THE GUINNESS GLOBAL ENERGY REPORT

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

GUINNESS GLOBAL ENERGY FUND

Fund size: $230m (31.7.2019)

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

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

Important information about this report

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

HIGHLIGHTS FOR JULY

OIL

Brent and WTI flat; OPEC+ agree to extend existing quotas

Brent and WTI both essentially flat over the month; Brent at $64/bl; WTI at $59/bl. It was confirmed at the start of July that OPEC+ are extending their existing production quotas for a further nine months. Supply tensions escalated in the Strait of Hormuz with the seizure of a British flagged tanker. 1H 2019 oil demand coming in as weak, though better in June.

NATURAL GAS

US gas prices lower; Asian & European prices also weak

Henry Hub prices weakened from $2.31/mcf to $2.23/mcf. Builds in storage moderating, though the market still looks oversupplied, thanks to growth in Appalachia and in associated gas from US shale oil production. Asian and European gas prices remain weak (c.$5/mcf and c.$4/mcf at end-June) as a result of oversupply of LNG.

EQUITIES

Energy underperforms the broad market in July

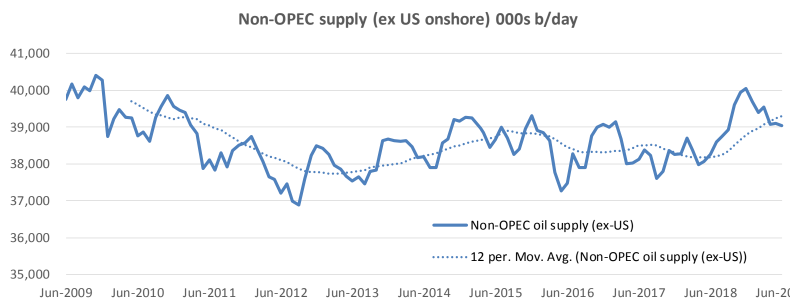
The MSCI World Energy Index (net return) fell in July by 2.8%, underperforming the MSCI World Index (net return) which rose by 0.5% over the month (all in US dollar terms). Year-to-date, the MSCI World Energy Index has underperformed the MSCI World by 7.3%.

CHART OF THE MONTH

Non-OPEC supply (ex US onshore)

Since 2014, the number of project start-ups the non-OPEC world (ex US onshore) has been sustained at a high level, despite lower oil prices, with projects that were sanctioned before the 2014 (when oil was $100/bl+) have continued to come onstream. On a ten year view, it is interesting to note though that non-OPEC (ex US) has essentially been flat, as new investment has simply offset the decline profiles of existing production. The slowdown in investment post 2014 creates the likelihood that non-OPEC (ex US) production will struggle to grow into the start of the 2020s.

__OPEC production vs quotas__



Source: PIW; Guinness (July 2019 and prior)

Tel: +44 (0) 20 7222 5703
Email: info@guinnessfunds.com
Web: guinnessfunds.com

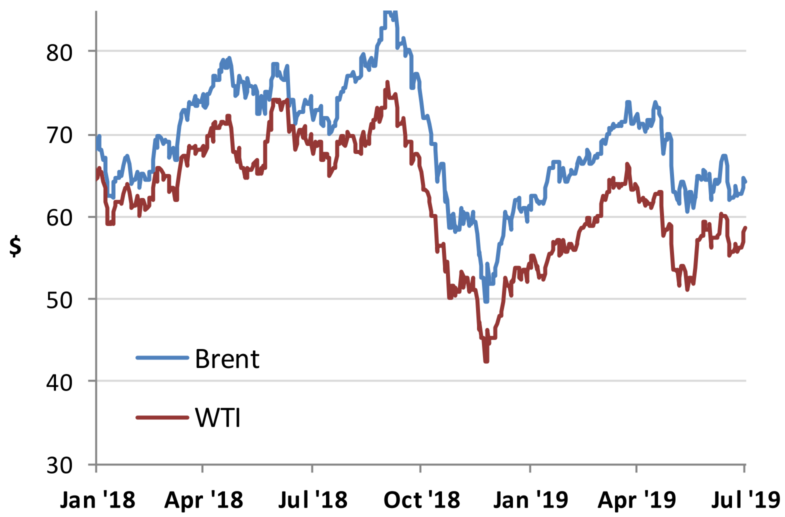
GUINNESS ASSET MANAGEMENT

Contents

1. JULY IN REVIEW

i) Oil market

Figure 1: Oil price (WTI and Brent $/barrel) 18 months January 31 2018 to July 31 2019



Source: Bloomberg LP

The West Texas Intermediate (WTI) oil price started July at $58.5/bl, traded in a range between $55.3/bl and $60.4/bl, before closing essentially unchanged at $58.6/bl. WTI has averaged $58/bl so far in 2019, having averaged $65/bl in 2018, $51/bl in 2017, $43/bl in 2016, $49/bl in 2015 and $93/bl in 2014.

Brent oil traded in a similar shape, opening at $64.4/bl, trading between $62/bl and $67/bl, before closing the month at $64.1/bl. Brent averaged $72/bl in 2018. The gap between the WTI and Brent benchmark oil prices narrowed slightly over the month, ending July at around $5.5/bl, versus over $9/bl at the end of May.

Factors which strengthened WTI and Brent oil prices in July:

- **OPEC+ maintaining existing quotas**
  OPEC held their latest meeting on 1 July, and confirmed the extension of current quotas for a further nine months. The 10 participating non-OPEC producers have signed a new Charter of Cooperation which formalises their involvement. OPEC's effective compliance with their quotas is currently greater than 100%, thanks to outages in Venezuela and Iran. Amongst OPEC members who are producing 'normally', there would be a further 0.4m b/day to come out of the market if individual country quotas were adhered to.

- **Heightened tensions around Middle Eastern oil export routes**

  After attacks on tankers in June, July saw a further escalation of tensions around Middle Eastern oil export routes. On July 19, Iranian authorities seized a British flagged tanker, the Stena Impero, which was travelling through the Straits of Hormuz. Iran's actions appear to be retaliation for the seizure near Gibraltar on July 4 of an Iranian tanker bound for Syria. 21m b/day of crude oil and refined product pass through the Strait of Hormuz/Gulf of Oman each day, of which around two-thirds ends being shipped to Asian markets.

- **US onshore supply growth relatively weak in May**
  The latest EIA production data showed a 54,000 b/day oil production increase in May 2019 (latest data point), taking year-on-year growth up to 1.3m b/day. This was more than offset by an 80,000 b/day growth in oil production in the US Gulf of Mexico. The US onshore drilling rig count fell by 23 rigs in July, taking the total decline since November 2018 to 118 rigs (-13%). Onshore rig operators in the US have signalled that they expect a further 100 rigs to come out of service over the next few months, increasing expectations that US shale oil production growth will not accelerate later this year. There is typically a 5-6 month lag from rig count change to production change.

- **Tightening US inventories**
  After a sharp rise in inventories of crude oil and refined product during May, June and July saw a reversal, with inventories in July falling by 11m barrels versus the 5 year average. Total US inventories now sit close to the five year average, but remain around 120m barrels above the ten year average.

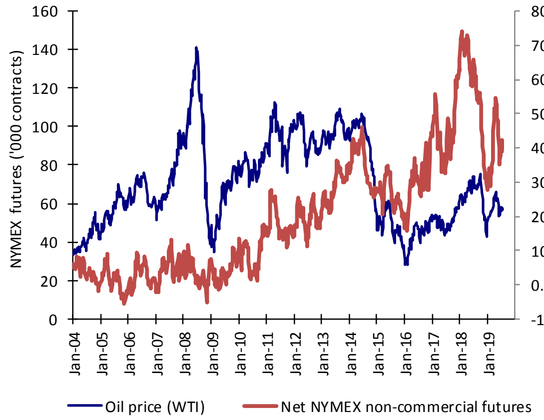
Factors which weakened WTI and Brent oil prices in July:

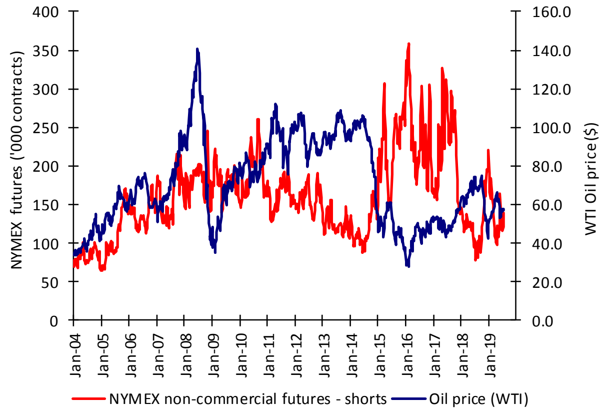
- **Global oil demand confirmed to be weak for 1H 2019**
  The IEA released figures in July to show that global demand growth in Q1 2019 was around 0.3m b/day, representing the lowest level of quarterly demand growth since 2011. This was attributed to warm weather in the OECD (dampening heating demand) and a slowdown in economic activity, including in the petrochemical industry which has been a key driver of growth. Demand growth in Q2 was thought to be around 0.8m b/day, so an improvement from Q1, but still well below the full year 1.2m b/day growth forecast for 2019. By implication, an acceleration in demand growth is expected in 2H 2019. The outcome of US-China trade tensions will be key to whether the acceleration comes.

Speculative and investment flows

The New York Mercantile Exchange (NYMEX) net non-commercial crude oil futures open position was 398,000 contracts long at the end of July versus 379,000 contracts long at the end of June. The net position peaked in February 2018 at 739,000 contracts long. Typically, there is a positive correlation between the movement in net position and movement in the oil price. The gross short position rose to 140,000 contracts at the end of July versus 118,000 at the end of June.

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



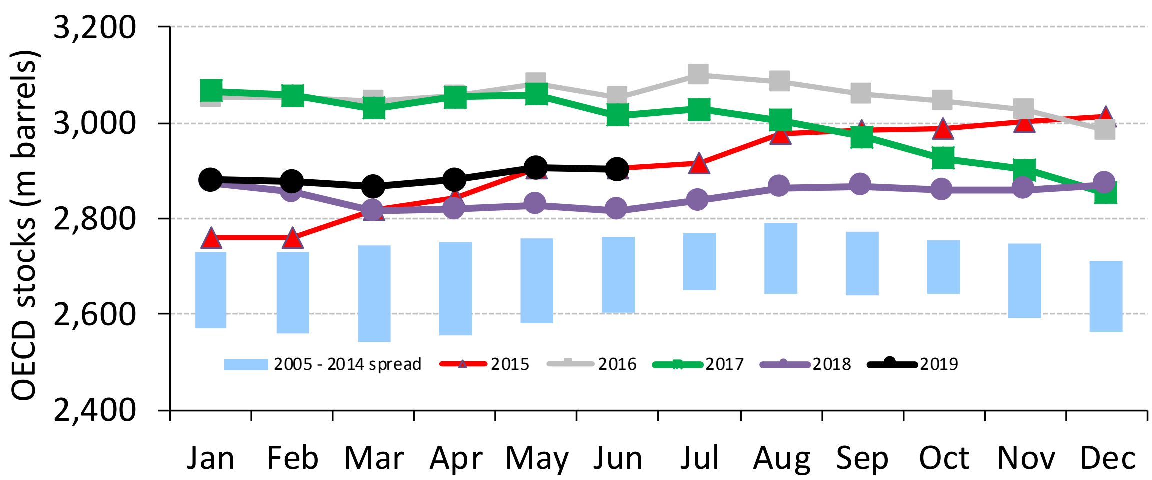


Source: Bloomberg LP/NYMEX/ICE (2019)

OECD stocks

OECD total product and crude inventories at the end of June (latest data point) were estimated by the IEA to be 2,904m barrels, down by 2m barrels versus the level reported for May. This compares to a 10-year average decrease for June of 22m barrels, implying that the market was oversupplied in June by around 0.2m b/day. Inventories were broadly flat in 2018.

