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Oil & gas

Oil & gas macro outlook

Current prices are not sustainable

14 January 2015

The oil market was late in appreciating the significance of the shale revolution and slowing demand growth. Arguably, however, the 50% plunge in prices in the second half of 2014 was excessive and is setting the scene for a rebound. Sub $60/barrel prices are below fully accounted costs for a wide swathe of projects. Sharp investment cutbacks are likely, which is particularly relevant for high depletion rate shale oil producers. The price trend may remain soft during early 2015 reflecting a continuing supply surplus. By the second half, however, we would expect a firming tendency once the significance of financing constraints and likely slowing US production growth are assimilated. Medium term, we believe a price ceiling could emerge at $75-80/barrel given the new found elasticity of supply through shale development, capacity additions in Brazil, Canada and Iraq and structural issues slowing demand growth.

Supply/demand: Surplus likely to narrow in 2015/16

The oil market in 2014 was comfortably in surplus and possibly exceeded 1.0mmb/d. The key factor was a record surge in non-OPEC output of almost 2mmb/d (3.5%) driven by North America. OPEC production was only marginally down on 2013 while world demand growth might have been as low as 0.6mmb/d (0.7%). For 2015 we look for another surplus but at a lower level than in 2014 reflecting a slowdown in non-OPEC output growth. The surplus could be about 0.3mmb/d reflecting growth in supply and demand of about 1mmb/d and 0.7mmb/d respectively. The former assumes OPEC crude output is broadly unchanged from 2014. For 2016 we would look for a balanced market. Major constraints on near term demand are likely to be deteriorating economic conditions in the developing world in general and Russia in particular plus reductions in energy subsidies.

Shale oil economics: Marginal zone entered

With WTI down to less than $50/barrel and other benchmarks such as the Bakken below $45/barrel, US shale oil economics has entered the marginal zone on a fully accounted basis even for the most attractive plays. Industry comments, in fact, suggest that fully accounted costs for the shale mainstream cluster around $65-70/barrel. At current prices internal cash flow is rapidly evaporating while the bond market is now closed to sub-investment or even low-end investment grade borrowers and bankers are no doubt casting a wary eye over their energy sector exposure. The upshot will be a sharp cutback in financing, capital spending and potentially production. Bakken pioneer, Continental Resources, has recently announced a 41% cut in its capital expenditure budget for 2015.

Price forecasts: 2015 downgraded, 2016 recovery

We are downgrading our 2015 Brent and WTI forecasts reflecting weaker than expected carryover from 2014 and the likely persistence of bearish fundamentals through the first half of the year. Our forecasts call for reductions in Brent to $52.5/barrel and in WTI to $49.0/barrel. A firming trend is expected in 2016 as slower supply growth particularly in the US tightens the market. The key leading indicators are the US rig count and production.

Analysts

Peter J Dupont	+44 (0)20 3077 5700
Ian McLelland	+44 (0)20 3077 5756
Will Forbes	+44 (0)20 3077 5749
Kim Fustier	+44 (0)20 3077 5741
Peter Lynch	+44 (0)20 3077 5731
Elaine Reynolds	+44 (0)20 3077 5700
Tim Heeley	+64 (0)4 8948 555

oilandgas@edisongroup.com

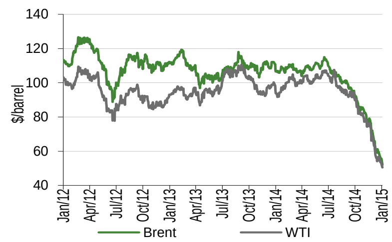
Edison profile page

For institutional enquiries please contact:

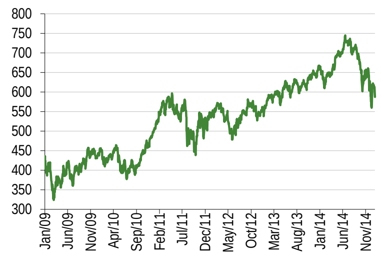
Jeremy Silewicz +44 (0)20 3077 5704

institutional@edisongroup.com

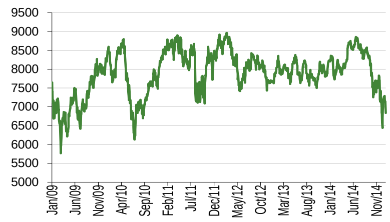
WTI vs Brent



S&P 500 Oil & Gas Index



FTSE 350 Oil & Gas Index



Source: Bloomberg

	WTI $/bbl	Brent $/bbl	Henry Hub $/mmBtu
2012	94.2	112.0	2.75
2013	98.0	108.8	3.73
2014	93.2	99.1	4.36
2015e	49.0	52.5	3.95
2016e	67.5	72.5	3.98

Note: Prices are yearly averages.

Contents

Highlights

- The 50% drop in oil prices from the June peak was the defining feature of oil markets in 2014.
- The backdrop to the recent price rout has shown similarities to 1985/86.
- Oil prices in real terms were running at historically high levels between 2010 and the first half of 2014 but have now returned to the levels of the early to mid-2000s.
- The key negatives for the oil market in 2014 were the continuing surge in non-OPEC output, lacklustre demand growth, a more robust than expected trend in OPEC output, Saudi Arabia's decision to relinquish its role as swing producer and the strong dollar.
- Non-OPEC supply in 2014 grew by almost 2mmb/d, a record according to the IEA. The US and Canada accounted for the bulk of the gain.
- Production now gathering momentum from the giant pre-salt fields offshore Brazil. Petrobras's gross production was up 13.5% year-on-year in October 2014.
- Significantly slower non-OPEC production growth in 2015 reflecting in particular lower shale development activity in the US. Overall non-OPEC supply growth of about 1mmb/d. Further decline is likely in 2016.
- Medium-term new deepwater projects are potentially vulnerable if sub $70/barrel oil is sustained for a year or more. Brownfield oil sands projects may still be viable.
- OPEC crude oil production in 2014 of an estimated 30.2mmb/d was above the target of 30mmb/d and well in excess of the 'call' of about 29mmb/d.
- Iraqi exports could increase by 0.5mmb/d in 2015 reflecting rising capacity both in the north and south plus upgraded logistics.
- OPEC will probably have difficulty in keeping to the 30mmb/d target in 2015 due in particular to Iraq. Libya is a significant wildcard for 2015.
- OPEC investment also likely to be affected by a period of sustained sub-$70/barrel prices.
- World oil demand appears to have increased by no more than 0.6-0.9mmb/d or less than 1% in 2014, according to the IEA, EIA and OPEC.
- Lacklustre world demand growth is likely to continue in 2015. This reflects the sluggish OECD economic backdrop outside North America, slower economic growth in China, fuel substitution in Japan and negative structural developments such as improving vehicle fleet fuel efficiency and the scaling back or phasing out of oil products subsidies in a number of developing countries.
- Potentially stringent climate change legislation represents a serious threat to the petroleum industry.
- Globally there may have been a supply surplus in excess of 1mmb/d in 2014.
- We believe the high water mark for the surplus will probably be in the first quarter of 2015. Approximate balance possible in 2016.
- Through mid-December 2014 US crude oil production continued to trend higher. Production in the four weeks to 26 December 2014 of 9.13mmb/d was up 12.8% on a year earlier.
- US petroleum demand grew by a modest 0.9% or so in 2014 to 19.2mmb/d. The trend in recent weeks is possibly pointing to accelerating growth.
- US petroleum inventories close to record levels, Cushing inventories trending higher.
- Large-scale US production shut-ins are extremely unlikely since prices are still above variable cost in the more productive shale plays of $25-35/barrel, including royalties and severance tax.
- Fully accounted costs for US shale plays cluster around $65-70/barrel but in the most productive zones of the Eagle Ford and Bakken could be $35-53/barrel.
- Sources of finance for sub-investment grade petroleum industry borrowers are rapidly evaporating reflecting both declining cash flow and the cessation of access to the bond market.
- US Gulf Coast refinery crack spreads came under heavy pressure from falling gasoline prices in late 2014.
- Brent and WTI forward curves are both in significant contango.

- Light crude benchmark prices of less than $55/barrel have now entered the marginal zone from a fully accounted cost perspective for a wide swath of projects globally.
- The trend in oil prices is likely to remain soft in the first quarter of 2015 reflecting a likely widening of the supply-surplus. This may constitute the nadir with spot lows of significantly under $45/barrel for Brent and $40/barrel for WTI possible.
- Oil prices to firm in the second half of 2015 and more particularly in 2016 as a pronounced slowdown in production growth tightens the market and the impact of swingeing cutbacks in capital spending become increasingly apparent.
- 2015 crude oil price forecasts sharply downgraded.
- US natural gas production has grown strongly in recent months and outpaced lacklustre consumption growth.
- US natural gas inventories are currently looking very comfortable seasonally.
- The rout in oil prices has negative implications for US LNG exports.
- US dry gas prices in December plumbed depressed levels by the experience of the past 10 years. Appalachian prices well below $1/mmBtu.
- US natural gas liquids prices were also under heavy pressure in the second half of 2014.
- Downgrading 2015 Henry Hub price forecast from $4.18/mmBtu to $3.95/mmBtu.
- Appalachian dry gas prices imply very marginal economics even on a cash basis. Wet gas producers in the region, however, may still be generating a cash contribution
- US rig count has shown signs of slippage of late but in the case of oil applications remains historically high.

Executive summary

Recent oil price developments: International light crude prices, along with the US inland benchmark WTI collapsed in the second half of 2014. From the respective high points in June and July to end December, Brent and WTI fell by approximately 50%. This took prices to $55/barrel for Brent and $54/barrel for WTI, which were 5 ½ year lows. In real terms Brent and WTI prices are now back to the levels of the early to mid-2000s after having spent the previous four years on a historically high plateau. At end December both Brent and WTI were in pronounced structural contango on the forward curve, indicating plentiful supplies. The price rout of the past six months or so reflects a combination of factors including surging non-OPEC production, growing evidence of lacklustre demand globally, stronger than generally expected OPEC production, OPEC's decision in late November not to support the market with production cuts and a robust trend in the dollar. Looking at the three major price collapses of the past 30 years, we believe the current one is most analogous to 1985/86 when OPEC similarly lost control of the market following a surge in non-OPEC supply and a period of lacklustre demand.

WTI-Brent spread: The WTI discount to Brent narrowed sharply in 2014. At end December the discount was a mere $1/barrel while for 2014 as a whole it averaged $5.9/barrel. This compares with about $12/barrel at end 2013 and an average $10.8/barrel for 2013. The narrowing trend has been despite the continuing Mid-Continent production build-up and the upturn in Cushing inventories in recent months. It appears to reflect WTI's greater exposure to robust US refining activity and the greater sensitivity of Brent to the growing Atlantic Basin supply surplus, weak markets in Europe and the business slowdown in China. At end December levels the WTI discount is significantly below pipeline costs from Cushing to the Gulf Coast of $3-4/barrel and well below rail costs of about $10/barrel. To facilitate shipments of oil to the Gulf we believe the WTI discount needs to be $6-7/barrel.

Inland US spreads: Prices in the inland US shale plays, notably, the Bakken in North Dakota, the Niobrara in Colorado/Wyoming and the Permian Basin plays of northern Texas/New Mexico, stand at significant discounts to WTI. This reflects a lack of local refinery capacity and consequent high logistical costs. Currently the Bakken and Niobrara and WTI Midland discounts stand at $4-5/barrel, which leaves prices below $50/barrel. Wellhead prices particularly in the Bakken are lower still at under $40/barrel.

Non-OPEC output: Non-OPEC petroleum output rose in 2014 by almost 2mmb/d or 3.5%, a record and slightly above forecasts of a few months ago. Once again, growth was driven largely by North America with the US contributing about 1.6mmb/d and Canada 0.2mmb/d. Brazilian output also showed clear signs of gaining momentum as the massive pre-salt fields began to be brought on-stream in earnest. Non-OPEC output growth is likely to decline significantly in 2015 and 2016 with the key factor being a slower pace of development in the US. We look for gains of about 0.9mmb/d and perhaps 0.5mmb/d respectively. In 2014 the regional breakdown is US 0.60, Canada 0.16, Brazil 0.17 with the rest of non-OPEC flat to down. Additionally we think a contribution of another 0.1-0.2mmb/d is possible from OPEC natural gas liquids (NGLs).

US output: US crude oil output continued to grow strongly in the closing weeks of 2014 driven by intensive development activity in the shale formations of the Great Plains and Texas. Based on EIA data, production in the four weeks to 26 December averaged 9.13mmb/d, up 1.05mmb/d or 12.8% on a year earlier. This is the highest level in more than 30 years. Looking at 2014 year-to-date production has climbed by 14.4% to 8.54mmb/d. The EIA is forecasting US crude production of 8.60mmb/d (+14.5%) in 2014 and 9.32mmb/d (+8.4%) in 2015. We believe the latter could be on the optimistic side given the likelihood of increasingly severe financing and capital expenditure constraints. NGL output also continued to grow strongly in 2014. In 2014 there was a gain of

13.9%. Given the likelihood of falling drilling activity combined with high rates of depletion in shale plays we tentatively look for little or no US production growth in 2016.

OPEC output: OPEC crude oil production has remained relatively buoyant in recent months at about 30.5mmb/d. This is above both the target of 30.0mmb/d and the 2014 fourth quarter 'call' of about 29.5mmb/d. OPEC announced at the end of November 2014 that it would maintain the 30mmb/d target until at least the next scheduled meeting in June 2015. Compliance with the target will probably be difficult to achieve given Saudi Arabia's desire to maintain market share and rising Iraqi production and exports. Libya and Iran are major wildcards for 2015 and could add to the difficulty of achieving target compliance. Significantly, the target is well above the call on OPEC output which the IEA puts at 28.9mmb/d in 2015.

Global demand: Expectations of oil demand for 2014 and 2015 have continued to be significantly downgraded by the IEA. It is now looking for growth of 0.7mmb/d (+0.7%) in 2014 and 0.9mmb/d (+1.0%) in 2015. Compared with three months ago these forecasts reflect downgrades of 0.2mmb/d and 0.4mmb/d respectively. As far as 2014 is concerned the key negatives have been the economic slowdown in China and quasi recessionary conditions in much of Europe and Japan. The recent downgrade for 2015 stems from softening economic conditions across a range of developing countries and oil producers with Russia very much to the fore in this context. Tending to dampen demand in several developing countries of late has been energy subsidy reductions and adverse exchange rate movements against the dollar and in several Latin American countries quasi-recessionary forces. US domestic demand probably increased by a modest 0.9% in 2014 and could grow by a similar amount in 2015 assuming GDP growth of 2.4% to 3.0%. Overall, given the sluggish economic backdrop in a large part of the OECD outside North America, the weakening economic picture in the developing world and the subsidy issue we believe the risks are to the downside for global demand growth in 2015. We suspect the outcome will be similar to 2014's gain of 0.7mmb/d.

Oil supply/demand balance: The oil market in 2014 was comfortably in surplus. This may have exceeded 1.0mmb/d with the key factor being the record surge in non-OPEC output of almost 2mmb/d at a time of lacklustre demand growth. For 2015 we look for another surplus albeit at a lower level than in 2014. The surplus could be about 0.3mmb/d reflecting growth in global supply and demand of about 1mmb/d and 0.7mmb/d respectively. The former includes OPEC NGLs and heroically assumes OPEC crude output unchanged from 2014. For 2016 we look for a balanced market with the key factor being the choking off of output growth in the US.

Shale oil economics: With WTI below $55/barrel and regional prices in the Bakken and elsewhere below $50/barrel US shale oil economics has clearly entered the marginal zone for new wells on a fully accounted basis. This conclusion is supported by our own analysis and is supported anecdotally by comments made by Bakken pioneer, Continental Resources, and others. The consultants, Wood Mackenzie, have in fact suggested that fully accounted costs for shale projects 'cluster' around $65-70/barrel so $50/barrel is towards the front end of the cost curve. Note, costs are tending to fall courtesy of advances in technology, improving techniques and declining input prices for items such as OCTG, diesel and oilfield services. Variable costs, which establish the benchmark for assessing short-run viability on existing wells, are estimated at $25-35/barrel. This includes site production costs, state severance tax, shipment to a local storage hub and royalties.

Shale oil financing: Upstream petroleum industry capital spending over the past few years has been running at $100bn or more annually. It has largely been financed by a combination of internally generated cash flow, bank debt and the publicly traded debt markets. Given that many of the operators are rated sub-investment grade a large part of the debt raised has been in the form of junk bonds. The problem now is that cash flow is rapidly evaporating while access to debt markets has effectively been cut-off for sub-investment grade or even low end investment grade borrowers.

The upshot will be sharp cutbacks in spending on exploration and development projects and corporate overhead. Inevitably this will impact production rates with a short lag.

Crude oil price forecasts: Near term the market backdrop is still looking bearish for oil prices due to a likely widening in the supply surplus in the first quarter of 2015. This period may, however, represent the nadir on a quarterly average basis. Over the balance of 2015 we expect the price trend to firm reflecting a combination of declining petroleum industry investment, particularly in the shale sector, along with evidence of slowing non-OPEC output growth to boost market sentiment and prices. As these factors become more pronounced we see scope for a significant upturn in prices in 2016. Due however to much weaker than expected carryover from the fourth quarter of 2014 and the likely persistence of bearish fundamentals in early 2015 we are sharply downgrading our 2015 average Brent and WTI price forecasts . Our forecasts call for reductions in Brent to $52.5/barrel and in WTI to $49.0/barrel. For 2016 we are looking for $72.5 and $67.5/barrel for Brent and WTI respectively. Medium term we believe there could be a price ceiling at around $75-80/barrel. This stems from the new found elasticity of supply through shale oil development, the sizeable capacity additions scheduled to come on-stream in Brazil, Canada, Iraq and Kazakhstan and structural forces tending to dampen demand growth. The last mentioned factor relates to trend improvements in automotive and aviation fuel efficiency and likely further cutbacks in energy subsidies in the world of developing countries and petroleum producers.

US natural gas fundamentals: US natural gas production grew strongly in 2014 driven by the new prolific Appalachian shale plays (Marcellus and Utica) plus by-product gains stemming from shale oil plays. Through September 2014 production was up 5.1% on a year earlier while in early December the consultancy Bentek Energy pointed to a year-on-year gain of 13%. Post the first quarter, which was characterised by extreme weather, US natural gas demand in 2014 was lacklustre with growth lagging production by a significant margin. For 2014 as a whole the EIA is forecasting demand growth of 3.2% but this looks vulnerable based on recent trends. As of mid-December natural gas inventories looked very comfortable seasonally particularly in view of there being no extreme weather on the near-term horizon.

US natural gas prices: US natural gas prices plunged between late November and late December to depressed levels based on the experience of the past 10 years. The traditional benchmark Henry Hub, Louisiana quote fell from $4.41 to $2.75/mmBtu while the Dominion South Hub price in Appalachia declined from $3.84 to $0.95/mmBtu. Recent prices we believe were approaching or around variable cost for the average dry gas producer. The price rout largely reflected a combination of strong production growth, particularly in the Appalachian Marcellus and Utica plays, mild weather conditions in the Midwest and North East and the comfortable level of inventories. US NGL prices also plunged in the closing months of 2014 pretty much in tandem with crude oil. For 2014 as a whole the Henry Hub quote averaged $4.36/mmBtu buoyed by a buoyant first quarter. Our forecast for 2015 has been cut from $4.18/mmBtu to $3.95/mmBtu reflecting bearish carryover fundamentals. For 2016 we do not expect a radically different market backdrop than in 2015 abstracting from extreme summer and winter weather conditions. It is possible, however, that market sentiment could be supported by slower production growth stemming from both likely cutbacks in dry and wet gas drilling activity and lower shale oil by-product gas output. Provisionally our 2016 Henry Hub price is $4/mmBtu, which implies a significant cash contribution but not a fully accounted profit for the average dry gas producer. Note wet gas producers tend to have superior economics by virtue of the extra contribution from liquids.

Crude oil market dynamics

Price overview

Market developments: Price collapse most analogous to 1985/86

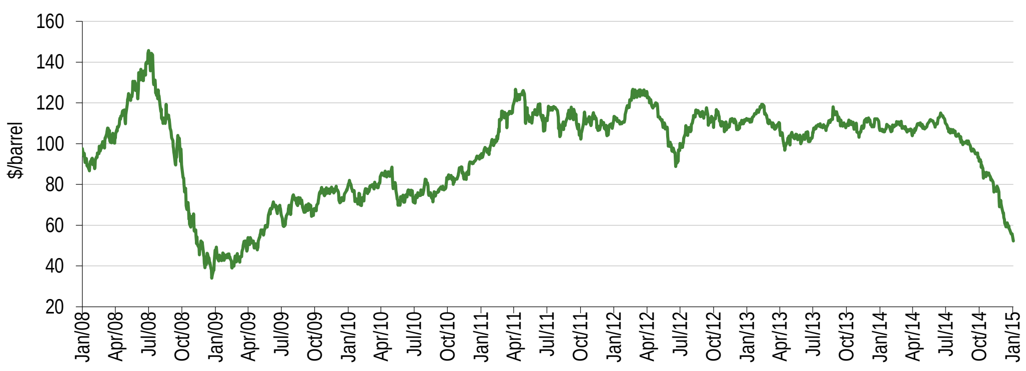
Recent months in retrospect: The collapse in international crude oil prices in the second half of 2014 was unquestionably the defining feature of oil markets in 2014. It is perhaps now difficult to comprehend that bullish sentiment predominated through much of the first half. This reflected optimism concerning the demand outlook and a spate of geopolitical convulsions relating to secession in Ukraine, intense factional fighting in Libya and IS's (Islamic State's) dramatic conquest of much of eastern Syria and western and northern Iraq. By late June some industry observers predicted that Brent would rise from the then recent high of about $115/barrel on 19 June to $130/barrel or more. Instead, there was a price rout, which should provide a salutary warning concerning the pitfalls of oil market prediction.

