THE GUINNESS GLOBAL ENERGY REPORT

Developments and trends for investors in the global energy sector | March 2019

GUINNESS GLOBAL ENERGY FUND

Fund size: $305m (28.2.2019)

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 FEBRUARY

OIL

Brent and WTI continue to strengthen; OPEC cuts hard

Brent and WTI both rose over the month; Brent was up from $61/bl to $66/bl; WTI rose from $54/bl to $57/bl. OPEC production down 1.5m b/day versus end 2018 levels while Saudi suffered a production outage at a major field. The US oil rig count continues to fall and the pace of US onshore growth is slowing. Near term, the global oil market will remain tight if OPEC holds its resolve.

NATURAL GAS

US gas prices broadly unchanged but international prices weaker

Henry Hub prices weakened intra month but finished broadly flat at $2.81/mcf. The US winter continues to be warmer than average, dampening demand. With strong production growth, the US market appears to be 1-2 Bcf/day oversupplied. Asian and European gas prices have weakened (to $6/mcf) in recent months as a result of seasonal oversupply of liquified natural gas.

EQUITIES

Energy underperforms the broad market

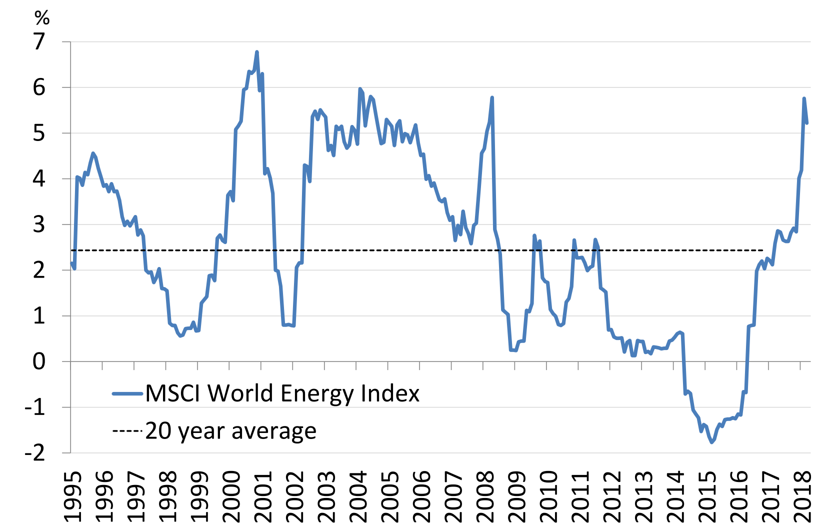
The MSCI World Energy Index (net return) rose in February by 2.6%, underperforming the MSCI World Index (net return) which rose by 3.0% over the month (all in US dollar terms).

CHART OF THE MONTH

Free cash flow yield of MSCI World Energy index exceeds 5%

Fourth quarter 2018 financial results have further confirmed that the oil and gas industry is pursuing a strategy focused on improving free cash flow generation. At the start of 2019, the free cash flow yield of the MSCI World Energy Index exceeded 5%, marking a ten year peak for the sector. The level and recent trend of improvement bears significant resemblance to the periods 1999-2001 and 2002-2005 when the energy equity sector delivered strong share price performance.

Free Cash Flow yield of the MSCI World Energy index



Source: Bloomberg; Guinness Asset Management estimates

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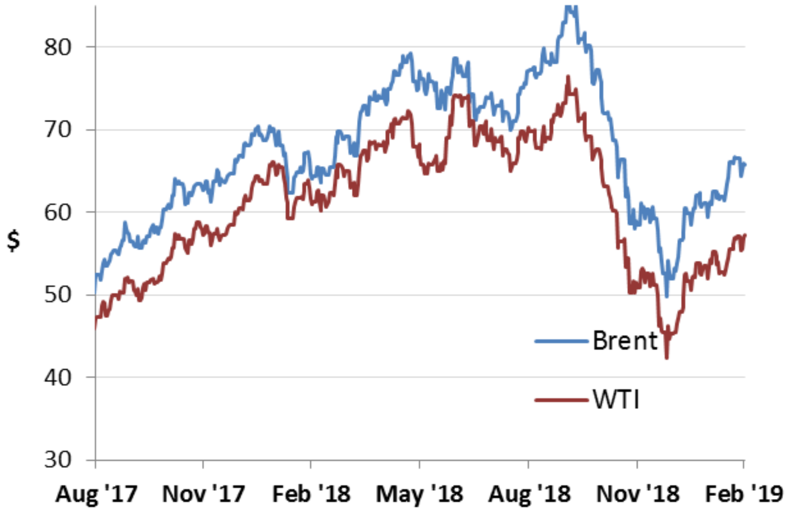
1. FEBRUARY IN REVIEW

i) Oil market

Figure 1: Oil price (WTI and Brent $/barrel) 18 months August 31 2017 to February 28 2019



Source: Bloomberg LP

The West Texas Intermediate (WTI) oil price started February at $53.8/bl and moved steadily higher during the month, closing the month at its highs of $57.2/bl. WTI has averaged $53.2/bl so far in 2019, having averaged $64.9/bl in 2018, $51/bl in 2017, $43/bl in 2016, $49/bl in 2015 and $93/bl in 2014.

Brent oil traded in a similar shape, opening at $60.9/bl and steadily trending higher before closing the month near to the intra month high at $65.8/bl. Brent averaged $71.7/bl in 2018. The gap between the WTI and Brent benchmark oil prices narrowed over the month, ending February at around $8.6/bl, versus a range of $8-10/bl over the previous five months.

Factors which strengthened WTI and Brent oil prices in February:

- **Lower production and exports from OPEC countries**
  Total OPEC-11 production in February 2019 is estimated by Bloomberg at 29.9m b/day, down by 1.5m b/day versus December 2018. If these figures are accurate, they imply that OPEC's compliance is more than 100% of the production cut agreed at the end of last year. The main active reductions have come from Saudi Arabia (down by 0.55m b/day) together with Kuwait and the UAE (jointly down by 0.3m b/day) while Venezuela (down by 0.15m b/day) and Iran (down by 0.25m b/day) also suffered production decreases. The market is taking OPEC's commitment to tighter supply positively.

- **US drilling rig count starting to fall**
  The US onshore drilling rig count has fallen by 42 rigs (5%) in the first in the first nine weeks of 2019, increasing expectations of a slowdown in US shale oil production growth later in 2019. It appears that there is currently a three to four month lag between oil price moves and subsequent changes in the rig count. The sharp fall in oil prices that started in October 2018 is therefore showing up in the rig activity at the start of 2019. In total, we expect the US rig count to fall by around 100 rigs from its high of 888 rigs in mid November 2018.

- **Saudi Aramco suffers a production outage**
  Saudi Aramco suffered a partial production outage at the 1.2m b/day Safiniya heavy oil field, as a result of the main power supply cable being cut accidentally. While Saudi has the ability to make up for the loss by increasing production at other fields, events such as this do use up the limited spare capacity that Saudi Arabia has. Safiniya started production in 1957 and is the largest offshore oil field in the world.

- **Venezuela production continues to remain under pressure**
  The situation in Venezuela continues to be problematic with estimates that production for March will fall further, reaching 0.8m b/day having been around 1.2m b/day in late 2018. The US Envoy to Venezuela was recently quoted as suggesting that production will fall to 0.5m b/day.

