THE GUINNESS GLOBAL ENERGY REPORT

Developments and trends for investors in the global energy sector | September 2017

GUINNESS GLOBAL ENERGY FUND

Fund size: $283m (31.8.17)

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

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

HIGHLIGHTS FOR AUGUST

OIL

Brent flat and WTI down as Tropical Storm Harvey strikes Texas

Brent flat and WTI down over the month; WTI fell from $50 to $47/bl, whilst Brent stayed at around $52/bl. Tropical Storm Harvey reduced refining demand for WTI, causing the Brent/WTI spread to widen to $5/bl. Onshore US oil production was reported to have declined in June (latest data point), contrary to most expectations. OECD oil and product inventories down sharply in July.

NATURAL GAS

US gas prices stronger; market still structurally undersupplied

Henry Hub prices rose in August, up from $2.79 to $3.04/mcf. Topical Storm Harvey temporarily shut in around 2% of US gas supply. Weather adjusted, the US gas market remained undersupplied, which is causing gas inventories to tighten, though production continues to grow.

EQUITIES

Energy underperforms the broad market

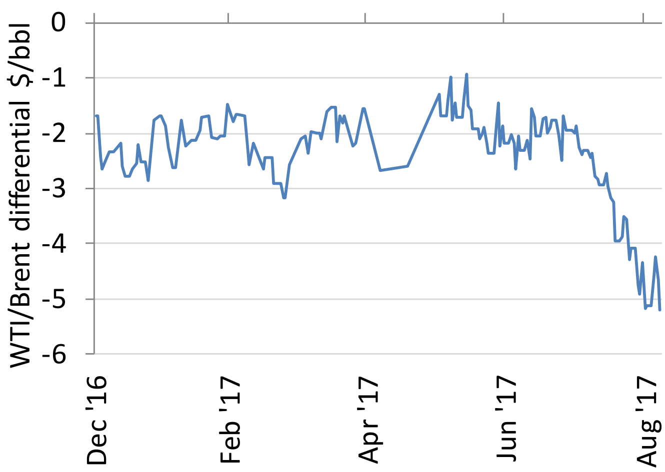
The MSCI World Energy Index fell in August by 3.3%,underperforming the MSCI World Index which rose by 0.2% (all in US dollar terms). Since the start of the year, the MSCI Energy Index is down by 9.0%, which compares to the MSCI World up by 13.9%.

CHART OF THE MONTH

Storm Harvey impacts US refining capacity, depressing WTI

At its peak, there appeared to be around 3.8m b/day of crude and condensate refining capacity in Texas that was shut-in. This represented around 21% of US refining capacity. A shortage of refining capacity has caused US gulf coast refining margins to spike higher, providing a short term boost to profitability to US refiners. It has also reduced demand for crude oil in the region, causing the spread between (local) WTI and (global) Brent oil prices to widen to over $5/bbl. We expect the differential to unwind over the next few weeks.

Brent/WTI oil price differential ($/bl) YTD



Source: Bloomberg; Guinness Asset Management

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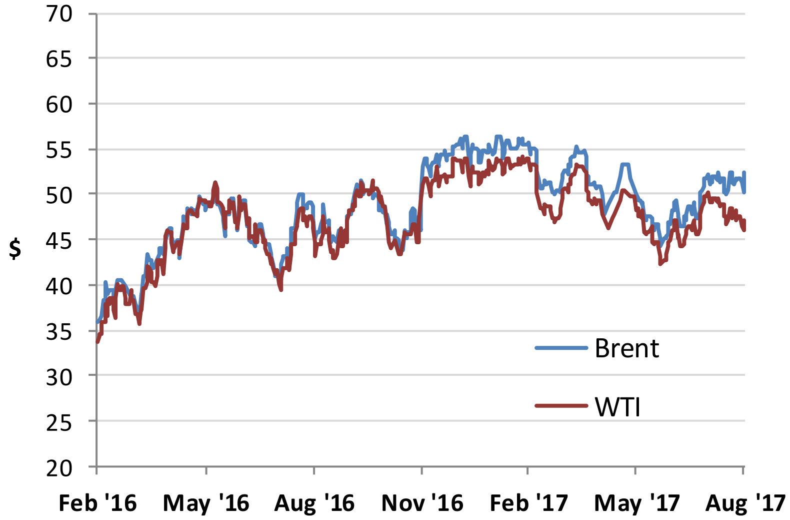
1. AUGUST IN REVIEW

i) Oil market

Figure 1: Oil price (WTI and Brent $/barrel) 18 months February 29 2016 to August 31 2017



Source: Bloomberg LP

The West Texas Intermediate (WTI) oil price started August at $50.2/bl and weakened steadily over the month to a low of $46.0/bl on August 30, before rallying slightly to close the month at $47.2/bl. WTI has averaged $49.3/bl so far in 2017, having averaged $43.4 in 2016, $48.7 in 2015 and $93.1 in 2014.

Brent oil traded more strongly, opening August at $52.2/bl, trading down to $50.3/bl and then recovering to $52.4/bl. Brent has averaged $52.3/bl so far in 2017. The gap between the WTI and Brent benchmark oil prices widened owing to the effects of Tropical Harvey, reaching just over $5/bl by the end of August, compared to around $2/bbl for the rest of the year.

Factors which weakened WTI oil prices in August:

- **Impact of Tropical Storm Harvey**
  At the end of August, Tropical Storm Harvey hit Texas, causing widespread disruption to oil & gas production and refining operations in the state. At its peak, the storm caused around 4.6m b/day of refining capacity to be taken offline, representing about 25% of the US refining capacity. At the same time, we estimate that around 0.8m b/day of oil production has temporarily been shut-in, around half of which is offshore Gulf of Mexico and half is onshore Eagleford basin production. The overall effect has been to temporarily depress the WTI oil price versus Brent, with oil production in the US struggling to find an end-market. History tells us that the outages, both production and refining, are likely to be short-lived.

- **Baseline global oil demand adjusted lower – but no impact on 2017 demand growth**
  In August, the IEA revised non-OECD demand reported for 2015, based on new analysis of the demand data used. The revision, of around 0.3m b/day, is then carried through to current demand numbers. . The 2015 revisions downgrade global demand growth in that year from 2.1m to 1.8m b/day. However, the revisions do not affect the more important statistic, being the increase in demand for 2017 versus 2016, which in fact was revised higher in August (versus the previous month) to 1.5m b/day.

Factors which strengthened WTI and Brent oil prices in August:

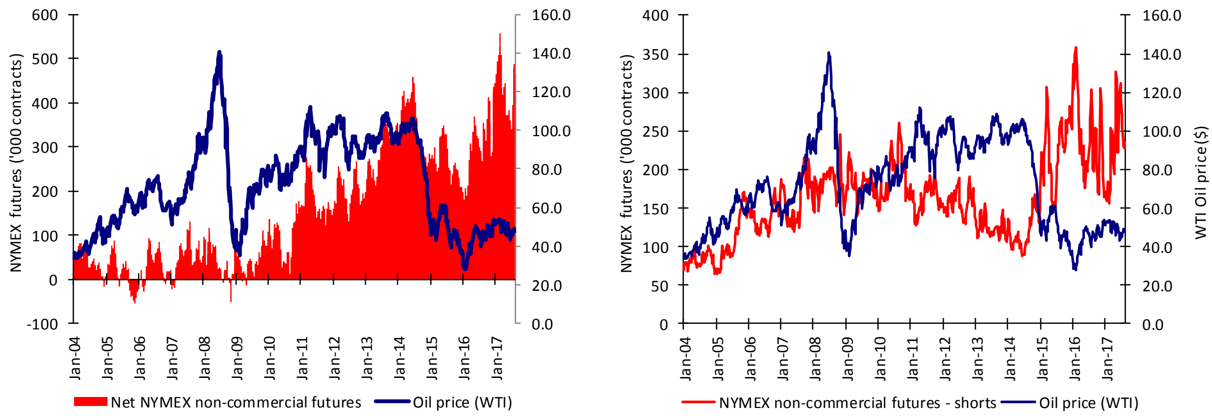
- **Unexpected decline in US onshore production in June (latest data point)**
  At the start of September, the EIA reported that US onshore oil production declined by 6,000 b/day during June 2017. This decline came contrary to the weekly production data that the EIA had previously published for June, which pointed to a substantial increase in supply. Quarterly results published by US onshore oil production has now increased by around 0.4m b/day from its low of 6.5m b/day in December 2016. We expect the US onshore production in 2017 to average around 300,000-400,000 b/day higher than 2016.

- **US oil and product inventories fell moderately in August**
  US oil and product inventories fell by 22m barrels over the four weeks reported in August, which compares to a 5-year average decline of 8m barrels. This implies that inventories tightened by around 0.5m b/day versus norms, a smaller move than that reported for July but still a step towards normalising inventories. OECD oil and product inventories for July (reported in August) also showed a tightening, with inventories falling by 8m barrels versus a seasonal build of 19m barrels. Total OECD inventories remain elevated, but we expect them to continue to decline over the remainder of 2017.

