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Global

Goodbye Triple Digit Oil

Global Macro Conditions Accelerate Oil's Decline to $70-90 Range

- **The recent decline in oil prices has short-term roots in global economic weakness: higher global growth would have spawned higher demand since 2012 and put off the day of reckoning** caused by the US shale revolution. In 2014 alone, disappointing global growth, falling at least 700-k b/d short of the IEA's expectations from last winter, makes up 70% of the 1-m b/d imbalance in global supply and demand conditions.
- **Over the past few years, Citi's Commodities Strategy team has painted a medium-term bearish picture for oil prices, arguing that by 2017-18 the prevailing floor price of Brent at $90 would become either a medium term mean-reversion level at best, or a new ceiling price at worst.** We also argued persistently that short-term market dynamics were putting pressure on prices and the most likely alternative scenario to a weaker market was a much weaker market. Yet we frankly misjudged the way that financial flows out of commodities, the rapid move from investor net length to net short position, decelerating Chinese growth, and Saudi pricing in Asia would so rapidly bring prices back to the trading range prevailing before the first Libyan disruption in 2011.
- **Two years ago, Citi projected a medium-term assessment (five years out) of the fair market value for Brent crude between $70-90/bbl based on four long-term crude forecasting models,** which we thought were reliable pointers, modified by unpredictable weather, economic and geopolitical conditions. In this report we revisit and test that analysis, which we now confirm.
- **The first model utilizes long-dated futures prices,** which indicate medium-term prices could be anchored between **$85-92.**
- **The second, Citi's "Fair Cost" Index,** provides a predictive model that analyzes the relationships between cost inputs to production and prices, and **finds that prices could be in the $80-85 range.**
- **The third model updates the work of energy economist Morris Adelman** to analyze the long-term relationship between reserve values and prices – **pointing to prices between $74 and $88.**
- Finally, we examine the cost curve for IOC projects to 2020 and identify the breakeven costs for **marginal projects, which point to a $90 ceiling and a $70 floor.**
- **Particularly striking is that all four approaches, utilizing entirely independent methods, are shouting that prices could find the $70-90 equilibrium level in the years ahead – geopolitical, economic conditions and weather aside.**
- **The implications of a lower price environment are transformational for consumers, petro states, E&P firms, and global energy intensity and global growth.**

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Citi's long-term oil price forecast points to levels between $70-90 per barrel

Projecting crude oil prices is in many respects a fool's errand. Forecasting geopolitical events involving supply disruptions is a divine mission, let alone forecasting business cycles impacting demand or the introduction of disruptive technologies affecting both supply and demand. Yet benchmarks are required to help assess and put into perspective short-term price movements.

Two years ago, Citi projected a medium-term assessment (five years out) of the fair market value for Brent crude between $70-90/bbl. At the time, many were skeptical, arguing the projection was too low, based on such assumptions that the costs of finding and developing new resources were rising along with rising demand from emerging markets – the Malthusian propensity to project that fueling another 2.5 billion people and a 9 billion person planet with rising income would stretch the global resource base. With awareness of hindsight that oil, like all commodities, is cyclical and that over long stretches of time costs and prices tend to fall, we used what we considered the best analytical tools available to assess and project prices by the end of this decade.

We argued that $90 was becoming the new ceiling for long-term prices – a prediction that now seems to be coming true. We re-confirm our view of a long-run equilibrium for Brent prices in the $70-90 range based on a comprehensive review and update of Citi's long-term crude forecasting models.

This year, markets rapidly telescoped our medium-term projection to today. As Brent has given up over $30/bbl since June, the market looks to have come back into balance within the $70-90 long run equilibrium. Previously, the market worried about spare capacity. In the new environment, there's distressed capacity – a bearish risk that has come back and looks set to stick around.

In the near term, OPEC action will play a large role in determining whether prices trade closer to $70 or even below, or to $90 or even above. If OPEC squabbles instead of cutting, deferred prices should stay anchored around $80 or even further below with prompt prices trading lower in the face of abundant supply and weak demand. If OPEC bites the bullet and surprises markets with a credible and deep cut, deferred prices will likely maintain their $90 anchor.

Other geopolitical risks, while largely swamped by the growth of US shale, can drive short-term volatility. Libyan production significantly alters the balance and might surge or collapse in the face of prolonged conflict. Iranian production too, might swing higher or be choked further depending on the outcome of nuclear negotiations.

In the midst of all the recent volatility, we step back and revisit the sign-posts for long-term equilibrium prices. This report carefully examines four key methods for forecasting long-term prices and finds that they continue to consistently point to a range of $70-90.

Four methods for forecasting long-term prices

Long-term price forecasting can be a precarious undertaking. In order to provide some stability and greater confidence, we utilize four separate methods for zeroing-in on long-term oil prices:

1. **Long-Dated Futures:** deferred futures prices for a commodity can provide a reasonable proxy of where market perceptions are today about where tomorrow's prices equilibrate. We examine the recent price and volatility behavior of long-term oil futures prices and suggest what can be gleaned from them.

2. **Citi's "Fair Cost" Index:** utilizing a technical analysis of the long-run relationship between cost inputs to oil production and prices, we show where current input costs indicate prices should head.

3. **The Adelman Method:** drawing on the pioneering work of late oil economist Morris Adelman, we revisit Adelman's model, update it, and demonstrate what the updated model implies for prices going forward. This is the methodology that prevails among energy economists in academia.

4. **Marginal Fields:** using a bottom-up project-by-project analysis of forecasted new production to 2020 from Citi's *Oil Vision,* we analyze which fields' project economics indicate are likely to be on the margin, and thus indicate the highest cost oil that IOCs are likely to invest in.

Taken alone, each of these methods point to long-term oil prices in the range we have indicated. But taken together, they provide a powerful signal that long-run equilibrium prices should converge in the $70-90 range.

(1) Long-Dated Futures Prices

Figure 1. Results of forecast based on long-dated futures prices

Forecasted Price Range
$85-92

Source: Citi Research

We begin our analysis with an examination of long-dated futures prices. In some ways, this is the simplest approach we consider – the forward curve can provide a sense of market expectations of prices in the future, with some biases based on the balance of market participants (producers, consumers, investors, swap dealers). Importantly, markets can also reach entrenched anchored levels for long-dated prices, when they seem to cluster or mean-revert around specific levels over longer periods of time.

The history of the market shows clear periods where long-dated prices stabilized around an equilibrium level. For the entire period from the late 1980s, when deferred prices first became meaningful with the rise of trading on NYMEX and ICE, through 2002, 60-month deferred prices (about the time it takes to get a large discovery developed and producing) were stable at around $21 a barrel (for WTI, with Brent at a small discount), and prices rarely diverged from this level by more than 10% (+/- $2).

Deferred Brent prices became unhinged between 2003 and 2009, rising sometimes faster and sometimes slower than prompt prices, peaking at $140 in 2008, falling to $67 in 2009, and then stabilizing at around $90 (for Brent as WTI exhibited increasing volatility and moved into a structural discount to Brent).

The other approaches in this report to zeroing-in on long-term oil prices suggest similar levels around long-dated futures prices (see later sections of this report). **With plenty of credible supply below the $90 level, and upside in supply from the $40-70 segment of the cost curve (particularly shale and deepwater), the back of the futures curve can remain well-anchored,** though potentially easing downwards over time as technological and cost-cutting improvements are developed. The convergence of expectations around a range of prices can be

reinforced by support and resistance levels based on producer/consumer hedging around expected price levels.

With the back of the curve providing an anchor, we could be back in a period like the late 1980s through the early 2000s, where the front of the curve rises and falls with nearer-term market tightness/looseness, and mean-reverting around the back of the futures curve. **Further confidence comes from the recent historically low and stable volatility regime that has emerged, that allows us to have better confidence in the forecasting power of long-term futures prices. We also note that the front part of the futures curve tends to be a poor predictor of prices, but deferred futures prices can be a better indicator, which is discussed below.**

What can futures prices tell us about the future?

Two theories of commodity futures pricing are widely used. The first is the "theory of storage", which is basic to commodity analysis and has been part of an understanding of all commodities since biblical times when it comes to agricultural markets. As a formal analytical tool it has been around for over 70 years and will be familiar to most. This idea argues that by a no-arbitrage relationship, futures prices should reflect current spot prices plus the costs of carry, often elaborated as interest, storage, and insurance. The holder of the physical commodity should also earn an additional "convenience yield", which may cause futures prices to deviate from prices implied by costs of carry. This theory is largely uncontroversial, but implies that futures prices have limited information content about expectations for future spot prices, or at least deviate enough from actual expectations of future spot prices to be a poor predictor of them.

A second theory of commodity futures argues that futures prices are derived from expected future spot prices plus or minus a risk premium. The risk premium is earned by the holder of commodity price risk (whether this is buyers or sellers would imply either positive or negative deviations from expected prices). This view is partially predicated on a balance between hedgers, who are naturally long the commodity (like producers), and those who are naturally short (like refiners or airlines or trucking companies). It also involves liquidity provided by speculators or investors. This view of futures prices is more difficult to prove for statistical reasons, and has therefore been somewhat controversial in academic literature. Nonetheless these ideas go back to John Maynard Keynes, and have long had significant influence on thinking about commodity futures markets.

Long-dated futures prices can indicate expectations of long-run equilibrium prices

If futures prices are in fact at times formed according to the second theory, then they can contain significant information about what market participants expect equilibrium prices in the future to be. For participants in the physical market who hedge long-dated positions, these expectations will likely be firmly grounded in expectations of long-term marginal costs, and should therefore reflect informed views about long-term fundamentals. Trading activity by speculators should also help form an equilibrium around expected future prices.

