sea grades and the frequent emergence of geopolitical issues, which are of greater significance for internationally traded grades than US grades. Currently, the Brent curve shows a similar pattern to WTI. The degree of backwardation, however, is slightly less pronounced in the front years for the former than the latter. For November deliveries the Brent curve commences at $108.7/bbl and then dips through early 2016 to $94.6/bbl. The curve terminates at $88/bbl in 2021. From $5.7/bbl for November 2013 deliveries the implied WTI discount to Brent widens to $7.8/bbl and $8.1/bbl one and two years out respectively.

Exhibit 17: Brent forward curve



Source: Bloomberg

Global supply/demand balance: Looks comfortable

The global oil supply/demand balance in 2013 is tighter than we and others thought a few months ago with the key variance being a loss of production from Libya and prospectively Iraq. Nevertheless, assuming no major and sustained disruptions to output over the balance of 2013 the situation is far from dire thanks to rising output in the non-OPEC world, Saudi Arabia and the UAE.

Looking purely at the relationship between the anticipated gains in global consumption and non-OPEC production plus OPEC natural gas liquids (not subject to OPEC quota restrictions) there would, in fact, be a surplus of 0.55mmb/d based on EIA data. Using IEA and OPEC data, the surpluses would be slightly less at 0.40mmb/d and 0.51mmb/d respectively. In the case of the EIA's scenario a forecast drop in OPEC crude production would trim the overall surplus in 2013 to about 0.1mmb/d. It should be noted here that the surplus reflects the performance in the first half. The second half shows a deficit of 0.17mmb/d, although this is not unusual from a seasonal perspective.

The key area of uncertainty regarding the supply/demand balance in 2013 concerns OPEC production over the balance of the year. Within this context the key issues surround Libya and Iraq, although as we have alluded to already the consensus view surrounding OPEC production may be too pessimistic. Due to the buoyant production trends in Saudi Arabia and the UAE there is, in fact, probably no reason to expect OPEC output to be significantly different than the implied call on OPEC supply. A key point to note is that it is very lucrative at present for OPEC producers to pump and sell oil. Other key risks in the coming months revolve around the potential for outages in the non-OPEC world with the North Sea and the Gulf of Mexico to the fore. So far the hurricane season in the Gulf has mercifully been quiescent but there are still another two months of potential vulnerability.

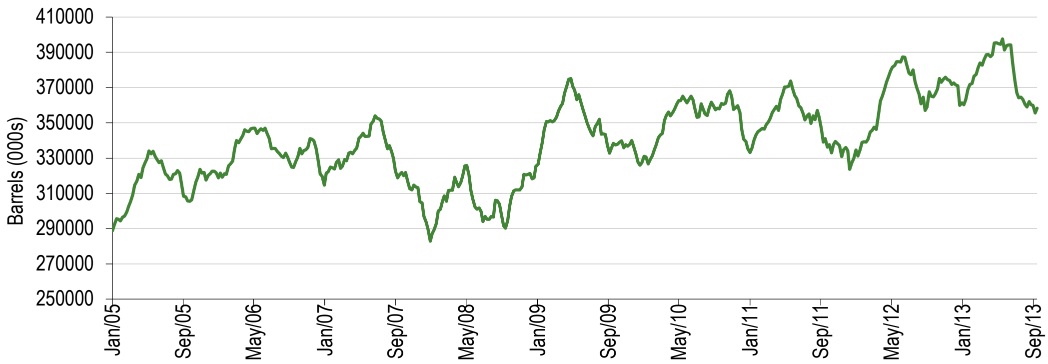
For 2014 the EIA along with the IEA and OPEC are looking for the growth in non-OPEC output together with OPEC natural gas liquids to comfortably exceed global consumption growth. In the EIA's case the surplus is 0.6mmb/d. However, allowing for an anticipated decline in OPEC output this reduces to around 0.12mmb/d. One of the key unknowns for 2014 is the extent to which OPEC will wish to offset the gain in non-OPEC production net of global consumption growth. Much will probably depend on how Libyan and Iraqi production develops in the coming months. High levels of uncertainty surrounding production in these two countries suggest that Saudi and UAE production will be maintained at a higher level in 2014 than might otherwise be expected. This could boost the supply surplus for 2014.

US inventories

Crude oil: Falling trend since May but inventories remain historically high

US commercial crude oil inventories rose strongly in the first five months of 2013 to record levels but have subsequently fallen sharply, reflecting to a large extent seasonal influences. The peak came on 24 May when the EIA reported crude inventories of 397.6mmbbl, a level that was about 10mmbbl above the top end of the range for the time of year. Between end May and 13 September inventories fell by 42mmbbl to 355.6mmbbl. This is the lowest level since early 2012 but it should be noted that they remained at the high end of the range seasonally. Furthermore, in the following week there was a gain 2.7mmbbl. Compared with a year ago, inventories on 20 September were off a modest 6.9mmb/d or 2%. The dip in inventories in recent months stems from a combination of upgraded transportation infrastructure that has removed bottlenecks in the Mid-continent and a pronounced upturn in refining activity. From the low point in February refinery runs have increased by about 1mmb/d to 16.1mmb/d, which has taken them back to the peak levels of the mid 2000s despite a significant decline in domestic demand in the meantime. Helping to buoy refinery runs has been a sharp swing from net product imports to exports over the past two or three years.

Exhibit 18: US crude oil inventory



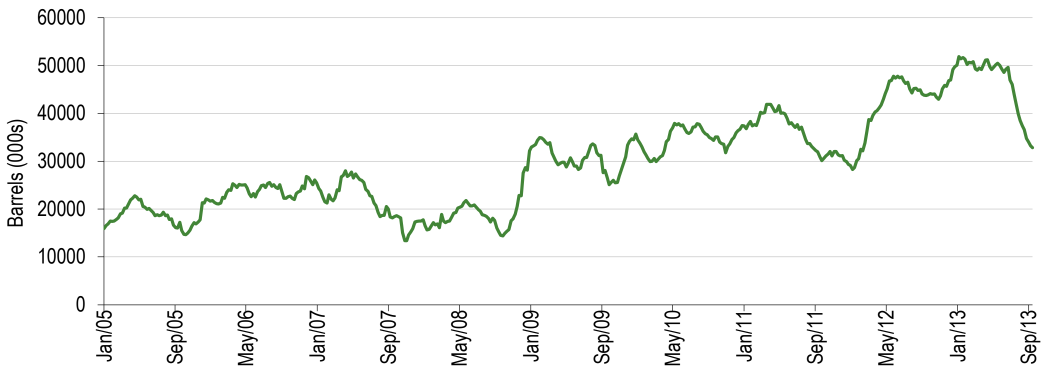
Source: EIA

On a days' supply basis there has been a clear decline in recent months, but from a historical perspective they are by no means low. Inventories on 20 September were equivalent to 22.6 days' supply against 25.0 days a year previously. Including the strategic petroleum reserve inventories on 20 September were 1,054.2mmbbl, equivalent to about 66 days' supply.

