THE GUINNESS GLOBAL ENERGY REPORT

Developments and trends for investors in the global energy sector | July 2018

GUINNESS GLOBAL ENERGY FUND

Fund size: $297m (30.6.2018)

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 JUNE

OIL

Brent and WTI up; spread narrows and outlook tightens

Brent stronger and WTI up over 10% over the month; Brent rose from $77.6/bl to $79.4/bl; WTI rose from $67.0/bl to $74.2/bl. OPEC committed to bring production in line with current quotas, potentially adding 0.6m b/day, and some non-OPEC members committed to add further as well. Iran sanctions now appear to be broaderthan initially expected and supply issues continue in Venezuela and Libya

NATURAL GAS

US gas prices flat; inventories low

Henry Hub prices were slightly lower on the month, falling from $2.95/mcf to $2.92/mcf. Inventories are at close to 10 year low levels and supply has responded (up 7 Bcf/day yoy). The US gas market is now slightly oversupplied but inventories could still undershoot by year end.

EQUITIES

Energy outperforms the broad market

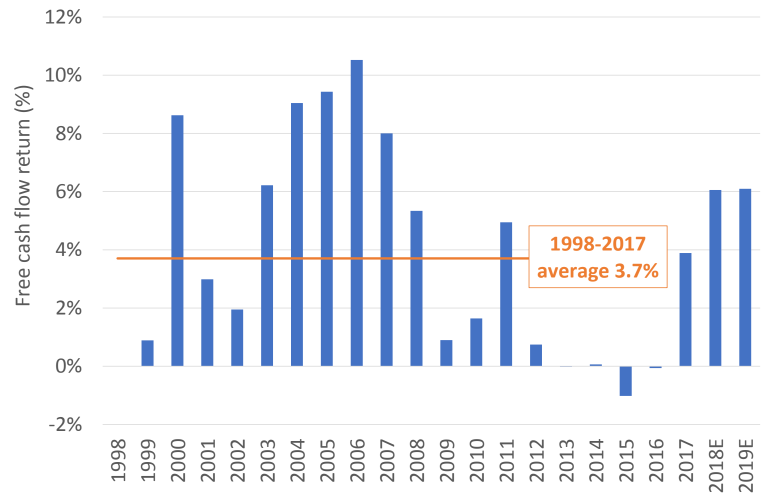
The MSCI World Energy Index rose in June by 1.3%, outperforming the MSCI World Index which was flat over the month (all in US dollar terms). For the year to June 30 2018, the MSCI World Energy Index is ahead of the MSCI World by 6.3%.

CHART OF THE MONTH

Free Cash Flow Return for energy equities exceeds 2008 levels

Control of capital expenditure coupled with sharply lower operating costs and a supportive oil price environments means that the Free Cash Flow Return of the Guinness Energy portfolio should reach 6% in 2018. This is the highest level for 10 years and higher than the FCF Return levels delivered when the oil price was $100/bl.

Free Cash Flow Return of Guinness Energy portfolio



Source: Bloomberg, Company Data and includes analysis of all 'full position' holdings (for which 1998-2017 data is available) in the Guinness Energy fund as of December 31 2017. FCF Return is operating cash flow less capex divided by Capital Employed. Data as of June 2018, $65/bl in 2018 and $60/bl in 2019.

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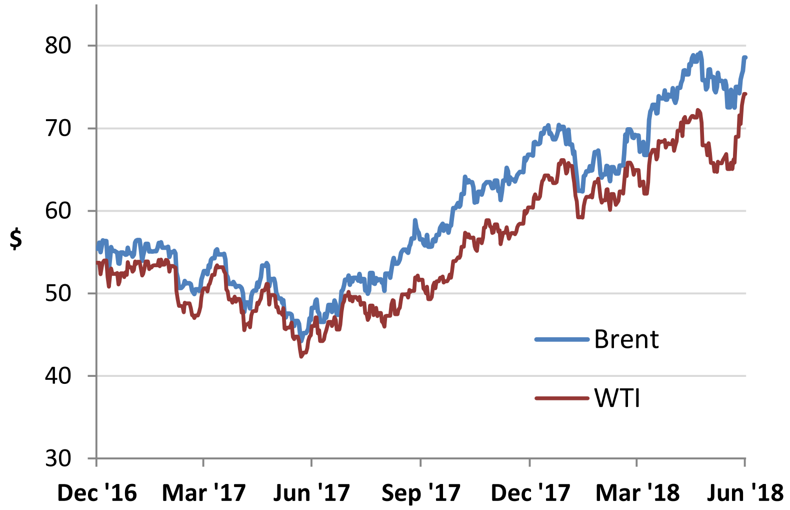
1. JUNE IN REVIEW

i) Oil market

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



Source: Bloomberg LP

The West Texas Intermediate (WTI) oil price started June at $67.0/bl and, after dipping at the start of the month, recovered strongly to end the month on its highs at $74.1/bl. WTI has averaged $65.4/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 well, opening at $77.6/bl and also closing on its highs of $79.4/bl. Brent has averaged $71.1/bl so far in 2018. The gap between the WTI and Brent benchmark oil prices closed quite substantially during the month, ending June at just over $5/bl versus a level of $10.3/bl at the end of May.

Factors which strengthened WTI and Brent oil prices in June:

- **OPEC meeting brought volatility in oil prices but highlighted an increasingly tight market**
  OPEC concluded their formal meeting on Friday June 22nd 2018 with an agreement, in practice, to raise production by around 0.6m b/day. Non-OPEC partners will add a smaller amount of production, albeit undefined. This outcome, which was generally in line with market expectations, was brokered by Saudi to start to address potential extreme tightness in the oil market in the second half of 2018. We see this is another logical step from OPEC towards rebalancing the market and sustaining an oil price that satisfies their own economics needs as well as balancing the supply and demand outlook.

- **Increasing likely impact of Iranian sanctions**

It increasingly looks like the US sanctions against Iran that were announced in May will have a broader impact on oil exports than initially expected. During June, we learnt that the US requested that Japanese refiners do not buy Iranian crude and at least one Indian refiner (definitely Reliance) has announced that it will not accept Iranian crude oil. On top of this, all European refiners have announced their intention to boycott Iranian crude oil. We initially expected the sanction impact to be 300-500k b/d but it now looks more likely to be an impact of over 1mn b/d. Even the Tehran Chamber of Commerce, Industries, Mines & Agriculture recently reported that the sanctions might impact Iran by 700-800kb/d.

- **Venzuelan production continues to decline**
  There have been no improvement yet in the outlook for Venezuelean oil production. Latest monthly data for June pegged production at 1.38m b/day versus 1.44m b/d in May 2018 and 1.7m b/day in December 2017. While upstream production has been poor as a result of low reinvestment (the country's rig count has dropped to 25 rigs, down 8 rigs in May, down 20 rigs ytd and down 52 rigs from the peak of 77 rigs in August 2014) there are also increased issues revolving around the inability to export crude oil. There are massive queues at ports and therefore there is the threst that Venzuela announces force majeure on its contracts.

- **Libya disruptions pick up in June**
  Towards the end of June there were was an uptick in supply disruptions from Libya. Civil unrest caused the the closure of the Es Sider, Ras Lanuf, Hariga & Zueitina ports thus reducing production by around 800k b/d. Libya's production was 0.69m b/day in June, down from 0.99m b/day in May. While the production loss is significant, we currently only expect these disruptions to be temporary

Factors which weakened WTI and Brent oil prices in June:

- **Increased US onshore oil supply**
  At the start of July, the EIA reported that US onshore production increased by 112k b/day during April 2018. This puts year over year growth for the US onshore system at around 1.47m b/day. Using production guidance data provided by the larger shale producers, we expect the US onshore oil system to maintain a similar pace of growth for the rest of the year.

