Edison investment research

Diverging Brent and WTI price trends

Oil markets have been dominated recently by two issues, EU sanctions on Iran and surging North American supply. The upshot has not only been diverging WTI and Brent prices but also the dramatic emergence of wide regional light oil spreads in North America. Near term, at least, we expect international prices to continue to be buoyed by the Iranian issue while WTI and other US light grades languish under the weight of rising supply.

Supply/demand balance: Swing to surplus

There is no shortage of oil. On the contrary, the oil market probably went into surplus in Q411. The supply/demand picture has been transformed of late by softening business conditions in much of the OECD, slowing economic growth in developing countries, a strong rebound in non-OPEC production after the outages of Q311 and an upward trend in OPEC output. Abstracting from major outages, a substantial supply surplus of perhaps a 1mm b/d is possible in 2012. EU import sanctions on Iran are, of course, a wild card for 2012 and maybe beyond. The loss of Iranian exports can, however, be offset by higher OPEC production and stepped-up Iranian deliveries to China.

International prices: Iran uncertainty premium

Brent has risen to a five-month high since the EU import embargo on Iran was agreed on 23 January. The firming is not unjustified given the geopolitical uncertainties unleashed by the EU's move plus the anticipated tightening utilisation rate within OPEC. In the absence of armed conflict between the west and Iran, the key impact of EU sanctions will be on spreads. The main developments are expected to be a widening of the WTI-Brent discount, a narrowing of the Brent-Urals premium and a narrowing of the Brent-Dubai premium. Urals is expected to be the grade of choice at Mediterranean refineries after the cessation of Iranian imports. Reflecting recent trends and the Iran factor, we have raised our 2012 forecast for Brent from $102.8 to $113.5/barrel.

US prices: WTI $20/barrel discount to Brent

WTI has trended flat to down this year while Brent has risen 9% resulting in a widening WTI discount from $9 to $20/barrel, the highest since October. We expect the WTI discount to remain wide in the coming months due partly to the Iranian issue and partly to burgeoning supplies of Bakken crude and Canadian Syncrude. These grades have recently traded at discounts of well over $20/barrel to WTI. We have modestly raised our WTI forecast for 2012 from $93.3 to $96.4/barrel to reflect recent trends and international influences.

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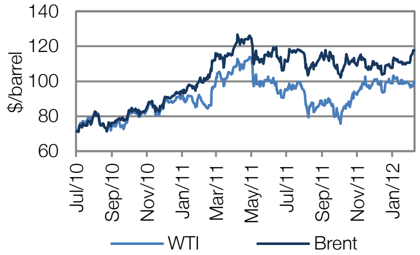
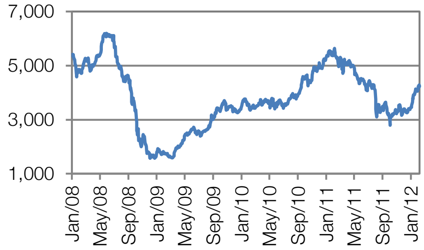
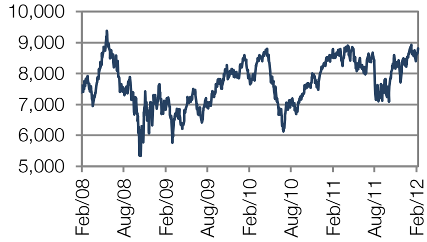
WTI vs Brent



AIM Oil & Gas Index



FTSE 350 Oil & Gas Index



Price trends

	WTI $/barrel	Brent $/barrel	Henry Hub $/mm Btu
2009	62.0	62.0	3.94
2010	79.5	79.7	4.37
2011	94.9	110.0	4.00
2012e	96.4	113.5	3.50
2013e	98.5	115.0	4.00

Note: Prices are yearly averages

Crude oil market dynamics

Price overview

Market backdrop: Iran vs macroeconomic concerns

Benchmark light crude oil prices trended broadly flat between early December 2011 and late January 2012. Subsequently, there has been a marked divergence between Brent and WTI with the former moving significantly higher and the latter trending flat to down. As of 7 February 2012 Brent was trading at $118/barrel while WTI was at $98/barrel. Over the past few weeks international prices have mainly been driven by two countervailing forces. On the bullish front the principal driver has been the EU embargo on Iranian oil imports and the related decision to freeze the assets of the Iranian central bank in the EU. After having first been proposed in December, the embargo was confirmed on 23 January by EU foreign ministers and applies to shipments from 1 July 2012. Iran has indicated that it may pre-empt the embargo by unilaterally cutting exports to the EU partly to drive up prices. The embargo and related financial sanctions reflect fears that Iran might be clandestinely developing nuclear weapons, which would be in contravention to the Nuclear Non-Proliferation Treaty (NPT), to which it is a signatory.

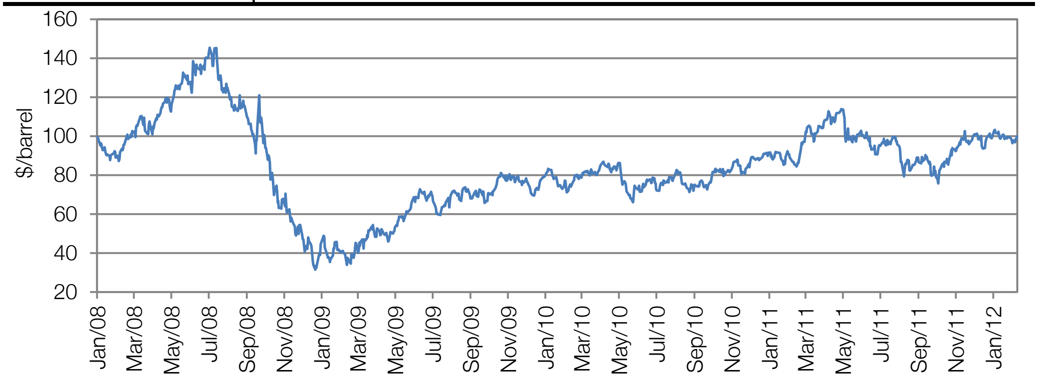
Until recently any upward tendency in international crude oil prices tended to be held in check by continuing bearishness over the direction of the world economy in 2012. Uppermost among the market's concerns have been the ongoing sovereign debt crisis and related fiscal tightening in Europe and the pronounced slowdown in the Chinese economy over the past six months or so. The spectre of recession is clearly present in Europe while in China a significant decline in economic growth to8% or less (2011 9.2%) would not be surprising. Indicative of the travails of the world economy the IMF has recently cut its forecasts for global economic growth from 4.0% to 3.3% for 2012 and from 4.5% to 3.9% for 2013. For perspective, economic growth globally came in at 5.2% in 2010 and 3.8% in 2011, according to IMF data. Following the emergence of the BRIC countries as major economies, global growth of significantly below 4% is now considered decidedly sub-par.

Underpinning bearish market sentiment at times in late 2011 and early 2012 were two further factors. These were the strong dollar and the mild winter in North America which has depressed heating oil demand. The dollar appreciated by about 10% between end October 2011 and mid January 2012 to €1.26, a 16-month high. The US demand picture overall has been fairly neutral for oil prices of late. Oil demand has remained weak while commercial inventories have trended flat to up in recent weeks. US macroeconomic newsflow, however, combined with the Federal Reserve's 25 January policy statement relating to maintaining the Federal Funds rate close to zero until at least end 2014 has been positive for oil prices.

Recent trends in Brent and WTI: In February Brent has risen while WTI has slipped

Brent, the key international light crude benchmark, traded within a fairly narrow trading range of roughly $105/barrel to $115/barrel for most of the period between early October 2011 and late January 2012. At the beginning of December Brent was trading at $109/barrel. Through the first half of the month Brent trended noticeably lower, driven by broad macroeconomic concerns, particularly the European sovereign debt crisis. Compounding sovereign debt concerns was a warning by the rating agencies that they were considering a down grading of European debt. Brent hit a two-and-a-half-month low on 15 December of $103.8/barrel. Upward momentum was regained in the second half of the month driven principally by the Iran issue. Brent hit a high for the month of $109.8/barrel on 27 December and closed the month at $107.6/barrel. The average for December was $107.9/barrel, the lowest monthly level since February 2011. Taking 2011 as a whole, Brent averaged $110.0/barrel, which was a record and 38% above a year previously. The gain for the year, however, stemmed very much from the Libya-driven surge in the first four months which took Brent to a month high of $126.7/barrel on 8 April 2011. Between early May and end December 2011 the trend was broadly flat.

Exhibit 1: WTI crude oil price trend

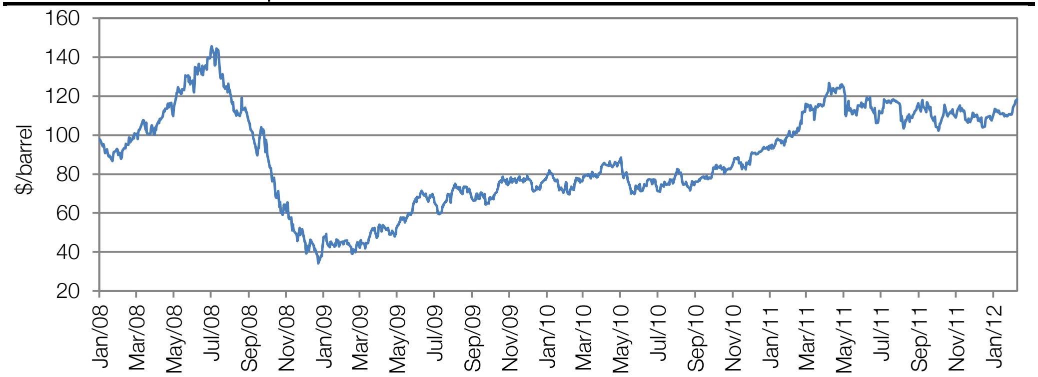


Source: Bloomberg

During early January 2012 Brent continued to trend higher with geopolitical issues to the fore. A one-and-a-half-month high of $113.4/barrel was reached on 4 January. Over the rest of the month Brent drifted down as European sovereign debt concerns once again resurfaced. Brent ended January at about $111/barrel. For January Brent averaged $111.2/barrel, up 2.7% on December. During early February Iran related concerns began to gain traction taking Brent to a five-month high on 7 February of $117.7/barrel.

Between early December 2011 and late January 2012 WTI followed a similar path to Brent. WTI started December at $100.2/barrel and by 16 December was down to $93.5/barrel, a one-and-a-half-month low. The rebound in the second half of December took WTI to a high for the month on 27 December of $101.3/barrel. This was followed by a softening to $98.8/barrel over the rest of the month. For December WTI averaged $98.6/barrel, up 1.5% on the prior month. The average for 2011 was $94.9/barrel, 19% above 2010. Unlike Brent, the WTI average for 2011 fell short of that for 2008, which came in at $99.8/barrel. A key difference between the WTI and Brent price trajectories in 2011 was the much heavier downward pressure sustained by WTI during the third quarter.

Exhibit 2: Brent crude oil price trend



Source: Bloomberg

WTI firmed noticeably through the first two trading days of January 2012. This took the price to around a seven-month high of $103.2/barrel on 4 January. As in the case of Brent, WTI drifted down through January 2012 taking the price to $98.5/barrel by month end. For January WTI averaged $100.3/barrel. In the early days of February WTI dipped to a one-and-a-half-month low of $96.4/barrel reflecting plentiful supplies in the US Mid-Continent and continuing evidence of weak US demand.

How important is Iran: Exports of 2.5mm b/d

Export flows and regional mix: Exports to EU almost 0.6mm b/d

As the second largest OPEC producer and exporter, Iran is an influential player in world oil markets. Production in 2011 averaged about 3.5mm b/d of mainly medium to heavy oil while exports through the nine months to September were 2.53mm b/d, according to IEA data. The regional mix for Iran's exports for the period was EU 24%, China 22%, Japan 13%, India 12%, South Korea 9%, Turkey 8%, South Africa 3% and other Asia 9%. Not surprisingly, given logistical considerations, the EU mix is heavily oriented to the Mediterranean markets of Greece, Italy and Spain. Through the first nine months of 2011 these three received shipments of 103,000b/d, 185,000b/d and 161,000b/d respectively. During the same period total EU imports from Iran were 592,000b/d.