Cushing: Sharp falls in recent months; planned Flanagan pipeline could increase supplies in 2014

Crude inventories at the Cushing, Oklahoma tank farm, the delivery point for Nymex crude, hit a record 51.9mmbbl in early 2013. After following a broadly flat trajectory over the first six months of this year inventories at Cushing have fallen sharply for similar reasons to those indicated above for the aggregate position. At 20 September Cushing inventories stood at 32.8mmbbl, down from 43.8mmbbl a year previously. Cushing is currently using 51% of its net working capacity of 65.3mmbbl.

Exhibit 19: Cushing crude oil inventories



Source: EIA

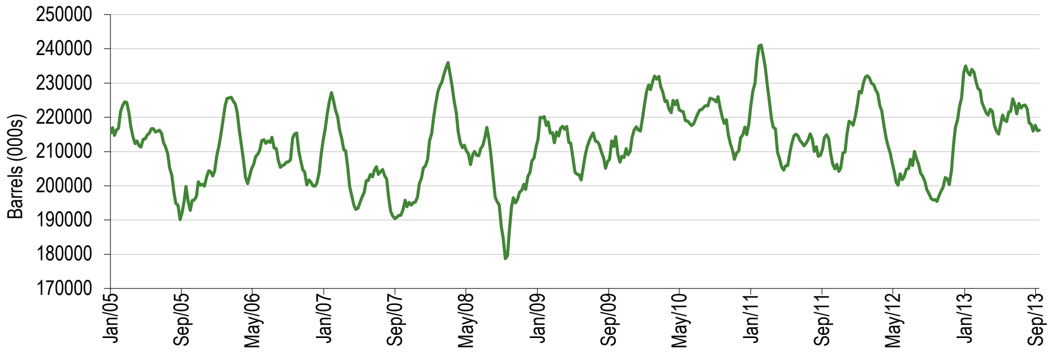
Seasonal influences in terms of potentially declining refinery activity could favour a modest gain in Cushing inventories in the coming months. Recent changes in the pipeline infrastructure directing oil to Gulf Coast markets will, however, probably keep inventories below peak levels in the near term. In mid 2014, however, a major new pipeline in the form of Enbridge's 600,000b/d Flanagan South is scheduled to bring new supplies into Cushing. The pipeline will originate in Flanagan Illinois and enable Bakken and Alberta oil to be readily shipped south in much the same way as proposed for Keystone XL. At this stage a presidential decision on Keystone is not expected until well into 2014.

Gasoline: Seasonally high level

US gasoline inventories have been running at seasonally high levels for most of 2013. According to EIA data inventories on 20 September were 216.2mmbbl, up 20.4mmbbl on a year earlier and towards the high end of the range for the time of year. Inventories have been supported by the buoyant trend in refinery runs and still lacklustre domestic demand for gasoline.

On a days' supply basis gasoline inventories continue to run at a historically high level seasonally. The days outstanding on 20 September were 24.3, up from 22.2 a year ago.

Exhibit 20: US gasoline inventories

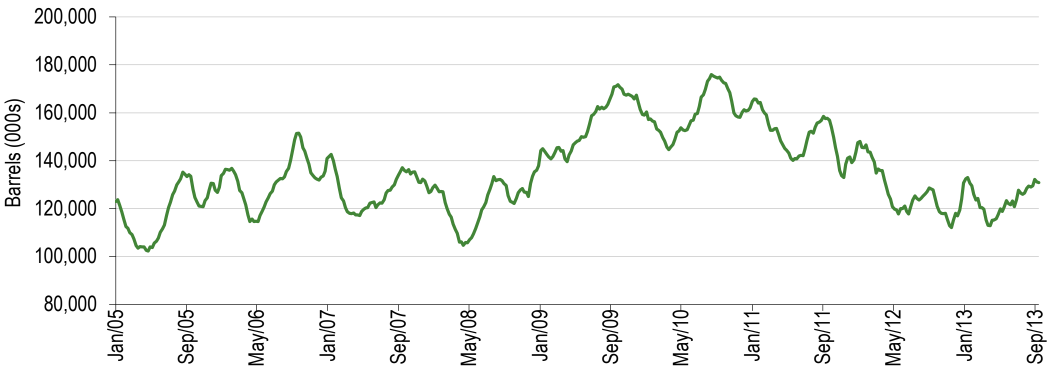


Source: EIA

Distillates: Continue to track low end of the seasonal range, days outstanding normal

Distillate inventories have been tracking close to the lower end of the seasonal range since mid 2012. For the week ended 20 September, inventories were 130.9mmbbl, up 2.4% on a year earlier and marginally above the low end of the seasonal range. In the latest week inventories were equivalent to 34.5 days, down from 37.3 days a year ago. While well down from the highs of 45 plus in 2009/10 the days outstanding currently are not unusually low historically.