Since late June 2014, the decline in oil prices has unquestionably been the most severe over the past five years but has yet to eclipse the most pronounced slumps of the past 30 or so years. These occurred between late 1985 and mid-1986, early 1997 and late 1998 and in the second half of 2008 and resulted in declines in Brent from peak to trough of 72%, 59% and 77% respectively. Additionally there was a sharp drop in prices in the second half of 1990 but this followed a price spike associated with the Iraqi invasion of Kuwait. Once a coalition was assembled to confront then Iraqi President Saddam Hussein, prices rapidly returned to normal. The mid-1980s price slump reflected the following:

- A surge in non-OPEC output stemming to a large extent from the North Sea and Alaska.
- A period of soft demand in the aftermath of the five-fold increase in oil prices from the mid-1970s through the early 1980s.
- A decision by Saudi Arabia to protect its market share.

In 1997 and 1998 prices came under heavy pressure from the Asian financial crisis and a surprising increase in OPEC output. The origins of the dramatic price slide of 2008 were different than the other two and reflected a decline in global demand following the acute global financial crisis in the third quarter of the same year. In early 2009 the market stabilised once the spectre of a financial collapse was exorcised and OPEC implemented a programme of production cutbacks. We believe the recent rout in oil prices is most analogous to that occurring in 1985/86. In fact, history appears to be repeating itself with OPEC losing control of the market amidst surging non-OPEC output growth and lacklustre demand.

Exhibit 1: Brent crude oil price trend



Source: Bloomberg

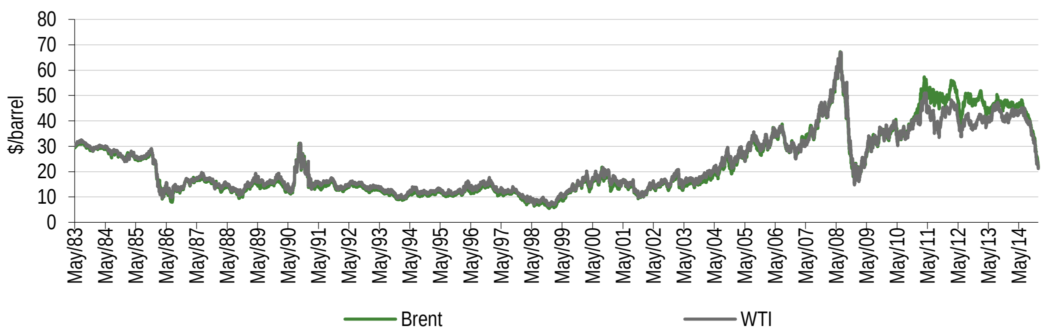
The low points for Brent and WTI in 2014 came at the end of December. Brent plumbed $55.8/barrel while WTI was at $53.3/barrel. There were further declines to about $50.0 for Brent and $48.0 for WTI in the early days of 2015. The end 2014 prices were down 52% and 51% on the June and July 2014 highs respectively and were the lowest since the second quarter of 2009. Compared with a year earlier, the end December lows were down 45% for Brent and 48% for WTI. Despite the second-half plunge, it is interesting to note that for 2014 as a whole averages for the year were still historically high at $99.1/barrel for Brent and $93.0/barrel for WTI. On a yearly average basis in 2014, Brent traded at the fourth highest and WTI the fifth highest on record. Historically, high yearly averages were, of course, a function of buoyant prices in the first half.

Exhibit 2: WTI crude oil price trend

Source: Bloomberg

What do real prices look like? In real terms, oil prices were running at historically high levels between 2010 and the first half of 2014 and even following the plunge of recent months remain above historical lows. Using Bloomberg data, WTI deflated by the US consumer price index, with a 1983 base year, averaged $41/barrel between 2010 and the first half of 2014. Post 1983 WTI in real terms only traded significantly higher in the second half of 2007 and first half of 2008 when a spot high of $67/barrel was reached. By end 2014, however, the deflated WTI price was down to about $22/barrel, which was in line with the levels prevailing in the early to mid-2000s but still above the lows of 1986, 1998 and 2008 of between roughly $7 and $15/barrel. From a historical perspective this might point to downside price risk from the end 2014 level for WTI and Brent but it should be borne in mind that the real costs of finding and developing the marginal barrel have probably trended higher over the years.

Exhibit 3: WTI and Brent real price trend 1983-2015



Source: Bloomberg

What has caused the price rout? Many of the factors driving oil prices lower in recent months have been apparent for some time and reflect weak fundamentals, a strong dollar and the waning sensitivity of markets to geopolitical concerns. It should also be noted that commodities in general came under significant pressure in 2014 with the S&P GSCI Index, for example, falling by 33% during the year. The key negatives for oil of late have reflected the following:

- A downgrading of petroleum demand forecasts by bodies such as the IEA, EIA and OPEC during the third and fourth quarters. This has reflected a broad malaise in the world economy combined with possibly deeper structural issues regarding use. Slower than expected demand growth in China appears to have been particularly influential in dampening market sentiment.

- A consistently more robust trend in OPEC output than generally expected. During 2014 OPEC production has tended to trend above the 'call' (world demand less OPEC crude supply and OPEC natural gas liquids and un-conventionals). Significantly in this context, Saudi production has remained at a historically high level in recent months, the trend in Iraq has been more buoyant than many had assumed possible and Libyan output, although erratic, has surprised to the upside.
- OPEC's decision at the 27 November meeting to maintain the long-established crude oil production target of 30mmb/d. Although comments by Saudi Arabia in advance of the meeting suggested that a significant cut of perhaps 1mmb/d was unlikely, OPEC's failure to act in the face of slumping prices disappointed some sections of the market and led to a sharp sell-off in prices on 28 November.
- The continuing robust trend in the dollar which at the margin tends to depress demand for oil from weaker currency zones, as for other commodities.

An interesting development during the second half of 2014 was the market's apparent willingness to overlook or downplay some potentially important geopolitical issues in the Middle East, North Africa and Ukraine. There are a number of factors at play. An underlying one relates to the growing independence of world markets from OPEC thanks to growing North American supply. Saudi Arabia, it might be added, has also tended in recent years to effectively fill the void in the event of outages or to offset sanctions. Specifically in the case of IS, the threat to oilfields in Iraq has been neutralised following the commencement of the US-led bombing campaign last August. Tumult in Ukraine remains a concern from a broad geopolitical perspective but is unlikely to lead to an interruption to Russian oil supplies.

Saudi Arabia unwilling to act as the swing producer, decides to test the unconventional plays. The motivation behind OPEC's decision to maintain its 30mmb/d production target probably stems from two factors. First, Saudi Arabia's unwillingness this time round to act as the swing producer. It may have decided that the magnitude of the task to balance the market is just too great given that many of its fellow members may be none too keen on restraining output growth. The second, possibly key motivation, is that Saudi Arabia wishes to test the staying power of the shale and other unconventional plays at prices substantially below $100/barrel. Saudi Arabia's thinking seems to be that a sustained period of depressed prices will at least radically slow if not roll back the advance of production from un-conventional sources. In this trial of strength, Saudi Arabia has the advantages of low costs and substantial foreign exchange reserves of about $745bn, equivalent to approaching one year's GDP. From an OPEC perspective the problem is perhaps that in testing the resilience of the unconventional plays that it will severely strain the finances of some of the weaker members of the organisation to breaking point.

We believe that the oil price rout of the past six months or so is broadly analogous to the situation applying in late 1985 and early 1986. Effectively, US shale and Canadian oil sands are the new Alaska and North Sea and once again Saudi Arabia appears to be focusing on market share.

Supply-demand dynamics

Non-OPEC supply: Record surge in 2014, much slower growth in 2015 and particularly 2016

2014. The trend in non-OPEC liquids output has remained robust in recent months and has tended to exceed expectations formulated at the beginning of 2014. After running at about 56.0mmb/d in the first half, production averaged 56.6mmb/d in the third quarter and reached 57.3mmb/d in November according to the IEA. In the fourth quarter output has shown year-on-year gains of about 1.5mmb/d somewhat down on the pace of 2mmb/d plus (3.8% year-on-year) in the first half but still an impressive performance. For 2014 as a whole the IEA is now looking for non-OPEC liquids output of 56.4mmb/d, up 1.9mmb/d or 3.3% on a year earlier. This is also 0.3mmb/d above a few months ago and compares with growth in 2012 and 2013 of 0.5mmb/d or 0.9% and 1.3mmb/d or

2.4% respectively. Significantly, the IEA's non-OPEC production growth forecast for 2014 is in line with that of the EIA.

Non-OPEC output growth in 2014 has been a record and has also propelled the absolute level to an all-time high. The performance is even more impressive bearing in mind that it is net of the natural decline rate for existing fields, which is probably running at about 5% pa. Output growth continues to be very much a North American phenomenon. Overall, production in the region is estimated by the IEA to have risen in 2014 by 1.60mmb/d or 11.3% to 15.81mmb/d. This would imply North America accounts for 84% of non-OPEC growth overall. Rapid development of shale and tight reservoir formations in both the US and Canada has remained the key driver behind non-OPEC growth but development activity in the Canadian oil sands has also been highly significant. Based on IEA data, output growth in 2014 has been 1.44mmb/d in the US and 0.16mmb/d in Canada. We regard these estimates as conservative based on rates of travel. Significantly, the EIA estimates that North American output rose by 1.77mmb/d in 2014 with the US accounting for 1.50mmb/d and Canada 0.27mmb/d.

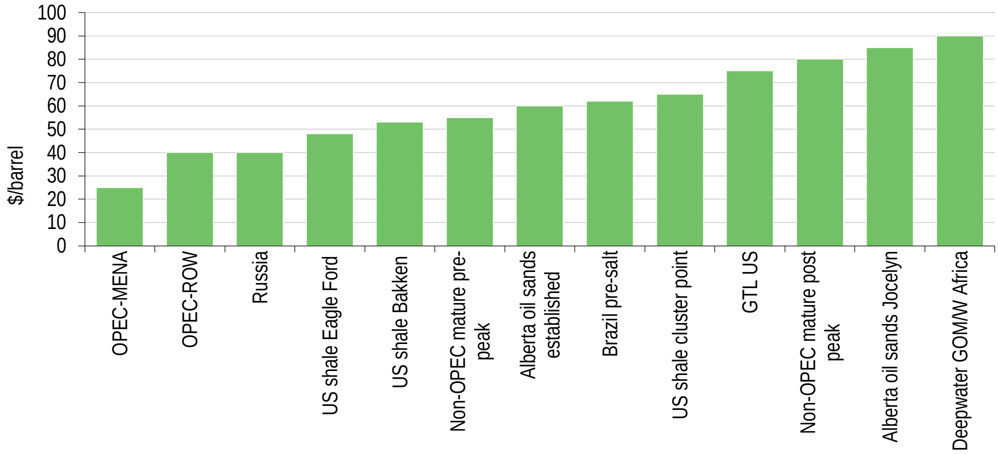
Production gathering momentum in Brazil. Outside North America, the key areas of growth in 2014 were Brazil, China and Russia. The gains in the latter two were modest at about 20,000b/d and 50,000b/d respectively. Growth in Brazil was, however, considerably greater. Indeed, Brazil was easily the most interesting development story outside North America in 2014. Significantly, production here trended higher during the year as development activity in the giant oilfields of the offshore pre-salt zone (recoverable resources of possibly well over 50bn boe), discovered by Petrobras in the Campos and Santos basins about eight years ago, has gained momentum. Clearly, high rates of depletion of around 10% a year on legacy Brazilian wells is now being more than offset by new production facilities.

Petrobras connected 46 pre- and post-salt wells to production facilities through the first nine months of 2014 against 24 a year previously. A further 16 were scheduled for the fourth quarter making 62 for the full year. This compares with 34 in 2013. The FPSO (floating production storage and offloading) vessel Cidade Mangaratiba came on-stream in mid-October and should have been followed by the Cidade de Ilhabela and P-61 by 2014 year-end. In total, 24 FPSOs are scheduled for installation between 2014 and 2018 with production of 0.15mmb/d planned for each vessel. Note that flow rates reported from pre-salt wells have been outstanding in a number of cases at 20,000 to over 30,000b/d. These are perhaps twice the flow rates of the most prolific wells in the North Sea and Gulf of Mexico.

Based on Petrobras data, gross crude oil and natural gas liquid output from its operated Brazilian wells was up year-on-year in the 10 months to October 2014 by 7.3% to 2.11mmb/d. Reflecting non Petrobras operations, production in Brazil would be about 0.14mmb/d higher. In addition, the country produces over 0.4mmb/d of ethanol. Gross Petrobras production in October was 13.5% higher than a year earlier at a record 2.27mmb/d. In the same month pre-salt production averaged 606,000 b/d, 27% of the Brazilian total. A record 640,000b/d was reported on 28 October. Given the rapid build-up of infrastructure both in recent months and scheduled, Brazilian production should increase strongly in the fourth quarter of 2014. We believe gross production for 2014 as a whole from Petrobras operated facilities could come in at about 2.15mmb/d, up 0.18mmb/d or 9% on 2013.

A question that arises in the wake of the plunge in oil prices in the second half of 2014 concerns the viability of Brazil's pre-salt reserves. Reflecting the technical (ultra-deepwater of 2,000-2,500m, ultra- deep drilling down to 4,000m below the sea floor), logistical (350km offshore) and industrial challenges (high local content requirements) of pre-salt development many observers consider that costs are stratospherically high. Petrobras, however, has always disputed this view. In its latest presentation the company suggests that breakeven prices for signed-off projects are between about $45 and $55/barrel, although it is not clear if this includes an allowance for the cost of capital and transportation to the coast and the exchange rate assumption used. Allowing for these two factors might lift fully accounted costs to between $52 and $62/barrel. Breakeven within this range is clearly within the international mainstream on the fully accounted petroleum production cost curve, which broadly runs from $25-100/barrel globally.

Exhibit 4: Petroleum cost curve



Source: Edison Investment Research. Note: Costs are fully accounted, pre-peak refers to field pre-peak production; post-peak is field post peak production; GTL US is based on the Sasol Westlake, Louisiana project.

We believe that at least three factors point to pre-salt development economics being more favourable than might otherwise be expected. These are critical mass thanks to the scale of pre-salt development, very low finding costs of $2/barrel or less and truly impressive well flow rates. It might also be added that potential downward pressure on steel prices in the wake of falling steelmaking raw material costs provides scope for a positive surprises on development costs.

In many ways the key issue now for Petrobras is financing, given the heavy demands relating to pre-salt development as well as downstream expansion over the next two or three years. Petrobras has indicated that net funding needs of about $1.1bn a year between 2014 and 2018 will be financed exclusively from debt. Conceptually this should be feasible given a not unduly strained balance sheet and the investment grade (S&P BBB-) credit rating. Clearly, however, the plunge in oil prices in recent months along with the corruption allegations swirling around the company have made Petrobras's financial backdrop considerably more challenging than hitherto. The allegations have delayed third-quarter reporting and may ultimately lead to a substantial write down but are unlikely to impact cash. There is also the possibility of a technical default due to the failure to report third-quarter financials in a timely fashion.

In the final analysis the Brazilian government and majority shareholder has intimated that it will underpin Petrobras financially in the event of extraordinary distress. Indeed, we would argue it is inconceivable that the Brazilian government would allow pre-salt development and downstream expansion to be interrupted. Further exploration activity may, however, be put on hold.

2015/16

Non-OPEC production growth will probably slow significantly in 2015 but it should still be highly meaningful. Based on its December 2014 reports, the IEA was looking for a gain in 2015 of 1.28mmb/d while the EIA was forecasting 0.84mmb/d. Once again, North America will probably lead the pack. The IEA's forecasts call for the region show a gain of 1.09mmb/d, which is equivalent to 85% of the overall total. Other areas showing significant gains in 2015 are expected to be Brazil (0.17mmb/d) and Colombia (0.12mmb/d). The EIA has a similar view on North American production in 2015 with a forecast gain of 1.10mmb/d. This is partly offset by declines in output in several countries/regions of which the most significant are Mexico (0.05mmb/d), North Sea (0.20mmb/d), Azerbaijan (0.06mmb/d) and Russia (0.05mmb/d). The EIA's forecast of a 0.20mmb/d decline in the North Sea follows a broadly unchanged showing in 2014 and reflects the by now familiar depletion issue, particularly in the UK. Significantly, CNOOC-Nexen has indicated that the UK's largest field, Buzzard, is now entering the decline phase in its life cycle. Plunging oil prices, a high tax regime and challenging technical issues could conceivably point to an acceleration in the downward trend in the UK medium term.

Oil priced at $90-$100/barrel provided a pretty favourable backdrop even for relatively exotic exploration and development projects, particularly bearing in mind that technological advances in the shale arena were tending to exert downward pressure on costs. Assuming a continuation of the OPEC pricing umbrella we would have expected non-OPEC production to grow by perhaps 1mmb/d or more on average over the balance of the decade. Supporting this view would be such factors as follows:

- Continuing rapid development of tight oil reservoir formations in the US and Canada.
- The potential to export the shale revolution from North America to other parts of the world including Russia. Prospective shale resources are widely distributed around the globe which should in principle provide major development opportunities. Unlike deep-water projects the shale exploration and development cycle is relatively short.
- Ongoing development of the Alberta oil sands in Canada, one of the world's largest petroleum resource bases.
- The planned unlocking of the giant pre-salt discoveries offshore Brazil.
- The belated start-up of the giant Kashagan project in the Caspian Sea. This has been delayed by a host of technical issues but production should be finally getting underway in earnest from 2016.

In addition, Arctic drilling opportunities might have surfaced although it is unlikely that much oil would have been brought ashore much before 2020.

The key issue now for non-OPEC oil production medium term is the potential impact of the plunge in oil prices in recent months assuming, of course, that the new levels are broadly sustained for more than a few months. Based on company announcements, particularly in North America, the lower price regime will clearly begin to impact exploration and development activity in 2015, although we suspect that production may not be unduly affected until the second half, due to development and well completion lags. We think there is very little chance in 2015 of US production being shut-in on a broad scale at virtually any conceivable price level. A decision on shut-ins is related to variable costs and in reality these are still significantly below current light crude prices of about $50/barrel. We believe that the impact on US production of cutbacks in capital spending on production will become considerably more apparent in 2016. Note here that the issues for operators will not just be a question of breakeven prices but also financing. Significantly, US credit market participants are suggesting that oil and gas companies rated as sub-investment grade or even the lower echelons of investment grade are already closed out.

Assuming light oil prices of $50-60/barrel on average in 2015, we believe that non-OPEC output growth could come in at about 0.9mmb/d in 2015 and 0.7mmb/d in 2016. Growth in 2015 might comprise US 0.6mmb/d, Canada 0.15mmb/d, Brazil 0.17mmb/d with the rest of non-OPEC flat to slightly down. We suspect that the US for the first time in several years will make little or no contribution to non-OPEC output growth in 2016.

What is looking vulnerable? From a medium-term exploration and development perspective a sustained period of sub $70/barrel oil would probably have profound implications. Broadly speaking this level or even above corresponds to the breakeven price for many of the more challenging oil development projects including shale/tight oil, oil sands and deepwater/ultra-deepwater. One category that looks particularly vulnerable in a depressed price environment is Arctic drilling given high costs and controversial environmental issues. It could also be argued that US shale plays are vulnerable given their exposure to fickle capital market financing and the relative ease with which development can be switched on and off.

Overall, we believe that if oil trends in a range of say $50-65/barrel over a period of a year or more, new large scale capital intensive deepwater and oil sands projects will probably be deferred pending a recovery in prices. Large scale investment cutbacks would, of course, ultimately sow the seeds of the next boom in prices assuming that the demand trend remained reasonably firm in the intervening period.

OPEC supply: Compliance with 30mmb/d will be difficult

2014

OPEC crude oil production tended to surprise to the upside in 2014 and has consistently been above the 'call' rate. Based on IEA data, production was 30.0mmb/d in the first quarter, 30.1mmb/d and 30.5mmb/d in the third quarter. After running at a 14-month high of 30.84mmb/d in September production has slipped but at 30.64mmb/d in October and 30.30mmb/d in November it not only remained well above the call of about 29mmb/d but also OPEC's production target of 30.0mmb/d. Allowing for some modest slippage in December we think fourth-quarter production could average about 30.3mmb/d in the fourth quarter and 30.2mmb/d for 2014 as a whole. This would be only 1% down on 2013 and a relatively high level by the standards of recent years. In addition to crude, OPEC produced in 2014 about 6.4mmb/d of natural gas liquids and un-conventionals, up 0.1mmb/d on 2013. Overall, OPEC accounted for about 39% of world oil supply in 2014.

The arguably surprising strength of OPEC production in 2014 can largely be attributed to three factors. These were historically high levels of output in Saudi Arabia, a rising trend in Iraq and a sharp rebound in Libyan production post the turmoil in the country in the first quarter. As far as Saudi Arabia is concerned, it should be noted that production was running at around or close to a 30-year high in the third quarter as it attempted to both compensate for shortfalls elsewhere in OPEC and cater for strong domestic demand during the summer months. At the beginning of 2014 many observers, including the IEA, were deeply pessimistic about the trend in Iraqi output. During the year, however, production trended significantly upward despite the outage at the large Kirkuk oilfield in the north of the country related to sabotage to the export pipeline to Ceyhan, Turkey. Through the 11 months to November 2014 production averaged about 3.3mmb/d, up 0.2mmb/d or 6.5% on a year earlier. In November itself production was running at 3.4mmb/d, which was approaching a 40-year high. The positives for Iraqi production have been field refurbishment activity in the south of the country, an expansion of export terminal capacity offshore Basra and development activity in the semi-autonomous region of Kurdistan. Importantly, the latter includes the installation of an export pipeline to Ceyhan.