Figure 3: OECD total product and crude inventories, monthly, 2004 to 2019



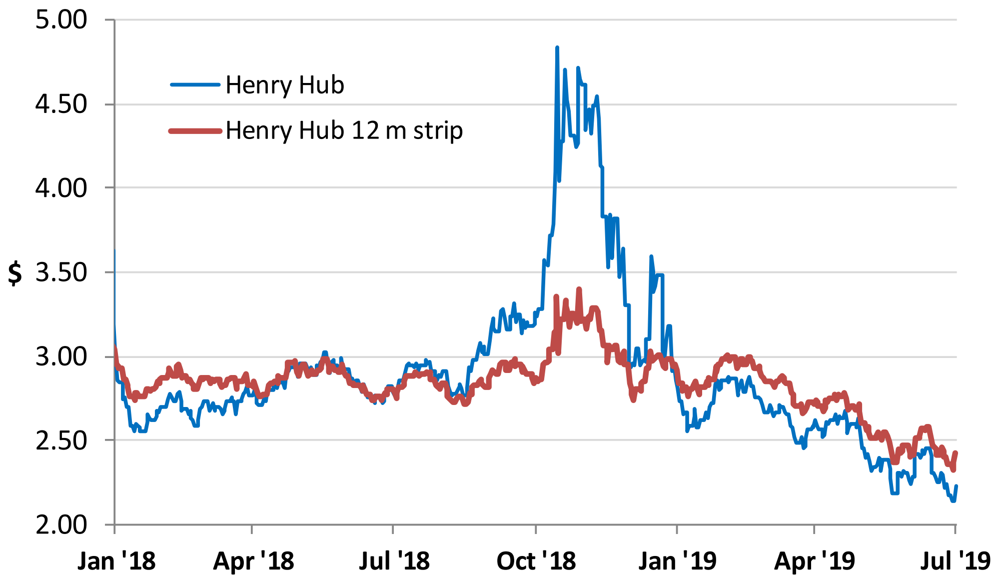
Source: IEA Oil Market Reports (June 2019 and older)

ii) Natural gas market

The US natural gas price (Henry Hub front month) opened July at \$2.31/mcf (1,000 cubic feet), rallied to a high of \$2.45/mcf in the middle of the month, before slumping to close at \$2.23/mcf. The spot gas price has averaged \$2.64/mcf so far in 2019, which compares to an average gas price of \$3.07 in 2018, \$3.02 in 2017, \$2.55/mcf in 2016 and \$2.61/mcf in 2015.

The 12-month gas strip price (a simple average of settlement prices for the next 12 months' futures prices) declined over the month, opening at \$2.47/mcf and closing at \$2.43 /mcf. The strip price averaged \$2.90 in 2018, \$3.12 in 2017, \$2.84 in 2016 and \$2.86 in 2015.

Figure 4: Henry Hub gas spot price and 12m strip (\$/Mcf) January 31 2019 to July 31 2019

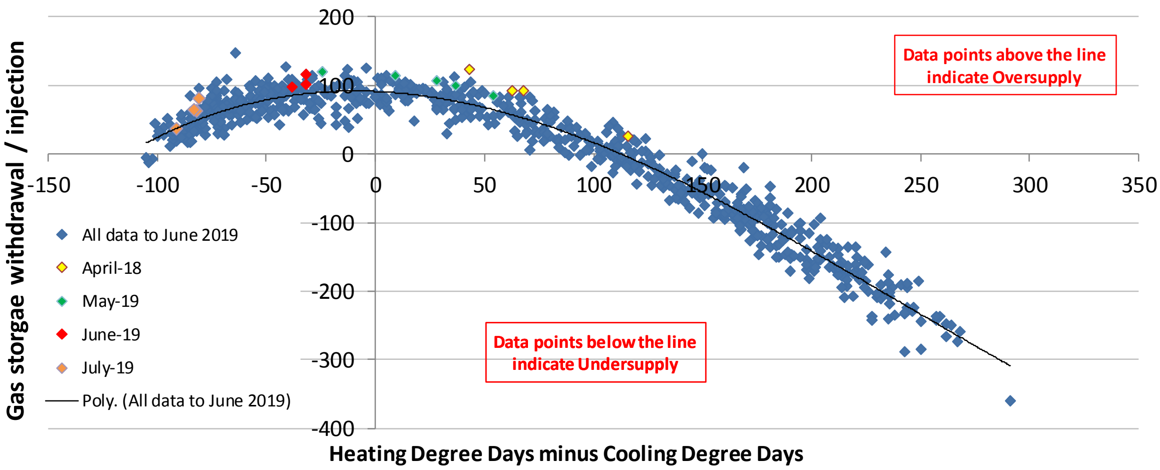


Source: Bloomberg LP

Factors which weakened the US gas price in July included:

- **Structurally oversupplied market**
  Adjusting for the impact of weather in July, the most recent movements of gas in storage suggest the market is, on average, operating at a surplus of around 1-2 Bcf/day (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

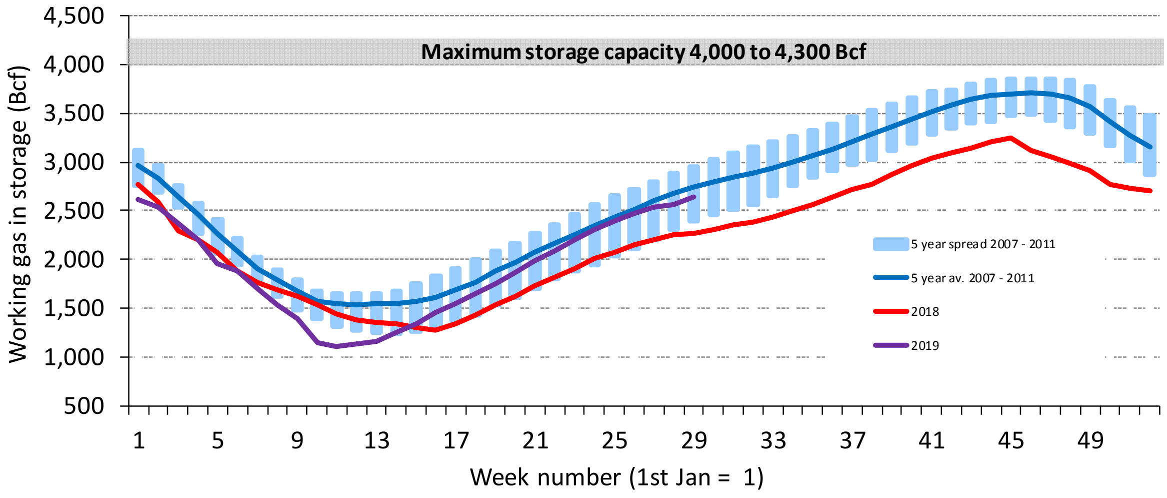
Factors which strengthened the US gas price in June included:

- **Small drop in US onshore natural gas production**
  Onshore US natural gas production averaged 97.2 Bcf/day in May 2019 (the latest available data point), down by 0.2 Bcf/day versus the level reported for April. However, onshore gas production remains by 9.5 Bcf/day on the level reported twelve months earlier. Rising associated gas supply from shale oil, and a pickup of activity in the Marcellus basin, are the key reasons for the rise in production: both look set to continue for the rest of 2019.

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 2.6 Tcf. Current gas in storage is, below the 10 year average as a result of strong demand plus increasing volumes of gas exported via LNG. Whilst gas inventories today are low, the high visibility of low cost supply growth for 2019 is keeping a cap on prices.

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



Source: Bloomberg; EIA (July 2019)

2. MANAGER'S COMMENTS

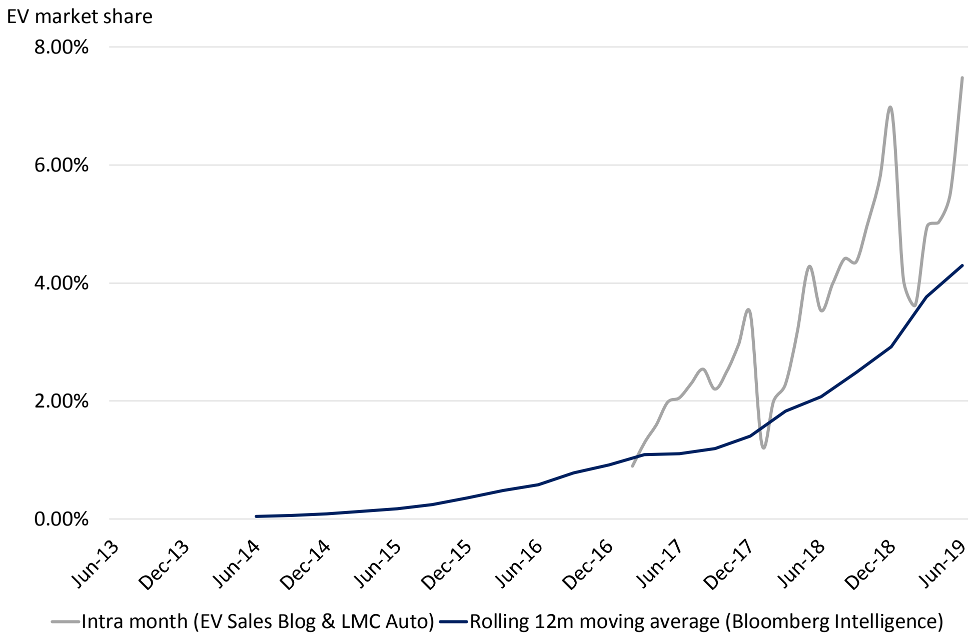
Bark or bite: EVs dominate the headlines, but what's the impact on global oil demand?

Last summer we reviewed developments in the electric vehicle (EV) sector and their expected impact on global oil demand. Since then, we have seen numerous advances in the sector. Tesla has reported record deliveries of its Model 3; new EV partnerships (e.g. Volvo Trucks with Samsung SDI and BYD with Toyota) have been announced; and EV market share in China has accelerated markedly. With this in mind, we thought we would revisit our thesis to test whether the conclusions we reached then remain valid today.

China: supreme leader

Around a decade ago, China's 12th Five-Year Plan (2011-2015) identified the alternative fuel industry as a strategic emerging industry, deserving of government support to help combat dangerous levels of air pollution. Ten years later, not only is China the largest car market in the world (purchasing around 26m of the 92m new cars sold worldwide), but it is also the largest EV market, accounting for over 50% of world demand (>1 million EVs), and home to over 400 EV manufacturers.

China plug-in electric vehicle market share (as % of total auto sales)



Source: Bloomberg, EV-Sales blog, LMC Auto, Guinness estimates

EV sales penetration in China was 4% in 2018, and we expect this to grow to around 7% in 2019 and nearing 10% in 2020. Subsidies have played a major part in the growth seen so far, though the subsidy regime is changing. In early 2019, the government cut central subsidies for EVs by 50%, with the intention of a complete phase out in 2020. The value of this lowered subsidy is around USD$3,700 on an estimated average car price of c.$19,000, meaning a 2020 phase out would have the effect of increasing prices for consumers (or decreasing revenues for auto OEMs) by 20%. In an attempt to drive sustainable growth of the industry past 2020, a dual credits scheme has been introduced, rewarding or penalising carmakers with credits based on a car's fuel consumption and driving range. Automakers that solely produce non-EVs will need to purchase credits and those with surplus credits can sell them in the market. Ultimately, we believe that it is important for EVs in the Chinese market to remain affordable to justify current growth forecasts. The removal of direct government subsidies may call this into question in the short term, however, we see significant EV sales growth in China over the long term.

