North America United States
Industrials Integrated Oil

Deutsche Bank

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The End of the Oil Age

2011 and beyond: a reality check

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We refresh our Peak Oil Market work; spare capacity gone by 2012?
We've argued since early '08 that the oil age is ending owing to the concentration of remaining reserves into government hands, & an attendant under-investment cycle. Our focus: no supply growth + demand growth = price spikes until demand growth = 0. In this note we review 2010 vs our late 2009 thesis and focus on key changes. The fact that 2010 demand growth (+2.2mb/d) will likely be the second fastest for 30 years raises a red flag, especially as we work through OPEC spare capacity - prices will be spiking by 2012 if demand continues to grow at this rate.

Staring into the crystal ball
What were the main developments over 2010? In this note we run through the demand and supply side highlights, compared to our view a year ago, and look forward with a refreshed view. Demand side, we highlight the surprising demand strength of 2010, despite $80/bbl average and rising prices, and focus on the major long term drivers: US cars, Chinese cars, and Middle Eastern demand. The battle is between US efficiency growth and GDP/population-driven emerging market growth. The shift from gasoline to diesel in the mix is a major theme.

Is supply growth easy to predict because there is none? Not that simple
On the supply side, clearly Macondo was the biggest issue on the bull side for oil prices, with Iraq the obvious offset. Deepwater Gulf of Mexico will never resume its previous activity levels. We are confident of Iraqi growth, but history says we shouldn't be. Mexico has also surprised with lower declines and an opening to investment. Canada continues to do well. Global NGL growth is a major theme that is extremely hard to pin down – Eagle Ford liquids growth is hard to count.

Near term outlook – which side of 2mb/d growth in 2010 are you on?
Although our commodities team expects tamer demand growth of 1.5mb/d in 2011, we see major upside risk to this view, starting with cold winter globally. Recent backwardation and market tightening are bullish; the fundamental drivers of demand are there: DB expects a weak-ish US$ through mid-2011 and strong, 3.8% global real GDP growth. We look with interest to sub salt Brazil, Ghana, and Colombia supply growth, offset by North Sea and Mexico. OPEC seems to have moved its price target to $90/bbl at its most recent meeting with no supply raise.

More growth & lower returns, anyone?
We intend to write a further note examining "corporate strategy at the end of the oil age". Quite obviously, the shift is from oil age to gas age for the major oils. E&Ps are being forced to integrate downstream as a function of excess supply. With CO2 legislation the next step would be into electricity generation, but this now seems unlikely unless a major global warming crisis forces an attitude change in Washington. We are concerned on potential tax increases. The challenge for oils is that they can only generate more growth at lower returns. Interestingly, the market appears to price this negatively already for the big oils, and pay aggressively for leverage based on a bullish oil bearish natgas view. We favour restructuring plays such as ConocoPhillips (PT $66) that are shrinking and returning cash, or those that can potentially find oil such as Murphy (PT $72), with major exploration news due. We value oil stocks based on top-down P/E methodology, and bottom-up NAVs. Risks include stronger/weaker-than-expected oil prices, exploration successes/failures, & deepwater permitting delays. See p.55-56.

Industry Update

Top picks

ConocoPhillips (COP.N),USD66.63	**Buy**
Canadian Natural (CNQ.TO),CAD43.86	**Buy**

Companies featured

ExxonMobil (XOM.N),USD72.72			**Hold**
	2009A	2010E	2011E
EPS (USD)	4.01	5.90	6.25
P/E (x)	17.7	12.3	11.6
EV/EBITDA (x)	8.2	6.4	6.0
Chevron (CVX.N),USD89.23			**Hold**
	2009A	2010E	2011E
EPS (USD)	4.81	9.19	9.31
P/E (x)	14.6	9.7	9.6
EV/EBITDA (x)	5.2	4.7	4.4
ConocoPhillips (COP.N),USD66.63			**Buy**
	2009A	2010E	2011E
EPS (USD)	3.66	5.94	6.47
P/E (x)	12.4	11.2	10.3
EV/EBITDA (x)	3.1	2.7	2.9
Occidental Petroleum (OXY.N),USD96.63			**Hold**
	2009A	2010E	2011E
EPS (USD)	3.79	5.60	6.71
P/E (x)	17.8	17.3	14.4
EV/EBITDA (x)	7.0	7.1	6.0
Marathon Oil (MRO.N),USD36.19			**Hold**
	2009A	2010E	2011E
EPS (USD)	1.61	3.41	4.22
P/E (x)	18.6	10.6	8.6
EV/EBITDA (x)	4.4	3.7	3.4
Hess Corporation (HES.N),USD76.01			**Hold**
	2009A	2010E	2011E
EPS (USD)	2.56	5.03	5.49
P/E (x)	22.0	15.1	13.9
EV/EBITDA (x)	4.2	3.5	4.3
Murphy Oil (MUR.N),USD73.44			**Buy**
	2009A	2010E	2011E
EPS (USD)	3.10	4.35	5.63
P/E (x)	17.3	16.9	13.1
EV/EBITDA (x)	4.7	5.0	4.4
Canadian Natural (CNQ.TO),CAD43.86			**Buy**
	2009A	2010E	2011E
EPS (CAD)	2.32	2.47	3.06
P/E (x)	13.0	17.8	14.3
EV/EBITDA (x)	6.1	7.6	6.4
Suncor Energy (SU.TO),CAD37.52			**Hold**
	2009A	2010E	2011E
EPS (CAD)	0.70	1.61	2.30
P/E (x)	47.7	23.3	16.3
EV/EBITDA (x)	19.5	8.9	7.6

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Table of Contents

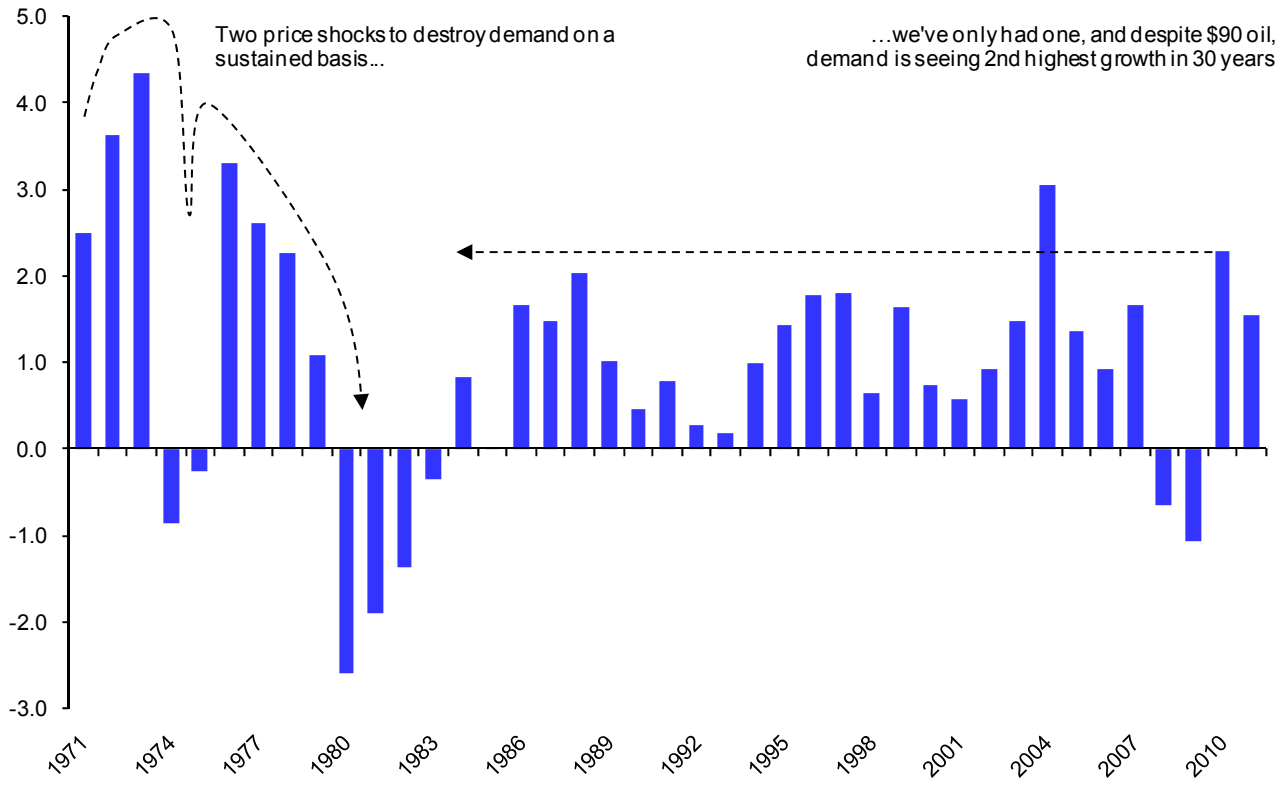
2011 Outlook

What 2010 says about 2011

This year, with a strong finish in Q4, has emerged as quite remarkable for demand growth. In simple absolute terms, absolute incremental demand at around 2.2mb/d of growth is the second highest in 30 years, despite oil prices in the $90/bbl region.

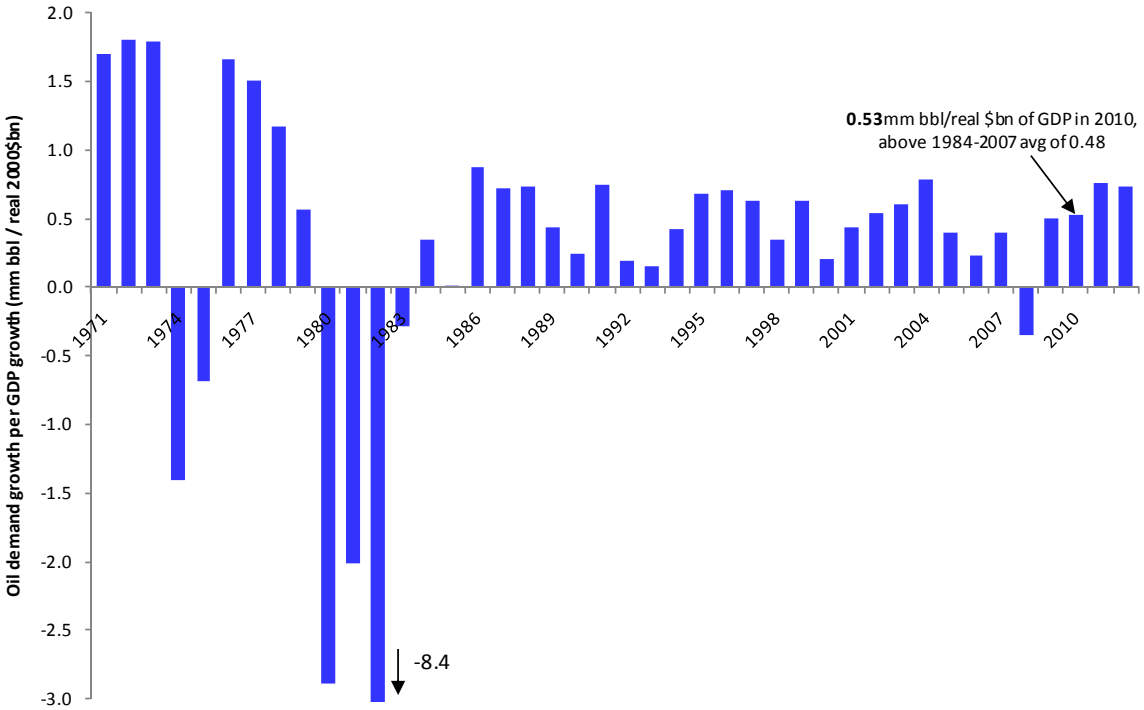
We note a similarity in this price cycle with the 1970s, when it took two major price spikes to truly change demand behaviour. Our view is that unless oil supply growth can markedly improve, then we will have to have a second high price excursion to truly shift behaviour. This could quite possibly come from pressure on global GDP growth if sufficient efficiency gains cannot be made.

Figure 1: Incremental Oil Demand (mb/d) in 2010 is second highest in 30 years



Source: Deutsche Bank, IEA

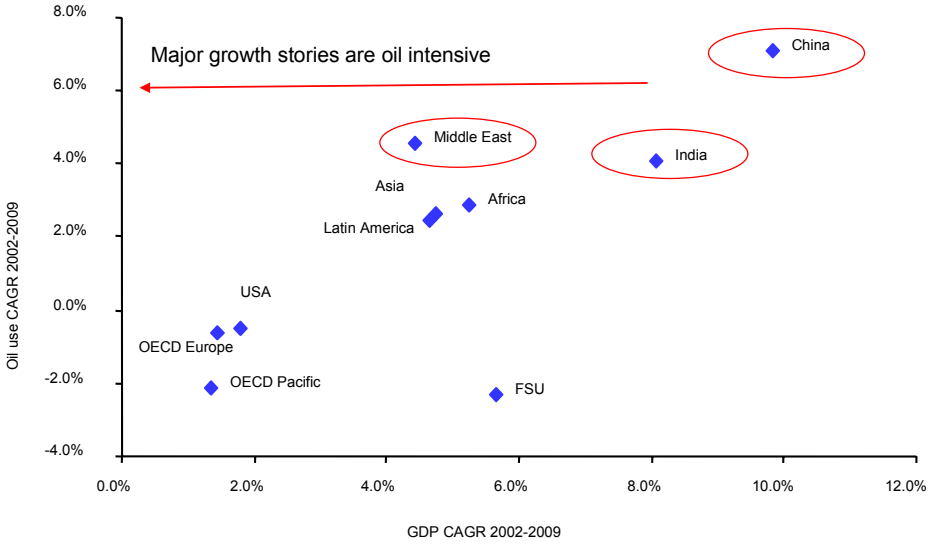
Figure 2: Oil intensity of GDP growth – 2010e above 24-year average, and not falling



Source: Deutsche Bank, World Bank

Notwithstanding a strong 4.6% real GDP growth expected for 2010, partially helped by a low base, oil intensity of GDP growth (0.53mm bbl/real $bn) will likely exceed the 1984-2007 average (0.48mm bbl/real $bn). Major GDP growth drivers all have high oil intensity of growth. We think risks are to the upside in global oil demand in 2011 as GDP will likely continue accelerating into 2011. Particularly, the potential for stronger US demand, combined with a cold start to the year globally, would imply upside pressure to demand forecasts.

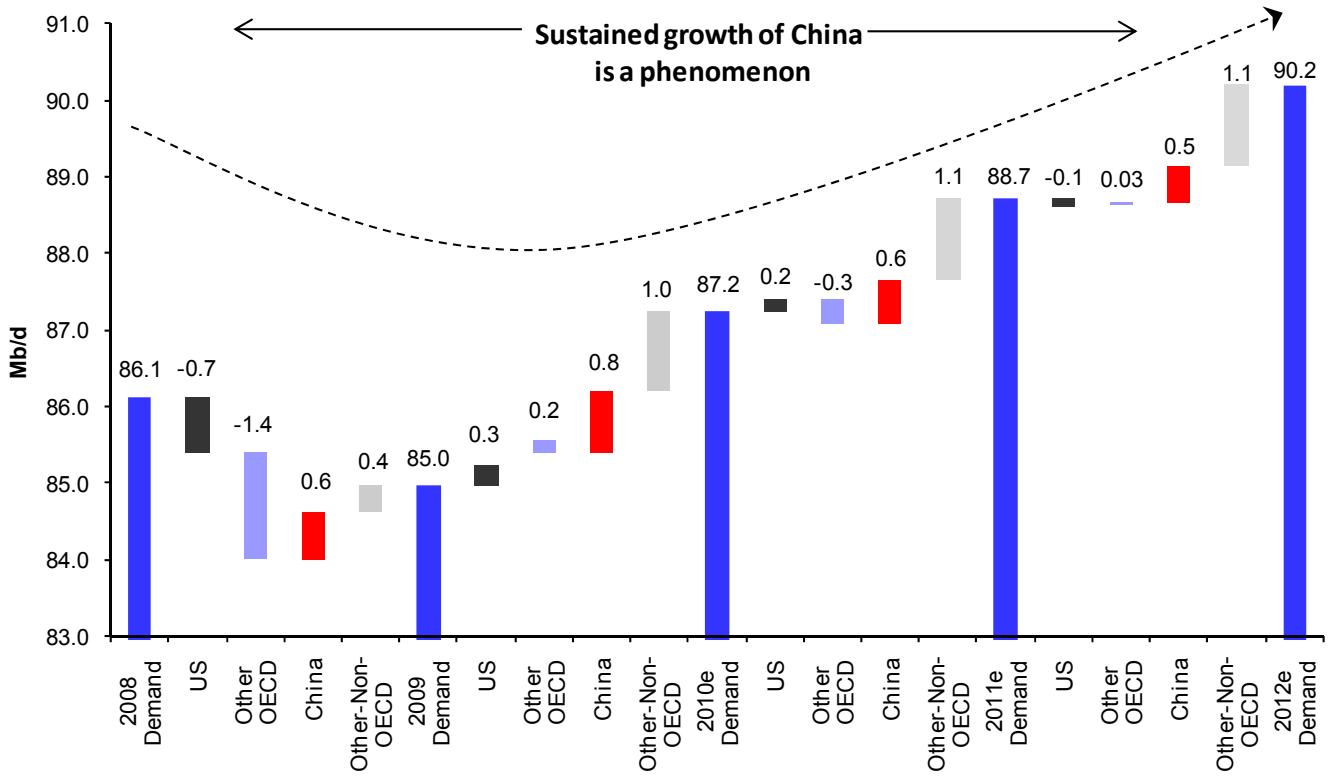
Figure 3: GDP vs Oil Demand – China, Middle East, India, Asia GDP all oil-intensive



Source: Deutsche Bank, World Bank

DB's existing demand forecast is muted for 2011 by very slight US demand growth and a fall back in other OECD demand (OECD ex US, Japan and OECD Europe). We would certainly argue there is upside to US demand forecasts. Equally a re-reversal of other OECD demand into decline after growth in 2010 seems relatively negative in a strengthening economic outlook. Again, this would argue that our current 1.5 mb/d global demand growth forecast is under upside, not downside, pressure.

Figure 4: Global Oil Demand Dynamics 2008-2012



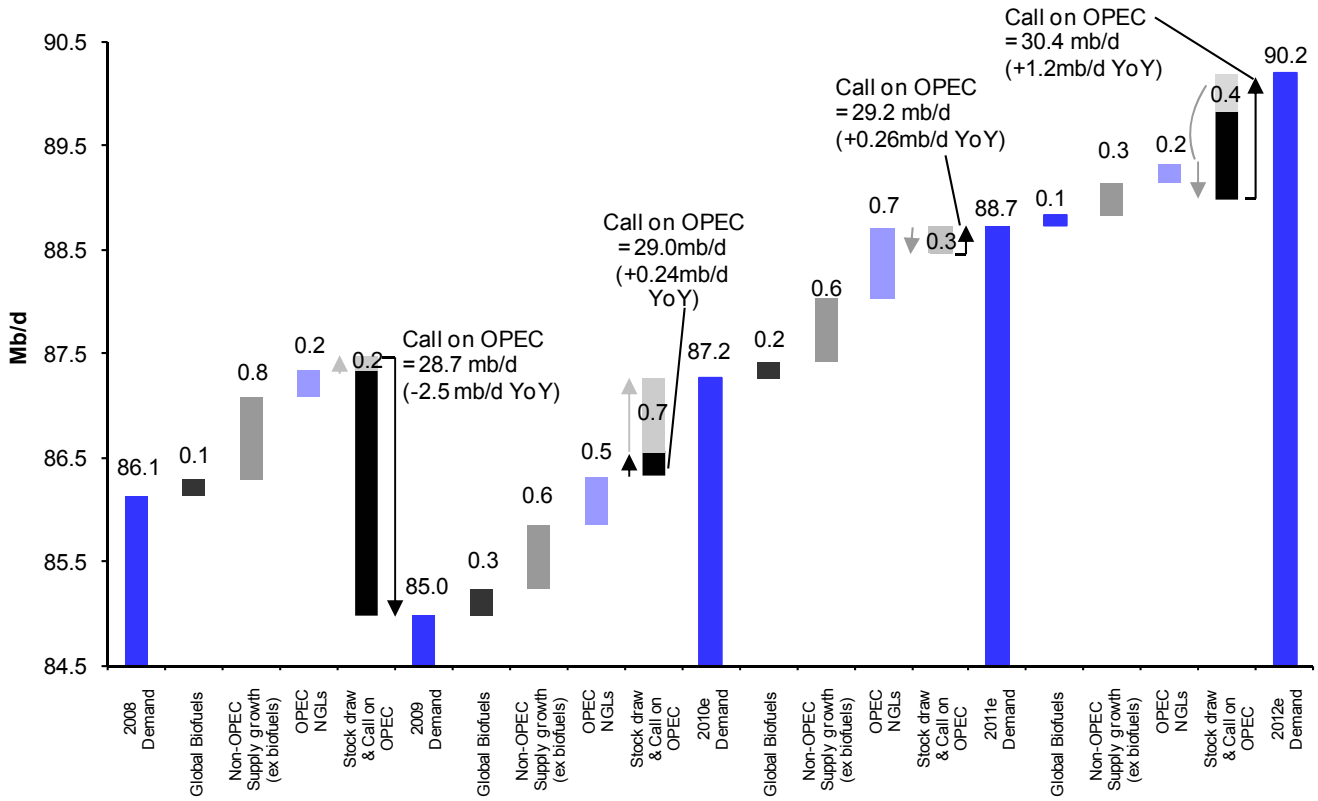
Source: Deutsche Bank, IEA

Non-OPEC is surprising to the upside, but call on OPEC rises

Illustrating the lack of price elasticity in oil supply, Non-OPEC supply had another relatively good year, certainly compared to expectations, in 2010. We had expected growth from Russia, unlike many others. Also confounding the doomsayers on supply, Mexico's declines were not as severe as many expected. US supply surprised to the upside, and Kazakhstan, Canada and Brazil sustained growth.

In 2011 Ghana will join these non-OPEC growth drivers, alongside the re-juvenated US. However we are concerned that there is little urgency in the White House to accelerate activity in the Gulf of Mexico deepwater. As our recent Washington DC trip made it clear to us, there will be a "permitorium" in the GoM for at least another year, maybe two, especially under the new Director of BOEM (Bureau of Ocean Energy Management, Regulation and Enforcement, formerly the MMS), Michael Bromwich, who will grade himself on the rigor of oversight, the absence of accidents or incidents of BOEM misbehavior, and the restoration of public confidence in the Gulf drilling regulatory system. Thus declines in the GoM will be accelerating throughout the year, to join usual decline suspects Mexico, UK and Norway. Even with relatively good Non-OPEC performance, of around 800kb/ d including biofuels, the implied call on OPEC still rises even in a 1.5mb/d demand growth model.

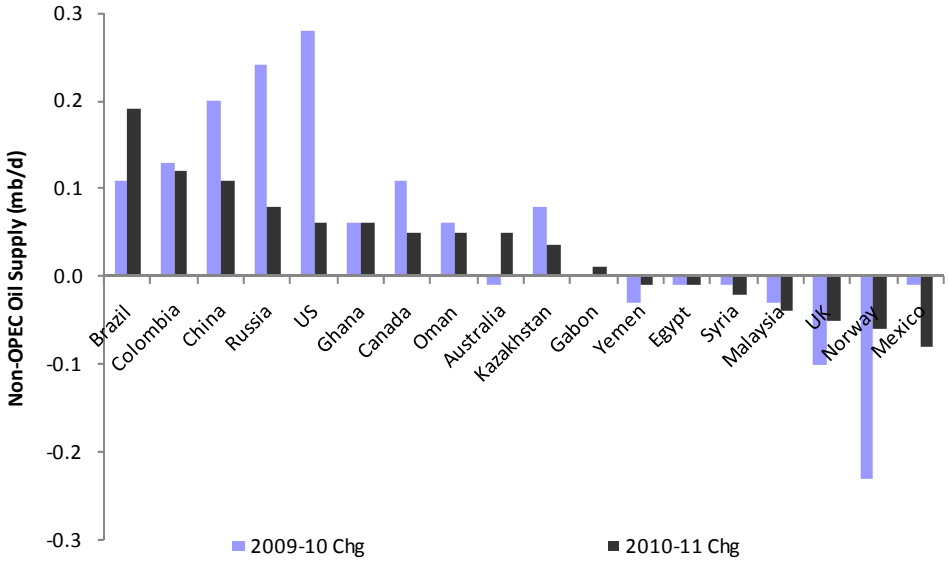
Figure 5: Global Oil Supply Dynamics 2008-2012



Source: Deutsche Bank, IEA

There are some interesting Non-OPEC developments in 2011, notably the ramp up of Brazil's first sub-salt production at Tupi and Jubilee in Ghana, both of which have recently started up. In Canada, Shell's Athabasca Oil sands project and Suncor's Firebag both offset East Coast declines. The US is essentially a battle between the decline in the deepwater Gulf of Mexico and other conventional, and the rise of the Bakken.

Figure 6: Non OPEC supply can't keep up – but declines are slowing?