Conceptually the EU embargo could make a major dent in Iran's exports. This, however, is not the whole story as the US is also putting pressure on Japan and South Korea to stop importing from Iran. Furthermore, US sanctions on foreign banks doing business with the Iranian central bank could make imports from Iran problematic in future for South Africa, Turkey and maybe south east-Asian countries. At minimum, we can safely say that almost 50% or 1.3mm b/d of Iran's exports is at risk. The question then arises as to how easy it would be for the EU and Japan/South Korea to find alternative supplies and what the impact will be on the world supply/demand balance. Theoretically, if the EU and others cease importing from Iran the displaced oil could simply be redirected to other markets much as happened in 1979 when the US banned imports from Iran. The net impact on the world supply/demand balance would therefore approximate to zero. The problem this time around for Iran is that tightening EU and US sanctions on potentially errant western financial institutions and the Iranian central bank are severely limiting its options for market development. Of course, Iran can resort to barter and maybe able to find financial centres outside the reach of the long arm of the US legal system willing to undertake transactions.

We suspect that China is the only major market able and willing to take significantly more Iranian oil in the months ahead. China might indeed be willing to barter oil for manufactured products, arms and engineering expertise. In practice, China's financial system is also outside the remit of the US. There are, however, limits to how much China could rapidly step up its imports from Iran, not least for technical reasons. If we assume China takes another 0.3mm to 0.5mm b/d at short notice and effectively releases supplies from other sources, the western world would be short of approaching 1mm b/d. Theoretically this can be made good by higher output from Saudi Arabia and some other OPEC producers but this will eliminate a quarter or so of current OPEC surplus capacity, excluding Iran, of about 3.8mm b/d.

Price implications: EU and US sanctions against Iran could potentially have highly significant negative price implications from a consumer perspective. This would apply particularly if Iran decides on its own accord to pre-empt the embargo and cease shipments to the EU and maybe Japan and South Korea. Major merchant refineries in the Mediterranean, such as Sarasin Sardinia and Hellenic Petroleum in Greece, would be subject to an immediate surge in prices and possibly with a short lag, spot shortages.

The IMF has recently suggested that a halt to Iranian exports could initially result in a 20-30% surge in prices, which might be equivalent to $20-30/barrel. Based on the price surge after stopping Libyan exports in early 2011, we believe such a movement is entirely plausible. The longer-term impact would depend on how quickly alternative supplies could be brought on-stream and to what extent Iran can find new markets.

Long-term impact on capacity: Tightening western sanctions on Iran also apply to the supply of oil and gas technology in terms of both equipment and engineering services. This factor is likely to adversely impact Iran's productive capacity over the longer term. The IEA has recently indicated that the impact between 2010 and 2016 could be a 0.89mm b/d fall in capacity to 3mm b/d. According to the IEA, Iran's share of OPEC capacity will fall from 11% to 8% between these two years.

Straits of Hormuz: Disastrous if closed

The stand-off between the west and Iran over Iran's nuclear programme has another aspect that could have potentially disastrous economic implications. This concerns Iranian threats to close the Straits of Hormuz near the mouth of the Arabian/Persian Gulf in the event of an EU embargo. Importantly, around 20% of the world's traded oil passes through the Straits. Iran has also warned oil producers in the Gulf not to step up production at the behest of the west. The US Chairman of the Joint Chiefs of Staff, General Martin E Dempsey, has recently suggested that Iran could indeed close the Straits. Doubtless in the last resort, Iranian forces would be no match for the American Navy and Air Force but it could easily take a month or more to neutralise the Iranian threat and clear the Straits of mines. The upshot of a shooting war with Iran combined with stopping exports from the Gulf would in all probability be a surge in crude oil prices to well over $200/barrel. Needless to say the implications for economic activity would be horrendous.

Some observers say that the Iranians would have a great deal to lose by provoking a shooting war with the west and that such a move would be 'irrational'. From a western perspective this might be the case but it would also inflict enormous damage on the west and almost certainly not lead to the abandonment of Iran's nuclear programme.

Light crude spreads

WTI-Brent: WTI discount widening again, now around $20/barrel

The WTI discount to Brent trended slightly down between end November and end December 2011 but then to late January 2012 widened modestly. The discount, however, remained well below the highs reached in the third quarter and the early part of the fourth quarter of 2011 of approaching $30/barrel. At the beginning of December the WTI discount was $9.2/barrel and at the end of the month was $8.8/barrel. The average for December was $9.3/barrel, down significantly on October's $23.1/barrel and November's $13.4/barrel and the lowest level since January 2011. For 2011 as a whole WTI traded on average at an unprecedented discount of $15.1/barrel to Brent. The pronounced narrowing of the WTI discount in late 2011 reflected a number of factors. The most influential were the improvement in the availability of light crudes on the eastern side of the Atlantic, following the completion of maintenance programmes in the North Sea and the resumption of Libyan exports and the announcement of the decision to reverse the Seaway pipeline flow between the Gulf Coast and Cushing, Oklahoma from south-north to north-south.

During January 2012 the discount widened from $8.8/barrel at the beginning to about $12/barrel at month end. The average for January was $10.7/barrel. The widening tendency during January, we believe, largely reflected the Iran issue which boosted the price of Brent relative to WTI in recent weeks. In early February the WTI discount widened substantially and on 7 February was about $20/barrel, the highest since October 2011. The widening reflected a combination of the Iranian issue boosting Brent and increasing evidence of plentiful supplies and weak demand depressing WTI.

Keystone in the news again: President Obama rejects Keystone XL for the moment

President Obama has recently rejected TransCanada's proposal to construct the 2,700km Keystone XL pipeline via a direct route from Hardisty, Alberta to the Gulf Coast. This follows an earlier announcement by the President that a decision on whether to proceed with the pipeline would be deferred until after the November 2012 election. The latest decision was precipitated by Congress, which set a 60-day deadline on whether to proceed.

According to the US State Department, the Keystone pipeline was 'determined not to serve the national interest'. Given the unquestionable energy security and economic benefits of Keystone, the State Department's conclusion appears highly dubious. As the Canadian Prime Minister, Stephen Harper, has noted a decision in the affirmative was a 'no brainer'. The President, however, was under intense pressure from the green lobby not to proceed with Keystone on the basis of hostility to the development of the Athabasca oil sands. In the lead up to the election rejection of the project at this stage was, therefore, arguably not totally surprising. TransCanada is not abandoning Keystone and is expected to reapply for a permit for the project at a more opportune time. In addition, TransCanada is expected to pursue more aggressively a new pipeline from Alberta to

Kitimat on the Pacific coast of British Columbia. This would enable output from oil sands projects to be exported to Asia.

It must also be noted that the need for Keystone XL from a broad logistical perspective is possibly a little less pressing than a few months ago. This reflects the Seaway reversal decision and rapidly improving rail links between the Bakken oilfields of North Dakota and the Gulf Coast, the Pacific coast and Chicago. Improving logistics imply that oil from Canada and the Bakken will be less likely to be locked in at the Cushing tank farm and in the process depressing the price of WTI.

North Dakota production continues to surge

Production in North Dakota continues to surge propelled by intensive drilling activity in the Bakken/Three Forks shale formation (roughly 87% of state production). In November 2011 production in the state, according to the Department of Mineral Resources, was a record 509,700b/d, up 21,600b/d on the prior month and 154,700b/d or 44% on a year previously. For 2011 as a whole, production probably averaged in the region of 410,000b/d, which would be a 33% gain over 2010. North Dakota now accounts for approaching 10% of US crude production and has established itself as comfortably the fourth largest oil producing state in the union after Texas, Alaska and California. In 2012 North Dakota could, in fact, displace California to take the number three slot. Based on recent trends in production and drilling activity, the Department of Mineral Resource's North Dakota production forecast of 750,000b/d in 2015 looks eminently plausible.

Reflecting surging output from shale formations in the Lower 48 states, US crude production continued to move ahead in 2011. Production for the year came in at 5.57mm b/d, a gain of 1.8% from 2010 and the highest level since 2003. Falling Alaskan production partly offset the gain made in the Lower 48. Total US oil production in 2011, including natural gas liquids and ethanol and bio-diesel, was an estimated 8.78mm b/d, up 4% from the prior year.

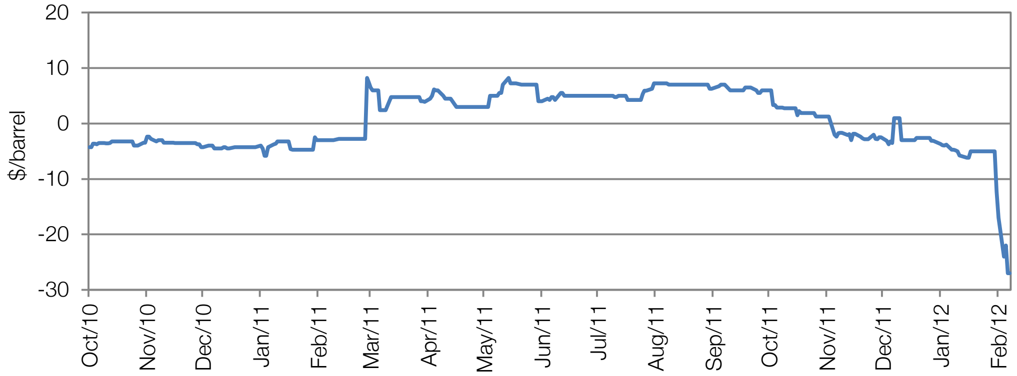
Importantly, the EIA has recently boosted its medium-term forecast of US crude oil production. The agency is now looking for 2020 production of 6.7mm b/d against 6.0mm b/d. This mainly stems from a reappraisal of shale oil development potential in the Lower 48. Broadly speaking, the petroleum industry believes shale development can boost US crude production by 1.5mm to 2mm b/d by 2015. This would imply perhaps 7mm b/d after allowing for depletion in established fields.

Bakken and Syncrude discounts dramatically widen in February

An interesting development in US Mid-Continent markets in the early weeks of February has been the emergence of wide discounts of Bakken and Canadian Syncrude oil to WTI. It should be noted that Bakken and Syncrude are both light, low sulphur crudes with specifications broadly similar to WTI. Syncrude, unlike Bakken grade oil, is a synthetic crude derived from the Athabasca oil sands. Taking the Bakken-WTI spread there was a swing from a Bakken premium of about $5/barrel in the third quarter of 2011 to a discount of $3.1/barrel at year end. During January and particularly February 2012 the discount widened sharply and by 7 February was a hefty $24/barrel. Syncrude was still trading at a premium to WTI of $3/barrel at the end of December 2011 but by 6 February this had swung to a $23/barrel discount. The implied prices of about $74/barrel, we believe, are easily the lowest for premium grade light oil anywhere in the world outside those countries with state controlled markets.

The emergence of wide Bakken and Syncrude discounts to WTI of late is indicative of plentiful supplies in the US Mid-Continent and Alberta along with pipeline constraints. Specifically in the case of Syncrude grade oil, the rapidly widening discount in early February was driven in part by statements by Syncrude Canada and Suncor Energy, the two largest producers of synthetic crude, concerning sizeable output gains in 2012. Syncrude has pointed to an increase of 7% and Suncor to a gain of 12%, based on company reports.