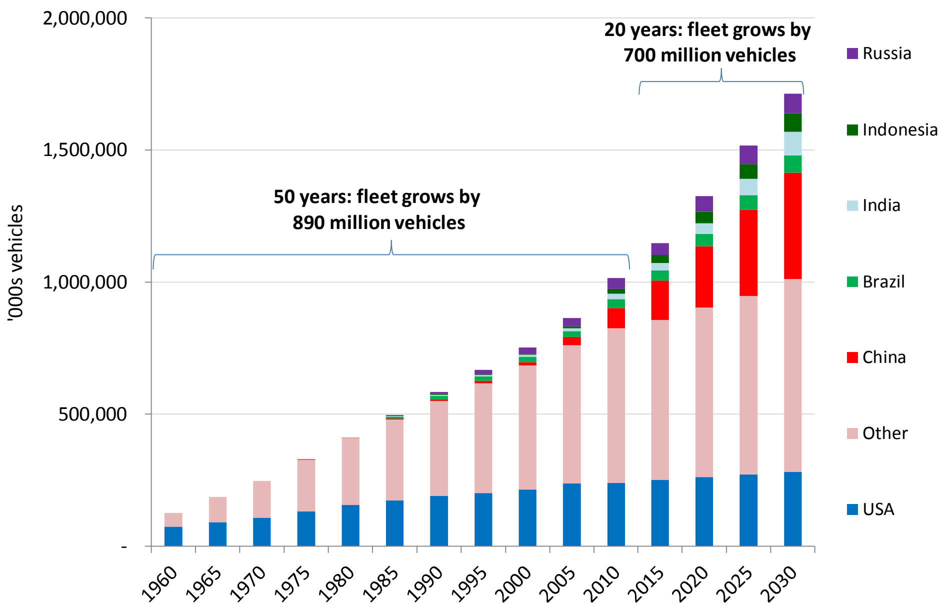
World vehicle fleet – pace of expansion

The growth in EV sales in 2019 comes at a time when global auto sales are stalling. According to IHS, annual light vehicle sales reached 94.5m units in 2017, dropped to 94m units in 2018, and are expected to grow only slightly to 95m units in 2019.

In China, light vehicle sales fell nearly 10% in June 2019 from the prior year, the twelfth consecutive month of declining sales. A number of factors are thought to be behind the recent slowdown, including: lower availability of auto loans, dealer destocking, changes to tax and emissions policy, growth of ride hailing, and the US-China trade war.

Global auto sales may have slowed in the shorter term, but there remains an expectation for growth to around 110m units by 2026, largely driven by emerging markets (expected to increase by 45% from 2018-26) and China (26%). It is also worth putting the current sales level of 95m units into context of the last 30 years: the rate is almost 50% higher than the annual average sales rate in the 2000s (c.62m units), and around double the annual average sales rate of the 1990s (c.47m units). Applying an average sales growth rate of 2.5% (below the 3% growth rate recorded between 1990-2016), combined with an expected vehicle retirement rate, produces the following forecast for the world light vehicle population to 2030.

World light vehicle population (1960-2030)



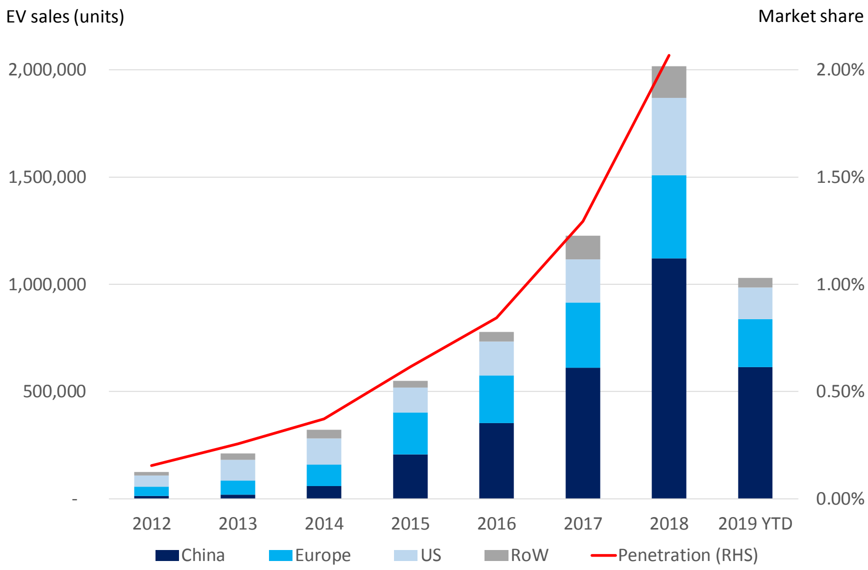
Source: Wood Mackenzie; Guinness estimates

As we stated before, this sets up the likelihood that the global vehicle fleet grows by nearly as much over 20 years, from 2010 to 2030, as it did in the previous 50 years.

Electric vehicles – pace of adoption

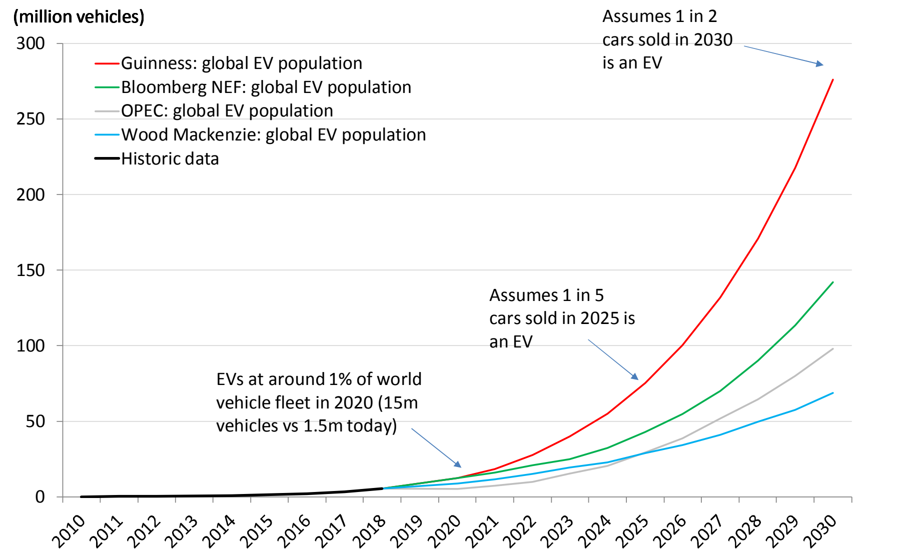
For all the interest in the roll-out of the EV industry, actual sales remain at low levels, relative to overall auto sales. In 2018, global EV sales totalled around 2m units, up from around 1.3m in 2017, lifting the EV share of the light auto sales from 1.3% to 2.1%. The rise in EV penetration in 2018 was driven by 80%+ increases in China and the US, but dragged down by 'slower' growth of 29% in Europe. This relatively sluggish pick up rate in Europe was reflected in comments made by BMW's development director, Klaud Frolich: "There are no customer requests for BEVs...from what we see, BEVs are for China and California and everywhere else is better off with PHEVs with good EV range."

Geographic breakdown of world EV sales (2012-2019 YTD)



Source: EV-Sales blog; Guinness estimates

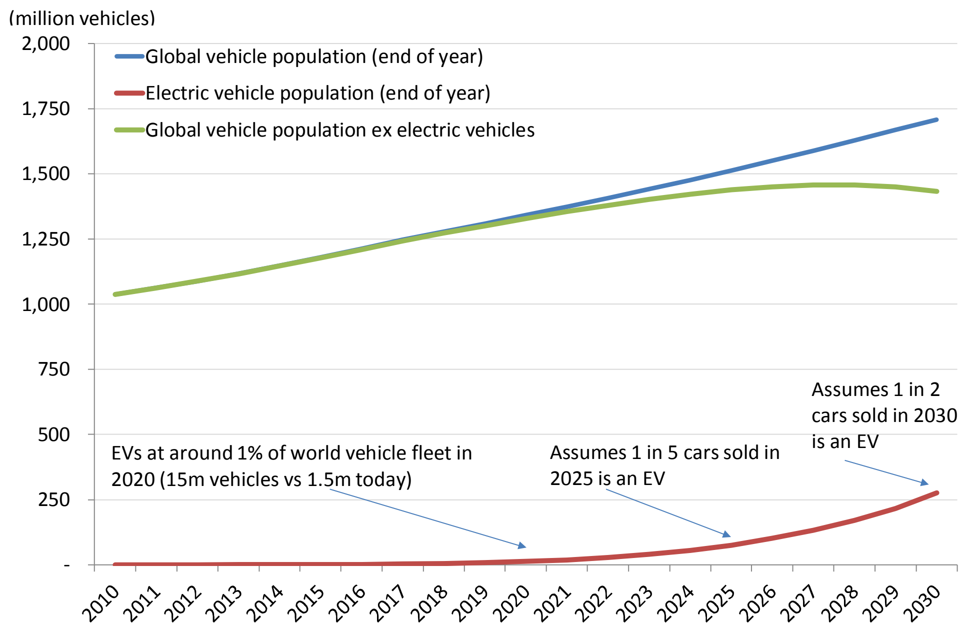
We expect a continuation of the 'S' curve now developing for EV sales, with 2019 sales likely at around 2.5m-3m units. Whilst only 1m EVs were sold in the first half of the year, we expect a similar seasonality to recent years, whereby second half sales accelerate. By 2025, we assume that 20% of total vehicles sales are EV, rising to 50% in 2030. Our assumptions imply the global EV population of just over 15m units by 2020, increasing to around 280m units in 2030. Below, we compare our forecasts with those from OPEC, BNEF and Wood Mackenzie.



Source: Wood Mackenzie; Bloomberg New Energy Finance; OPEC; Guinness estimates

Consistent with our previous analysis, we note that the Guinness EV forecast is higher than those produced by other observers. We are content with this since, given the objective is to assess the impact of EV penetration on oil demand, we prefer to pitch ourselves at the 'aggressive' end of the spectrum.

What does the Guinness scenario imply for the size of the ICE population?

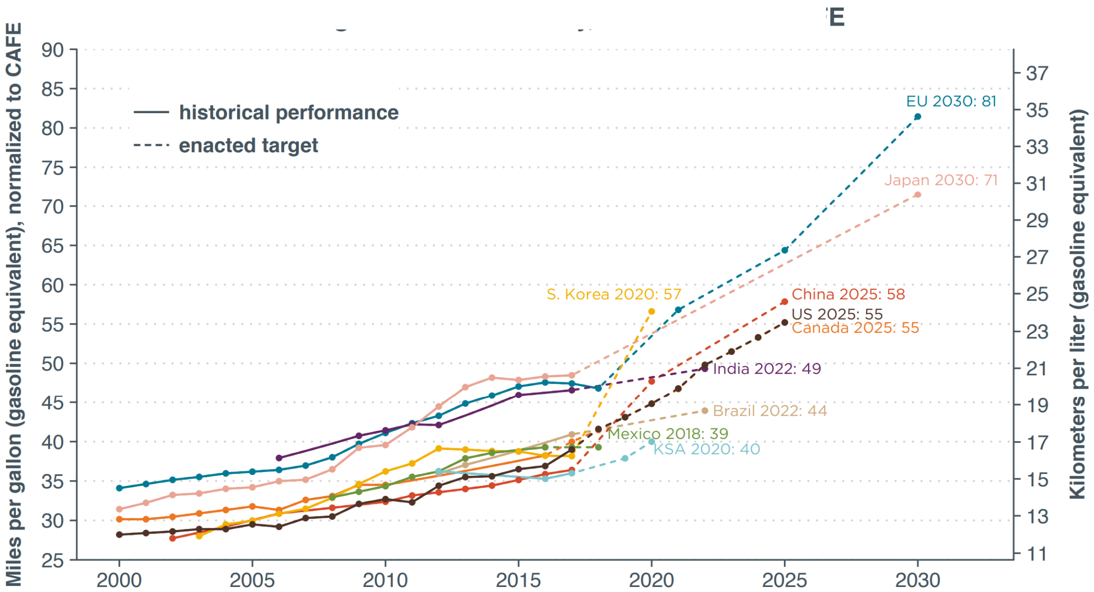


Source: IHS; Guinness estimates

Despite our relatively bullish assumptions on EV adoption, the offsetting impact of global vehicle population growth implies that the global population of ICE vehicles does not peak until the late 2020s. And after peaking just below 1.5bn, the population of ICE vehicles moves into relatively shallow decline, returning to the number of ICE vehicles that we see in the world today (1.2bn) in the mid 2030s.

