

GUINNESS GLOBAL ENERGY FUND

Fund size: \$232m (31.3.2018)

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

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.

HIGHLIGHTS FOR MARCH

OIL

Brent and WTI up on stronger demand, declines from Venezuela

Brent and WTI both up over the month; WTI rose from \$61.6/bl to \$64.9/bl; Brent rose from \$64.4/bl to \$69.1/bl. Global oil demand growth for 2018 was upgraded by the IEA; Venezuela's production fell to its lowest level since 2003; US onshore supply growth slowed; all of which helped OECD and US inventories to tighten.

NATURAL GAS

US gas prices up slightly; market undersupplied

Henry Hub prices were slightly higher on the month, rising from \$2.67/mcf to \$2.73/mcf. Weather adjusted, the US gas market remained under supplied, but onshore US supply in January 2018 (latest EIA data) now 83.5 bcf/day, 8.5 bcf/day higher than start of 2017.

EQUITIES

Energy outperforms the broad market

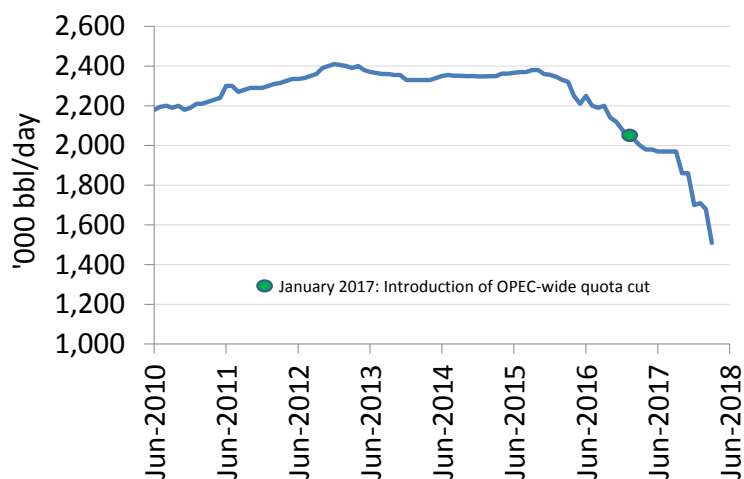
The MSCI World Energy Index rose in March by 1.3%, outperforming the MSCI World Index which declined by 2.1% (all in US dollar terms). For the year to March 31 2018, the MSCI World Energy Index is behind the MSCI World by 4.1%.

CHART OF THE MONTH

Venezuelan oil production nearly 0.5m b/day lower than quota

Bloomberg reported that Venezuelan oil production declined in March by 0.1m b/day, falling to an average of 1.5m b/day. This means that Venezuela is producing nearly 0.5m b/day less than their January 2017 quota of 1.97m b/day, providing a meaningful contribution to the tightening of oil markets globally. Infrastructure issues, weak reservoir management, poor quality control and poor relations with foreign service partners all contributing.

Venezuelan oil production (2010-2018)



Source: Bloomberg; Guinness Asset Management

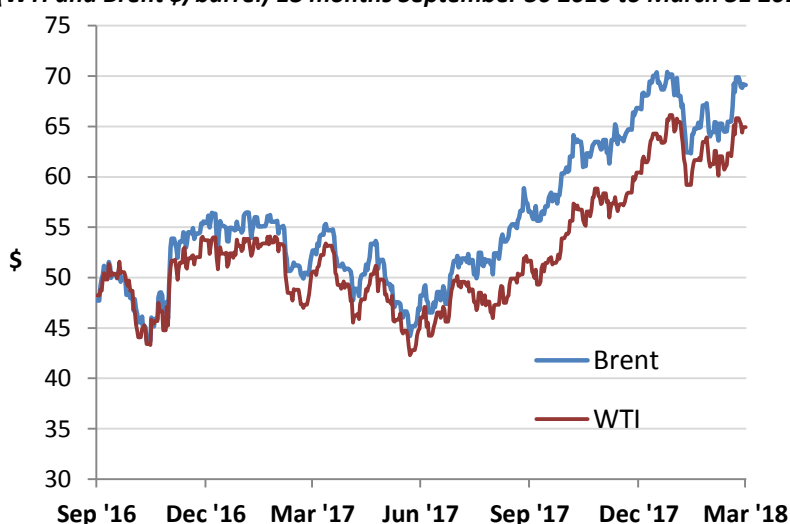
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1. MARCH IN REVIEW

i) Oil market

Figure 1: Oil price (WTI and Brent \$/barrel) 18 months September 30 2016 to March 31 2018



Source: Bloomberg LP

The West Texas Intermediate (WTI) oil price started March at \$61.6/bl and traded up to a high of \$65.8 on March 23, before declining a little to close the month at \$64.9/bl. WTI has averaged \$62.9/bl so far in 2018, having averaged \$51 in 2017, \$43.4 in 2016, \$48.7 in 2015 and \$93.1 in 2014.

Brent oil traded in a similar pattern, opening at \$64.4/bl and rising to \$69.9/bl before dipping to close the month at \$69.1/bl. Brent has averaged \$67.0/bl so far in 2018. The gap between the WTI and Brent benchmark oil prices widened during the month, ending March at \$4.2/bl, having been less than \$3/bl in February.

Factors which strengthened WTI and Brent oil prices in March:

- **Upgrade for global oil demand forecasts in 2018**
 In the middle of March, the IEA upgraded their global oil demand forecast for 2018 by 0.1m b/day to 1.5m b/day. The growth is mainly expected to come from emerging markets (+1.2m b/day), consistent with recent years. Despite the IEA’s increase to their demand expectation, if the IMF’s forecast for global GDP growth in 2018 of 3.9% is achieved, we would expect demand growth to be higher still, exceeding the IEA’s current forecast.

- **Weak Venezuelan production**

Bloomberg reported that Venezuelan oil production declined in March by 0.1m b/day, falling to an average of 1.5m b/day. This means that Venezuela is producing nearly 0.5m b/day less than their January 2017 quota of 1.97m b/day, providing a meaningful contribution to the tightening of oil markets globally.

- **Decreased US onshore oil supply**

At the start of April, the EIA reported that US onshore production declined by 69k b/day during January 2018. This brings year over year growth for the US onshore system to around 1.2m b/day. Using production guidance data provided by the larger shale producers for the rest of the year, we expect the US onshore oil system to grow in the region of 1.2m b/day. Whilst this level of growth would be significant, it does not represent much of a change versus expectations 6-9 months ago.

Factors which weakened WTI and Brent oil prices in March:

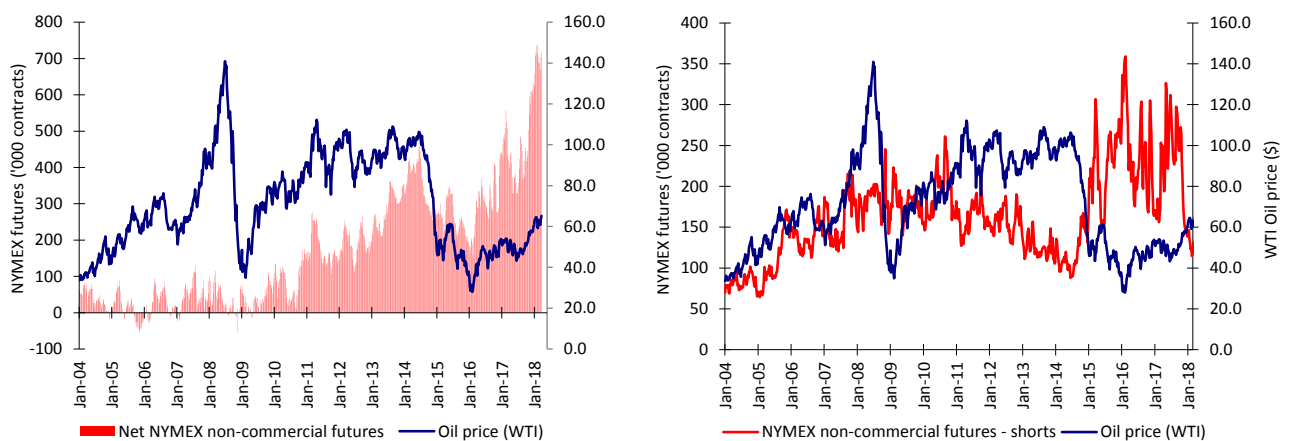
- **Rise in US onshore drilling rig count**

The US oil directed drilling rig count rose by 9 rigs during March, up to 808 rigs. This compares to a low in the middle of 2016 of 316 rigs, and an average rig count in 2017 of 703 rigs. Whilst not a big increase, the rise in the rig count in March follows a rise of 40 oil directed drilling rigs in February, and is a closely watched indicator as to whether US onshore supply growth is likely to accelerate.

Speculative and investment flows

The New York Mercantile Exchange (NYMEX) net non-commercial crude oil futures open position (WTI) increased in March, ending the month at 716,000 contracts long versus 704,000 contracts long at the end of February. Typically there is a positive correlation between the movement in net position and movement in the oil price. The gross short position rose from 119,000 contracts to 138,000 contracts. This short position is now at relatively low level versus those seen in the last couple of years.

Figure 2: NYMEX Non-commercial net and short futures contracts: WTI January 2004 – March 2018

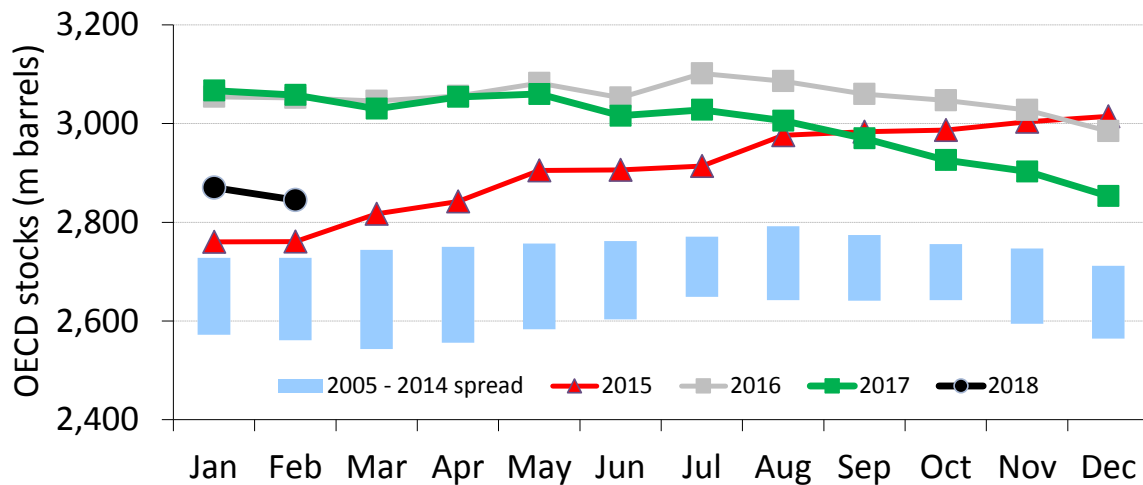


Source: Bloomberg LP/NYMEX/ICE (2018)

OECD stocks

OECD total product and crude inventories at the end of February (the latest data point available) were estimated by the IEA to be 2,845m barrels, down by 25m barrels versus the level reported in January. This compares to a 10-year average draw for February of 24m barrels. Inventories have been tightening since the middle of 2017, and remain around 100m barrels above the 'normalised' (pre-2015) range. We expect them to continue to tighten over 2018, predominantly as a result of OPEC's quota system.