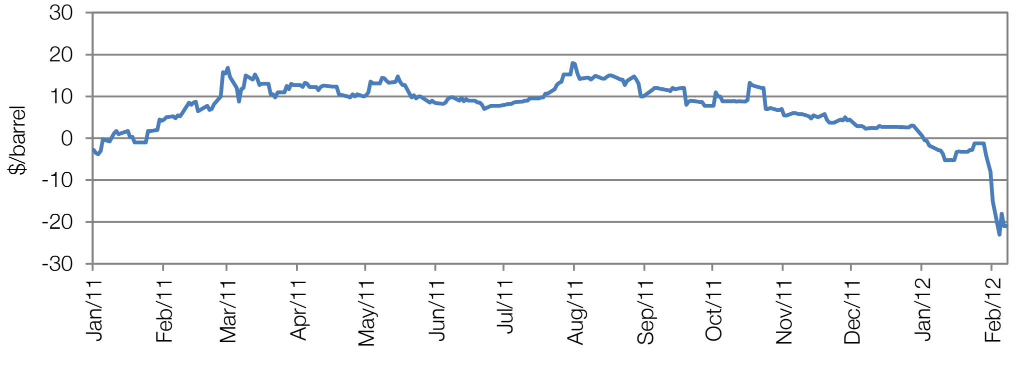
Exhibit 3: Bakken-WTI spread



Source: Bloomberg

The key issue now is whether the wide Bakken and Syncrude discounts are ephemeral or a sustainable phenomenon. We suspect that discounts of over $20/barrel probably are not sustainable over a period of months given the likelihood that action will be intensified to ship surplus supplies by rail to Cushing or some other higher priced hub such as St James, Louisiana. It also needs to be remembered that Syncrude production tends to be volatile and susceptible to plant outages. Nevertheless, rapidly rising Bakken and Syncrude production probably does imply at least a significant discount of, say, $5 to $10/barrel, until pipeline connections can be upgraded.

Exhibit 4: Syncrude-WTI spread



Source: Bloomberg

Where is the WTI-Brent spread heading?

Before the EU made its decision to embargo imports and tighten financial sanctions on Iran our expectation was that the WTI-Brent spread would narrow from the unprecedentedly high levels of the late third quarter of 2011 to $5-$10/barrel over the medium term. The drivers were expected to be, on the one hand, upgraded rail and pipeline logistics in the US Mid-Continent and, on the other, an improving supply picture on the eastern side of the Atlantic basin, reflecting Libya coming back on-stream and the non-recurrence of major outages in Angola and the North Sea. The residual WTI discount reflected the assumption of a continuing bullish supply picture in the Mid-Continent stemming from shale development for the foreseeable future.

While we believe this underlying analysis is still valid, recent actions by the EU over Iran have complicated the outlook for the WTI-Brent spread. Specifically, the embargo on Iran is now likely to tighten the supply-demand relationship in Europe which, all things being equal, will probably boost Brent relative to WTI. Given this, we think the WTI discount near to medium term is likely to settle well above $10/barrel and probably closer to $20/barrel. In an extreme situation related, for example, to a complete cessation of exports from the Persian Gulf, the WTI discount to Brent would sky rocket and in all probability exceed the highs reached in 2011.

Exhibit 5: WTI 2008-12 quarterly prices $/barrel

	Q1	Q2	Q3	Q4	Total
2008	97.9	123.8	118.2	59.1	99.9
2009	43.2	59.7	68.1	76.0	62.0
2010	78.8	77.9	76.1	85.2	79.5
2011	93.9	102.3	89.5	94.0	94.9
2012e	97.4	96.0	95.0	97.0	96.4

Source: Bloomberg and Edison Investment Research

Exhibit 6: Brent 2008-12 quarterly prices $/barrel

	Q1	Q2	Q3	Q4	Total
2008	96.5	122.2	115.9	56.2	97.7
2009	45.1	59.4	68.4	75.0	62.0
2010	76.8	78.6	76.4	86.9	79.7
2011	104.9	116.8	109.1	109.3	110.0
2012e	113.0	114.0	114.0	113.0	113.5

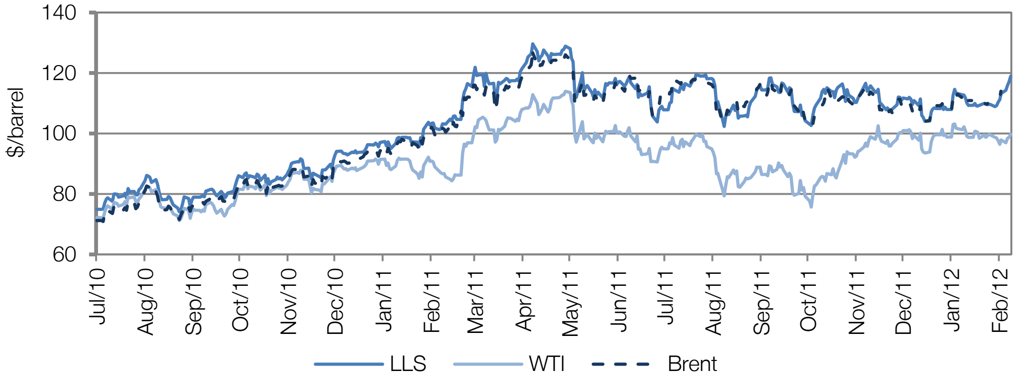
Source: Bloomberg and Edison Investment Research

LLS-WTI: LLS premium to WTI widens sharply in February

Light Louisiana Sweet (LLS) is a Gulf of Mexico sourced light crude with a specification similar to WTI and Brent. It competes with waterborne imported grades at Gulf Coast refineries and has traditionally traded at a dollar or so premium to WTI and perhaps $2-3/barrel to Brent. Given its waterborne characteristics, LLS broadly tracked Brent in 2011, resulting in a hefty premium to WTI during the late third quarter and early fourth quarter. The high point was $29.8/barrel on 22 September. The LLS premium narrowed sharply during November and December averaging $14.8/barrel and $10.2/barrel respectively. For 2011 as a whole, the LLS premium to WTI averaged $16.5/barrel against $2.2/barrel in 2010. In January the LLS-WTI spread was broadly unchanged at $10.4/barrel before widening sharply to $18.5/barrel in early February. This suggests that Gulf refineries dependent on waterborne feedstock remain at a major competitive disadvantage compared with those in the Mid-Continent able to source WTI.

After trading at a discount for much of the first nine months of 2011, LLS swung to a more normal premium to Brent of about $1.5/barrel in the fourth quarter. This essentially stemmed from a lessening of Brent supply constraints which was particularly apparent in the third quarter of 2011. Once again, however, Brent strengthened relative to LLS in January reflecting the indirect impact of Iranian influences on Gulf waterborne grades. For January as a whole, LLS traded at a slight discount of $0.4/barrel to Brent.

Exhibit 7: Recent trends in WTI, LLS and Brent



Source: Bloomberg

Other key international light crude benchmarks: Urals potentially the grade of choice

Brent-Urals Mediterranean: Urals is a Russia sourced medium-sour export blend that is shipped either from the Black Sea or via Baltic ports. Reflecting its inferior quality in terms of gravity and sulphur, it has typically sold at a discount of $1-3/barrel to Brent. Urals is nevertheless well suited to producing middle distillates such as diesel. The traditional Urals discount to Brent pretty well evaporated during the third quarter of 2011 as a result of strong demand in Russia which reduced export shipments. Interestingly, Urals traded on occasion at a rare premium to Brent of up to a dollar per barrel, in November and December. During January 2012 Urals swung back to a discount to Brent of $1.3/barrel on average but towards month end was trading at approximate parity.

Urals is expected to be the grade of choice for Mediterranean refiners looking to replace lost Iranian supplies. This reflects in part logistical considerations and in part the broad similarity of specification between Urals and high sulphur Iranian crude. Note here that the refineries have been specified to handle sour crudes. The problem for the Mediterranean refiners is that the supply of Urals is very tight. This suggests that Urals premiums to Brent may not be unusual in the months ahead.

Brent-Dubai: Dubai is a Gulf-sourced light but relatively sour crude popular with Far Eastern refineries. During the third quarter of 2011 Dubai was selling at historically hefty discounts of $5-6/barrel to the higher grade Brent. The discount however narrowed sharply in November and December to a more normal $1.9 and $1.7/barrel respectively reflecting an easier trend in Brent and buoyant Far Eastern demand for Dubai grade. In January 2012 the Dubai discount narrowed further to $1.3/barrel, which indicates the improving availability of light sweet crudes on the eastern side of the Atlantic and in the Mediterranean in recent months.

Tapis-Dubai: The premium of the ultra-high grade Malaysian sourced Tapis to Dubai has also contracted sharply in recent months. In January Tapis was trading at a premium of $11.7/barrel on average, well down on the third-quarter highs of almost $15/barrel.

Brent-Bonny: The key eastern Atlantic basin Brent-Bonny (Nigerian ultra low sulphur light grade) spread was running at normal levels in the closing months of 2011. In November and December the Brent discount to Bonny was $1.5/barrel and $1.9/barrel respectively after having been over $2/barrel since the beginning of the year. The discount widened in January to $2.4/barrel probably reflecting civil unrest in the country, although there is no evidence that oil production in Nigeria has been greatly affected.

Exhibit 8: Recent benchmark light crude prices and spreads

Note: All prices are averages for the period shown other than where indicated.

					2011								2012
$/barrel	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb/09
WTI	89.5	102.9	110.0	101.3	96.3	97.3	86.3	85.6	86.4	97.1	98.6	100.3	99.7
Brent	104.0	114.4	123.4	114.5	113.8	116.5	110.8	110.9	109.5	110.5	107.9	111.2	118.5
Dubai	100.3	108.6	115.7	108.5	107.5	110.0	105.1	106.0	103.7	108.6	106.2	109.8	114.8
Bonny	105.9	117.8	126.2	117.1	116.0	118.6	112.9	114.6	111.4	112	109.8	113.4	120.9
Tapis	107.7	118.7	129.2	121.9	122.3	124.2	118.6	120.0	118.6	120.5	117.5	121.5	125.3
LLS	106.3	117.6	126.0	116.5	113.2	115.8	109.3	112.8	111.8	111.9	108.8	110.7	118.9
Spreads													
WTI-Brent	(14.5)	(11.5)	(13.4)	(13.2)	(17.5)	(19.2)	(24.5)	(25.3)	(23.1)	(13.4)	(9.3)	(10.9)	(18.8)
Brent-Dubai	3.7	5.8	7.7	6.0	6.3	6.5	5.4	4.9	5.8	1.9	1.7	1.4	3.7
Brent-Bonny	(1.9)	(3.4)	(2.8)	(2.6)	(2.2)	(2.1)	(2.1)	(3.7)	(1.9)	(1.5)	(1.9)	(2.2)	(2.4)
Tapis-Dubai	7.4	10.1	13.5	13.4	14.8	14.2	13.5	14.0	14.9	11.9	11.3	11.7	10.5
LLS-WTI	16.8	14.7	16.0	15.2	16.9	18.5	23.0	27.2	25.4	14.8	10.2	10.4	19.2
LLS-Brent	2.3	3.2	2.6	2.0	(0.6)	(0.7)	(1.5)	1.9	2.3	1.4	0.9	(0.5)	0.4

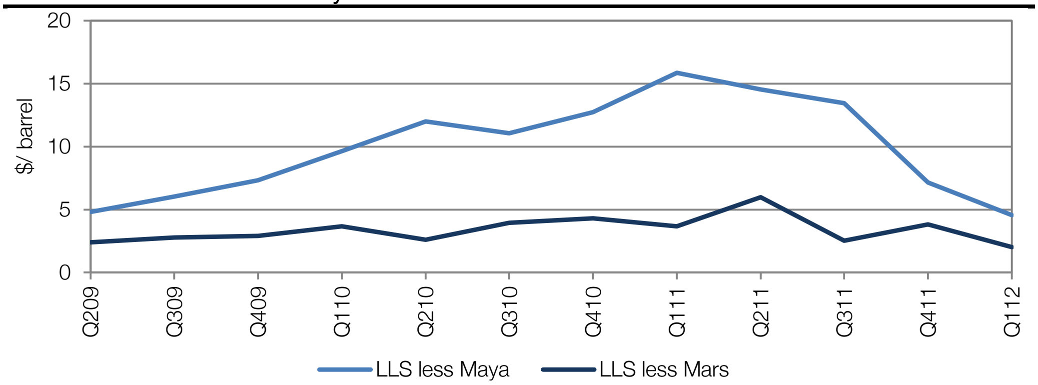
Source: Bloomberg

US heavy crude spreads: Heavy discounts narrowing

US heavy crude discounts based on waterborne-sourced supplies have continued to trend down over the past few months. This has been most pronounced with Mars, a medium-sour grade sourced from the Gulf of Mexico. The Mars discount to LLS in December 2011 averaged $3.6/barrel and in January 2012 was $2.1/barrel. Significantly, the discount narrowed during January and towards month-end was down to $1.9/barrel. This is substantially below the recent May 2011 high of $6.8/barrel. In the case of Maya, a Mexican heavy sour grade, the discount in January 2012 was $4.5/barrel which, although up on the previous month's $4/barrel, was well down on the $11.8/barrel recorded as recently as October and the April 2011 high of $17.3/barrel. The Mars and Maya discounts remain substantially below the longer-term averages of $6/barrel and $13/barrel respectively. The contraction in heavy crude discounts over recent months has sharply reduced the competitive advantage of sophisticated refineries able to process low-grade feedstock.