As EV adoption progresses over the next 10 or 15 years, we must also acknowledge that the fuel efficiency of the ICE portion of the market will improve, which will put further pressure on oil demand growth from the ICE fleet. The graph below, produced by the International Council on Clean Transportation, shows historic and targeted passenger fuel economy standards from selected countries. History tells us that targeted fuel economy standards are rarely met, particularly in the US, but over the next 10 years, we believe that improvements in fuel efficiency will have more of an impact on global oil demand than EVs.

Passenger car fuel economy, normalized to CAFE



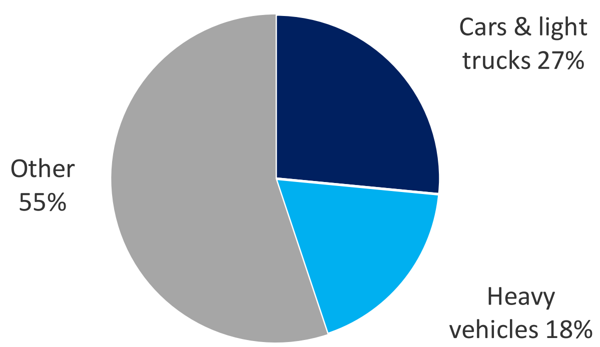
Source: International Council on Clean Transportation

Taken together, we continue to believe a growing fleet, improving fuel efficiency and EV penetration points to oil demand from cars and light vehicles peaking in the mid to late 2020s.

How important is oil demand from road transport in the context of total oil demand?

Given how often electric vehicles, batteries and climate change hit the headlines, there is a danger of overestimating the impact of road transport electrification on global oil demand. Cars and light trucks account for around 27% of global oil usage, with heavy vehicles accounting for 18%.

Structure of global oil demand



Source of demand	%
Power	5%
Petrochemicals	13%
Other industry	13%
Cars & light trucks	27%
Heavy vehicles	18%
Air travel	6%
Shipping	4%
Rail	2%
Other	11%
Total	**100%**

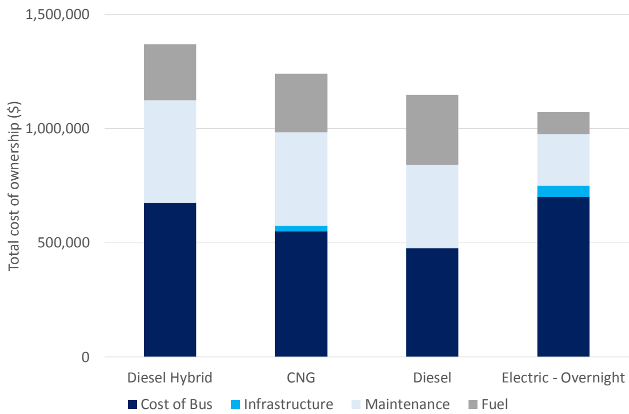
Source: OPEC; Bernstein; Guinness estimates

Historically we have focused on the 1.1tn light auto fleet, responsible for 25m b/day of global oil demand, but we are now seeing attention turning to the heavy vehicles market. Heavy vehicles are responsible for 18% of global oil demand and 60% of transport CO2 emissions, despite accounting for just 25% of vehicles on the road.

So far, electrification in the heavy vehicles market has mostly been focused on buses. In 2018, electric buses (e-buses) held over a 40% share of global bus sales and currently make up over 15% of the global bus fleet. However, these statistics are dominated by China, which accounts for 99% of e-bus sales and 99% of the e-bus fleet. Looking ahead, we forecast much stronger adoption in the US and the EU, with regional policy being a key driver (e.g. Los Angeles' target of a fully electric bus fleet by 2030; London's policy for all single decker buses from 2020 being emissions free). There is a strong case for electrifying buses due to high utilization, political focus on urban air quality, and driving patterns which gain the most from electrified powertrains. Despite upfront costs being 1.5-3x higher than diesel alternatives, in many regions e-buses are already cost competitive or cheaper on a total cost of ownership basis.

Again though, there is a danger of exaggerating the importance of these developments in the context of global oil demand. The 1.5m global municipal bus fleet is tiny when compared to the 220m heavy duty vehicle fleet, which consumes 17-18m b/day of oil. This fleet can be split into 190m light and urban heavy-duty vehicles (8m b/day) used for refuse, construction and urban-regional distribution; and 30m heavy and long-haul vehicles (9m b/day) employed in drayage, freight and regional-long-haul distribution.

Estimated Total Cost of Ownership (TCO) of municipal buses by drivetrain (USD)



Due to heavier vehicle weights, the efficiency of commercial EVs in kWh used per mile is much lower than lighter passenger vehicles. In addition, bigger battery packs take up more space, meaning less cargo can be carried, leading to lower revenues per journey, and slow payback periods, ultimately leading to far lower expected adoption rates. And although the EU's target of 30% lower emissions by 2030 seems strict, unlike in the passenger vehicle space, there should be many opportunities for efficiency gains in the form of adding skirts, improving aerodynamics, and light-weighting to allow for compliance with minimal electrification.

What about the rest of oil demand?

Assessing the direction of oil demand growth over the next decade or two also, of course, requires consideration of how other uses of oil are likely to evolve. In real terms, the world economy roughly doubled in size between 2004 and 2018, having also doubled over the previous fourteen years (1990-2014). Even taking a more conservative view of the next fourteen years, the level of economic expansion implies there will be a very significant increase in, for example, air passenger miles, ethylene production and seaborne trade:

• **Air revenue passenger kms** rising from 11trn in 2018 to 16trn in 2030

• **Seaborne trade** rising from 60trn ton miles in 2018 to 90trn ton miles in 2030

• **Ethylene demand** rising from 160m tons in 2018 to 235m tons in 2030

Source: IHS; IATA; IMF; Bernstein; Guinness estimates

In isolation, these impacts would put enormous upward pressure on oil demand, implying average growth of around 2m b/day each year between now and 2030. However, once we factor in improving efficiency of the light vehicle fleet, efficiencies for other types of vehicle and in other industries, plus the impact of electrification, the net effect is persistent but slowing demand growth into 2030. And when will oil demand then peak? The most likely scenario would be sometime around the mid 2030s, reaching a peak of somewhere between 110-115m b/day. This would imply average demand growth of 1m b/day between now and the peak: higher than that in the near years and tailing off in later years.

We believe that falling battery prices, concern around climate change, and tightening government policy will drive even faster adoption of electric vehicles than that assumed by most commentators. However, significant challenges remain, in the form of raw material availability, (especially for cobalt and nickel), charging infrastructure and battery quality. Even with our aggressive assumptions for EV adoption, analysis of oil demand until the 2030s relies more heavily on trends in fuel efficiency, light and heavy vehicle fleet expansion, and the trajectory for global GDP growth, with EVs taking a sharper bite out of oil demand in the decade following. The signs still point to significant new oil resources being required to keep up with continuing demand growth.

1) PERFORMANCE Guinness Global Energy Fund

The main index of oil and gas equities, the MSCI World Energy Index (net return), was down by 2.8% in June, while the MSCI World Index (net return) rose by 0.5%. The Fund was down by 3.4% (class E) in the month, underperforming the MSCI World Energy index by 0.6% (all in US dollar terms).

Within the Fund, May's strongest performers were Sunpower, OMV, Gazprom, Occidental and Anadarko while the weakest performers were Apache, Oasis, Unit Corp, Soco and Tullow.

Performance (in USD) 31/07/2019

Annualised

% returns	1 year	3 years	5 years	10 years	1999 to date
Guinness Global Energy	-21.9	-0.8	-10.6	-0.5	8.7
MSCI World Energy Index	-14.8	2.5	-5.2	2.5	5.7

Calendar year

% returns	2019	2018	2017	2016	2015	2014	2013	2012	2011	2010	2009	2008	2007
Guinness Global Energy	0.0	-19.7	-1.3	27.9	-27.6	-19.1	24.4	3.0	-13.6	15.3	61.8	-48.2	37.6
MSCI World Energy Index	0.0	-15.8	5.0	26.6	-22.8	-11.6	18.1	1.9	0.2	11.9	26.2	-38.1	29.8

Source: Guinness Asset Management and Financial Express, bid to bid, gross income reinvested, in US dollars

Calculation by Guinness Asset Management Limited, simulated past performance prior to 31.3.08, launch date of Guinness Global Energy Fund. The Guinness Global Energy investment team has been running global energy funds in accordance with the same methodology continuously since November 1998. These returns are calculated using a composite of the Investec GSF Global Energy Fund class A to 29.2.08 (managed by the Guinness team until this date); the Guinness Atkinson Global Energy Fund (sister US mutual fund) from 1.3.08 to 31.3.08 (launch date of this Fund), the Guinness Global Energy Fund class A (1.49% OCF) from launch to 02.09.08, and class E (1.24% OCF) thereafter. Performance would be lower if an initial charge and/or redemption fee were included.

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

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

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

2) PORTFOLIO Guinness Global Energy Fund

Buys/Sells

In July, there were no stock switches made. The portfolio was actively rebalanced during the month.

Sector Breakdown

The following table shows the asset allocation of the Fund at **July 31 2019**.

(%)	31 Dec 2011	31 Dec 2012	31 Dec 2013	31 Dec 2014	31 Dec 2015	31 Dec 2016	31 Dec 2017	31 Dec 2018	31 July 2019
Oil & Gas	***97.9***	***97.3***	***93.7***	***93.7***	***95.1***	***96.7***	***98.4***	***99.7***	***96.9***
Integrated	30.9	30.4	29.2	27.0	30.4	32.5	28.6	27.2	27.1
Integrated – Can & Em Mkts	8.8	8.4	9.4	10.3	11.1	14.3	14.2	15.3	15.2
Exploration & production	41.1	40.3	35.4	36.2	36.5	35.4	37.0	39.0	36.6
Oil & Gas Storage & Transportation	0.0	0.0	0.0	0.0	0.0	0.0	3.5	3.9	3.6
Drilling	5.9	7.1	6.4	3.3	1.5	2.2	1.9	1.4	0.9
Equipment & services	6.1	7.4	9.8	13.4	11.4	8.6	9.5	8.8	9.5
Refining and marketing	5.1	3.7	3.5	3.5	4.2	3.7	3.7	4.1	4.0
Solar	**1.3**	**1.2**	**2.6**	**3.7**	**4.7**	**0.9**	**1.4**	**0.4**	**0.7**
Coal & consumables	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Construction & engineering	**0.4**	**0.6**	**1.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Cash	**0.4**	**0.9**	**2.7**	**2.6**	**0.2**	**2.4**	**0.2**	**-0.1**	**2.4**
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

Source: Guinness Asset Management
Basis: Global Industry Classification Standard (GICS)

The Fund at July 31 2019 was on a price to earnings ratio (P/E) for 2019 of 12.8x versus the S&P 500 Index at 17.9x as set out in the following table:

	2012	2013	2014	2015	2016	2017	2018	2019
Guinness Global Energy Fund P/E	6.9	7.5	7.7	20.7	40.0	21.6	12.0	12.8
S&P 500 P/E	30.8	27.8	24.8	29.7	28.1	23.9	19.7	18.4
Premium (+) / Discount (-)	*-78%*	*-73%*	*-69%*	*-30%*	*42%*	*-10%*	*-39%*	*-30%*
Average oil price (WTI $/bbl)	94	98	93	49	43	51	66	

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

Portfolio holdings

Our integrated and similar stock exposure (c.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, Equinor and OMV. At July 31 2019 the median P/E ratios of this group were 11.2x/12.4x 2018/2019 earnings. We also have two Canadian integrated holdings, Suncor and Imperial Oil. Both companies have significant exposure to oil sands in addition to downstream assets.

