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Inertia in US shale continues

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As the oil market awaits a negative supply response to the sharp correction in crude prices since mid-2014, we suggest a period of inertia may be ahead, with oil production, particularly from US shale, holding up in the near term. Supporting this inertia we see falling service costs, improved operating efficiencies and significant hedging as combining to sustain near-term activity. Hence, while a price correction is likely in the medium term, we forecast crude prices to remain subdued at current levels for the remainder of 2015, for which we estimate an average crude price of $52.5/bbl for the year. As 2015 capex cuts bite, hedges unwind and funding becomes increasingly difficult to secure, we expect this will form the foundation of a recovery early in 2016, where we estimate an average of $72.5/bbl will be achieved for the full year.

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Fall in US output needed to rebalance oil market

The collapse in oil prices in the last six months and OPEC's inaction are forcing a rebalancing of the oil market. Lower oil prices should logically trigger a supply response, with high-cost producers among the US shale group expected to be the first to cut production. The ability of US shale producers to quickly cut investment in response to gyrations in commodity prices (unlike longer-cycle offshore projects) supports the commonly-held view that oil prices will trough in Q1 as US production growth stalls in response to the weak macro environment.

Shale activity carries significant inertia

We see several reasons why US production could be stickier at lower oil prices than many expect, particularly continually improving operating and capital efficiencies among the main shale basins, sustained cash flow from pre-existing hedges and falling service costs and taxes. On this basis, we can envisage an increase in US liquids production during H115 despite the anticipated reduction in activity. We estimate that it would take a nearly 40% drop in the rig count for production to stop growing in Q215. However, with oil price hedges falling off in 2016 and a material slowdown in drilling activity, we expect much reduced US production growth in 2016.

Oil price outlook

We see Brent staying around current spot levels of $45/bbl through the first half of 2015 as supply growth continues to exceed demand growth in H115. We expect a rebound in the second half to $55-65/bbl as US production growth slows. We assume an average of $72.5/bbl for 2016 as the global inventory overhang is worked off and the supply/demand balance comes closer to equilibrium.

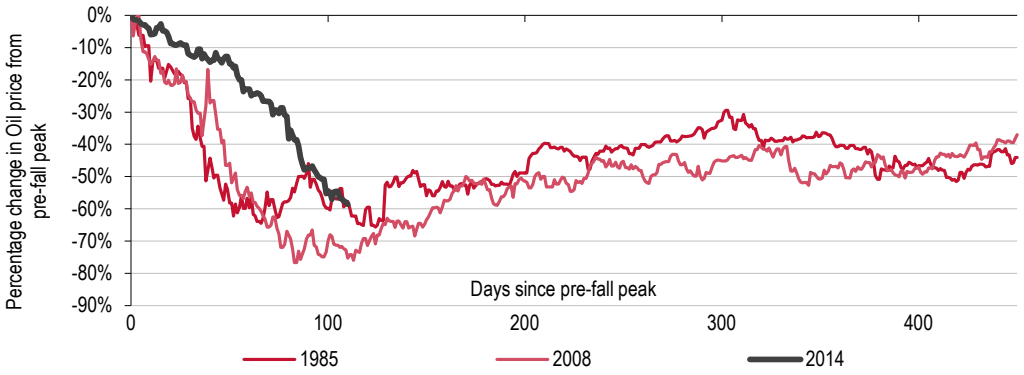
Exhibit 1: Brent-WTI 2015-16e quarterly price assumptions ($/bbl)

	2015	Q1	Q2	Q3	Q4	2016	Q1	Q2	Q3	Q4
Brent	52.5	45	45	55	65	72.5	68	72	75	75
WTI	49	43	42	51	60	67.5	63	67	70	70

Source: Edison Investment Research

Oil price outlook

Exhibit 2: Current oil price fall vs previous crashes (% decline since pre-peak price)



Source: Bloomberg, Edison Investment Research

The current oil price fall has been slower than in previous large crashes, but we think a more prosaic recovery is likely. The US shales provide a price-elastic source of new production that is more apparent than in the previous supply-side crash of 1985, with less demand uncertainty than in 2008.

