GUINNESS ATKINSON FUNDS

Energy brief

Tim Guinness

Will Riley

September 2013

Commentary and Review by portfolio managers Tim Guinness and Will Riley

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REPORT HIGHLIGHTS

FUND NEWS

• Fund size $69 million at end of August

OIL

• WTI & Brent rise on supply disruption

WTI rose from $105 to $110 in August. Brent increased by $7, ending at $116. Price supported by African supply disruption, particularly in Libya.

NATURAL GAS

• US gas price rises to $3.57

Henry Hub spot traded up 11 cents (c) to end August at $3.57 (well up from April 2012 low of $1.84) on warm weather outlook.
12-month gas strip price rose 3% to $3.85. Market slightly undersupplied (by circa 1 bcf/day).

EQUITIES

• Energy equities outperform on relative basis

The MSCI World Energy Index fell by 0.7% in August, outperforming the MSCI World Index which fell by 2.1% (all in US dollar terms). Fund outperforms both.

GUINNESS TEAM

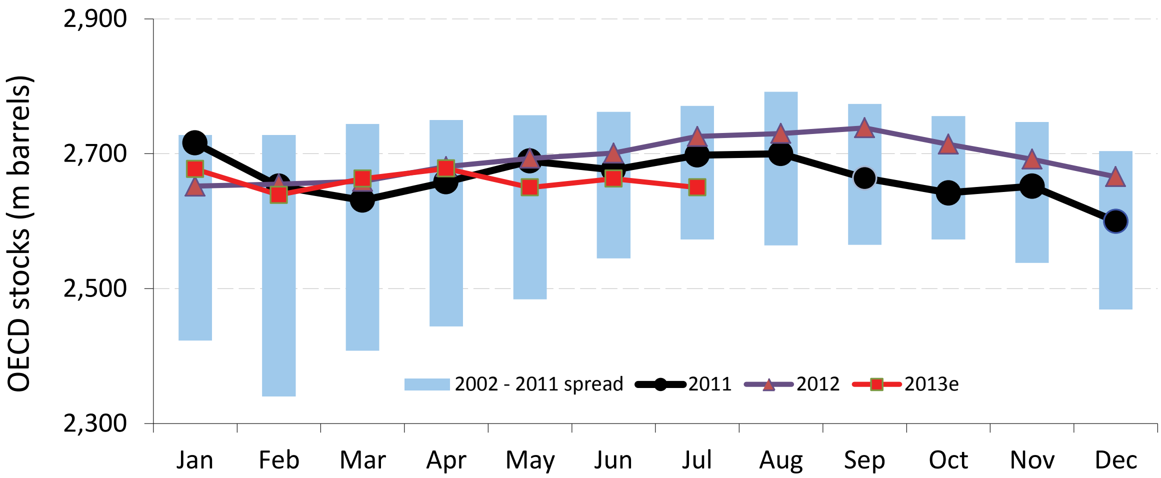
We are delighted to announce the hire of Jonathan Waghorn as co-portfolio manager of the Guinness Global Energy Fund, to work alongside existing portfolio managers Tim Guinness and Will Riley. For further comment see page 9.

- August in Review
- Manager's Comments
- Performance: Guinness Atkinson Global Energy Fund
- Portfolio: Guinness Atkinson Global Energy Fund
- Outlook
- Appendix: Oil and Gas Markets, Historical Context

Chart of the Month:

OECD oil inventories tightening

Since April, OECD oil inventories have tightened, an indication that strong global demand growth and various supply disruptions are starting to show up in the physical market. The July figure for OECD oil storage (the latest data point available) shows a particularly marked move, with inventories *declining* by 13 million barrels compared to 10 year average inventory build of 25 million barrels. Total OECD inventories now sit in the bottom half of the 10 year high-low range and at their (seasonal) lowest since 2008.



Source: Bloomberg LP; Guinness Atkinson Asset Management (September 2013)

Middle Eastern unrest – the Guinness Atkinson view

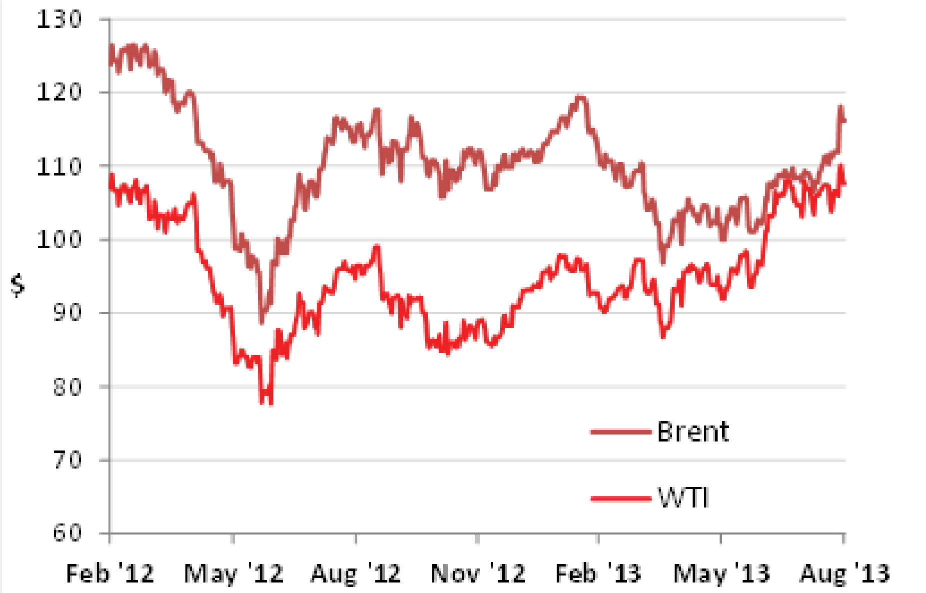
Despite the focus on Syria and Egypt in recent weeks, falling Libyan production is the main driver of market tightness.

See page 8 for the Guinness Atkinson Global Energy team's comment on Middle Eastern unrest and what it means for oil markets.

1. August 2013 Review

Oil market

Figure 1: Oil price (WTI and Brent $/barrel) 18 months February 29, 2012 to August 31, 2013



Source: Bloomberg LP

The West Texas Intermediate (WTI) oil price opened August at $105.03. The price traded in a range between $103 and $108 for the first 3 weeks of the month, before rising in the last few days to close the month at a high of $110.10. So far this year, WTI has averaged $97.17. WTI averaged $94.12 in 2012 and $95.04 in 2011.

Brent also rose in August, increasing from $108.66 to $116.17. The gap between the WTI and Brent benchmark oil prices, which opened at the beginning of 2011, grew during August from around $4 to $6. The spread, caused by high stock levels and infrastructure bottlenecks resulting from increased US onshore production, was as high as $20+ but has narrowed considerably over the past 5 months following pipeline capacity expansions in numerous oil producing basins.

Factors which strengthened the WTI oil price in August:

- **Libyan production shut-ins**

  Libyan oil production at the end of August was reported to be as low as 200,000 barrels(b)/day, down from 1.4million(m) b/day in July. Initially, the disruption to supply seemed to stem from standard labor disputes, but it now appears that the disruption may be more serious, with parties in the east of the country attempting to sell oil independently from the national oil company. Libya's oil production had recovered quickly from the 2011 civil war: capacity is around 1.6-1.8m b/day.

- **Escalation of Syrian civil war**

  The likelihood that the US and other allies may enter the conflict in Syria increased in August. This will not have a direct impact on oil supply given that almost all of Syria's production (pre-war 380,000 b/day) is already shut in, but raises the more remote threat that the conflict widens to disrupt other oil producing neighbors (Saudi and Iran in particular).

- **Tightening OECD oil inventories**

  The July figure for OECD oil storage (the latest data point available) shows a particularly marked move, with inventories declining by 13 million barrels compared to 10 year average inventory build of 25 million barrels. Total OECD inventories now sit in the bottom half of the 10 year high-low range and at their (seasonal) lowest since 2008.

- **Recovering US demand**

Total US refined product demand for July and August averaged 19.5m b/day, up by 2.6% compared to the same period in 2012 (19.0m b/day). General expectation at the start of the year seemed to be that US oil demand would be down, or flat at best, whereas the picture emerging is for overall demand to be up in 2013, coincident with the strengthening of the US economy.

Factors which weakened the WTI oil price in August:

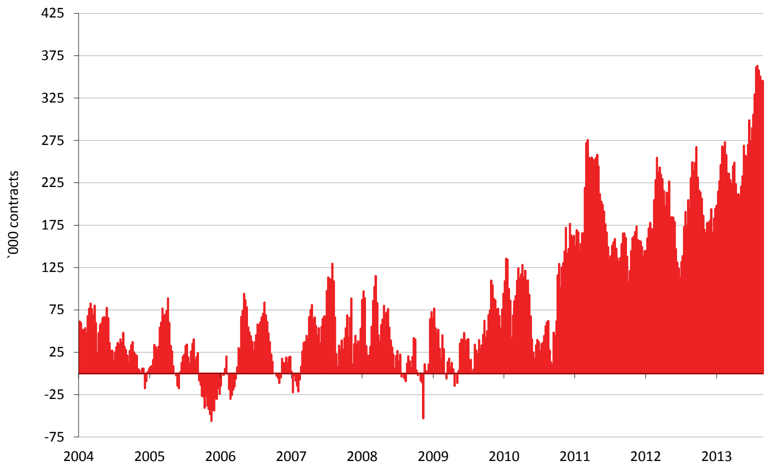
- **Strong US onshore supply growth**

The latest figures for US oil & other liquids production suggest year on year growth of nearly 1.1m b/day. The key drivers of growth have been the Eagleford (+0.4m b/day), Permian (+0.1m b/day) and Bakken (+0.1m b/day) basins. As a reminder, though, total non-OPEC supply including the US is also expected to grow 1.1m b/day in 2013, implying that the rest of non-OPEC will show no net growth.

Speculative and investment flows

The New York Mercantile Exchange (NYMEX) net non-commercial crude oil futures open position declined slightly in August. It started the month at 363,000 contracts long and decreased each week to end the month at 345,000 contracts. We regard a net long position over 225,000 contracts to be relatively high – any unwinding will dampen the WTI price.

