EDISON

Oil & gas macro outlook

A price rout is possible

Oil & gas

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The near- to medium-term outlook for oil prices is looking increasingly bearish. Largely driven by North America, non-OPEC supplies are growing robustly, OPEC production is buoyant, demand growth is subdued and inventories are very comfortable. There is clearly the possibility of a price rout over the next year or two. However, we suspect that, in the near term at least, geopolitical uncertainties, fears concerning the fragility of production infrastructure and bullish financial market sentiment will help support prices. An extended period of soft prices could be on the cards through mid-decade. The analogy could be the second half of the 1980s.

Supply/demand position: Non-OPEC output growth

The key story surrounding the oil market continues to be the surge in supply in Canada and particularly the US driven by the development of the Athabasca oil sands and the shale and tight reservoir revolution. Non-OPEC controlled supply growth should be comfortably over 1mmb/d in 2013 and possibly nearer 2mmb/d in 2014. Meanwhile, demand is being held in check by recessionary and negative structural influences in the OECD world related to improving vehicle fuel efficiency and fewer miles driven. Demand globally is unlikely, in our view, to grow by more than 0.8mmb/d in 2013 and 1mmb/d or possibly a little more in 2014. Non-OPEC controlled production growth looks like exceeding global demand growth by perhaps 0.5mmb/d and 0.8mmb/d in 2013 and 2014 respectively. We could be looking at a similar picture possibly over the balance of the decade. The key question now concerns OPEC's response. So far it has been phlegmatic.

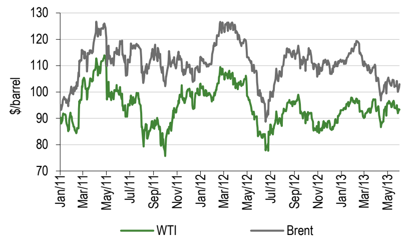
WTI-Brent spread: Sharply narrows

The substantial increase in pipeline and particularly rail takeaway capacity in the US Mid-Continent and Texas has had a marked impact on narrowing the WTI discount to Brent of late. From a peak of $23/barrel in mid-February the discount was down to $8/barrel by the end of May. Abstracting from a severe dislocation to supplies outside the US we believe the high-water mark has been seen for the WTI discount. However, there may be a structural WTI discount to Brent in the longer term closer to $6-8/barrel rather than the $4-5/barrel suggested by pipeline costs. Key factors to bear in mind include the shear influx of supply expected in the Mid-Continent over the next few years and refinery conversions in the Midwest and Gulf Coast reducing the need for light oil. The rapidly increasing availability of light oil is now likely to put pressure on prices along the Gulf Coast and further afield.

Price forecasts: Brent reduced, WTI increased

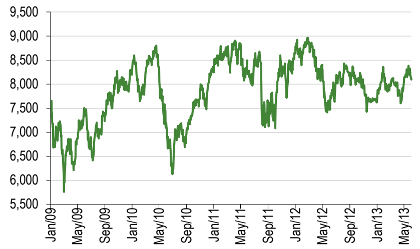
Reflecting the bearish supply/demand outlook we look for light crude prices to trend flat to down over the balance of 2013 and in 2014. We have reduced our Brent forecast for 2013 from $108.7 to $105.3/barrel reflecting the weaker than expected trend over the first five months and the growing evidence of deteriorating fundamentals. Our Brent forecast for 2014 has been reduced marginally from $100.3 to $99.0/barrel. Reflecting year-to-date trends and a reassessment of the discount to Brent we have raised our WTI forecast for 2013 from $91.8 to $93.7/barrel. For 2014 our WTI forecast is largely unchanged at $90.9/barrel.

WTI vs Brent



S&P 500 Oil & Gas Index

FTSE 350 Oil & Gas Index



	WTI $/barrel	Brent $/barrel	Henry Hub $/mmBtu
2010	79.5	79.7	4.37
2011	94.9	110.0	4.00
2012	94.2	112.0	2.75
2013e	93.7	105.3	3.86
2014e	90.9	99.0	4.10

Note: Prices are yearly averages.

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Executive summary

Recent oil price developments: The recent peak for international light oil prices was in mid February 2013. Subsequently, prices have trended down from historically elevated levels and by end May were off almost $20/barrel or 15% from the earlier highs. The decline has been part of a broader sell-off in commodities. For oil prices the key negatives have been the lacklustre global economic backdrop, increasing availability particularly of light crudes, very comfortable inventories and a firm dollar.

WTI-Brent spread: In recent months WTI has outperformed Brent. The WTI discount has consequently narrowed from a recent peak of $23/barrel in mid-February to $8/barrel at the end of May. The latter is around the lowest discount in two and a half years. The rapid narrowing of the discount reflects a major increase in takeaway capacity from the Mid-Continent and Texas Permian Basin plus improving availability of Brent and other Atlantic Basin light crudes. However, inventories at the Cushing tank farm and NYMEX WTI delivery point remain close to record levels.

Non-OPEC output: Non-OPEC crude oil output growth looks like being strong or very strong in 2013 and 2014. Based on the forecasts of the International Energy Agency (IEA), OPEC and EIA the gains could be in the region of 1mm (2%) in 2013 and approaching 2mmb/d (over 3%) in 2014. OPEC natural gas liquids should add to these gains. The key driver behind the output growth forecasts is surging production in Canada and particularly the US. Propelled by the US and Canada and in due course also Brazil and Kazakhstan (Kashagan), the trend in non-OPEC output looks like being robust possibly over the balance of the decade.

US output: For the four weeks to 24 May US crude production averaged 7.31b/d, a 21-year high and 1.12mmb/d or 18% 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 output gains of 14% and 10% in 2013 and 2014 respectively.

OPEC output: OPEC crude oil production has arguably been more buoyant than expected in 2013 and has recently been running at about 30.5mmb/d. OPEC's influence on oil markets is likely to lessen significantly, if non-OPEC output trends up at an annual 1mmb/d plus, as seems possible, over the next few years.

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 0.8-0.9mmb/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 0.5mmb/d and 0.8mmb/d respectively. Assuming OPEC crude production continues to trend at about 30.5mmb/d, the market as a whole should be broadly balanced.

North American supply shock: The IEA has recently referred to surging North American production as an oil shock. In our view, it has implications not only for oil markets, but also for the world economy. The IEA's forecast increase in production over the next five years of almost 4mm b/d is sufficiently large as to fundamentally loosen the world supply/demand balance and weaken the power of OPEC.

Crude oil prices: We have reduced our Brent forecast for 2013 from $108.7 to $105.3/barrel due to the weaker than expected trend in the year-to-date and the growing evidence of deteriorating fundamentals. Our 2014 Brent forecast has been lowered from $100.3 to $99.0/barrel. In contrast to Brent, our WTI forecast for 2013 has been raised from $91.8 to $93.7/barrel reflecting the trend in the year-to-date and a reassessment of the discount to Brent. Our WTI forecast for 2014 is largely unchanged at $90.9/barrel.

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 two months of 2013, US gas production was roughly unchanged from 2012. Gas consumption meanwhile increased in the early months of 2013 driven by relatively cold conditions in the Midwest and Eastern Seaboard. However, last year's surge in power generation demand is being reversed in 2013 due to a marked loss in the competitiveness of gas compared to coal. The upshot is that US demand growth will probably be marginal in 2013.

US natural gas prices: US natural gas prices have recovered significantly from the lows of early 2012. Towards the end of May 2013 the Henry Hub benchmark quote was around $4.15/mmBtu, a level that is probably sufficient to achieve fully accounted break-even for the average dry gas producer. Reflecting the trends to date and tightening inventories we have raised our Henry Hub forecast for 2013 from $3.58 to $3.86/mmBtu. Our forecast for 2014 has been lifted from $4.00/mmBtu to $4.10/mmBtu. Given subdued drilling activity, there is the potential for a more pronounced upturn in US gas prices in 2015.

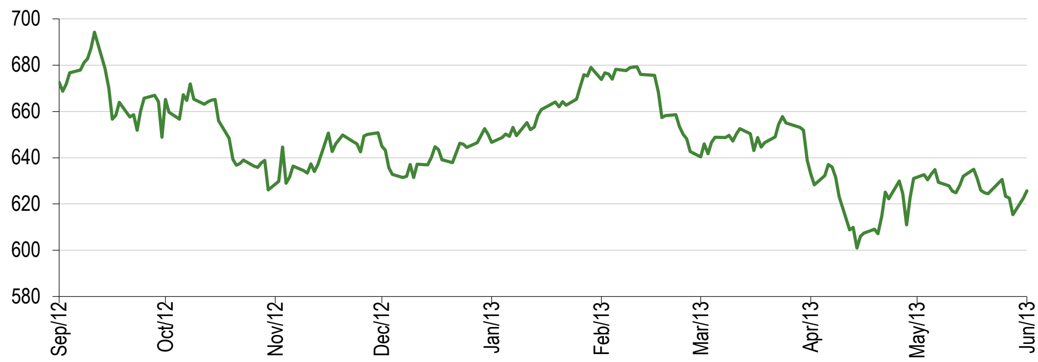
Crude oil market dynamics

Price overview

Market developments: Prices trend strongly down from the February highs

Recent months in retrospect: Benchmark light crude prices rose strongly in early 2013, but lost ground markedly between mid-February and late April. During this period international benchmarks fell about $20/barrel or over 15% from the historically high levels of mid-February of approaching $120/barrel. A rebound in the international benchmarks proved short-lived. By end May prices were again under pressure and approached the recent mid-April lows. Interestingly, the rebound in WTI, the inland US benchmark, has been more pronounced since mid-April, resulting in a significant narrowing in the discount to Brent. As of 31 May Brent was down 11% while WTI was roughly unchanged from end 2012. Looked at from a longer-term perspective, both Brent and WTI have trended broadly flat since early 2011.

Exhibit 1: S&P GSCI commodity index



Source: Bloomberg

The generally weak trend in international benchmark light crude oil prices since mid-February has been part of a broader sell-off in commodities in recent months. However, the drop in the international benchmarks since mid-February of 14% has been somewhat greater than the decline of about 10% in the S&P GSCI benchmark commodity index. The key bearish influences in recent months for commodities have been the lacklustre backdrop to the world economy and growing evidence of surplus supplies. In terms of the former, the business slowdown in China and the continuing recession in Europe have been particularly influential. Superimposed on the macroeconomic picture in the case of oil have been a well supplied market, no major geopolitical or supply shocks, a firm US dollar and downgrades to oil demand forecasts by the likes of the IEA and OPEC.

The general buoyancy of financial markets has been providing an element of support to commodity markets including oil in recent weeks. This has very much been driven by supportive monetary policy and optimism that tail risks concerning the world economy and financial system have, for the moment at least, been eliminated.

Non-OPEC output rising: The more positive trend in non-OPEC output noted in the fourth quarter of 2012 continued in the first quarter of 2013. Production for the latest period, based on OPEC data, came in at about 53.9mm barrels, up 0.1% on the fourth quarter of 2012 and 1.3% on a year earlier. On a quarterly sequential basis the key areas of strength were Canada, the UK and Russia. The year-on-year movement, not surprisingly, was driven to a large degree by the US and Canada, where there were gains of about 9% and 5.5% respectively. The US benefited from the continuing rapid development of shale and tight reservoir formations in the Great Plains and Texas, while the

Alberta oil sands and a recovery in offshore production following maintenance activity were the key positives for Canada.

After being hit hard in the third quarter of 2012 by heavy planned and unplanned maintenance schedules, North Sea production has recovered noticeably. The recovery has been especially pronounced in the UK, where production in the first quarter of 2013 was up 17% on depressed third-quarter 2012 levels. UK production, however, remained at historically low levels in the first quarter at around 0.97mm barrels according to IEA data. Compared with a year ago, this was down 11%. For 2013 as a whole the IEA is expecting production to fall from 2012 by about 5% in the UK and 4% in Norway. The implied UK production of 0.92mm barrels will be the lowest since 1977. However, rising investment is pointing to the potential for a recovery in UK output post 2013. The EIA in fact is forecasting a 2.7% gain to 3.0mmb/d in North Sea production between 2013 and 2014.

Abstracting from major and sustained unplanned outages, 2013 looks like being a strong year for non-OPEC oil production. Both the IEA and EIA are looking for a gain of 1.1mmb/d or 2% to about 54mmb/d, while OPEC is forecasting growth of 1.0mmb/d. Driving the gain is expected to be the US, Canada, Brazil, China and Sudan/South Sudan. The first two will be by far the most significant influences. In the case of Brazil output should benefit from new offshore facilities being brought on-stream and the resumption of operations at the Frade field following last year's legal/environmental dispute between Chevron and the Brazilian regulatory authorities. China's output should be buoyed by the Weizhou field in the South China Sea coming on-stream. In the case of Sudan the key factor is the resumption of operations following the resolution of the border and pipeline disputes between Sudan and South Sudan.