Exhibit 21: US distillate inventories



Source: EIA

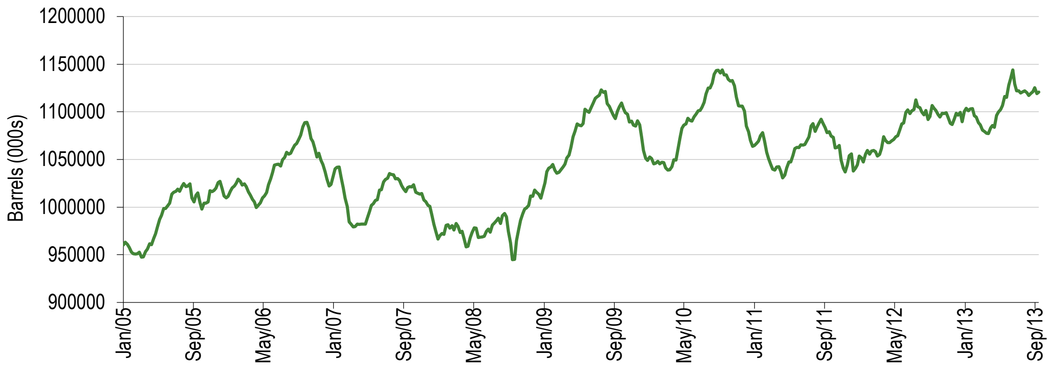
We continue to believe that seasonally depressed distillate inventories reflect in large part buoyant export business remembering that crack spreads tend to be higher than on domestic sales. In the latest week distillate exports were 1.39mmb/d, up 28% and 57% on one and two years ago respectively.

All petroleum product inventories: Remain historically high

We continue to believe that the soundest basis for assessing the adequacy of petroleum inventories is on the all encompassing definition including US commercial crude oil and refined product inventories. Based on EIA data for 20 September, US commercial inventories in total were

1,120.7mmbbl, up 1.0% on a year earlier and only 2.0% under the post 2000 high of 1,143.5mmbbl recorded in September 2010. In total therefore commercial inventories remain historically high.

Exhibit 22: US all petroleum product inventories

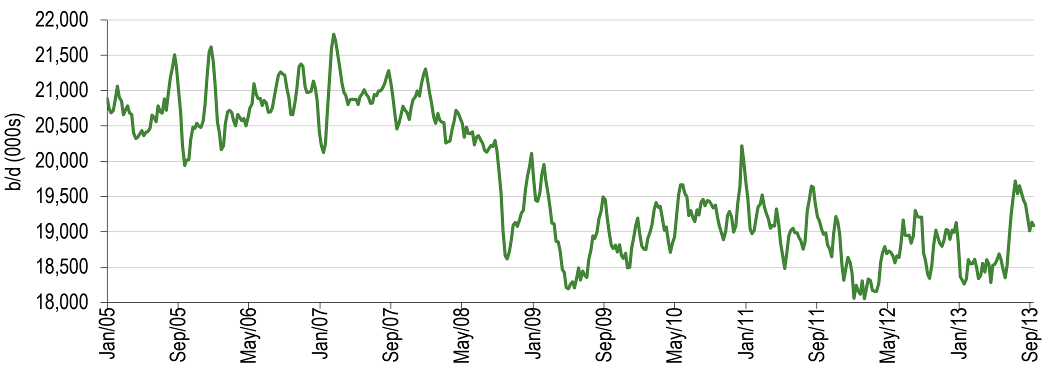


Source: Bloomberg

US petroleum product demand: Firming trend continues

There is no question that US petroleum product demand has firmed in recent months and not just for seasonal reasons. Looking at the most recent four-week period ending 20 September, petroleum product demand (product supplied is used as a proxy) overall averaged 19.09mmb/d, up 3.8% on a year previously. Peak summer demand also showed a similar year-on-year gain, which compares with earlier in 2013 when demand was more or less unchanged from 2012. In the latest four-week period all key product categories, with the exception of fuel oil, showed year-on-year gains as follows: gasoline 0.5%, distillates 10.8%, kerosene 4.4%, propane/propylene 5.0% and miscellaneous 1.7%. Fuel oil demand dropped 7.2%. Reflecting the softer backdrop earlier in 2013 year-to-date demand through 20 September has shown a more modest year-on-year gain of 1.1% split by product line as follows: gasoline 0.6%, kerosene 1.8%, distillates 4.6%, fuel oil -17.9%, propane/propylene 9.6% and miscellaneous -2.5%.

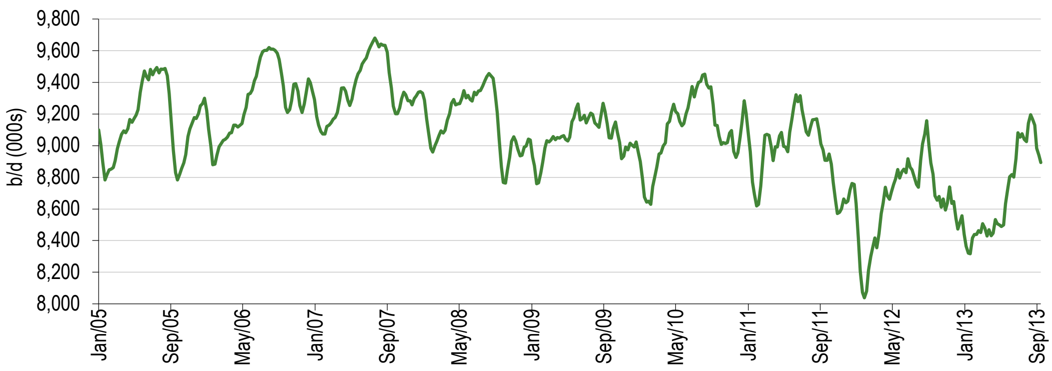
Exhibit 23: US petroleum product supplied



Source: EIA. Data relate to four-week averages

Reviewing September and year-to-date movements the clear highlights are the continuing sluggishness in gasoline and the surge in distillates consumption. The former continues to largely reflect a combination of improving light vehicle fuel (cars and light trucks) efficiency, engine downsizing and declining miles driven. Tightening regulatory requirements in terms of corporate average fuel economy (CAFE) and lifestyle changes reinforced by high fuel prices by US standards at least, are the key underlying factors at play. High levels of hidden unemployment (workers that have dropped out of the registered labour force) may also be depressing gasoline consumption. This year's strong showing by distillates we believe stems from two key factors. Firstly, the continuing upturn in the US economy, which boosts transportation usage in the form of medium/heavy trucks and railroads. In addition, power generation could be lifting distillates consumption. The second key positive for distillates concerns very high activity in the agricultural sector, a major user of diesel. According to the USDA acreage planted for grains is at multi-year highs.