Speculative and investment flows

The New York Mercantile Exchange (NYMEX) net non-commercial crude oil futures open position (WTI) grew in August, ending the month at 445,000 contracts long versus 323,000 contracts long at the end of July. Typically there is a positive correlation between the movement in net position and movement in the oil price. The gross short position declined from 236,000 contracts to 231,000 contracts. We regard this gross short position as high but no longer extreme.

Figure 2: NYMEX Non-commercial net and short futures contracts: WTI January 2004 – August 2017

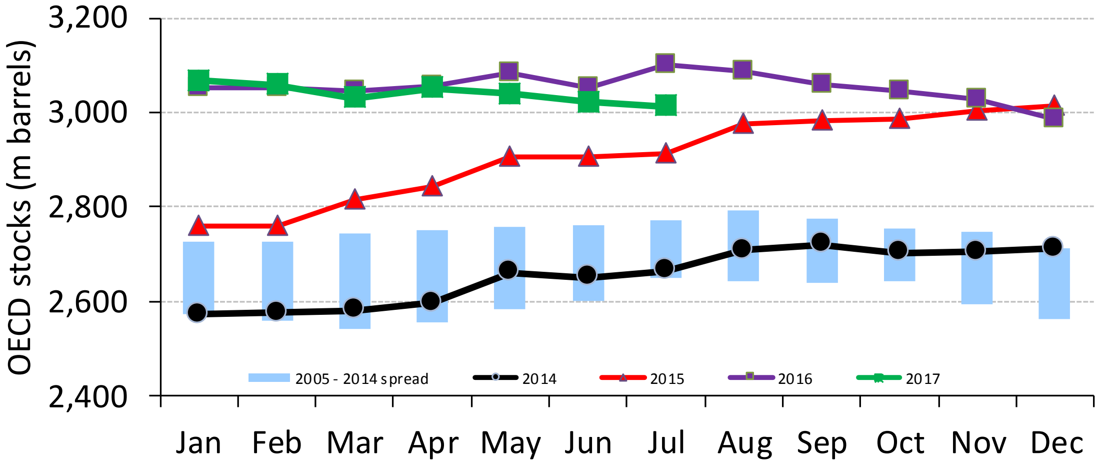


Source: Bloomberg LP/NYMEX/ICE (2017)

OECD stocks

OECD total product and crude inventories at the end of July (the latest data point available) were estimated by the IEA to be 3,013m barrels, down by 8m barrels versus the previous month. This compares to a 10-year average build for July of 19m barrels. Having been in decline over the second half of 2016, inventories loosened at the start of 2017, as a flush of pre-OPEC cut production reached the market, but are now tightening again. Inventories remain considerably above the top of the 10 year historic range, and we expect them to continue to tighten over the remainder of 2017.

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



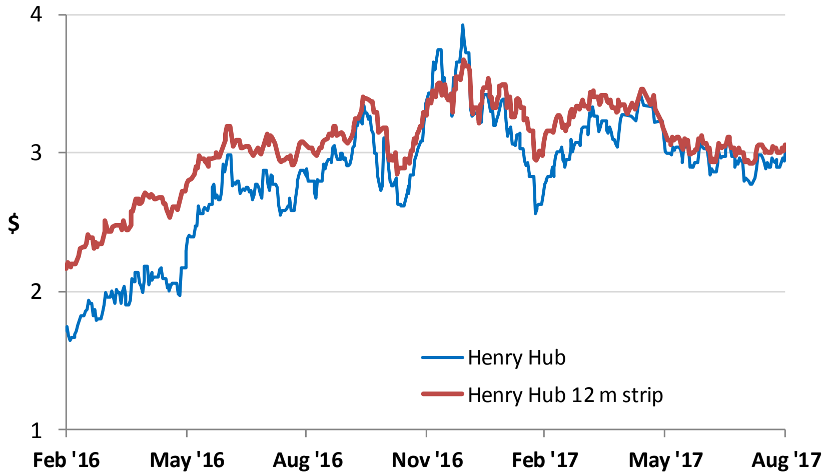
Source: IEA Oil Market Reports (August 2017 and older)

ii) Natural gas market

The US natural gas price (Henry Hub front month) opened August at \$2.79 per Mcf (1,000 cubic feet). The price rallied during the month, trading up to close at an August high of \$3.04/mcf. The spot gas price has averaged \$2.99/mcf so far in 2017, which compares to an average gas price of \$2.55/mcf in 2016, \$2.61/mcf in 2015 and \$4.26/mcf in 2014 (assisted by a very cold 2013/14 US winter). The price averaged \$3.72/mcf over the preceding four years (2010-2013).

The 12-month gas strip price (a simple average of settlement prices for the next 12 months' futures prices) also traded higher in August, up from \$2.93 to \$3.06. The strip price averaged \$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) February 29 2016 to August 31 2017



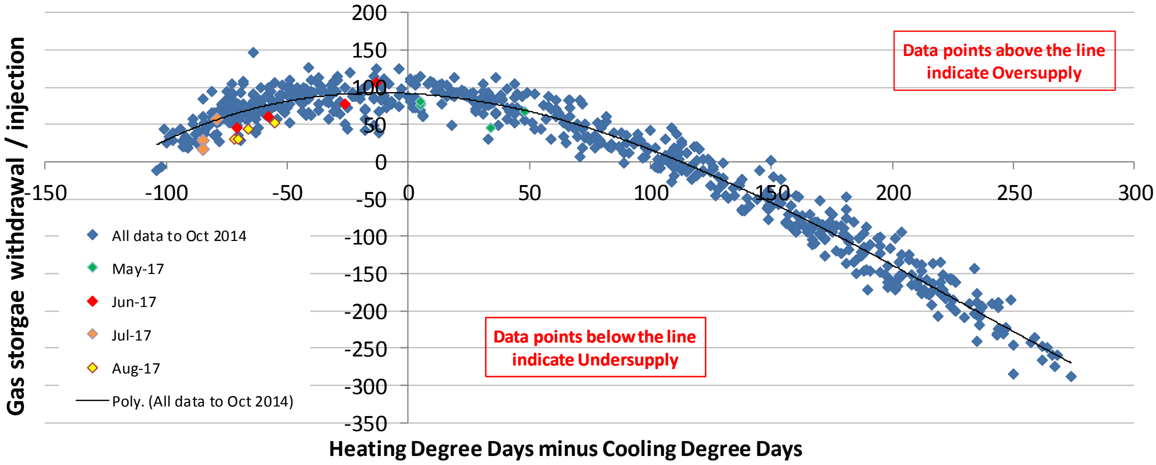
Source: Bloomberg LP

Factors which strengthened the US gas price in August included:

- **Impact of Tropical Storm Harvey**
  We believe Tropical Storm Harvey caused around 1.6 Bcf/day of natural gas production to be shut-in, representing about 2% of US gas supply. Around half of this was offshore Gulf of Mexico production (c.26% of GoM's 3.2 Bcf/day) and half onshore Eagleford production. The impact of Harvey on the US gas market has been far less than Hurricane Katrina caused in 2005. At that time, the Gulf of Mexico produced over 10 Bcf/day of gas, versus 3 Bcf/day (normally) at present.

- **Structurally undersupplied market**
  Adjusting for the impact of weather in August, the most recent injections of gas into storage suggest the market is, on average, around 3 bcf/day undersupplied (as indicated by the yellow dots on the graph below). The gas market shifted into structural undersupply in late 2015, but that has been trumped over the last 18 months by two successive warm winters which have lowered demand.

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



Source: Bloomberg LP; Guinness Asset Management

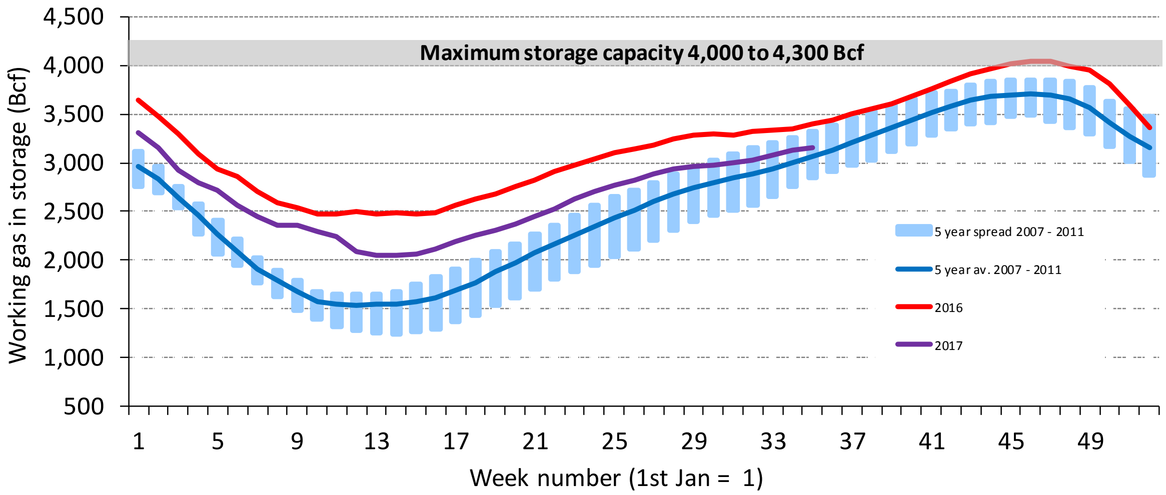
Factors which weakened the US gas price in August included:

- **Stronger US onshore natural gas production**
  Onshore US natural gas production averaged 78.4 Bcf/day in July 2017 (the latest available data point), up by 1.0 Bcf/day on the level reported for June 2017. We expect US onshore natural gas production to continue to grow in the second half of 2017, supported by rising associated gas supply from shale oil, and the increase in the natural gas rig count seen over the last 12 months.