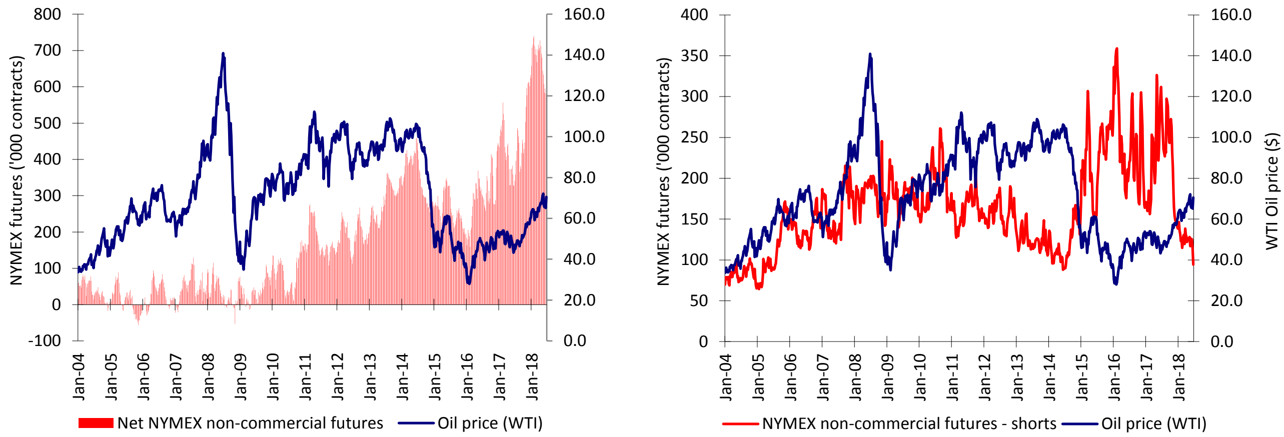
- **Concerns over higher oil and oil product prices affecting demand growth**
  Higher oil prices are starting to raise questions about the sustainability of the current strong levels of global oil demand growth. Compounding the matter is the recent strength in the USD which means that locally priced oil products in many emerging market countries have risen sharply this year. The US has not been immune to these fears and we note the recent 'tweets' from Donald Trump highlighting his view that oil prices are too high and requesting that Saudi Arabia adds more production to the market.

- **Infrastructure constraints in the US onshore causing depressed US regional oil prices**
  US infrastructure bottlenecks have become a greater concern in recent weeks. As oil production grows we will see further labour, pipeline and general infrastructure issues resulting in (among other things) oil being 'trucked' out of the Permian Basin to the US Gulf Coast in order to access export markets. Local oil prices have fallen to reflect the higher cost of trucking .We expect production efficiencies to fall and costs to inflate in this environment, somewhat capping the ability for the US system to grow. Some of the larger E&P companies (including Anadarko and ConocoPhillips) have publicly announced interest in diverting some of their capital away from the Permian basin and in recent weeks we have seen the overall US onshore oil directed rig count start to flatten

Speculative and investment flows

The New York Mercantile Exchange (NYMEX) net non-commercial crude oil futures open position (WTI) increased in June, ending the month at 625,000 contracts long versus 608,000 contracts long at the end of May. Typically there is a positive correlation between the movement in net position and movement in the oil price. The gross short position reduced from 122,000 contracts to 94,000 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 – June 2018

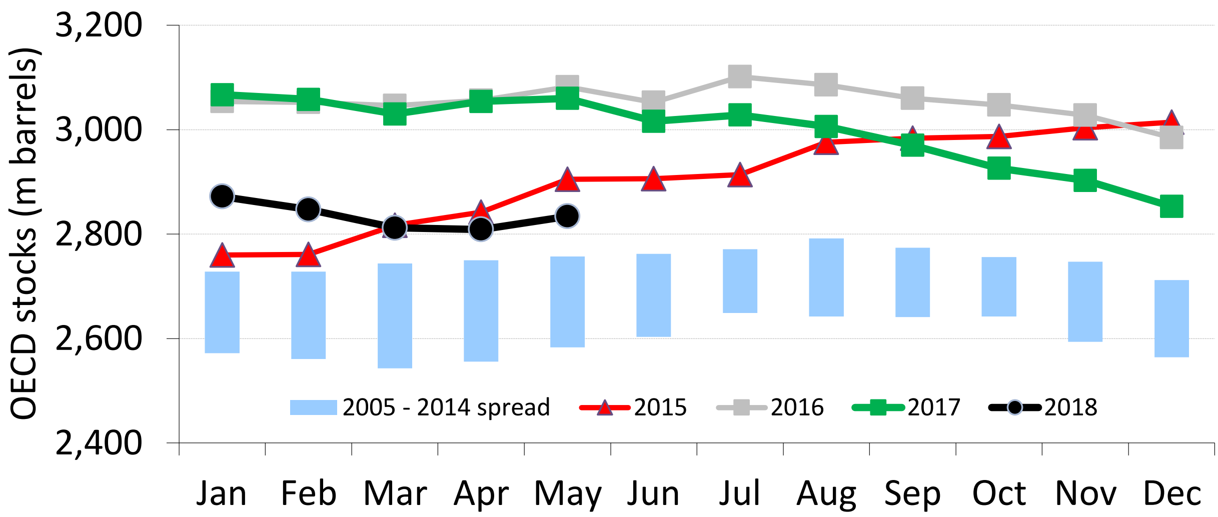


Source: Bloomberg LP/NYMEX/ICE (2018)

OECD stocks

OECD total product and crude inventories at the end of May (the latest data point available) were estimated by the IEA to be 2,834m barrels, up 25m barrels versus the level reported for April. This compares to a 10-year average build for May of 24m barrels. Inventories have been tightening since the middle of 2017, and remain around 60m barrels above the 'normalised' (pre-2015) range. We expect them to continue to tighten over 2018.

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



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

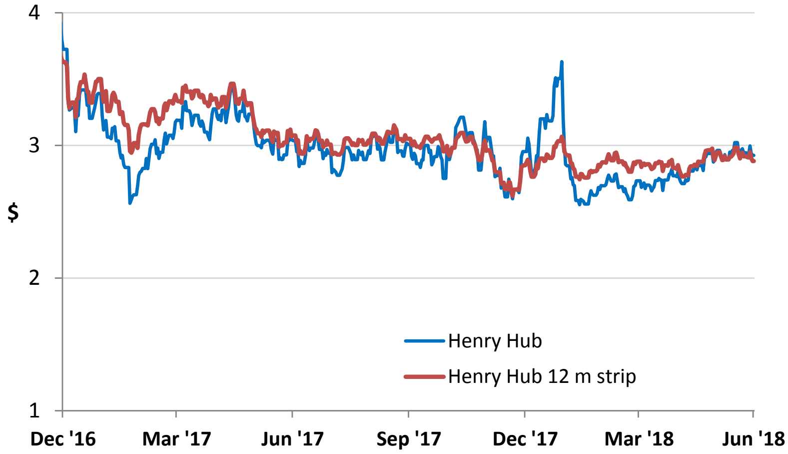
ii) Natural gas market

The US natural gas price (Henry Hub front month) opened June at $2.95/mcf (1,000 cubic feet) and remained in a $2.90/mcf to $3.00/mcf range for the month, ending the month at $2.92/mcf. The spot gas price has averaged

$2.84/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 also traded in a tight range over the month, opening at $2.93/mcf and closing at $2.98 /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) December 31 2016 to June 30 2018



Source: Bloomberg LP

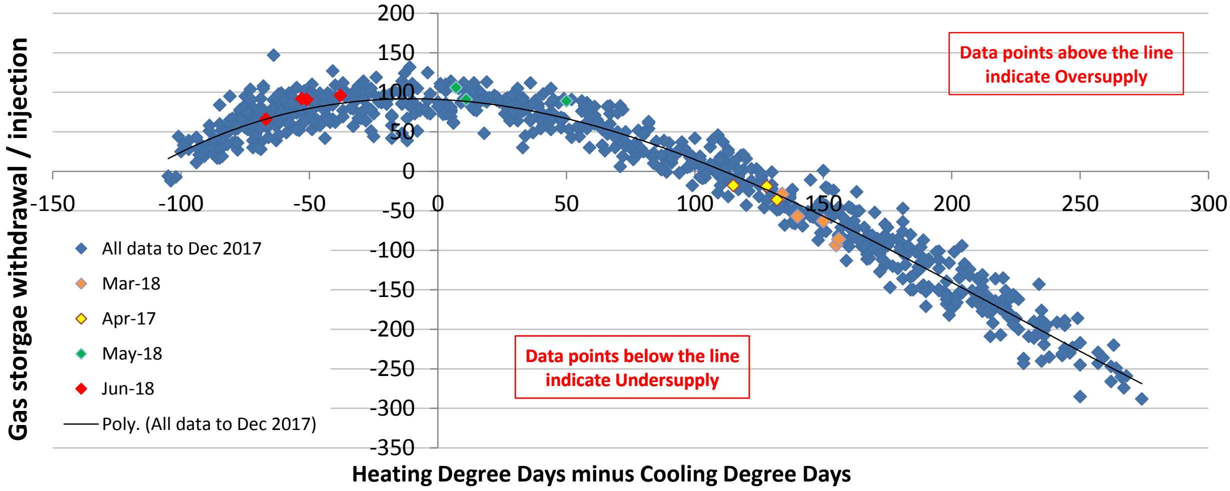
Factors which strengthened the US gas price in June included:

- **Depressed gas inventories**
  US natural gas inventories were estimated to be around 2.074 Tcf at the end of June, 0.48 Tcf lower than the 10 year average, and very close to the 10 year low. In order for inventories to reach 'full' at the end of November, it would require an oversupply for the remainder of the year to be around 3-4 Bcf/day.
- **Constraints to associated gas supply**
  Whilst the supply of associated gas in the US (i.e. gas produced as a by-product of shale oil) is growing well this year, infrastructure and service capacity constraints in Texas have lowered expectations for associated gas supply growth over the coming 12-18 months. This has served to boost both the Henry Hub spot price and twelve month pricing strip in recent weeks.

