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Energy

How will Tight Oil Impact Global Oil Prices this Decade?

December 2012

Can Tight Oil Do To the Oil Price What Shale Gas Did to the Gas Price?

One of the major concerns among oil industry investors is the potential impact of the shale revolution on global oil prices. After all, look at the impact of shale gas production on US gas prices (Figure 1), which have averaged less than $3/mcf so far in 2012, having reached highs of over $12/mcf in 2005 and 2008. The precipitous drop and subsequent stagnation of US gas prices have been a direct result of surging US domestic gas production, driven by a rapid increase in production from shale gas plays due to overcapitalization (see our report "*Creeping to a Correction? Why the US Gas Market May be Poised to Recover*"), fuelled by plays such as the Barnett, Haynesville, Marcellus, Fayetteville and Eagle Ford. US gas production has increased from 50-55 Bcf/d from 1997-2007, to over 65 Bcf/d currently.

Not only will the US be self-sufficient in gas production for many decades to come, if investment continues in shale gas plays, but there is also the very real possibility that the US will become a major gas exporter, with several LNG liquefaction plants already being permitted. We believe that exports of gas from the US could help restore balance in the US natural gas market and help lift prices above the marginal cost in the medium term (in the near term falling production in high cost plays such as the Haynesville should help restore gas prices above the marginal cost). However, one key difference to note in the US between the oil and gas markets is that oil exports are not allowed under US law, while gas exports are allowed (albeit controlled by FERC such as the historical export of LNG from Alaska to Japan).

Nevertheless, given the surge in US gas production and more recent ramp up in US oil production, resulting from rapidly rising production in the Bakken (now over 600 kbopd), Eagle Ford (over 300 kbopd) and Permian Basin (over 1.6 Mbpd), there are real concerns over future US oil prices, as WTI is already heavily discounted versus Brent (Figures 2 & 3).

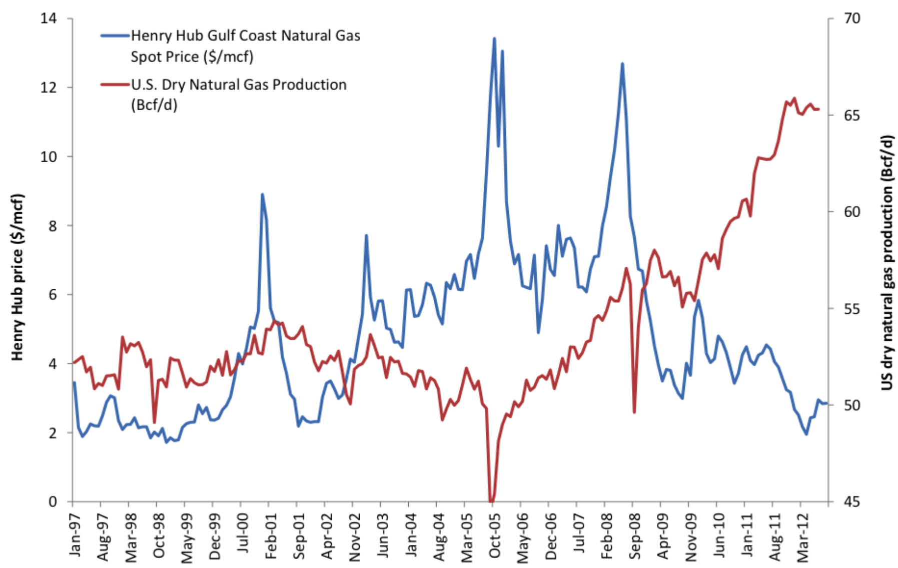


Figure 1: US natural gas price vs. US natural gas production (Source: EIA)

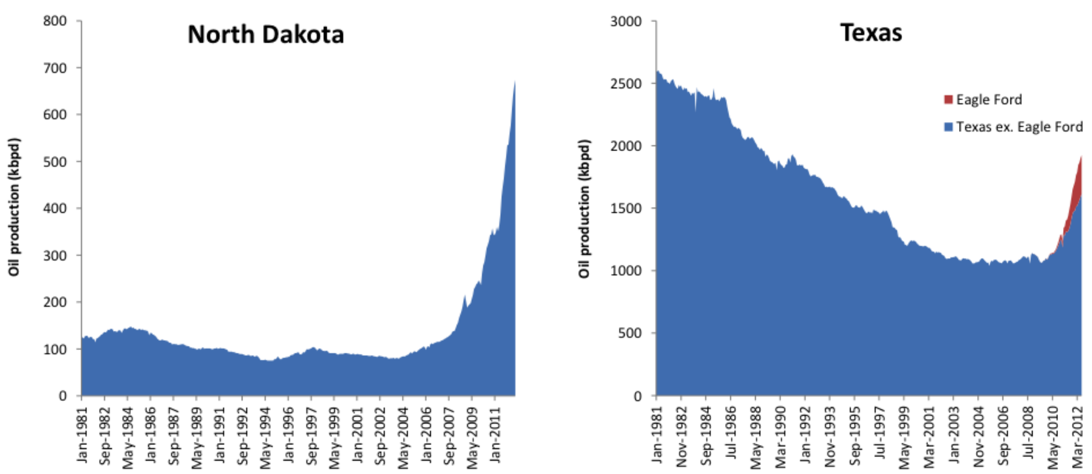
Indeed, as recently as the US Presidential election both candidates appeared to envisage a world where the US was self-sufficient in oil, not requiring any OPEC volumes, with the result that US foreign policy could change dramatically. Although as ever, politicians may appear to inhabit a parallel universe, the sudden growth in US oil production courtesy of new completion technology has to be studied and also projected on other oil producing regions across the globe.

Furthermore, investors and oil companies may be concerned that surging US oil production will result in a similar scenario as the US gas market, with prices dropping below the marginal cost and severely pressuring gas production economics. Additionally, without the ability to export oil, there is currently no long term solution to rebalancing the US oil market if oil production increases to the point where the US becomes self-sufficient.

It is important to note that although rising oil production from US shale plays has contributed to the discount of WTI relative to Brent, this has more to do with bottlenecks in the US crude transportation system that have resulted in excess supply in inland regions such as Cushing and little to do with oversupply in the US as a whole. Indeed, the discount of WTI initially began when crude pipelines were reversed to cope with increased volumes of Canadian crude, which also coincided with refinery outages and lower utilization, resulting in a disconnect between inbound volumes into the Cushing hub and Rockies region and outbound disposition of crude. Another important factor was the surge in light, sweet crude production from the Bakken and Permian Basin tight oil plays, which further exacerbated the excess supply situation and resulted in discounted oil prices in these regions.

When you think about it most of the onshore regions seeing new oil production from tight reservoirs were themselves the main oil producing areas from decades ago, and with the decline in their conventional production over the past 30 years, the midstream and downstream industry had to evolve, prior to the current about-turn.

In the near term we do expect to see continued discounts of WTI to Brent and other seaborne crudes of similar quality. However, with new pipeline and rail capacity being built to cope with growing supply from areas like the Bakken and Texas, we expect that in the medium term bottlenecks in the transportation system will be resolved allowing WTI to trade closer to Brent. Therefore, while the current discount of WTI to Brent is not driven by oversupply in the US, rather by regional bottlenecks, the key question is whether increasing tight oil production could impact oil prices through the rest of this decade in the same way that surging US gas production has impacted US gas prices.



Figures 2 & 3: North Dakota and Texas oil production (Source: EIA)

The Simple Answer

The simple answer to the "will it, won't it" debate on tight oil leading to oversupply, is no – we do not believe oil prices will be impacted in the same way as US gas prices. For now, tight only is a US-only phenomenon and US production is simply too small to influence global oil prices in the way that US gas production can influence US gas prices.

It is worth pointing out the fundamental differences between oil and gas as commodities. Specifically, gas is a regional commodity, with prices driven by local supply and demand. Because gases have much higher volume than liquids, natural gas is predominantly transported through pipelines, since the cost of transporting gas via tanker is much higher than oil (gas needs to be super-cooled, liquefied and compressed for export and then regasified on arrival).

In contrast oil is a global commodity, with prices set in the global market, as cheap transportation of crude oil can occur across the globe in VLCC's. This means that regional discrepancies in price tend to be quickly arbitraged away, resulting in convergent prices for crude oils of similar quality e.g. Brent, Arab Light, Nigerian Light and WTI.

But before we progress further, let us interject with a quick guide to crude types. Crude is typically described using two measures – sweet vs. sour (sulphur content) and light vs. Heavy (API gravity). Sour crude has a higher percentage of sulphur, making it harder to refine, thus lowering its price. The light versus heavy distinction refers to the chemical composition of the hydrocarbons, as is measured by API Gravity (inverse relation to Specific Gravity), where higher API numbers indicate higher proportion of light hydrocarbons constituting the crude oil, and thus lower density (or lower specific gravity). Oil contains a mixture of lighter, more valuable hydrocarbon compounds, such as gasoline and diesel, as well as heavier compounds, like asphalt. Thus the best (and therefore most expensive) type of oil would be a light sweet crude, while the least valuable would be a heavy sour crude.

