THE GUINNESS GLOBAL ENERGY REPORT

Developments and trends for investors in the global energy sector | March 2016

GUINNESS GLOBAL ENERGY FUND

Fund size: $227m (29.02.16)

The Guinness Global Energy Fund invests in listed equities of companies engaged in the exploration, production and distribution of oil, gas and other energy sources. We believe that over the next twenty years the combined effects of population growth, developing world industrialisation and diminishing fossil fuel supplies will force energy prices higher and generate growing profits for energy companies.

The Fund is run by Tim Guinness, Will Riley and Jonathan Waghorn. The investment philosophy, methodology and style which characterise the Guinness approach have been applied to the management of energy equity portfolios since 1998.

HIGHLIGHTS FOR FEBRUARY

OIL

Brent up; WTI flat; OPEC provisional production freeze

Brent oil traded up by $2/bbl to $36/bbl, whilst WTI stayed flat at $34/bbl, though there was significant intra-month volatility, with WTI falling as low as $26/bbl. Saudi and Russia announced on February 16 that they had provisionally agreed to freeze output at end-January levels, the first formal production response from an OPEC member since November 2014. US onshore oil production fell in December 2015 (latest data point) by 155,000 b/day, the largest monthly decline since 1989.

NATURAL GAS

US gas prices down significantly on warm weather and bloated inventories; market remains structurally undersupplied

Henry Hub prices traded up down 26% to close February at $1.71 per mcf. High levels of gas in storage and warmer weather in February more than normal trumped the structural (i.e. weather adjusted) undersupply that we can see (c. 1 Bcf/day).

EQUITIES

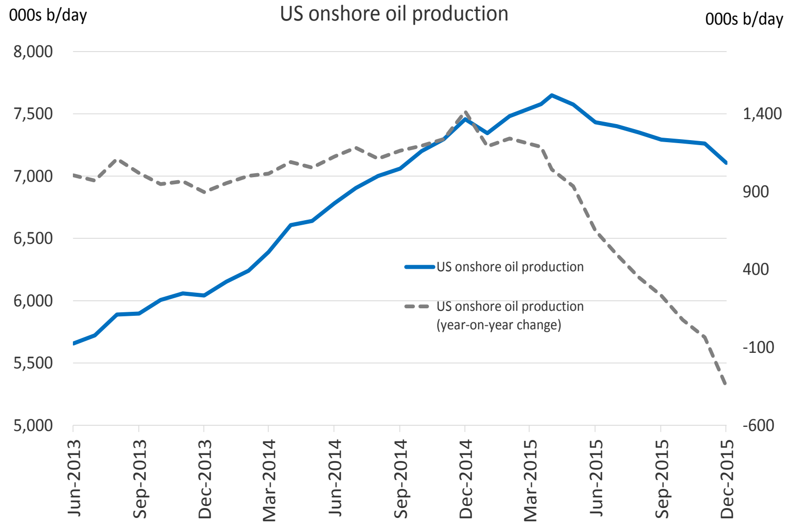
Energy outperforms the broad market

The MSCI World Energy Index fell in February by 0.3%, outperforming the MSCI World Index which fell by 0.6% (all in US dollar terms). So far in 2016, the Energy Index is down by 3.2%, versus the MSCI World down 6.6%.

CHART OF THE MONTH

Sharp fall in onshore US oil production

US onshore oil production declined by 155,000 b/day in December 2015 (the latest data point available from the EIA) versus November 2015. This represents the sharpest monthly fall in US production since 1989, and results from the significant decline in the US oil drilling rig count, and which has fallen much further since this data point. Year-on-year onshore oil production is now in decline by around 350,000 b/day. US oil supply is a key component in the global oil market rebalancing equation.



Important information about this report

This report is primarily designed to inform you about recent developments in the energy markets invested in by the Guinness Global Energy Fund. It also provides information about the Fund's portfolio, including recent activity and performance. This document is provided for information only and all the information contained in it is believed to be reliable but may be inaccurate or incomplete; any opinions stated are honestly held at the time of writing, but are not guaranteed. The contents of the document should not therefore be relied upon. It is not an invitation to make an investment nor does it constitute an offer for sale.

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GUINNESS ASSET MANAGEMENT LTD

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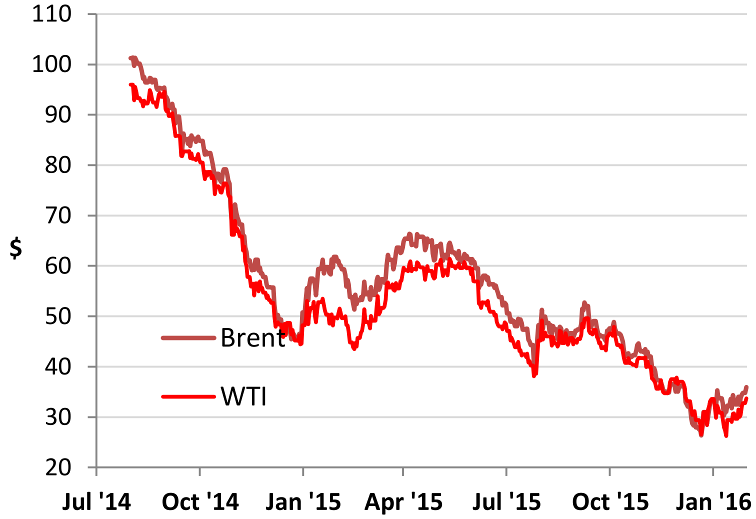
1. FEBRUARY IN REVIEW

i) Oil market

Figure 1: Oil price (WTI and Brent $/barrel) 18 months August 31 2014 to February 29 2016



Source: Bloomberg LP

The West Texas Intermediate (WTI) oil price started February at $33.6/bbl and fell sharply over the first two weeks of the month to a low on February 11 of $26.2, before recovering to close at $33.7/bbl. The February 11 close represents the lowest price for WTI since 2003. WTI averaged $48.7 in 2015, having averaged $93.1 in 2014, $98.0 in 2013 and $94.1 in 2012.

Brent oil traded in a similar way, opening the month at $34.7/bbl, and moving lower before recovering to close February at $36.0/bbl. The gap between the WTI and Brent benchmark oil prices therefore widened in February to around $2/bbl. The WTI-Brent spread averaged $5.8/bbl during 2014, having been well over $20/bbl at times since 2011.

Factors which strengthened WTI and Brent oil prices in February:

- **Provisional production freeze from Saudi & Russia**
  Four OPEC producers (Saudi Arabia, Russia, Qatar and Venezuela) announced on February 16 that they had agreed to freeze output at end-January levels. The Saudi minister, Ali al-Naimi, said freezing production was an adequate measure if other producers joined in. "The reason we agreed to a potential freeze of production is simple: it is the beginning of a process which we will assess in the next few months and decide if we need other steps to stabilise and improve the market," Naimi explained. The agreement is provisional, dependent on others joining the production freeze. Russia and Venezuela said last week they are planning a broad meeting of producers on 20 March, in an attempt to finalise the plan. We view these

moves as a sign from Saudi that, whilst they have the ability to tolerate a sub $50/bbl better than almost all other participants in the market, even they have limited appetite for oil at $30-35/bbl. A production freeze would still require the market to rebalance 'naturally', but it significantly reduces the risk that Saudi and its closest allies dump crude onto the market in 2016, as they did in 2015.

- **Falling onshore US oil production**
  US onshore oil production declined by 155,000 b/day in December 2015 (the latest data point available from the EIA) versus November 2015. This represents the sharpest monthly fall in US production since 1989, and results from the significant decline in the US oil drilling rig count, and which has fallen much further since this data point. Year-on-year onshore oil production is now in decline by around 350,000 b/day.

- **US oil drilling rig count falls further**
  The Baker Hughes oil directed rig count continued to roll over during the month, falling from 498 at the end of January to 400 at the end of February. In February therefore, 98 rigs were dropped, representing around 20% of the drilling fleet in operation. The oil directed rig count is now at its lowest level since 2009.

Factors which weakened WTI and Brent oil prices in February:

- **Iranian oil exports resuming**
  Sanctions over Iranian oil exports were officially lifted on January 16 after the International Atomic Energy Agency confirmed that Tehran had fulfilled its obligations under 2015's nuclear accord. According to Bloomberg's provisional supply survey for February, Iranian production was up by 140,000 b/day, to 3m b/day. We expect Iranian production to rise by around 500,000 b/day in total, this year.

- **Movements in OECD inventories indicate oversupply**
  OECD total product and crude inventories at the end of December (latest data point available)were reported as being up by 8m barrels versus the previous month. This compares to an historic 10 year average decline in inventories in December of 39m barrels, implying an oversupply of around 1.5m b/day. On a three months moving average basis, we observe the level of oversupply to be around 0.7m b/day.

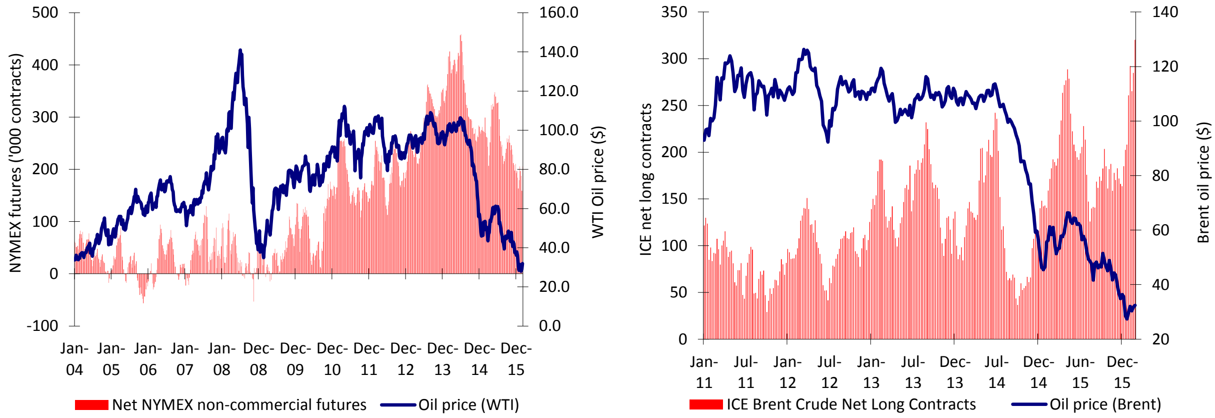
- **Elevated level of OPEC supply, particularly from Iraq and Saudi Arabia**
  Initial estimates suggest that OPEC-13 production averaged 33.1m b/day in February, flat versus the start of the year but still at an elevated level compared to a year or so ago (December 2014 production was 30.4m b/day) and the calculated 'call on OPEC' for 2015. The main contributors to OPEC's higher production since December 2014 continue to be Iraq (at 4.4m b/day) and Saudi (at 10.1m b/day).

Speculative and investment flows

The New York Mercantile Exchange (NYMEX) net non-commercial crude oil futures open position (WTI) stayed flat in February, ending the month at 206,000 contracts long versus 206,000 contracts long at the end of January. The current net long position is significantly down from its peak of 460,000 contracts in June 2014.

The equivalent non-commercial position for Brent oil, ICE Brent crude oil net long contracts, rose sharply in February, up from 261,000 contracts to 320,000 contracts long.

