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Oil & gas

Oil & gas macro outlook

The market is returning to equilibrium

1 May 2015

Since the 2015 first quarter lows, light crude oil prices have risen by around 30% despite inventories rising to record levels. Rather than inventories, the market has chosen to focus on one of the sharpest drops in the US rig count on record and the potential for a weakening US production trend in the coming months. While the lows for this cycle have probably been seen, we believe the price trend could soften near term reflecting hefty inventories and buoyant OPEC supply. The issue of Iranian exports could also weigh on prices ahead of the end June deadline for a final agreement between the world's major powers and Iran over its nuclear programme. Looking at the balance of 2015, however, we continue to expect an upward trend in prices as the market returns to equilibrium driven by slowing non-OPEC supply growth and firming demand.

Supply/demand: Supply surplus narrowing

After 2014's hefty supply surplus, which according to the EIA (US Department of Energy) was about 1.3mmb/d, a sharp narrowing should take place in 2015. The EIA is looking for a modest deficit of 0.10mmb/d reflecting growth in non-OPEC supply of 0.94mmb/d and a gain in global demand of 1.04mmb/d. Significantly, after one of the largest gains on record in 2014 of 2.2mmb/d, non-OPEC supply growth is expected by the EIA to slow to 0.73mmb/d in 2015 driven by the US. The EIA forecasts a widening in the non-OPEC supply deficit to 0.55mmb/d in 2016.

US production: Signs of a weakening trend

Non-OPEC output growth over the past few years has been very much driven by the US. There is now gathering evidence of a weakening trend in the weekly US production data. North Dakota output in February was 4% below the December peak. The EIA's latest drilling report suggests a decline in oil production in US shale plays of 57,000b/d or 1% between April and May. The US oil-directed rig count is down 54% from the October 2014 all-time high. We regard the US rig count and production trends as the key leading indicators for oil prices currently.

Shale oil economics: Returning to viability

At the first quarter lows of $45/barrel for WTI and $38/barrel for Bakken we believe prices were marginal from a fully accounted cost perspective for the bulk of US shale producers. Hub prices, however, remained well above field variable cost which we would put at $20-30/barrel including royalties and state production taxes. Mid-April prices of about $57 for WTI and $53 for Bakken probably imply on average between modest and comfortable fully accounted profitability in key shale plays.

Price forecasts: 2015 upgraded, 2016 unchanged

We are upgrading our 2015 Brent and WTI forecasts reflecting stronger than expected trends year-to-date. Our forecasts call for increases in Brent from $52.5 to $58.5/barrel and for WTI from $49.0 to $53.4/barrel. The Brent and WTI forecasts for 2016 remain unchanged at $72.5 and $67.5/barrel respectively.

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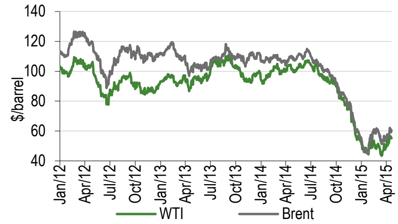
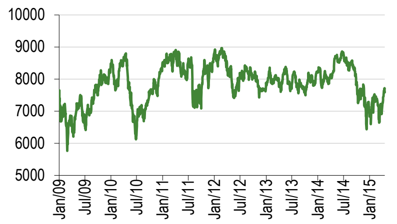
WTI vs Brent



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	53.4	58.5	3.12
2016e	67.5	72.5	3.40

Source: Edison. Note: Yearly averages.

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Contents

Highlights

Pricing

- Oil prices have been surprisingly buoyant in recent months given the backdrop of sizeable inventory gains.
- Brent and WTI forward curves remain in contango but less pronounced than in early 2015.
- At the early 2015 lows, WTI and Bakken prices were marginal on a fully accounted basis for shale producers. Prices however remained comfortably above variable cost.
- WTI-Brent spread has fluctuated sharply in 2015, ranging from $0.2/barrel in mid-January to $12.8/barrel at end-February. In recent weeks, bullishness concerning the prospects for slower US output growth has helped narrow the discount to about $5/barrel.
- 2015 crude oil price forecasts upgraded, 2016 forecasts unchanged. Light crude benchmark prices expected to trend higher over the balance of 2015 and in 2016 driven by a tightening supply/demand balance. Near term, however, we expect the trend to flatten given the inventory overhang and the Iran nuclear issue.
- Medium term, we look for a light crude price ceiling emerging at $75-80/barrel reflecting the potential for buoyant supply growth and subdued demand. US shale producers are potentially a key supply driver.

Supply

- The market has focused lately on the plunging US rig count, cutbacks in petroleum industry capital spending, the weakening trend in US production and firming US demand.
- Iran is a major wild card for supply in 2015/16 owing to uncertainty surrounding the nuclear programme negotiations and the status of the sanctions regime.
- Non-OPEC oil production increased by 2.2mmb/d in 2014, one of the highest growth rates on record. North America was the key driver.
- The US oil-directed rig count has fallen 54% from the October 2014 high. Rig productivity is however trending higher.
- Non-OPEC production growth is likely to slow sharply in 2015 and 2016 driven by the US. The EIA is looking for gains of 0.73mmb/d and 0.42mmb/d respectively.
- Driven by Canada, US crude oil imports have been buoyant in recent months.
- EIA data suggests slowing US production growth in 2015 year-to-date. North Dakota production is down from peak end-2014 levels.
- The EIA's latest drilling report suggests that US shale oil output is turning down. A decline of 57,000b/d is predicted between April and May 2015.
- OPEC production in recent months has been buoyant and above the 30mmb/d target driven by record levels of Saudi output, a partial recovery in Libya and a continuing rising trend in Iraq.

Demand

- Slower supply growth and strengthening demand could lead to a narrowing in the supply surplus in 2015. The EIA is, in fact, looking for a modest deficit.
- Global demand growth in 2015 could be over 1mmb/d buoyed by a strong showing in the US.
- Sinopec points to diesel demand in China peaking by 2017.
- US petroleum demand in 2015 year-to-date is up 4.5% versus a year earlier.

Other

- US net product exports remain at a historically high level but the trend has flattened in 2015.
- US crude oil inventories have climbed sharply in 2015 to record levels. Cushing inventories also hit an all-time high.
- ConocoPhillips has announced that it will increasingly focus development on US tight hydrocarbon resources over deepwater projects.

Executive summary

Crude oil price forecasts: our crude oil price scenario for 2015 and 2016 is broadly unchanged from our January report. We believe the nadir for prices in this cycle occurred in the first quarter of 2015 when they dropped below long-run marginal cost for a wide swathe of projects even in the sweet spots of some of the most productive shale plays. Marginal economics have led to a sharp cutback in petroleum industry capital investment which will increasingly be reflected in a weakening production trend. Meanwhile, demand, particularly in the US, is firming. The upshot should be a significant tightening in the supply/demand balance. This could set the scene for a recovering trend in crude prices over the balance of 2015 and possibly in 2016. Near-term we would however, expect the pace of recovery to be constrained by the hefty supply overhang and uncertainty regarding Iranian exports. Reflecting stronger than expected trends year-to-date we have raised our 2015 forecasts for Brent from $52.5/barrel to $58.5/barrel and for WTI from $49.0 to $53.4/barrel. Our Brent and WTI forecasts for 2016 are unchanged. We continue to believe that medium term light crude prices are likely to hit a ceiling at $75-80/barrel given the potential for relatively buoyant supply growth and subdued demand over the next few years. Key factors here relate to the flexibility of shale projects, scheduled new capacity additions and Saudi Arabia’s desire to fend off competition, not only from unconventionals but also renewables.

Recent oil price developments: after the slump in the second half of 2014, Brent and WTI bottomed in mid- to late-January 2015 at $45.3 and $44.5/barrel respectively. These prices were close to six-year lows and down about 60% on the June/July 2014 highs. After rallying strongly over the following six or so weeks, prices again came under pressure in early March, driven by burgeoning inventories. By mid-March, WTI was actually trading slightly below the January low at $43.5/barrel. Since mid-March prices have firmed noticeably. In the third week of April Brent and WTI reached around six-month highs of $62.2 and $56.7/barrel respectively. Compared with the first quarter lows, these prices were up 37% and 30% respectively. The recent rally in prices has occurred despite a sustained surge in inventories. The key driver appears to have been evidence of strengthening demand and slowing US production growth. The forward curves for both Brent and WTI remain in contango, indicating plentiful supplies but have flattened slightly since the beginning of 2015. This is consistent with more bullish market sentiment.

WTI-Brent spread: the WTI-Brent spread has fluctuated sharply in 2015 ranging from $0.2/barrel in mid-January to $12.8/barrel at end February. In the early weeks of 2015 the spread was compressed by pipeline upgrades that removed the Cushing tank farm bottleneck and facilitated the flow of oil to the Gulf refining centres. Subsequently, a heavy inventory build-up at Cushing led to a renewed widening of the WTI discount. By early March, however, sentiment was turning more bullish concerning the prospects for slower US output growth, driven by the sharp drop in the rig count and cutbacks in petroleum industry capital expenditure. In mid-April 2015, WTI was trading at a discount of about $5/barrel to Brent. This is slightly above pipeline costs for uncommitted shipments from Cushing to the Gulf Coast but somewhat below railage between the two locations.

Inland US spreads: hub 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 usually stand at significant discounts to WTI. This reflects a lack of local refinery capacity and hefty transport costs. Discounts to WTI are even more marked looking at wellhead prices netted back for transport costs and handling fees. Currently, discounts for the key Bakken and WTI Midland grades are historically low. At mid-April Bakken was trading at a discount of $3.1/barrel to WTI, well down from the $5.2/barrel average for 2014. WTI Midland, the benchmark for the Permian Basin has recently been trading at a discount of only $0.6/barrel to WTI Cushing. This compares with an average of 5.9$/barrel in 2014. The narrowing of the Bakken and WTI Midland discounts in 2015 reflects a combination of new pipeline capacity and specifically in the case of the Bakken, a softening trend in production.

Non-OPEC output: non-OPEC petroleum output rose in 2014 by 2.2mmb/d or 3.6%. This was the largest annual increase since at least 2000 and one of the largest on record. Growth is likely to decline sharply in 2015 largely driven by swingeing cutbacks in US shale oil development activity. Production is also likely to continue slipping in the mature oil-producing provinces of the North Sea and Mexico while Russia could show some slippage stemming from depletion and sanctions-related investment constraints. The EIA is looking for non-OPEC output growth in 2015 of 0.73mmb/d. For 2016, a further decline in non-OPEC production growth to 0.42mmb/d is forecast, reflecting the same factors as in the previous year. Helping buoy production in 2015/16 should be a solid upward trend in Brazil. Despite the corruption and mismanagement allegations surrounding Petrobras, the news concerning production from the giant pre-salt offshore fields remains positive.