Figure 3: OECD total product and crude inventories, monthly, 2004 to 2017



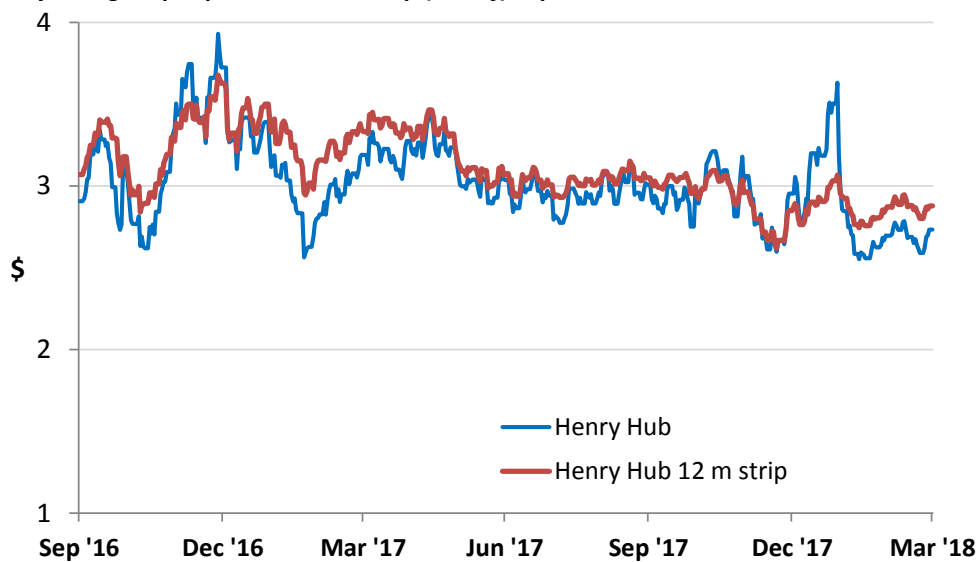
Source: IEA Oil Market Reports (March 2018 and older)

ii) Natural gas market

The US natural gas price (Henry Hub front month) opened March at \$2.67/mcf (1,000 cubic feet). The price fluctuated through the month in a band between \$2.59 and \$2.79, before closing at \$2.73/mcf. The spot gas price has averaged \$2.87/mcf so far in 2018, which compares to an average gas price of \$3.02 in 2017, \$2.55/mcf in 2016 and \$2.61/mcf in 2015. The price averaged around \$3.90/mcf over the preceding five years (2010-2014).

The 12-month gas strip price (a simple average of settlement prices for the next 12 months' futures prices) was less volatile over the month, opening at \$2.84/mcf and closing at \$2.88/mcf. The strip price averaged \$3.12 in 2017 and \$2.84 in 2016, having averaged \$2.86 in 2015, \$4.18 in 2014 and \$3.92 in 2013.

Figure 4: Henry Hub gas spot price and 12m strip (\$/Mcf) September 30 2016 to March 31 2018

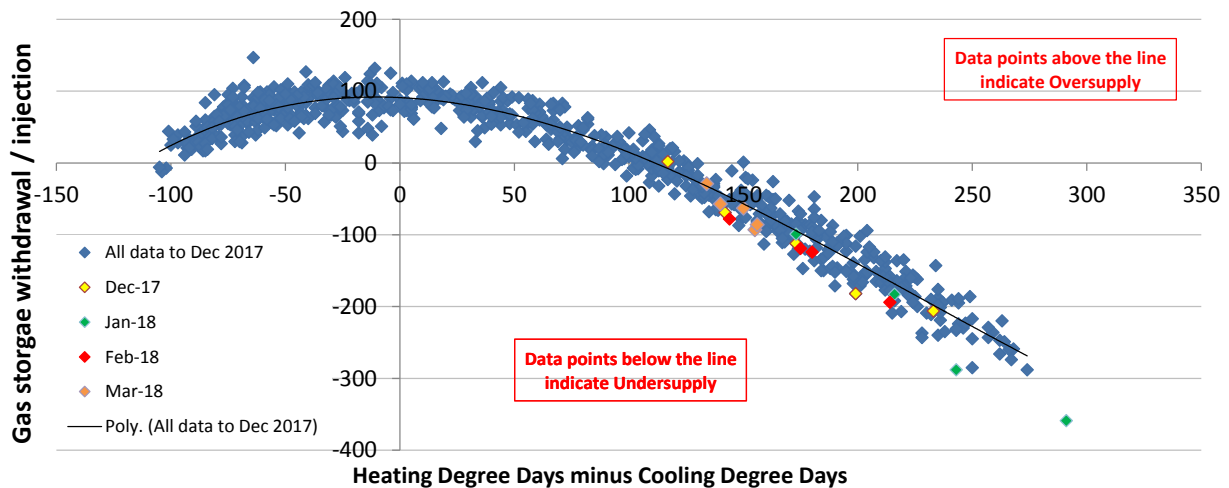


Source: Bloomberg LP

Factors which strengthened the US gas price in March included:

- **Structurally undersupplied market**
Adjusting for the impact of weather in March, the most recent injections of gas into storage suggest the market is, on average, around 3 bcf/day undersupplied (as indicated by the pink dots on the graph below).

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



Source: Bloomberg LP; Guinness Asset Management

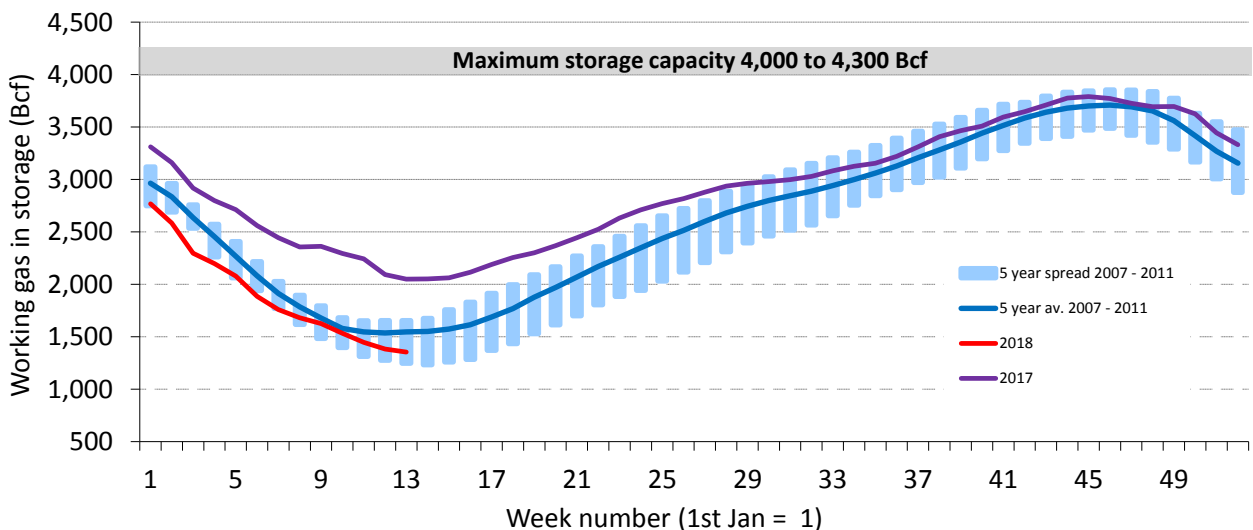
Factors which weakened the US gas price in March included:

- Strong US onshore natural gas production**
 Onshore US natural gas production averaged 83.5 Bcf/day in January 2018 (the latest available data point), down by 1.2 Bcf/day on the level reported for December 2017. Nevertheless, onshore production is up by and up by 8.5 Bcf/day versus the level reported twelve months before. Rising associated gas supply from shale oil, and a pickup of activity in the Marcellus basin, are the key reasons for the rise in production: both look set to continue for the rest of 2018.

Natural gas inventories

Swings in the balance for US natural gas should, in theory, show up in movements in gas storage data. Natural gas inventories at the end of March were reported by the EIA to be 1.35tcf. The withdrawal season started with inventories peaking at 3.8tcf in mid-November, the lowest starting point of the winter season for US gas inventories since November 2014. Exceptionally cold weather and an undersupplied market has brought inventories back from being at the top of the ten year range (in November and December) to being below seasonal norms during March.

