Tight oil in the United States: recent developments and future financial sustainability

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1. Introduction

Optimistic assessments of the "gamechanging" qualities of U.S. tight oil production, as well as its unabated growth, are now plentiful in industry, academia, and policy circles.[1] However, like in all such periods of overt exuberance or pessimism over a development in energy markets that is foreseen to carry on in perpetuity, more granular analysis of the underlying trends is merited. This was true of the "peak oil" narrative that preceded the shale revolution, and is equally true of the "age of abundance" trope that has now replaced it. This paper aims to identify three important but under-scrutinized aspects of the current boom in North American tight oil production: the changing composition and value of liquids production, the challenging economics of tight oil production amidst high decline rates, and the vagaries of future financing for tight oil exploration and production.

In doing so, key uncertainties and risks are highlighted that may cause continued production growth to prove unsustainable. By better understanding these financial undercurrents, countries seeking to replicate the U.S. shale revolution as a component of a broader sustainable energy transition will enhance their appraisals of the suitability of fostering shale production given their particular financial and market environments.

2. Tight oil in the United States

Between the years 2005 and 2007, world oil production largely stagnated while demand - driven largely by China and other emerging economies - continued to increase, sending prices to record levels in 2008 that exceeded those witnessed following the 1979 oil crisis.[2]

Catalyzed by high prices and a fortuitous convergence of technological innovations, the U.S. oil and gas industry has responded by unlocking a bevy of new shale gas and shale oil (used here interchangeably with "tight oil") resources across the continental United States. The decline in U.S. oil production has quickly reversed, largely due to the exploitation of tight oil. The 3 mb/d increase seen since 2005 has more than offset the aggregate 0.6 mb/d fall in lower 48, Alaska, and offshore production of conventional oil.

Though the goal of full independence may be neither realistic nor desirable, U.S. net oil imports from outside of North America decreased to approximately 1.95 mb/d by mid-2014 from over 9 mb/d in 2005

U.S. oil and gas production is now at a record high, and the country is now on pace to become the world's largest liquids[3] producer, surpassing Saudi Arabia. Indeed, if recent production from the U.S. is removed from consideration, the stagnation in global oil production would be unchanged, despite dramatic swings and historic highs for the global oil price in real terms (see figure 1).

These developments have catapulted the United States closer to net energy independence. Though the goal of full independence may be neither realistic nor desirable, U.S. net oil imports from outside of North America had by mid-2014 decreased to approximately 1.95 mmb/d

1 See, for example:
Morse et al., Energy 2020: North America, the new Middle East?, Citi Global Research, 20 March 2012
Leonardo Maugeri, Oil: The Next Revolution, Belfer Center for Science and International Affairs, Harvard Kennedy School, Discussion Paper 2012-10, June 2012

2 U.S. Energy Information Administration (EIA), "Real Prices Viewer", Short Term Energy Outlook, 12 August 2014

3 Taking into account both crude oil, lease condensate, natural gas plant liquids, and other liquids. When only crude oil or crude oil plus condensate is taken into account, the United States remains second to Saudi Arabia and Russia. For the most recent pertinent data available, see:
U.S. Energy Information Administration (EIA), Table 3.1: Petroleum Overview, Monthly Energy Review: and
Joint Organisations Data Initiative (JODI), "Crude Oil Production Top 30 Countries", JODI - Oil World Database