Our exploration and production holdings (c.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 (EnCana, Devon and Oasis), with five other names (Apache, Occidental, ConocoPhillips, Noble Energy, Anadarko) having a mix of US and international production and one (Tullow) which is African focused. One of the key metrics behind a number of the E&P stocks held is low enterprise value / proven reserves. Almost all of the US E&P stocks held also provide exposure to North American natural gas.

We have exposure to four (pure) emerging market stocks in the main portfolio, though one is a half-position, and in total represent 12% of the portfolio. Two are classified as integrateds (Gazprom and PetroChina) and two as E&P companies (CNOOC and SOCO International). Gazprom is the Russian national oil and gas company which produces approximately a quarter of the European Union gas demand and trades on 3.7x 2019 earnings. PetroChina is one of the world's largest integrated oil and gas companies and has significant growth potential and, alongside CNOOC, enjoys advantages as a Chinese national champion. SOCO International is an E&P company with production in Vietnam.

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

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

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

Portfolio at June 30 2019 (for compliance reasons disclosed one month in arrears)

Guinness Global Energy Fund 30 June 2019

Stock	Curr.	Country	% of NAV	2009 B'berg mean PER	2010 B'berg mean PER	2011 B'berg mean PER	2012 B'berg mean PER	2013 B'berg mean PER	2014 B'berg mean PER	2015 B'berg mean PER	2016 B'berg mean PER	2017 B'berg mean PER	2018 B'berg mean PER	2019 B'berg mean PER
Integrated Oil & Gas														
Chevron	USD	US	4.00	24.3	13.4	9.3	10.1	11.2	12.9	34.2	89.7	30.0	15.4	16.6
Royal Dutch Shell PLC	EUR	NL	3.95	14.8	10.5	7.8	7.7	10.2	9.0	19.1	31.4	17.0	12.6	11.7
BP PLC	GBP	GB	3.85	8.8	6.1	6.1	7.6	9.4	11.2	19.7	37.7	22.5	11.6	12.7
Total SA	EUR	FR	4.01	13.8	10.7	9.6	9.1	10.2	10.3	13.3	15.7	14.7	11.0	10.4
ENI SpA	EUR	IT	4.06	10.2	7.8	7.4	7.3	11.6	13.5	63.2	nm	25.5	12.1	11.6
Equinor ASA	NOK	NO	3.85	11.4	8.6	7.4	6.6	8.1	11.3	27.6	139.9	14.6	9.8	10.7
OMV AG	EUR	AT	3.84	17.2	10.7	13.4	9.4	11.5	14.2	12.7	13.0	8.7	9.0	8.6
			27.57											
Integrated / Oil & Gas E&P - Canada														
Suncor Energy Inc	CAD	CA	3.76	38.7	25.8	11.5	12.7	12.8	12.8	36.3	nm	21.9	14.6	12.5
Canadian Natural Resources Ltd	CAD	CA	3.87	14.7	14.5	15.3	22.2	15.7	10.3	254.0	nm	30.1	12.6	10.7
Imperial Oil	CAD	CA	3.85	18.3	15.8	9.8	8.7	11.3	9.5	20.4	60.2	28.3	13.2	13.4
			11.48											
Integrated Oil & Gas - Emerging market														
PetroChina Co Ltd	HKD	HK	3.68	6.4	5.2	5.1	5.8	6.5	6.4	19.8	77.6	30.2	12.2	11.7
Gazprom OAO	USD	RU	4.45	8.4	6.6	4.5	4.7	4.3	7.2	4.4	6.3	7.1	3.9	3.9
			8.12											
Oil & Gas E&P														
Occidental Petroleum Corp	USD	US	3.59	13.5	8.9	6.0	7.3	7.2	8.7	302.9	nm	56.0	10.2	13.5
ConocoPhillips	USD	US	3.89	16.9	10.3	7.2	10.7	10.9	11.5	nm	nm	97.9	13.7	14.0
Anadarko Petroleum Corp	USD	US	3.01	nm	40.7	22.3	21.1	17.0	15.4	nm	nm	nm	28.4	30.7
Apache Corp	USD	US	3.22	5.2	3.1	nm	3.0	3.6	5.2	nm	nm	273.3	17.3	28.5
Devon Energy Corp	USD	US	3.25	8.8	4.8	4.7	8.8	6.7	5.5	11.6	nm	15.6	18.9	18.0
Noble Energy Inc	USD	US	3.17	13.2	10.8	8.5	9.8	7.2	9.6	393.0	nm	1400.0	23.2	nm
EnCana Corp	USD	US	2.65	1.3	4.2	7.0	3.1	4.1	2.5	nm	218.0	9.5	5.9	5.5
Oasis Petroleum Inc	USD	US	1.88	nm	33.8	6.9	3.8	2.1	2.3	7.1	nm	nm	20.1	41.2
			24.67											
International E&Ps														
CNOOC Ltd	HKD	HK	3.96	17.4	10.1	7.6	8.1	8.3	9.9	29.6	nm	17.1	9.6	9.6
Tullow Oil PLC	GBP	GB	1.72	40.5	19.7	4.5	4.0	30.3	nm	nm	nm	13.7	23.7	10.6
Soco International PLC	GBP	GB	0.55	5.1	7.1	4.6	1.3	1.3	2.1	nm	nm	nm	26.6	19.9
			6.22											
Midstream														
Enbridge Inc	USD	CA	3.68	50.9	43.9	39.6	36.4	33.6	30.8	27.8	25.8	31.3	22.7	23.3
			3.68											
Drilling														
Unit Corp	USD	US	1.13	3.4	2.9	2.2	2.1	2.4	2.1	nm	nm	16.7	8.9	11.7
			1.13											
Equipment & Services														
Halliburton Co	USD	US	3.41	17.4	11.3	6.8	7.6	7.3	5.8	15.4	nm	19.6	12.3	16.9
Helix Energy Solutions Group Inc	USD	US	2.06	14.9	16.3	5.7	4.6	8.0	4.5	51.1	nm	nm	39.2	29.4
Schlumberger Ltd	USD	US	3.70	14.6	14.4	11.0	9.5	8.4	7.2	11.9	34.4	27.2	24.4	25.9
			9.17											
Solar														
Sunpower Corp	USD	US	0.74	9.3	7.4	130.4	71.3	7.6	8.1	5.4	nm	nm	nm	nm
			0.74											
Oil & Gas Refining & Marketing														
Valero Energy Corp	USD	US	4.29	nm	53.9	21.5	17.5	20.9	14.1	9.7	23.3	17.6	13.9	13.5
			4.29											
Research Portfolio														
Cluff Natural Resources PLC	GBP	GB	0.21	nm	nm	nm	nm	nm	nm	nm	nm	nm	nm	nm
EnQuest PLC	GBP	GB	0.57	nm	3.3	3.8	1.1	1.3	2.3	22.6	1.5	nm	5.0	2.4
JKX Oil & Gas PLC	GBP	GB	0.11	1.0	1.2	1.4	1.8	3.5	9.7	nm	nm	nm	24.3	16.2
Diversified Gas & Oil PLC	GBP	GB	0.46	nm	nm	nm	nm	nm	nm	nm	nm	nm	nm	nm
Reabold Resources PLC	GBP	GB	0.52	nm	nm	nm	nm	nm	nm	nm	nm	nm	nm	nm
Shandong Molong Petroleum Machiner	HKD	HK	0.06	6.8	2.7	3.7	nm	nm	nm	nm	nm	nm	nm	nm
			1.93											
		Cash	0.99											
		Total	100											
		PER		11.0	9.2	8.1	7.1	7.6	7.9	20.5	39.5	21.8	12.1	12.2
		Med. PER		13.5	10.3	7.3	7.7	8.2	9.5	20.1	32.9	21.9	13.2	13.1

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

3) OUTLOOK

i) Oil market

The table below illustrates the difference between the growth in world oil demand and non-OPEC supply since 2015:

	2015	2016	2017	2018	2019E	2020E
					IEA	*IEA*
World Demand	***95.3***	***96.4***	***98.0***	***99.1***	***100.3***	***101.7***
Non-OPEC supply (inc NGLs)	*59.8*	*59.2*	*60.1*	*62.9*	*64.9*	*67.0*
OPEC NGLs	*5.2*	*5.4*	*5.5*	*5.5*	*5.6*	*5.6*
Non-OPEC supply plus OPEC NGLs	**65.0**	**64.6**	**65.6**	**68.4**	**70.5**	**72.6**
Call on OPEC (crude oil)	**30.3**	**31.8**	**32.4**	**30.7**	**29.8**	**29.1**
Congo supply adjustment	0.3	0.3	0.3	0.3	0.3	0.3
Gabon supply adjustment	0.2	0.2	0.2	0.2	0.2	0.2
Eq Guinea supply adjustment	0.1	0.1	0.1	0.1	0.1	0.1
Call on OPEC-11 (crude oil)	**29.7**	**31.2**	**31.8**	**30.1**	**29.2**	**28.5**

Source: 2006 - 2014: IEA oil market reports; 2015 - 19: July 2019 Oil market Report
OPEC-11 = Algeria; Angola; Ecuador; Iran; Iraq; Kuwait; Libya; Nigeria; Saudi Arabia; UAE; Venezuela

Global oil demand in 2018 was 12m b/day higher than the pre-financial crisis (2007) peak. This means the combined effect of the 2007/08 oil price spike and the 2008/09 recession was shrugged off remarkably quickly, thanks to growth in demand from emerging markets. The IEA forecast a further rise of 1.2m b/day in 2019, which would take oil demand to an all-time high of 100.3m b/day.

OPEC

The last five years have proved a testing time for OPEC. They have tried to keep prices strong enough that OPEC economies are not running excessive deficits, whilst not pushing the price too high and over-stimulating non-OPEC supply.

The effect of $100+ bbl oil, enjoyed for most of the 2011-2014 period, emerged in 2014 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. OPEC met in late 2014 and responded to rising non-OPEC supply with a significant change in strategy to one that prioritised market share over price. Post the November 2014 meeting, OPEC not only maintained their quota but also raised production significantly, up over 18 months by 2.5m b/day. This contributed to an oversupplied market in 2015 and 2016.