We continue to believe that the most powerful influence behind narrowing US Gulf Coast heavy discounts is the increasing availability of high-grade feedstock. The key factor here is the rapid development of the Eagle Ford shale oil fields. Significantly, these are in close proximity to Gulf refineries and have good pipeline, railroad and highway connections.

Exhibit 9: US medium and heavy discounts

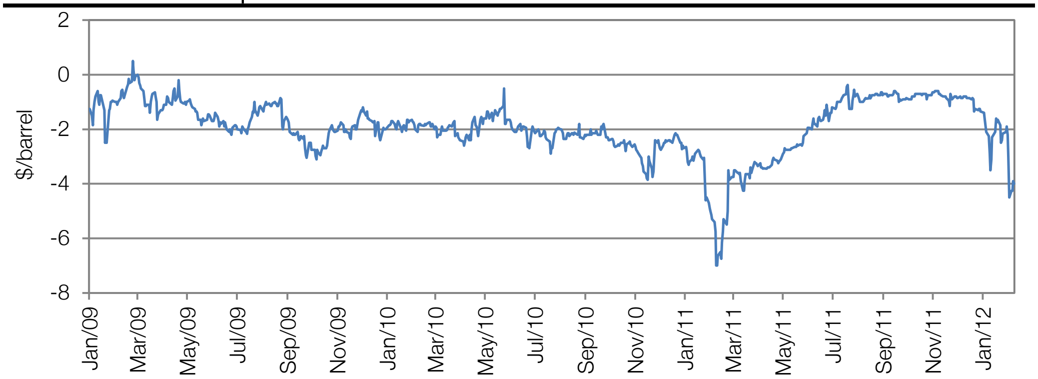


Source: Valero Energy

WTS-WTI discount widens

WTS (West Texas Sour) is an inland medium gravity sour grade with a specification similar to Mars and a delivery point of Midland, West Texas. After having trended flat at about $0.8/barrel since mid 2011, the WTS discount to higher specification WTI widened markedly in late December and early January to $3.5/barrel. The discount then narrowed again to about $2/barrel over the rest of the month but widened in early February to around $4/barrel. This is in line with the longer-term average of $3.5 to $4.0/barrel and is a more plausible reflection of specification differences than the second half 2011 WTS discount of less than one dollar per barrel. Burgeoning supplies of premium quality crude in the Mid-Continent and Texas had earlier compressed the WTS discount well below historical levels.

Exhibit 10: WTS-WTI spread



Source: Bloomberg

Forward curves: WTI switches back to contango

Reflecting readily available supplies in the Mid-Continent and a tendency for Cushing inventories to move higher over recent weeks the WTI forward curve has switched over the past two months from backwardation (near-term prices higher than forward dates) to moderate contango (near-term prices lower than forward dates) for all months through January 2013. From a spot price of about $98/barrel in early February the WTI forward curve rises to $98.8/barrel in April 2012 and $101.96/barrel in January 2013. The curve then switches to backwardation over the next six years or so, dropping to a low of $90.23/barrel in December 2018. Over the following two years the curve reverts to a very mild contango with a rise to $90.43/barrel. The build-up of Bakken and Syncrude supply could conceivably result in a more pronounced WTI contango in the coming months.

By contrast with WTI, Brent is in backwardation for all months between March 2012 and December 2020. Furthermore, the degree of backwardation is slightly greater in the early years than two months ago. After starting at $117/barrel in March 2012 the Brent curve drops to $112.89/barrel by end December 2012, which equates to a $10.95/barrel premium to WTI. After 2012 the Brent curve dips consistently through late 2016 before flattening over the following four years. By December 2020 it has dipped to $90.8/barrel, which constitutes approximate parity with WTI. Continuing Brent backwardation reflects perceived market tightness and a persistent scrambling for near-term supplies. Clearly uncertainties surrounding Iran are contributing to backwardation pressures. As long as these uncertainties persist Brent will probably remain in significant backwardation.

Supply/demand balance

2011 in retrospect: Moderate deficit for the year as a whole

The oil market globally was in moderate deficit in 2011 but the picture changed fundamentally in the fourth quarter as signs of a surplus emerged. According to data released by the IEA, oil demand grew 0.73mm b/d (0.8%) in 2011 while a combination of gains in non-OPEC supplies, OPEC natural gas liquids plus non-conventional fuels (not subject to OPEC quota) amounted to 0.50mm b/d. The deficit was therefore 0.23mm b/d. On the same basis OPEC put the supply deficit in 2011 at 0.4mm b/d while the EIA estimated 0.58mm b/d.

The global oil demand backdrop was considerably more subdued in 2011 than 2010 when there was a gain of 2.7mm b/d or 3.2%, based on IEA data. As has been the pattern in recent years, growth was driven by the non-OECD world with a gain of 1.2mm b/d. Partly offsetting this was a 0.5mm b/d drop in OECD demand. Perhaps the most significant feature of 2011 was heavily constrained non-OPEC supply growth reflecting a combination of major planned maintenance programmes, unplanned outages for a variety of technical reasons, strikes, civil unrest/sabotage and in the case of Syria an EU oil embargo. According to the IEA, non-OPEC supplies grew by only 70,000b/d in 2011. Interestingly, at the high point in the third quarter the IEA estimated that outages reduced output by a hefty 0.85mm b/d. The overall non-OPEC supply deficit in 2011 was covered by a combination of slightly higher OPEC crude output and a rundown in OECD inventories. Significantly, OPEC crude oil production rose by about 0.5mm b/d in 2011, despite the loss of the bulk of Libyan output for about nine months due to the civil war in the country. Buoying OPEC output in 2011 was the uptrend in Iraq, as new capacity came on-stream and stepped up production rates from around mid-year in a number of countries, most notably, Saudi Arabia, UAE and Kuwait.

OECD inventories started 2011 at a relatively high level both absolutely and in terms of days supply. At the beginning of the year total inventories (crude plus refined products) were 2,700mm barrels, which was at the high end of the 2006-2010 range. In terms of days' supply, inventories were equivalent to a very comfortable 59 days. By end October OECD inventories were down to

2,630mm barrels which, although close to the lower end of the four-year range, still left the number of forward days' cover at 57 days, well within the historical range.

In the fourth quarter of 2011 global demand growth slowed sharply while supply trended higher driven by both OPEC and non-OPEC sources. Based on IEA data, demand globally in the fourth quarter was unchanged from a year previously. With supply running at record levels of about 89.5mm b/d according to OPEC, the market was probably in surplus for the quarter. Transforming the supply/demand balance in recent months have been softening business conditions throughout much of the OECD world, a strong rebound in non-OPEC production from the outages of the third quarter and a continuing robust output trend within OPEC. The last mentioned has been buoyed by a powerful recovery in Libyan output since September. Significantly, Libya has reported that at the end of 2011 its output was running at over 1mm against 50,000b/d in the third quarter. Clearly, the recovery in Libya has been stronger than expected by many a few months ago.

2012/13 outlook: Supply surplus in prospect for 2012

OPEC has recently indicated that the oil market is 'very well supplied'. This would indeed appear to be the case, given lacklustre demand and robust supply growth. A supply surplus looks a very real possibility near term at least.

Surprisingly perhaps, in view of expectations of slowing economic growth, the IEA, OPEC and EIA are all currently looking for higher demand growth in 2012 than 2011. The IEA and OPEC's forecasts call for a gain of 1.1mm b/d while the IEA is forecasting a growth of 1.3mm b/d. OPEC has, however, indicated that it is likely to cut its demand forecast for 2012 while we suspect the other two will trim their expectations, partly in response to the macroeconomic reality and partly the IMF's recent sizeable downgrading of its world GDP growth forecasts for 2012 (4.0% to 3.3%) and 2013 (4.5% to 3.9%).Note, the IEA, OPEC and EIA all base their demand projections to varying degrees on the IMF's GDP forecasts. Given this and remembering the structural factors that are reducing petroleum usage (principally improving fuel economy in transportation),we believe that it is very unlikely that oil demand growth will exceed 1mm b/d in 2012. In our view 0.5 to 0.7mm b/d is more plausible. This might reflect a gain of around 1mm b/d in the non-OECD world and a decline of about 0.5mm b/d in the OECD. Zero oil demand growth in 2012 is certainly not beyond the realms of possibility, assuming an intensification of deflationary forces in the OECD and a spill-over into the developing world. In the event of a major banking crisis in Europe a decline of perhaps 2mm b/d would not be surprising. Admittedly the odds of this occurring have declined sharply since the ECB (European Central Bank) decision in December to provide almost €500bn of low-cost financing to European banks.

Arguably the key issue concerning the world oil supply/demand balance in 2012 is supply rather than demand. The EU embargo on Iranian imports has created major supply uncertainties and several medium to large scale producers such as Syria, Iraq, Sudan/South Sudan and Nigeria are suffering from civil unrest/sabotage or indeed civil war. Capacity expansion in the non-OPEC world is expected to be highly meaningful in 2012 driven by projects in Canada, US, Brazil, Colombia, Ghana and the Caspian region. Based on IEA data, these projects could boost output by about 1mm b/d in 2012. Including OPEC NGLS, which might contribute another 0.6mm b/d, non-OPEC petroleum output could therefore grow by around 1.6mm b/d. The caveat is that there are no major unplanned outages along the lines of 2011. Libyan output is also scheduled to increase by another 0.6mm b/d by end 2012 while capacity additions may enable Iraq, which is not subject to OPEC quota, to boost production by 0.5mm b/d during the year. A substantial supply surplus of at least 1mm b/d would therefore be entirely plausible, assuming demand growth in the 0.5mm to 0.7mm b/d range and no early attempt by OPEC to rein in output. Interestingly, the implied surplus is roughly equivalent to our estimate of the adverse impact on supply stemming from an embargoing of Iranian exports to the EU, Japan and South Korea partly offset by higher Iranian exports to China. It must be added that in the event of a closure of the Straits of Hormuz and the consequent loss of 20mm b/d of crude, no alternative sources of supply could come anywhere near to filling the void over a sustained period.

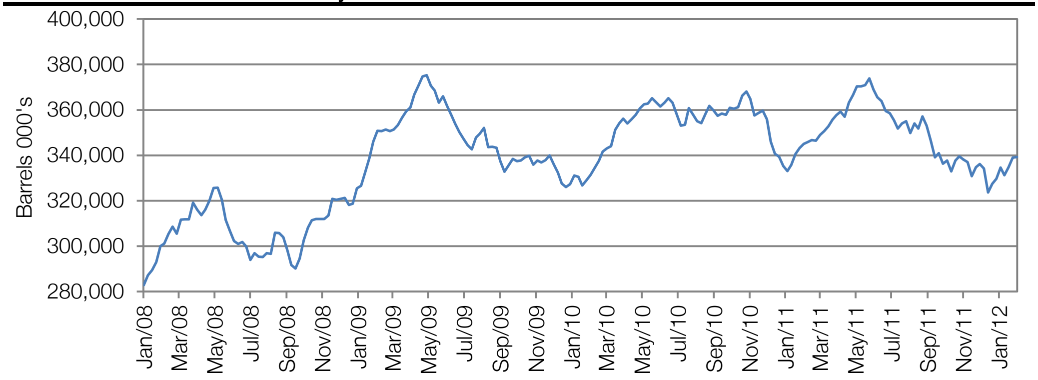
As far as 2013 is concerned, global oil demand growth looks like being moderate given the subdued outlook for the world economy. A gain of no more than 1mm b/d would seem likely. This can probably be covered by a combination of capacity expansion in the non-OPEC world, OPEC NGL's and Iraq. Among the positives for supply in 2013 should be the start of operations at the giant Kashagan field in the Kazakhstan sector of the Caspian Sea.