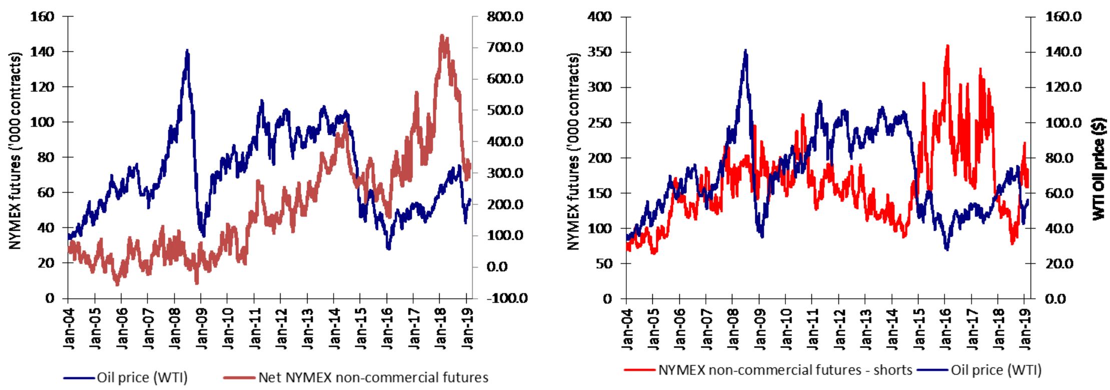
Factors which weakened WTI and Brent oil prices in February:

- **Increase in US onshore oil supply**
  At the start of March, based on restricted EIA reporting, we estimate that US onshore production increased by 69k b/day during December 2018. This keeps year over year growth for the US onshore system at around 1.6m b/day for 2018. Lower oil prices have caused the oil directed rig count to decline, which we expect to dampen the rate of production growth in 2019.

Speculative and investment flows

The New York Mercantile Exchange (NYMEX) net non-commercial crude oil futures open position was 328,000 contracts long at the end of February versus 341,000 contracts long at the end of January. The net position peaked in February 2018 at 739,000 contracts long. Typically, there is a positive correlation between the movement in net position and movement in the oil price. The gross short position was broadly flat at 158,000 contracts between the end of January and the end of February. This short position is now roughly back to the level at the start of the 2018.

Figure 2: NYMEX Non-commercial net and short futures contracts: WTI January 2004 – February 2019

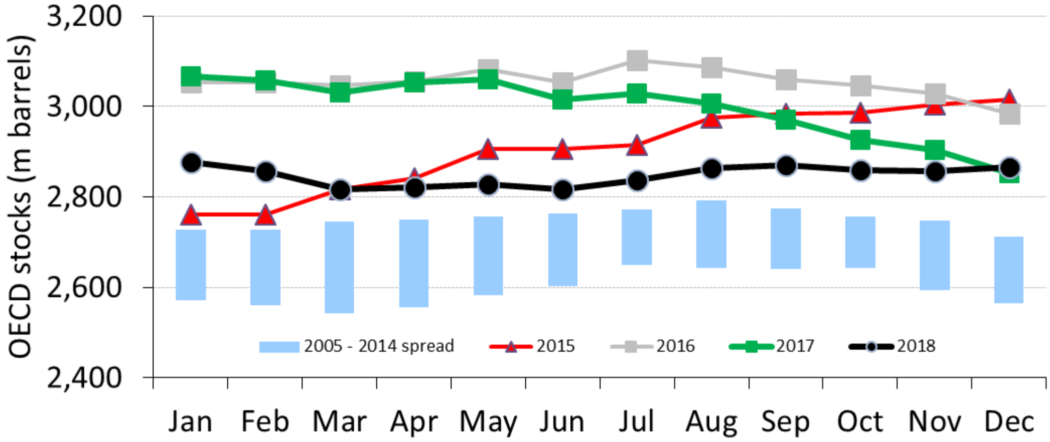


Source: Bloomberg LP/NYMEX/ICE (2019)

OECD stocks

OECD total product and crude inventories at the end of December were estimated by the IEA to be 2,866m barrels, up by 9m barrels versus the level reported for November. This compares to a 10-year average decrease for December of 34m barrels, implying that the market loosened by around 1.0m b/day. Inventories tightened in the first half of 2018 and loosened in the second half of the year, leaving inventories broadly flat over the year.

Figure 3: OECD total product and crude inventories, monthly, 2004 to 2018



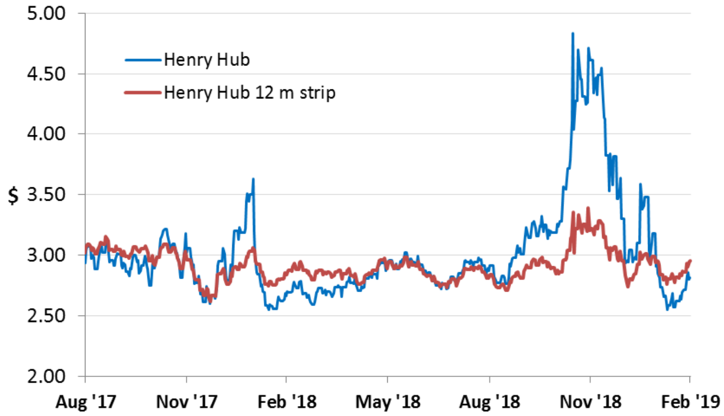
Source: IEA Oil Market Reports (February 2019 and older)

ii) Natural gas market

The US natural gas price (Henry Hub front month) opened February at $2.81/mcf (1,000 cubic feet) and weakened to a low of $2.55/mcf mid-month before recovering to close the month unchanged at $2.81/mcf. The spot gas price has averaged $2.92/mcf so far in 2019, which compares to an average gas price of $3.07 in 2018, $3.02 in 2017, $2.55/mcf in 2016 and $2.61/mcf in 2015.

The 12-month gas strip price (a simple average of settlement prices for the next 12 months' futures prices) rose over the month, opening at $2.92/mcf and closing at $2.95 /mcf. The strip price averaged $2.90 in 2018, $3.12 in 2017, $2.84 in 2016 and $2.86 in 2015.

Figure 4: Henry Hub gas spot price and 12m strip ($/Mcf) August 31 2017 to February 28 2019



Source: Bloomberg LP

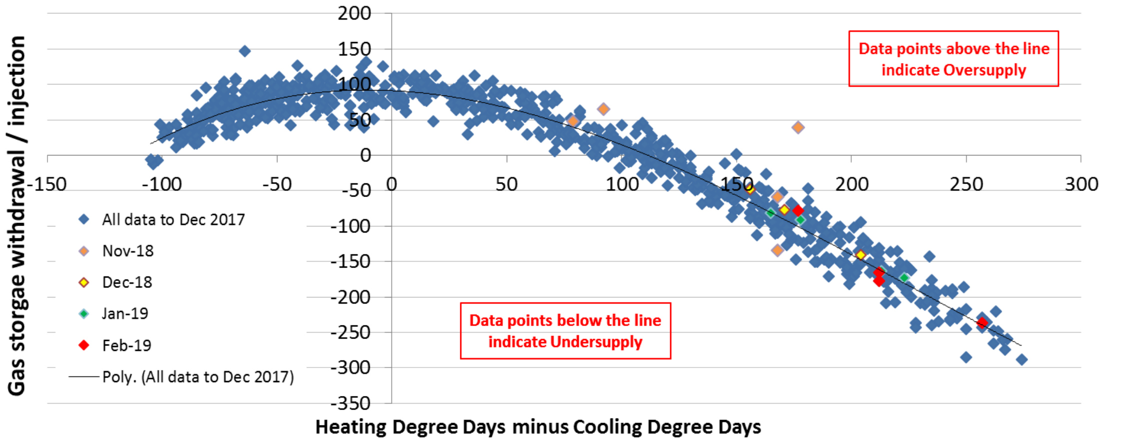
Factors which weakened the US gas price in February included:

- **A warmer than normal start to winter**
  Despite extreme cold weather at the end of January, the US winter has actually been warmer than normal so far. According to the American Gas Association, heating degree days are now 2.7 percent fewer than normal (ie warmer) since the start of the winter season, on October 1.

- **Strong US onshore natural gas production**
  Onshore US natural gas production averaged 95.2 Bcf/day in December 2018 (the latest available data point), up by 0.9 Bcf/day on the level reported for November. Onshore production has risen by 10.0 Bcf/day versus the level reported twelve months before, close to maintaining very high annual growth rates versus history. 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 2019.