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



Source: Bloomberg; EIA (March 2018)

2. MANAGER'S COMMENTS

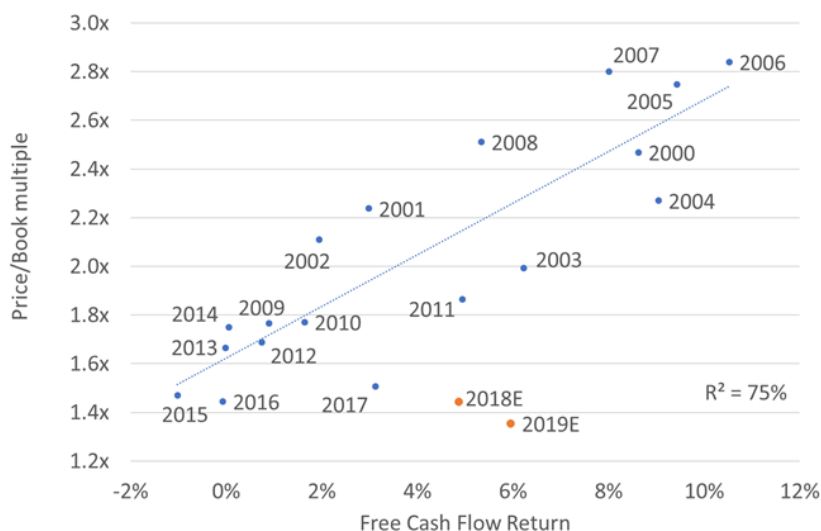
The energy equity sector started 2018 strongly, outperforming the broad market in January. February's energy equity sell-off was then particularly acute, as broad market equity declines were compounded in the oil sector by renewed concerns over accelerating US onshore oil supply, which dampened the long-dated end of the oil futures curve. Since the start of March, energy equities have recovered again, thanks to a combination of tightening fundamentals in the oil market, heightened political risk, and a rotation in equities from growth (tech) to value. Here, we provide some commentary on three key topics of interest that have impacted energy markets (physical and equity) so far this year:

- 1) Improving large-cap cashflows (improving equity story)
- 2) US onshore oil production (rising supply)
- 3) Venezuelan oil production (falling supply)

1) Improving large-cap cashflows

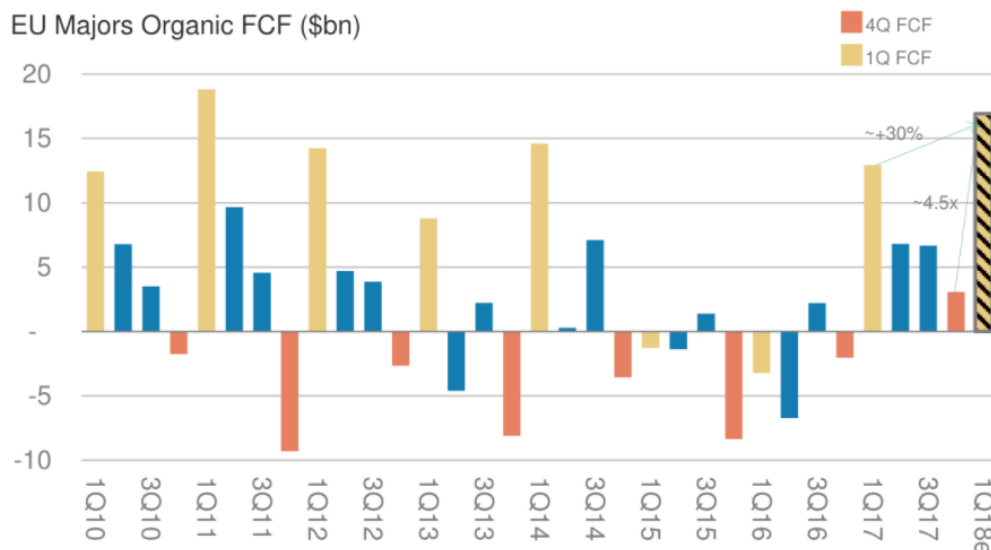
In our annual outlook for 2018, we pointed out that thanks to a modest improvement in the oil price in 2017, and better capital discipline from the companies, impressive free cash flow yields were already emerging in the energy sector. We see this as a leading indicator that returns on capital should also improve, both of which will catalyse an uplift in the price-to-book valuation that the sector currently trades on.

Guinness Global Energy portfolio: FCF return vs P/B multiple (2000-2019)



Source: Guinness Asset Management

So far this year, strength in spot oil prices, and continued capital spending restraint (particularly in Europe), should result in a material increase in free cashflows reported for Q1 2018, beyond what we forecasted in January. Considering the largest five European integrateds (Royal Dutch Shell, BP, Total, ENI and Statoil), for example, we expect to see aggregate free cashflow of around \$17bn for Q1, which would be the highest quarterly free cash flow since the start of 2011, and better than any quarter between 2012 and 2014 when the oil price averaged over \$100/bl.



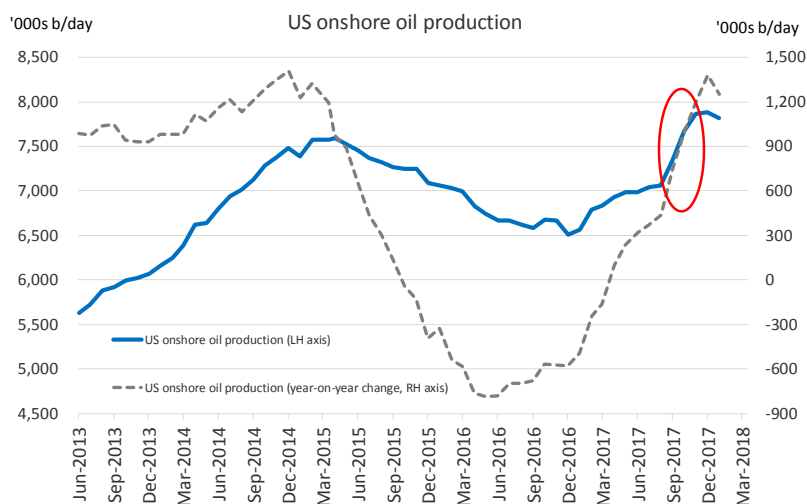
Source: Morgan Stanley

As the chart above shows, Q1 cashflows tend to be seasonally stronger (thanks to lower tax payments and a seasonal dip in capital spending), nevertheless we expect the strength of cashflows to be a positive surprise to the market.

Our current forecast for the Guinness energy portfolio in 2018 is a FCF return (defined as cashflow from operations less CAPEX, over capital employed) of around 5%, which would be the highest since 2011. Note though that this is based on an average oil price of \$55/bl. Applying the spot oil price for the remainder of 2018 would lift this FCF return to just over 7%, the highest level since 2007.

2) US onshore production

Reliable US onshore crude production is typically reported with a two to three month delay. During the first quarter, the EIA reported a significant surge in production for September to November 2017, with onshore supply rising by around 0.8m b/day over those three months. This information weighed on energy stocks in the first quarter of 2018, with questions arising over the rate of growth likely for the rest of this year and beyond.



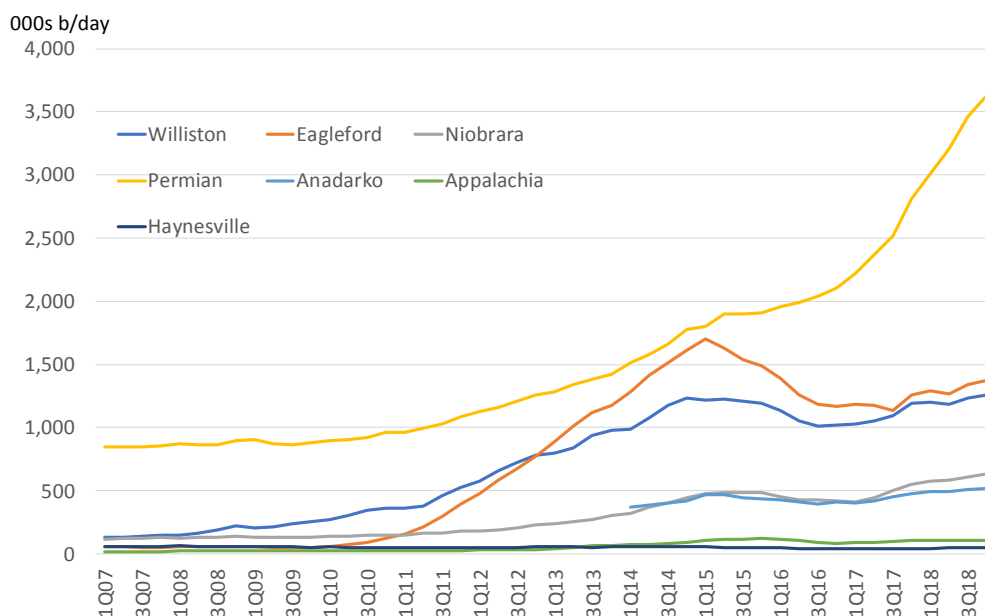
Source: EIA; Guinness Asset Management

With the surge of new production at the end of 2017, shale oil growth in 2017 (Q4 2017 versus Q4 2016) totalled around 1.2m b/day.

Looking ahead, we observe that the improved cashflow discipline exhibited by the majors is now filtering down to the US E&P community. Historically, the E&P economic model was typically to reinvest over 100% of cashflows into capital spending. In the first quarter, E&Ps guided to a reinvestment ratio for 2018 of 92%. And importantly, a significant number of larger E&Ps either raised/initiated dividends, or expanded their share repurchase programs, suggesting that the reinvestment rate is likely to remain below 100%. We are also seeing signs of greater oilfield service inflation than was generally expected, now running in many cases at 10-15% per annum. Against this, the strength in spot oil prices so far this year leaves WTI averaging around \$62/bl, versus \$51/bl in 2017, which generates greater cashflow to reinvest. Pulling these factors together, and considering the guidance given by E&Ps during the first quarter, we expect to see US shale oil growth in 2018 (Q4 2018 vs Q4 2017) of around 1.1-1.2m b/day, so a similar growth rate to 2017. Importantly, despite the Q4 2017 surge in production, the forecast for 2018 production is no higher than that we assumed 9-12 months ago. We believe the US can grow well at \$60/bl (>1m b/day), but effectively there has been no acceleration in recent months, only a lumpy well completions schedule.