Preliminary indications are pointing to very strong non-OPEC production growth in 2014. The EIA, for example, is looking for a gain of 1.8mmb/d or 3.3%. Once again, North America will probably be the dominant influence with a gain of comfortably over 1mmb/d. Significant contributions should also be made by Brazil and Sudan plus a miscellaneous group of countries including China, Colombia, Kazakhstan and the UK. Importantly, following the scheduled start-up of operations at the much delayed giant Kashagan field in mid-2013 production could be gathering momentum strongly in Kazakhstan during 2014. In addition to the anticipated gains in non-OPEC output in 2013/2014, it should also be noted that OPEC natural gas liquids production, which is not subject to quota, will probably grow by 0.2 to 0.3mmb/d in both years.

North American oil shock: In a recent report the IEA has referred to the surge in North American oil output as a supply shock that has major ramifications not just for oil markets but for the world economy. The argument is that projected North American production growth over the next five years or more is now sufficiently large as to fundamentally loosen the world supply-demand balance and by implication weaken the power of OPEC. We would certainly concur with this view but believe it is belated given the discernible trends over the past year or two. In fact, we would go further and say that the North American supply shock is among the most important developments to affect the world economy over the past 30 to 40 years.

The IEA's current forecast of a 3.9mmb/d increase in North American production by 2018 certainly does not appear outlandish in relation to recent rates of growth and may indeed be conservative. Given that production elsewhere in the world is expected to grow by a similar amount we believe that non-OPEC supply is likely to comfortably cover global demand over the medium term. Conceptually, OPEC could attempt to bring the market back into balance by cutting production but in practice is unlikely to be willing to do so. The sacrifice in terms of revenues for many producers will be just too great. The potential therefore clearly exists for at least a partial reversal of the oil price hike of the past 10 years or so.

The interesting question now concerns not so much developments in North America that are well established but the outlook for shale and tight reservoir production in other parts of the world. Large scale development of shale formations outside North America would have truly revolutionary implications for oil markets and prices. The consensus view is that shale development will be much slower outside than inside North America due to such factors as an absence of mineral rights for property owners, insufficient oilfield services capacity, scarce water supplies and a variety of environmental/political objections. All these factors have some validity and probably will result in slower development than in North America. It is, however, difficult to believe that in an energy hungry world development will generally not take place where the geology is prospective and where there is a political will. One aspect is not in doubt and that is there is no shortage of prospective shale zones around the world. Indeed, the first place to start looking is probably where oil has historically been produced.

What about the decline curve? In an article in the *Financial Times* of 30 May reference was made to the thoughts of Andy Hall, a former highly successful Citigroup oil trader and now hedge fund manager, which tend to poor cold water on the US shale revolution. The gist of his argument as reported by the *Financial Times* is that shale wells have sharp production decline curves, which necessitate a great deal of costly drilling to maintain output. This in turn would necessitate oil prices remaining at historically high levels. Alternatively in the absence of drilling activity being maintained at high levels production would rapidly slide, resulting in a 'temporary' shale revolution.

The issue of the decline curve is not unknown in shale and tight reservoir circles and relates fundamentally to the low levels of permeability of the formations. Unlocking the shales is indeed an expensive operation, with wells in the Bakken, for example, typically costing about $7m to drill and complete. Assuming a typical estimated ultimate recovery rate of 500,000 barrels, this would imply a cost per barrel of $14. To this we would probably need to add another $40/barrel or so for a combination of lifting costs, SG&A, royalties, state taxes and transport costs. Assuming current Bakken realisations of around $90/barrel the cost/price relationship still appears attractive, which is why Williston Basin drilling activity is booming. Clearly there are limits to drilling activity if prices were to fall precipitously. However, at today's costs prices would probably have to drop below $75/barrel on a sustained basis for drilling in the prolific basins of the Great Plains and Texas to be sharply scaled back.

While it is certainly valid to raise the issue of decline rates in the context of shale, there is little doubt that shale reserves are and will continue to provide a highly significant new source of production at least in the near to medium term. In essence the petroleum industry has perfected (or maybe is perfecting) the technique of extracting oil from very tight formations economically. What the position might be in terms of production rates by, say, 2020 in the more mature plays such as the Bakken is an open question.

YPF cuts a deal with Chevron: Outside North America one of the world's most prospective shale zones is the Neuquen Basin in western Argentina. This is a well established oil producing province where major shale discoveries have been made by the state-controlled oil company YPF (BA, NY: YPF) and juniors such as TSX-listed Americas Petrogas (TSX-V: BOE) and Madalena Ventures (TSX-V: MVN). Importantly, Neuquen has well developed infrastructure and plenty of access to oilfield services. According to YPF, one of the Neuquen Basin's three major shale formations, the Vaca Muerte, holds at least 23bnboe (based on a Ryder Scott report), which would suggest a similar scale to the Bakken in North Dakota. The other two formations, Los Molles and Agrio, could add significantly to the resource base in due course. YPF owns about 13bn of the 23bnboe.

Importantly, YPF announced on 15 May that it had signed a $1.5bn agreement with Chevron (NY: CVX) to develop the Vaca Muerte on blocks Loma La Lata Norte and Loma Campana. The initial phase of the project will be to drill more than 100 non-conventional wells over the next 12 months. This will probably be a prelude to the full-scale development of the Vaca Muerte, which could involve capital outlays of $15bn and more than 2,000 wells. Arguably, the project's initial scope is greater than many observers were expecting. The fact that there is an agreement will also have surprised many given the legacy issues regarding the partial nationalisation of YPF and the earlier freezing of Chevron's assets in Argentina relating to an environmental lawsuit in Ecuador. In another recent deal Bridas, a private Argentine E&P company controlled by the Bulgheroni family and CNOOC, has agreed a $1.5bn joint venture with YPF for the development of the Vaca Muerte.

YPF's production from the Vaca Muerte is currently modest at about 7,000b/d. However, this is sharply up from 3,000b/d at the end of 2012, reflecting increasing drilling and completion activity. Prospectively over 2,000 wells would imply production of perhaps 200,000b/d, assuming well rates broadly in line with the Bakken's 95b/d. Assuming that the Vaca Muerte is as prolific as the Bakken we could ultimately be looking at production rates of over 1mmb/d. This compares with Argentina's current production of about 0.7mmb/d.

OPEC production firm: Through the first four months of 2013 OPEC crude oil production has arguably shown a firmer trend than might have been anticipated at the beginning of the year given concerns over inventories and deteriorating fundamentals. For the first four months, production averaged about 30.3mmb/d. Although down 0.8mmb/d on a year earlier, this was not greatly changed from the level prevailing at the end of 2012. Significantly, OPEC production actually rose between March and April by approaching 0.3mmb/d to 30.5mmb/d. Tending to buoy production in April were significant gains of over 0.1mmb/d in Saudi Arabia and Iraq. Saudi production it appears has been boosted of late by the completion of refinery maintenance programmes in Asia and the expansion of the Motiva Shell/Aramco refinery at Port Arthur Texas.

Iraq's production and particularly exports in early 2013 have been constrained by three factors. Firstly, adverse weather conditions in the Gulf have at times depressed export loadings offshore Basra. Secondly, limitations surrounding the logistical infrastructure in the south of the country acted as a cap on output. Thirdly terrorist activity has interrupted flow on the northern Kirkuk-Ceyhan (Turkey) pipeline. April's upturn appears to mainly reflect a return to more benign weather conditions in the Gulf. Production of 3.14mmb/d in April was close to a post 1990 high, but significantly below earlier forecasts by Iraqi officials of 3.5mmb/d or so by this time. Field development work, upgrades to the infrastructure and increasing export capacity may enable Iraq's output to trend up towards 3.5mmb/d during the balance of 2013. Exports could be 2.8-2.9mmb/d.

Significantly, OPEC production in the first four months of 2013 has been running modestly above the call on OPEC supply of perhaps 29.7mmb/d. Interestingly, this is despite continuing falling production and exports from Iran, traditionally the number two producer. Currently, OPEC's surplus capacity is running at a comfortable 4.8mmb/d. The previously mentioned expansion of non-OPEC capacity could result in OPEC surplus capacity rising by 2m or 3mmb/d over the next few years.

A key area of concern regarding OPEC supplies currently relates to the deteriorating security backdrop in Iraq and Libya. So far this factor does not appear to have greatly affected output in these two locations, but there is a potential risk of more significant disruption in the event of an intensification in civil and sectarian strife.

Saudi Aramco puts expansion plans on ice: Reflecting the spectre of rising output in the non-OPEC world, Saudi Aramco is putting its own expansion plans on ice. There had been talk of boosting capacity from the current 12.5mmb/d to 15mmb/d in the near to medium term, but this has recently been firmly quashed by the Saudi oil minister. Interestingly, he has stated that Saudi Arabia will be "lucky" to exceed 9mmb/d by 2020 and believes that the call on Saudi supplies is unlikely to exceed 11.0 to 11.5mmb/d by 2030 or 2040.

Global demand remains subdued: From a global oil demand perspective 2013 looks very much like 2012. Initial indications for the first quarter of 2013 point to continuing subdued demand globally, with a year-on-year gain of 1% or 0.89mmb/d based on OPEC data. Compared with the fourth quarter of 2012 demand was off 1.2mmb/d or 1.3%.According to OPEC, demand in the first quarter of 2013 was somewhat weaker than expected. As in 2012, the key area of weakness has been Western Europe, where demand in the first quarter of 2013 was down 0.32mmb/d or 2.3% from a year earlier. Demand in Western Europe is now 2.2mmb/d or 14% below pre financial crisis levels in 2007. Clearly recessionary conditions have taken their toll in Europe, but fuel conservation measures and advances in the fuel economy of the transportation sector have also been factors in reducing demand.

Elsewhere in the OECD demand showed a year-on-year gain of 0.5% in the Americas in the first quarter of 2013 but was off 1.7% in Asia-Pacific. More than offsetting the soft OECD demand backdrop have been buoyant conditions in the non-OECD world. Particularly significant has been year-on-year growth of 4.4% in Latin America, 4.3% in the Middle East and 3.5% in China. Indicative of the strength of demand in the Middle East was the hefty 7% gain in Saudi Arabia driven by rapidly growing transportation and industrial needs. It should be noted that Chinese demand growth has slowed significantly since the early- and mid-2000s, when growth was averaging about 8% pa.

The three principal forecasting agencies are all pointing to similar world oil demand outcomes in 2013. OPEC and the IEA are forecasting growth of 0.79mmb/d and 0.80mmb/d respectively, while the EIA is looking for a slightly higher gain of 0.89mmb/d. Broadly, these gains translate into growth of 0.9% and imply demand of around 90mmb/d. Regionally the picture is growth of 1.2mmb/d in the non-OECD world (China around +0.4mmb/d) partially offset by a drop of 0.4mmb/d in the OECD (Europe -0.3mmb/d, Americas unchanged, and Japan -0.1mmb/d). The global gain of 0.9% considerably lags the IMF's forecast for world GDP growth in 2013 of 3.25%. We believe the current oil demand growth forecasts for 2013 made by the three principal forecasting agencies are plausible within the context of the IMF's GDP expectations, but we think the risks are probably to the downside. This reflects the sluggish OECD economy plus the likelihood that Japan's recent high consumption of fuel oil and crude drops back to more normal levels, as its nuclear power stations are brought back online.

For 2014 the EIA is forecasting global oil demand growth of 1.2mmb/d. This might be plausible assuming that the IMF's 4% world economic growth forecast is valid. We would argue, however, that in the 'new normal' economy, 4% growth rates are too bullish. Furthermore, there are powerful structural influences tending to reduce consumption in the OECD such as the increasing fuel efficiency of the vehicle fleet and fewer miles being driven. All told, we therefore believe that global demand growth in 2014 might be closer to 1mmb/d.

OECD inventories look very comfortable: OECD commercial inventories look very comfortable for the time of year, especially on a day's supply basis. Against the seasonal trend, inventories in March rose by 14.9mm barrels to 2.658mm barrels and were in line with the five-year average for the time of year and up from a year earlier by 8mm barrels. According to preliminary indications by the IEA, OECD inventories in April increased by a seasonally strong 32.4mm barrels. Trends of late have been stronger for crude than refined products, leaving inventories tighter for the latter than the former. On a day's supply basis OECD commercial inventories averaged 59 in the first quarter of 2013 against 58 a year earlier. Preliminary indications for April would suggest 60 days, a high level by recent historical standards.