Figure 2: NYMEX Non-commercial net futures contracts: WTI January 2004 – August 2013



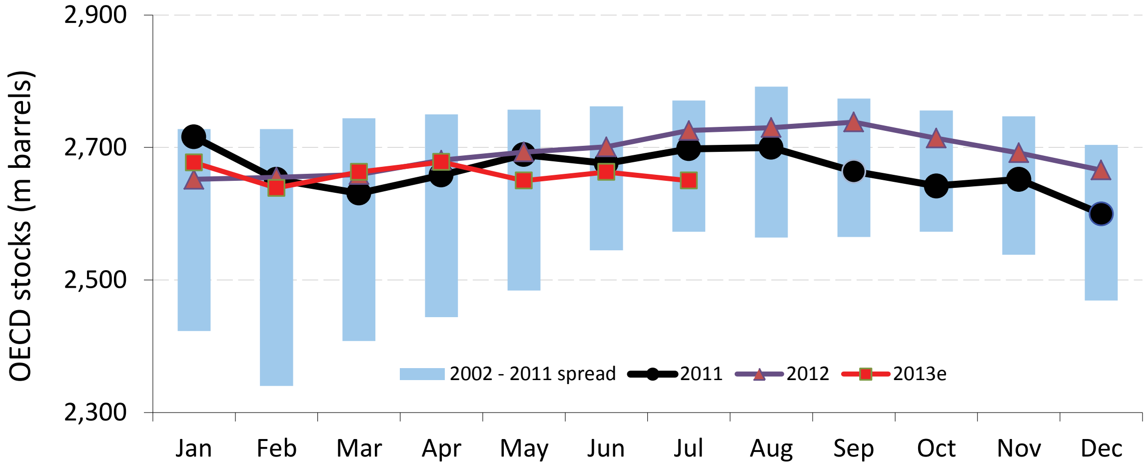
Source: Bloomberg LP/Nymex (August 2013)

OECD stocks

OECD estimated total crude and product stocks for July 2013 (published in the August 2013 International Energy Agency (IEA) Oil Market Report) declined counter-seasonally by 13 million barrels from 2,663 million barrels, giving a total stock of 2,650 million barrels. Over the preceding ten years, the average inventory build in July was 25 million barrels.

Since April, OECD oil inventories have tightened, an indication that strong global demand growth and various supply disruptions are starting to show up in the physical market. Total OECD inventories now sit in the bottom half of the 10 year high-low range and at their (seasonal) lowest since 2008. We believe that OPEC would like to manage supply so that OECD inventories remain comfortably within the 10 year range: a further tightening is likely to be a prompt to Saudi et al to raise production.

Figure 3: OECD total product and crude inventories, monthly, 1998 to 2013



Source: IEA Oil Market Reports (August 2013 and older)

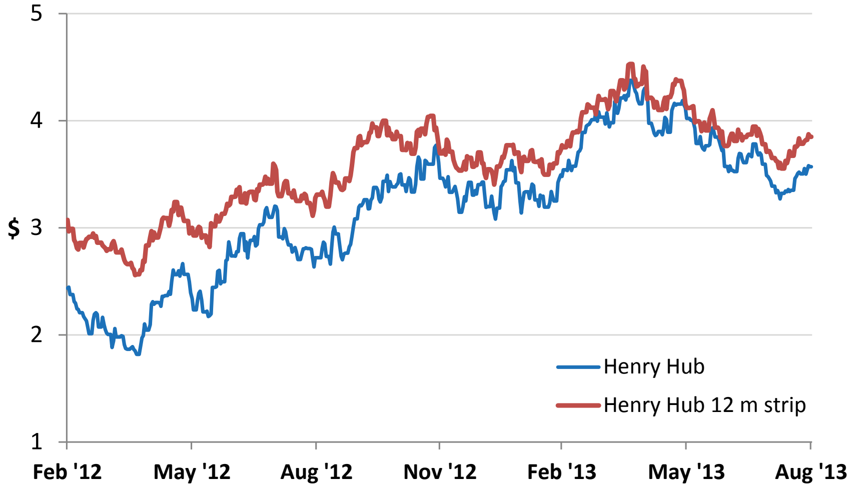
2. Natural Gas Market

The US spot natural gas price (Henry Hub) opened August at $3.46 per Mcf (1000 cubic feet), fell to reach a low for the month of $3.27, before rising to close August at $3.57.

The spot gas price has nearly doubled from a low of $1.84 in April 2012. The price has averaged $3.70 so far in 2013, well above the 2012 average of $2.75 but down on the 2010 and 2011 averages of $4.38 and $4.00 and significantly below the average in each of the previous 5 years (2005-2009).

The 12-month gas strip price (a simple average of settlement prices for the next 12 months' futures prices) rose over the month by 3% from $3.73 to $3.85. The strip price has averaged $3.92 so far this year, having averaged $3.28 last year, $4.35 in 2011, $4.86 in 2010 and $5.25 in 2009.

Figure 4: Henry Hub Gas spot price and 12m strip ($/Mcf) February 29, 2012 to August 31, 2013



Source: Bloomberg

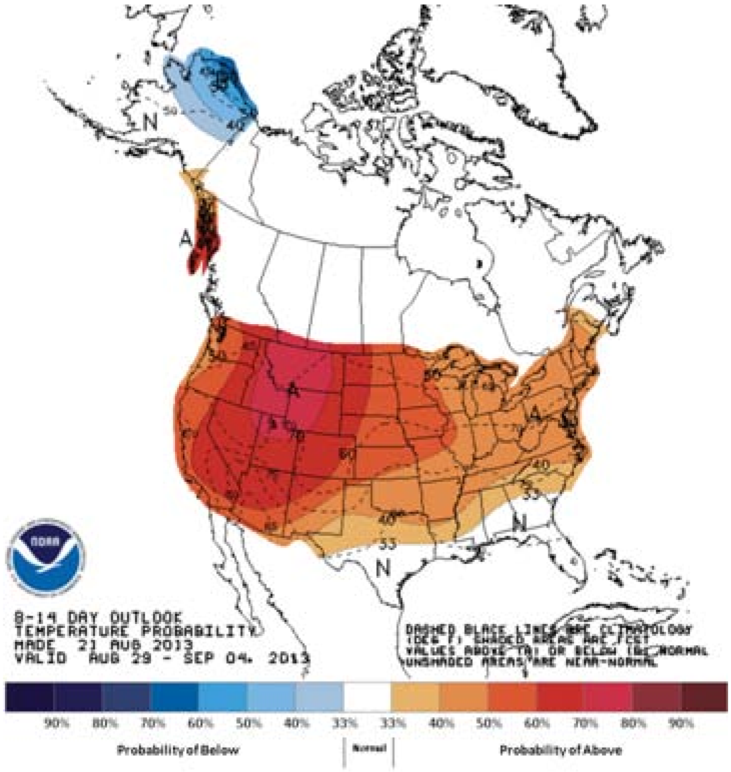
Factors which strengthened the US gas price in August included:

- **Low gas drilling rig count**

The US natural gas-directed rig count (reported by Baker Hughes) rose from 369 to 380 rigs during August. However, over the last 18 months, the rig count has declined from 923 rigs (i.e. by 59%). The falling rig count reflects a suspension of activity in areas that are no longer economic to drill, given the depressed gas price. Of course there is a reasonable lead time between a fall in the rig count and a fall in production, but we think the cumulative effects of the slide can only grow for as long as the rig count is low.

- **Warm weather outlook**

Expectations of warm weather in the US in August, and thus higher-than-normal energy demand for air conditioning, led to a rise in the Henry Hub spot price towards the end of the month. The following image shows the 8-14 day weather outlook (forecast made August 21) – the red colors indicate above-average expected temperatures.

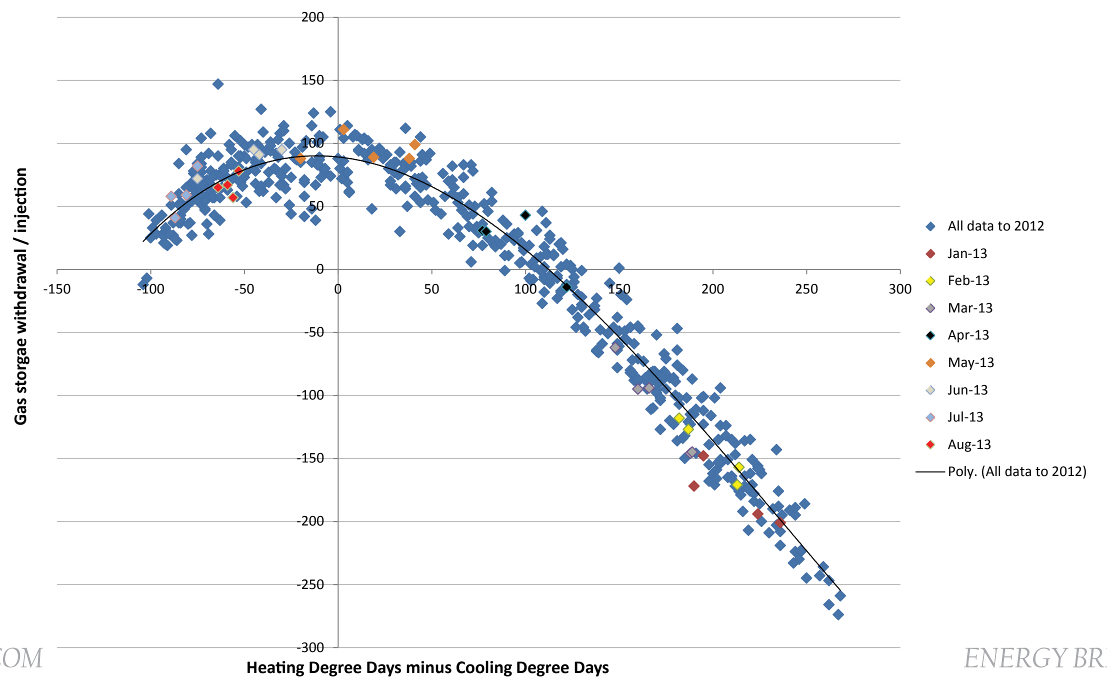


Source: Simmons/National Oceanic and Atmospheric Administration (August 2013)

- **Overall market slightly undersupplied**

Our analysis of injections of gas into storage implies that the market has shifted over the past 4 months from slight oversupply (May to July) to slight undersupply (August). We estimate the undersupply to be around 1 bcf/day. The following chart indicates the move in recent months from oversupply (above the line) to undersupply (below the line).

Figure 5: Weather adjusted changes in gas storage



Source: Bloomberg

Factors which weakened the US gas price in August included:

- **US onshore production**

The June data (latest available) from the Energy Information Agency indicated that total US natural gas production (Lower 48 States) was up slightly, increasing by 0.1 Bcf/day month-on-month. Total onshore production rose by 0.4 Bcf/day month-on-month, implying that offshore production fell slightly. We are encouraged that total production for June 2013 remains 0.2 Bcf/day below peak production in November 2012.