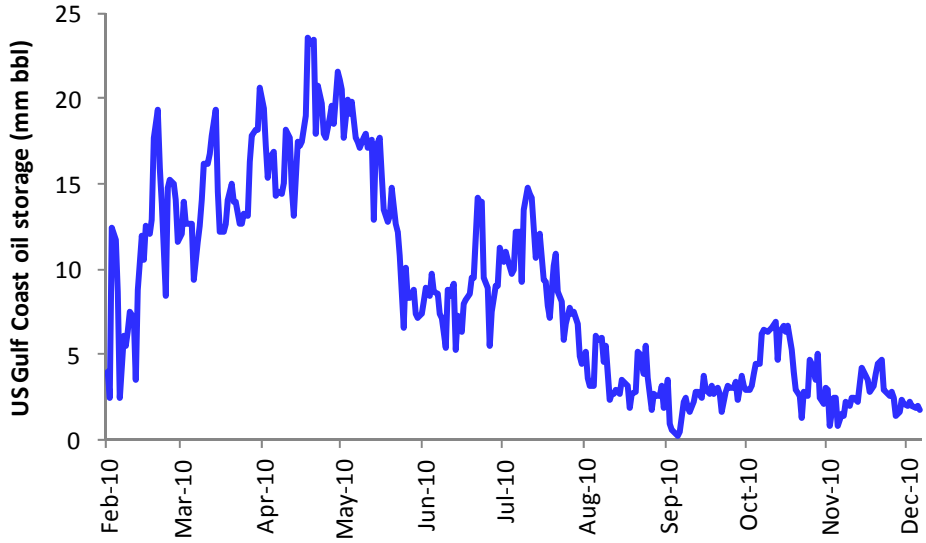
Source: Deutsche Bank, IEA

It is worth noting that in our "Diamond Age of Refining" bull case for medium term US refining, we highlight the potential for lower ethanol blending in the US gasoline pool in 2011 as blending economics are negatively affect by high corn prices and a lower blending subsidy. Indeed, numerous people on our recent Washington DC trip felt there was a strong possibility that the next ethanol tax credit extension (passed on December 17; the current one expires December 31) might be the last (or possibly a second year through 2012). Ethanol's base of support has been eroding over the last few years, and notably, former Vice President Al Gore now admits his tie-breaking Senate vote to support ethanol subsidies in 1994 had been politically motivated. The potential for lower ethanol blending in the US could knock back biofuels growth in 2011.

What happens next?

We have argued there would be three phases to the tightening of the oil market globally post-financial crisis. First we would see the reduction in stocks of oil at sea. In the US Gulf Coast, floating storage has been significantly drawn down from a high of 23.6mm bbl in May to below 2mm bbl.

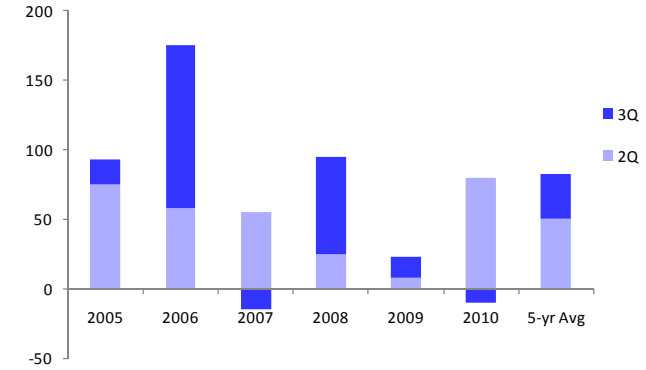
Figure 7: US Gulf Coast floating storage



Source: Bloomberg Finance LP, Deutsche Bank

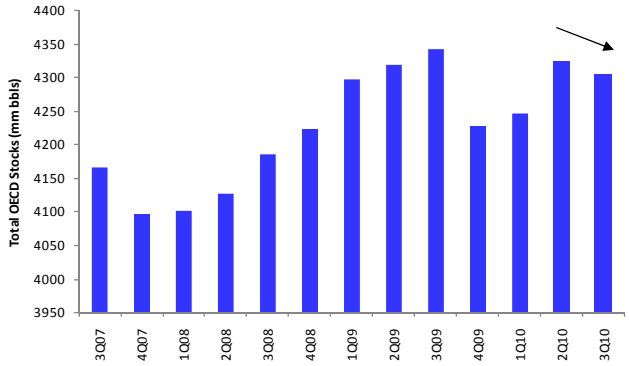
Second, we expect to see a continued drawdown of stocks on land. OECD stocks fell counter-seasonally in 3Q10 and the recent backwardation suggests that the drawdown will continue into 4Q.

Figure 8: OECD stocks fell counter-seasonally in 3Q10



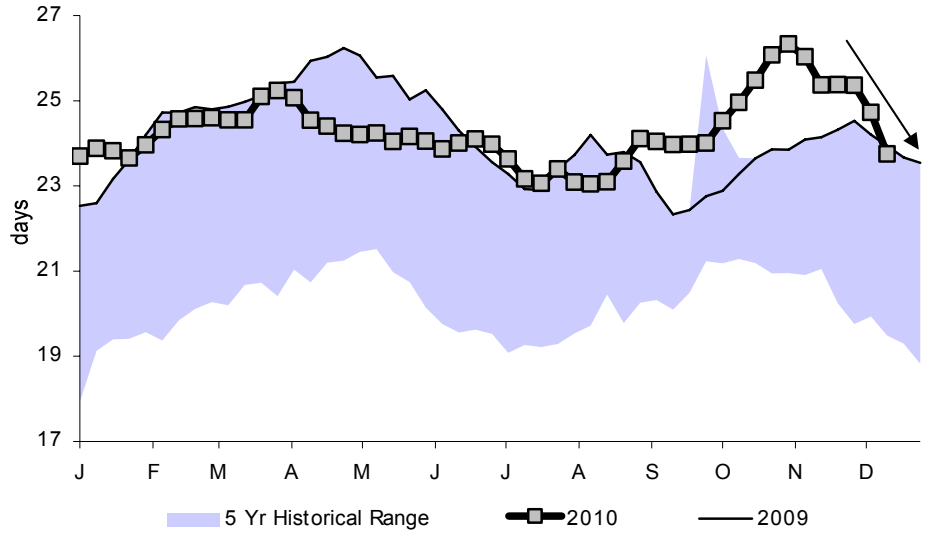
Source: IEA, Deutsche Bank

Figure 9: OECD stocks trend



Source: IEA, Deutsche Bank

Figure 10: US inventories fall from record highs – and cold weather hits with winter



Source: Deutsche Bank, EIA

Finally we would work through OPEC spare capacity. That spare capacity, at face value, has looked generous, with most observers working on an assumption of around 5mb/d of spare capacity in a market that was thought to be growing at around 1.5mb/d. However the strength of global demand at over 2mb/d growth, combined with a globally cold start to winter, has caused the market to question how much spare capacity OPEC really has. Based on previously sustained maximum levels, it could be argued that OPEC spare capacity is closer to 4mb/d. If that number is combined with demand closer to 2.5mb/d growth in 2011, then we are within two years of running out of spare capacity cover, at which point the market prices to the point of demand destruction. Given inelasticity of Middle East and China demand, and high taxes and efficiency in Europe, we believe that demand has to be broken the US. We analyse that point at the end of this note.

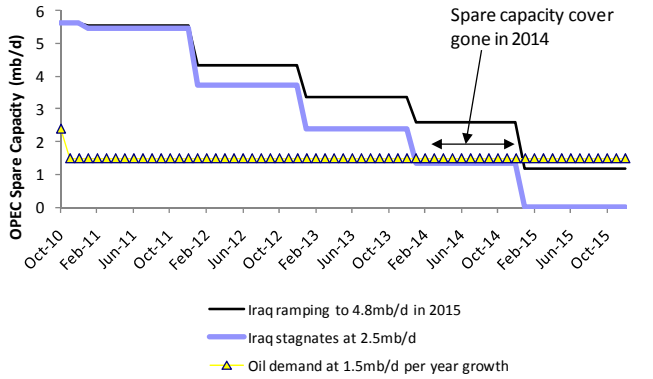
Figure 11: And the market questions the reality of OPEC spare capacity

OPEC Member	Bloomberg Reported Capacity kb/d	Capacity based on actual production performance	Comment
Algeria	1400	1400	Showed sustained production at this level in 2008
Angola	2050	1900	Showed sustained production at this level in 2008
Ecuador	500	400	Showed sustained production at this level in 2008
Iran	4000	3900	Has only exceeded 3900 on a spike basis in last decade
Iraq	2500	2400	Assumes that with no quota Iraq has been producing at max
Kuwait	2650	2650	Ramped to and sustained 2600 in 2008
Libya	1785	1750	Ramped to 1785 in 2008 for around two months
Nigeria	2500	2100	Wildly over-produces vs 1700 OPEC target = @ max capacity
Qatar	900	900	Sustained over 850 in 2008
Saudi	11500	11000	Maximum 9500 sustained output in 2008; then had declared spare capacity of 1500 (heavy)
UAE	2650	2650	Sustained over 2650 for three months in 2008
Venezuela	2400	2200	Production has steadily declined to this level
Total Capacity	34835	33250	
Call on OPEC 2011	29200	29200	
Spare Capacity	**5635**	**4050**	
Spare capacity cover (demand+ /spare)	**3.76**	**2.70**	At 1.5mb/d there is spare capacity cover for nearly 3 years, giving Iraq time to ramp
Spare Capacity at 2.5 mbd growth '11	4635	3050	
Spare capacity cover	1.85	1.22	But at 2.5mb/d of demand growth, we will be spiralling by 2012

Source: Bloomberg Finance LP, Deutsche Bank

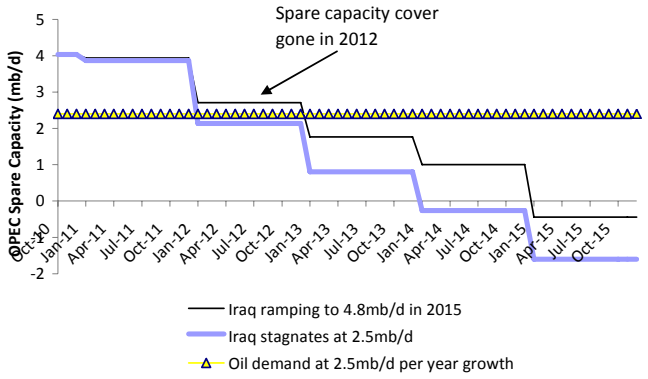
The difference in picture is illustrated below. Rather than over 5mb/d spare, based on actual production performance, we see current spare capacity at 4.1mb/d (vs Bloomberg's estimated 5.6mb/d) and then 3.1mb/d in 2011. Assuming 2.5mb/d global supply growth, we will be spiralling by 2012.

Figure 12: Spare capacity based on Bloomberg + 1.5mb/d demand growth



Source: Deutsche Bank, Bloomberg Finance LP

Figure 13: Spare capacity based on production performance + 2.5mb/d demand growth



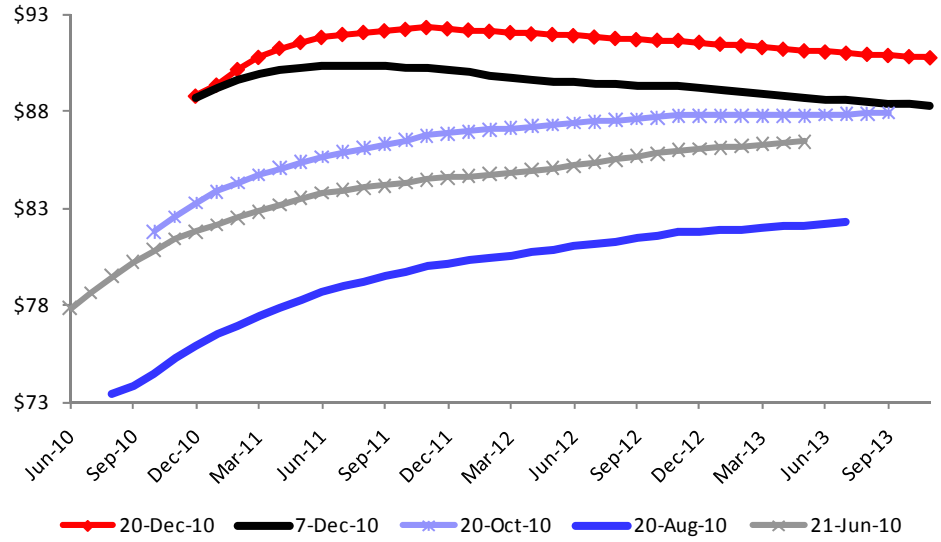
Source: Deutsche Bank, Bloomberg Finance LP

Technical points of interest: forward curves and the US$

Much interest was generated by the move, in early December, to backwardated markets after several years of contango – in fact it is only in mid-2008 was the market last backwardated. That has typically been a bullish indicator, with the market typically rising in the backwardation phase more often than in contango, given contango indicates near term weakness vs longer term perception of strength.

However there was a trade occurring that we believed was not related to a market view of future weakness relative to current markets, but was rather natgas producers selling liquids upside in order to lock in higher natgas prices – the "Robin Hood" trade.

Figure 14: And the market goes to backwardation – generally a bullish indicator



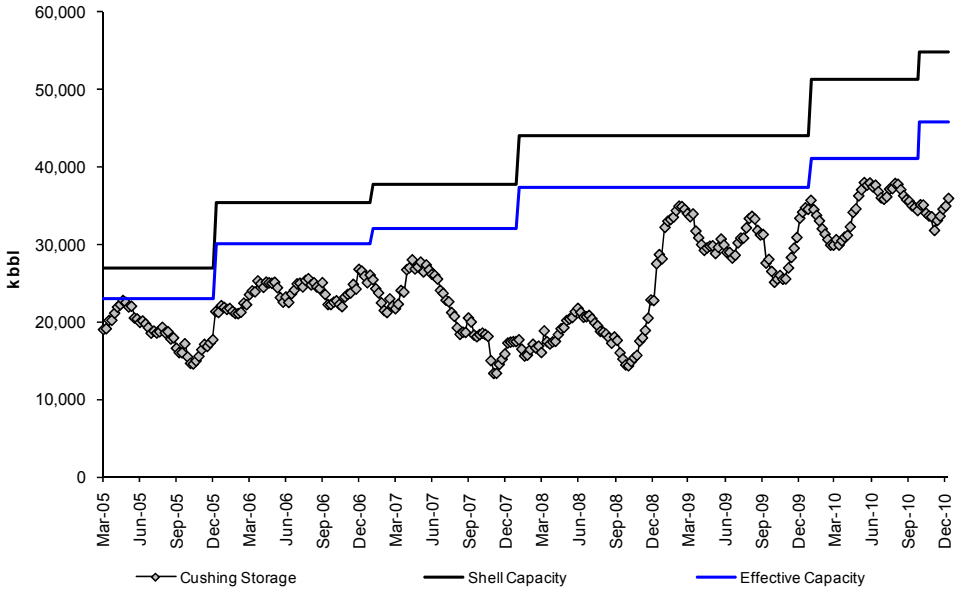
Source: Deutsche Bank

We also find it interesting that a backwardated curve is backwardated in nominal terms, and would imply future deflation, especially given the cost of holding inventory would tend to provide support for higher prices in the future.

What is clear to us, is that the backwardation implies a tight current market for oil, and that it occurred right at the time of the OPEC meeting on December 11th. At the time, Saudi oil minister Ali al-Naimi stated that there was "absolutely" no need to increase production as markets were comfortable. We took that to be an implicit raising of the OPEC target band towards $90/bbl, up from $75/bbl stated target as recently as early 2010.

On the bear side, the flattening of the curve would potentially imply more inventory draw down, adding to supply and reducing demand (for building inventory). However our counter argument is that 1) inventory levels are structurally low for oil, relative to its economic importance, with just 60 days of forward demand cover in the OECD, hardly representing a major supply cushion especially as 2) the market is increasingly concerned over the concentration of global oil reserves into non-OECD government hands, and would naturally consider total oil inventory to include reserves in the ground. As the market frets about the true availability of oil in case of trouble, so it will build inventory on a sustained basis. For example, China can be expected to continue building and holding inventory on a sustained basis, adding to their demand for oil. Capacity and levels held at Cushing continue to make record highs, and we expect this to continue until global demand starts to fall. On our numbers, that does not occur until 2020, post another major oil price spike.

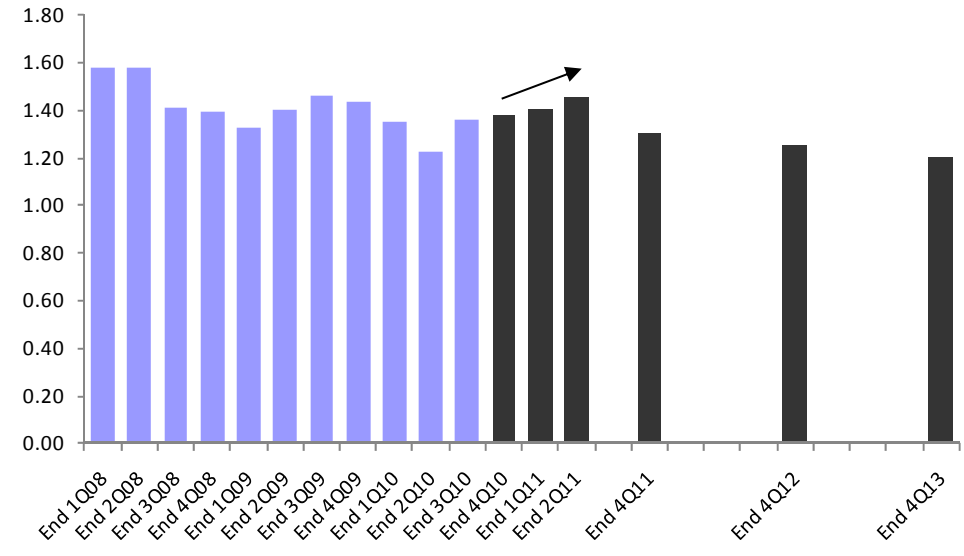
Figure 15: Inventories at Cushing keep rising



Source: Deutsche Bank, EIA

Our long term view remains that the US$ remains an important driver of crude prices. We rationalised this at the start of 2010 in our US$ vs oil note, that argued that as 90% of world oil trade remains US$ denominated, compared to less than 20% of actual US share of world oil markets, that changes in the value of the US$, even when for totally non-oil related reasons such as a European debt crisis, could lead the price of oil, for sustained periods. That will only change if OPEC, led by Saudi, abandons the US$ for pricing. There is no evidence that is about to occur. That said, we are not forecasting a dramatic change in the global "ugly contest" among major currencies. In the short term, the market may benefit from the weak dollar (1.40 by end 1Q11, 1.45 by end 2Q11), but DB expects the dollar to strengthen into the end of 2011 and beyond.

Figure 16: DB expects a weakening USD into mid-2011



Source: Deutsche Bank, Bloomberg Finance LP (historicals)

Figure 17: Oil Supply/Demand Balance

	2008	2009	2010E	2011E	2012E	2013E	2014E	2015E	Annual Avg Rate % 00>05	05>10	10>15
CONSUMPTION											
United States	19.5	18.8	19.0	19.2	19.1	19.0	18.9	18.8	1.1	-1.8	-0.2
OECD Europe	15.4	14.5	14.4	14.2	14.2	14.1	14.1	14.0	0.6	-1.7	-0.5
Japan	4.8	4.4	4.4	4.3	4.2	4.1	4.1	4.1	-1.0	-3.6	-1.8
Other OECD	7.9	7.8	8.1	8.1	8.2	8.3	8.3	8.4	1.5	-0.1	0.9
Total OECD	**47.6**	**45.5**	**45.9**	**45.7**	**45.6**	**45.5**	**45.4**	**45.3**	**0.8**	**-1.7**	**-0.2**
USSR (former)	**4.2**	**4.0**	**4.2**	**4.4**	**4.4**	**4.5**	**4.6**	**4.7**	**1.2**	**1.8**	**2.1**
Non-OECD Europe	0.8	0.7	0.7	0.7	0.7	0.8	0.8	0.8	2.9	-0.6	2.1
China	7.7	8.4	9.2	9.7	10.2	10.7	11.3	11.8	8.0	6.5	5.2
Other Asia	9.6	10.0	10.3	10.6	10.9	11.3	11.7	12.1	3.3	3.3	3.4
Latin America	6.0	6.0	6.3	6.4	6.7	6.9	7.1	7.3	1.1	4.1	3.3
Middle East	7.0	7.2	7.5	7.9	8.1	8.3	8.5	8.7	3.4	4.6	3.0
Africa	3.2	3.2	3.2	3.3	3.4	3.5	3.6	3.7	3.5	1.7	2.7
Other Non-OECD	**34.3**	**35.5**	**37.1**	**38.7**	**40.1**	**41.5**	**42.9**	**44.4**	**3.9**	**4.2**	**3.7**
TOTAL CONSUMPTION	**86.1**	**85.0**	**87.2**	**88.7**	**90.2**	**91.6**	**93.0**	**94.5**	**1.8**	**0.8**	**1.6**
SUPPLY											
United States	6.9	7.4	7.7	7.8	7.9	8.0	8.0	8.0	-2.5	1.8	0.8
OECD Europe	4.8	4.5	4.2	4.0	3.8	3.6	3.5	3.3	-3.6	-6.0	-4.5
Other OECD	7.1	6.8	6.9	6.9	6.9	7.0	7.3	7.7	1.0	-1.4	2.1
Total OECD	**18.7**	**18.8**	**18.8**	**18.7**	**18.7**	**18.6**	**18.8**	**19.0**	**-1.6**	**-1.4**	**0.2**
USSR (former)	**12.8**	**13.3**	**13.6**	**13.8**	**14.1**	**14.1**	**14.0**	**14.0**	**8.3**	**2.9**	**0.6**
Non-OECD Europe	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	-2.3	-7.5	4.9
China	3.8	3.9	4.1	4.2	4.2	4.2	4.2	4.2	2.2	2.6	0.4
Other Asia	3.7	3.6	3.6	3.6	3.5	3.3	3.2	3.1	9.7	-0.1	-3.2
Latin America	3.7	3.9	4.1	4.4	4.6	4.7	4.9	4.8	2.6	1.5	3.4
Middle East	1.6	1.7	1.7	1.7	1.7	1.6	1.5	1.4	-3.3	-1.6	-3.3
Africa	2.7	2.6	2.6	2.6	2.6	2.4	2.4	2.4	4.2	0.5	-1.5
Other Non-OECD	**15.5**	**15.8**	**16.2**	**16.6**	**16.7**	**16.4**	**16.4**	**16.0**	**3.2**	**0.8**	**-0.2**
Processing Gains	2.2	2.3	2.2	2.2	2.3	2.3	2.3	2.4	1.3	2.3	1.5
Global Biofuels	1.4	1.6	1.8	2.0	2.1	2.2	2.3	2.4	na	23.9	5.8
Total Non-OPEC	**50.8**	**51.7**	**52.6**	**53.4**	**53.8**	**53.7**	**53.8**	**53.8**	**2.2**	**1.0**	**0.5**
OECD Stock Withdraw	-0.4	0.1	-0.2	0.4	0.0	0.0	0.0	0.0			
OPEC NGLs	4.4	4.6	5.1	5.8	6.0	6.2	6.3	6.5	**7.0**	**4.2**	**5.0**
Other and Balance	0.2	-0.2	0.8	0.0	0.0	0.0	0.0	0.0			
OPEC CRUDE OIL	**31.2**	**28.7**	**29.0**	**29.2**	**30.4**	**31.7**	**32.8**	**34.1**	**1.0**	**-1.1**	**3.4**
Memo Items:											
FSU exports	8.6	9.3	9.3	9.4	9.7	9.6	9.4	9.3			
US imports	12.4	11.1	11.1	11.2	10.9	10.8	10.7	10.6			
Europe imports	10.6	10.0	10.2	10.2	10.4	10.5	10.6	10.7			
China imports	3.9	4.5	5.1	5.5	6.0	6.5	7.1	7.7			
Demand Outside FSU	**81.9**	**81.0**	**83.0**	**84.4**	**85.7**	**87.0**	**88.4**	**89.8**	**1.9**	**0.7**	**1.6**
Y/Y % Change	-0.8	-1.1	2.5	1.6	1.6	1.5	1.5	1.6			
Non-OPEC Sup. Ex-FSU	**37.9**	**38.4**	**39.0**	**39.6**	**39.7**	**39.5**	**39.8**	**39.8**	**0.7**	**0.4**	**0.4**
Y/Y % Change	-0.3	1.3	1.5	1.4	0.3	-0.4	0.6	0.1			
Brent (1st Month) $/bbl	98.52	62.67	79.70	87.50	90.00	93.00	96.00	100.00			
WTI (1st Month) $/bbl	99.65	62.09	79.15	87.50	90.00	93.00	96.00	100.00			
US Imported (RAC) $/bbl	92.78	59.17	76.20	84.00	86.50	89.50	92.50	96.50			

US oil growth could be even lower as efficiency programs take hold

Mexico and Korea growing above OECD avg

China's growth slower in 2010-15 but is still the fastest global rate

Loss of tax preferences could reduce this estimate

Could be worse than this

Negative impact of investment slowdown

Overall non-OECD growth situation deteriorates after 2010

Non-OPEC production expected to go flat during 2011-15

Call on OPEC production grows modestly after 2010, but the pace quickens each year

This gap suggest increasing reliance on OPEC post 2010

Source: Deutsche Bank, IEA

Long term Demand

Transportation update

It has been an eventful year in the global transportation sector, and we have adjusted our model accordingly. Taken together, the developments suggest somewhat slower electrification trends than we expected a year ago and greater near-term gasoline demand, but also increased confidence in the pace and breadth of the long-term shift to a more efficient transportation system. Some of the key developments:

POSITIVE FOR GASOLINE DEMAND:

- **Stunningly strong Chinese car growth in 2010**, particularly in the first half of the year, with vehicle sales up 30% YoY through the first eleven months of 2010. In our Fall 2009 note, we had expected 12%. By mid-2Q, we had increased our estimate to 25%.
- **Slower than expected sales of hybrids** everywhere in the world but Japan in 2010. In the US hybrids fell from about 3% of total sales in 2008-09 to 2.2% in 2010. Less concern about gasoline prices, and therefore fuel efficiency, as well as fewer government subsidies for hybrids, were the likely causes.
- **Increasing political animus towards the ethanol tax credit**, which was bedrudgingly renewed for one year in the lame-duck tax bill. It now appears that corn-based ethanol is losing political support outside the corn states, and this may be the last extension for the credit. A CARB LCFS determination did lower the footprint for ethanol however.