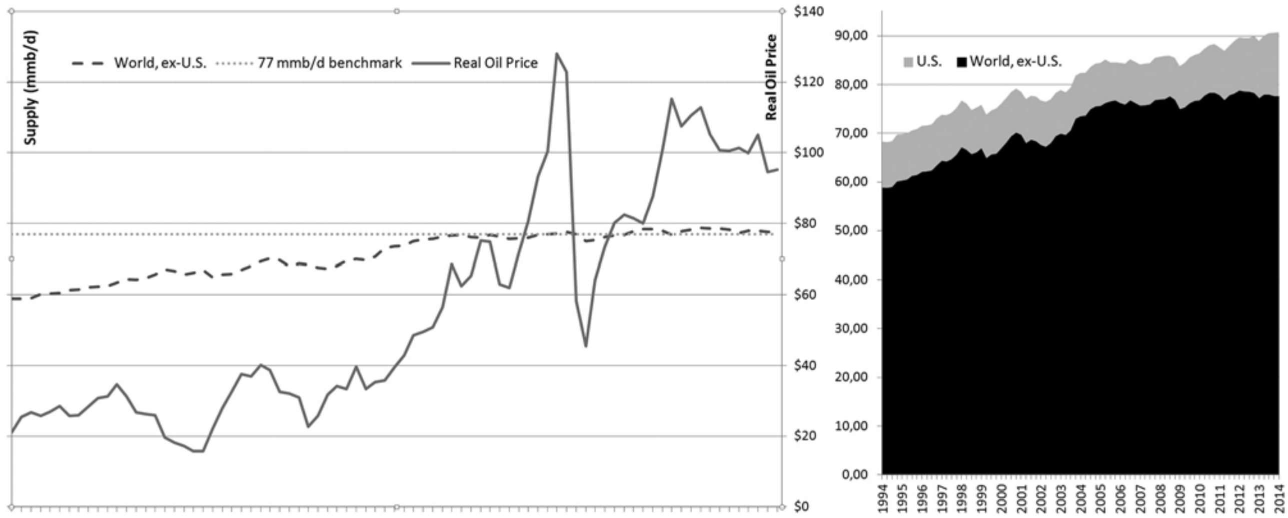


Figure 1 *- Total non-U.S. Oil Supply (mmb/d) and Real Oil Price (2014 $).*
(source: U.S. EIA, International Energy Statistics; U.S. EIA, Short Term Energy Outlook)

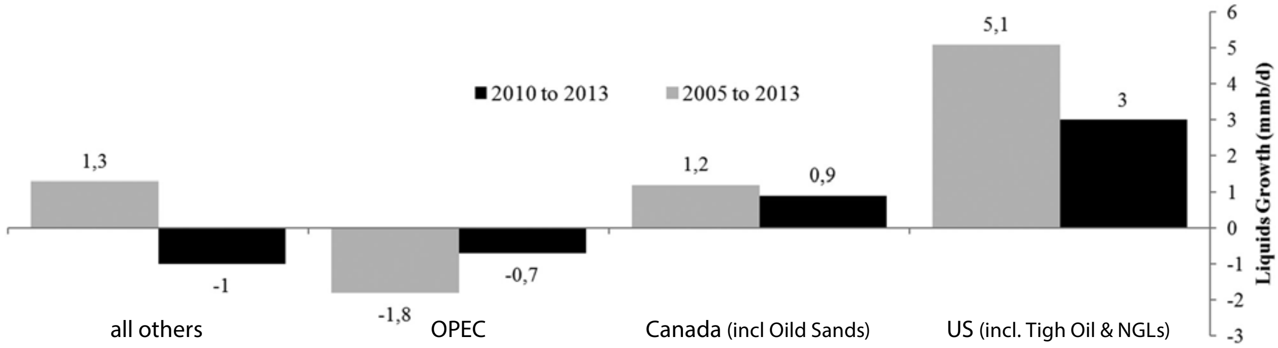
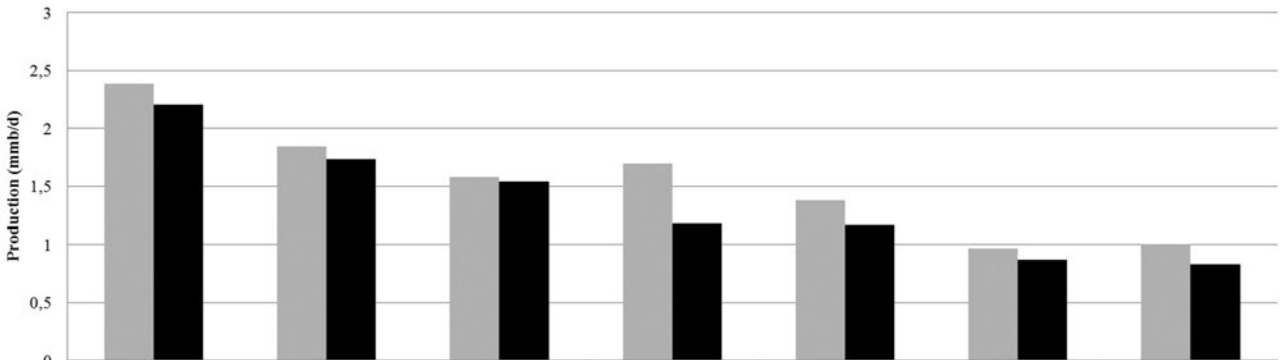
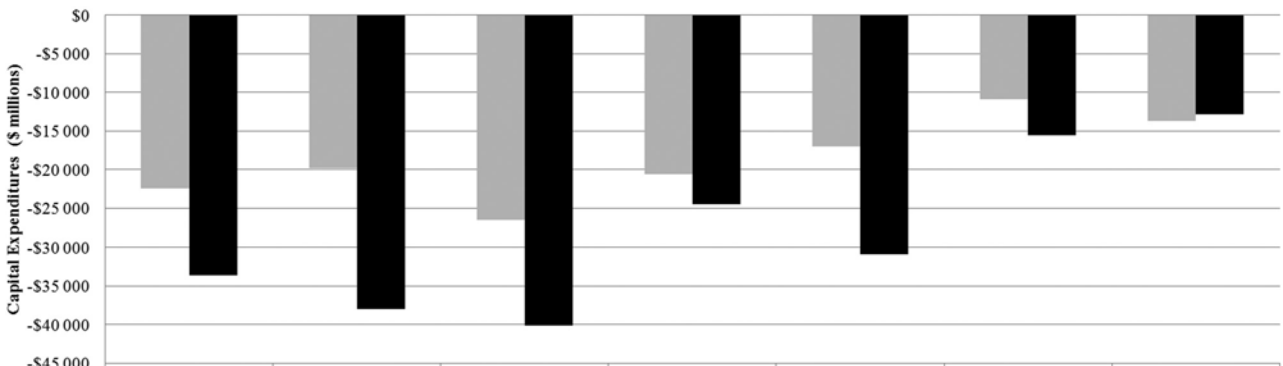