In late 2014 Iraqi exports were running at about 2.8mmb/d with approximately 2.54mmb/d stemming from the southern fields and the rest from Kurdistan. In early December 2014 an important agreement was announced between the central government in Baghdad and the Kurdistan Regional Government (KRG), which will potentially provide a significant boost to both production and exports. The agreement establishes a legal framework for KRG exports, thereby breaking a longstanding impasse on this subject and critically provides for the restart of exports from Kirkuk using the KRG pipeline to Ceyhan. It should be noted that the KRG captured the Kirkuk oilfields in the summer months to prevent them falling into the hands of IS. The aim is to ultimately ship 0.3mmb/d from Kirkuk in addition to the existing KRG shipments of about 0.25mmb/d. Shipments are expected to start in December at about 0.15mmb/d. The Iraqi Oil Minister has suggested that exports in 2015, including from the KRG, will average about 3.2mmb/d, up an estimated 0.5mmb/d on 2014. Total Iraqi production on this basis would probably be about 3.8mmb/d. Iraq has downgraded its medium term ambitions of late but is still planning output of 7mmb/d by 2020. This compares with 9mmb/d previously.

Libyan output has followed an erratic path in 2014 but the overall flow has probably been far greater than most observers would have dreamt possible at the beginning of the year. Any recovery in output from the low point early in 2014 was expected to be severely constrained by a combination of a fraught security situation reflecting fierce factional fighting and technical issues related to damaged facilities and a lack of maintenance. After running at 0.25mmb/d early in 2014, production rebounded to almost 1mmb/d in September and October. In November, however, production slipped back to towards 0.5mmb/d as a renewed upsurge in fighting closed the largest field, El Sharara. We believe there was further slippage to about 0.2mmb/d in December. Assuming the fighting subsides, recent experience suggests production could quickly rebound to more than 0.5mmb/d. For reference Libyan production was running at 1.4mmb/d in early 2013 and was about 1.6mmb/d prior to the overthrow of Colonel Gaddafi in 2011.

The short medium-term outlook for Libyan oil production is unusually uncertain given the continuing factional turmoil in the country and indeed the existence of two governments. In all probability the path will remain erratic.

2015

We believe that OPEC will have considerable difficulty in keeping within its self-imposed crude oil output ceiling of 30.0mmb/d in 2015. The caveat is that there are no major outages due to geopolitics or other matters. The key issues here are as follows:

- Saudi Arabia, traditionally the swing producer, for the moment at least seems intent on maintaining market share.
- Iraq, the number two producer, is not only increasing capacity but as we have noted is looking to restore output at its Kirkuk operations and has seen rising production in the KRG.
- Libya will probably be aiming to boost output from the depressed levels of the past two or so years, assuming that factional strife subsides and political life in the country shows the semblance of normality.
- Several producers, with Venezuela perhaps being the most notable, have acute budgetary problems at anything like current oil prices. These countries in effect have no option other than boost output as much as technically possible.
- Iran could return to full production in the second half of 2015 if a comprehensive agreement can be reached with the five permanent members of the UN Security Council plus Germany (P5+1) over the former’s nuclear programme. The new deadline for completion of the talks is 30 June 2015. According to the IEA, in the event of sanctions being lifted Iran’s production could be raised by 0.5mmb/d to 0.8mmb/d within a short lag of a few months.

Investment also potentially vulnerable in OPEC. A sustained period of depressed oil prices has negative implications for OPEC petroleum industry investment, much the same as for non-OPEC world. The most obvious vulnerability is in those areas with relatively high costs and operations under the control of western oil companies. Deepwater Angola and Nigeria spring readily to mind in this context. Although development costs are low, Saudi Arabia would now seem even more unlikely to expand capacity from the current 12.5mmb/d to the sometimes mooted 15.0mmb/d for the foreseeable future. Given its dependence on private oil companies for development, Iraq may also have difficulty in attracting sufficient finance to achieve its 7mmb/d 2020 target.

One of the most interesting issues currently surrounding OPEC oil production is what happens in Venezuela, home to the world’s largest proven oil reserves. The country has a heavy debt repayment schedule over the next few years exacerbated by nationalisation liabilities, rapidly dwindling foreign exchange reserves, declining cash flow due to plunging oil prices and a very real risk of default. In these circumstances petroleum industry investment is likely to suffer with negative implications for production as has indeed been the case since the advent of Bolivarian socialism when Colonel Hugo Chavez came to power in 1998. Given the rapidly worsening economic backdrop in Venezuela, there is the possibility of a civil strife erupting in Venezuela in the coming months, possibly resulting in disrupted oil production. National Assembly elections are scheduled in Venezuela in late 2015 but it is not clear that the ruling Socialist party would accept an unfavourable result at the ballot box.

Global demand: Sluggish picture, price subsidy regimes unwinding

2014

Global oil demand in 2014 proved considerably less buoyant than expected at the beginning of the year. Based on its latest forecast, the IEA is anticipating growth for 2014 of 0.68mmb/d or 0.7% to 92.4mmb/d, the lowest annual gain in five years. The EIA and OPEC both take a more bullish view with forecast growth of 0.90mmb/d and 1.05mmb/d respectively or around 1%. Earlier in the year the IEA, EIA and OPEC had been looking for demand growth in 2014 of more like 1.1 to 1.4mmb/d, so expectations have been significantly downgraded. For perspective, the IMF's world GDP growth forecast for 2014 reported in October is 3.3%. This was 0.4 percentage points lower than the April forecast.

The sluggish demand growth picture in 2014 was particularly apparent in the second quarter when, according to the IEA, volume was up only 0.3mmb/d year-on-year. Subsequently, the IEA estimates that year-on-year growth increased from 0.6 to 0.7mmb/d but this remains subdued. Overall, sluggish growth seems to have reflected three broad forces as follows:

- The decidedly lacklustre economic backdrop in OECD-Europe, which generates about 15% of world demand. The IEA is forecasting a drop in demand of 0.2mmb/d to 13.5mmb/d in 2014 which maintains a downward trend that has been apparent since 2006. The decline in OECD-Europe demand since 2006 has been about 2.2mmb/d or 14%.
- Slowing economic growth and negative structural demand influences in China. Negative structural influences in this context include improving vehicle fuel efficiency and a switch from diesel and gasoline to CNG and LNG in transportation equipment applications, particularly in urban areas. The latter is being driven partly by economic considerations and partly concern over emissions. More broadly on the emissions front, measures to limit vehicle use in urban areas are probably beginning to have an impact on fuel consumption while in the industrial sector there is a tendency for fuel oil to be substituted by natural gas. It has been increasingly apparent over the past few years that the days of runaway growth in oil demand in China are over. The IEA is looking for Chinese demand growth of 0.25mmb/d or 2.5% to 10.35mmb/d in 2014. This compares with growth of 7% pa between 2000 and 2010 and absolute gains in some years during that period of over 0.5mmb/d.
- Sliding oil demand in Japan which accounts for about 5% of the global total. This reflected a lacklustre economy and most significantly substitution in power generation as alternative lower cost fuels became readily available. For 2014 the IEA estimates a drop in Japanese demand of 0.23mmb/d or 5.1% to 4.30mmb/d.

An underlying factor that is tending to curb oil demand growth globally is the improving fuel efficiency of vehicle and aviation fleets. This is being driven in part by technological advance and in part by tightening regulation. In the US the current CAFÉ standards are scheduled to almost double mileage/gallon on new light vehicle sales between 2012 and 2025. A similar regime is in force in Europe. Structural changes in demand increasingly imply declining sensitivity to developments in the economy, particularly in the OECD world and China.

Not surprisingly and has been the case for many years, demand growth was driven by the non-OECD world in 2014. According to the IEA, growth here was 1.10mmb/d, which comfortably more than offset a decline of 0.42mmb/d in the OECD. In the OECD demand was broadly flat in North America and down 0.2mmb/d in both Europe and Asia/Oceania. Significantly, in the non-OECD world, demand in 2014 rose by a strong 0.28mmb/d or 4% in Saudi Arabia and 0.10mmb/d or 3.2% in Brazil. The latter occurred despite decidedly sluggish economic growth.

2015

The expectation among the likes of the IEA and EIA is for global oil demand growth to strengthen in 2015, reflecting what is expected to be a more buoyant economic backdrop. Based on the IMF's GDP growth forecast of 3.8%, the IEA is forecasting that global oil demand will increase by 1.14mmb/d or 1.2% to 93.6mmb/d. The EIA's forecast calls for a very similar gain of 1.12mmb/d. We believe the IEA's and EIA's forecasts are plausible assuming global economic growth of approaching 4%. In our view, however, demand forecasts are possibly on the high side bearing in mind the likely carryover weakness in OECD Europe, the likelihood of further declines in Japanese oil consumption as nuclear plants are brought back on-stream and the increasingly significant structural negatives noted above. Arguably, demand growth in 2015 might be closer to 0.8-0.9mmb/d than the 1mmb/d plus suggested by the IEA and EIA.

In terms of the structural negatives it should be noted that fuel subsidies in a number of non-OECD economies are being scaled back or even phased out. Two of the most significant moves announced on this front of late have been Indonesia's subsidy cutback and India's announcement in October that it is phasing out diesel subsidies altogether. Interestingly, Angola a member of OPEC and the second largest oil producer in Africa, has recently hiked diesel and gasoline prices. In our view subsidy cutbacks are increasingly likely given pressure on budgets and specifically in the case of oil producers the potential to increase export capacity of a lucrative product. Arguably, one of the more likely candidates to eliminate subsidies in the coming months is Brazil given the heavy cash needs of Petrobras. Indeed, Brazil is probably already moving in this direction following recent refined product price hikes. Falling prices on world markets have, of course for the moment at least, tended to make the withdrawal of subsidies more palatable for consumers.

Medium term, which we define as the balance of the decade, we believe global oil demand growth is unlikely to greatly exceed 1mmb/d or about 1% pa. This reflects the trend to slower global economic growth in recent years and the structural negatives, including subsidy reduction/elimination, tending to depress demand. In a weak year for economic growth it would not be surprising if demand grew by less than 0.5mmb/d. Medium term the petroleum industry probably needs to become increasingly concerned about stringent climate change legislation/regulation. The lead up to the UN Climate Change Conference in Paris in December 2015, which will seek to impose globally a legally binding emission reduction regime will be crucial in this regard. Climate change protagonists argue that to limit global warming to 2 degrees above pre-industrial levels a substantial part of the world's existing petroleum reserves (also applies to coal and natural gas) will need to be left unexploited. The spectre of stranded oil assets looms on the not too distant horizon.

Global supply/demand balance: Surplus likely to narrow in 2015/16

It has been apparent for some time that the oil market was significantly in surplus in 2014. Assuming an increase in non-OPEC production of 1.9mmb/d in line with IEA forecasts, a rise of 0.1mmb/d in OPEC NGL's and global demand growth of 0.7mmb/d, the implied surplus would be a sizeable 1.3mmb/d. This would fall to a still highly significant 1.1mmb/d on a global basis allowing for a slight drop in OPEC crude output between 2013 and 2014 of 0.2mmb/d. By contrast, the market overall was in approximate balance in 2013.

The global supply surplus looks like widening near term. The key issues here are the likelihood of seasonally slack demand in the first quarter of 2015, carryover strength in non-OPEC production from 2014 and the expectation of broadly unchanged OPEC output from 2014 in the early months of 2015. These factors, we believe, could all conspire in a widening in the global surplus to about 1.6mmb/d. Using OPEC's forecast of the call of 28.40mmb/d and assuming OPEC production carried over from 2014 of about 30.2mmb/d and the first quarter surplus would be an even greater 1.8mmb/d.

Over the balance of 2015 we would expect to see the surplus narrow from first quarter levels reflecting seasonal factors and possibly some underlying firming of demand in the second half. For full-year 2015 we believe the surplus might be about 0.2mmb/d. This assumes an increase of 0.9mmb/d for non-OPEC crude, 0.1mmb/d for OPEC NGLs, 0.8mmb/d for demand growth and unchanged OPEC crude production. As always, these numbers are not cast in stone. The key caveats are that there are no major unplanned outages, the world economy is not substantially stronger than presently anticipated by the likes of the IMF and OPEC's production policy does not change radically in the months ahead.

The outlook for the supply/demand balance in 2016 is clearly highly uncertain at this juncture. We are tentatively looking for approximate balance as the most likely scenario assuming no great change in OPEC production, global economic growth of 3.5% to 4.0% and non-OPEC output growth in line with the 0.7mmb/d indicated earlier. It is possible, in fact, to envisage a modest supply deficit in 2016 if demand is more buoyant than our implied conservative forecast.

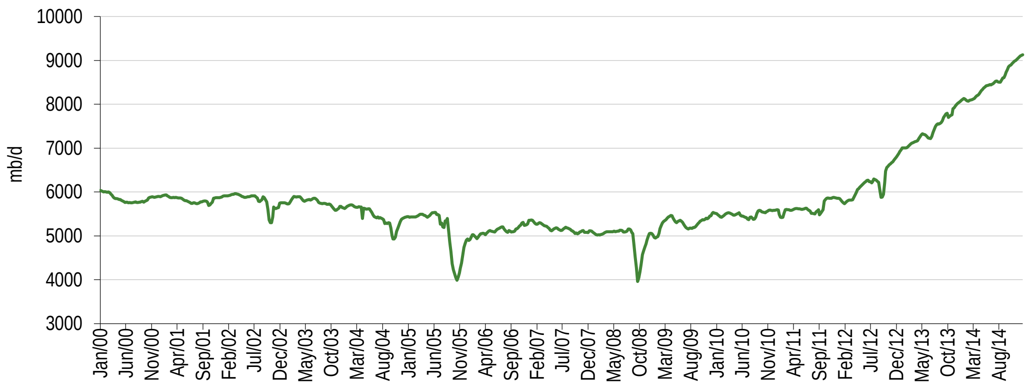
US scene

Oil production: Trend remains buoyant but softening in the cards for second half of 2015

Crude oil

So far, US crude oil production has not been greatly affected by the price slump of the past six months or so. The strong upward trend that began in earnest in 2010 has been maintained, although there are signs of a marginal slowing in recent weeks. Based on EIA data, production in the four weeks to 26 December 2014 averaged 9.13mmb/d, up 12.8% on a year earlier. For the period there was a year-on-year gain of 14.0% to 8.61mmb/d in the Lower 48 states and a decline of 4.1% to 0.52mmb/d in Alaska. The latter continues to be impacted by natural depletion but the rate of decline has fallen from the high levels of the third quarter when there was heavy maintenance activity. Looking at the week ended 26 December, production also came in at 9.13mmb/d, down a marginal 6,000b/d from the previous week but up 1.01mmb/d on a year previously. The decline related entirely to Alaska. Significantly, production in recent weeks has been the highest recorded since the EIA's weekly series began in January 1983. Production in December 2014 was running about 5mmb/d higher than the weekly lows recorded in 2008. In 2014 US crude production was up 14.3% to 8.55mmb/d, comprising a gain of 14.3% in the Lower 48 and a 3.1% decline in Alaska.

Exhibit 5: US crude oil production



Source: EIA. Note: Data shown are 4-week averages.

Production in the Lower 48 continues to be driven by intensive development of the shale and tight reservoir formations of the Great Plains and Texas. While the key plays are the Bakken/Three Forks formation in North Dakota, the Eagle Ford formation in Texas and the stacked formations (Sprayberry, Wolfcamp, Avalon/Bone Spring and Cline) in the Permian Basin of Texas/New Mexico, a number of others are now also making a significant and growing contribution to production. Prominent members of this group are the Mississippian Lime and Woodford formations of the Ardmore and Anadarko basins of Oklahoma and the Niobrara formation of the Denver-Julesburg basin in Colorado/Wyoming. According to EIA/Bloomberg data, estimated production from US shale plays in December 2014 was 5.24mmb/d.

Exhibit 6: US shale oil production by basin/formation

Formation	Basin	State	b/d (000)
Sprayberry, Wolfcamp, Avalon/Bone Spring, Cline	Permian	Texas, New Mexico	1824.3
Eagle Ford	Western Gulf	Texas	1654.8
Bakken	Williston	N Dakota, Montana	1223.6
Niobrara	Denver-Julesburg	Colorado, Wyoming	374.6
Haynesville	Texas-Louisiana Salt	Texas, Louisiana	57.4
Marcellus	Appalachia	Pennsylvania, W Virginia	54.2
Utica	Appalachia	Ohio	48.2
Total			5237.1

Source: Bloomberg, EIA, Edison Investment Research. Note: Production is estimated December 2014

NGLs and renewables

US production of NGLs also showed very strong growth in 2014, driven in particular by intensive development activity in the liquids-rich Eagle Ford (wet gas zone) and the Marcellus and Utica formations of the Appalachia Basin. In the four weeks to 26 December NGL production was 3.13mmb/d, up 15.4% on a year earlier. However, renewable output in the same period at 1.03mmb/d was down 1.5% on the same basis reflecting a sharp decline in denaturants, oxygenates and biodiesel. Total US supply of liquids in the four weeks to 26 December at 13.29mmb/d was 12.6% higher than a year earlier. We believe the US remains comfortably the world's largest producer of hydrocarbon liquids and renewables.

Observations on 2014

2014 was the sixth year of growth US crude oil production. Compared with the 2008 low of 5.00mmb/d, crude oil production has grown 71% over the past seven years or by 9.4% pa. Significantly, NGL output also rose by 75% between 2008 and 2014. It is perhaps worth noting that the surge in US hydrocarbons liquids production over the past six years or so has been achieved without any grand plan at government level. Indeed, it would probably be fair to say that it has occurred despite the federal government. The key ingredients behind the surge in production have been the buccaneering spirit of operators and entrepreneurs, innovative engineering, highly liquid capital markets and risk-accepting investors.

2015/16 outlook

The key issue now concerning US hydrocarbons liquids production is how the trend will develop in 2015 and 2016 in the light of the plunges in prices in recent months and actual and prospective cutbacks in capital expenditure. Anecdotally, we believe that announced cutbacks in expenditure programmes in recent weeks are at least 25%. Interestingly, Bakken pioneer, Continental Resources, announced in December a 41% cut in its capital expenditure programme for 2015. This followed a 12% cutback in early November. As we have noted earlier, operators are extremely unlikely to shut-in production at any conceivable price levels. With WTI at under $55/barrel, prices remain significantly north of well variable costs of perhaps $25 to $35/barrel, including royalties and severance tax. Excluding royalties, costs are probably closer to $20 to $25/barrel. The issue then becomes just how quickly scaled back capital expenditure flows through to production bearing in mind very high rates of shale oil depletion of perhaps 60-80% in the first year post well completion. We believe that the impact will be muted in the first half of 2015 reflecting the following:

- There are probably significant lags of at least a few weeks, if not months, before cutbacks can be implemented due to contractual commitments with suppliers and landowners.
- Spending cutbacks have probably been oriented to non-operational aspects of the businesses.

- Drilling targets have probably been high-graded so that the emphasis is on wells with rapid paybacks. It should be remembered here that the shale operators typically have a large inventory of drilling prospects, which can be easily ranked for play type curves.
- Likely pressure from land owners to continue boosting production due to a not surprising desire for royalty payments.
- Our expectation that tight reservoir drilling and completion costs will decline reflecting in part positive learning curve effects associated with development activity and in part lower input costs particularly for OCTG (oil country tubular goods), diesel and oilfield services.
- Operator reluctance to concede declines given that production is one of the key metrics that capital markets use for performance assessment purposes.

Post the first half of 2015 we believe the impact on production of likely sharp falls in capital spending will accelerate if WTI remains significantly sub $60/barrel on a sustained basis in the coming months. Our thinking here is that fully accounted costs including capital are typically in the range of $60-70/barrel for the major shale formations. Furthermore, there are sizeable transportation costs from the Great Plains oilfields to refineries in the Midwest, Gulf Coast and the eastern and western seaboards.

The EIA's December forecast calls for US crude oil production in 2015 of 9.32mmb/d, which is about 0.2mmb/d down on the September forecast but still up 0.72mmb/d on 2014. It should also be noted that approaching half the downgrade is attributable to a reassessment of the contribution of projects in the Gulf of Mexico. Despite the downgrade, forecast production in 2015 would still be close to the 1970 all-time US high of 9.6mmb/d. In the event that oil prices remain below say $65/barrel going into late 2015 we would expect oil company capital expenditure programmes and hence drilling and completion activity prospectively to show a more pronounced downturn in 2016. In such circumstances zero growth or even an absolute decline is possible.

Flexible technology

One of the clear advantages of on-shore shale oil development projects applying horizontal drilling and high pressure hydraulic fracturing, is that lead times are short compared with large scale development of conventional reservoirs, particularly in deepwater. Typically, wells can be drilled in a month or less while output can easily be trucked off the site without large infrastructural outlays. The significance of this is that if prices rebound drilling can quickly follow suit. The shale operators are the new swing producers.

US crude oil imports/exports: Imports continue to trend down, Canada dominant supplier

US crude oil imports continued to fall in 2014 reflecting the build-up of domestic production. The downward trend did however tend to level off in December. Taking the four weeks to 26 December gross imports averaged 7.53mmb/d, up 1.7% on 2013. For 2014 as a whole, imports averaged 7.40mmb/d, down 5.0% on the prior year and 32% on the 2005 peak of 10.7mmb/d. Based on its latest forecast, the EIA is anticipating a further fall in net crude (net of exports) imports in 2015 of 11.5% to 6.15mmb/d. This would imply the lowest level of imports since the early 1990s.