US output: US crude oil output has continued to grow in the year-to-date but in recent weeks a distinct slowdown is apparent. Production averaged 9.39mmb/d in the four-weeks to 10 April which has left the trend broadly flat over the past month or so. Cumulatively in 2015 year-to-date, US crude oil production has averaged 9.31mmb/d, up 14.1% versus a year earlier. On the same basis, natural gas liquids and renewables have shown a gain of 9.2%. Significantly, the EIA's latest drilling report points to a potential drop in US shale oil production of 57,000b/d or 1% between April and May. The decline is modest but it does break a long period of strong uninterrupted growth. Confirming the weakening shale oil picture is the 4.1% drop in North Dakota (the source of the bulk of Bakken grade oil) production between the December 2014 all-time high and February 2015. The weakening US production trend reflects in part a lagged response to the plunge in the rig count, in part deteriorating drilling/completion economics and in part the steepness of the decline curve in shale formations. The EIA has recently downgraded its production forecasts for 2015 and 2016 to 9.23mmb/d and 9.31mmb/d (2014 8.68mmb/d) respectively from 9.33mmb/d and 9.51mmb/d previously.

OPEC output: OPEC crude oil production has remained buoyant in 2015 averaging about 30.3mmb/d through the first three months. This is above the target of 30.0mmb/d but in line with the 2015 second half 'call'. OPEC output has recently been buoyed by record production in Saudi Arabia of 10.3mmb/d, the continuing upward trend in Iraq and a surprisingly strong recovery in Libya from the depressed levels at the end of 2014. Iran is a key wild card for 2015 and particularly for 2016 OPEC production and exports. This reflects uncertainty surrounding negotiations between the world's major powers and Iran over its nuclear programme and the related UN sanctions regime. A tentative accord has been reached. The deadline for a final agreement is 30 June 2015.

Global demand: the global demand picture has firmed in recent months driven to a considerable extent by the US. Both the EIA and IEA have recently raised their forecasts for 2015 by about 0.1mmb/d. The EIA is now looking for growth of 1.04mmb/d or 1.1% in 2015 (0.86mmb/d 2014) and 1.11mmb/d in 2016. Through mid-April 2015 US demand has averaged 19.4mmb/d, up 4.3% versus a year previously. Allowing for seasonality, US demand is running at a post-2008 high. The EIA's 2015 US demand growth forecast of 1.7% appears conservative given the year-to-date trend, a relatively buoyant economy and refined product prices that are around five-year lows.

Oil supply/demand balance: the oil market in 2014 was in substantial surplus. Based on EIA data this now appears to have been1.32mmb/d, the second highest since 2000. In 2015, the surplus should narrow substantially and may even go into deficit reflecting a combination of sharply declining supply growth and rising demand. The EIA's forecast calls for a modest non-OPEC supply deficit in 2015 of 0.10mmb/d. A widening in the deficit to 0.55mmb/d is forecast for 2016. On an all-encompassing global basis the market could be looser than suggested by the aforementioned deficits due to the potential for rising OPEC output.

Shale oil economics: at the first quarter lows of $45/barrel for WTI and $38/barrel for Bakken we believe prices were distinctly marginal from a fully accounted perspective for the bulk of US shale producers. Hub prices at Cushing (WTI), Oklahoma and Clearbrook Minnesota (Bakken) however, remained well above field costs which we would estimate at $20-30/barrel including royalties and state production taxes. Mid-April 2015 prices of about $57/barrel and $53/barrel for Bakken probably imply on average between modest and comfortable fully accounted profitability on new projects in key shale plays such as the Bakken, Eagle Ford, Permian and Niobrara. Our conclusions on economics reflect fully accounted costs excluding the cost of capital per completed well of $47/barrel in shale play sweet spots. Note, wellhead economics particularly in the more remote plays such as the Bakken may be significantly inferior to that indicated, due to the need to net back hefty transportation costs.

Crude oil market dynamics

Price overview

Market developments: Prices arguably surprisingly buoyant of late

Recent months in retrospect – arguably, oil markets have been surprisingly buoyant over the past two to three months. After the slump in the second half of 2014, Brent and WTI bottomed in mid- to late-January 2015 at $45.3/barrel and $44.5/barrel respectively. These prices were close to six-year lows and down about 60% on the June/July 2014 highs. The decline was similar to that between early-1997 and late-1998 in the wake of the Asian financial crisis. Compared with the two other price slumps of the past 30 or so years, however, the latest one was less pronounced than the 72% in late-1985 to mid-1986 and the 77% in the second half of 2008.

Exhibit 1: Brent crude oil price trend

Source: Bloomberg

Post the January 2015 lows, WTI and particularly Brent rallied significantly over the following four to six weeks. Brent and WTI both reached approximate two-month highs in mid- to late-February of $61.8/barrel and $52.8/barrel respectively. The recovering price trend in late-January and February was despite a backdrop of sizeable inventory gains in the US and more generally in the OECD. Market participants appeared willing to overlook burgeoning inventories and instead focus on the rapidly falling US rig count and sharp cutbacks in petroleum industry capital investment which probably portend a tightening market later in 2015. Post late-February Brent and WTI again softened with prices dropping back by mid-March to about $51/barrel for Brent and $43.5/barrel for WTI. During early-March, WTI in particular was affected by the bearish inventory picture. Since mid-March, prices have firmed noticeably with Brent and WTI reaching around six-month highs of $62.2 and $56.7/barrel respectively by 16 April. These prices were up 37% in the case of Brent and 30%

for WTI versus the first quarter 2015 lows. Compared with a year earlier, Brent was down 43% while WTI was off 44%.

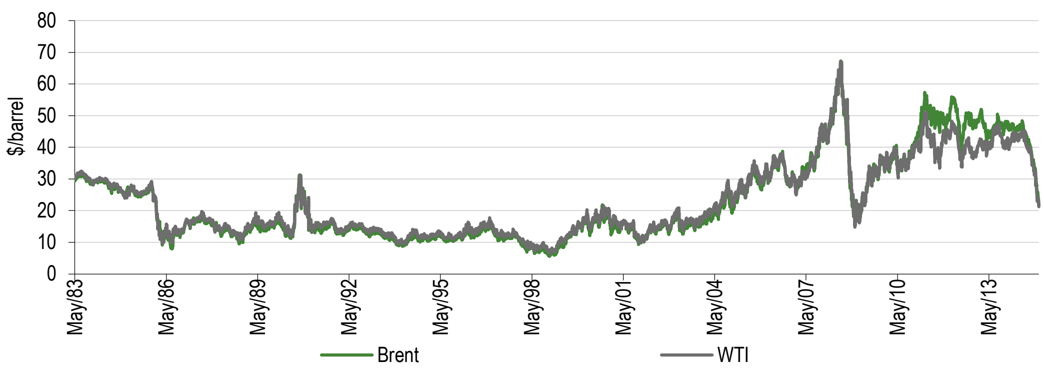
Exhibit 2: WTI crude oil price trend

Source: Bloomberg

The firming price trend in recent weeks has once again been despite strongly increasing US crude oil inventories. New factors tending to support prices of late, have been evidence of strengthening demand especially in the US and signs of slowing US production growth. A potentially bearish development for oil prices in early April was the preliminary accord between the world's major powers (five UN Security Council members plus Germany, P5+1) and Iran over its nuclear programme. Theoretically, this could pave the way for a substantial increase in Iranian exports of crude oil by late 2015. Doubts however regarding implementation of the accord, due to opposition in the US Congress and Iranian demands for an immediate cessation of sanctions post a definitive agreement have tended to dampen bearish sentiment.

What do real prices look like? In real terms, Brent and WTI prices at the low points in the first quarter of 2015 were approaching those of December 2008 at the height of the financial crisis. Using Bloomberg data, both WTI and Brent deflated by the US consumer price index with a 1983 base year, fell approximately $18/barrel in the first quarter of 2015. This compared with about $15/barrel in late 2008 and roughly $7/barrel at the earlier low points in 1986 and 1998 respectively. In mid-April 2015, Brent and WTI in real terms were trading at about $26/barrel and $24/barrel respectively, roughly 60% of the average level of $41/barrel prevailing between 2010 and the first half of 2014. It should be noted that over this period, oil prices in real terms were running at historically very high levels. Over the past 30 or so years Brent and WTI have only traded significantly higher in real terms in the second half of 2007 and the first half of 2008. Since the early 1980s the high for Brent in real terms was $67/barrel in July 2008.

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



Source: Bloomberg

Oil supply-demand balance

A substantial surplus in 2014

Globally, the oil market was in substantial surplus in 2014 reflecting a surge in non-OPEC supply and subdued demand. Based on EIA data, the production of non-OPEC liquids plus OPEC NGLs (natural gas liquids) which are unrestricted, rose for the year by 2.18mmb/d or 3.6%. Meanwhile, global demand increased by a considerably more modest 0.86mmb/d or 0.9% resulting in a surplus of 1.32mmb/d. This was the second largest since 2000. It however followed modest deficits over the previous four years averaging 0.46mmb/d.

Significantly, the gain in non-OPEC controlled supply was the largest since 2000 and one of the largest on record. It also followed the buoyant trend of the prior five years when growth averaged 1.13mmb/d and occurred despite natural depletion of perhaps 5%. As in recent years, production growth was driven largely by the US and Canada which collectively accounted for 89% (1.95mmb/d) of the gain. The contribution of the US was 1.64mmb/d while that of Canada was 0.31mmb/d. The other key contributor to non-OPEC output growth in 2014 was Brazil where production rose by 0.25mmb/d as development of the large scale offshore pre-salt discoveries gathered pace. Partly offsetting the gains in the US, Canada and Brazil were declines in mature oil producing provinces, notably the UK and Mexico.

OPEC crude oil production in 2014 was 30.08mmb/d according to the EIA. This was very close to the previous year's 30.12mmb/d and a relatively high level in terms of recent history. Consequently, net of OPEC crude, the surplus was similar to that indicated above at 1.28mmb/d. Supporting OPEC output in 2014 was a continuing buoyant trend in Saudi Arabia, a partial recovery in Iran and most significantly, growth in Iraq as new capacity was brought on-stream both in the north and south of the country. For 2014 as a whole production rose by 0.12mmb/d in Iran and 0.31mmb/d in Iraq based on EIA data. The key areas constraining OPEC growth in 2014 were Libya and Angola. Libyan output was depressed by a complex mix of civil war and strikes whilst in Angola the problems have been high decline rates and other technical issues.

Oil demand growth globally in 2014 at 0.9% was significantly under the average rate of 1.3% in the ten years to 2013. Growth was constrained by a number of factors as follows:

- recessionary forces across much of Europe and Japan;
- fuel substitution from fuel oil to coal, natural gas and renewable in power generation in Japan;
- a combination of a business slowdown and measures to curb air pollution in China.
- slower economic growth across wide tracts of the non-OECD with the former Soviet Union very much to the fore in this regard; and
- trend fuel efficiency gains across the transportation fleet particularly in the OECD world.