As has been the case since 2014, the majority of growth this year will come from the Permian Basin:

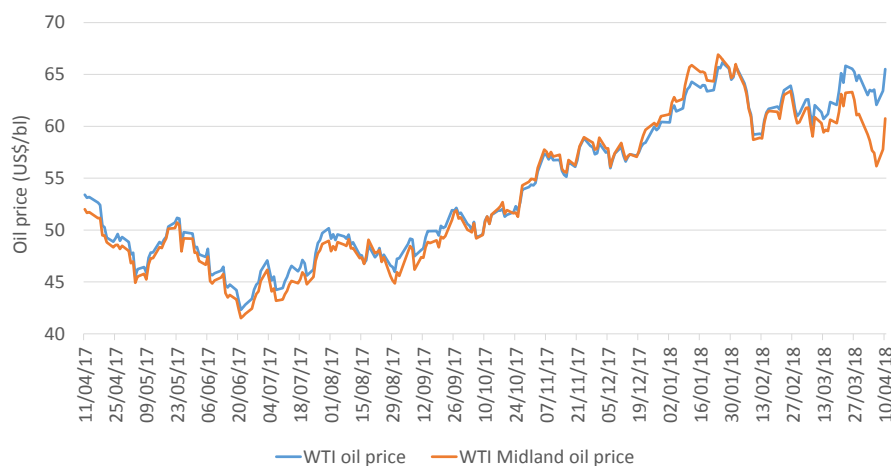
US shale oil production by basin (2007-2018e)



Source: Heikkinen Energy; Guinness Asset Management

One question arising which may affect production forecasts is the takeaway capacity in the Permian. Logistical bottlenecks in the US shale oil system are nothing new: we saw major oil price dislocations in local markets in 2012-2014, for example. However, the concentration of growth in the Permian is now posing new infrastructure and refining challenges, and has, very recently, caused local (Midland) oil prices to fall up to \$6/bl below the WTI spot price. In the short term, it appears that the price dislocation between the Permian and WTI has more to do with lower local refinery runs than a lack of pipelines to export the crude oil. However, it does appear that for a period later this year, stretching into the second half of 2019, Permian production will saturate the basin’s pipeline takeaway capacity. This would likely result in some barrels being trucked to US refining centres, holding price differentials wider under the second half of 2019, when new oil pipes are scheduled to come online.

WTI spot oil price versus Midland (Permian) spot oil price (2017-2018)



Source: Bloomberg, Guinness Asset Management

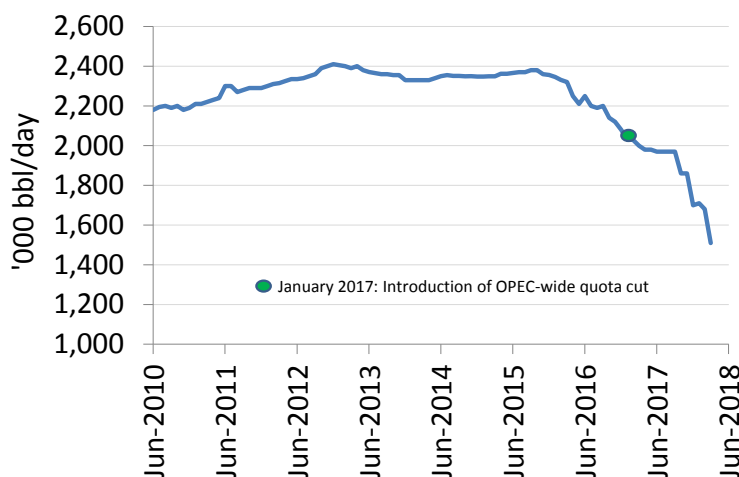
Our US shale oil production growth forecast for 2018 of 1.1-1.2m b/day does not assume any significant Permian disruption - we prefer to think conservatively and assume higher supply as a base case – but infrastructure constraints are likely to have an impact at the margin.

3) Venezuelan oil production

Since the sharp fall in the oil price in late 2014, there has been much focus on the resulting decline in upstream investment across the non-OPEC world. Within OPEC, Gulf states have been able to weather the storm successfully (at least from an upstream investment perspective, if not a fiscal one). However, it is clear that under investment is starting to have a more meaningful impact on ‘tier 2’ OPEC countries, none more so than Venezuela, where production has been under significant strain.

Venezuelan oil production declined in March by 0.1m b/day, falling to an average of 1.5m b/day. This means that Venezuela is producing nearly 0.5m b/day less than their January 2017 quota of 1.97m b/day, and nearly 0.9m b/day less than recent peak production in 2015.

Venezuelan oil production, 2010-2018



Source: Bloomberg; Guinness Asset Management

Venezuela’s national oil company, PdVSA, is struggling to pay back foreign joint venture partners, as oil revenues are increasingly diverted to support social spending programmes. Deteriorating infrastructure, weak reservoir management and, according to the IEA, issues sourcing diluent to mix with domestic heavy crude oil production, have combined to lower production. These trends have been persisting for nearly a decade, but have accelerated since 2014. Towards the end of 2017, it was reported that US Gulf Coast refiner, Phillips 66, had rejected over 4m barrels of Venezuelan crude due to quality issues, including a lack of basic treatments to remove water, salt, metals and other impurities. Similar issues have been reported from shipments made to China and India, resulting in large quality pricing discounts, lowering proceeds from production yet further.

Oil industry problems in the country have been compounded by a new round of sanctions imposed on the Venezuelan government by the US in 2017. The sanctions prevent US corporations from providing new debt or equity financings to the Venezuelan government or institutions under its control (i.e. including PdVSA). This has resulted in Venezuela being unable to issue new debt, and for the oil industry, has caused US-oriented institutions to back away from offering letters of credit to purchasers of PdVSA’s oil.

Venezuela continues to rely on foreign oilfield services expertise, but service partners are acting increasingly cautiously due to sizeable receivables that are outstanding. According to CIBC, PdVSA had an estimated US\$20bn of outstanding payables to contractors, with little prospect of a resolution.



All of these factors combine to create an exceedingly difficult outlook for Venezuelan oil production. It is thought that by the end of 2018, capacity may be down to 1.4m b/day, which would be Venezuela’s lowest production level since the late 1940s. And whilst a continued steady deterioration seems most likely, a sharp drop in production thanks to a national strike, as the country experienced in 2002-03, also remains a possibility.

Venezuelan production at current levels tightens the oil market by around 0.5m b/day more than OPEC were planning, and is helping to accelerate the move to normalised oil inventories across the globe.

Conclusions

The factors discussed here – declining OPEC supply, as expected US supply growth – combined with strong global demand, have combined so far this year to continue to tighten the oil market. At the start of 2017, OECD oil inventories sat around 300m barrels (around 11%) higher than ‘normal’. The inventory surplus has now been reduced to around 100m barrels, and we expect it to fall further over the rest of 2018.

Combined with capital constraint and lower operating costs, a tighter oil market is boosting profitability for energy producers, pulling free cashflow returns to their highest levels since the start of the decade. We see energy equities discounting an oil price in the mid \$50s/bl, with good upside if equities were to discount \$60/bl or higher in their valuations.

1) PERFORMANCE Guinness Global Energy Fund

The main index of oil and gas equities, the MSCI World Energy Index, was up by 1.3% in March, while the MSCI World Index fell by 2.1%. The Fund was up by 2.2% (class E) in the month, outperforming the MSCI World Energy Index (all in US dollar terms).

Within the Fund, March's strongest performers were Hess, Apache, QEP Resources, Tullow and Sunpower, while the weakest performers were Imperial Oil, Petrochina, Gazprom, Helix and JA Solar.

Performance (in USD)												31/03/2018
Annualised												
% returns			1	3		5		10		1999		
			year	years		years		years		to date		
Guinness Global Energy			2.2	-3.5		-3.6		-2.2		9.8		
MSCI World Energy Index			5.4	1.2		0.0		0.5		6.9		
Calendar year												
% returns	2018	2017	2016	2015	2014	2013	2012	2011	2010	2009	2008	2007
Guinness Global Energy	-4.7	-1.3	27.9	-27.6	-19.1	24.4	3.0	-13.6	15.3	61.8	-48.2	37.6
MSCI World Energy Index	-5.2	5.9	27.6	-22.1	-11.0	18.8	2.5	0.7	12.5	27.0	-37.7	30.4
<i>Source: Guinness Asset Management and Financial Express, bid to bid, gross income reinvested, in US dollars</i>												
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 (1.49% OCF) from launch to 02.09.08, and class E (1.24% OCF) 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.												

2) PORTFOLIO Guinness Global Energy Fund

Buys/Sells

In March we rebalanced the portfolio. There were no stock switches.

Sector Breakdown

The following table shows the asset allocation of the Fund at **March 31 2018**.

(%)	31 Dec 2009	31 Dec 2010	31 Dec 2011	31 Dec 2012	31 Dec 2013	31 Dec 2014	31 Dec 2015	31 Dec 2016	31 Dec 2017	31 Mar 2018	Change YTD
Oil & Gas	98.2	93.3	97.9	97.3	93.7	93.7	95.1	96.7	98.4	97.5	0.8
Integrated	35.9	33.0	30.9	30.4	29.2	27.0	30.4	32.5	28.6	28.9	-3.6
Integrated – Can & Em Mkts	11.9	8.2	8.8	8.4	9.4	10.3	11.1	14.3	14.2	14.7	0.4
Exploration & production	32.8	37.1	41.1	40.3	35.4	36.2	36.5	35.4	37.0	36.3	0.9
Oil & Gas Storage & Transportation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.5	3.4	3.4
Drilling	8.5	6.1	5.9	7.1	6.4	3.3	1.5	2.2	1.9	1.7	-0.5
Equipment & services	5.9	5.4	6.1	7.4	9.8	13.4	11.4	8.6	9.5	8.9	0.3
Refining and marketing	3.2	3.5	5.1	3.7	3.5	3.5	4.2	3.7	3.7	3.6	-0.1
Solar	0.0	3.2	1.3	1.2	2.6	3.7	4.7	0.9	1.4	1.5	0.6
Coal & consumables	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Construction & engineering	0.3	0.3	0.4	0.6	1.0	0.0	0.0	0.0	0.0	0.0	0.0
Cash	1.5	3.2	0.4	0.9	2.7	2.6	0.2	2.4	0.2	1.0	-1.4
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	

Source: Guinness Asset Management

Basis: Global Industry Classification Standard (GICS)

The Fund at March 31 2018 was on a price to earnings ratio (P/E) for 2018 of 15.6x versus the S&P 500 Index at 16.9x as set out in the following table:

	2011	2012	2013	2014	2015	2016	2017	2018
Guinness Global Energy Fund P/E	7.5	7.8	8.4	9.2	20.9	37.0	22.7	15.6
S&P 500 P/E	27.4	27.3	24.6	22.8	26.3	24.9	21.3	16.9
Premium (+) / Discount (-)	-73%	-71%	-66%	-60%	-21%	49%	7%	-8%
Average oil price (WTI \$/bbl)	95	94	98	93	49	43	51	57

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

Portfolio holdings

Our integrated and similar stock exposure (c.44%) is comprised of a mix of mid cap, mid/large cap and large cap stocks. Our four large caps are Chevron, BP, Royal Dutch Shell and Total. Mid/large and mid-caps are ENI, Statoil, Hess and OMV. At March 31 2018 the median P/E ratios of this group were 17.5x/14.9x 2017/2018 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.34%) 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, Oasis and QEP Resources), with four other names (Apache, Occidental, ConocoPhillips, Noble) having a mix of US and international production and one (Tullow) which is African focused. 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.