Exhibit 24: US gasoline supplied

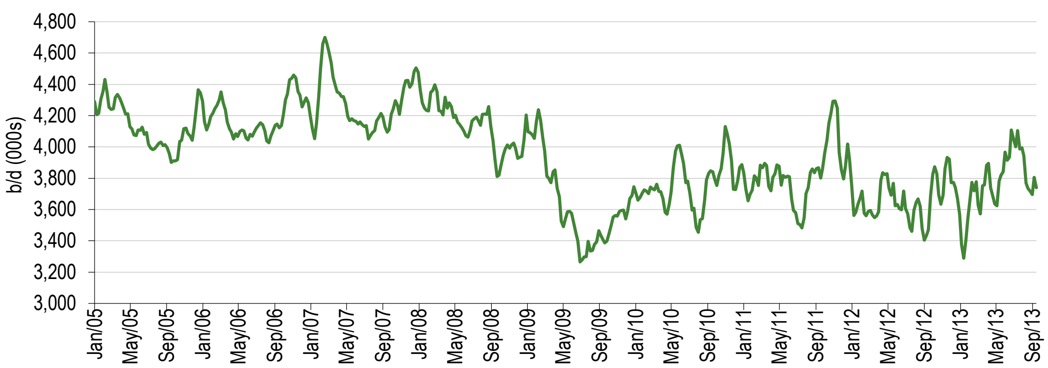


Source: EIA. Data relate to four-week averages

The EIA has modestly upgraded its US petroleum product demand forecasts for 2013 and 2014 in recent months. In the case of 2013 demand is now 18.68mmb/d against 18.55mmb/d in May/June. Compared with 2012 the gain is 0.7% rather than 0.4% previously. The key driver, not surprisingly, is distillates consumption, which is forecast to grow by 3.2% in 2013. Significantly, the forecasts for gasoline and jet fuel are unchanged from 2012, while fuel oil shows a decline of 6%. For 2014 the EIA is forecasting petroleum product consumption to grow by 0.2% to 18.72mmb/d, which compares with a flat forecast previously. Again, distillates are expected to drive consumption in 2014 with a gain of 1.3%. Gasoline consumption in 2014 is expected to dip by 0.5%, reflecting gains in the fuel efficiency of the light vehicle fleet.

The EIA's US consumption forecasts for 2013 and 2014 are predicated on GDP growth forecasts of 1.6% and 2.6% respectively. Based on the firming tendency of late, the EIA's 2013 consumption growth forecast might be on the conservative side. Overall, however, the EIA's consumption scenario for 2013 and 2014 appears realistic given the backdrop of moderate economic growth and structural forces tending to reduce consumption in the transportation sector.

Exhibit 25: US distillates supplied



Source: EIA. Note: Data relate to four-week averages.

Crude oil price outlook: Softening trend expected; Iran potentially significant

We believe international and US light crude prices should decline in the fourth quarter of 2013 from the elevated levels of August. The softening tendency is expected to be driven by receding geopolitical tension over Syria and the apparent sharp recovery in Libyan production towards the end of September. In the light of the accord between the US and Russia aimed at quarantining and then destroying Syria's chemical weapons stockpile, it is inconceivable that the US would launch an attack on Syria even if there are some technical difficulties in the coming weeks. As we have noted earlier, the underlying supply-demand picture really is far from dire particularly if Libyan production returns to the semblance of normality in the weeks ahead and Saudi Arabia and UAE continue to produce at recent rates. Effectively, prices were bid up in August reflecting, not for the first time, grossly exaggerated fears over supply.

After averaging around $110/bbl in the third quarter of 2013 we look for a modest dip in Brent to $108.5/bbl in the closing quarter of the year. This would imply an average for 2013 as a whole of $108.6/bbl which is up $3.3/bbl on our previous forecast but down $3.4/bbl or 3% on a year previously. Our quarterly scenario for 2013 is as follows: Q1 $112.8, Q2 $102.9, Q3 $110.1, Q4 $108.5. The forecast upgrade reflects the Syria and Libya induced price surge of the third quarter and the carryover effect into the following quarter.

For 2014 we continue to look for a modestly downward trend in Brent albeit from a higher base than previously. The key factor remains the potential emergence of a significant supply surplus as demand growth lags non-OPEC supplies. Our forecast calls for Brent to average $103/bbl. This constitutes a significant increase from the prior forecast of $99.0/bbl reflecting the assumptions of greater carryover strength from 2013 and potentially lingering geopolitical issues in the Middle East. We remain of the view that a supply build-up stemming from North America, Brazil, the Caspian region and Iraq could weigh on oil prices for several years over the balance of the decade. In this context we may not necessarily be looking at price rout but rather an extended period of Brent in the $90-100/bbl zone. Much here will depend on how OPEC reacts to growing supplies from non-OPEC countries plus quota free Iraq. It would seem to us that OPEC will find it increasingly difficult economically to shut off supply to offset rising non-OPEC production.

In the fourth quarter of 2013 we would also expect WTI to trend down reflecting potentially mildly bearish international influences plus buoyant local supplies. For the period, we forecast an average price of $102/bbl which would imply an average for 2013 of $99.1/bbl. This is a significant upgrade to our earlier forecast of $93.7/bbl and stems from the unexpected second and third quarter price surge related to a more rapid than expected rundown in inventories at Cushing, the resurgence in geopolitical concerns surrounding the Middle East and the sharp fall in Libyan production. Our quarterly WTI scenario for 2013 is as follows: Q1 $94.3, Q2 $94.1, Q3 $106.1, Q4 $102.0.

In 2014 we expect the WTI price trend to be moderately downward. This reflects burgeoning domestic supply, pipeline developments particularly through Flanagan that could once again lead to an inventory build up at Cushing and potentially bearish international influences. Our 2014 WTI forecast calls for an average of $96.5/bbl with a quarterly scenario as follows: Q1 $98.0, Q2 $97.0, Q3 $96.0, Q4 $95.0. The full year forecast constitutes an upgrade from the $90.9/bbl given previously and largely stems from the positive carryover effect from 2013. We believe that in the event of a major dissipation in Middle East geopolitical tension WTI and Brent could, in fact, move nearer to $90/bbl and $98/bbl respectively in 2014.