Figure 2 *- World Liquids Production Growth (mmb/d). Source: U.S. EIA, Short Term Energy Outlook*



	ExxonMobil	Chevron	Shell	BP	Total	ConocoPhillips	Eni
2009	2,387	1,846	1,581	1,695	1,381	0,968	1,007
2013	2,202	1,731	1,541	1,176	1,167	0,867	0,833

Figure 3 *- Production Trends, Seven Largest Publically-Owned Oil Companies (source: Platts; Company Statements)*



	ExxonMobil	Chevron	Shell	BP	Total	ConocoPhillips	Eni
2009	-$22 491	-$19 843	-$26 516	-$20 650	-$16 977	-$10 861	-$13 695
2013	-$33 669	-$37 985	-$40 145	-$24 520	-$30 932	-$15 537	-$12 800

Figure 4 *- CapEx Trends, Seven Largest Publically-Owned Oil Companies (source: Morningstart; Company Statements)*

from over 9 mmb/d in 2005.[4] U.S. liquid fuels production from 2011 onwards has more than offset global unplanned supply disruptions brought about by geopolitical turbulence, with 4.0 mmb/d of liquids production being added during that time versus unplanned disruptions of 2.8 mmb/d.

These developments have catapulted the United States closer to net energy independence. Though the goal of full independence may be neither realistic nor desirable, U.S. net oil imports from outside of North America had by mid-2014 decreased to approximately 1.95 mmb/d from over 9 mmb/d in 2005. U.S. liquid fuels production from 2011 onwards has more than offset global unplanned supply disruptions brought about by geopolitical turbulence, with 4.0 mmb/d of liquids production being added during that time versus unplanned disruptions of 2.8 mmb/d.[5]

Interestingly, production by the seven largest publicly-owned international oil companies has peaked and seen steady decline in the past several years (a fall of 1.4 mmb/d from 2009 to 2013) despite an overall increase in capital expenditures (by nearly $65 million) over that time:

3. The role of independent E&P companies

One often-overlooked component of the U.S. shale boom has been the role of hundreds of independent companies operating throughout North America. These independents are commonly distinguished from large "integrated" firms by virtue of the fact that they are engaged exclusively in upstream exploration and production (E&P) activities and do not engage in midstream (refining, transportation, and marketing) activities. They have traditionally played a role at the vanguard of oil exploration and production in the U.S., and have also been some of the first to apply new technologies and tools in unconventional or particularly challenging formations.

From 2012 to 2013, independents and large independents[6] together accounted for the entire net increase in end-of-year U.S. oil reserves. The former group increased reserves by 771.6 mmb of oil equivalent (a 14% year-on-year increase), while the latter group increased reserves by 1.3 billion barrels of oil equivalent (a 13% year-on-year increase) and reserves of the large integrated oil companies remained flat.[7]

The involvement of independent companies has been critical for the tight oil production growth seen in North America given the unique attributes of shale economics.