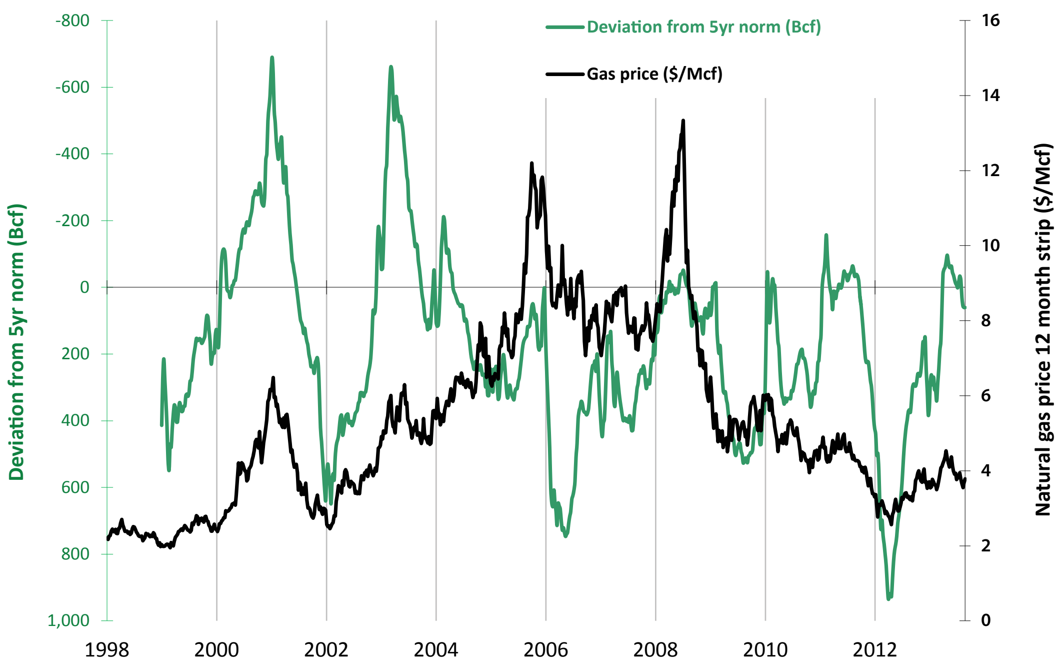
- **Gas to coal switching**

With the gas spot price in August trading at around $3.50, it is likely that much of the coal to gas switching that occurred in 2012 was reversed. At its peak in May/June 2012, we could identify around 6 Bcf/day of switching. This implied that in total, coal and natural gas were fueling the same amount of electricity generation. We believe the level of switching is now down to less than 2 Bcf/day (implying that coal has regained its lead in overall electricity generation), but even fluctuations in this smaller amount could affect the overall balance of the gas market. Our interpretation of the slight swings from oversupply to undersupply (identified above) is that they reflect a degree of coal to gas switching at the margin.

Natural gas storage

Swings in the supply/demand balance for US natural gas should, in theory, show up in movements in gas storage data. The following graph shows the 12 month gas strip price (in black) against the amount of gas in storage expressed as the deviation from the 5 year storage average (in green). Swings in storage have frequently been a leading indicator to movements in the gas strip price.

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



Source: Bloomberg, EIA (August 2013)

The surplus of gas in the second half of 2008 and 2009, a result of oversupply during the recession, can be seen in gas storage data, with the inflection point in storage occurring in July 2008 and the storage line moving from negative (i.e. deficit) to positive (i.e. surplus) territory over this 18 month period. This coincided with the gas strip price falling from a peak of over $13 in July to below $5. An unusually cold 2009/10 winter boosted demand and pushed the gas storage level back into balance, only for oversupply to persist again for much of the rest of 2010. A cold 2010/11 winter followed by a hot 2011 summer tightened storage again, with storage levels staying around the 5 year average for much of this period.

The very mild 2011/12 winter (in combination with rising production) caused gas storage levels to balloon to record levels, driving prices down to their lowest levels for a decade. Since then coal-to-gas switching and shut ins and the sharp rig count drop have worked in the other direction, seeing gas prices rising from their sub $2 lows in April 2012 to around $3.50 now.

We watch movements in gas storage closely as a tightening from here, weather adjusted, is likely to be a coincident indicator for the start of a sustained gas price recovery.

3. Manager's Comments

Oil has been prominent in news agendas over the past couple of months as observers try to piece together what political unrest across the Middle East and Africa might mean for the balance of the oil market. Here we comment on the most talked about countries and what it means for oil fundamentals. Note that despite the focus on Syria and Egypt in recent weeks, falling Libyan production is the main driver of market tightness:

Selected oil trouble spots in Middle East & Africa

Daily average production (000s b/day)						
Country	2010	2012	August 2013	Aug 2013 vs 2010	Aug 2013 vs 2012	Strategic importance
Libya	1,550	1,390	575	-975	-815	Medium
Iran	3,700	3,000	2,570	-1,130	-430	High
Syria	380	170	50	-330	-120	High
Nigeria	2,080	2,100	2,020	-60	-80	Low
Algeria	1240	1,170	1,120	-120	-50	Medium
Egypt	750	730	710	-40	-20	High
Sudan	475	115	150	-325	35	Low

Source: Bloomberg LP; IEA Oil Market Reports (January 2011; August 2012)

Renewed disruption to **Libya's** oil production represents the largest physical disruption to supply globally this year. Libyan oil production is estimated to have averaged 575,000 b/day in August 2013, down sharply over the last two months as local protests and unrest spread. Production in the last week of August is thought to have fallen even lower, to around 200,000 b/day, as some of the largest western oilfields closed (El Feel and El Sharara). Pre-war production averaged around 1.6m b/day.

Syria is a relatively small producer (pre-civil war production of 380,000 b/day, today already close to zero), so an escalation in the conflict there will have little direct effect on oil supply. But the country has important political relationships with a number the Middle East's largest oil producers, in particular Iran as supporters of the Syrian government and Saudi as supporters of government opposition. US military action in Syria will likely make Iranian nuclear negotiations more difficult, raising the probability that oil sanctions against Iran continue for longer. It also muddies the situation in Iraq (and for the oil market, lessens the prospect of higher Iraqi production), with the likelihood of unified democracy in Iraq looking more remote.

Iran's production in 2013 has been relatively stable, but it is worth remembering that Iranian supply is over 1m b/day lower than in the period before EU oil sanctions were introduced in mid-2012. As noted above, US action against Syria lessens the prospects of an early removal of oil sanctions against Iran. We have stated for some time that we believe one of Saudi's motivations in controlling the oil price nearer $100 is to reduce Iran's oil revenues and make the sanctions bite.

It is interesting to note that **Egypt's** production has barely wavered, either in the latest post-Morsi unrest or during the 2011 Arab Spring that saw the end of Mubarak's presidency. Egypt produces a relatively modest 710,000 b/day of oil & other liquids, representing 0.8% of world supply. However, it also controls the overland SUMED pipeline and Suez Canal, which between them carry 3-4m b/day of oil between the Red Sea and the Mediterranean. Problems on either route would not take oil off the market but it would cause disruption as oil would be forced to divert via the Horn of Africa (adding around 15 days to a typical transit). Notably, the Chinese Government took a stake in Egyptian oil at the end of August via a position in Apache Corporation's oil acreage, giving de facto support for existing oil contracts in the country.

Similarly, **Algeria** has seen relatively little reduction to oil production despite terrorist attacks against oil & gas facilities earlier this year. Algeria is of more importance as a natural gas (and associated liquids) exporter into Europe.

We must also keep an eye on the rest of Africa, especially **Nigeria** and **South Sudan/Sudan**. Theft of oil from pipelines in Nigeria has received a fair amount of attention in recent months. The reality here seems to be that it has checked the growth of Nigerian supply (if looked at on a 3 year view) rather than caused significant supply decline. The dispute between South Sudan and Sudan rumbles on: Sudan provides the route to market for the majority of the oil produced in South Sudan, but has closed pipelines because of ongoing political dispute. Flows of oil between the two countries had resumed in April 2013 after a 16 month stand-off, then essentially stopped again as relations worsened, and now seem to be picking up again. The dispute has removed around 300,000 b/day of supply from the market.

Together, the disruption to oil supply across this group of Middle Eastern and African countries has resulted in nearly 1.5m b/day of shut-in production versus average 2012 production levels. What to make of this? On the one hand it is starting to show up in oil inventory levels, which are as low as they have been since 2008. This is supportive of the oil price, and all but confirms the fact that the Brent oil price will average over $100 for the third year in a row. On the other hand, one might take a bearish view. If all of the disrupted supply from the seven countries discussed here were to recover, it could bring 3m b/day of supply back to the market versus production averages in 2010. However, we take comfort from the supply response that we have seen from other Middle Eastern nations and the production versatility they would likely show if needed. Since 2010, Saudi (+1.3m b/day), UAE (+0.6m b/day) and Kuwait (+0.7m b/day) have had to raise their production by 3m b/day to balance the market. So should Libya, Iran, Syria & co resume full production, we think Saudi, UAE and Kuwait would simply cut their production accordingly.

What does this mean for price? Despite the disruption, we think the most likely scenario going forward is that we will see the average price of Brent and WTI in the trading range of $90-110. Should the oil price rise much over $125 and we think demand will start to weaken, putting a ceiling on the price for the time being (absent a more serious supply shock). If the floor of our range looks threatened, OPEC will start to reduce supply and any significant price weakness below $100 (Brent) will be prevented by OPEC cuts.

As regards the other two big price drivers: US shale oil production growth and emerging market demand growth (net of developed demand decline), we discuss them elsewhere in our report and overall see the two as fairly similar in size and unlikely to unbalance the market; if anything they are likely to tighten it since shale oil growth will decline as development matures while emerging market demand growth will march on.