According to the EIA, non-OECD demand in 2014 grew by 1.22mmb/d while that in the OECD fell by 0.37mmb/d. This compared with growth in 2013 of 1.31mmb/d and 0.16mmb/d respectively. The key areas of weakness in the OECD were Europe and Japan where there were declines of 0.24mmb/d and 0.21mmb/d respectively. Western European consumption has now fallen 2.02mmb/d or 13.1% since 2008. Providing some support for OECD consumption in 2014 was a modest gain in the US of 0.7%. Canadian demand in 2014 was roughly unchanged from the previous year.

Tightening picture in 2015/16

The supply surplus should at least narrow in 2015. The EIA is, in fact, forecasting a swing to a modest deficit during the year of 0.10mmb/d reflecting non-OPEC controlled supply growth of 0.94mmb/d and a gain in global demand of 1.04mmb/d. On an all-encompassing global basis including OPEC crude, the EIA's latest forecast calls for a marginal surplus of 0.03mmb/d. The key components of this forecast are a sharp reduction in non-OPEC supply growth to 0.73mmb/d

(0.94mmb/d including OPEC NGLs) and an increase in demand growth to 1.04mmb/d. OPEC crude oil production is expected to increase slightly between 2014 and 2015 by 0.1mmb/d to 30.2mmb/d. Interestingly, the IEA's latest forecasts for 2015 are very similar to those of the EIA and also imply a marked tightening in the supply/demand balance compared with 2014.

Lower non-OPEC supply growth in 2015 reflects to a large degree a deceleration in the US and Canada as sharp cutbacks in investment in shale oil development activity following the price rout of the past eight months take hold. US growth is expected by the EIA to decline by about 50% to 0.78mmb/d while for Canada a decline of about 85% to 0.05mmb/d is forecast. It should also be noted that the downward trend in the mature producing provinces of the North Sea and Mexico is likely to continue apace while there could also be some slippage in Russia stemming from depletion in established fields and sanctions-related investment constraints.

As far as global demand is concerned, there was some evidence of a firmer trend in the closing months of 2014. During early-2015 this has continued, driven to a large extent by developments in the US. For 2015 as a whole, the EIA is looking for US growth of 0.35mmb/d or 1.7% which appears conservative compared with the performance in the early months of the year.

Globally, the EIA is forecasting demand growth in 2015 of 1.04mmb/d or 1.1%. Excluding the US, demand growth is expected to derive much as in recent years from China, East Asia, Middle East and Latin America. The EIA continues to look for declining demand in OECD Europe and Japan. The underlying reasons for expecting strengthening demand in 2015 are in part a more buoyant OECD economy particularly in the US and in part significantly lower refined product prices than in 2014. The more buoyant OECD economy in all probability considerably outweighs the significantly lower refined product prices given the low price elasticity of petroleum product demand. Note; demand growth in the developing world is likely to be dampened in 2015 by the removal or scaling back of fuel subsidies and the strong dollar.

For 2016, the EIA is forecasting a further decline in non-OPEC supply growth 0.42mmb/d (0.56mmb/d including OPEC NGLs). Meanwhile, demand growth is expected to increase to 1.11mmb/d according to the EIA, resulting in a widening in the supply deficit to 0.55mmb/d. Declining supply growth reflects the same factors as in 2015. Higher demand in 2016 stems from continuing modest growth in the US and a firmer picture in the non-OECD world predicated on strengthening economic activity.

Significantly, the EIA has recently upgraded its forecast of global petroleum demand growth while downgrading its forecast of non-OPEC supply growth in 2015/16. The upshot is a widening of the forecast deficit especially in 2016. The forecast of higher demand reflects the incorporation of recent trends while lower supply growth stems in particular from a more rapid than expected fall in the US rig count.

What are the wild cards?

We believe the EIA's forecasts for 2015/16 of the oil supply/demand balance in principle are perfectly plausible. They however are based on many moving parts and as always are subject to a high degree of uncertainty. The key areas of uncertainty at this juncture probably relate firstly to just how quickly cutbacks in oil company capital expenditure are reflected in development activity and hence production. Even modest delays compared with forecasts could significantly change the supply/demand balance picture.

Iran – we believe the second key area of uncertainty relates to Iran and specifically whether or not the tentative accord between the world's major powers and the country over its nuclear programme can be converted into a final agreement. The key issue here is that in the event of a final accord and an immediate relaxation or elimination of the sanctions regime over 30mm barrels (this number is not definitive but has been widely reported by industry observers) of oil currently in floating storage could rapidly find their way onto the market. Assuming the oil was unleashed over six months it would be equivalent to about 165,000b/d. In the event of a removal of sanctions, Iran may be in a position to boost output significantly, although would likely take several months. According to the EIA, the magnitude of the boost could be of the order of 0.7mmb/d by end-2016. The combination of a release of inventory and higher production could be highly influential for the supply/demand balance in the absence of any offsetting action.

OPEC policy stance: Focus likely to remain on market share

At its last OPEC meeting at the end of November 2014 OPEC announced that it was intent on maintaining market share. No change in this policy would seem likely in the short term at least. Recent statements by the Saudi oil minister suggest a willingness to consider controlling output is contingent on obtaining agreement with both OPEC members and also with non-OPEC producers. The chances of an accord across this disparate group would appear practically zero. Furthermore, non-OPEC producers have no interest in under-utilising capacity and anyway are not in a position to deliver collective production cuts.

OPEC crude oil production has remained buoyant in 2015 averaging about 30.3mmb/d (OPEC secondary sources) through the first three months. This is above the target of 30.0mmb/d but in line with the second half 'call'. OPEC output has been buoyed of late by record Saudi Arabian production of 10.3mmb/d, the continuing upward trend in Iraq and surprisingly perhaps, a recovery in Libya from the ultra-depressed levels of January 2015. Libyan production in March has been reported by OPEC (secondary sources) at 0.47mmb/d, up 38% on January.

It should be noted that the Saudis appear to be having some success with their policy of protecting market share. The price rout since the third quarter of 2014 has indeed exerted pressure on US shale producers to sharply cut development activity. This is gradually choking-off supply which should help contribute to at least the semblance of market balance by end-2015.

IEA medium-term forecasts: Downgraded expectations for supply and demand, shift from market balance to deficit

The IEA in its Medium Term Oil Market report published earlier this year downgraded its expectations for non-OPEC supply and global demand growth over the balance of the decade. Its current thinking is that the former will increase by around 0.57mmb/d pa on average in the six years to 2020. This compares with the previous forecast in the six years to 2019 of about 1.0mmb/d. Regarding global demand, the IEA's latest forecast calls for an average annual gain in the six years to 2020 of about 1.17mmb/d or 1.2%. Previously, the IEA had been looking for an annual average increase of 1.27mmb/d in the six years to 2019.

The above implies that rather than an approximate equivalence between non-OPEC supply and demand growth a significant deficit would be on the cards over the balance of the decade. This in turn would imply an increase in the OPEC 'call'. We suspect however that the IEA's demand growth forecast may be on the high side particularly in an environment characterised by low world economic growth and fuel subsidy reductions. In our view, medium-term demand growth is unlikely to exceed 1mmb/d on average and quite possibly might not be more than 0.8-0.9mmb/d.

Sinopec forecasts declining Chinese diesel consumption

Sinopec, the largest refiner in China, has recently suggested that diesel demand in the country will peak possibly by 2017. It has also indicated that it believes gasoline consumption will peak within ten years. These two product lines account for 53% of Chinese petroleum consumption. Sinopec's predictions caused considerable consternation in oil industry circles given that China is usually seen as one of the key reasons for bullishness concerning long-term petroleum demand trends globally. At least regarding diesel, the prediction arguably is not so radical given that Chinese demand was in fact down by 0.4% in 2014 according to IEA data. Gasoline however showed a gain of 7.3% for the same year.

The basic drift of the Sinopec argument is that a combination of a shift in the centre of gravity of the economy away from energy-intensive sectors and fuel substitution in transport fleets by CNG (compressed natural gas) and LNG (liquefied natural gas) will steadily exact a toll on diesel consumption. We would say however, that given current technology it will be very difficult if not impossible to substitute CNG and LNG in long-distance trucking fleets and aviation. Diesel is considerably more energy intensive than either of the two alternatives which translates into lower fuel consumption, smaller fuel tank capacity and higher payloads. The argument behind gasoline consumption peaking over the next ten years probably relates to prospective improvements in the fuel efficiency of the conventional light vehicle fleet and potential inroads by electric vehicles in the sales mix.

We believe Sinopec's comments regarding Chinese diesel and gasoline consumption are a salutary reminder that China can no longer be relied on to underpin world petroleum demand growth. The glory days are probably behind us.

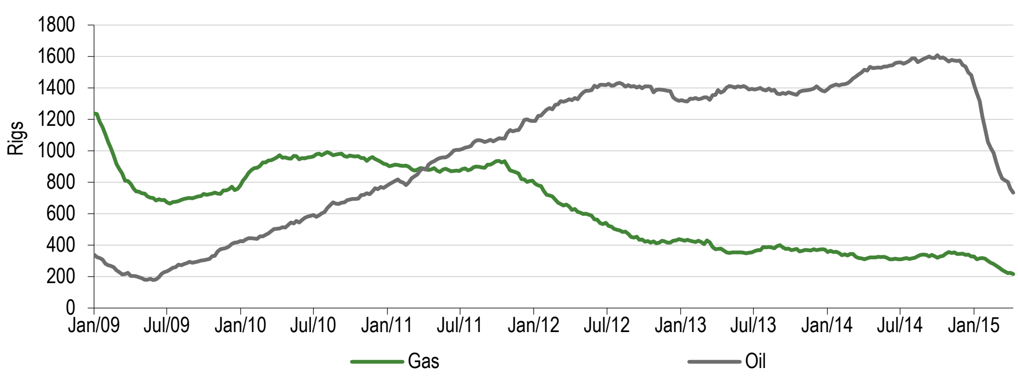
US scene

Rig count: Plunging

We believe the Baker Hughes rig count is the most insightful leading indicator for future production trends. The rig count is indicative of future drilling rates which in turn drives development activity. Having peaked in the week ending 10 October 2014 at an all-time high of 1,609 the US oil-directed rig count has subsequently plunged, driven by sharp cutbacks in petroleum industry capital spending in the wake of the collapse in oil prices. By 17 April 2015 the rig count had fallen 53% to 734, the lowest level since October 2010. The decline in the more productive horizontal rigs has been less at 43%, but not drastically so. The mid-April rig count, remains high based on the experience of the past 30 years or so, but it has to be remembered that for much of this period US onshore drilling activity was tending to be scaled back. The period from 2008 to the fourth quarter of 2014 reflected an unprecedented boom in drilling activity.