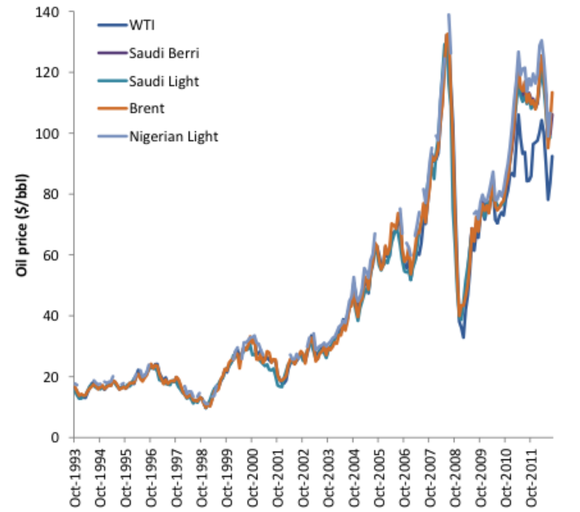


Figure 4: Prices for global light sweet crude oils (Source: EIA)

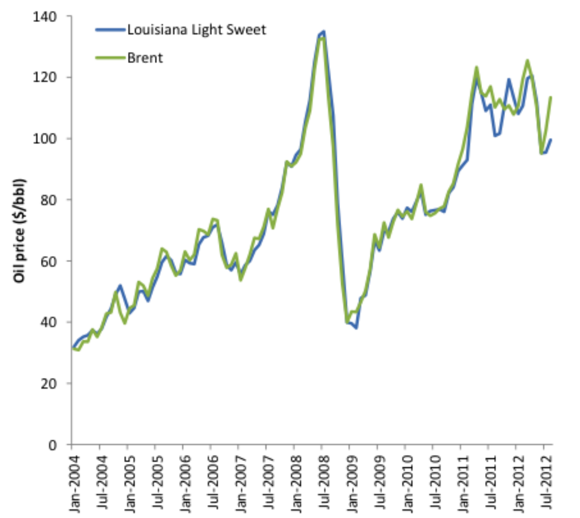


Figure 5: Louisiana Light Sweet crude price vs. Brent (Source: EIA)

Over the past 15 years, the world (and especially US refining companies) have been preparing for a world dominated by heavy (<30 deg API gravity) and sour (sulphur content >1%) crude from countries such as Canada, Venezuela and Saudi Arabia. However, the "tight oil" found in unconventional reservoirs is typically higher quality light (>35 deg API) and sweet (<0.5% sulphur) crude, similar to West Texas Intermediate (WTI) and Brent.

So a confluence of factors resulted in oversupply of crude oil at the Cushing Hub (the main Mid-Continent collection point in Oklahoma), including pipeline reversals to take Canadian crude south to the US; a surge in production of light, sweet crude from the Bakken and Permian Basin; and US refining capacity that is configured for heavy, sour crude oils. The result has been oversupply of light sweet crude at Cushing, where storage volumes have been at record levels for several years.

Therefore, WTI has moved to a significant discount to Brent and other seaborne light crudes in recent years (see Figure 4), due to a temporary imbalance between supply (inbound pipeline capacity) into the Cushing hub and disposition capacity (outbound pipeline capacity and local refining capacity). However, this is the exception rather than the rule, and if we look at Louisiana Light Sweet crude (similar quality to WTI), which does not suffer the same local supply bottleneck, it has traded very close to Brent over the last 8 years (see Figure 5).

A simple way to envisage the difference between oil and gas markets is to compare US gas supply as a proportion of US gas demand and US oil supply as a proportion of Global oil demand (see Figures 6 & 7). While this may seem to be comparing apples and oranges, this is actually appropriate since the relevant market for US gas is just the US market but the relevant market for oil is the global one.

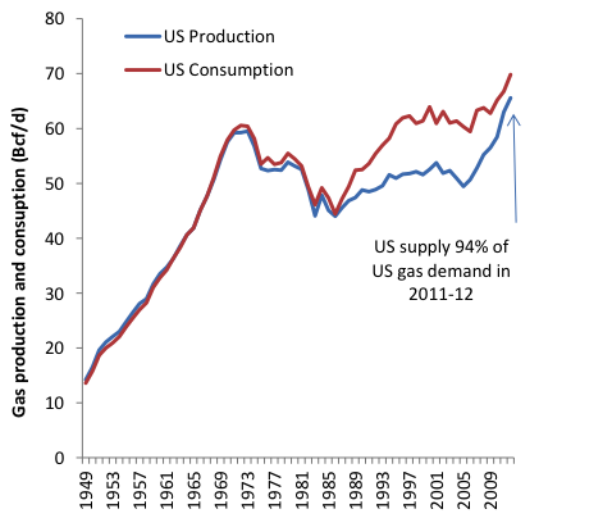


Figure 6: US gas supply vs. US consumption (Source: EIA and IEA)

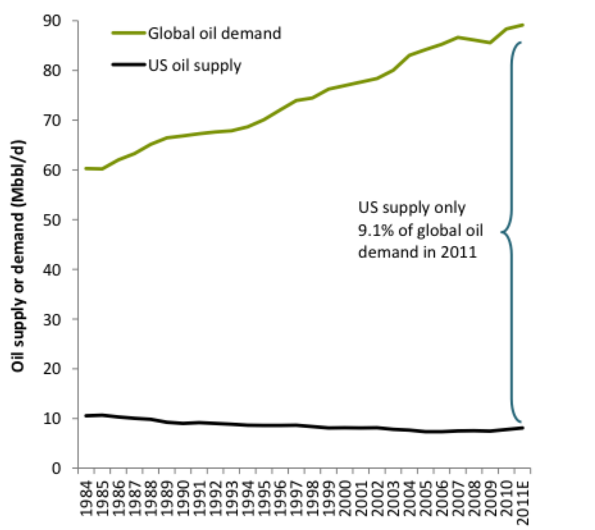


Figure 7: US oil supply vs. global consumption (Source: EIA and IEA)

The above makes it clear that even modest changes in US gas supply can have material impact on US gas prices, while increases in US oil supply will have a much more marginal impact on global oil prices. Indeed, in the last 3 years US oil supply (crude and other liquids) has increased by more than 1 Mbbl/d, but this is only 1% of the global market, so this has done little to prevent oil prices increasing consistently over this period. One major controlling factor in the oil market is OPEC supply, which is managed according to a quota system and is designed to control prices at levels that maximize OPEC member revenues without hampering global economic growth. Therefore, OPEC acts as a release valve in the global oil market. Such a release valve is absent from the US gas market (until a time when sufficient LNG export capacity exists) – US production is eventually shut-in when prices are low enough to make some gas supply uneconomic, as is the case currently (albeit slowly).

Consequently, with the US being the only major producer of tight oil currently, and potentially only Canada able to replicate this volume growth anytime soon, we do not anticipate a major impact on global oil prices in the near to medium term, despite the frenzy in shale appraisal activity globally.

Key point 1: *Tight oil production has a long way to go in the near to medium term, before it impacts global crude prices. However, regional oil prices such as WTI, will continue to be affected by transportation bottlenecks due to the renaissance of old production centres and insufficient existing takeaway capacity.*

Lessons from Shale Gas – Will Oil Follow the Same Path?

When analysing and forecasting commodity prices, it is often tempting to focus on macroeconomic trends and analogous scenarios for similar commodities. While these are useful, we also believe that accurate forecasting requires a fundamental understanding of what drives economics for a specific commodity, which can mean going all the way down to the molecular level.

Oil molecules are typically 10-20 times the size of a gas molecule, so extracting oil from tight rocks such as shale can be many times harder than extracting gas. Consequently, for a shale oil play to work with the same technology that works for shale gas, the oil needs to be located in more porous and permeable associated lithofacies (i.e. rocks that are adjacent to or interbedded in the shale). For today's technology, the dolomitic Middle Bakken or carbonate-rich Eagle Ford, are plays where tight oil has worked on a commercial scale.

In comparison, most shale gas production does come directly from areally extensive black, organic-rich shales, where the primary mode of gas storage is increasingly believed to be within the kerogen network. Despite the kerogen having only nano-porosity, the smaller size of gas molecules enables gas to be stored in these tiny pore spaces. The process of hydraulic fracturing and proppant embedment, results in an order of magnitude increase in permeability of the shale reservoir, which allows the flow of gas into the wellbore to occur.

Therefore, we believe that the set of potential economic shale oil plays is more restricted than gas plays (at least with current technology), due to the inherent difficulties in extracting a larger molecule from tiny pore spaces, and thus the need to find more particular geological circumstances in a tight oil play for economic production to occur.

Nevertheless, the industry has come a long way since pioneering horizontal gas wells with hydraulic fracturing in the Barnett shale since 2001. The learning curve in the Barnett with this new technology was slow, with the Barnett well

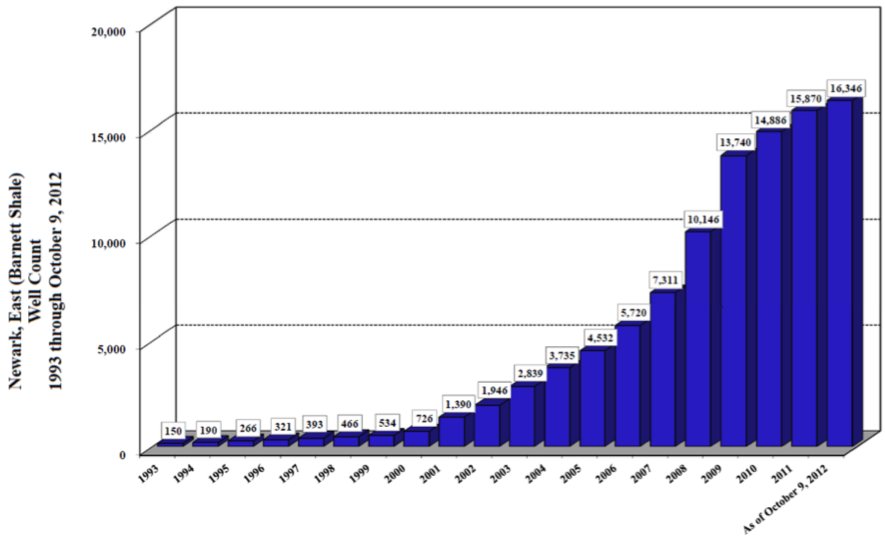


Figure 8: Well count in the Barnett shale gas play (Source: Texas RRC)

count only rising significantly after 7/8 years of testing and fine-tuning of the optimal completion method (Figure 8).