- **Structurally oversupplied market**
  Adjusting for the impact of weather in January and February, the most recent injections of gas into storage suggest the market is, on average, operating at a surplus of around 1-2 Bcf/day (as indicated by the green and red dots on the graph below).

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



Source: Bloomberg LP; Guinness Asset Management

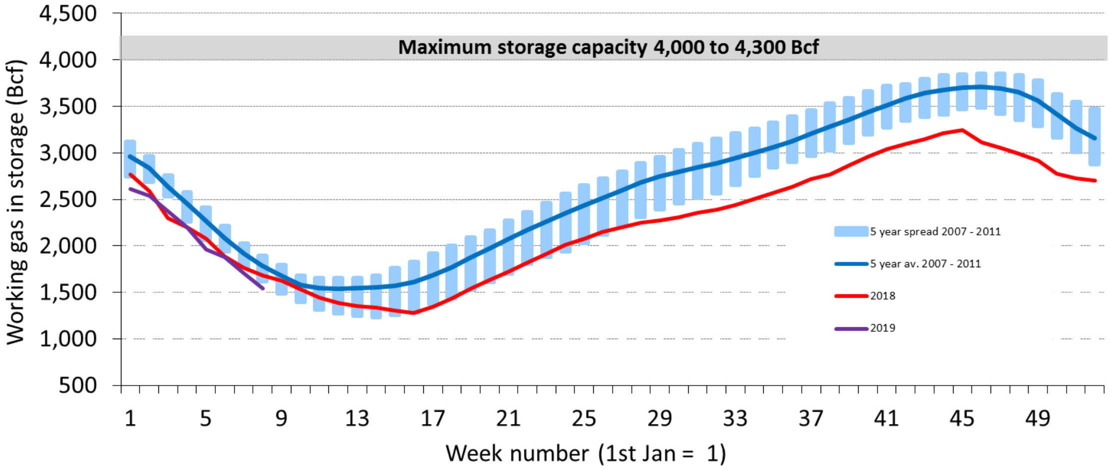
Factors which strengthened the US gas price in February included:

- **Depressed gas inventories**
  US natural gas inventories were estimated to be around 1.54 Tcf at the end of February (nearly 0.5 Tcf lower than the 10-year average) and close to a 10 year low. Low inventories and cold weather caused the recent spike in gas price, though the market remains sanguine about the tightness of this market (see only a modest move up in the 12 month pricing strip) in the face of continued supply increases via associated gas (from shale oil) and the north-east of the US.

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 February were reported by the EIA to be 1.54 Tcf. Current gas in storage is, therefore, close to 10 year low levels (only 2014 saw a lower level of storage at this point in the year) as a result of weather and strong demand plus increasing volumes of gas exported via LNG. Whilst gas inventories today are low, the high visibility of low cost supply growth for 2019 is keeping a cap on prices.

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



Source: Bloomberg; EIA (March 2019)

2. MANAGER'S COMMENTS

A review of the 2018 'results season' for the energy sector

Most full year 2018 financial results have been announced. Below we highlight some of the key themes that we have seen in results season so far.

1) Capital discipline, free cash flow and the return of capital to shareholders

As we saw in 2018, the 'capital discipline' theme continues to be the key theme in most results announcements, with now even more small and mid-capitalisation companies stressing their commitment to it. Whilst the ability of each company to exhibit improved capital discipline depends on business mix and stage of development, we note a clear intention of the majority of oil and gas companies to highlight either current free cash flow generation or the longer-term plan to become more free cash flow generative. We see this as a positive development.

- The **integrated oil & gas companies (including the super-majors)** continues to be the 'advantaged' energy sub sector when it comes to free cash flow generation. This group of companies, broadly speaking, is now able to cover dividend commitments at oil prices of around $50/bl and is therefore able to deliver sustained free cash flow generation at higher prices.

- Most larger **exploration & production companies** have already started pursuing the capital discipline trend and in 4Q results we saw a commitment to keep capex under control and to return excess free cash flow to shareholders. While this strategy does not make sense for every company, we believe that the intention to maintain capex levels (especially if oil prices rise) will help to control cost inflation, maintain higher efficiency levels and, potentially, strengthen the overall oil macro environment.

- A number of other (predominantly smaller) **exploration & production companies** stated their intentions to pursue the strategy and, correspondingly, presented capex and growth plans for 2019 that were below analyst consensus expectations.

2) Outlook for capital expenditure, implication for service companies

A key variable in the delivery of free cash flow generation is the ability for a company to restrain capital expenditure. Overall, we do not see the oil and gas industry increasing capital expenditure particularly in 2019 (maybe a 5% growth) as it focuses on greater capital efficiency rather than growth per se.

- For the **super-majors** and other **integrated oils**, we expect to see flat to slightly up capex in 2019 vs 2018 (as has been previously highlighted by the group). ExxonMobil is a standout among the super-majors in that capex here is likely to grow to $24-25bn in 2019 (versus only $15bn in 2017) as the company pursues a number of new growth projects internationally. Also, ExxonMobil (together with Chevron) is tilting its capex back towards the US onshore, via the development of the Permian Basin. Within the 2019 capex allocation for this group towards large scale international projects, we can see a clear preference for natural gas developments at the expense of oil. On our calculations, we expect that the large non-OPEC development projects being sanctioned this year have around 75% of their reserves in natural gas and only 25% in crude oil.

- In the **Exploration & Production** sector, it is clear to us that the sharply lower oil prices of 4Q 2018 have restrained capital expenditure budgets for 2019. As it stands, we would expect to see around 10% decline in 2019 budgets for US Lower 48 onshore operators, versus an increase for the same group last year of around 15-20%. The larger and better positioned companies are likely to maintain broadly flat capex while the smaller, more highly levered or private companies are likely to be seeing much sharper decreases in capital expenditure.

- This muted capex outlook does not bode particularly well for capital intensive **oil services companies**. We expect upstream investment to be focussed predominantly on projects that deliver near term production (e.g. unconventional oil and gas, near field developments with fast tie-in options or the maintenance of existing production plant) at the expenses of large-scale new infrastructure projects. We continue to have, therefore, a preference for US-focussed rather than international-focussed companies and a preference for low capital intensity/service-oriented companies rather than high capital intensity companies (for example seismic, drillers or subsea equipment installers).

3) US shale growth potential and impact on macro environment

The level of North American onshore activity was a particular focus for us within the 4Q results. As the key marginal area of new oil supply, we were pleased to see further slowdown in the delivery of drilling and completion efficiency gains and a clear moderation in the initial production rates that are achieved on new shale wells. Countering this, we are now seeing i) a clear switch in industry activity towards large scale shale developments (bringing increased efficiencies at the larger scale development area) and ii) increasing capital and activity from the super-majors who are focusing on large scale (predominantly Permian) developments. To illustrate this latter point, the recent strategy presentations of both Exxon and Chevron confirmed the intention of both companies to aggressively pursue growth from the Permian basin:

- Exxon plans to grow production to around 1m boe/day (about 60% oil) by 2024. This production target is up sharply from the previous target and compares to Exxon's Permian production of 0.2m barrels of oil equivalent per day in 2017.

- Chevron plan on taking production from 0.2m boe/day in 2017 to 0.90m boe/day in 2023. This 2023 target was increased from 0.65m boe/day.

So, while the near-term production growth outlook for the US onshore (especially the Permian Basin) has moderated because of lower oil prices and a lower rig count, the longer-term production growth outlook continues to be robust. We expect the start-up of new Permian pipelines in 2H 2019 to be the catalyst allowing more capital efficient larger scale developments (driven predominantly by the larger companies) to drive further US onshore oil production growth.