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 supply/demand the end of August were reported by the EIA to be 3,155 Bcf. The 156 Bcf injection in inventories during August was smaller than the ten-year average of 221 Bcf, meaning that inventories tightened towards the long-term average.

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



Source: Bloomberg; EIA (August 2017)

2. MANAGER'S COMMENTS

The last two weeks have seen the greatest weather disruption to the US oil & gas system this decade, as Tropical Storm Harvey progressed over Texas. Here, we explore the impact of Harvey on oil and natural gas production, refining, demand and commodity prices.

At the end of August, we saw Tropical Storm Harvey form and cross the Gulf of Mexico, then head north across Texas and Louisiana. This took the storm through major oil & gas producing and refining territory, and caused the most significant weather disruption to the industry since Hurricance Katrina struck the region in 2005. Despite this, the lasting impact of Tropical Storm Harvey on the oil & gas sector is expected to be limited: some effects will be a few days, others a month or two but unlikely to be more. In summary, compared to the undisturbed situation, we see slightly higher Brent prices, slightly lower WTI prices, higher refining margins and unchanged natural gas prices.

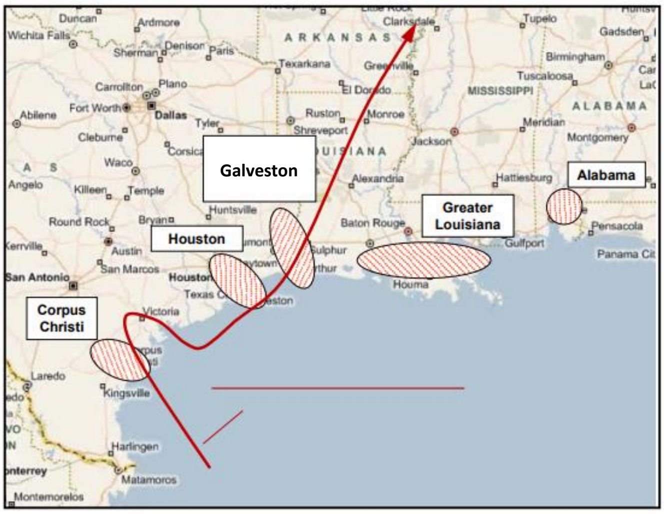
i) Oil production

We believe a total of around 0.7-0.8m b/day of oil production was shut-in at the peak of the Tropical Storm, representing around 0.8% of world oil supply. Around half of this was offshore Gulf of Mexico production (c.20% of GoM's 1.75m b/day) and half was onshore Eagleford production. As the Eagleford basin lay directly in Harvey's path, operators were been prudent in ordering mandatory staff evacuations ahead of the storm arriving. This will impact Q3 volumes for Eagleford operators and associated service companies. There has also been some damage to equipment and infrastructure, but it will not be long lasting. At the time of writing (7 Sept), production shut-ins have already been reduced to less than 0.2m b/day.

ii) Refining & demand

Tropical Strom Harvey cut a path directly through the Gulf Coast refinery system, as can been seen on the following map:

<u>Path of Tropical Storm Harvey, with major refiners centres (circled in red)</u>

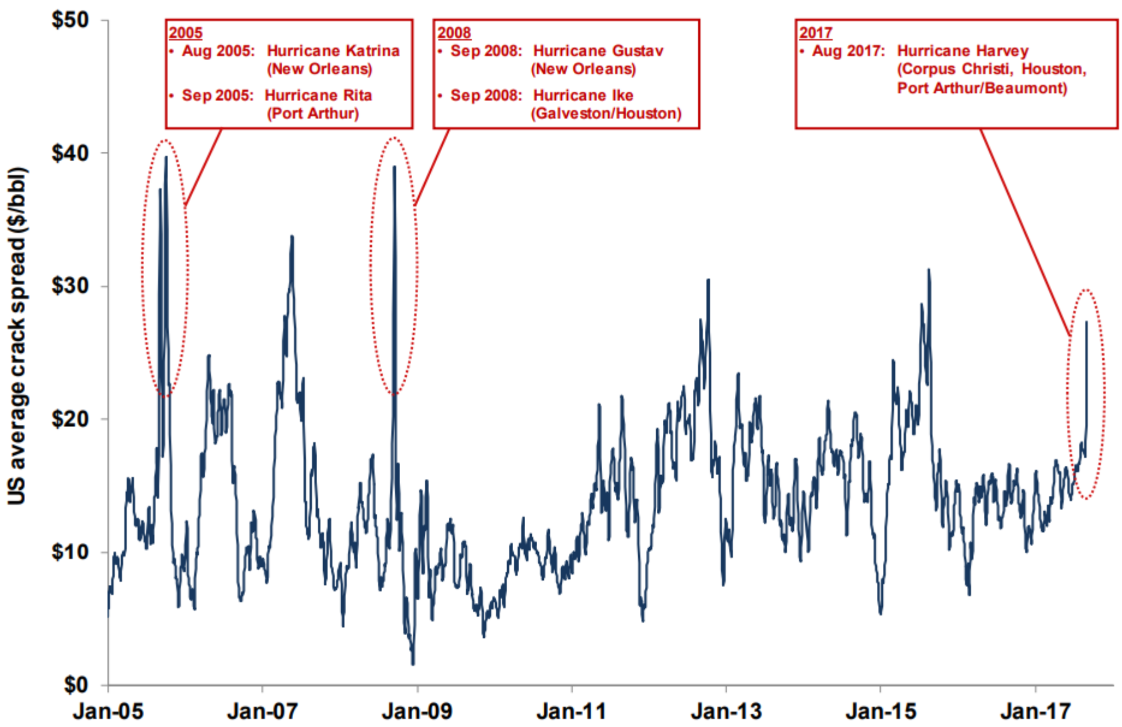


Source: TPH; Guinness Asset Management

At its peak, there appeared to be around 3.8m b/day of crude and condensate refining capacity in Texas that was shut-in. This included all six refineries in the Corpus Christi area, seven in Houston/Galveston and two in Port Arthur, and represented 40% of Gulf Coast refining capacity and 21% of US refining capacity. Today (7 Sept), 1.7m b/day of capacity remains shut-in and a further 1.7m b/day of capacity was operating at reduced rates.

A shortage of refining capacity has caused US gulf coast refining margins to spike higher (up to c.$30/bbl versus $12-13/bbl before Storm Harvey hit), providing a short term boost to profitability to US refiners. This has translated into a c.20% increase in US gasoline prices, up from the low $2.20s/gallon in June and July to something in the mid $2.60s/gallon at the peak. After Hurricane Katrina in 2005 and Hurricanes Gustav and Ike in 2008, which saw similar shut-ins of refining capacity, margins had normalised within 2 months of the hurricane event.

US Gulf coast refining margin (3-2-1 spread) 2005-2017

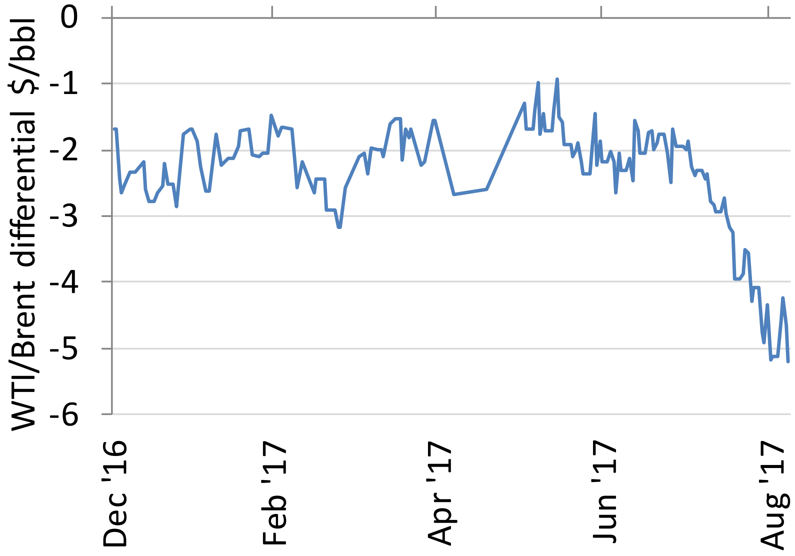


Source: Bloomberg; TPH; Guinness Asset Management

There has of course also been an impact on refined product demand, with a huge shock felt to the greater Houston region. Some commentators estimate that up to 500,000 cars will have been written off by the effects of Hurricane Harvey, causing a sharp but short term drop in demand as the clean up takes place and vehicles are replaced. By comparison, following Hurricanes Gustav and Ike in 2008, September gasoline demand for the US fell by around 0.5m/day (-5%) versus norms.