NEGATIVE FOR GASOLINE DEMAND:

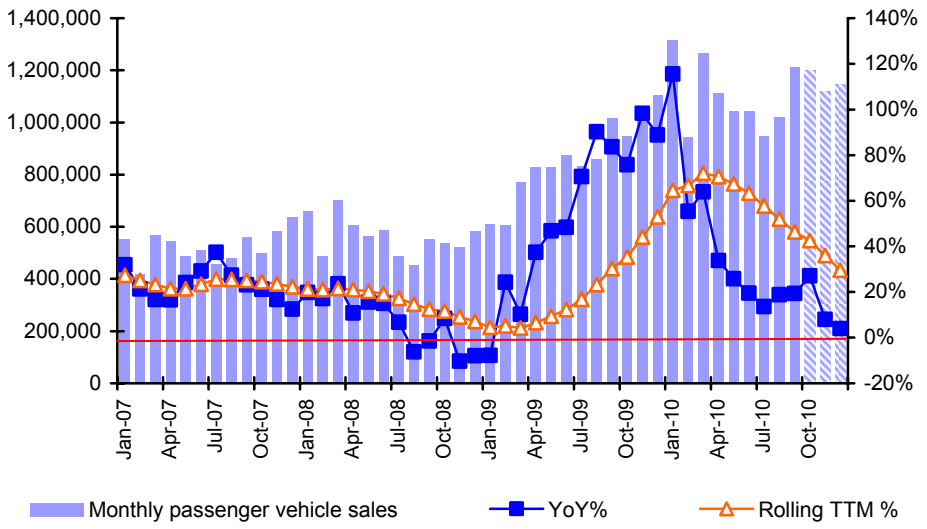
- **Rapidly falling lithium-ion battery prices**, and steepening expected cost reduction curves for both batteries and electric drive components.
- **Strong indications of commitment by the Chinese** government to support the rapid development of both domestic demand for electric vehicles and a competitive domestic electric vehicle industry.
- **New US fuel efficiency/emissions standards** which will not be achievable without significant penetration of electric vehicles.
- **Fuel standards in Europe, Japan and Canada** that will require widespread adoption of electrics. There is pressure to make European standards even more aggressive.
- **More governmental consumer incentives** (rebates or tax credits) to encourage the purchase of new electrics and plug-in electrics
- **An explosion of hybrid sales in Japan**. The Toyota Prius became the biggest selling car in Japan in 2009, and has remained in that position throughout 2010. Several other hybrid models also made the leaderboard. Hybrids went from about 8% of sales in 2009 to over 11% in 2010. Honda believes that hybrids will account for 23% of the market by the end of 2011.
- **Strong pre-sales of electrics in the US** by commercial enterprises. In November General Electric put in a pre-order for 12,000 GM electric cars, and said it planned to buy 25,000 EVs from all manufacturers by 2015 for its corporate fleet. At the consumer level, dealers have put in more 2011 orders than can be produced for both GM's Chevrolet Volt and Nissan's Leaf. Volt manufacturing capacity will rise from 10K in 2011 to about 65K in 2012. Nissan is building a 150K capacity plant in Tennessee for the Leaf which will come on line in 2012.

- **New business models**, combined with government incentives and subsidies, that dramatically lower the entry price for consumers.
- **A growing number of xEV options** around the world. The DB auto team counts at least 130 models in the global pipeline for 2012.
- **Aggressive near-term OEM lease pricing** – Leaf for $349/month, all-in costs only $30-40/month more than a Sentra.
- Increasingly apparent that **micro-hybridization** will be a major part of increasing efficiency, with a majority of ICE's will actually be micro-hybrids by 2020

China – Surge in car sales

Chinese car sales in 2010, +40% YoY YTD, have been extraordinary, even on the back of ~50% YoY growth in 2009. The DB China auto team expects slower growth in November and December to moderate full year 2010 growth to about 25-30%, still a remarkable trend in light of reduced incentives YoY.

Figure 18: Monthly passenger auto sales in China



Source: CAAM, Deutsche Bank estimates

Interestingly, there has been no corresponding spike to gasoline demand (up just low-to-mid single digits in 2010, despite ~20% growth in the number of cars on the road), suggesting that many of the auto purchases in 2009 and 2010 were made simply to capture government tax benefits, which many people believe may roll off in 2011. Transportation behavior appears to have changed much less, with new vehicles remaining in the driveway while middle class car-owners continue to bike/bus to work.

Nonetheless, Deutsche Bank's China Auto analyst, Vincent Ha, continues to see robust light vehicle sales over the next few years, with a slow to about 11% YoY growth in 2011 (due to a high base from the 2010 surge, and reductions in government stimulus), followed by sustainable low double digit growth in 2012. He also believes that sub-1.6L passenger cars will outgrow larger vehicles due to favorable policies.

China's commitment to high efficiency vehicles

Early consumer adoption of "new energy" vehicles has been negligible, and it is not yet clear that the current government incentives (~$8,800/vehicle) are enough to drive a lot of sales, though a recent Ernst & Young survey did find that 60% of potential Chinese car buyers show a strong interest in purchasing an EV (a higher number than in the US, Europe or Japan).

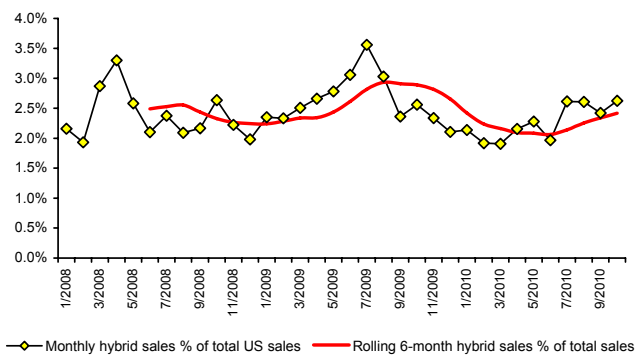
In a 6 May note on gasoline demand in China, we highlighted that the most important question regarding China's widespread adoption of HEV/EV's, in some ways the only important question, is the degree of commitment the Chinese government has to the electric vehicle market. We think there is ample evidence that the government at the highest levels is committed to the electrification of the road transportation fleet:

- Electric vehicles are classified as a "strategic industry" under the twelfth Five-Year Plan (2011-15), and parts manufacturers will receive tax breaks and subsidies. The government has pledged that it will do whatever is necessary to push the Chinese auto industry into the lead on electric vehicles over the next decade.
- Premier Wen Jiabao's choice three years ago for Minister of Science and Technology, Wan Gang, was the first minister in at least three decades who is not a member of the Communist Party, but he is a former Audi auto engineer and ex-chief scientist for the Chinese' government's research panel on electric cars.
- Senior Chinese officials, including Wan Gang, have outlined China's aim to be the world's largest producer of electric cars within three years, with a near-term goal of producing 500K units in 2011.
- The central government has already pledged about $17B to push the electric vehicle effort, including about $2B for R&D and an $8,800/car subsidy in 26 cities (announced in June). Provincial governments have been encouraged to contribute on top of that.
- The state-owned utilities have been tasked with building out the smart grid and charging infrastructure required for a rapid ramp up in electrics. According to the State Grid Corporation (SGC), which provides about 85% of the country's power, 75 electric charging stations are planned for 27 cities by the end of 2010. The pace will accelerate next year.

A lag in US hybrid sales

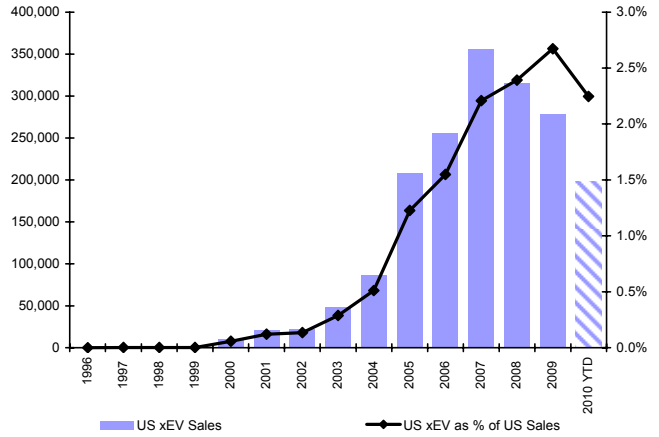
After more than a decade of rising US market share since the launch of the first commercial hybrid in 2007, xEV sales slipped as a percentage of total vehicle sales for the first time in 2010 (at least YTD). In all likelihood the biggest driver was a moderate at-the-pump gasoline price and a fading memory of the 2006-08 oil price ramp, though we believe that many potential hybrid purchasers have also waited on the sideline until the coming wave of plug-in hybrid and full electrics come to market in 2011 and beyond. As we've said before, it may take another $140/bbl+ oil price surge to truly and finally change US transportation behavior and policy.

Figure 19: Monthly US hybrid sales



Source: Ward's Automotive, Deutsche Bank

Figure 20: Annual US hybrid sales trend



Source: Ward's Automotive, Deutsche Bank

Japan – hybrids go mainstream

While hybrid sales in Europe and the US lagged in 2010, hybrids have entered the mainstream in Japan, where they will account for about 12% of light vehicle sales for the year. The Toyota Prius will be the top-selling car in Japan for the second year running, and Honda is now pushing hard to catch up with its domestic rival, introducing a hybrid version of its popular Fit compact last month, a wagon version of the Fit Hybrid in March 2011, and a hybrid version of the Freed small minivan later in the year. Honda expects hybrids to capture 23% of the Japanese market by the end of 2011.

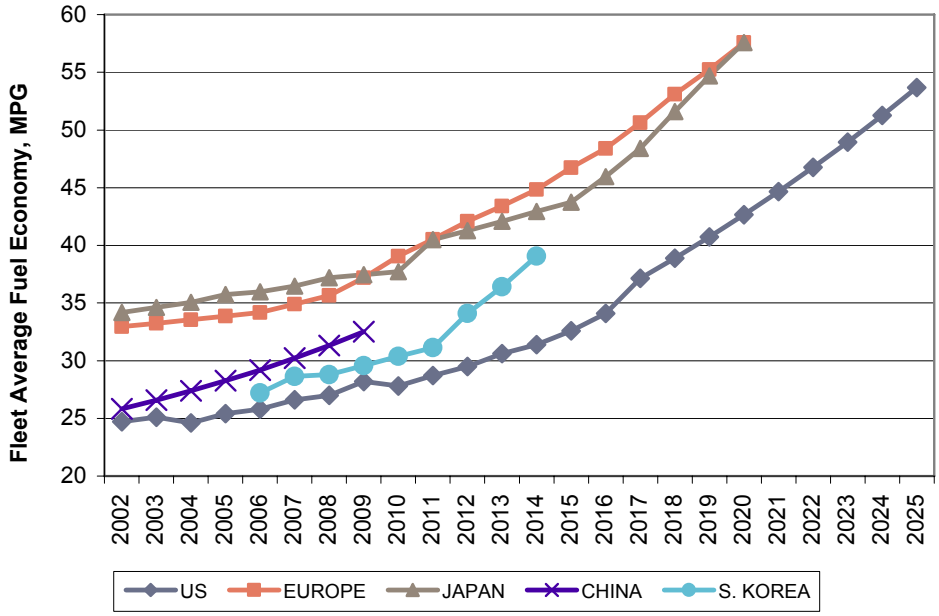
Regulatory standards are tightening everywhere

Though average fuel economy for combustion vehicles in the US has improved very slowly in the US since the 1970's, the pace of mandated improvement will accelerate sharply going forward. Current US CAFE standards require average MPG for new vehicles to improve from the current ~25mpg to over 34mpg by 2016.

In early October, the US EPA and NHTSA issued a "notice of intent" that starts the process of setting the vehicle emissions standards for the 2017-2025 period. We expect a final proposal by September, 2011, and a final rule by July, 2012. The proposed standards would mandate an emissions improvement of somewhere between 3% and 6% per annum starting in 2016, which would mean, on a fuel efficiency equivalent basis, average new vehicle mileage of 47 mpg to 62 mpg by 2025 (we currently model 52 mpg for the US in 2025).

Given that the EPA has signaled that it wants to align with California's carbon emission targets (40-50% reduction from 2016 levels by 2025), we would expect a regulation towards the high-end of the 3% to 6% range.

Figure 21: Avg. new car fuel economy (past) & standards (future) in major markets



Source: International Council on Clean Transportation, NHTSA, EPA, ACEA, Deutsche Bank

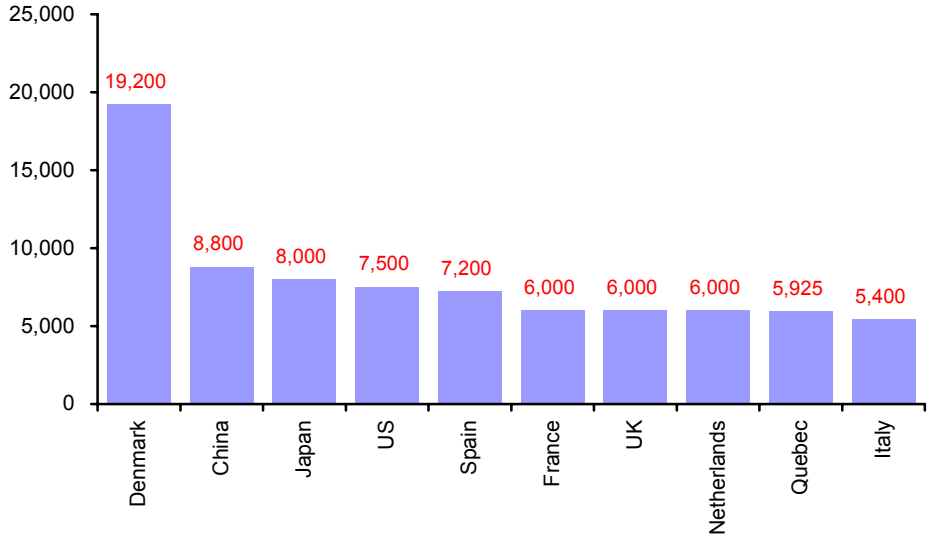
The DB Auto team expects that regulations in this range will require a substantial penetration of electrified vehicles. The EPA estimates that under the 6% per year scenario, hybrids would account for 43% to 68% of US sales volumes in 2025, while PHEV/EV sales would contribute another 9% to 16% (52% to 74% combined, compared to 43% expectation, and our 23% forecast for 2020).

For reference, European regulations require a 209g/mile average for emissions, and 153g/mile by 2020 (compared to a range of 190g/mile to 143g/mile by 2025 under the proposed US standard.

Government incentives

During the past year we saw numerous OECD governments, as well as China, establish substantial subsidies to encourage purchase of the first wave of electric vehicles. Many of the subsidies are in the form of a tax credit, though several, including in the US, are rebates to the dealer, who in theory will pass along the subsidy to customers to close the sticker price gap with combustion analogs.

Figure 22: Per unit (US$) consumer incentives for electric cars in some key markets



Source: ACEA, US DOE, hybridcars.com, Deutsche Bank

In addition to these federal level subsidies, there are now scores of local-level incentives that will further reduce the price gap. In the US, for example, California now offers a $5,000 per unit purchase rebate, while Colorado offers a personal tax credit up to 40% of the vehicle purchase price (capped at $6K). At least eight other states either exempt EV's from sales tax (which is worth $3,600 to $4.200 on a $60k purchase) or a direct tax credit of $1,500 to $5,000 per unit. Some states and municipalities are providing a rolling benefit to electric car owners in the form of HOV lane access and reduced or free parking spaces.

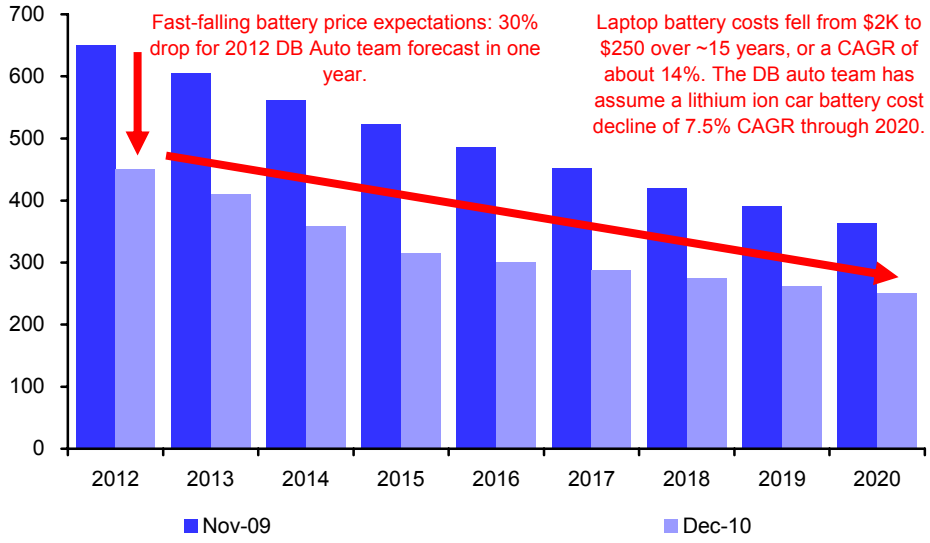
Battery prices coming down fast

The Deutsche Bank auto team went out on a limb early by forecasting a rapid decline in lithium ion electric car battery prices. Their aggressive outlook put them well out of consensus, and yet, in retrospect, it has proven to be not quite aggressive enough. Indeed, one of the most important developments in the transportation sector in the past twelve months has been the steep decline (and expected decline) in battery prices.

Based on discussions with industry experts and several automakers, the DB Auto team has lowered its advanced lithium ion battery cost projection by about 30% for 2012. Current prices have fallen from $650/kWh+ in 2009 to about $450/kWh now, and DB's forecast is the price to fall at about a 7.5% CAGR from 2012 through 2020 to about $250/kWh.

A steeper price decline trajectory obviously makes for better consumer comparison economics (last year's 2012 estimate put a full electric 25kWh battery cost at $16,250, while DB's auto team now sees a 2012 battery cost of about $11,250, and a 2020 battery of the same size at about $6,250. The decline is being driven by intense competition, which does raise some concern about the profitability and long-term viability of some of the battery producers, but from the consumer side, the decline will clearly shorten the payback period for electrics.

Figure 23: DB Auto team lithium-ion battery price forecast ($ per kWh)



Source: DB Auto team, industry discussions and private interviews, Deutsche Bank

The consumer economics of a pure electric start to work without subsidy by about 2020 under this battery price decline scenario. The industry rule of thumb suggests that consumers will consider a 3-4 year payback to be an economic choice. With no subsidy, 2012 electric vehicle models will have a 10+ year payback vs. a typical combustion analog, assuming $3.25/gallon gasoline. With a $7,500/vehicle subsidy in 2012, an electric will have about a 5 year payback. Around 2015, assuming a $4,500/vehicle subsidy, the payback period starts to fall into a range at which consumers will view the economics favorably. By 2020, the economics should be able to more or less stand on their own with subsidy, and a small subsidy would clearly nudge the payback below 3 years.

Figure 24: Consumer economics of pure electrics vs. ICEs as battery prices fall over the next decade

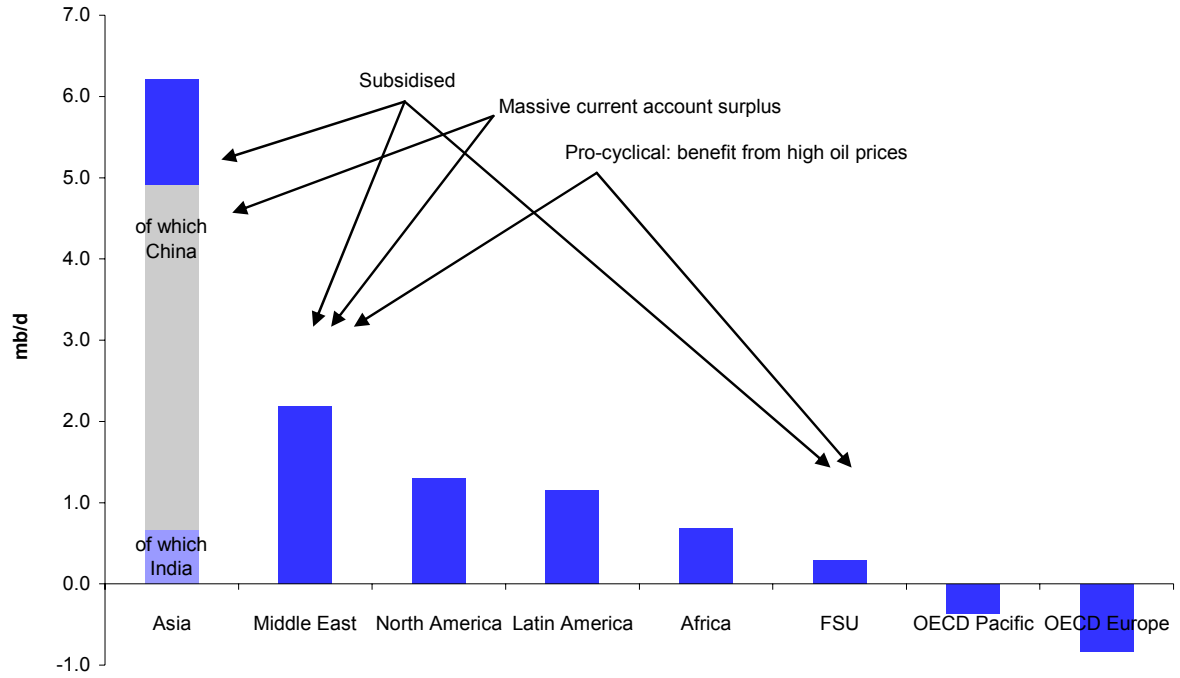
	2010		2012		2015		2020	
	No Subsidy	**With Subsidy**	**No Subsidy**	**With Subsidy**	**No Subsidy**	**With Subsidy**	**No Subsidy**	**With Subsidy**
Battery Cost $/kWh	650	650	450	450	315	315	250	250
kWh	25	25	25	25	25	25	25	25
Total Battery Cost	**16,250**	**16,250**	**11,250**	**11,250**	**7,875**	**7,875**	**6,250**	**6,250**
Other Incremental Costs	2,000	2,000	2,000	2,000	1,000	1,000	0	0
Government Subsidy	0	(7,500)	0	(7,500)	0	(4,500)	0	(2,000)
Total Incremental Capital Costs	**18,250**	**10,750**	**13,250**	**5,750**	**8,875**	**4,375**	**6,250**	**4,250**
Annual Gasoline Cost Savings	1,552	1,552	1,625	1,625	1,591	1,591	1,985	1,985
Annual Electric Costs	375	375	375	375	375	375	375	375
Total Annual Fuel Savings	**1,177**	**1,177**	**1,250**	**1,250**	**1,216**	**1,216**	**1,610**	**1,610**
Payback (Years)	**15.5x**	**9.1x**	**10.6x**	**4.6x**	**7.3x**	**3.6x**	**3.9x**	**2.6x**
Assumptions								
Average Miles Traveled per Vehicle	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000
Gasoline Price	3.00	3.00	3.25	3.25	3.50	3.50	4.50	4.50
ICE Mileage	29	29	30	30	33	33	34	34
Cost of Electricity	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
EV Miles Per kWh	4	4	4	4	4	4	4	4

Source: Deutsche Bank Auto Team, DB estimates

Middle East oil demand – subsidies & the youth bubble

The Middle East continues to be a grossly under-appreciated component of global oil demand. Oil consumption in the region is nearly as big as China and is growing almost as fast. Furthermore, the Middle Eastern countries are far less focused on transportation efficiency, in fact deeply subsidizing the combustion engine through cheap gasoline. While Chinese demand growth will surge and then peak or plateau due to efficiency gains, Middle Eastern demand growth is likely to rise out to the foreseeable horizon.

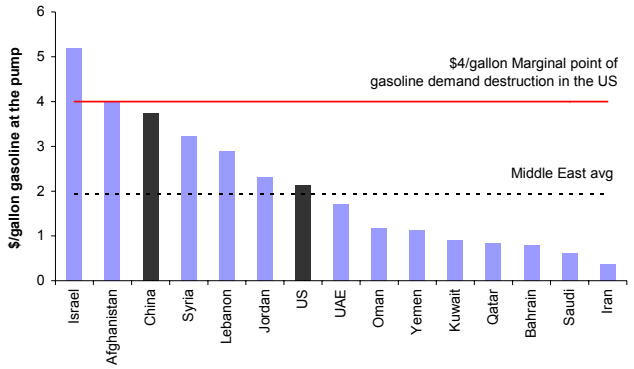
Figure 25: Oil Demand Growth 2001-2010



Source: Deutsche Bank, IEA

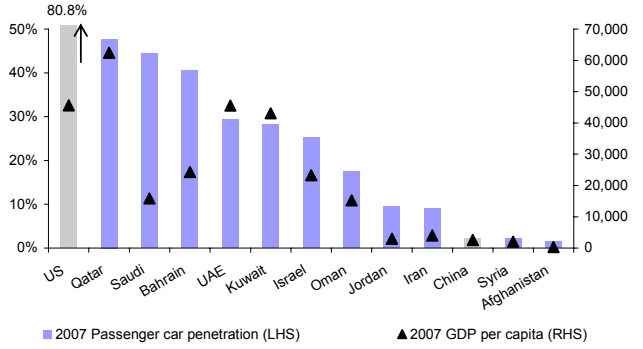
Because of oil wealth and massively subsidized fuel in most of the major Middle Eastern markets, regional demand is pro-cyclical, rising faster with higher oil prices (rising income, more state revenue to fund subsidies). Further increasing demand, the Middle East's population is growing close to double the rate of global population, GDP growth is higher than average, and car ownership penetration is high (about 40% in Saudi) and rising.