Iran seeks a rapprochement with the west: The Iranian nuclear issue again looks like moving onto the oil market agenda in the coming weeks. This time however we could be looking at a loosening or even a removal of the sanctions regime rather than a tightening. In our view this would have clearly bearish implications for oil prices. The key development of late has been the move made by the new Iranian president Hassan Rouhani to open a dialogue with the west to reach an accord over Iran's nuclear programme. Negotiations will effectively revolve around finding a formula that will enable Iran to continue its nuclear programme (Iran is perfectly entitled to having such a programme under the Non Proliferation Treaty of which it is a signatory) while being monitored to prevent uranium enrichment to weapons grade standards. Significantly, President Rouhani has suggested that he wants to come to an agreement within three months and certainly not longer than six months. Significantly Rouhani appears to have been empowered to engage in negotiations with the west by Iran's Supreme Leader, Ayatollah Ali Khamenei. President Obama has responded positively to the Iranian overtures. An accord over the nuclear issue could lead to a wider political rapprochement between the US and Iran thereby ending 34 years of hostility between the two countries. This hostility, of course, has long been an underlying factor behind Middle Eastern geopolitical tension.

If the sanctions regime is dismantled it would effectively enable over 1mmb/d of Iranian exports to flow back onto the market. Furthermore, it could pave the way for western involvement in revamping and expanding Iran's creaking petroleum industry infrastructure. There is little doubt in our view that Iran's production of oil and gas could be significantly expanded from the levels of recent years with the application of technology and dollars. The issue is not the existence of reserves.

Quantifying what the impact of a potential accord between the US and Iran might have on oil prices is clearly a fraught exercise. Interestingly, Bank of America has played down the impact suggesting less than $10/bbl. This however would not be without significance for oil markets. Furthermore, $10 does not take into account the potential longer term second order implications such as capacity expansion and the freeing up of oil and gas capacity for exports as nuclear power generating facilities come on-stream. Clearly, in the short term the potential impact of the removal of the Iran sanctions regime will depend on the reaction of Saudi Arabia. The view of Bank of America is that Saudi production would be cut in response to an increase in Iranian exports. This might be the case, but at a time when production will probably also be increasing strongly in Iraq and in the non-OPEC world, would the Saudis really want to concede market share and revenue to Iran, which has historically been their main rival in the Middle East?

Exhibit 26: Brent and WTI annual price trends

$/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	99.1	96.5
Brent	54.5	65.4	72.7	97.7	62.0	79.7	110.0	112.0	108.6	103.0

Source: Bloomberg, Edison Investment Research. Note: Prices are yearly averages.

US natural gas market

Production and consumption

Recent trends: Production and consumption subdued, exports to Mexico strongly upward

Production: The flattening trend in US natural gas production that became apparent in the second half of 2012 carried over into the first half of 2013. Based on EIA data, marketed production in the six months to June 2013 of 12.59tcf was actually down 1.6% on the prior half year but compared with a year previously there was a gain of 0.5%. Taking the two most recent months, May and June, there were year-on-year gains of 1.3% and 1.7% respectively. US gas production continues to be buoyed by non-traditional sources particularly in Pennsylvania, West Virginia and North Dakota.

Pennsylvania and West Virginia are benefiting from rapid development of the prolific Marcellus shale formation which is not only one of the largest gas discoveries in recent years in the US but also the world. According to the Pennsylvania Department of Environmental Protection, production in Pennsylvania was 1.4tcf in the first half of 2013, up around 50% from a year earlier. For the full year production of about 3.2tcf is expected by the Department. Bentek, a Evergreen Colorado-based consultancy, has also suggested that West Virginian production was up around 50% in the first half of 2013. Including West Virginia and Ohio, we believe Marcellus production in 2013 could top 4tcf, over 15% of the US total. In North Dakota, gas production through the first seven months of 2013 was up 43% from a year earlier based on State data. Production in Texas and Oklahoma in the first half of 2013 also rose year-on-year by 0.4% and 6% respectively but there were declines of 18% in Louisiana, 10% in Wyoming, 14% in the Gulf of Mexico and 5% in New Mexico.

The recent flat trend in US marketed gas production has continued to reflect a lagged response to falling drilling activity in 2012 and delays in establishing pipeline connections. Significantly, however, the net import balance in 2013 has continued to narrow and in the first half of the year was pretty marginal at 618 bcf, down 22% on a year earlier. In June 2013 97% of imports related to pipeline gas from Canada. The balance comprised a trickle of pipeline imports from Mexico and a small amount of LNG from Trinidad. All exports currently are in the form of pipeline supplies to Canada and Mexico. The narrowing net import balance has boosted overall US industry gas shipments by approaching 2tcf since 2008.

Consumption: US gas consumption has been subdued through the first six months of 2013. Consumption for the period came in at 13.3tcf, up 2% on a year earlier. In May and June consumption actually showed year-on-year declines of 7% and 8% respectively. So far in 2013 gas consumption has been supported by buoyant trends in the residential, commercial and industrial sectors driven by relatively cold winter conditions and the general economic recovery. Detracting from demand in 2013 has been a sharp 16% drop in the largest segment, electrical power generation. This largely reflects gas's loss of competitiveness against coal over the past year or so and a consequent increase in the coal burn rate in power stations. According to the EIA, gas prices to the power generation sector in 2013 are likely to increase by about 30% from 2012 while coal prices decline by 2% or so. The EIA is forecasting a decline in the power station gas burn rate between 2012 and 2013 from an historically high 30% to 27%. In the first half of 2013 the gas burn rate was about 25%.

Outlook: Near-term trends likely to remain subdued

The trend in marketed US natural gas production is likely to remain fairly subdued near term due to the earlier fall in drilling activity along with delays in making pipeline connections. It should be noted, however, that the gas-focused rig count recovered a little in the third quarter of 2013 and, as we have noted, drilling remains buoyant in the prolific Marcellus and Eagle Ford formations. In North Dakota considerable amounts of gas are being produced as a by-product of oil production. Significantly, several major pipeline connections are scheduled to come on-stream in the last three months of 2013, which will boost takeaway capacity in the Marcellus by 0.5 bcf/d. We suspect therefore that production is not in imminent danger of falling on a sustained basis. The EIA continues to look for modest gains in US gas production of 1.0% to 25.5tcf in 2013 and 0.7% to 25.7tcf in 2014.