The greater shut-in of US refining capacity versus oil production capacity has depressed the WTI oil price versus Brent, widening the spread from around $2-3/bl to just over $5/bl:

Brent/WTI oil price differential ($/bl) YTD



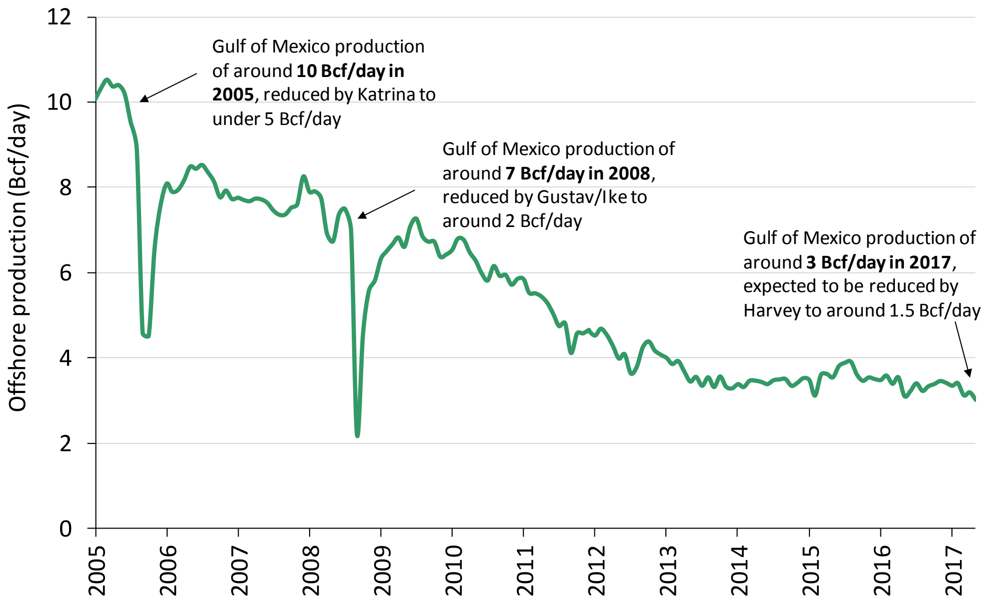
Source: Bloomberg; Guinness Asset Management

We expect the WTI/Brent spread to settle back to around $2-3/bl at some point in September/October.

iii) Natural gas production

We believe a total of around 1.6 Bcf/day of gas production was shut-in (c.2% of US gas supply) at the peak of Harvey. Similar to the picture for oil, around half of this is offshore Gulf of Mexico production (c.26% of GoM's 3.2 Bcf/day) and half is onshore Eagleford production. The impact of Harvey on the US gas market is far less than Hurricane Katrina caused in 2005. At that time, the Gulf of Mexico produced over 10 Bcf/day of gas, versus 3 Bcf/day (normally) at present. Moreover, the majority of GoM gas production is located off the Louisiana coast which was not on Harvey's path.

US Gulf of Mexico natural gas production 2005-2017



Source: EIA; Bloomberg; Guinness Asset Management

Natural gas prices have picked up a little in the last two weeks, tempered by how short the supply disruption is expected to be.

Further Hurricanes are expected to strike the US as the 2017 Hurricane season continues to be an active one. Hurricane Irma, bringing Category 5 winds, is currently over the Northern Caribbean and is expected to track across to Florida. Unlike Texas, however, Florida is not a refining centre, nor is it a particularly important oil producing state, supplying less than 0.2m b/day (<2% of US production).

3. PERFORMANCE Guinness Global Energy Fund

The main index of oil and gas equities, the MSCI World Energy Index, was down by 3.3% in August, while the MSCI World Index rose by 0.2%. The Fund was down by 4.0% (class E) in the month, underperforming the MSCI World Energy Index by 0.7% (all in US dollar terms).

Within the Fund, August's strongest performers were Statoil, Imperial Oil, CNOOC, Gazprom and JA Solar while the weakest performers were Hess, QEP, Apache, Sunpower and Noble Energy.

Performance (in USD) 31/08/2017

Annualised

% returns	1 year	3 years	5 years	10 years	1999 to date
Guinness Global Energy	-3.2	-2.0	0.0	0.0	9.8
MSCI World Energy Index	0.4	0.1	0.0	0.0	6.8

Calendar year

% returns	2017	2016	2015	2014	2013	2012	2011	2010	2009	2008	2007
Guinness Global Energy	-12.5	27.9	-27.6	-19.1	24.4	3.0	-13.6	15.3	61.8	-48.2	37.6
MSCI World Energy Index	-6.0	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 (1.00% AMC) from launch to 02.09.08, and class E (0.75% AMC) thereafter. Performance would be lower if an initial charge and/or redemption fee were included.

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

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

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

4. PORTFOLIO Guinness Global Energy Fund

Buys/Sells

In August we rebalanced the portfolio but made no stock switches.

Sector Breakdown

The following table shows the asset allocation of the Fund at **August 31 2017**. We have also shown the asset allocation of the Guinness Atkinson Global Energy Fund (our US global energy fund which was started in 2004 and is managed in tandem with the Guinness Global Energy Fund) at year-end 2007 for comparative purposes:

(%)	31 Dec 2007*	31 Dec 2008	31 Dec 2009	31 Dec 2010	31 Dec 2011	31 Dec 2012	31 Dec 2013	31 Dec 2014	31 Dec 2015	31 Dec 2016	31 August 2017
Oil & Gas	**103.5**	**96.4**	**98.2**	***93.3***	***97.9***	***97.3***	***93.7***	***93.7***	***95.1***	***96.7***	***98.0***
Integrated	40.3	41.6	35.9	33.0	30.9	30.4	29.2	27.0	30.4	32.5	30.8
Integrated – Can & Em Mkts	25.9	12.1	11.9	8.2	8.8	8.4	9.4	10.3	11.1	14.3	15.5
Exploration & production	25.8	28.7	32.8	37.1	41.1	40.3	35.4	36.2	36.5	35.4	34.3
Oil & Gas Storage & Transportation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.7
Drilling	8.1	5.2	8.5	6.1	5.9	7.1	6.4	3.3	1.5	2.2	1.5
Equipment & services	3.4	6.4	5.9	5.4	6.1	7.4	9.8	13.4	11.4	8.6	8.5
Refining and marketing	0.0	2.4	3.2	3.5	5.1	3.7	3.5	3.5	4.2	3.7	3.7
Solar	**0.0**	**0.0**	**0.0**	**3.2**	**1.3**	**1.2**	**2.6**	**3.7**	**4.7**	**0.9**	**1.4**
Coal & consumables	**2.5**	**2.3**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Construction & engineering	**0.0**	**0.4**	**0.3**	**0.3**	**0.4**	**0.6**	**1.0**	**0.0**	**0.0**	**0.0**	**0.0**
Cash	**-6.0**	**0.9**	**1.5**	**3.2**	**0.4**	**0.9**	**2.7**	**2.6**	**0.2**	**2.4**	**0.6**
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

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

The Fund at August 31 2017 was on a price to earnings ratio (P/E) for 2017 of 22.6x versus the S&P 500 Index at 19.5x as set out in the following table:

	2011	2012	2013	2014	2015	2016	2017	2018
Guinness Global Energy Fund P/E	6.7	6.9	7.6	8.3	18.1	32.5	22.6	17.6
S&P 500 P/E	25.6	25.5	23.0	21.3	24.6	23.3	19.5	17.1
Premium (+) / Discount (-)	*-74%*	*-73%*	*-67%*	*-61%*	*-26%*	*39%*	*16%*	*3%*
Average oil price (WTI $/bbl)	95	94	98	93	49	43		

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

Portfolio holdings

Our integrated and similar stock exposure (c.47%) is comprised of a mix of mid cap, mid/large cap and large cap stocks. Our four large caps are Chevron, BP, Royal Dutch Shell and Total. Mid/large and mid-caps are ENI, Statoil, Hess and OMV. At August 31 2017 the median P/E ratios of this group were 16.6x/15.6x 2017/2018 earnings. We also have two Canadian integrated holdings, Suncor and Imperial Oil. Both companies have significant exposure to oil sands in addition to downstream assets.

Our exploration and production holdings (c.34%) give us exposure most directly to rising oil and natural gas prices. We include in this category non-integrated oil sands companies, as this is the GICS approach. The stock here with oil sands exposure is Canadian Natural Resources. The pure E&P stocks have a bias towards the US (Newfield, Devon, Oasis and QEP Resources), with four other names (Apache, Occidental, ConocoPhillips, Noble) having a mix of US and international production and one (Tullow) which is African focused. One of the key metrics behind a number of the E&P stocks held is low enterprise value / proven reserves. Almost all of the US E&P stocks held also provide exposure to North American natural gas.