Figure 26: Gasoline prices



Note: Gasoline price in Iran (2008) was $2.01/gal (53c/liter) for sales above 120 liters/mth.
Source: Deutsche Bank, World Bank, EIA

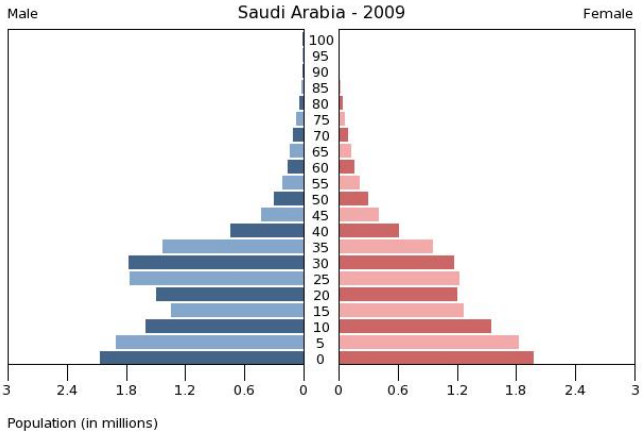
Figure 27: Car penetration



Source: Deutsche Bank, World Bank, JD Power

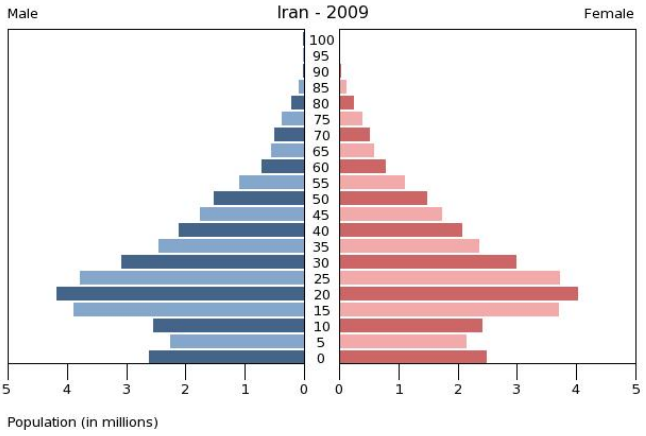
One risk to a robust Middle Eastern oil demand forecast, though, is the shifting shape of the population age distribution – the Middle East has a massive youth bubble. More than 750,000 young Iranians join the workforce each year, and official unemployment is nearly 12% (unofficial estimates point towards double that number). Across the region growing young populations are increasingly urbanized, unemployed and poor. This leads to volatile socio-political situations in many Middle Eastern cities, making removal or reduction of gasoline subsidies an extremely challenging undertaking.

Figure 28: Saudi population pyramid



Source: US Census Bureau

Figure 29: Iran population pyramid



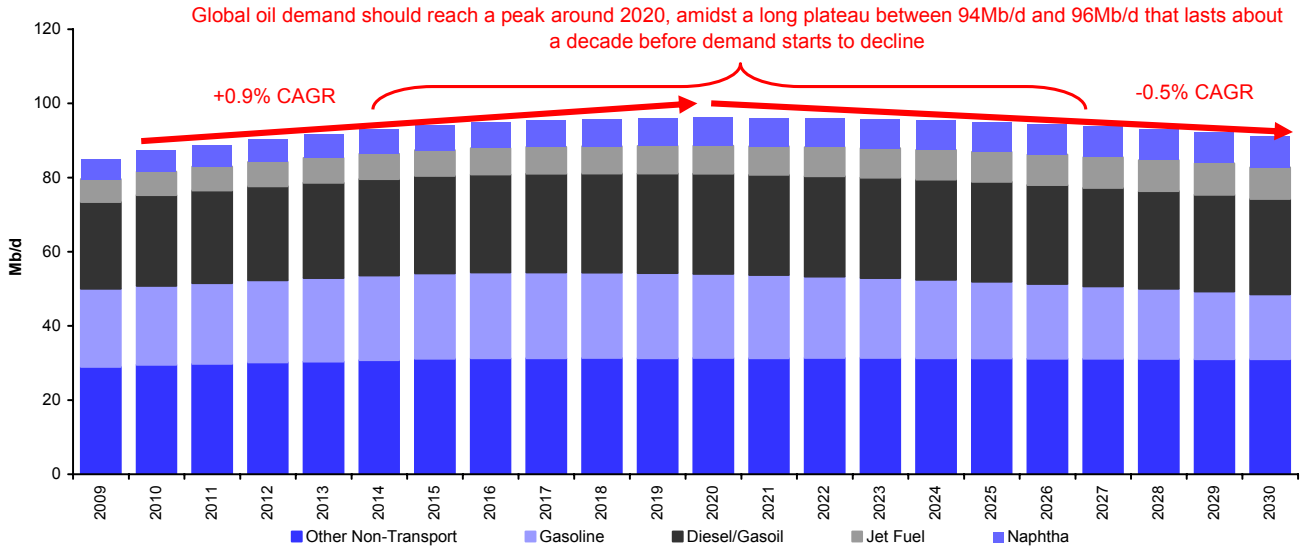
Source: US Census Bureau

Working on a country-by-country basis, we have rolled the thirteen markets in the Middle East (as per IEA definition) into our global oil demand model. As the charts in the next section show, the Middle East's demand growth profile is unique, due to the combination of massively subsidized fuel in all but a few markets (Israel has no subsidy, Jordan eliminated subsidies in 2008, and Syria is phasing them out), a fast growing population (>2% region-wide) and rising GDP/capita. We expect about 3.5% annual growth in regional gasoline demand through 2020, which will drive about 2.5% annual growth in total Middle Eastern oil demand (~200kb/d+ incremental demand per year). Over the next decade we expect the Middle East to contribute about a quarter of incremental oil demand, exceeded only by China.

Updated gasoline and oil demand for major markets

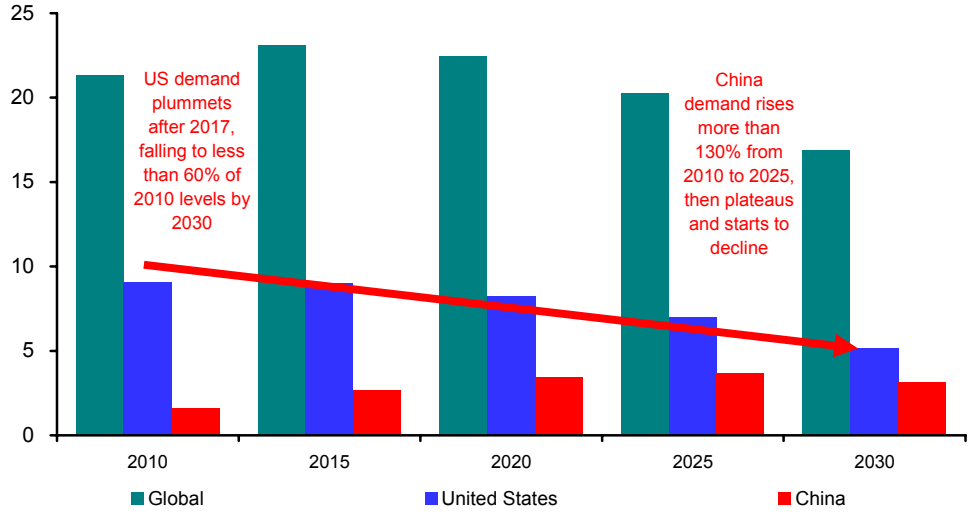
Rolling all of the incremental data points and factors we've observed in 2010 into our revised long-term global gasoline and oil demand model, we now believe we'll see substantial near-term growth in demand (1.5kb/d to over 2.0kb/d per year), probably driving a demand-destroying price surge within the next 3-5 years. After that, we expect a long plateau in which demand stays between about 94kb/d and 96kb/d for more than a decade, as increasing transportation fleet efficiency (and likely some power gen switching outside of the US) begins to offset growing emerging market demand.

Figure 30: Our long-term oil demand forecast – "The Long Plateau" from 2015 past 2026



Source: IEA, EIA, World Bank, IMF, CIA World Factbook, Wood Mackenzie, DB Auto team, Deutsche Bank estimates

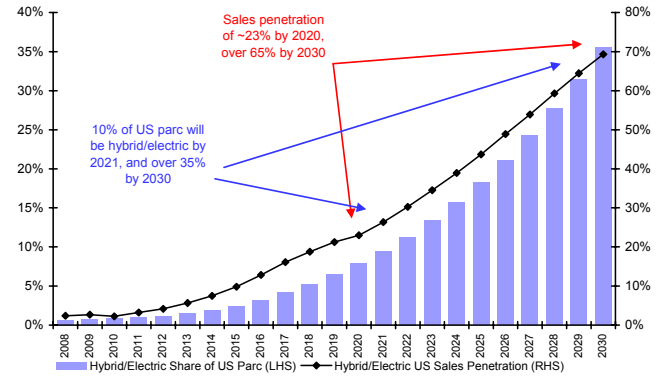
Figure 31: Global gasoline demand projection, 2010-2030



Source: Deutsche Bank

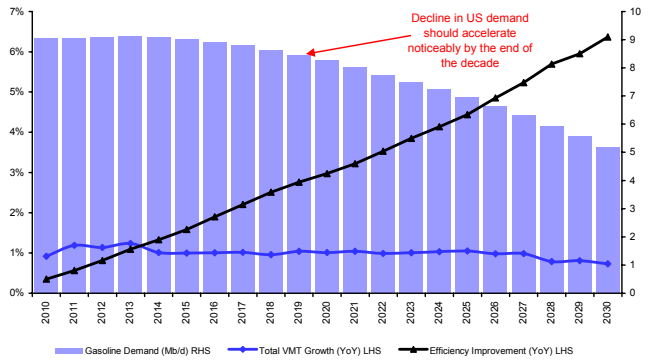
Gasoline demand, which currently accounts for about a quarter of global oil demand, will start to peak a few years earlier than overall oil demand. Demand in the US, which accounts for over 40% of global gasoline consumption in 2010, will continue to plateau between 9.0Mb/d and 0.3Mb/d for the next several years, then mid-decade it should start to decline in an accelerating fashion, driven by growing adoption of high efficiency vehicles. We currently see US demand falling to about 5.2Mb/d by 2020, a bit over half of 2010's 9.1Mb/d.

Figure 32: US xEV sales and parc, 2010-2030



Source: Deutsche Bank

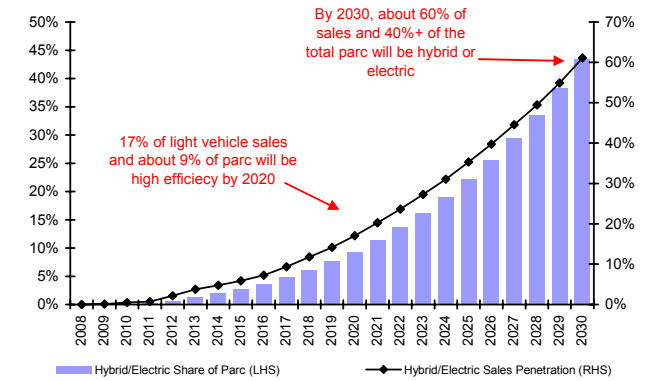
Figure 33: US gasoline demand forecast, 2010-2030



Source: Deutsche Bank

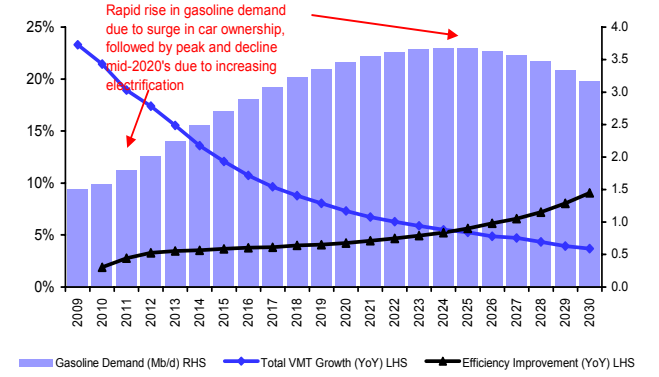
While the US may have hit its gasoline consumption peak in 2007, China's rapid demand growth should continue for another dozen years or more, despite its push to electrify its transportation fleet. Eventually transportation efficiency improvement will overtake growth in vehicle miles traveled/car ownership penetration, but we don't see that happening until about 2024.

Figure 34: China xEV sales and parc, 2010-2030



Source: Deutsche Bank

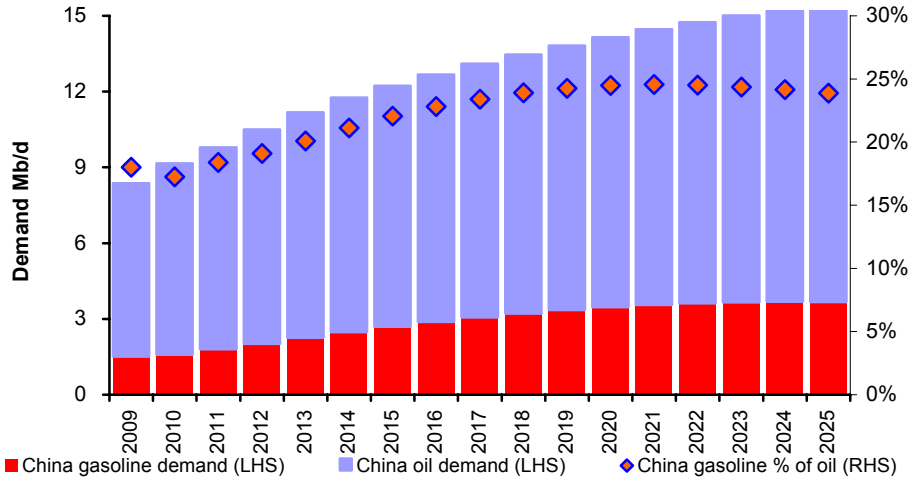
Figure 35: China gasoline demand forecast, 2010-2030



Source: Deutsche Bank

China's oil demand should continue to rise beyond the peak in gasoline demand, perhaps plateauing near the end of the 2020's.

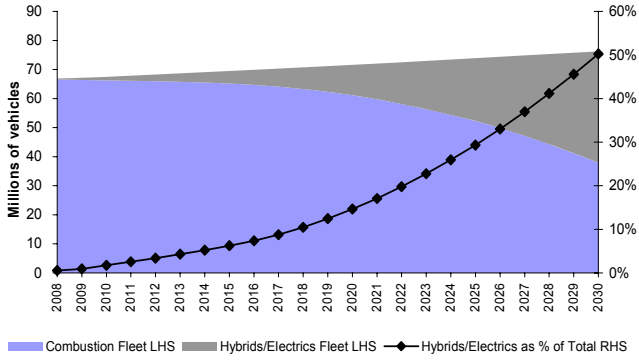
Figure 36: China gasoline and total oil demand, 2009-2025



Source: Deutsche Bank

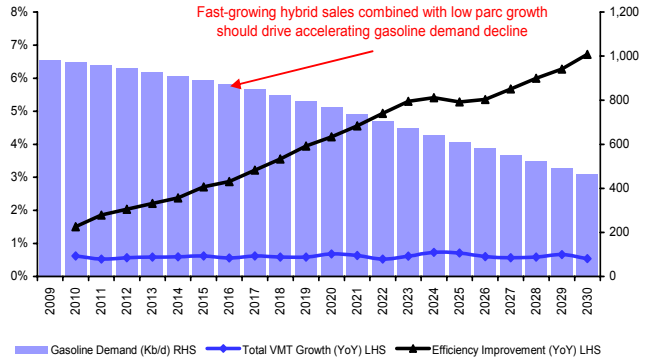
Japanese and European gasoline demand have very likely peaked and are in continual decline, and both should experience substantial high efficiency vehicle penetration by the end of this decade, and therefore an accelerating decline in gasoline consumption (and likely diesel as well).

Figure 37: Japan car parc mix shift, 2010-2030



Source: Deutsche Bank

Figure 38: Japan gasoline demand forecast, 2010-2030

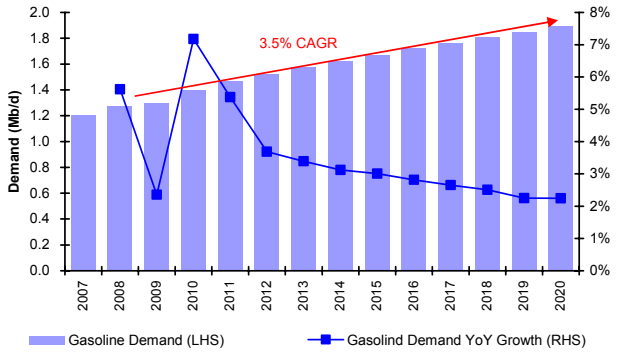


Source: Deutsche Bank

By sharp contrast, Middle Eastern demand will continue to rise, as well highlighted in the previous section. Gasoline demand in the region, spurred by heavy subsidization and a surging population, should grow at 3%+ per annum for the foreseeable future. Overall oil demand in the Middle East should be about 2.5% through at least 2020.

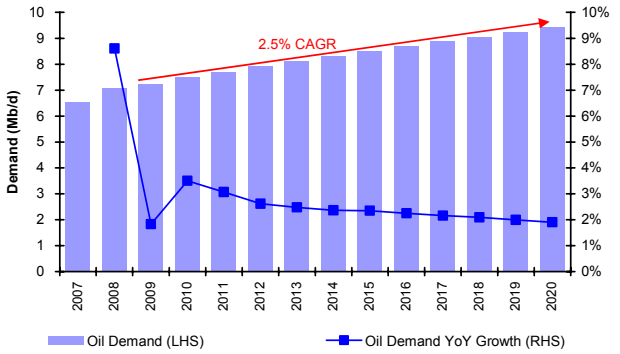
In our 31 May 2010 note on Middle Eastern demand ("The Peak Oil Market V – Youth Bubble: the Middle East's Oil Demand") we highlighted the interesting contrast between the shape of the Middle East's demand outlook and the other major demand regions.

Figure 39: Middle East gasoline demand forecast



Source: IEA, World Bank, IMF, Economist Intelligence Unit, Deutsche Bank estimates

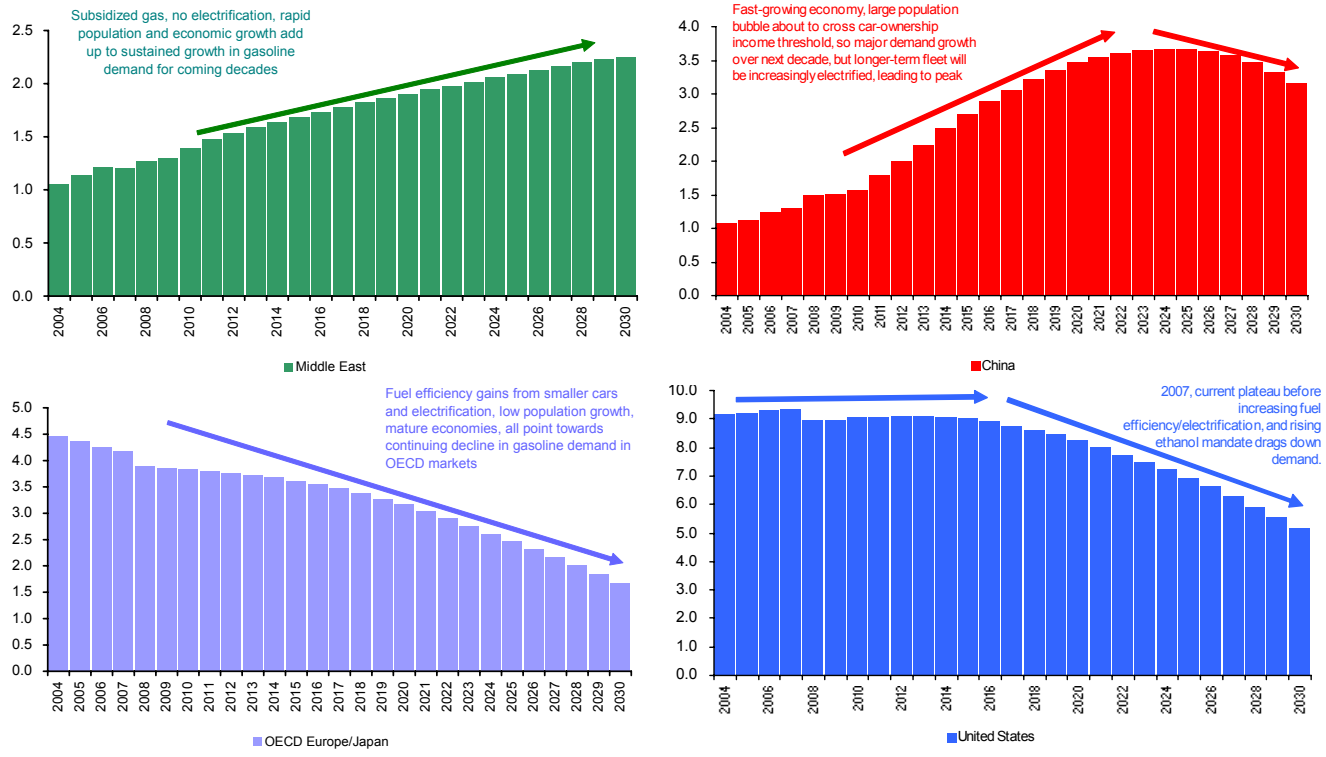
Figure 40: Middle East oil demand forecast



Source: IEA, World Bank, IMF, Economist Intelligence Unit, Deutsche Bank estimates

Both China and the Middle East are experiencing major economic growth, with fast-rising GDP/capita, growing car ownership penetration, and surging near-term demand for gasoline and oil. However, China doesn't subsidize gasoline (though it does centrally control pump prices), and out of necessity has elected to pursue an electrified future transportation fleet.

Figure 41: The shape of demand to come – four very different long-term gasoline demand profiles



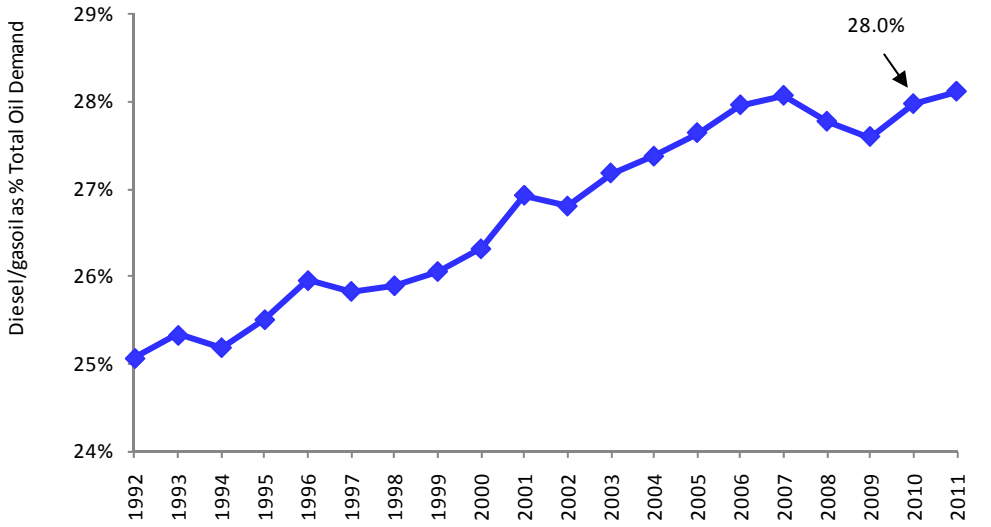
Source: IEA, EIA, World Bank, IMF, JD Power & Associates, Economist Intelligence Unit, CIA World Factbook, CAAM, DB China Auto Team, DB US Auto Team, China Statistical Yearbook, Zawya, CEIC, Deutsche Bank

The chart above highlights the different shape of future demand for the Middle East and China, as well as the demand trend unfolding in OECD countries, where increasing fuel efficiency, low population growth (in Europe and Japan) and mature economic growth are combining to reduce gasoline demand for the foreseeable future.

Analysis for 2011: global distillate demand dynamics

We have highlighted that there are two major factors increasing the complexity of modeling and understanding global oil dynamics: NGLs on the supply side, and distillate on the demand side. Distillate has steadily grow as a share of the world oil barrel, and our gasoline forecasts for the US strongly imply this will keep occurring. However modeling distillate is far more difficult as its end use is so diverse, from transport, to power generation, to industry and to home heating use.

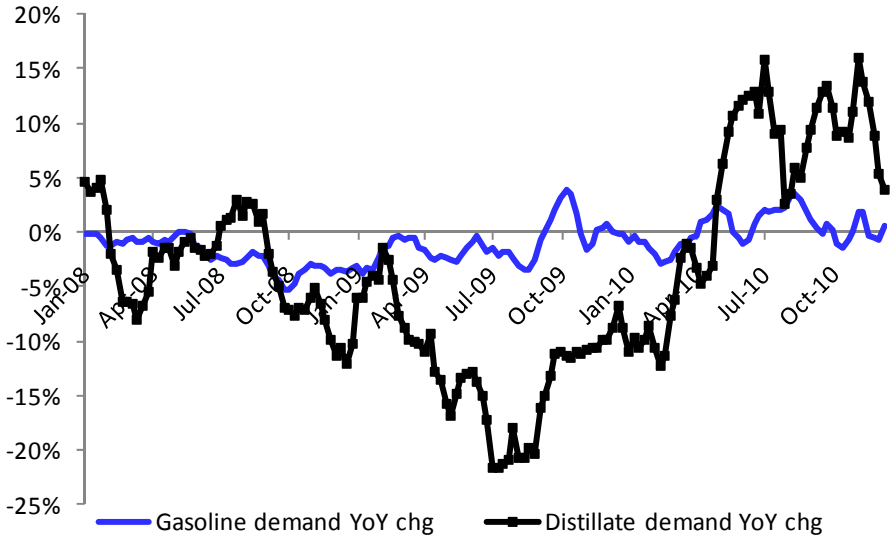
Figure 42: Global diesel/gasoil demand



Source: Deutsche Bank, IEA

The core observation regarding distillate in 2010, and generally post economic crisis, is that where we would have expected gasoline demand to be price sensitive and diesel to be GDP sensitive, we saw far more robustness of gasoline demand, despite and economic crisis, and far more diesel sensitivity, than we would have expected. Ultimately, this may make our future work on distillate easier, as we can correlate it closely with changes in GDP expectations.

Figure 43: US distillate vs gasoline demand changes



Source: Deutsche Bank, EIA

Long Term Outlook: Supply

Tug of war: Non-OPEC growth vs. post-Macondo GoM decline

Since we wrote on the under-investment cycle caused by governments' increased control of oil over the past three years, changes have emerged. Where private activity is allowed and even encouraged, supply growth, as evidenced in our Non-OPEC supply commentary above, has been robust, such as in Ghana, Brazil, Canada, the US onshore and even quasi-state Russia and Kazakhstan.