Given recent trends, US domestic gas consumption also seems likely to be subdued near term. The EIA is currently looking for marginal growth of 0.3% in 2013 and a decline of 0.9% in 2014. The former is down from the 0.7% forecast a few months ago. The key constraint on consumption near- to medium-term remains gas's loss of competitiveness in the power generation sector. Recently consumption has probably also been indirectly depressed by relatively cool conditions during the third quarter in the key air conditioning markets of the Eastern Seaboard and Midwest.

Medium- to long-term drivers Medium term, we would expect US gas consumption growth to pick up momentum compared with the recent lacklustre showing. We see four potential drivers as follows:

- exports both in the form of pipeline gas to Mexico and possibly LNG to Asian markets;
- industrial related primarily to the petrochemicals and metallurgical sectors;

- vehicular fuels in the form of both CNG and LNG; and
- economic growth.

Exports of gas to Mexico would appear to be a promising medium-term prospect for US producers. Exports to Mexico have been growing strongly in recent years as demand has outstripped local production growth. In 2012 exports to Mexico were 1.69bcf/d, up 24% on the previous year. Cross-border capacity is currently about 3.4bcf/d while planned capacity additions could roughly double this amount by end-2014/15. Export growth is expected to be driven principally by development in the Eagle Ford and Permian Basin. Significantly, pipeline gas exports to Mexico tend to attract less political attention than LNG exports and new capacity is relatively easy and cheap to install.

The possibility of large scale LNG exports has attracted a lot of controversy over the past two or three years. The advocates rest their case on the arbitrage opportunity between international LNG export prices of around $15/mcf and US domestic prices of around $3.5/mcf. The argument is that this is too attractive a spread to ignore, although exporting LNG would of course involve substantial costs in terms of establishing processing facilities and transportation. The contrary argument is that exporting LNG would boost domestic prices, thereby undermining a potential industrial renaissance in the US. Dow Chemical, the largest US chemical company, not surprisingly, is the leading advocate for this position. So far, the federal authorities have authorised four LNG export facilities in the US but many regulatory hurdles remain. If LNG exports are given the green light we believe that they are unlikely to commence before 2016, given the regularity and political issues and long construction lead times for new facilities.

Major petrochemical plant expansion projects are planned in the US by the likes of Dow, Shell and Statoil to take advantage of internationally highly competitive feedstock costs in terms of gas and natural gas liquids. Note, low natural gas prices also give a competitive boost to energy intensive sectors such as petroleum refining, metallurgy and foundries/forges. Clearly, some of the planned projects in petrochemicals and other energy-intensive process industries would be choked off if US gas prices were to lose their internationally ultra-competitive status.

CNG and LNG are potentially substitutes for diesel in vehicle applications, while CNG can also substitute for gasoline. Using CNG and LNG as diesel and gasoline substitutes in vehicle applications is superficially attractive given direct fuel cost savings of up to about 40%. There are, however, drawbacks to using vehicular gas-based fuels that will probably severely constrain their use. These include much lower fuel density than diesel, leading to a shorter range and possibly inferior performance and the need for bulky and heavy cryogenic tanks. Specifically in the case of LNG, there is a need to store fuel at very low temperatures, which necessitates a complex and expensive refuelling system. Consequently, we suspect that the vehicular gas segment will remain relatively small for the foreseeable future.

Assuming economic growth gathers a modicum of momentum over the next few years, natural gas consumption should also receive a boost. The key beneficiary will probably be power generation. Long term, power generation-related demand could also be boosted by tightening US emissions regulation, bearing in mind that gas generates about 50% less carbon dioxide than coal per unit of energy.

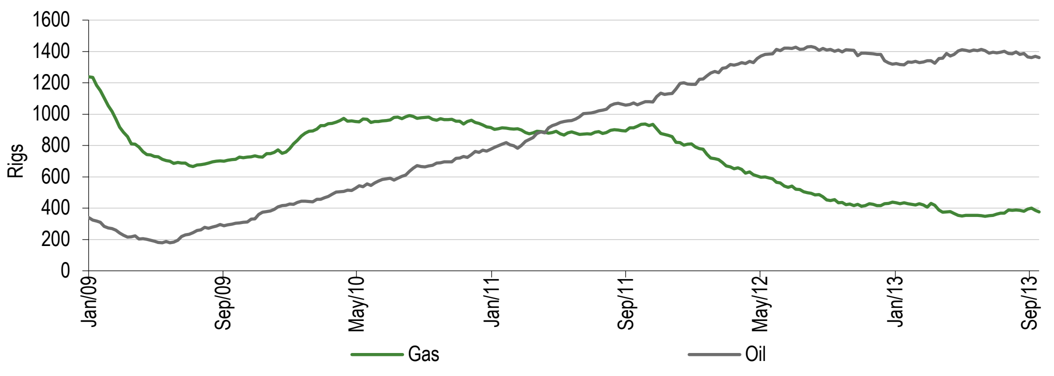
Drilling activity: Slight firming in the dedicated gas rig count of late

US oil and gas drilling activity has followed a broadly flat trend in 2013 and has remained at a historically high level, if somewhat below the peak levels of late 2011. Based on Baker Hughes data, the rotary rig count overall on 20 September was 1,761, which was close to the end-2012 level. The 20 May reading was off 5% from a year earlier and 14% from the 4 November 2011 high of 2011.

After the more or less uninterrupted upwards trend between mid-2009 and mid-2012, which saw an approximate seven-fold increase, the US oil-based rig count has recently followed a flat trend at close to record levels. The Baker Hughes oil rig count on 20 September of 1,369 was down 2.4% from a year ago and 4.4% from the all-time high of 1,432 on 8 October 2012. The dedicated oil rig count has continued to be buoyed by high levels of development activity in the shale and tight reservoir plays but clearly momentum has waned. Based on the latest data the greatest concentration of oil-based rigs is in the Permian Basin. The rig count here on 20 September of 444 accounted for 32% of the total.