In our view, the rig count is likely to remain under further pressure in the coming months in the absence of a sharp rebound in oil prices. The key factors are falling petroleum industry capital spending and rising rig productivity. EIA data points to production/new well in shale plays increasing by 29% between May 2014 and April 2015. Whether or not drilling activity bottoms out by late-2015 will essentially depend on the trend in domestic oil prices and hence petroleum industry economics.

Exhibit 4: Baker Hughes rig count



Source: Bloomberg, Baker Hughes

Uncompleted wells – an interesting aspect of oilfield development activity in the US of late has been the appearance of a large inventory of drilled but uncompleted wells. According to industry sources there were 4,000 such wells in early April. The thinking here on the part of operators is a desire to firstly, save the sizeable cost of well completion until prices turn higher and secondly, to wait for the full impact of sliding oilfield service prices. For the more complex tight reservoir projects, completion costs are in the $4-5m range or approximately 50% of total well costs. Of course, in the meantime operators will have to finance the cost of drilling without any cash flow from the well.

This backlog of uncompleted wells may introduce a wild card into the equation concerning future production rates, but this may be overstated by looking at headline figures – we understand that the uncompleted well count is around 3,500 normally.

Oil production: Flattening trend in recent weeks, EIA anticipates a dip in shale plays

Recent trends and 2015/16 outlook – US crude production continued to increase strongly in late-2014 despite cutbacks in capital spending and drilling activity. Production in the final week of the year came in at 9.21mmb/d so there was considerable carryover strength going into 2015. So far in 2015, production has trended higher but over the past month or so there has been a significant loss of momentum. In the latest four-week period ending 17 April, crude production averaged 9.39mmb/d, up 2.8% vs end-2014 and 13.5% vs a year earlier. Cumulatively in the year-to-date 17 April 2015, US crude production has increased by 14.1% year-on-year with a gain of 15.4% in the Lower 48 states and a decline of 5.1% in Alaska. In the year-to-date, NGL production has risen by 15.4% while renewables have gained 6.2%. All told, hydrocarbons and renewables output in the year-to date has risen 13.7% to 13.42mmb/d.

Exhibit 5: US crude oil production

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

Based on EIA/Bloomberg data, shale/tight oil output is estimated to have been running at 5.62mmb/d in April 2015, up 5.3% vs December 2014 and 20.1% vs June 2014. The former growth rate has comfortably outpaced the picture for the US as a whole. Out of the top four plays the fastest rate of growth since end-2014 has been shown by the Permian with a gain of 7.3%.

Production rates have tended to reflect considerable inertia since the third quarter of 2014 bearing in mind the rapidly declining rig count, sharp cutbacks in petroleum capital spending and very high first year depletion rates in shale plays of 60 to 80%. The muted response so far of production to capital spending cutbacks and a falling rig count has not however been entirely unexpected. The explanation probably mainly reflects the following:

- lags before contractual changes between operators and drillers and other suppliers become effective;
- rising rig productivity and falling drilling costs (stemming in part from the productivity issue and in part from declining costs across a broad spectrum of inputs);
- high grading of drilling targets; and
- hedging activity.

We believe that the upward trend in US shale and tight oil production is likely to weaken in the coming months if WTI remains significantly below $60/barrel on a sustained basis. This reflects in part a lagged response to the plunge in the rig count over the past six months, in part less than compelling drilling economics outside the sweet spots at WTI prices of less than $60/barrel and in part the steepness of the decline curve in the year post well completion. On the issue of economics our thinking is that fully accounted costs, including the cost of capital are typically in the $60-70/barrel range for the major shale formations outside the sweet spots. Furthermore, there are sizeable transportation costs of up $10-$15/barrel from the Great Plains oilfields to refineries in the Midwest, Gulf Coast and the eastern and western seaboards. Realised wellhead prices in the remote plays may therefore be significantly under benchmark hub levels. Admittedly, economics in the sweet spots, particularly in the Eagle Ford, could be significantly more favourable but even here, after allowing for royalties and state taxes, profitability with WTI at significantly under $60/barrel might be considered none too enticing. Note that as drilling/completion activity levels off, very high rates of shale well depletion will inevitably become more apparent in terms of production.

Interestingly, the EIA's latest estimates point to US shale production being roughly unchanged between March and April 2015 and falling by 57,000b/d between April and May. All four major shale plays with the exception of the Permian are expected to show declines between the two months. Month-on-month declines of 23,000b/d, 33,000b/d and 14,000b/d are expected for the Bakken, Eagle Ford and Niobrara respectively. For the Permian, output is forecast to increase by 11,000b/d between April and May. Reflecting a sharper than expected drop in the rig count, the EIA has recently reduced its 2015 and 2016 full-year US crude oil production forecasts. The former has fallen by 0.1mmb/d to 9.23mmb/d and the latter by 0.2mmb/d to 9.31mmb/d. Growth in 2015 is now forecast at 0.58mmb/d or 6.7%, a marked slowdown from the previous year's 1.22mmb/d. For 2016, growth would show a further sharp decline to 80,000b/d and leave production adrift of the 1970 all-time high of 9.64mmb/d. Until recent months US crude production in 2016 appeared likely to equal or even exceed the 1970 record.

We believe that a weaker production performance than currently predicted by the EIA is a possibility in 2015 and 2016. Essentially the strength of the trend will depend on oil prices and hence petroleum industry economics and drilling/completion activity.

Exhibit 6: US shale oil production by basin/formation

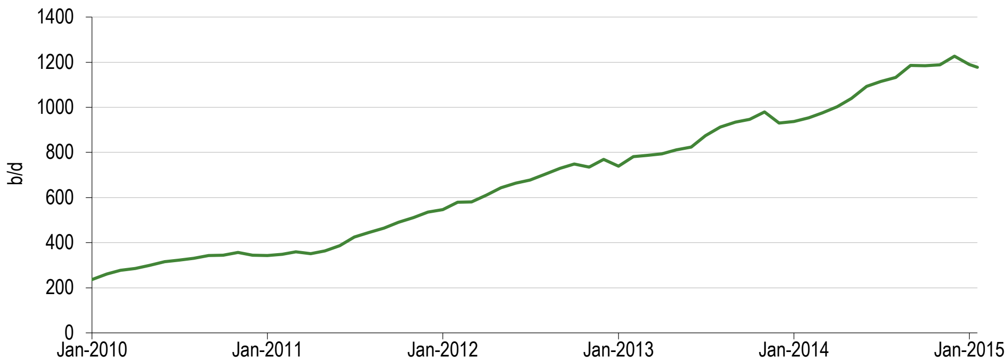
Formation	Basin	State	Apr-15 b/d (000)	May-15 b/d (000)
Sprayberry, Wolfcamp, Avalon/Bone Spring, Cline	Permian	Texas, New Mexico	1,981.4	1,992.1
Eagle Ford	Western Gulf	Texas	1,722.7	1,690.1
Bakken	Williston	North Dakota, Montana	1,320.5	1,297.9
Niobrara	Denver-Julesburg	Colorado, Wyoming	416.7	402.4
Haynesville	Texas-Louisiana Salt	Texas, Louisiana	58.5	58.5
Marcellus	Appalachia	Pennsylvania, W Virginia	57.2	57.1
Utica	Appalachia	Ohio	62.2	64.4
Total			5,619.2	5,562.5

Source: Bloomberg, EIA, Edison Investment Research

North Dakota production slips – North Dakota has firmly established itself over the past year or two as the second largest oil producing state in the US, after Texas. Around 92% of production is obtained from the Bakken/Three Forks shale/tight reservoir petroleum system. The strong upward trend in production of the past few years continued in 2014. In December, production was a record 1.23mmb/d, up 32% versus a year earlier. During the first two months of 2015 the trend has softened. There were month-on-month declines in both January and February which took production down to 1.18mmb/d, 4% lower than December 2014. While this is not a major decline, it is unusual in a North Dakota context. Typically in recent years, production slippage has largely been associated with adverse weather conditions. We are not aware of any particular abnormalities on this front in the first two months of 2015.

Based on leading indicators such as permitting, drilling rigs in operation, spuds and well completions, North Dakota production would appear likely to continue slipping in the near term at least. In March 2015, the rig count in the state at 108 was down a hefty 40% on December 2014 and was at the lowest level since the second quarter of 2010. Spuds in March 2015 at 125 were 27% below three months earlier, but slightly above the 115 or so that the local regulatory body believes is necessary to maintain production at 1.2mmb/d. Many of the new wells, however, are not being completed. The rig count has also continued to slump and in mid-April was down to 88, a level not seen since early 2010.

Exhibit 7: North Dakota production



Source: EIA

The EIA long term view shows production peaking in 2020 – the EIA recently provided its long-term forecasts for the energy sector. In terms of crude oil production it is looking for a peak in 2020 at 10.6mmb/d based on its reference case for oil prices of $75.2/barrel. This is up 15% on the forecast for 2014 with the gain driven by tight oil development. Post 2020, the EIA assuming the reference case, is looking for production to trend down to 9.43mmb/d by 2040. On the alternative low ($54.1/barrel) and high ($143.1/barrel) price scenarios the EIA forecasts production in 2020 of 9.96mmb/d and 12.29mmb/d respectively. In the 2015 reference case, production peaks a year later than forecast in 2014. The forecast made in 2015 is also about 0.8mmb/d higher.

We believe the latest EIA peak production forecast looks plausible in terms of rate of travel and our understanding of the resource base available. The shallow rate of decline projected post 2020, however, appears optimistic unless recovery rates in shale formations can be substantially boosted from current levels.

Crude oil imports: Surprisingly firm trend driven by Canada

US imports of crude were on a significant downward trend between the peak in 2006 and 2014, reflecting both declining consumption and since the late 2000s, rising domestic output. Between 2006 and 2014 the decline was 2.78mmb/d or 28% to 7.34mmb/d. The process however in recent months has ground to a halt or even gone into reverse. Taking the most recent four-week period ending 17 April 2015, crude imports averaged 7.62mmb/d, up 0.9% versus a year earlier. In the year-to-date imports are down marginally year-on-year at 7.36mmb/d.

At first glance, the recent firming trend in US crude oil imports appears surprising given very high inventories, the price discount on domestic light grades and the upward trend in US production. Import statistics suggest that the recent firming trend in crude imports is being driven by Canada. Imports from this source in 2014 averaged 2.89mmb/d, up 0.31mmb/d versus 2013, while in January 2015, they came in at 3.21mmb/d, reflecting a year-on-year gain of 0.36mmb/d. Canada is now comfortably the largest source of imported crude oil, accounting for 45% of the total in January 2015.