Most important recent news-flow has been the opening of Mexico to new investment, a major development from a "quasi-OPEC" player that has limited private investment and subsidised local oil prices, in the style of an OPEC member.

As one opens, another closes, however, and the post-Macondo environment for investment in the deepwater Gulf of Mexico, a vital play for major oils, has become radically more difficult, with strong indications that the White House is in no rush to accelerate activity any time soon. Current Washington sentiment indicates that no acceleration even beyond 2011 is a real possibility, and Wood Mackenzie estimates that 80kb/d of supply will be lost in 2011 – the entirety of Hess's five year Bakken growth plan gone in one year. Equally the EPA is clearly concerned about hydrofracking, which is increasingly a liquids-oriented activity. Expect ongoing 2011 battles between the EPA and the Republican controlled Energy and Commerce Committee in the House to maintain government pressure on US oil supply growth.

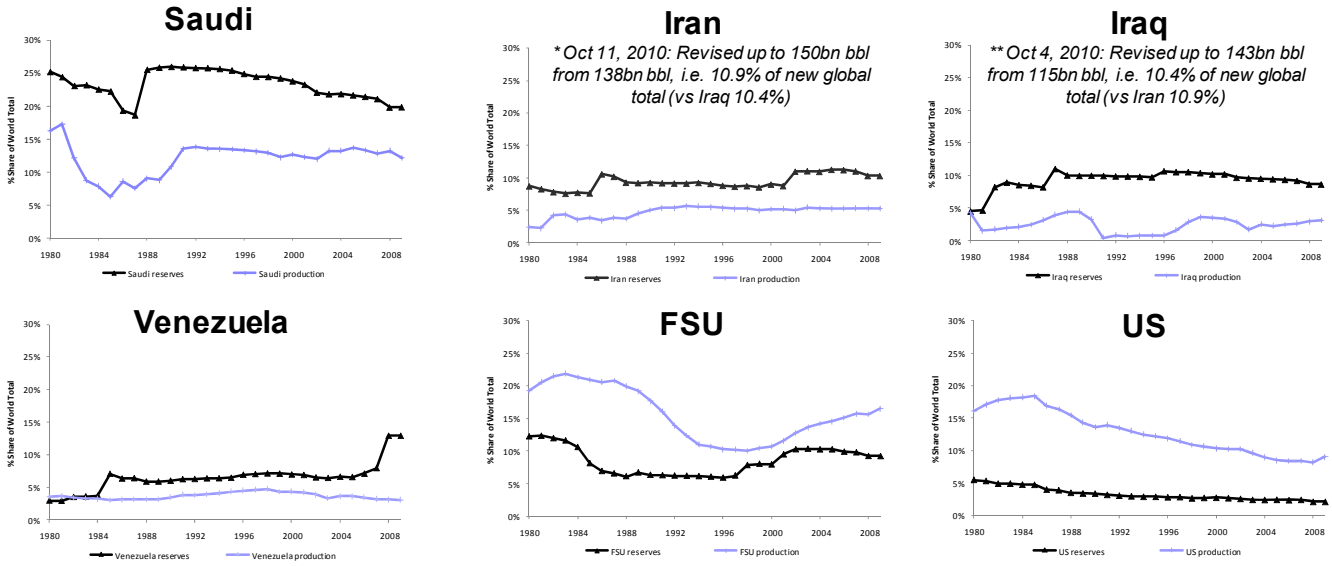
Remaining oil reserves concentrate in the hands of governments

As reserves become concentrated into the hands of nationalist governments (beyond OPEC, the major reserves holders with no or very limited access are Mexico, Russia, and arguably Brazil), under-investment will likely become increasingly chronic.

In the chart below we highlight that major OPEC reserves holders restrict access, activity, and ultimately production. This is evidenced by the relationship between their share of global reserves and share of global production of oil. By contrast the US and Russia produce more oil than their share of reserves would imply, showing how more aggressive private activity can generate production in excess of implied market share.

Figure 44: Top 10 Reserves Holders *(black indicates reserves, blue indicates production)*

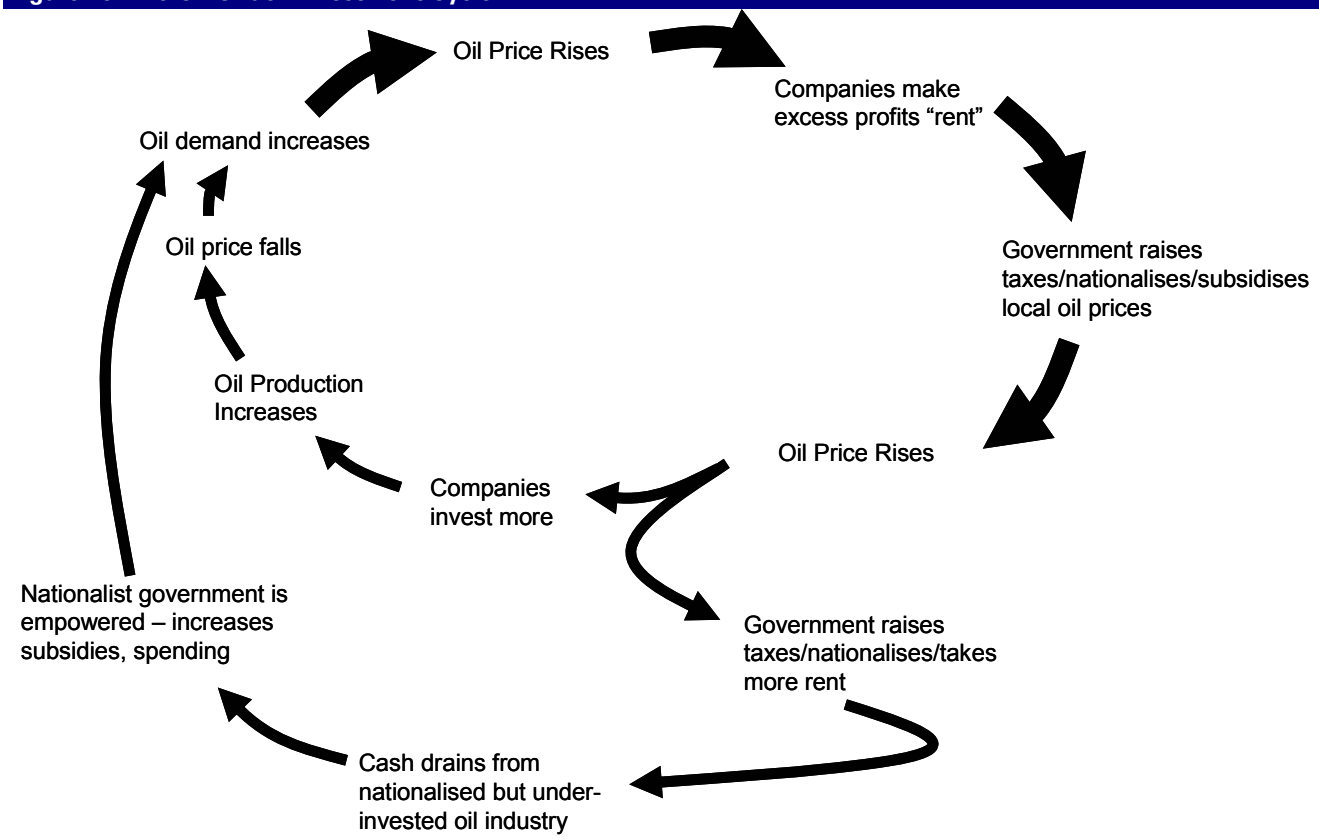
		Remaining Reserves (2009)	Share of Total	Oil/Political Orthodoxy	Local oil prices
1	Saudi	264.6	19.8%	OPEC Islamic	Subsidised
2	Venezuela	172.3	12.9%	Socialist	Subsidised
3	Iran*	137.6	10.3%	OPEC Islamic	Subsidised
4	Iraq**	115.0	8.6%	OPEC Islamic	Subsidised
5	Kuwait	101.5	7.6%	OPEC Islamic	Subsidised
6	UAE	97.8	7.3%	OPEC Islamic	Subsidised
7	Russian Fed	74.2	5.6%	Socialist	Subsidised
8	Libya	44.3	3.3%	OPEC Islamic	Subsidised
9	Kazakhstan	39.8	3.0%	Islamic Socialist	Subsidised
10	Nigeria	37.2	2.8%	OPEC Islamic/Christian	Subsidised



Source: Deutsche Bank, BP

There is a particular issue with four major reserves holders, ex GCC, who are massively important in terms of remaining oil, but highly volatile in terms of supply reliability. They are Iran, Venezuela, Iraq and Nigeria. Between 2004 and 2008, supply from these countries declined in the face of all-time record total market growth. With the possible exception of Iraq, there is little prospect of any near-or medium-term growth from these massive reserves holders.

Figure 45: The Oil Under-Investment Cycle



Source: Deutsche Bank

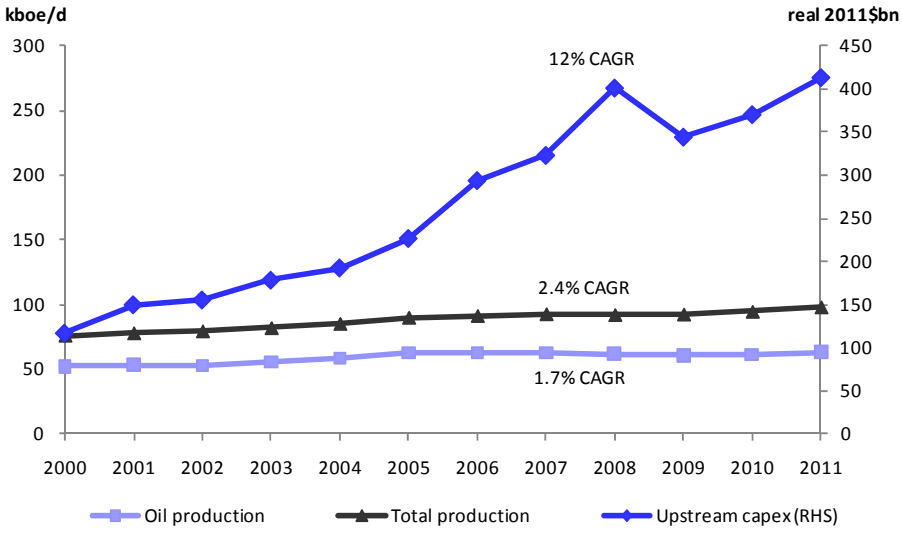
As oil prices rise, supply still fails to react

We have highlighted capex cuts, but in reality, major oil companies, including national oil companies, have massively ramped their spending over the course of the past decade, as a break-out in oil prices has generated huge profits, particularly for OPEC members.

Global industry spending representing companies with some 61mb/d of oil production has risen, in real 2011 terms, from around $120bn annually in 2000, to around $370bn today, including a 2008 peak of $400bn, a compound annual growth rate of around 12% annually. We expect global upstream capex to hit $410bn+ in 2011.

These companies' oil production during that time has risen just 1.7% annually.

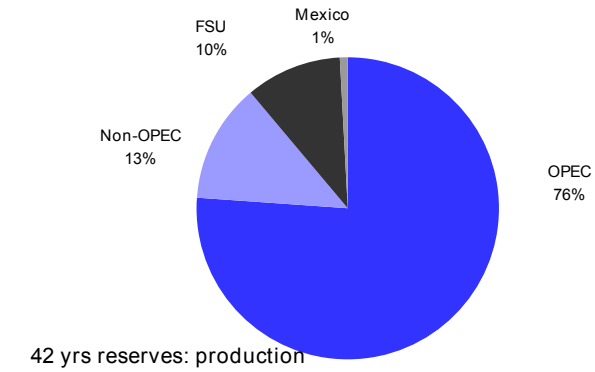
Figure 46: Oil production, total production, and capex spend by major oil companies*



*Source: Deutsche Bank, Company data, DOE, EIA, IEA, *includes OPEC state companies*

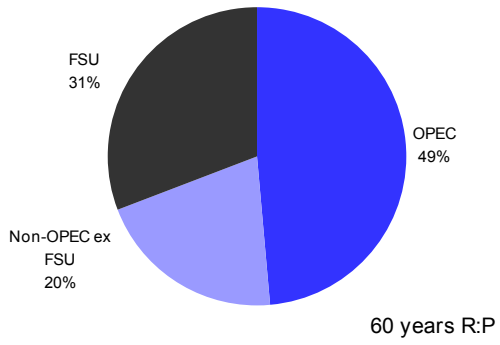
The story is different for natural gas. It is a hugely important related fact that natural gas supply **does** react to higher prices. First, natgas is more accessible, with a far higher proportion of overall reserves, longer reserves to production, and a far greater proportion of remaining natgas found in non-OPEC countries.

Figure 47: Global remaining oil reserves 1.2trn bbls



Source: BP

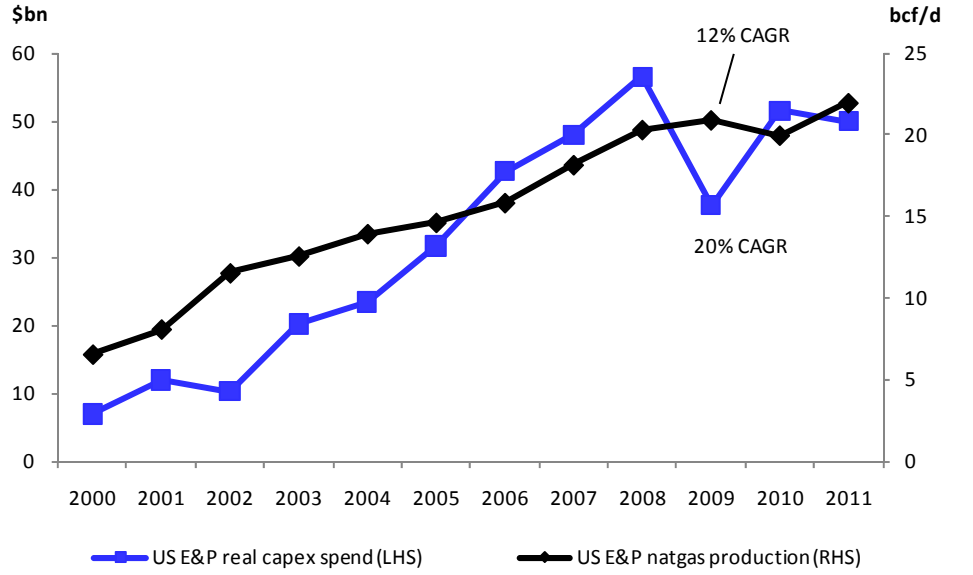
Figure 48: Natural gas – 6,000 TCF – excludes shale



Source: BP

Second, natgas companies, particularly US E&P companies have proven themselves to be far more aggressive in terms of their willingness to invest. US E&P companies have increased their spending at 20% per annum over the period 2000-2009, even allowing for the major cut back in spending in 2009. At the same time, supply has reacted, with a 12% increase in output annually over the same period. As discussed later this is clearly very important for fuel choice, consumption, and **prices of natgas relative to oil; additionally, natgas does not compete directly with oil in any major markets – in the US, oil is for transport, in China, demand is incremental, and in the Middle East, the "convenience premium" of oil causes it to be the fuel of choice, because of the long lead times and greater complexity of natgas projects**.

Figure 49: US natural gas supply reacts to higher prices and spending



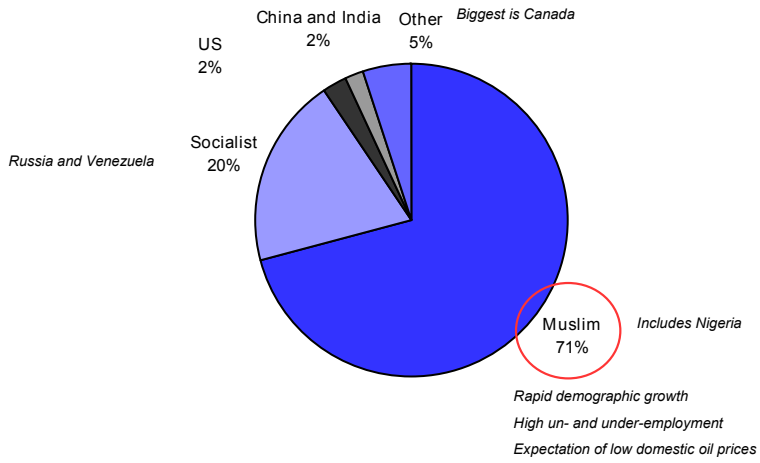
Source: Deutsche Bank, Company data
Note: XTO acquired by XOM in 2010 and hence included in this chart only through 2009

Supply and demand uncertainty

What has changed since our last assessment highlighted the issues in Venezuela, and under-performance there, and in Iran and Nigeria. All of those have behaved in line with expectations in terms of under-performing their reserves potential. Equally we highlighted Russia's active tax policies, and Brazilian government response to major discoveries there as being suppressant on rapid supply growth, although in both cases policy has followed a responsible logic in terms of orderly development.

Unquestionably the major change has been the Deepwater Horizon disaster and the dramatic shift in the pace of development seen in the deepwater Gulf of Mexico, previously a major Non-OPEC growth driver, now with barely any activity. Wood Mac estimate that in 2011 we are expected to lose 80kb/d of production from the deepwater GoM, ironically almost exactly Hess's planned output growth in the North Dakota Bakken *over the next five years*.

Figure 50: World remaining proven oil reserves



Source: BP, Wood MacKenzie, Deutsche Bank estimates

The ultimate result of the level of uncertainty on both the supply and demand sides of the equation is that oil companies have to have conservative price planning assumptions. By being conservative, they are aiming to be right, or rather, not wrong, on future prices. But by uniformly having conservative planning assumptions, the companies are effectively under-investing in future oil supply, and by extension, are putting more pressure on state (i.e., OPEC government) companies to provide marginal oil supply growth.

Because of Saudi spare capacity, and its organisation of OPEC behaviour, the oil supply cycle is more price responsive than demand in the short term. By contrast in the long term, the demand cycle is more responsive. Later in this note we analyse what this means for actual prices, but the conclusion from a supply/under-investment cycle is that oil will tend towards short-term over-supply and long-term under-supply, again exacerbating volatility. So major private oil companies are faced with projects that by their scale and challenges, require stable fiscal regimes and higher, sustained, oil prices, but they are faced with neither. This is the second leg of the under-investment cycle.

The Macondo Deepwater Horizon Disaster

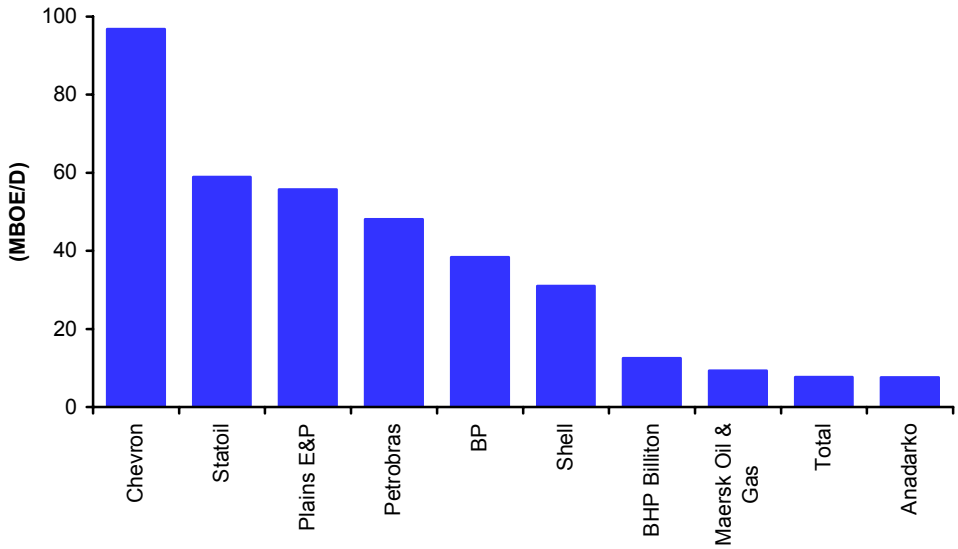
The US supply picture was permanently altered on April 20, 2010, when the Macondo blowout and the subsequent five month crude leak caused a cascade of political and regulatory fall-out. The US government implemented a complete moratorium on new deepwater drilling activity in May, and though that temporary ban was officially lifted on October 12 (ahead of schedule by about a month), few operators have been granted a permit to drill in the deepwater. Numerous official investigations are being conducted still, with reports expected in early 2011.

A recent day of meetings in Washington made it clear to us that the pace of deepwater permitting in the Gulf of Mexico will remain glacial for the foreseeable future – at least another year, maybe two – and the long-term development pace will be slower than what occurred before Macondo. The charts in this section below highlight that Hess and Chevron have the most to lose from delays in GoM development, while Oxy and COP have no or minimal impact. Overall production in the Gulf will be negatively affected for the foreseeable future, with Wood Mackenzie forecasting a post-Macondo peak hit to production of 143kboe/d in 2011. Wood Mackenzie does see long-term Gulf production returning to their pre-spill outlook by 2016, though we are skeptical that production will "catch up" in the new regulatory equilibrium once it emerges. In our view, permitting will forever be more deliberate and constrained.

Regarding the pace of permitting in the Gulf, our conversations with policymakers and DC analysts yielded the following handful of reasons for near-term delays:

- **Obama is not motivated to increase permits**. Other than job creation, Obama has no strong incentive to reaccelerate permitting, and several reasons to keep things moving slowly – 1) An increase in activity would mostly benefit Texas and Louisiana, two states that are squarely Republican in terms of Presidential election politics; 2) a large portion of Obama's base doesn't want a return to aggressive permitting in the Gulf, and 3) more activity means more risk of another incident, which would be a disaster for 2012.

Figure 51: 2010-2016 incremental US GoM production volume by company



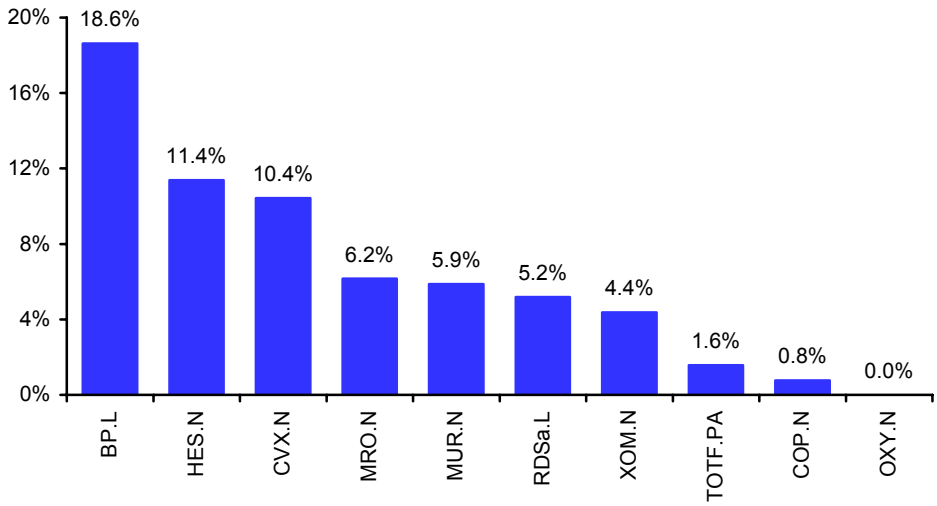
Source: Deutsche Bank, Deutsche Bank

- **Director Bromwich's priorities**. Bureau of Ocean Energy Management, Regulation and Enforcement Director Michael Bromwich was brought in to be a sheriff and bring law and order to an MMS (now BOEM) that was considered dysfunctional, inefficient, somewhat beholden to industry, certainly rife with conflicts of interest. The metrics by which Bromwich will measure success won't be the same as the previous MMS, where permit counts, development activity, and government-captured tax/royalty revenue were the gauges. Bromwich, a former Inspector General for the US Department of Justice with no background in oil and gas (but with plentiful experience overseeing or investigating troubled government entities), will grade himself on the rigor of oversight, the absence of accidents or incidents of BOEM misbehavior, and the restoration of public confidence in the Gulf drilling regulatory system. One of Bromwich's first actions as the new Director was to create a new Investigations and Review Unit within BOEM,

essentially an "internal affairs" department whose task is to keep BOEM employees on the independent straight and narrow. BOEM's focus right now is clearly on reforming BOEM more than on getting permits approved quickly.

- **BOEM is understaffed.** BOEM wants to strengthen its inspection program, though funding issues could limit steps in this regard. BOEM is widely thought to be understaffed, but Director Bromwich has said he would like to add 200 new inspectors, engineers and environmental scientists in 2011.

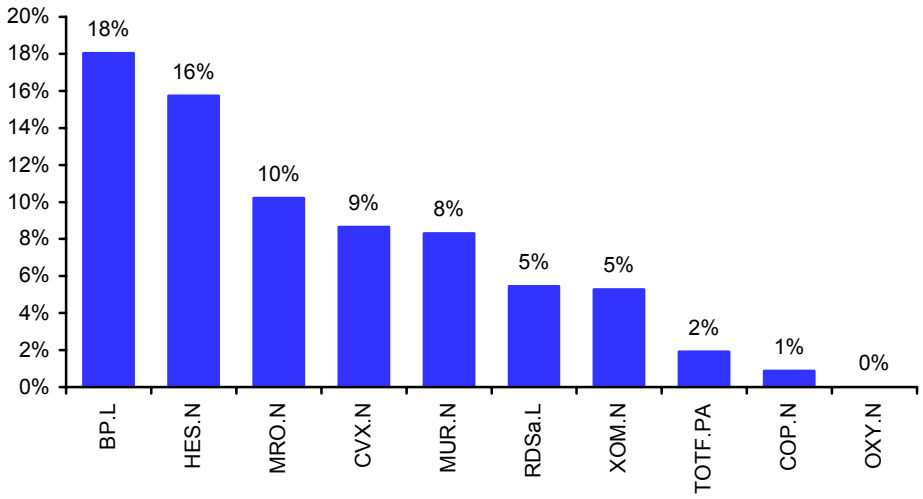
Figure 52: Gulf of Mexico NAV relative to company market cap



Source: Wood Mackenzie, Deutsche Bank estimates

- **BOEM likely wants containment systems in place**. It seems unlikely we will see more than a couple of new permits until the industry-sponsored containment enterprises are fully at the ready. Two JV coalitions have formed to address the spill-containment issue. In July, ExxonMobil, Chevron, Shell and ConocoPhillips each pledged $250M to form a non-profit JV, called the Marine Well Containment Corp. (MWCC), to build a comprehensive spill response system that could capture 100kb/d+ of oil. The MWCC agreements will be signed next week, and the system will be built by 2Q11. A second coalition has been formed around Helix Energy Solutions (which was at the center of the Macondo response), with membership composed of about 20 smaller energy companies. Helix system is smaller (about 55kb/d oil containment capacity), but is already built. Both systems will charge a retainer fee to members. Until the MWCC system is in place, we think there will be very few permit approvals in the GoM.