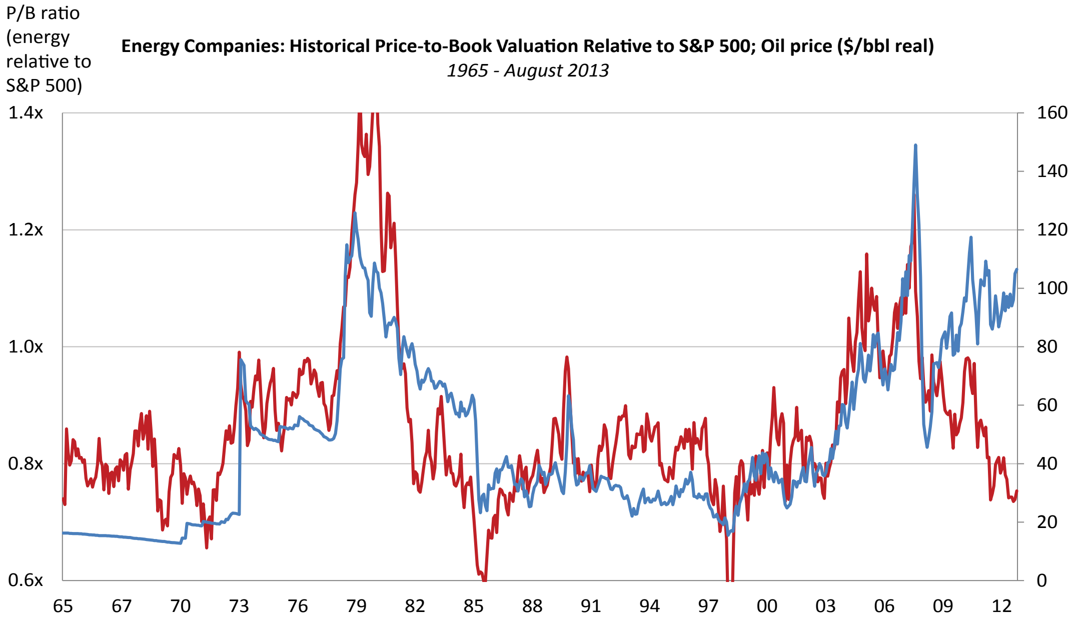
At the heart of it all, we believe that Saudi are working hard to try and maintain a 'good' oil price (Brent at $100-110). So far, they are succeeding.

Outlook for energy equities

Energy equities over the past 12 months have been ahead of general natural resources but a little behind the broad equity market.

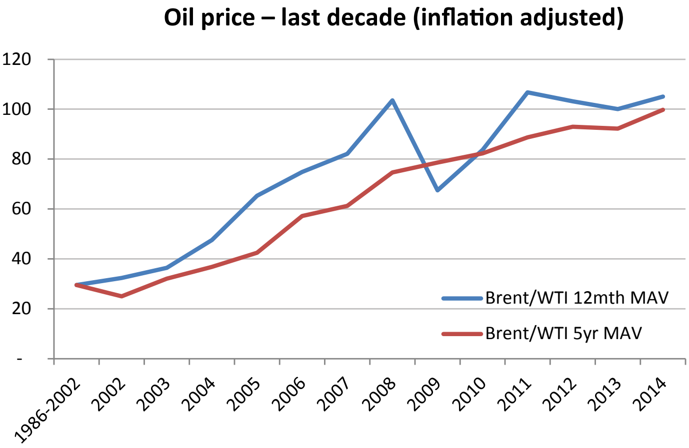
We believe that energy equities have underperformed the broad market this year because various factors are misunderstood. Principally, we think that energy equity valuations reflect an expectation that international oil prices return in the longer term to around $80 (driven by concerns of oversupply), something we do not expect to happen, based on the fundamentals for the commodity.

As a result, on traditional metrics of P/E ratio, price to discounted cash flow (e.g. the SEC's PV-10 calculation) or Enterprise Value to Reserves, many energy companies are at historically low levels. The 2013 P/E ratio of our Fund at August 31 is 11.5x versus 15.3x for the S&P500.



Source: Bernstein; Guinness Atkinson Asset Management

We expect the dislocation to correct when the current oil price and long-run market expectations come together. $100 oil is around where that could happen.

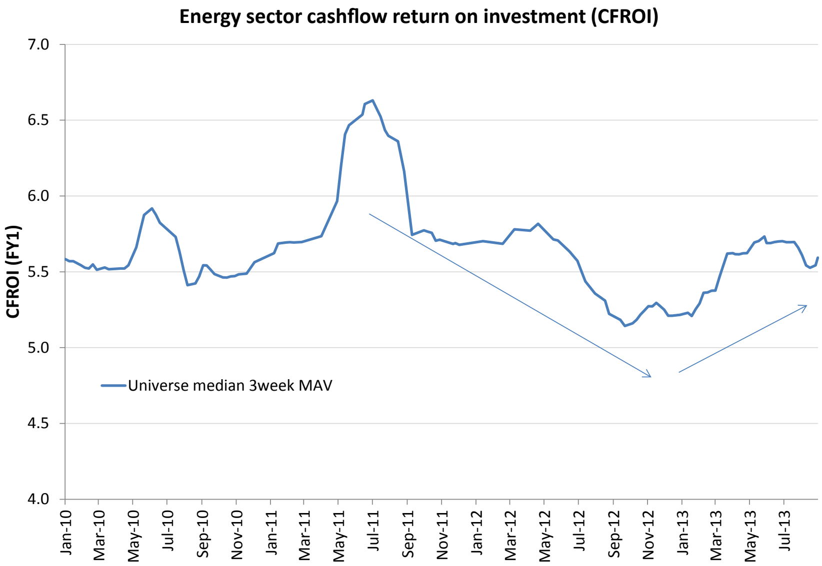


Oil Price (inflation adjusted)													*Forecast*	
12 month MAV	1986-2002	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	*2013*	*2014*
WTI	30	33	38	49	66	75	82	104	68	84	99	94	95	100
Brent	30	32	35	46	64	75	82	103	67	84	115	112	105	110
Brent/WTI 12mth MAV	**30**	**32**	**36**	**48**	**65**	**75**	**82**	**103**	**67**	**84**	**107**	**103**	**100**	**105**
Brent/WTI 5yr MAV	30	25	32	37	42	57	61	75	79	82	89	93	92	100

Source: Bloomberg (actuals); Guinness Atkinson Asset Management (forecasts)
MAV = Moving Average

Energy equity valuation sentiment

For considering a good entry point at which to buy energy equities the following may be helpful. Two of the energy sector specific headwinds over the last 24 months have been the pull back in oil price from the highs reached at the time of the Libyan crisis and more recently as embargoes were placed on Iranian exports; and the weakness in the US natural gas price which troughed a year ago. Earnings estimates (and cashflow return on investment) for energy companies, as a result, were generally trending down from mid-2011 to late 2012. A good entry point may well be when earnings estimates stop falling. We have been looking at this for several months and as the graph below indicates, the most recent 12 month move is a trend higher. We hope that energy equities will follow.



Source: CSFB HOLT; Guinness Atkinson Asset Management

All this of course assumes the oil price stabilizes around the five year moving average price of $100 (blended Brent/WTI) and the gas price in due course recovers, which is what we believe is increasingly likely to occur.

We think energy equities also remain one of the better inflation hedges. If we see dollar inflation of 30/50% over the next decade it will be surprising if oil and gas prices do not rise by a comparable percentage.

Guinness Atkinson appoints leading energy specialist

We are delighted to announce the hire of Jonathan Waghorn as co-portfolio manager of the Guinness Global Energy fund. Jonathan's appointment marks the next step in Guinness Asset Management's expansion. He will join our established energy team at the start of September 2013 to work alongside existing portfolio managers Tim Guinness and Will Riley.

Jonathan brings 17 years of energy investment and industry experience. He was co-portfolio manager of the Investec Global Energy Fund from 2008 to 2012, succeeding Tim Guinness who managed the fund from 1998 to 2008. Prior to Investec, he acted as co-head of Goldman Sachs' energy equity research team.

We are delighted to welcome Jonathan to the firm. He is a proven energy fund manager with first-rate investment experience and is a natural fit to join the firm. Jonathan is well known by energy investors for his rigorous and disciplined investment process which we believe is highly complementary to the approach we apply to managing portfolios. We believe Jonathan can help us consolidate our position as one of the leaders in the sector and to grow our energy franchise.

We are also pleased to say that Ian Mortimer, who has divided his time between our energy, innovators and inflation managed dividend funds, will now focus his efforts fully on our innovation and inflation managed dividend franchise, to focus on the success he has had in that sector.

4. Performance – Guinness Atkinson Global Energy Fund

The main index of oil and gas equities, the MSCI World Energy Index, was down by 0.70% in August. The S&P 500 was down by 2.89% over the same period. The fund was up by 0.69% over this period, outperforming the MSCI World Energy Index by 1.39% (all in US dollar terms).

Within the fund, August's stronger performers were Trina Solar, Stone, Chesapeake, Soco and Carrizo. Poorer performers were JA Solar, Shawcor, QEP, PetroChina and Exxon.

Performance as of June 30, 2013

Inception date 6/30/04	Full Year 2009	Full Year 2010	Full Year 2011	Full Year 2012	1 year (annualized)	Last 2 years (annualized)	Last 5 years (annualized)	Since Inception (annualized)
Global Energy Fund	63.27%	16.63%	-13.16%	3.45%	12.61%	-8.01%	-5.24%	11.80%
MSCI World Energy Index	26.98%	12.73%	0.71%	2.54%	10.45%	-0.80%	-2.75%	9.41%
S&P 500 Index	26.47%	15.06%	2.09%	15.99%	20.75%	12.83%	7.05%	6.14%

Performance as of August 31, 2013

Inception date 6/30/04	Full Year 2009	Full Year 2010	Full Year 2011	Full Year 2012	1 year (annualized)	Last 2 years (annualized)	Last 5 years (annualized)	Since Inception (annualized)
Global Energy Fund	63.27%	16.63%	-13.16%	3.45%	12.19%	1.99%	0.16%	12.51%
MSCI World Energy Index	26.98%	12.73%	0.71%	2.54%	8.38%	6.59%	1.34%	9.78%
S&P 500 Index	26.47%	15.06%	2.09%	15.99%	18.75%	18.33%	7.30%	6.17%

Source: Bloomberg
Gross expense ratio: 1.35%

Performance data quoted represent past performance and does not guarantee future results. The investment return and principal value of an investment will fluctuate so that an investor's shares, when redeemed, may be worth more or less than their original cost. Current performance of the Fund may be lower or higher than the performance quoted. For most recent month-end and quarter-end performance, visit www.gafunds.com or call (800) 915-6566.

The Fund imposes a 2% redemption fee on shares held for less than 30 days. Performance data does not reflect the redemption fee and, if deducted, the fee would reduce the performance noted.

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5. Portfolio – Guinness Atkinson Global Energy Fund

Buys/Sells

There were no buys or sells in August.

Sector Breakdown

The following table shows the asset allocation of the Fund at **August 31, 2013**.