In contrast, using modern completion methods enabled material ramp-up in production in the Bakken to occur much more rapidly, with production rising from 2,000 bpd to over 100,000 bpd in less than 4 years. Further evidence of industry's move up the learning curve has been the Eagle Ford, which ramped up production from around 2,000 boepd to over 100,000 boepd in only 20 months (Figure 9). So although the set of potential tight oil plays may be more restricted than shale gas, the rapid progression of US technology should continue to expand the set of potential plays and also enable faster ramp-up to commercial production.

Indeed, throughout the US, previously marginal historic plays in e.g. the Mississippi Lime, have sprung back to life with the application of long laterals and hydraulic fracturing. In many instances, oil production was limited by porosity and permeability cut-offs in tight dolomites (carbonate rocks similar to limestone, but with higher porosity), despite the fact that the rock may have been oil saturated. Thus, the ability to improve reservoir properties has enabled areas like the Permian Basin to undergo a renaissance in production, due to the targeting of tight oil plays which are typically a combination of a shale and an adjacent tight carbonate interval that is oil saturated.

The technology that has enabled targeting of source rock intervals, which themselves present a huge potential resource, has also enabled companies to revisit marginal conventional plays and to boost recovery rates from existing fields. Therefore, while we believe that US liquids (crude, condensate and NGLs) production has plenty more scope to grow from its current level of around 8 Mbpd and is very likely to exceed its previous peak of over 10 Mbpd in the 1970s, we do not believe that the US will be flooded by oil from shale plays, largely because oil is much harder to produce from tight rocks than gas.

Key point 2: *Although lessons from shale gas can and have been applied to tight oil, it is important to remember that oil is not gas. It is a big molecule (C7+) versus a single carbon atom for dry gas, and therefore the criteria necessary for a successful economic tight oil play are narrower than for gas. So although new technology has allowed a faster ramp-up in new tight oil plays like the Eagle Ford, the set of tight oil plays is more restricted than shale gas plays.*

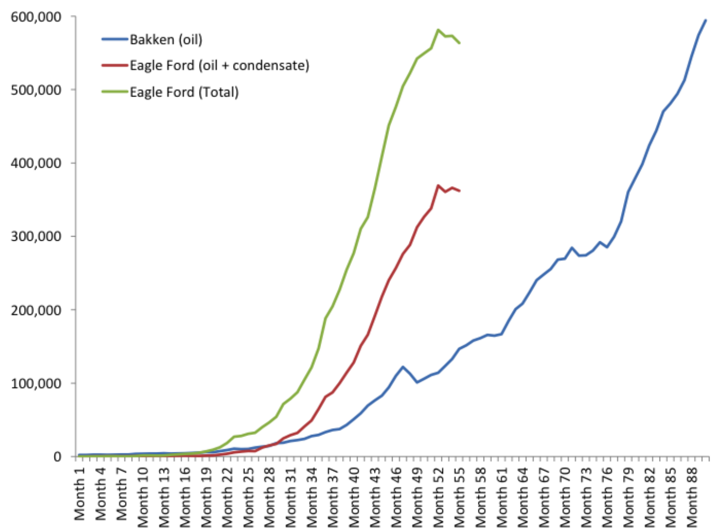


Figure 9: Comparison of production ramp-up in Bakken and Eagle Ford (Source: Texas RRC & North Dakota DMR)

The Impact of Tight Oil on US Production ... Returning to the Halcyon Days of Old

Currently, three plays/areas are already contributing material tight oil volumes in the US. These are the Bakken, Eagle Ford and Permian Basin. Plays like the Niobrara, Woodford and Utica are also contributing, but currently to a lesser extent. New tight oil plays will be discovered, and some currently marginal ones may ramp-up if a commercial completion method is figured-out.

We forecast that US liquids production (crude, condensate and NGLs) could surpass 10 Mbbl/d next year, and exceed the previous peak of >11 Mbbl/d (in 1973) by 2016 (see Figure 10). Our forecast has US liquids production getting to >13 Mbbl/d by 2021. This is driven by our expectation that the Bakken ramps up to 1.5 Mbbl/d, the Eagle Ford reaches >1 Mbbl/d of liquids, the Permian Basin horizontal plays reach >1.7 Mbbl/d, and new tight oil plays achieve commercial production. Additionally, we assume that US base production from conventional fields continues to decline at the historic rate of around 0.1% per month.

Given the lack of type curves for new tight oil plays, we have used the following methodology to forecast volumes. Depending on the type of play, we use either the Bakken (oil play) or Eagle Ford (combo play) as an analogue. Using our mass balance-derived unconventional resource estimates, we apply a Probability of Exploration Success and Probability of Commercial Success, to risk the potential resource size. We then apply recovery rates (according to play type) to derive estimates for recoverable oil reserves.

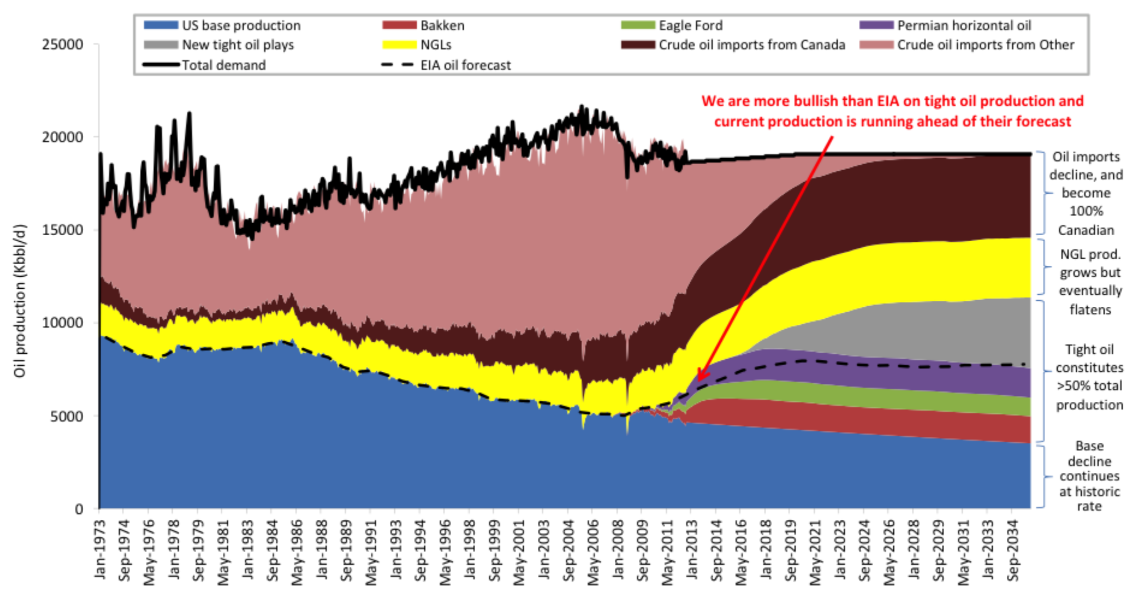


Figure 10: Forecast US liquids production (Source: EIA, Kimmeridge Energy, Texas RRC, North Dakota DMR)

The production profile for a given new play is then simply the recoverable reserves of that play, divided by the recoverable reserves of the analogue play (Bakken or Eagle Ford), multiplied by the monthly production rate of the analogue play. This essentially scales new tight oil plays versus proven analogues, to derive estimated production profiles that incorporate both potential resource size and the risks associated with achieving commercial production.

Overall, our forecast is more bullish than the EIA (US Energy Information Administration), but in line with other industry estimates (see Figure 11). Furthermore, the phenomenal increase in the US oil rig count (see Figure 12) gives us confidence that the surge in US oil production will be sustained going forward, as operators continue to shift their focus from gas to oil/liquids plays due to poor gas economics and technology continues to improve.

Such bullish forecasts for US oil production are now credible, due to the booming production in plays such as the Eagle Ford, Bakken and Permian Basin. Furthermore, our forecasts assume only a modest contribution from plays such as the Utica, which we estimate could contain massive in-place resources >600 Bnboe – the uncertainty with the Utica is how much is economically recoverable and what percentage of this is liquids and more specifically, how much of this liquids is equivalent to crude and not NGLs.

This leads us onto a broader issue, which is the substitutability of NGLs and crude. While natural gas condensate can be considered a substitute for crude oil, since it is similar in composition to gasoline (it is often called casinghead or natural gasoline, due to the fact that it usually has a C5-C9 composition, and has high content of C8 octane which is a primary constituent of gasoline), NGL cannot be considered a direct substitute, because it is primarily composed of lighter hydrocarbons such as ethane, propane and butane. These lighter hydrocarbons are used as petrochemical feedstocks to produce plastics, rather than refinery feedstocks to produce fuels. So, while surging US gas production from shales has greatly boosted NGL production, and thus overall US liquids production, this has not resulted in a one-for-one reduction in crude oil imports for the US.