We have exposure to four (pure) emerging market stocks in the main portfolio, though one is a half-position, and in total represent 12% of the portfolio. Two are classified as 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 4.1x 2017 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% 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 July 31st 2017 (for compliance reasons disclosed one month in arrears)

Guinness Global Energy Fund 31 July 2017

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	3.69	21.3	11.7	8.1	8.9	9.9	11.4	30.0	78.7	27.3	22.0
Royal Dutch Shell PLC	EUR	NL	3.77	12.9	9.1	6.8	6.7	8.8	7.8	16.5	27.2	16.3	14.2
BP PLC	GBP	GB	3.62	7.4	5.2	5.1	6.4	7.9	9.4	16.6	31.8	20.5	15.6
Total SA	EUR	FR	3.62	12.0	9.4	8.4	8.0	8.9	9.1	11.6	13.7	12.8	11.8
ENI SpA	EUR	IT	3.89	9.4	7.1	6.8	6.7	10.6	12.4	57.9	nm	23.5	18.4
Statoil ASA	NOK	NO	4.02	10.7	8.0	7.0	6.2	7.6	10.7	25.9	131.5	16.5	17.4
Hess Corp	USD	US	3.62	23.3	8.6	7.4	7.5	7.8	10.7	nm	nm	nm	nm
OMV AG	EUR	AT	3.87	19.2	12.0	15.0	10.5	12.9	15.8	14.1	14.5	11.2	13.4
			30.10										
Integrated / Oil & Gas E&P - Canada													
Suncor Energy Inc	CAD	CA	4.21	38.5	25.6	11.4	12.6	12.7	12.7	36.1	nm	28.6	26.8
Canadian Natural Resources Ltd	CAD	CA	3.79	15.8	15.7	16.5	24.0	17.0	11.1	274.3	nm	42.6	21.2
Imperial Oil	CAD	CA	3.72	18.0	15.6	9.7	8.6	11.2	9.4	20.1	59.4	27.0	22.5
			11.71										
Integrated Oil & Gas - Emerging market													
PetroChina Co Ltd	HKD	HK	3.49	7.3	5.9	5.8	6.6	7.4	7.3	22.5	88.3	25.0	18.0
Gazprom OAO	USD	RU	3.43	4.2	3.3	2.2	2.3	2.2	3.4	2.4	3.2	4.2	3.7
			6.92										
Oil & Gas E&P													
Occidental Petroleum Corp	USD	US	3.90	16.7	11.0	7.4	8.9	8.9	10.7	373.1	nm	92.3	44.5
ConocoPhillips	USD	US	3.59	12.5	7.7	5.3	8.0	8.1	8.6	nm	nm	250.7	34.4
Apache Corp	USD	US	3.80	8.9	5.3	4.2	5.2	6.1	8.8	nm	nm	152.7	76.7
Devon Energy Corp	USD	US	3.27	10.2	5.6	5.5	10.3	7.9	6.5	13.5	nm	20.1	15.8
Noble Energy Inc	USD	US	3.33	17.1	14.0	11.0	12.6	9.3	12.4	507.2	nm	nm	171.1
QEP Resources Inc	USD	US	1.59	nm	6.2	5.2	6.9	6.1	6.1	nm	nm	nm	nm
Newfield Exploration Co	USD	US	3.18	5.6	6.2	7.1	11.8	16.0	15.6	39.6	26.7	14.5	12.7
Oasis Petroleum Inc	USD	US	1.58	nm	46.3	9.4	5.3	2.8	3.2	9.8	nm	nm	243.1
			24.26										
International E&Ps													
CNOOC Ltd	HKD	HK	3.66	11.1	6.4	4.9	5.2	5.3	6.3	18.9	nm	15.7	11.8
Tullow Oil PLC	GBP	GB	2.08	33.7	16.4	3.7	3.3	25.2	nm	nm	nm	30.4	15.8
Soco International PLC	GBP	GB	0.81	9.2	12.7	8.2	2.3	2.4	3.7	nm	nm	1580.4	32.3
			6.55										
Midstream													
Enbridge Inc	USD	CA	3.71	58.5	50.5	45.5	41.9	38.6	35.4	32.0	29.6	32.2	26.0
			3.71										
Drilling													
Unit Corp	USD	US	1.58	6.8	5.9	4.4	4.3	4.9	4.2	nm	nm	31.9	13.5
			1.58										
Equipment & Services													
Halliburton Co	USD	US	3.48	32.4	21.1	12.7	14.3	13.7	10.8	28.7	nm	38.9	19.2
Helix Energy Solutions Group Inc	USD	US	1.75	11.3	12.4	4.4	3.5	6.1	3.4	38.7	nm	nm	38.5
Schlumberger Ltd	USD	US	3.50	25.2	24.9	18.9	16.4	14.4	12.4	20.5	59.4	45.6	28.7
			8.73										
Solar													
JA Solar Holdings Co Ltd	USD	US	0.77	nm	0.9	nm	nm	nm	7.2	3.7	8.5	157.1	15.8
Sunpower Corp	USD	US	0.64	9.7	7.7	135.9	74.3	7.9	8.5	5.7	nm	nm	33.1
			1.40										
Oil & Gas Refining & Marketing													
Valero Energy Corp	USD	US	3.63	nm	43.5	17.3	14.1	16.8	11.3	7.9	18.8	16.9	12.5
			3.63										
Research Portfolio													
Cluff Natural Resources PLC	GBP	GB	0.27	nm	nm	nm	nm	nm	nm	nm	nm	nm	nm
EnQuest PLC	GBP	GB	0.58	nm	5.0	5.7	1.7	1.9	3.5	33.6	2.2	nm	3.9
JKX Oil & Gas PLC	GBP	GB	0.10	0.5	0.5	0.6	0.8	1.6	4.4	nm	nm	nm	nm
Ophir Energy PLC	GBP	GB	0.04	nm	nm	nm	nm	nm	2.9	nm	nm	nm	3.7
Shandong Molong Petroleum Machiner	HKD	HK	0.05	7.2	2.8	3.9	nm	nm	nm	nm	nm	nm	nm
Sino Gas & Energy Holdings Ltd	AUD	AU	0.12	nm	nm	nm	85.0	nm	85.0	nm	nm	28.3	5.7
			1.17										
		Cash	0.24										
		Total	100										
		PER		12.9	8.4	7.0	7.2	8.0	8.7	19.1	34.5	23.6	17.6
		Med. PER		11.6	8.6	7.0	7.7	8.1	9.1	21.5	27.2	27.3	18.0
		Ex-gas PER		13.4	8.8	7.3	7.2	8.3	9.0	18.2	31.2	22.6	16.8

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

5. OUTLOOK

i) Oil market

The table below illustrates the difference between the growth in world oil demand and non-OPEC supply over the last 13 years, together with IEA forecasts for 2017.

	2004	2005	2006	2007	2008	*2009*	2010	2011	2012	2013	2014	2015	2016	2017E *IEA*
World Demand	**82.5**	**84.0**	**85.2**	**87.0**	**86.5**	**85.5**	**88.5**	**89.5**	**90.7**	***91.7***	***92.9***	***94.8***	***96.1***	***97.6***
Non-OPEC supply (includes Angola, Ecuador and Indonesia for periods when each country was outside OPEC[1])	**50.3**	**50.4**	**51.3**	**50.5**	**49.6**	**51.4**	**52.7**	**52.8**	**53.3**	***54.5***	***56.7***	***58.2***	***56.8***	***57.5***
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
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
Indonesia/Gabon supply adjustment[2]	1.0	0.9	0.9	1.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.6
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**	**56.7**	**58.2**	**57.4**	**58.1**
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*
Non-OPEC supply plus OPEC NGLs (ex. Angola/Ecuador and inc. Indonesia for all periods)	**54.0**	**53.9**	**54.6**	**55.3**	**55.1**	**56.5**	**58.2**	**58.7**	**59.7**	**60.6**	**63.1**	**64.8**	**64.2**	**65.0**
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	29.8	30.0	31.9	32.6
Iraq supply adjustment[4]	-2.0	-1.8	-1.9	-2.1	-2.4	-2.4	-2.4	-2.7	-3.0	-3.1	-3.3	-4.0	-4.4	-4.4
Call on OPEC-11[5]	**26.5**	**28.3**	**28.7**	**29.6**	**29.0**	**26.6**	**27.9**	**28.1**	**28.1**	**28.0**	**26.5**	**26.0**	**27.5**	**28.2**

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

Source: 2003 - 2008: IEA oil market reports; 2009 - 17: August 2017 Oil market Report

Global oil demand in 2016 was over 9m b/day higher than the pre-recession (2007) peak. This means the combined effect of the 2007/08 oil price spike and the 2008/09 recession was shrugged off remarkably quickly. The IEA forecast a rise of 1.5m b/day in 2017, which would take oil demand to an all-time high of 97.6m b/day.