Importantly, the relative weight of market participants might drive long-dated prices away from expectations of prices over certain periods. These market participants include producers, consumers, investors, as well as swap dealers. Consumers, investors need to provide a high enough price for the upstream sector to bring on future marginal projects to meet expected demand. But producers tend to be the largest entities with the most concentrated appetite for long-dated futures,

on the natural seller side. However, the 2000s saw a relentless bid higher for long-dated oil futures, particularly with the rise in new classes of financial flows that were long oil, but in line with the fundamental story of lagging non-OPEC and OPEC oil supply, trying to keep up with surging emerging market demand growth across commodities, but particularly acute in oil. Going forward though, the bias looks to be producer hedging (from companies and sovereigns) weighing on deferred futures prices, combined with lower consumer interest.[1]

This second theoretical view of futures prices should be particularly applicable to long-dated prices, when frictions related to deliverability and physical logistics prevent markets from exhibiting the no-arbitrage relationships expected in the "theory of storage". Thus there is a weaker "arbitrage anchor" between spot and long term futures prices.

To see why this is the case, consider the following. In the short term, storing oil to arbitrage dislocations between spot and futures is not only possible, it is expected. The contango structure of the Brent curve in 2008 and to some degree in recent months had incentivized both land-based and floating storage. But over the much longer-term, few if any market participants are executing these types of arbitrages on a five to ten year timeframe, as frictions prevent these types of trades from being either physical possible or financially advantageous.

As a result, we argue **long-dated prices will often be more anchored to expectations about future spot prices than to strict arbitrage relationships with the current spot price.** There is, of course, potential and indeed a high probability for some distortions to emerge from time to time, but these should eventually be smoothed out and the deferred price should mean-revert to the anchored level of expectations. Variations in risk premia and financial flows, and currency effects are unavoidable. The recent exit of some banks from the back of the curve has impacted liquidity and thus may have magnified the impact of financial flows on prices over the last year.

Yet stable deferred prices over significant periods of time should still contain useful information about expectations. Hence while we do not claim to settle an old academic debate, we find the second theory particularly helpful in examining behavior of long-dated futures prices.

The current volatility regime indicates sufficient stability in long-dated futures to draw conclusions from deferred prices

To the extent long-dated oil futures converge towards a stable value, they can be a useful indicator of long-term oil prices. The longer deferred Brent (5-years out) is stable at around $90, the more logical it is to treat this as a mean-reverting level and therefore helps frame the range within which oil is likely to trade. It is the highest of the price indicators we have identified. Historically, there have been

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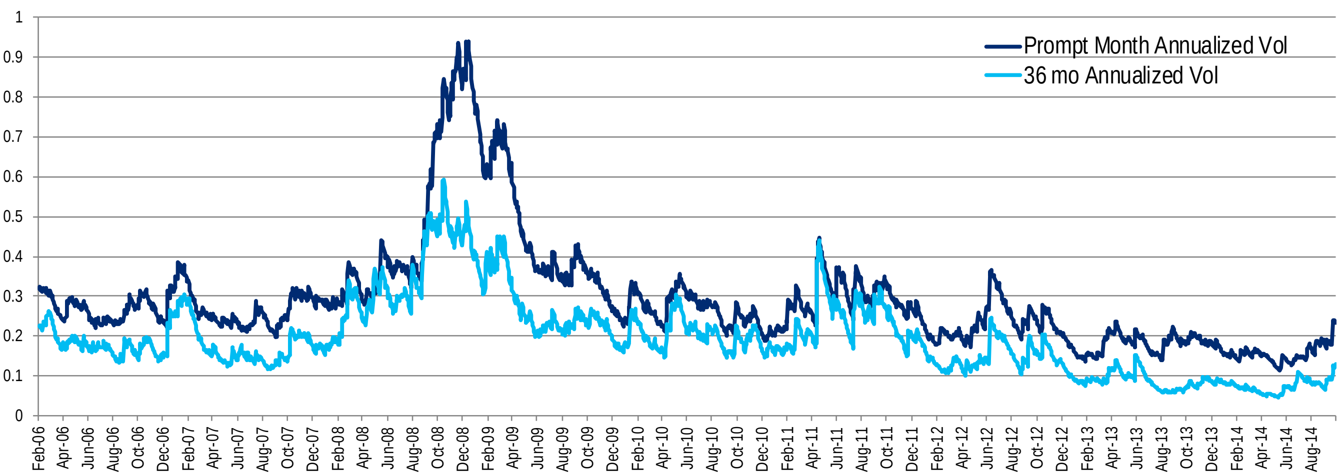
[1] Variations in risk premiums could imply downward pressure on long-run prices. As we have explained, long-run prices may be formed by expected future spot prices plus or minus a risk premium. It is worth noting that trading activity at the back of the curve looks set to shift risk premiums in the coming years, implying that for any given expected price, the realized price will be lower. Over the last decade of the super cycle we observed a relentless bid higher by passive funds and managed money. This implied small risk premiums for buyers as the demand to be long oil was abundant, meaning buyers did not receive much discount to an expected future spot price. We think this dynamic has flipped going forward, with significant sovereign hedging and reduced passive consumer longs looking to weigh heavily on flows at the back of the curve. This implies that buyers of long-dated futures are fewer and might command a higher risk premium.

several pronounced periods where this method has proven useful. As noted earlier, during the 1980s, 1990s, and early 2000s, long-dated prices were stable around the $20-21 range. Yet markets witnessed a departure from this stability during the 2003-08 "super cycle" due partly to escalating costs of finding and developing oil (see Figure 11), but also due to speculative behavior, denomination effects from a weaker dollar, and disruptions to spare production capacity.

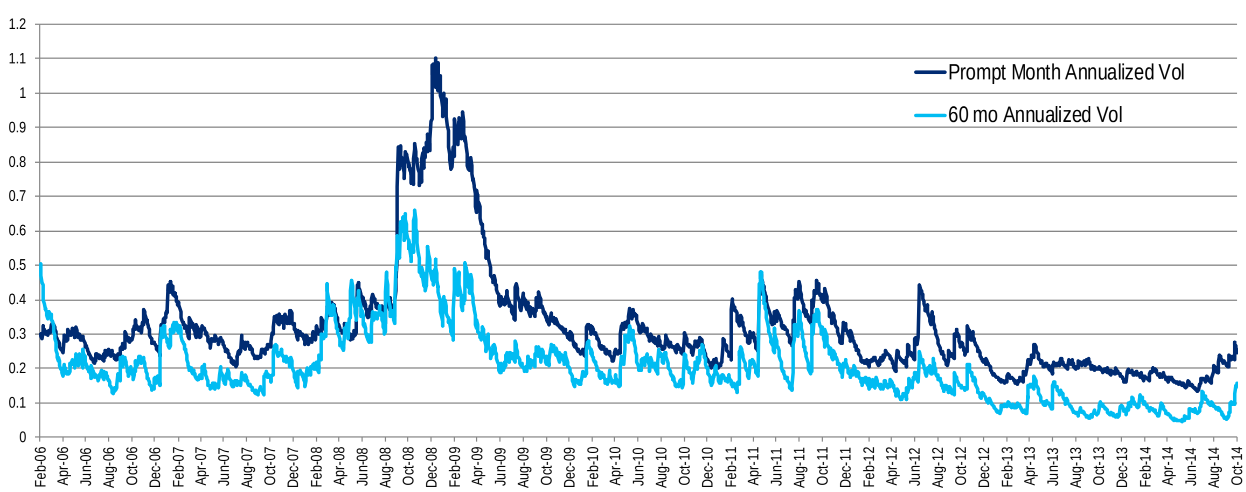
So how stable have long-dated futures been recently? We analyze the stability of futures contracts by utilizing a GARCH volatility model for both the rolling prompt month and the rolling 5 year futures contracts, for both WTI and Brent (see below).

Figure 2. Volatility of long-dated Brent futures has been low and relatively stable in recent years



Source: Bloomberg, Citi Research. Note: GARCH(1,1) shown. 36mo contract analyzed due to greater liquidity.

Figure 3. Volatility of long-dated WTI futures has been low and relatively stable in recent years



Source: Bloomberg, Citi Research. Note: GARCH (1,1) shown.

In general, deferred contracts exhibit lower volatility than prompt prices, with some notable exceptions around large shocks (see fall '08). What is noteworthy for both Brent and WTI, though particularly so for WTI, is that we seem to have entered a lower volatility regime since mid-2012. Both Brent and WTI volatility for

deferred contracts have hovered around and often below 10%, which on a historical basis is low. Volatility on the 60-month contract had hovered around mean levels near 20% both pre- and post-crisis; volatility anchored near 10% since late 2012 represents a departure and a new vol regime. Through 2011 and 2012 we can witness a steady decline in volatility, which by the second half of 2012 appears to point to a new level of stability in the market. As backdrop, the Fed's quantitative easing program has generally had damping effects on volatility across multiple assets. We find this volatility pattern consistent with an "anchoring" of expectations around a long-run equilibrium for long-dated futures prices.

Up-ticks in volatility in recent weeks are noteworthy, though short spikes in vol are not totally new to the "post-2012 volatility regime". Volatility temporarily jumped to levels near 17% and 18% in April and June of 2013. Recently, markets have been grappling with robust supply, weak demand (see Peering over the Oil Cliff) and signals that some OPEC members like Saudi Arabia may be willing to tolerate lower prices.

Despite recent turmoil, the current volatility regime is both low and stable by the standards of the last decade. The pronounced drop in volatility for long dated futures, which has persisted over the last few years, indicates that current long dated-prices are more "anchored" than they have been in a long time. Thus we feel comfortable in concluding that since the second half of 2012 deferred prices have been adequately stable for drawing insights as to the long term price.[2]

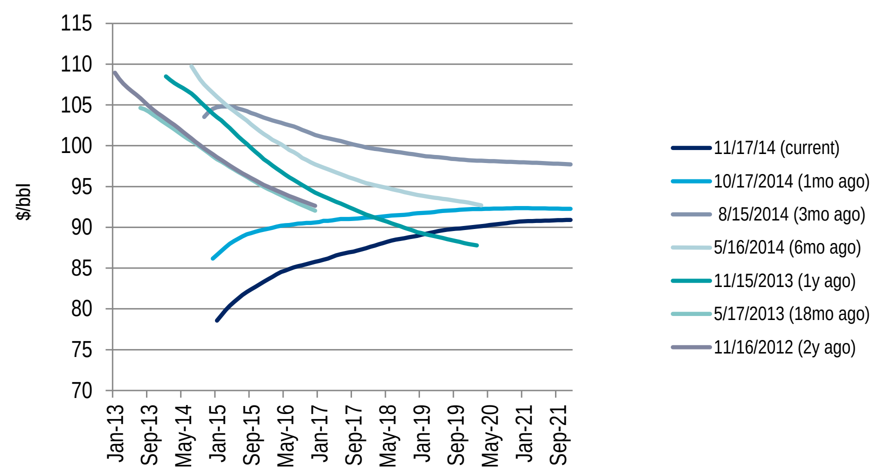
If long-dated futures prices are stable and anchored, what do current markets tell us?