US E&Ps still guiding to production growth

Below we have summarised 2015 guidance from five large US E&Ps (COP, CLR, RRC, MRO and CXO). The companies point to 10-12% expected production growth in 2015 despite an average 25-30% reduction in capital spending. Albeit based on a small sample, we believe this outlook is representative of the wider US E&P universe.

Exhibit 3: US E&Ps' 2015 guidance on capex and production

Company	Ticker	Shale basin	Capex (US$)			Production (kboed)		
			2014	2015	% chg	2014	2015	% chg
ConocoPhillips	COP	Eagle Ford, Bakken	16.88	13.5	(20)	1525-1535	1571-1581	3
Continental	CLR	Bakken, SCOOP	4.6	2.7	(41)	174	201-208	16-20
Range Resources	RRC	Marcellus	1.52	0.87	(43)	193	232	20
Marathon Oil	MRO	Eagle Ford, Bakken and Oklahoma	5.50	4.4	(20)	350-360	378-389	8
Concho Resources	CXO	Permian	2.6	2.0	(20)	111	128-133	16-20
Average					**(27)**			**10**

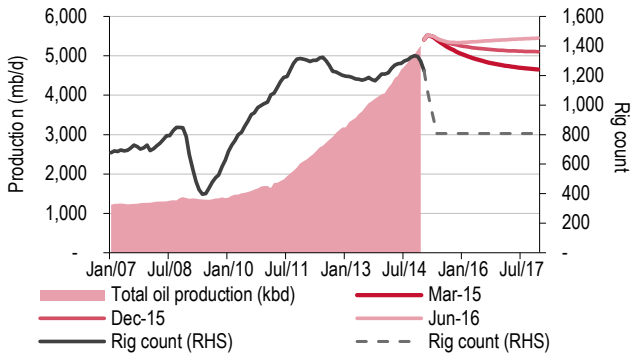
Source: Company reports, Edison Investment Research

US production continues to rise despite falling rig count

The US rig count has so far fallen by 15% (c 300 rigs) from its October 2014 peak, but production has continued to tick upwards into November according to preliminary IEA production data.

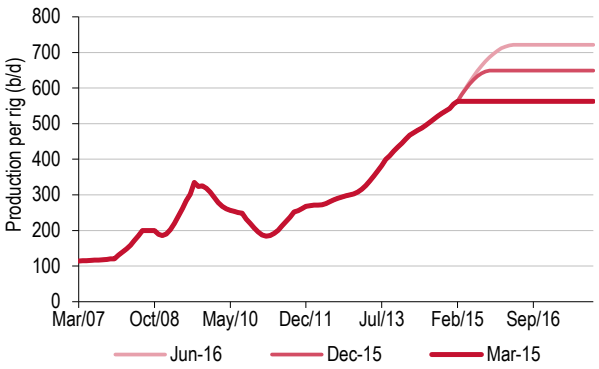
Based on our US basin model and assuming zero improvements in rig productivity, we estimate that a c 40% drop in the total rig count is needed for US oil production to stop growing in Q215 and return to end-2014 level by Q315. Even if US production exited the year 3% lower year-on-year, average annual production would still be 14% higher (+650mb/d y-o-y), adding to the current inventory overhang. If we assume some small improvements in rig productivity (a more realistic scenario), US production would exit 2015 flat y-o-y and be up c 16% y-o-y (+725mb/d y-o-y).

Exhibit 4: Effect of prolonged growth in production per well given fixed number of rigs



Source: Edison Investment Research, EIA. Note: Dates denote the end of "learning period", where there is no further growth in IP per well. A linear decline in growth rate is assumed up to this point. There is no modelled reduction in overall decline rates over time.