We have exposure to four (pure) emerging market stocks in the main portfolio, though one is a half-position, and in total represent 12% of the portfolio. Two are classified as integrated (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 3.9x 2018 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.

The portfolio contains one midstream holding, Enbridge, North America's largest pipeline company. With the growth of onshore oil and gas production expected in the US and Canada over the next five years, we believe Enbridge is well placed to execute its pipeline expansion plans.

We have useful exposure to oil service stocks, which comprise around 11% 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 split between across two companies: JA Solar and Sunpower. JA Solar is a Chinese solar cell and module manufacturer 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 February 28th 2018 (for compliance reasons disclosed one month in arrears)

Guinness Global Energy Fund 28 February 2018													
Stock	Curr.	Country	% of NAV	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
				B'berg mean PER	B'berg mean PER	B'berg mean PER	B'berg mean PER	B'berg mean PER	B'berg mean PER	B'berg mean PER	B'berg mean PER		
Integrated Oil & Gas													
Chevron	USD	US	3.59	21.8	12.0	8.3	9.1	10.1	11.6	30.8	80.7	27.0	17.8
Royal Dutch Shell PLC	EUR	NL	3.87	14.6	10.3	7.7	7.6	10.0	8.9	18.8	30.9	16.7	13.4
BP PLC	GBP	GB	3.82	8.4	5.8	5.8	7.2	8.9	10.6	18.7	35.7	21.3	14.6
Total SA	EUR	FR	3.78	13.1	10.2	9.1	8.7	9.8	9.9	12.7	15.0	14.0	12.2
ENI SpA	EUR	IT	3.66	9.6	7.3	7.0	6.8	10.9	12.7	59.4	nm	24.0	15.8
Statoil ASA	NOK	NO	3.89	13.2	10.0	8.6	7.7	9.4	13.2	32.1	162.9	17.0	15.6
Hess Corp	USD	US	3.59	23.7	8.8	7.6	7.7	7.9	10.9	nm	nm	nm	nm
OMV AG	EUR	AT	3.63	18.9	11.8	14.8	10.3	12.7	15.6	13.9	14.3	9.6	10.2
				29.82									
Integrated / Oil & Gas E&P - Canada													
Suncor Energy Inc	CAD	CA	3.73	40.0	26.6	11.8	13.1	13.2	13.2	37.5	nm	22.6	16.8
Canadian Natural Resources Ltd	CAD	CA	3.61	16.5	16.4	17.2	25.0	17.7	11.5	286.0	nm	33.9	18.2
Imperial Oil	CAD	CA	3.74	17.5	15.2	9.4	8.4	10.8	9.1	19.5	57.7	27.1	18.4
				11.07									
Integrated Oil & Gas - Emerging market													
PetroChina Co Ltd	HKD	HK	3.70	7.6	6.1	6.0	6.9	7.6	7.5	23.4	91.6	36.2	16.8
Gazprom OAO	USD	RU	3.75	5.1	4.0	2.7	2.9	2.6	4.1	2.9	3.9	4.2	3.9
				7.45									
Oil & Gas E&P													
Occidental Petroleum Corp	USD	US	3.67	17.6	11.6	7.9	9.5	9.4	11.3	395.2	nm	73.1	25.3
ConocoPhillips	USD	US	3.88	15.0	9.2	6.4	9.5	9.7	10.2	nm	nm	87.2	20.9
Apache Corp	USD	US	3.11	6.1	3.7	2.9	3.6	4.2	6.1	nm	nm	322.2	26.5
Devon Energy Corp	USD	US	3.04	9.4	5.2	5.1	9.5	7.2	6.0	12.4	nm	16.7	14.5
Noble Energy Inc	USD	US	3.66	17.6	14.4	11.4	13.0	9.6	12.8	523.3	nm	1864.4	38.0
QEP Resources Inc	USD	US	1.67	nm	6.2	5.3	6.9	6.2	6.1	nm	nm	nm	nm
Newfield Exploration Co	USD	US	2.90	4.6	5.1	5.7	9.6	13.0	12.6	32.2	21.7	10.9	7.6
Oasis Petroleum Inc	USD	US	1.82	nm	46.9	9.6	5.3	2.9	3.2	9.9	nm	nm	37.0
				23.74									
International E&Ps													
CNOOC Ltd	HKD	HK	3.65	13.7	7.9	6.0	6.4	6.5	7.8	23.2	nm	13.2	9.2
Tullow Oil PLC	GBP	GB	1.67	38.4	18.6	4.3	3.8	28.7	nm	nm	nm	13.0	12.7
Soco International PLC	GBP	GB	0.82	7.6	10.4	6.7	1.9	2.0	3.0	nm	nm	nm	28.1
				6.15									
Midstream													
Enbridge Inc	USD	CA	3.45	48.2	41.6	37.5	34.5	31.8	29.2	26.4	24.4	29.6	23.6
				3.45									
Drilling													
Unit Corp	USD	US	1.60	7.3	6.3	4.7	4.6	5.2	4.5	nm	nm	36.1	12.4
				1.60									
Equipment & Services													
Halliburton Co	USD	US	3.74	35.5	23.1	13.9	15.6	15.0	11.8	31.4	nm	39.9	18.4
Helix Energy Solutions Group Inc	USD	US	1.49	10.3	11.3	4.0	3.2	5.5	3.1	35.3	nm	nm	48.9
Schlumberger Ltd	USD	US	3.62	24.2	23.8	18.1	15.7	13.8	11.9	19.6	56.8	44.9	30.0
				8.84									
Solar													
JA Solar Holdings Co Ltd	USD	US	1.14	nm	1.0	nm	nm	nm	8.1	4.1	9.5	12.7	14.1
Sunpower Corp	USD	US	0.51	6.2	4.9	86.5	47.3	5.0	5.4	3.6	nm	nm	nm
				1.65									
Oil & Gas Refining & Marketing													
Valero Energy Corp	USD	US	3.69	nm	57.0	22.7	18.5	22.0	14.9	10.3	24.6	18.5	12.1
				3.69									
Research Portfolio													
Cluff Natural Resources PLC	GBP	GB	0.26	nm	nm	nm	nm	nm	nm	nm	nm	nm	nm
EnQuest PLC	GBP	GB	0.68	nm	4.7	5.3	1.6	1.8	3.3	31.7	2.1	nm	4.7
JXX Oil & Gas PLC	GBP	GB	0.16	0.6	0.7	0.8	1.0	2.0	5.5	nm	nm	nm	27.5
Ophir Energy PLC	GBP	GB	0.04	nm	nm	nm	nm	nm	2.2	nm	nm	nm	nm
Reabold Resources PLC	GBP	GB	0.36	nm	nm	nm	nm	nm	nm	nm	nm	nm	nm
Shandong Molong Petroleum Machiner	HKD	HK	0.06	6.2	2.4	3.4	nm	nm	nm	nm	nm	nm	nm
Sino Gas & Energy Holdings Ltd	AUD	AU	0.31	nm	nm	nm	139.0	nm	139.0	nm	nm	nm	nm
				1.87									
Cash			0.66										
Total			100										
PER				13.2	8.4	7.3	7.6	8.2	8.9	20.0	35.3	21.8	15.1
Med. PER				13.5	10.0	7.3	8.0	9.4	9.9	23.3	24.6	23.3	16.8
Ex-gas PER				14.3	9.1	8.0	7.8	8.8	9.6	19.5	32.4	21.2	14.9

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.

3) OUTLOOK

i) Oil market

The table below illustrates the difference between the growth in world oil demand and non-OPEC supply over the last 12 years, together with IEA forecasts for 2018.

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018E
World Demand	82.5	84.0	85.2	87.0	86.5	85.5	88.5	89.5	90.7	91.7	93.1	95.0	96.3	97.8	99.3
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	54.5	56.6	58.1	56.8	57.5	59.3
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	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	0.0	0.0
Indonesia/Gabon 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	0.6	0.6	0.6
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	54.5	56.6	58.1	57.4	58.1	59.9
OPEC NGLs	4.2	4.3	4.3	4.3	4.5	5.1	5.5	5.9	6.4	6.1	6.4	6.6	6.8	6.9	7.0
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	59.7	60.6	63.0	64.7	64.2	65.0	66.9
Call on OPEC-12³	28.5	30.1	30.6	31.7	31.4	29.0	30.3	30.8	31.0	31.1	30.1	30.3	32.1	32.8	32.4

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, but is now suspended again

³ Algeria, Angola, Ecuador, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi, U.A.E. Venezuela

Source: 2003 - 2008: IEA oil market reports; 2009 - 17: March 2018 Oil market Report

Global oil demand in 2017 was 10.8m b/day higher than the pre-financial crisis (2007) peak. This means the combined effect of the 2007/08 oil price spike and the 2008/09 recession was shrugged off remarkably quickly, thanks to growth in demand from emerging markets. The IEA forecast a rise of 1.5m b/day in 2018, which would take oil demand to an all-time high of 99.3m b/day.