Implications for the macro environment and energy equities

At the global level, the near-term supply/demand outlook appears to be skewed reasonably positively as the near-term moderation of US onshore growth is met with greater than expected OPEC (and Russia) production cuts plus persistent declines from Venezuela and the potential full impact of sanctions against Iran. The culmination of these various events could support oil prices for the coming months. Higher oil prices could well lead to stronger US onshore growth again (as it did in 2018) and, combined with new pipelines and the ending of OPEC quota cuts, we do not expect to see higher oil prices being sustained.

We see Brent oil trading in a $50/bl-$70/bl range for 2019, averaging around $60/bl Brent over the year, and note that this oil price should be sufficient for the oil and gas industry to further improve its return on capital employed and sustain high levels of free cash flow generation. The messaging from 4Q results is that the industry, on the whole, will work hard to deliver these attractive free cash flow levels and we believe that, if the companies can provide confidence that they can be sustained, then energy equities will perform well.

1) PERFORMANCE Guinness Global Energy Fund

The main index of oil and gas equities, the MSCI World Energy Index (net return), was up by 2.6% in February, while the MSCI World Index (net return) rose by 3.0%. The Fund was up by 1.3% (class E) in the month, underperforming the MSCI World Energy index by 1.3% (all in US dollar terms).

Within the Fund, February's strongest performers were Helix, SunPower, Tullow, Devon Energy and EnCana while the weakest performers were Anadarko Petroleum, QEP Resources, Oasis Petroleum, Soco International and Valero..

Performance (in USD) **28/02/2019**

Annualised

% returns	1 year	3 years	5 years	10 years	1999 to date
Guinness Global Energy	-1.8	7.8	-8.1	4.6	9.2
MSCI World Energy Index	2.0	9.4	-2.8	5.3	6.0

Calendar year

% returns	2018	2017	2016	2015	2014	2013	2012	2011	2010	2009	2008	2007
Guinness Global Energy	14.1	-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	13.3	5.0	26.6	-22.8	-11.6	18.1	1.9	0.2	11.9	26.2	-38.1	29.8

Source: Guinness Asset Management and 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 (1.49% 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

During February, the all share acquisition of Newfield Exploration by EnCana Corporation was completed. EnCana is a Canadian listed exploration and production company with onshore assets across North America, including the Permian Basin and the Eagle Ford. The deal, which was announced in early November 2018 (at a time of sharply falling oil prices and depressed North American E&P equity valuations) adds further diversification to EnCana's onshore operations and provides more options for flexibility in capital allocation. Newfield Exploration's onshore assets were dominated by its 400,000 net acres in the SCOOP/STACK play in the Anadarko Basin but also included stakes in the Bakken and the Uinta Basins.

The portfolio was actively rebalanced during the month. There were no stock switches.

Sector Breakdown

The following table shows the asset allocation of the Fund at **February 28 2019**.

(%)	31 Dec 2011	31 Dec 2012	31 Dec 2013	31 Dec 2014	31 Dec 2015	31 Dec 2016	31 Dec 2017	31 Dec 2018	28 Feb 2019
Oil & Gas	***97.9***	***97.3***	***93.7***	***93.7***	***95.1***	***96.7***	***98.4***	***99.7***	***98.2***
Integrated	30.9	30.4	29.2	27.0	30.4	32.5	28.6	27.2	27.2
Integrated – Can & Em Mkts	8.8	8.4	9.4	10.3	11.1	14.3	14.2	15.3	15.4
Exploration & production	41.1	40.3	35.4	36.2	36.5	35.4	37.0	39.0	37.7
Oil & Gas Storage & Transportation	0.0	0.0	0.0	0.0	0.0	0.0	3.5	3.9	3.8
Drilling	5.9	7.1	6.4	3.3	1.5	2.2	1.9	1.4	1.4
Equipment & services	6.1	7.4	9.8	13.4	11.4	8.6	9.5	8.8	9.0
Refining and marketing	5.1	3.7	3.5	3.5	4.2	3.7	3.7	4.1	3.7
Solar	**1.3**	**1.2**	**2.6**	**3.7**	**4.7**	**0.9**	**1.4**	**0.4**	**0.4**
Coal & consumables	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Construction & engineering	**0.4**	**0.6**	**1.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Cash	**0.4**	**0.9**	**2.7**	**2.6**	**0.2**	**2.4**	**0.2**	**-0.1**	**1.4**
Total	**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 February 28 2019 was on a price to earnings ratio (P/E) for 2019 of 13.6x versus the S&P 500 Index at 16.5x as set out in the following table:

	2012	2013	2014	2015	2016	2017	2018	2019
Guinness Global Energy Fund P/E	7.7	8.2	8.9	19.9	35.2	21.3	11.8	13.6
S&P 500 P/E	27.9	25.2	22.9	26.9	25.5	21.7	17.3	16.5
Premium (+) / Discount (-)	*-72%*	*-67%*	*-61%*	*-26%*	*38%*	*-2%*	*-32%*	*-18%*
Average oil price (WTI $/bbl)	94	98	93	49	43	51	66	

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 four large caps are Chevron, BP, Royal Dutch Shell and Total. Mid/large and mid-caps are ENI, Equinor and OMV. At February 28 2019 the median P/E ratios of this group were 11.8x/11.8x 2018/2019 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 (EnCana, Devon, Oasis and QEP Resources), with five other names (Apache, Occidental, ConocoPhillips, Noble Energy, Anadarko) 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 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 3.1x 2019 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 10.4% 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.

Portfolio at January 31 2019 (for compliance reasons disclosed one month in arrears)