Recent trends in Brent and WTI: WTI shows relative strength

The key development of late in the trends of Brent and WTI has been the relative strength of the latter. Brent performed strongly through the first one and a half months of 2013, rising from $111.9/barrel to a nine-month high on 12 February 2013 of $119.3/barrel. In the early weeks of the year Brent tended to mirror the positive trend in financial markets and drew strength from bullish economic news flow the US and China. Post mid February the trend in Brent weakened noticeably, leaving the price at $109.3/barrel on 29 March. Brent averaged $112.9/barrel in the first quarter of 2013. This was up 2.2% on the fourth quarter of 2012, but down 5% on a year earlier. The downward trend continued into the third week of April with Brent plumbing around a 10-month low on 17 April of $96.8/barrel, 19% below the February high. Between the third week of April and the third week of May Brent firmed modestly and by 20 May was trading at $104.6/barrel. Over the closing 10 days of May there was a renewed period of weakness, which took Brent down to $100.0/barrel on 31 May. This was 2% below a year earlier.

Exhibit 2: Brent crude oil price trend

Source: Bloomberg

The downward trend in Brent since mid-February has been driven largely by a combination of rising supplies of light crudes in the Atlantic Basin and a lacklustre economic backdrop particularly in Europe. The former factor reflects both increasing production in the North Sea and displaced exports from the eastern side of the Atlantic Basin. Lacklustre economic conditions in Europe have also tended to depress crack spreads for distillates and hence demand for light grades. The modest firming in Brent post the third week in April mainly reflected bullish sentiment in financial markets and speculation that the civil war in Syria could spread to other parts of the Middle East. The sharp dip on 31 May of $2/barrel was also associated with negative financial market influences

Contrasting with the moderate downward trend in Brent so far in 2013, WTI has trended modestly higher, although there have been significant fluctuations on occasion. After ending 2012 at $91.8/barrel, WTI trended higher through the early weeks of 2013 hitting around a four and a half month high of $97.8/barrel on 2 February. The trend weakened significantly over the next month or so taking WTI down to $90.1/barrel, roughly a two and a half month low. This was driven by a bearish sequence of US petroleum industry reports pointing to rising inventories and weak demand. WTI rebounded strongly through much of March and closed the month at $97.2/barrel. For the first quarter WTI averaged $94.3/barrel, down 8% from year earlier levels, but up 8% from the fourth quarter of 2012.

The trend abruptly reversed through the first three weeks of April, driven by more bearish US petroleum industry reports. Around a four-month low of $86.7/barrel was plumbed on 17 April. Over the following month or so WTI trended higher despite a considerably less than bullish US petroleum industry backdrop. WTI tended to be supported by optimism surrounding both the direction of the US economy and the ability of pipeline upgrades to eliminate bottlenecks in transporting oil from the Mid-Continent and the Permian Basin to the refineries of the Gulf Coast. In the final 10 days or so of May WTI came under some renewed pressure, reflecting a combination of bearish petroleum industry data and negative financial market influences. WTI closed May at $91.97/barrel, approximately a one-month low but up 6% from a year earlier.

Exhibit 3: WTI crude oil price trend

Source: Bloomberg

US production developments

North Dakota: New records, leading indicators positive

The upward trend in North Dakotan oil production was dampened in late 2012 and early 2013 by adverse weather conditions but subsequently it has strengthened. In fact, production in March, according to North Dakota Department of Mineral Reserves data, was a record 782,934b/d, up a hefty 43% on a year earlier. The gain in the first quarter was lower but still highly significant at 36%. North Dakota is now comfortably the number two oil producing state in the US. Production continues to be driven by a combination of the application of horizontal drilling and multi-stage fracking technology and intensive drilling/completion activity in the Bakken/Three Forks shale formation. In addition to North Dakota, the Williston Basin is contributing around another 68,000b/d in eastern Montana and 5,000b/d in South Dakota.

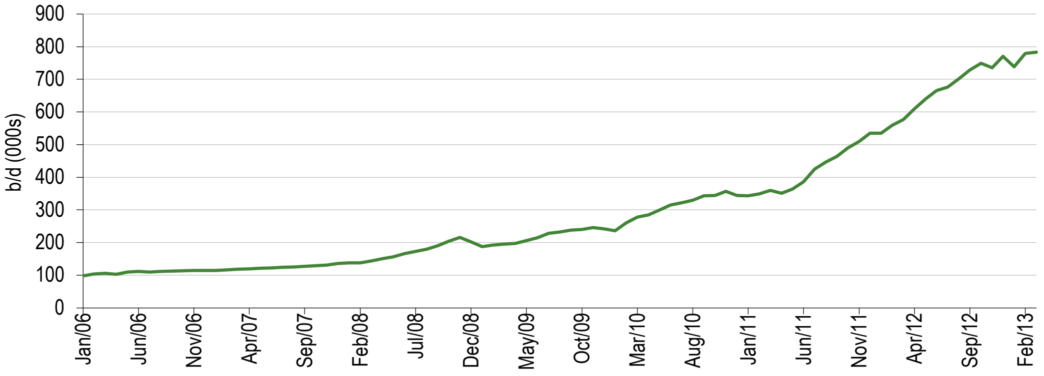
The leading indicators are pointing to production remaining on a strong upward trend over the balance of 2013. Spuds, for example, averaged 300 in the first quarter and were no less than 330 in March. The former was 18% above the average for 2012 and is a record level. Permitting is also running at a high level and so far in 2013 has been in line with 2012. The rig count at an average 185 in the first quarter of 2013 was down on the 200 of 2012, but remains historically high. It should also be noted that drilling efficiency is improving so a smaller capacity is adequate for a given level of drilling activity than in the past. As we have noted previously, production growth rates in North Dakota should be expected to slow over the medium term compared with the heady pace of the past two or three years. The key constraints are high rates of depletion and the very large number of wells in existence of 8,500. Nevertheless, we believe North Dakotan production of approaching 900,000b/d is on the cards by end 2013, while petroleum industry estimates of 1mmb/d in 2015 are certainly looking plausible for 2015.

USGS Bakken resource estimates raised: The USGS's (United States Geological Survey) recoverable resource estimate for the Bakken/Three Forks petroleum system in North Dakota, South Dakota and Montana has been virtually doubled from 3.65 billion barrels in 2008 to 7.38bn barrels. The increase relates entirely to the inclusion this time around of the Three Forks formation. In addition, USGS estimates Bakken/Three Forks mean recoverable gas resources of 6.7tcf and natural gas liquids of 0.53bn barrels. These estimates constitute almost a threefold increase over those made in 2008.

Based on USGS estimates, the Bakken/Three Forks petroleum system is easily the largest oil discovery in the US since Prudhoe Bay (14bn barrels recoverable) in Alaska in 1968. It should, however, be noted that petroleum industry estimates for the Bakken/Three Forks are considerably larger than those made by the USGS. The largest producer in the Bakken, Continental Resources (CLR), for example estimates recoverable resources at 24bnboe, of which oil and gas represent

20bn barrels and 4bnboe respectively. Importantly, Continental's estimate makes no allowance for the Lower Three Forks benches.

Exhibit 4: North Dakota crude oil production



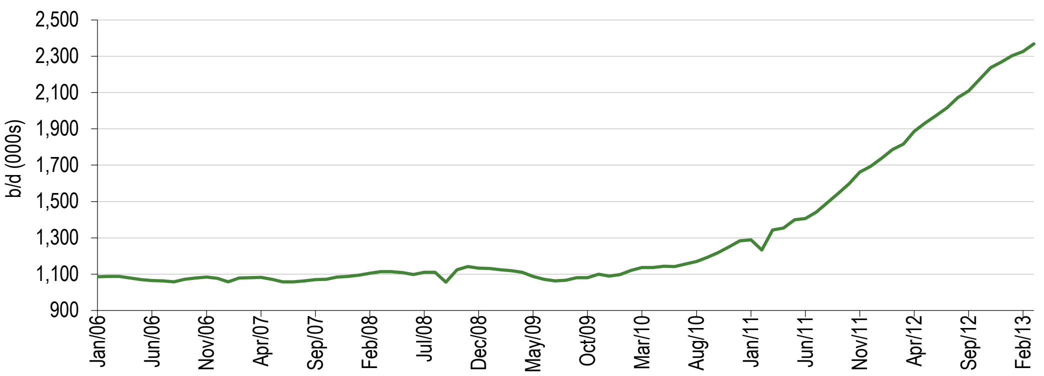
Source: EIA

Texas: Trending strongly upward

Texas oil production has continued to trend strongly upward in recent months. Based on EIA data, production in March of 2,369mmb/d was running 0.101mmb/d ahead of December 2012 and 0.553mmb/d or 30.5% above a year earlier. Production in March was around a 27-year high.

Surging production in Texas over the past few years has been driven by development of the tight carbonate and sandstone reservoir formations of the Permian Basin in the north-west and the Eagle Ford shale formation in the south-west of the state. Eagle Ford production in particular has remained very buoyant. According to the Texas Railroad Commission, production in March 2013 of 529,874b/d was up 3.6% on the previous month and 77% on a year earlier. It should be noted in this context that the first Eagle Ford well was only drilled in 2008 and that as recently as 2010 production averaged a mere 15,163b/d. Based on industry projections, production from the Eagle Ford could reach 1.4mmb/d by 2016.

Exhibit 5: Texas crude oil production



Source: EIA

US: 21-year high

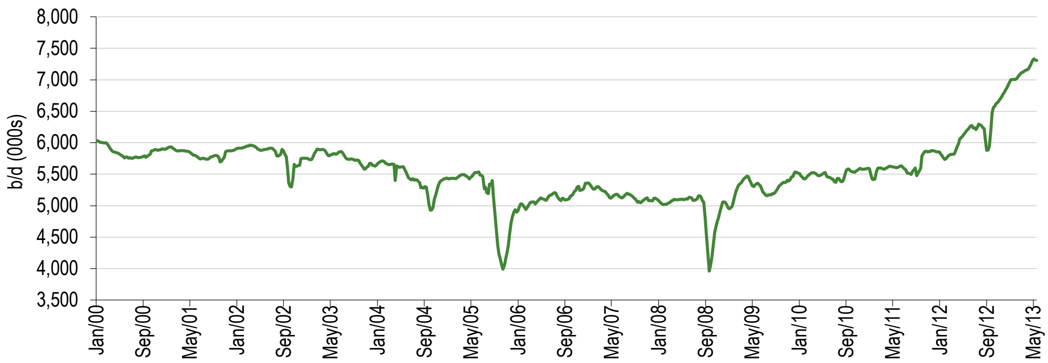
US crude oil production has trended significantly higher in 2013 based on EIA weekly data. The key factor has been development in the shale and tight reservoir formations of the Great Plains and Texas.

For the four weeks to 24 May US production averaged 7.31b/d, around a 21-year high. It was also 5.6% or 0.389mmb/d above the level for the four weeks to 28 December 2012 and 18% or 1.12mmb/d in excess of a year earlier. By world standards these are impressive growth rates.

Among the larger oil producing states outside Texas and North Dakota, Colorado, Oklahoma and New Mexico all showed highly significant year-on-year growth rates of between 15% and 27% in March 2013. Constraining growth over the past year in the US have been the flat to declining trends in Alaska and California, the third- and fourth-largest oil producing states and also the Federal Offshore waters of the Gulf of Mexico. The EIA is forecasting growth in US crude production of 14% to 7.42mmb/d in 2013 and 10% to 8.17mmb/d in 2014. The former would be the highest annual level since 1992 and the latter since 1987. The EIA's latest forecasts constitute slight upgrades compared with those given earlier in 2013.

While US production has been rising, crude oil imports have been continuing to fall. In the four weeks to 24 May crude imports averaged 7.79mmb/d, down 12% on a year earlier. Compared with the record annual total of 10.13mmb/d in 2005 there has now been a decline of 2.37mmb/d, which is similar to Venezuela's current rate of production. During the course of 2013 US domestic crude production is likely to exceed imports for the first time in about 20 years. Total US oil production, including bio-fuels and natural gas liquids of 10.7mmb/d, of course, already comfortably exceeds crude imports.