Exhibit 5: Sample of production per well in Bakken, given end of "learning period" by given dates

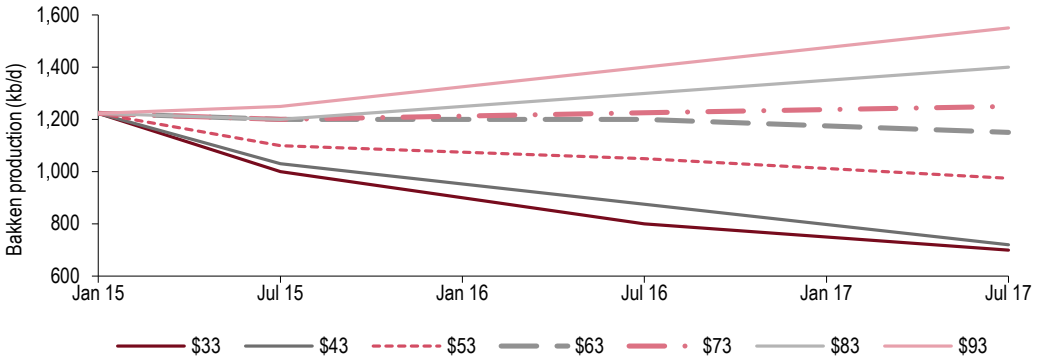


Source: Edison Investment Research, EIA. Note: Dates denote the end of "learning period", where there is no further growth in IP per well. A linear decline in growth rate is assumed up to this point. There is no modelled reduction in overall decline rates over time.

We highlight that these are only indicative numbers as well productivity is far from homogeneous between and within basins. Companies are dropping rigs quicker in the least productive or "non-core" areas in each shale basin. The impact of rig count reductions on production will therefore almost certainly not be linear.

The Bakken is a good example of this trend. Its rig count is down 23% from its early-October peak; and the non-core Bakken has already become "pretty quiet" while core counties remain "as busy as ever", according to North Dakota's Department of Mineral Resources (DMR). This makes sense considering break evens in core counties are estimated by the DMR at just $29-41/bbl, compared to $44-75/bbl in non-core areas. Interestingly, the DMR forecasts broadly flat production from the Bakken at c 1.2mb/d over the next two and half years at a Bakken crude price of $55-65/bbl, equivalent to $63-73/bbl WTI.

Exhibit 6: Bakken production scenarios at various WTI prices



Source: North Dakota Department of Mineral Resources, EIA. Note: Assumes $8/bbl Bakken-WTI differential.

Improving efficiency is lowering break evens

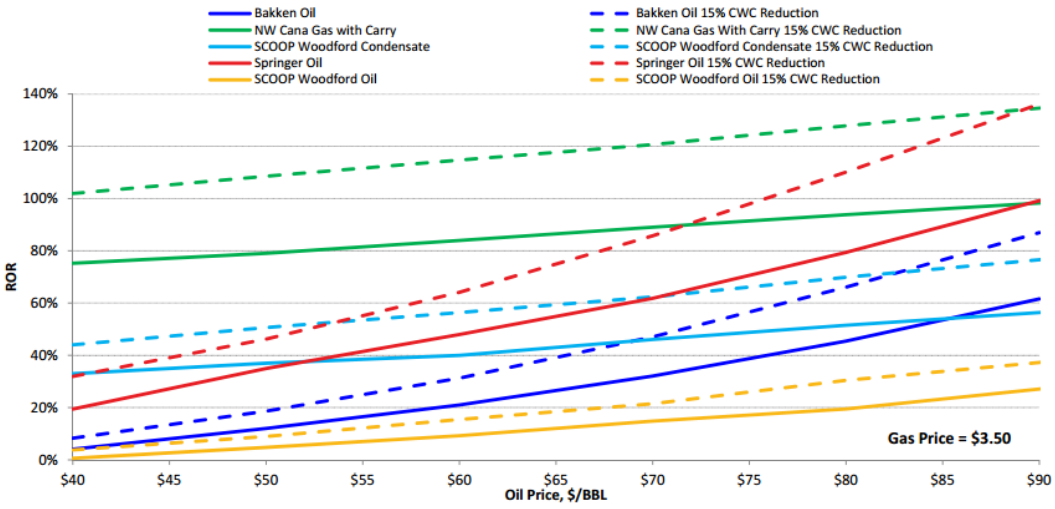
US tight oil break evens continue to fall thanks to production efficiencies such as enhanced drilling and completion techniques, acreage high-grading, unit cost reductions, longer laterals and downspacing. To quote a few examples of capital and operating efficiencies, Marathon Oil is seeing 25% average improvements from enhanced completions relative to modelled type curves in its Eagle Ford acreage, while Continental is seeing a 30-45% uplift in average 90-day IP rates and a 25-30% increase in EURs in its Bakken acreage. Oil production per rig is up by c 27% y-o-y across the US as each rig is able to drill more wells per year and individual well productivity is