(%)	31 Dec 2007	31 Dec 2008	31 Dec 2009	31 Dec 2010	31 Dec 2011	31 Dec 2012	31 Aug 2013	*Change YTD*
Oil & Gas	**103.5**	**96.4**	**96.1**	**93.2**	**98.5**	**98.6**	**95.1**	***-3.5***
Integrated	66.2	53.7	47.2	41.2	39.6	39.1	37.8	*-1.3*
Exploration and production	25.8	28.7	32.0	36.9	41.5	41.6	38.2	*-3.4*
Drilling	8.1	5.2	8.4	6.3	6.0	7.4	6.3	*-1.1*
Equipment and services	3.4	6.4	5.4	5.3	6.6	7.1	9.7	*2.6*
Refining and marketing	0.0	2.4	3.1	3.5	4.8	3.4	3.1	*-0.3*
Coal and consumables	**2.5**	**2.3**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Solar	**0.0**	**0.0**	**0.0**	**3.2**	**1.2**	**1.2**	**3.2**	**2.0**
Construction and engineering	**0.0**	**0.4**	**0.4**	**0.4**	**0.4**	**0.6**	**0.8**	**0.2**
Cash	**-6.0**	**0.9**	**3.5**	**3.2**	**-0.1**	**-0.4**	**0.9**	**1.3**
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**0.0**

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

Guinness Atkinson Global Energy Fund Portfolio

The fund at August 31, 2013 was on an average price to earnings ratio (PE) versus the S&P 500 Index at 1,633 as set out in the table. (Based on S&P 500 'operating' earnings per share estimates of $49.5 for 2008, $56.9 for 2009, $83.8 for 2010, $96.4 for 2011, $96.8 for 2012 and $106.8 for 2013). This is shown in the following table:

	2007	2008	2009	2010	2011	2012	2013
Fund PER	9.0	8.0	15.4	9.9	10.1	11.3	11.5
S&P 500 PER	19.8	33.0	28.7	19.5	16.9	16.9	15.3
Premium (+) / Discount (-)	*-55%*	*-76%*	*-46%*	*-49%*	*-40%*	*-33%*	*-25%*
Average oil price (WTI $)	$72.2/bbl	$99.9/bbl	$61.9/bbl	$79.5/bbl	$95/bbl	$94/bbl	$97/bbl

Source: Standard and Poor's; Guinness Atkinson Asset Management Inc.

Portfolio Holdings

Our integrated and similar stock exposure (c.38%) is comprised of a mix of mid cap, mid/large cap and large cap stocks. Our five large caps are Exxon, BP, Chevron, Royal Dutch Shell and Total. Mid/large and mid-caps are ENI, StatoilHydro, Hess and OMV. As at July 31 2013 the median PE ratio of this group was 8.1x 2012 earnings. We have one Canadian integrated holding, Suncor, which merged in 2009 with PetroCanada. The company has significant exposure to oil sands and stands on an attractive PE of 10.1x 2012 earnings given the company's good growth prospects.

Our exploration and production holdings (c.37%) 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 are all largely in the US (Newfield, Devon, Chesapeake, Carrizo, Stone, Penn Virginia, Ultra, QEP and Bill Barrett) and three more (ConocoPhillips, Apache and Noble) which have significant international production. One of the key metrics behind a number of the E&P stocks held is low enterprise value / proven reserves. All of the E&P stocks held also provide exposure to North American natural gas and include two of the industry leaders (Devon and Chesapeake). In PE terms, the group divides roughly into two: (i) ConocoPhillips, Apache, Chesapeake, Devon, Newfield, Carrizo, Ultra and Stone all with quite low PEs (9x – 16x 2013 earnings); and (ii) Noble, Bill Barrett, Penn Virginia and QEP with higher PE ratios. However, all look reasonably attractive on EV/EBITDA multiples.

We have exposure to four (pure) emerging market stocks in the main portfolio, though all but one are half-positions. Two are classified as integrateds by the GICS (Gazprom and PetroChina) and two as E&P companies (Dragon Oil 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 2.6x 2012 earnings. PetroChina is one of the world's largest integrated oil and gas companies and has significant growth potential and advantages as a Chinese national champion. Dragon Oil is an oil and gas E&P-focused on offshore Turkmenistan in the Caspian Sea and trades on 7.4x 2012 earnings. SOCO International is an E&P company with production in Vietnam and exploration interests across East Africa in Angola, Democratic Republic of Congo and the Republic of Congo.

We have useful exposure to oil service stocks. The stocks we own are split between those which focus their activities in North America (land drillers Patterson and Unit on 11.0x and 11.1x 2012 earnings) and those which operate in the US and internationally (Helix, Halliburton and Shawcor on 13.5x – 18.8x 2012 earnings).

Our independent refining exposure is currently in the US in Valero, the largest of the US refiners, which is currently trading at significant discount to book and replacement value. 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 a single unit split equally between two companies: JA Solar and Trina Solar. Both were loss making in 2012 due to sharp falls in solar prices during the year but the prospects for a return to profitability over the next 12 months are improving. Trina is a Chinese solar module manufacturer and JA Solar is a Chinese solar cell manufacturer. Some measure of their recovery potential may be indicated by their 2010 PEs of 2.8x and 0.9x respectively.

Portfolio at August 31, 2013

Guinness Atkinson Global Energy Fund 31 August 2013

Stock	ID_ISIN	Curr.	Country	% of NAV	2006 Bberg mean PER	2007 Bberg mean PER	2008 Bberg mean PER	2009 Bberg mean PER	2010 Bberg mean PER	2011 Bberg mean PER	2012 Bberg mean PER	2013 Bberg mean PER
Integrated Oil & Gas												
Exxon Mobil Corp	US30231G1022	USD	US	3.34	13.31	120	103	224	14.6	104	11.1	11.5
Chevron Corp	US1667641005	USD	US	3.28	154	13.7	106	235	12.9	90	98	100
Royal Dutch Shell PLC	GB00B03MLX29	EUR	NL	3.28	81	64	75	148	10.5	78	7.7	83
BP PLC	GB0007980591	GBP	GB	3.37	63	64	51	89	6.2	6.1	76	89
Total SA	FR0000120271	EUR	FR	3.28	76	78	67	121	90	8.1	7.7	83
ENI SpA	IT0003132476	EUR	IT	3.26	61	67	62	121	9.2	88	86	11.8
Statoil ASA	NO0010096985	NOK	NO	3.34	72	97	73	133	100	86	8.1	9.1
Hess Corp	US42809H1077	USD	US	3.25	136	125	102	391	14.5	124	12.7	11.5
OMV AG	AT0000743059	EUR	AT	3.43	69	66	55	140	88	11.0	76	79
				29.83								
Integrated Oil & Gas - Canada												
Suncor Energy Inc	CA8672241079	CAD	CA	3.21	144	149	11.1	336	224	9.9	11.0	11.5
Canadian Natural Resources Ltd	CA1363851017	CAD	CA	3.30	220	152	98	134	13.2	13.9	20.2	14.4
				6.51								
Integrated Oil & Gas - Emerging market												
PetroChina Co Ltd	CNE1000003W8	HKD	HK	3.17	84	82	106	11.2	90	8.9	10.2	9.7
Gazprom OAO	US3682872078	USD	RU	1.60	49	4.7	4.1	48	3.7	2.5	26	28
				4.78								
Oil & Gas E&P												
ConocoPhillips	US20825C1045	USD	US	3.20	6.48	6.86	6.22	18.38	11.18	7.80	11.62	11.43
Apache Corp	US0374111054	USD	US	3.52	11.7	99	76	154	9.2	7.2	89	106
Bill Barrett Corp	US06846N1046	USD	US	1.03	152	222	79	127	106	12.2	406.2	nm
QEP Resources Inc	US74733V1008	USD	US	1.15	nm	nm	nm	nm	198	16.7	220	179
Ultra Petroleum Corp	CA9039141093	USD	US	1.18	145	182	78	11.5	93	8.1	11.2	123
Devon Energy Corp	US25179M1036	USD	US	3.28	91	82	58	158	96	9.5	12.7	138
Chesapeake Energy Corp	US1651671075	USD	US	3.36	71	80	73	104	88	9.2	53.2	16.2
Noble Energy Inc	US6550441058	USD	US	3.19	324	226	174	363	23.7	234	268	176
Newfield Exploration Co	US6512901082	USD	US	3.15	68	74	76	4.7	5.2	58	98	134
Stone Energy Corp	US8616421066	USD	US	1.59	100	53	49	11.9	13.5	7.1	99	93
Carrizo Oil & Gas Inc	US1445771033	USD	US	1.70	483	489	190	233	26.9	33.3	23.5	134
Penn Virginia Corp	US7078821060	USD	US	1.63	27	26	19	nm	nm	nm	nm	nm
Trinity Exploration & Production PLC	GB00B8G4KB91	GBP	GB	0.29	nm	nm	nm	nm	nm	nm	nm	123
Ophir Energy PLC	GB00B24CT194	GBP	GB	0.75	nm	nm	nm	nm	nm	nm	nm	nm
Triangle Petroleum Corp	US89600B2016	USD	US	0.77	nm	nm	nm	nm	nm	nm	nm	nm
Pantheon Resources PLC	GB00B1295X82	GBP	GB	0.10	nm	nm	nm	nm	nm	nm	nm	nm
Gulf Natural Resources PLC	GB00B65YWF01	GBP	GB	0.20	nm	nm	nm	nm	nm	nm	nm	nm
				30.07								
Oil & Gas E&P - Emerging markets												
Dragon Oil PLC	IE0000590798	GBP	GB	1.60	261	155	129	187	13.5	73	74	74
Soco International PLC	GB00B572ZV91	GBP	GB	1.74	589	54.1	582	363	500	32.3	90	88
JKX Oil & Gas PLC	GB0004697420	GBP	GB	0.87	21	1.7	21	22	2.5	3.0	4.0	4.2
WesternZagros Resources Ltd	CA9600081009	CAD	CA	0.50	nm	nm	nm	nm	nm	nm	nm	nm
				4.71								
Drilling												
Patterson-UTI Energy Inc	US7034811015	USD	US	3.11	49	77	83	nm	28.9	9.1	11.0	156
Unit Corp	US9092181091	USD	US	3.23	69	81	68	175	15.1	11.3	11.1	11.8
				6.34								
Equipment & Services												
Halliburton Co	US4062161017	USD	US	3.33	219	189	221	367	23.9	14.3	16.1	14.9
Helix Energy Solutions Group Inc	US42330P1075	USD	US	3.29	88	75	103	432	47.4	16.7	13.5	28.6
ShawCor Ltd	CA8204391079	CAD	CA	3.05	33.5	261	216	229	33.5	57.3	188	100
Shandong Molong Petroleum Machinery Co Ltd	CNE1000001N1	HKD	HK	0.08	84	58	39	107	4.2	58	nm	nm
				9.74								
Solar												
Trina Solar Ltd	US89628E1047	USD	US	2.05	nm	130	78	57	28	34.78	nm	nm
JA Solar Holdings Co Ltd	US4660902069	USD	US	1.14	80	21.7	32.1	nm	0.9	nm	nm	nm
				3.18								
Oil & Gas Refining & Marketing												
Valero Energy Corp	US91913Y1001	USD	US	3.10	43	46	66	nm	224	8.9	73	84
				3.10								
Construction & Engineering												
Kentz Corp Ltd	JE00B28ZGP75	GBP	GB	0.84	nm	354	359	353	24.3	184	15.5	13.5
			Cash	0.91								
			Total	100								
				PER	92	90	80	154	9.9	10.1	11.3	11.5
				Med. PER	84	82	78	148	11.2	9.2	11.0	11.5
				Equal PER	94	92	87	169	9.9	10.3	10.4	10.8

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.