Factors which weakened the US gas price in June included:

- **Strong US onshore natural gas production**
  Onshore US natural gas production averaged 86.6 Bcf/day in April 2018 (the latest available data point), up by 0.4 Bcf/day on the level reported for March. Onshore production has risen by 9.8 Bcf/day versus the level reported twelve months before, the highest year-on-year growth recorded. 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.
- **Structurally oversupplied market**
  Adjusting for the impact of weather in June, the most recent injections of gas into storage suggest the market is, on average, around 1 bcf/day oversupplied (as indicated by the red dots on the graph below).

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

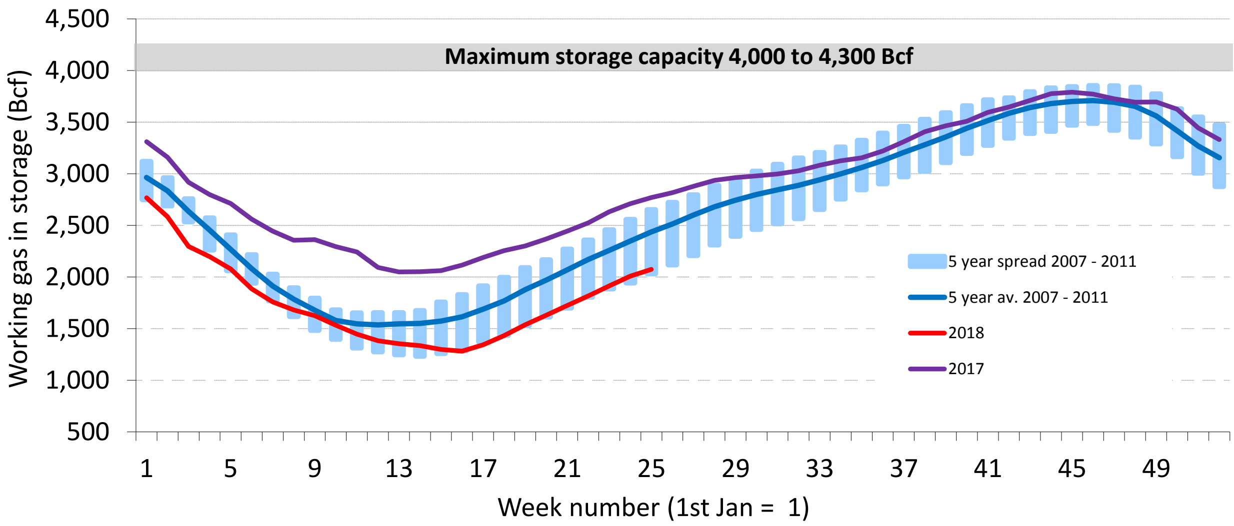


Source: Bloomberg LP; Guinness Asset Management

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 June were reported by the EIA to be 2.074 Tcf. The withdrawal season started with inventories peaking at 3.8 Tcf in mid-November, the lowest starting point of the winter season for US gas inventories since November 2014. Exceptionally cold weather and, until recently, 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 June.

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



Source: Bloomberg; EIA (May 2018)

2. MANAGER'S COMMENTS

This commentary was published by the Guinness Energy Team on June 22nd, after the OPEC meeting concluded, and is repeated here with a few additional comments regarding more recent events relating to the OPEC meeting.

OPEC respond rationally to a tightening oil market

OPEC concluded their formal meeting on Friday June 22nd 2018 with an agreement, in practice, to raise production by around 0.6m b/day. Non-OPEC partners will add a smaller amount of production, albeit undefined. This outcome, which was generally in line with market expectations, was brokered by Saudi to start to address potential extreme tightness in the oil market in the second half of 2018. We see this is another logical step from OPEC towards rebalancing the market and sustaining an oil price that satisfies their own economics needs as well as balancing the supply and demand outlook.

Key Points

- Agreement will add around 0.6m b/day of production from OPEC to the market. While not allocated by country, we think it most likely comes from Saudi, Kuwait, Iraq and the UAE
- Some non-OPEC members, led by Russia, will also increase production, taking the potential increase in overall OPEC and non-OPEC volumes potentially as high as 1m b/day
- There are significant OPEC supply risks in the second half of 2018 with further supply disruptions from Venezuela, Iran and Libya each capable of offsetting OPEC's production increase
- OPEC remain committed to delivering a reasonable oil price to satisfy their own economies but also to incentivise investment in long term projects
- If OPEC are successful and equity markets were to price in a long term oil price of $70/bl, we believe that there would be over 50% upside in the Guinness Global Energy portfolio.

What has been announced?

At the conclusion of their meeting on Friday June 22nd 2018 in Vienna, OPEC's headline announcement was "to strive to adhere to the overall conformity level of OPEC-12, down to 100%, as of 1 July 2018". OPEC had reached "152% conformity" with their 2017 production cuts, and a move to 100% conformity implies an increase in production of around 0.6m b/day.

The quota controls in total, as they stand before today's announcement, can be seen in the table below:

OPEC-12 Quotas, production and Current Compliance

Source: Bloomberg, Guinness Asset Management estimates

	Oct 2016	Jan 2017 quota	May 2018		
(m b/day)	mn b/d	mn b/d	mn b/d	vs quota	Compliance
Saudi	10.54	10.05	10.01	-0.04	108%
Iran	3.70	3.79	3.81	0.02	122%
Iraq	4.56	4.35	4.48	0.13	38%
UAE	3.01	2.87	2.87	0.00	100%
Kuwait	2.84	2.71	2.71	0.00	100%
Venezuela	2.07	1.97	1.44	-0.53	630%
Angola	1.75	1.66	1.53	-0.13	244%
Algeria	1.09	1.04	1.02	-0.02	140%
Qatar	0.65	0.62	0.60	-0.02	167%
Gabon	0.20	0.19	0.20	0.01	0%
Ecuador	0.55	0.52	0.52	0.00	100%
OPEC-12	**31.0**	**29.8**	**29.2**	**-0.58**	**149%**

The announcement is straightforward in one sense, recommending a return to 100% compliance, but it does not attempt to allocate future production increases across member countries. We believe that only Saudi Arabia, Kuwait, the UAE and Iraq hold individual spare capacity of more than 100k b/day, therefore these countries will be the ones to increase production. While this can be delivered in the near term, it does use up available spare capacity.

A group of non-OPEC countries also promised production cuts at the start of 2017, totalling just under 0.6m b/day. After OPEC's announcement, the 4th OPEC and non-OPEC Ministerial Meeting was held and concluded with a commitment to "strive to adhere to overall conformity". We believe that this means that Russia will increase production in the second half of 2018 although no official figures were presented. Overall, we believe that a reasonable share of the original cuts have been achieved via natural production decline rather than voluntary reduction and we note that, as a group, these countries delivered only 75% compliance on their quota cuts in May 2018.

Non-OPEC Quotas, production and Current Compliance

Source: Bloomberg, Guinness Asset Management estimates

	Oct 2016	Jan 2017 quota	May 2018		
(m b/day)	mn b/d	mn b/d	mn b/d	vs quota	Compliance
Russia	11.23	10.93	10.97	0.04	87%
Mexico	2.14	2.04	1.90	-0.14	235%
Azerbaijan	0.76	0.72	0.69	-0.04	200%
Khazakhstan	1.65	1.63	1.84	0.21	-940%
Oman	1.01	0.97	1.01	0.03	18%
Others *	1.00	0.95	0.98	0.03	45%
Non-OPEC	**17.8**	**17.2**	**17.4**	**0.14**	**75%**

*Bahrain, Brunei, Malaysia, Sudan and South Sudan

OPEC's current stance towards the global oil market

OPEC's current stance towards the oil market was best characterised by OPEC President Suhail Mohamed Al Mazrouei's introductory remarks. In them, he re-iterated OPEC's commitment to a balanced market, but also to keep the oil price sufficiently high to incentivise longer term investments. Below is a selection of his comments, with our highlighting:

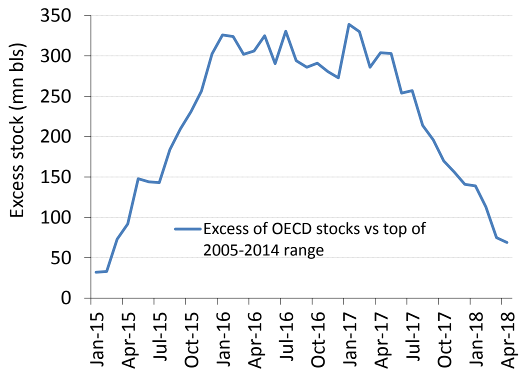
- On the oil market recovery *"Since the last Meeting of the Conference in late November 2017, the oil* *market situation has further improved. The global economy is strong, oil demand remains robust, the market is evidently rebalancing, and the return of more stability has been welcomed by all stakeholders."*

- On providing stability and guardianship *"Our focus today is on reviewing all the market fundamentals to help better understand the market balance and stability we all desire, in the interests of producers, consumers and the global economy. We fully appreciate and take on board the viewpoints and concerns of all industry stakeholders. We are watchful, responsive and fully committed to market stability and global energy security…. we need to continue to tread carefully; none of us want to see the return of the kind of volatility that allows pessimism to return to the markets"*

- On future investments to ensure a balanced market *"So far in 2018, the pace of investment has gradually picked up, but we are still not seeing enough robust investment in long-cycle projects. To put this into some perspective, in the period to 2040, the required global oil sector investment in OPEC's World Oil Outlook is estimated to be $10.5 trillion, with oil demand set to surpass 111 million barrels a day by 2040… It is also important to remember that investments are not only about boosting new production. Oil producers also need to account for natural decline rates… Every effort should be made to avoid a potential supply gap that could present a future serious challenge."*

Why have OPEC raised production?

The production cuts put in place by OPEC at the start of 2017 were designed to tighten an oversupplied market and raise oil prices from depressed levels. The cuts took around six months to feed into the physical market, with market tightness emerging in the second half of 2017 and first half of 2018. OECD oil and product inventories, which were sitting around 300m barrels above normal (an excess of around 12%), have declined to around 60m barrels above normal. This coincided with the Brent oil price rallying from around $50/bl twelve months ago to around $80/bl at the end of May.

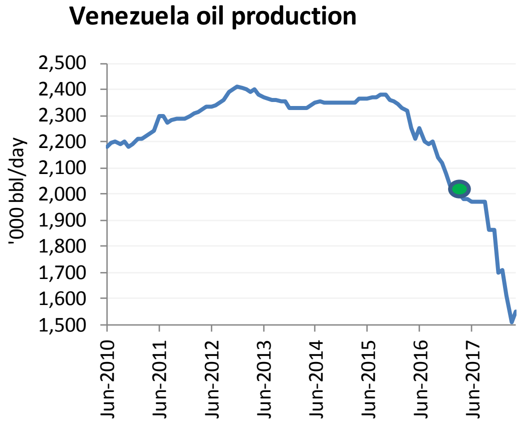


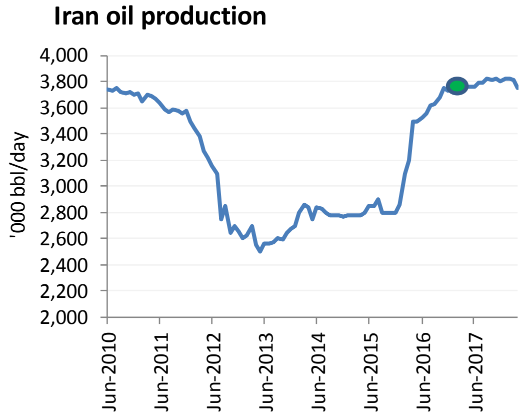
Source: IEA; Guinness Asset Management

When the 2017 production framework was established, OPEC were relying on the discipline of their own members in adhering to the 1.2m b/day production cuts. That production discipline has been evident throughout, with members rationally embracing the trade-off of lower volumes for higher oil prices which has resulted in much stronger revenues. 0.6m b/day of cuts were promised by non-OPEC countries in support of OPEC's actions, and in practice, we saw around 0.4m b/day of these cuts come through, led by a Russian cut of 0.25m b/day. OPEC would also have been optimistic about oil demand in 2017 and 2018, and that optimism has been rewarded, with healthy demand growth of around 1.5m b/day expected in both years. Meanwhile, the US oil system is growing year-on-year by around 1.2m b/day, a level of growth anticipated by OPEC given where oil prices have been.

So far, so good. Since the start of 2018, however, we have seen two OPEC 'wildcards' muddy this picture, one being an actual reduction in supply from Venezuela, the other being the likelihood of lower supply from Iran. In addition, Since the OPEC meeting we have also seen further disruption in oil production from Libya and questions over the sustainability of production from that country.

- In Venezuela, production has fallen to an average of 1.5m b/day, nearly 0.5m b/day less than their quota of 1.97m b/day. Infrastructure issues, weak reservoir management, poor quality control and poor relations with foreign service partners have all contributed to the decline, and there seems little prospect of an improvement in the short-term.
- In Iran, President Trump's decision to remove sanction waivers in relation to the country's nuclear program, will effectively block Iranian exports to countries that do business with the US. The impact on Iranian oil exports remains unclear, but using previous sanctions as a guide, we expect a decline of at least 0.5m b/day (versus current exports of just over 2m b/day).
- In Libya, we see continued civil unrest which has started to impact oil export infrastructure again. While potentially only temporary, the loss of 0.5mnb/d of production in the second half of 2018 would be very poorly timed.





Green dot = OPEC quota cut, 1 Jan 2017

Source: Bloomberg; Guinness Asset Management

From a supply perspective, the most recent news from both Venezuela and Iran is not encouraging. In Venezuela, national oil company PDVSA notified eight international customers that it will not be able to meet its full supply commitments for June, falling well short of the 1.5m b/day PDVSA is obligated to supply. The export picture from Iran remains far from clear, but recent indications suggest that various Asian importers (e.g. India), who supported Iranian crude during the previous round of sanctions, are likely now to bow to US pressure to reduce consumption from Iran. We have also seen European refiners fully wind down their purchases of Iranian crude. This implies that the overall decline in Iranian oil exports may be worse than first anticipated.

Indeed, Saudi oil minister Al-Falih commented on the morning of the OPEC meeting that without any action, the world was facing an oil supply deficit of 1.8m b/day in the second half of 2018.

The Saudi/OPEC game plan

In the face of a much tighter oil market than expected at the start of 2018, OPEC are therefore starting the unwinding that was always promised, but previously signalled for 2019. Indeed, Saudi already indicated its commitment to supporting the stability of oil markets immediately after the U.S. decision in May to withdraw from the Iran nuclear deal, with Saudi's energy ministry making the following statement: "The kingdom will work with major producers and consumers within and outside OPEC to curb the effects of any supply shortages".

What to make of this? We continue to think that Saudi are managing the oil price in a rational fashion. On the one hand, the IMF still forecasting Saudi requiring oil price of $70+ /bl in 2018 in order to close their fiscal deficit to zero. An IPO or private sale of 5% of Saudi Aramco is also still planned: we estimate that the targeted $100bn proceeds can only be achieved at an assumed long-term oil price of $70. These factors underpin Saudi's efforts over the last twelve months to bring Brent back above $70/bl. However, Saudi are also well aware of the risks of over-stimulating non-OPEC supply (especially shorter cycle US shale oil), whilst also the dangers to oil demand growth posed by too sharp an oil price increase.

An increase in OPEC production is therefore logical, and we see it in the interests of energy investors, who we think are best served by a flattening of the oil curve: near-term oil prices stabilising to ensure that there is no oil shock to the world economy, whilst longer dated oil prices firm up, in recognition of the supply challenges caused by chronic underinvestment in non-OPEC outside the US.

Overall, we believe that Saudi/OPEC's long-term objective remains to maintain a 'good' oil price, higher than the current oil futures curve is indicating, and managing the unwinding of OPEC's production quotas is another step on that journey.

Implications of OPEC's actions for oil prices and equities

Consistent with OPEC's longer term plan, we believe that long run oil prices will return to a $60-70/bl range. This is a price which is sufficient for world oil demand and US shale oil to grow while also providing acceptable economics for OPEC countries and sufficient profitability for investment in new oil projects around the world. This would be a 'reasonable' oil price level for all constituents of the global oil market, economic and political.

Today, assuming operating and capital costs are held constant, we calculate that our portfolio of energy equities currently offers fair value assuming a long term Brent oil price in the mid to high $50s (i.e. about $5 or so below where long dated Brent oil prices currently are). Looking out two years, while we see downside risk of about 10% if energy equities were to factor in $50/bl long-term and we see around 30% upside at a $60 /bl and more like 60% upside at a $70/bl oil price.