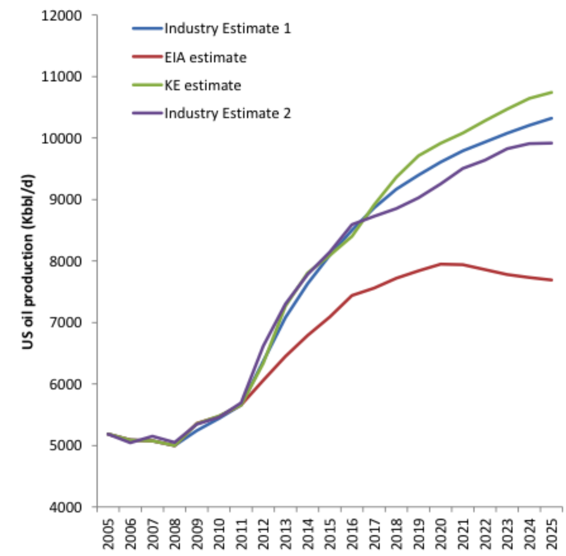


Figure 11: Comparison of US oil production estimates (Source: EIA, Kimmeridge Energy, Baker Hughes)

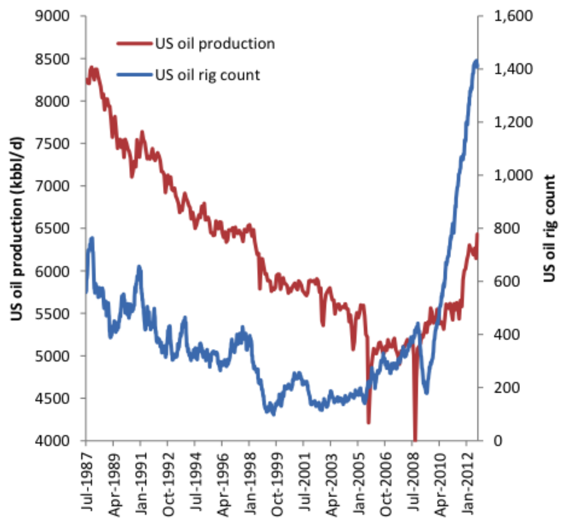


Figure 12: US oil production vs. rig count (Source: EIA, Kimmeridge Energy, Baker Hughes)

Therefore, assuming a significant ramp-up in existing unconventional plays like the Bakken and Eagle Ford; that new material tight oil plays are discovered and commercialized; Canadian import volumes continue to increase; and NGL production grows further, we do not expect that the US to become completely self-sufficient, although it should become independent from "foreign oil" (ex-Canada). Such strong growth in domestic production may continue to drive discounted US crude prices versus Brent, especially in areas with transportation bottlenecks such as Cushing. However, this discount does not result from oversupply in the US as a whole, rather from temporary regional oversupply.

Ultimately, since oil is a global commodity, we need to model global tight oil production to understand the likely impact of the shale revolution on oil prices. In the next section we look at the main technical bottlenecks that will slow the pace of the tight oil industry outside the US; which countries are most likely to contribute meaningful tight oil volumes; and ultimately forecast global unconventional oil production and its likely impact on the oil price. Although we are sure that tight oil will become a global phenomenon, it will take time, due to the nature of the industry outside the US.

Bottleneck 1: Knowledge is King

Looking at drilling density in countries around the globe, it is clear that the US and Canada have significantly more wells drilled over time than most other countries. Indeed, the number of wells in a mature US basin is often in the hundreds of thousands, versus e.g. the Lower Saxony Basin in Germany, which although one of the most prolific onshore basins in Europe has comparatively few wells drilled at around 18,000.

The most useful data for learning about the viability of unconventional projects are results and scientific measurements from wells that have penetrated the potential tight reservoir in the area of interest. Based on wildcat drilling activity in the last 4-5 decades (See Figure 13), it is clear that the US and Canada have a huge advantage in terms of availability of well data versus other countries. Basins in Russia and China have also seen a decent amount of drilling, but not on the same scale as North America. Additionally, much of the data in the US is publically available and often free, which allows easier entry for new players, and thus greater competition for resources and more rapid development.

One interesting example of this lack of knowledge is the Permian shales of the Junggar basin in Northwestern China. There has been much speculation about the potential tight oil production from Chinese shale deposits, but the lack of well penetrations in some basins means that resource estimates could be off by orders of magnitude due to scarce existing data. Permian shales in the Junggar Basin are quite possibly the richest known shales in the world, with a much higher Source Potential Index (SPI) than almost any other known source rocks on the planet,

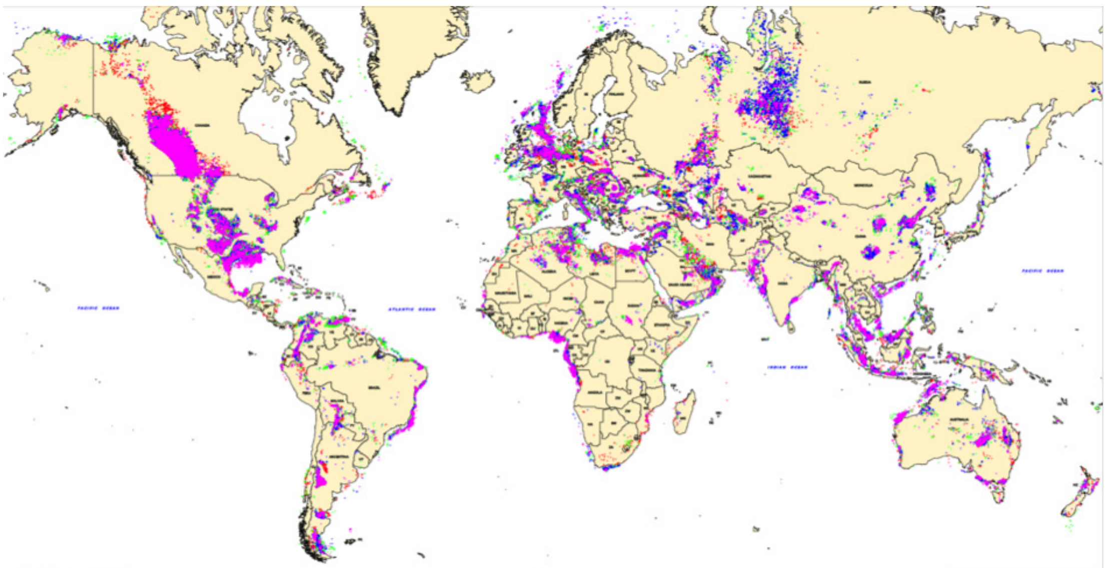


Figure 13: Wildcat exploration wells drilled 1965-2005 (note the very high density in the US & Canada) (Source: IHS)

including established US shale plays (See Figure 14). SPI measures the generative potential of a source rock per m2, based on S1 (free liquid hydrocarbons in place), S2 (remaining generative potential), and thickness.

However, the Permian Junggar shales are primarily lacustrine (type I kerogen, with some terrestrial type III input), and all of the proven shale plays in the US so far have been type II or mixed type II/III, which raises a big question mark over whether the Permian Junggar shales can work as a resource play. Since lacustrine source rocks expel much of the oil they generate, this typically leaves a much lower proportion of hydrocarbons in place, within or adjacent to the source rock interval (Permian Junggar shales do contain some type III kerogen, which is highly petroleum retentive, so may limit overall expulsion efficiency).

Furthermore, looking beyond the immense richness of this Permian lacustrine shale, there is very little knowledge of areal extent (see Figure 15), lateral homogeneity, maturity, expulsion, migration, mineralogy, etc. This obviously makes accurate assessment of resource size very difficult and thus by definition building a reasonable production profile is almost impossible. Thus far our knowledge of this potentially world class source rock comes largely from one outcrop where the shale is extremely thick (>2000m with 800m net shale), early-mature for oil and organic-rich (average TOC ~4%).

This scarcity of data is not confined to the Junggar basin in China. Indeed looking outside of the US and Canada, where there is typically much lower well density, companies face a much longer learning curve, as existing knowledge of domestic shales and basins lags significantly behind North America.

Furthermore, once sufficient knowledge of potential resource size is gained, through analysis of historic wells and modern science wells plus seismic, the next major challenge is to understand optimal completion techniques for a play. Again, there is a huge knowledge gap between the US and every other country, except

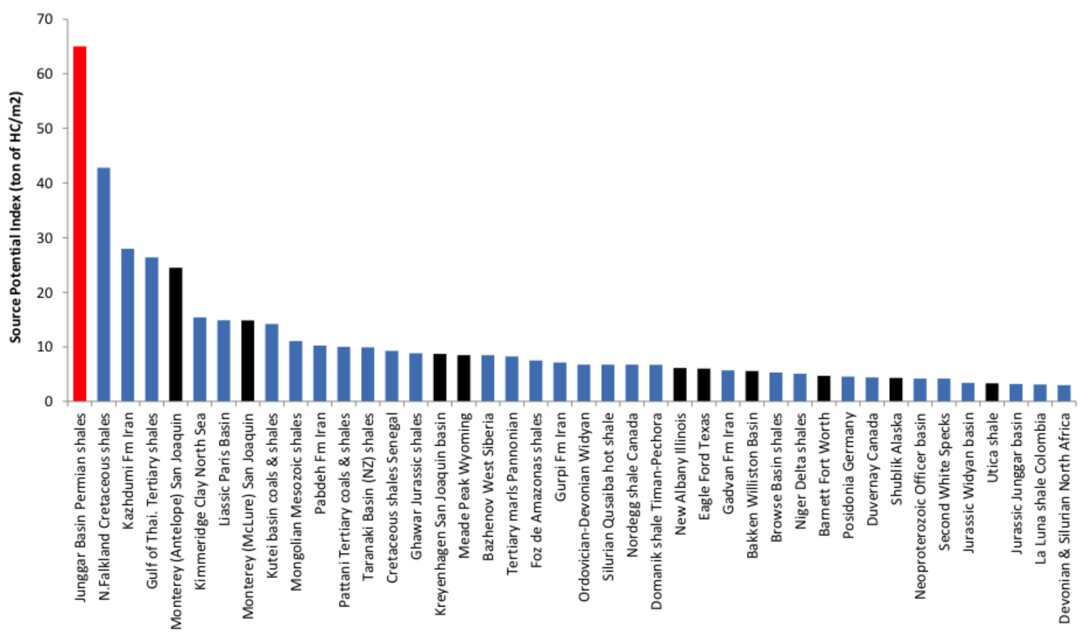


Figure 14: Source potential index for global source rocks
(Source: USGS, AAPG, Kimmeridge Energy, numerous academic papers and industry reports)

arguably Canada, due to cross border knowledge exchange. Some may argue that "where there's demand, supply will materialize", which certainly seemed to be the case in Poland.