OPEC

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

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

Iraq might develop. In response to lower Libyan, 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:

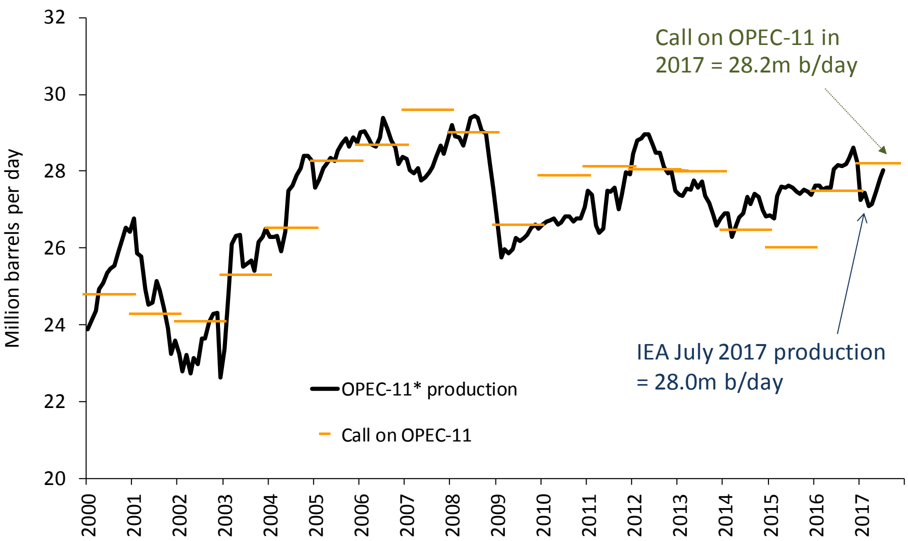
('000 b/day)	31-Dec-10	30-Nov-14	31-Jul-17	Change vs Dec 2010	Change vs Nov 2014
Saudi	8,250	9,650	**10,030**	**1,780**	**380**
Iran	3,700	2,780	**3,790**	90	**1,010**
Iraq	2,385	3,370	**4,500**	2,115	**1,130**
UAE	2,310	2,800	**2,910**	600	**110**
Kuwait	2,300	2,790	**2,700**	400	**-90**
Nigeria	2,220	1,970	**1,710**	-510	**-260**
Venezuela	2,190	2,350	**1,970**	-220	**-380**
Angola	1,700	1,640	**1,680**	-20	**40**
Libya	1,585	580	**1,010**	-575	**430**
Algeria	1,260	1,100	**1,060**	-200	**-40**
Qatar	820	650	**610**	-210	**-40**
Ecuador	465	561	**530**	65	**-31**
OPEC-12	**29,185**	30,241	**32,500**	**3,315**	**2,259**

Source: Bloomberg, DOE

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

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

Figure 7: OPEC-11 apparent production vs call on OPEC 2000 – 2017



Source: IEA Oil Market Report (June 2017 and prior); Guinness estimates

OPEC-12 met in November 2014, with the growing looseness in the physical market and a falling oil price (in the mid $70s at the time of the meeting) prompting a significant change in strategy to one that prioritised market share over price. As a result, there was no quota cut, as many had anticipated, and a confirmation that the 30m b/day target would be maintained. Post the November 2014 meeting, OPEC-14 (Indonesia and Gabon joined the group) not only maintained their quota but also raised production significantly, up over 18 months by 2.5m b/day. Iraq recovered its production by 1.2m b/day; Iran by 0.8m b/day post the lifting of sanctions relating to their nuclear programme; and Saudi by 0.9m b/day.

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

The November 2016 announcement amounted to a 5% cut for all members except for 1) Libya and Nigeria, recognising their unusually depressed levels of production due to unrest, and 2) Iran, recognising its journey back to normalised production post the lifting of sanctions in January 2016. Indonesia has been suspended from the group since, as a net importer of oil, it chose not to participate. The agreed cuts came into effect on 1 January 2017, and were initially designed to be kept in place for six months. In May 2017, OPEC met to consider extending the cuts and agreed, together with key non-OPEC producers, to extend the cuts for a further nine months (to the end of March 2018). Compliance with the cuts has so far been strong and, after been delayed initially by a variety of temporary factors, is now causing inventories to decline.

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

Saudi’s actions at the head of OPEC appear designed to achieve an oil price that to some extent closes their fiscal deficit (though $75-80/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, well 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.

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 2008-2016.

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. The IEA forecasts that non-OPEC supply recovers by 0.7m b/day in 2017, as US onshore production swings from decline back to growth.

The growth in US shale oil production, in particular from the Permian, Bakken and Eagleford basins, 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 and has now returned to growth. Our assessment is that US shale oil is a capital intensive source of oil but one where 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. Naturally, cashflows available for reinvestment in a $40-60 world are far lower than in a $100 world, but with efficiency improvements and recent cost deflation, enough to see moderate growth returning.

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 reported that oil demand grew in 2016 by around 1.3m b/day, and expect 2017 growth of 1.5m 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 forecast for 2017 comprises an increase in non-OECD demand of 1.2m b/day and OECD demand of 0.3m b/day. The components of this non-OECD demand growth can be summarised as follows:

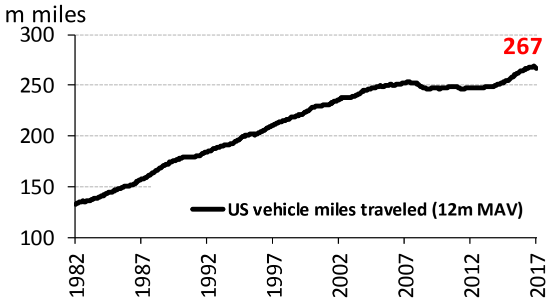
Figure 8: Non-OECD oil demand

m b/day	Demand								Growth						
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017e**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017e**
Asia	19.7	20.3	21.4	22.1	22.8	24.0	24.8	25.8	0.6	1.1	0.7	0.7	1.2	0.8	0.9
Middle East	7.3	7.4	7.8	7.9	8.4	8.4	8.3	8.3	0.1	0.4	0.1	0.5	0.0	-0.1	0.1
Latin America	6	6.2	6.4	6.7	6.8	6.7	6.6	6.6	0.2	0.2	0.3	0.1	-0.1	-0.1	0.0
FSU	4.1	4.4	4.6	4.7	4.66	4.6	4.8	4.8	0.3	0.2	0.1	0.0	-0.1	0.2	0.1
Africa	3.5	3.5	3.8	3.9	3.8	4.1	4.1	4.2	0.0	0.3	0.1	-0.1	0.3	0.0	0.1
Europe	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**41.3**	**42.5**	**44.7**	**46.0**	**47.2**	**48.4**	**49.3**	**50.5**	**1.2**	**2.2**	**1.3**	**1.2**	**1.2**	**0.9**	**1.2**

Source: IEA Oil Market Report (August 2017)

Asia has settled down into a steady pattern of growth since 2010, and accounts for much of expected growth in 2017. Historically, China has been the most important component of this growth, but signs are emerging that India may grow by as much, having made the largest contribution to growth in 2016.

OECD demand in 2017 is forecast to be up 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 2-3% per year.



The trajectory of global oil demand over the next few years will be a function of global GDP, pace of the 'consumerisation' of developing economies, and price. At current prices, the world oil bill as a percentage of GDP is around 1.5-2%, the lowest level since 1998/99, and a likely stimulant of strong multi-year demand growth. If oil prices return to a higher range (say around $75/bbl, representing 3% of GDP), we probably return to the pattern established over the past 5 years, with a flat to shallow decline picture in the OECD more than offset by strong growth in the non-OECD area. The small decline in the OECD reflects improving oil efficiency over time, though this effect will be dampened by economic, population and vehicle growth. Within the non-OECD, population growth and rising oil use per capita will both play a significant part. Overall, we would not be surprised to see average annual non-OECD demand growth of around 1.5m b/day to the end of the decade. This would represent a growth rate of 3% p.a., no greater than the growth rate over the last 15 years (3.2% p.a.).

We keep a close eye on developments in the 'new energy' vehicle fleet (electric vehicles; hybrids etc), but see nothing that makes a significant dent on the consumption of gasoline and diesel in the next few years. Sales of electric vehicles (pure electric and plug-in hybrid electrics) globally were around 0.8m in 2016, up from 0.4m in 2014. Sales of 0.8m electric vehicles represents around 1% of total light vehicle sales, and increases EV's share of the world car fleet to 0.15%. We expect to see EV sales accelerate in 2017 to around 1.2m, or 1.5% of total global sales. Even applying an aggressive growth rate to EV sales, we see EVs comprising only around 1% of the global car fleet in 2020.