higher. As a result of higher rig productivity, the number of wells drilled will fall far less than the rig count – for instance Hess is cutting its Bakken rig count by 44% but expects to drill just 12% fewer wells. On the cost side, Range Resources is seeing 10% cost savings from drilling wells on existing pads in the Marcellus.

Thanks to these efficiencies, expected rates of return remain very respectable even at lower oil prices. For instance, Continental expects average IRRs of 35% at $50/bbl and 45% assuming a 15% reduction in costs, ranging from 15-20% in the Bakken to 40-50% in the SCOOP (Oklahoma Woodford) shale. Concho sees 50-60% IRRs in the Permian basin with enhanced completions at $60/bbl.

Given these high returns (comfortably above those in most conventional onshore or offshore projects), it is not poor economics that will prompt US producers to cut spend, but rather an inability to fund capex with organic cash flows and debt.

Exhibit 7: Continental Resources' view on rates of return at various oil prices



Source: Continental Resources. NB: CWC is completed well costs.

One important caveat is that the E&P companies we have cited above hold acreage in the "core" of their respective shale plays, where economics are materially better than in the "non-core" areas, as previously mentioned. Operators are likely to high-grade their drilling activity and focus on core areas, while reducing production in the fringe.

In short, we believe some in the market may be underestimating the improvement in capital efficiency in US tight oil production, just as the market underestimated efficiency gains in US shale gas in 2009-12. During this period, US gas prices were range-bound in a low band of $2-5/mcf and were effectively capped by the significant productive capacity of shale gas basins. However, the comparison stops there: the key difference is that the US gas market is insulated from the rest of the world, whereas the US oil market is connected to the global oil market and production declines outside the US affect global prices.

Financing issues

US producers will once again outspend their organic flows in 2015. Such funding gaps have not stopped US E&Ps from spending in the past few years, so the real question shifts to the availability of debt/equity financing and debt ceilings. We note that many large US E&Ps (eg Continental, Range) have ample liquidity with committed credit facilities and no debt maturities before the end of the decade. For the US E&P group as a whole, debt levels are high but not spectacularly so: forecast 2015 ND/EBITDAX ratios of 1.5-3x at $60/bbl look far less scary than for many European E&Ps in our coverage. However, yields on high-yield energy bonds have risen sharply in the last

three months and hit c 8% in December 2014, while equity issuance would be expensive given the drop in share prices. Overall, we think the smaller E&Ps with lower-quality assets could be hit hardest by liquidity issues.

Price hedges could protect producers' cash flows in 2015

Inertia in US production could be reinforced by the existence of oil price hedges, which partly shield producers' cash flows through 2015. Although we do not know how much production is hedged, we note that several US producers are 50-75% hedged at $80-90/bbl in 2015, such as Range Resources, Concho, Devon, Pioneer and Oasis Petroleum. Having said this, we note that US E&Ps are staying largely silent on the extent of their hedging programmes in 2016. We suspect that hedging should fall off significantly next year and leave producers wholly exposed to lower oil prices.