Initially no modern rigs or fraccing crews were available in Poland but once sufficient critical mass was achieved with E&Ps on the ground ready to test the shale gas concept, modern rigs and frac crews materialized, courtesy of companies such as Schlumberger. Companies ranging from small E&Ps to supermajors subsequently drilled numerous test wells (horizontals and hydraulically fractured), but none of these achieved commercial flow rates. Failure was likely down to a combination of insufficient historic knowledge of the geology and inexperience with completion design.

While ExxonMobil has exited the play, smaller players that have essentially "bet the farm" on Poland, are now targeting the deeper Cambrian shales, as these are believed to have lower clay content than the previously targeted Silurian-Ordovician shales, so may respond better to hydraulic fracturing. Notably, we conducted initial geologic screening and due diligence on Poland, and visited several well sites in 2011, but we remained very uncomfortable about the lack of significant historic conventional production, which greatly increases the geological risk of the play, as there is no certainty that the source rock has generated large amounts of hydrocarbons. Indeed, we believe that targeting mature petroleum provinces with significant historic production and reserves is the best place to look for unconventional deposits and certainly reduces overall investment risk (see our report "*Brother From the Same Mother? The Relationships Between Unconventional and Conventional Oil and Gas Resources*", Sep 2012).

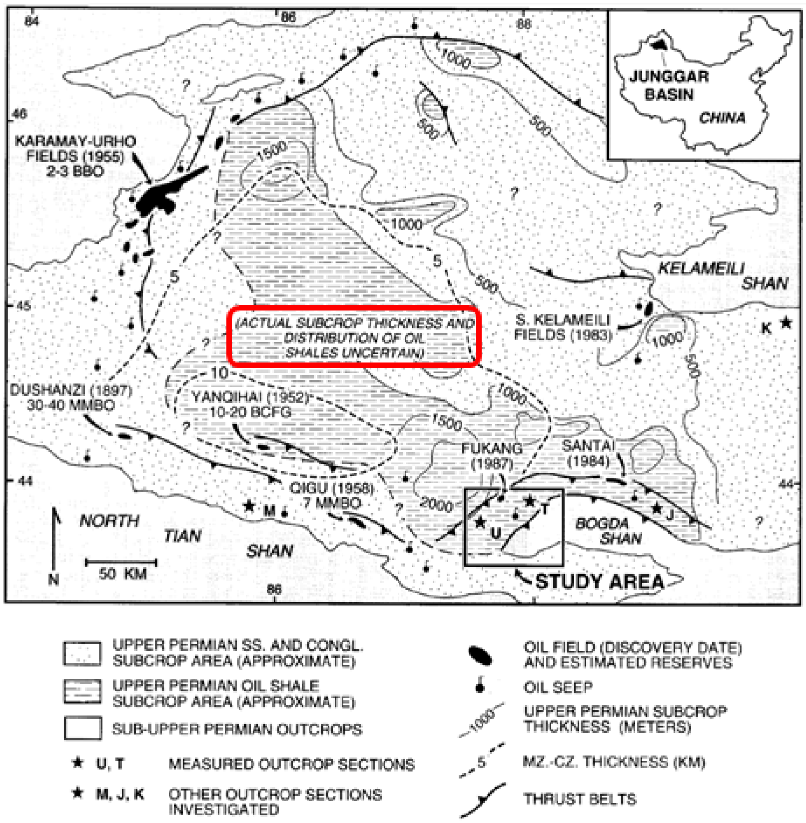


Figure 15: Approximate areal extent and thickness of Permian shales in the Junggar basin (Source: Carroll et al. 1992)

Bottleneck 2: Quantity and Quality of Oil Services

Another reason to expect a slower pace of unconventional production outside of the US and Canada is the availability of rigs. According to Baker Hughes, there are over 2100 land rigs operating in the US and Canada, but only 1100 land rigs operating in the rest of the world, excluding Russia and China. This means that E&Ps in the US and Canada have a huge advantage due to the constant availability of rigs not only in the exploration phase, but more importantly in the development phase, where big plays like the Bakken and Eagle Ford require something like 200 rigs continuously operating in full development mode. Indeed, according to the North Dakota Mineral Resources Department, there are currently 188 rigs active in North Dakota, 184 of which appear to be targeting the Bakken/Three Forks play (Figure 16).

Furthermore, the quality of the service industry is crucial, as we are increasingly discovering the heterogeneity of different shale plays, and thus the very different optimal completion strategy for each play, and consequently different service requirements for each. And while Russia and China are believed to have significant onshore rig fleets, neither is comparable in quality to the US and Canada. For example, many of the rigs in Russia are Soviet era and not suitable for drilling modern horizontal wells. Additionally, there is limited availability of frac crews outside of the US and Canada. Added to this is a complete lack of experience in developing unconventional resource plays.

Key point 3: *Outside the US and Canada, the availability of historical well and geological data is significantly reduced and will slow the pace of new unconventional exploration. Coupled with this is the time delay to export oil field services and knowledge outside the US and Canada, which means that the pace of production growth of tight oil globally will not be on a par with North America.*

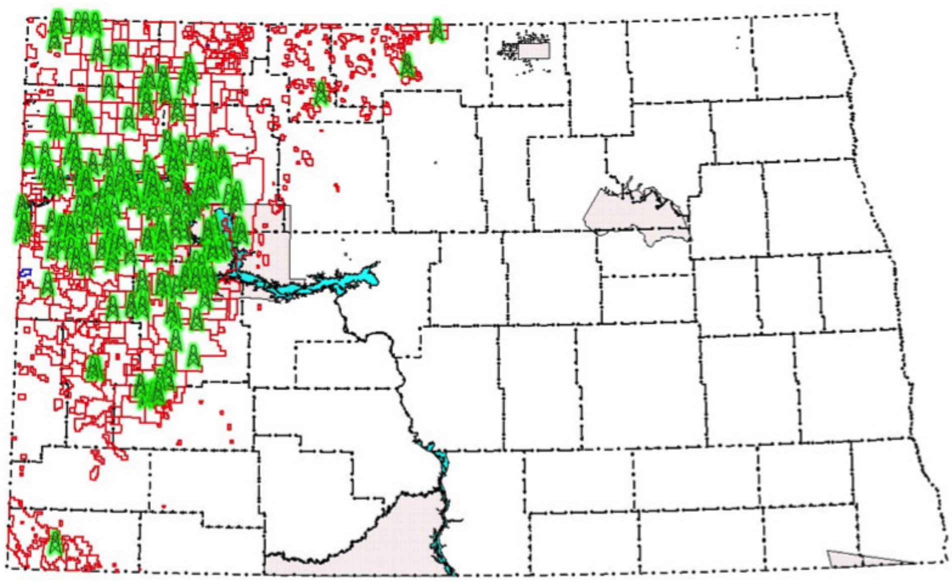


Figure 16: Current active rigs in North Dakota (North Dakota DMR)

Ranking Countries with Meaningful Tight Oil Production Potential This Decade

We believe the five most prospective global regions for tight oil production growth this decade outside of the US are Canada, China, Russia, Argentina and Western Europe, and we rank them as follows (Figure 17):

Notably, these are pretty much the same places where the oil industry began for conventional exploration and production, in large part due to the high quality of source rocks. There is of course significant geological potential in other regions such as the Middle East and North Africa, but we believe that development of these resources will significantly lag the above countries.

The US is already a major producer of shale gas and oil, so is clearly ranked first. Canada is fast following suit and is already producing material shale gas and oil volumes (see Exhibit 18), although it has no plays in full-scale development mode as per the Bakken and Eagle Ford in the US.

After the US and Canada, we believe the next country to produce material volumes of shale gas or oil could be Argentina, since around 100 wells have already been drilled into unconventional reservoirs in the Neuquen Basin in the last 18 months, with YPF (responsible for around 80% of wells drilled) reporting "spectacular" results on 2 wells with multi-stage hydraulic fracturing. One of the wells is believed to have produced "impressive" amounts of oil after a 10-stage frac, but no production data has been released.

Despite elevated expropriation risk following confiscation of YPF's assets from Repsol, the Neuquen Basin's exceptional geology, similarities

Ranking Country	1 US	2 Canada	3 Argentina	4 China	5 Russia	6 W. Europe
Significant in-place oil	>2 trillion boe	>1 trillion boe	~600 Bnboe	>2 trillion boe	>5 trillion boe	~300 Bnboe
Availability of land rigs	>1800	>300	66	Moderate	High	70
Quality of services	Very high	Very high	Low	Low	Moderate	Moderate
Drilling costs	Very low	Very low	High	Low	Low	Very high
Commodity prices	Moderate	Moderate	High	High	Moderate	Very high
Pipeline infrastructure	Excellent	Good	Very poor	Poor	Moderate	Poor
Favourable fiscal regime	Excellent	Good	Poor	Poor	Moderate (new regime)	Moderate
Population density	Low	Very low	Low	Low	Very low	Very high
Mineral rights & land access	Private, State & Federal	Mainly Provincial; some private	Federal	Federal	Federal	Mainly Federal
Political support	High	High	Moderate	Very high	High	Low
Environmental opposition	Low	Low	Low	Very low	Low	High
Energy demand/capita	Very high	High	Moderate	Moderate but growing fast	Moderate	Very high
Energy imports	High for oil	Exporter	Net importer	High for oil & gas	Exporter	High for oil & gas

Figure 17: Ranking of most prospective tight oil producing countries (Kimmeridge Energy)

with the Eagle Ford and early successful completion results have attracted numerous US oil companies into the play.

After this, we believe that China could be next to produce material shale gas and oil volumes, primarily due to its rapidly growing energy demand and desperate need to move away from coal, which continues to provide around 60-70% of its total energy needs. This has resulted in major political support for shale exploration; JVs between Sinopec, Shell and ExxonMobil; and the US-China shale gas initiative announced by President Obama in 2009. Furthermore, Chinese state oil companies have drilled many thousands of wells in the past half century, offering significant amounts of data on potential shale plays (albeit less than the US or Canada). Research to date has focused on the lacustrine black shales of eastern China, and the Ordos Basin has already seen economic production of tight oil in the Changqing field. And according to PetroChina's Research Institute, China has an estimated 300 billion barrels of recoverable tight oil reserves, with average production costs of $50/bbl.