The upward trend in Canadian imports has been driven by upgraded pipeline and rail links between Alberta and refineries located in the US Midwest and Gulf Coast (and lack of alternative supply routes for producers). The key development of late was the opening in December 2014 of Enbridge's Flanagan South 0.6mmb/d pipeline from Pontiac, Illinois to Cushing Oklahoma. This connects with existing pipelines and greatly increased capacity for shipping diluted bitumen from Alberta to the Gulf Coast. Rail takeaway capacity in Alberta was also greatly expanded during 2014. By early 2015 this was about 1mmb/d having been virtually zero a year earlier. A ready market exists in the Midwest and along the Gulf Coast for low-cost heavy feedstock from Canada following recent refinery reconfigurations/upgrades.

Given the ready availability of light crude in the US, crude imports have increasingly focused on heavy grades in recent years. This trend is likely to persist with Canada probably taking an increasing share, reflecting planned increases in oil sands bitumen output and further upgrades to takeaway capacity from Alberta.

Inventories: Crude surges to record levels

Crude oil – US crude oil inventories have been on a modest upward trend in recent years but in 2015 they have surged, resulting in multi-decade if not record highs. Based on EIA data, crude oil inventories stood in the week ended 17 April 2015 at 489.0mm barrels. This was up 91.3mm barrels or 23.0% versus a year earlier and 103.5mm barrels versus end 2014. The EIA has referred to crude inventories being at the highest level in at least 80 years.

Significantly, historically high inventories have occurred despite seasonally robust refining activity. Refinery runs in the latest four-week period, supported by both buoyant domestic demand and export demand, were 16.21mmb/d, up 2.0% versus a year earlier and at a high level historically for the time of year. The explanation for this year's surge in inventories reflects two key factors. In the first place supply has been buoyant driven by both domestic production and imports. The second factor we believe has been the pronounced contango (forward prices higher than spot) on the forward curve which arguably encourages those of a speculative bent to hold inventory on the expectation of rising prices in due course. This strategy could be considered doubly attractive given ultra-low interest rates.

On a days' supply basis crude inventories are also at very high levels versus history. Since end-2014 days' supply has increased from 23.5 to 30.6. The latter is the highest level in about 33 years. Including the strategic petroleum reserve, US crude inventories on 17 April were 1,180mm barrels, equivalent to about 74 days.

We believe the surge in inventory accumulation could be partially rolled back in the coming months. This reflects a likely seasonal increase in refining activity, an emerging shallower forward curve contango and an expected weakening trend in US oil production. The wild card in the equation is the trend in imports. Any dip in crude oil inventories in the months ahead will, however, probably still leave them at historically high levels.

Exhibit 8: US crude oil inventories

Source: EIA

Cushing – crude inventories at the Cushing, Oklahoma tank farm, the delivery point for Nymex crude and the largest tank farm in the US, have also surged to record levels since end-2014. Inventories on 17 April 2015 stood at 62.2mm barrels, slightly more than double end-December 2014 and comfortably in excess of the previous high in early 2013 of almost 52mm barrels.

We believe the surge in Cushing's inventories in 2015 relates in part to the contango issue mentioned earlier and in part to new pipeline capacity coming on-stream in recent months. In the case of the new pipeline capacity, the key developments have been the previously discussed Flanagan South and the 0.23mmb/d Tallgrass Pony Express pipeline from the Guernsey, Wyoming hub to Cushing. The pipeline opened in October 2014 and currently carries oil from the Powder River Basin. A 100 mile lateral extension is currently being constructed to transport oil from the Niobrara fields of the Denver-Julesburg Basin in northern Colorado and south eastern Wyoming. When this is on-stream later in the second quarter of 2015 the capacity of the Pony Express pipeline will increase to 0.32mmb/d.

Near term, we believe logistical developments involving both pipelines and rail could keep inventories at historically high levels. Arguably however, the surge in recent months has run its course. According to the EIA the working storage capacity of the Cushing tank farm is 70.8mm barrels so there is technically still significant headroom available. The shell capacity stands at 84.9mm barrels.

Exhibit 9: Cushing crude inventories

Source: EIA

Gulf Coast – the Gulf Coast hosts the largest concentration of refinery and oil storage capacity in the US. Crude inventories along the Gulf Coast have also risen in recent months to historically high levels but the trend has been less pronounced than at Cushing. Inventories on 17 April were reported by the EIA at 242.5mm barrels, 43.8mm barrels higher than at end 2014 and 32.9mm barrels above a year earlier. They were also the highest level since at least 1990.

ConocoPhillips focusing on US shale

The CEO of ConocoPhillips, the largest US independent, recently indicated that it would increasingly focus on the development of tight hydrocarbon formations in the US. The rationale reflects the lower capital cost and greater operational flexibility offered by shale and tight reservoir development than long lead time deepwater and LNG projects which might take up to 10 years to complete. Shale projects typically have the virtue of short lead times once a play has been de-risked with wells often taking only a month or so to drill and complete. Production can also easily be trucked off site with minimal infrastructural outlays. Because of the short lead times and relatively low capital outlays, development activity can additionally be rapidly adjusted to swings in economics.

Given the virtues of shale oil development, the case for long lead time, frontier deepwater project development at this juncture is arguably difficult to justify. In addition to cost and long lead time considerations there is the emerging risk of stranded assets to take into account. Assets could become stranded in the event of climate change legislation being tightened globally in an attempt to radically curb carbon dioxide emissions. The global warming advocates argue that to limit the potential increase in temperatures to no more than 2 degrees above pre-industrial levels, 60% to 80% of hydrocarbon reserves will need to remain undeveloped. Long lead time projects could conceivably become increasingly subject to stranded asset risk in the years ahead.

The only point of criticism regarding the ConocoPhillips strategy is that it focuses on the US. Arguably US basins have already been well picked over for shale development potential. This may well necessitate looking elsewhere for new shale opportunities.

What's happening in Canada?

Canada is the world's fifth largest oil producer and as we have noted, one of the two largest sources of non-OPEC output growth in recent years. Thanks to the Alberta oil sands, it also has the world's third largest proved oil reserves after Venezuela and Saudi Arabia. According to the EIA, oil production in 2014 was 4.39mmb/d (+7.6%) while for 2015 and 2016 it forecasts 4.44mmb/d and 4.65mmb/d respectively. The Alberta oil sands have been driving Canadian production and are expected to continue to do so. In 2014, production from this source was about 2.2mmb/d with the balance in Canada stemming from conventional and shale reserves in the Western Canadian Basin and offshore the Atlantic coast. Significantly, in the first quarter of 2015, production had returned to more normal levels of about 294,000b/d at Syncrude, the largest oil sands producer, after a spate of unplanned outages in 2014.

Many industry observers suggested that oil sands development was particularly vulnerable in the wake of the late 2014 oil price collapse due to theoretically marginal economics. Indicative of this in the first quarter of 2015 was that the Syncrude price at the low point, was down pretty well to cash operating costs of around US$40/barrel. While there have certainly been cuts in oil sands capital investment (probably at least a third compared with planned levels) the major players such as Suncor, Canadian Oil Sands and Imperial continue to pursue existing projects. The only greenfield to be cancelled so far in 2015, has been Shell's 0.20mmb/d Pierre River project in northern Alberta. Instead, Shell will concentrate on enhancing the profitability of its Athabasca mining project. It should be noted that Pierre River has been long delayed and was considered marginal at prices considerably higher than those prevailing currently. Elsewhere in recent months, Suncor has deferred the second phase of its Mackay River project while Cenovus and ConocoPhillips have postponed expansions of their Christina Lake and Foster Creek joint projects.

Oil sands producers have also understandably expressed no interest in cutting production. Indeed on the contrary they are looking to expand output to lower unit cost and boost cash flow. Remember here, that not only are fixed costs high due to the engineering complexity of the process, but stopping key processes such as steam generation only to restart them a few months later would probably be prohibitive.

The oil sands have major positives – oil sands projects are usually critiqued on the basis of costs and the environment. Regarding costs, the situation is probably improving given falling input prices, intensified action by operators to improve operational performance and the cheapening Canadian dollar. Environmental objections relate to GHG emissions**,** water usage, large scale tailings ponds for mining projects and destruction of the boreal forest.

Against the well-publicised negatives of oil sands projects we see some major positives compared with either conventional or shale oil projects which are generally less well understood. These include an absence of exploration risk, very high recovery rates and low or virtually non-existent decline rates in the case of mining projects. In summary, oil sands projects provide large scale, long- life sources of oil at costs that are probably less than deepwater projects and not greatly different than many shale projects. From a pure financial perspective the key drawback to the oil sands are arguably high transportation costs reflecting the land-locked location in Alberta and the need to use diluents to transport bitumen by pipeline. Light crude spreads

WTI-Brent: Volatile picture in early 2015

The WTI-Brent spread, after stabilising in the fourth quarter of 2014, swung sharply in the first quarter of 2015. In early January 2015, in fact, the WTI discount that had existed largely uninterrupted since late 2010 almost vanished. At the narrowest point on 14 January it was a marginal $0.2/barrel. The narrowing tendency in December 2014 and the early days of January 2015 reflected pipeline upgrades that effectively removed the Cushing bottleneck and facilitated the flow of oil from Texas and the Mid-Continent to the Gulf Coast. Post the January low, the WTI discount to Brent rapidly widened as a consequence of the renewed heavy inventory build-up at Cushing, the Nymex delivery point. By end-February 2015, WTI was trading at a $12.8/barrel discount to Brent. This was the widest in about a year.

Subsequent to end-February, the WTI discount has narrowed despite further increases in Cushing's inventories to record levels. The new driver has been the emergence of more bullish sentiment surrounding WTI reflecting expectations of slower US output growth. For the first quarter of 2015 the WTI discount to Brent averaged $5.4/barrel, somewhat wider than the $3.2/barrel of the fourth quarter of 2014, but narrower than the year earlier $9.2/barrel. Through the first three weeks of April, WTI traded on average at a discount of $5.9/barrel to Brent.

Currently, the WTI discount is somewhat in excess of pipeline costs for uncommitted shipments from Cushing to the Gulf Coast of $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 need to be around $7/barrel. To facilitate the flow of oil to the Gulf Coast, we would normally expect the WTI discount to be at least $6-7/barrel. In practice the WTI-Brent spread will also be sensitive to international developments. Geopolitical issues, for example, that threaten to affect oil availability outside the US will therefore tend to widen the discount. Conversely, stepped-up exports from Libya and Iran would, other things being equal have the opposite effect.

Exhibit 10: Brent 2009-16 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	53.9	57.0	58.0	65.0	58.5
2016e	68.0	72.0	75.0	75.0	72.5

Source: Edison Investment Research, Bloomberg. Note Q115 is an actual.