Figure 2: NYMEX Non-commercial net futures contracts: WTI January 2004 – January 2016 ; ICE Brent crude net long contracts : January 2011 – February 2016

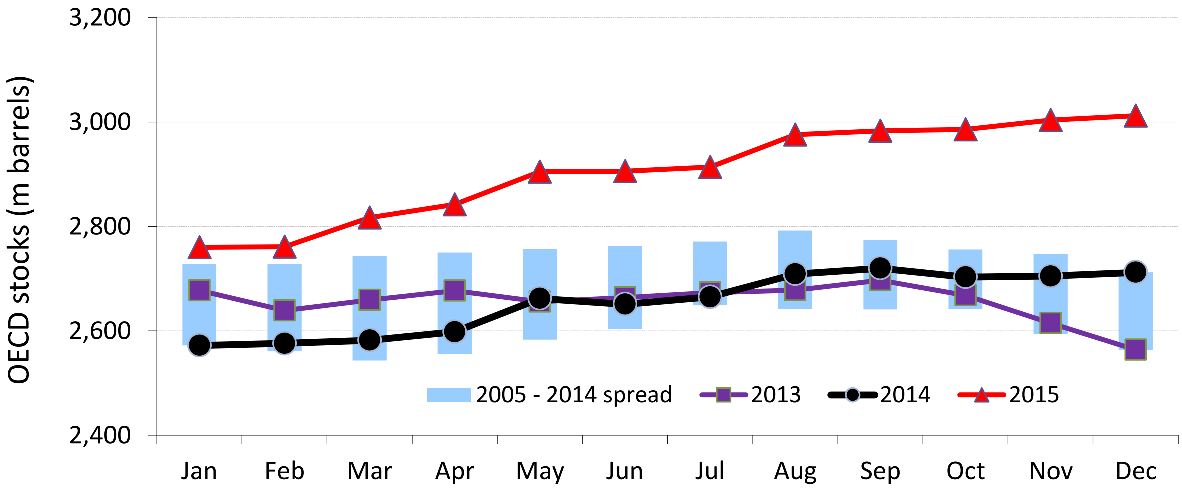


Source: Bloomberg LP/NYMEX/ICE (2016)

OECD stocks

OECD total product and crude inventories at the end of December (the latest data point available) were estimated by the IEA to be 2,990m barrels, up by 8m barrels versus the previous month. The increase compares to an average 39 million barrel decline that has been witnessed over the last ten years, so a substantial difference. The three month rolling average for changes to inventories indicates continued oversupply of around 0.7m b/day, and all this leaves inventories considerably above the top of the 10 year historic range.

Figure 3: OECD total product and crude inventories, monthly, 2004 to 2015



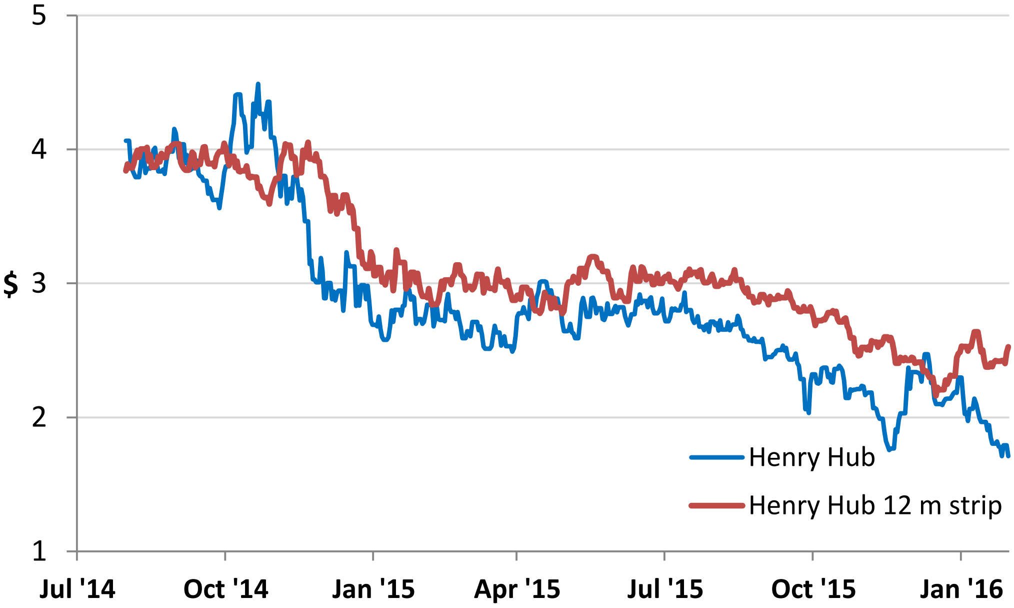
Source: IEA Oil Market Reports (February 2016 and older)

ii) Natural gas market

The US natural gas price (Henry Hub front month) opened February at $2.30 per Mcf (1,000 cubic feet). The price fell shaply over the month to close at a low of $1.71 on February 29. The spot gas price averaged $2.61/mcf in 2015, which compares to an average gas price in 2014 of $4.26 (assisted by a very cold 2013/14 US winter). The price averaged $3.72 over the preceding four years (2010-2013).

The 12-month gas strip price (a simple average of settlement prices for the next 12 months' futures prices) traded in a similar fashion, starting the month at $2.53 and ending at $2.16. The strip price averaged $2.86 in 2015, having averaged $4.18 in 2014, $3.92 in 2013, $3.28 in 2012, $4.35 in 2011, $4.86 in 2010 and $5.25 in 2009.

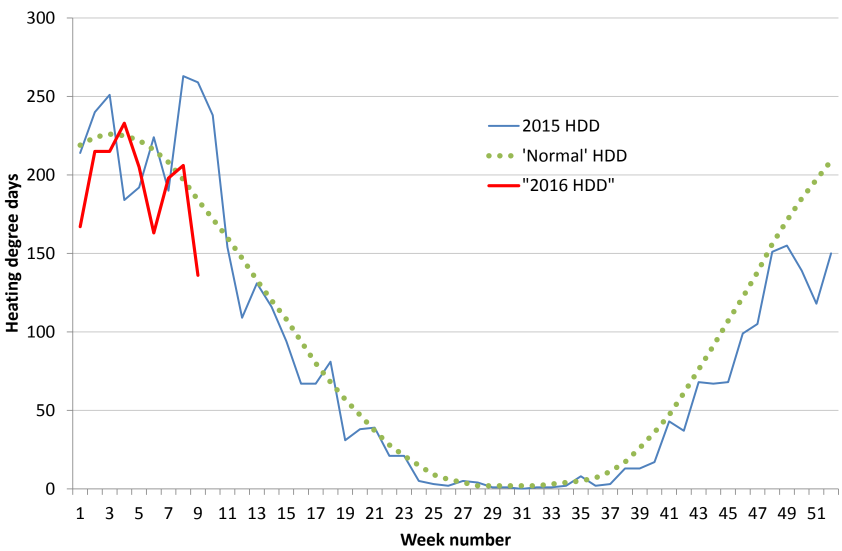
Figure 4: Henry Hub Gas spot price and 12m strip ($/Mcf) August 31 2014 to February 29 2016



Source: Bloomberg LP

Factors which weakened the US gas price in February included:

- **Warm weather lowering winter heating demand**
  February saw a continuation of the very warm weather conditions experienced across the US for most of the winter season, dampening heating demand for gas. The chart below shows Heating Degree Days so far in 2016, averaging well below normal.



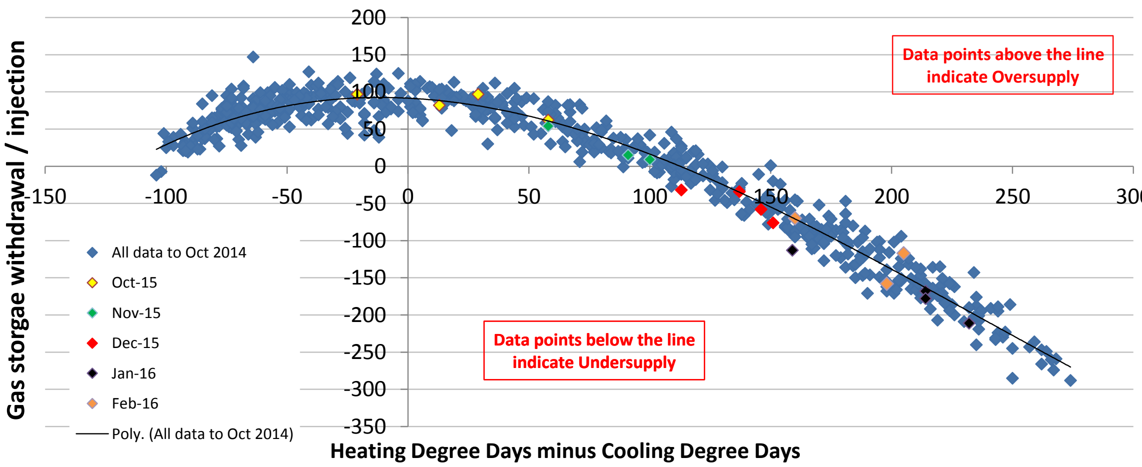
- **High level of gas in inventories**
  Withdrawals from inventories in the US were lower average in February, due to the warm weather, leaving the total level of gas left in storage remains well above the five year average.

Factors which strengthened the US gas price in February included:

- **Structurally undersupplied market**
  Adjusting for the impact of weather in January, the most recent injections of gas into storage suggest the market is, on average, about 1 Bcf/day undersupplied (as indicated by the black dots on the graph below). The gas market shifted into structural undersupply in November 2015, but this was trumped in the early part of winter by warmer weather, causing natural gas inventory levels to expand rapidly.

- **Onshore gas production flat in December**
  The EIA reported that December US onshore natural gas production (the latest data point available) was flat versus the previous month at 78.3 Bcf/day. Year-on-year onshore production is now running at a decline of 1.7 Bcf/day, having been as high as 8 Bcf/day growth at the end of 2014.

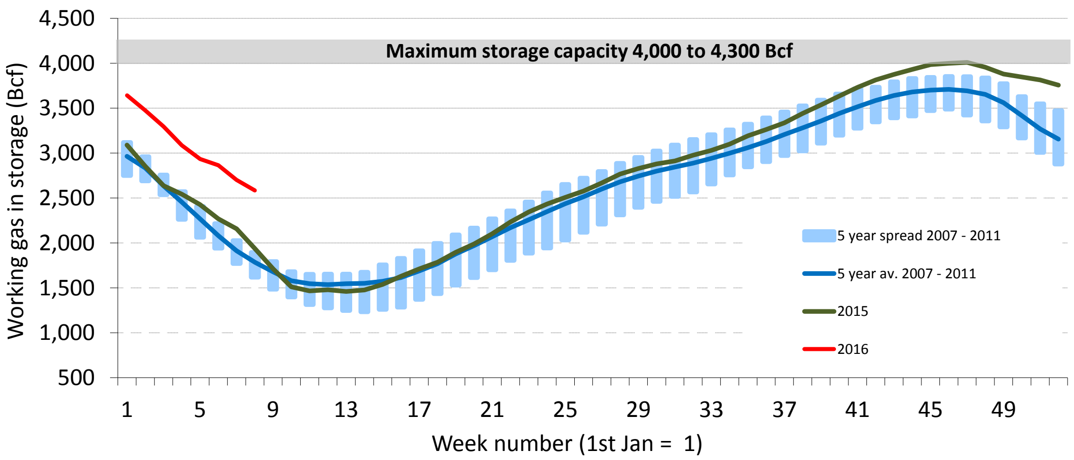
Figure 5: Weather adjusted US natural gas inventory injections and withdrawals



Natural gas inventories

Swings in the supply/demand balance for US natural gas should, in theory, show up in movements in gas storage data. Natural gas inventories at the end of February were reported by the EIA to be 2,584 Bcf. The month on month draw was less than average (due to warm weather), leaving inventories above the top of the five year range.

Figure 6: Deviation from 5yr gas storage norm vs gas price 12 month strip (H. Hub $/Mcf)



Source: Bloomberg; EIA (February 2016)

Gas in storage in 2015 started at roughly average levels and stayed that way for the first half of the year, as a combination of rising Marcellus production, slowing 'associated' gas production (a by-product of shale oil production) and increase in coal to gas switching by electric utility companies, worked to keep the market in balance. Over the last few months of 2015, gas in storage expanded at a faster than average rate, as an extremely mild autumn and early winter dampened heating demand. This leaves storage levels in the first quarter of 2016 at above average levels: assuming more normal weather, we expect this overhang to be worked off during the next few months.

2. MANAGER'S COMMENTS

What did the annual results season tell us about the North American shale oil industry?

Annual results season has brought a plethora of news and commentary around the North American shale oil industry over the last few weeks. The industry suffered under $50/bbl oil in 2015 and is looking very precariously placed for 2016 under a $35/bbl scenario. In this month's Managers' Comments, we examine some of the key topics emerging, for a region which is critical to the rebalancing of world oil supply and demand in 2016.