Conventional oil plays have traditionally been the remit of large, integrated international oil companies due to their expertise in managing complex projects. These projects generally encompass:

(a) long intervals between project lifecycle components: this can include approximately two to three years between discovery and a Final Investment Decision (FID), another two to three years for project development, and seven to eight years (or more[8]) before the project reaches financial break-even on a discounted cash flow basis;

(b) large project budgets with production profiles: over the lifespan described above, a company may spend several billion dollars before a field achieves production and begins to recover costs. Once at this point, it may take several years before costs are fully recovered, and the field's peak production levels may not be reached for several more years beyond that. At this point, it is typical for production to stabilize for an extended period, providing subsequent multiple years of stable profit generation for the company;

(c) relatively uniform economics across projects: Over time, the project economics for similar conventional resources are consistent enough that large oil companies can create a standardized framework for their finance and execution. Companies are thus empowered to make strategic investment decisions on the basis of long-term oil price and project cost expectations that are relatively robust against short-term fluctuations.[9]

In contrast, the economics of the shale sector encompass:

(a) short intervals between project lifecycle components: for well-organized companies with favorable conditions, it may take only a matter of months to spud, drill, case, and begin production in a well following the acquisition of a drilling license;

(b) smaller project budgets with unstable production profiles: as discussed in further detail elsewhere in this article, most shale wells experience a multi-week (~ 30

4 Author's calculations with data from:
U.S. Energy Information Administration (EIA), Weekly Petroleum Status Report, 20 August 2014

5 U.S. Energy Information Administration (EIA), U.S. liquid fuels production growth more than offsets unplanned supply disruptions, Today in Energy, 27 August 2014

6 Large independents defined as those with global reserves greater than one billion barrels of oil equivalent (boe) at the end of 2013, and independents as those with less than one billion boe.

7 EY, U.S. Oil and Gas Reserves Study 2014, 2014.

8 For further context on the debate over an appropriate estimation of the time between first discovery and "first oil", see: Carbon Tracker, Responding to Shell: An Analytical Perspective, June 2014

9 Leonardo Maugeri, The Shale Oil Boom: A U.S. Phenomenon, Belfer Center for Science and International Affairs, Harvard Kennedy School, June 2013

day) period of high initial production, followed by a steep decline over the ensuing months. As a result, the total ongoing expenditure in a single well is relatively small, and instead capital must continually be expended on new wells to maintain high production rates. Despite continual industry improvement in terms of drilling efficiency and well configuration, macro well performance has remained surprisingly constant, with initial production rates and decline slopes remaining particularly constant in more mature formations such as the Bakken and Eagle Ford;

(c) heterogenous well economics even within a single formation: given the significant geological diversity both amongst and within shale formations, as well as the significant variation in price-per-acre paid by companies during the land acquisition phase.[10] The unit economics of individual wells can vary widely. This is particularly true in light of the youth of the shale sector overall, in which there are instances of strong performance and repeatability but the general trend is toward unpredictable well performance. Moreover, shale plays often display something akin to an "80/20" rule in terms of well performance, with 20% of the wells providing 80% of total play production.[11] Given this unpredictability and short well lifespan, tight oil production is very responsive to short-term fluctuations in drilling costs or oil prices. This is particularly the case for companies that find sophisticated price-risk hedging operations to be unfeasible or unaffordable.

10 Whereas first-movers in 2007 through 2009 were able to secure lease agreements priced around $250-450 per acre, some acreage more recently obtained through company acquisitions has seen implicit valuations that are orders of magnitude higher (~$73,000 per acre). For details, see: Claire Pool, Devon Energy $6B asset buy a big win for Blackstone, The Deal Pipeline, 20 November 2013

11 This is a trend generally true for firms in the sector, as well, with the preponderance of shale oil and gas production coming from a small cluster of operators

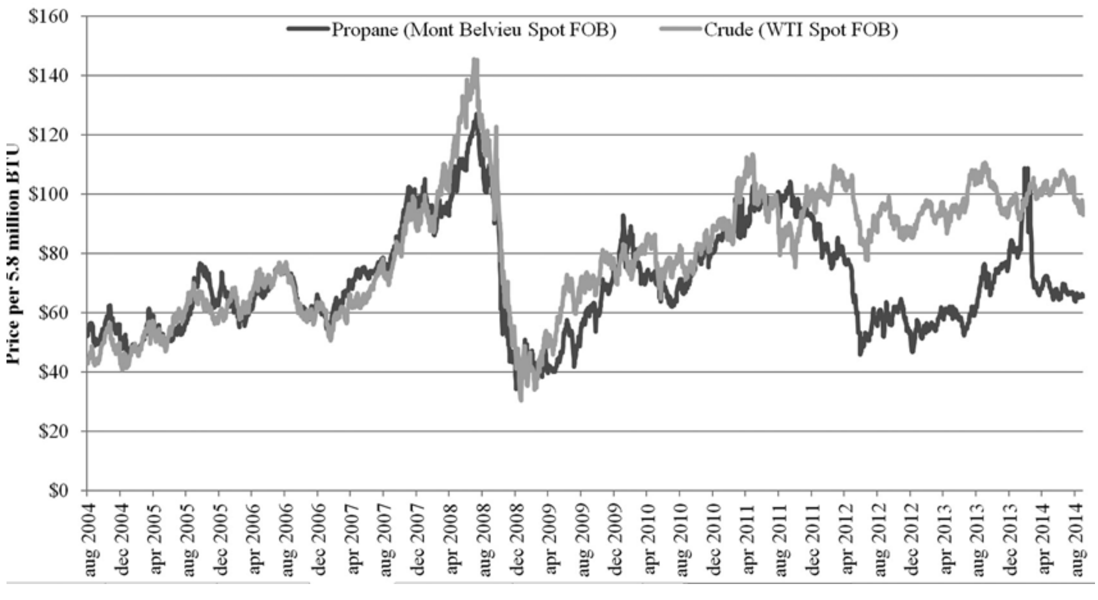
4. Changing Composition of Liquids Production