We take the beginning of the current volatility regime around mid-2012 as the beginning of a period of relative stability during which we can analyze the behavior of long-dated futures prices. Over this period, Brent forward curves have consistently pointed to levels between $88 and $98. We can narrow the range further if we isolate the effects of the price rise between June and September 2014, which was partly due to geopolitical risks around the rise of ISIS and geopolitics surrounding Ukraine and the difficulty that the market had in assessing the impact of such rapid developments on oil markets. These developments were likely expressed as increased risk premia embedded in prices. Excluding impacts from these periods, both the current curve and curves from October 2012 through 1H 2014 point more narrowly to prices between $85-92.

Broadly speaking, long term futures prices indicate five year-ahead equilibrium prices between $85-92. Of course, disruptive events or new information are possible in the meantime. But absent the power to predict those disruptions, the futures curves look to be targeting levels at these levels.

[2] Given that we don't know what will happen with volatility in the coming months and year, we rely on realized volatility observed to date. If volatility were to change dramatically this may merit review.

Figure 4. Brent forward curves have been anchored between $85-95, but excluding response to ISIS in summer 2014 point to $85-92

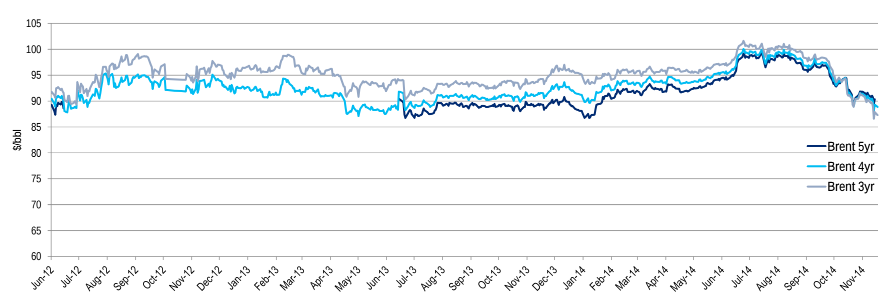


Source: Bloomberg, Citi Research

As is seen in Figure 4, this past year has witnessed a movement up in deferred prices of $6-8 a barrel, depending on the starting point, as deferred Brent rose to $100. This was largely due to an imbalance of buyers and sellers of deferred options and contracts. The events in Ukraine and with ISIS in Iraq appears to have led the investor community to reach a record level of net length in anticipation of higher prices, while consumers (airlines in particular) also bought deferred call options to hedge against higher prices. Producers stayed on the sidelines, expecting still higher prices so there was no counterbalancing of buyers and sellers. Subsequently later in the year investors reduced their net length and went short, pulling deferred prices back to the $90-92 level. More recently a rash of producer hedging is pulling prices below that level. But so far the ~$8 swing above $90-92 or below it is similar to the $2 swings around the mean reverting $21 of the 1990s. However, given the precarious fiscal position of many sovereign producers Citi thinks it likely that producer hedging will become a more consistent and bearish factor in oil markets going forward, pushing deferred prices below the $90/bbl level and capping rallies especially in deferred prices.

In short, we believe that the market is finding a new mean-reverting level below at around $90 Brent, which places this at the high end of our expected trading range. But downward pressure is likely to prevail, so it remains unclear as to whether $90 or $80 is the new $21.

Figure 5. Deferred Brent prices have been largely range-bound near $90



Source: Bloomberg, Citi Research

(2) Citi's Proprietary "Fair Value" Index for Long Term Oil Prices

Figure 6. Forecasted price range from Citi proprietary "fair value" index

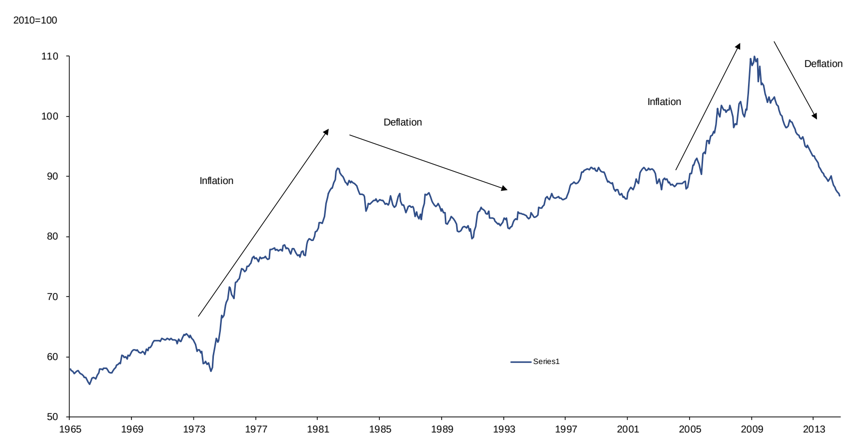
Forecasted Price Range
$80-85

Source: Citi Research

Another method we utilize to zero in on long term oil prices is to analyze the long-run relationship between oil prices and key input costs into oil production. We create a "fair value" index for oil prices as a function of cost. This appears to be a good forecaster of future prices (five years out) and indeed large divergences of realized prices from those indicated by the index may indicate distortions from speculation or changes in the risk premium. Over long enough periods, if markets are generally competitive at the margin and producer market power is limited, we expect prices should generally track our index.

We construct our index by regressing deferred Brent prices on key cost indices from the US Bureau of Labor Statistics. The cost index is based on factors that reflect global costs even though they come from US data. Trends for the index for the inflation-adjusted cost of field machinery, one of the elements of the index, are shown in the figure below, which illustrates these costs can witness cyclical fluctuations in response to changes in both the supply and demand for equipment.

Figure 7. Cost Inputs to oil production exhibit inflationary and deflationary cycles



Source: US BLS, Citi Research

Figure 8 shows the predicted value for WTI versus the 5-yr forward price. The chart shows that from 2004 to 2005, prices actually lagged fair value, before tracking them almost exactly through 2006. But by the second half of '06 prices again lagged fair value, before wildly overshooting by 36% at the peak of the financial crisis. Post-crisis, we observe two distinct periods. From 2009 to 2012, there were sustained 12-20% premiums of deferred prices above fair value. That gap narrowed to less than 5% from early 2012 to early 2014.

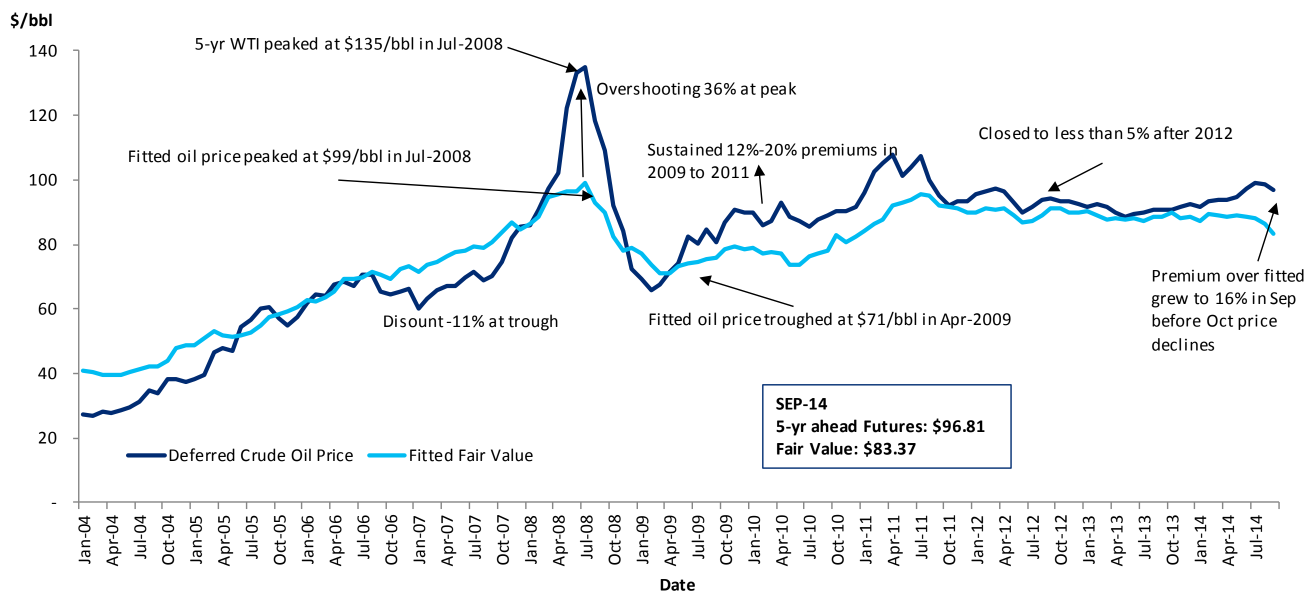
Fair costs indicate prices should be stabilizing at levels near $80-85

Before the price fall since 3Q'14, the gap was widening again as fair value started to drop while deferred prices rose from January 2014 into summer. As noted above, this was in the context of imbalanced activity on the forward curve with investors going long in response to geopolitical events related to Ukraine and ISIS in Iraq. While our model is only updated through September due to data availability and thus does not capture the decline of Brent prices after that, the model indicates that prices had been diverging from fair value and a sharp downward correction was

likely. Data updates for October and 4Q'14 that capture recent price movements are likely to show a better alignment of prices and fair values. **And right now, fair value indicates long-term oil prices should be at the $80-85 level.**

The $80-85 level could be impacted going forward by further cost deflation, and as we have discussed futures can overshoot moves in the fair cost index. We elaborate on several key factors that can impact the relationship below.