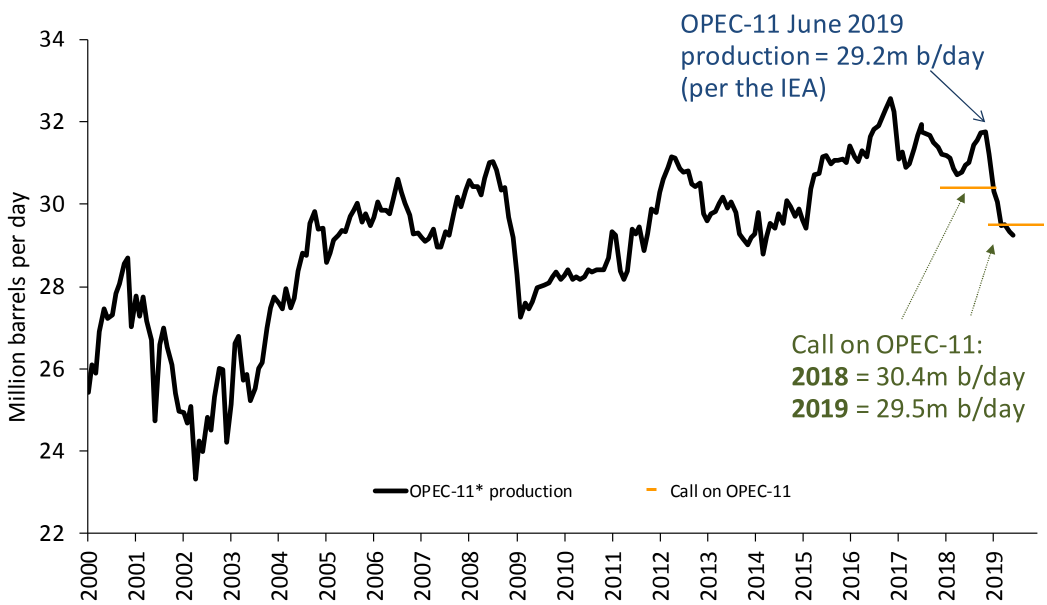
In November 2016, faced with sharply lower oil prices, OPEC stepped back from their market share stance, announcing plans for the first production cut since 2008, opting for a new production limit of 32.5m b/day. The announcement represented a cut of 1.2m b/day. There was also an understanding that non-OPEC, including Russia, would cut production by 0.6m b/day, taking the total reduction to 1.8m b/day. Compliance with the cuts was very strong and, after been delayed initially by a variety of temporary factors, inventories started to decline from mid 2017. Having originally been excluded from the cuts, Libya and Nigeria were subsequently included in the quota system.

('000 b/day)	30-Nov-14	31-Dec-16	31-Jul-19	Current vs Nov 2014 (OPEC hold mkt share)	Current vs Dec 2016 (OPEC cut production)
Saudi	9,650	10,480	**9,870**	220	-610
Iran	2,780	3,730	**2,210**	-570	-1,520
Iraq	3,370	4,630	**4,700**	1,330	70
UAE	2,800	3,070	**3,060**	260	-10
Kuwait	2,790	2,860	**2,710**	-80	-150
Nigeria	1,970	1,500	**1,890**	-80	390
Venezuela	2,350	2,080	**760**	-1,590	-1,320
Angola	1,640	1,670	**1,390**	-250	-280
Libya	580	630	**1,100**	520	470
Algeria	1,100	1,110	**1,010**	-90	-100
Ecuador	561	550	**540**	-21	-10
OPEC-11	**29,591**	**32,310**	**29,240**	**-351**	**-3,070**

Source: Bloomberg; Guinness Asset Management

The last eighteen months has continued to be a volatile time for OPEC. For the first half of 2018, a steep production decline from Venezuela and the promise of lower Iranian exports lead other OPEC members to raise supply, designed to prevent oil prices spiking too high. Towards the end of the year, it became apparent that OPEC had over-compensated and risked oversupplying the market in 2019. In December 2018, OPEC met in Vienna and, together with non-OPEC, announced a proposed cut of 1.2m b/day starting in January 2019 and lasting for an initial period of six months. It was proposed that OPEC (excluding Libya, Venezuela and Iran) cut total production by 0.8m b/day while non-OPEC (led predominantly by Russia) cut a total of 0.4m b/day. In July 2019, the existing quota cuts were extended to March 2020.

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



Source: IEA Oil Market Report (July 2019 and prior); Guinness estimates

OPEC's actions in recent years demonstrate a commitment to delivering a reasonable oil price to satisfy their own economies but also to incentivise investment in long term projects. Saudi's actions at the head of OPEC appear designed to achieve an oil price that to some extent closes their fiscal deficit ($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, in excess of current levels to balance their fiscal needs, but they realise that patience is required to achieve that goal.

Overall, we reiterate two important criteria for Saudi:

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

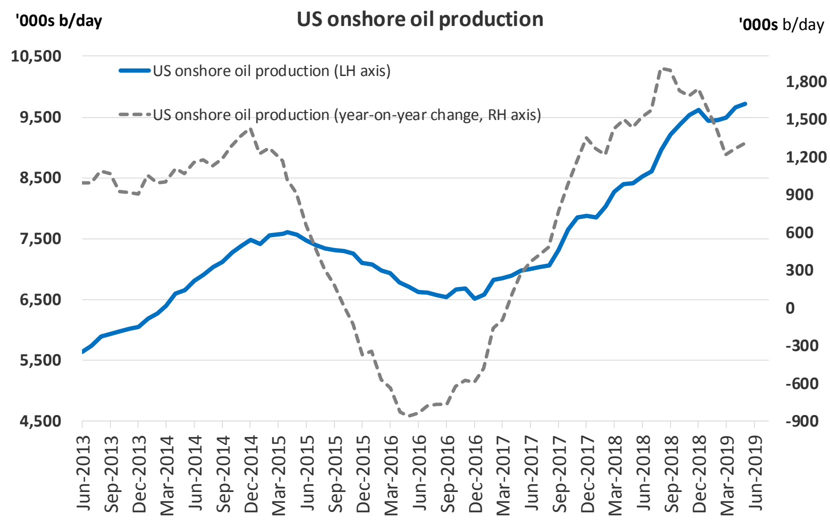
Nothing in the market in recent years has changed our view that OPEC can put a floor under the price – as they did in 2016, 2008, 2006, 2001, 1998 – and again in late 2018. Recent meetings and decisions indicate that OPEC have the resolve to continue in this manner.

Supply looking forward

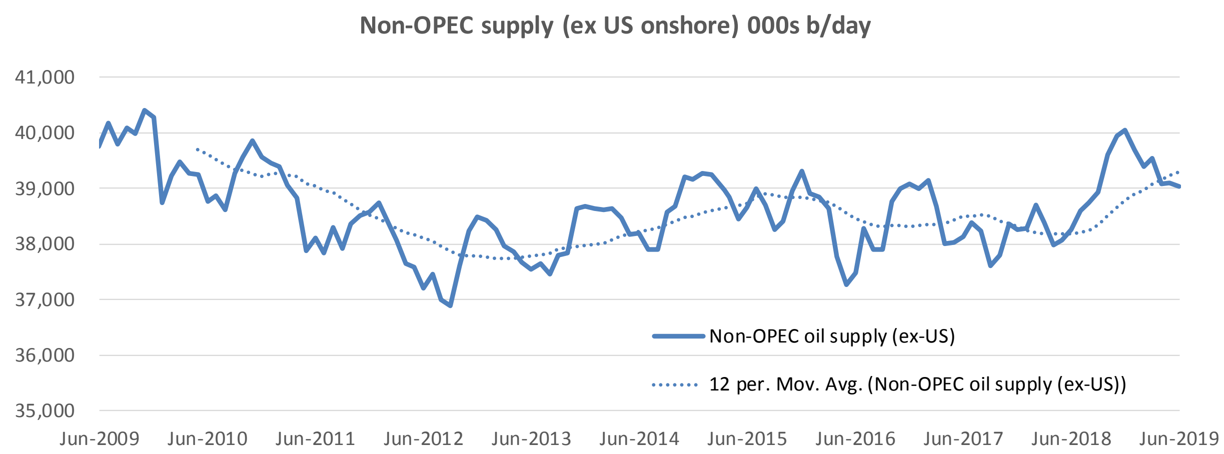
The non-OPEC world has, since the 2008 financial crisis, grown its production more meaningfully than in the seven years before 2008. The growth was 0.9% p.a. from 2001-2008, increasing to 1.7% p.a. from 2008-2018.

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

The growth in US shale oil production, in particular from the Permian basin, raises the question of how much more there is to come and at what price. New oil production from these sources peaked in April 2015 at around 4m b/day, then declined by around 1.1m b/day, but is now well above the previous peak. Our assessment is that US shale oil is a capital intensive source of oil but one where real growth is viable, on average, at around $50 oil prices. In particular, there appears to be ample inventory in the Permian basin to allow growth well into the 2020s. In total, it could be comparable in size to the North Sea, i.e. it could grow by around a further 4m b/day over the next five years, but only if the price is sufficiently high to incentivise growth. The rate of development is heavily dependent on the cashflow available to producing companies, which tends to be recycled immediately into new wells, and the underlying cost of services to drill and fracture the wells. Naturally, cashflows available for reinvestment in a $50-60/bl world are far lower than in a $100/bl world, but with efficiency improvements, enough to see growth sustaining.



Offsetting US onshore shale oil growth, we expect to see non-OPEC supply growth outside the US slow, as the queue of large conventional project start-ups slows. Since 2014, the number of project start-ups in this region has been sustained at a high level, despite lower oil prices, since projects that were sanctioned before the 2014 (when oil was $100/bl+) have continued to come onstream. However, the slowdown in investment post 2014 creates the likelihood that non-OPEC (ex US) production will struggle to grow into the start of the 2020s. On a ten year view, it is interesting to note that non-OPEC (ex US) has essentially been flat, as new investment has simply offset the decline profiles of existing production:



Source: PIW; Guinness (July 2019 and prior)

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

Demand looking forward

The IEA estimate that 2019 oil demand growth will be 1.2m b/day, taking demand to over 100m b/day. Generally speaking, we have seen demand forecasts revised consistently higher since 2014, with the positive effect of lower oil prices continuing to surprise.

The IEA's global demand estimate for 2019 comprises an increase in non-OECD demand of 1.0m b/day and OECD demand growth of 0.2m b/day. The components of this non-OECD demand growth can be summarised as follows:

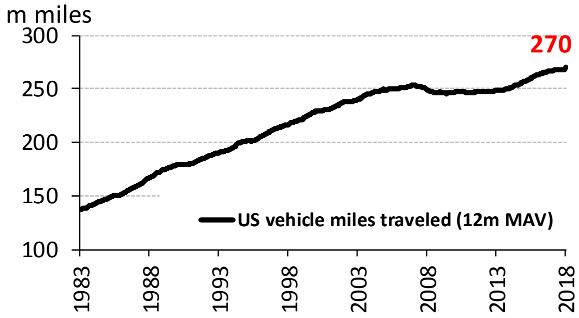
Figure 8: Non-OECD oil demand

m b/day	Demand								Growth							
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019e**	**2020e**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019e**	**2020e**
Asia	22.1	22.8	24.1	25.0	26.0	26.8	27.7	28.3	0.7	0.7	1.3	0.9	1.0	0.8	0.9	0.6
Middle East	7.9	8.4	8.5	8.5	8.5	8.4	8.5	8.5	0.1	0.5	0.1	0.0	0.0	-0.1	0.1	0.1
Latin America	6.7	6.8	6.7	6.4	6.5	6.4	6.4	6.4	0.3	0.1	-0.1	-0.3	0.1	-0.1	0.0	0.0
FSU	4.7	4.66	4.6	4.5	4.5	4.7	4.8	4.9	0.1	0.0	-0.1	0.0	0.0	0.2	0.1	0.1
Africa	3.9	3.8	4.2	4.3	4.3	4.3	4.4	4.4	0.1	-0.1	0.4	0.1	0.0	0.0	0.1	0.0
Europe	0.7	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0
Total	**46.0**	**47.2**	**48.7**	**49.5**	**50.5**	**51.4**	**52.5**	**53.4**	**1.3**	**1.2**	**1.6**	**0.7**	**1.1**	**0.9**	**1.1**	**0.8**

Source: IEA Oil Market Report (July 2019)

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

OECD demand in 2019 is forecast to be up by 0.2m 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% 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, the development of alternative fuels 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.