From the outset, it is important to understand that the growth in U.S. liquids production is not synonymous with U.S. crude oil production. Indeed, the consonance between these two terms is increasingly under strain. Over 50% of the increase in U.S. liquids production seen since 2005 has been comprised of liquids other than crude oil. These include biofuels, natural gas liquids (NGLs), and refinery process gains. While biofuels growth has indeed been significant, driven largely by state and federal mandates such as the U.S. Renewable Fuels Standard (RFS), it is NGLs that have seen the greatest growth.

NGLs are hydrocarbons that are categorized as neither oil nor natural gas, but are nonetheless co-produced along with oil and gas in varying ratios. While they composed a small percentage of U.S. liquids supply in 2005, production has been growing rapidly. One NGL in particular, propane, has seen the most significant production growth as a byproduct of the shale revolution and now accounts for approximately one-third of all U.S. NGL production.

Although propane's role in the transport sector is growing[12], it is most often used for residential and commercial heating and also as a cooking fuel. The energy content of propane is not equal to crude oil, at around 3.8 mmBTU) per barrel, in contrast to an average of 5.8

12 Today, there are estimated to be approximately 300,000 propane-fueled heavy duty trucks in the United States. For more information, see the U.S. Energy Information Administration (EIA), Alternative Fuels Data Center



mmBTU for each barrel of crude. Nor are NGLs economically equivalent with crude oil, even when adjusted for their different energy contents. The figure below shows that while the price of propane has historically closely tracked that of U.S.-produced crude, a discontinuity has occurred since 2011 as an over-supply of NGLs due to idiosyncrasies of the shale revolution now sees propane sell at about a 40% discount to crude on an energy-equivalent basis.

Propane should thus not be counted as a fungible substitute for crude oil, though this is often implicitly suggested when companies list various production streams of crude oil and NGLs under a single production indicator of "barrels of oil equivalent" (boe). The "boe" metric has utility in certain circumstances, but can also be used to obfuscate the dilution of value in liquids production as certain non-crude products take up a greater share over time.

5. Decline rates and tight oil economics

A second key risk to tight oil production trends exists in the extremely high decline rates seen in shale oil and gas wells.

Production from shale wells typically falls 65% to 90% over the first year, with operators ultimately extracting on average between 1% to 2% of the total crude oil in tight reservoirs.[13] For the most productive areas of individual plays, this yield can increase to 5% to 6% of total oil. This accordingly produces a substantial fall in output in a given field or shale play, unless enough additional hydraulic fracturing can be carried out to maintain or even increase overall production levels.

While these high levels of additional drilling have thus far occurred in the U.S., and at rates that have allowed total tight oil production to increase over multiple years, the expenditures associated with such continued acreage acquisition and drilling activity are substantial, and are augmented further by the costs of building out the requisite infrastructure and obtaining the necessary technology to ensure successful operations. On average, unconventional wells cost more than twice conventional wells to drill and complete, and additionally more costly to maintain with higher variable costs. One analyst reports that independent E&P firms are currently expending approximately $1.50 for every $1 they get back in revenue.