2016 capital expenditure and production guidance

2016 is going to be another year of substantial capital expenditure reductions across onshore North America. Consecutive years of 30%+ capital expenditure cuts (2015 & 2016) are unprecedented in this industry and according to Bernstein Research, the North American producers will see 49% capex cuts in 2016 following, yielding an aggregate cut of 70% in 2016 relative to 2014 levels.

Despite efficiency gains and cost deflation helping each dollar of capex stretch further, the activity cut in the US will still be unprecedented. Even the best placed (i.e. Permian basin producers) and best capitalised North American E&Ps have cut capex by 40% plus in 2016 vs 2014. As we see it, the sector is now depleting itself, cutting capex to below the 'maintenance' capex level and implying declining production for a number of years, if sustained.

For 2016, the oil production outlook has worsened. Goldman Sachs reported that their coverage group of North American-oriented E&Ps would deliver 4% year-on- year decline in oil production on average in 2016 (against Goldman's expectation at the start of the year of a 1%year-on-year decline). And keep in mind that this group is biased towards the better quality companies: other reports indicate a decline of closer to 10% year-on-year.

Most companies indicate that production will decline steadily through the year meaning that 2016 exit rate production will yield decline rates that are significantly in excess of those recorded on average across the year.

While not discussed by the producers in any detail, the results and guidance imply that US oil production in 2017 will also be very disappointing. If companies face declining production throughout 2016 and exit decline rates are significantly below year-average decline rates then there is a real likelihood that US oil production could be flat in 2017 even after allowing for higher expenditure and higher levels of drilling activity.

Efficiency gains in the US shale

Much has been made of efficiency gains in the US Shale industry in recent years and we note that the industry now achieves far more with less capex spend than it did in the days of $100 oil. As an example, Anadarko is now taking only 4.7 days to drill its wells in the Wattenberg – these types of shale drilling operations have become highly efficient. However it is also increasingly clear to us that the rate of efficiency gains is slowing despite the fact that the industry is now only drilling its best opportunities. At some point, the poorer quality opportunities with poorer economics will also need to be developed and efficiency gains may turn the other way. Also we saw the majority of US onshore service companies (e.g. land drillers, pressure pumpers) reporting negative earnings for 2015 and expected again in 2016. Service costs are at unsustainably low levels and will rebound. Overall, we do not see reason to expect significant continued efficiency gains across the US shale oil industry from here.

Balance sheets

Many companies in the North American E&P group will descend into financial distress if oil prices stay at current levels for all of 2016 and 2017. According to Bernstein, at $30 WTI oil prices in 2016, one third of the US E&P sector has i) debt/EBITDA greater than 10x and ii) EBITDA to interest expense less than one. Pretty stretched metrics. Similarly, according to Jefferies, the 2016 net debt to EBITDA will be over 4x for their sector coverage on average (including the beneficial impact of hedges) and over 5x if hedges are excluded. The sector is having to adjust to harsh new financial realities.

To a fair extent adjustment is being achieved and, despite having 'growth-oriented DNA', the US E&P group is planning to live broadly within their cash flow generation in 2016. We assume that this is being forced upon them by their lending banks. The companies are proposing swingeing capex cuts (as previously mentioned) and numerous significant dividend cuts (including Anadarko, Devon Energy, Noble Energy, Range Resources, QEP Resources and Cimarex) while a number of companies are choosing to rely on the ability to divest assets in 2016 and 2017 into, what we assume must be, a market significantly skewed in favour of the buyer. Hedges are not a solution at this time either; the industry is substantially less well hedged than it was in early 2015.

Even with these measures being implemented, a large number of E&P companies have attempted partially to plug any financial shortfall via equity raises, thus getting finances into better shape ahead of the round of credit facility renegotiations that are coming in the next month or two. Around US$8bn of equity has been raised so far in 2016.

Ability and willingness to increase drilling activity when oil prices recover

Oil price bears tell us that the US E&Ps will just reinvest and produce rapidly again once the oil price increases, thus forcing oil prices to stay in a $40-50/bbl range. We noted a number of interesting management comments on this topic during results season and have highlighted them here by each company:

- **Pioneer Resources** believe that, at $50/bbl WTI, it is just not possible for the US shale industry to deliver any growth. At $60/bbl WTI, they see US shale oil growing for two years (with most of that growth coming from the Permian), so therefore the US needs in excess of $60/bl WTI to deliver production growth longer term. If oil reaches $100/bl, they would see Permian oil production growing from 2m b/day to 5m b/day (although there was no indication over timing of such an increase).

- **Occidental Petroleum** concur that $60/bbl WTI is an important economic level for new supply from their Permian acreage. They see only 4% of their future Permian well locations as being economic at $40/bl WTI and only 14% economic at $50/bbl WTI. However, at $60/bbl WTI, 40% become economic and this rises to 48% at $70/bbl and then 60% at $80/bbl.

- **EOG Resources** have started referring to their "premium inventory" across all their North American shale basins. This inventory earns a 30% after tax rate of return (ATROR) at the wellhead at a $40/bl WTI oil price, although the company concede that this ATROR is unlikely to add positively to corporate ROCE. "We're not going to be ramping up production the first time oil hits $60 a barrel," said CEO, Bill Thomas.

- **Concho Resources**, located in the core of the Permian, believe that 27% of their 18,000 future well locations are economic at $40/bl WTI (ie delivering a >20% ATROR). We note that this is a significant number of potential well locations but find it at odds that Concho is only running less than 10 rigs in 2016 and is expecting to see production down 0% to 5% versus 2015.

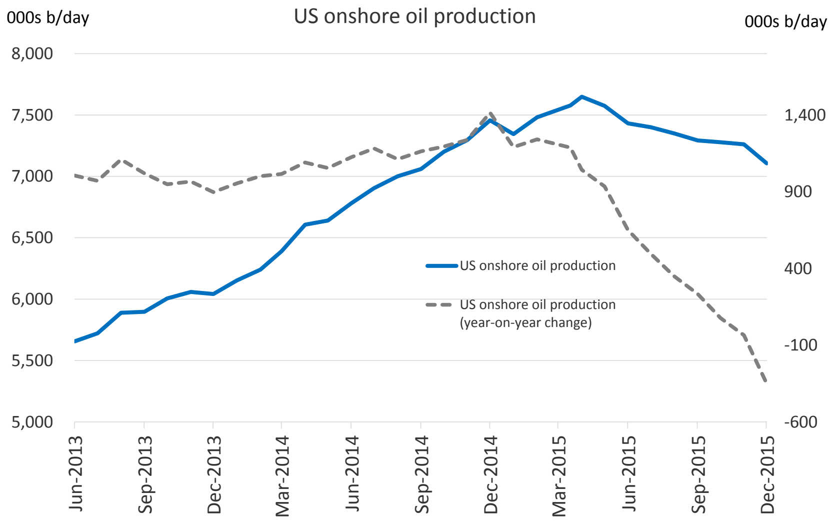
- Another core Permian operator, **Diamondback**, has 500 new well locations that are economic at $25-35/bbl WTI and the inventory grows to 1,500 locations at $35-45/bbl. Despite the attractive theoretical well-level economics, we are intrigued that Diamondback would not consider hedging until WTI is between $40 and $50/bl; thus indicating the delta between 'well economics' and 'corporate returns'.

- Moving away from the Permian, **Pioneer Resources** would need to see $50/bbl WTI to consider starting drilling in the Eagle Ford again.

In aggregate, the industry appears to be willing to pick up some activity at around $50/bbl WTI (and this would allow total US shale oil production to remain flat) but that $60/bl is required to make a more meaningful amount of investment opportunities economic. If larger volumes of new oil production are required (and we think that they will be required to offset future declines in other non-OPEC areas to the end of the decade) then oil prices higher than $70/bbl are likely to be needed.

Conclusion

The recent results season has provided clear insight into the issues facing north American-oriented companies at the moment. 18 out of 23 US E&Ps delivered negative adjusted earning in calendar year 2015, despite having $50+/bl oil prices and positive hedging. 2016 is looking like it will be a very tough year indeed. The silver lining of course is that a more rapidly depleting onshore US oil sector, down as much as 1m b/day at the end of 2016 versus end of 2015, is hastening the rebalance of the global oil market.



Source: EIA; Guinness Funds

3. PERFORMANCE Guinness Global Energy Fund

The main index of oil and gas equities, the MSCI World Energy Index, was down 0.3% in February, while the MSCI World Index was down by 0.7%. The Fund was down 2.8% (class E) in the month, underperforming the MSCI World Energy Index by 2.6% (all in US dollar terms).

Within the Fund, February's strongest performers were Royal Dutch Shell, Statoil, Bankers, Imperial and Trina Solar, while the weakest performers were Southwestern, QEP, Carrizo, Devon and Valero.

Performance (in USD) 29/02/2016

Annualised

% returns	1 year	3 years	5 years	10 years	1999 to date
Guinness Global Energy	-34.1	-13.7	-12.0	-1.7	9.4
MSCI World Energy Index	-24.5	-8.6	-6.2	0.8	6.0

Calendar year

% returns	2016	2015	2014	2013	2012	2011	2010	2009	2008	2007	2006
Guinness Global Energy	-7.6	-27.6	-19.1	24.4	3.0	-13.6	15.3	61.8	-48.2	37.6	10.1
MSCI World Energy Index	-3.2	-22.1	-11.0	18.8	2.5	0.7	12.5	27.0	-37.7	30.4	18.4

Source: Financial Express, bid to bid, gross income reinvested, in US dollars

Calculation by Guinness Asset Management Limited, simulated past performance prior to 31.3.08, launch date of Guinness Global Energy Fund. The Guinness Global Energy investment team has been running global energy funds in accordance with the same methodology continuously since November 1998. These returns are calculated using a composite of the Investec GSF Global Energy Fund class A to 29.2.08 (managed by the Guinness team until this date); the Guinness Atkinson Global Energy Fund (sister US mutual fund) from 1.3.08 to 31.3.08 (launch date of this Fund), the Guinness Global Energy Fund class A (1.00% AMC) from launch to 02.09.08, and class E (0.75% AMC) thereafter. Performance would be lower if an initial charge and/or redemption fee were included.

Past performance should not be taken as an indicator of future performance. The value of this investment and any income arising from it can fall as well as rise as a result of market and currency fluctuations as well as other factors. You may lose money in this investment.

Returns stated above are in US dollars; returns in other currencies may be higher or lower as a result of currency fluctuations. Investors may be subject to tax on distributions.

The Fund's Prospectus gives a full explanation of the characteristics of the Fund and is available at www.guinnessfunds.com.

4. PORTFOLIO Guinness Global Energy Fund

Buys/Sells

In February we made no stock switches.