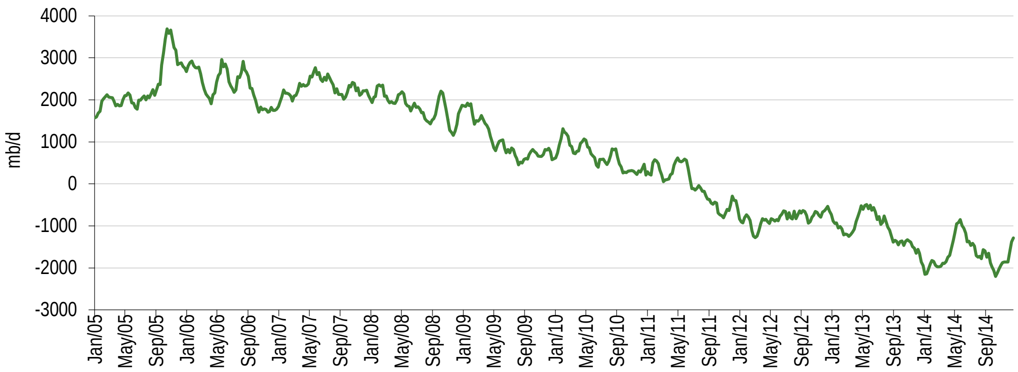
Canada is by far the largest exporter of crude to the US. In 2014 crude imports from Canada averaged about 3.3mmb/d and accounted for 45% of the total, significantly up from 40% in 2013. The US could, in principle, be largely free of non-North American net imports over the next few years.

Product net trade balance: Substantial surplus in 2014, tougher export markets in 2015

The US energy revolution of recent years has consisted of two strands, shale oil and gas development and a dramatic swing in the trade balance on refined products from net imports to net exports. Since early 2011, the US has, in fact, been consistently in surplus after having spent the previous 60 years or so in deficit. During 2014 the refined product surplus widened reflecting both falling imports and increasing exports. Taking the 2014, imports fell by 9.3% to 1.77mmb/d while exports rose by 11.5% to 3.42mmb/d. This resulted in a net export balance of 1.65mmb/d, well up on the 1.11mmb/d of 2013. The net export balance in the four weeks to 26 December at 1.29mmb/d was, however, somewhat narrower than both the average for 2014 and the year ago 1.86mmb/d. Since the 2005 peak for net imports of 2.45mmb/d, there has been a positive swing of 4.10mmb/d.

The continuing strength of net exports reflects a number of factors including the availability of competitive feedstock supplies and natural gas, the proximity of the Gulf Coast refining complex to buoyant Latin American markets, Latin American capacity constraints and the closure of refining capacity in the Atlantic basin. Arguably, the competiveness of the Gulf refining complex has deteriorated somewhat of late given the strengthening dollar and a narrowing of the WTI discount to Brent. The levelling off in distillate exports in recent months probably also points to a softening in export markets, particularly in Latin America. The recent inauguration of Petrobras's 0.23b/d Abreu e Lima in north eastern Brazil combined with a marked slowdown in economic growth in Latin America probably implies more challenging export markets for Gulf Coast refiners in 2015.

Exhibit 7: US net petroleum product net imports/(exports)



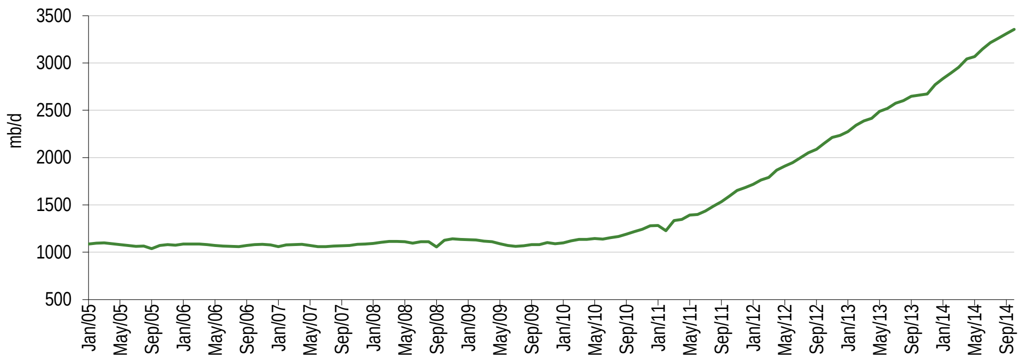
Source: EIA. Note: Data refers to four-week averages, negative numbers relate to net exports.

Texas: Closing in on the 1972 record of 3.4mmb/d, one of the world's major oil producing provinces

Texas is not only the largest oil producing state in the union but also one of the world's leading oil producing provinces. Production in Texas has undergone an impressive renaissance since the mid-2000s low of1.07mmb/d. The trend remained strongly upward in 2014. In September, the most recent month for which EIA data is available, production was 3.25mmb/d up 22.8% on a year earlier and easily the highest level in at least 33 years. Texas production has risen from 2013 to 2014 by a slightly greater 24%.

Texas production continues to be very much driven by the rapid development of the prolific Eagle Ford shale play in the Western Gulf Basin in the south west of the state and the Permian Basin stacked plays in the northwest. Based on EIA/Bloomberg data, production from the Eagle Ford and Permian was running at about 1.7mmb/d and 1.8mmb/d respectively in December 2014. About 10% of the latter is attributable to New Mexico. Texas production overall could conceivably exceed the 1972 record of 3.4mmb/d by 2014 year end. The latest EIA drilling report is pointing to the robust trend in Eagle Ford and Permian Basin production continuing in January 2015. Compared with the prior month, gains of 30,000 b/d (1.8%) and 46,000 b/d (2.5%) respectively are forecast, which would imply production of 1.69mmb/d for the Eagle Ford and 1.87b/d for the Permian.

Exhibit 8: Texas crude oil production

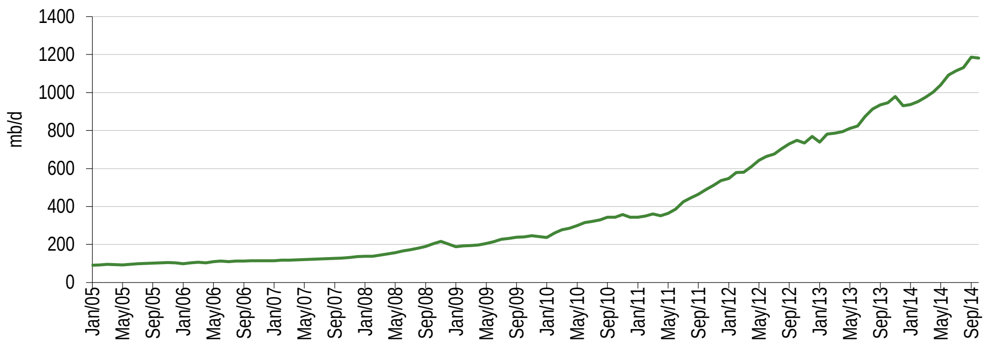


Source: EIA

North Dakota: Robust upward trend continues but for how long given marginal economics

North Dakota has established itself over the past two or three years as comfortably the second largest oil producing state in the union after Texas. Currently, it accounts for about 13% of US output. The trend has been robust in recent months. Based on North Dakota Department of Mineral Resources (DMR) data production in September 2014 was 1.18mmb/d, up 0.25mmb/d or 27% on a year earlier. Through the nine months to September North Dakota monthly production increased on average by 29,000b/d. The EIA in its latest drilling report has suggested that production in December will be about 1.22mmb/d. This is 32% higher than a year earlier but it has to be remembered that year ago production was depressed by adverse weather conditions. In January the EIA is looking for production to increase by a robust 27,000b/d or 2.2% to 1.25mmb/d.

Exhibit 9: North Dakota crude oil production



Source: EIA

Currently, the key forward indicators for development activity in North Dakota are pointing upward and are probably suggesting a continuing strong production trend through the first half of 2015. Drilling and well completion permits in October 2014 were 328, up 23% on a year earlier and a very high level by historical standards. Spuds in October of 230 were down on the previous month's 249 but this was still a high level historically and above the 2014 year-to-date average of 220. Given the advent of multi-well pad drilling, the rig count is possibly a less reliable indicator of future production than was historically the case but nevertheless retains relevance. At the 10-month stage in 2014 the North Dakota rig count averaged 191/month. Although down on peak levels of over 200 in 2012, the rig count in the months leading up to October were running at the highest level in 18 months to two years. The year-to-date average of 191 was, in fact, 3% higher than in 2013. If we look at Baker Hughes data for the Williston Basin (North Dakota plus Montana), which provides more up-to-date information, the rig count shows noticeable slippage since the recent high in September 2014 of 198. The rig count for the week ending 26 December 2014 at 179 was down 10% on late September levels and 2% on a year earlier.

Assuming the price of Bakken grade crude remains at around the late-December 2014 level of less than $50/barrel, Clearbrook Minnesota, on a sustained basis permits, spuds and drilling activity are all likely to take a dive in the coming months. This could start affecting production growth in earnest during the second half of 2015. Not only are fully accounted costs in the Bakken typically in the $60-70/barrel range but there are in addition sizeable transportation and handling costs involved in shipping the oil to markets in the Midwest and Gulf Coast. These are about $6-7/barrel assuming shipment by pipeline and $15-20/barrel by rail. Presently, about 65% of Bakken production is shipped by rail, 30% by Enbridge's North Dakota System pipeline to Clearbrook and Canada and 5% directly by pipeline and truck to Tesoro's refinery at Mandan, North Dakota. We believe at current economics drilling activity in the Bakken is becoming increasingly difficult to justify. Deteriorating cash flow and the declining availability of credit are likely to impose a severe constraint on new development activity in the coming months.

Domestic demand: Signs of a strengthening trend of late, EIA's forecasts too cautious

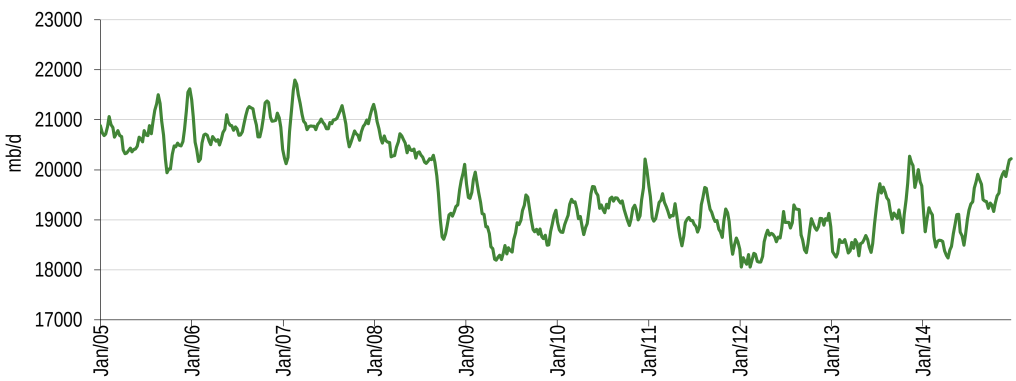
US domestic petroleum demand increased modestly in 2014 but there were signs of a firmer trend towards year end. For the year as a whole, based on EIA data, product supplied (a proxy for demand) averaged 19.21mmb/d, up 0.9% on a year earlier. Growth by product line was as follows: gasoline (the largest) 1.1%, kerosene 3.2%, distillates 1.5%, fuel oil -14.2%, propane/propylene -12.9% and miscellaneous 5.3%. Demand in 2014 was at the highest level since the 19.5mmb/d of 2008 and significantly exceeded the EIA's forecast of 18.96mmb/d. Compared with the 2005 all-time high of 20.80mm/b/d there was, however, still a shortfall in 2014 of 1.59mmb/d.

Looking at the most recent four-week period ending 26 December, demand averaged 20.22mmb/d, up 2.3% on the year ago period. The underlying trend remains broadly flat using a 2009 base. For the most recent four-week period the key surprises were perhaps the buoyant showing by gasoline. For the latest period gasoline demand was up 4.6% on a year earlier which contrasts with the lacklustre showing earlier in 2014. After exhibiting clear signs of softness in the early part of the fourth quarter, distillate demand trended significantly higher in December 2014. Taking the four weeks to 26 December demand of 4.06mmb/d was up 9.2% on a year earlier. Kerosene demand was also buoyant in December and was up 2.6% on a year previously. The buoyancy of the demand for gasoline, distillates and kerosene in December was probably indicative of a rapidly strengthening economy.

Elsewhere in the four-weeks to 26 December 2014, residual fuel showed a year-on-year gain of 21.9% while for propane/propylene and miscellaneous declines of 13.9% and an increase of 4.0% respectively were reported. Propane consumption in late 2014 was probably depressed compared with a year earlier due to more clement weather conditions.

For 2015 the EIA is forecasting another year of modest growth in US petroleum demand. Overall it is looking for a 0.1%. The key areas of strength are expected to be distillates and miscellaneous with gains of 2.0% and 1.7% respectively. Gasoline and kerosene demand in 2014 is expected to be broadly unchanged. The 2015 demand forecast is predicated on a GDP growth assumption of 2.4%. Overall we believe the demand forecast is highly conservative assuming a period of moderate economic growth and given the carryover strength going into the first quarter of 2015. While improving fuel efficiency in both the automotive and aviation sectors is likely to constrain gains in gasoline and kerosene consumption we think a more buoyant economy combined with sharply lower refined product prices should at least mildly more than offset these factors. Assuming GDP growth of 2.4% to 3.0% in 2015 we believe petroleum product demand should grow by at least 0.5% in 2015 and possibly closer to 1%.

Exhibit 10: US petroleum product supplied



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

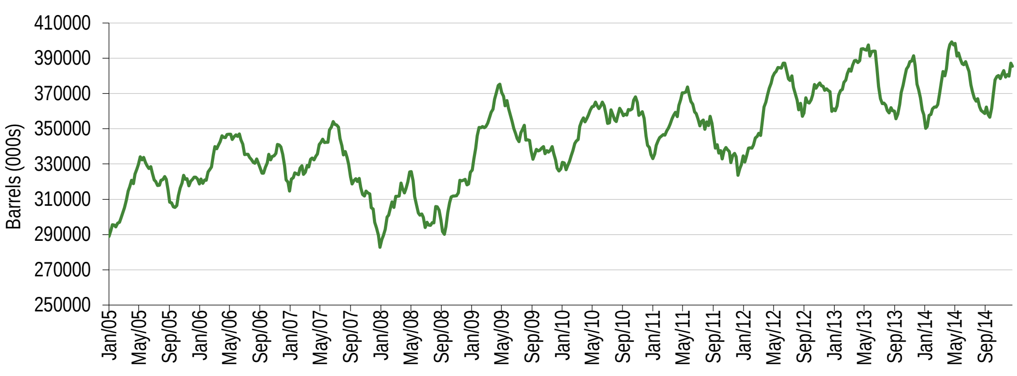
Inventories

Crude oil: Inventories remain seasonally high

US commercial crude oil inventories have continued to run at a seasonally high level in the closing months of 2014. Based on EIA data, crude oil inventories stood in the week ended 26 December at 385.5mm barrels. This was up 24.9mm barrels from a year earlier and at or above the top of the five-year range for the time of year. Significantly, seasonally high inventories have continued to be reported despite historically high refinery activity. Refinery runs in the latest four-week period, propelled by solid domestic demand and buoyant net product exports, were 16.4mmb/d, up 0.8% on a year ago and close to a 30-year high. Seasonally high US crude inventories remain a function of the buoyant trend in liquids production.

On a days' supply basis, crude inventories are at comfortable levels allowing for seasonality. On 26 December inventories were equivalent to 23.5 days' supply, which was significantly above the 22.3 days of a year earlier and well within the range that has prevailed since 2000. Including the strategic petroleum reserve, inventories on 26 December were 1076.4mm barrels, equivalent to about 66 days' supply.

Exhibit 11: US crude oil inventories



Source: EIA

Cushing: Inventories could increase in Q4 due to pipeline start-ups

Crude inventories at the Cushing, Oklahoma tank farm, the delivery point for Nymex crude, were on a pronounced downward trend from early 2013 to July 2014. At the recent low on 25 July inventories stood at 17.90mm barrels, down 65% on peak levels. The drop contrasted sharply with the upward trend in the US overall and reflected a combination of pipeline infrastructure developments which relieved the Cushing bottleneck and very high refinery activity. The key developments were the following:

- TransCanada's Cushing Marketlink (the southern section of Keystone) linking Cushing with Houston.
- Sunoco's Permian Express linking the Permian basin with the Gulf.
- Magellan Midstream Partners Longhorn linking the Permian basin with the Gulf Coast. Both the Longhorn and the Permian Express diverted oil that had previously been shipped to Cushing.

Since the recent July low, Cushing inventories have trended moderately higher. As of 26 December they stood at 30.8mm barrels, which is broadly in line with the levels prevailing between 2005 and 2008 that pre-dated the surge in US petroleum domestic production.

We believe the upward trend inventories at Cushing could continue in the coming months. This reflects the recent opening of two pipelines. The most important is Enbridge's 0.6mmb/d Flanagan South running from Pontiac, Illinois to Cushing, which facilitates the movement of crude sourced from Alberta and North Dakota. The other is the 0.25mmb/d Tallgrass Pony Express pipeline from the Guernsey, Wyoming hub to Cushing. Initially this will transport crude from the Denver-Julesburg and Powder River Basins but in future a connection is expected to be made to the Double H Pipeline from the Bakken oilfields to Guernsey.

Exhibit 12: Cushing crude oil inventories

Source: EIA

Gulf Coast

The Gulf Coast hosts the largest concentration of refinery capacity in the US. Following the upgrading of the pipeline infrastructure mentioned above, linking the Gulf Coast with Cushing and the Permian Basin, Gulf Coast inventories trended significantly higher in late 2013 and 2014. Inventories reached record levels of about 216mm barrels in May of the latter year. Since then inventories have trended down but remained historically high at 198.7mmb/d on 26 December 2014.

Gasoline: Looking comfortable for the time of year

US gasoline inventories have trended higher in recent months, in-line with the normal seasonal pattern. Based on EIA data for the week ending 26 December inventories were 229.0mm barrels, up 8.3mm barrels or 3.7%% on a year earlier and towards the high end of the five-year range for the time of year. Looked at from a longer-term perspective gasoline inventories have trended broadly flat since 2009 pretty much in tune with demand. On a days' supply basis gasoline inventories are significantly below peak levels in recent years of about 28 days but still look pretty comfortable based on the experience since 2000. For the week ended 26 December the actual reading was 24.7 days against 24.9 days a year earlier. The days' supply has increased from recent lows in October and November of about 22.6 days.

In analysing refined product inventory trends, it should be noted that given the strength of demand internationally along with what we believe are superior margins on such business, there is no incentive to keep excessively high inventories. US gasoline production has recently been running at record levels. In the latest four-week period production averaged 9.73mmb/d up 5.0% on a year previously.

Distillates: Adequate for the time of year

US distillate inventories fell sharply between mid-2010 and end 2013 but the trend has subsequently levelled out. Taking the week ending 26 December 2014, inventories stood at 125.7mm barrels, up 5.5% on a year earlier and slightly above the low end of the seasonal range. Distillate inventories have, in fact, trended around the low point of the seasonal range for at least the past two years. The latest inventory reading is equivalent to 31.0 days, slightly below the 32.0 days of a year ago but well above the lows of about 22 days plumbed in the early to mid-2000s. Days' outstanding at about 50 in 2009/10, by contrast, were unusually high and a function of recessionary conditions at the time.

We believe strong international demand and attractive crack spreads have been the key factors depressing distillate inventories over the past few years. Effectively, these factors have led to a new normal for distillate inventories and a downward shift in desired inventories. Distillate exports at about 1.2mmb/d in recent months have slipped in recent months from peak levels in late 2013 and early 2014 of almost 1.4mmb/d but remain comfortably above the 1.0mmb/d or so of two years ago. Distillate production at 5.25mmb/d in the most recent four-week period is up 2.3% on a year ago and around an all-time high.

All petroleum products: Inventories remain historically high

In our view, the acid test concerning the adequacy of petroleum industry inventories is the all-encompassing definition including US commercial crude oil and refined product. Based on EIA data for 26 December inventories on this basis stood at 1,139.1mm barrels. This is up 8% on a year earlier and is very close to a record level.

Light crude spreads

WTI-Brent: WTI discount narrows sharply

The WTI-Brent discount narrowed sharply through the first nine months of 2014 from about $12/barrel to $3.4/barrel. Subsequently it has stabilised at around the latter level and moved in a tighter range than had been the case over the three prior years. On a quarterly basis in 2014 the WTI-Brent discount averaged: Q1 $9.2, Q2 $6.7, Q3 $4.2 and Q4 $3.2. The discount during 2014 ranged between $1.4/barrel on 15 October and $14.9/barrel on 13 January. The average for the year of $5.8/barrel was sharply narrower than the $10.8/barrel and $17.8/barrel of 2013 and 2012 respectively. The narrowing trend in the WTI discount in 2014 occurred despite the continuing Mid-Continent production build-up and reflected the following:

- The earlier sharp drop in inventories at Cushing, the Nymex pricing point, stemming in large part from developments of the pipeline infrastructure. These have enhanced the flow to the Gulf Coast and re-directed supplies away from Cushing.
- Robust refining activity supported by a solid domestic market and strong export demand.
- The build-up of a supply surplus in the Atlantic basin reflecting lacklustre Western European demand and the sharp drop in US imports from West Africa.
- The greater sensitivity of Brent to the economic slowdown in China and the rebound in Libyan production during the third quarter of 2014.