Exhibit 6: US crude oil production



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

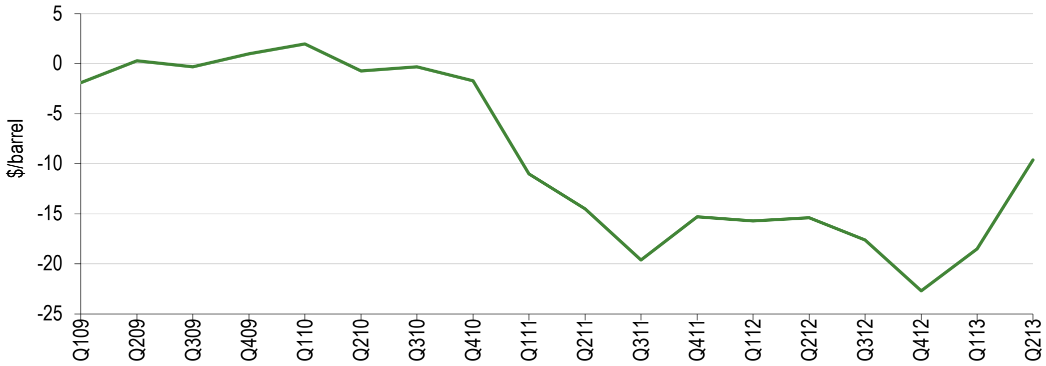
Light crude spreads

WTI-Brent: WTI discount narrows sharply

Reflecting the buoyant trend of WTI relative to Brent of late the WTI discount has narrowed sharply since the recent 15 February high of $23/barrel. At the time, WTI had been temporarily boosted by Enterprise Products' announcement that the Seaway Pipeline from Cushing to the Gulf Coast would be operating at the restricted capacity of 175,000b/d due to a lack of storage space at the Jones Creek terminal Texas until late 2013. The concern about pipeline capacity soon ebbed, leaving the WTI discount at $12/barrel at end March. The average discount for the first quarter of 2013 was $18.6/barrel, significantly down on the $22.7/barrel of the fourth quarter of 2012.

During the second quarter through late May WTI has traded on average at a discount of $9.6/barrel to Brent. In late May the discount was down to $7.8/barrel, which is close to the narrowest in two and a half years. Interestingly the narrowing of the WTI has occurred despite Cushing, Oklahoma inventories (NYMEX delivery point for WTI) remaining at historically high levels. The market seems to have concluded that the takeaway capacity from Cushing by one means or another is adequate to at least prevent any further build-up in Cushing inventories in the short term. The question remains, however, as to whether $7-8/barrel is sufficient to attract rail, track and barge transportation to move oil the 500 miles or so from Cushing to the refining centres along the Gulf Coast. We believe that the costs involved are in the region of $10 to $15/barrel by rail and maybe $20/barrel or more by truck.

Exhibit 7: WTI to Brent spread



Source: Bloomberg

The issue of pipeline takeaway capacity from Cushing should, of course, be largely resolved by early 2014 following the planned completion of TransCanada's 700,000b/d Gulf Coast pipeline and Enterprise's 400,000b/d pipeline running parallel to Seaway. In addition, pipeline capacity linking the Permian Basin and the Eagle Ford with the Houston/Port Arthur refining complex is being upgraded. The key developments are Magellan Midstream Partners' Longhorn reversal from El Paso to Houston and Sunoco's Permian Express, which links Wichita Falls with Port Arthur. The Longhorn reversal and the first stage of the Permian Express have both recently been completed. The second stage of the Permian Express is scheduled for completion in the second quarter of 2014. Crucially these new pipeline links enable oil to be shipped directly to the Gulf Coast and to avoid the Cushing tank farm completely.

Exhibit 8: WTI 2009-14 quarterly prices, $/barrel

	Q1	Q2	Q3	Q4	Average
2009	43.2	59.7	68.1	76.0	62.0
2010	78.8	77.9	76.1	85.2	79.5
2011	93.9	102.3	89.5	94.0	94.9
2012	103.0	93.3	92.2	88.2	94.2
2013	94.3	94.0	93.5	93.0	93.7
2014	91.0	91.0	91.0	90.5	90.9

Source: Bloomberg and Edison Investment Research. Note: 2013 quarter 1 is an actual

Exhibit 9: Brent 2009-14 quarterly prices, $/barrel

	Q1	Q2	Q3	Q4	Average
2009	45.1	59.4	68.4	75.0	62.0
2010	76.8	78.6	76.4	86.9	79.7
2011	104.9	116.8	109.1	109.3	110.0
2012	118.7	108.7	109.8	110.9	112.0
2013	112.8	103.5	103.0	102.0	105.3
2014	100.0	99.0	99.0	98.0	99.0

Source: Bloomberg and Edison Investment Research. Note: 2013 quarter 1 is an actual.

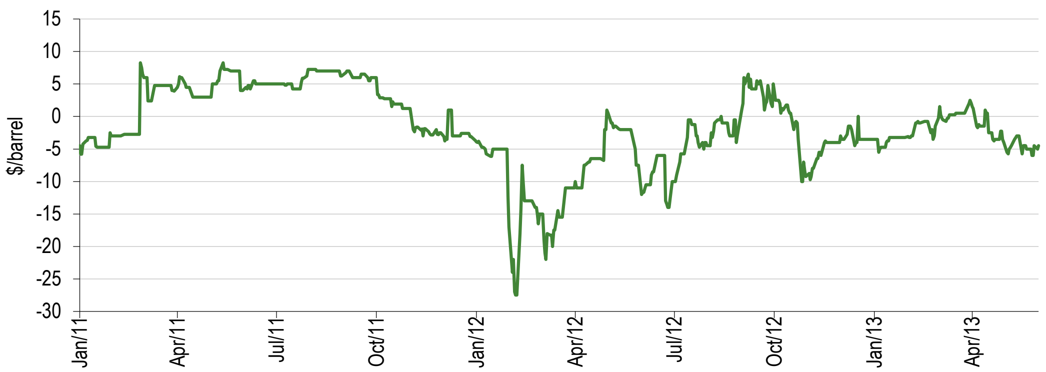
Abstracting from a severe dislocation to oil supplies outside the US, the high-water mark for the WTI discount has in all likelihood been seen. Conceptually it might be thought that the discount should be no more than the pipeline cost of shipping oil from Cushing to the Gulf Coast for uncommitted shipments. This is currently about $4/barrel. However, there are reasons for expecting a somewhat wider discount. These include the shear influx of supply expected over the next few years, refinery conversions in the Midwest and Gulf Coast aimed at reducing the need for light crude feedstock and the possibility that much of the additional pipeline capacity planned will largely result in the substitution for higher-cost rail shipments. Given these factors we think the WTI discount to Brent might be more like $6-8/barrel in the longer term rather than the $4-5/barrel that would be suggested by pipeline costs.

For 2013 we look for the quarterly WTI-Brent discount profile to be as follows: Q1 $18.5, Q2 $9.5, Q3 $9.5, and Q4 $9.0. The average for the year of $11.6/barrel is well down on our previous forecast of $16.9/barrel, reflecting the sharp downward trend of the past three months or so. For 2014 we would look for a discount of about $8/barrel, which compares with $10/barrel previously.

WTI Midland-Cushing spread: There are two pricing point for WTI, Cushing Oklahoma (30 miles west of Tulsa) and Midland, west Texas (300 miles west of Dallas and 400 miles south-west of Cushing), with the former serving the Mid-Continent and the latter the Permian Basin. Historically, WTI Cushing had sold at a dollar or less to WTI Cushing. Reflecting transportation bottlenecks in the Permian Basin and an outage for maintenance at the Phillips 66 Sweeny refinery 65 miles south-west of Houston, WTI Midland was trading at unusually wide discounts of up $20/barrel to WTI Cushing during the fourth quarter of 2012 and in the early weeks of 2013. Over the balance of the first quarter the discount narrowed sharply and by end March was at 5 cents/barrel. During April WTI Midland continued to trade at a discount of a few cents while in early May was actually trading at a premium of up to 65 cents. At the end of May there was a WTI Midland discount of 15 cents/barrel. We believe the rapid narrowing of the WTI Midland discount in 2013 reflects a radical upgrade of the rail and pipeline takeaway capacity from the Permian Basin.

Bakken and Syncrude spreads: Bakken (Clearbrook Minnesota hub) and Syncrude (Edmonton Alberta hub) prices were very volatile for much of 2012, resulting in pronounced swings in spreads compared to WTI. In early 2012 discounts to WTI for both Bakken and Syncrude had been $20-25/barrel resulting in ultra-low prices by world standards for light crude grades. So far in 2013 the picture has normalised. Over the past three months Bakken, for example, has traded between a premium of about $1/barrel and a discount of $6/barrel, while Syncrude has moved between a premium of $10/barrel and a discount of $1/barrel. At the end of May Bakken and Syncrude were trading at discounts of $4.5/barrel and 16 cents/barrel to WTI respectively. The narrowing of discounts and has been a great source of relief to producers. Particularly in the case of Syncrude, the wide discounts to WTI in 2012 had at times cast doubt on the economics of relatively high-cost oil sands projects in Alberta.

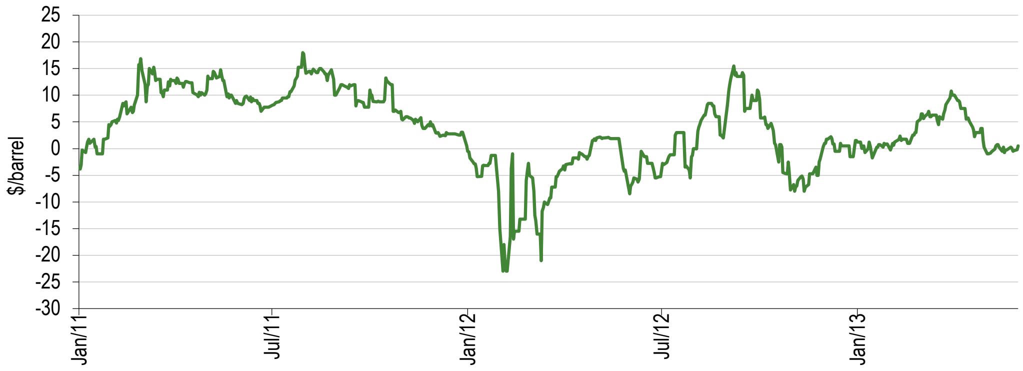
Exhibit 10: Bakken-WTI spread



Source: Bloomberg

Narrowing discounts for Bakken and Syncrude in 2013 can be attributed to rapidly expanding export capacity particularly by rail. According to the North Dakota Pipeline Authority, export capacity is expected to climb 32% between 2012 and 2013 to about 1.45mmb/d, of which rail will account for 850,000b/d and pipelines 600,000b/d. Total capacity should be more than adequate for Bakken producer's needs in 2013. A further expansion in Bakken export capacity to 1.9mmb/d is planned for 2014. Significantly, Bakken oil is now being regularly shipped by rail to eastern seaboard refineries in addition to those in the Midwest and Gulf Coast and to the Cushing tank farm.

Exhibit 11: Syncrude-WTI spread



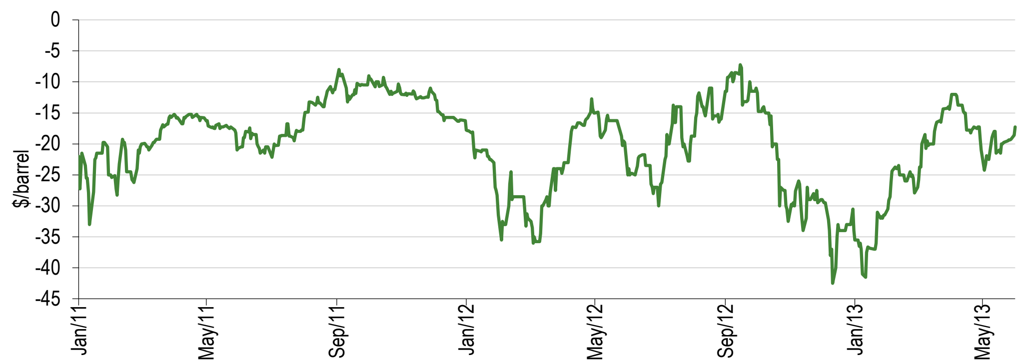
Source: Bloomberg

The key question now concerns the appropriate differential to WTI ongoing for similar specification Bakken and Syncrude. Transport costs by rail might suggest discounts of $10/barrel or more, but this may well be too pessimistic given the ability of producers to ship by rail to coastal locations where relatively high waterborne international prices can be captured. In practice we suspect that normally Bakken and Syncrude will trade between a discount of $5/barrel and approximate parity with WTI. As always, the Syncrude spread will be sensitive to planned and unplanned outages at Athabasca oil sands facilities and Alberta refineries. To some extent movements in spreads will be a seasonal phenomenon related to planned maintenance programmes in the second quarter.