Stock	Curr.	Country	% of NAV	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	2017 B'berg mean PER	2018 B'berg mean PER	2019 B'berg mean PER
Guinness Global Energy Fund 31 January 2019														
Integrated Oil & Gas														
Chevron	USD	US	3.66	22.3	12.3	8.5	9.3	10.4	11.9	31.5	82.7	27.7	14.2	16.7
Royal Dutch Shell PLC	EUR	NL	3.80	14.0	9.9	7.3	7.3	9.6	8.5	17.9	29.5	16.0	11.8	11.4
BP PLC	GBP	GB	3.82	8.7	6.0	6.0	7.5	9.3	11.1	19.5	37.3	22.2	11.5	12.6
Total SA	EUR	FR	3.84	13.4	10.5	9.3	8.9	10.0	10.1	12.9	15.3	14.3	10.8	10.1
ENI SpA	EUR	IT	3.86	10.4	7.9	7.5	7.4	11.8	13.7	64.1	nm	25.9	12.3	12.2
Equinor ASA	NOK	NO	3.81	12.8	9.6	8.3	7.4	9.1	12.6	31.0	157.0	16.4	11.0	11.9
OMV AG	EUR	AT	3.86	17.4	10.9	13.6	9.5	11.7	14.4	12.8	13.1	8.8	9.1	8.5
			26.65											
Integrated / Oil & Gas E&P - Canada														
Suncor Energy Inc	CAD	CA	3.80	40.1	26.7	11.9	13.2	13.3	13.2	37.6	nm	22.7	15.2	17.0
Canadian Natural Resources Ltd	CAD	CA	3.68	14.7	14.5	15.3	22.2	15.7	10.2	253.7	nm	30.0	12.6	16.3
Imperial Oil	CAD	CA	3.85	18.8	16.3	10.1	9.0	11.6	9.8	20.9	61.9	29.1	13.6	15.6
			11.33											
Integrated Oil & Gas - Emerging market														
PetroChina Co Ltd	HKD	HK	3.70	7.3	5.9	5.8	6.6	7.4	7.3	22.5	88.3	34.3	13.9	13.4
Gazprom OAO	USD	RU	3.88	5.8	4.6	3.1	3.2	3.0	5.0	3.0	4.4	4.9	2.9	3.2
			7.57											
Oil & Gas E&P														
Occidental Petroleum Corp	USD	US	3.66	18.0	11.9	8.0	9.6	9.6	11.5	402.3	nm	74.4	13.5	21.7
ConocoPhillips	USD	US	3.61	18.7	11.4	8.0	11.9	12.1	12.8	nm	nm	108.7	15.2	19.5
Anadarko Petroleum Corp	USD	US	3.05	nm	27.3	15.0	14.1	11.4	10.3	nm	nm	nm	19.0	28.5
Apache Corp	USD	US	3.19	5.9	3.5	2.8	3.4	4.0	5.9	nm	nm	309.6	19.6	55.4
Devon Energy Corp	USD	US	3.06	8.2	4.5	4.4	8.3	6.3	5.2	10.8	nm	14.5	17.6	20.7
Noble Energy Inc	USD	US	3.03	13.2	10.8	8.5	9.8	7.2	9.6	391.9	nm	1396.3	23.1	125.5
QEP Resources Inc	USD	US	1.36	nm	6.0	5.1	6.7	5.9	5.9	nm	nm	nm	116.5	22.3
Newfield Exploration Co	USD	US	3.07	3.6	4.0	4.5	7.5	10.2	9.9	25.2	17.0	8.5	5.1	6.1
Oasis Petroleum Inc	USD	US	1.44	nm	35.8	7.3	4.1	2.2	2.5	7.6	nm	nm	21.3	20.3
			25.46											
International E&Ps														
CNOOC Ltd	HKD	HK	3.75	16.6	9.6	7.3	7.7	7.9	9.5	28.2	nm	16.3	9.1	9.8
Tullow Oil PLC	GBP	GB	1.73	41.3	20.0	4.6	4.1	30.9	nm	nm	nm	14.0	24.2	9.8
Soco International PLC	GBP	GB	0.49	5.7	7.8	5.0	1.4	1.5	2.3	nm	nm	nm	29.3	15.9
			5.96											
Midstream														
Enbridge Inc	USD	CA	3.68	55.3	47.7	43.0	39.6	36.5	33.5	30.3	28.0	34.0	24.7	26.1
			3.68											
Drilling														
Unit Corp	USD	US	1.30	6.1	5.2	3.9	3.8	4.3	3.7	nm	nm	30.1	16.0	18.2
			1.30											
Equipment & Services														
Halliburton Co	USD	US	3.61	24.0	15.6	9.4	10.5	10.1	8.0	21.2	nm	27.0	17.0	22.7
Helix Energy Solutions Group Inc	USD	US	1.54	11.8	12.9	4.5	3.7	6.3	3.5	40.4	nm	nm	31.0	26.4
Schlumberger Ltd	USD	US	3.54	16.3	16.0	12.2	10.6	9.3	8.0	13.2	38.3	30.2	27.2	27.7
			8.68											
Solar														
Sunpower Corp	USD	US	0.33	5.1	4.0	70.9	38.7	4.1	4.4	3.0	nm	nm	nm	nm
			0.33											
Oil & Gas Refining & Marketing														
Valero Energy Corp	USD	US	3.91	nm	55.3	22.1	18.0	21.4	14.4	10.0	23.9	18.0	14.3	12.0
			3.91											
Research Portfolio														
Cluff Natural Resources PLC	GBP	GB	0.26	nm	nm	nm	nm	nm	nm	nm	nm	nm	nm	nm
EnQuest PLC	GBP	GB	0.47	nm	3.3	3.9	1.2	1.3	2.4	22.9	1.5	nm	4.6	5.0
JKX Oil & Gas PLC	GBP	GB	0.12	1.3	1.4	1.7	2.3	4.4	12.1	nm	nm	nm	nm	nm
Ophir Energy PLC	GBP	GB	0.03	nm	nm	nm	nm	nm	2.2	nm	nm	nm	nm	17.9
Reabold Resources PLC	GBP	GB	0.30	nm	nm	nm	nm	nm	nm	nm	nm	nm	nm	nm
Shandong Molong Petroleum Machiner	HKD	HK	0.05	6.7	2.6	3.6	nm	nm	nm	nm	nm	nm	nm	nm
			1.22											
		Cash	3.90											
		Total	100											
		PER		13.2	9.4	7.4	7.7	8.2	8.9	19.9	35.3	21.3	12.1	13.3
		Med. PER		13.2	10.2	7.4	7.7	9.3	9.6	22.5	28.8	25.9	14.3	16.5
		Ex-gas PER		15.1	11.0	8.4	8.2	9.1	9.8	19.8	33.1	21.3	12.2	13.1

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 10 years, together with IEA forecasts for 2018 and 2019.

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018E	2019E
											IEA	*IEA*
World Demand	**86.5**	**85.5**	**88.5**	**89.5**	**90.7**	***91.7***	***93.1***	***95.3***	***96.4***	***98.0***	***99.2***	***100.6***
Non-OPEC supply (includes Angola, Ecuador and Indonesia for periods when each country was outside OPEC)	**49.6**	**51.4**	**52.7**	**52.8**	**53.3**	***54.5***	***56.6***	***57.8***	***56.5***	***57.3***	***60.0***	***61.8***
Indonesia supply adjustment	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.6	0.6	0.6
Non-OPEC supply (ex. Angola/Ecuador and inc. Indonesia for all periods)	**50.6**	**51.4**	**52.7**	**52.8**	**53.3**	**54.5**	**56.6**	**57.8**	**57.1**	**57.9**	**60.6**	**62.4**
Gabon/E Guinea/Congo supply adjustment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.3	0.6	0.6	0.6
Qatar supply adjustment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.6	0.6
OPEC NGLs	4.5	5.1	5.5	5.9	6.4	*6.1*	*6.4*	*6.6*	*6.8*	*6.9*	*6.9*	*7.0*
Non-OPEC supply plus OPEC NGLs plus Gabon/E Guinea/Congo (ex. Angola/Ecuador and inc. Indonesia for all periods)	**55.1**	**56.5**	**58.2**	**58.7**	**59.7**	**60.6**	**63.0**	**64.7**	**64.2**	**66.0**	**68.7**	**70.6**
Call on OPEC-11	**31.4**	**29.0**	**30.3**	**30.8**	**31.0**	**31.1**	**30.1**	**30.6**	**32.2**	**32.0**	**30.5**	**30.0**

Global oil demand in 2018 was 12.2m 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 further rise of 1.4m b/day in 2019, which would take oil demand to an all-time high of 100.6m b/day.

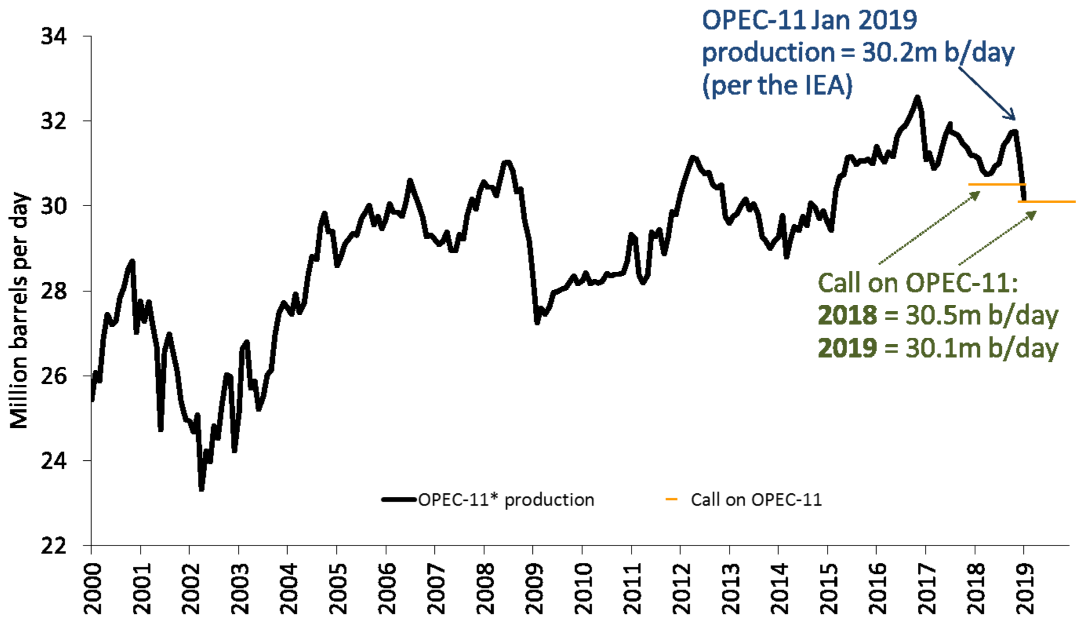
OPEC

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; (4) US shale oil.