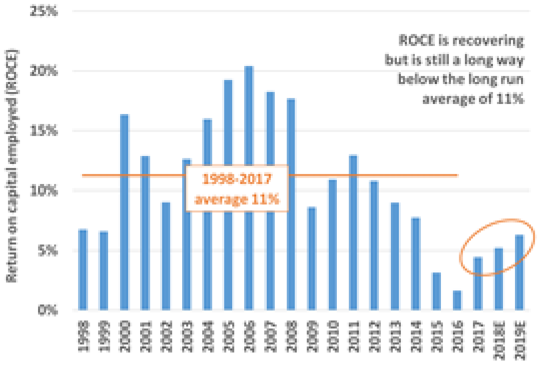
While forecasting oil prices is inherently difficult, we are comfortable that we are seeing positive results from energy companies' recent efforts to control operating and capital costs in order to improve profitability. Our preferred method for monitoring longer term profitability is Return on Capital Employed (ROCE) while we use Free Cash Flow Return on Capital Employed (FCF Return) as our preferred measure of near term profitability movements.

- ROCE is recovering from a low of 2% in 2016 to around 5% in 2018. The long run average for our portfolio is around 11% and we see good reason to believe that profitability will return to around the long run average level, just as it did after 1998 when oil prices last hit a bottom. It takes time for ROCE to improve but we have increasing confidence that this will happen.

- We are comfortable with this because the FCF return has rebounded sharply and is now at above average levels (based on only $55/bl crude oil prices). This is a pre-cursor for improving ROCE.

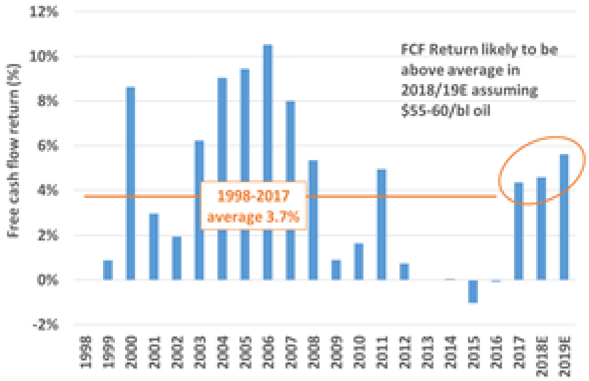
ROCE is recovering but still at a low level

Source: Bloomberg, Guinness Asset Management estimates



FCF Return has recovered sharply

Source: Bloomberg, Guinness Asset Management estimates



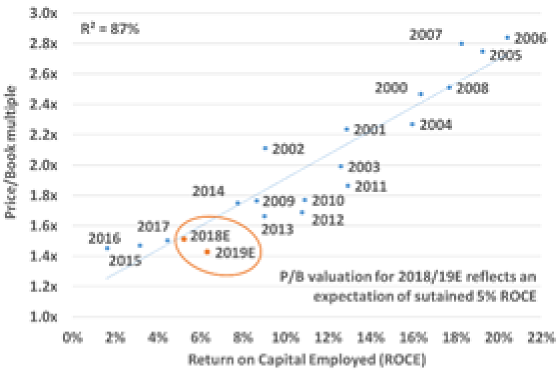
The stock market has historically valued energy companies based on their sustainable levels of profitability (generally a combination of both ROCE and FCF Return) whether it is delivered by self-help improvements or via increases in the long term oil price.

- Current valuation implies that the ROCE of our companies will not improve from the current level. If ROCE improves to 11% and the market were to pay for it sustainably, it would imply an increase in the equity valuation of around 35%.

- Current valuation implies that the FCF Return of the portfolio will fall considerably from current levels. If FCF Return maintains these levels, and the market paid for it sustainably, it would imply an uplift in equity valuation of 40%. Currently, the market remains sceptical that the energy companies will sustain their capital discipline and free cash flow generation.

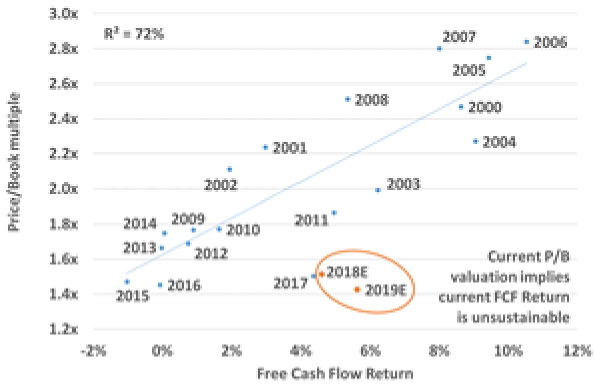
Energy equities are priced as if their ROCE stays at this low level forever

Source: Bloomberg, Guinness Asset Management estimates



Energy equity valuation implies that current FCF Return will not be sustained

Source: Bloomberg, Guinness Asset Management estimates



Ultimately, we see rising profitability for the Guinness Global Energy portfolio stemming from a combination of higher long dated oil prices and sustained capital discipline. After a long period of underperformance relative to the broad market, we see energy equities continuing to play catch-up.

Conclusion

We see the June 22nd announcement from OPEC (and subsequent announcement from non-OPEC partners) as another logical step towards rebalancing the market and sustaining an oil price that satisfies OPEC's own economics needs as well as balancing the supply and demand outlook. The threat of further production issues from Venezuela, Iran and Libya highlights how tight the oil market could become in the second half of 2018. Should OPEC be successful, we believe that it will supportive of the free cash flow generation and profitability for the companies in the Guinness Global Energy portfolio.

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 June, while the MSCI World Index was flat. The Fund was up by 1.3% (class E) in the month, performing in line with the MSCI World Energy index (all in US dollar terms).

Within the Fund, June's strongest performers were Enbridge, Apache, Anadarko, Devon Energy and Helix Energy Solutions, while the weakest performers were PetroChina, Soco International, Halliburton, SunPower and Valero.

Performance (in USD) 30/06/2018

Annualised

% returns	1 year	3 years	5 years	10 years	1999 to date
Guinness Global Energy	29.2	1.6	-0.2	-2.9	10.6
MSCI World Energy Index	25.0	5.7	2.9	0.0	7.5

Calendar year

% returns	2018	2017	2016	2015	2014	2013	2012	2011	2010	2009	2008	2007
Guinness Global Energy	10.4	-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	7.0	5.9	27.6	-22.1	-11.0	18.8	2.5	0.7	12.5	27.0	-37.7	30.4

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

We made no stock switches during the month but did rebalance the portfolio.

Sector Breakdown

The following table shows the asset allocation of the Fund at **June 30 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	30 June 2018	*Chg YTD*
Oil & Gas	***98.2***	***93.3***	***97.9***	***97.3***	***93.7***	***93.7***	***95.1***	***96.7***	***98.4***	***97.3***	***-1.1***
Integrated	35.9	33.0	30.9	30.4	29.2	27.0	30.4	32.5	28.6	24.7	*-3.9*
Integrated – Can & Em Mkts	11.9	8.2	8.8	8.4	9.4	10.3	11.1	14.3	14.2	14.5	*0.3*
Exploration & production	32.8	37.1	41.1	40.3	35.4	36.2	36.5	35.4	37.0	39.9	*2.9*
Oil & Gas Storage & Transportation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.5	4.0	*0.5*
Drilling	8.5	6.1	5.9	7.1	6.4	3.3	1.5	2.2	1.9	1.8	*-0.1*
Equipment & services	5.9	5.4	6.1	7.4	9.8	13.4	11.4	8.6	9.5	8.9	*-0.6*
Refining and marketing	3.2	3.5	5.1	3.7	3.5	3.5	4.2	3.7	3.7	3.5	*-0.2*
Solar	**0.0**	**3.2**	**1.3**	**1.2**	**2.6**	**3.7**	**4.7**	**0.9**	**1.4**	**1.2**	***-0.2***
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**	**1.6**	***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 June 30 2018 was on a price to earnings ratio (P/E) for 2018 of 14.4x versus the S&P 500 Index at 17.3x as set out in the following table:

	2011	2012	2013	2014	2015	2016	2017	2018
Guinness Global Energy Fund P/E	8.8	9.1	9.8	9.2	22.5	39.2	25.2	14.4
S&P 500 P/E	28.1	27.9	25.2	23.3	26.9	25.5	21.7	17.3
Premium (+) / Discount (-)	*-69%*	*-67%*	*-61%*	*-61%*	*-16%*	*54%*	*16%*	*-17%*
Average oil price (WTI $/bbl)	95	94	98	93	49	43	51	65

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

Portfolio holdings

Our integrated and similar stock exposure (c.43%) 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 and OMV. At April 30 2018 the median P/E ratios of this group were 19.5x/13.9x 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.36%) 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 five other names (Apache, Occidental, ConocoPhillips, Noble, 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 3.0x 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 May 31st 2018 (for compliance reasons disclosed one month in arrears)