US inventories

Crude oil: Very comfortable all round

US crude oil inventories are at very comfortable levels both absolutely and relative to supply. Based on EIA data commercial inventories for 27 January were 338.9mm barrels, up 4.2mm barrels on the prior year but down by the same amount or 1.3% on a year previously. In looking at the year-on-year comparison it should be noted that crude inventories were running at historically very high levels in early 2011. After falling in the second and third quarters inventories have trended broadly flat since September and are close to the upper limit of the range for the time of year. Crude oil inventories for the week ending 27 January were equivalent to 23.4 days. This was slightly down on the 24.2 days of a year ago but in line with the 22- to 23-day average for the period since 2000. The strategic reserve would boost forward days cover to about 70 days.

Exhibit 11: US crude oil inventory



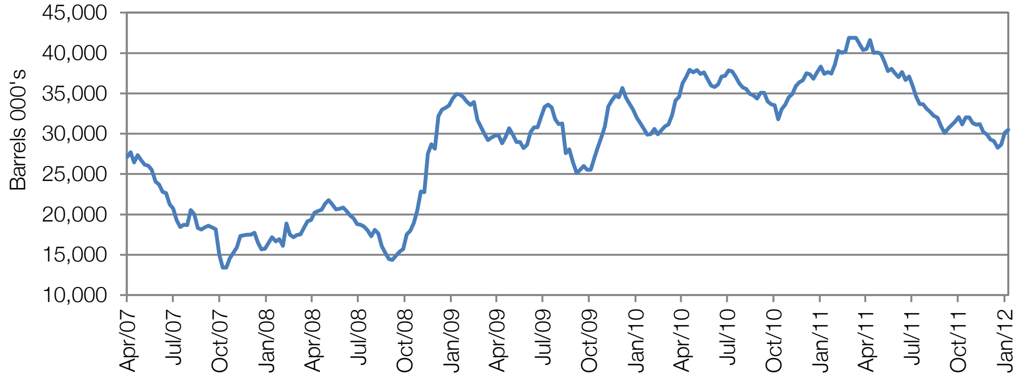
Source: Bloomberg/EIA

Cushing: Possible upward trend in coming weeks

The trend in crude inventories at Cushing Oklahoma, the world's largest tank farm, has remained flat in recent weeks despite continuing buoyant production in the Mid-Continent. For the week ending 27 January Cushing's inventories stood at 30.1mm barrels, up 1.5mm barrels on the prior week but 11.8mm barrels below the April 2011 all-time high of 41.9mm barrels. Operators appear to have been successful in preventing a large inventory overhang developing at Cushing along the lines once feared. The solution has apparently been intensified use of trucks and railroads to ship oil to more lucrative Gulf Coast markets. The utilisation rate is currently around 55% based on Cushing's working capacity of 55mm barrels. Utilisation has been sharply reduced over the past year or so reflecting both the drop in inventories and an increase in capacity.

Given the emergence of hefty Bakken and Syncrude discounts to WTI of late, we believe there is a possibility that Cushing inventories could trend higher in the coming weeks and months.

Exhibit 12: Cushing crude oil inventory

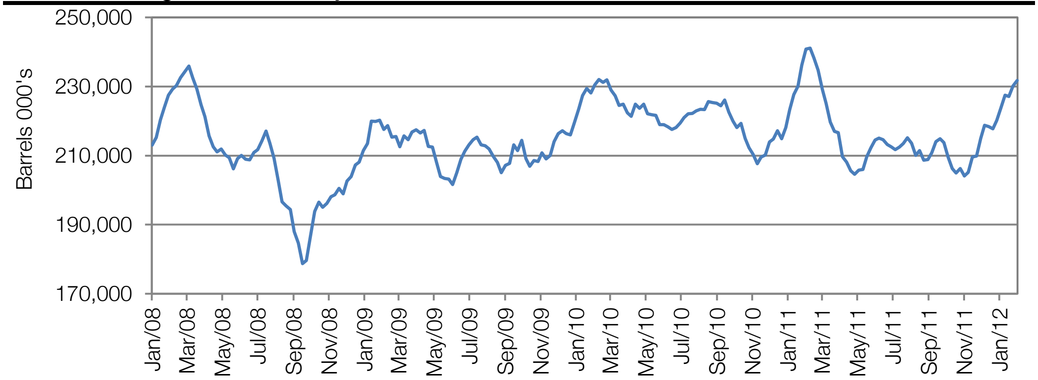


Source: Bloomberg/EIA

Gasoline: Very comfortable

US gasoline inventories are also running at very comfortable levels. According to the EIA, inventories for the week ending 27 January were 230.1mm barrels, up 3mm barrels on the previous week but down 6.1mm barrels from a year ago. As in the case of crude, gasoline inventories are close to the upper limit of the range for the time of year. In terms of days supply gasoline inventories were the equivalent of 25.5 days against 27.9 a year earlier.

Exhibit 13: US gasoline inventory

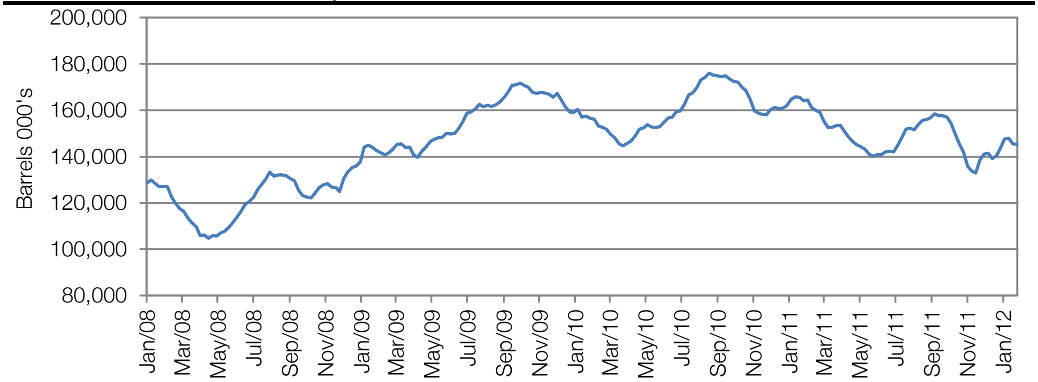


Source: Bloomberg/EIA

Distillates: Comfortable

The picture for the trend in distillate inventories is less robust than for gasoline but the status is nevertheless comfortable aided no doubt by depressed heating oil usage due to the mild winter along the US Eastern Seaboard and Midwest. For the week ending 27 January inventories came in at 145.4mm barrels. This was in line with the prior week but 18.7mm barrels lower than a year earlier. Distillate inventories have, however, increased by 12mm barrels from the recent 18 November low and are in the middle of the range for the time of year. On a day's supply basis distillate inventories are currently running at 41. Although down from the 44.4 days of a year ago, the days cover currently exceeds longer term averages.

Exhibit 14: US distillate inventory



Source: Bloomberg/EIA

All product commercial inventories: Historically high

Overall US commercial crude and refined product inventories are currently running at high levels based on experience since 2000. On this basis, at the end of January 2012 inventories stood at 1.056bn barrels and have trended broadly flat since end October 2011 after having fallen sharply over the prior two or three months. Since 2000, total commercial inventories have only been significantly higher than at present in 2009 and 2010. During these two years a high of 1.144bn barrels was reached in September 2010.

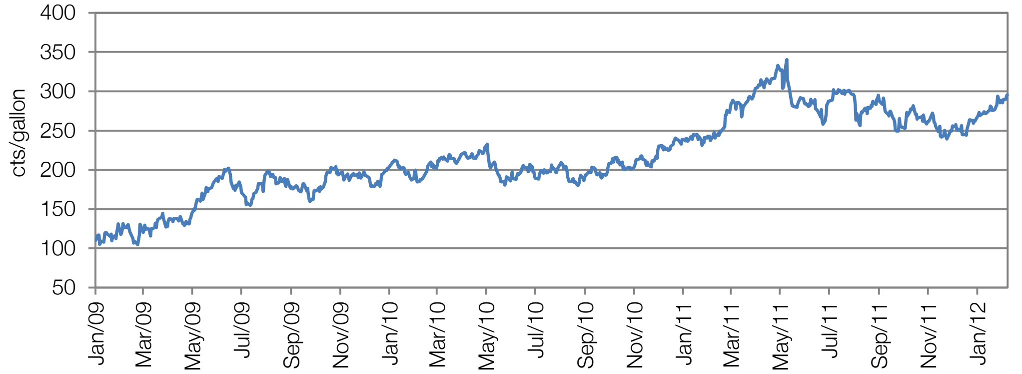
Refinery crack spreads

USA: Attractive spreads for inland refineries

Surprisingly perhaps, US Gulf Coast crack spreads have widened substantially since the recent lows of early December 2011. Taking, for example, the Bloomberg Gulf Coast/WTI 321 crack spread (the margin before refining costs on converting three barrels of WTI into two barrels of gasoline and one of diesel) there was a widening from about $10/barrel at the beginning of December to $25.6/barrel on 1 February 2012. This is a very profitable spread for the typical refinery and compares with a longer-term average of $9 to $10/barrel. The only problem from a Gulf Coast refinery perspective is that higher cost waterborne feedstock is more likely to be used rather than WTI. Based on LLS, the Gulf Coast 321 crack spread would be around $12/barrel. However, inland refineries with access to WTI should be able to realise a 321 spread broadly in line with that indicated by Bloomberg. For those that can source Bakken or Syncrude currently crack spreads would be truly inspiring from a refinery perspective. If feedstock costs were maintained at current levels on a sustained basis we would, however, expect product prices and therefore crack spreads to decline in due course.

The key driver behind the widening in Gulf Coast and Mid-Continent WTI based crack spreads over the past two months has been a surge in refined product prices. Between the beginning of December and early February Gulf Coast wholesale regular gasoline climbed 16% to $2.90/gallon while diesel rose 4% to $3.02/gallon. WTI by contrast actually slipped by 2.5% over the same period.

Exhibit 15: US GC wholesale gasoline price trend

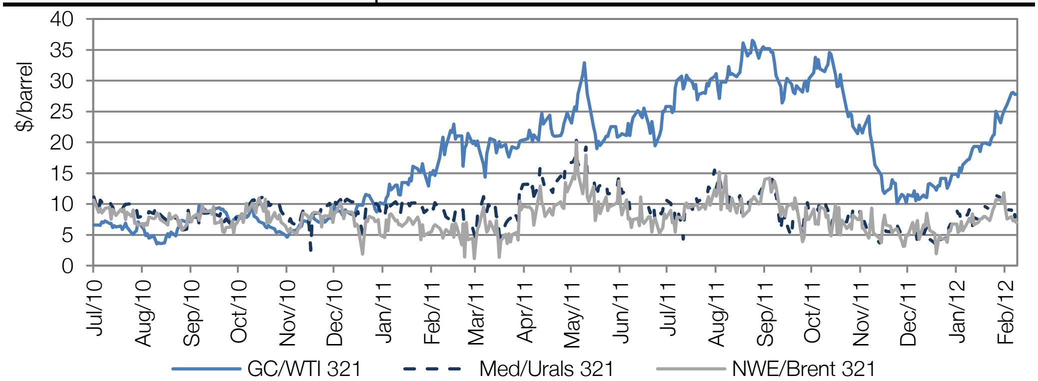


Source: Bloomberg

The sharp upturn in product prices of late has been a response to major refinery closures along the Eastern Seaboard and the US Virgin Islands towards the end of 2011 and in early 2012. The closures relate to Sunoco and ConocoPhillips facilities at Marcus Hook and Trainer, Pennsylvania respectively and the Hess-PDVSA refinery at St Croix. Sunoco has also suggested that it intends closing its Philadelphia refinery by mid-2012. All told, the existing closures imply a loss of 50% or more of the refining capacity in the US Northeast. The loss of Northeast refining capacity will have to be made good mainly by higher shipments from the Gulf Coast and to a more limited extent from the Midwest and imports. Unless buyers can be found, the refinery closures announced over recent months imply a very significant tightening in the marketplace. In addition to a shrinking market and tightening environmental standards, the underlying drawback to the Northeast refineries is their use of high-cost waterborne feedstock. Few have the ability to refine low-grade feedstock cost effectively.