Sector Breakdown

The following table shows the asset allocation of the Fund at **February 29 2016**. We have also shown the asset allocation of the Guinness Atkinson Global Energy Fund (our US global energy fund which was started in 2004 and is managed in tandem with the Guinness Global Energy Fund) at year-end 2007 for comparative purposes:

(%)	31 Dec 2007*	31 Dec 2008	31 Dec 2009	31 Dec 2010	31 Dec 2011	31 Dec 2012	31 Dec 2013	31 Dec 2014	31 Dec 2015	29 Feb 2016	*Change YTD*
Oil & Gas	**103.5**	**96.4**	**98.2**	***93.3***	***97.9***	***97.3***	***93.7***	***93.7***	***95.1***	***91.5***	***-3.6***
Integrated	40.3	41.6	35.9	33.0	30.9	30.4	29.2	27.0	30.4	31.7	*1.3*
Integrated – Can & Em Mkts	25.9	12.1	11.9	8.2	8.8	8.4	9.4	10.3	11.1	14.9	*3.8*
Exploration & production	25.8	28.7	32.8	37.1	41.1	40.3	35.4	36.2	36.5	32.0	*-4.5*
Drilling	8.1	5.2	8.5	6.1	5.9	7.1	6.4	3.3	1.5	0.7	*-0.8*
Equipment & services	3.4	6.4	5.9	5.4	6.1	7.4	9.8	13.4	11.4	8.5	*-2.9*
Refining and marketing	0.0	2.4	3.2	3.5	5.1	3.7	3.5	3.5	4.2	3.7	*-0.5*
Solar	**0.0**	**0.0**	**0.0**	**3.2**	**1.3**	**1.2**	**2.6**	**3.7**	**4.7**	**6.5**	***1.8***
Coal & consumables	**2.5**	**2.3**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	***0.0***
Construction & engineering	**0.0**	**0.4**	**0.3**	**0.3**	**0.4**	**0.6**	**1.0**	**0.0**	**0.0**	**0.0**	***0.0***
Cash	**-6.0**	**0.9**	**1.5**	**3.2**	**0.4**	**0.9**	**2.7**	**2.6**	**0.2**	**2.0**	***1.8***
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	

**Guinness Atkinson Global Energy Fund*
Source: Guinness Asset Management
Basis: Global Industry Classification Standard (GICS)

The Fund at February 29 2016 was on a price to earnings ratio (P/E) for 2015 of 16.1x versus the S&P 500 Index at 18.4x as set out in the table. (Based on S&P 500 'operating' earnings per share estimates of $83.8 for 2010, $96.4 for 2011, $96.8 for 2012, $107.3 for 2013, $113.0 for 2014, $100.0 for 2015 and $119.4 for 2016). This is shown in the following table:

	2010	2011	2012	2013	2014	2015	2016
Guinness Global Energy Fund P/E	6.7	6.5	6.7	7.2	7.4	16.1	24.2
S&P 500 P/E	23.1	20.0	20.0	18.1	17.1	19.1	16.2
Premium (+) / Discount (-)	*-71%*	*-68%*	*-67%*	*-60%*	*-57%*	*-16%*	*49%*
Average oil price (WTI $)	$79.5/bbl	$95/bbl	$94/bbl	$98/bbl	$93/bbl	$49/bbl	

Source: Standard and Poor's; Guinness Asset Management Ltd

Portfolio holdings

Our integrated and similar stock exposure (c.46%) is comprised of a mix of mid cap, mid/large cap and large cap stocks. Our five large caps are Exxon, Chevron, BP, Royal Dutch Shell and Total. Mid/large and mid-caps are ENI, Statoil, Hess and OMV. At February 29 2016 the median P/E ratios of this group were 17.1x/28.9x 2015/2016 earnings. We also have two Canadian integrated holdings, Suncor and Imperial Oil. Both companies have significant exposure to oil sands in addition to downstream assets.

Our exploration and production holdings (c.32%) give us exposure most directly to rising oil and natural gas prices. We include in this category non-integrated oil sands companies, as this is the GICS approach. The stock here with oil sands exposure is Canadian Natural Resources. The pure E&P stocks have a bias towards the US (Newfield, Devon, Carrizo, Southwestern and QEP Resources), with four other names (Apache, Occidental, Noble, CNOOC and SOCO) having significant international production and two (Enquest and Bankers Petroleum) which are North Sea and European focused respectively. One of the key metrics behind a number of the E&P stocks held is low enterprise value / proven reserves. Almost all of the US E&P stocks held also provide exposure to North American natural gas and include two of the industry leaders (Southwestern and Devon).

We have exposure to four (pure) emerging market stocks in the main portfolio, though one is a half-position. Two are classified as integrateds (Gazprom and PetroChina) and two as E&P companies (CNOOC and SOCO International). Gazprom is the Russian national oil and gas company which produces approximately a quarter of the European Union gas demand and trades on 2.9x 2016 earnings. PetroChina is one of the world's largest integrated oil and gas companies and has significant growth potential and, alongside CNOOC, enjoys advantages as a Chinese national champion. SOCO International is an E&P company with production in Vietnam.

We have useful exposure to oil service stocks, which comprise just under 10% of the portfolio. The stocks we own are split between those which focus their activities in North America (land driller Unit Corp) and those which operate in the US and internationally (Helix, Halliburton and Schlumberger).

Our independent refining exposure is currently in the US in Valero, the largest of the US refiners. Valero has a reasonably large presence on the US Gulf Coast and is benefitting from the rise in US exports of refined products seen in recent times.

Our alternative energy exposure is currently two positions of the fund split equally between across three companies: JA Solar, Trina Solar and Sunpower. JA Solar and Trina are both Chinese solar cell and module manufacturers, whilst Sunpower is a more diversified US solar developer. We see them as well placed to benefit from the expansion in the solar market we expect to continue for a number of years.

Portfolio at January 31st 2016 (for compliance reasons disclosed one month in arrears)

Guinness Global Energy Fund 31 January 2016

Stock	ID_ISIN	Curr.	Country	% of NAV	2007 B'berg mean PER	2008 B'berg mean PER	2009 B'berg mean PER	2010 B'berg mean PER	2011 B'berg mean PER	2012 B'berg mean PER	2013 B'berg mean PER	2014 B'berg mean PER	2015 B'berg mean PER	2016 B'berg mean PER
Integrated Oil & Gas														
Exxon Mobil Corp	US30231G1022	USD	US	3.40	10.48	9.0	19.6	12.8	9.1	9.7	10.3	10.4	20.0	28.8
Chevron	US1667641005	USD	US	3.45	9.7	7.5	16.6	9.2	6.3	6.9	7.7	8.9	23.4	45.5
Royal Dutch Shell PLC	GB00B03MLX29	EUR	NL	3.24	4.5	5.1	10.2	7.2	5.4	5.3	7.0	6.2	13.1	16.0
BP PLC	GB0007980591	GBP	GB	3.17	4.9	3.9	6.9	4.7	4.7	5.9	7.3	8.7	15.3	24.1
Total SA	FR0000120271	EUR	FR	3.08	5.4	4.4	11.2	8.7	7.8	7.4	8.3	8.5	10.6	14.8
ENI SpA	IT0003132476	EUR	IT	3.08	5.1	4.7	9.2	7.0	6.7	6.5	10.5	12.2	46.8	39.0
Statoil ASA	NO0010096985	NOK	NO	3.37	8.3	6.2	11.2	8.5	7.4	6.9	7.6	8.6	18.5	24.3
Hess Corp	US42809H1077	USD	US	3.26	7.0	5.7	21.8	8.1	6.9	7.1	7.3	10.0	nm	nm
OMV AG	AT0000743059	EUR	AT	3.12	4.4	3.6	9.4	5.8	7.3	5.1	6.3	7.7	6.9	16.6
				29.17										
Integrated / Oil & Gas E&P - Canada														
Suncor Energy Inc	CA8672241079	CAD	CA	3.26	13.4	10.0	30.1	20.1	8.9	9.9	10.0	9.9	28.6	53.8
Canadian Natural Resources Ltd	CA1363851017	CAD	CA	3.71	13.8	8.9	12.1	12.0	12.6	18.3	13.0	8.5	178.5	nm
Imperial Oil	CA4530384086	CAD	CA	3.46	12.9	10.2	21.1	18.2	11.4	10.1	13.0	11.0	24.2	40.1
				10.43										
Integrated Oil & Gas - Emerging market														
PetroChina Co Ltd	CNE1000003W8	HKD	HK	3.33	4.8	6.2	6.5	5.3	5.2	6.0	6.6	6.5	17.8	29.3
Gazprom OAO	US3682872078	USD	RU	3.37	nm	nm	4.8	3.7	2.5	2.7	2.5	3.8	2.7	2.9
				6.69										
Oil & Gas E&P														
Occidental Petroleum Corp	US6745991058	USD	US	3.41	12.7	7.4	17.9	11.8	8.0	9.6	9.6	11.5	401.0	nm
Apache Corp	US0374111054	USD	US	3.50	4.7	3.6	7.3	4.4	3.4	4.3	5.0	7.3	nm	nm
Devon Energy Corp	US25179M1036	USD	US	2.73	3.7	2.6	7.2	4.4	4.3	8.1	6.1	5.1	10.6	nm
Noble Energy Inc	US6550441058	USD	US	3.39	11.6	9.0	18.7	15.3	12.1	13.8	10.2	13.5	nm	nm
QEP Resources Inc	US74733V1008	USD	US	1.63	nm	nm	nm	8.8	7.5	9.8	8.8	8.7	nm	nm
Newfield Exploration Co	US6512901082	USD	US	3.29	8.7	9.0	5.5	6.1	6.9	11.6	15.7	15.3	38.7	nm
Southwestern Energy Co	US8454671095	USD	US	2.84	13.4	5.5	5.7	4.9	4.6	6.2	4.2	3.8	49.4	nm
Carrizo Oil & Gas Inc	US1445771033	USD	US	1.75	38.5	15.0	18.3	21.2	26.2	18.5	12.1	12.2	27.6	152.1
				22.54										
International E&Ps														
CNOOC Ltd	HK0883013259	HKD	HK	3.36	8.9	6.5	9.5	5.5	4.2	4.4	4.5	5.4	15.7	42.9
Bankers Petroleum Ltd	CA0662863038	CAD	CA	0.80	nm	nm	213.8	9.4	3.4	3.3	2.3	2.0	19.4	nm
Tullow Oil PLC	GB0001500809	GBP	GB	1.50	7.8	5.1	32.9	15.9	3.6	3.2	24.5	nm	nm	47.1
Soco International PLC	GB00B572ZV91	GBP	GB	1.41	20.7	22.2	13.8	19.1	12.3	3.4	3.6	5.6	nm	157.8
				7.06										
Drilling														
Unit Corp	US9092181091	USD	US	1.24	1.7	1.5	3.8	3.3	2.4	2.4	2.7	2.3	nm	nm
				1.24										
Equipment & Services														
Halliburton Co	US4062161017	USD	US	3.51	12.4	14.6	24.2	15.7	9.5	10.6	10.2	8.0	21.4	56.5
Helix Energy Solutions Group Inc	US42330P1075	USD	US	1.25	1.2	1.6	6.8	7.5	2.6	2.1	3.7	2.1	24.2	nm
Schlumberger Ltd	AN8068571086	USD	US	3.39	17.1	15.9	26.3	25.9	19.7	17.1	15.0	12.9	21.3	33.9
				8.14										
Solar														
Trina Solar Ltd	US89628E1047	USD	US	2.08	12.6	7.6	5.6	2.7	339.6	nm	nm	11.4	10.7	6.7
JA Solar Holdings Co Ltd	US4660902069	USD	US	2.27	11.8	4.9	nm	1.2	nm	nm	nm	9.9	5.6	5.3
Sunpower Corp	US8676524064	USD	US	2.21	29.5	12.8	16.2	12.9	250.9	123.8	13.2	14.1	9.8	14.2
				6.56										
Oil & Gas Refining & Marketing														
Valero Energy Corp	US91913Y1001	USD	US	3.54	8.8	12.7	nm	43.3	17.3	14.1	16.7	11.3	7.8	8.9
				3.54										
Research Portfolio														
Cluff Natural Resources PLC	GB00B6SYKF01	GBP	GB	0.19	nm	nm	nm	nm	nm	nm	nm	nm	nm	nm
EnQuest PLC	GB00B635TG28	GBP	GB	0.38	nm	nm	nm	2.3	2.6	0.8	0.9	1.6	3.1	nm
JKX Oil & Gas PLC	GB0004697420	GBP	GB	0.22	0.6	0.7	0.8	0.9	1.0	1.4	2.7	7.4	nm	nm
Ophir Energy PLC	GB00B24CT194	GBP	GB	0.08	nm	nm	nm	nm	nm	nm	nm	4.0	nm	nm
Shandong Molong Petroleum Machinery Co Ltd	CNE1000001N1	HKD	HK	0.10	6.0	4.0	11.2	4.4	6.0	nm	nm	nm	nm	nm
Sino Gas & Energy Holdings Ltd	AU000000SEH2	AUD	AU	0.06	nm	nm	nm	nm	nm	23.8	nm	23.8	nm	7.9
WesternZagros Resources Ltd	CA9600081009	CAD	CA	0.02	nm	nm	nm	nm	nm	nm	nm	nm	nm	nm
				1.06										
			Cash	3.56										
			Total	100										
			PER		7.6	6.4	11.2	6.9	6.7	6.9	7.4	7.6	16.4	23.4
			Med. PER		8.8	6.2	11.2	8.1	6.9	6.9	7.6	8.6	19.0	28.8
			Ex-gas PER		7.6	6.7	12.2	7.2	7.1	6.9	7.6	7.8	15.0	19.8

The Fund's portfolio may change significantly over a short period of time; no recommendation is made for the purchase or sale of any particular stock.