Figure 8. Citi's Fair Value Index for oil prices tracks the relationship between input costs and prices



Source: US BLS, Citi Research

Factors that might impact the relationship between fair costs and deferred prices

1. **OPEC: OPEC's ability to exercise market power and raise prices above levels dictated by marginal cost has often distorted prices** relative to the index, because this method assumes that the slope of the supply curve is largely intact, with no substantial changes to low-cost production. A large cut by OPEC could affect the curve shape. With a much-anticipated meeting coming up November 27 and prices having tanked by $30 since June, OPEC is facing its biggest challenge in years and Citi sees the cartel struggling to come up with an acceptable and credible agreement. For detailed discussion, see Curtain Raiser or Curtain Call?

   We project that OPEC would need to cut about 1.3-m b/d to support prices in 2015. Citi's view is that the Saudis are willing to cut production to support prices but are unwilling to do so unilaterally. The Kingdom and other GCC members of OPEC thus face a difficult problem in marshalling consensus for a cut within OPEC to "share the burden".

   Yet several countries within the organization face political challenges that are likely to dominate their production decisions and minimize their ability or desire to coordinate. Those include Iran, whose oil production is subject to sanctions; Libya, which currently has at least two rival governments for

which oil revenue is lifeblood in an existential fight for survival; and Venezuela and Ecuador, whose financial situations are increasingly precarious and can ill afford to forgo oil revenues. That being said, **were OPEC to be able to orchestrate and sustain a sizable cut (which might utilize some transfer payments to overcome coordination obstacles), prices might rise to levels above those dictated by costs alone.**

2. **Risk Premiums:** As we have already discussed, it is useful to conceptualize deferred prices as a function of expected future spot prices and a risk premium to speculators, hedgers, or buyers. Further, we can reasonably argue that expected future spot prices should be largely a function of costs, which our index indicates. But **movement of risk premiums can cause prices to move away from levels indicated by costs alone**. Multiple factors could influence risk premiums including volatility and geopolitical conditions and the imbalance between market participants in deferred parts of the curve. In the current situation, producer hedging in the absence of investors willing to go long could depress forward prices below fair market value.

3. **Liquidity Premiums:** Regulatory conditions have prompted multiple financial institutions to withdraw from trading at the back of the curve. **As markets become more illiquid, liquidity premiums (similar to risk premiums) demanded by those who hold price risk are likely to expand.** Additionally, as liquidity drops, effects of financial flows, including those from speculators, could be magnified.

(3) The Adelman Method

Figure 9. Price forecast result from the Adelman method

Forecasted Price Range
$74-88

Source: Citi Research

Late MIT energy economist Morris Adelman developed analytically rigorous methods for examining the relationship of in-ground values and development costs to downstream oil prices.[3] Several of the relationships Adelman examined have historically provided important indicators of where oil prices may be headed and his methodology has been useful in defining value for oil reserves in M&A transactions.

Adelman's analysis created an industry rule of thumb that argued the ratio of prices (pre-tax and royalties) to the value of in-ground oil reserves should be about 3:1. He found this to be strikingly true between 1955 and 1977, while the database he used extended further back in time. From 1977 to1980, the ratio noticeably increased, likely because of the price increase that resulted from the nationalization of oil by producer countries, significantly higher resource taxes imposed by producer countries where foreign investment was still allowable, the second oil crises, and the further impact of the Iranian revolution. From 1981 to 1985 the ratio returned to levels near 3:1 before exhibiting some uptick in 1986, where Adelman ended his analysis. We pick up where Adelman left off (see Appendix I for detailed discussion of Adelman's methods).

Adelman Updated

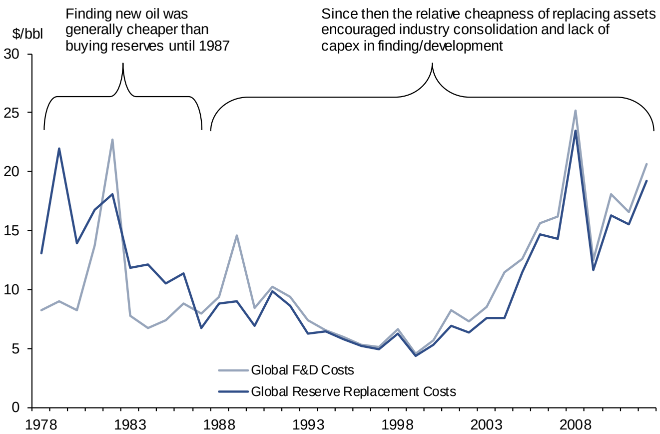
In looking at the last 25 years of oil prices since Adelman's work, we focus on two key relationships for long-term oil prices: (1) the relationship between wellhead prices and underground values ($/bbl proved reserves from M&A

[3] Adelman, M. *The Economics of Petroleum Supply.* MIT Press. 2003.

transactions), and (2) the relationship between wellhead prices and finding and development costs (F&D costs).

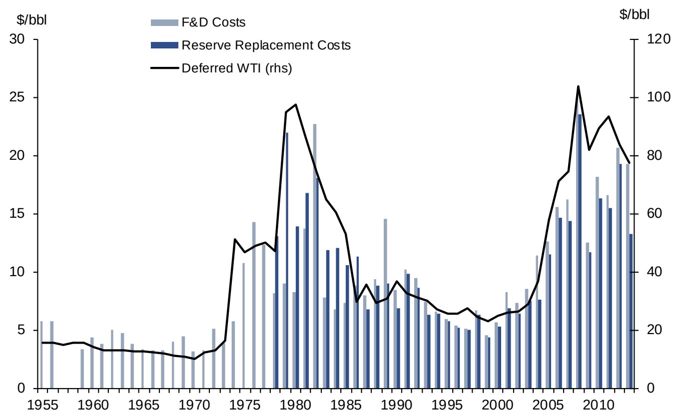
We find both are useful because while each may exhibit idiosyncratic movements over time, over a long-run equilibrium, firms should be willing to pay the same amount for already proved reserves which are in development versus finding and developing new reserves. Figure 10 below illustrates this point – F&D costs and reserve replacement costs can diverge, but have historically tracked each other closely. In fact, both F&D costs and reserve replacement costs have historically been good indicators of deferred oil prices (see below).

Figure 10. F&D costs and reserve replacement costs should find long-run equilibrium



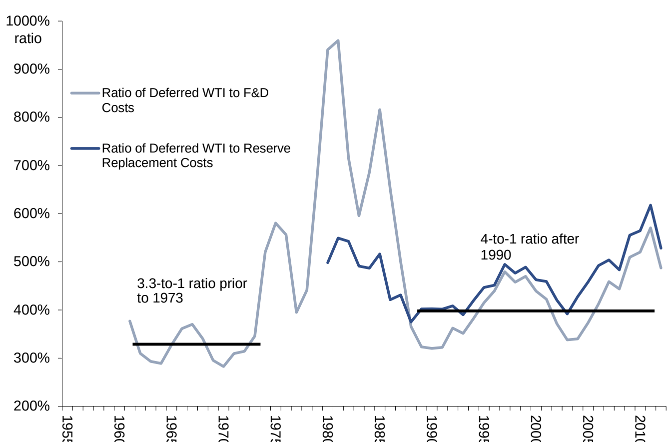
Source: IHS Herold, Citi Research

Figure 11. F&D costs closely track deferred oil prices



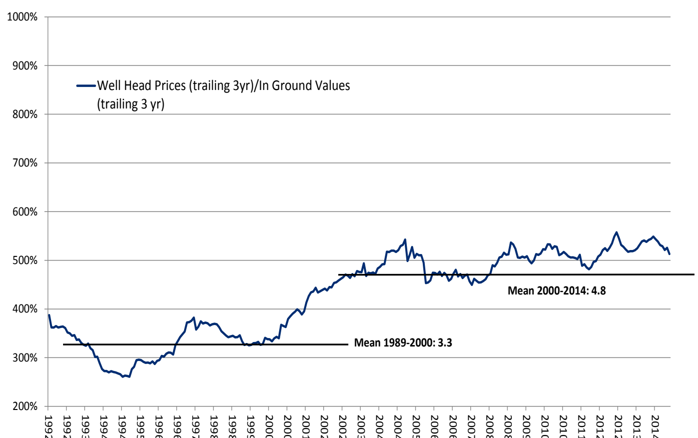
Source: IHS Herold, Citi Research

Figure 12. F&D costs show strong relationships to prices



Source: IHS Herold, Citi Research

Figure 13. Ratio of prices to reserves long stable at 3:1 has moved closer to 4:1



Source: IHS Herold, Citi Research

Wellhead Prices versus In-Ground Value Point to prices between $76-91/bbl

As discussed above, the ratio of prices to in-ground values (proved reserves from M&A) exhibited long periods of stability near 3:1, including over two

decades from 1955 to 1977. Further, the 3:1 ratio of in ground value to prices was mean-reverting; departures from this ratio during the oil crisis witnessed reversions in the first half of the 1980s. This ratio has thus historically been a valuable assessment of the relationship between reserves and prices and a reliable indicator of long-term prices.

We pick up Adelman's analysis where he left off in the late 80s, shown in Figure 13 above. Strikingly, the relationship generally held throughout the late 80s and through the 90s, indicating over four decades of consistency back to 1955.

Yet the relationship appeared to have shifted as of 1998-1999 to closer to levels of 4:1 and has stabilized at those levels since 2001 (see Figure 13 above). We argue this shift is due to two semi-structural changes in the oil market: (1) the rise of observable, persistent backwardation in Brent prices until the summer of 2014, and (2) cost increases due to the end of "easy oil", triggering a scramble for new reserves in frontier oil areas, including oil sands, deep water and finally light tight oil, where costs have been higher than traditional conventional oil in the past. Developments around both of these issues explain a structural change in Adelman's modeled relationship between prices and in-ground values. Both of these issues suggest that on a forward-looking basis, we may need to adjust the ratio downward in the years ahead to account for major recent developments in the oil market, especially downward pressure on costs in the deep water and even more so in tight oil formations. For those interested in deeper understanding of the model's mechanics, see Appendix I. Additionally, see The Abyss Stares Back and Out of America.