Western Canada Select (WCS) discount

WCS, a heavy sour Canadian blended grade with an API of 20.5°, remains among the world's lowest-priced crude grades. However, the discount to WTI has narrowed considerably since late 2012 and early 2013 when on occasion it was over $40/barrel, reflecting a build-up of production, a lack of pipeline capacity and refinery outages. However, the supply surplus appeared to ease during the first quarter of 2013, resulting in a narrowing of the discount to about $12/barrel in late March. At the end of May WCS was trading at a $19/barrel discount to WTI, giving rise to a price of about $75/barrel against $50/barrel in early January 2013. We would expect WCS to continue trading at wide discounts to WTI in the coming months, reflecting the expected rising trend in oil sands production. The imminent start-up, however, of BP's upgraded Whiting refinery near Chicago, with its greater capability to process heavy Alberta crude, may alleviate the situation somewhat. Following completion of the upgrade, Whiting will be able to process 0.35mmb/d of heavy crude rather than the 0.08mmb/d previously.

Exhibit 12: WCS-WTI spread



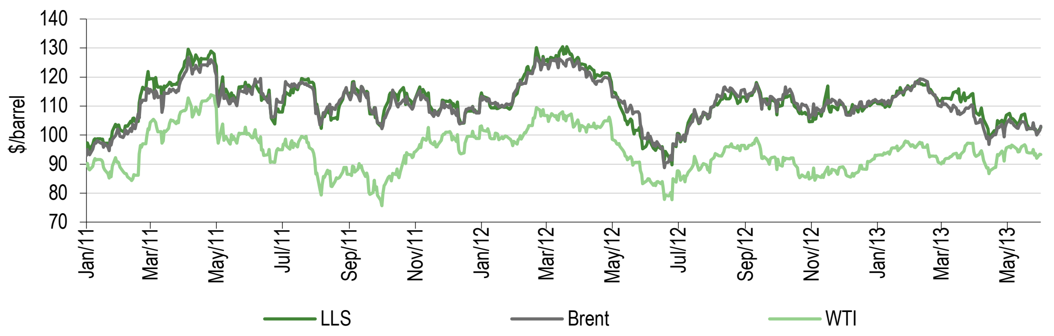
Source: Bloomberg

LLS-WTI and LLS-Brent spreads: Surprising LLS premium to Brent

Light Louisiana Sweet (LLS) is a Gulf of Mexico-sourced light crude comparable in specification to WTI and Brent. It competes with waterborne imports at Gulf Coast refineries and has traditionally traded at a $2 to $3/barrel premium to Brent. Given Gulf sourcing, LLS tracks Brent rather than WTI. As a consequence, there has been a sharp narrowing in the premium to WTI from a recent high of about $23/barrel in late March to $10/barrel in late May 2013.

Reflecting the increasing availability of low-cost, inland-sourced light crudes along the Gulf Coast, LLS swung between 2011 and early 2013 from a premium to Brent of about $4.8/barrel to a discount of approaching $2/barrel on occasion. Since late February however LLS has swung back to a premium to Brent. At the end of May this was about $2/barrel. Given the build-up of supply along the Gulf Coast the resurfacing of an LLS premium is surprising. Possibly it is reflecting the rapid loosening in the supply/demand balance for light crudes in the Atlantic Basin and the consequent downward pressure on Brent. Due to the anticipated influx of US-sourced crude along the Gulf Coast we would still expect to see a LLS-Brent discount of at least $2/barrel to emerge pretty much on a sustained basis.

Exhibit 13: Recent trends in WTI, LLS and Brent



Source: Bloomberg

Other key light crude benchmarks: Narrowing medium/heavy sour crude discounts

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

In the first quarter of 2013 the Urals discount was pretty much within the historical range. The average for the period was $1.20/barrel, somewhat down from the $1.90/barrel in the fourth quarter of 2012. Interestingly, the discount has narrowed sharply in the second quarter and by late May there was unusually a marginal Urals premium of 10 cents. This, we believe, is a reflection of both the pronounced improvement in the availability of Brent in recent months and strong demand in the Mediterranean as refinery maintenance programmes ended. Urals also appears to have been supported by a lack of supplies from Kirkuk in northern Iraq and relatively attractive refining margins.

Brent-Dubai: Dubai Fateh is a Gulf-sourced light but relatively sour crude popular with Far Eastern refineries. Historically, Dubai has traded at a discount of about $2/barrel to Brent. Reflecting the strength of Brent at the time and a plentiful supply of sour grades, the Dubai discount widened considerably early in the first quarter of 2013 from about $3.5/barrel to $5.6/barrel on 20 February. Subsequently the Dubai discount has narrowed and in late April was down to a recent low of about $1.2/barrel. Over the following month or so the discount once again widened but at $2.9/barrel in late May was still well below the February high. The pronounced narrowing in the Dubai discount over the past three months has reflected a combination of attractive fuel oil crack spreads in Asia, which has tended to support sour grades and increasingly plentiful supplies of light crude grades in the Atlantic Basin, which has detracted from Brent.

Brent-Bonny: Nigerian sourced Bonny is a key eastern Atlantic ultra-low sulphur light crude. Normally it trades at a premium of $1-2.5/barrel to Brent. In the first quarter of 2013 Bonny traded at an average premium to Brent of $1.87/barrel, which was well within the historical range. Indicative perhaps of the weakness of Brent over the past few months the Bonny premium has widened to $2.9/barrel on average so far in the second quarter. In late May the premium was $2.65/barrel. We continue to believe that the Bonny premium may narrow significantly and possibly disappear altogether over the next few years given the likely increasing availability of light crude in the Atlantic Basin.

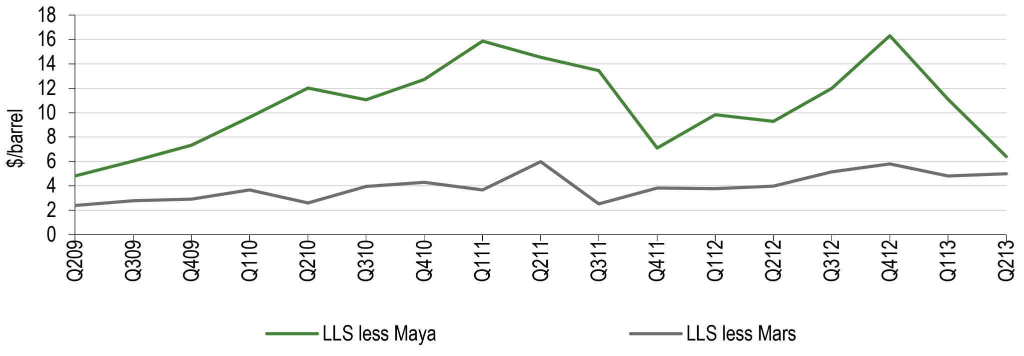
Tapis-Dubai: Tapis is a low-sulphur Malaysia-sourced light crude popular with refineries in the Far East. The spread to Dubai Fateh is one of the key sweet-sour crude oil price relationships. Typically Tapis trades at a significant premium of $7-10/barrel to Dubai reflecting its premium specification. The Tapis premium widened markedly between the fourth quarter of 2012 and the first quarter of 2013 from $6.1/barrel to $10.4/barrel, driven by strong demand in the Far East for grades with a high middle distillates yield. During the second quarter the premium has narrowed to about $7.3/barrel on average. In late May it was around $8.3/barrel. The narrowing of the Tapis premium between the first and second quarters of 2013 reflects the greater availability of light crude grades and a sharp reversal in Far Eastern demand for grades with high light and middle distillates yields. The former is part of a wider pattern globally at present, while the latter probably stems in part from refinery maintenance and in part from increased Chinese exports of diesel. As in the case of Bonny, we believe the Tapis premium could be vulnerable long term to increasing supplies of light crude in the Atlantic Basin and Caspian (Kashagan oilfield) region.

US Gulf heavy crude spreads: Sharply narrowing Maya discount

Movements in US Gulf heavy crude spreads have shown a mixed picture of late. In the case of Mars, a medium-sour grade sourced from the Gulf of Mexico, the discount to LLS has remained broadly unchanged between the first and second quarters of 2013 at about $5/barrel. This is within the historical range of $2-6/barrel. Looking at Maya, a Mexican heavy-sour grade with a specification similar to Canadian WCS, the discount to LLS has narrowed sharply from an average of $11.1/barrel in the first quarter to $6.4/barrel in the second quarter of 2013. The Maya discount is currently towards the low end of the historical range. Interestingly, Maya was trading at a discount of a hefty $16/barrel on average to LLS as recently as the fourth quarter of 2012.

The reasons for the sharply narrowing Maya discount are not clear cut but would appear to relate to two factors. Firstly, the possibility of strengthening demand for heavy crudes in Gulf of Mexico/Caribbean markets following the start-up of the PDVSA's large Amuay refinery in Venezuela after extensive unplanned maintenance and the recent bringing on-stream of a new hydrocracker, which is capable of handling heavy grades, at Valero's Port Arthur refinery. Secondly, the rapidly growing supply of light crude along the Gulf Coast, which could be depressing prices for this grade. Gulf Coast heavy discounts may be in secular decline given the expected continuing influx of light domestic crude and the scheduled expansion of refining capacity using heavy feedstock. Significantly Valero will shortly be bringing on-stream a hydrocracker at its St Charles, Louisiana, refinery.

Exhibit 14: US medium and heavy discounts



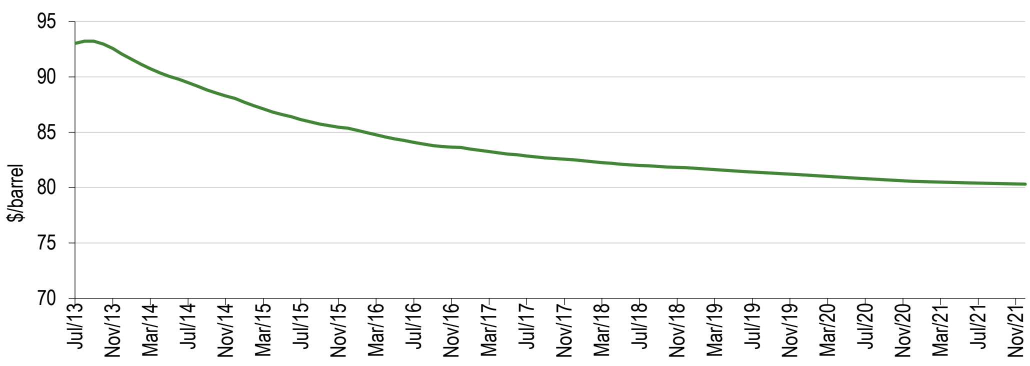
Source: Bloomberg, Edison Investment Research

WTS-WTI: West Texas Sour (WTS) is an inland medium-gravity sour grade with a specification similar to Mars and a delivery point of Midland, West Texas. After plunging to unprecedented levels of up to $20/barrel in late 2012 and early 2013, the WTS discount to WTI narrowed dramatically during the course of the first quarter. By the end of the quarter WTS was trading at a marginal discount of 15 cents to WTI. The average discount for the first quarter of $6.2/barrel was well down on the unusually wide $9.4/barrel of the fourth quarter of 2012. In the second quarter the WTS discount has averaged 8 cents and on some occasions has actually traded at a premium of up to 40 cents. This compares with an average WTS discount over the past five years of $2.9/barrel. The dramatic narrowing in the WTS discount in recent months appears to reflect an unwinding of transportation bottlenecks and a resumption of operations at the Phillips 66 Sweeny refinery.

Forward curves: WTI contango lessens

There have been no major changes in the profiles of the forward curves for Brent and WTI in recent months. However, WTI is now only in modest contango (near-term prices lower than for the forward dates) in the front months. The latest WTI forward curve peaks at $93.23/barrel in September 2013, a mere $0.58/barrel higher than the spot price at the end of May. This compares with a $2/barrel variance earlier in the year. The narrowing in the contango probably reflects perceptions of a lessening in the supply overhang at Cushing. Post September WTI goes into significant backwardation (near-term prices higher than for forward dates). The curve drops to $92.07/barrel in December 2013 and $85.37/barrel in December 2014, before subsequently levelling out. It terminates at $80.3/barrel in December 2021.