At just over $3/barrel the WTI discount of late is less than pipeline costs for uncommitted shipments from Cushing to the Gulf Coast of about $4/barrel. Substantial quantities of crude are also shipped by rail from Cushing at a cost closer to $10/barrel including tank-car terminaling. On a blended basis average transportation costs between Cushing and the Gulf Coast might therefore be around $7/barrel, which is well above the current WTI discount. To facilitate the flow of oil from Cushing to the Gulf Coast we would normally expect the discount to be at least $6-7/barrel. In practice we think it may be necessary to add another $2-3/barrel given the discount to Brent that has opened on up on occasion for Gulf-sourced light crude grades such as LLS. This would suggest a range of $6-10/barrel. Geopolitical issues threatening to constrain supplies outside the US could lead to a considerably higher upper level from time to time as could pipeline outages. Conversely, other things being equal, a large scale resumption of Libyan exports would tend to compress the WTI discount.

Exhibit 13: Brent 2009-16e quarterly prices ($/bbl)

	Q1	Q2	Q3	Q4	Average
2009	45.1	59.4	68.4	75.0	62.0
2010	76.8	78.6	76.4	86.9	79.7
2011	104.9	116.8	109.1	109.3	110.0
2012	118.7	108.7	109.8	110.9	112.0
2013	112.8	102.9	110.0	109.4	108.8
2014	107.9	109.8	102.2	76.4	99.1
2015e	45.0	45.0	55.0	65.0	52.5
2016e	68.0	72.0	75.0	75.0	72.5

Source: Edison Investment Research, Bloomberg

Exhibit 14: WTI 2009-16e quarterly prices ($/bbl)

	Q1	Q2	Q3	Q4	Average
2009	43.2	59.7	68.1	76.0	61.8
2010	78.8	77.9	76.1	85.2	79.5
2011	93.9	102.3	89.5	94.0	94.9
2012	103.0	93.3	92.2	88.2	94.2
2013	94.3	94.1	105.8	97.6	98.0
2014	98.7	103.1	97.6	73.2	93.2
2015e	43.0	42.0	51.0	60.0	49.0
2016e	63.0	67.0	70.0	70.0	67.5

Source: Edison Investment Research, Bloomberg

Near term we think it is likely that WTI will continue to trade at a modest discount of $2-4/barrel. Tending to keep the discount narrow will probably be the relative strength of petroleum market fundamentals in the US compared to those prevailing on the eastern side of the Atlantic basin. However, if inventories continue to build at Cushing, which we believe is possible, we would expect to see some renewed widening perhaps from the second quarter of 2015. We also believe some widening is required to establish the viability of flows from Cushing to the Gulf Coast. For 2015 we are looking for the WTI-Brent discount to trend as follows: Q1 $2.0, Q2 $3.0, Q3 $4.0, Q4 $5.0. This would imply an average of $3.5/barrel. Tentatively we look for WTI to trade on average at a discount to Brent of $5.0/barrel in 2016. The forecast discounts for 2015/16 assume no major geopolitical events that might interrupt supplies.

Exhibit 15: WTI-Brent spread

Source: Bloomberg

WTI Midland-Cushing spread: There are two pricing points for WTI, Cushing, Oklahoma (30 miles west of Tulsa) and Midland, West Texas (300 miles west of Dallas and 400 miles south-west of Cushing). The former serves the Mid-Continent and the latter the Permian Basin. Historically, WTI

Midland has sold at a small discount of a dollar or less to WTI Cushing which broadly reflects pipeline costs. During 2014 the Midland discount fluctuated sharply. At the beginning of the year Midland was trading at a $2/barrel discount to Cushing WTI but by late August this had widened to a virtually unprecedented $21.0/barrel, implying an absolute price for WTI Midland of a then depressed $73.5/barrel. Subsequently, the Midland discount narrowed sharply and by end December was back to a more normal $3/barrel. On average in 2014 WTI Midland traded at a highly unusual $6.9/barrel discount to its Cushing counterpart. This compared with $1.7/barrel in 2013.

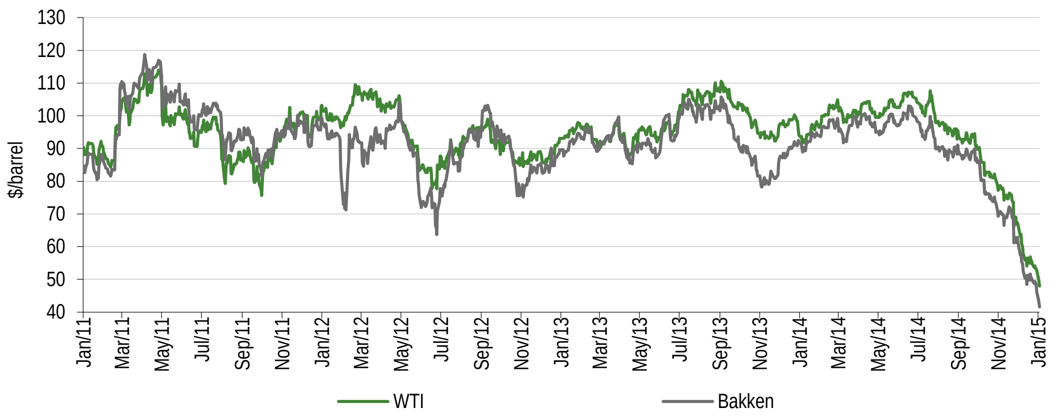
The widening trend in the Midland discount in 2014 reflected a combination of buoyant production in the Permian Basin, lags in expanding takeaway capacity and refinery outages. The most significant outage was probably at Phillips 66's facility at Borger Texas during the summer months. Effectively, the discount had to widen to provide an incentive to ship either to Cushing or the Gulf Coast. Railage from the Midland hub to Houston is $8-9/barrel, according to industry sources. During the fourth quarter of 2014 the depressing influences on the Midland price eased following the opening of Magellan Midstream Partner's 0.3mmb/d Bridgetex Pipeline from Colorado City, Texas to Houston and the restart of local refineries. Logistics should continue to improve imminently between the Permian Basin and Houston with the scheduled start-up of the Sunrise Pipeline between Midland and Colorado City 80 miles to the east. We would therefore expect the Midland discount to return to a normal $1-2/barrel in 2015 abstracting from local refinery outages.

Given the availability of sizeable discounts to WTI Cushing, refineries located in northern and western Texas and New Mexico clearly had the advantage of competitively priced feedstock in 2014. Key beneficiaries would have been Western Refining, Delek Holdings, Alon USA Partners, Phillips 66 and Valero Energy.

Bakken-WTI: Bakken discount narrows in 2014 to normal levels

Bakken grade oil (Clearbrook Minnesota hub) has a broadly similar specification to WTI and is therefore a high quality light crude. With the exception of Tesoro's modest Mandan 71mb/d facility near Bismark, North Dakota, there is currently no refinery capacity within close proximity to Bakken crude production. The bulk of Bakken output therefore has to be exported from the Williston Basin with a price point of Clearbrook, Minnesota. Bakken oil was initially mainly shipped either to Midwest and mountain state refineries, including four in Montana or to Cushing. Over the past two or so years, new markets have opened up on the eastern and western seaboards, as rail connections have been upgraded. This has enabled Bakken producers to capture higher-priced markets leveraged to Brent and Alaska North Slope (ANS). Approximately 70% of Bakken crude is shipped by rail.

Exhibit 16: Bakken vs WTI



Source: Bloomberg

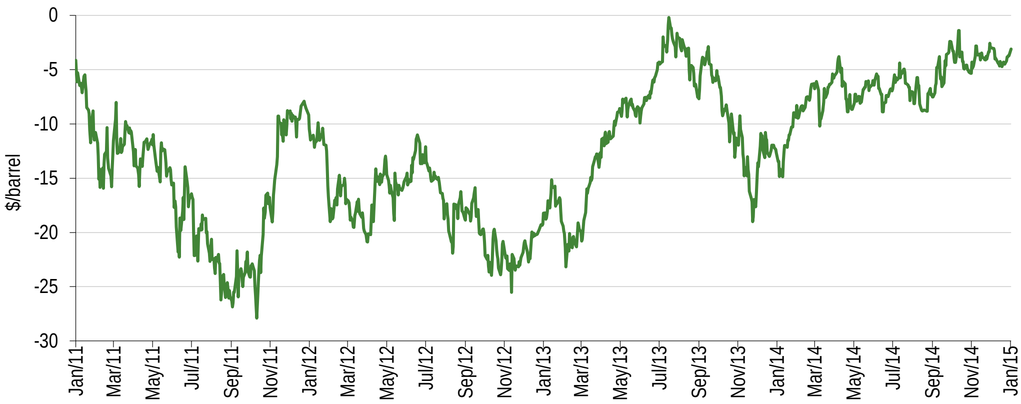
Historically, Bakken oil has sold at a discount of several dollars/barrel to WTI, although the market has in practice been highly volatile and at times premiums have been recorded. Volatility has reflected the potential for outages at a relatively small group of refineries plus, from time-to-time disruptions to logistics. Since the advent of large-scale shipments to the seaboards, the discount is also sensitive to swings in the WTI-Brent spread. In principle, for producers to be competitive in seaboard markets Bakken grade oil, broadly speaking, needs to sell at a discount to ANS (Alaska North Slope) and Brent at least equivalent to rail costs. Based on Valero Energy data, the cost of railage from North Dakota to the Pacific Northwest is about $9/barrel (perhaps $15/barrel to Los Angeles), to the eastern seaboard $14-17/barrel and to the Gulf Coast $12/barrel. These costs assume delivery to the railhead. Logistical and handling costs from the wellhead to the railhead might add another $2-5/barrel.

As far as shipments to Gulf Coast refineries are concerned, the differential compared with Brent may in practice need to be little larger than implied by the above. This reflects the discount to Brent that has emerged over the past year or so for benchmark US light crude grades such as LLS sold on the Gulf Coast. In the case of crude sold to Tesoro’s Mandan facility, together with refineries in the upper Midwest states of Wisconsin and Minnesota and the Mountain States of Montana, Utah Colorado and Wyoming, we would expect Bakken prices inclusive of the discount to WTI to prevail. In the case of shipments to Chicago by pipeline we think that a discount of $5-6/barrel would probably suffice.

The Bakken-WTI spread in 2014 moved in a much narrower range than in 2012 and 2013, probably indicating improving logistical connections. On average in 2014 Bakken grade crude sold at a discount to WTI of $5.2/barrel, which was similar to the two prior years. However, in 2014 the spread ranged between -$1.75/barrel and -$8.1/barrel versus +$3.5/barrel to -$16.0/barrel in 2013. After the acute volatility of 2012 and 2013 when at times the Bakken discount widened to over $15/barrel or even $20/barrel, the trend in 2014 followed a more subdued course. At end-December 2014 Bakken was trading at a discount of $4.8/barrel to WTI, which implied an absolute price of $48.5/barrel. A widening in the discount to $6.7/barrel occurred in early January 2015 due to the closure of the Bakken pipeline network following a fire at a loading facility. The Bakken discount presently is insufficient to cover railage to the seaboards and the Gulf Coast. With Brent trading at about $56/barrel in early January 2015, the required Bakken price ex the railhead for shipment to the Gulf Coast would probably need to be $45/barrel or less to achieve viability.

Recently there have been reports of well head prices in the Bakken being around $20/barrel less than levels prevailing on the Gulf Coast and $15/barrel under WTI. At early January 2015 status this would imply operators realising about $30/barrel, which is close to variable cost including royalty and severance tax payments. We believe realisations at this level would make drilling completely uneconomic.

Exhibit 17: Bakken-WTI spread



Source: Bloomberg

Refinery capacity expansion: The sizeable discounts required to sell Bakken crude on the coasts clearly depress producer economics. One answer to the problem would be to sell more crude into the upper Midwest and Mountain State refineries. This strategy, however, is constrained by high refinery utilisation rates. Some modest relief is at hand given actual and planned capacity expansion in North Dakota. Six refinery projects here are in the pipeline. The first relates to the construction of the Dakota Prairie refinery at Dickinson in the west of the state. This is a joint venture between MDU Resources and Calumet Specialty Products and relates to a relatively small 20,000b/d topping facility focusing on distillates and naphtha. MDU recently confirmed that work on the Dickinson refinery was scheduled for completion by end 2014. Interestingly, MDU has indicated that it is considering adding another refinery in North Dakota with a planned capacity of 20,000b/d. Once regulatory approval is given lead times for the planned refineries are about two years.

Refinery expansion in North Dakota is being driven by surging demand for diesel and other distillates in the region as a direct result of the petroleum industry development boom. MDU suggests that the demand for diesel in the state currently is about 61,000b/d. Tesoro's Mandan refinery supplies about 36% of the market leaving the balance to be imported into the state often from locations several hundred miles away, such as Denver and Minneapolis/St Paul. When MDU's Dickinson refinery operates at full capacity, in-state refineries, including Tesoro's facility, will consume about 8% of North Dakota's current oil output. We believe that at least one other refinery will come on-stream by mid-2017, which will take feedstock needs to about 0.10mmb/d. Given the buoyant energy driven economy in the northern Great Plains, we also believe that refinery expansion projects are a very real possibility in both the upper Midwest and the Mountain States.

Syncrude-WTI: Modest Syncrude discount, Syncrude producers should remain cash generative

Syncrude is a synthetic sweet crude sourced from the Athabasca oil sands in Alberta. The pricing hub is Edmonton, Alberta. Given significant refining capacity in Alberta and Saskatchewan and the pipeline capacity to the Midwest and Ontario, Syncrude normally trades close to WTI. Refinery and pipeline outages, however, can at times result in substantial deviations, as in November 2013 when a discount of $16/barrel surfaced. Pipeline upgrades to Enbridge's existing network and construction of the northern leg of Keystone XL, assuming it is ever given the go ahead, should improve the consistency with which WTI and other benchmarks are tracked. We believe light oil pipeline costs from Edmonton to the Gulf Coast are currently about $12-15/barrel but could potentially be somewhat less with Keystone XL, reflecting a more direct route. To be competitive on the Gulf Coast currently, Syncrude would probably need to trade at a discount to WTI of about $9/barrel (WTI discount to Brent of $4/barrel assumed).

The Syncrude-WTI spread was much less volatile in 2014 than in recent years. During 2014 Syncrude traded between a premium of $4.5/barrel and a discount of $6.3/barrel to WTI. The high point was reached in April reflecting an outage at one of Syncrude Canada's two coker facilities for unplanned maintenance. At end-December 2014 Syncrude was trading at a discount of $3.0/barrel to WTI. On average in 2014 the Syncrude-WTI spread was -$1.2/barrel, slightly up from the previous year's -$0.7/barrel. Abstracting from major plant outages or harsh weather conditions, we would expect Syncrude prices to continue to trade close to WTI over the near to medium term.

Economics

At end-December 2014 Syncrude was trading in absolute terms at about $50.3/barrel, down 54% on the peak in 2014 of $108.6/barrel. Syncrude producers using existing facilities probably remain significantly cash generative at the operational level. Based on Suncor Energy's guidance for 2014 cash operating costs are estimated at C$33.0/barrel or US$28.5/barrel. Cash costs, however, for Canadian Oil Sands, another major Syncrude producer, are somewhat higher at C$46.8/barrel or US$38.0/barrel. The company has been hit by several unplanned outages during 2014 which have boosted costs/barrel. Costs over the past five years may therefore be more representative and these have averaged C$38.0/barrel or US$32.7/barrel. Note pure variable costs are probably significantly below the operating costs given above for Suncor and Canadian Oil Sands.

Canadian dollar weakness bolsters economics

Helping bolster the economics of Syncrude producers of late has been the weakening trend in the Canadian dollar. The currency depreciated against the US dollar about 10% during 2014 and is 20% below the 2011 high. It should also be noted that although Syncrude projects are relatively high cost due primarily to engineering and operational complexity, they do have some important advantages compared with conventional and shale projects. These relate to very high rates of recovery and low or virtually non-existent rates of depletion for those operators using mining extraction. Syncrude and more broadly oil sand projects indeed continue to offer the benefits of very large scale and long life reserves (40 to 50 years).

WCS-WTI: WCS discount narrowed to more normal levels in 2014, structural changes in the marketplace support WCS

WCS (Western Canada Select) is a heavy-sour Alberta blended grade, using conventional and oil sands bitumen feedstock, with an API of 20.5˚. The pricing hub is Hardisty, Alberta. Reflecting the difficult to refine specification and sourcing, WCS typically sells at a substantial discount to WTI and is usually one of the world's lowest cost crudes. Historically, WCS has been shipped to refineries in the Midwest and Ontario. Owing to high viscosity, diluents (thinning agents) are added to WCS in the form of naphtha, natural gas liquids and synthetic crude to enhance pipeline flow. The quantity of diluents required depends on crude grade and pipeline specification. Typically about 25% of each barrel of WCS shipped by pipeline comprises diluents.

The WCS discount to WTI narrowed significantly during 2014 and for the year was well below 2013 on average. During 2014 the discount came in as: Q1 $20.8, Q2 $19.1, Q3 $18.4 and Q4 $16.0. The average for the year was $18.6/barrel against $24.5/barrel in 2013. In late-December WCS was trading at a $16.0/barrel discount to WTI implying an absolute price of $37.3/barrel. Compared with the similar specification Mexico-sourced Maya crude, the benchmark Gulf Coast heavy grade, WCS was trading at a discount of about $7/barrel in late December. This is significantly below pipeline costs from Alberta to the Gulf Coast of at least $15/barrel allowing for diluents. We believe however that at about $37/barrel WCS is attractively priced for those Midwest refineries capable of processing the grade. Based on Bloomberg data, the implied price for bitumen at end-December was about $32/barrel.

We believe the narrowing of the WCS discount in 2014 is symptomatic of structural changes taking place in the market for Albertan heavy crude along with takeaway capacity expansion. The key factors are:

- The conversion of BP's Whiting, Indiana refinery (the largest inland refinery in the US) to operate on a diet of mainly heavy feedstock sourced from Alberta. Following the completion of the Whiting upgrade last year, it now uses 80% heavy feedstock rather than 20% previously. The impact of the changeover is about 0.3mmb/d.
- Rapid expansion of Alberta rail takeaway capacity. Until recently such capacity was virtually non-existent but in the second quarter of 2014 was about 0.55b/d and by early 2015 could be 1mmb/d. Further expansion is planned, which would take capacity to 1.5mmb/d by end 2015. Significantly, the first shipment of WCS was made in September by rail from Alberta to Suncor's newly constructed terminal near Montreal. Industry sources have suggested that railage from Alberta to Montreal costs about $12/barrel, although this probably assumes that the shipper owns the rail cars. Costs otherwise might be closer to $20/barrel.
- The recent connection by pipeline for the first time of Alberta with Montreal/Quebec City. This follows the completion of Enbridge's Line9B reversal from North Westover in Ontario, the previous terminus for the Main Line pipeline from Alberta. The reversed Line9B has a capacity of 0.3mmb/d and enables the Suncor and Valero refineries at Montreal and Quebec City to be largely independent of imported feedstock. Potentially it will also provide a high volume export route for WCS.

Importantly, the opening of the 0.6mmb/d Flanagan South pipeline is imminent, which greatly expands capacity from Alberta to the Gulf Coast. The pipeline runs from Pontiac, Illinois to Cushing and to some extent obviates the need for the Keystone XL. In addition, Enbridge is contemplating building a rail terminal at Pontiac capable of taking two trains a day from Alberta. This could be in service by mid-2016 and would significantly relieve the pipeline capacity bottleneck in southern Alberta.

We believe that the combination of new pipeline and rail takeaway capacity should result in less volatility in the WCS discount than has been the case historically. Ongoing, we would expect the discount to broadly reflect pipeline costs to the seaboards of $15-20/barrel.

An expansion of pipeline takeaway capacity from Alberta to the west remains on the cards, although nothing imminent appears on this front. Enbridge's Northern Gateway project from Bruderheim north of Edmonton to the port of Kitimat, British Columbia, was given statutory approval in June but an agreement with the First Nations has yet to be struck. The target of a 2018 start-up is no longer feasible. Indeed, Northern Gateway as currently planned might never be constructed, according to industry insiders. In the short term, at least, a viable alternative might be to expand Kinder Morgan's Trans Mountain Pipeline from Edmonton to Vancouver and Puget Sound in Washington State. Kinder Morgan has, in fact, suggested an expansion from 0.3mmb/d to 0.89mmb/d.

Economics

According to the Canadian Energy Research Institute (CERI), the fully accounted costs, including a 10% return on investment, for producing a barrel of bitumen from the oil sands are $65 and $46 using the mining and in-situ production routes respectively. Based on the Bloomberg late December quote of $32/barrel, bitumen (ex-Edmonton) would look to be significantly under water on a fully accounted basis. Existing projects may however still be cash generative.

In many ways the key drawback to Alberta oil sands sourced bitumen is high pipeline costs stemming from long distances to end markets, high viscosity and the need to add costly diluents. Pipeline costs for light oil from Alberta to the Gulf Coast are $12-15/barrel but for bitumen could be closer to $20/barrel. This would imply a delivered price to the Gulf Coast of about $52/barrel (based on an ex Edmonton price of $32/barrel), which is somewhat above the late December Maya price of about $44/barrel. Note also that bitumen is lower grade refinery feedstock than Maya. Looking at WCS the economics could be somewhat more favourable given the likelihood of lower pipeline costs stemming from lower diluent requirements.

LLS-Brent: LLS traded close to parity with Brent in Q414

Historically, LLS, the Gulf Coast-based light crude benchmark, traded at a premium of a dollar or two to Brent. During late 2013 this relationship rapidly broke down under the weight of an influx of domestic supply along the Gulf Coast. A discount of $8.3/barrel surfaced in the fourth quarter of 2013. Surprisingly perhaps, given the continued build-up of supply, the LLS discount narrowed during the first three quarters of 2014. The discount averaged $1.2/barrel in the third quarter and by end September LLS was trading close to parity with Brent. The narrowing trend appeared to have reflected high refinery utilisation along the Gulf Coast and weak Brent fundamentals.