Figure 14. Detailed price outlook from Adelman ratios

		Implied Price Forecast
Historical Ratio	4.8:1	$88.8/bbl
Forward Looking Ratio	4:1	$74/bbl

Source: Citi Research

Using a trailing three year average of the value of in-ground proved reserves of $18.5/bbl, we can put the Adelman ratio to work. Using a backward looking historical value for the ratio of 4.8:1 (mean values from 2000-2014), we obtain a predicted oil price of $88.8/bbl. Utilizing the forward looking ratio of 4:1 (see Appendix I), we obtain a predicted price of $74/bbl. Similar levels are suggested by applying a the 4:1 ratio to F&D costs, which averaged $19.75/bbl, implying market prices of $79/bbl.

(4) Marginal Fields

A final method of examining the outlook for long-term prices is to review the highest cost projects undertaken by private sector oil companies as a signal for how companies estimate what price is required for a return on investment and to use that as a proxy estimate of what the marginal production will be in the future and how this will influence prices. There are two reasons to focus on marginal production.

Figure 15. Price forecast from marginal fields method

Forecasted Price Range
$80-90

Source: Citi Research

First, many major international oil projects have lead times on the order of five years for calculating project economics for development projects. Thus many of the projects now under consideration by oil producers are likely to be a good indicator for the ongoing full-cycle marginal cost of production five years from now. By narrowing in on the breakeven costs of projects which oil companies are willing or not willing to undertake, we gain a picture of a key driver of future oil prices. We utilize Citi's Oil Vision cost curve for international oil company (IOC) production in 2020 to estimate what breakeven costs for production in 2020 look to be, at least from today's perspective.

Second, the marginal costs of production are reflective of the price level at which companies will invest to extend the productive life of a field. If prices fall below that level, companies will more likely abandon these fields. Lower prices could therefore

have an effect not only on development of future projects but on expensive current production as well. Shutting down marginal production is one way markets adjust to lower prices. In addition, early field abandonment has a direct impact on global oil production decline rates. By example, current global decline rates are around their historical 5% average (setting aside the more complex issue of light, tight oil production from US shales). In a 90-m b/d environment, that means that 4.5-m b/d of production needs to be replaced before global supply grows. Adding 1% to the decline rate through early abandonment over a two year period in response to lower prices would mean that 5.4-m b/d of production would need to be replaced before incremental supply would be added to global production.

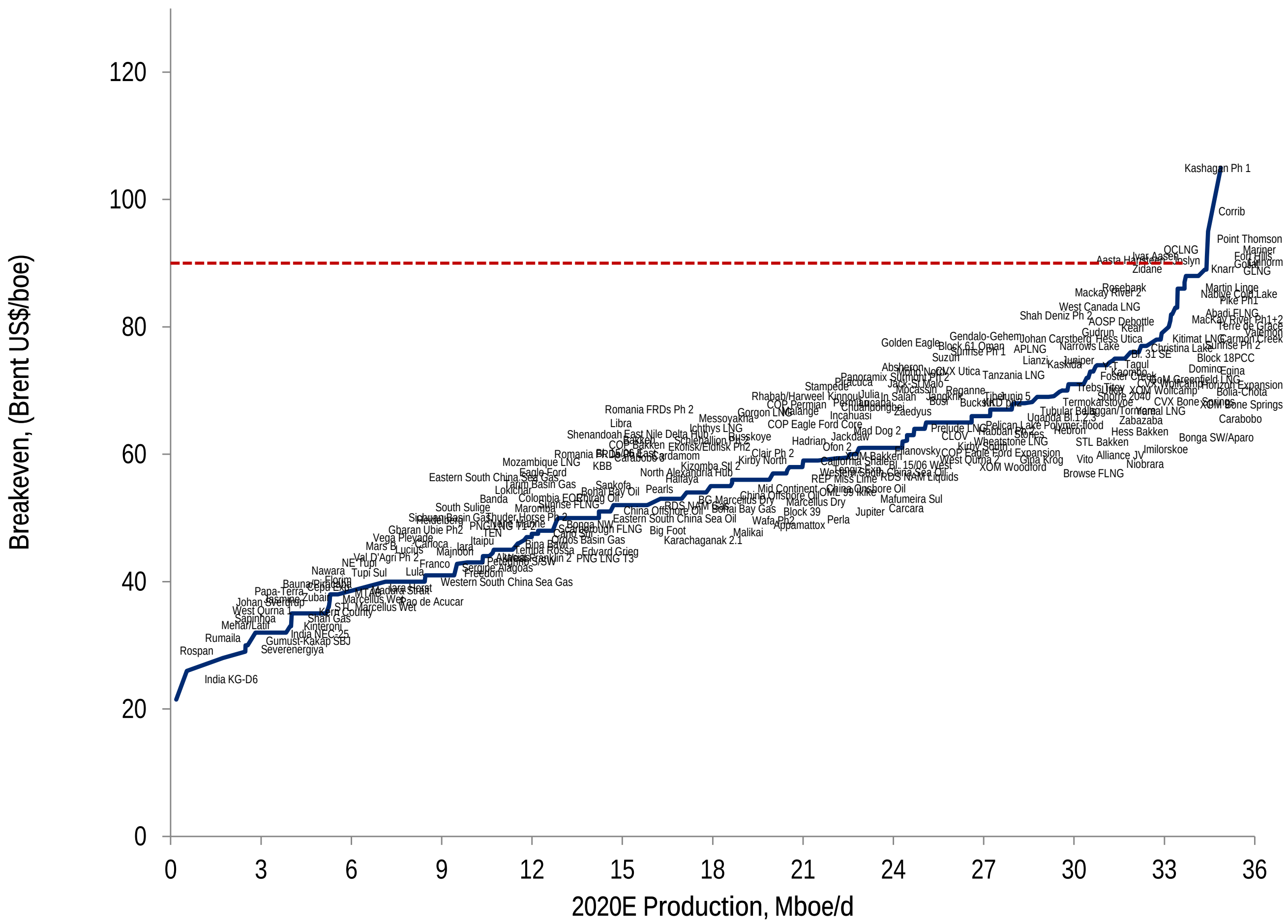
The marginal field has recently hovered around $90/bbl and may now be falling to $80

In recent years the most expensive oil company investments have been based on maximum all-in cost requiring around $90 to trigger an investment plan. Through 2013 and 2014 IOCs have been largely postponing if not abandoning projects requiring a higher price than this, though with lower oil prices now prevailing, downward pressure going forward is likely.

The below figure shows global projects being undertaken or considered by IOCs by 2020 (as captured in Oil Vision). As can be seen below, almost the entire universe of projects producers are willing to consider has been below a $90/bbl breakeven. There are a few projects above that level, but these are driven by particular idiosyncratic factors like sunk costs which escalated, very long-term cash generation that allow companies with large balance sheets and companies whose cost of capital is low or negative (as in the case of some Asian SOEs) to undertake such projects, or strategic factors that make the break-evens look higher in a standardized analysis.

But more recently, firms have started to postpone or even cancel projects with a breakeven over $80, and new pressures are pushing down the maximum breakeven price which firms are willing to consider. One such factor is the inability to put on hedges significantly above $90 when it comes to Brent or above $80 for WTI, given where forward curves have moved to in recent months.

Figure 16. Citi's Oil Vision 2020 cost curve for IOC projects shows the curve starts peaking around $90, indicating a upper bound for IOC project development appetites



Source: Company reports, Citi Research

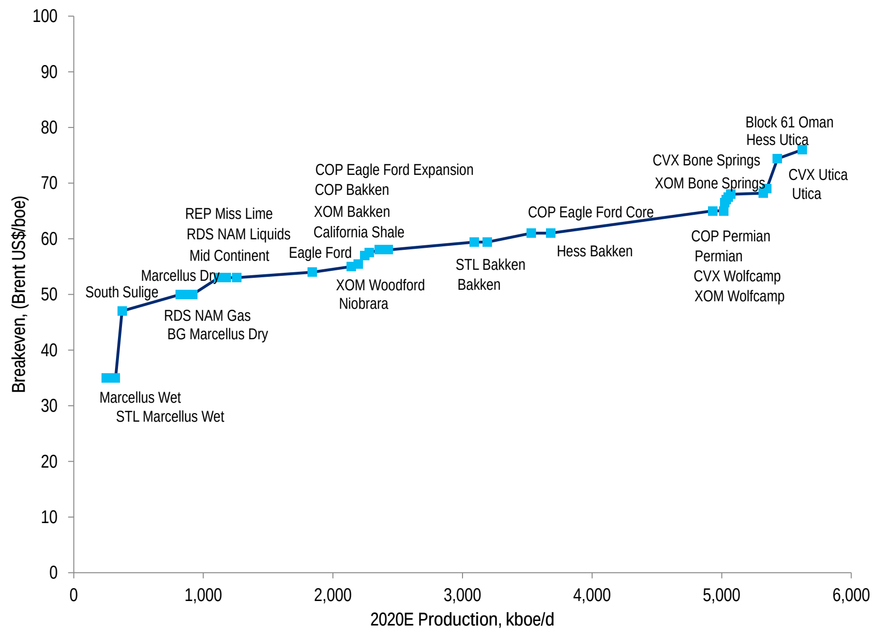
Shale development is an additional reason why $80 looks to be the new level for marginal projects going forward and why that level might be falling. As productivity gains increase for shale production and more becomes available at lower costs – which we fully expect to happen – the recent cost curve depicted above could see significant downward pressure this year. More specifically, shale is likely to elongate the middle section of the curve, creating a large pool of oil that can be developed well below $90.