Conclusions about oil

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

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

Oil price (inflation adjusted)																	*Est*
12 month MAV	1986-2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
WTI	30	33	38	49	66	75	82	104	68	84	99	94	98	93	49	45	50
Brent	30	32	35	46	64	75	82	103	67	84	115	112	108	99	52	45	52
Brent/WTI (12m MAV)	**30**	**33**	**37**	**48**	**65**	**75**	**82**	**104**	**68**	**84**	**107**	**103**	**103**	**96**	**51**	**45**	**51**
Brent/WTI y-on-y change (%)		8%	12%	30%	37%	15%	9%	26%	-35%	24%	27%	-4%	0%	-7%	-47%	-11%	13%
Brent/WTI (5yr MAV)	30	25	32	37	42	51	61	75	79	82	89	93	93	99	92	80	69

We expect oil to trade in a $45-60 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 moderate growth.

The world oil bill at around $50 per barrel would represent 2% of 2016 Global GDP, 42% under the average of the 1970 – 2015 period (3.4%). A return to oil representing 3.4% of GDP implies an oil price of around $85/barrel.

We believe that Saudi's long-term objective remains to maintain a 'good' oil price, higher than current levels, that will allow the country to IPO Saudi Aramco successfully during 2018.

Natural gas market

US supply & demand: recent past

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

Industrial demand (of which around 35% comes from petrochemicals) tends to trend up and down depending on the strength of the economy, the level of the US dollar and the differential between US and international gas prices. Between 2000 and 2009 industrial demand was in steady decline, falling from 22.2 Bcf/day to 16.9 Bcf/day. Since 2009 the lower gas price (particularly when compared to other global gas prices) and recovery from recession has seen demand rebound, up in 2016 to around 21.8 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 2016, 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.

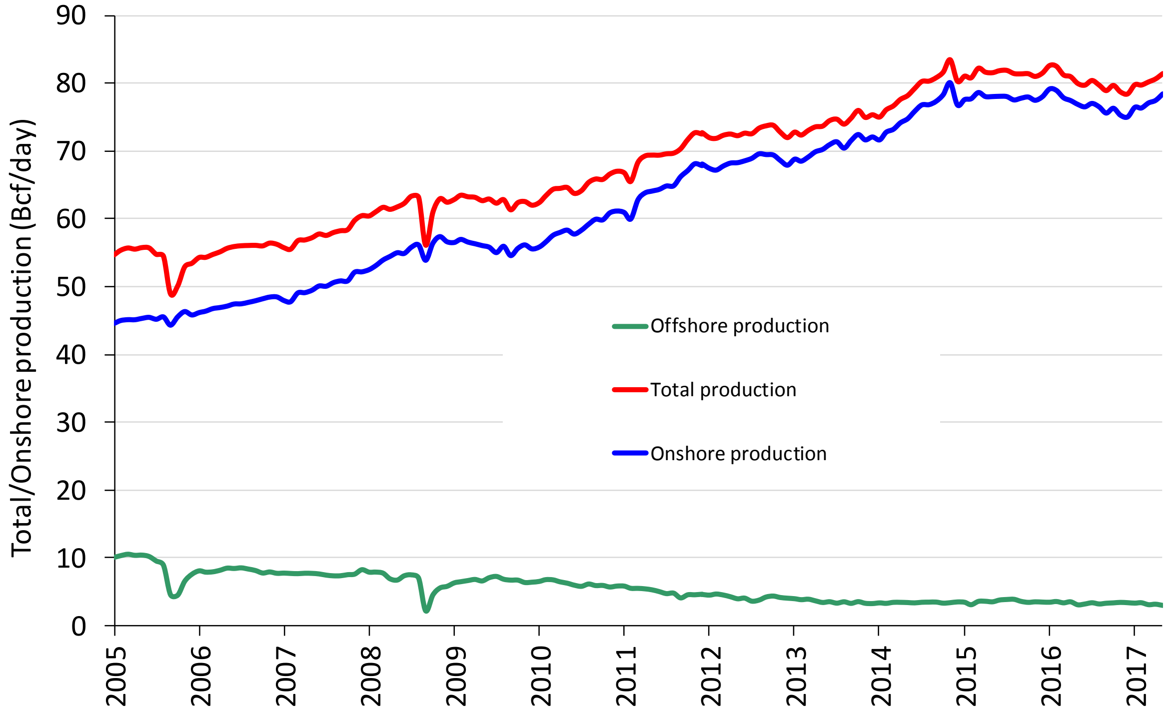
Total gas demand in 2016 (including Canadian and Mexican exports) was around 81.9 Bcf/day, up by 1.9 Bcf/day (2.4%) vs 2015 and up 4.2 Bcf/day (5%) vs the 3 year average. The biggest change in 2016 vs 2015 is exports to Mexico (+1.1 Bcf/day), as the network of gas pipelines from Texas into Mexico expands. Industrial demand (+0.5 Bcf/day) was made a positive contribution, as US GDP picked up.

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

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

Since the middle of 2008 the weaker gas price in the US reflects growing onshore US production driven by rising 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 192 at the end of July 2017. 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) is now at 78.4 Bcf/day, 21.0 Bcf/day (37%) above the 57.4 Bcf/d peak in November 2008 before the rig count collapsed.

Figure 10: US natural gas production 2005 – 2017 (Lower 48 States)



Source: EIA 914 data (June 2017 published in September 2017)

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.

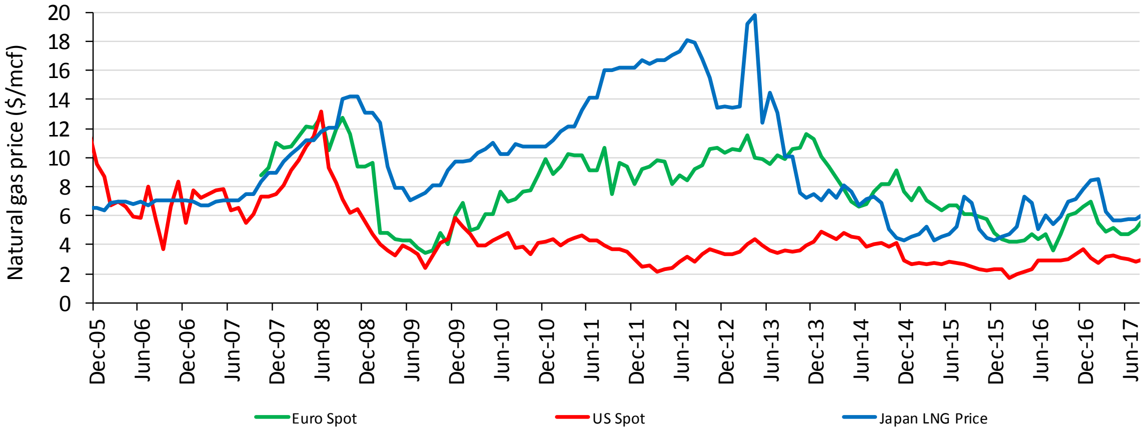
Considering these factors together, we expect US onshore gas production to return to growth in 2017 (around 2 bcf/day) if the price remains in the $2.50-$3.50/mcf range.

	2009	2010	2011	2012	2013	2014	2015	2016	2017E
Onshore production - average (Bcf/day)	55.9	58.6	64.6	68.4	70.2	75.3	77.8	77.1	79.0
Change (Bcf/day)	0.9	2.7	5.9	3.9	1.8	5.1	2.5	-0.7	1.9
Change (%)	*1.7%*	*4.8%*	*10.1%*	*6.0%*	*2.6%*	*7.2%*	*3.3%*	*-0.8%*	*2.5%*

Source: EIA; Guinness estimates

Liquid natural gas (LNG) arbitrage

The UK national balancing point (NBP) gas price – which serves as a proxy to the European traded gas price – strengthened in 2016, rising to around $7/mcf at the end of 2016, predominantly as a result of price-linkage to recovering oil prices. We note that current prices remain at a premium to the US gas price (c.$5 versus c.$3). Asian spot LNG prices fell sharply down to around $4.50/mcf at the start of 2016 (pulled lower by lower oil prices and due to a negative demand response in Asian markets to previously higher natural gas prices) but have since recovered to around $6/mcf.



Demand outlook

US total demand in 2016 (including exports to Canada and Mexico) was around 81 Bcf/day, nearly 3 Bcf/day higher than 2014. We expect demand in 2017, assuming prices remain around $$3/mcf, to be about flat, with weaker power generation demand (coal to gas switching returning at our assumed price level) offset by stronger residential/commercial use (normalised weather) and a rise in exports to Mexico.

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 and Canada, many of which are still in the construction stages but will come online by 2020. Exports from the first project to come on-line, Sabine Pass, commenced in February 2016. Additional exports are slated to come from the following projects, but exports will ultimately depend on spot economics between Henry Hub and global prices. In June 2017, total US LNG exports averaged 1.7 Bcf/day, up sharply from a year before.