5. OUTLOOK

i) Oil market

The table below illustrates the difference between the growth in world oil demand and non-OPEC supply over the last 11 years, together with the IEA forecasts for 2015 and 2016.

	2004	2005	2006	2007	2008	*2009*	2010	2011	2012	2013	2014	2015	2016E
													IEA
World Demand	**82.5**	**84.0**	**85.2**	**87.0**	**86.5**	**85.5**	**88.5**	**89.5**	**90.7**	***91.9***	***92.8***	***94.4***	***95.6***
Non-OPEC supply (includes Angola, Ecuador and Indonesia for periods when each country was outside OPEC[1])	**50.3**	**50.4**	**51.3**	**50.5**	**49.6**	**51.4**	**52.7**	**52.8**	**53.3**	***54.6***	***57.0***	***58.4***	***57.1***
Angola supply adjustment[1]	-1.0	-1.2	-1.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ecuador supply adjustment[1]	-0.5	-0.5	-0.5	-0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Indonesia supply adjustment[2]	1.0	0.9	0.9	1.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8
Non-OPEC supply (ex. Angola/Ecuador and inc. Indonesia for all periods)	**49.8**	**49.6**	**50.3**	**51.0**	**50.6**	**51.4**	**52.7**	**52.8**	**53.3**	**54.6**	**57.0**	**58.4**	**57.8**
OPEC NGLs	4.2	4.3	4.3	4.3	4.5	5.1	5.5	5.9	6.2	*6.2*	*6.4*	*6.6*	*6.9*
Non-OPEC supply plus OPEC NGLs (ex. Angola/Ecuador and inc. Indonesia for all periods)	**54.0**	**53.9**	**54.6**	**55.3**	**55.1**	**56.5**	**58.2**	**58.7**	**59.5**	**60.8**	**63.4**	**65.0**	**64.7**
Call on OPEC-12[3]	28.5	30.1	30.6	31.7	31.4	29.0	30.3	30.8	31.2	31.1	29.4	29.4	30.9
Iraq supply adjustment[4]	-2.0	-1.8	-1.9	-2.1	-2.4	-2.4	-2.4	-2.7	-3.0	-3.1	-3.3	-3.9	-4.3
Call on OPEC-11[5]	**26.5**	**28.3**	**28.7**	**29.6**	**29.0**	**26.6**	**27.9**	**28.1**	**28.3**	**28.0**	**26.1**	**25.5**	**26.6**

[1]Angola joined OPEC at the start of 2007, Ecuador rejoined OPEC at the end of 2007 (having previously been a member in the 1980s)
[2]Indonesia left OPEC as of the start of 2009; rejoined at start of 2016
[3]Algeria, Angola, Ecuador, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi, U.A.E. Venezuela
[4]Iraq has no offical quota
[5]Algeria, Angola, Ecuador, Iran, Kuwait, Libya, Nigeria, Qatar, Saudi, U.A.E. Venezuela

Source: 2003 - 2008: IEA oil market reports; 2009 - 15: February 2016 Oil market Report

Global oil demand in 2015 was 7.6m b/day up on the pre-recession (2007) peak. This means the combined effect of the 2007/08 oil price spike and the 2008/09 recession was small and was shrugged off remarkably quickly. The IEA forecast a further rise of 1.2m b/day in 2016, which would take oil demand to an all-time high of 95.6m b/day.

OPEC

In December 2011, OPEC-12 introduced a group-wide target of 30m b/day without specifying individual country quotas. The 30m b/day figure included 2.7m b/day for Iraq, so the target for OPEC-11 (excluding Iraq) was 27.3m b/day.

At the date of the announcement, and in the period since, OPEC's production has been complicated by numerous issues: notably (1) erratic production from Libya, affected by the ongoing civil war; (2) depressed production in Iran due to western sanctions over its nuclear programme; (3) real difficulty in forecasting how

Iraq might develop. In response to lower Libyan and Iranian production, and to cope with rising global oil demand, the three key swing producers within OPEC (Saudi, Kuwait and UAE) have each raised their production significantly, as the following table shows:

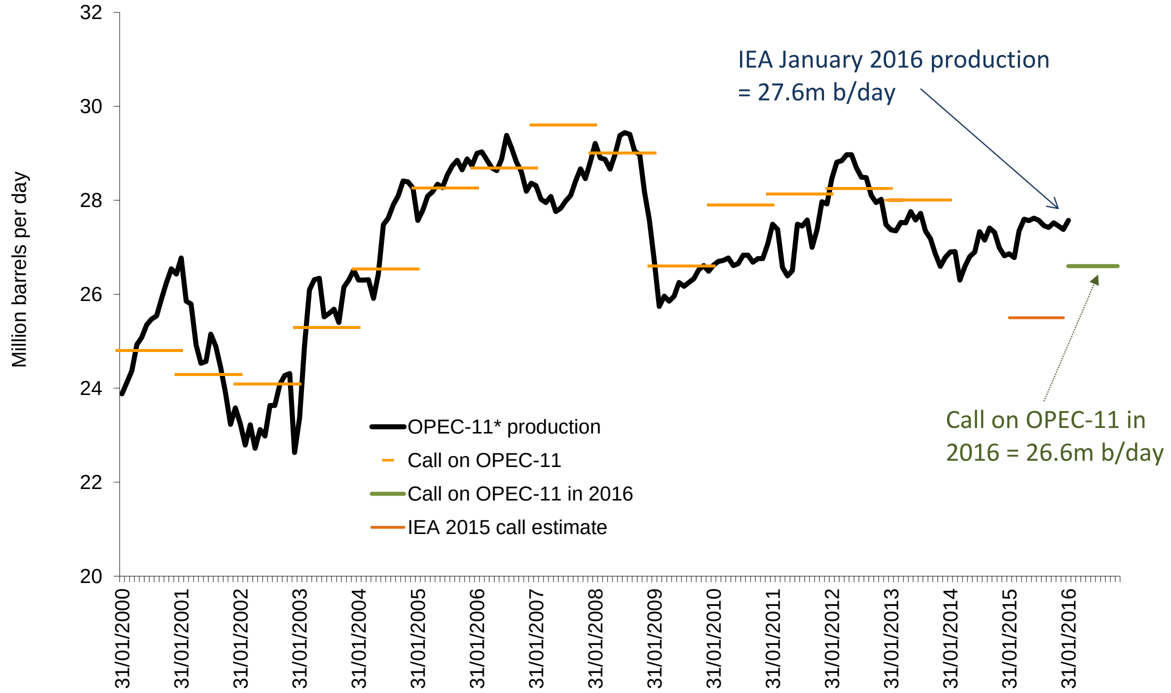
('000 b/day)	31-Dec-10	30-Nov-14	29-Feb-16	Change vs Dec 2010	Change vs Nov 2014
Saudi	8,250	9,650	**10,200**	**1,950**	**550**
Iran	3,700	2,780	**3,000**	-700	**220**
Iraq	2,385	3,370	**4,385**	2,000	**1,015**
UAE	2,310	2,800	**2,980**	670	**180**
Kuwait	2,300	2,790	**3,000**	700	**210**
Nigeria	2,220	1,970	**1,889**	-331	**-81**
Venezuela	2,190	2,470	**2,451**	261	**-19**
Angola	1,700	1,640	**1,759**	59	**119**
Libya	1,585	580	**370**	-1,215	**-210**
Algeria	1,260	1,100	**1,110**	-150	**10**
Indonesia	927	786	**726**	-201	**-60**
Qatar	820	650	**650**	-170	**0**
Ecuador	465	561	**540**	75	**-21**
OPEC-13	**30,112**	31,147	**33,060**	**2,948**	**1,913**

Source: Bloomberg, DOE

The effect from 2011 to the middle of 2014 was OPEC-12 (ex Indonesia) producing at around 30m b/day, plus or minus 1m b/day, in an attempt to keep the global oil market in balance.

Since the second half of 2014, we have moved into a period where the global oil balance has become looser, driven principally by surging non-OPEC supply (+2.4m b/day in 2014 and +1.3m b/day in 2015). The effect of $100+ oil, enjoyed for most of the 2011-2014 period, emerged in the form of an acceleration in US shale oil production and a slowdown in declines in other non-OPEC regions. And as a result, we estimate that the call on OPEC-11 for 2015 has been reduced to 25.7m b/day, around 1.7m b/day lower than December 2015 production of 27.4m b/day (according to the IEA). In the graph below we show how the call on OPEC-11 has evolved since 2000:

Figure 7: OPEC-11 apparent production vs call on OPEC 2000 – 2016



Source: IEA Oil Market Report (February 2016 and prior); Guinness estimates

OPEC-12 met in November 2014, with the growing looseness in the physical market and a falling oil price (in the mid $70s at the time of the meeting) prompting anticipation that OPEC would either reduce their overall quota or announce a firm commitment to comply with the 30m b/day target. In the event there was no quota cut, and a confirmation that the 30m b/day target would be maintained. This marked a significant change in OPEC strategy to one that prioritised market share over price.

In the meantime, Saudi and other OPEC members continue to act rationally in their response to a depressed oil price, realising that an ‘emergency’ production cut would be a fools’ errand as they would simply encourage a sharp recovery in non-OPEC growth. It makes more sense for them to continue to tolerate a lower oil price for now, resulting in diminished prospects for oil production outside OPEC when the price starts to rise again. Longer term, we believe that Saudi seek a ‘good’ oil price, well in excess of current levels to balance their fiscal needs, but they realise that patience is required to achieve that goal.

Saudi went through a similar experience in the first half of the 1980s, trying to maintain price at the expense of volume as non-OPEC supply grew, causing them to reduce their production from 9.6m b/day in 1979 to 3.4m b/day in 1985. Eventually the strategy failed and Saudi shifted to an alternative plan of boosting supply and allowing oil prices to fall, slowing non-OPEC supply growth and invigorating demand. This time Saudi are short-cutting the problem, acting sooner rather than later to choke off non-OPEC supply.

Overall, we reiterate two important criteria for Saudi:

1. Saudi is interested in the average price of oil that they get, they have a longer investment horizon than most other market participants
2. Saudi wants to maintain a balance between global oil supply and demand to maintain a price that is acceptable to both producers and consumers

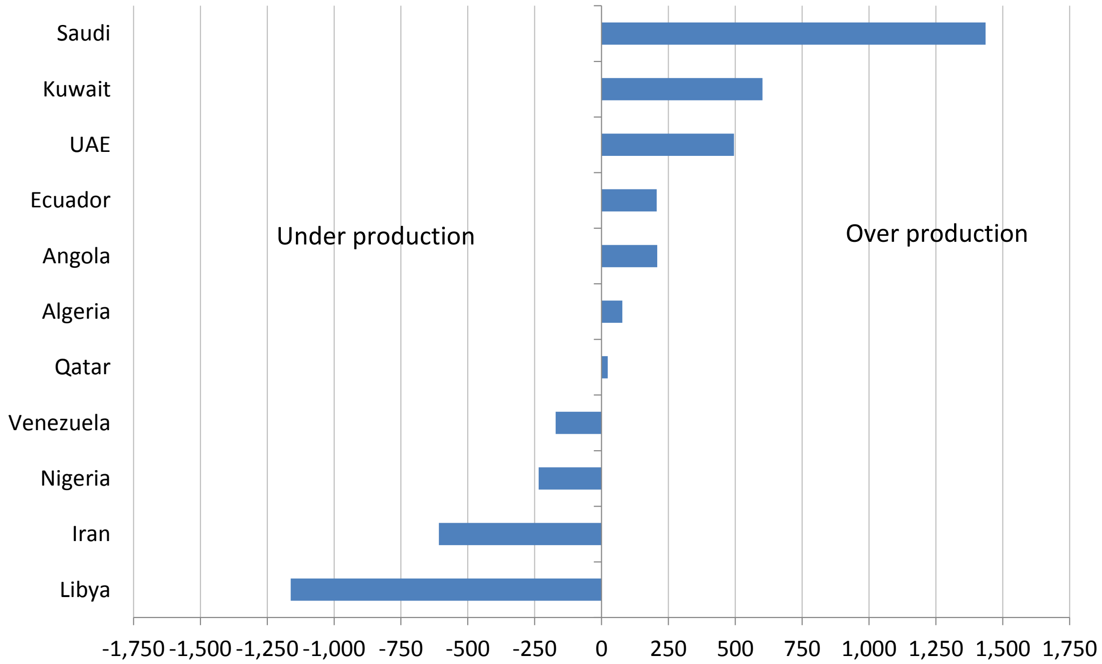
Saudi’s decision not to shoulder an OPEC production cut for the timebeing is consistent with both of those objectives.