Exhibit 11: WTI 2009-16 quarterly prices ($/bbl)

	Q1	Q2	Q3	Q4	Average
2009	43.2	59.7	68.1	76.0	62.0
2010	78.8	77.9	76.1	85.2	79.5
2011	93.9	102.3	89.5	94.0	94.9
2012	103.0	93.3	92.2	88.2	94.2
2013	94.3	94.1	105.8	97.6	98.0
2014	98.7	103.1	97.6	73.2	93.2
2015e	48.5	52.0	53.0	60.0	53.4
2016e	63.0	67.0	70.0	70.0	67.5

Source: Edison Investment Research, Bloomberg. Note Q115 is an actual.

In the absence of major geopolitical developments we would expect WTI to trade over the next few months at a $4-5/barrel discount to Brent. We believe that market expectations of slower output growth in the US will tend to keep the discount compressed compared with the situation in recent years. Any sign of falling inventories at Cushing on a sustained basis would reinforce the compression as possibly would an end to the Iranian sanctions regime. On average, we look for WTI to trade at a discount of about $5/barrel to Brent in both 2015 and 2016.

Exhibit 12: 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). Cushing serves the Mid-Continent and Midland, 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. In 2014, however, there were wild fluctuations reflecting a combination of buoyant production in the Permian Basin, lags in installing new takeaway infrastructure and a series of refinery outages. These issues culminated in the unprecedented WTI Midland discount of $21/barrel in August last year.

In recent months the WTI Midland- Cushing spread has returned to normal and trended broadly flat reflecting upgrades to the pipeline network in the Permian Basin and the non-recurrence of refinery outages. The key upgrades were the start-ups in September 2014 of Magellan Midstream Partner's/Plains 0.3mmb/d Bridgetex Pipeline from Colorado City, Texas to Houston and in early 2015 of the Sunrise Pipeline linking Midland to Colorado City. The Midland discount year-to-date

2015 has averaged $1.2/barrel and on 15 April was $0.6/barrel. We believe that in the absence of refinery outages, the WTI Midland should continue to trade between approximate parity and a modest discount of a dollar or two to WTI Cushing in the coming months.

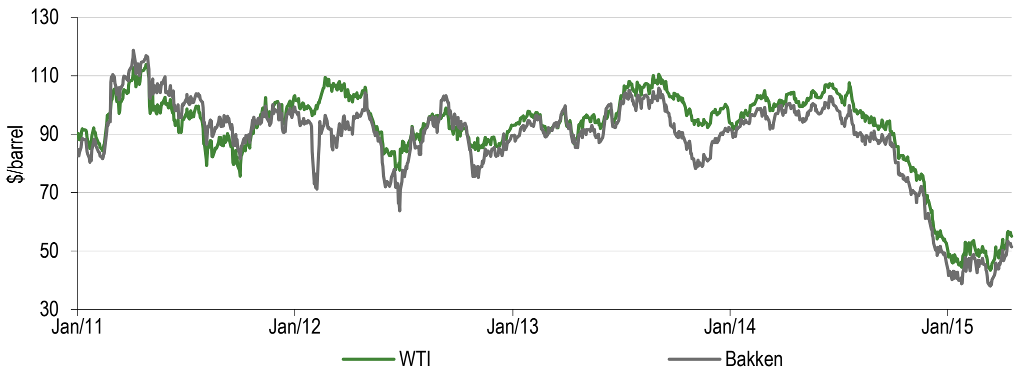
The narrowing of the WTI Midland discount in recent months has removed a key competitive advantage for a number of refineries in northern and western Texas and New Mexico.

Bakken-WTI: Logistical upgrades and slipping production help narrow the Bakken discount

Bakken grade oil (Clearbrook Minnesota hub) has a broadly similar specification to WTI and is therefore a high quality light crude. Currently the only operational refinery in close proximity to the core Bakken production zone is Tesoro's modest 71mb/d Bismark, North Dakota facility. Within the coming weeks, however, the MDU Resources/Calumet Dakota Prairie refinery at Dickinson in the west of the state is scheduled to come on-stream. This will also be modest in size at 20mb/d. The two facilities combined will supply about 70% of the North Dakota diesel market. MDU is planning a further refinery in North Dakota but local feedstock needs will remain low for the foreseeable future relative to current crude production of about 1.2mmb/d.

Currently, the bulk of Bakken crude output has to be shipped out of North Dakota. While some is destined for relatively close Mountain State refineries, much has to be shipped over long distances to the Midwest, Gulf Coast and the eastern and western seaboards. Broadly speaking, around 58% of Bakken oil production is shipped by rail, 35% by pipeline, 6% to the Tesoro refinery and 1% by truck to Canadian pipelines. Historically, pipeline connections have largely been with the Midwest although recently a direct link has been added to Cushing with the opening of the Double H pipeline which connects with the Pony Express Pipeline at Guernsey, Wyoming. Markets along the Gulf Coast and the seaboards are supplied predominantly by rail. The Keystone XL pipeline, assuming it is ever constructed, would in principle considerably increase pipeline capacity to the Gulf Coast.

Exhibit 13: Bakken vs WTI



Source: Bloomberg

Given the distance of the Bakken oilfields from major refining centres, logistical costs are inevitably substantial. 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 $15/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/barrel. In the case of pipeline shipments to Chicago we believe costs could be $5-6/barrel.

Historically, Bakken grade oil has sold at a significant discount to WTI of $5/barrel or more reflecting logistical constraints and the high cost of transportation to Cushing. In the year-to-date mid-April 2015 Bakken has traded at an average discount of $4.9/barrel, slightly under the $5.2/barrel for 2014 as a whole. During April the discount has actually narrowed and on the 15 April was $3.10/barrel, the lowest level over the past year. This left Bakken grade oil trading at $52.9/barrel, a five-month high and 40% above the recent 17 March low of $38.0/barrel. We believe that the compression of the discount of late reflects a combination of the start-up of the Double H pipeline and the softening trend in North Dakota production. Assuming the trend continues to soften, we believe the Bakken discount will remain narrow from a historical perspective. Given high transportation costs to the Gulf Coast and the eastern and western seaboards, netted back Bakken wellhead prices are probably significantly below hub levels.

Exhibit 14: Bakken-WTI spread

Source: Bloomberg

Syncrude-WTI: Syncrude close to parity

Syncrude is a synthetic sweet crude sourced from the Alberta oil sands. 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. Outages both upstream and downstream, however, can at times result in substantial deviations from parity. Reflecting the long distances involved, shipments out of Alberta carry heavy transportation costs. We believe light oil pipeline costs from Edmonton to the Gulf Coast for example, could be in the region of $10/barrel. To be competitive on the Gulf Coast currently Syncrude would probably need to trade at a discount to WTI of at least $5/barrel (WTI discount to Brent of $5/barrel assumed).

Since end-2014 Syncrude has moved from a discount to WTI of about $3/barrel to a premium of almost $4/barrel. In the year-to-date however, a discount of $0.6/barrel has been recorded. This compares with an average $1.2/barrel in 2014. Overall in recent months, the Syncrude-WTI spread has been consistent with the historic experience, which probably reflects smoothly running operations. In absolute terms, Syncrude in mid-April was trading at $59.6/barrel, up 41% on the mid-January low of $42.2.

WCS-WTI: WCS discount narrows,

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 remote 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 syncrude to enhance pipeline flow. Typically about 25% of each barrel of WCS shipped by pipeline comprises diluents. Owing to long distances to market and the need for diluents, pipeline costs for WCS are very high. In the case of shipments to the Gulf Coast we believe that they would be at least $15/barrel.

The narrowing trend in the WCS discount that was apparent in 2014 has continued in 2015. In the year-to-date the discount has averaged $13.6/barrel and in mid-April was $11.6/barrel. This compares with $18.6/barrel on average in 2014. Interestingly, WCS at $44.4/barrel in mid-April was trading at an approximate four-month high. This is up $14.7/barrel or 49% from 17 March low of

$29.7/barrel. Compared with similar specification Mexico-sourced Maya crude, the benchmark Gulf Coast heavy grade, WCS was trading at a discount of $9.41/barrel in mid-April. This is significantly below our estimate of pipeline costs from Alberta to the Gulf Coast for WCS. We believe, however, that at about $44/barrel WCS is a competitive source of heavy feedstock for Midwest refineries.

The narrowing trend in the WCS discount reflects a combination of expanded rail and pipeline transportation capacity and buoyant demand for heavy feedstock from Midwest and Gulf Coast refineries. The pipeline upgrades relate to Flanagan South and the extension of the Main Line pipeline (originates in Alberta) from Ontario to the Suncor and Valero refineries in Montreal. Rail takeaway capacity from Alberta was virtually zero at the beginning but is currently perhaps 1mmb/d and could be 1.5mmb/d by end 2015. In addition to routes to the south, trains are now running east from Alberta to Montreal. Enbridge is planning to add a rail terminal at Pontiac, Illinois capable of taking two trains a day from Alberta. This could be on-stream by mid-2016 and in conjunction with Flanagan South would relieve the pipeline bottleneck in southern Alberta on shipments to the south, including the Gulf Coast.

Trans Canada's Keystone XL second phase would provide highly significant extra pipeline capacity to the Gulf but the timing of this project remains uncertain. The need for Keystone XL phase 2 may also have been partially obviated by Flanagan South, Keystone XL phase one (a more circuitous route from the Canadian border to Cushing than phase two), at least in the short term.

LLS-Brent: LLS close to parity

LLS is the light crude Gulf Coast benchmark similar in specification to WTI and Brent. So far in 2015, LLS has traded on average at a small discount to Brent of $1.2/barrel. This is similar to the fourth quarter of 2014 but constitutes a narrowing from the discounts prevailing between late 2013 and the third quarter of 2014. By mid-April 2015, LLS was trading at a marginal premium to Brent of $0.6/barrel. Note however, that LLS probably retains a competitive advantage in Gulf markets due to Brent transport costs.

Given the build-up of light crude supplies along the Gulf Coast, it is perhaps surprising that a significant LLS discount has not emerged. The explanation for this not happening appears to be very high Gulf Coast refinery activity and relatively weak Brent fundamentals.

Brent-Dubai: Dubai discount narrows

Dubai Fatah is a Gulf-sourced light but relatively sour crude popular with Far Eastern refineries. Historically Dubai has traded at a modest discount to Brent of $2-3/barrel. At $1.6/barrel the discount is somewhat narrower and also below the $2.9/barrel of the fourth quarter of 2014. The narrowing tendency in recent months seems to reflect strong Asian demand for Dubai due in large part to attractive refinery crack spreads. Rising shipments of sour grades from Iraq could, however, result in a widening of the Dubai discount in the coming months.