During the fourth quarter of 2014 LLS traded on average close to parity with Brent. At end December there was a marginal LLS discount of $0.32/barrel. As indicated in earlier reports we continue to expect LLS to trade at a discount of $2-3/barrel near to medium term reflecting upgraded pipeline and rail connections to the Gulf Coast. The caveats are that the export embargo remains intact and that Brent fundamentals do not deteriorate unduly in the coming months.

Brent-Dubai: Resumption of Kirkuk exports could widen the Dubai discount

Dubai Fateh is a Gulf-sourced light but relatively sour crude popular with Far Eastern refineries. After trading at a discount to Brent of around $3.5/barrel in the first and second quarters of 2014, a pronounced narrowing took place in the third quarter to $0.7/barrel reflecting a supply overhang for light crudes, depressed refining margins and the cessation of Kirkuk supplies due to the closure of the Ceyhan pipeline. During the fourth quarter the discount widened significantly to $2.9/barrel, which we would regard as broadly normal. On average, in 2014 Dubai traded at a $2.98/barrel discount to Brent, up marginally from the $2.92/barrel of the previous year. The variance between 2013 and 2014 is mainly explained by the strength of Brent in the first half. Assuming that Kirkuk production, along with pipeline shipments to Ceyhan, restart as scheduled in the near future there is the possibility of a widening of the Dubai discount in early 2015.

Tapis-Dubai: Tapis premium could be in secular decline due to abundance of light crude

Tapis is a low-sulphur Malaysia-sourced light crude popular with refineries in the Far East. The Tapis-Dubai spread is one of the key sweet-sour crude oil price relationships. Reflecting its premium specification, Tapis typically trades at a significant premium of $7-10/barrel. During the first and second quarters of 2014 the premium averaging $9.5/barrel was in line with the top end of the historical range and largely unchanged from the fourth quarter of 2013. During the third quarter, however, the Tapis premium to Dubai narrowed to an unusually low $4.7/barrel, probably reflecting abundant supplies of light crudes and constrained availability of sour grades due at least in part to the cessation of Kirkuk production. In the fourth quarter of 2014 the Tapis premium widened modestly to $5.2/barrel but remained historically low. The average Tapis premium in 2014 of $6.9/barrel was significantly narrower than the $9.3/barrel of 2013. Given the structural shift in Atlantic light crude fundamentals post the build-up of US supplies, it is possible that the Tapis premium to sour grades is in secular decline.

US Gulf heavy crude spreads: Mars and Maya discounts narrow, WTS discount returns to normal

LLS-Mars: Mars is a medium-sour grade sourced from the Gulf of Mexico that normally trades at a discount to LLS of $2-6/barrel and in 2013 averaged $5.1/barrel. The Mars discount narrowed in 2014 but remained within the historical range. Averages for the first, second, third and fourth quarters were $3.5, $4.8, $3.6 and $4.2/barrel respectively with an average in 2014 of $4.0/barrel. Compressing the Mars discount in 2014 was the abundance of light crude along the Gulf Coast.

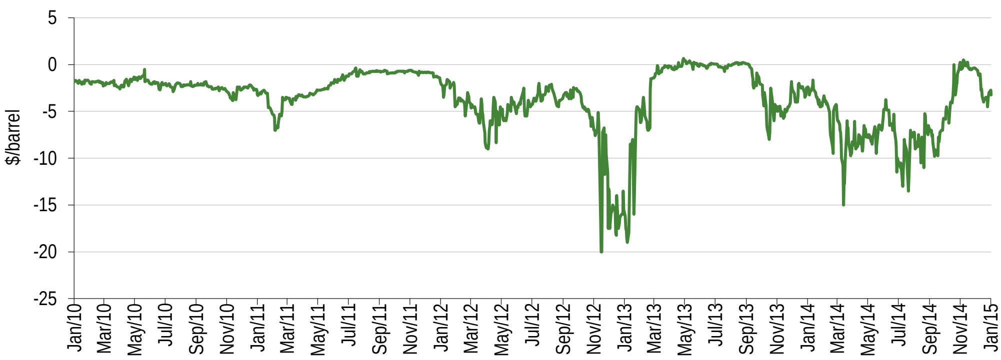
The expected continuing build-up of light crude supply along the Gulf Coast could portend a longer term narrowing of the Mars discount. It should be remembered here that many Gulf Coast refineries are currently configured for heavy-sour feedstock.

LLS-Maya: Maya is a Mexico-sourced heavy-sour grade with a specification similar to WCS. It normally trades at a discount to LLS in the range of $5-12/barrel. The Maya discount trended down noticeably in 2014 from the historically high level of $15.2/barrel in the first quarter. The discount was about $10/barrel in the second and third quarters before narrowing to $9/barrel on average in the fourth quarter. In late December the Maya discount widened to $10/barrel. For 2014 as a whole the discount of $11.0/barrel was sharply down from the previous year's $15/barrel. As in the case of Mars, we believe the compression of Maya discount in 2014 reflected the light crude supply build-up along the Gulf Coast.

WTS-WTI: West Texas Sour (WTS) is a US inland medium-sour grade with a specification similar to Mars and a delivery point of Midland, West Texas. Historically, WTS has generally traded at a discount to WTI of $1-3/barrel and in 2013 averaged $2.6/barrel. The discount widened dramatically through the nine months to September 2014, averaging $5.5, $7.2 and $8.8 in the first, second and third quarters of 2014 respectively. In March and July it, in fact, reached a virtually unprecedented $14-15/dollar. Wide discounts appear to have largely reflected burgeoning supplies in the Permian Basin and a lag in installing takeaway capacity. Contributory factors may also have been a release of sour crude from the strategic reserve in March and refinery outages, with one of the key ones being in June at Valero's Mckee refinery in northwest Texas.

The widening tendency reversed sharply in the fourth quarter of 2014. By late November WTS was trading at approximate parity with WTI and for the final quarter of the year averaged $2.2/barrel. In late-December the WTS discount stood at $3.6/barrel. The average WTS discount in 2014 came in at $5.9/barrel. We believe that the narrowing in the fourth quarter WTS discount reflected upgraded takeaway Permian capacity with the Bridgetex pipeline being one of the key factors.

Exhibit 18: WTS-WTI spread



Source: Bloomberg

Shale oil economics and financing

Economics: The fully accounted marginal zone entered; however, prices remain above variable cost

With WTI at end-December 2014 trading at under $55/barrel and regional prices in the Bakken, Niobrara and Permian below $50/barrel, tight and shale oil economics have now entered the marginal zone on a fully accounted basis, including the cost of capital. Indeed, prices are currently at or close to the level at which the Continental Resources chairman/CEO and Bakken pioneer, Harold Hamm, has indicated is economically critical. Interestingly, the Occidental CEO has suggested that the industry is 'not healthy' below $70/barrel. However, on a variable production cost basis, which is the key criterion for assessing short-run viability, end-December prices probably still imply a significant cash contribution. Hence there is no pressure to cut production from existing wells.

So-called unconventional tight and shale oil development now define long-run marginal costs in the US. Fully accounted costs are inevitably high relative to the development of conventional onshore reservoirs given greater technical complexity related to such factors as deeper wells, horizontal drilling and high pressure multi-stage hydraulic fracturing. Shale development costs vary significantly depending on the play and also within plays reflecting variations in geology and depth of reservoir.

According to the petroleum industry consultants, Wood Mackenzie, US shale project fully accounted costs ‘cluster’ around $65-70/barrel. Based on published data for the Bakken we would, however, estimate fully accounted costs for the high well productivity zones such as the Nesson Anticline, somewhat lower at about $53/barrel excluding the cost of capital (possibly about $2/barrel). This assumes royalty and severance costs based on a Bakken price of $46/barrel, $8m/well and an EUR (estimated ultimate recovery) of 550,000 barrels. Note, variable production/logistics costs (field collection and pipeline to Clearbrook, Minnesota assumed), including royalties and state severance tax but excluding G&A, would be a modest $33/barrel. Using data specifically relating to Continental Resources, which has very low production costs of about $6/barrel, variable cost would be about $27/barrel including royalties. The implied Bakken economics in practice are possibly slightly more favourable than indicated above given that no allowance has been made for by-product natural gas.

By common industry consent the US shale oil play with the most favourable economics is the Eagle Ford. Positive attributes include carbonate reservoirs that are ideally suited to fracking, high EURs by shale standards and prolific initial production rates of over 4,000b/d in some cases. Industry data would suggest that Eagle Ford costs might be up to $5/barrel lower on average than in the Bakken which would imply fully accounted costs of as low as $48/barrel at the local storage hub. Another major positive for the Eagle Ford is its proximity to the refining complexes of the Gulf Coast in the region of Houston and Corpus Christy. This implies pipeline costs of $5/barrel or less against $12/barrel from the Bakken and nearer $20/barrel by rail. As far as Eagle Ford variable costs are concerned we would argue that assuming shipment to the local storage hub these are not significantly different than in the Bakken.

A key point to note in the shale economics debate is that completed well costs (CWCs) are trending down. EOG, for example, points to CWCs in the Bakken falling 17% from $10.5m in 2012 to $8.7m in 2014. Spud-to-TD (total depth) drilling times over the same period have declined 45% from 22.7 to 12.5 days. Driving costs down have been several factors including positive learning curve influences, well down-spacing (more wells per acre) and multi-well pad drilling. In addition, improved completion techniques are tending to boost initial flow rates and possibly EURs, thereby reducing costs per barrel. Examples include increasing the number of frack stages and frack clusters/stage and the more intensive use of proppants.

The important question now is to what extent the shale oil operators can continue pushing down costs near to medium term. The industry, not surprisingly perhaps, is bullish in this regard with Continental Resources, for example, looking to reduce Bakken CWCs near term by $0.5m to $7.5. We believe operators will be supported in their cost reduction objectives near term by falling prices for oilfield services plus in all likelihood key inputs such as OCTG (oil country tubular group) products. Driving costs lower should be a combination of lower drilling activity, declining steel raw material costs (directly impacting the cost of OCTG) and falling diesel fuel prices (impacts lifting and transportation costs). Overall, we believe that OCTG and steel related accounts for about 10% of well costs.

North Dakota Department of Mineral Resources 8 January presentation

The North Dakota Department of Mineral Resources, the regulatory authority for oil and gas production in the state, recently provided some very interesting information concerning breakeven prices and production scenarios. The data effectively relates to the Bakken. The key conclusions were:

- Breakeven costs (defined as the price at which new drilling would cease) across the key producing counties in North Dakota range from $29 to $77/barrel. The former relates to Dunn, the second largest producing county in the state accounting for 16% of production in October 2014. The largest producing county, McKenzie (34% of production), has breakeven costs of $30/barrel.
- The average breakeven cost across 12 counties in North Dakota is $51/barrel.
- Active drilling rigs in North Dakota fell by 17 or 9% in the week ended 7 January 2015.
- Production in North Dakota would trendas follows using the following price assumptions:
  -$25/barrel: July 2015 1.00mmb/d, July 2016 0.80mmb/d, July 2017 0.70mmb/d
  -$35/barrel: July 2015 1.03mmb/d, July 2016 0.88mmb/d, July 2017 0.72mmb/d
  -$45/barrel: July 2015 1.10mmb/d, July 2016 1.05mmb/d, July 2017 0.98mmb/d
  -$55/barrel: July 2015 1.20mmb/d, July 2016 1.20mmb/d, July 2017 1.15mmb/d
  -$65/barrel: July 2015 1.20mmb/d, July 2016 1.23mmb/d, July 2017 1.25mmb/d
  -$75/barrel: July 2015 1.20mmb/d, July 2016 1.30mmb/d, July 2017 1.40mmb/d

For perspective, North Dakota's oil production in October 2014 was 1.18mmb/d and as we have noted previously could be around 1.25mmb/d in January 2015, based on EIA data. With Bakken prices as of January 2015 significantly less than $40 we could therefore be looking at a drop in North Dakota production of around $0.5mmb/d prospectively in the 2 ½ years to the third quarter of 2017. This assumes, of course, that price realisations were held constant at $35/barrel.

Exhibit 19: Bakken economics

	$/barrel
Gross realisations 1 October 2014	86
Royalties	-16
Net realisations	70
Lifting and site operating costs	-12
Severance costs	-7
G&A	-5
Transport to Clearbrook, m	-5
EBITDA	41
Drilling/completion costs	-15
EBIT	26
Assumptions	
Royalty rate 18.5%	
Severance rate 8%	
Drilling/completion costs $8m/well, EUR 550,000 barrels	
No allowance for natural gas	

Source: Edison and industry presentations. Note: Variable costs include lifting costs given that these would become marginal in the event of a decision to cease production. However, lifting/ site costs are mainly fixed (80-90%) on a monthly basis. Any reduction in output would therefore raise costs/barrel in the short term.

Financing: Shale producers' Achilles heel

The US shale boom of the past four or five years has resulted in massive financing needs. We would argue that a heavy ongoing financing requirement is the Achilles heel of the shale oil operators in the current environment of plunging prices. In 2014 alone we believe the financing requirement approached $100bn reflecting the following numbers of unconventional wells ($7m/well): Permian Basin 5,000, Eagle Ford 4,000, Bakken 2,600 and others 2,000. Infrastructure costs would add to the outlays. Based on Bloomberg/Evaluate Energy data sourced from 123 oil and gas companies the EIA has, in fact, recently indicated that US upstream capital expenditure averaged $107bn annually between 2012 and the third quarter of 2014.Development costs have largely been financed by bank debt, the corporate bond market and internally generated cash flow. Corporate debt includes both investment and sub-investment grade or junk paper (S&P below BB and Moody's under Ba). According to Barclays, energy related paper now accounts for 16% of the $1.3tn junk bond market. This is up from about 4% five or six years ago.

The problem for shale operators is now that internally generated cash flow is rapidly evaporating as prices plunge, access to the bond markets has ceased even for investment or near investment grade names such as Continental Resources. The debt of some of the mid-tier plays such as Sandridge Energy is, in fact, looking seriously distressed with yields to maturity of almost 20% on paper maturing in 2022. Sandridge's debt has halved in value since the third quarter and is currently selling at 55 cents on the dollar. Based on a recent Bloomberg article quoting Barclays as the source, junk bond yields to maturity on energy sector paper have broadly doubled to over 11% since the third quarter of 2014.

One company that must be pleased that it accessed the debt market when it did is Continental. During June 2014 it raised $1.7bn just as the proverbial train was pulling out the station. Of this amount $1.0bn was raised through a 2024 maturity bond with a coupon of 3.80% and $0.7bn was paper with a 2044 maturity and a coupon of 4.90%. The former is now selling at 85 cents on the dollar and a yield to maturity of 5.9% while the latter is at 81 cents on the dollar and a yield on the same basis of 6.3%. Significantly, at the time of issuing the paper Continental had very impressive operational and financial characteristics with production growing strongly and excellent margins cash margins of 75%. At third quarter 2014 status the net debt: EBITDAX ratio was a modest 1.5x, well under the 3.0x to 4.0x threshold that banks normally use for lending purposes. Given the excellence of its operations, sizeable reserve position and strong near-term growth potential Continental, of course, remains very favourably positioned to pursue its development programmes vis-a-vis its peers.

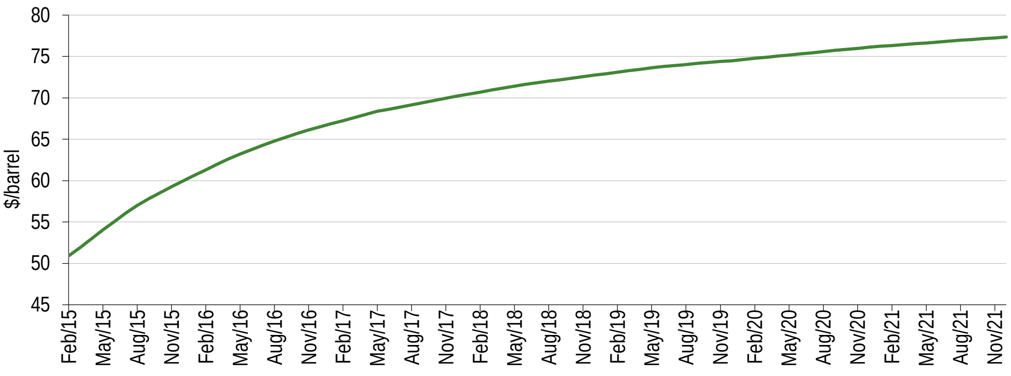
Looking at shale oil development as a whole the inevitably rapid deterioration in key financial ratios in recent months and the consequent evaporation of financing sources will severely constrain capital spending in the oil patch. Many companies, we believe, will have to resort to conserving cash assuming that sub $60/barrel oil is more than a passing phenomenon. A decline in spending between 2014 and 2015 of over 50% would not be totally surprising. The impact of the decline on shale oil production could be surprisingly rapid in the second half of 2015 reflecting very high rates of depletion post well completion. With depletion rates typically of 60-80% in the year following completion drilling has to be maintained at a high level merely to hold production constant.

Note, cutbacks in petroleum industry capital spending in the US will partially offset to a significant extent the benefits for consumers and businesses of lower gasoline and diesel prices. Interestingly in early January 2015 United States Steel announced the idling of two tube mills.

Forward curves: Brent and WTI both in pronounced contango

As of end December 2014 the forward curves for both Brent and WTI were in pronounced structural contango (near-term prices lower than for the forward dates) indicating plentiful supplies. This is consistent with historically high inventories both in the US and internationally. The Brent forward curve swung from backwardation (near-term prices higher than for the forward dates) to contango during the third quarter of 2014 as evidence emerged of a growing supply surplus on the eastern shore of the Atlantic Basin. As of end 2014, the Brent curve was in contango for all dates between February 2015 and end 2021. The Brent curve starts at $57.8/barrel for February 2015 deliveries and then climbs over the following 24 months or so to $71.6/barrel. Thereafter the rate of climb lessens with the curve terminating at $80.4/barrel in December 2021.

Exhibit 20: Brent forward curve

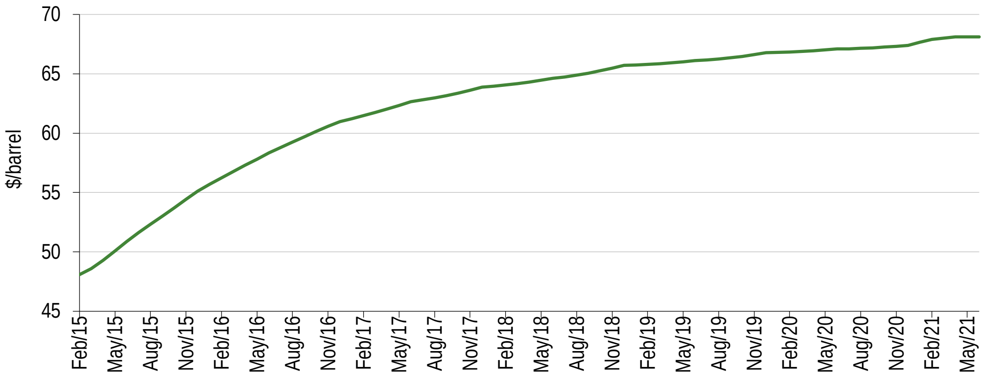


Source: Bloomberg

Surprisingly perhaps given the inventory position in the US, WTI remained in backwardation until early in the fourth quarter of 2014. It then flipped into contango as evidence of plentiful supplies, including at the Nymex pricing point of Cushing, became overwhelming. Another factor encouraging the swing may have been a reduction in producer hedging as prices declined to depressed levels by the standards of the previous four or five years. Until the fourth quarter we believe that the WTI backwardation phenomenon may have partly reflected hedging as producers moved to reduce risk by locking in prices through derivative instruments. This we believe possibly increased supply and depressed prices at the back end of the curve. An interesting development in the context of hedging in recent months was the decision by Continental's Harold Hamm to dispense with all hedges. The decision in retrospect might have been a little early but Harold made a tidy profit on the deal and now.

As of end December 2014, the WTI forward curve was in pronounced contango for all dates through to December 2019. After starting at $53.8/barrel for February deliveries the WTI curve rises over the following five or so years to $70.0/barrel. Subsequently it edges marginally higher and terminates in December 2023 at $71.1/barrel.

Exhibit 21: WTI forward curve



Source: Bloomberg

WTI forward curve

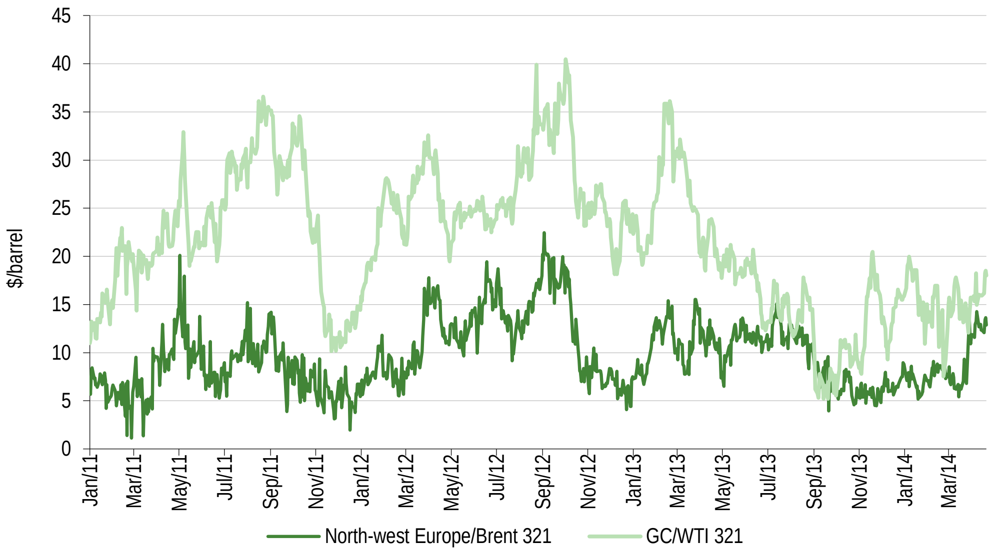
Forward curve analysis points to a widening of the WTI-Brent spreads over the balance of the decade and beyond. The implied WTI discount widens from $4.0/barrel for February 2015 deliveries to $6.6/barrel and $7.5/barrel two and four years later. The discount for December 2021 deliveries is $9.2/barrel. The discounts post 2015, are broadly in line with our theoretical estimates of logistics costs from Cushing to the Gulf Coast.