6. Outlook

Oil market

The table below illustrates the difference between the growth in world oil demand and non-OPEC supply over the last 10 years, together with the IEA forecasts for 2013 and 2014.

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013e	2014e
										IEA	IEA
World Demand	82.5	84.0	85.2	87.0	86.5	85.5	88.3	88.9	89.9	90.8	92.0
Non-OPEC supply (Includes Angola and Ecuador 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	53.4	54.5	55.9
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
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
Indonesia supply adjustment[2]	1.0	0.9	0.9	1.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0
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	53.4	54.5	55.9
OPEC NGLs	4.2	4.3	4.3	4.3	4.5	5.1	5.6	5.9	6.3	6.5	6.7
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	58.3	58.7	59.7	61.0	62.6
Call on OPEC-12[3]	28.5	30.1	30.6	31.7	31.4	29.0	30.0	30.2	30.2	29.8	29.4
Iraq supply adjustment[4]	-2.0	-1.8	-1.9	-2.1	-2.4	-2.4	-2.4	-2.7	-3.0	-3.2	-3.2
Call on OPEC-11[5]	26.5	28.3	28.7	29.6	29.0	26.6	27.6	27.5	27.3	26.6	26.2

[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

[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 - 13: 9 August 2013 Oil market Report

Global oil demand in 2012 was 2.8m b/day up on the previous 2007 peak. This means the combined effect of the 2007-8 oil price spike and the 2008/09 recession was quite small and has been shrugged off remarkably quickly. The IEA forecast further rises in demand of 0.9m b/day in 2013 and 1.2m b/day in 2014, which would take oil demand to an all-time high of 92.0m b/day.

OPEC

Five years ago, in order to put a floor under a plunging oil price, OPEC announced in its December 17, 2008 meeting a new quota target of 25.0m b/day with effect from January 1, 2009. This figure represented a 4.2m b/day cut from the actual OPEC-11 September 2008 production level (29.2m b/day). From then, quotas remained unchanged until the OPEC meeting on December 13 2011, at which OPEC substituted a 30 m b/day target without specifying individual country quotas. The statement read as follows:

"In light of .... the demand uncertainties, the Conference decided to maintain the current production level of 30.0 mb/day, including production from Libya, now and in the future. The Conference also agreed that Member Countries would, if necessary, take steps (including voluntary downward adjustments of output) to ensure market balance and reasonable price levels. In taking this decision, Member Countries confirmed their preparedness to swiftly respond to developments that might have a detrimental impact on orderly market developments. Given the ongoing worrying economic downside risks, the Conference directed the Secretariat to continue its close monitoring of developments in supply and demand, as well as non-fundamental factors, such as macro-economic sentiment and speculative activity, keeping Member Countries abreast at all times."

The 30m b/day figure includes 2.7m b/day for Iraq, so in effect 25.0m b/day for OPEC-11 was moved up to 27.3m b/day. The timing of this announcement was clearly complicated by numerous issues, notably: (1) a range of tricky problems in four OPEC member countries – Libya (recovery from civil war), Iran (western sanctions over nuclear weapons development), Venezuela (a change of leadership), Nigeria (tribal unrest in the delta and sectarian unrest elsewhere); (2) production problems in certain non OPEC countries that might or might not resolve themselves speedily (Yemen, Syria and Southern Sudan); and (3) a real problem in forecasting how Iraq might develop. Our view is that this 30m b/day needs to be taken as a marker in the sand (this is where we would like to see production all things being normal) but little more than that at present. July 2013 production for OPEC-11 is reported to be around 27.6m b/day, indicating that OPEC are slightly higher but reasonably well aligned with their overall target. None of this changes our view that OPEC may be ill-disciplined when prices are high but remain capable of being totally effective at cutting production when the oil price weakens significantly – as they did in December 2008, 2006, 2001 and 1998.

OPEC met in May 2013 and no changes to production levels were made. Little new came out of the conference, with OPEC reiterating its desire to *"achieve a stable oil market by ensuring that the market is well supplied to meet demand from consumers at fair and reasonable prices"*. The next meeting is scheduled for December 2013.

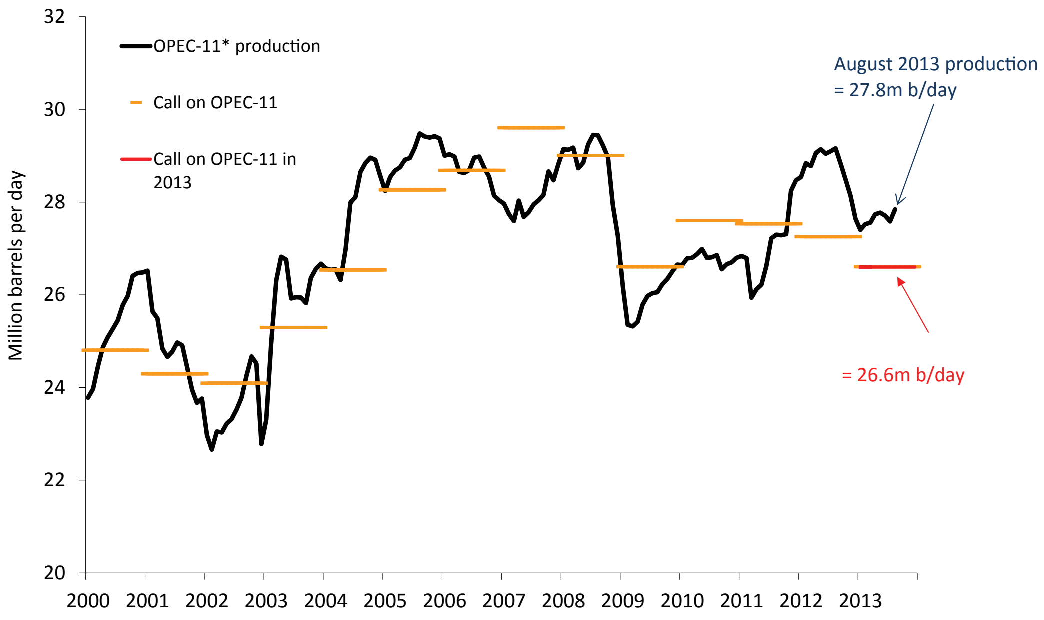
The table below shows changes in production among OPEC-12 since the end of 2010 and shows how production is running well ahead of pre-MENA (Middle East & North Africa) unrest levels. In addition to the non-OPEC problems mentioned above, Saudi Arabia's increased production is an indication of their desire to see US and European sanctions succeed against Iran (so avoiding military action against Iran by Israel). Saudi are well aware that if the oil price is $120+, Iran's overall oil revenues are strong even if production weakens. Saudi production alone is up around 1.4m b/day, and total OPEC-12 production is 1.5m b/day higher than December 2010.

('000 b/day)	31-Dec-10	31-Aug-13	Change
Saudi	8,250	**9,950**	**1,700**
Iran	3,700	**2,570**	-1,130
UAE	2,310	**2,920**	610
Kuwait	2,300	**3,000**	700
Nigeria	2,220	**2,020**	-200
Venezuela	2,190	**2,690**	500
Angola	1,700	**1,740**	40
Libya	1,585	**575**	-1,010
Algeria	1,260	**1,120**	-140
Qatar	820	**720**	-100
Ecuador	465	**535**	70
OPEC-11	**26,800**	**27,840**	**1,040**
Iraq	2,385	3,200	815
OPEC-12	**29,185**	**31,040**	**1,855**

Source: Bloomberg LP (August 2013)

The graph below shows the estimated call on OPEC-11 for 2013, which we currently estimate to be around 26.6m b/day versus apparent production of 27.8m b/day. Given that the market is starting to tighten, it suggests that the actual call has recently been considerably higher than 26.6m b/day. The gap can most likely be bridged via 'missing' demand (a reference to non-OECD demand, in particular, being higher than the IEA are reporting) and overstated non-OPEC supply.

Figure 7: OPEC apparent production vs. call on OPEC 2000 – 2013



Source: Bloomberg/IEA Oil Market Report (August 2013)

Supply looking forward

The non-OPEC world is struggling to grow production meaningfully. The growth was 2% p.a. from 1998-2003, 0.2% p.a. from 2003-2008 and 1.9% p.a. from 2008-2012.

In 2011 and 2012, non-OPEC production grew by only 0.7m b/day (0.1m b/day in 2011 and 0.6m b/day in 2012). Nearly all of the growth came from the successful development of shale oil and oil sands in North America (+1.8m b/day over 2 years), implying that the rest of the non-OPEC region declined by 1.1m b/day over the period. The decline in the rest of non-OPEC has been driven by a combination of political (e.g. Sudan; Syria & Yemen) and operational/geological (e.g. UK & Norwegian North Sea) factors.

The IEA forecast non-OPEC supply growing by 1.1m b/day in 2013, driven again by North American supply (+1.0m b/day). Other areas expected to grow their production slightly include Russia, Colombia and China, offset by declines in the North Sea and Mexico. Should the IEA's forecast for 2013 be achieved, it would represent the highest level of non-OPEC supply growth since 2010.

Looking further ahead, we must consider in particular increases in supply from two regions: Iraq and North America. Starting with Iraq, the question of how big an increase is likely, in what timescale, and the reaction of other OPEC members are all important issues. Our conclusion is that while an increase in Iraqi production may be possible (say, 2m barrels over the next 5 years), if it occurs it will be surprisingly easily absorbed by a combination of OPEC adjustment, if necessary, modest non-OPEC supply growth and continuing growth in demand from developing countries of c.15m b/day over the next 10 years. Iraqi production was running at 3.1m b/day in July 2013, down from a high of 3.6m b/day in mid-2000. Despite this potential, continued unrest across the country does not fill us with confidence that growth can easily be achieved.