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. 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 onshore) projects reaching production.

Figure 7: OPEC-12 apparent production vs call on OPEC 2000 – 2019



Source: IEA Oil Market Report (February 2019 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. 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. This contributed to an oversupplied market in 2015 and 2016.

In November 2016, faced with sharply lower oil prices, 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, taking the total reduction to 1.8m b/day. Compliance with the cuts was very strong and, after been delayed initially by a variety of temporary factors, inventories started to decline from mid 2017. Having originally been excluded from the cuts, Libya and Nigeria were subsequently included in the quota system.

('000 b/day)	31-Dec-10	30-Nov-14	31-Dec-16	28-Feb-19	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	**10,100**	1,850	450	-380
Iran	3,700	2,780	3,730	**2,650**	-1,050	-130	-1,080
Iraq	2,385	3,370	4,630	**4,620**	2,235	1,250	-10
UAE	2,310	2,800	3,070	**3,070**	760	270	0
Kuwait	2,300	2,790	2,860	**2,690**	390	-100	-170
Nigeria	2,220	1,970	1,500	**1,760**	-460	-210	260
Venezuela	2,190	2,350	2,080	**1,070**	-1,120	-1,280	-1,010
Angola	1,700	1,640	1,670	**1,440**	-260	-200	-230
Libya	1,585	580	630	**900**	-685	320	270
Algeria	1,260	1,100	1,110	**1,030**	-230	-70	-80
Ecuador	465	561	550	**530**	65	-31	-20
OPEC-11	**28,365**	**29,591**	**32,310**	**29,860**	**1,495**	**269**	**-2,450**

The last twelve months has continued to be a volatile time for OPEC. For the first half of 2018, a steep production decline from Venezuela and the promise of lower Iranian exports lead other OPEC members to raise supply, designed to prevent oil prices spiking too high. Towards the end of the year, it became apparent that OPEC had over-compensated and risked oversupplying the market in 2019. In December 2018, OPEC met in Vienna and, together with non-OPEC, announced a proposed cut of 1.2m b/day starting in January 2019 and lasting for an initial period of six months. It was proposed that OPEC (excluding Libya, Venezuela and Iran) cut total production by 0.8m b/day while non-OPEC (led predominantly by Russia) cut a total of 0.4m b/day. As of March 2019, it appears that OPEC is being compliant with its production quotas.

OPEC's actions in recent years demonstrate a commitment to delivering a reasonable oil price to satisfy their own economies but also to incentivise investment in long term projects. Saudi's actions at the head of OPEC appear designed to achieve an oil price that to some extent closes their fiscal deficit ($70-75/bl is needed to close the gap fully), whilst not spiking the oil price too high and over-stimulating 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 2016, 2008, 2006, 2001, 1998 – and again in late 2018. 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 2008-2018.

Growth in the non-OPEC region since the start of the decade has been dominated by the successful development of shale oil and oil sands in North America (up around 7m b/day between since 2010), implying that the rest of non-OPEC region has barely grown over this period, despite the sustained high oil price until mid 2014.

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 is now well above 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/bl world are far lower than in a $100/bl world, but with efficiency improvements, enough to see growth sustaining.

Offsetting US onshore shale oil growth, we expect to see non-OPEC supply outside the US to weaken, as the queue of large conventional project start-ups slows. 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/bl+) 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 lack of supply response 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 2019 oil demand growth will be 1.4m b/day, taking demand to nearly 101m 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 2019 comprises an increase in non-OECD demand of 1.1m b/day and OECD demand growth of 0.4m b/day. The components of this non-OECD demand growth can be summarised as follows:

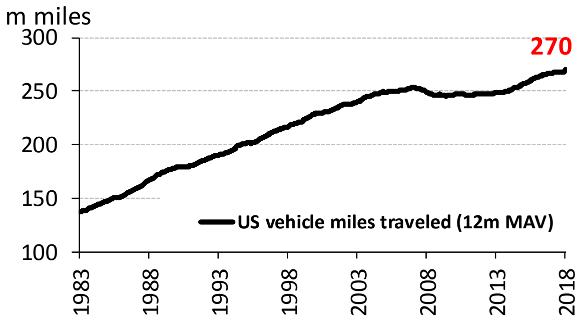
Figure 8: Non-OECD oil demand

m b/day	Demand								Growth						
	2012	2013	2014	2015	2016	2017	2018e	2019e	2013	2014	2015	2016	2017	2018e	2019e
Asia	21.4	22.1	22.8	24.1	25.0	26.0	26.8	27.7	0.7	0.7	1.3	0.9	1.0	0.8	0.9
Middle East	7.8	7.9	8.4	8.5	8.5	8.5	8.4	8.5	0.1	0.5	0.1	0.0	0.0	-0.1	0.1
Latin America	6.4	6.7	6.8	6.7	6.4	6.5	6.4	6.3	0.3	0.1	-0.1	-0.3	0.1	-0.1	0.0
FSU	4.6	4.7	4.66	4.6	4.5	4.5	4.7	4.8	0.1	0.0	-0.1	0.0	0.0	0.2	0.1
Africa	3.8	3.9	3.8	4.2	4.3	4.3	4.3	4.4	0.1	-0.1	0.4	0.1	0.0	0.0	0.1
Europe	0.7	0.7	0.7	0.7	0.7	0.7	0.8	0.8	0.0	0.0	0.0	0.0	0.0	0.1	0.0
Total	**44.7**	**46.0**	**47.2**	**48.7**	**49.5**	**50.5**	**51.4**	**52.5**	**1.3**	**1.2**	**1.6**	**0.7**	**1.1**	**0.9**	**1.0**

Source: IEA Oil Market Report (February 2019)

Asia has settled down into a steady pattern of growth since 2010, and accounts for much of expected growth in 2018. Historically, China has been the most important component of this growth and continues to be a major component, although signs are emerging that India will also grow rapidly.

OECD demand in 2019 is forecast to be up by 0.4m 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 a $60/bl oil price, the world oil bill as a percentage of GDP is around 2.5% and this will still be a stimulant of multi-year demand growth. If oil prices move 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 flatter picture in the OECD more than offset by strong growth in the non-OECD area. Flatter OECD demand reflects improving oil efficiency over time, 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 1.8m in 2018, up from 1.2m in 2017. We expect to see EV sales accelerate in 2019 to around 2.5m, or 3% of total global sales. Even applying an aggressive growth rate to EV sales, we see EVs comprising only around 0.7% 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 2019 against their historic levels, and rises/falls in percentage terms that we have seen in the period from 2002 to 2018.

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	2019
WTI	30	33	38	49	66	75	82	104	68	84	99	94	98	93	49	45	51	65	58
Brent	30	32	35	46	64	75	82	103	67	84	115	112	108	99	52	45	54	72	60
Brent/WTI (12m MAV)	**30**	**33**	**37**	**48**	**65**	**75**	**82**	**104**	**68**	**84**	**107**	**103**	**103**	**96**	**51**	**45**	**53**	**68**	**59**
Brent/WTI y-on-y change (%)		8%	12%	30%	37%	15%	9%	26%	-35%	24%	27%	-4%	0%	-7%	-47%	-11%	17%	30%	-14%
Brent/WTI (5yr MAV)	30	25	32	37	42	51	61	75	79	82	89	93	93	99	92	80	69	63	55

We expect oil to trade in a $60-75/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 $70/bl would represent 3.0% of 2018 Global GDP, 12% 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, something around $70/bl.