The gas-based rig count slumped during 2012 but the trend has stabilised in 2013. In fact, since June there have been some signs of firming. On 20 September the gas rig count of 386 was 15% below the previous year's earlier levels but up 11% on the recent June low of 349. With 86 the Marcellus Basin had the largest number of gas dedicated rigs on 20 September. The firming trend of late is consistent with the modest recovery in dry gas prices of early 2012 and more particularly the recent rebound in some natural gas liquids prices. As we have noted before, natural gas prices in excess of $4.5/mmBtu would probably be required to markedly boost the dry gas dedicated rig count on a sustained basis from current levels.

Exhibit 27: Baker Hughes US rig count



Source: Baker Hughes, Bloomberg

Inventories: Comfortable

US natural gas inventories were running at seasonally very high levels for most of 2011 and 2012, but in 2013 the situation has normalised. Based on EIA data for 13 September, inventories stood at 3,299bcf, down 5.4% on a year earlier and marginally higher than the five-year average for the time of year of 3,281bcf. Restrained increases in production combined with modest gains in consumption seem to have trimmed inventory injection rates in recent months compared to prior years. The EIA is predicting inventories of 3,820 bcf at the end of the injection period in late October, which would be about 88 bcf or 2% below a year earlier. Abstracting from a period of very severe weather, gas inventories look like running at comfortable levels seasonally through the winter months.

Recent price developments and outlook: Near term no grounds for excitement, 2014/15 could look more interesting

Dry gas: US natural gas prices are well off the lows of the second quarter of 2012 but the trend has been lacklustre in recent months. Taking the Henry Hub, Louisiana benchmark, the high-water mark so far in 2013 has been $4.38/mmBtu on 19 April. This was a 21-month high and 138% above the multi-year low of $1.84/mmBtu recorded a year earlier. Following the April high, the Henry Hub quote trended down through early August, hitting around a five-month low on 8 August of $3.27/mmBtu. Subsequently, a little ground has been regained, taking the Henry Hub on 23 September to $3.64/mmBtu, up 29% on a year previously. The lacklustre trend during most of the second and third quarters of 2013 reflects fairly benign weather along the Eastern Seaboard, no major storms and a comfortable supply position. These factors appear likely to carry over into the early fourth quarter of 2013.

Exhibit 28: Henry Hub price trend

Source: Bloomberg

Reflecting the relatively weak showing during the third quarter and comfortable supplies we are slightly downgrading our 2013 Henry Hub forecast from $3.86/mmBtu to $3.72/mmBtu. The quarterly profile is as follows: Q1: $3.49, Q2: $4.02, Q3: $3.56, Q4: $3.79. The fourth quarter reflects a modest uplift from the $3.55/mmBtu given previously, due to the assumption of less benign weather conditions late in the period. For 2014 we have also slightly downgraded the Henry Hub forecast from $4.10 to $4.01/mmBtu reflecting a weaker carryover position from 2013 than previously forecast.

The 2015 price outlook will probably depend on two factors in addition to the severity of the summer and winter weather conditions. They are the extent to which drilling activity resumes an upwards trend in the coming months and the strength of the US economy. The combination of subdued drilling activity, a reasonably buoyant economy and extreme summer and winter weather could conceivably propel US natural gas prices to more than $5/mmBtu in 2015.

Exhibit 29: Henry Hub quarterly price trend

$/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	3.49	4.02	3.56	3.79	3.72
2014e	4.00	3.75	4.10	4.20	4.01

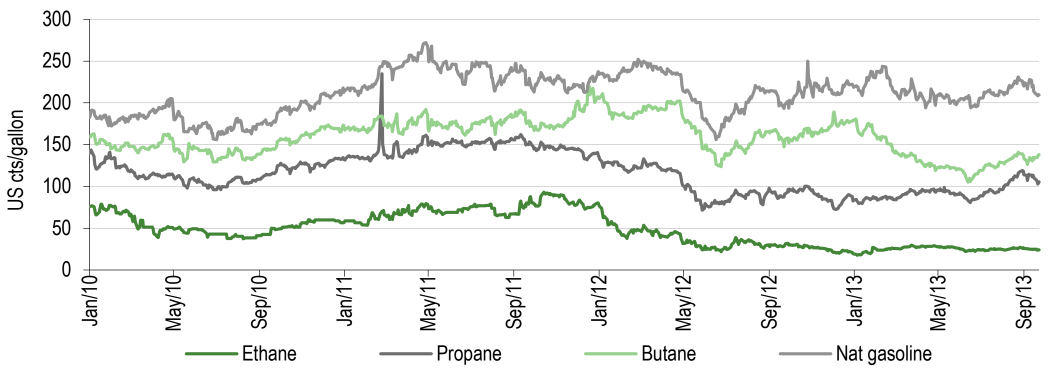
Source: Bloomberg, Edison Investment Research. Note: 2013 quarters 1-3 are actuals

NGLs: Natural gas liquids (NGLs) such as ethane, propane, butane and natural gasoline are important petrochemical feedstocks, gasoline-blending agents and fuels. They are also 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 such as the Marcellus and Eagle Ford. Importantly, production has continued to grow rapidly in 2013 and has comfortably outpaced dry gas. Taking the four weeks to 13 September the EIA has reported NGL output of 2.49mmb/d, up 5.6% on a year earlier, while for the year to date there has been a gain of 4.3%. Against this backdrop the EIA's forecasts for NGL production in 2013 and 2014 appear conservative at 2.49mmb/d (+3.8%) and 2.51mmb/d (+0.8%) respectively.

After having fallen sharply in 2012 and remained soft in early 2013, US NGL prices have generally firmed in recent months. From the recent lows in June, propane and butane have risen in the subsequent three months by 30% and 27% to $0.813 and $1.333/gallon (Mt Belvieu Texas, the main US hub for NGL prices) respectively. Natural gasoline has also risen by 6% on the same basis but ethane, the key building block in ethylene production, is little changed at $0.241/gallon. Ethane, however, is up significantly from the end-December 2012 low of $0.19/gallon. Compared with a year previously, Mt Belvieu prices reflected differentials as follows: ethane -15%, propane +21%, butane -13% and natural gasoline +1%.

The generally strengthening trend in NGL prices of late has been despite sizeable production gains and appears to reflect upgraded pipeline and port handling facilities plus strong export demand. According to EIA data, NGL exports were up by 27% in the first half of 2013 year-on-year. Exports now account for about 16% of production, up by three percentage points on 2012. US prices, it should be noted, remain substantially below European prices. Propane, for example, ex Mt Belvieu, was selling in late September at a discount to NW Europe prices of about $0.9/gallon.