The most recent OPEC meeting was held in December 2015 with concluding remarks that were somewhat ambiguous but implied their production quota would remain unchanged, and that the group was content to keep production at the current elevated levels. The meeting confirmed Indonesia's re-entry to OPEC, having left the group in 2008, but nothing was said explicitly about Indonesia's quota. In their concluding remarks, OPEC made the following statement:

"Having reviewed the oil market outlook for 2015, and the projections for 2016, the Conference observed that global economic growth is currently at 3.1% in 2015 and is forecast to expand by 3.4% next year. In terms of supply and demand, it was noted that non-OPEC supply is expected to contract in 2016, while global demand is anticipated to expand again by 1.3 mb/d.In view of the aforementioned, and emphasizing its commitment to ensuring a long-term stable and balanced oil market for both producers and consumers, the Conference agreed that Member Countries should continue to closely monitor developments in the coming months."

As an important aside, we also point to the complicated production picture within OPEC, illustrated here by an estimation of the amount of over/under production versus each country's implied quota:

OPEC-11: over/under production vs implied quota (000s b/day)



Source: IEA; Guinness estimates (February 2016)

Saudi, Kuwait and UAE are over-producing versus their implied quota by around 2.5m b/day, whilst Iran and Libya, but also Nigeria and Venezuela, are under-producing. Unified action by OPEC has been made difficult by the current position, with the under-producing nations reluctant to contribute.

All of that said, nothing in the market has changed our view that OPEC have the ability to put a floor under the price – as they did in 2008, 2006, 2001 and 1998 – *should they choose*.

Supply looking forward

The non-OPEC world has, since the 2008 financial crisis, grown its production more meaningfully than in the six years before 2008. The growth was 0.2% p.a. from 2002-2008, increasing to 2.3% p.a. from 2008-2014.

Growth in the non-OPEC region over the last 5 years has been dominated by the successful development of shale oil and oil sands in North America (up around 4m b/day since 2010), implying that the rest of non-OPEC region has grown by only around 0.5m b/day over the period, despite the sustained high oil price until mid 2014.

After the strongest year for non-OPEC production in 2014 (+2.4m b/day) since 1978, non-OPEC growth in 2015 was also strong, at 1.3m b/day. Whilst sub $60 oil environment has caused significant deferral and cancellation of new developments, start-up projects that were sanctioned before the fall in the oil price are still coming to completion, creating this resilience in production. However, the effect of sub $60 oil starts to impact more in 2016 when non-OPEC supply is expected to fall by more than 0.5m b/day.

Looking further ahead to how global oil supply may evolve in the current oil price environment, we must consider in particular increases in supply from three regions: North America, Iraq and Iran.

The growth in US shale oil production, in particular from the Bakken, Permian and Eagleford basins, raises the question of how much more there is to come. New oil production from these sources amounts peaked in April 2015 at around 4m b/day and is now in decline. Our assessment is that US shale oil is a high cost source of oil but one where growth is viable, on average, at $60-70 oil prices. In total, it could be comparable in size to the UK North Sea, i.e. it could grow by around a further 3m b/day over the next five years, but only if the price is sufficiently high to incentivise growth. The rate of development is heavily dependent on the cashflow available to producing companies, which tends to be recycled immediately into new wells. Naturally, cashflows available for reinvestment in a sub $50 world are far lower than in a $100+ world, so initially slowed the growth rate, then sent production into month on month decline. Indeed, we note that year-over-year production at the end of 2015 was negative.

As for Iraq, the questions of how big an increase is likely, in what timescale, and how other OPEC members react are all important issues. Iraqi production was running at 4.3m b/day in December 2015 (according to the IEA), up from 3.7m b/day at the start of 2015. However, unrest in the country, strained government finances and a likely slowdown in investment from foreign partners does not fill us with confidence that significant growth beyond here can easily be achieved.

Iranian oil production increases have been on the agenda for some time now, although the process of approval and sanction lifting has been slower than many expected. With most sanctions now lifted, we expect an increase in supply of around 500k b/day during 2016. Iran has a target of ultimately producing 5m b/day (vs current production of 2.9m b/day); while it has the resources to do so, it would need a new hydrocarbon fiscal regime and maybe $50bn of investment from international oil companies – unlikely in the near term in our opinion.

Other opportunities to exploit unconventional oil likely exist internationally, notably in Argentina (Vaca Muerta), Russia (Bazhenov), China (Tarim and Sichuan) and Australia (Cooper). However, the US is far better understood geologically; the infrastructure in the US is already in place; service capacity in the US is high; and the interests of the landowner are aligned in the US with the E&P company. In most of the rest of the world, the reverse of each of these points is true, and as a result we see international shale being 5-10 years behind North America.

Demand looking forward

The IEA expect that demand grew in 2015 by around 1.8m b/day, then see 2016 demand growth of 1.2m b/day. The 2016 forecast ties in with the IMF forecast for global GDP growth of 3.6% (which has since been reduced to 3.4%, implying that the IEA's demand forecast will come down somewhat). We see it as logical that demand growth in 2016 will be lower than 2015, since 2015 enjoyed various one-off boosts to demand as a result of the lower price. That said, growth of around 1m b/day in 2016 would still represent close to average demand growth when compared to the last 5 years.

The IEA's global demand growth forecast for 2016 comprises an increase in non-OECD demand of around 1.1m b/day and 0.1m b/day increase in OECD demand. The components of this non-OECD demand growth can be summarised as follows:

Figure 8: Non-OECD oil demand

m b/d	Demand								Growth						
	2009	**2010**	**2011**	**2012**	**2013**	**2014e**	**2015e**	**2016e**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Asia	18.25	19.70	20.35	21.42	22.05	22.65	23.70	24.53	1.45	0.65	1.07	0.63	0.60	1.05	0.83
M. East	7.10	7.32	7.43	7.76	7.91	8.04	8.18	8.32	0.22	0.11	0.33	0.15	0.13	0.14	0.14
Lat. Am.	5.70	6.03	6.17	6.42	6.67	6.84	6.77	6.77	0.33	0.14	0.25	0.25	0.17	-0.07	0.00
FSU	4.00	4.15	4.39	4.61	4.71	4.92	4.87	4.86	0.15	0.24	0.22	0.10	0.21	-0.05	-0.01
Africa	3.37	3.48	3.48	3.78	3.89	3.95	4.06	4.22	0.11	0.00	0.30	0.11	0.06	0.11	0.16
Europe	0.70	0.68	0.66	0.65	0.66	0.68	0.70	0.72	-0.02	-0.02	-0.01	0.01	0.02	0.02	0.02
	39.12	**41.36**	**42.48**	**44.64**	**45.89**	**47.08**	**48.28**	**49.42**	**2.24**	**1.12**	**2.16**	**1.25**	**1.19**	**1.20**	**1.14**

Source: IEA Oil Market Report (February 2016)

As can be seen, Asia has settled down into a steady pattern of growth since 2010. In 2015 and 2016, the lion's share of growth comes from Asia, with the rest of non-OECD demand being dampened by the FSU's consumption going into reverse.

OECD demand in 2016 is forecast to be up 0.1m b/day, with North America slightly higher and Europe and Pacific flat. The IEA have consistently revised demand expectations higher in 2015, and we continue to think that they may be being conservative in their outlook, particularly in North America, as long as current GDP forecasts hold up.

The trajectory of global oil demand over the next few years will be a function of global GDP, pace of the 'consumerisation' of developing economies, and price. At current prices, the world oil bill as a percentage of GDP is around 1-1.5%, the lowest level since 1998/99, and a likely stimulant of strong multi-year demand growth. If oil prices return to a higher range (say $75-100/bbl, representing 3-4% of GDP), we probably return to the pattern established over the past 5 years, with a flat to shallow decline picture in the OECD more than offset by strong growth in the non-OECD area. The small decline in the OECD reflects improving oil efficiency over time, though this effect will be dampened by economic, population and vehicle growth. Within the non-OECD, population growth and rising oil use per capita will both play a significant part. Overall, we would not be surprised to see average annual non-OECD demand growth of around 1.5m b/day to the end of the decade. This would represent a growth rate of 3% p.a., no greater than the growth rate over the last 15 years (3.2% p.a.).

We keep a close eye on developments in the 'new energy' vehicle fleet (electric vehicles; hybrids etc), but see nothing that makes a significant dent on the consumption of gasoline and diesel in the next few years. Sales of electric vehicles (pure electric and plug-in hybrid electrics) globally were around 0.4m in 2015, up from 0.3m in 2014. Sales of 0.4m electric vehicles represents around 0.4% of total light vehicle sales, and increases EVs share of the world car fleet to 0.1%. We expect to see EV sales accelerate in 2016 to around 0.6m, or 0.6% of total global sales. Even applying an aggressive growth rate to EV sales, we see EVs comprising less than 1% of the global car fleet in 2020.

Conclusions about oil

The table below summarises our view by showing our oil price forecasts for WTI and Brent in 2015 against their historic levels, and rises in percentage terms that we have seen in the period from 2002 to 2014.

Figure 9: Average WTI & Brent yearly prices, and changes

Oil price (inflation adjusted)															
12 month MAV	1986-2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
WTI	30	33	38	49	66	75	82	104	68	84	99	94	98	93	49
Brent	30	32	35	46	64	75	82	103	67	84	115	112	108	99	52
Brent/WTI (12m MAV)	**30**	**33**	**37**	**48**	**65**	**75**	**82**	**104**	**68**	**84**	**107**	**103**	**103**	**96**	**51**
Brent/WTI y-on-y change (%)		8%	12%	30%	37%	15%	9%	26%	-35%	24%	27%	-4%	0%	-7%	-47%
Brent/WTI (5yr MAV)	30	25	32	37	42	51	61	75	79	82	89	93	93	99	92

We expect oil to trade in a $30-50 range in the near term. This is an unsupported level which may fluctuate significantly. If this price range persists, we expect North American unconventional supply declines to continue. This points to a rise in oil prices over the year.

In 2016/17 the likelihood is that the price will fluctuate quite widely but move on an upwards trajectory as accelerating emerging country demand growth and US shale oil growth flattening slowly tightens the global oil supply/ demand balance. The world oil bill at around $50 per barrel would represent 2% of 2015 Global GDP, 42% under the average of the 1970 – 2015 period (3.4%). A return to oil representing 3.4% of GDP implies an oil price of around $85/barrel.

We believe that Saudi's long-term objective remains to maintain a 'good' oil price, significantly higher than current levels.

Natural gas market

US supply & demand: recent past

On the demand side, industrial gas demand and electricity gas demand, each about a third of total US gas demand, are key. Commercial and residential demand, which make up the final third, have been fairly constant on average over the last decade – although yearly fluctuations due to the coldness of winter weather can be marked.

Industrial demand (of which around 35% comes from petrochemicals) tends to trend up and down depending on the strength of the economy, the level of the US dollar and the differential between US and international gas prices. Between 2000 and 2009 industrial demand was in steady decline, falling from 22.2 Bcf/day to 16.9 Bcf/day. Since 2009 the lower gas price (particularly when compared to other global gas prices) and recovery from recession has seen demand rebound, up in 2015 to around 21.2 Bcf/day.