The recent growth in US shale oil, in particular from the Bakken, Permian and Eagleford basins, raises the question of how much more there is to come. So far, new oil production from these sources amounts to around 2.0m b/day. Our assessment is that US shale oil is a high cost source of oil but one that is viable at current oil prices. In total, it could be comparable in size to the UK North Sea, i.e. it could grow by a further 2-3m b/day between now and 2017. We also observe that since the discovery of the Bakken, Eagleford and Permian, the US has struggled to find another large shale resource, despite 3 years of trying.

Other opportunities to exploit unconventional oil likely exist internationally, 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 5-10 years behind North America.

Demand looking forward

The IEA reported growth in oil demand in 2012 of 1.0m b/day, comprising an increase in non-OECD demand of 1.5m b/day and a decline in OECD demand of 0.5m b/day. The non-OECD growth forecast for 2013 is similar to 2012 at 1.3m b/day. The components of this growth can be summarized as follows:

Figure 8: Non-OECD oil demand

Million b/day	Demand					Growth			
	2009	**2010**	**2011**	**2012**	**2013**	**2010**	**2011**	**2012**	**2013**
Asia	18.25	19.70	20.33	21.11	21.75	1.45	0.63	0.78	0.64
M. East	7.10	7.32	7.42	7.65	7.83	0.22	0.10	0.23	0.18
Lat. Am.	5.70	6.03	6.17	6.42	6.58	0.33	0.14	0.25	0.16
FSU	4.00	4.15	4.39	4.50	4.62	0.15	0.24	0.11	0.12
Africa	3.37	3.48	3.44	3.56	3.72	0.11	-0.04	0.12	0.16
Europe	0.70	0.68	0.69	0.68	0.68	-0.02	0.01	-0.01	0.00
	39.12	**41.36**	**42.44**	**43.92**	**45.18**	**2.24**	**1.08**	**1.48**	**1.26**

Source: IEA Oil Market Report (August 2013)

As can be seen, Asia has settled down into a steady pattern of growth since 2010. Collective growth in the Middle East, Latin America, FSU and Africa in 2013 is likely to almost match that in Asia. These other non-OECD regions are all central to the developing world industrialisation and urbanisation thesis and should not be overlooked.

For OECD demand in 2013, the IEA's forecast of a decline of 0.3m b/day sees North America up slightly and Europe and the Pacific down. The expected decline in European demand reflects weak economic expectations for the region, but is shallower than predicted earlier this year, while the Pacific decline reflects the gradual switching back to nuclear by Japan post Fukushima.

Global oil demand over the next few years is likely to follow a similar pattern, with a shallow decline in the OECD overshadowed 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. Price and the trajectory of global GDP will have an effect at any point in the short term, but 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.).

Conclusions about oil

From the low of $31.42 on December 22, 2008 we saw the oil price (WTI) recover to above $70 by May 2009, and range trade around $65-$85 for the subsequent 20 months. Since November 2010 it has generally moved above this range, trading in a wider range of $80-$110. Brent's trading range over the same period has been higher, at $90-$125.

The table below summarizes our view by showing our oil price forecasts for WTI and Brent in 2013 against their historic levels, and rises in percentage terms that we have seen in the period from 2002 to 2012.

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

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013e
Average WTI ($)	31.2	41.7	56.6	66.1	72.2	99.9	61.9	79.5	95.0	94.1	95
Average Brent ($)	28.9	38.5	54.7	65.5	73.2	97.1	62.5	79.7	111.0	112.0	105
Average Brent and WTI	30.1	40.1	55.7	65.8	72.7	98.5	62.2	79.6	103.0	103.1	100
Average Brent and WTI Change+ y-o-y ($)		10.1	15.6	10.2	6.9	25.8	-36.3	17.4	23.4	0.05	-3.05
Avge Change+ y-o-y (%)		33%	39%	18%	10%	35%	-37%	28%	29%	0%	-3%

We think the most likely scenario going forward is that we will see the average price of Brent and WTI in the trading range of $90-110. Once the floor of this range looks threatened, OPEC will start to cut back and any significant price weakness below $100 (Brent) will be prevented by OPEC cuts. Should the oil price rise much over $125 and we think demand will start to weaken, putting a ceiling on the price for the time being (absent a supply shock).

This year, non-OPEC supply is growing better than at any point over the last three years, but is being countered by supply disruption across North and West Africa (Libya, Nigeria & Algeria) and the Middle East (Syria, Yemen and foremost, Iran). Factor in respectable demand growth and the market looks balanced, though we should recognize that we are only one ill-judged military move away from another oil spike.

At the heart of it all, we believe that Saudi are working hard to try and maintain a 'good' oil price (Brent at $100-110). So far, they are succeeding.

Natural gas market

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 30% 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 2012 to around 19.5 Bcf/day.

The supply side fundamentals for natural gas in the US are driven by 5 main moving parts: onshore and off-shore domestic production, net imports of gas from Canada, exports of gas to Mexico and imports of liquefied natural gas (LNG). Of these, onshore supply is the biggest component, making up over 80% of total supply.

Since the middle of 2008 the weakening gas price in the US reflects growing onshore US production driven by rising gas shale and associated gas production (coming from growing onshore US oil production). These trends initially were mitigated by declining offshore production and falling net Canada and LNG imports and rising exports to Mexico. Most recently, from about September 2011, the mitigating factors became exhausted and a net imbalance developed. This, combined with very warm winter temperatures in early 2012, caused gas in storage to balloon and precipitated a gas price sell off. Since around April 2012, we have seen the gas rig count fall month on month as producers seek to cut back supply. We also saw significant coal to gas switching by US electric utilities, particularly during the summer of 2012, though much of these has now unwound again.

Total gas demand in 2012 (excluding Canadian exports) is estimated to have been 71.8 Bcf/day, up by 3.3 Bcf/day (4.8%) vs. 2011 and up 6.1 Bcf/day (9%) vs the 5 year average. The principal contributor to the increase in 2012 vs. 2011 was power generation (+4.2 Bcf/day), driven by coal to gas switching. Other notable changes were industrial demand (+0.6 Bcf/day), exports to Mexico (+0.4 Bcf/day) and residential/commercial demand (-2.2 Bcf/day) which was pulled lower by the very warm start to 2012.

Overall, while gas demand in the US has been reasonably strong over the past three years, it has been trumped over this period by a rise in onshore supply, pulling the gas price lower.

Supply Outlook

Change in Rig Count

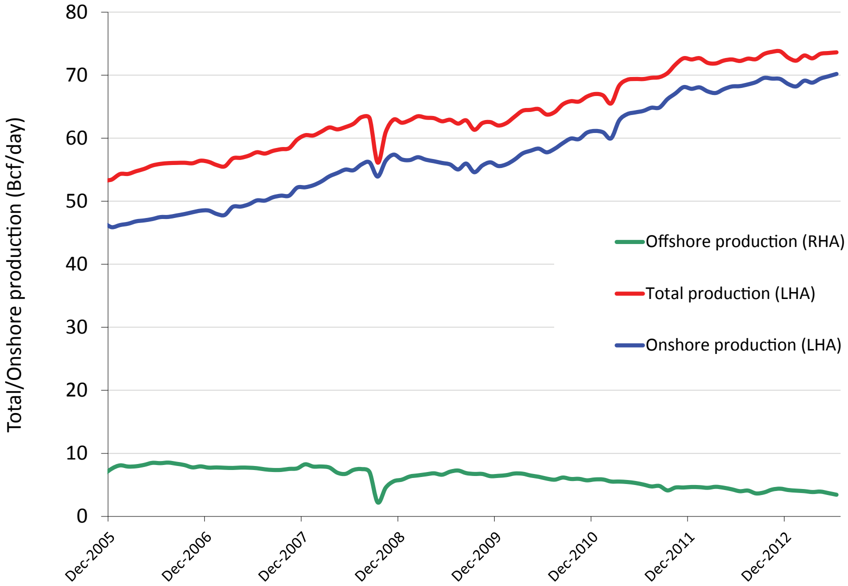
The onshore drilling rig count is the key driver of gas supply. When looking at changing totals, however, the accelerating shift from vertical to horizontal drilling has to be factored in as too does growing associated gas from rising onshore oil production, itself linked to a rising US oil rig count.

In total, the onshore gas rig count has dropped from a 1,606 peak in September 2008 to 380 at the end of August 2013. Over the same period the oil rig count has risen from 416 to 1,388. The total number of rigs has therefore declined recently but not changed dramatically (it has gone from 2,031 Aug 2008 to 1,990 Sep 2011 to 1,776 August 2013. Within this, however, the mix has changed as illustrated by the following table:

RIG COUNT BHI	Aug 2008		Sep 2011		Aug 2013	
Gas Rigs	1606		923		380	
Oil Rigs	416		1060		1388	
Misc Rigs	9		7		8	
Total Rigs	**2031**		**1990**		**1776**	
		%		%		%
Horizontal Rigs	626	*31%*	1135	*57%*	1078	*61%*
Directional Rigs	388	*19%*	238	*12%*	248	*14%*
Vertical Rigs	1017	*50%*	617	*31%*	450	*25%*
Total Rigs	**2031**	*100%*	**1990**	*100%*	**1776**	*100%*

One result of the change from vertical to horizontal drilling has been that onshore gas supply has continued to rise (the average productivity per rig has grown significantly) and is now at circa 70.2 Bcf/day, around 12.8 Bcf/day (22%) above the 57.4 Bcf/d peak in 2009 before the rig count collapsed. But as we mentioned earlier, we do not believe this growing excess in production over demand can continue indefinitely with natural gas trading well below the marginal cost of supply: a combination of reduced capital spending by the exploration companies, lowering production, and growing natural gas demand stimulated by the low gas price will rebalance the market, as is now happening.

Figure 10: US natural gas production 2005 – 2013 (Lower 48 States)



Source: EIA 914 data (June 2013 published in August 2013)

Liquid natural gas (LNG) arbitrage

The UK national balancing point (NBP) gas price – which serves as a proxy to the European traded gas price – edged down in August, but remains at a very significant premium to the US gas price ($9.90 versus $3.57). LNG supplies to the UK have been somewhat constrained, particularly in light of strong demand for LNG to Asian markets. This, together with a prolonged European winter, has been helping to support the price in recent months. US LNG imports remained well below 1 Bcf/day in August as cargoes took advantage of the higher prices in Europe and Asia.