Exhibit 30: Recent trends in US NGL prices



Source: Bloomberg

Economics: Still marginal for the dry gas operators, liquids-rich operators probably significantly profitable

US dry gas prices in late-September of $3.6/mmBtu imply a reasonably comfortable operating cash contribution, but after allowing for SG&A and finding and development costs operators are probably still looking at a significant fully accounted loss on average. Our thinking here is that cash operating costs are about $2.8/mcf (including lifting, production taxes, royalties processing and pipeline tie-in) while finding and development could be in the range $1.5-2.0/mcf.

Wet gas producers, of course, continue to have considerably more favourable economics. Particularly in the liquids-rich zones of the Eagle Ford and the Marcellus, NGLs can boost price realisations by a further $2/mcfe to approaching $6/mcfe. This probably implies a significant fully accounted profit even allowing for addition processing and pipeline costs.

Exhibit 31: 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	3.72	4.01

Source: Bloomberg, Edison Investment Research. Prices are yearly averages

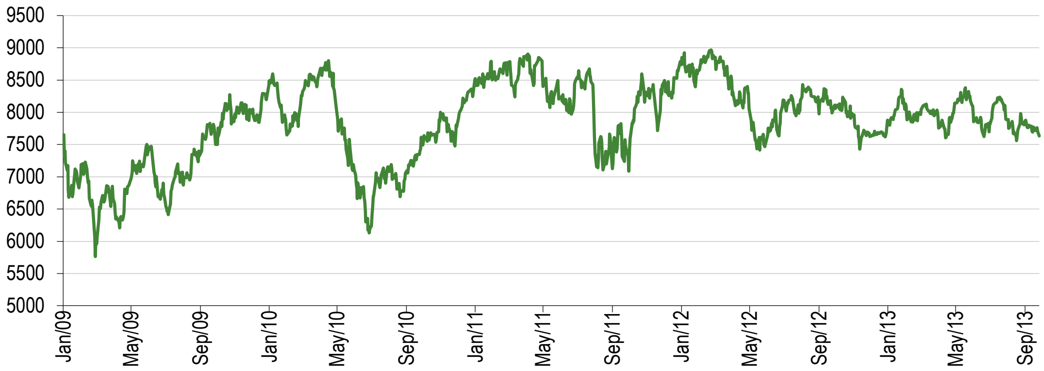
Oil and gas sector performance

UK: AIM juniors have gained some traction of late

In recent months large capitalisation UK-based oil and gas stocks have continued to perform in lacklustre fashion while the juniors have firmed. Between 30 June and late September the FTSE 350 Oil & Gas Index, an index of medium and large capitalisation stocks dominated by BP and Shell, dipped by 0.8%, a significant underperformance compared with the 5% gain in the FTSE 100. Over the same three-month period, the AIM Oil & Gas Index, the benchmark for the juniors, rose by 12.8%. This approached the 14% gain in the AIM All Share Index. Compared with end-December

2012, the large capitalisation oil and gas stocks have risen by 1% while the juniors have dipped 7%. Both groups have underperformed the approximate 11% gain in both the FTSE 100 and the AIM All-Share Index.

Exhibit 32: FTSE 350 Oil & Gas Index



Source: Bloomberg

Looking at the longer-term picture, both the FTSE 350 Oil & Gas Index and the AIM Oil & Gas Index have trended pretty well flat since early 2010. The large capitalisation index has, of course, had the advantage of a significant dividend yield. At the end of September this was 4.5%. Compared with their respective 2008 highs, the FTSE 350 Oil & Gas and the AIM Oil & Gas indices, as at end-September, were down 18% and 50% respectively.

Exhibit 33: AIM Oil & Gas Index

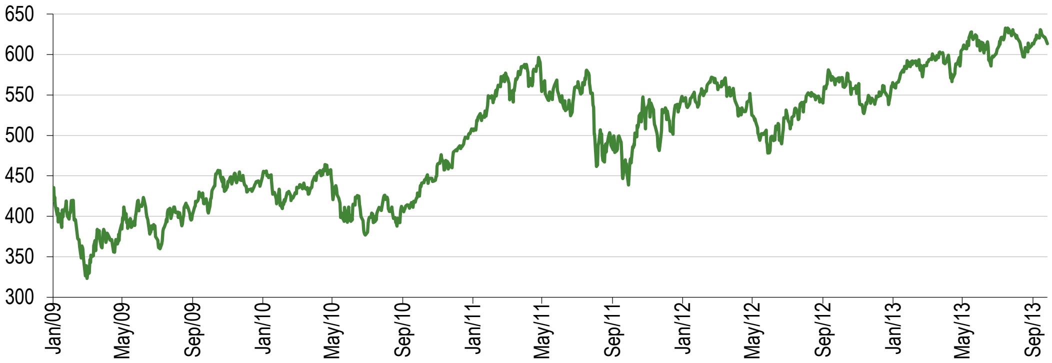
Source: Bloomberg

USA: The independents have been performing strongly absolutely and relatively

Large capitalisation US oil and gas independents have performed strongly of late and indeed over the past year both absolutely and relatively. This is manifested by the gains in the S&P 500 Oil & Gas Exploration and Production Index (an index of large capitalisation oil and gas independents) of 13% and 28% in the three and twelve months to end-September 2013 respectively. For comparison, the S&P 500 Index in late September was 6% higher than twelve months previously and 18% above a year earlier. The strong showing by the independents is consistent until recently at least with upward trends in WTI and a firmer tendency in natural gas/NGL prices. The independents have also tended to be supported by generally positive newsflow on booming US oil production.

Big oil has clearly been outpaced by the independents in 2013. The broadly based S&P 500 Oil & Gas Index, which includes the majors plus the large E&P independents and refinery groups, has climbed by 4% and 10% in the three months and twelve months to September respectively. Both the S&P 500 Oil & Gas and S&P 500 Oil & Gas Exploration and Production indices are around 5 ½-year highs.

Exhibit 34: S&P 500 Oil & Gas Index



Source: Bloomberg

Exhibit 35: S&P Oil & Gas Exploration and Production Index

Source: Bloomberg

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