In fact, a more detailed look at shale cost curves (see below) shows how this might take place. Citi sees the top end of the full-cycle US shale cost curve in the $80-90 range. Under a scenario where shale developers' exports are not restricted, shale is more and more likely to deliver a greater share of the world's "marginal oil", and would present a second producing group in the world that would make frequent, ongoing decisions on near-term oil production based on near-dated oil futures prices, which used to be the province of only OPEC. In short, US shale oil would be a new swing producing base. In addition, downward cost pressures including efficiency gains are at work, thus the marginal barrel demanded is likely to only get cheaper (all else equal).

If the ceiling is $90, the floor is $70

But while we see the ceiling for marginal projects moving from $90 to $80, the floor for marginal projects looks to be firming around $70. Below this level, prices are not high enough to incentivize adequate production growth to compensate for both demand growth and rising global declines from 5% to 6% or 7% per year on existing production (for detailed discussion of demand growth, declines, and the "call on IOCs", see Appendix II). As can also be seen in the below chart, as prices move closer to $60 a significant amount of shale production (at current costs) would be challenged. The same is true for IOC projects (shown above). Thus we think the world has plenty of oil at $90 going forward, but supply may be less adequate on a sustainable basis at prices much below $70. This is even though on a shorter-term basis, US shale production can continue to grow robustly even at lower prices, based on focusing on developing core, productive shale areas, with ongoing productivity gains and cost reductions.

Figure 17. US full-cycle costs for shale are below $80/bbl



Source: Company reports, Citi Research

Figure 18. Summary of forecast results

	Summary of Forecasts
Futures Prices	$85-92
Fair Value	$80-85
Adelman	$74-88
Marginal Fields	$80-90

Source: Citi Research

Widespread repercussions of a lower oil price regime

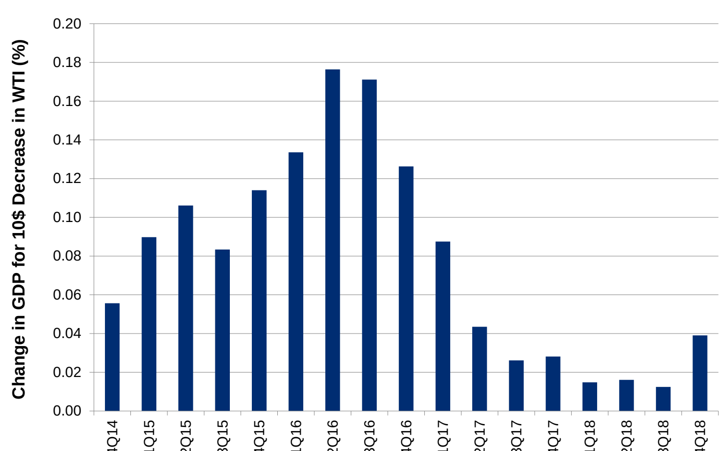
As we indicated in the beginning, forecasting oil prices is a precarious undertaking. But zeroing-in on a range can be made less precarious by utilizing multiple, rigorous, fundamentally grounded models in concert to calibrate an equilibrium price level. That is exactly what we have done here.

Of course, even the most rigorous methods are not perfect. We don't know what we don't know, and the oil market is no stranger to unpredictable shocks. But, many of the tools we have utilized here are anchored in deep historical relationships that have transcended generations of shocks and withstood the test of time. Additionally, shocks are shocks because they appear – and then dissipate; **in the long-run equilibrium, prices cannot diverge too significantly from costs or other variables which inescapably shape prices for physical commodities.**

These physical properties of commodities markets make forecasting quite unique as compared to other asset classes. And in a world where shale production is turning the oil markets on its head – and may continue to do so as costs keep being pushed down by technology gains and operating improvements and as it proliferates globally – understanding the fundamentals we have examined here is more important than ever. Surely, technology will evolve and shocks will come and go. But when markets confront times of significant uncertainty, as they are now, the best we can do is to step back from the fray and look confidently ahead armed with analysis that cuts to bedrock fundamentals in all times, turbulent or calm.

With the move down to a lower price range for oil, this is a windfall for consumers and net importers. The price drop could provide a boost to GDP growth, as well as some feedback to stronger oil demand, though there are headwinds from currency moves and removal of fuel subsidies in emerging markets. The sharp fall in oil prices touches almost every corner of the global economy. Advanced economies, other major energy importers, energy-intensive industries and regular consumers are apparent winners. Results from our macroeconomic analysis show that a $10/bbl drop in crude oil prices would lead to an average of 0.08% increase to GDP growth through 4Q 2018. The GDP impact of the price drop to date could be 0.18% at its peak and 0.1% on average in 2015.

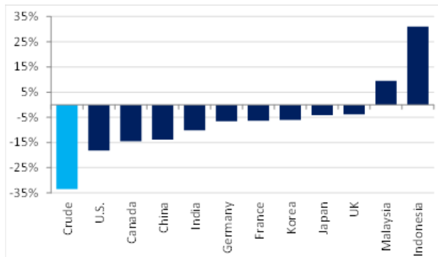
Figure 19. Impact of a $10 decline in oil prices on global GDP



Source: Oxford Economics model, Citi research

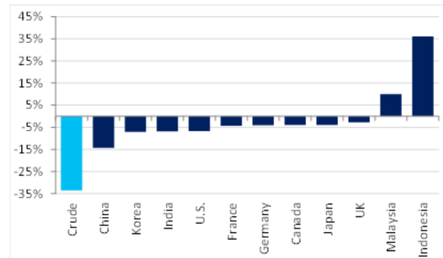
The effects of lower oil prices are already beginning to be felt in gasoline prices (see below charts). While the effects are complicated by FX impacts and local price and subsidy regimes, clearly the directional pressure is downwards. The below charts highlight that impacts will be uneven across countries, particularly those that have historically more strictly controlled prices (Indonesia). Generally, however, as gasoline prices decline we would expect to see rising expenditures in other segments of the economy.

Figure 20. % change in local gasoline prices (local currencies) from Jun 2014 to Nov 2014



Source: Bloomberg, Citi Research

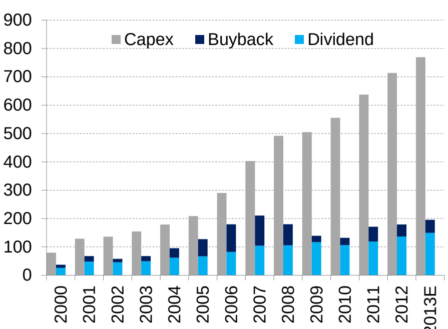
Figure 21. % change in local diesel prices (local currencies) from Jun 2014 to Nov 2014



Source: Bloomberg, Citi Research

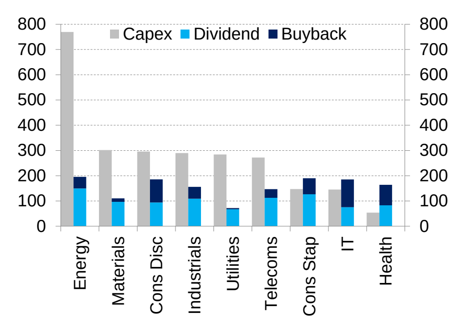
But lower prices present challenges to oil producers and the services sector, as well as to petro states that rely on oil revenues to finance government budgets. IOC's upstream capex had been surging, particularly through the 2000s as oil prices rose; in particular, shale producers – on both the oil and gas side – have seen negative cash flows on an aggregate level as initial capex in land acquisition and infrastructure initially eclipsed earnings from ongoing production. But as shale development has matured and land acquisition and infrastructure capex has now been sunk, cash flows can move decidedly positive and continue to improve, or alternatively, ongoing capex spend at >100% of cash flows would be reflecting an aggressive growth strategy.

Figure 22. Energy equity capex versus payout ($bn, 2000-13E)



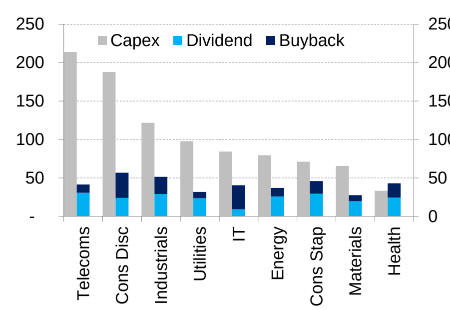
Source: Factset, Citi Research

Figure 23. Equity capex versus payout ($bn, 2013E)



Source: Factset, Citi Research

Figure 24. Equity capex versus payout ($bn, 2000)



Source: Factset, Citi Research

Nevertheless, as oil prices move down, producers on the very margin are impacted, reducing capex for those projects that can become uneconomic at the upper end of the cost curve, while also precipitating a move to refocus capex to projects lower down the cost curve. (See "Global Oil Vision".) Capex might need to be recalibrated in a lower price environment. Lower capex, particularly for shale activity, can mean an even looser services sector, helping drive the downward trend for services sector costs further. As we have discussed, this

means the oil production cost curve can shift down over time; shale and deep water services sector costs are reflecting this trend already.

Figure 25. Fiscal breakeven oil prices for selected petro states

	2011	2012	2013	2014	2015
Algeria	110	125	111	132	131
Bahrain	111	119	125	125	127
Iran	84	130	127	131	131
Iraq	95	102	106	111	101
Kuwait	46	49	51	54	54
Libya	149	63	111	317	184
Oman	78	80	84	99	103
Qatar	79	69	45	55	60
Russia	90	106	108	105	107
Saudi Arabia	78	78	89	98	106
UAE	93	78	84	79	77
Venezuela	140	175	168	161	151
Yemen	195	237	215	160	145

Source: MEES, IMF, Citi Research

Petro states, particularly those in OPEC, are challenged in a different way – these countries' oil production costs are at the bottom of the marginal cost curve, but oil production and exports are a primary source of government revenues. The oil prices required for oil revenues to balance government budgets – the so-called fiscal breakeven prices of oil for these petro states – are far higher than the $70-90 range, with several countries requiring oil prices of well above $100. These petro states might try to raise production, or work together to coordinate production cuts in order to support prices (for a recent analysis, see "Curtain Raiser or Curtain Call?"). But with a loss of global market share due to non-OPEC supply growth over this decade, the ultimate implication should be that they need to reduce government spending to live within this long-term oil price outlook.