Next could be Russia, due its enormous potential resource size, historic production from shales (Bazhenov and Domanik), the new fiscal regime for unconventionals, political support and deals by the Majors with Russian oil companies to appraise Russian shale plays (e.g. ExxonMobil and Rosneft). However, a major factor that could slow production ramp-up from tight oil, is simply Russia's large remaining conventional reserves and production, and the fact that it remains a large exporter.

Finally, in Europe with recent moves by Germany and the UK to allow hydraulic fracturing; companies already testing shale plays; increased political support; declining conventional production; a move away from nuclear; and the desire to reduce dependence on Russian gas – all of these suggest that countries such as Germany and the UK could see shale gas and oil production in the foreseeable future.

The real question is how significant volumes of tight oil could be in a global context and could they affect the oil price, which we attempt to answer in the rest of the report.

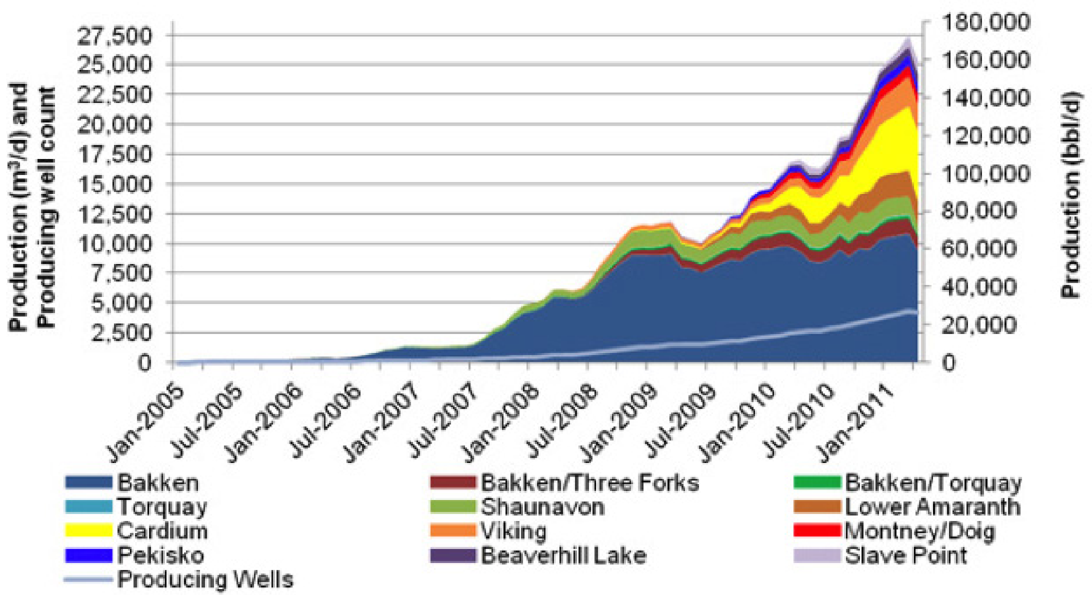


Figure 18: Oil production from Canadian tight oil plays (Canadian National Energy Board)

The Bakken and Eagle Ford As Analogues For Predicting Global Tight Oil Production

Constructing full field production profiles for the Bakken and Eagle Ford shale plays is admittedly a journey into the unknown. These are the first 2 development-scale tight oil plays on the planet, with less than 10 years of modern production history. Indeed, the USGS in 2008 estimated the Bakken's technically recoverable reserves of around 3.6 Billion barrels of oil, which given cumulative production since 2005 of 400 Mbbls and continued rapid month-on-month growth in production, looks extremely conservative.

Since then, the USGS has been tasked with improving their estimate, based on the incremental data gained from 4 extra years of production. In general the USGS estimates recoverable reserves for a continuous hydrocarbon accumulation by applying a type curve EUR and multiplying this by the number of potential drill locations, given the areal extent of the play. This approach seems reasonable in an established play like the Bakken, but less useful for new plays where limited wells have been drilled. Even for plays like the Eagle Ford, operators are still fine-tuning their completions, and defining the sweet spots of the play. Indeed, initially the Eagle Ford was a gas play with some liquids (see Figure 19). It is now primarily an oil play (due to current gas economics) with significant condensate and gas production.

Our own approach to estimating recoverable reserves and production profiles for tight oil plays is to first assess the oil and gas in place, based on a geochemical mass-balance approach, and then apply a range of recovery rates according to the play type and characteristics, based on existing rates in established plays. Next we estimate recoverable reserves using a type curve (based on an average of modern development wells) multiplied by the number of potential drilling locations (based on our assessment of the areal extent of the play). If the latter estimate falls within our range of estimates from our mass-balance approach, we can then model a full field production profile, based on 2 different but consistent methodologies.

For the Bakken, our mass-balance assessment indicates in place resources of around 276 Bnboe (primarily oil). Applying recovery rates of

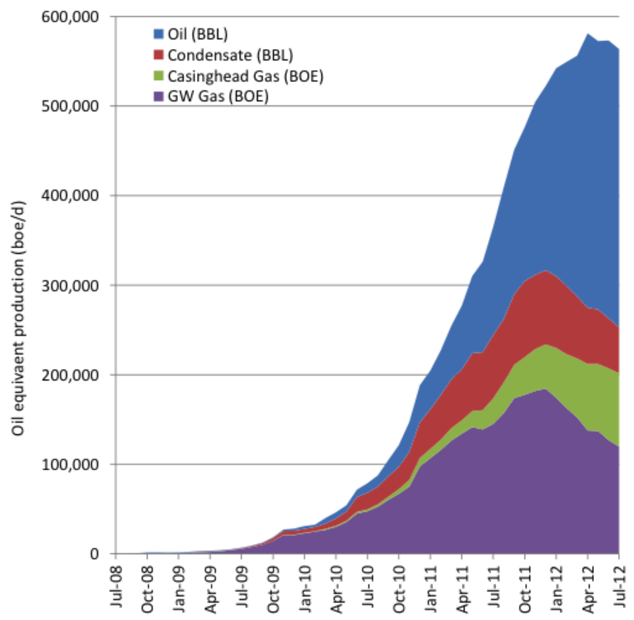


Figure 19: Oil, condensate and gas production from the Eagle Ford (Texas RRC)

5-10% gets us a range of recoverable reserves of 13.8-27.6 Bnboe, with a mean of 20.7 Bnboe. This is around 5 times the amount of recoverable reserves estimated by the USGS in 2008.

Next we used a type curve with the following assumptions:

- 30-day IP of 500 boe/d
- Well spacing of 320 acres
- Decline exponent of 1.15
- Nominal decline rate of 0.1
- Well life of 30 years
- This results in an EUR of 503 Kboe

To date well results in the play have been highly variable, with the highest 24-hour IP at over 7,000 boe/d. However, the average in the play for 30-day IPs is much lower, and the following map from the North Dakota DMR shows that the typical range for 60-90 day IPs in the play is 250-1000 boe/d (Figure 20).

Therefore, we believe that an assumed IP of 500 boe/d and EUR of 500 kboe is reasonable, based on existing data. Using our estimated play extent (based on technical screening criteria) of 22,000 square miles, a prospective area of 95%, average EUR of 503 Kboe and 320-acre spacing (roughly 42,000 wells for full field development), results in an estimated EUR for the entire Bakken play of 21 Bnboe. This is well within the range of estimates from our mass-balance derived recoverable reserves estimate, and very close to the mean (see Figure 21). A full field production profile can be constructed based on the preceding estimates and assuming sufficient active rigs to drill over 100 new wells per month on average over the next 20 years (Figure 22). This seems reasonable given the current active rig count of over 180, and the fact that Bakken wells now take as little as 25 days to drill.

Similarly for the Eagle Ford our mass-balance assessment indicates in place resources of around 147 Bnboe (mix of oil, condensate and gas). Applying recovery rates of 10-30% (higher than the Bakken due to higher gas content) gets us a range of recoverable reserves of 14.7-44 Bnboe, with a mean of 29.3 Bnboe. This is more than 4 times the amount of recoverable reserves estimated by the EIA in July 2011.

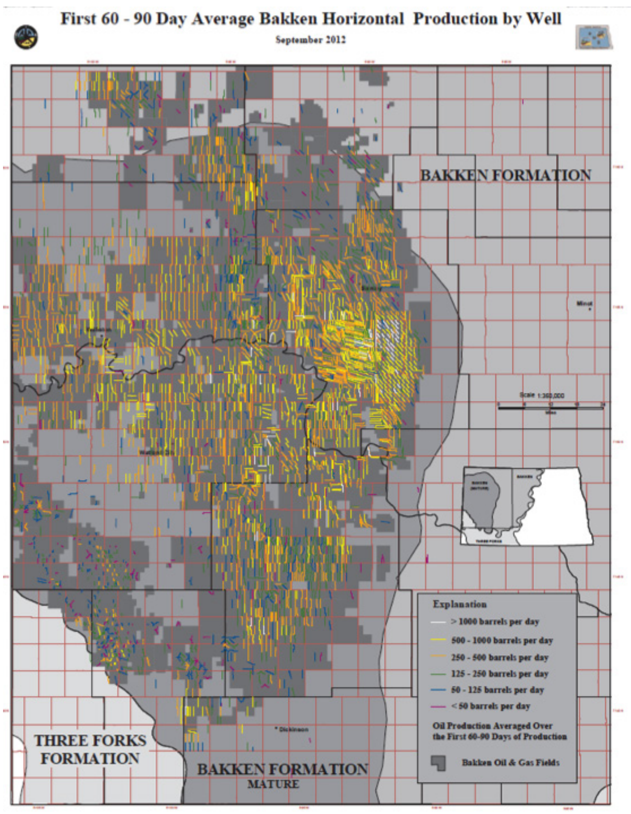


Figure 20: 60-90 day IPs in the Bakken (North Dakota DMR)