This trend may be sustainable in the short run given the availability of fresh credit, but it will also require high, sustained oil prices. The breakeven price of most current tight oil projects in the range of $75 to $90 per barrel[14], and a prolonged dip below this threshold would likely result in budget cutbacks on the part of shale producers and a quick reduction in tight oil production. While industry consultancy Wood Mackenzie has reported that 70% of U.S. tight oil reserves would remain "economic" at an oil price of $75 per barrel, other analysis suggests that most public oil and gas companies require prices over $100 to achieve positive free cash flow under current capex and dividend programmes, with nearly half of the industry - shale and otherwise - requiring prices of over $120 per barrel.[15]

There is also concern that in the future, as companies exhaust production in the so-called "sweet spots" of various shale plays, drilling will increasingly be relegated to more marginal locations with lower initial production rates, higher decline rates, and/or a lower ratio of oil and NGLs to comparatively less valuable natural gas.

It is therefore incumbent upon industry to undertake a multi-pronged campaign aimed at improving productivity. This includes increases the quantity of wells that can be drilled in a given time period with a single rig, increasing drilling depth and lateral length, increasing the overall number of laterals, and most importantly increasing the overall production per well.

The U.S. Energy Information Administration publishes a monthly "Drilling Productivity Report" that summarizes recent trends in drilling activity across key shale basins of the U.S. A cursory analysis of the September edition of this report when compared against previous production figures indicates that given the monthly tight oil production decline rates for the Bakken (6.33%), Eagle Ford (7.93%), Niobrara (9.55%), and Permian (3.26%), a U.S.-wide average of 6% per month production decline is taking place across all tight oil plays. For the two largest tight-oil producing regions, the Bakken and Eagle Ford, the growth in the rate of production decline (i.e. - the second derivative of production decline) was increasing for the early years of the shale revolution, until mid-2013. Since that time, production decline rates continue to increase at a steady rate of approximately 1,400 barrels per day in the Bakken, and approximately 2,400 barrels per day in the Eagle Ford.

As shale production matures, the first wave of wells drilled during the initial stage of the shale revolution will begin to cross into the age threshold that necessitates more maintenance, repair, and workover services. Mov-

13 Ivan Sandrea, U.S. shale gas and tight oil industry performance: challenges and opportunities, Oxford Institute for Energy Studies, March 2014

14 Published studies, company reports, and conversations with industry stakeholders

15 Goldman Sachs research, as cited in: Steven Kopits, "Oil and economic growth: a supply-constrained view," Douglas Westwood, presentation to Columbia University Center on Global Energy Policy, 11 February 2014

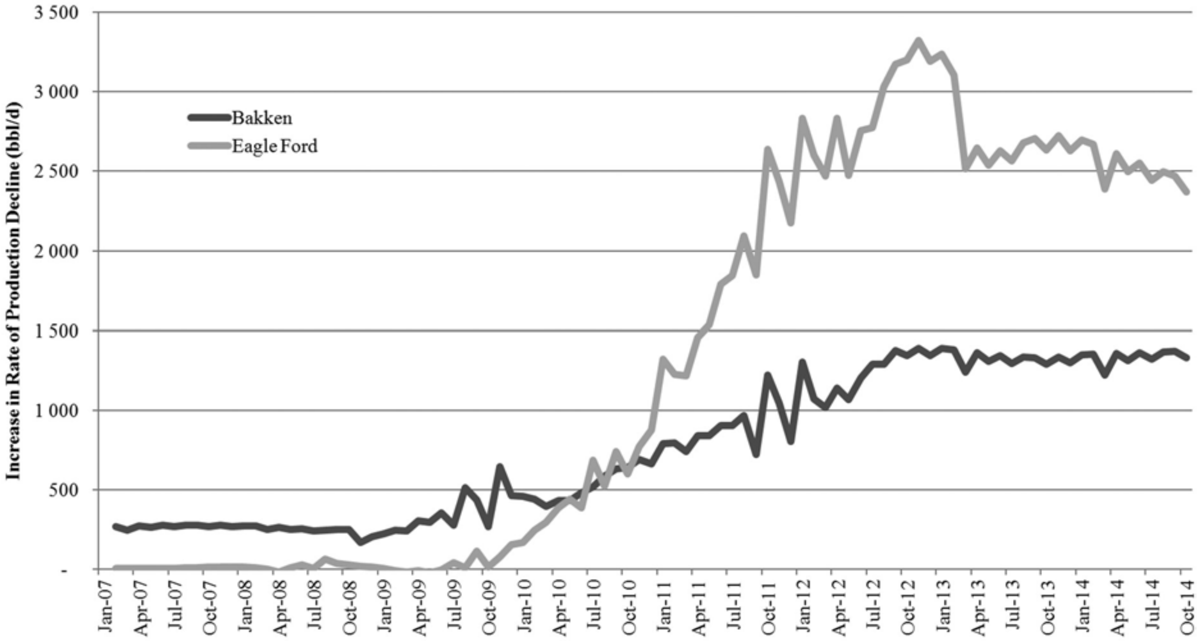


***Figure 6** - Bakken and Eagle Ford Monthly Decline Rate Increase. (source: U.S. EIA, Drilling Productivity Report)*

ing forward, spending trends will likely see decreased spending on rigs, and increased spending on completions and production phase services such as artificial lift technology. In addition, increased spending may be allocated towards applying hydraulic fracturing technology to vintage wells - a process known as "re-fracking" that is only beginning to take shape at large scales in North America.