Figure 53: Gulf of Mexico 2P NAV as % of total upstream 2P NAV



Source: Wood Mackenzie, Deutsche Bank estimates

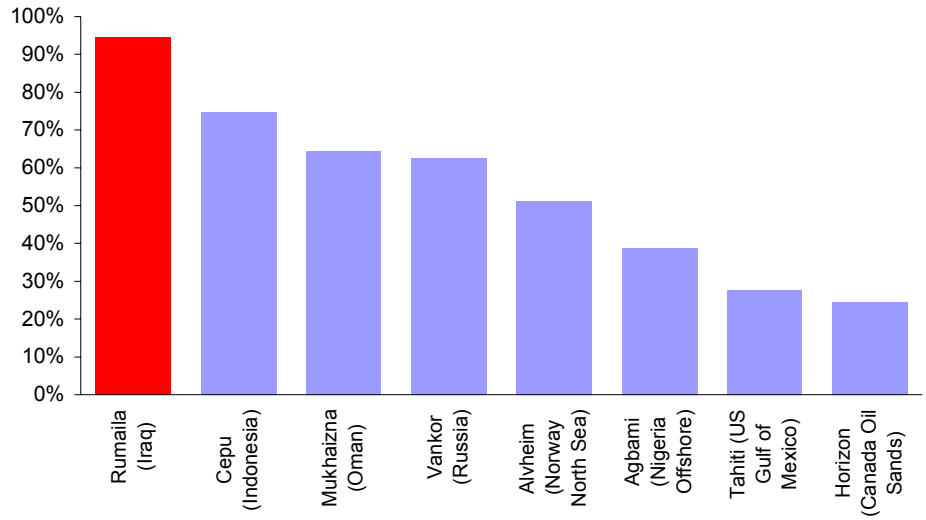
- **New standards are harder to meet and may lack some clarity**. This fall BOEM announced two new rules (the Drilling Safety Rule and the Workplace Safety Rule) that meaningfully raise the standards for US GoM safety and environmental practices, and which will contribute to a more deliberate permitting process. The standards address well design, casing, cementing and well-control equipment, such as blow-out preventers. Operators must now get independent third-party inspection and certification at different stages of the drilling process, and must develop comprehensive safety and environmental management programs that identify potential risks and risk-reduction strategies. Some operators complained of ambiguity regarding compliance with these standards in the new application process, and BOEM issued guidelines for compliance on December 13. The guidelines don't add any requirements, but do clarify, for example, the notice that drillers must give to BOEM before tests on BOPs, or how to calculate a worst-case discharge.
- **BOEM likely to issue more requirements**. Over the next half year, BOEM will move forward with additional safety requirements for BOPs and other deepwater equipment.
- **Oil Spill Commission**. A key conclusion the Oil Spill Commission, created by Presidential executive order (May 21), is likely to reach (report is due January 12) is that the US's deepwater regulatory approach has not kept up with advances in technology, and that rather than having a proscriptive regulatory scheme, the US should follow the North Sea countries' lead and employ a more proactive risk-based approach. Along those lines, the Commission will likely propose the formation of a non-governmental "Safety Institute," which will have an independent auditing function (the Oil Spill Commission adamantly believes it should not be a trade association, such as API), similar to the nuclear industry's INPO. The challenge of this proposal will be to obtain buy-in from a hyper-competitive industry that values proprietary techniques and technology, and is wary of public information being used against them by the media and NGOs. Thus the Safety Institute design, a work in progress at the moment, will need to find the right mix of transparency and respect for proprietary information to make the oil companies comfortable enough to commit to it. As with the containment capabilities, we believe that BOEM will likely maintain a very slow approval pace pending the Oil Spill Commission report and adoption of some of its recommendations.

Focus update: Iraq – formidable hurdles, but clear progress

Iraq is emerging as the biggest oil supply story in at least a decade, and we believe it is one of the three mega-stories that will drive supply/demand/price dynamics over the next ten years, along with China's demand growth and increasing global (particularly OECD) transportation efficiency.

Just three years ago, Iraq was a complete mess with pie-in-the-sky oil development aspirations. In 2009, despite no hydrocarbons law, the Oil Ministry held two successful licensing rounds, lining up some of the world's most expert and well-funded oil companies to ramp the countries production towards ambitious heights. Remarkably, the Oil Ministry convinced the IOCs to agree to deals that strongly incentivize a rapid early ramp up, a massive injection of capital over a sustained period of time, while also capturing over 90% of the revenue over the long life of the projects.

Figure 54: Long-term government take for Rumaila vs. sample of other fiscal regimes



Source: Wood Mackenzie, Deutsche Bank

While the initial Oil Ministry target of 12Mb/d (the cumulative production plateau target of the dozen Iraqi TSCs plus some existing production) is pure fantasy given the numerous physical and political constraints, we believe a ramp to 6Mb/d+ by the end of the decade is probably feasible. The physical constraints (pipelines, export capacity, water access, associated nat gas, refining capacity) are formidable and will undoubtedly cause delays, but they are ultimately solvable – we think the major bottlenecks should be worked out by 2015. The two biggest fatal risks, in our view, are political – the country's center must hold (i.e., no civil war), and regional/OPEC tensions must be worked out or ignored, particularly with long-term rival Iran.

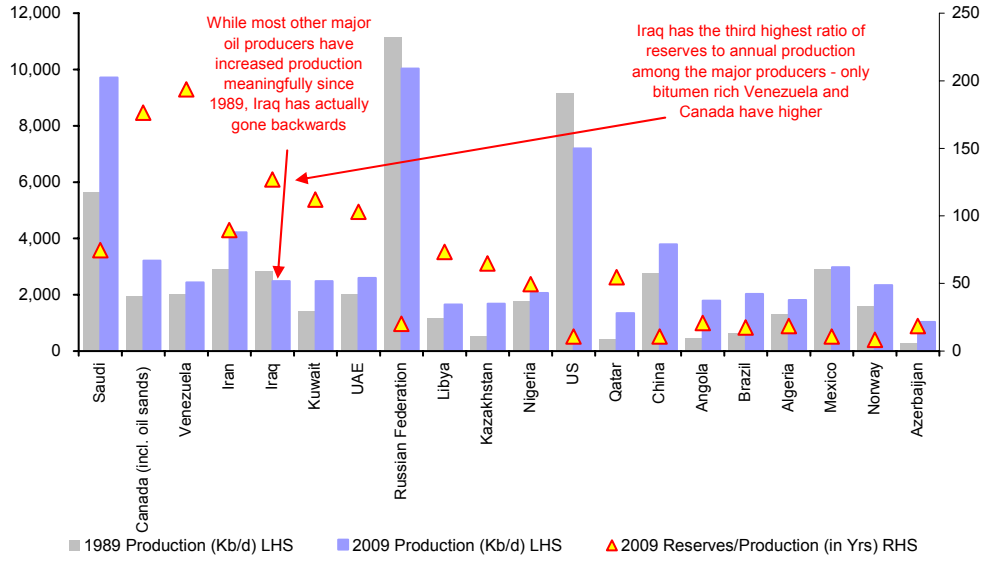
In October we published a long note on the state of play in Iraq along with our current expectations for production, and the impact we think the huge ramp up in volume will have on the global oil market. We summarize some of the key points from the note and from recent events here:

⇒ After 8 months of maneuvering and negotiating, Prime Minister Maliki was finally able to strike a deal in late November with the Kurds and the INA coalition (which includes Moqtada al Sadr and his followers). A new government is in process of formation.

⇒ Now that we almost have a government, **expect a hydrocarbons law to be passed**, TSC contracts to be ratified and federal-regional revenue-sharing to be finally worked out.

⇒ Despite enormous reserves, Iraq hasn't produced more than 3Mb/d since 1979. Iraq's R/P ratio, given recently revised reserves of 143B bbls, is about 150 yrs. The only producers with a higher R/P are bitumen-rich Canada and Venezuela, two high-cost producers that need a high oil price.

Figure 55: Reserves to production for world's biggest reserve holders



Source: IEA, Wood Mackenzie, Deutsche Bank

- Six of the dozen Iraqi TSC fields (11 from two licensing rounds, one contract from 2008) stand out as the primary drivers of growth over the next decade: Rumaila, West Qurna 1 & 2, Zubair, Majnoon and Halfaya. Combined these six hold oil in place of about 200B bbls.
- Technical Service Contract (TSC) key points

  1) Unlike your typical global PSC, there is no cost recovery/remuneration until production grows 10% from an agreed upon baseline level. **This strongly incentivizes a quick early ramp up.**

  2) There were two primary biddable elements in the licensing rounds – the per barrel remuneration fee and the ultimate Plateau Production Target ("PPT"). **The remuneration fee is much more important to returns.**

  3) The remuneration fees strike many people as being quite low – at the Big Six they range from $1.30/bbl at West Qurna 2 to $2.00/bbl at Rumaila. And they will be further reduced due to a mandatory 25% state company equity stake, taxes and a sliding scale once the field reaches profitability. **These are low margin, high volume economics.**

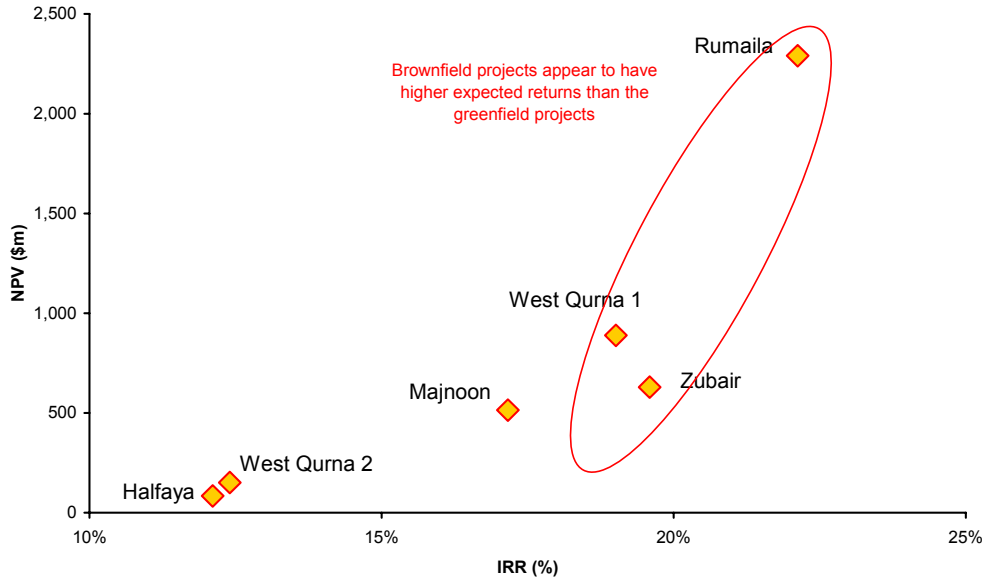
  4) One key aspect of the remuneration fee – it is a fixed amount per barrel. Which means that unlike almost every other oil contract in the world, **the IOCs have essentially no upside to the price of oil.**

  5) The PPTs theoretically must be achieved within six years, but the penalty isn't overly severe. **Achieving PPT isn't crucial to adequate returns**.

- **Returns on the TSC projects are not spectacular** – the weakest among the Big Six will likely barely return the cost of capital if things go moderately well, and if there are major

delays or cost overruns, they won't be economic at all. The best projects (the first round "brownfield" projects) should have decent returns, but only have NPVs in the $1B to $2B range, hardly moving the needle for $100B+ super-majors.

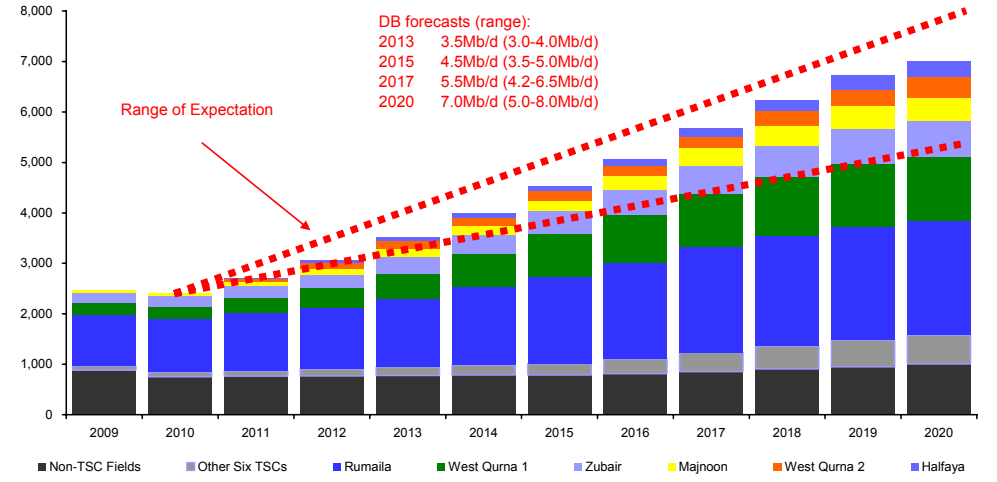
Figure 56: Expected project returns for Iraq's Big Six fields



Source: Deutsche Bank

- **Our current production forecast (and range) is below**. We expect Iraqi volumes to climb to about 4-4.5Mb/d by 2015, 5-6Mb/d by 2017 and perhaps 7Mb/d by 2020. IOC's, highly motivated to start cost recovery, will ramp up early to get to their First Commercial Production levels – that should get Iraq to about 3.5Mb/d within the next few years. If everything goes as planned, Iraq should add 200-500Kb/d of production each year.

Figure 57: DB production forecast for Iraq, with range



Source:IEA, BP, Wood Mackenzie, Bloomberg, Deutsche Bank estimates

- There are a dozen or more key constraints, both physical and political, that could delay or derail growth. The physical constraints include:

  1) **Equipment import capacity & local logistics** – hard to get people and stuff into the country due to neglected and war-damaged airports, ports and roads

2) **Access to rigs & other equipment** – at peak around 2015, IOCs will need to drill about 600 wells/yr via 150-200 rigs. That level of activity has been achieved before in Saudi, but we should expect cost inflation.

3) **Access to water for injection** – the projects from the first licensing round alone (Rumaila, West Qurna 1 and Zubair) are expected to need 6-8Mb/d of water to increase production meaningfully. Exxon is leading the study and development of a massive $10B+ water treatment and transportation project that will bring 12Mb/d+ of seawater from the Gulf to the southern fields.

4) **Pipelines & export capacity** – need to expand both export routes, the Iraq-Turkey pipeline (will add about 1Mb/d of capacity) and the Southern Export System (increase from current 1.7Mb/d to 4.5Mb/d by 2015). Foster Wheeler is leading the engineering and project management effort, Leighton Offshore signed a $733M deal to build two new large offshore pipelines and three 900kb/d capacity single point mooring offshore loading facilities. We should see useable capacity expansion come on-stream by the end of 2012.

5) **Dealing with associated natural gas** – Iraq currently flares about 700mmcf/d of natgas in the Southern fields, a number that could rise to 6-7Bcf/d if oil ramps to the levels we are anticipating. Oil Ministry struck a deal in 2008 with Shell to gather associated gas from four of the Big Six fields. Deal still hasn't been finalized, but expected soon. Iraq is woefully short natgas for power gen, so much of the gas will go to domestic needs, but Shell has talked about building a 1-2Bcf/d LNG facility at some point.

6) **Refining capacity & efficiency** – current 600-700kb/d refining system is dilapidated and inefficient. Oil Ministry wants to build 4 refineries with 750kb/d of capacity, but there has been no investor interest. Oil Ministry has said they'll build one themselves (near Karbala). They'll need all four by 2020 to keep up with growing domestic demand for products.

- The political constraints include:

1) **Stability & on-the-ground safety** – getting better, but one of the biggest risks for complete derailment of production is if the country destabilizes back towards a civil war.

2) **Ratification of contracts** – now that Maliki has cut a deal and a government will likely be formed by the end of the year, we will likely see a new Hydrocarbon Law and ratification of the IOC's TSC contracts.

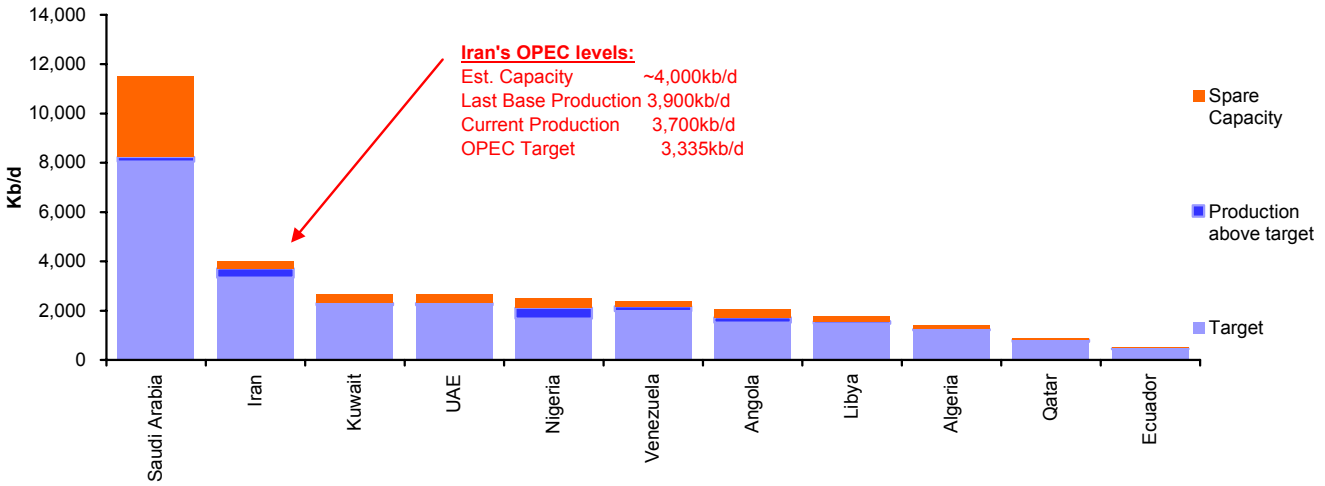
3) **Federal vs. regional vs. local** – Kurds likely joined Maliki in exchange for resolution of the federal-regional revenue sharing issue. Provincial governments have been pretty belligerent so far, IOCs have needed to be diplomatic in their interaction with local leaders.

4) **Regional rivalries** – Iran in particular. Iran will be very sensitive to production/quota parity with Iraq. Iran will increasingly be hurt by sanctions, while Iraq is attracting massive external capital, so there may be a shift in regional wealth and power towards Iraq after two decades of Iranian ascendance. It is unclear what Iran's reaction will be when and if Iraq production shoots past Iranian capacity of about 4Mb/d, but expect that to happen by 2015.

5) **OPEC politics** –Beyond Iran, OPEC and Saudi may at some point present a hurdle to production growth, but given that Iraqi oil is very much needed by the market, we think the issue of OPEC quotas may prove to be a smaller challenge than many currently perceive (unless global demand is well below expectation). Saudi is likely more concerned with a spike to $150/bbl+ than another drop to

$40/bbl, as they can make money at almost any price, but OECD behavioral change can kill the goose that lays the golden egg.

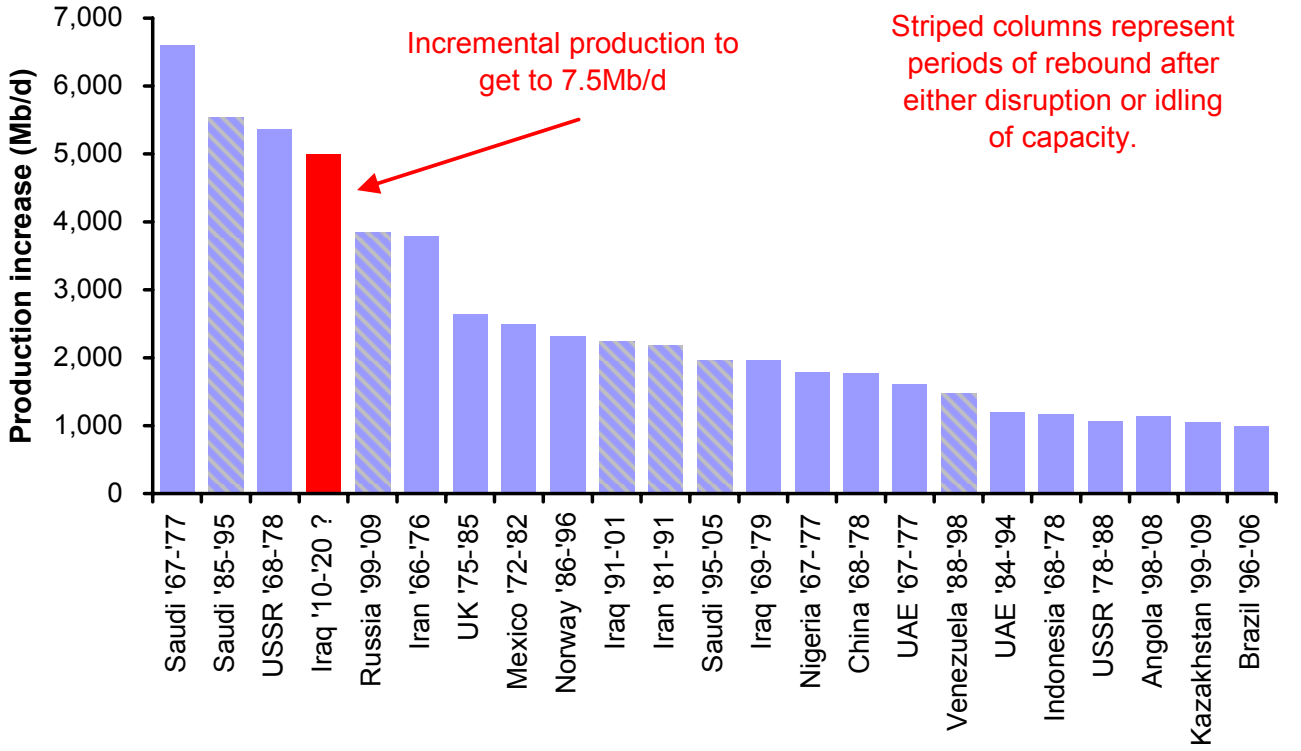
Figure 58: OPEC levels by member – estimated capacity, last base production, current production, OPEC target



Source: Bloomberg Finance LP, Deutsche Bank

- Kurdistan has its own contract format, a much more generous PSC that compensates for the risks of defying Baghdad's will and investing in the independent province. All of the super-majors and most of the majors have stayed away, but a couple of giant discoveries in 2009 (two of the biggest three oil discoveries in the world) prompted both Marathon and Murphy to sign exploration contracts this year. Baghdad will use pipeline access to limit Kurdish production growth, but we expect production in Kurdistan to ramp from the current 100kb/d to as much as 1Mb/d by 2020.
- Capex – For a ramp to 7Mb/d by 2020, we expect project capex of about $130B over the next decade. Another $70B or so will need to be spent on other related projects, such as pipelines, the Southern Export terminals, the Iraq-Turkey pipeline, the refineries, the water project, ports, roads, compounds, etc. That's about $200B over ten years, or on average $20B a year within an economy that is about $110B of GDP on a PPP basis. Given that level of spending, we expect Iraq to be the fastest growing economy in the world for the next decade.
- Over the long-term, we expect Iraq to lower global oil prices by about $5-$15/bbl, as low-cost Iraqi oil displaces marginal high cost supply, such as onshore Nigeria, Canadian Oil Sands, Venezuelan heavy, etc. See our Iraq note for the various cost curve scenarios through which we made this rough estimate.
- Over the medium-term, as we discussed in the first section of this note, Iraq's oil is very much needed by a market that may experience a rapid erosion of OPEC swing capacity. With 1.5-17.Mb/d of demand over the next five years, in the absence of Iraq growth, we think OPEC spare capacity would hit the "panic level" in about 3-4 years. With Iraq growth, that moment is pushed back by 2-3 years. If demand growth proves to be 2.0Mb/d+ per year, Iraq won't be able to save the day.
- To put the expected Iraqi production ramp in perspective, the chart below highlights the best ten-year volume ramp ups over the last 50 years. Only Saudi (twice) and the former Soviet Union have pulled off production growth greater than the 4-5Mb/d that we are forecasting for Iraq.