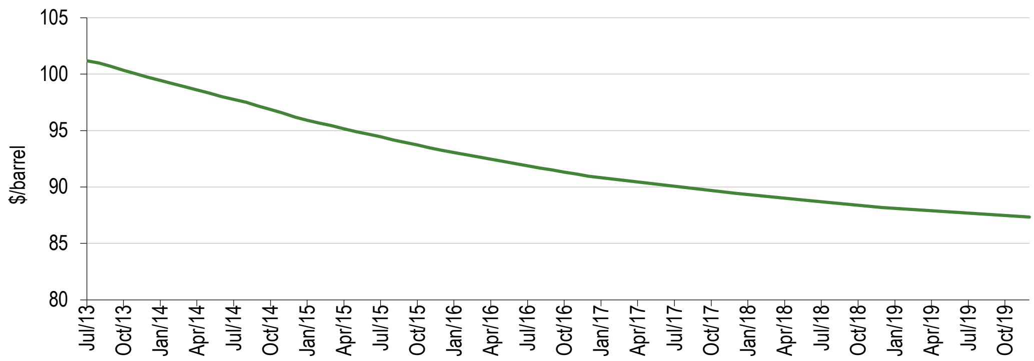
Exhibit 15: WTI forward curve



Source: Bloomberg

The Brent forward curve is in significant backwardation for all dates between July 2013 and December 2019. From a July price $101.19/barrel the curve drops to $99.73/barrel and $96.21/barrel by December 2013 and 2014 respectively. It terminates at $87.33/barrel in December 2019. The Brent and WTI curves imply a narrowing in the WTI discount from $8.16/barrel in July 2013 to $6.17/barrel in December 2019. The latter discount compares with $7.6/barrel earlier in 2013.

Exhibit 16: Brent forward curve



Source: Bloomberg

Global supply/demand balance: Non-OPEC production gains likely to comfortably outpace demand growth

Based on our earlier comments regarding non-OPEC production and demand, the oil market globally should be comfortably in surplus in 2013 and 2014 assuming no major change in OPEC output. Assuming growth in demand and non-OPEC production of 0.8mmb/d and 1.3mmb/d respectively in line with the forecasts made by the IEA, OPEC and the EIA, the implied surplus in 2013 would be 0.5mmb/d. Using the EIA's forecasts for demand and production the surplus in 2014 would be 0.8mmb/d.

The key issue now concerning the global supply/demand balance near to medium term relates to OPEC output. As noted previously, OPEC output in 2013 has been running below year earlier levels but significantly above the 30mmb/d quota and also the recent implied 'call' on OPEC supply of 29.7mmb/d. If OPEC output continues to run at the year-to-date rate of 30.3mmb/d the market overall would approach balance, based on consensus demand forecasts, while at the April rate of 30.5mmb/d it would be approximately balanced. Achievement of a balanced market overall in 2013 will probably be crucially dependent on the success of Iraq in boosting output in the coming months. Iraq, it should be noted, is not subject to OPEC quotas. The other key sensitivities regarding the achievement of market balance in 2013 relate to unplanned outages in the non-OPEC world. As in recent years the main area of vulnerability is probably the North Sea.

Interestingly, the EIA is forecasting that the oil market, including OPEC, will be in surplus to the tune of 0.42mmb/d in 2014. The implied assumption is that OPEC will not fully compensate for the forecast increase in non-OPEC production net of demand growth. This is very much a wild card at this stage, but as previously noted, given the scale of the prospective increase in non-OPEC output, is very much a possibility.

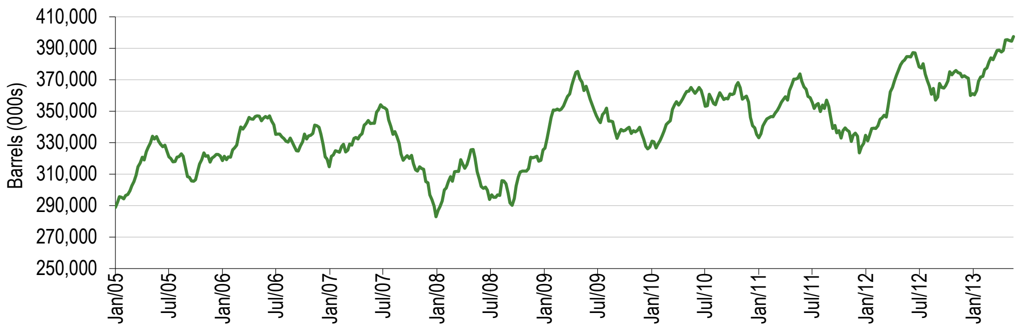
US inventories

Crude oil: Recently at record levels

US crude oil inventories have continued to edge up in recent weeks, both absolutely and in terms of days' supply. On 24 May the EIA reported commercial inventories of 397.6mm barrels, the highest level in at least 31 years and about 10mm barrels above the high point of the range for the time of year. Compared with a year earlier inventories on 24 May were 12.9mm barrels or 3.3% higher than a year previously.

Inventories on 24 May were the equivalent of 26.2 days' supply against 25.7 days' supply a year previously. The former was close to a 20-year high. Including the strategic petroleum reserve, inventories on 24 May were 1,093.5mm barrels, equivalent to about 72 days' supply.

Exhibit 17: US crude oil inventory



Source: EIA

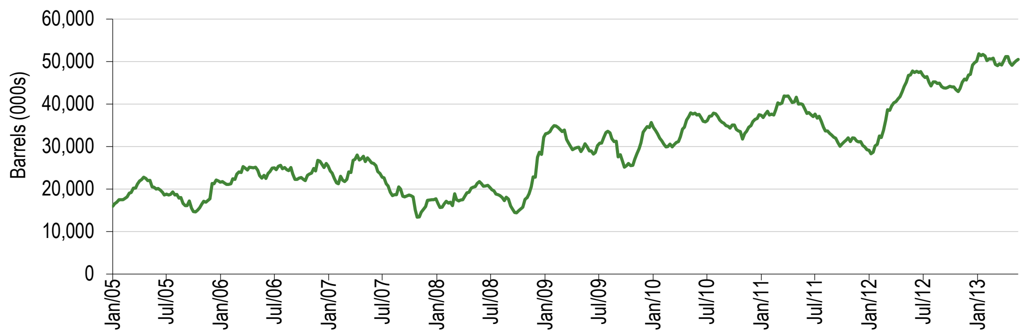
Historically high inventories continue to reflect the surge in US oil production, transportation bottlenecks and a lag in refinery activity. Refinery runs have averaged 14.70mmb/d and 15.18mmb/d on a year-to-date and most recent four-week basis respectively for year-on-year gains of 0.5% and 1.3%. Net exports continue to support refining activity, but so far in 2013 are slightly down from 2012, unchanged from a year ago and so have provided no new impetus.

Cushing: Still near to record levels

Crude oil inventories at Cushing, Oklahoma, the world's largest tank farm and the delivery point for Nymex crude, have been at or close to record levels in 2013. The high point so far was 51.9mm barrels on 11 January. Subsequently the trend has been pretty well flat at between 49mm and 51.4mm barrels. Inventories of 50.5mm barrels on 24 May were up 3.7mm barrels or 8% on a year earlier. Cushing is currently using 79% of its working capacity of 64.3mm barrels.

Near-record levels of inventory continue to reflect the build-up in Mid-Continent production and increasing supplies from Canada following upgraded pipeline connections and rising oil sands production. This has been despite a substantial increase in takeaway capacity over the past year or so. Given the expectations for supply entering the tank farm, a major reduction in inventories at Cushing seems unlikely in the coming months.

Exhibit 18: Cushing crude oil inventories



Source: EIA

Gasoline: Very comfortable for the time of year

US gasoline inventories look very comfortable for the time year, both absolutely and on a days' supply basis. For the week ended 24 May inventories stood at 219.2mm barrels, which is close to the top end of the range for the time of year. Compared with a year ago inventories are up 10%. Seasonally high inventories continue to reflect, at least in part, lacklustre domestic demand.

Based on the experience of the past 20 years or so, gasoline inventories on a days' supply basis are running at historically high levels. On 24 May inventories were equivalent to 25.4 days against 22.6 days a year earlier.

Exhibit 19: US gasoline inventories

Source: EIA

Distillates: Stabilising, day's supply normal

After trending down in 2012, distillate inventories so far in 2013 have stabilised. This has left them modestly above rather than below the lower end of the seasonal range, as was the case in late 2012 and the early weeks of 2013. For the week ended 24 May inventories were 120.7mm barrels, up 2.5% on a year earlier. In the latest week inventories were equivalent to 31.6 days' supply, against 31.3 days' in 2012. Although significantly down from the highs in 2010 of around 50 days, the current level of days' outstanding is not out of line with longer-term trends.

Seasonally low distillate inventories over the past year or more we believe reflect to a considerable extent a surge in exports, remembering that exports tend to have higher crack spreads than for domestic business. After hitting almost 1.1mmb/d in early 2013 distillate exports have subsequently eased to a little over 0.8mmb/d. This may have helped support inventory levels.

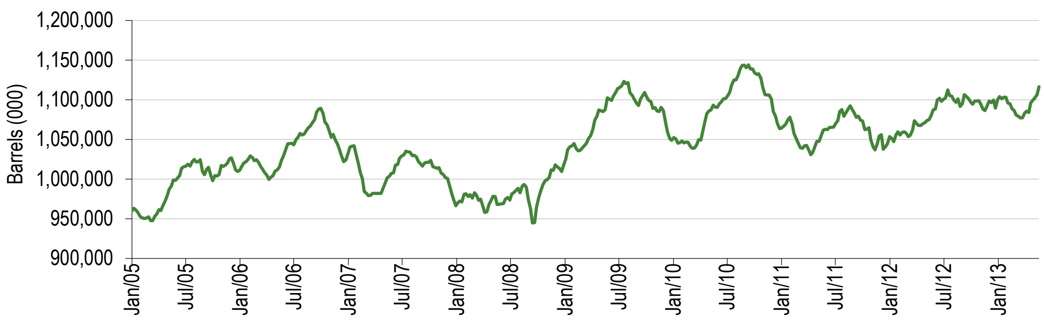
Exhibit 20: US distillate inventories

Source: EIA

All petroleum product inventories: Close to the 2000 high

We believe the soundest basis for assessing the adequacy of petroleum inventories is on an all-encompassing definition including US commercial crude oil and refined product inventories. Based on EIA data for 24 May 2013, US commercial crude and refined product inventories were 1,116.3mm barrels, up 35.8mm barrels on a year earlier. Inventories on this definition slightly exceeded the recent high on 20 July 2012 of 1,112.6mm barrels and were within 2.5% of the post 2000 high of 1,143.5mm barrels recorded in September 2010. Total commercial inventories therefore clearly continue to run at historically very high levels.

Exhibit 21: US all petroleum product inventories

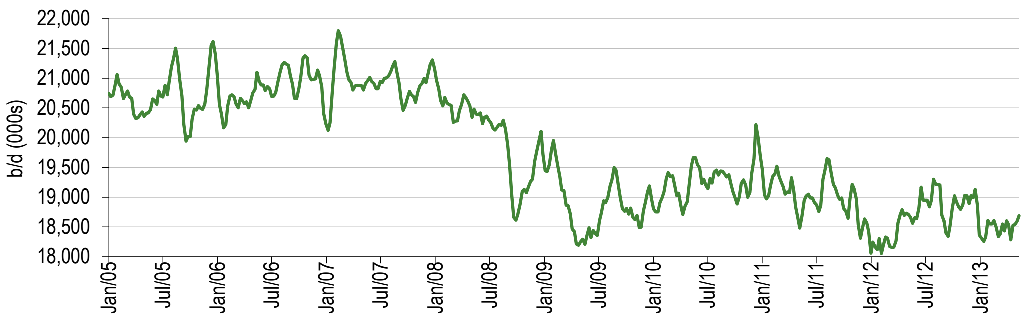


Source: EIA

US petroleum product demand: Still lacklustre, but some signs of firming

US petroleum product demand has remained lacklustre in 2013, although the underlying trend has arguably firmed marginally since early 2012. Taking the most recent four-week period ending 24 May, petroleum product demand (product supplied is used as a proxy) overall averaged 18.69mmb/d, up 0.2% on a year earlier. On the same basis gasoline and fuel oil showed declines of 2.7% and 7.7% respectively, while distillates was up 1.4%, kerosene was 5.7% higher and propane/propylene rose 11.1%.

Exhibit 22: US petroleum product supplied



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

Reflecting a particularly soft patch for demand in early 2012 related to mild weather conditions and a modest recovery in the second half of last year, the year-on-year comparison was relatively easy in the first quarter of 2013, but has subsequently become a little tougher. On a year-to 24 May basis, demand in 2013 has actually risen 0.5% from a year ago. In terms of the product mix the year-on-year movements in the year-to-date are as follows: gasoline 0%, distillates 0.9%, kerosene 1.1%, fuel oil -23.4%, propane/propylene 17.5% and miscellaneous -2.3%.