Electricity gas demand (i.e. power generation) is affected by weather, in particular warm summers which drive demand for air conditioning, but the underlying trend depends on GDP growth and the proportion of incremental new power generation each year that goes to natural gas versus the alternatives of coal, nuclear and renewables. Gas has been taking market share in this sector: in 2014, 27.2% of electricity generation was powered by gas, up from 21.6% in 2007. The big loser here is coal which has consistently given up market share over the past 10 years.

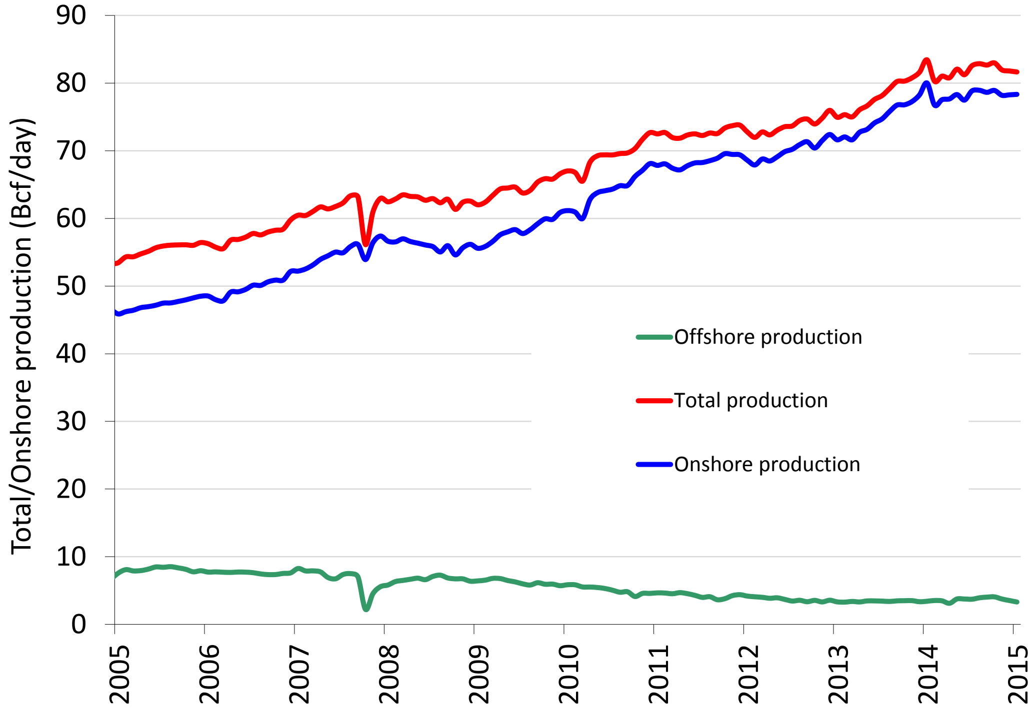
Total gas demand in 2015 (including Canadian and Mexican exports) was around 80.9 Bcf/day, up by 3.1 Bcf/day (4.0%) vs 2014 and up 7.2 Bcf/day (10%) vs the 5 year average. The biggest change in 2015 vs 2014 is power generation (+2.9 Bcf/day), with low prices causing an acceleration in coal to gas switching by the electric utility sector. Exports of gas to Mexico (+0.7 Bcf/day) were also up strongly in 2015, as the network of gas pipelines from Texas into Mexico expands.

Overall, whilst gas demand in the US has been strong over the past five years, it has been overshadowed by a rise in onshore supply, pulling the gas price lower.

The supply side fundamentals for natural gas in the US are driven by 5 main moving parts: onshore and offshore domestic production, net imports of gas from Canada, exports of gas to Mexico and imports of liquefied natural gas (LNG). Of these, onshore supply is the biggest component, making up over 85% of total supply.

Since the middle of 2008 the weaker gas price in the US reflects growing onshore US production driven by rising gas shale and associated gas production (a by-product of growing onshore US oil production). Interestingly, the overall rise in onshore production has come despite a collapse in the number of rigs drilling for gas, which has dropped from a 1,606 peak in September 2008 to 121 at the end of January 2016. However, offsetting the fall, the average productivity per rig has risen dramatically as producers focus their attention on the most prolific shale basins. Onshore gas supply (gross) is now at 78.3 Bcf/day, 21 Bcf/day (36%) above the 57.4 Bcf/d peak in 2009 before the rig count collapsed.

Figure 10: US natural gas production 2005 – 2015 (Lower 48 States)



Source: EIA 914 data (December 2015 published in February 2016)

Supply outlook

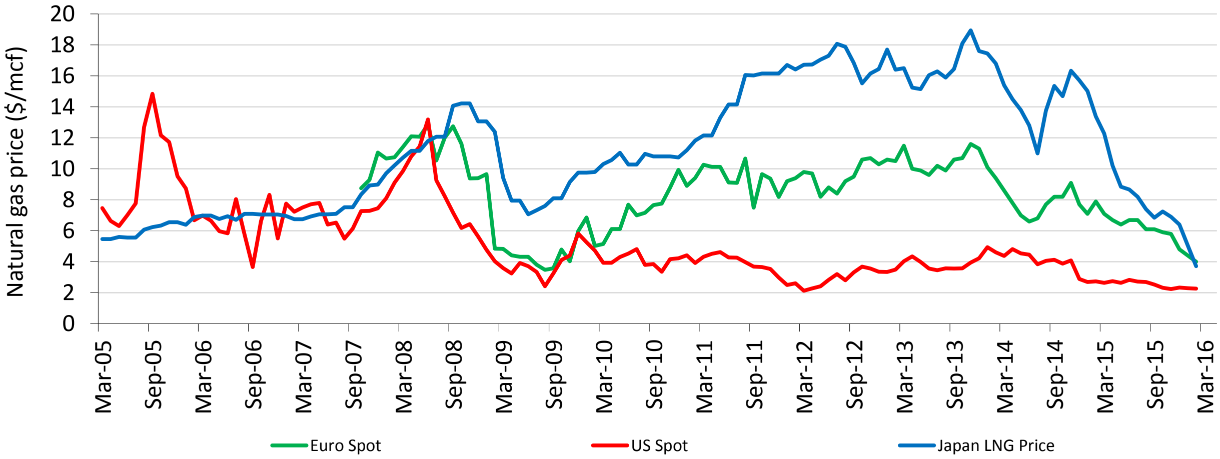
The outlook for gas production in the US depends on three key factors: the rise of associated gas (gas produced from wells classified as oil wells); expansion of the newer shale basins, principally the Marcellus/Utica, and the decline profile of legacy gas fields. The outlook for US oil production growth has changed significantly over the last 12 months with the decline in the oil price. US onshore oil production peaked in April 2015 and is now declining, which has caused associated gas production to decline. Generally, we expect to see rates of around 1-2 Bcf/day of associated gas per 1m b/day of oil production. The Marcellus/Utica region, which includes the largest producing gas field in the US and the surrounding region, reached production of around 17 Bcf/day in 2015. Further growth of 3-4 Bcf/day is likely over the next couple of years, but only if local price differentials improve from the extreme levels seen in recent months. Then there is an expected decline in legacy gas fields, particularly if the gas drilling rig count stays low. Considering these factors together, we expect total onshore production gains to continue (c.1-2 Bcf/day per annum for the next two or three years), but only if the price has recovered to the $2.50-$3mcf range.

	2009	2010	2011	2012	2013	2014	2015	2016(est)
Onshore production - average (Bcf/day)	55.9	58.6	64.6	68.4	70.2	75.3	78.0	78.5
Change (Bcf/day)	0.9	2.7	5.9	3.9	1.8	5.1	2.7	0.5
Change (%)	*1.7%*	*4.8%*	*10.1%*	*6.0%*	*2.6%*	*7.2%*	*3.6%*	*0.6%*

Source: EIA; Guinness estimates

Liquid natural gas (LNG) arbitrage

The UK national balancing point (NBP) gas price – which serves as a proxy to the European traded gas price – weakened in 2015, falling to around $6/mcf, predominantly as a result of price-linkage to oil prices. We note that it still remains at a premium to the US gas price (c.$4.0 versus c.$2.25), albeit much reduced from 12 months ago. Asian spot LNG prices have fallen sharply, now trading at around $4/mcf, also pulled lower by their link to oil prices and due to a negative demand response in Asian markets to previously higher natural gas prices.



Demand outlook

US total demand in 2015 (including exports to Canada and Mexico) was around 81 Bcf/day, nearly 3 Bcf/day higher than 2014 as demand from power generation was up strongly. We expect demand in 2016, assuming prices remain around $2.50-$3/mcf, to increase by around 1 Bcf/day, with weather as ever remaining the wild card.

Looking out further, the low US gas price has stimulated various initiatives that are likely have an increasingly material impact on demand as we move through the second half of the decade. The most significant is the group of LNG export terminals in the US and Canada, most of which are in the planning/ construction stages. There is now around 10 Bcf/day of capacity under construction, much of which will come online by 2020. Exports from the first project to come on-line, Sabine Pass, commenced in February 2016.

Company	Project	Location	Currently under construction (Bcf/day)	Date of first exports	Likely under construction by end 2015 (Bcf/day)	Total potential capacity (Bcf/day)
Cheniere Energy	Sabine Pass	LA	2.4	Q1 2016	3.6	4.1
FLNG Liquefaction	Freeport LNG	TX	1.4	Q4 2017	1.8	1.8
Sempra Energy	Cameron LNG	LA	1.7	Q2 2018	1.7	1.7
Dominion	Cove Point LNG	MD	0.8	Q3 2018	0.8	0.8
Cheniere Energy	Corpus Christi LNG	TX	-	Q1 2019	1.8	2.1
Lake Charles Exports	Lake Charles LNG	LA	-	tba	-	2
Veresen	Jordan Cove LNG	OR	-	tba	-	0.8
LNG Development Comp	Oregon LNG	OR	-	tba	-	1.3
Total			**6.3**		**9.7**	**14.6**

Source: Johnson Rice

Industrial demand will also grow thanks to the increased use of gas in the oil refining process and the construction of new petrochemical plants: Dow Chemical and Chevron Phillips have large new Gulf Coast facilities planned for 2017, the first new crackers to be built in the US since 2001.

We also believe that gas will continue to take the majority of incremental power generation growth in the US and continue to take market share from coal. Coal fired power generation closures have been a feature of 2015 as pollution standards come into force in an effort to reduce mercury and acid gases emissions, which likely accelerates the switch to gas. Our working assumption is for gas fired power generation to grow 0.8-1.5 Bcf/day per year, although this will be affected by actual gas prices.

Increased demand from natural gas vehicles (compressed natural gas typically for shorter haul and liquefied natural gas for longer haul journeys) is emerging, but starts from such a small base that it is unlikely to contribute meaningfully to the overall demand picture in the next 5 years.