Project	Location	2017E	2018E	2019E	2020E
Sabine Pass 3	LA	0.6			
Sabine Pass 4	LA	0.6			
Sabine Pass 5	LA			0.7	
Freeport 1	TX		0.5		
Freeport 2	TX			0.5	
Freeport 3	TX			0.5	
Cove Point LNG	MD		0.8		
Cameron 1	LA		0.6		
Cameron 2	LA		0.6		
Cameron 3	LA			0.6	
Corpus Christi 1	TX			0.8	
Corpus Christi 2	TX			0.8	
Sub-total		**1.2**	**2.5**	**3.9**	**0.0**
Total (cumulative)		**1.2**	**3.7**	**7.6**	**7.6**

Source: 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 large new Gulf Coast facilities planned for 2017, the first new crackers to be built in the US since 2001.

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

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

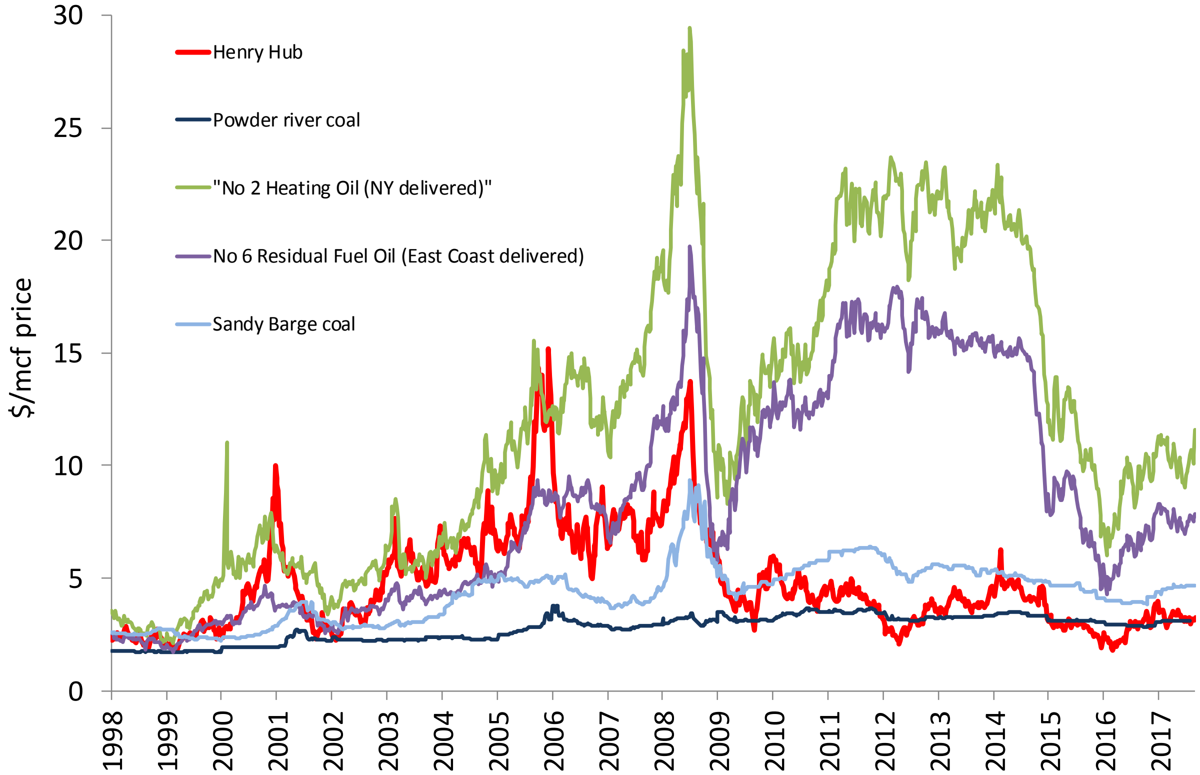
Other

The oil/gas price ratio ($ per bbl WTI/$ per mcf Henry Hub) of around 16x at the end of August continues well outside the long-term ratio of 6-9x. Recent weakness in both oil and natural gas prices has continued to keep the ratio elevated but, at $60 oil, this would imply the gas price at around $7 if the long-term ratio returned.

The following chart of the front month US natural gas price against heating oil (No 2), residual fuel oil (No 6) and coal (Sandy Barge adjusted for transport and environmental costs) seeks to illustrate how coal and residual fuel oil switching provide a floor and heating oil a ceiling to the natural gas price. When the gas price has traded below the coal price support level (2012 and 2016), resulting coal to gas switching for power generation was significant.

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

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



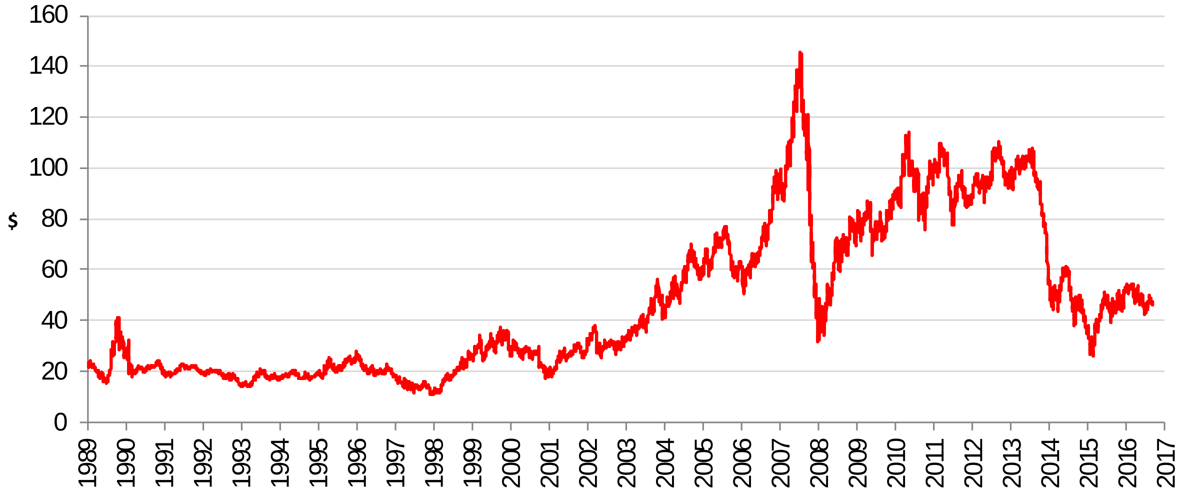
Source: Bloomberg LP (September 2017)

Conclusions about natural gas

The US natural gas price bottomed in 2012 and a tepid recovery since then has been muted by continued strength in gas supply, particularly from the Marcellus/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 $3.00 – 3.50 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 $3.50+.

3. APPENDIX Oil and gas markets historical context

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



Source: Bloomberg LP

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

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

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

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

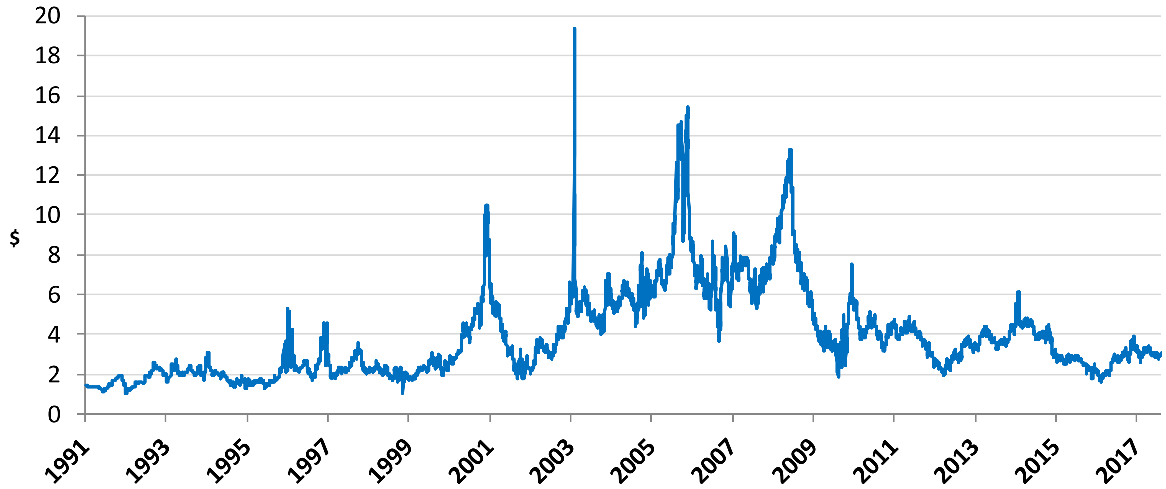
After 2005 we saw a further strong run-up in the oil price. Hurricanes Katrina and Rita, which devastated New Orleans, caused oil to spike up to $70 in August 2005, and it spiked up again in July 2006 to $78 after a three week conflict between Israel and Lebanon threatened supply from the Middle East.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

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

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

Most recently, since the end of 2014, Brent and WTI have dropped well below these trading ranges, as OPEC made clear their intention not to support the price, leaving the market oversupplied. Oil prices found a bottom in 2016 as a result of OPEC cutting production again, but remains capped for the timebing by US onshore shale supply.

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



Source: Bloomberg LP

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

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

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