Guinness Global Energy Fund 31 May 2018													
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
Integrated Oil & Gas													
Chevron	USD	US	3.51	24.2	13.3	9.2	10.1	11.2	12.9	34.2	89.6	30.0	16.3
Royal Dutch Shell PLC	EUR	NL	3.48	15.9	11.3	8.4	8.3	10.9	9.7	20.4	33.6	18.2	12.9
BP PLC	GBP	GB	3.58	9.9	6.8	6.8	8.5	10.5	12.5	22.0	42.1	25.1	15.2
Total SA	EUR	FR	3.49	14.6	11.3	10.1	9.7	10.8	11.0	14.1	16.6	15.5	12.1
ENI SpA	EUR	IT	3.25	10.9	8.2	7.9	7.7	12.3	14.4	67.1	nm	27.1	14.3
Statoil ASA	NOK	NO	3.57	15.3	11.5	10.0	8.9	10.9	15.1	37.1	188.2	19.6	14.8
OMV AG	EUR	AT	3.26	19.8	12.3	15.4	10.8	13.3	16.3	14.6	14.9	10.0	9.7
			24.13										
Integrated / Oil & Gas E&P - Canada													
Suncor Energy Inc	CAD	CA	3.70	48.9	32.6	14.5	16.1	16.2	16.1	45.9	nm	27.7	16.4
Canadian Natural Resources Ltd	CAD	CA	3.31	18.6	18.5	19.4	28.2	20.0	13.0	322.9	nm	38.2	14.3
Imperial Oil	CAD	CA	3.70	21.4	18.5	11.5	10.2	13.2	11.1	23.8	70.5	33.1	16.2
			10.71										
Integrated Oil & Gas - Emerging market													
PetroChina Co Ltd	HKD	HK	3.85	8.9	7.2	7.0	8.1	9.0	8.9	27.6	108.1	42.0	17.0
Gazprom OAO	USD	RU	3.50	5.1	4.0	2.7	2.8	2.6	4.4	2.7	3.8	4.3	3.4
			7.35										
Oil & Gas E&P													
Occidental Petroleum Corp	USD	US	3.60	22.6	14.9	10.1	12.1	12.1	14.5	507.2	nm	93.8	19.0
Anadarko Petroleum Corp	USD	US	3.63	nm	40.3	22.1	20.9	16.8	15.3	nm	nm	nm	25.2
ConocoPhillips	USD	US	3.62	18.6	11.4	7.9	11.8	12.0	12.7	nm	nm	108.2	17.8
Apache Corp	USD	US	3.43	7.2	4.3	3.4	4.2	4.9	7.1	nm	nm	377.4	23.3
Devon Energy Corp	USD	US	3.66	12.7	7.0	6.9	12.9	9.8	8.1	16.9	nm	22.7	26.1
Noble Energy Inc	USD	US	3.68	21.1	17.2	13.6	15.6	11.5	15.3	626.3	nm	2231.3	32.3
QEP Resources Inc	USD	US	1.86	nm	8.7	7.4	9.7	8.7	8.6	nm	nm	nm	nm
Newfield Exploration Co	USD	US	3.53	5.8	6.3	7.2	12.0	16.3	15.8	40.3	27.2	13.6	8.7
Oasis Petroleum Inc	USD	US	2.20	nm	77.6	15.8	8.8	4.7	5.3	16.4	nm	nm	33.2
			29.21										
International E&Ps													
CNOOC Ltd	HKD	HK	3.47	15.9	9.2	7.0	7.4	7.6	9.1	27.1	nm	15.7	9.4
Tullow Oil PLC	GBP	GB	1.84	52.0	25.2	5.8	5.2	38.8	nm	nm	nm	17.6	12.3
Soco International PLC	GBP	GB	0.75	8.4	11.6	7.5	2.1	2.2	3.4	nm	nm	nm	31.9
			6.05										
Midstream													
Enbridge Inc	USD	CA	3.43	46.2	39.8	35.9	33.1	30.5	28.0	25.3	23.4	28.4	22.3
			3.43										
Drilling													
Unit Corp	USD	US	1.58	8.3	7.2	5.3	5.3	5.9	5.1	nm	nm	41.1	24.2
			1.58										
Equipment & Services													
Halliburton Co	USD	US	3.29	38.0	24.7	14.9	16.7	16.0	12.6	33.7	nm	42.8	20.1
Helix Energy Solutions Group Inc	USD	US	1.56	13.1	14.4	5.1	4.1	7.1	3.9	45.0	nm	nm	51.0
Schlumberger Ltd	USD	US	3.46	25.3	24.9	19.0	16.4	14.4	12.4	20.5	59.5	47.0	33.3
			8.31										
Solar													
JA Solar Holdings Co Ltd	USD	US	0.81	nm	1.0	nm	nm	nm	7.9	4.0	9.4	12.5	23.3
Sunpower Corp	USD	US	0.50	7.3	5.8	102.3	55.9	6.0	6.4	4.3	nm	nm	nm
			1.31										
Oil & Gas Refining & Marketing													
Valero Energy Corp	USD	US	3.79	nm	76.4	30.5	24.8	29.5	19.9	13.8	33.0	24.9	16.7
			3.79										
Research Portfolio													
Cluff Natural Resources PLC	GBP	GB	0.29	nm	nm	nm	nm	nm	nm	nm	nm	nm	nm
EnQuest PLC	GBP	GB	0.64	nm	5.3	6.1	1.8	2.0	3.8	36.1	2.4	nm	5.5
JKX Oil & Gas PLC	GBP	GB	0.13	0.9	1.0	1.2	1.6	3.1	8.4	nm	nm	nm	42.2
Ophir Energy PLC	GBP	GB	0.03	nm	nm	nm	nm	nm	2.3	nm	nm	nm	23.5
Reabold Resources PLC	GBP	GB	0.30	nm	nm	nm	nm	nm	nm	nm	nm	nm	nm
Shandong Molong Petroleum Machiner	HKD	HK	0.05	7.1	2.8	3.9	nm	nm	nm	nm	nm	nm	nm
Sino Gas & Energy Holdings Ltd	AUD	AU	0.33	nm	nm	nm	179.2	nm	179.2	nm	nm	nm	nm
			1.78										
		Cash	2.34										
		Total	100										
		PER		15.7	10.2	8.8	9.1	9.8	10.7	22.5	39.2	25.2	15.0
		Med. PER		15.3	11.4	8.1	9.9	10.9	11.1	26.2	33.0	27.4	17.0
		Ex-gas PER		17.1	11.2	9.6	9.3	10.4	11.3	21.3	35.3	24.1	14.4

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
														IEA	*IEA*
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*	*96.2*	*97.8*	*99.1*
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*	*57.6*	*59.7*
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 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	58.2	60.3
Gabon/E Guinea supply adjustment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.3
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*	*6.9*
Non-OPEC supply plus OPEC NGLs plus Gabon/E Guinea (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	65.4	67.5
Call on OPEC-12[3]	28.5	30.1	30.6	31.7	31.4	29.0	30.3	30.8	31.0	31.1	30.1	30.3	32.0	32.4	31.6

[1]Angola joined OPEC at the start of 2007, Ecuador rejoined OPEC at the end of 2007 (having previously been a member in the 1980s)
[2]Indonesia left OPEC as of the start of 2009; rejoined at start of 2016, 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: June 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 1.3m b/day in 2018, which would take oil demand to an all-time high of 99.1m 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:

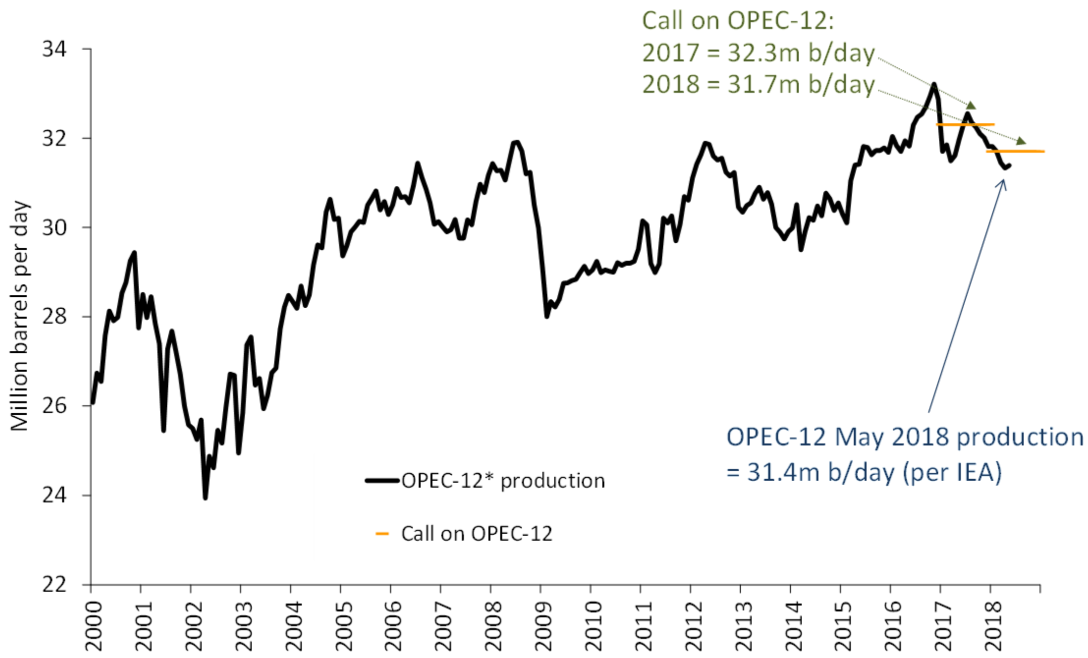
('000 b/day)	31-Dec-10	30-Nov-14	31-Dec-16	31-May-18	Current vs Dec 2010 (start of Arab Spring)	Current vs Nov 2014 (OPEC hold mkt share)	Current vs Dec 2016 (OPEC cut production)
Saudi	8,250	9,650	10,480	**10,010**	1,760	360	-470
Iran	3,700	2,780	3,730	**3,810**	110	1,030	80
Iraq	2,385	3,370	4,630	**4,480**	2,095	1,110	-150
UAE	2,310	2,800	3,070	**2,870**	560	70	-200
Kuwait	2,300	2,790	2,860	**2,710**	410	-80	-150
Nigeria	2,220	1,970	1,500	**1,620**	-600	-350	120
Venezuela	2,190	2,350	2,080	**1,440**	-750	-910	-640
Angola	1,700	1,640	1,670	**1,530**	-170	-110	-140
Libya	1,585	580	630	**990**	-595	410	360
Algeria	1,260	1,100	1,110	**1,020**	-240	-80	-90
Qatar	820	650	620	**600**	-220	-50	-20
Ecuador	465	561	550	**520**	55	-41	-30
OPEC-12	**29,185**	**30,241**	**32,930**	**31,600**	**2,415**	**1,359**	**-1,330**

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 onshore) projects reaching production.

Figure 7: OPEC-12 apparent production vs call on OPEC 2000 – 2018



Source: IEA Oil Market Report (May 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 was 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 were subsequently extended to the end of 2018. 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.

OPEC showed clear intention to end the production cuts in a manner that was consistent with maintaining a balanced market. And in June 2018, with Brent oil averaging around $75/bl and OPEC compliance to the agreed production cuts running at just over 150%, OPEC met in Vienna. At the conclusion of their meeting, OPEC's headline announcement was "to strive to adhere to the overall conformity level of OPEC-12, down to 100%, as of 1 July 2018". Details were skant but we interpret the announcement as implying an increase in production of around 0.6m b/day. Some non-OPEC members, led by Russia, are expected to increase production as well, taking the potential increase in overall OPEC and non-OPEC volumes potentially as high as 1m b/day for the second half of 2018.

The meeting confirmed that OPEC remain committed 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 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 $60 world are far lower than in a $100 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 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 1.6m b/day, and they expect a further increase of 1.3m 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 1.0m b/day and OECD demand growth of 0.3m b/day. The components of this non-OECD demand growth can be summarised as follows:

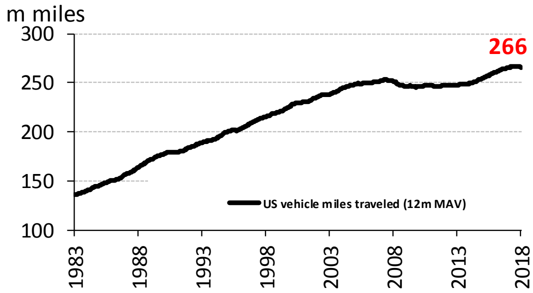
Figure 8: Non-OECD oil demand

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	26.6	1.1	0.7	0.7	1.2	0.8	1.0	0.8
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	6.5	0.2	0.3	0.1	-0.1	-0.1	0.0	-0.1
FSU	4.4	4.6	4.7	4.66	4.6	4.7	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**	**51.4**	**2.2**	**1.3**	**1.2**	**1.2**	**1.0**	**1.1**	**1.0**

Source: IEA Oil Market Report (June 2018)

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 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 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 1.2m 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 2017.

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	64
Brent	30	32	35	46	64	75	82	103	67	84	115	112	108	99	52	45	54	68
Brent/WTI (12m MAV)	**30**	**33**	**37**	**48**	**65**	**75**	**82**	**104**	**68**	**84**	**107**	**103**	**103**	**96**	**51**	**45**	**53**	**66**
Brent/WTI y-on-y change (%)		8%	12%	30%	37%	15%	9%	26%	-35%	24%	27%	-4%	0%	-7%	-47%	-11%	17%	26%
Brent/WTI (5yr MAV)	30	25	32	37	42	51	61	75	79	82	89	93	93	99	92	80	69	62

We expect oil to trade in a $55-70/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 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. 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 21.6 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	25.3	26.9
Industrial	18.2	18.2	16.9	18.5	19.0	19.7	20.3	20.9	20.6	21.1	21.6	22.2
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
LNG exports	-	-	-	-	-	-	-	-	0.1	1.0	2.6	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	6.5	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**	**87.6**
Demand growth	**4.0**	**0.8**	**- 0.6**	**3.2**	**2.5**	**3.0**	**1.8**	**0.9**	**3.0**	**2.6**	**0.5**	**4.5**

Source: EIA; Simmons; Guinness estimates

Total gas demand in 2017 (including Canadian, Mexican and LNG exports) was 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 rose significantly this year (+2 Bcf/day), but 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.

US demand outlook

We expect US demand in 2018, assuming prices remain around $3/mcf, to exhibit strong growth of around 4.5 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 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.

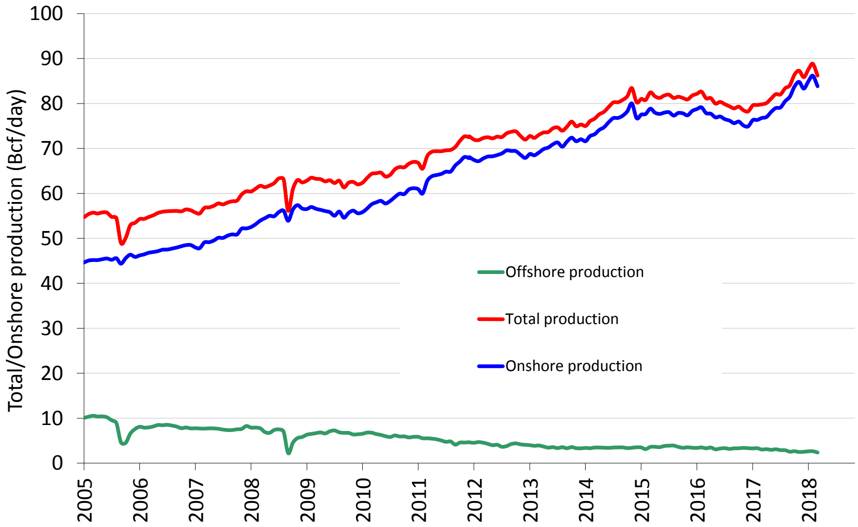
The supply side fundamentals for natural gas in the US are driven by 3 main moving parts: onshore and offshore domestic production, and pipeline imports of gas from Canada. Of these, onshore supply is the biggest component, making up over 85% of total supply.

Bcf/day	2007	2008	*2009*	2010	2011	2012	2013	2014	2015	2016	2017	2018E
US natural gas supply:												
US onshore	45.1	48.8	49.8	52.2	57.7	61.5	62.7	67.5	70.6	69.4	70.4	77.3
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	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	0.4
Total supply	**65.5**	**66.1**	**66.9**	**68.8**	**72.2**	**74.5**	**74.4**	**78.5**	**81.8**	**81.2**	**81.9**	**88.9**
Supply growth	**3.2**	**0.6**	**0.8**	**1.9**	**3.4**	**2.3**	**-0.1**	**4.1**	**3.3**	**-0.6**	**0.7**	**7.0**

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 187 at the end of June 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 86.6 Bcf/day, 29.2 Bcf/day (over 50%) 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 (April 2018 published in June 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.