OPEC

In December 2011, OPEC-12 introduced a group-wide target of 30m b/day without specifying individual country quotas. 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, Iranian and Nigerian production, and to cope with rising global oil demand, the three key swing producers within OPEC (Saudi, Kuwait and UAE) each raised their production significantly, as the following table shows:

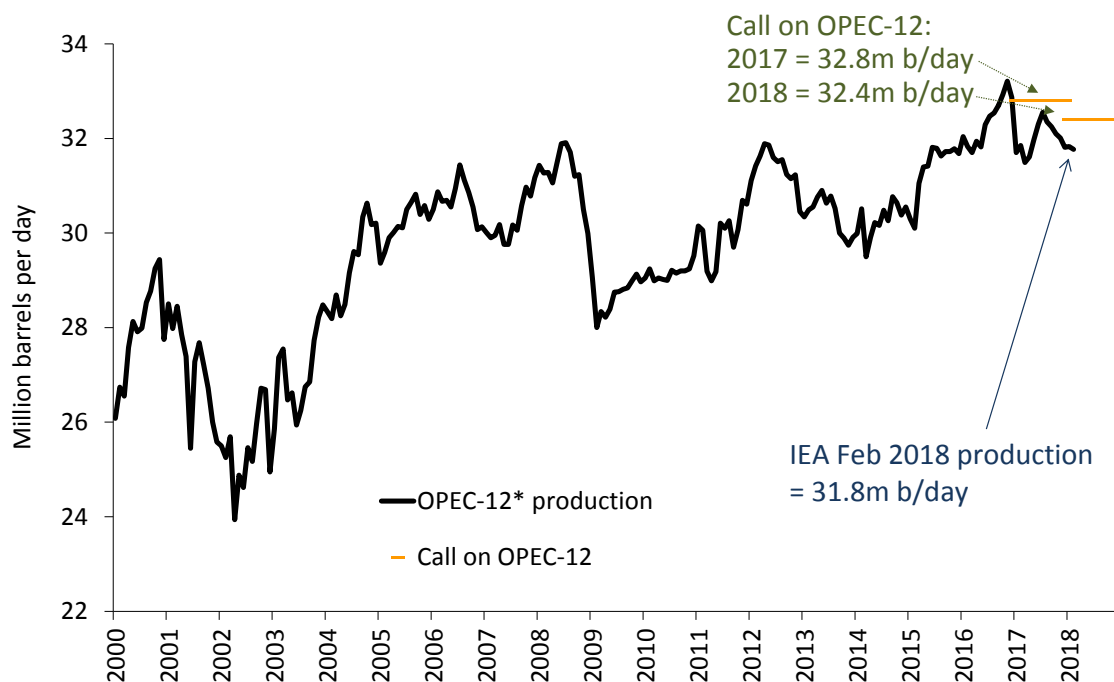
('000 b/day)	31-Dec-10	30-Nov-14	31-Dec-16	31-Mar-18	Current vs Dec 2010 (start of Arab Spring)	Current vs Nov 2014 (OPEC hold mkt share)	Current vs Dec 2016 (OPEC cut production)
Saudi	8,250	9,650	10,480	9,870	1,620	220	-610
Iran	3,700	2,780	3,730	3,810	110	1,030	80
Iraq	2,385	3,370	4,630	4,430	2,045	1,060	-200
UAE	2,310	2,800	3,070	2,860	550	60	-210
Kuwait	2,300	2,790	2,860	2,700	400	-90	-160
Nigeria	2,220	1,970	1,500	1,850	-370	-120	350
Venezuela	2,190	2,350	2,080	1,510	-680	-840	-570
Angola	1,700	1,640	1,670	1,570	-130	-70	-100
Libya	1,585	580	630	990	-595	410	360
Algeria	1,260	1,100	1,110	1,000	-260	-100	-110
Qatar	820	650	620	610	-210	-40	-10
Ecuador	465	561	550	520	55	-41	-30
OPEC-12	29,185	30,241	32,930	31,720	2,535	1,479	-1,210

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.

From the second half of 2014, we moved into a period where the global oil balance became looser, driven principally by surging non-OPEC supply (+2.4m b/day in 2014 and +1.4m b/day in 2015). The effect of \$100+ bbl oil, enjoyed for most of the 2011-2014 period, emerged in the form of an acceleration in US shale oil production and an acceleration in the number of large non-OPEC (ex US) projects reaching production.

Figure 7: OPEC-11 apparent production vs call on OPEC 2000 – 2018



Source: IEA Oil Market Report (March 2018 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 a significant change in strategy to one that prioritised market share over price. As a result, there was no quota cut, as many had anticipated, and a confirmation that the 30m b/day target would be maintained. Post the November 2014 meeting, OPEC-14 (Indonesia and Gabon joined the group) not only maintained their quota but also raised production significantly, up over 18 months by 2.5m b/day. Iraq recovered its production by 1.2m b/day; Iran by 0.8m b/day post the lifting of sanctions relating to their nuclear programme; and Saudi by 0.9m b/day.

In November 2016, OPEC stepped back from their market share stance, announcing plans for the first production cut since 2008, opting for a new production limit of 32.5m b/day. The announcement represented a cut of 1.2m b/day (all numbers for OPEC-14 including Gabon). There was also an understanding that non-OPEC, including Russia, would cut production by 0.6m b/day, which would bring the total reduction to 1.8m b/day.

The November 2016 announcement amounted to a 5% cut for all members except for 1) Libya and Nigeria, recognising their unusually depressed levels of production due to unrest, and 2) Iran, recognising its journey back to normalised production post the lifting of sanctions in January 2016. Indonesia has been suspended from the group since, as a net importer of oil, it chose not to participate. The agreed cuts came into effect on 1 January 2017, and were initially designed to be kept in place for six months, but have since been extended to the end of 2018. Compliance with the cuts has so far been strong and, after been delayed initially by a variety of temporary factors, is now causing inventories to decline. Having originally been excluded from the cuts, Libya and Nigeria are now included in the quota system.

OPEC has showed clear intention to end restore the current production cuts in a manner that is consistent with maintaining a balanced market.

Clearly, OPEC economies have been under significant stress, which has been the near-term driver for the decision to cut production and bring oil prices higher. There is also the growing concern that the oil industry will be unable to supply enough in the future, leading to the next oil price spike, though that is probably a secondary concern to OPEC at present.

Saudi's actions at the head of OPEC appear designed to achieve an oil price that to some extent closes their fiscal deficit (though \$65-70/bl is needed to close the gap fully), whilst not spiking the oil price too high and overstimulating non-OPEC supply. Longer term, we believe that Saudi seek a 'good' oil price, in excess of current levels to balance their fiscal needs, but they realise that patience is required to achieve that goal.

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

Nothing in the market in recent years has changed our view that OPEC can put a floor under the price – as they did in 2008, 2006, 2001, 1998 – and again in 2016. Recent meetings and decisions indicate that OPEC have the resolve to continue in this manner.

Supply looking forward

The non-OPEC world has, since the 2008 financial crisis, grown its production more meaningfully than in the seven years before 2008. The growth was 0.9% p.a. from 2001-2008, increasing to 1.7% p.a. from 2008-2017.

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 between 2010 and 2015), implying that the rest of non-OPEC region grew 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 1.4m b/day. Whilst the 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 a low oil price impacted more in 2016, when non-OPEC supply fell by around 0.8m b/day. Non-OPEC supply recovered by 0.7m b/day in 2017, as US onshore production swung from decline back to growth.

The growth in US shale oil production, in particular from the Permian basin, raises the question of how much more there is to come and at what price. New oil production from these sources peaked in April 2015 at around 4m b/day, then declined by around 1.1m b/day, but has now passed the previous peak. Our assessment is that US shale oil is a capital intensive source of oil but one where real growth is viable, on average, at around \$50 oil prices. In particular, there appears to be ample inventory in the Permian basin to allow growth well into the 2020s. In total, it could be comparable in size to the UK North Sea, i.e. it could grow by around a further 4m 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, and the underlying cost of services to drill and fracture the wells. Naturally, cashflows available for reinvestment in a \$50-60 world are far lower than in a \$100 world, but with efficiency improvements and recent cost deflation, enough to see growth sustaining.

Offsetting US onshore shale oil growth, we expect to see non-OPEC supply outside the US start to decline in 2019, as the queue of large conventional project start-ups dries up. Since 2014, the number of project start-ups in this region has been sustained at a high level, despite lower oil prices, since projects that were sanctioned before the 2014 (when oil was \$100+) have continued to come onstream. We believe 2019 marks a point, however, when the cancellation of projects that should have been sanctioned in 2015/16 starts to bite. A supply decline in the non-OPEC ex US region will increase the 'call' on US shale to balance the market.

Looking longer term, other opportunities to exploit unconventional oil likely exist internationally using techniques established in the US, 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 10+ years behind North America.

Demand looking forward

The IEA estimate that 2017 oil demand growth was 1.5m b/day, and they expect a further increase of 1.5m b/day in 2018, taking demand to just over 99m b/day. Generally speaking, we have seen demand forecasts revised consistently higher since 2014, with the positive effect of lower oil prices continuing to surprise.

The IEA's global demand estimate for 2018 comprises an increase in non-OECD demand of 1.2m b/day and OECD demand growth of 0.3m b/day. The components of this non-OECD demand growth can be summarised as follows:

Figure 8: Non-OECD oil demand

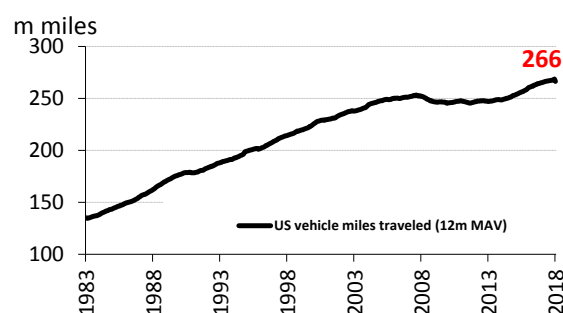
Non-OECD demand (source: IEA monthly report)

m b/day	Demand								Growth							
	2011	2012	2013	2014	2015	2016	2017	2018e	2012	2013	2014	2015	2016	2017	2018e	
Asia	20.3	21.4	22.1	22.8	24.0	24.8	25.8	26.7	1.1	0.7	0.7	1.2	0.8	1.0	0.9	
Middle East	7.4	7.8	7.9	8.4	8.4	8.3	8.3	8.4	0.4	0.1	0.5	0.0	-0.1	0.1	0.1	
Latin America	6.2	6.4	6.7	6.8	6.7	6.6	6.6	6.6	0.2	0.3	0.1	-0.1	-0.1	0.0	0.0	
FSU	4.4	4.6	4.7	4.66	4.6	4.8	4.7	4.8	0.2	0.1	0.0	-0.1	0.2	0.0	0.1	
Africa	3.5	3.8	3.9	3.8	4.1	4.3	4.3	4.4	0.3	0.1	-0.1	0.3	0.2	0.0	0.1	
Europe	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Total	42.5	44.7	46.0	47.2	48.4	49.4	50.5	51.6	2.2	1.3	1.2	1.2	1.1	1.0	1.2	

Source: IEA Oil Market Report (March 2018)

Asia has settled down into a steady pattern of growth since 2010, and accounts for much of expected growth in 2017. Historically, China has been the most important component of this growth and continues to be a major component, although signs are emerging that India may also start to grow rapidly.