Refinery crack spreads: Sharp fall in GC spreads in late 2014

Gulf Coast spreads

After trending flat through the first three quarters of 2014, US Gulf Coast refinery crack spreads, based on Cushing sourced WTI feedstock, narrowed sharply in the fourth quarter. Taking, for example, the Gulf Coast/WTI 321 (GC/WTIC) spread (the margin before refining costs on converting three barrels of WTI into two barrels of gasoline and one of diesel) the quarterly sequence in 2014 was Q1$14.9/barrel, Q2 $15.2/barrel, Q3 $14.0/barrel and Q4 $7.0/barrel. The average for the year of $12.8/barrel was well down compared with the $17.6 of 2013 and considerably below the $23.1 and $30.4 of 2011 and 2012 respectively. Overall then a less than stellar year for the Gulf Coast refinery sector in terms of crack spreads.

Exhibit 22: Recent trends in US Gulf Coast and NWE crack spreads

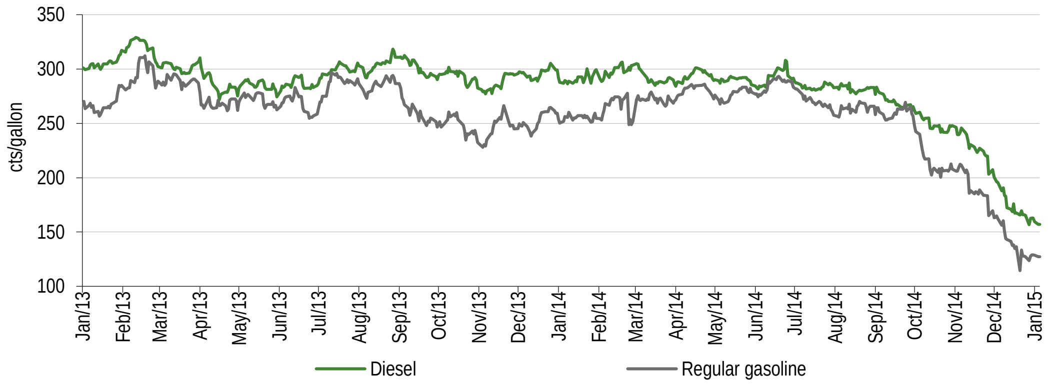


Source: Bloomberg

In late December 2014 the GC/WTI 321 crack spread was actually reported by Bloomberg as being slightly negative although by early January 2015 it had recovered to $4.6/barrel. Pressure on the GC/WTI spread in late 2014 largely reflected a sharp decline in gasoline prices, which more than offset the drop in crude. Between the end of the third and fourth quarters of 2014 Gulf Coast regular gasoline prices have slumped 50%% while WTI dropped 41%. On the same comparison diesel prices fell broadly in line with WTI. Interestingly, there were some seemingly freakish product price movements particularly in gasoline in the closing days of December. Gulf Coast gasoline, for example, plunged 16% to 114.5cts/gallon on 22 December before rebounding 13% over the remainder of the month. The price on that date was close to a six-year low.

The NWE/Brent 321 spread also came under heavy pressure late in the fourth quarter of 2014 but at end -December was still positive at $4.9/barrel. 2014 was the first year since 2010 that the NWE/Brent 321 was wider than the Gulf Coast/WTI 321 spread on occasion. However, for 2014 as a whole the NWE spread lagged that on the Gulf Coast by $2.5/barrel. The spreads between the two regions have tended to converge as the WTI discount to Brent has narrowed. We believe the pronounced weakness in gasoline prices in late 2014 reflected very high rates of refining activity.

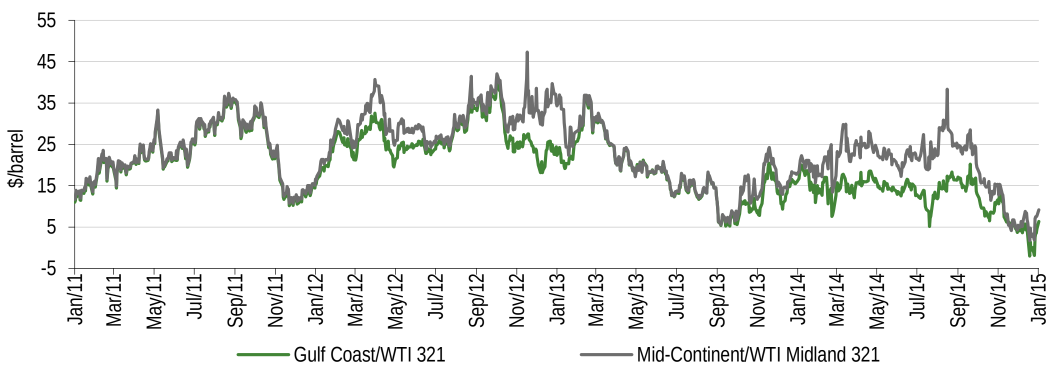
Exhibit 23: US Gulf Coast wholesale gasoline and diesel prices



Source: Bloomberg

Mid-Continent spreads: Mid-Continent refining spreads also tailed away noticeably in the fourth quarter of 2014. They, however, remained above those on the Gulf Coast reflecting lower cost Midland WTI feedstock and a slight price premium on refined products. The quarterly sequence for the Mid-Continent/WTIM 321 spread in 2014 was: Q1 $23.3/barrel, Q2 $25.3/barrel, Q3 $27.3/barrel and Q4 $10.3/barrel. The average for the year of $21.6/barrel was up on the $19.4/barrel of 2013 and impressively wide by world standards. The Mid-Continent spread was buoyed at times through the first three quarters of 2014 by ultra-depressed WTI Midland feedstock prices of $15/barrel plus on occasion. As the WTI Midland discount to WTI Cushing normalised in the fourth quarter, crack spreads also narrowed. By end 2014 the Mid-Continent/WTIM 321 spread was down to $7.5/barrel.

Exhibit 24: Recent trends in Gulf Coast and Mid-Continent crack spreads



Source: Bloomberg

Crude oil price outlook:

Backdrop: Spending cutbacks are possibly sowing the seeds of the next boom

Oil market participants were slow in appreciating the emergence of a very significant supply surplus over the past two or three years. Until recently there was a tendency to underestimate the significance of the shale revolution and overestimate the strength of demand trends and the power of OPEC. In the closing months of 2014, however, the market, in our view, more than compensated for weak fundamentals as indeed often is the case.Since late December 2014 with key benchmark light crude prices plumbing $55/barrel or less we are now at or below fully accounted costs for a wide spectrum of projects not only in the shale basins of the US but also more widely. We would also emphasise that benchmark light crude prices in real terms are back to the levels of the early 2000s. Admittedly, prices remain significantly above US variable production costs including royalties and taxes of perhaps $25-35/barrel ex the regional pricing hub but neither the macroeconomic backdrop nor the scale of the underlying surplus suggests a need to visit such levels for any length of time.

If oil prices are sustained for more than a few months below, say, $60/barrel, financing for short lead time US shale projects will rapidly evaporate if it has not done so already. Decisions on long lead time projects, whether they are the Alberta oil sands or deep water locations, will in all likelihood be deferred until the market backdrop turns more auspicious on a sustained basis. Such projects probably require prices significantly north of $70/barrel, although there might be scope for brown field oil sands projects below this level. The upshot of the downdraft in prices over recent months is that production capacity will inevitably be significantly less than might previously have been expected. This applies not today or tomorrow but medium term with a likely cutback in shale oil development the most significant factor. Developments in the marketplace could potentially sow the seeds of the next boom.

Scenario: We expect Q115 to be the nadir for prices

2015

We believe the bulk of the downdraft in benchmark crude oil prices is behind us for reasons alluded to above, in terms of investment cutbacks and medium term slower output growth. Given, however, that the supply surplus is likely to widen in early 2015, we expect the price trend to remain soft in the first half of 2015. Spot lows of below $45/barrel for Brent and $40/barrel for WTI would not be surprising during the period. This would probably imply lows for Bakken and other regional Mid-Continent crudes of well below $40/barrel and possibly nearer to $30/barrel. We look for the first half of 2015 to be the nadir on an average basis for benchmark light crudes. Our forecasts call for a 2015 first quarter average of $45.0/barrel for Brent and $42.0/barrel for WTI.

At this stage the market still looks like being in significant surplus during the second quarter of 2015 and we think that signs of falling capital expenditure will become increasingly apparent, which may buoy market sentiment. Though some firming in light crude benchmarks during the period may occur, we continue to forecast low prices in the second quarter (remaining at $45/bbl for Brent and $42/bbl for WTI). During the second half of 2015 we expect a combination of declining petroleum industry investment, particularly in the shale sector, along with rapidly slowing non-OPEC output growth to provide a more pronounced boost to prices. Our forecasts therefore call for a recovery in prices in the third and fourth quarter ($55-65/bbl for Brent in Q3-Q4 and $51-60/bbl for WTI). The averages for 2015 as a whole on our scenario are $52.5 for Brent and $49 for WTI. These averages don't pretend to be accurate to the nearest decimal place but instead to give an indication of our thoughts on possible trends.

The latest 2015 forecasts reflect major downgrades compared with those made in our early October 2014 report, which at the time were considered bearish. The downgrade reflects the sharper than expected downturn in the fourth quarter of 2014 and consequent weaker than expected carryover going into 2015. Underlying fundamentals are also proving weaker than expected particularly in terms of demand.

2016

In 2016 we see scope for a significant rebound in prices. This derives from our view that the market is likely to be showing clear signs of tightening during the year while investment intentions continue to be adjusted downward reflecting the lagged impact of marginal economics on new projects. Our 2016 forecasts call for Brent and WTI to average $72.5barrel and $67.5/barrel respectively.

Upside and downside risks

In the near term, which we will define as over the next six months, we believe there are three key issues concerning the direction of the oil market:

- The strength of the Chinese economy and the speed of adjustment to slower growth. Officially the Chinese economy is growing at 7% pa or so but many key indicators such as vehicle sales, power consumption and steel production point to a significantly slower pace. A further downgrading of expectations for Chinese petroleum demand would be highly influential for the supply/demand balance and market sentiment in a negative direction.
- The trend in US drilling activity and oil production bearing in mind that the surge of recent years has been the key factor driving the market into surplus. Quite simply, the longer the US trend remains strongly upward, the more bearish for oil prices and vice versa. Any signs of significant declines in US drilling activity and output could result in a major price rebound. It should be remembered here that the US rig count and production statistics are published weekly. We regard US drilling activity and production as the key leading indicators for oil prices.
- The deliberations of OPEC. Although the conventional wisdom is that OPEC will maintain output at the target level of 30mmb/d until at least the next regular meeting in June, there is a possibility, albeit remote, that an extraordinary meeting at an earlier stage will result in a cut. An unexpected cut would clearly catch the market off balance. Another factor to bear in mind on the OPEC front is the extent to which there is compliance with the 30mmb/d target. Compliance with the target would probably be perceived as bullish for prices.

How likely is a return to $90-100 oil?

We believe this is unlikely on a two-year view. The caveats are that the OPEC umbrella is not reinstated, there are no major geopolitical events that disrupt (rather than threaten to disrupt) supply and the world economy is not stronger than the consensus now believes possible. In our view, a key constraint on a rapid rebound in prices to say $100/barrel is the relative ease with which shale oil development could be restarted or existing development programmes intensified. The major US shale oil operators all have a suite of drilling locations in their respective plays with well-defined operational characteristics and economics based on type curve analysis. Lead times in terms of drilling and well completion are short and transportation infrastructure is not an insuperable problem. We all know now, if not previously, that shale oil development is highly viable at $90-100/barrel and costs are tending to fall. Furthermore, as we have noted, over the next two years Brazilian production should be gaining momentum, Kashagan should at last be coming on-stream, Alberta oil sands output will continue to grow and Iraq production could be growing strongly.

The question now arises as to what might constitute a medium-term price ceiling. We think the answer might be around $75-80/barrel assuming no re-emergence of the OPEC umbrella. This is $5-10/barrel above the top end of the range of fully accounted costs as defined by Wood Mackenzie for core US shale projects and thereby makes a comfortable allowance for capital costs. Effectively, shale projects now determine industry medium to long run marginal cost.

Exhibit 25: Brent and WTI price scenarios

$/bbl	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015e	2016e
WTI	56.6	66.1	72.2	99.8	62.0	79.5	94.9	94.2	98.0	93.2	49.0	67.5
Brent	54.5	65.4	72.7	97.7	62.0	79.7	110.0	112.0	108.8	99.1	52.5	72.5

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

US natural gas market

Production and net imports

Recent trends: Production buoyed by Marcellus and by-product gas shale oil plays

Production

US natural gas production has continued to grow strongly in recent months. Based on EIA data, marketed production in the nine months to September 2014 came in at 20.10tcf, up 5.1% on a year earlier. In September itself production of 2.29tcf was 7.5% higher than a year previously, although slightly down on the previous month's 2.35tcf, which we believe was a record. Production appears to have remained on a strong upward trend in the closing months of 2014. According to the Denver-based consultancy Bentek Energy, production in the week ending 7 December was running at about 73bcf/d, a hefty 13% above a year earlier. The EIA is forecasting marketed production for 2014 of 27.1tcf, a record and up 5.5% on 2013. This comfortably exceeds the five-year growth rate to 2014 of 3.3%.

Significantly, the strong production performance in 2014 was achieved despite declining dry gas drilling activity. The explanation foro the apparent conundrum can be attributed in part to rising by-product gas production in shale oil plays and in part the bringing on-stream of highly prolific new wells in the Marcellus and Utica plays in the Appalachia Basin. At the end of 2014 new-well output per rig in the Marcellus was almost 8,000mcf/d (easily the highest in the US), up about 7% on a year earlier and roughly 7x the level prevailing in 2010. In the case of the Utica play, output per new well has climbed over the past year by over 40% to 4,246mcf/d. Importantly, in terms of economics, drilling and well completion times are all on a downward trend.

Overall, shale plays now contribute about 58% of US marketed gas output which at end 2014 was running at about 76.2bcf/d. Production from shale formations of about 44bcf/d towards end 2014 was 19% above a year earlier. The Marcellus formation of Pennsylvania and West Virginia is by far the largest shale contributor with estimated production in December 2014 of 16.1bcf/d, according to the EIA. Compared with a year earlier, this was up 42%. The Marcellus is now comfortably the largest source of gas in the US and accounted for about 21% of overall US production in late 2014. In fact, the Marcellus is vying for the world's number one position as a source of gas. Remember here that Marcellus production only started to gather pace in 2010.

The Utica formation, which lies beneath the Marcellus in Pennsylvania and Ohio and is the newest major US shale gas play, witnessed very strong growth in 2014. According to the EIA, Utica dry gas production in November 2014 was 1.98bcf/d, 4x the level of a year earlier and about 2.4% of the US total. Based on EIA forecasts, Utica production will probably account for over 3% of the US total in early 2015. Production in the Utica only started in earnest in 2012.

Impressive discoveries in the Utica of late

The newsflow concerning exploration and development activity in the Utica play has been very interesting in recent months. First, there was the announcement in September concerning Magnum Hunter's Stewart Winland 1300U well in Tyler County, West Virginia. An initial production rate of a highly impressive 46.5mmcf/d or 7,750boe/d was reported. Stewart Winland was followed in December by Range Resources even more impressive Point Pleasant well in Washington County, Pennsylvania. This had a 24-hour initial production rate of 59.0mmcf/d or 9,833boe/d. Furthermore, Point Pleasant, like Stewart Winland, is in the little explored eastern sector of the Utica. The results of the two wells point to the emergence of a major new Utica play zone. Taken as whole, the Utica play appears to have the potential to follow the Marcellus as a world-class source of natural gas.

Production trends in 2014 were also strong in key gas plays such as the Bakken, Eagle Ford along with a group of miscellaneous plays, which the EIA has identified as the rest of the US. In

November, year-on-year gains were 27%, 43% and 37% respectively. The Woodford play in Oklahoma also showed a year-on-year gain of 5% but for the more mature shale plays such as the Barnett (Texas), Fayettville (Arkansas) and Haynesville (Louisiana and Texas) there were declines of 3% to 11%. As has been apparent for some time, rapid growth in shale gas production has been partially offset by declines from conventional sources. This is exemplified by the year-on-year declines in the year-to-date September 2014 of 20% in Louisiana, 8% in the Gulf of Mexico and 4% in Wyoming.

Net imports

Historically, the US has had a net import balance in natural gas mainly reflecting sizeable pipeline imports from Canada. In recent years net gas imports have fallen sharply reflecting both rising exports to Canada and Mexico and falling imports from the former. Between 2009 and 2013 the balance narrowed by 51% to 3.59bcfb/d (marketed production averaged 70.2bcf/d in 2013). The underlying drivers behind the narrowing have been the surge in the availability of gas over the past 10 years, courtesy of intensive shale development activity and strong demand growth in Mexico.

In early 2014 the trend in net imports temporarily reversed due to adverse weather conditions in the US, which depressed pipeline exports to Canada and Mexico and actually sucked in more imports from Canada. Net imports in January and February averaged 4.51bcf/d, up 18% on a year earlier. Following the first two months the underling export and import trends reasserted themselves resulting in a renewed narrowing in the net import balance. By September 2014, this was down to a mere 2.73bcf/d or 3.6% of marketed production. For the nine months to September 2014 net imports averaged 3.12bcf/d down 10.6% on 2013. Interestingly, imports and exports both fell in the nine months to September 2014. Year-on-year, imports were down 8.2% while exports were off 6.4%. The drop in imports and exports essentially reflected movements from and to Canada. Meanwhile, exports to Mexico in the nine months to September continued to rise and were up 7.0% on a year earlier at 2.0bcf/d. During the third quarter of 2014 exports to Mexico were running at a record level of 2.17bcf/d.

For 2014 as a whole the EIA is looking for a net import balance of 3.12bcf/d, which based on recent trends appears on the high side. A narrowing to 2.20bcf/d or 2.9% of marketed production is forecast for 2015. This largely stems from both the buoyant production trend, which should cut Canadian imports and strong Mexican import demand growth. Mexico's demand is growing at over 5% pa according to the national oil company Pemex, driven by buoyant industrial activity and power generation needs. Significantly, the production trend in Mexico is flat. Note burgeoning supplies are available from Texas at prices close to US levels of $4/mmBtu, a considerable discount to international LNG prices, which even after the dip in recent months are still above $10/mmBtu on a spot basis.

Los Ramones pipeline

Net Midstream's 2.1bcf/d Agua Dulce Pipeline from the hub of the same name near Corpus Christi to Rio Grande City on the Mexican border has recently been completed and should come fully on-stream during 2015. Significantly, the first phase of the 114km Los Ramones pipeline from Rio Grande to Los Ramones, near Monterrey in Mexico's Nuevo Leon State was inaugurated at the beginning of December 2014. Work is underway on the second phase from Los Ramones to Apaseo e Alto in north-central Mexico. Completion of this is possible by late 2015 or early 2016. The Los Ramones pipeline covering 850km is Mexico's largest pipeline expansion project in over 40 years and will enable the Eagle Ford gas fields to be connected with some of Mexico's major industrial centres. Given the Los Ramones project in particular, US export of gas to Mexico should grow very strongly over the next few years.

LNG exports

LNG export shipments are seen by industry sources as offering a major new market for US natural gas. Currently, four projects along the Gulf Coast and Chesapeake Bay on the eastern seaboard have been approved for exports with a total capacity of about 8.3bcf/d or 11% of current US natural gas production. The most advanced by far is Cheniere Energy's 2.8bcf/d Sabine Pass facility in Louisiana. This is scheduled for start-up in late 2015. The other three approved facilities are expecting to commence operations between mid-2017 and 2019.

A key commercial advantage of the planned US LNG start-ups was considered to be their plans to sell LNG using a Henry Hub pricing base (plus fees for liquefaction and transport) rather than an oil-based formula as is standard industry practice. Assuming $100/barrel oil and $4mmBtu, the proposed pricing formula might have suggested an advantage to the US facilities of about $3.90/mmBtu or 35% on shipments to Asia. The rout in oil prices in recent months potentially changes the picture radically. If we now assume $60/barrel oil (one barrel is equivalent to approximately 6mmBtu) and a pricing formula based on an 85% discount to reflect LNG's lower calorific value (contract prices are usually slightly less than the 6:1 heat equivalent parity between oil and natural gas), the LNG price would be $9.00/mmBtu rather than the $15 or so prior to the oil price rout. Meanwhile, at the early January 2015 Henry Hub price of $3.10/mmBtu the implied cif Asia LNG price would be $10.07/mmBtu, including $3.50 for liquefaction, $3.00 for transportation and a 15% handling fee. LNG projects are, of course, long term in nature and economics might be substantially different than at present in two or three years' time. Nevertheless, recent oil market developments might well result in the abandonment of some US LNG projects not yet approved.