6. Case study: production trends in the Bakken

To illustrate the risks introduced by decline rates, a high-level disaggregation of the production increase in North Dakota's Bakken shale is instructive. The Bakken has seen production increase from less than 100,000 barrels per day for most of 2008 to in excess of 1 mb/d today, making it a larger production source than Argentina, Colombia, Indonesia, Malaysia, or the United Kingdom, amongst others.

Nearly 30% of U.S. oil production growth over the past five years can be attributed to North Dakota. Looking ahead the U.S. Energy Information Administration further expects the state to comprise 45% of U.S. growth between 2013 and 2020. While it took more than two years for Bakken production to increase from 100,000 b/d to consistently above 300,000 b/d, it has taken less than a year for each subsequent 200,000 b/d of additional production - a particularly impressive feat for a state not historically accustomed to significant drilling activity.

Yet this is also likely unsustainable over the long term. If recently observed exponential production growth trends in the Bakken were to continue, North Dakota would be producing more than 480 billion barrels per year by 2024, which would surpass the current oil production of the entire U.S. It is important to note that the well counts themselves - and more precisely their first and second derivatives - are crucial variables undergirding the production growth in regions such as North Dakota.

For example, whereas 1,092 additional wells were needed to increase production from 300,000 to 500,000 b/d, a simple replication of this drilling volume was insufficient to deliver the next 200,000 b/d of production growth.[16] Instead, a total of 1,554 additional wells were needed to bring production from 500,000 to 700,000 b/d (representing an increase of 462 wells, or 42%, over the previous increment), and a yet-greater number, 1,736 additional wells, was needed to take production to the 900,000 b/d mark (representing an increase of 182 wells, or 12%, over the previous increment).

In other words, decline rates are so steep that a prolific level of new drilling must take place if both production decline is to be offset and new net production is to be introduced. Before the Bakken had reached the 1 million barrels per day production benchmark, one study estimated that 1,542 wells annually well needed in the Eagle Ford and Bakken plays alone to offset declines, at an estimated cost of $14 billion.[17] More recently, the IEA

16 Author's calculations based upon underlying data from: Ivan Sandrea, U.S. shale gas and tight oil industry performance: challenges and opportunities, Oxford Institute for Energy Studies, March 2014

17 David Hughes, Drill Baby Drill: Can Unconventional Fuels Usher in a New Era of Energy Abundance?, Post Carbon Institute, February 2013

estimated that new wells in the Bakken must be drilled at a rate of 2,500 per year if output of 1 million barrels per day is to be maintained.

As pad drilling leads to higher drill rates and completion efficiencies, average well costs in the Bakken have declined. In the first quarter of 2014, the Bakken and Three Forks recorded average costs of $7-8/well, marking a reduction of 20-30% from the $10/well cost prior to 2011.[18] Nevertheless, while it is true that the Bakken has seen significant increases in pad drilling, drilling accounts for only about 30% of the overall well costs, and in many instances drilling cost reductions are overshadowed by increases in completion costs with the advent of deeper wells, longer laterals, and multiple fracking stages.[19] Since 2010, lateral length in the Bakken has increased over 25% and the average number of fracking stages have increased from 22 to more than 30.[20] Though these advances in drilling sophistication have led to marked increases in 24-hour initial production levels, the longer-term average decline curves for Bakken wells have not shown significant changes since 2010. Unless rig productivity shows dramatic improvements or drilling costs moderate significantly, the ability of the shale industry to shoulder this implied expenditure over the long run will likely be increasingly called into question.

This case study of the challenges ahead for the Bakken bring a degree of levity to estimates of future Bakken tight oil production, many of which have been predicated upon initial estimates without a full understanding of tail production profiles for fields that have been in decline for some time. A recent compilation of six mainstream projections for 2020 the Bakken production shows a range between 1 million and 1.74 million barrels per day, with further divergence in terms of the rate of growth and eventual peak production point.[21] Notably, even the most optimistic estimates appear to be incongruent with recently announced rail, pipeline, and local refinery projects in the Bakken region.