Tapis-Dubai; Tapis premium narrows sharply to historically low levels

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 price relationships. Reflecting its specification, Tapis typically trades at a premium to Dubai of $7-10/barrel. Significantly, the Tapis premium narrowed sharply in the second half of 2014 and has continued to do so in 2015. In 2015 year-to-date it has averaged $3.9/barrel, well down from the $5.2/barrel of the fourth quarter of 2014. During April there was further evidence of narrowing with the Tapis premium on 16 April down to a usually low $2.9/barrel. The narrowing Tapis premium could be indicative of a major structural shift taking place in the marketplace reflecting the build-up in light crude availability post the surge in US production. Effectively, light crude produced on the east side of the Atlantic basin and North

Africa is being displaced to other regions. The situation could be exacerbated in the event of Libya returning to full production.

US Gulf heavy crude spreads

LLS-Mars: Mars discount continues to narrow

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 2014 averaged $4.0/barrel. The narrowing trend in the discount in 2014 has continued so far in 2015. Through mid-April the Mars discount has averaged $3.0/barrel and at mid-month was $2.9/barrel which are both towards the low end of the historical range. The narrowing tendency in the Mars discount over the past year or more continues to reflect the abundance of light crude along the Gulf Coast and buoyant demand locally for heavy-sour feedstock. It should be noted here that many Gulf Coast refineries are configured for such feedstock and refinery utilisation has been high. As noted previously, expectations of a continuing build-up of light crude along the Gulf Coast could portend a longer term narrowing trend in the Mars discount.

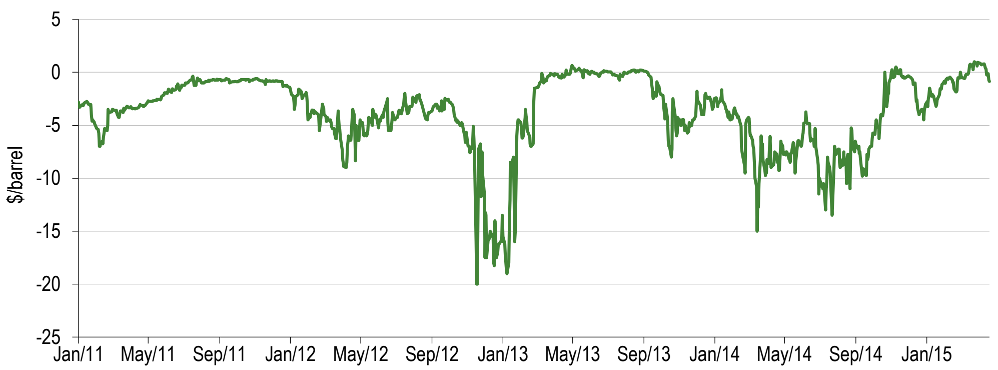
LLS-Maya: Maya discount also narrows

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 $5-12/barrel. As in the case of Mars and for similar reasons, the Maya discount has been on a narrowing trend over the past year. In 2015 year-to-date it has averaged $8.1/barrel which compares with $9/barrel in the fourth quarter of 2014 and $11/barrel for 2014 as a whole.

WTS-WTI: WTS trading close to parity

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 reflecting specification differences, but in 2014 averaged an unusually high $5.9/barrel reflecting strong supply growth, logistical bottlenecks in the Permian Basin and a spate of refinery outages. Since the fourth quarter of 2014, the WTS discount has narrowed sharply and on a 2015 year-to-date basis has averaged $0.74/barrel. Interestingly, during early April WTS actually traded at a premium of $0.7/barrel. The sharp narrowing in the WTS discount in recent months stems from major upgrades to the pipeline infrastructure from the Permian Basin to the Gulf Coast, rapidly growing supplies of light crude and the non-recurrence of refinery outages. As in the case of the other medium/heavy-sour grades, there is probably a structural narrowing of the WTS discount underway.

Exhibit 15: WTS-WTI spread



Source: Bloomberg

Shale oil economics: Hub prices suggest fully accounted profitability, wellhead prices less favourable

US shale oil concerns are now the petroleum industry's swing producers. This reflects the scale of the resource base, the flexibility of the extraction technology (development activity can be easily switched on and off) and low exploration and development costs relative to large scale offshore projects. Effectively, shale projects now set a key benchmark for petroleum industry long-run marginal cost.

At the recent 2015 first quarter lows for WTI of about $45/barrel and less than $40/barrel in the more remote plays notably the Bakken, shale oil economics had clearly entered the marginal zone from a fully accounted cost perspective. Even at these levels, however, prices remained comfortably above cash and particularly variable cost. Based on industry data we would estimate Bakken fully accounted costs on a generic basis in the sweet spots at about $47/barrel including royalties but excluding the cost of capital (possibly $2/barrel). Within this total, developments costs are put at $15/barrel assuming $8m/well and an EUR (estimated ultimate recovery) of 550,000 barrels. At the 2015 first quarter Bakken low of $38/barrel the implied fully accounted loss was $9/barrel. On a cash basis (excluding development costs), however, there was a contribution of $6/barrel while the variable profit was $11/barrel (based on cash costs of $32 less G&A of $5).

Using data specifically relating to Continental Resources, which has very low production costs in the Bakken of just over $5/barrel, cash and variable costs would be nearer $25/barrel and $20/barrel respectively. This would imply approximate fully accounted breakeven at a price of around $40/barrel. Interestingly, in its latest presentation, Continental shows its Bakken rate of return as being slightly positive at an oil price of $40/barrel and a gas price of $3.00/mcf. Assuming the mid-April Bakken price of about $53/barrel the rate of return would be about 15% (over 20% including planned cost reductions) based on the Continental analysis.

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 and prolific initial production rates of 4,000b/d or more in some cases. Industry data would suggest that that Eagle Ford development costs might be up to $5/barrel less on average than in the Bakken. Another major positive for the Eagle Ford is its proximity to the refining complexes of the Gulf Coast. This implies pipeline costs of less than $5/barrel against nearer $10/barrel from the Bakken by pipeline and $12/barrel by rail. As far as cash costs are concerned, we believe these are not significantly different than in the Bakken abstracting from transportation. Rapidly growing Eagle Ford player, Carizzo Oil & Gas, in its latest presentation, shows Eagle Ford PV-10 breakeven prices across its properties ranging from $35/barrel to $56/barrel. Over 80% of its locations are estimated to have breakeven prices below $44/barrel.

The above analysis would certainly imply that at mid–April prices key shale plays such as the Bakken and Eagle Ford should be at least comfortably cash generative and in all probability profitable on a fully accounted basis. It needs to be remembered, however, that development costs can vary significantly both within and between plays. The implied margins above are possibly more indicative of the sweet spots. The petroleum industry consultants, Wood Mackenzie, have in fact suggested that US shale fully accounted costs cluster around $65-70/barrel. Furthermore, as we have noted, wellhead realisations in the more remote plays may in practice be below indicative benchmark prices due to the high cost of transporting crude over long supply lines to refining centres.

Exhibit 16: Bakken economics

	Bakken hub prices	
Prices/costs per barrel	**Q115 low**	**Late-Apr 2015**
Gross realisations	38	52
Royalties	-7	-10
Net realisations	31	42
Lifting and site operating costs	-12	-12
Severance costs	-3	-4
G&A	-5	-5
Transport to Clearbrook, Mn	-5	-5
EBITDA	6	16
Drilling/completion costs	-15	-15
EBIT	-9	1
Variable cost	-27	-31
Cash costs	-32	-36
Fully accounted costs	-47	-51
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.

Costs are trending down – shale oil players continue to emphasise declining costs. Continental, for example, indicates that it is looking for a decline in completed well costs (CWCs) in 2015 of around 15%. EOG is planning reductions in CWCs of 7% and 12% in the Eagle Ford and Bakken respectively. Falling costs are being driven in part by improving techniques which are reducing drilling times and boosting the effectiveness of well completion work in terms of recovery and flow rates. In addition to these structural factors, costs are also coming under pressure in 2015 from declining input prices across a range of commodities and services. This phenomenon is linked directly to the plunge in oil prices. Assuming that the rebound in oil prices over the past month or two proves enduring, the decline in input costs will probably level off in the coming months.

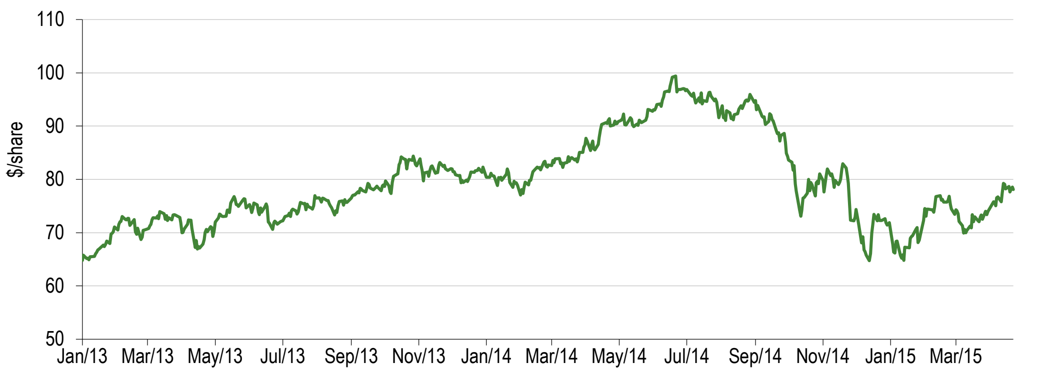
Financing: Junk bond window reopens, equity issues

The US shale revolution was financed to a considerable extent by debt in the form of junk bonds and bank loans. The junk bond financing window was effectively closed in late 2014 for all but the most highly rated US E&P names as the oil price rout gained momentum. Interestingly, the window has reopened of late. Several mid-tier concerns including Halcon Resources, Goodrich Petroleum and Energy XXI have recently issued high-yield bonds with coupons of up to 8.625%. Significantly for existing unsecured bond holders, assets are being pledged against the debt. The reopening of the bond market window reflects investors hunger for yield in an ultra-low yield environment. Fortunately for the E&Ps, the window has opened at a time when bank credit lines are being cut back following a reassessment of reserves in the wake of the oil price rout. The recent bond market issues therefore provide liquidity at a critical time for the E&Ps and enable development activity to be maintained.

Recent months have also seen a series of equity issues in the US and Canadian oil patch generally for the higher profile names. According to Bloomberg, $12bn in equity was raised in the first quarter of 2015. Issuers have included Whiting Petroleum, Carrizo Oil & Gas, Noble Energy and Encana. Interestingly Carrizo has also raised $650m in new corporate debt with a maturity of 2023 at a coupon of 6.25%. This however has been earmarked for redeeming an existing 2018 maturity bond yielding 8.625%.

Overall, the evidence is mounting that there is considerable financing available in North America for energy investments. As noted this partly reflects a search for yield but also relates to perceived upside in the case of equity based on the scope seen for a rebound in oil and gas prices. A manifestation of the growing interest in energy is the approximate 23% gain in the ishares US E&P ETF, IEO, since the recent low in January 2015. This constitutes a clear outperformance of the approximate 6% increase in the S&P 500 over the same period.