We keep a close eye on developments in the ‘new energy’ vehicle fleet (electric vehicles; hybrids etc), but see nothing that makes a significant dent on the consumption of gasoline and diesel in the next few years. Sales of electric vehicles (pure electric and plug-in hybrid electrics) globally were around 1.8m in 2018, up from 1.2m in 2017. We expect to see EV sales accelerate in 2019 to around 2.5m, or 3% of total global sales. Even applying an aggressive growth rate to EV sales, we see EVs comprising only around 0.7% of the global car fleet in 2020. Looking further ahead, we expect the penetration of EVs to accelerate, causing global gasoline demand to peak at some point in the second half of the 2020s. However, owing to the weight of oil demand that comes from sources other than passenger vehicles (around 70%), which we expect to continue growing linked to GDP, we expect total oil demand not to peak until the mid 2030s.

Conclusions about oil

The table below summarises our view by showing our oil price forecasts for WTI and Brent in 2019 against their historic levels, and rises/falls in percentage terms that we have seen in the period from 2002 to 2018.

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

Oil price (inflation adjusted)																			*Est*
12 month MAV	1986-2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
WTI	30	33	38	49	66	75	82	104	68	84	99	94	98	93	49	45	51	65	58
Brent	30	32	35	46	64	75	82	103	67	84	115	112	108	99	52	45	54	72	60
Brent/WTI (12m MAV)	**30**	**33**	**37**	**48**	**65**	**75**	**82**	**104**	**68**	**84**	**107**	**103**	**103**	**96**	**51**	**45**	**53**	**68**	**59**
Brent/WTI y-on-y change (%)		8%	12%	30%	37%	15%	9%	26%	-35%	24%	27%	-4%	0%	-7%	-47%	-11%	17%	30%	-14%
Brent/WTI (5yr MAV)	30	25	32	37	42	51	61	75	79	82	89	93	93	99	92	80	69	63	55

We expect Brent oil to trade in a $60-70/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 over the next few years as conventional non-OPEC supply declines.

The world oil bill at around $70/bl represents 3.0% of 2018 Global GDP, 12% under the average of the 1970 – 2015 period (3.4%). A return to oil representing 3.4% of GDP implies an oil price of around $80/bl.

We believe that Saudi's long-term objective remains to maintain a 'good' oil price, something around $70/bl.

Natural gas market

US gas demand

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

Industrial demand (of which around 35% comes from petrochemicals) tends to trend up and down depending on the strength of the economy, the level of the US dollar and the differential between US and international gas prices. Electricity gas demand (i.e. power generation) is affected by weather, in particular warm summers which drive demand for air conditioning, but the underlying trend depends on GDP growth and the proportion of incremental new power generation each year that goes to natural gas versus the alternatives of coal, nuclear and renewables. Gas has been taking market share in this sector: in 2018, 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	2018	2019E
US natural gas demand:													
Residential/commercial	21.2	22.0	21.6	21.6	21.6	19.2	22.4	23.4	21.4	20.5	20.9	22.1	21.5
Power generation	18.7	18.2	18.8	20.2	20.8	24.9	22.3	22.3	26.5	27.3	25.3	28.5	28.5
Industrial	18.2	18.2	16.9	18.5	19.0	19.7	20.3	20.9	20.6	21.1	21.6	22.8	23.2
Pipeline exports (Canada & Mexico)	2.1	2.5	2.8	2.9	4.1	4.4	4.4	4.1	4.9	6.3	6.2	7.0	7.8
LNG exports	-	-	-	-	-	-	-	-	0.1	1.0	2.6	3.4	6.7
Pipeline/plant/other	5.2	5.3	5.5	5.6	5.8	6.1	6.7	6.3	6.5	6.4	6.5	6.8	6.8
Total demand	**65.4**	**66.2**	**65.6**	**68.8**	**71.3**	**74.3**	**76.1**	**77.0**	**80.0**	**82.6**	**83.1**	**90.6**	**94.5**
Demand growth	**4.0**	**0.8**	**- 0.6**	**3.2**	**2.5**	**3.0**	**1.8**	**0.9**	**3.0**	**2.6**	**0.5**	**7.5**	**3.9**

Source: EIA; Simmons; Guinness estimates

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

We expect US demand in 2019, assuming prices remain around $2.50/mcf, to exhibit further strong growth of around 4 Bcf/day. Normalised weather would keep a cap on power generation demand, but there should be a surge in LNG exports (c.3 Bcf/day), as a wave of new export terminals come into service. The table below shows the scheduled start-up of terminals, with 4.3 Bcf/day of capacity coming in 2019.

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

Source: EIA; Simmons

Looking further ahead to 2025, 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. Beyond the mid-2020s, we expect power generation from gas to face stronger competition from renewables.

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.

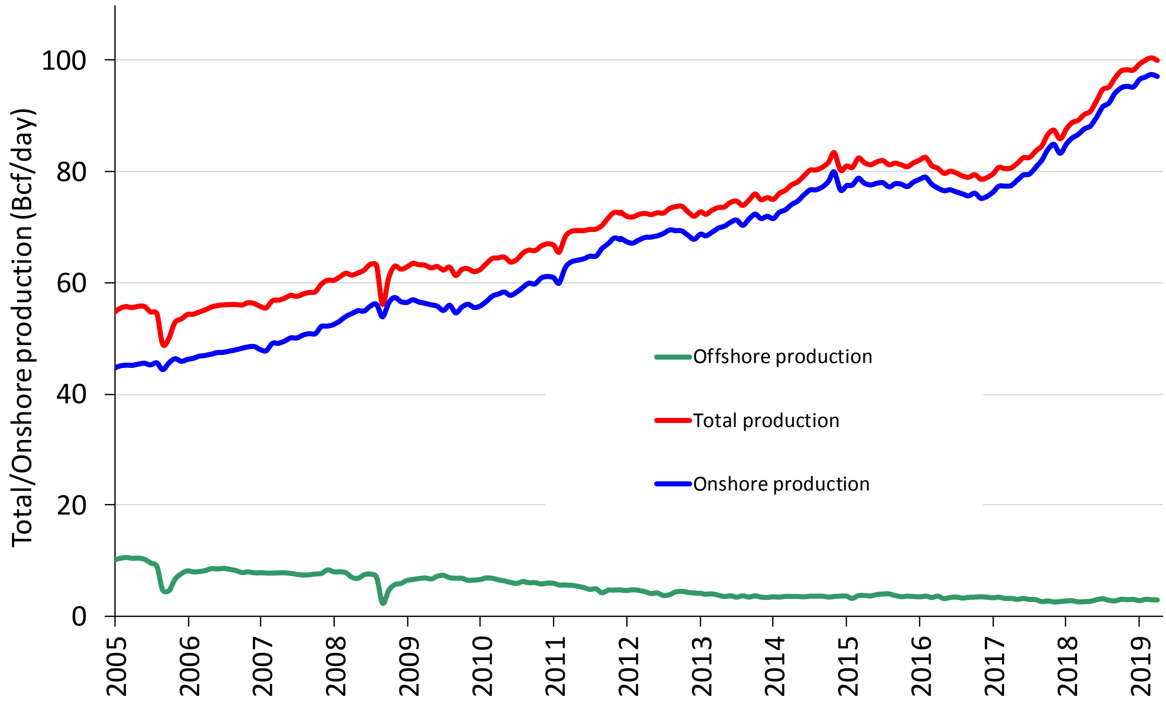
The supply side fundamentals for natural gas in the US are driven by 3 main moving parts: onshore and offshore domestic production, and pipeline imports of gas from Canada. Of these, onshore supply is the biggest component, making up over 85% of total supply.

Bcf/day	2007	2008	*2009*	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019E
US natural gas supply:													
US onshore	45.1	48.8	49.8	52.2	57.7	61.5	62.7	67.5	70.6	70.0	71.1	79.2	84.8
US offshore (Gulf of Mexico)	7.7	6.3	6.7	6.2	5.0	4.2	3.6	3.4	3.6	3.4	2.5	2.1	2.0
Pipeline imports (Canada)	10.4	9.8	9.0	9.0	8.5	8.0	7.5	7.1	7.1	8.0	8.0	8.0	8.0
LNG imports & other	2.3	1.2	1.4	1.4	1.0	0.8	0.6	0.5	0.5	0.4	0.3	0.3	0.3
Total supply	**65.5**	**66.1**	**66.9**	**68.8**	**72.2**	**74.5**	**74.4**	**78.5**	**81.8**	**81.8**	**81.9**	**89.6**	**95.1**
Supply growth	**3.2**	**0.6**	**0.8**	**1.9**	**3.4**	**2.3**	**- 0.1**	**4.1**	**3.3**	**-**	**0.1**	**7.7**	**5.5**
(Supply)/demand balance	**- 0.1**	**0.1**	**- 1.3**	**-**	**- 0.9**	**- 0.2**	**1.7**	**- 1.5**	**- 1.8**	**0.8**	**1.2**	**1.0**	**- 0.6**

Source: EIA; Simmons; Guinness estimates

Since the middle of 2008 the weaker gas price in the US reflects growing onshore US production driven by rising shale gas and associated gas production (a by-product of growing onshore US oil production). Interestingly, the overall rise in onshore production has come despite a collapse in the number of rigs drilling for gas, which has dropped from a 1,606 peak in September 2008 to only 81 in September 2016 and now 169 at the end of July 2019. However, offsetting the fall, the average productivity per rig has risen dramatically as producers focus their attention on the most prolific shale basins, whilst associated gas from oil production has grown handsomely. Onshore gas supply (gross, before processing) is now (April 2019) at 97.3 Bcf/day, far above the 57.4 Bcf/day peak in November 2008 before the rig count collapsed.

Figure 10: US natural gross gas production 2005 – 2019 (Lower 48 States)



Source: EIA 914 data (May 2019 published in July 2019)

The outlook for gas production in the US depends on three key factors: the rise of associated gas (gas produced from wells classified as oil wells); expansion of the newer shale basins, principally the Marcellus/Utica, and the decline profile of legacy gas fields.

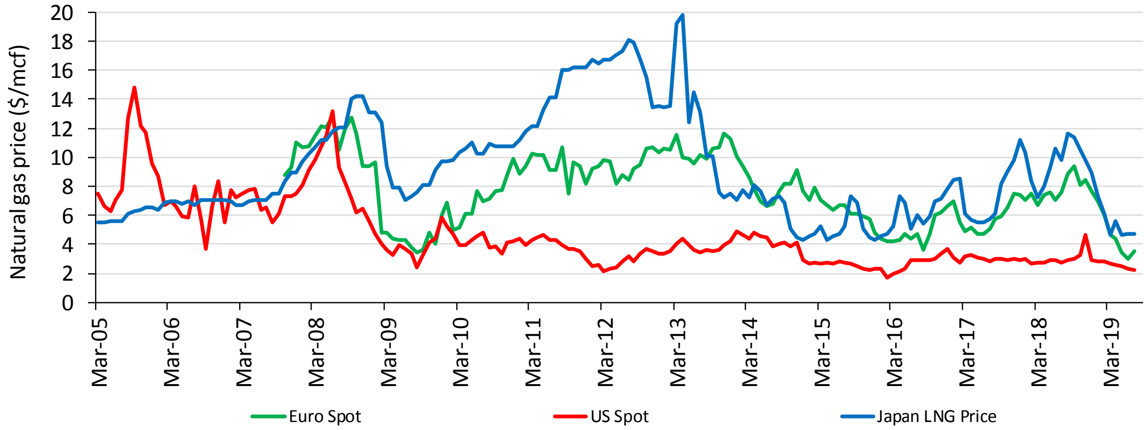
Associated gas production declined in 2016 with the fall of shale oil production, but with US oil supply now growing well again, so associated gas production has picked up. Generally, we expect to see rates of around 2-3 Bcf/day of associated gas per 1m b/day of oil production growth.