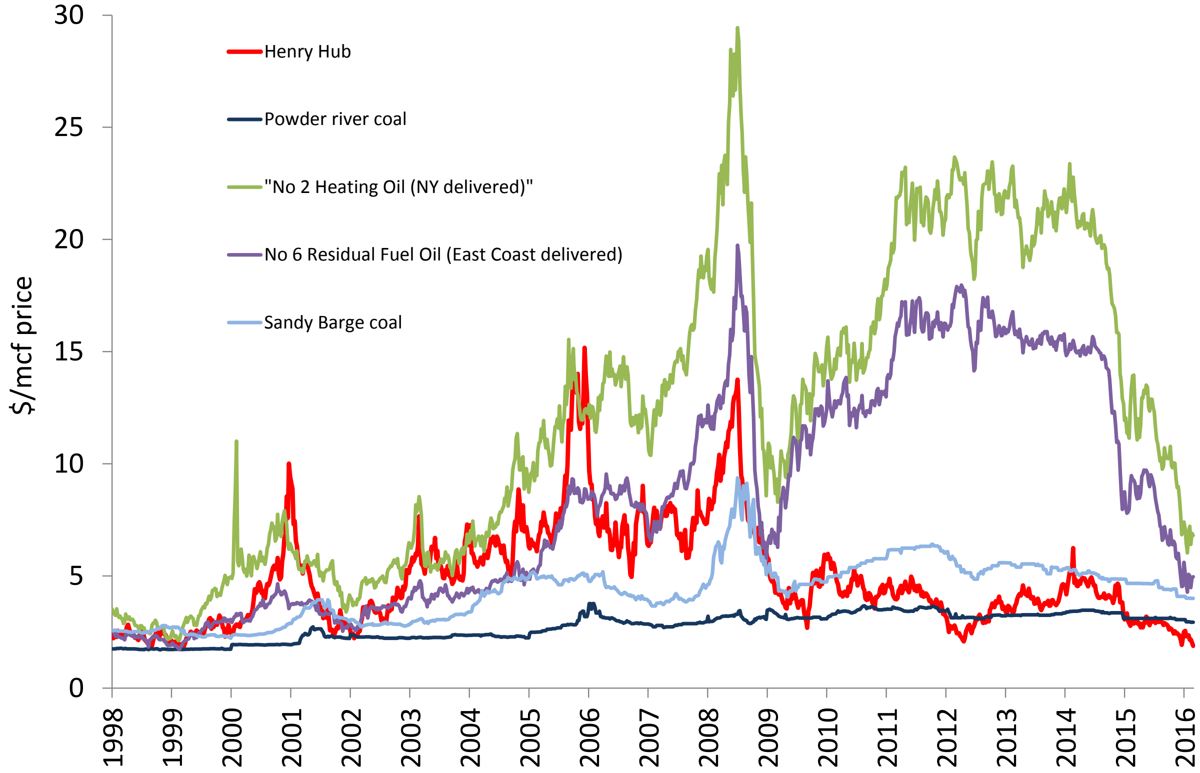
Other

The oil/gas price ratio ($ per bbl WTI/$ per mcf Henry Hub) of around 20x at the end of February continues well outside the long-term ratio of 6-9x. Recent weakness in both oil and natural gas prices has continued to keep the ratio elevated but, at $70 oil, this would imply the gas price at around $8 if the long-term ratio returned.

The following chart of the front month US natural gas price against heating oil (No 2), residual fuel oil (No 6) and coal (Sandy Barge adjusted for transport and environmental costs) seeks to illustrate how coal and residual fuel oil switching provide a floor and heating oil a ceiling to the natural gas price. With the gas price trading below the coal price support level for the first 8 months of 2012, resulting coal to gas switching for power generation was significant. With strong production growth depressing the price below $3 again today, we expect to see coal to gas switching re-accelerate.

Figure 11: Natural gas versus substitutes (fuel oil and coal)

Henry Hub vs residual fuel oil, heating oil, Sandy Barge (adjusted) and Powder River coal (adjusted)



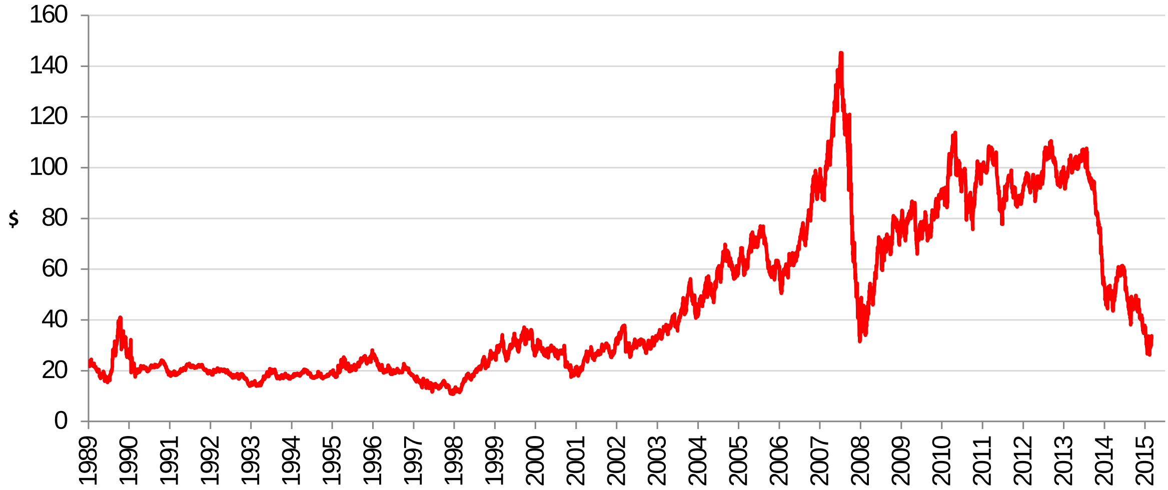
Source: Bloomberg LP (February 2016)

Conclusions about natural gas

The US natural gas price bottomed in 2012 and a tepid recovery since then has been muted by continued strength in gas supply, particularly from the Marcellus and from gas produced as a by-product of shale oil. Average 2015 natural gas prices (at around $2.70) will be around 50% higher the April 2012 low, though we suspect that the (full cycle) marginal cost of supply remains above $3.50. We do not believe the excess in production over demand can continue indefinitely with natural gas trading at this level: a combination of reduced capital spending by the producing companies and growing natural gas demand stimulated by the low gas price will create a new market equilibrium. As this all happens we expect the price to stabilise in the $3.00 – 4.00 range. It may be held at this level for a period until demand grows further (2016 and beyond), and longer term we expect the price to normalise to $4.00+.

3. APPENDIX Oil and gas markets historical context

Figure 12: Oil price (WTI $) last 26 years.



Source: Bloomberg LP

For the oil market, the period since the Iraq Kuwait war (1990/91) can be divided into two distinct periods: the first 9-year period was broadly characterized by decline. The oil price steadily weakened 1991 - 1993, rallied between 1994 –1996, and then sold off sharply, to test 20 year lows in late 1998. This latter decline was partly induced by a sharp contraction in demand growth from Asia, associated with the Asian crisis, partly by a rapid recovery in Iraq exports after the UN Oil for food deal, and partly by a perceived lack of discipline at OPEC in coping with these developments.

The last 13 years, by contrast, have seen a much stronger price and upward trend. There was a very strong rally between 1999 and 2000 as OPEC implemented 4m b/day of production cuts. It was followed by a period of weakness caused by the rollback of these cuts, coinciding with the world economic slowdown, which reduced demand growth and a recovery in Russian exports from depressed levels in the mid 90's that increased supply. OPEC responded rapidly to this during 2001 and reintroduced production cuts that stabilized the market relatively quickly by the end of 2001.

Then, in late 2002 early 2003, war in Iraq and a general strike in Venezuela caused the price to spike upward. This was quickly followed by a sharp sell-off due to the swift capture of Iraq's Southern oil fields by Allied Forces and expectation that they would win easily. Then higher prices were generated when the anticipated recovery in Iraq production was slow to materialise. This was in mid to end 2003 followed by a much more normal phase with positive factors (China demand; Venezuelan production difficulties; strong world economy) balanced against negative ones (Iraq back to 2.5 m b/day; 2Q seasonal demand weakness) with stock levels and speculative activity needing to be monitored closely. OPEC's management skills appeared likely to be the critical determinant in this environment.

By mid-2004 the market had become unsettled by the deteriorating security situation in Iraq and Saudi Arabia and increasingly impressed by the regular upgrades in IEA forecasts of near record world oil demand growth in 2004 caused by a triple demand shock from strong demand simultaneously from China; the developed world (esp. USA) and Asia ex China. Higher production by OPEC has been one response and there was for a period some worry that this, if not curbed, together with demand and supply responses to higher prices, would cause an oil price sell off. Offsetting this has been an opposite worry that non OPEC production could be within a decade of peaking; a growing view that OPEC would defend $50 oil vigorously; upwards pressure on inventory levels from a move from JIT (just in time) to JIC (just in case); and pressure on futures markets from commodity fund investors.

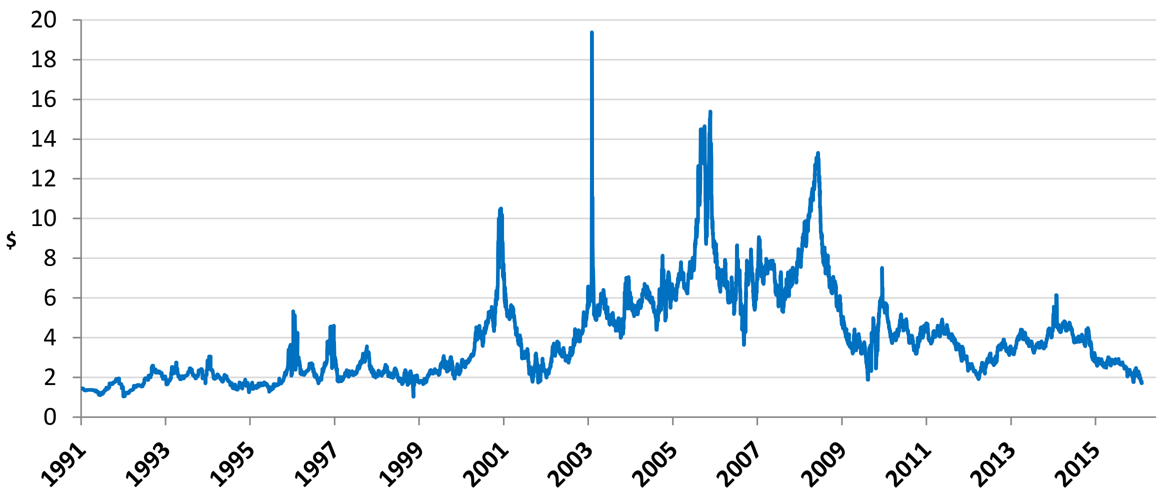
After 2005 we saw a further strong run-up in the oil price. Hurricanes Katrina and Rita, which devastated New Orleans, caused oil to spike up to $70 in August 2005, and it spiked up again in July 2006 to $78 after a three week conflict between Israel and Lebanon threatened supply from the Middle East. OPEC implemented cuts in late 2006 and early 2007 of 1.7 million barrels per day to defend $50 oil and with non-OPEC supply growth at best anaemic demonstrated that it could to act a price-setter in the market at least so far as putting a floor under it.

Continued expectations of a supply crunch by the end of the decade, coupled with increased speculative activity in oil markets, contributed to the oil price surging past $90 in the final months of 2007 and as high as $147 by the middle of 2008. This spike was brought to an abrupt end by the collapse of Lehman Brothers and the financial crisis and recession that followed, all of which contributed to the oil price falling back by early 2009 to just above $30. OPEC's responded decisively and reduced output, helping the price to recover in 2009 and stabilise in the $70-95 range where it remained for two years.

Prices during 2011-2014 moved higher, averaging around $100, though WTI generally traded lower than Brent oil benchmarks due to US domestic oversupply affecting WTI. During this period, US unconventional oil supply grew strongly, but was offset by the pressures of rising non-OECD demand and supply tensions in the Middle East/North Africa.

Most recently, since the end of 2014, Brent and WTI have dropped well below these trading ranges/ Non-OPEC supply (especially US) has accelerated and OPEC have made clear their intention not to support the price for the timebeing, leaving the market oversupplied.

Figure 13: North American gas price last 25 years (Henry Hub $/Mcf)



Source: Bloomberg LP

With regard to the US natural gas market, the price traded between $1.50 and $3/Mcf for the period 1991 - 1999. The 2000s were a more volatile period for the gas price, with several spikes over $8/mcf, but each lasting less than 12 months. On each occasion, the price spike induced a spurt of drilling which brought the price back down. Excepting these spikes, from 2004 to 2008, the price generally traded in the $5-8 range. Since 2008, the price has averaged below $4 as progress achieved in 2007-8 in developing shale plays boosted supply while the 2008-09 recession cut demand. Demand has been recovering since 2009 but this has been outpaced by continued growth in onshore production, driven by the prolific Marcellus/Utica field and associated gas as a by-product of shale oil production.

North American gas prices are important to many E&P companies. In the short-term, they do not necessarily move in line with the oil price, as the gas market is essentially a local one. (In theory 6 Mcf of gas is equivalent to 1 barrel of oil so $60 per barrel equals $10/Mcf gas.) It remains a regional market more than a global market because the infrastructure to export LNG from North America is not yet in place.

IMPORTANT INFORMATION AND RISK FACTORS