Contrary to popular opinion that lower oil prices hurt renewables, Citi finds that the drop in oil prices will not have much impact on the majority of the renewable energy industry, despite the fact that the assumption of ever higher prices for both hydrocarbons and carbon has been embedded in most of the bullish outlooks for sector, and now oil prices are following US gas prices and carbon prices lower. In the power sector oil prices are of limited importance, as oil accounts for just 5% of global power supplies according to the IEA. Gas is a weightier 22%, and lower oil prices could mean lower gas prices via oil-indexed LNG in Asia and some of Southern Europe, though this would only possibly result in coal-to-gas switching. The renewables sector remains largely driven and protected by government regulation which will mute the impact of lower oil prices.

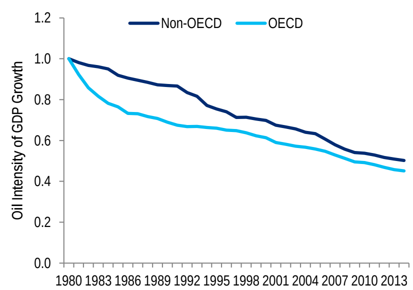
The transportation sector has been facing two separate shifts: biofuels and electric vehicles. Lower gasoline prices do pose a threat to the biofuels industry on the margin, though blending mandates remain in place even though the environmental benefits of biofuels have been called increasingly into question and this could be the bigger threat to the industry. Given the high price of electric cars, their adoption has not been obviously driven by consumer optimization of $ per mile driven, which points to the industry's likely resilience in the face of lower gasoline prices.

The two structural factors that Citi has long discussed in terms of lowering the forecast rate of oil demand growth below market expectations are improving fuel efficiency and fuel substitutions, particularly natural gas

substituting for oil in transportation. Fuel efficiency gains have mainly been driven by rising fuel economy mandates, which will not be impacted by lower oil or gasoline/diesel prices. The outlook for fuel substitution has been somewhat dimmed by the fall in oil prices; a fleet owner contemplating the capex to switch his fleet from diesel to CNG or LNG is more likely to pause with the fall in oil prices, but at $80 oil and $5 gas, the ratio between the two is 16:1, against a traditional relationship of 7:1; this leaves plenty of room for gas to substitute going forward.

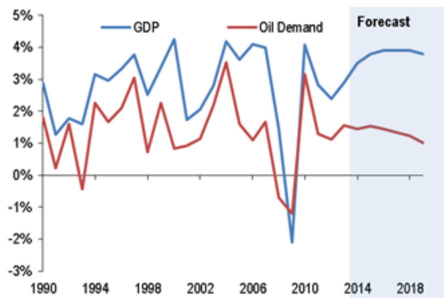
A long-term structural trend which Citi has identified previously is the reduction in the oil intensity of GDP growth; we expect this trend to continue despite lower oil prices. Lower prices will likely lead to an increase in demand, but this increase is unlikely to be of sufficient size to de-rail the structural shift towards lower oil intensity of growth.

Figure 26. Oil intensity of GDP (indexed 1980=1, 1980-2013)



Source: BP, Citi Research

Figure 27. IEA MTOMR 2014 Global Oil Demand and GDP (%, 1990-2019E)



Source: IEA, Citi Research

APPENDIX

Appendix I: Updating Adelman – Understanding the Changing Relationship between Reserve Values and Prices

As we have noted, there appears to be a "regime shift" in the ratio between prices and the value of in-ground reserves as of around 1998, when the ratio stepped up from 3:1 to above to 4:1. We highlight two key features of this relationship which are important to understanding how the relationship has changed over time, and how it may change in the future. Background definitions and discussion of these two issues are below.

Definitions

- **Value of in-ground reserves:** Adelman measured these values as the $/bbl price for *proved* oil reserves paid in M&A transactions. Historical data for M&A transactions are collected by IHS Herold in both Adelman's and our calculations. Important to note is that Adelman argued that theoretically, reserve value should be a function of discounted future cash flows from oil sales from those reserves. These cash flows are largely a function of three things: (1) decline curves; (2) costs; (3) oil prices.

- **Prices:** Importantly, at the time Adelman developed his model, futures markets were nascent and illiquid. Thus, he defined prices using spot wellhead prices, as at the time Adelman developed the model, futures markets were brand new and we assume that he was not able to take into account curve structure. This becomes important below to our update (as described below), as understanding how forward curves impact expectations about cash flows in turn impacts reserve values and the Adelman ratio.

Why we shifted from a 3:1 to a 4:1 regime

1. **The rise of futures curves with observable, persistent backwardation:** If the value of reserves is a function of cash flows, and cash flows are largely a function of future prices, curve structure should impact reserve values by indicating future cash flows. Because Adelman's model only captured spot prices, it did not take into account how curve structure should impact the relationship of reserves to prices.

   For any given spot price, backwardation implies lower cash flows and hence lower reserve values than contango (all else equal). The reason is straightforward – anticipated cash flows from backwardated oil prices are lower, and therefore the NPV of reserves is lower. Therefore, we expect that for any given spot price, in backwardated markets, reserve values should be lower than in contango markets.

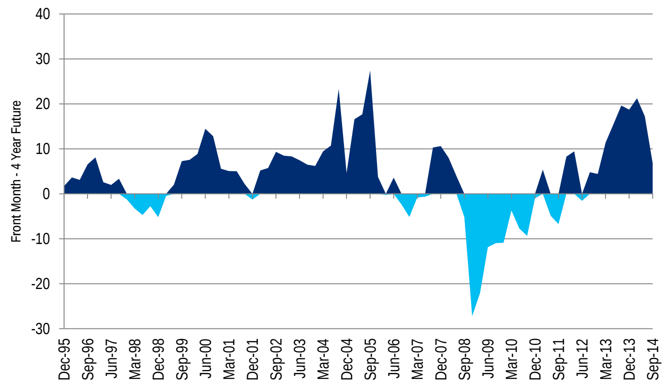
   We think taking this effect into account in large part explains the observed change in the "Adelman ratio" from near 3:1 to closer to 4:1, as the emergence of oil futures markets brought about two things: (1) observable curve structure for future prices, which impacts bid prices and reserve values in M&A transactions, and (2) demonstrated persistent backwardation which in fact likely impacted both reserve values and expectations of reserve values (via expectation of cash flows). Put simply,

if an acquirer of reserves sees a backwardated curve and expects it to persist, one should offer a lower bid for the reserves.

The below figures illustrate historical backwardation levels and show distributions which demonstrate that expectations of backwardated structure were in fact the obvious expectations to have at most points over the previous several decades.

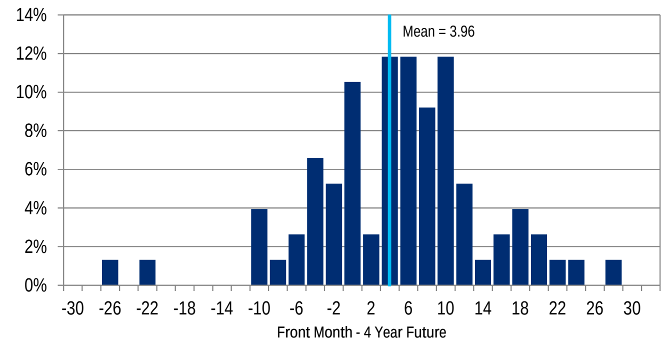
In particular, it is striking that backwardation became both increasingly pronounced and observable in the late 1990s, exactly when the Adelman ratio shifts to the 4:1 regime. We illustrate this feature of curve structure in the below charts, which show the spread between prompt and deferred contracts as a proxy for backwardation.

Figure 28. WTI spreads show persistent backwardation since the 1990s (positive values=backwardation)



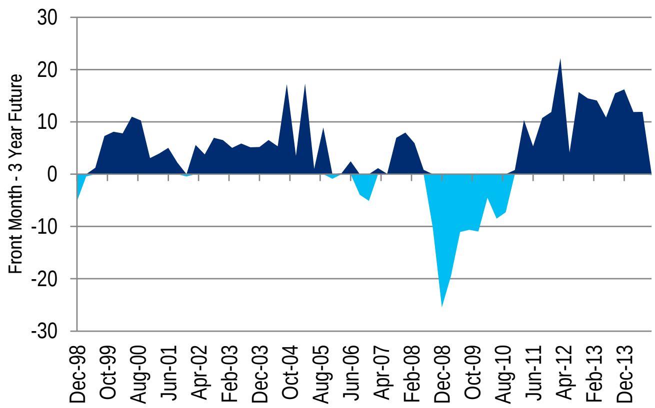
Source: Bloomberg, Citi Research

Figure 29. Histogram of WTI spreads since early 1990s indicate strong historical tendencies towards backwardation (positive values=backwardation)



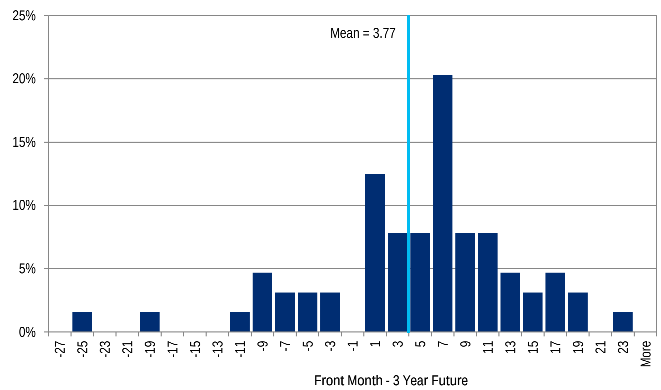
Source Bloomberg, Citi Research

Figure 30. Brent spreads show persistent backwardation since the 1990s (positive values=backwardation)



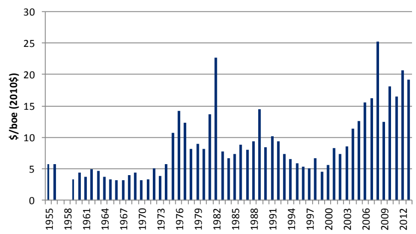
Source: Bloomberg, Citi Research

Figure 31. Distributions of Brent spreads indicate strong historical tendencies towards backwardation (positive values=backwardation)



Source: Bloomberg, Citi Research

Figure 32. Steep cost escalations coincide with shift in Adelman ratio from late 1990s



Source: Citi Research

2. **Cost escalations:** F&D costs also impact reserve values via cash flows. At any given oil price, an increase in costs will cause a decrease in free cash flows. This will in turn decrease the NPV of reserve values, even if oil prices do not change. What can we observe about F&D costs around the time the ratio switches to the 4:1 regime? Figure 32 paints a clear picture – the dramatic rise of F&D costs from 1999 closely tracks the rise of the Adelman ratio from that period as F&D costs also outstrip reserve replacement values. It appears that the "end of easy oil" during the super cycle, when demand outstripped supply, may have also led to a regime shift in the Adelman ratio (this effect also hints at things to come as shale production proliferates). Operating costs including EOR may also have increased.