Interestingly, the billionaire investor, Carl Icahn, has recently taken a 14.5% stake in Houston-based CVR Energy, a company with refining interests in Coffeyville, Kansas and Wynnewood, Oklahoma. Clearly this is clearly a contrarian move and arguably a shrewd one given the cutbacks in refining capacity elsewhere and the ability of CVR to tap low-cost WTI and quite possibly Bakken feedstock.

Exhibit 16: Recent trends in crack spreads



Source: Bloomberg

Europe: Spreads have widened from the depressed levels of December

European crack spreads dropped to marginal levels in December 2011 but have subsequently recovered as product prices have firmed. At the low point around mid month the Bloomberg NWE/Brent 321 spread was $2/barrel and the Mediterranean/Urals 321 spread $2.8/barrel. These were clearly highly unprofitable spreads for refineries even on a cash contribution basis after allowing for refining costs and overheads. By early February, however, the NWE/Brent and Mediterranean/Urals 321 spreads had rebounded to $11.6/barrel and $11.1/barrel respectively. Once again, the driver was a surge in refined product prices reflecting in large part refinery closures. Compared with the mid December lows, gasoline in north-west Europe has climbed about 14% while diesel is up 8%. The refinery closures are associated with the financial collapse of Petroplus, the largest independent refinery group in Europe. Out of the five Petroplus refineries, at least two, Coryton and Ingolstadt, are expected to find buyers so in all probability not all the capacity will be shuttered permanently.

A clear risk for Mediterranean refineries in the months ahead is a loss of competitiveness stemming from the EU embargo of Iran. This relates partly to the need to source alternative feedstock which, in all likelihood will be more expensive than current supplies, and partly to the distinct possibility that refining groups in the Middle East, India and Far East will obtain discounts on Iranian crude. The upshot could be a Mediterranean market flooded with low-cost refined product.

US petroleum product demand

2011 in retrospect: Down 1.6%

US petroleum product demand was clearly weak in 2011. Based on preliminary EIA data for products supplied (a proxy for demand), demand overall averaged 18.87mm b/d, down 1.6% on a year previously and only marginally above the recent low of 18.77mm b/d in the recessionary year of 2009. Overall, demand in 2011 was down almost 2mm b/d from the 2005 all-time annual high of 20.8mm b/d. Gasoline, the largest product group accounting for 46% of the mix in 2011, was the clear weak spot in 2011 as it has been for some time. Demand for this product was off for the year by 2.7% to 8.75mm b/d. This was almost 6% below the 2007 record of 9.29mm b/d and the lowest level of gasoline demand since 2001. Distillates, by contrast, showed a gain for the year of 1.6% while residual fuel oil showed a drop of 11%. For most of the other key product categories volume in 2011 was flat to down compared with 2010.

Soft US petroleum product demand in 2011 was partly a function of a lacklustre economy. In this regard, high levels of unemployment were particularly influential for gasoline consumption given the overwhelming use of gasoline powered vehicles (diesel powered light vehicles account for only a few per cent of the mix against more than 50% in Europe) for commuting. The economy, however, was only part of the explanation for softening product demand in 2011. As we have noted before, there are also structural influences depressing demand on a secular basis. The key ones are improvements in the fuel economy of the vehicle fleet, consumer fuel conservation measures leading to less intensive vehicle usage and the substitution of petroleum products by lower cost alternatives, notably natural gas.

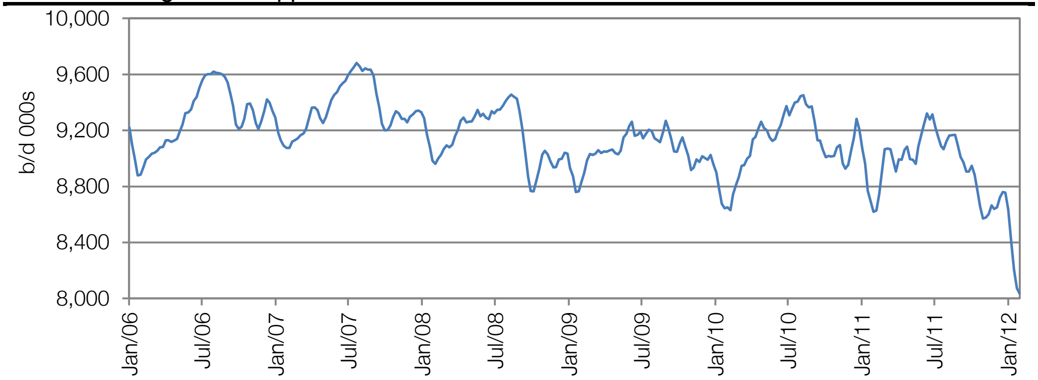
Exhibit 17: US petroleum products supplied

Source: EIA

2012/13: Demand has continued to weaken

The trend in US petroleum product demand has weakened noticeably in early 2012. Based on EIA data, demand in the four weeks to 27 January averaged 18.15mm b/d, down 0.5% on the prior four-week period and 4.3% on a year previously. Significantly, this was the lowest level of demand for a four-week period since 1997. In terms of product categories, the year-on-year movements for the four weeks to 27 January were as follows: gasoline -7.3%, distillates -1.7%, kerosene -4.1%, residual fuel oil -1.7%, propane/propylene -14.6% and miscellaneous +6.0%. Gasoline use in the four weeks to 27 January of 8.06mm b/d was the lowest for a four-week period since early 2001. Taking the week ending 27 January in isolation gasoline demand was a mere 7.97mm b/d, around an 11-year low. Depressed gasoline demand in the latest period was not related to inclement weather conditions.

Exhibit 18: US gasoline supplied



Source: EIA

Exhibit 19: US distillates supplied

Source: EIA

The EIA's latest forecasts for 2012 call for a modest increase in US petroleum product demand of 0.5% to 18.96mm b/d. This constitutes a marginal downgrade compared with two months ago. Gasoline is forecast to be roughly unchanged between 2011 and 2012. Given the weak volume trend and far from robust economy, downgrades to the EIA's petroleum demand forecast for 2012 would seem likely in the months ahead. For 2013 the EIA is looking for a modest gain in US petroleum demand of 0.3%. Assuming economic growth in line with current IMF forecasts of 2.2%, this might not be unreasonable although quite possibly the base in 2012 will probably be lower than currently estimated. As far as gasoline is concerned, the EIA is currently looking for a marginal decline of 0.2%.

Exhibit 20: US petroleum product demand trend

Mm b/d	2004	2005	2006	2007	2008	2009	2010	2011	2012e	2013e
Gasoline	9.11	9.16	9.25	9.29	8.99	9.00	8.99	8.75	8.74	8.72
Other	11.62	11.64	11.44	11.39	10.51	9.77	10.19	10.12	10.22	10.29
Total	20.73	20.80	20.69	20.68	19.50	18.77	19.18	18.87	18.96	19.01

Source: EIA

US refined product trade balance: Surging exports

US Gulf Coast refineries in particular were thrown a lifeline in 2011 by a surge in product exports. For the year there was a gain of 24% to a record 2.87mm b/d, around 16% of total US refining capacity and about third of that located on the Gulf Coast. Meanwhile imports slipped 3% to 2.49mm b/d resulting in a swing from a net import balance of 0.27mm b/d in 2010 and to a net export balance of 0.38mm b/d in 2011. This was the first US net export product balance since 1949.

The surge in exports in 2011 was part of a longer-term trend that has resulted in a 2.5-fold gain since 2005. Exports were driven in 2011 largely by strong demand and refining capacity constraints in Latin America and Canada. The largest markets in descending order were Mexico, Canada, Brazil and Panama. In the early weeks of 2012 US product exports have remained buoyant and the trade balance has remained positive. In the four months to 27 January exports averaged 2.87mm b/d, up 30% from a year earlier. The net export balance over the same period averaged 0.80mm b/d against net imports in the period year ago of 0.50mm b/d.

The EIA continues to look for US net export balances in 2012 and 2013 with forecasts of 0.31mm b/d and 0.29mm b/d respectively. Based on recent trends the former, at least, appears conservative.

Exhibit 21: US refined product trade balance trend

Mm b/d	2005	2006	2007	2008	2009	2010	2011e	2012e	2013e
Exports	1.13	1.29	1.41	1.77	1.98	2.31	2.87	-	-
Imports	3.59	3.59	3.44	3.13	2.68	2.58	2.49	-	-
Net exp +/imp-	(2.46)	(2.30)	(2.03)	(1.36)	(0.70)	(0.27)	+0.38	+0.31	+0.29

Source: EIA

Crude oil price: Brent forecast upgraded, widening WTI discount

In the absence of EU sanctions on Iran crude oil prices would be lower and in all likelihood substantially more so than at present. The supply/demand balance is anything but tight. Supply is gathering pace from both OPEC and non-OPEC sources while demand is under significant pressure in the OECD world and growth is slowing in the developing world. In all probability the market is in supply surplus and, barring a major and sustained interruption to production, will probably be so for 2012 as a whole. We suspect that oil demand forecasts made by the likes of the IEA and EIA will have to be trimmed for both 2012 and 2013 in the weeks and months ahead.

The key near- to medium-term issue for international crude oil prices is clearly Iran. The advent of the EU import embargo and related financial sanctions has elevated uncertainty concerning supplies. Theoretically a loss of Iranian exports to the EU can be fairly comfortably absorbed by OPEC. Obviously, if the embargo is broadened to include Japan and South Korea the supply backdrop will become considerably more fraught but the void can, in principle, still be filled. The wild card is perhaps how much oil Iran can redirect to markets outside the EU, Japan and South Korea. In a way, the EU has a vested interest in Iran maximising the reorientation of its exports to non EU markets. This would simultaneously enable the adverse impact on oil prices to be minimised while allowing the EU to appear as a paragon of virtue to the world community.

There are two underlying drawbacks from an oil price perspective to the argument that OPEC can fill the void created by the loss of Iranian exports. The first is the significant erosion of spare capacity and the second is the elevation of geopolitical tension possibly leading to military conflict or terrorist activity. The upshot is an uncertainty price premium which depending on the market could easily add much more than $10/barrel to prices. In the absence of the conflict between the west and Iran leading to a shooting war and/or a major and supply interruption, the key impact of EU sanctions on Iran will be on spreads. Broadly speaking, the main developments are expected to be:

- a widening in the WTI-Brent discount;
- a narrowing or even an elimination of the Brent-Urals premium; and
- a narrowing of the Brent-Dubai premium

Effectively, major regional divergences are surfacing in the supply/demand balance with the key one being between the US and more generally North America and the eastern side of the Atlantic basin and Mediterranean. Increasingly North America, due to burgeoning supplies and declining consumption, is becoming insulated from the rest of the world. The upshot is a widening WTI discount to international prices.

For 2012 we have upgraded our oil price forecast for Brent to reflect heightened geopolitical tension relating to the Iranian nuclear issue and the EU's response in terms of tightening sanctions. Our new forecast is $113.5/barrel against $102.8/barrel previously with the following quarterly scenario: Q1 $113.0, Q2 $114.0, Q3 $114.0 and Q4 $113.0. In the case of WTI we have also upgraded our 2012 forecast but by less than for Brent. The new forecast is $96.4/barrel against $93.3/barrel previously with a quarterly scenario as follows: Q1 $97.4, Q2 $96.0, Q3 $95.0 and Q4 $97.0.

For 2013 we continue to believe that the scope for upside in oil prices will be limited by an extended period of sluggishness in the world economy. Supply should be capable of keeping pace with global demand growth, which we do not expect to exceed 1mm b/d. On this basis we look for average prices in 2013 of $115.0/barrel and $98.5/barrel for Brent and WTI respectively. These forecasts compare with $106.0/barrel and $97.0/barrel previously. Our forecasts for 2012 and 2013 reflect the following assumptions:

- A global macroeconomic scenario in tune with the IMF's 24 January 2012 World Economic Outlook. Key features of the Outlook are a significant slowdown in world economic growth between 2011 and 2012 from 3.8% to 3.3% followed by a moderate upturn to 3.9% in 2013; a mild Euroland recession in 2012 and a slowdown in Chinese economic growth between 2011 and 2012 from 9.2% to 8.2%.
- A muddling-through scenario for the European sovereign debt crisis implying no disintegration of the eurozone and related financial debacle.
- Sustained high levels of geopolitical tension relating to the Iranian nuclear programme but no shooting war.