OECD demand in 2018 is forecast to be up by 0.3m b/day. In the US, the sharp fall in gasoline prices since 2014 has stimulated a reversal in improving fuel efficiency, as drivers switch back to purchasing larger vehicles, and a rise in total vehicle miles travelled, as shown in the chart opposite. Total vehicle miles travelled had stalled between 2007 and 2014, after two decades of growth, and are now growing again at a rate of around 1-2% per year.



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 2.5%, a likely stimulant of multi-year demand growth. If oil prices return to a higher range (say around \$75/bbl, representing 3% 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 annual non-OECD demand growth of around 1.5m b/day by 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 1.2m in 2017, up from 0.8m in 2016. Sales of 1.6m electric vehicles represents around 1.5% of total light vehicle sales, and increases EV’s share of the world car fleet to 0.25%. We expect to see EV sales accelerate in 2018 to around 1.9m, or 2% of total global sales. Even applying an aggressive growth rate to EV sales, we see EVs comprising only around 0.6% of the global car fleet in 2020. Looking further ahead, we expect the penetration of EV’s to accelerate, causing global gasoline demand to peak at some point in the second half of the 2020s. However, owing to the weight of oil demand that comes from sources other than passenger vehicles (around 70%), which we expect to continue growing linked to GDP, we expect total oil demand not to peak until the mid 2030s.

Conclusions about oil

The table below summarises our view by showing our oil price forecasts for WTI and Brent in 2017 against their historic levels, and rises/falls in percentage terms that we have seen in the period from 2002 to 2016.

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

Oil price (inflation adjusted)																		Est
12 month MAV	1986-2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
WTI	30	33	38	49	66	75	82	104	68	84	99	94	98	93	49	45	51	57
Brent	30	32	35	46	64	75	82	103	67	84	115	112	108	99	52	45	54	60
Brent/WTI (12m MAV)	30	33	37	48	65	75	82	104	68	84	107	103	103	96	51	45	53	59
Brent/WTI y-on-y change (%)		8%	12%	30%	37%	15%	9%	26%	-35%	24%	27%	-4%	0%	-7%	-47%	-11%	17%	11%
Brent/WTI (5yr MAV)	30	25	32	37	42	51	61	75	79	82	89	93	93	99	92	80	69	61

We expect oil to trade in a \$50-65/bl range in the near term, supported at the lower end by OPEC. If this price range persists, we expect North American unconventional supply to sustain growth. We believe that the 'call' on unconventional supply, however, is likely to grow into the end of the decade, as conventional non-OPEC supply declines.

The world oil bill at around \$60/bl would represent 2.5% of 2018 Global GDP, 26% 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 \$80/bl.

We believe that Saudi's long-term objective remains to maintain a 'good' oil price, similar to current spot levels, and that will allow the country to IPO Saudi Aramco successfully in the next year or so.

Natural gas market

US gas demand

On the demand side, industrial gas demand and power generation gas demand, each about a quarter of total US gas demand, are key. Commercial and residential demand, which make up a further quarter, 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 2017 to around 21.4 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 2017, 33% of electricity generation was powered by gas, up from 22% in 2007. The big loser here is coal which has consistently given up market share over the past 10 years.

Bcf/day	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018E
US natural gas demand:												
Residential/commercial	21.2	22.0	21.6	21.6	21.6	19.2	22.4	23.4	21.4	20.5	20.9	21.7
Power generation	18.7	18.2	18.8	20.2	20.8	24.9	22.3	22.3	26.5	27.3	24.6	25.8
Industrial	18.2	18.2	16.9	18.5	19.0	19.7	20.3	20.9	20.6	21.1	21.4	21.6
Pipeline exports (Canada & Mexico)	2.1	2.5	2.8	2.9	4.1	4.4	4.4	4.1	4.9	6.3	6.7	7.3
LNG exports	-	-	-	-	-	-	-	-	0.1	1.0	3.1	3.4
Pipeline/plant/other	5.2	5.3	5.5	5.6	5.8	6.1	6.7	6.3	6.5	6.4	6.4	6.4
Total demand	65.4	66.2	65.6	68.8	71.3	74.3	76.1	77.0	80.0	82.6	83.1	86.2
Demand growth	4.0	0.8	- 0.6	3.2	2.5	3.0	1.8	0.9	3.0	2.6	0.5	3.1

Source: EIA; Simmons; Guinness estimates

Total gas demand in 2017 (including Canadian, Mexican and LNG exports) is expected to be around 83.1 Bcf/day, up by just 0.5 Bcf/day (0.6%) versus 2016 but 5 Bcf/day (6.5%) higher than the 5 year average. LNG exports have risen significantly this year (+2 Bcf/day), but this has been offset by a 2 Bcf/day decline in demand from power generation, owing to normalising weather and gas to coal utility switching, prompted by prices back above \$3/mcf.

Demand outlook

We expect demand 2018, assuming prices remain around \$3/mcf, to exhibit strong growth of around 3 Bcf/day. We see several sources of higher demand driving this growth, including rising pipeline exports to Mexico, rising demand from power generation (gas taking share back from coal) and slightly higher LNG exports.

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 to the end of the decade. The most significant is the group of LNG export terminals in the US, many of which are still in the construction stages but will come online in 2019 and 2020. The table below shows the scheduled start-up of terminals, with 5.7 Bcf/day of capacity coming in 2019 – inevitably, some of this will be delayed into 2020.

Terminal	Location	2015	2016	2017	2018E	2019E	2020E
Cameron 1-2	LA					1.2	
Cameron 3	LA					0.6	
Corpus Christi 1-2	TX					1.5	
Cove Point 1	MD			0.8			
Elba Island 1-6	GA				0.3		
Elba Island 7-10	GA					0.2	
Sabine Pass 1-2	LA						
Sabine Pass 3-4	LA	0.1	1.0	1.2			
Sabine Pass 5	LA					0.7	
Freeport 1	TX					0.5	
Freeport 2-3	TX					1.0	
Incremental LNG exports		0.1	1.0	2.0	0.3	5.7	0.0
Total US LNG exports		0.1	1.1	3.1	3.4	9.1	9.1

Source: EIA; Simmons

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 started up a large new Gulf Coast facility this year, the first new cracker 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 0.8-1.2 Bcf/day per year, although this will be affected by actual gas prices.

US gas supply

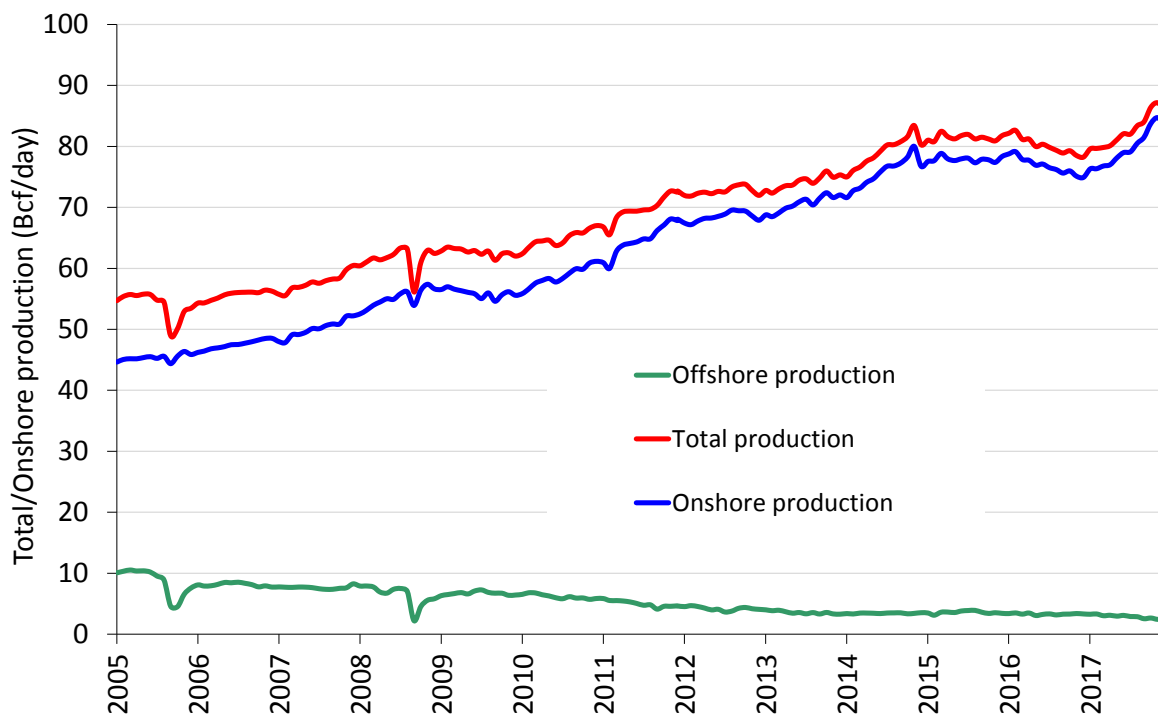
Overall, whilst gas demand in the US has been strong over the past five years, it has been overshadowed by a rise in onshore supply, pulling the gas price lower.

The supply side fundamentals for natural gas in the US are driven by 3 main moving parts: onshore and offshore domestic production, and pipeline imports of gas from Canada. Of these, onshore supply is the biggest component, making up over 85% of total supply.

Bcf/day	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018E
US natural gas supply:												
US onshore	45.1	48.8	49.8	52.2	57.7	61.5	63.1	67.5	70.5	68.9	70.1	75.4
US offshore (Gulf of Mexico)	7.7	6.3	6.7	6.2	5.0	4.2	3.6	3.4	3.6	3.4	3.2	3.2
Pipeline imports (Canada)	10.4	9.8	9.0	9.0	8.5	8.0	7.5	7.1	7.1	8.0	7.9	7.4
LNG imports & other	2.3	1.2	1.4	1.4	1.0	0.8	0.6	0.5	0.5	0.4	0.3	0.4
Total supply	65.5	66.1	66.9	68.8	72.2	74.5	74.8	78.5	81.7	80.7	81.5	86.4
Supply growth	3.2	0.6	0.8	1.9	3.4	2.3	0.3	3.7	3.2	- 1.0	0.8	4.9
(Supply)/demand balance	- 0.1	0.1	- 1.3	-	- 0.9	- 0.2	1.3	- 1.5	- 1.7	1.9	1.6	- 0.2

Source: EIA; Simmons; Guinness estimates

Since the middle of 2008 the weaker gas price in the US reflects growing onshore US production driven by rising shale gas 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 only 81 in September 2016 and now 194 at the end of February 2018. However, offsetting the fall, the average productivity per rig has risen dramatically as producers focus their attention on the most prolific shale basins, whilst associated gas from oil production has grown handsomely. Onshore gas supply (gross, before processing) is now at 84.7 Bcf/day, 27.3 Bcf/day (48%) above the 57.4 Bcf/d peak in November 2008 before the rig count collapsed.