Backlog of uncompleted wells to be tied-in

Companies are sitting on an inventory of wells drilled but not completed, which could boost production even if drilling activity slows. The marginal cost of bringing onstream a drilled but uncompleted well is low, so producers' willingness to connect these wells depends on their views on the timing of the oil price recovery and near-term funding situation. The uncompleted well backlog rose in the last few months as producers have chosen to delay completions in the expectation of a short-term rebound in oil prices. However, as the new reality of lower oil prices sinks in, producers may decide not to wait for several years after all and complete the wells to generate extra cash flow.

There are currently 775 Bakken wells drilled and awaiting completion – around 3x the number of net wells that Continental (the play's second-largest producer) plans to drill in 2015. Assuming that 100 Bakken wells are tied in per month at an IP rate of 500bo/d, additional production from uncompleted wells could be as high as c 300mb/d after eight months. While it is unclear when the wells could come onstream, they represent an overhang of low marginal cost supply. We recall that uncompleted well backlogs played a role in the 2010-12 US natural gas bear market.

Lower service costs

Service costs in onshore US (and elsewhere) are likely to decline. In Q414 producers engaged pricing discussions with their OFS suppliers on all product lines, particularly in hydraulic fracturing and drilling services. On its Q414 conference call, Halliburton mentioned that initial discussions, customers had requesting pricing reductions of 25-30% – it believes final pricing cuts should be somewhat smaller. Halliburton expects pricing concessions to be "less severe" than in previous cycles (eg 2008-9) given the higher technical content in complex wells.

Demand: Unlikely to come to the rescue

The critical question in today's oversupplied oil market would appear to be when and by how much will the US shale producers cut supply in response to low oil prices. This focus on the US shale appears justified in our view, as a resurgence of demand is unlikely to ride to the rescue, either through strong economic recovery or increased purchasing in response to lower prices.

IEA estimates of demand growth continue to head lower

Global oil demand growth continues to suffer due to the sluggish economic recovery in Europe and resultant slowdown in manufacturing and exports from growing economies, particularly China. In its December 2014 oil market report, the IEA reduced its forecast for global oil demand growth by 230mb/d for 2015 to +0.9mb/d, reflecting particularly weaker demand from the FSU. Global oil

demand for 2015 is estimated at 93.3mb/d, which still represents growth vs 2014, though the acceleration in demand continues to be at a more modest pace.

Russian oil demand falls as low oil price, economic sanctions and weaker currency bite

The Russian economy has arguably been one of the greatest casualties of the falling oil price with lower export revenues, Western sanctions and the volatile rouble combining to slow domestic economic activity. Russia's economy ministry itself recently revised down its GDP estimate for 2015 to -0.8% from its previous forecast of +1.2%, while this week the S&P reduced Russia's credit rating to 'junk' status, reflecting the troubled outlook for Russia's economy.

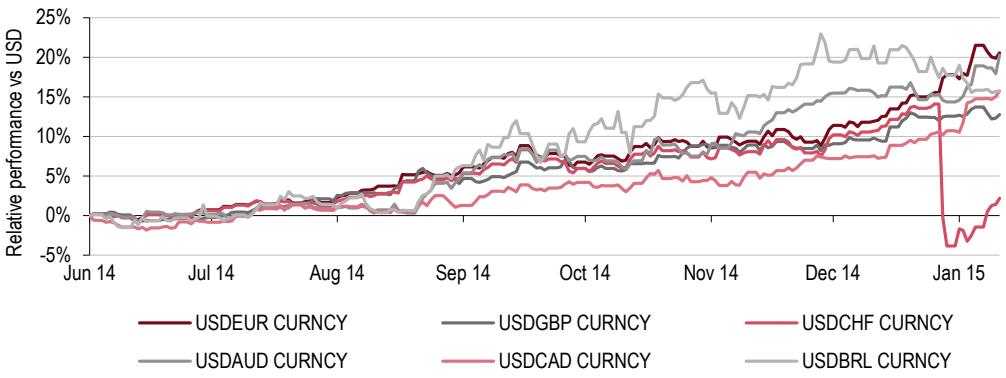
In one of its largest negative revisions to oil demand, the IEA reduced its estimate for 2015 demand in Russia by 195mb/d to 3.4mb/d in its December oil monthly report. We expect oil demand in Russia could have further to fall given the potential for a biting recession in 2015.