The key features of the demand side of the marketplace in 2013 continue to be the softness of gasoline, easily the largest product category, and the buoyancy of propane/propylene. Over the four weeks to 24 May US gasoline consumption has averaged 8.63mmb/d, which compares with peak levels of second-quarter demand of about 9.5mmb/d in 2007. The all-time annual peak for gasoline consumption was 9.29mmb/d in 2007.Continuing soft gasoline demand has surprised many given the recovery in the economy. The explanation to the apparent conundrum would appear to be a combination of the improving fuel efficiency of the vehicle fleet and declining miles being driven. Note, the former applies not only to cars but also to light trucks (roughly half new light vehicle sales) and is being driven by tightening regulatory requirements. In the case of propane/propylene, consumption has been supported by strong demand for liquefied petroleum gas (LPG) in 2013 related to cold weather conditions. Compared with 2012, this factor has also been a positive for distillates consumption, although there was probably a partial offset in terms of gasoline usage.

The EIA continues to look for a mild firming in US petroleum product demand in 2013. A gain of 80,000b/d or 0.4% to 18.55mmb/d is forecast, driven primarily by LPG, distillates and miscellaneous uses. Growth in these areas is expected to be partially offset by modest declines in gasoline and kerosene consumption, reflecting improving vehicle and aircraft fleet fuel economy. For 2014 the EIA is forecasting unchanged petroleum product demand with structural factors again constraining growth. The EIA's petroleum product demand forecasts are predicated on GDP growth assumptions of 1.8% in 2013 and 2.7% in 2014. Given this backdrop along with the structural negatives we believe the EIA's forecasts of petroleum demand in 2013/14 are realistic.

Exhibit 23: US distillates supplied

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

Crude oil price outlook: Supply surpluses are pointing to downward pressure

International crude oil prices still appear on the high side, notwithstanding the marked decline from the highs of the first quarter of 2013. Prices, of course, in the early weeks of the year were bid up to unrealistically high levels on the back of euphoria in financial markets fueled by easy money policies practically globally. The fundamentals continue to tell a different story. Non-OPEC supply is growing robustly, OPEC output is as buoyant as could be expected and broadly in line with demand, global demand itself remains subdued and inventories are very comfortable in the OECD and at near record levels in the US. In all probability, non-OPEC supply growth will comfortably exceed global demand growth in both 2013 and 2014.

Reflecting the bearish supply/demand backdrop we look for international prices to trend flat to down over the balance of 2013. Tending to constrain any weakness we believe will be a combination of bullish financial market sentiment concerning the economic outlook, especially in the US, and supply side uncertainties related to technical issues and civil strife/war in the Middle East. In terms of facility outages the key areas of vulnerability are probably once again the North Sea and the

Athabasca oil sands in Canada. In terms of the Middle East the principal area of concern is Iraq. Iran may also re-emerge in the coming months as a geopolitical hot spot. Our quarterly scenario for Brent in 2013 is as follows: Q1 $112.8 (actual), Q2 $103.5, Q3 $103.0, Q4 $102.0. This would imply an average price for the year of $105.3/barrel, down $3.4/barrel on the earlier forecast and $6.7/barrel on 2012. The downgrade for 2013 reflects the weaker than expected performance in the first five months of the year and the growing evidence of weak fundamentals in international markets.

For 2014 we look for Brent to average $99.0/barrel. This is slightly down on the $100.3/barrel of the previous forecast and is $6.3/barrel below our new 2013 forecast. The modest weakening between 2013 and 2014 stems from the previously mentioned supply surplus as demand growth lags non-OPEC supplies. We believe, in fact, that surplus supplies may weigh on international prices for several years over the balance of this decade, possibly in analogous fashion to the mid to late1980s when non-OPEC supply was boosted by the backwash of supply growth in Alaska, the North Sea and Mexico. Although geopolitical uncertainties and the fragility of the production infrastructure in some parts of the world may prevent a replay of the approximate 60% drop in Brent between the 1980 peak of $36.8/barrel and the 1988 low of $14.9/barrel, an extended period of price weakness is perfectly plausible if supply is as robust as seems possible. This applies particularly if we are also looking at a sustained period of weak economic growth globally combined with structural weakness in OECD oil demand.

WTI remains to a large extent insulated from international influences reflecting the surge in US inland supplies and the cost of shipment to the refining centres of the east, west and Gulf coasts. Expanding takeaway capacity from the Mid-Continent implies a trend narrowing in the WTI discount over the next year or two, although it needs to be remembered that the costs of transporting surplus oil to the coasts are not insignificant. Bearing this in mind together with the year-to-date performance, our 2013 quarterly WTI scenario is as follows: Q1 $94.3 (actual), Q2 $94.0, Q3 $93.5, and Q4 $93.0. The average for 2013 is $93.7/barrel, modestly up from the $91.8/barrel of the earlier forecast and marginally down from the $94.2/barrel of 2012. The forecast upgrade reflects the stronger showing in the year-to-date than originally expected and, in the light of recent trends, a reassessment of the discount to Brent in the second half. For 2014 we are looking for another modest dip in WTI driven by the continuing influx of Mid-Continent supply. Our forecast for the year on average is $90.8/barrel with a broadly flat trend between the first and fourth quarters. The new forecast is marginally up on the previous $90.0/barrel. The upgrade implies a narrowing in the WTI discount from $10.3 to $9.1/barrel, which is consistent with the expansion of the Mid-Continent's takeaway capacity expected. As before, the trend is flat between the first and fourth quarters of 2014.

Geo-political issues: All our oil price forecasts continue to reflect broadly unchanged levels of geo-political tension compared with end May 2013 levels. Intensified tension stemming, for example, from stepped-up sectarian violence in Iraq combined with a dislocation to exports would doubtless send international oil prices, for a while at least, considerably above those in our forecasts. The problem for producers would, however, be the negative feedback loop in terms of demand. For many years this has tended to be reflected with a lag as a second order effect on economic activity given the traditional price inelasticity of gasoline and diesel. All the indications are that oil demand has now become more sensitive to price in recent years, at least in the OECD world. Significantly, China's petroleum product pricing regime is also now more sensitive to fluctuations in crude prices than a few years ago. A surge in prices could therefore in short order be followed by a collapse.

Exhibit 24: Brent and WTI price scenarios

$/bbl	2005	2006	2007	2008	2009	2010	2011	2012	2013e	2014e
WTI	56.6	66.1	72.2	99.8	62.0	79.5	94.9	94.2	93.7	90.9
Brent	54.5	65.4	72.7	97.7	62.0	79.7	110.0	112.0	105.3	99.0

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

US natural gas market

Production and consumption

Recent trends: Production growth has abated, consumption boosted by cold weather

US marketed gas production surged by 4.2% a year between the recent annual low in 2005 and 2012 to a record 25.3tcf. By contrast, US consumption rose by a significantly slower 2.1% a year over the same period. The growth in annual production slowed noticeably in the second half of 2012 and in the fourth quarter was down to 1.6% year-on-year. The trend continued to ease early in 2013. Based on EIA data, production in the first two months was actually 1.3% below a year earlier on a crude comparison. However, allowing for fewer days in February 2013 this converted into a modest 0.4% year-on-year gain.

As in 2012, the key area of strength production wise has remained what the EIA terms ‘other’ states. These include non-traditional areas of large-scale production such as Pennsylvania, West Virginia and North Dakota and are now the largest source of gas in the US, accounting for a third of production. Through the first two months of 2013 production in the ‘other’ states was up 12.4% on a year previously, driven by continuing rapid development, particularly in the Marcellus formation of Appalachia. Importantly, the Marcellus formation now accounts for about 35% of US gas production against marginal quantities as recently as 2009. Despite the robust trend recorded by the ‘other’ states, the growth rate has nevertheless slowed significantly from 2012’s 25% gain. Offsetting this year’s increase in production in the ‘other’ states have been falls in most of the traditional major sources of gas. In the first two months of 2013 production was, for example, down year-on-year by 4% in Alaska, 16% in Louisiana, 2% in Texas and 14% in the Gulf of Mexico.

The flattening trend in US gas production continues to reflect declining dry gas drilling activity and well shut-ins stemming from highly unattractive gas industry economics in 2011/12. The surge in US production of recent years has also enabled the net import balance to be sharply reduced. The balance of 1.5tcf in 2012 was down 60% on the 2007 peak and through the first two months of 2013 there was a year-on-year decline of 20%. In the year-to-date the narrowing import balance reflects both falling imports and rising exports, particularly to Mexico. Roughly 95% of imports relate to pipeline gas from Canada.

US gas consumption rose by 4.6% in 2012 to 25.5tcf. The key driver was an increasing gas burn rate in power generation related to depressed gas prices at the beginning of the year. In 2012 natural gas accounted for 30.4% of power generation against 23.5% in 2011. Overall, the power generation market was comfortably the largest in 2012 at 9.1tcf, around 36% of total gas consumption and up 21% on a year earlier. Through the first two months of 2013 US gas consumption was 3.1% higher than in 2012. This time the key drivers have been residential and commercial markets, which have shown gains of 11.7% and 8.4% respectively. A significantly cooler winter than in 2012 sharply boosted space heating demand. Elsewhere, industrial markets showed a gain of 1.3% while power generation was down 7.3%. In 2013 gas usage in power generation has been hit by a reversal of the favourable trends that dramatically boosted the competitiveness of gas in 2012. The price of gas rose over 40% between early 2012 and 2013, while the price of coal for power generation was broadly unchanged. The share of natural gas in the power generation market in early 2013 was back down to 24%.

Outlook: Near-term subdued production and consumption trends

Depressed dry gas drilling activity suggests that the trend in US natural gas production will remain subdued in the near to medium term. Helping to underpin marketed production should be a still relatively high rig count in the prolific Marcellus formation and by-product gas from oil drilling in the

Bakken and elsewhere. It should be noted that regulation is tightening around gas flaring, which will in all probability boost marketed production in due course. The EIA is looking for gas production to trend marginally upwards between 2012 and 2014, with gains of 1.0% in 2013 and 0.3% in 2014. This is similar to the picture predicted earlier in the year. In the absence of a significant increase in drilling activity in the coming months there is the possibility of a marked drop in US natural gas production in 2015.

The EIA also has a subdued near- to medium-term forecast for US domestic gas consumption. After growth of 0.7% in 2013 a decline of 0.9% is forecast for 2014. The key drivers behind the forecast are an assumed continuing deterioration in competitiveness for gas compared to coal in the power generation sector and relatively mild summer weather conditions. In terms of power generation, gas's share is expected to be 27.8%, significantly down on the outcome for 2012 but up on 2011's 24.7%. The EIA bases its usage forecasts during the summer months on data provided by the National Oceanic and Atmospheric Administration. It needs to be emphasised that gas consumption forecasts are highly sensitive to weather conditions in both the winter and summer months. The actual outcome for consumption could vary considerably from the EIA's forecasts. We believe the consumption forecasts are conservative in the absence of unusually mild winters and summers.

Railroads investigate LNG as a locomotive fuel

An interesting story recently surfaced concerning broadening the market for natural gas in the transportation sector. The four largest US railroads along with GE and Caterpillar (the two major US suppliers of diesel locomotives) are apparently all studying the potential for substituting LNG for diesel as a locomotive fuel. The incentives are significant cost savings of perhaps 30% or more and lower emissions. The latter is coming into focus due to tightening emission standards from 2015.

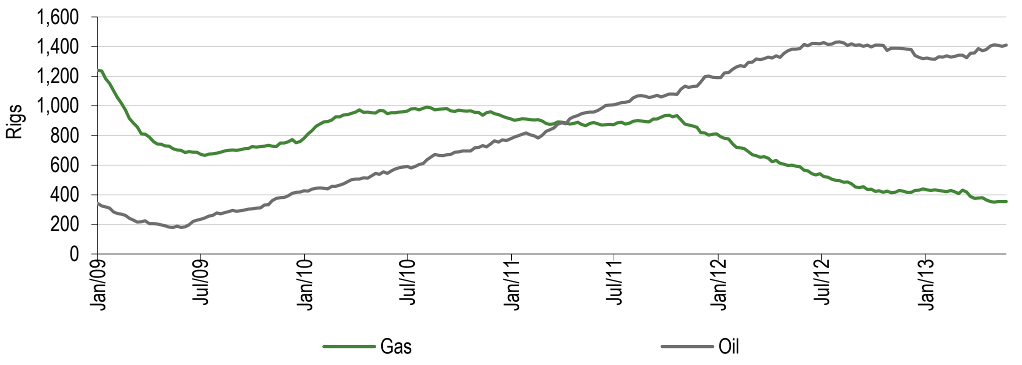
Inevitably there are some significant drawbacks in substituting LNG for diesel as a locomotive fuel, much as for heavy trucks. These include a lower energy density (about 60% of diesel) leading to a shorter range before refuelling and inferior performance, the need for expensive bulky and heavy cryogenic tanks and, due to the need to store fuel at very low temperatures, a complex and expensive refuelling system. LNG is therefore unlikely to become the fuel of choice for railroads in the near term. For the record according to the EIA, US railroads consume about 3.1bn of diesel a year, equivalent to 207,000b/d.