Figure 10: US natural gross gas production 2005 – 2018 (Lower 48 States)

Source: EIA 914 data (January 2018 published in April 2018)

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.

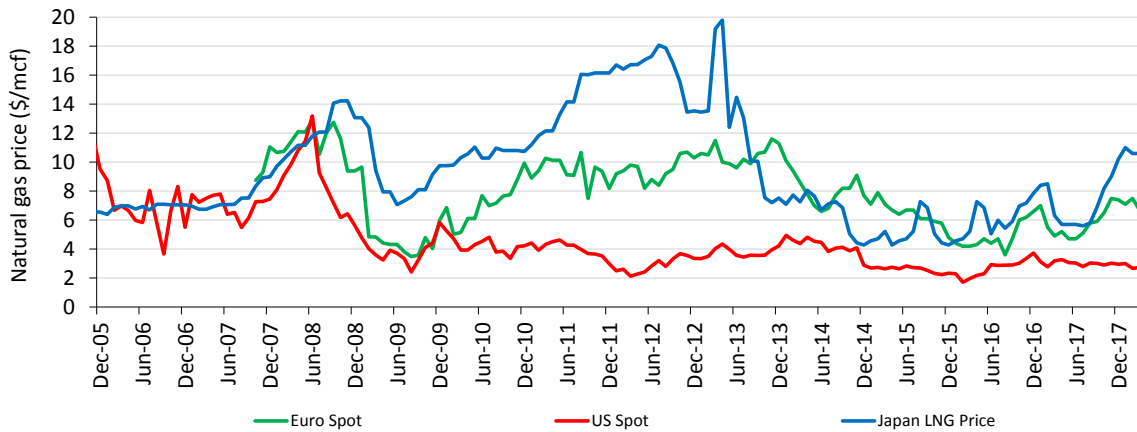
Associated gas production declined in 2016 with the fall of shale oil production, but as US oil supply now growing again, so associated gas production is also picking up. Generally, we expect to see rates of around 2-3 Bcf/day of associated gas per 1m b/day of oil production.

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 2016, though growth has recently slowed. Further growth is likely over the next couple of years, but only if local price differentials improve from the extreme levels seen in 2016. Then there is an expected decline in legacy gas fields, particularly if the gas drilling rig count stays low.

Overall, if the price remains in the \$2.50-\$3.50/mcf range, we expect a significant jump in onshore gas supply in 2018, up by around 5 Bcf/day versus this year.

Outlook for US LNG exports – global gas arbitrage

The prospects for US LNG exports depend on the differentials to European and Asian gas prices, and whether the economic incentive exists to carry out the trade. The UK national balancing point (NBP) gas price – which serves as a proxy to the European traded gas price – remains at a premium to the US gas price (c.\$6/mcf versus c.\$3/mcf). Asian spot LNG prices fell sharply down to around \$4.50/mcf at the start of 2016 but have since recovered to around \$10/mcf as Chinese gas demand strengthens. The implied economics are tight at these levels into Europe, better into Asia, but sufficient to expect exports to proceed.



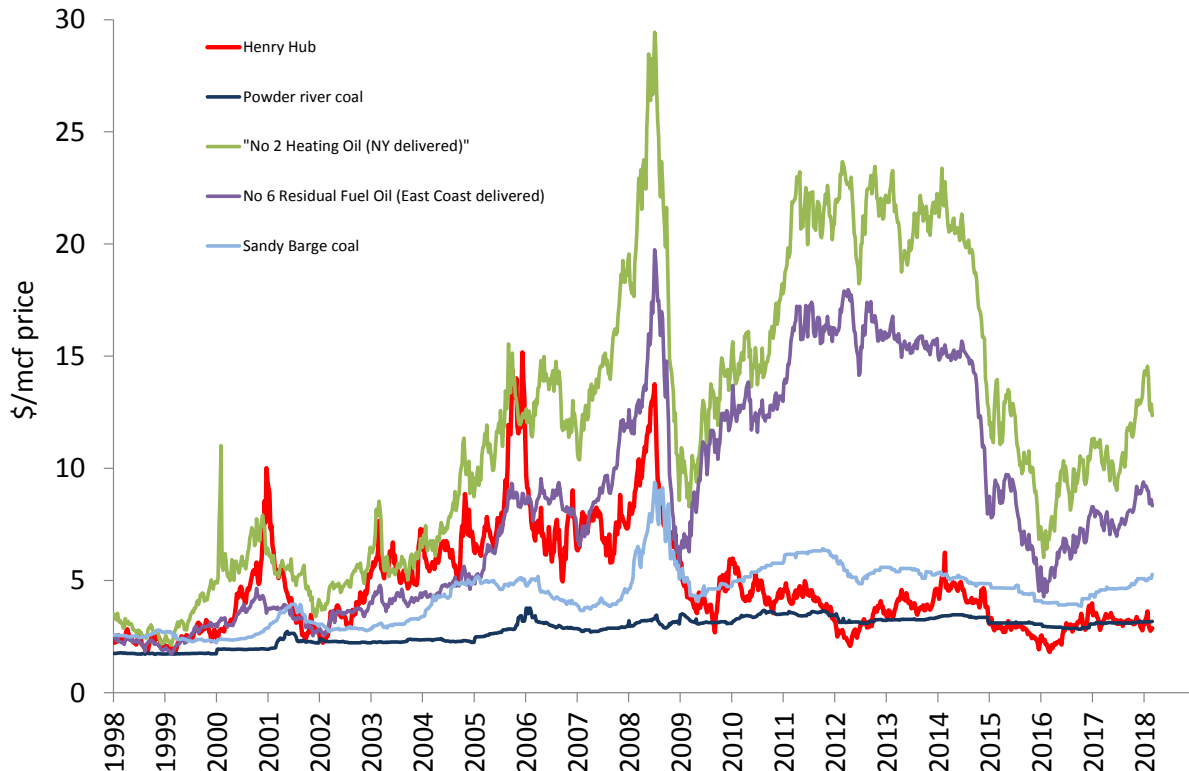
Relationship with oil and coal

The oil/gas price ratio (\$ per bbl WTI/\$ per mcf Henry Hub) of around 24x at the end of March 2018 continues well outside the long-term ratio of 6-9x.

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. When the gas price has traded below the coal price support level (2012 and 2016), resulting coal to gas switching for power generation was significant.

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 (April 2018)

Conclusions about US natural gas

Bcf/day	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018E
Total demand	65.4	66.2	65.6	68.8	71.3	74.3	76.1	77.0	80.0	82.6	83.1	86.2
Demand growth	4.0	0.8	- 0.6	3.2	2.5	3.0	1.8	0.9	3.0	2.6	0.5	3.1
Total supply	65.5	66.1	66.9	68.8	72.2	74.5	74.8	78.5	81.7	80.7	81.5	86.4
Supply growth	3.2	0.6	0.8	1.9	3.4	2.3	0.3	3.7	3.2	- 1.0	0.8	4.9
(Supply)/demand balance	- 0.1	0.1	- 1.3	-	- 0.9	- 0.2	1.3	- 1.5	- 1.7	1.9	1.6	- 0.2

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/Utica and from gas produced as a by-product of shale oil. Average 2016 natural gas prices (at \$2.55) were 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 \$2.75 – \$3.25/mcf range. It may be held at this level for a period until demand grows further, and longer term we expect the price to normalise to the top end of this range.

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.

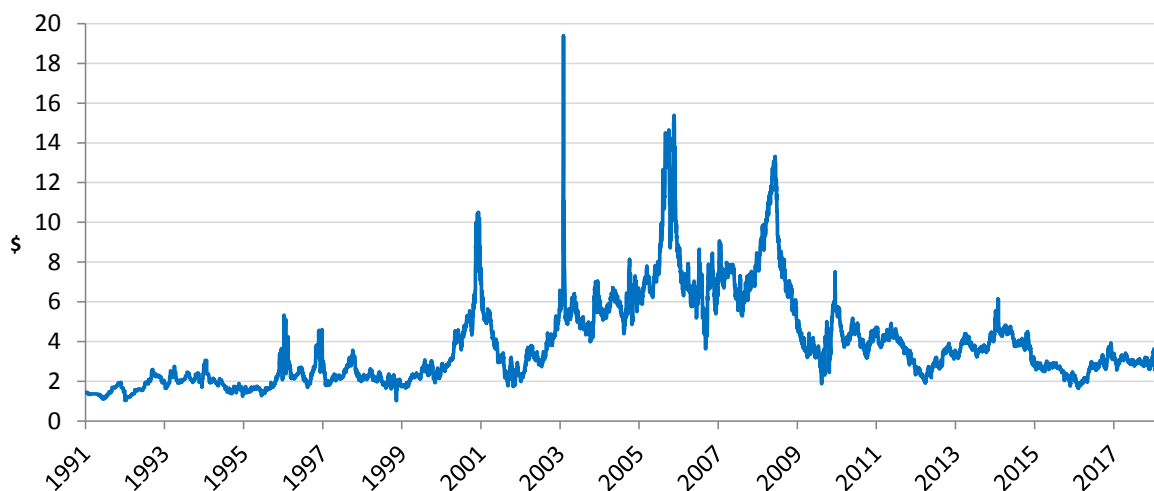
After 2005 we saw a further strong run-up in the oil price. Hurricanes Katrina and Rita, which devastated New Orleans, caused oil to spike up to \$70 in August 2005, and it spiked up again in July 2006 to \$78 after a three week conflict between Israel and Lebanon threatened supply from the Middle East. 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, as OPEC made clear their intention not to support the price, leaving the market oversupplied. Oil prices found a bottom in 2016 as a result of OPEC cutting production again, but remains capped for the time being by US onshore shale supply.

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.

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