Exhibit 17: ishares E&P ETF IEO

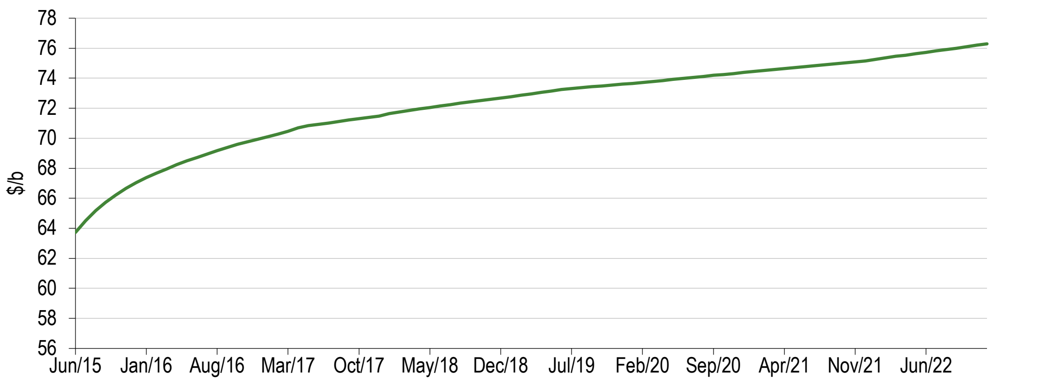


Source: Bloomberg

Forward curves: The contango persists

As of mid-April 2015 the forward curves for both Brent and WTI remained in contango (near-term prices lower than those for forward dates) indicating plentiful near term supplies. This is consistent with historically high inventories both in the US and internationally. The forward curves have been in contango since the third quarter and early in the fourth quarter of 2014 for Brent and WTI respectively. Although the contango remains steep for both curves, looking out over the next two years or so there has been a slight flattening tendency over the past month or two. This reflects a return to more bullish market sentiment supported by generally seasonally buoyant levels of refining activity and historically high crack spreads.

Exhibit 18: Brent forward curve

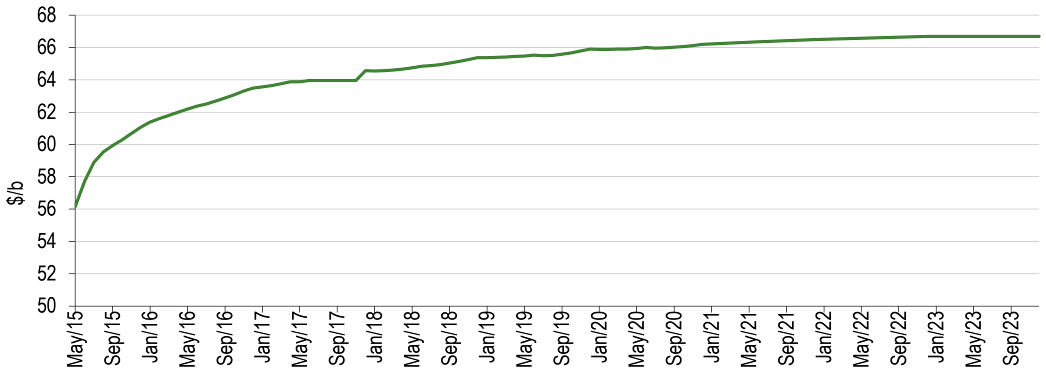


Source: Bloomberg

As of mid-April the Brent curve was in contango for all dates through 2022. The Brent curve starts at $63.7/barrel for June 2015 deliveries and then climbs over the following 24 months to $70.9/barrel. Thereafter, the rate of climb lessens with the curve terminating at $76.2/barrel in December 2022.

In the case of WTI, the forward curve in mid-April was in pronounced contango for all dates through end 2017. The curve shows $56.1/barrel for May 2015 deliveries and then climbs to $64.6/barrel over the following seven months. Subsequently, the curve levels-out and terminates in December 2023 at $66.7/barrel.

Exhibit 19: WTI forward curve



Source: Bloomberg

An analysis of the forward curve reveals a slight widening in the WTI discount to Brent between June 2015 and end 2017 from $6.0/barrel to $6.8/barrel. Thereafter the discount widens more significantly and by end 2022 stands at $9.6/barrel. The implied WTI discounts over the next few years are somewhat above mid-April 2015 levels of $5/barrel or so but are broadly consistent with blended logistical costs from Cushing to the Gulf Coast.

Crude oil price outlook

Background: Price scenario broadly unchanged

Our crude oil price scenario for 2015 and 2016 is broadly the same as in our January 2015 report. We believe the nadir for prices in this cycle was seen in the first quarter of 2015 when prices dropped below long-run marginal for a wide swathe of projects even in the sweet spots for some of the more productive US shale plays. This, together with the sharp cutback in petroleum industry investment announced since the third quarter of 2014 and manifested by the plunging US rig count is now beginning to affect supply. In the months ahead the supply impact is likely to intensify. Meanwhile, demand particularly in the US is firming. The upshot could be a tightening in the supply/demand balance over the rest of 2015 and in all likelihood the semblance of balance by year-end. This is expected to provide a favourable backdrop for a recovering trend in crude oil prices over the balance of the year. We would, however, expect the pace of recovery to be constrained, particularly in the second and third quarters, by the hefty supply overhang in terms of inventories and a high level of uncertainty regarding Iran exports.

2015: Year-to-date prices stronger than expected

The trend in prices for Brent and WTI in 2015 year-to-date has been significantly stronger on average than we forecast in early January. In the first quarter, Brent averaged $53.9/barrel while WTI came in at $48.5/barrel. This compares with our earlier forecasts of $45.0/barrel and $43.0/barrel respectively. Through the first three weeks of April, Brent and WTI have averaged $57.7/barrel and $52.7/barrel respectively which are considerably above our second quarter forecasts conceived in January of $45.0/barrel and $42.0/barrel respectively. As expected, the supply/demand balance has indeed been loose but the market, probably rightly, has been prepared to look past this, given the sharp cutback in capital investment and evidence that US production is beginning to slip.

Near term, we look for the upward trend in oil prices to mark time, reflecting the supply overhang issue. Our forecasts for the second and third quarters are as follows: Brent Q215 $57.0, Q315 $58.0; WTI Q215 $52.0, Q315 $53.0. In the fourth quarter we forecast a significant firming in the price trend as evidence of a tightening marketplace gathers momentum driven by both supply and demand factors. Our Q4 forecasts for Brent and WTI are $65.0/barrel and $60.0/barrel respectively and are unchanged from our January forecasts. Based on our latest quarterly scenario the forecast averages for 2015 are $58.5/barrel and $53.4/barrel respectively. The new forecasts reflect significant upgrades on the $52.5/barrel for Brent and $49.0/barrel for WTI given previously. The upgrades reflect the stronger than expected trend year-to-date. Note the forecasts assume no major change in Iranian exports over the balance of 2015.

2016: Potential for a firming trend

We continue to see the potential for a firming trend in benchmark light crude prices in 2016. This derives from our view that the market will show further evidence of tightening driven by the lagged impact of capital spending cutbacks and a modestly firming demand backdrop. We are maintaining our previous forecasts for 2016 at $72.5/barrel and $67.5/barrel for Brent and WTI respectively. Again, this assumes no major change in Iranian exports.

Upside and downside risks: US production trend, Iran

Near term, which we will define as the balance of 2015, we see two key issues for oil prices. The first relates to the speed with which production falls in the US. Related issues concern the extent of any further declines in the US rig count and the rate at which uncompleted wells are brought on-stream in the event of a firming price trend. A more rapid than generally expected decline in production would in all likelihood provide a disproportionate boost to prices and vice versa.

We regard Iran and the UN sanctions regime as the second of the key issues for oil prices in the coming months. A lifting of oil-related sanctions in the wake of a comprehensive agreement between Iran and the P5+1 group of world powers by the 30 June deadline could theoretically result in a significant dip in oil prices. The EIA has put the potential vulnerability for Brent at $1-3/barrel in 2015 and $5-15/barrel in 2016. The timing of any change in the sanctions regime however is highly uncertain even if an agreement is made. We also believe that in the event of prices slipping in line with the EIA's thoughts, petroleum industry investment would probably take another downward lurch which could help stabilise the market.

Beyond 2016: $75-80/barrel price ceiling

We continue to believe that medium term (2016-2020), a price ceiling of $75-80/barrel is likely to prevail for light crude benchmarks. Our thinking here is that supply has the potential to be relatively buoyant over the next few years while trend demand stays subdued. On the supply front, major new capacity additions are scheduled to come on-stream in Brazil, Kazakhstan, Iraq and the Canadian oil sands, while at prices above $75-80/barrel we believe US shale projects would be quickly reinstated. All the evidence suggests that at $75-80/barrel the bulk of such projects are comfortably profitable while as we have noted lead times are short. It is also becoming increasingly apparent that Saudi Arabia wishes to avoid an upsurge in oil prices that could result in a loss of market share to renewables and natural gas. This suggests that Saudi Arabia might well decide to keep production running at historically high levels.

Likely subdued demand growth stems from a combination of the lacklustre macroeconomic backdrop, declining fuel subsidies in the developing world and technological developments that are boosting fuel economy and encouraging fuel substitution in the transportation sector. More controversially the electrification of the light vehicle fleet could also gather pace over the next few years although this will probably require major advances in either battery storage or fuel cell technology. As Exxon has recently noted, existing electric vehicles do not offer the capability in terms of range re-charging times that most users require. Cracking the problem will be highly challenging.

How plausible is $20/barrel oil?

Earlier this year Citigroup raised the possibility of WTI dropping in price to $20/barrel on a spot basis in the coming months. This view was based on the potential for an extreme inventory build-up exhausting storage capacity. In this event, to restore equilibrium and choke off supply, WTI would have to rapidly drop in price to variable cost or less which is around $20/barrel. Such a situation would result in widespread well shut-ins in addition to a curtailment of drilling/completion activity. Once equilibrium was restored the scene would then be set for a price rebound as the marketplace tightened, giving rise to a W-shaped price scenario from the second halves of 2014 and 2015.

While we believe a drop in WTI to $20/barrel is conceptually possible we think it unlikely in the near term. As we have noted, in the coming months US production is likely to trend down while demand moves significantly higher. The Cushing tank farm also retains significant spare capacity.

Exhibit 20: Brent and WTI price scenarios

$/bbl	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015e	2016e
Brent	54.5	65.4	72.7	97.7	62.0	79.7	110.0	112.0	108.8	99.1	58.5	72.5
WTI	56.6	66.1	72.2	99.8	62.0	79.5	94.9	94.2	98.0	93.2	53.4	67.5

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