Natural gas market

US gas demand

On the demand side for the US, 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. 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	2019E
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	22.1	21.5
Power generation	18.7	18.2	18.8	20.2	20.8	24.9	22.3	22.3	26.5	27.3	25.3	28.5	28.5
Industrial	18.2	18.2	16.9	18.5	19.0	19.7	20.3	20.9	20.6	21.1	21.6	22.8	23.2
Pipeline exports (Canada & Mexico)	2.1	2.5	2.8	2.9	4.1	4.4	4.4	4.1	4.9	6.3	6.2	7.0	7.8
LNG exports	-	-	-	-	-	-	-	-	0.1	1.0	2.6	3.4	6.7
Pipeline/plant/other	5.2	5.3	5.5	5.6	5.8	6.1	6.7	6.3	6.5	6.4	6.5	6.8	6.8
Total demand	**65.4**	**66.2**	**65.6**	**68.8**	**71.3**	**74.3**	**76.1**	**77.0**	**80.0**	**82.6**	**83.1**	**90.6**	**94.5**
Demand growth	**4.0**	**0.8**	**- 0.6**	**3.2**	**2.5**	**3.0**	**1.8**	**0.9**	**3.0**	**2.6**	**0.5**	**7.5**	**3.9**

Source: EIA; Simmons; Guinness estimates

Total gas demand in 2018 (including Canadian, Mexican and LNG exports) is expected to be around 90.6 Bcf/day, up by 7.5 Bcf/day (9.0%) versus 2017 and 10.8 Bcf/day (13.5%) higher than the 5 year average. The biggest contributors to the growth in demand in 2018 will be power generation (hot summer and start-up of numerous gas plants increasing gas' share over coal), industrial demand (US GDP growth and petrochemical plant start-ups), and LNGS exports (opening of new export terminals).

We expect US demand in 2019, assuming prices remain around $3/mcf, to exhibit further strong growth of around 4 Bcf/day. Normalised weather would keep a cap on power generation demand, but there should be a surge in LNG exports (c.3 Bcf/day), as a wave of new export terminals come into service. The table below shows the scheduled start-up of terminals, with 4.3 Bcf/day of capacity coming in 2019.

Terminal	Location	2015	2016	2017	2018E	2019E	2020E
Cameron 1-2	LA					1.4	
Cameron 3	LA						0.7
Corpus Christi 1-2	TX					1.3	
Cove Point 1	MD				0.8		
Elba Island 1-6	GA				0.2		
Elba Island 7-10	GA					0.2	
Sabine Pass 1-2	LA						
Sabine Pass 3-4	LA	0.1	1.0	1.3			
Sabine Pass 5	LA					0.7	
Freeport 1	TX					0.7	
Freeport 2-3	TX						1.4
Incremental exports		**0.1**	**1.0**	**1.3**	**1.0**	**4.3**	**2.1**
Total US LNG exports		**0.1**	**1.1**	**2.4**	**3.4**	**7.7**	**9.8**

Source: EIA; Simmons

Looking further ahead, 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 as new pollution standards have 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.

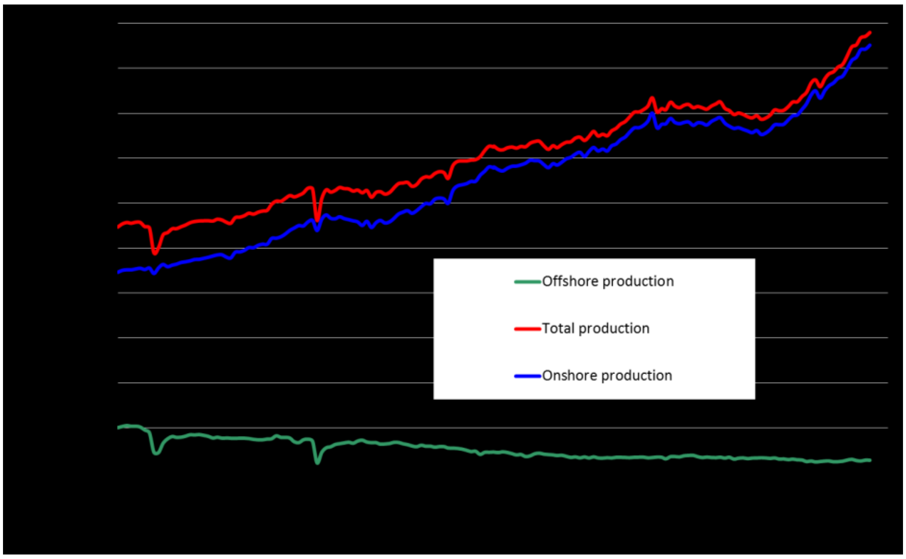
The supply side fundamentals for natural gas in the US are driven by 3 main moving parts: onshore and offshore domestic production, and pipeline imports of gas from Canada. Of these, onshore supply is the biggest component, making up over 85% of total supply.

Bcf/day	2007	2008	*2009*	2010	2011	2012	2013	2014	2015	2016	2017	2018E	2019E
US natural gas supply:													
US onshore	45.1	48.8	49.8	52.2	57.7	61.5	62.7	67.5	70.6	70.0	71.1	79.2	84.8
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	2.5	2.1	2.0
Pipeline imports (Canada)	10.4	9.8	9.0	9.0	8.5	8.0	7.5	7.1	7.1	8.0	8.0	8.0	8.0
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	0.3	0.3
Total supply	**65.5**	**66.1**	**66.9**	**68.8**	**72.2**	**74.5**	**74.4**	**78.5**	**81.8**	**81.8**	**81.9**	**89.6**	**95.1**
Supply growth	**3.2**	**0.6**	**0.8**	**1.9**	**3.4**	**2.3**	**- 0.1**	**4.1**	**3.3**	**-**	**0.1**	**7.7**	**5.5**
(Supply)/demand balance	**- 0.1**	**0.1**	**- 1.3**	**-**	**- 0.9**	**- 0.2**	**1.7**	**- 1.5**	**- 1.8**	**0.8**	**1.2**	**1.0**	**- 0.6**

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 195 at the end of February 2019. 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 (December 2018) at 95.2 Bcf/day, over 65% 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 (December 2018 published in February 2019)

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.

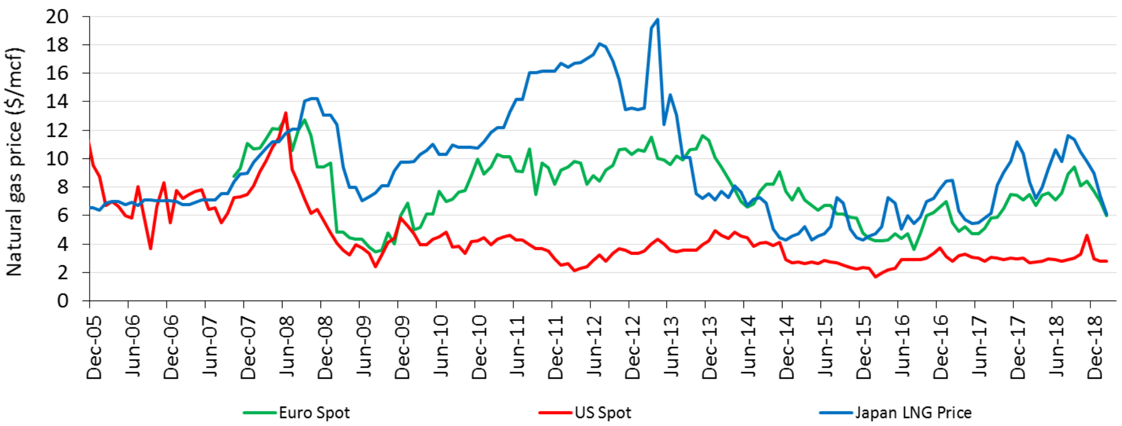
Associated gas production declined in 2016 with the fall of shale oil production, but as US oil supply now growing again, so associated gas production is also picking up. Generally, we expect to see rates of around 2-3 Bcf/day of associated gas per 1m b/day of oil production.