Canadian imports into the US

Net Canadian imports of gas into the US dropped from 9.1 Bcf/day in 2007 to 5.4 Bcf/day (estimated) in 2012. This was initially driven by falling rig counts and a less attractive royalty regime enacted in 2007 and has accelerated due to increased domestic demand from Canadian oil sands development. Although the Canadian rig count has recovered somewhat, we expect net imports to continue to decline in 2013 to around 5 Bcf/day.

Demand Outlook

For 2013, we expect demand from power generation to be down on 2012 (a reversal of much of the 2012 coal to gas switching if the gas price stays above $3) but about 1-1.5 Bcf/day above 2011. Residential and commercial gas demand will as ever be weather dependent, but assuming average temperatures, demand should be around 2 Bcf/day better than 2012 and unchanged from 2011. And we expect industrial consumption about 0.3 Bcf/day above 2012. Overall, assuming average weather, we expect 2013 demand to be around 71-72 Bcf/day, down a little on 2012 but around 2.5-3 Bcf/day higher than 2011.

Looking out further, the low US gas price has stimulated various initiatives that are likely have a material impact on demand from 2015/16 onwards. The most significant is the group of LNG export terminals in the US and Canada which are in the planning/early construction stages. There are over 26 bcf/day of LNG export projects proposed in the US today, plus a further 6 bcf/day in Canada, as shown below:

Source: Bernstein, Guinness Atkinson Asset Management (August 2013)

#	Terminal	Sponsor	MTPA Capacity
US – Approved			
1	Sabine Pass	Cheniere	16.0
US – FERC Review			
2	Freeport	Freeport	10.0
3	Corpus Christi	Cheniere	13.5
4	Coos Bay	Jordan Cove	6.0
5	Lake Charles	ETE-BG	7.0
6	Hackberry (Cam)	Sempra	12.0
7	Cove Point	Dominion Res.	7.2
8	Astoria	Oregon LNG	8.0
US – Proposed			
9	Alaska LNG	XOM-BP-COP	15.0
10	Brownsville	Gulf Coast LNG	20.6
11	Pascagoula	Gulf LNG	9.0
12	Lavaca Bay	Excelerate	8.5
13	Elba Island	ETE	3.0
14	Golden Pass	XOM	16.0
15	Plaquemines Parish	CE FLNG	7.5
	US Total		**159.3**
Canada – Review			
16	Kitimat	EOG-APA-ECA	5.5
17	BC LNG	Var.	1.8
18	LNG Canada	RDS	24.0
Canada – Proposed			
19	Prince Rupert	Petronas	8.5
20	Ridley Island	BG	8.5
	Canada Total		**48.3**

Not all these facilities will be built but we think that exports of between 6-10 bcf/day from the US by 2020, or around 10-15% of new demand, are likely. Additional LNG exports from Canada will contribute a few extra bcf, tightening the natural gas balance across North America. Importantly, the DoE-sponsored report concluded that LNG exports will have a net benefit to the US economy and that benefits are likely to increase as LNG exports rise.

Industrial demand will also grow thanks to 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 believe that gas will continue to take the majority of incremental power generation growth in the US. The combined cycle gas turbine fleet (CCGT) operated in 2010 at 39% of capacity versus the coal fleet at 70% of capacity. 2012 has given us a glimpse of the scale of switching that is possible, and while the CCGT fleet will not reach 70% anytime soon (it is not all in the 'right place' geographically), we do expect it to grow its underlying market share and add several Bcf/day to gas demand over the next few years. Our working assumption is 1 Bcf/day per year.

We also watch with interest the efforts being made to increase the usage of LPG and LNG by the US truck, bus and delivery van fleets. Whether this will gain traction is hard to know. If it does its impact will be meaningful. If the entire fleet described above moved to gas, we estimate that it would increase demand by 18 Bcf/day. A much smaller transport market but one that might be easier to convert is the US railways. BNSF Railway announced in March 2013 that they would trial a switch for their train engines from diesel to liquefied natural gas. BNSF Railway is the US's second largest freight railroad network. Rail engines in the US currently consume around 0.25m b/day of distillate, equivalent to around 1.5 Bcf/day of gas.

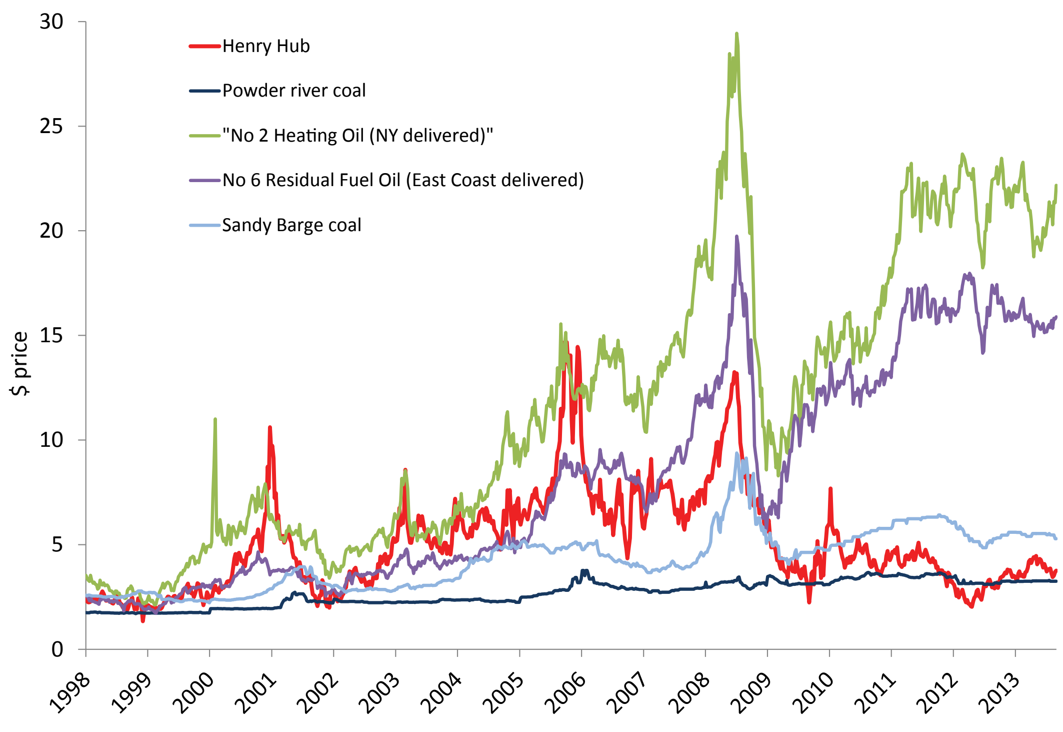
Other

Relationship between gas price and other energy commodity prices in the US

The oil/gas price ratio ($ per bbl WTI/$ per mcf Henry Hub) of 30.2x at the end of August continues well outside the more normal ratio of 6-9x. If the oil price averages around $95 in 2013 and the relationship between the oil and gas price returning to its longer-term average of 6-9x, this would imply the gas price increasing back to above $10 once the gas market has returned to balance. This is quite a thought and a long way away from current market sentiment.

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. With the gas price trading below the coal price support level for the first 8 months of 2012, resulting coal to gas switching for power generation was significant. It will be interesting to see how much of the switching persists in 2013 with gas back generally above $3.50/Mcf – some but not all, we think.

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 (August 31, 2013)

Conclusions about US natural gas

The US natural gas price bottomed in 2012 and the recovery has begun. Natural gas at around $3.50 spot is nearly double the April 2012 low but still below the (full cycle) marginal cost of supply and as the depressed rig count holds back new supply we expect the price to recover further. We believe the gas price may then be held around the $4-5 range for a period until demand grows further, and longer term we expect the price to normalize to $6-8.

7. Appendix: Oil and Gas markets historical context

Figure 12: Oil price (WTI $) last 23 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.

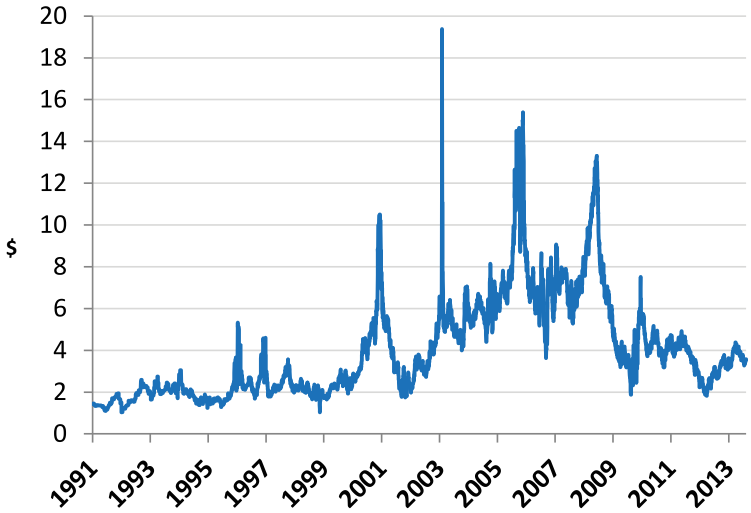
Then, in late 2002 early 2003, war in Iraq and a general strike in Venezuela caused the price to spike upward. This was quickly followed by a sharp sell-off due to the swift capture of Iraq's Southern oil fields by Allied Forces and expectation that they would win easily. Then higher prices were generated 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. Since 2011 we have seen a disconnect between the WTI and Brent oil benchmarks due to US domestic oversupply affecting WTI. The WTI price has generally moved up and into a wider range of $80-$110, whilst Brent's trading range over the same period has been higher, at $90-$125, with the pressures of non-OECD demand persistently outstripping non-OPEC supply and supply tensions in the Middle East/North Africa prevailing.

Figure 13: North American gas price last 22 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.

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.

Tim Guinness
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Will Riley & Jonathan Waghorn
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Commentary for our views on Alternative Energy and Asia markets is available on our website. Please click here to view.

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One cannot invest directly in an index.

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Earnings per share (EPS) is calculated by taking the total earnings divided by the number of shares outstanding.

Book Value is the net asset value of a company, calculated by subtracting total liabilities from total assets.

Enterprise value (EV) is defined as the market capitalization of a company plus debt minus total cash and cash equivalents.

EV/EBITDA is EV divided by "Earnings Before Interest, Taxes, Depreciation and Amortization" (EBITDA)

EV/R is the enterprise ealue to revenue multiple and a measure of the value of a stock.

Cash Flow Return on Investment (CFROI) is a valuation model that assumes the stock market sets prices based on cash flow, not on corporate performance and earnings. CFROI is a proprietary metric prepared by HOLT, a division of Credit Suisse.

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