Drilling activity and rig count: Gas rig count continues to decline

The downward trend in the US rotary rig count in 2012 has levelled out in 2013. According to Baker Hughes, the rig count overall on 24 May 2013 was 1,762, a level that is very much in line with that prevailing since end 2012. The 24 May reading was off 11% from a year ago while compared with the November 2011 all-time high of 2,026 it was down 13%. Despite the decline over the past 18 months or so the US rig count overall remains at a historically high level. In the early 2000s the rig count was, for example, running at about 750, while in the mid 2000s it was around 1,350.

The decline in the US rig count in 2012 was, of course, very much gas-driven. After showing signs of stabilising in late 2012 and in the early weeks of 2013 the dedicated gas rig count since late March has taken another step down. Based on Baker Hughes data the gas rig count on 24 May was 354, roughly 18% down on end 2012 levels and 40% below a year ago. For perspective, the US gas rig count was running at peak rates in 2008 of about 1,600.

Exhibit 25: Baker Hughes US rig count



Source: Baker Hughes, Bloomberg

The US oil rig count presents a different picture. After slipping by about 7% from a record 1,432 in the second half of 2012 the oil rig count has rebounded in 2013 to date. On 24 May it was 1,402, which was close to the 2012 high and up 1% on a year earlier. The oil rig count continues to be supported by a combination of attractive economics in the established shale and tight reservoir plays and optimism concerning the potential in new ones.

The slump in the gas rig count of course parallels the slide in dry gas economics in 2011/12 to historically depressed levels. Drilling for gas in the US is now broadly limited to meeting lease commitments and/or liquids rich plays such as the Marcellus in Pennsylvania/West Virginia, the Utica in Ohio and the Eagle Ford in Texas. With benchmark US gas prices having recently modestly exceeded $4/mmBtu, the conditions may have been established for a stabilisation in the gas rig count. Prices in excess of $4.5/mmBtu on a sustained basis would probably be required to significantly boost the dedicated rig count on a sustained basis from current levels.

Inventories: Now below the seasonal average

After running at seasonally very high levels for most of 2011 and 2012, US natural gas inventories have moved sharply below the top end of the seasonal range of late. Based on EIA data, inventories on 17 May stood at 2,053bcf, which was 680bcf or 25% below year ago levels and 84bcf or 4% under the five-year average for the time of year of 2,137bcf. The seasonally strong downward pressure on inventories in the first quarter of 2013 and the subsequent relatively subdued upturn so far in the summer injection period reflects cold weather in the late winter in the Midwest and Eastern Seaboard and relatively cool conditions in April and May. This has resulted in significantly higher space heating needs than in 2012, when mild conditions prevailed. Based on the EIA’s assumptions for weather conditions and indeed gas demand, US gas inventories should remain well within the seasonal range during the third quarter of 2013 and going into the winter withdrawal season.

Recent price developments and outlook

Dry gas: The Henry Hub, Louisiana US benchmark natural gas quote bottomed out at around a 10-year low of $1.84/mmBtu on 20 April 2012. Since then it has trended higher and on 19 April traded at around a 21-month high of $4.37/mmBtu. Subsequently there has been a softening, which left the Henry Hub quote at $4.15/mmBtu on 29 May. This was 74% above a year earlier. Elsewhere, at end May prices at other key hubs along the Gulf Coast/Texas and in the Midwest, with the exception of Agua Dulce, were trading at similar levels to the Henry Hub. At $3.59/mmBtu the Agua Dulce quote stood at a discount of 13% to the Henry Hub quote, which is in line with the historical picture.

The strengthening trend in the Henry Hub quote over the past year or so reflects several influences. The key factor has perhaps been speculative activity based on the proposition that the earlier depressed prices were not sustainable given prevailing production economics. The other key factors have been the cold weather late in the first quarter of 2013 and the rundown in inventories to below average levels seasonally.

Exhibit 26: Henry Hub price trend

Source: Bloomberg

Reflecting the stronger than expected showing in the year-to-date and the tightening inventory position, we are upgrading our 2013 Henry Hub price quote from $3.58 to $3.86/mmBtu. Our quarterly scenario is: Q1 $3.47 (actual), Q2 $4.10, Q3 $4.30 and Q4 $3.55. The second quarter forecast is in line with the showing in the first two months. For the third quarter we have assumed an uptick related to seasonal influences associated with heavy air conditioner usage during the summer months. The dip in the fourth quarter relates to the tendency for mild weather conditions to typically prevail through at least the first two months. For 2014 we have slightly upgraded our Henry Hub forecast from $4.00/mmBtu to $4.10/mmBtu, stemming from the assumed greater carryover strength from 2013. Given subdued drilling activity we believe there is the potential for a more pronounced upturn in US gas prices in 2015. An average for the Henry Hub quote in this year of $5/mmBtu would perhaps not be surprising.

Exhibit 27: Henry Hub quarterly price scenario

$/mmBtu	Q1	Q2	Q3	Q4	Average
2008	8.66	11.37	9.06	6.45	8.89
2009	4.54	3.7	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
2012	2.43	2.29	2.88	3.4	2.75
2013e	3.47	4.1	4.3	3.55	3.86
2014e	4.1	3.9	4.5	3.9	4.1

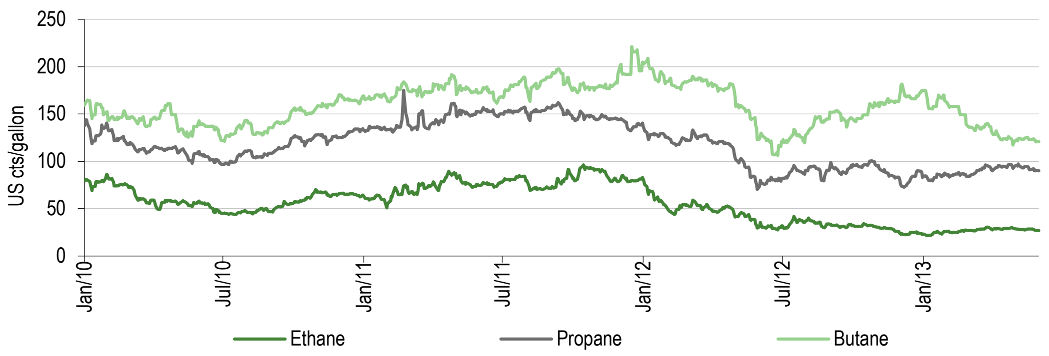
Source: Bloomberg, Edison Investment Research. Note: Q113 is actual.

NGLs: Natural gas liquids (NGLs) such as ethane, propane and butane 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 in the Marcellus and Eagle Ford. The EIA gives US NGL production in 2012 as 2.40b/d, up 8.3% on 2011. For 2013 it is forecasting roughly unchanged production, while for 2014 it is looking for a gain of 2.1%. We believe a dip in production is possible in 2015 unless gas-orientated drilling activity gathers pace in 2013/14.

As in the case of natural gas, US NGL prices came under heavy pressure in the second half of 2011 and the first half of 2012, reflecting an influx of supply and no ready market. Since mid 2012 the trend overall in NGL prices has been lacklustre. At end May ethane and butane were both down on a year previously, by about 19% $0.27 and $1.22/gallon respectively. Propane has turned in a stronger performance in recent months and is up 15% on a year earlier at $0.90/gallon. All prices are Mont Belvieu Texas. Compared with the 2011/12 highs, ethane is off about 70%, while butane and propane are both down about 40%.

The salvation for NGL prices rests on a combination over the next few years of the potential for a considerably slower rate of production growth and a large increase in US petrochemical capacity. There is little doubt that at anything like current NGL prices the US is highly competitive globally across a range of petrochemicals. Based on industry estimates ethylene costs, for example, at about $250/tonne are now similar to those in Saudi Arabia. A number of major petrochemical projects are being planned in the US by the likes of Exxon, Dow, Formosa Plastics, Lyondell Basell and Sasol.

Exhibit 28: Recent trends in US NGL prices



Source: Bloomberg

Economics: Dry gas fully accounted break-even

The late May Henry Hub quote of $4.15/mmBtu points for the first time in many months to the semblance of viability for US dry gas producers. A price around this level should, in fact, yield a very comfortable cash contribution given what we believe are typical cash costs of about $2.6/mcf comprising $1.5/mcf for operations (including lifting costs, production taxes and royalties), $0.9/mcf for SG&A and $0.2/mcf for processing and pipeline tie-in. After allowing perhaps $1.5-2.0/mcf for finding and development costs we could be looking at approximate fully accounted break-even at a Henry Hub price of $4.15/mmBtu.

The picture for wet gas producers is potentially much more attractive depending on the price and quantity of NGLs available. Particularly in the liquids-rich zones of the Eagle Ford and Marcellus formations, NGLs can boost realisations by a further $2/mcfe to over $6/mcfe. This would probably imply a comfortable fully accounted profit even after allowing for greater processing costs.

Exhibit 29: Henry Hub natural gas price trend

	2005	2006	2007	2008	2009	2010	2011	2012	2013e	2014e
$/mmBtu	8.79	6.72	6.96	8.89	3.94	4.37	4	2.75	3.86	4.1

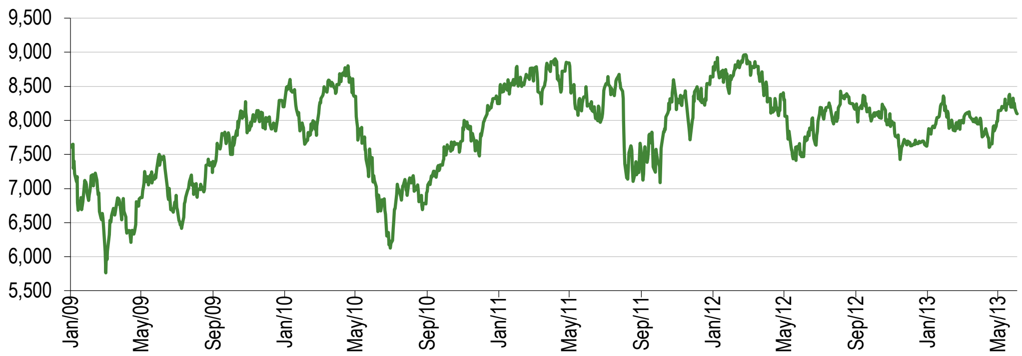
Source: Bloomberg and Edison Investment Research

Oil and gas sector performance

UK: Lagging oil stock performance, juniors particularly weak

Both large capitalisation and junior UK-based oil and gas stocks have failed to provide much excitement for investors in 2013, which continues a trend that has been apparent for some time. The large capitalisation stocks have comprehensively outperformed the juniors so far in 2013. The FTSE 350 Oil & Gas Index, an index of medium- and large-capitalisation stocks dominated by BP and Shell, as at end May was up about 8% since end December 2012. This compares on the same basis with a decline of roughly 9% for the AIM Oil & Gas Index and a gain of 12% for the FTSE 100 Index. Significantly, the AIM oil and gas juniors have also lagged the 3% gain in the broader AIM All Share Index in the five months to end May.

Exhibit 30: FTSE 350 Oil & Gas Index



Source: Bloomberg

Looked at from a longer-term perspective, both the FTSE 350 Oil & Gas and the AIM Oil & Gas indices have trended flat over the past three or four years. Compared with their respective 2008 highs, the former as of end May 2013 was off 12% while the latter was down 51%.

Exhibit 31: AIM Oil & Gas Index

Source: Bloomberg

US: Outperformance of UK peers, but slight underperformance of the S&P 500

US oil and gas stocks have significantly outperformed their UK peers in 2013, but have nevertheless underperformed the 18% gain in the S&P 500 since end December 2012. As of end May the S&P 500 Oil & Gas Exploration and Production Index (an index of large capitalisation oil and gas independents) was up 15% from end 2012, while the more broadly based S&P 500 Oil & Gas Index (which includes the majors along with the large independents and refinery groups such as Valero) has shown a slightly smaller gain of 13%. The former index continues to lag the 2008 high by about 20%, while the latter is off only 4% on the same basis. The S&P 500, of course, at end May 2013 was close to a record.

Exhibit 32: S&P 500 Oil & Gas Index

Source: Bloomberg

Exhibit 33: S&P Oil & Gas Exploration and Production Index

Source: Bloomberg

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