Looking ahead: the global spread of shale will likely cause the value of the Adelman ratio to revert to traditional levels closer to 3:1 or 4:1 as M&A values for reserves increase relative to prices

Shale production has revolutionized North America, and looks set to spread globally in the next decade. The dramatic increases in shale productivity improvements of around 25% per year will likely impact both M&A values for proved reserves as well as costs, both of which would shift the ratio back towards historical levels. Several features of shale suggest M&A values may increase relative to prices:

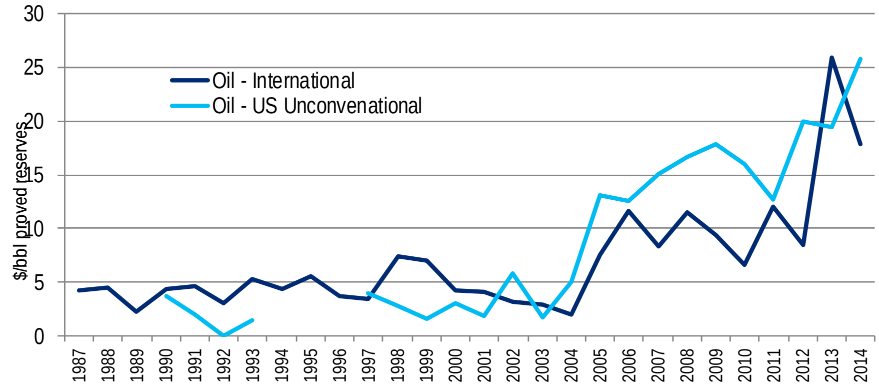
1. Because the Adelman ratio assigns the full value of an M&A transaction to *proved reserves* only, it does not fully capture when producers pay more for a property because they are optimistic about new discoveries (non-proved reserves becoming economic) enhanced production techniques leading to greater estimated ultimate recovery (EUR). The torrid pace of shale technological development should drive up land values relative to prices as optimism about ever-greater recoveries cascades into valuations. Of course, there comes a point after which optimism would be more tempered.

2. Productivity gains in shale imply lower costs per barrel of production. We expect shale will help drive down production costs going forward. This in turn improves free cash flows and raises land values (see above discussion on cost). Both of these factors suggest the spread of shale will therefore drive up land values relative to prices, moving the tightening the relationship between prices and reserve values.

In fact, M&A data appear to support these hypotheses. As seen in the below figure, reserve values for US barrels from unconventional acreage are priced consistently higher than global values for conventional acreage over the last 9 years, with relative premium for unconventional increasing in tandem with the shale boom since 2009.[4]

[4] Additional factors could include a premium for geopolitical risk or differences in tax/royalty regimes.

Figure 33. Shale proved reserve values are higher than conventional reserves



Source: IHS Herold, Citi Research

As shale spreads globally, this increasingly relevant feature of shale asset valuations should push the Adelman ratio back towards 4:1 ratios and perhaps even further towards 3:1.

What does this mean for forecasting based on the Adelman ratio?

Empirically observed levels of the ratio have been near 1:4.8 recently, but the spread of shale and a robust pace of technological improvement in the oil industry should drive these values lower. Thus, for a forward looking forecast for a market that is increasingly impacted by shale, we use suggest using a tempered ratio between in-ground values and prices of 4:1.

Appendix II

We also consider a modified approach to estimating the cost of marginal production in 2020, which tries to forecast the "call on IOCs" and match that to a Citi's Oil Vision project cost curve. This allows us to offer an additional estimate of what the break even costs for the projects "on the margin" are.

Demand to 2020

The first step in targeting marginal fields is estimating necessary production growth to 2020. Two components are important: (1) decline of existing production and (2) required growth of new IOC production to meet demand growth. We calibrate all estimates to be net of national oil company (NOC) production.

For decline rates, we assume a weighted average global decline rate of 6%, based on a study by IEA in 2013. For demand growth, we utilize Citi's base case crude demand forecast. The results of this scenario are shown below, which indicate about 30-m b/d of incremental IOC (or non-NOC) supply required by 2020.

Figure 34. Estimated "call on IOCs" to 2020 is around 30-m b/d

Decline Rate	0.06
Assumed 2012 NOC supply	45.0

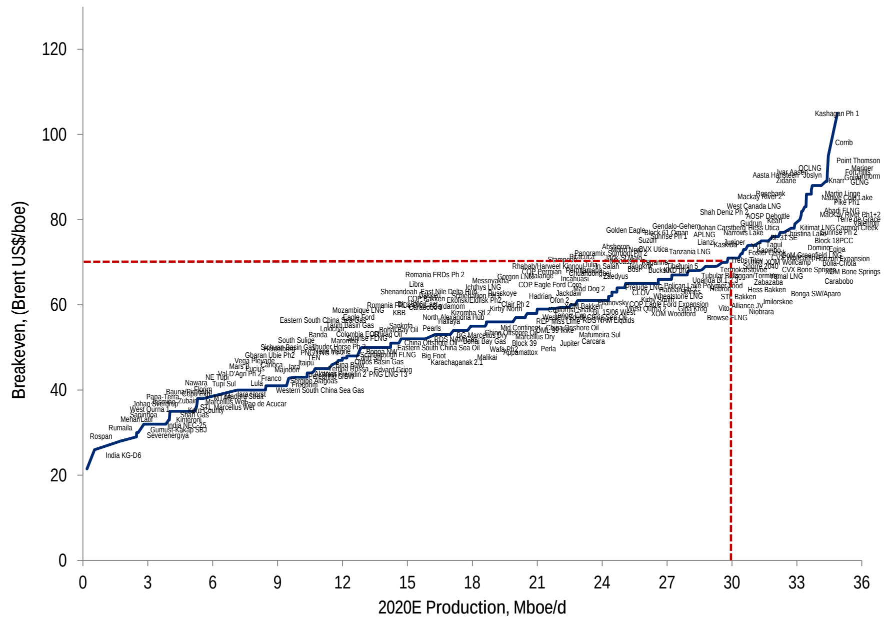
	2012	2013	2014	2015	2016	2017	2018	2019	2020	Incremental Supply
Total Supply	89.8	91.4	92.5	93.9	95.1	96.4	97.8	98.9	100.0	10.2
Estimated IOC Supply	44.8	45.3	45.9	46.4	47.0	47.5	48.1	48.7	49.3	4.5
IOC Declines	2.7	2.7	2.8	2.8	2.8	2.9	2.9	2.9	3.0	25.4
Total IOC New Supply Required										29.9

Source: EIG, Citi Research. Note: NOC production for 2012 based on EIG ranking of NOCs which are at least 50% state owned. Notes: Assumes constant NOC/IOC production shares.

The marginal field is near $70/bbl

Using 29.9-m b/d as an anchor for necessary incremental IOC (non-NOC) production, we obtain price levels of $70/bbl (see below).

Figure 35. Marginal IOC fields point to price anchors around $70



Source: Citi Research

Of course $70 is subject to some unknowns and sensitivities. Those include:

- **Shale production growth:** While shale production is proven in the US and there are abundant shale and tight oil resources available globally, the pace of development for international shale remains difficult to forecast before 2020. If international shale surprises to the upside, this could significantly impact which projects are marginal, thereby extending the lower portion of the above cost curve and lowering the equilibrium price. As seen in the below chart, full-cycle costs for US shale are becoming well below $70 for the most part. In the current environment we expect that as E&P companies reduce upstream capex, the services sector will respond through margin compression and this, in addition to ongoing technological change, will push the whole cost curve down.

- **The relative growth of NOC vs non-NOC production:** Should NOC production make dramatic gains, the “call on IOCs” could shift down, thereby lowering prices. On the other hand the long term trend has been in the opposite direction. In 1980, OPEC was producing around 30-m b/d in a 60-m b/d world. Today OPEC is still producing 30-m b/d but in a 90-m b/d world, a significant decline in market share, which goes a long way to explain OPEC's loss of pricing power and an increasingly painful effort by OPEC to shift the burden of adjustment to lower prices onto non-OPEC producers.

- **Decline rates:** As shale proliferates, decline rates are likely to be impacted, which can impact the amount of replacement production required. But technological change has pushed down well costs and increased initial production significantly. On the other hand if the world enters a period of lower prices, owners of the most expensive or marginal conventional oil, whether in areas like Bakersfield California or in much of East Siberia are likely to move to earlier abandonment of fields rather than

to invest in extending the life of fields. This redeployment of upstream capex could result in an increase in decline rates for the world. By example with capex deployed to extend field life the world has about a 6% decline rate according to the IEA, meaning that each year in a 90-mb/d world producers need to replace 5.4-m b/d just to hold production steady. A once percent increase in decline rates due to redeployed capex would add another 900-k b/d to the level of oil that needs to be replaced.

- **Project cutbacks:** If producers pull back from planned projects, we would expect those pullbacks to be focused on the top end of the curve. Yet pullbacks happen for various reasons, and curtailments of projects on the lower end of the curve might steepen the curve and imply higher prices.

Appendix A-1

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