Figure 59: Best ten-year production ramps over last 50 years



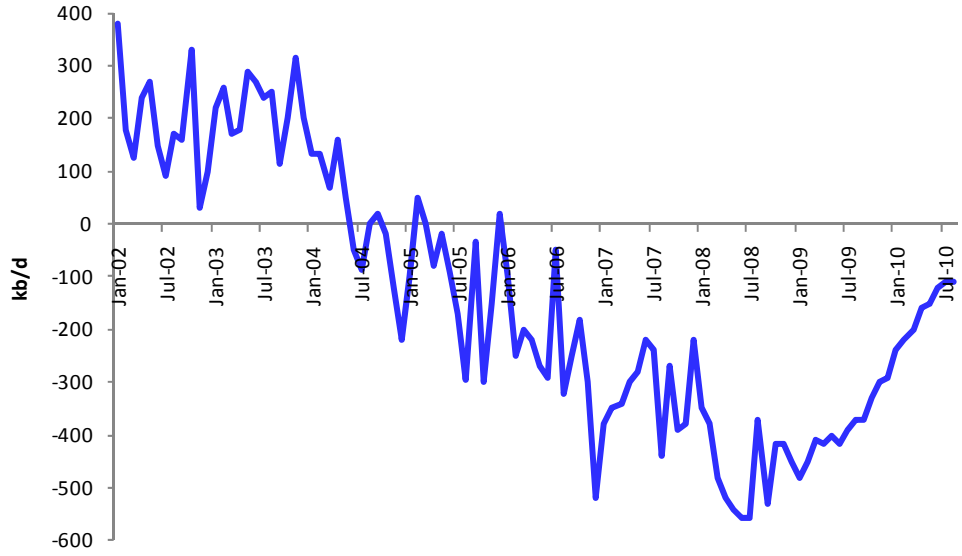
Source: BP, IEA, Deutsche Bank

The Mexican surprise – less declines and contract opening

Mexico's Supreme Court ruled on Dec 7 that Pemex may proceed with plans to award new "integrated service contracts", approved by the Pemex board on Nov 24, to private companies to drill for oil in the country for a flat per-barrel fee plus recovery costs. It also "removed obstacles" for the state oil company by re-iterating the legality of reforms to Mexico's restrictive energy laws in 2008; their Constitution prohibits the country from granting oil concessions or property rights in the energy sector to any foreign or domestic private companies. In fact, Pemex had been issuing "multiple service contracts" to Halliburton, Schlumberger and other private contractors for several years, and with this ruling, the way is clear for Pemex to open bidding on these more appealing "integrated service contracts" as early as this month, starting with mature fields in southern Mexico, then moving up to mature fields in the north, the complex Chicontepec basin, and the Gulf of Mexico. All contracts are expected to be awarded in 2011.

At the same time, the decline at the offshore super-giant Cantarell oil fields has been significantly slowed. Total Mexican production has flattened or is slightly up this year, surprising most forecasters.

Figure 60: Cantarell production stabilising



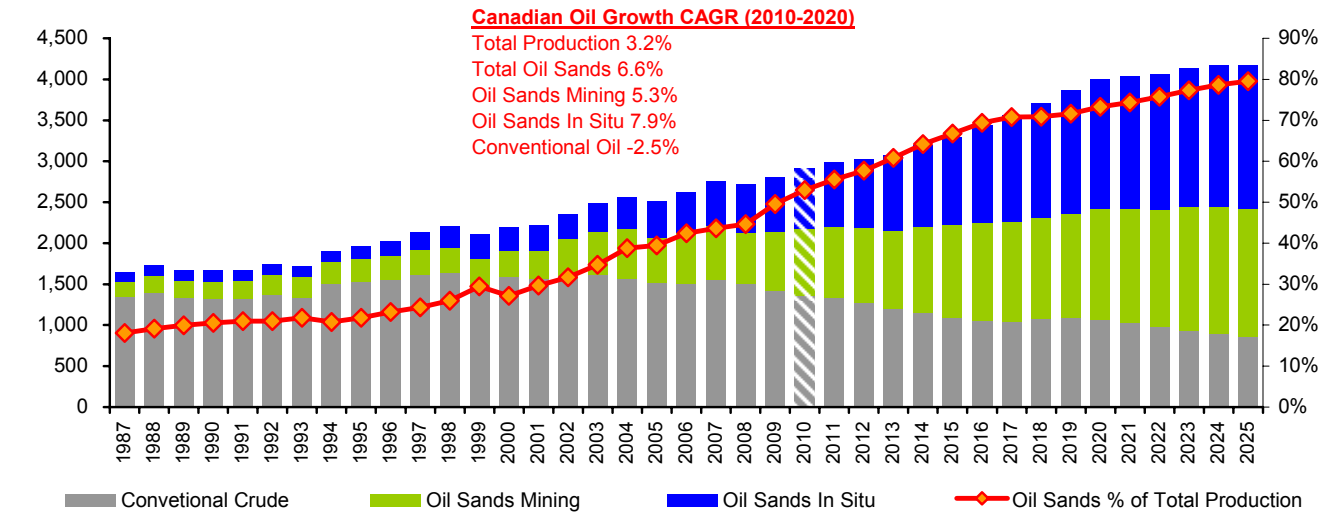
Source: IEA

Canada – steady volume growth from the oil sands

With lower geological and geopolitical risk than other oil producing regions, as well as a rising oil price that can justify investment, major international oil companies are driving another development surge in the Canadian oil sands.

Numerous projects were shelved during and following the 2008-09 credit crisis and economic slowdown, and now with $90 WTI, many of those projects are once again in the active queue. Over the next half dozen years we'll see mining expansions at Shell's AOSP, CNRL's Horizon and Syncrude, as well as start-ups at Imperial/ExxonMobil's Kearl, Suncor's Fort Hills and Total's Joslyn.

Figure 61: Canadian oil historical production and forecast (1987 to 2025)

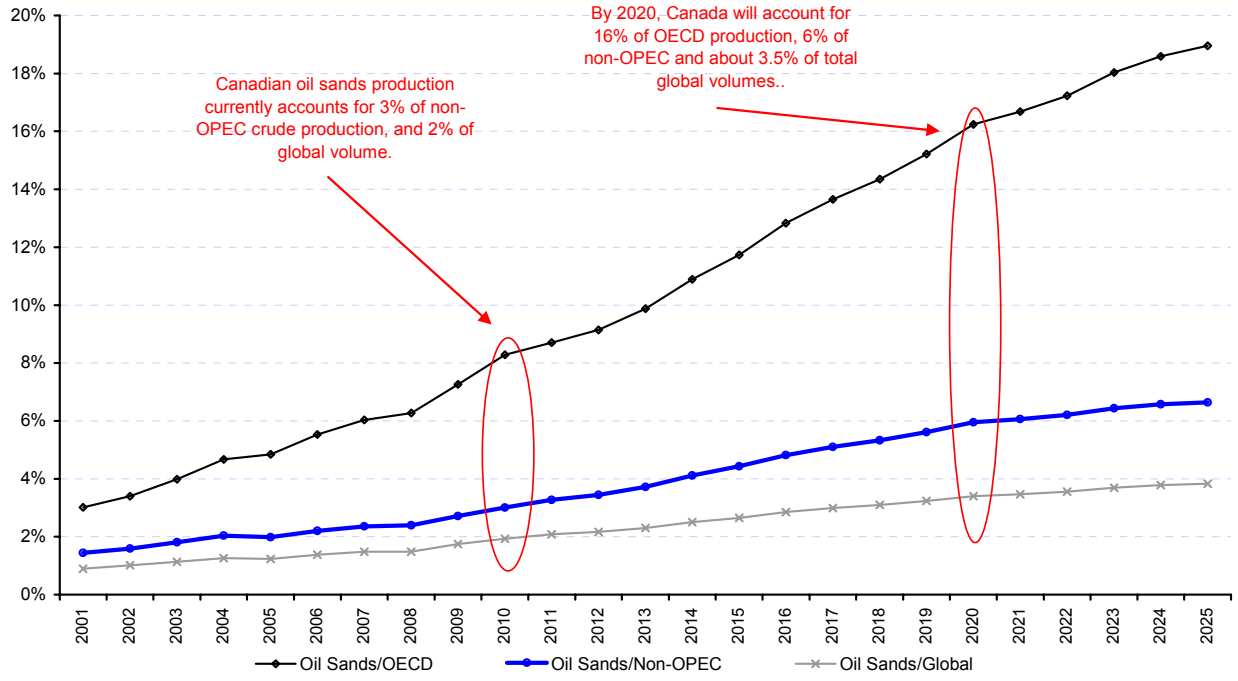


Source: CAPP, Deutsche Bank

The SAGD project queue is even more robust, with numerous phases of Firebag (Suncor), Foster Creek (Cenovus/ConocoPhillips), Christina Lake (Cenovus/ConocoPhillips), MEG Christina Lake, MacKay River (Suncor), Jackfish (Devon), Surmont (Total/ConocoPhillips), Long Lake (Nexen), Kai Kos Dehseh (Statoil), and Kirby (CNRL) coming onstream, with scores more by the end of the decade.

Altogether these projects will likely drive about 7% annual growth from the oil sands, and over 3% annual growth for total Canadian production, despite declining production on the East Coast.

Figure 62: Canadian oil is increasingly important to global supply



Source: CAPP, Wood Mackenzie, IEA,Deutsche Bank

By 2020 we expect Canada to account for 6% of non-OPEC supply and over 16% of OECD production.

Long Term Price

Calculating a theoretical equilibrium

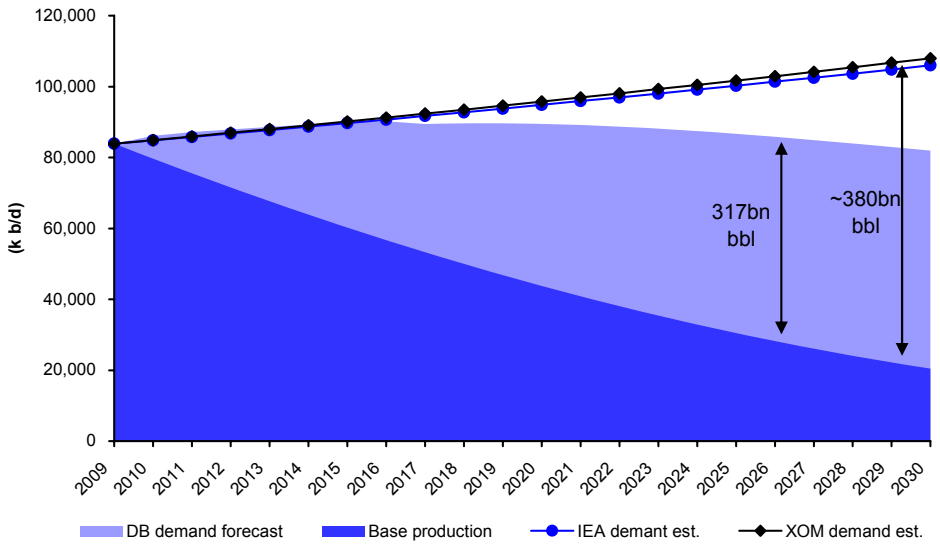
Based on simple arithmetic, over-layering a massively complex question, we can generate an investment requirement both in terms of barrels required for the future oil market, and in terms of new production developed to meet this demand, assuming given existing oil supply decline rates.

The most complete and thoughtful work on global oil supply decline rates comes from Fatih Birol and Trevor Morgan at the IEA, and essentially expects an acceleration in global oil supply decline rates from existing fields from around 5% to around 8% annually by 2030. So, as remaining oil concentrates into tougher geologic, geopolitical, and geographic provinces, simultaneously the supply challenge accelerates.

We have a less aggressive demand forecast than major credible forecasters such as the IEA and ExxonMobil, who expect a global market of around 110 mb/d in 2030. We are all using similar GDP (IMF) and population (World Bank) forecasts. The key differentiator is efficiency gains from transport, and increasing substitution by natgas in non-transport, as analysed in the demand section below.

We are forecasting a peak oil market in 2016-17 and sustained declines beyond that, quite unlike the remarkably similar ExxonMobil and IEA long term oil demand forecasts. That still presents a massive investment challenge, requiring some 317bn bbl of oil development and production over the given period 2009-2030.

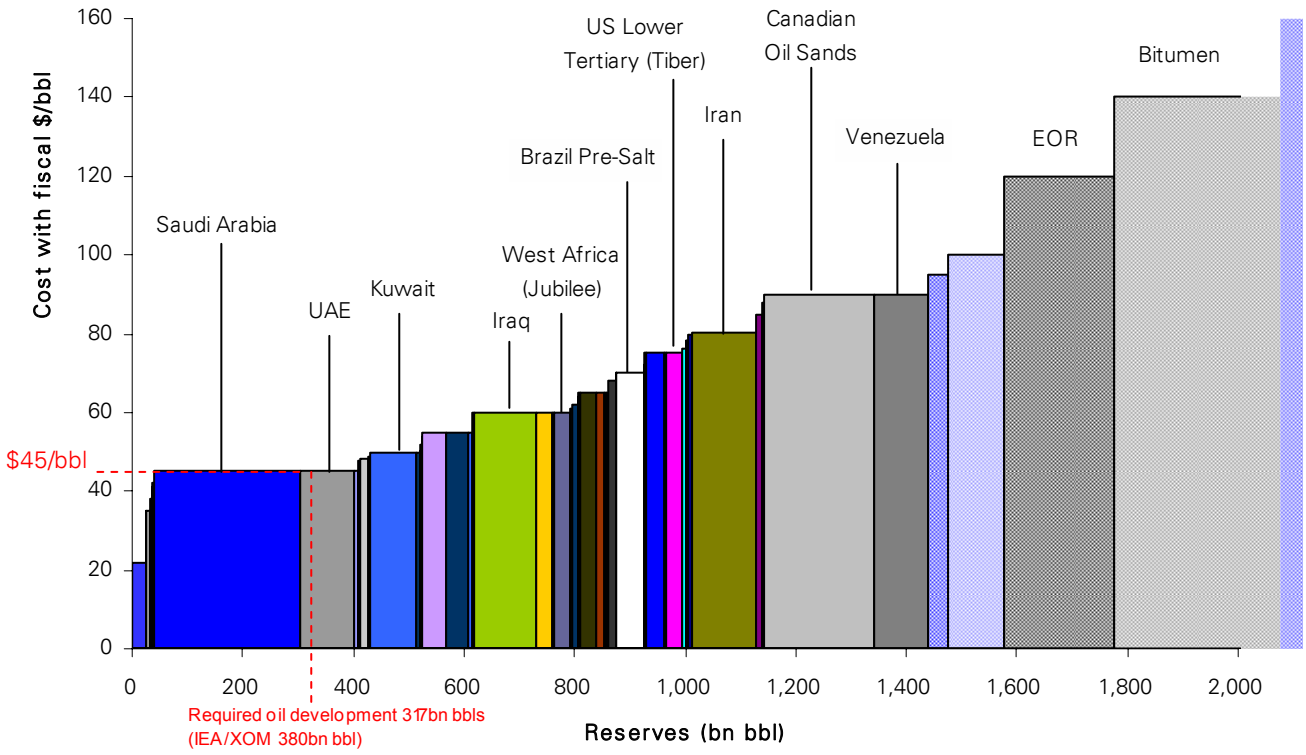
Figure 63: Required new barrels to meet forecast demand – DB vs XOM/IEA



Source: IEA, ExxonMobil, EIA, IDeutsche Bank

Looking at the full cost supply curve of major oil reserves, we can establish a supply price based on our 335bn bbl requirement.

Figure 64: Cost curve of future oil supply, assuming open access – available reserves at a given level of oil price

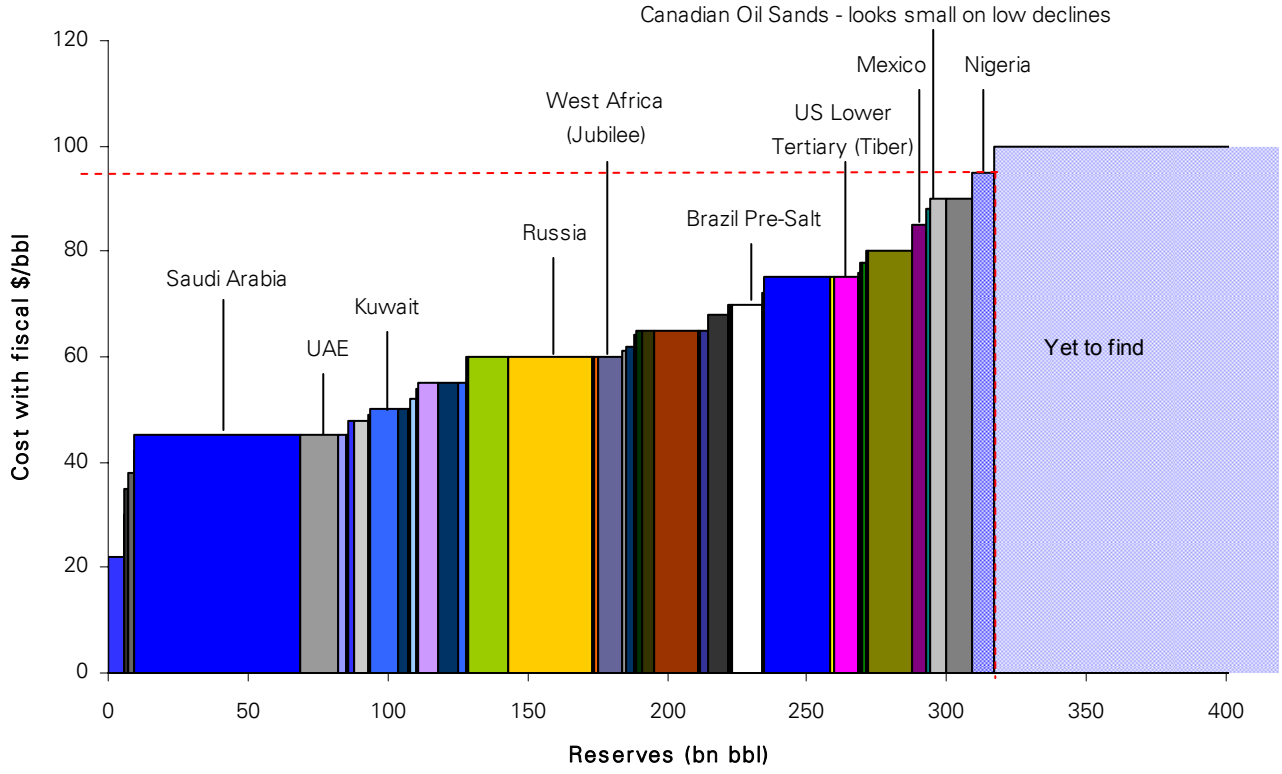


Source: IEA, Deutsche Bank

If the global reserves were exploited on a pure price basis, we could develop Qatar, UAE, Kuwait and above all Saudi reserves to the tune of the required 317bn barrels, which would imply a required price of around $45/bbl oil, even allowing for fiscal/social costs in those high demographic growth, government-spend-dominated economies.

However if we examine our own forecast of production growth, and the marginal cost of that production, the under-investment of major OPEC and government reserves holders will force the price of oil higher towards the marginal cost of the ~317bn bbl of realistically accessible resources. That immediately shifts the marginal cost of supply towards ~$100 per barrel.

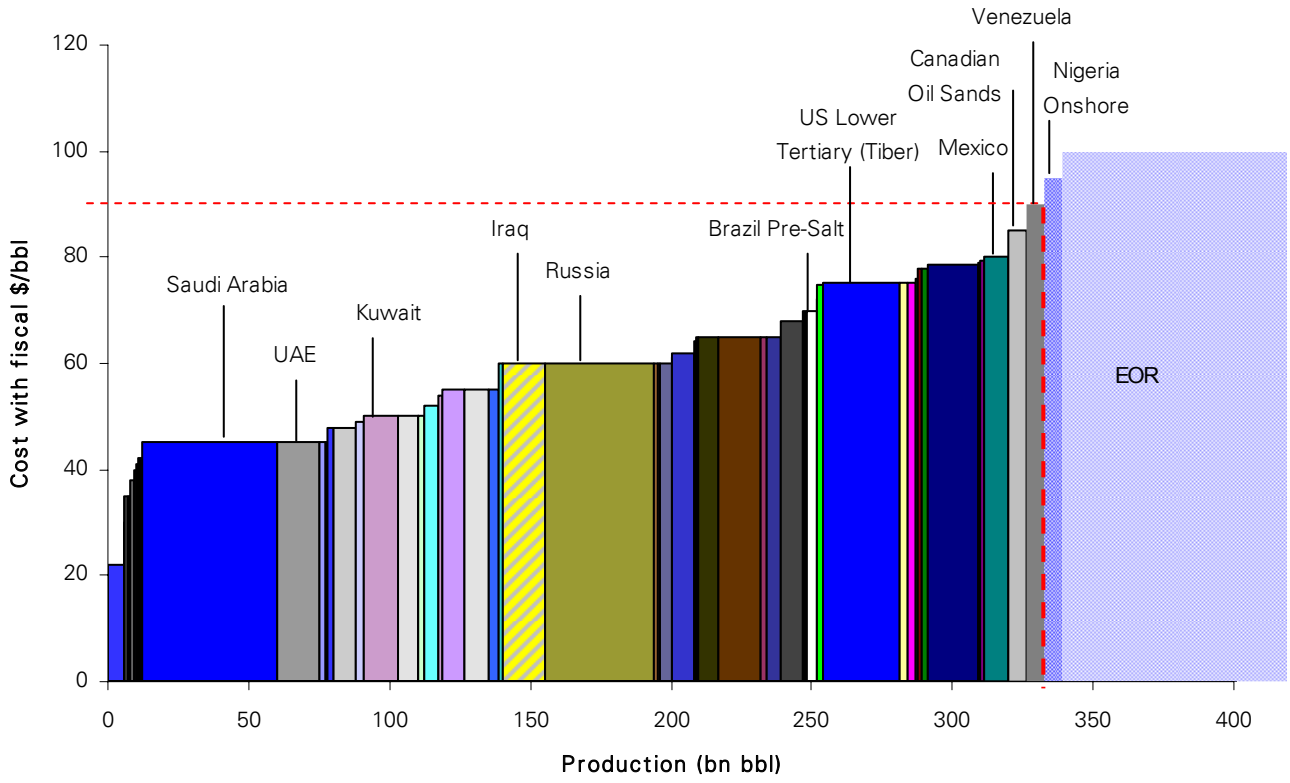
Figure 65: Cost curve of future oil supply, allowing for expected access and forecast development



Source: IEA, Deutsche Bank

And under the scenario where Iraq produces at 4mb/d, we see about a $5/bbl downward impact on the global oil price over the long term.

Figure 66: Cost curve of future oil supply, assuming Iraq produces at 4Mb/d



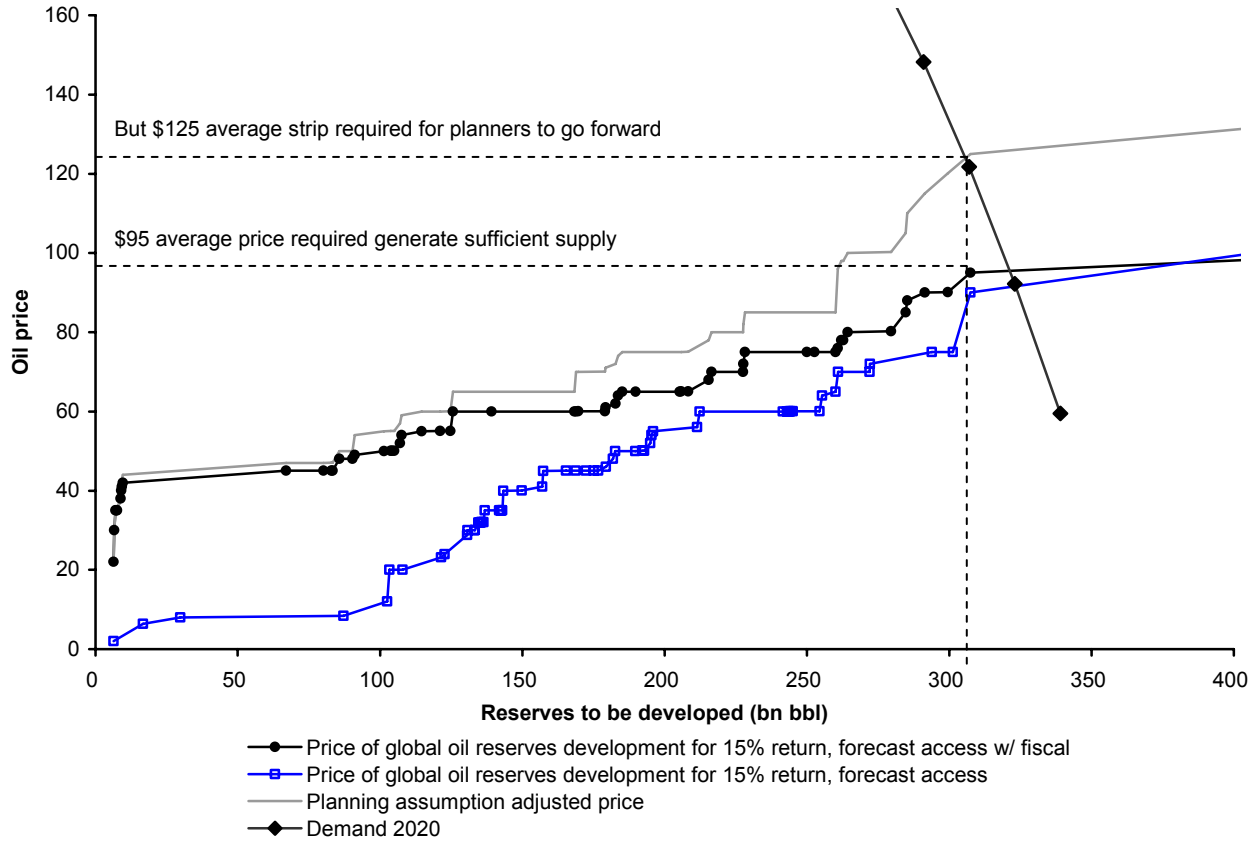
Source: IEA, Deutsche Bank

However, the price of oil has to be considerably higher than the full cycle development cost for a private company, made nervous by volatility and government risk, to invest. So whilst for certain government companies, such as Aramco, conviction on $50/bbl long term oil is enough to justify major investment in new capacity, for investors in Canadian oil sands, who require an $80/bbl long-term oil price to make a fair return (15% IRR), it would require a planning assumption/visible average oil price (i.e., average futures strip) of around $100/bbl for a major new investment to be sanctioned.

In short, the higher the oil price is forced by government intervention, the higher it must go to persuade volatility-nervous oil companies to risk capital.

The most obvious corollary of this function has been the rise of the buyback, whereby major oil companies in the oil price boom of 2004-2008, rather than chase rising costs and over-heated markets, focused instead on shrinking their capital employed by buying back stock. This is not as much under-investment as de-investment, but it could be argued to be the same thing; it certainly is in terms of its practical effect on physical oil supply.