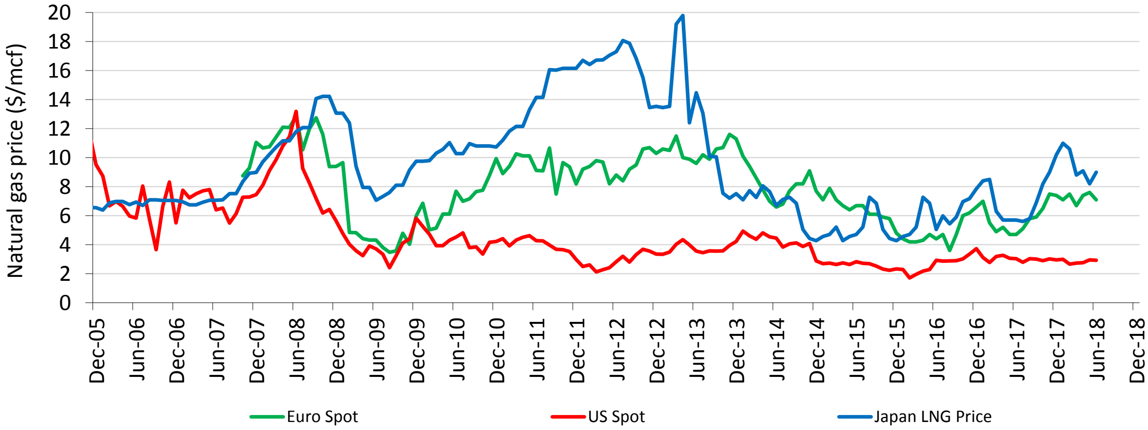
Associated gas production declined in 2016 with the fall of shale oil production, but as US oil supply now growing again, so associated gas production is also picking up. Generally, we expect to see rates of around 2-3 Bcf/day of associated gas per 1m b/day of oil production.

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 7 Bcf/day versus 2017.

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.$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 $9/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.



Source: Bloomberg (June 2018)

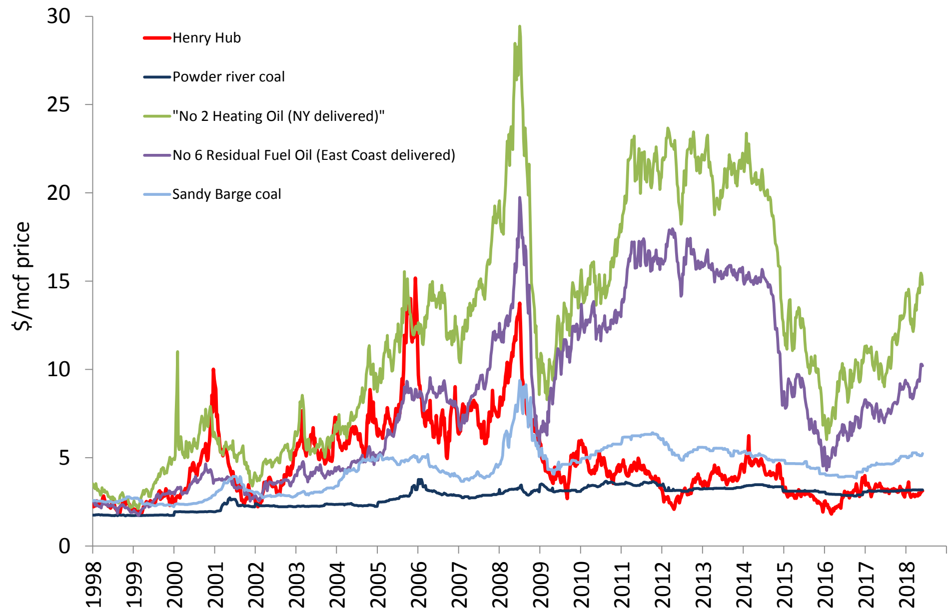
Relationship with oil and coal

The oil/gas price ratio ($ per bbl WTI/$ per mcf Henry Hub) of around 25x at the end of June 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 (June 2018)

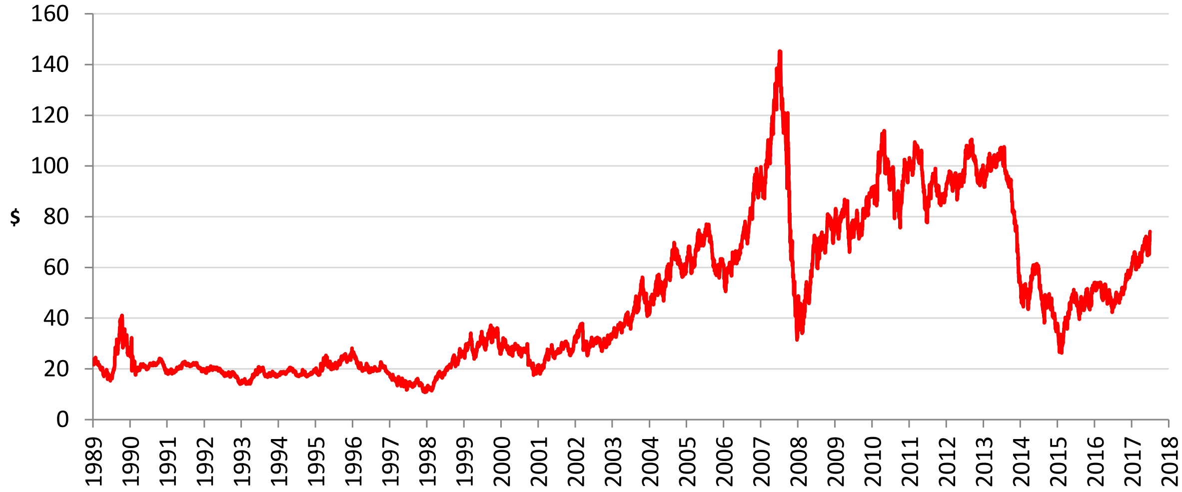
Conclusions about US natural gas

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	87.6
Demand growth	4.0	0.8	-0.6	3.2	2.5	3.0	1.8	0.9	3.0	2.6	0.5	4.5
Total supply	65.5	66.1	66.9	68.8	72.2	74.5	74.4	78.5	81.8	81.2	81.9	88.9
Supply growth	3.2	0.6	0.8	1.9	3.4	2.3	-0.1	4.1	3.3	-0.6	0.7	7.0
(Supply)/demand balance	-0.1	0.1	-1.3	-	-0.9	-0.2	1.7	-1.5	-1.8	1.4	1.2	-1.3

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 $) 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.

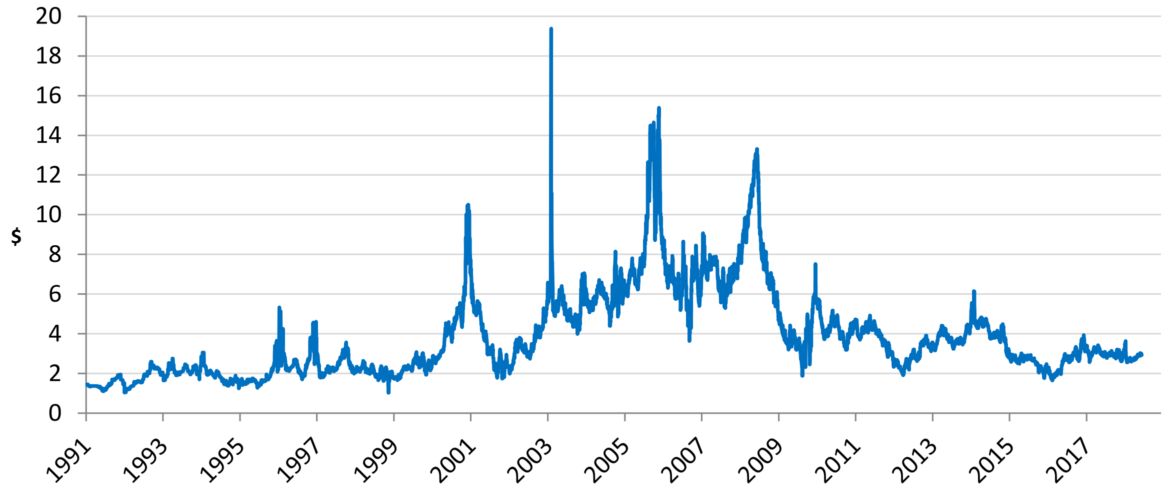
After 2005 we saw a further strong run-up in the oil price. Hurricanes Katrina and Rita, which devastated New Orleans, caused oil to spike up to $70 in August 2005, and it spiked up again in July 2006 to $78 after a three week conflict between Israel and Lebanon threatened supply from the Middle East. 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.

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 timebeing by US onshore shale supply.

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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