Exhibit 22: WTI and Brent price trends

$/b	2004	2005	2006	2007	2008	2009	2010	2011	2012e	2013e
WTI	41.5	56.6	66.1	72.2	99.8	62.0	79.5	94.9	96.4	98.5
Brent	38.3	54.5	65.4	72.7	97.7	62.0	79.7	110.0	113.5	115.0

Source: Bloomberg and Edison Investment Research

US natural gas market

Robust production, subdued consumption

2011 in retrospect: US natural gas production remained robust in the closing months of 2011 which rounded off a record year and the sixth consecutive year of gains. Based on EIA estimates, production in the fourth quarter of 6.21tcf was up 7.2% on a year earlier. For 2011 production was an estimated 24.06tcf, resulting in gains of 7.4% from 2010 and no less than 27% from the recent 2005 low. The US was also the world's largest producer of natural gas in 2011.

As in recent years, production in 2011 was driven by shale development activity in the Lower 48 states. Production here in 2011 surged by about 11% but slipped 2% in Alaska and 19% in the Federal waters of the Gulf of Mexico. Reflecting the buoyant production trend, net imports fell sharply in 2011. The EIA's estimate for the year is 1.87tcf against 2.60tcf in 2010. The drop in net imports stemmed from both lower gross imports and higher exports. In the case of imports, pipeline flows from Canada and Mexico were off roughly 6% while LNG imports were down 20%. Gross exports in 2011 rose about 36% driven by both higher pipeline flows to Canada and Mexico and LNG cargoes to several overseas markets. LNG exports in 2011 were still small at about 72bcf.

US natural gas consumption in 2011 was reasonably buoyant but growth significantly lagged that of production. The EIA's estimate of consumption is 24.43tcf, up 2.7% on 2010. For the year the most buoyant major markets were commercial and industrial which showed gains of 3.3% and 3.5% respectively. Usage in the largest market, power generation, rose by about 2.5% while residential was up by a modest 0.6%. Overall, natural gas consumption in 2011 was constrained by a very mild fall in the Northeast and Midwest. This would have affected both residential and power generation markets.

EIA slashes resource estimate: The EIA recently slashed its estimate of unproved but technically recoverable shale gas resources in the US from 827tcf to 482tcf. This largely reflects a downgrading of the estimate for the Marcellus shale formation, which underlies large tracts of New York and Pennsylvania, from 410tcf and 141tcf. The downgrading stems from new data obtained from intensive drilling activity in the Marcellus over the past two or three years along with a growing body of information from the rapidly growing production operations in the zone. Nevertheless, the new US natural gas resource estimate is still very substantial indeed and the EIA continues to look for production to trend significantly higher in the period to 2035. In fact, the EIA's latest US production forecast for 2035 of 27.0 quadrillion Btu is 7% higher than in 2011. This reflects a combination of technological advances and the focus on shale plays with high concentrations of liquids which have higher energy coefficients than dry gas.

It should also be noted that current EIA natural gas resource estimates include only 16tcf for the Utica shale. This lies under the Marcellus and has been little explored. The Utica formation could therefore provide scope for a resource upgrade down the trail.

2012/13 outlook: Production growth likely to slow

The EIA is anticipating a marked slowdown in US natural gas production in 2012 and 2013 from the heady pace of recent years. Gains in marketed production are forecast of 2.1% to 24.6tcf in 2012 and 1% to 24.8tcf in 2013. Slower growth stems from declining drilling activity and recent and anticipated moves to shut-in production related to increasingly uneconomic natural gas prices. Towards the end of January the number two US gas producer, Chesapeake Energy, announced the immediate shut-in of 500mm cf/d of dry gas production and indicated that it could shut-in another 500mm cf/d in the coming weeks. The combination of the two would be equivalent to about 1.6% of current US gas production. Chesapeake has also said that it is in the throes of cutting its dry gas rig drilling count by about 50%. Several other leading US operators such as

ConocoPhillips, Southwestern Energy and Exco Resources, have indicated that they would be prepared to shut-in production, if there is no improvement in prices in the coming weeks.

The EIA continues to look for modest US natural gas consumption growth in 2012 and 2013. Growth is put at 2.0% and 1.3% respectively, which is roughly in line with production. As always, usage is highly sensitive to weather conditions both summer and winter in addition to economic activity. EIA forecasts are based on normalised assumptions on weather patterns. A sustained period of hot weather along the US Eastern Seaboard and in the Midwest this summer followed by a cold fall would therefore probably boost usage significantly above that currently being forecast by the EIA.

Potential medium-term demand drivers

The current ultra-low US natural gas price regime on an energy equivalent basis will ultimately give a boost to underlying usage. Arguably the most obvious market is power generation given the political pressure to reduce dependence on coal for generating electrical power. Natural gas generates about 50% less CO^2 on an energy equivalent basis and at anything like current gas prices is reasonably competitive with coal for power generation purposes. Lead times for gas turbine-based power stations are also short relative to either coal or particularly nuclear.

Other promising markets medium to long term for natural gas include petrochemicals, GTL (gas-to-liquids) and vehicle fuels in the form of CNG (compressed natural gas) and LNG (liquefied natural gas). There is of course, also the possibility of undertaking LNG exports although this is understandingly highly controversial politically. In our view GTL projects are a particularly interesting long-term use of gas if the current massive spread between natural gas and oil prices persists.

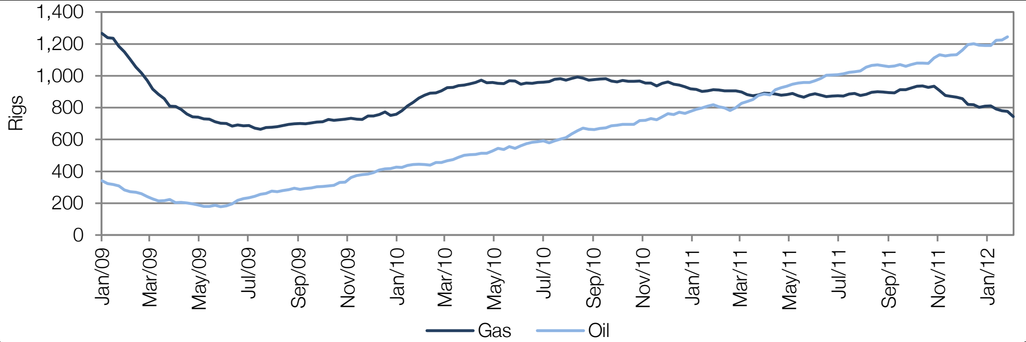
The interesting point about GTL is that large quantities of high value fuels and chemical feedstock in the form of diesel, kerosene and naptha can be produced cost effectively at anything like current gas prices. Furthermore, the products produced can be supplied through the existing infrastructure and used in the existing vehicle/aircraft fleet without costly modifications. Performance is identical to conventionally derived fuels while sulphur and other noxious emissions are lower, thanks to the nature of the process. By contrast, CNG and LNG fuelled vehicles require expensive modification particularly in the form fuel tanks and engine management systems and compared with diesel and gasoline fuelled engines suffer from the drawbacks of inferior performance and greatly reduced range. CNG and LNG also require heavy investment in a new fuelling network.

Drilling activity: Gas rig count falling

US gas drilling activity has slipped noticeably in recent months after apparently defying gravity for much of 2011. Based on Baker Hughes data for 3 February the US rotary rig count devoted to gas was 745, down 191 or 20% on the recent high on 14 October 2011. Taking the most recent week the rig count was down 32 while compared with a year ago it was off 166 or 18%. Given the recent announcements by Chesapeake and others about scaling back development activity, further significant falls in the rig count would appear to be on the cards in the coming weeks and months. We suspect, in fact, that the rig count might well drop to the levels last seen in the third quarter of 2009. At current gas prices of around $2.4/mcf we believe, based on industry comments, the bulk of gas development projects are uneconomic on a fully accounted basis unless there are substantial by-product liquids. This does not imply, however, that gas drilling activity is about to plunge off the scale due partly to existing lease commitments and partly differing views about the duration of currently depressed prices.

Contrasting with gas, US oil-related drilling activity continues to trend higher. The oil based Baker Hughes rig count for the week to 3 February was 1,245, up 20 on the previous week and 427 or 52% on a year earlier. Baker Hughes has indicated that the latest reading is the highest level since the oil and gas rig counts were separated in 1987. Not surprisingly, oil and gas companies continue to re-orientate their drilling activity towards oil in response to considerably more attractive economics and the abundance of promising shale development opportunities.

Exhibit 23: Baker Hughes rig count



Source: Bloomberg/Baker Hughes

Inventories: Seasonally very high

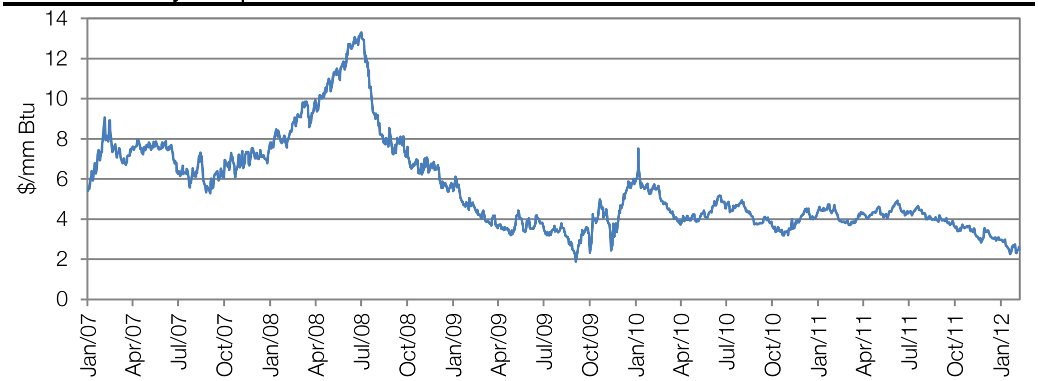
US natural gas inventories remain seasonally very high. For the week ending 27 January they stood at 2,966bcf according to EIA estimates. This was 586bcf higher than a year earlier and 601bcf above the five-year average for the time of year. Significantly, inventories are above the five-year average in all storage regions while the variance compared with the five-year average has been tending to widen since September 2011. Given that the winter withdrawal season is now past the half way mark, inventories look like remaining seasonally very high at the beginning of the gas injection season in April. At the time of writing in early February there are no signs of any severe weather in the principal domestic and commercial gas consuming regions of the Northeast and Midwest.

Price trend: Historically low prices

US natural gas prices have continued to trend down in recent weeks and as of early February were at historically low levels. The key Henry Hub, Louisiana benchmark plunged from around $3.50/mm Btu at the beginning of December to $2.98/mm Btu at end month. During the first 20 days of January there was a further dip to $2.25/mm Btu which was close to a 30-month low and rapidly approaching the April 2009 low of $1.88/mm Btu. The Henry Hub quote firmed to a recent high of $2.73/mm Btu at the end of January following the Chesapeake announcement on production cutbacks but by early February the quote was back down to $2.41/mm Btu, 44% below year-ago levels. Elsewhere, prices at key hubs on 3 February were $2.55/mm Btu at New York, $2.48/mm Btu at Chicago, $2.25/mm Btu at Carthage, Texas, $2.38/mm Btu at Opal, Wyoming and $2.24/mm Btu at Cheyenne, Wyoming. Essentially, US gas prices at the beginning of February were back to the levels prevailing in the early 2000s.