Figure 67: Required oil price to generate planning assumption increase



Source: Deutsche Bank

If we take the line of economic break-even from Figures 65 and 66, we can show how governments force prices higher, by some $30/bbl on this chart, by under-investing in their own, lower cost resource (the difference between the lowest line's intersection with 317bn bbl requirement, and the middle line's intersection).

Again, there is an exponential effect, on planning assumptions, exacerbated by the higher the oil price the higher the volatility. Basically, a company will not invest in a project that requires a $100/bbl break even if the average oil price is $100/bbl. In fact, the company will require a degree of comfort, which we calculate here is around $25/bbl, to make an investment in a marginal project. So only with a visible and sustained strip price of $115/bbl, will oil companies invest in sufficient reserves to meet long-term oil supply needs sufficient to meet even a forecast declining demand profile for global oil.

For rising demand to 2030 (i.e., not our forecast but XOM/IEA), closer to $125/bbl is required, and the development of enhanced oil recovery, bitumen and oil shales becomes imperative. Additionally, as outlined in the demand section, we believe that in the short-term prices towards $125/bbl will be required to rationalise US demand sufficiently to offset inexorable controlled price and subsidised price oil demand growth, because the market will not - cannot - rationalise through more supply, but rather through less demand.

The next price surge

In the late 1970's price shock, it took oil rising to 11% of GDP to break demand. The 2008 price shock saw oil rise to 7.5% before there was a major demand response. We think that it will take less of a spike - perhaps 6.5% of GDP - for the next price surge to destroy demand because

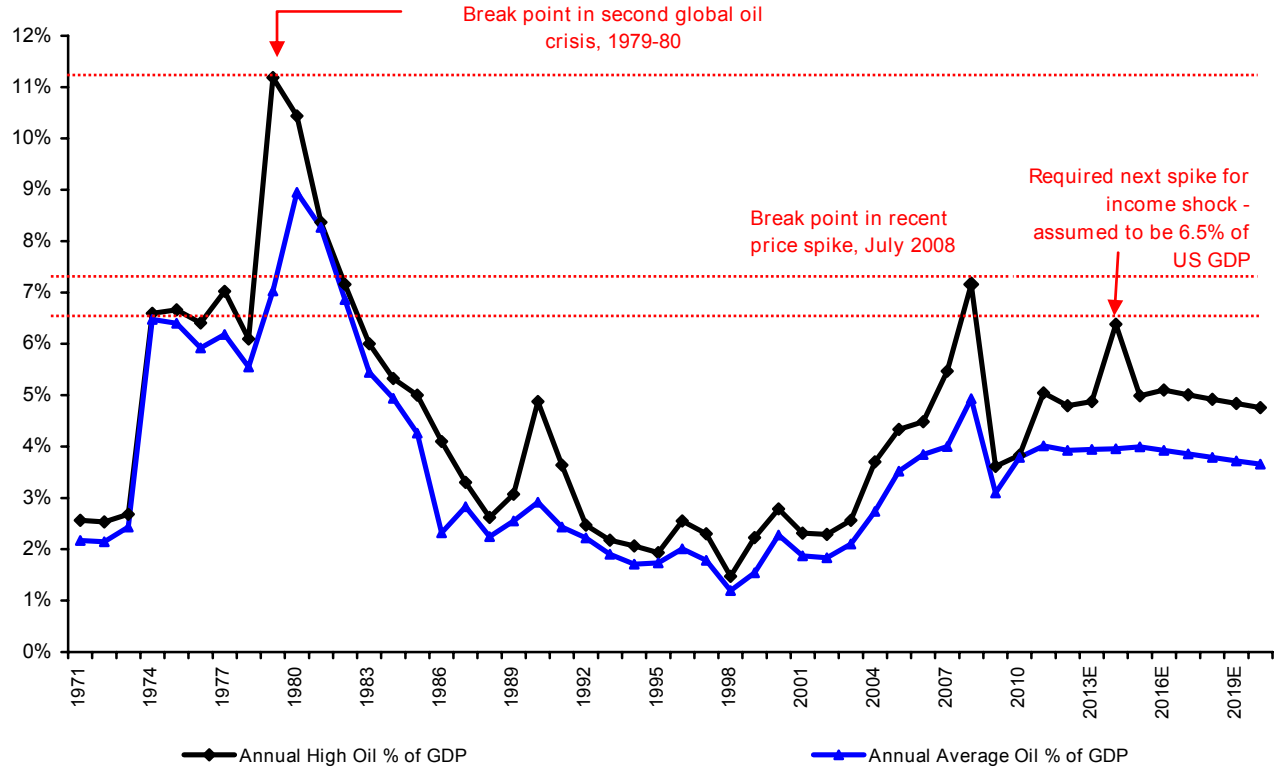
⇒ the last shock set in motion major behavioral and policy changes that will facilitate rapid behavioral changes when the next one comes, and

⇒ underemployment and weak wage growth has increased sensitivity to gasoline prices – last time it took $4.50/gal gasoline to finally tip demand, this time it might only take $3.75/gal to $4.00/gal to do it.

⇒ The counter argument is that Americans have become comfortable with paying more for gasoline, and it may take higher prices to force behaviour change.

⇒ Note that in early 2008 we argued that oil could not surpass $200/bbl because of the economic impacts, both negative (US, China) and positive (Middle East, Russia) that would over-whelm economies on both sides. In the event, as we reached $150/bbl, refining margins were crushed, and as the price of a tanker of oil spiraled, small cap US refiners were quickly pushed towards bankruptcy. We believe that if prices had gone higher, before long, shortages would have occurred in US product supply as refiners went bust, and demand would have corrected that way. In the event, US consumers changed behaviour.

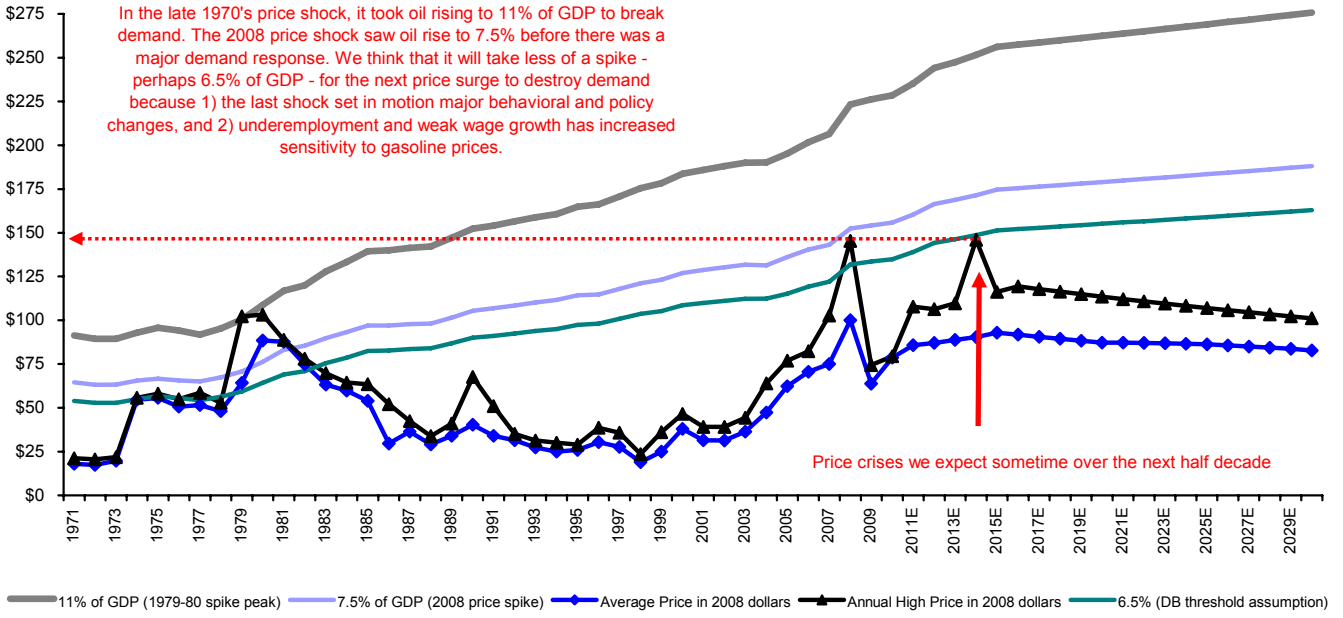
Figure 68: Break points in US oil demand – when consumers pay no more



Source: Deutsche Bank

If we translate the break point of oil cost relative to GDP in US$ per barrel, again we arrive at a price around $125 per barrel as the next peak point, sometime before 2015, depending on demand strength in the interim.

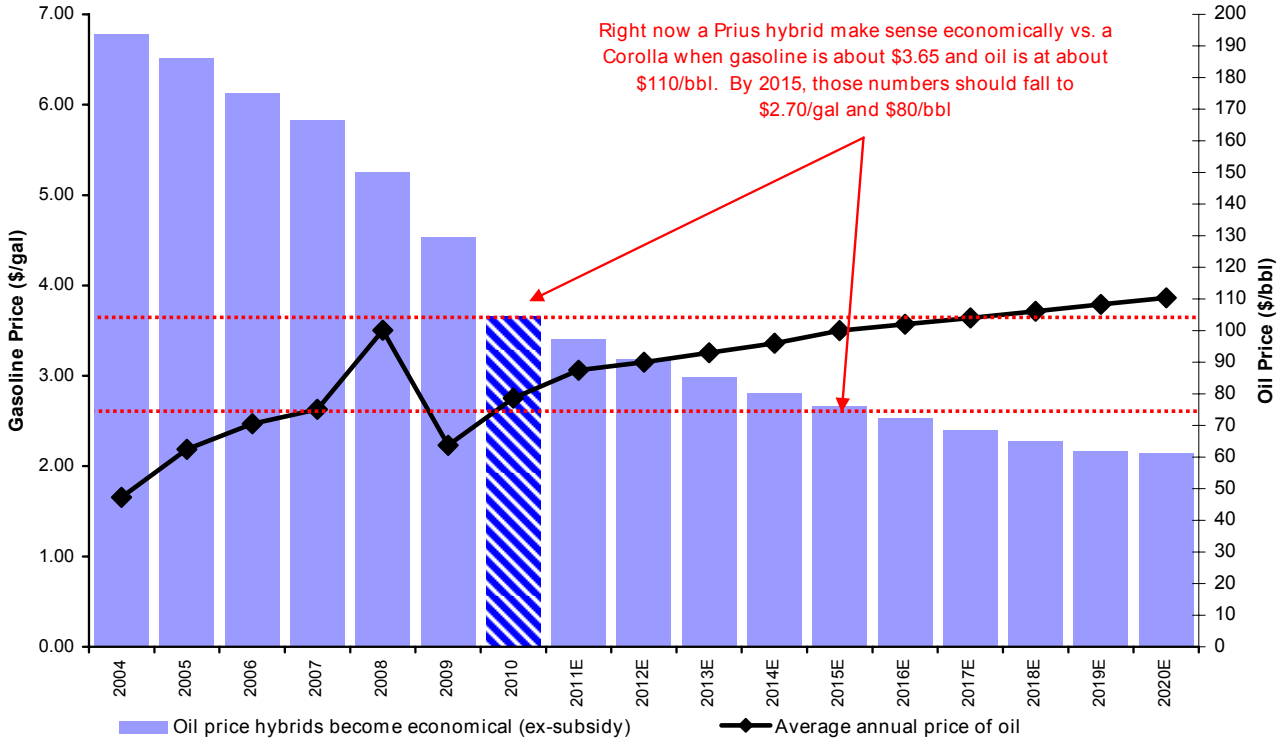
Figure 69: US oil in GDP expressed in US$ per barrel of oil



Source: Deutsche Bank

The market is trying to shift US behaviour towards long term greater efficiency, and as we have highlighted, that process is starting with the bankruptcy of the US auto industry and the imposition of greater MPG requirements that may yet prove to be, in our view, be the largest and least appreciated achievement of the Obama first term. As we have highlighted, and expected, as automakers compete to build hybrids and electrics their costs will fall, lowering the oil price at which they become economically attractive. As shown below, we are not at a high enough price yet to incentivise a US consumer to buy a Prius instead of a Corolla for purely economic reasons based on greater efficiency vs relative price premium, but that point is rapidly approaching and explains why our long term price charts have falling real prices. By 2014, US consumers will be incentived to buy a hybrid rather than conventional car at $3/gallon and falling.

Figure 70: Hybrids becoming economically competitive at lower gasoline prices



Source: Deutsche Bank

DB Oil Price & Refining Deck

Figure 71: DB oil & gas price and refining margins forecasts

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Average annual oil price/bbl - nominal	66.05	72.32	100.07	63.28	79.15	87.50	90.00	93.00	96.00	100.00	100.00	100.00	100.00	100.00	100.00
Average annual oil price/bbl - real 2008$	70.54	75.09	100.07	63.73	78.67	85.79	87.05	88.75	90.41	92.96	91.77	90.61	89.48	88.38	87.31
Intra-year high oil price/bbl - real 2008$	82.27	102.68	145.29	74.37	79.52	107.85	106.39	109.75	145.98	116.20	119.30	117.80	116.33	114.89	113.50
Natural Gas ($/mmbtu)	6.98	7.26	8.88	4.17	4.40	4.30	5.25	5.50	5.75	6.00					
Refining Margins															
Gulf Coast	10.85	15.10	11.00	7.11	8.03	8.63	8.63	8.63							
Gulf Coast Complex	21.23	21.52	19.00	9.38	12.27	13.80	13.80	13.80							
East Coast 2-1-1	11.75	13.54	14.00	7.35	8.72	8.00	8.00	8.00							
Midcontinent 3-2-1	14.13	18.85	10.00	7.88	9.20	12.00	12.00	12.00							
Midcontinent 6-3-2-1	8.86	12.69	6.00	5.57	6.44	8.50	8.50	8.50							
West Coast 5-3-2	21.44	23.68	17.00	14.46	14.67	16.25	16.25	16.25							
PNW 5-3-1-1	21.85	21.02	22.00	11.46	14.05	16.25	16.25	16.25							
Crude Spreads															
WTI-Maya	15.01	12.65	15.64	5.23	8.90	7.00	7.00	7.00							
WTI- Lloyd	21.09	23.84	22.54	10.67	11.80	10.00	10.00	10.00							
WTI-WCS			19.47	9.60	14.52	12.00	12.00	12.00							
WTI-WTS	5.21	5.06	3.76	1.55	2.00	2.00	2.00	2.00							

Source: Deutsche Bank, Bloomberg Finance LP

Valuation and risks

Figure 72: Valuation Comparison

Ticker	Company	Share Price	Price Target	Rec	Market Cap (US$bn)	Price/Earnings Ratio (x)			EV/DACF			EV/EBITDA			EV/ 1P Reserves
						2009	2010E	2011E	2009	2010E	2011E	2009	2010E	2011E	$/boe
Super Majors															
BP.L	BP	GBp 472.45	520.0	Buy	137.52	10.4	6.5	6.6	5.6	6.8	5.8	5.1	3.7	3.1	9.0
CVX.N	Chevron	$ 89.23	80.0	Hold	177.88	14.6	9.7	9.6	7.3	5.2	5.6	5.2	4.1	4.5	13.7
XOM.N	ExxonMobil	$ 72.72	65.0	Hold	355.43	17.7	12.3	11.6	12.0	6.8	7.1	9.1	6.2	6.5	14.4
RDSa.L	Royal Dutch Shell a	GBp 2103.50	2420.0	Buy	199.68	14.0	10.6	8.4	8.0	6.9	6.3	6.8	5.0	5.1	15.1
RDSb.L	Royal Dutch Shell b	GBp 2093.50	2420.0	Buy	198.73	13.7	10.6	8.4	7.1	5.9	5.4	6.0	4.3	4.4	12.8
TOTF.PA	Total SA	EUR 40.55	52.0	Buy	118.51	11.4	8.8	8.1	6.2	5.4	5.0	4.9	3.8	3.6	13.1
	Average					**13.6**	**9.8**	**8.8**	**7.7**	**6.2**	**5.9**	**6.2**	**4.5**	**4.5**	**13.0**
Mid-Majors															
BG.L	BG Group	GBp 1317.00	1330.0	Hold	69.15	15.7	17.1	15.7	9.2	7.0	7.9	6.3	6.1	6.1	20.7
COP.N	ConocoPhillips	$ 66.63	66.0	Buy	98.45	12.4	11.2	10.3	7.3	6.4	5.9	5.3	3.6	4.6	9.4
ENI.MI	Eni	EUR 16.55	17.0	Hold	78.54	11.5	9.1	7.9	6.5	4.8	5.0	4.0	3.2	3.3	17.7
HES.N	Hess Corporation	$ 76.01	58.0	Hold	24.96	22.0	15.1	13.9	6.6	5.5	6.6	4.9	3.3	5.0	16.2
MRO.N	Marathon Oil	$ 36.19	36.0	Hold	25.72	18.6	10.6	8.6	5.2	6.3	5.7	4.5	3.4	3.5	17.6
MUR.N	Murphy Oil	$ 73.44	72.0	Buy	14.19	17.3	16.9	13.1	6.0	4.3	6.2	5.2	4.4	4.8	27.1
OXY.N	Occidental Petroleum	$ 96.63	84.0	Hold	78.64	17.8	17.3	14.4	9.8	8.3	8.3	7.3	6.2	6.2	21.0
SU.TO	Suncor Energy	C$ 37.52	C$33	Hold	57.88	47.7	23.3	16.3	20.9	11.8	9.6	19.8	8.3	7.8	32.3
CNQ.TO	Canadian Natural Resources	C$ 43.86	C$44	Buy	46.79	13.0	17.8	14.3	7.0	7.3	7.4	6.1	6.6	6.4	13.5
REP.MC	Repsol	EUR 21.58	22.5	Buy	34.51	16.5	12.3	11.1	6.7	5.1	6.5	5.7	4.3	5.3	26.5
STL.OL	Statoil	NOK 139.10	138.0	Hold	73.82	12.0	10.5	10.5	6.1	5.1	5.7	2.8	2.8	2.7	15.8
	Average					**19.2**	**15.0**	**12.6**	**8.4**	**6.6**	**6.9**	**6.7**	**4.9**	**5.1**	**20.9**

Ticker	Company	Discounted Oil Price	ROCE			Price/Cash Flow (x)			Free Cash Flow Yield			Net Debt/Total Cap. Employed (%)		Dividend Yield	Total Cash Yield
		$/bbl	2009	2010E	2011E	2009	2010E	2011E	2009	2010E	2011E	2009	2010E	2011E	2011E
Super Majors															
BP.L	BP	90.48	9%	13%	13%	5.5	6.9	5.7	6%	4%	7%	15%	13%	5.3%	5.3%
CVX.N	Chevron	84.22	9%	17%	15%	7.2	6.0	5.6	1%	7%	5%	2%	0%	3.4%	5.1%
XOM.N	ExxonMobil	73.16	16%	20%	19%	12.1	7.4	6.9	2%	7%	7%	-1%	6%	2.5%	8.2%
RDSa.L	Royal Dutch Shell a	98.50	6%	9%	11%	7.7	6.9	5.5	-4%	1%	5%	13%	15%	5.3%	5.3%
RDSb.L	Royal Dutch Shell b	98.50	6%	9%	11%	7.5	6.9	5.5	-4%	1%	5%	13%	15%	5.3%	5.3%
TOTF.PA	Total SA	78.47	10%	12%	13%	6.1	5.1	4.6	3%	9%	8%	15%	12%	5.8%	5.8%
	Average	**87.22**	**9%**	**13%**	**13%**	**7.7**	**6.5**	**5.6**	**1%**	**5%**	**6%**	**9%**	**10%**	**4.6%**	**5.8%**
Mid-Majors															
BG.L	BG Group	169.88	12%	12%	11%	10.5	9.3	9.2	-3%	-1%	-1%	-17%	-19%	1.1%	1.1%
COP.N	ConocoPhillips	77.13	7%	11%	11%	5.5	6.8	5.2	4%	25%	10%	31%	17%	3.5%	10.0%
ENI.MI	Eni	117.30	9%	11%	10%	4.3	3.9	3.9	-1%	4%	7%	31%	30%	6.2%	6.2%
HES.N	Hess Corporation	94.24	6%	9%	9%	6.0	6.2	6.0	1%	-3%	-1%	18%	17%	0.5%	-0.5%
MRO.N	Marathon Oil	132.49	4%	8%	9%	4.1	5.7	4.6	-1%	6%	2%	21%	20%	2.8%	2.8%
MUR.N	Murphy Oil	106.16	10%	10%	11%	5.5	5.2	5.9	-1%	4%	0%	12%	8%	1.7%	1.7%
OXY.N	Occidental Petroleum	81.79	10%	13%	14%	9.4	9.6	8.4	1%	2%	4%	5%	3%	1.7%	1.7%
SU.TO	Suncor Energy	133.93	2%	5%	8%	15.6	11.8	7.9	-4%	0%	5%	28%	23%	1.3%	1.3%
CNQ.TO	Canadian Natural Resources	111.63	9%	10%	11%	5.1	7.3	6.6	11%	2%	3%	32%	30%	0.9%	0.8%
REP.MC	Repsol	97.40	3%	6%	6%	4.3	4.8	3.9	-11%	6%	2%	44%	44%	4.8%	4.8%
STL.OL	Statoil	110.14	13%	15%	13%	5.6	7.7	4.5	-1%	-21%	47%	27%	31%	4.1%	4.1%
	Average	**116.02**	**8%**	**10%**	**10%**	**7.0**	**7.2**	**6.1**	**-1.1%**	**0.0%**	**6.7%**	**20%**	**19%**	**2.5%**	**2.4%**

Source: Deutsche Bank, Bloomberg Finance LP

We take a two pronged approach to valuation of the integrated oil sector.

- Top down: taking financial performance from quarterly results and SEC filings, we calculate the classic ROCE / WACC model (ROIC/WACC = EV/IC; etc.). This states that returns above the cost of capital will enhance equity value. This yields an implied P/E which we apply to a mid-cycle earnings to derive a per share equity valuation.
- Bottom up: we cross check our valuation on an asset-by-asset basis. The value of an asset is the present value of the future free cashflow, net of debt, or net asset value (NAV). The sum of all the assets is the implied equity value.

Key downside risks for the integrateds include economic weakness that softens oil and gas demand, falling commodity prices, over-valued acquisitions, onerous regulation or changes to taxation, delayed permitting in key regions, such as the US Gulf of Mexico or Australia, cost inflation in very active regions, exploration disappointments and falling returns on marginal projects. Key upside risks include stronger-than-expected oil prices and exploration success.

In particular:

We value **ConocoPhillips** based on the average of our NAV and P/E analyses. We estimate net asset value at $77 based on a bottom-up analysis of future cash flows with ROCE/WACC. We then apply a discount of 10% to our NAV estimate to reflect asset risk, lowering our NAV-implied target to $69. Our analysis of Return on Capital Employed (ROCE) over cost of capital yields a target P/E of 9x, which we apply to our mid-cycle EPS estimate of $7.10 and results in a valuation of $64. The average of these two figures results in our blended $66 PT.

Risks to a Buy recommendation include a disappointing execution of their announced restructuring plan and much weaker oil and gas prices, to which COP is highly exposed, and more so than rival super-major oils. Another downside risk is yet another unexpected acquisition that puts further pressure on equity holders, though this risk has been mitigated by the company's clearly articulated asset rationalization plan.

We set our price target for **Murphy Oil** based primarily on our NAV. We estimate NAV at $66 based on a bottom-up analysis of future cash flows with a raised value based on an 80% risked addition of Suriname value. Apply a 10% premium for growth and oil price leverage optionality given its aggressive exploration programme/Asian crude leverage for an adjusted NAV target of $73. Our target P/E multiple of 14x (exploration premium) applied to our midcycle EPS estimate of $5.00 yields a $70 PT. The average of these two figures results in our blended $72 PT.

The main risk to our Buy is oil prices if China growth evaporates (although our recent note on 70% Chinese auto sales annual growth does not support this) and the potential of Iraq to get past 4m b/d of production over the coming 4 years. Murphy-specific risks are successive failures of its exploration activity, involving high risk and potentially costly efforts.

Appendix 1

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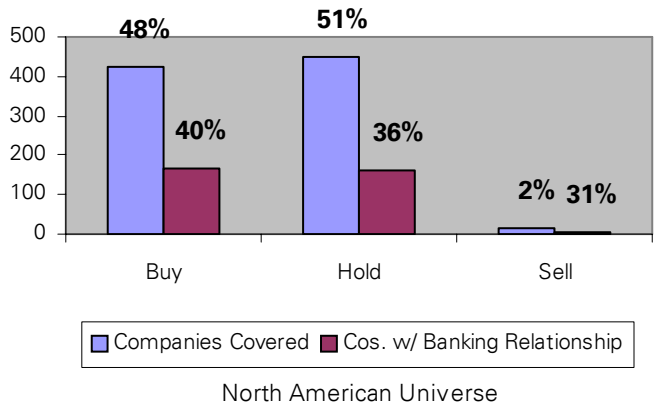
The views expressed in this report accurately reflect the personal views of the undersigned lead analyst about the subject issuers and the securities of those issuers. In addition, the undersigned lead analyst has not and will not receive any compensation for providing a specific recommendation or view in this report. Paul Sankey

Equity rating key	Equity rating dispersion and banking relationships

Buy: Based on a current 12- month view of total share-holder return (TSR = percentage change in share price from current price to projected target price plus projected dividend yield) , we recommend that investors buy the stock.
Sell: Based on a current 12-month view of total share-holder return, we recommend that investors sell the stock
Hold: We take a neutral view on the stock 12-months out and, based on this time horizon, do not recommend either a Buy or Sell.
Notes:
1. Newly issued research recommendations and target prices always supersede previously published research.
2. Ratings definitions prior to 27 January, 2007 were:
Buy: Expected total return (including dividends) of 10% or more over a 12-month period
Hold: Expected total return (including dividends) between -10% and 10% over a 12-month period
Sell: Expected total return (including dividends) of -10% or worse over a 12-month period



North American Universe

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