Removal of energy subsidies blunts the stimulus impact of weaker crude

There is an expectation in the oil market that the recent fall in oil price will bring about a stimulus effect, with global demand for diesel and gasoline increasing in line with affordability. However, it seems many governments in emerging economies are seizing the opportunity offered by cheaper oil to remove domestic fuel subsidies, particularly China, Indonesia, Kuwait, India, Thailand, Egypt and Malaysia. This removal of subsidies is effectively negating the benefit of lower fuel prices to the consumer, hence mitigating any impact on demand.

Globally, many economist are pointing to the lower oil prices as an effective stimulus globally, (reports of over $1tn from bulge bracket economists) though we caution that the ever increasing dollar is offsetting this. Since 19 June (the peak of the oil price at $115/bbl Brent), the US dollar has appreciated by around 15%.

Exhibit 8: US$ vs selected currencies (since oil price peak 19 June 2014)

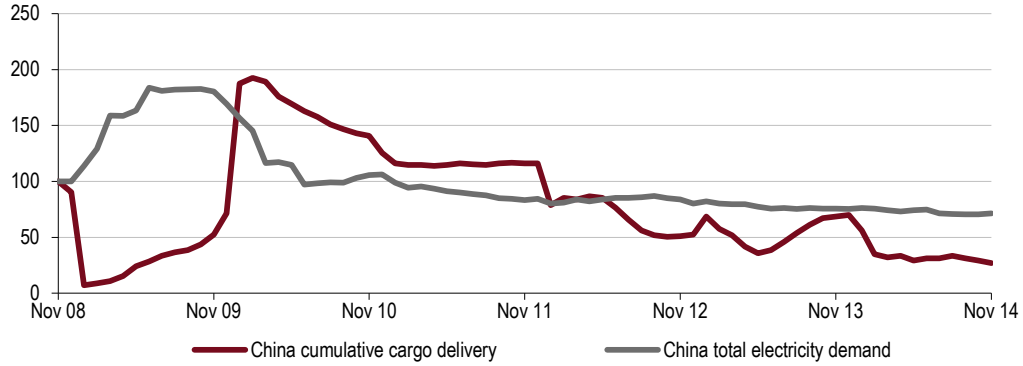


Source: Bloomberg, Edison Investment Research

China experiencing a slowdown in all but GDP

Having experienced a sharp downturn in oil demand growth in 2014, the market is questioning whether Chinese demand could rebound in 2015, absorbing the oversupply from US shale. According to the IEA, Chinese oil demand came in at 10.4mb/d in October 2014, up by just 285mb/d (3%) higher than the previous year. Despite state-sanctioned Chinese GDP estimates remaining fixed at 7%, by contrast many other indicators, such as electricity usage and rail freight (shown in Exhibit 9) are pointing to a material slowdown in Chinese economic activity.

Exhibit 9: China: Industrial activity in decline



Source: Edison Investment Research

Beneath the headline oil demand numbers in China, there are two distinct trends: rising gasoline demand from increased vehicle 'park' and, offsetting this growth, falling demand from oil used in power generation on expansion of the electricity network. According to the IEA, new car sales in China showed lacklustre growth in 2014, growing only 6% on a year earlier. On this basis the IEA expects growth in gasoline demand in China to decelerate in 2015, with overall oil demand in 2015 to increase by just 2.5% as a result. On this basis we see limited potential for a sharp rebound in Chinese oil demand in the near term.

Inventory overhang

Based on IEA data, global oil stocks are set to rise in H115, on the back of already sharp stock builds in 2014. If OPEC produces at its target of 30mb/d in H115, OECD commercial inventories could reach a record high by mid-2015. It is unclear whether existing storage capacity is sufficient to accommodate the upcoming stock build.

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