Outlook: Production trend stronger than previously expected

US natural gas production has trended more robustly over the past two or three years than might have been expected given the slump in dry gas drilling activity. Tending to support production have been three key factors:

- Advances in drilling and completion techniques that are cutting well completion times, boosting well productivity and lowering costs.
- Rapid growth in by-product gas production stemming from shale oil development activity.
- High-productivity well development in the Marcellus and Utica formations.

The EIA is forecasting US production gains of 5.5% to 74.26bcf/d in 2014 and 3.1% to 76.58bcf/d in 2015. The forecasts constitute significant upgrades compared with growth of 3.0% and 2.5% anticipated earlier in 2014.

Consumption

Recent trends: Subdued of late due to mild weather

US natural gas consumption in 2014 was relatively buoyant but this was largely a first quarter phenomenon driven by harsh weather conditions in much of the country at the time. Based on the EIA's latest data, year-on-year growth in the first quarter was 7.9% to 95.5bcf/d. In the second and third quarters year-on-year gains slowed to 2.1% and 1.4% respectively, while in the fourth quarter consumption was broadly flat, according to the EIA. Significantly, third-quarter temperatures across the eastern seaboard and Midwest were below normal, which held air conditioner and hence electricity use in check. In the aggregate temperatures appear to have been normal in the fourth quarter with mild conditions in October and December offset by a colder than average November. On average in 2014 the EIA estimates natural gas consumption at 73.87bcf/d, up 3.2% on a year earlier. Based on Bentek Energy data, consumption has recently been trending about 7% below year-ago levels reflecting mild weather conditions. This could point to some vulnerability to the EIA fourth-quarter forecast.

The most buoyant market segments for natural gas in 2014 were residential and commercial. Through the first nine months the former and latter were down year-on-year by 8.4% and 8.5% respectively. Industrial users also showed solid growth of 4.6% but power generation, normally the largest market, was down 1.1%. In terms of the former, demand was supported by a reasonably buoyant economy but the latter has continued to suffer from a loss of competitiveness vis-à-vis coal. Not surprisingly, consumption growth in the first half was driven by the residential and commercial segments (about 50% of households use gas for space heating) with gains of 8.9% and 10.2% respectively. Industrial users also lifted consumption by 4.3% but power generation use, normally the largest market for gas, slipped by 0.4%. In terms of the former, demand has been supported by reasonably buoyant industrial activity. Power generation demand, however, has continued to be adversely impacted by deteriorating competiveness vis-à-vis coal. According to the EIA, the natural gas power station burn rate dropped slightly in the nine months to September from a year earlier from 27.4% to 27.1%. By contrast, the coal burn rate rose from 39.1% to 39.4%.

The EPA's (Environmental Protection Agency) proposals announced in June 2014 to cut US power station emissions by 30% by 2030 from a 2005 base could provide significant medium- to long-term support for natural gas usage in the US. Natural gas generates about 50% less CO_2 per unit of energy than coal. The EPA intends finalising the ruling by June 2015 and requires states to submit implementation plans by June 2016. Not surprisingly, a number of states have criticised the EPA's costly proposals while 15 have challenged their legality. There is also strong opposition across a wide swath of Congress, so the EPA's proposals in their current form may not be a fait accompli.

Outlook: Lacklustre trend likely to continue near term

The EIA is forecasting a modest decline in US natural gas consumption in 2015 of 0.6% to 73.39bcf/d. The latest forecast is driven by the residential and commercial segments and reflects a normalisation of weather conditions. Largely offsetting weakness in residential and commercial is expected to be gains in industrial and power generation. The former should continue to be buoyed by a strengthening economy while the latter may benefit from the closure of coal-fired generating capacity as emissions regulation tightens and possibly more competitive natural gas prices. As always, US natural gas consumption is highly sensitive to weather conditions. A colder than normal first quarter and a warmer than normal third quarter of 2015 could substantially alter the picture.

Inventories: Looking comfortable given the supply/demand backdrop

US natural gas inventories entered the current extraction season at the beginning of November 2014 at 3,611bcf, 237bcf below the five-year average. This reflected the severe drain on inventories in the first quarter due to the previously referred to harsh weather conditions. A combination, however, of the robust trend in production and subdued demand in the second and third quarters, resulted in a much smaller variance compared with the five-year average at the beginning of the extraction period than might have been expected.

US natural gas inventories would appear to be at comfortable levels even if weather conditions deteriorate radically in the coming weeks. On 26 December they stood at 3,220bcf, 8% higher than a year ago and within the five-year range, albeit at the lower end. We believe that a continuation of normal weather conditions in the coming weeks and a continuation of the robust production trend could result in inventories at or above the five-year average at the beginning of the injection period in early April 2015.

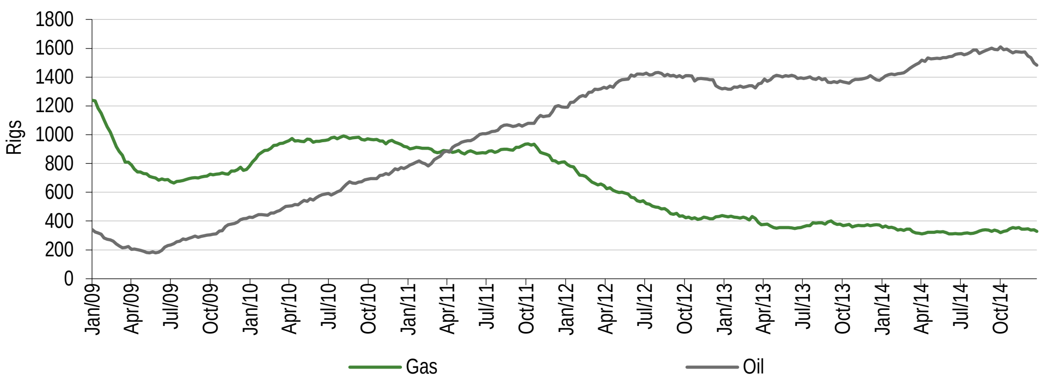
Drilling activity: Signs of slippage in the oil-based rig count, downward trend likely to gather pace in 2015

US drilling activity overall has shown signs of slippage since September 2014 when the pressure on oil prices started to gather momentum and the lower end of the four-year trading range was approached. Based on Baker Hughes data, the rotary rig count in total on 26 December 2014 was

1,840, down 5% from the high on 26 September. This decline, however, occurred from an historically high level. Compared with a year earlier the rig count overall on 26 December was in fact still up 4.7%. Significantly, the oil rig count has dipped 6.8% to 1,499 from the record high of 1,609 on 10 October but it still remains 8.5% above a year ago. In contrast to oil, the dry gas rig count has followed a flat to downward trend in 2014. On 26 December it stood at 340, down 9.1% on a year earlier and considerably below peak levels of around 1,600 in 2008 and 992 as recently as 2010.

Looking at the largest shale oil plays, Eagle Ford, Williston Basin and the Permian Basin the rig count has slipped noticeably in all three of late. Compared with the recent highs in September /October the rig count on 26 December was down 10.5% (22 rigs), 10.1% (20 rigs) and 6.1% (35 rigs). The Denver-Julesburg Basin has also witnessed a decline of 16% (8 rigs) since the 3 October high. Downward pressure on the rig count and drilling activity is hardly surprising in the light of the dramatic deterioration in petroleum industry economics in recent months and the already announced cutbacks in capital expenditure. The trend has further to run in the absence of a strong rebound in prices. A halving in the oil rig count from peak levels would not be surprising during 2015. As far as dry gas is concerned, we would expect to see the rig count continuing to trend at historically low levels for the foreseeable future. Significant cutbacks in dry gas drilling from recent levels are very much in the cards in our view, given distinctly marginal economics at current prices particularly in Appalachia and the spillover effects of pared back energy sector capital spending more broadly. We continue to believe that US gas prices will probably have to be sustained at about $5/mmBtu before a resurgence in dry gas drilling activity takes place.

Exhibit 26: Baker Hughes US rig count



Source: Bloomberg/Baker Hughes

Recent price developments and outlook

Dry gas: Prices plunge in late 2014, Dominion South hub below $1/mmBtu

After receiving a boost in November from unseasonally cold weather in the Midwest and eastern seaboard, US natural gas prices slumped in December 2014 to depressed levels based on the experience of the past 10 years. Taking the traditional Henry Hub, Louisiana benchmark, the spot high was $4.41/mmBtu on 20 November but by 24 December the price was down to $2.75/mmBtu. This was a clear closing low for 2014 and also the lowest level in 30 months. Compared with a year earlier, when gas prices were buoyed by harsh weather conditions the December low was down 38%. Over the balance of December the Henry Hub quote recovered to $2.99/mmBtu. Owing to the buoyant November showing at $3.82/mmBtu the fourth quarter average was only 4.8% down on the prior quarter. The trend in the Henry Hub price during 2014 was clearly downward as reflected by the quarterly profile ($/mmBtu): Q1 $5.16, Q2 $4.59, Q3 $3.94, Q4 $3.74. The average for the year of $4.36/mmBtu was 17% above a year previously and a post 2010 high.

The key driving forces behind both the quarter to quarter swings and the trend in the Henry Hub price in 2014 were harsh weather conditions during the first quarter, unseasonally cool conditions in the summer months, mild weather in December and buoyant production. The market not unreasonably, in our view, has come to the conclusion that inventories in the coming months are likely to be at very comfortable levels bearing in mind mild winter weather and strong production growth.

Increasingly influential Dominion South hub

The Henry Hub is losing relevance as the key US natural gas benchmark. This reflects the declining trend in Gulf of Mexico production and rapidly growing output in the Appalachian region from the Marcellus and Utica formations. The Gulf of Mexico now accounts for just 5% or so of US natural gas production while the Marcellus and Utica weighting combined is about 25%. One of the key natural gas pricing reference points for Appalachia is Dominion Transmission's South Point pool with hubs in Lebanon, Ohio and Oakford, Pennsylvania.

As in the case of the Henry Hub, the Dominion Transmission South price rose strongly between late October and November, reflecting a sharp increase in demand related to harsh weather conditions. The price hit a peak of almost $3.84/mmBtu, 2.7x the mid -October 2014 low. Not surprisingly, the Dominion South price subsequently slumped in a similar fashion to the Henry Hub and by 23 December was down to $0.95/mmBtu. This was not just a 2014 low but also 65% below the Henry Hub level on the same date. Since early 2014 the Henry Hub and Dominion prices have tended increasingly to diverge,. The quarterly sequence for the Dominion South price in 2014 was Q1 $4.95, Q2 $3.60, Q3 $2.33 and Q4 $2.50. The average for the year of $3.35/mmBtu reflected a discount of 23% to Henry Hub.

The Dominion South discount reflects slack demand, particularly during the summer months, in Appalachia and the eastern seaboard, surging production and pipeline constraints. Effectively, a sizeable supply surplus has built up in the region. Medium-term pricing relief could come from petro-chemical industry expansion and pipeline construction taking more gas to the eastern seaboard and westwards to the Midwest and southwest to potential LNG plants on the Gulf Coast.

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	3.70	3.17	4.37	3.94
2010	5.15	4.15	4.32	3.86	4.37
2011	4.18	4.37	4.12	3.33	4.00
2012	2.43	2.29	2.88	3.40	2.75
2013	3.49	4.02	3.55	3.84	3.73
2014	5.16	4.59	3.94	3.74	4.36
2015e	4.00	3.50	4.20	4.10	3.95
2016e	4.10	3.40	4.30	4.10	3.98

Source: Bloomberg and Edison Investment Research

Outlook: Near term, the trend in US natural gas prices is expected to remain seasonally weak given buoyant production, comfortable inventories and mid-term weather forecasts which appear to preclude sustained seasonally low temperatures across the Midwest and eastern seaboard. Against this backdrop, it would not be surprising if the Henry Hub averages $4/mmBtu or less during the first quarter of 2015. Doubtless, however, there will be a cold spell at some stage during the first quarter that will significantly lift the number of heating days and hence gas prices. At this stage the outlook for prices in the second quarter is particularly bearish given the prospect of seasonally high inventories going into the injection period. Provisionally we look for the Henry Hub to average $3.50/mmBtu. As usual, the third quarter is dependent on the seasonal strength of air conditioner use during the summer months. Possibly this time around we are due a quarter with above average temperatures. Assuming this to be the case, we forecast a third quarter average of $4.20/mmBtu.

For the fourth quarter we forecast $4.10/mmBtu on the assumption of seasonally normal weather conditions.

The implied average for 2015 based on the above is $3.95/mmBtu. This is down from $4.18/mmBtu forecast previously reflecting the assumption of a significantly looser supply/demand balance than expected particularly in the first half. We believe that in the absence of a sustained period of extreme weather during the winter and summer or major infrastructure outages that an average Henry Hub price in 2015 much above $4.20/mmBtu is highly unlikely.

As far as 2016 is concerned, we look for the Henry Hub price trend to remain on a lacklustre course abstracting from the factors mentioned in the previous paragraph. Assuming normal summer and winter weather conditions we would look for an average price roughly in line with 2015 at $3.98/mmBtu. Potentially supportive developments for natural gas prices in the second half of 2015 and more particularly 2016 are a significantly weaker trend in by-product gas production stemming from shale oil development activity and cutbacks in dry gas drilling activity. The trend in the rig count and gas production will be important forward indicators for US natural gas prices in the coming months.

Exhibit 28: Henry Hub natural gas price trend

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015e	2016e
$/mmBtu	8.79	6.72	6.96	8.89	3.94	4.37	4.00	2.75	3.73	4.36	3.95	3.98

Source: Bloomberg and Edison Investment Research

NGLs: Prices also under heavy downward pressure

Natural gas liquids (NGLs) such as ethane (the highest volume NGL), propane (second highest volume), butane and natural gasoline are important petrochemical feedstocks, gasoline-blending agents, pipeline diluents and fuels. They are indeed valuable by-products of natural gas production.US NGL production has grown rapidly in recent years in tandem with the development of liquids-rich natural gas formations such as the Marcellus and Eagle Ford and more recently the western zone of the Utica. The US is comfortably the world's largest producer of NGLs.

In 2014, production, based on EIA data, looks like coming in at about 2.96mmb/d, up 15.4% on 2013. This comfortably exceeds the anticipated gain in dry gas production in 2014 of 5.5%. Taking the most recent four-week period ending 26 December 2014 production was running at 3.13mb/d, 15.4% above a year earlier. Growth will probably ease in 2015 and 2016 reflecting a likely slowdown in wet gas drilling and shale oil drilling activity. The EIA is forecasting NGL production in 2015 to grow by 8.8% to 3.22mmb/d which is only modestly above the end 2014 level.

US NGL prices in 2014 fluctuated sharply. After the weather-induced spike early in the first quarter, prices plunged over the following month or two before trending flat to down in the four or five months to August. Since August prices have plunged to historically very depressed levels. Between end August and 23 December prices (Mt Belvieu, Texas) fell as follows: ethane -21.3%, butane -44.6%, propane -45.0% and natural gasoline -49.5%. With the exception of ethane the declines have broadly paralleled that in WTI. NGL prices in late December were around 10-year lows other than for natural gasoline, which was more like a five-year low.

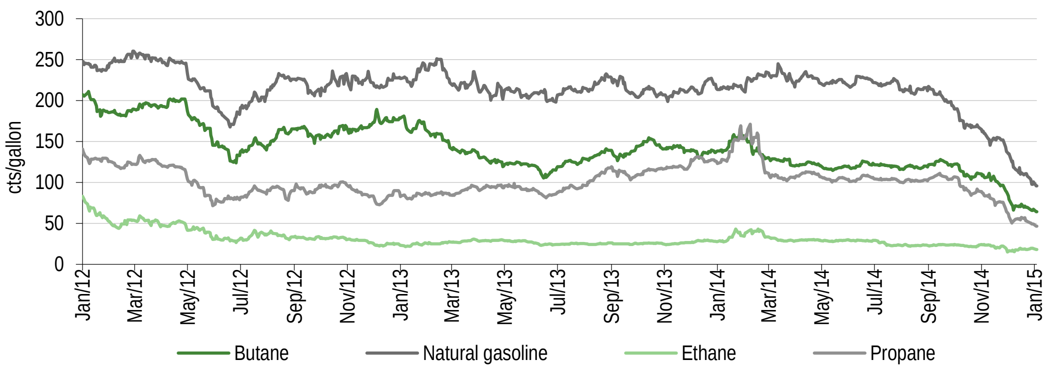
The slump in US NGL prices in recent months stems from two key factors. First, a sizeable supply surplus has emerged owing to very rapid production growth and lagging demand. A key point here has been the bringing on-stream of prolific liquids-rich gas fields in the Eagle Ford in Texas and the Marcellus and Utica formations of Appalachia. Looking specifically at propane, use in late 2013 was boosted by harsh weather but in the fourth quarter of 2014 demand was depressed by generally mild conditions. In the latest four-week period to 26 December 2014, propane demand was actually down 13% on a year earlier while inventories were significantly above the five-year average for the time of year. On a days' supply basis, propane inventories have increased by 96% over the past year to 58.5.

The second point to take into account in the slump in NGL prices is the close relationship to oil-based products. This is perhaps most obvious in the case of propane which can be used as a substitute for heating oil. Ethane in terms of applications is also closely related to oil derived naphtha. Both commodities are used as feedstock in the production of ethylene, although in the US ethane is preferred on account of the ready availability of low-cost supplies. In the light of the slump in oil and therefore in naphtha prices, an issue that has arisen for the US chemical sector is its presumed loss in competitiveness. We would argue, however, that any loss due to this factor is probably slight since NGL prices, with the exception of ethane, have tended to fall in tandem with crude oil. It should also be noted that the decline in ethane prices in recent months, unlike for crude oil, has been from an already depressed base. According to Platts, a leading energy and petrochemical journal, the ethane crack spread early in the third quarter of 2014 was about twice as high as for naphtha. This advantage is unlikely to have been completely eroded for US ethylene producers.

Near term, the trend in US NGL prices is likely to be sensitive to crude oil. In the event of a rebound in oil prices in 2015 the upside potential for NGLs may however be constrained by the supply surplus, particularly for ethane. Medium to long term (post 2016) we believe a tightening in the NGL supply/demand balance leading to a firmer price trend than has been seen in recent years is a possibility. This reflects three factors:

- The likelihood of a slower pace of capacity expansion post the price slump of late 2014. The key point here is anticipated financial constraints in the light of unattractive economics on new wet gas project development.
- US petro-chemical industry capacity expansion driven by wide ethane crack spreads. According to Platts, there are 10 major greenfield ethane-cracking projects scheduled to come on-stream in the US between 2017 and 2020 with a combined capacity of about 10.7mmtpy or 0.555mmb/d. This is equivalent to around 50% of current ethane output. There is of course a risk that some of the projects could be abandoned in the event of a narrowing of spreads.
- The possibility of significant ethane exports. Two major terminal projects are being undertaken by Sunoco at Marcus Hook on the Delaware River (70,000b/d) and by Enterprise Products adjacent to the Houston Ship Canal (240,000b/d). The projects are scheduled to come on-stream in 2015 and 2016 respectively. The key target market is Europe where ethylene is currently largely produced from high-cost naphtha. Clearly, the scale of exports will depend to a large degree on the difference between ethane and naphtha crack spreads.

Exhibit 29: Recent trends in US NGL prices



Source: Bloomberg

Natural gas economics: Dry gas distinctly marginal, wet gas still cash generative

Economics for the typical US dry gas producer is looking distinctly marginal at the late December 2014 price of around $3.00/mcf. In fact, we believe prices at this level are broadly equivalent to cash costs although still modestly above variable cost. Based on company reports we would estimate variable costs at $2.53/mcf for the typical dry gas producer reflecting $1.00 for lifting, $0.24 for severance tax, $0.75/mcf for pipeline tie-in and $0.54/mcf for royalties. After adding $0.45/mcf for G&A, cash costs would be $2.98/mcf. Finding and development cost typically run from $0.65/mcf to $3.00/mcf so even at the lower end of this range we would be looking at a significant fully accounted loss on average at a price of $3.00/mcf.

The economics of dry gas producers in the Marcellus where prices are about $1.35/mcf would appear disastrously marginal even allowing for lower operating costs than in other plays, courtesy of very high well productivity. Based on data from Marcellus pioneer Range Resources, variable costs might typically be about $1.47/mcf including royalties while cash costs would be $1.71/mcf after allowing a further $0.24/mcf for G&A. Given Range's finding and development costs of $0.63/mcf breakeven prices in the Marcellus would therefore need to be $2.34/mcf before allowing for the cost of capital.

For wet gas producers economics continues to be bolstered by revenue from liquids production. According to Range Resources, liquids currently boost realisations in the Marcellus by $3.48/mcfe (possibly somewhat less in the light of the latest plunge in NGLs) to about $4.48/mcfe (assume $1.00/mcf for gas). Cash operating costs will admittedly be greater than for a dry gas producer due to the extra processing and transportation required but the impact should be comfortably less than that of the liquids realisations. All told, we believe that Marcellus wet gas production probably still makes a significant cash contribution at late December 2014 gas and liquids prices. However, on a fully accounted basis allowing for project capital costs, including the processing plant, a Marcellus wet gas producer might not be achieving much better than breakeven.

Frankfurt +49 (0)69 78 8076 960
Schumannstrasse 34b
60325 Frankfurt
Germany

London +44 (0)20 3077 5700
80 Hgh Holborn
London, WC1V 7EE
United Kingdom

New York +1 646 653 7026
245 Park Avenue, 39th Floor
10167, New York
US

Sydney +61 (0)2 9258 1161
Level 25, Aurora Place
88 Phillip St, Sydney
NSW 2000, Australia

Wellington +64 (0)4 8948 555
Level 15, 171 Featherston St
Wellington 6011
New Zealand