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

Overall, if the price remains in the $2.50-$3/mcf range, we expect a significant jump in onshore gas supply in 2019, up by around 5 Bcf/day versus 2018.

Outlook for US LNG exports – global gas arbitrage

The prospects for US LNG exports depend on the differentials to European and Asian gas prices, and whether the economic incentive exists to carry out the trade. The UK national balancing point (NBP) gas price – which serves as a proxy to the European traded gas price – remains at a small premium to the US gas price (c.$4/mcf versus c.$2.70/mcf). Asian spot LNG prices fell sharply down to around $4.50/mcf at the start of 2016 but have since averaged around $8/mcf (though currently around $5/mcf on seasonal weakness) as Chinese gas demand strengthens. The implied economics for US LNG exports into Europe and Asia are reasonably attractive assuming international prices are over $5/mcf.



Source: Bloomberg (July 2019)

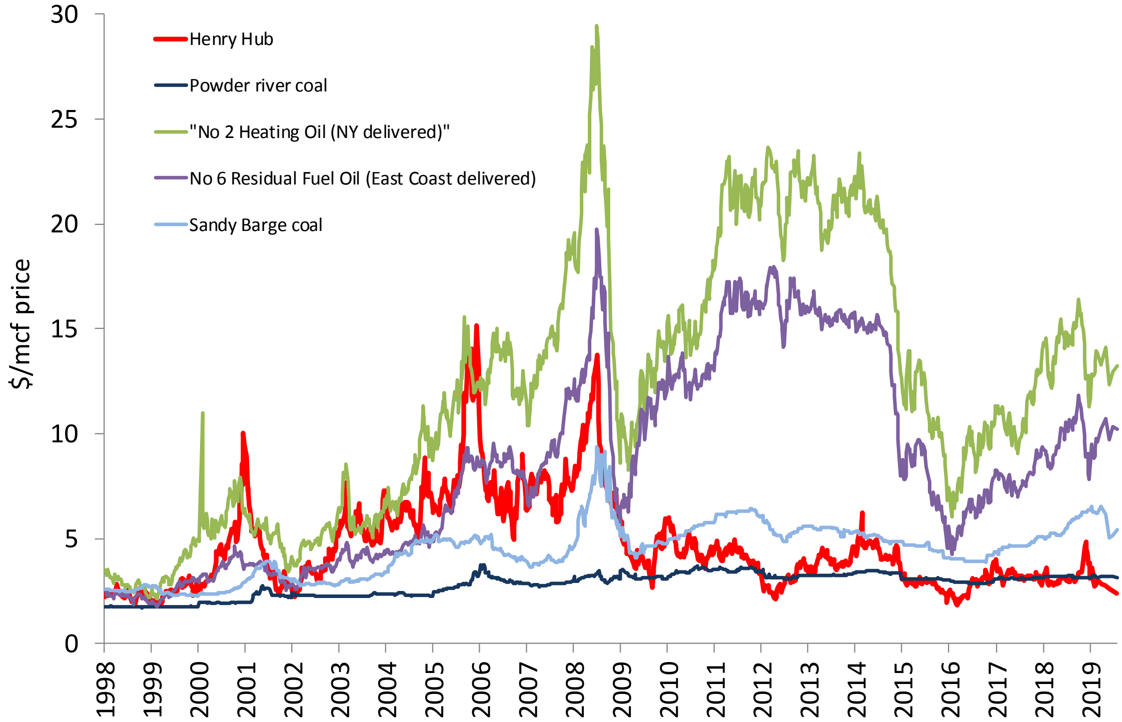
Relationship with oil and coal

The oil/gas price ratio ($ per bbl WTI/$ per mcf Henry Hub) of around 27x at the end of July 2019 sits well above the long-term ratio of c.10x.

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

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

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



Source: Bloomberg (June 2019)

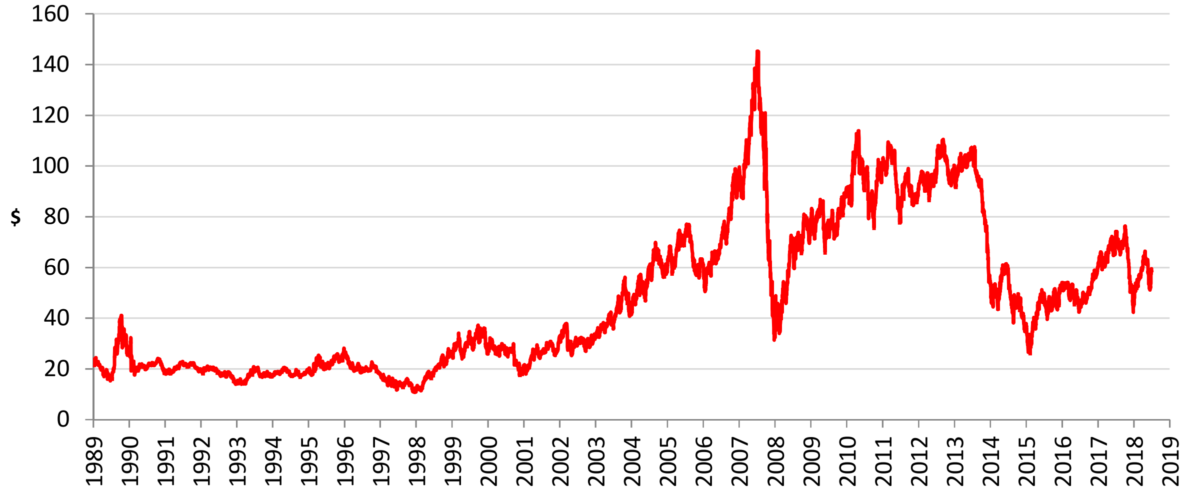
Conclusions about US natural gas

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

The US natural gas price bottomed in 2012 and any 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 2018 natural gas prices (at $3.07) were around 75% higher the April 2012 low, and we suspect that the (full cycle) marginal cost of supply is now around $3/mcf. However, the continued growth of associated gas (from shale oil) will probably pin the price closer to $2.50/mcf for the foreseeable future. Longer term we expect the price to normalise to nearer $3/mcf.

3. APPENDIX Oil and gas markets historical context

Figure 12: Oil price (WTI $) since 1989.



Source: Bloomberg LP

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

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

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

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

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

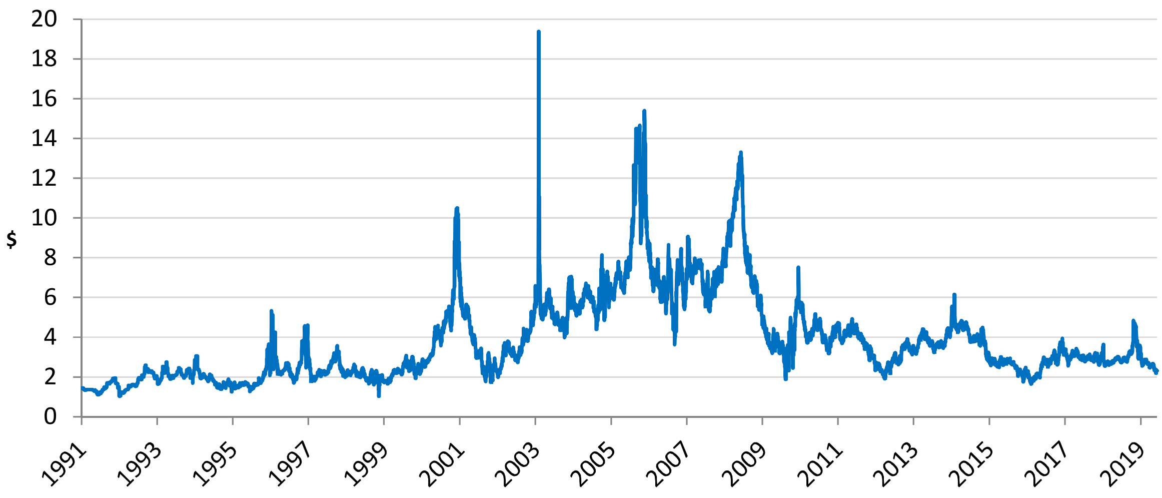
Continued expectations of a supply crunch by the end of the decade, coupled with increased speculative activity in oil markets, contributed to the oil price surging past $90 in the final months of 2007 and as high as $147 by the middle of 2008. This spike was brought to an abrupt end by the collapse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

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

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

Today, the new oil cycle is characterised by good demand growth but a reduced cost curve which has stimulated non-OPEC supply, pinning average prices in the $50-70/bl range once again.

Figure 13: North American gas price since 1991 (Henry Hub $/Mcf)



Source: Bloomberg LP

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

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

IMPORTANT INFORMATION AND RISK FACTORS

Issued by Guinness Asset Management Limited, authorised and regulated by the Financial Conduct Authority.

This report is primarily designed to inform you about recent developments in the energy markets invested in by the Guinness Global Energy Fund. It may also provide information about the Fund's portfolio, including recent activity and performance. It contains facts relating to the energy market and our own interpretation. Any investment decision should take account of the subjectivity of the comments contained in the report.

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 should not be taken as a recommendation to make an investment in the Fund or to buy or sell individual securities, nor does it constitute an offer for sale.

Risk
The Guinness Global Energy Fund is an equity fund. Investors should be willing and able to assume the risks of equity investing. The value of an investment and the income from it can fall as well as rise as a result of market and currency movement, and you may not get back the amount originally invested. The Fund invests only in companies involved in the energy sector; it is therefore susceptible to the performance of that one sector, and can be volatile. Details on the risk factors are included in the Fund's documentation, available on our website.

Documentation
The documentation needed to make an investment, including the Prospectus, the Key Investor Information Document (KIID) and the Application Form, is available from the website www.guinnessfunds.com , or free of charge from:

- the Manager: Link Fund Manager Solutions (Ireland) Ltd, 2 Grand Canal Square, Grand Canal Harbour, Dublin 2, Ireland; or,
- the Promoter and Investment Manager: Guinness Asset Management Ltd, 14 Queen Anne's Gate, London SW1H 9AA.

Residency
In countries where the Fund is not registered for sale or in any other circumstances where its distribution is not authorised or is unlawful, the Fund should not be distributed to resident Retail Clients. **NOTE: THIS INVESTMENT IS NOT FOR SALE TO U.S. PERSONS.**

Structure & regulation
The Fund is a sub-fund of Guinness Asset Management Funds PLC (the "Company"), an open-ended umbrella-type investment company, incorporated in Ireland and authorised and supervised by the Central Bank of Ireland, which operates under EU legislation. If you are in any doubt about the suitability of investing in this Fund, please consult your investment or other professional adviser.

Switzerland
The prospectus and KIID for Switzerland, the articles of association, and the annual and semi-annual reports can be obtained free of charge from the representative in Switzerland, Carnegie Fund Services S.A., 11, rue du Général-Dufour, 1204 Geneva, Switzerland, Tel. +41 22 705 11 77, www.carnegie-fund-services.ch. The paying agent is Banque Cantonale de Genève, 17 Quai de l'Ile, 1204 Geneva, Switzerland.

Singapore
The Fund is not authorised or recognised by the Monetary Authority of Singapore ("MAS") and shares are not allowed to be offered to the retail public. The Fund is registered with the MAS as a Restricted Foreign Scheme. Shares of the Fund may only be offered to institutional and accredited investors (as defined in the Securities and Futures Act (Cap.289)) ('SFA') and this material is limited to the investors in those categories

Telephone calls will be recorded and monitored.