The Marcellus/Utica region, which includes the largest producing gas field in the US and the surrounding region, reached production of around 29 Bcf/day in 2018, with growth accelerating further in 2019 as infrastructure capacity expands. Further growth in region is likely over the next couple of years, supported by a small increase from legacy gas fields, which have reversed the decline seen for much of the earlier part of this decade.

Overall, if the price remains in the $2.50-$3.50/mcf range, we expect a significant jump in onshore gas supply in 2019, up by around 5 Bcf/day versus 2018.

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.$7/mcf versus c.$4/mcf). Asian spot LNG prices fell sharply down to around $4.50/mcf at the start of 2016 but have since averaged around $8/mcf as Chinese gas demand strengthens. The implied economics for US LNG exports into Europe and Asia are attractive at these levels.



Source: Bloomberg (March 2019)

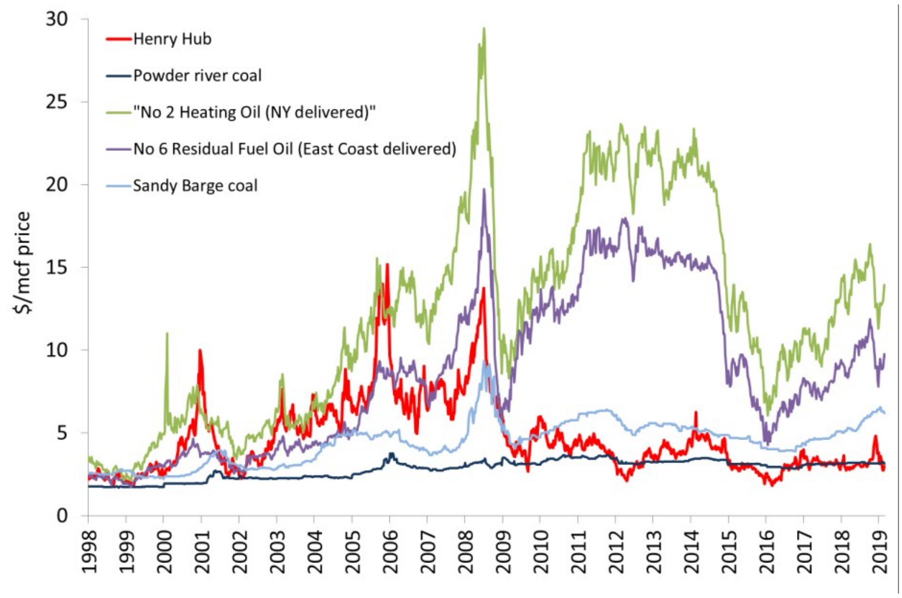
Relationship with oil and coal

The oil/gas price ratio ($ per bbl WTI/$ per mcf Henry Hub) of around 18x at the end of February 2019 sits well above the long-term ratio of c.10x.

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 (February 2019)

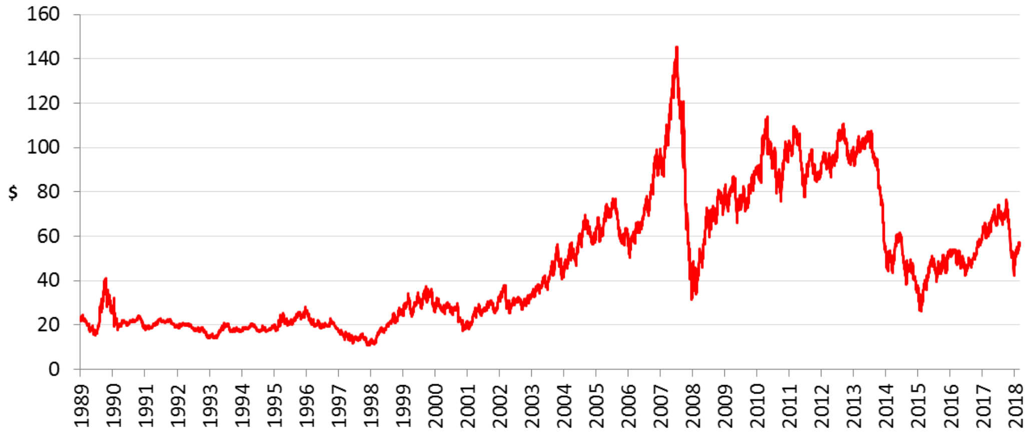
Conclusions about US natural gas

Bcf/day	2007	2008	*2009*	2010	2011	2012	2013	2014	2015	2016	2017	2018E	2019E
Total demand	**65.4**	**66.2**	**65.6**	**68.8**	**71.3**	**74.3**	**76.1**	**77.0**	**80.0**	**82.6**	**83.1**	**90.6**	**94.5**
Demand growth	4.0	0.8	- 0.6	3.2	2.5	3.0	1.8	0.9	3.0	2.6	0.5	7.5	3.9
Total supply	**65.5**	**66.1**	**66.9**	**68.8**	**72.2**	**74.5**	**74.4**	**78.5**	**81.8**	**81.8**	**81.9**	**89.6**	**95.1**
Supply growth	3.2	0.6	0.8	1.9	3.4	2.3	- 0.1	4.1	3.3	-	0.1	7.7	5.5
(Supply)/demand balance	- 0.1	0.1	- 1.3	-	- 0.9	- 0.2	1.7	- 1.5	- 1.8	0.8	1.2	1.0	- 0.6

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. 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/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 $) since 1989.



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.

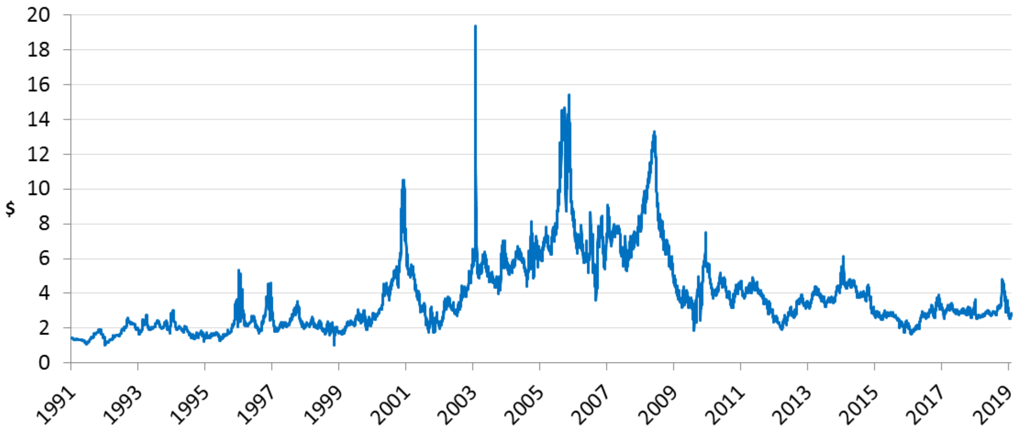
Continued expectations of a supply crunch by the end of the decade, coupled with increased speculative activity in oil markets, contributed to the oil price surging past $90 in the final months of 2007 and as high as $147 by the middle of 2008. This spike was brought to an abrupt end by the collapse 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.

2014 marked the end of the oil cycle that started in the early 2000s. Ten years of high prices catalysed a wall of new non-OPEC supply, sufficient that OPEC saw no choice but to stop supporting price and re-set the investment cycle. Oil prices found a bottom in 2016 (as a result of OPEC cutting production again), but its recovery was capped by the volume of new supply still coming into the market from projects sanctioned pre the 2014 price crash.

Today, strong global demand growth, underinvestment in OPEC states outside the Arabian Gulf, and a slowdown in non-OPEC growth have combined to set up the new oil cycle, with prices in the $50-50/bl range once again.

Figure 13: North American gas price since 1991 (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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