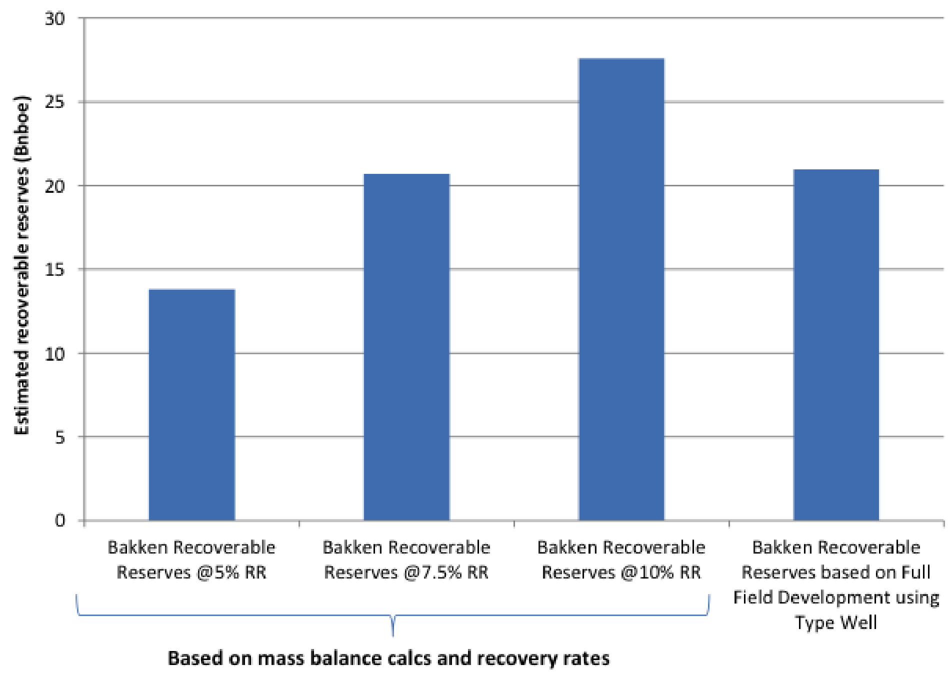


Figure 21: Estimated EUR for the Bakken based on mass balance approach and type curve analysis (Source: Kimmeridge Energy)

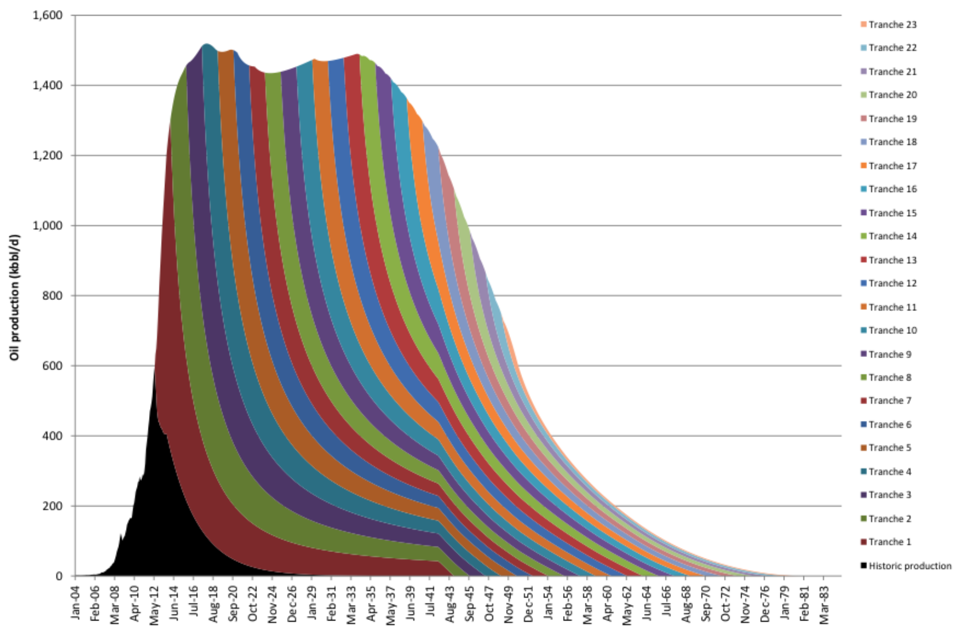


Figure 22: Modelled full field production profile for the Bakken (Source: North Dakota DMR and Kimmeridge Energy)

Next we used a type curve based on data from an SPE report that analysed of over 1000 wells drilled in the play, with the following assumptions:

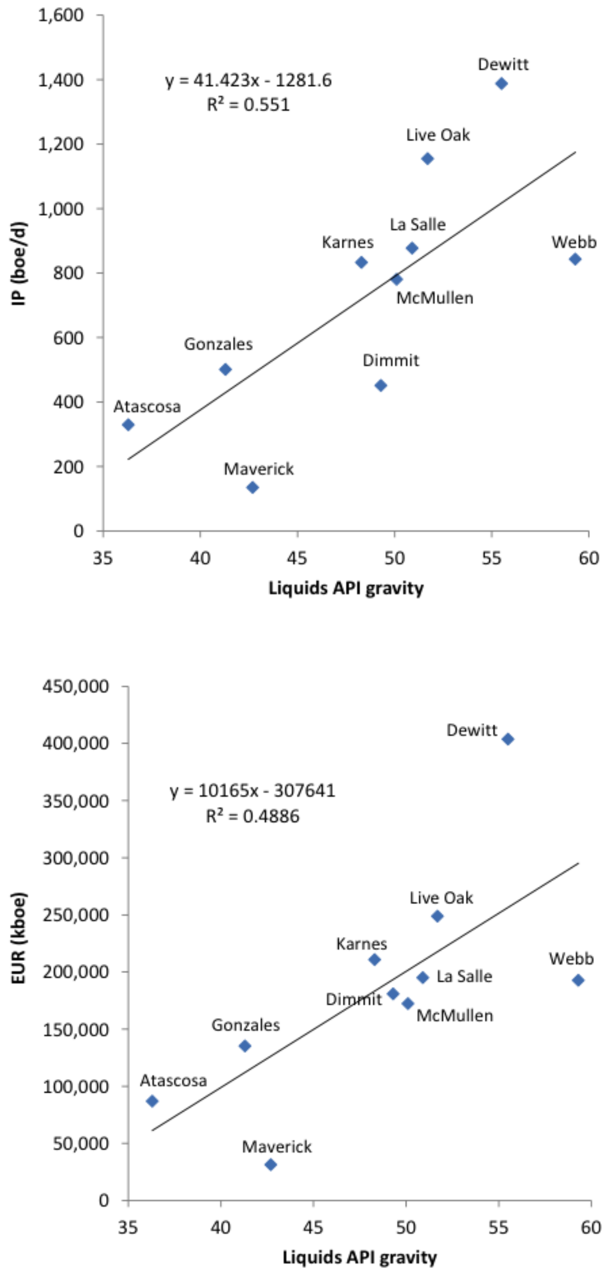
- 30-day IP of 775 boe/d (average from SPE dataset)
- Well spacing of 107 acres (6 per section)
- Decline exponent of 1.3
- Nominal decline rate of 0.35
- Well life of 30 years
- This results in an EUR of 277 Kboe (average from SPE dataset)

In terms of pure recovery and flow rates, well results to date have been highest in the dry gas zone. And we can see a positive correlation between the API gravity of liquids produced and both IP and EUR (see Figures 23 & 24).

This is to be expected, since oil molecules are 20-30 times larger than gas molecules so correspondingly much harder to produce from tight reservoirs. Additionally, gas is generated at greater depths than oil, where pressures are higher, which helps flow rates and EUR. However, due to low gas and condensate prices, operators have focused where wells have been most economic, which is on the edge of the oil and condensate zones where there is sufficient gas in the system to help with recovery rates, but the main product is oil.

Using our estimated play extent (based on technical screening criteria) of over 18,000 square miles, a prospective area of 95%, average EUR of 277 Kboe and 107-acre spacing (over 100,000 wells for full field development), results in an estimated EUR for the entire Eagle Ford play of 29 Bnboe. This is also well within the range of estimates from our mass-balance derived recoverable reserves estimate, and very close to the mean.

We expect hydrocarbon recovery from the Eagle Ford to be broadly equal between liquids (oil and condensate) and gas, over the lifetime of the play (although it has recently been skewed towards liquids). A full field production profile can be constructed based on the preceding assumptions and estimates, and assuming sufficient active rigs to drill between 150-250 new wells per month on average over the next 40 years (see Figure 25). This seems reasonable given that the rig count as of mid-November 2012 was already at 270 (213 oil and 57 gas), the average level through 2012.