The continuing weakness in natural gas prices reflects the previously mentioned supply-demand imbalance and the resulting build-up in inventories to virtually unprecedented levels seasonally. Following the plunge of recent weeks US gas prices are selling at massive discounts to crude oil on an energy equivalent basis. Taking the Henry Hub quote, for example, of $2.41/mm Btu the price per boe is only about $15 while WTI is trading close to $100/barrel. Similarly, US gas prices are depressed internationally and along with those of Canada are easily the lowest in the OECD region. For perspective, US LNG prices for imports from Trinidad at end 2011 were running at $4.21/mcf, while LNG imports into the Far East are around $12/mcf and the UK NBP price in early February was 75.5p/therm or $11.7/mm Btu.

Exhibit 24: Henry Hub price trend



Source: Bloomberg

Cost/price relationship: Based on data supplied by Southwestern Energy in its latest presentation, US lifting costs for a sample of 18 natural gas operators range from about $1/mcfe to $3.5/mcfe with most clustered around $1.5/mcfe. In addition, production taxes might add another $0.3/mcfe, which would suggest variable costs of perhaps $1.8/mcfe for the typical producer. Arguably for a pure dry gas producer variable costs might be a little lower due to lower processing requirements. Anyway a Henry Hub price of about $2.4/mcf still provides significant headroom for variable cost of $1.8/mcf. Clearly in the case of a liquids-rich field which might easily add another $1 to $2/mcfe to revenues the variable contribution could indeed be described as comfortable. The fact that there are still significantly positive variable profit contributions presumably explains why US gas producers have not yet made swingeing production cutbacks.

In addition to variable costs, gas producers also incur significant overhead in the form of SG&A and finding and development costs. On a per unit basis both, of course, depend in part on volume. Very broadly, however and based on information provided by Chesapeake and Southwestern, we believe that SG&A costs could be around $0.9/mcfe while finding and development costs are about $2/mcfe for the typical operator (Southwestern gives its own F&D costs as $1/mcfe). This would suggest total cash costs of $2.7/mcfe (variable plus SG&A) and fully accounted costs of $4.7/mcfe again on a typical operator basis. However, low-cost competitors such as Southwestern might have cash costs of about $2.2/mcfe and fully accounted costs of around $3/mcfe.

The upshot of the above is that on a total cash basis gas production economics in the absence of a liquid-rich mix are decidedly marginal at present for a typical operator. Low cost operators with a liquids rich mix, however, should still be comfortably profitable on both a cash and fully accounted basis at current economics.

Price outlook: Less than auspicious near term

The likes of Anadarko and Chesapeake, not surprisingly, have suggested that the US gas market may be near to bottoming. Medium to long term, the CEO of the former has indicated that he expects prices to rebound to between $5 and $7/mm Btu. Clearly, a rebound will ultimately be driven by a scaling back of drilling activity and the stimulus to consumption from an ultra low price regime. In this context it is worth noting that $5 to $7/mm Btu would still only equate to $30 to $42/boe.

Although a strong case can be made for a medium term rebound in US natural gas prices, the near-term outlook is less than auspicious. The problem is the unseasonal inventory overhang and the still robust trend in production relative to consumption. In the light of this, along with the downward trend in the early weeks of the year we are sharply reducing our 2012 Henry Hub price forecast from $4.14mm Btu to $3.50/mm Btu. The quarterly profile is as flows: Q1 $2.40, Q2 $3.00, Q3 $4.10 and Q4 $4.50. The upward trend post the first quarter reflects anticipated announcements concerning production shut-ins, falling drilling activity and an assumed less benign weather backdrop than over recent months. If weather conditions remain benign through the second and third quarters thereby precluding a strong increase in air conditioner use, there is a danger that prices could languish below $3/mm Btu over an extended period.

For 2013 we continue to look for a recovery in US gas prices, albeit from a lower base than previously forecast. We now look for the Henry Hub price to average $4.00/mm Btu against $4.40/mm Btu. The recovery reflects the supply-demand balance gradually returning to equilibrium as drilling activity falls and usage gains a little momentum. As always, much will depend on weather conditions.

Exhibit 25: Henry Hub quarterly price scenario

$/mm Btu	Q1	Q2	Q3	Q4	Average
2008	8.66	11.37	9.06	6.45	8.89
2009	4.54	3.70	3.17	4.37	3.94
2010	5.15	4.15	4.32	3.86	4.37
2011	4.18	4.37	4.12	3.33	4.00
2012e	2.40	3.00	4.10	4.50	3.50

Source: Bloomberg and Edison Investment Research

Exhibit 26: Henry Hub natural gas price trend

$mm/Btu	2004	2005	2006	2007	2008	2009	2010	2011	2012e	2013e
	5.85	8.79	6.72	6.96	8.89	3.94	4.37	4.00	3.50	4.00

Source: Bloomberg and Edison Investment Research

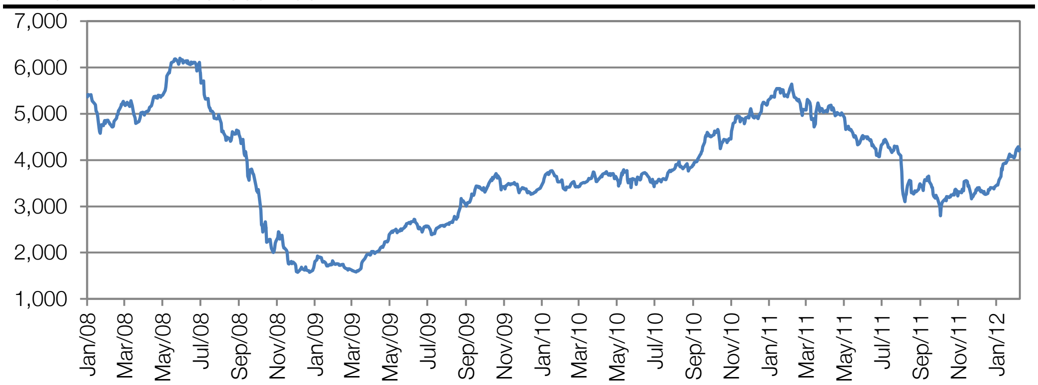
Share price performance

UK: Strong recovery, AIM juniors outperform

The FTSE 350 Oil & Gas Index, which is dominated by the majors, recovered strongly from the low of early October 2011 and on 10 January hit a 43-month high. Subsequently, the index has dipped about 3% but remains at an elevated level. As of early February, the FTSE 350 Oil & Gas Index was around 1% higher than a year earlier, a slight outperformance of the FTSE 100, which was down about 3% on the same basis. The 22% gain in the FTSE 350 Oil & Gas Index since the October low also constitutes a slight outperformance of the FTSE 100.

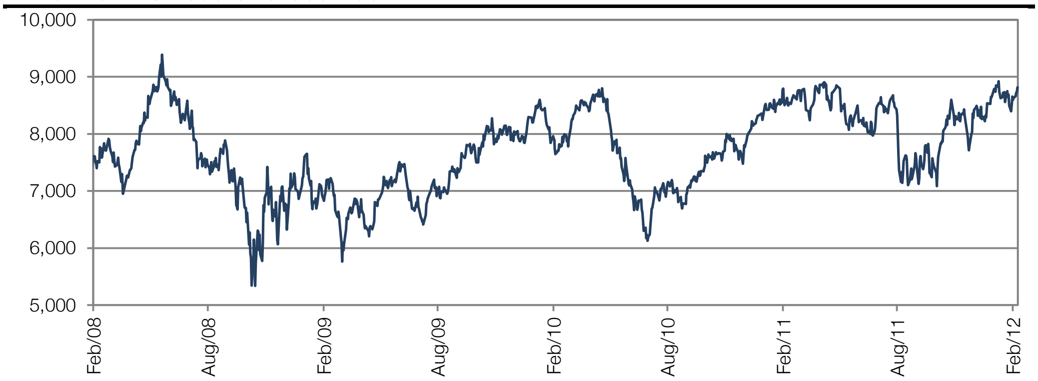
The AIM junior oil and gas stocks have clearly outperformed the majors and larger independents in recent months. In early February 2012 the AIM Oil & Gas Index was up by around 53% from the early 25 October month low driven by a dramatic switch in investor sentiment from 'risk off' to 'risk on'. Helping buoying the switch in the case of the juniors was a generally supportive oil market environment and the emergence of some attractive underlying valuations after the 50% plunge in the AIM Oil & Gas Index between early February and early October 2011. Despite the rebound in recent months, the AIM Oil & Gas Index remains about 25% below the February 2012 high and continues to be at a depressed level historically. The AIM All Share Index has also recovered some lost ground in recent months. The 19% gain since the October 2012 has, however, lagged the AIM Oil & Gas Index by a wide margin.

Exhibit 27: AIM Oil & Gas Index



Source: Bloomberg

Exhibit 28: FTSE 350 Oil & Gas Index

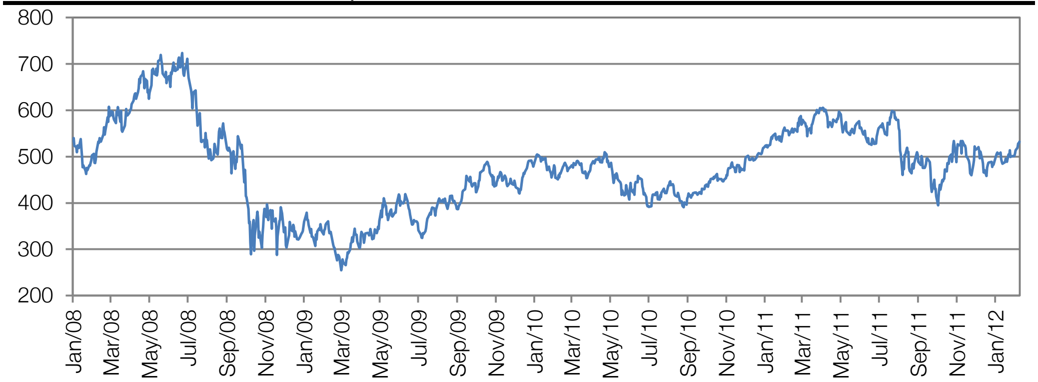


Source: Bloomberg

USA: Failure to regain the high ground of April 2011

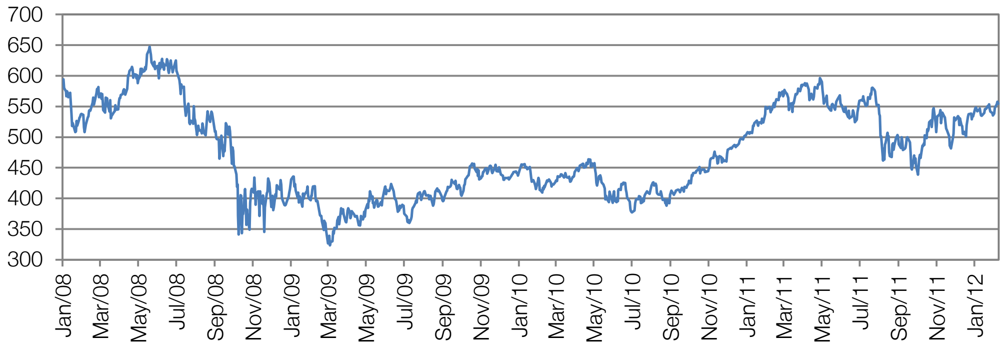
US large and mid capitalisation oil and gas stocks have rebounded strongly from the lows of early October but unlike their UK counterparts, have failed to regain the high ground of late April 2011. Taking the broadly based S&P 500 Oil & Gas Index, there was a gain of 26% between early October 2011and the beginning of February 2012. The bulk of this, however, was concentrated in October and tended to track the surge in WTI at the time. Post early November the S&P 500 Oil & Gas Index has trended broadly flat which has left it lagging the April 2011 high by around 7%. As of early February this Index was up by about 1% on a year earlier. Similarly, the S&P 500 Oil & Gas Exploration and Production Index has pretty well trended flat between early October 2011 and early February 2012, which has left it lagging the April and June highs for 2011 by around 14%. Compared with a year ago, the S&P 500 Oil & Gas Exploration and Production Index is down 7%. Tending to constrain the performance of the E&P independents of late has been the plunge in US gas prices and the softening tendency in WTI.

Exhibit 29: S&P 500 Oil & Gas Exploration and Production Index



Source: Bloomberg

Exhibit 30: S&P 500 Oil & Gas Index



Source: Bloomberg