Figures 23 & 24: IP and EUR vs. liquids API gravity in the Eagle Ford (Swindell 2012 and Kimmeridge Energy)

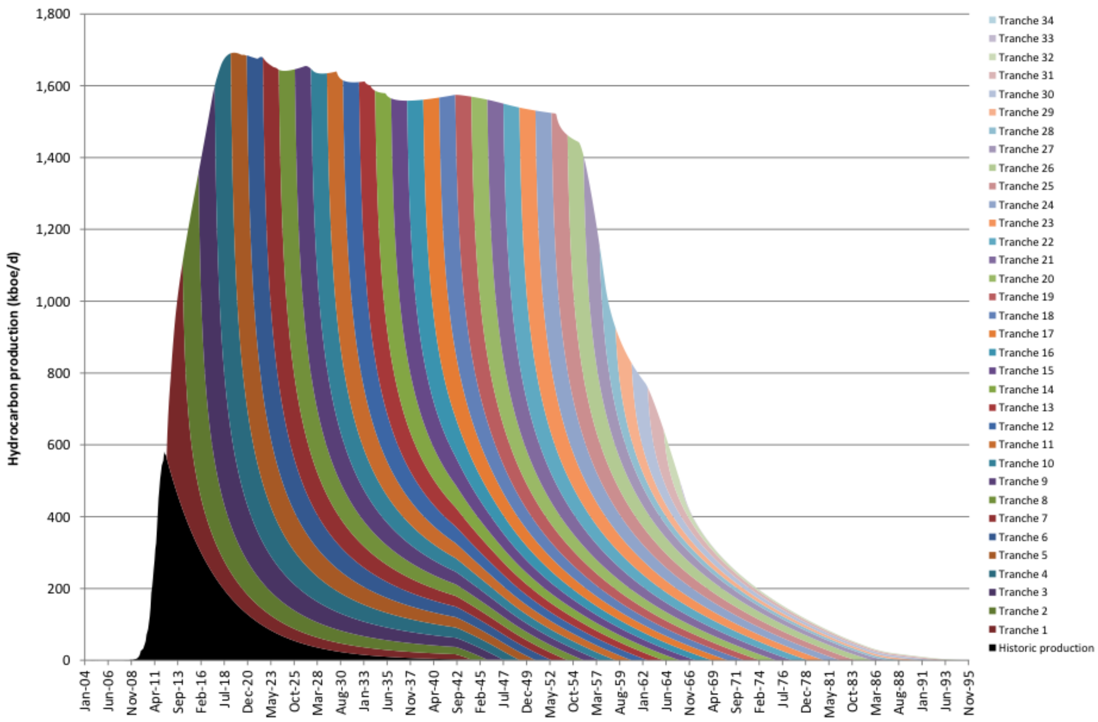


Figure 25: Modelled full field production profile for the Eagle Ford (Texas RRC and Kimmeridge Energy)

Forecasting Global Tight Oil Production

We have assumed no meaningful unconventional volumes from OPEC countries in the near-to-medium term, due primarily to large remaining cheap-to-extract conventional reserves. Amongst Non-OPEC countries we have focused on countries such as Russia, China, Argentina and Canada, which have potentially massive in-place tight oil resources, and seem most likely to contribute meaningful volumes within the foreseeable future, due to a combination of political will, improved fiscal regimes for unconventional resources, rapidly declining conventional production and growing per capita energy consumption.

Given the lack of extensive drilling and therefore no credible type curves available, the validity of detailed bottom-up modelling of production profiles for individual plays outside the US or Canada is highly questionable. However, we have used our full-field production profiles for the Bakken and Eagle Ford as basic analogues to forecast country level volumes, since these are the only proven large development-scale tight oil plays on the planet.

The key is really to determine the timing of material tight oil volumes, from countries with sizeable in-place resources (assessed through our mass-balance approach) and the right circumstances above-ground for development in the near-to-medium term. We estimate that by 2020, around 2 Mbbl/d of tight oil could be produced outside of the US, and over 4.5 Mbbl/d by 2029 (see Figure 26). Looking at the next 8 years, based on our global supply/demand balance for oil, and incorporating tight oil volumes for the

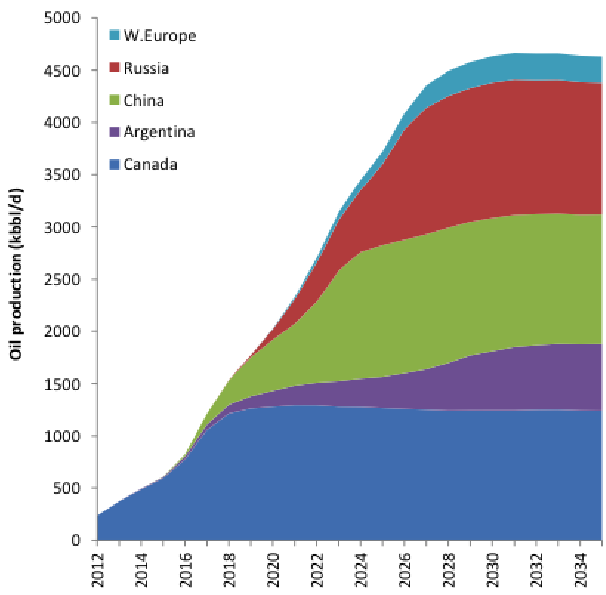


Figure 26: Forecast for non-US tight oil production volumes (Kimmeridge Energy)

US and 5 other countries, we could expect to see an increase in OPEC spare capacity as a percentage of global oil demand, which may give some downward pressure to oil prices (see Figure 27). However, in a historical context, OPEC spare capacity as a percentage of global oil demand will remain moderate at around 6% from 2018-20. And at the same time, the marginal cost (long term driver of oil prices) will continue to increase in a secular upward trend, as per well EUR's decline and the industry requires more service intensity to arrest decline rates at mature fields and exploit technology-intensive tight oil resource plays. Furthermore, we have used the EIA's global oil demand forecasts, which may be conservative, as they assume demand growth of around 1.1% on average per annum until the end of this decade. If demand surprises to the upside, OPEC spare capacity would diminish and the global oil market could tighten, putting upward pressure on oil prices.

Key point 4: *Even if we model in substantial tight oil volumes from the US and countries like Canada and Argentina, and use an optimistic timeframe for development based on experience in successful US plays, the impact on global supply should be limited and thus suggests only a minor potential impact on global oil prices within this decade.*

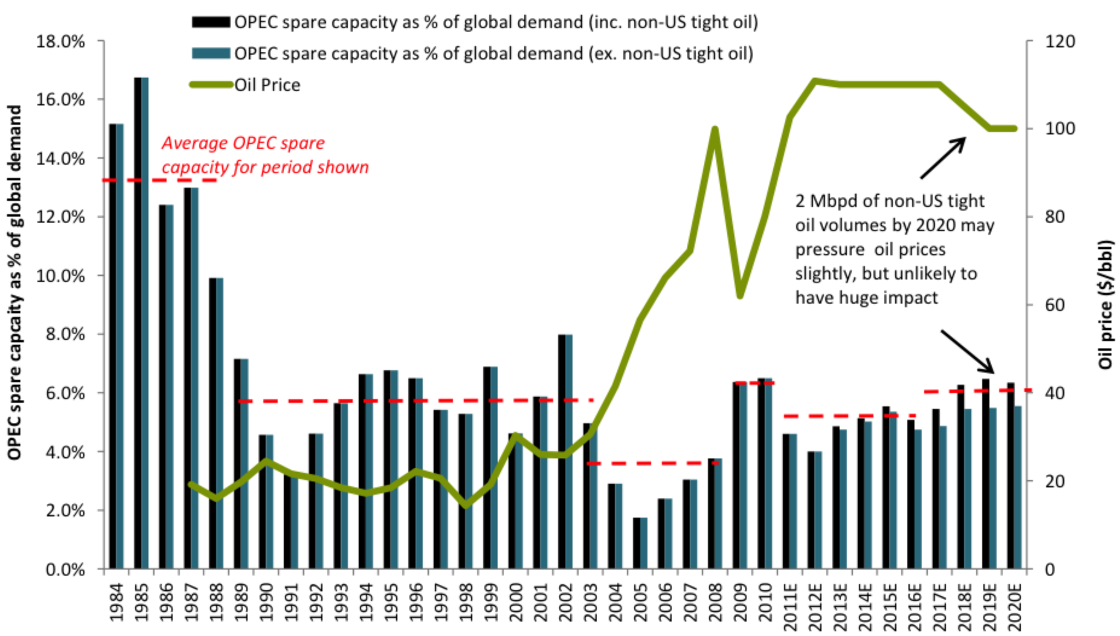


Figure 27: OPEC spare capacity as a percentage of global oil demand vs. oil price (IEA, EIA and Kimmeridge Energy)

Conclusion

In summary, the four key points from our analysis are:

Key point 1: *Tight oil production has a long way to go in the near to medium term, before it impacts global crude prices. However, regional oil prices such as WTI, will continue to be affected by transportation bottlenecks due to the renaissance of old production centres and insufficient existing takeaway capacity.*

Key point 2: *Although lessons from shale gas can and have been applied to tight oil, it is important to remember that oil is not gas. It is a big molecule (C7+) versus a single carbon atom for dry gas, and therefore the criteria necessary for a successful economic tight oil play are narrower than for gas. So although new technology has allowed a faster ramp-up in new tight oil plays like the Eagle Ford, the set of tight oil plays is more restricted than shale gas plays.*

Key point 3: *Outside the US and Canada, the availability of historical well and geological data is significantly reduced and will slow the pace of new unconventional exploration. Coupled with this is the time delay to export oil field services and knowledge outside the US and Canada, which means that the pace of production growth from tight oil globally will not be on a par with North America.*

Key point 4: *Even if we model in substantial tight oil volumes from the US and countries like Canada and Argentina, and use an optimistic timeframe for development based on experience in successful US plays, the impact on global supply should be limited and thus suggests only a minor potential impact on global oil prices within this decade.*

From what we can see today, unconventional tight oil production will have at most a modest impact on global oil prices this decade, especially if oil demand surprises to the upside. Potentially OPEC spare capacity could rise, but any resulting substantial drop in oil prices would, as can now be seen with natural gas activity in the US, result in a collapse in the capital investment in the industry, which in turn would also lower new supply growth from tight oil. The much greater capital intensity of exploring and developing tight oil means that it is not going to replace conventional oil at the front of the cost curve. However, it will compete with other higher cost oil categories, such as deepwater, Arctic and new oil sands developments, and indeed many of the modest sized conventional discoveries made in the past decade. There, tight oil will occupy an ever increasing position on the global oil production scene as long as demand for oil remains robust – indeed the pricing environment reflects that over the past five years. In this scenario, the world may have found a saviour for the decline cliff being faced by conventional oil fields over ten years old, but it has not found the "silver bullet" that will restore oil prices to the level from a few decades ago and also thwart OPEC's significant global influence.

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