As of September 2014, if all announced infrastructure projects were to realized, it would lead to total takeaway capacity in the Bakken of approximately 3.27 million barrels per day in 2016.[22] The developers of these projects must contend not only with expected future production volumes, but also to the variability introduced by decline rates and firm decision-making. As tight oil wells cost far less to drill and bring into production, it not only makes it easier to increase drilling when oil prices are high, but also easier to rapidly draw down production in low-price environments. This asymmetry between long-term infrastructure commitments and short-term fluctuations in tight oil production rates presents another source of prospective financial risk in the shale sector.

7. Financing tight oil exploration

As noted above, meeting the demands of increased aggregate production in the midst of continual steep declines in producing wells requires a non-stop program of acreage acquisition and extraction operations, from well-spudding to well completion. Considering the up-front and variable expenditures associated with such operations, it is crucial to understand the financing environment for the shale sector, and how future changes to this environment may impinge upon the financial health of tight oil E&P companies and projected future tight oil production levels.

When companies are unable to generate sufficient free cash flow from current income in order to finance the new capital expenditures and other business assets, these costs must be covered through the procurement of external capital. The canonical model of oil company finance holds that these companies generate capital from two primary sources: (1) net cash generated from operations, and (2) net cash raised from financing activities. The latter is traditionally composed of equity financing activities, in which cash is exchanged for shares of ownership in the company itself, and debt financing activities, in which cash is exchanged for a non-equity note that entails the return of principal after a fixed in addition to regular or accumulated interest payments.

The strength of cash flow, other key performance indicators, and the financing options available to a com-

"If recent trends were to be extrapolated, North Dakota would (unrealistically) be producing more than 480 bb/d by 2024, surpassing the current oil production of the entire U.S."

18 Oil & Gas Journal, WoodMac: Bakken Capex to top $15 billion in 2014, 7 April 2014

19 Rystad Energy, U.S. Shale Newsletter, Vol. 1, Issue 3, 3 July 2014

20 Ibid.

21 Catherine Ngai, Shale boom confounds forecasts as US set to pass Russia, Saudi Arabia, Reuters, 9 July 2014

22 Aggregated estimate, based upon data from Genscape and North Dakota Pipeline Authority

pany all directly impact its capacity for future leverage and, thus, its competitive position and future strategic flexibility as changes manifest in the company's own operations or in the industry or economy more broadly. Companies that struggle to raise financing for extended periods or that suffer from liquidity crises, yet that possess attractive assets in terms of acreage, technology or expertise, may become acquisition targets for larger companies with healthy balance sheets.

7.1. Equity markets

One option for companies to raise funds is to exchange ownership shares for capital. While smaller oil companies have certainly been able to raise equity capital in the past, this is typically contingent upon a company's demonstrable growth prospects, as well as the perceived likelihood of future dividend payments. For companies that meet this profile, it may be the case that equity investors offer an attractive alternative to issuing debt with substantial interest costs and restrictive covenants.

Within equity markets, companies are often categorized as "large-cap", "mid-cap", or "small-cap" depending upon their market capitalization. Most independent E&P companies involved in the shale sector are either small-cap or mid-cap firms. Equity financing became increasingly challenging for small-cap firms in the aftermath of the U.S. great recession due to decreased liquidity, increasing caution on the part of equity investors, and disappointing price performance (capital gains) over that period.

Nevertheless, a number of E&P companies have listed on equity markets in recent years, and a number of small or mid-sized shale operators used the advent of the 2008-2009 financial crisis to acquire other smaller, financially-distressed shale firms. In the event that market conditions or the challenges of maintaining both production and positive revenue levels proves difficult for smaller, less well-positioned firms in the next few years, it is entirely feasible that another round of industry consolidation via equity markets could again occur.

7.2. Credit markets

Credit ratings agencies (e.g. Fitch, Moody's, and S&P) play a critical role in credit markets by providing a succinct, timely, and ostensibly objective appraisal of the financial performance and creditworthiness of firms that they monitor.[23] These ratings are in turn used by investors as measurements of the likelihood of default on the part of the company, or inversely of the probability that the company will be able to "make good" on its financial commitments according to the terms of any agreement. Ratings are divided into two buckets: "investment grade" (AAA to BBB in the S&P/Fitch nomenclature, Aaa to Baa2 for Moody's), and "non investment grade" or "junk bond" status (BB to CCC and less in the S&P/Fitch nomenclature, Ba3 to Caa for Moody's). Bonds with lower ratings typically bear higher interest rates, providing a yield premium, or spread, over ostensibly "risk-free" treasury bills.

Many large, integrated oil majors enjoy extremely attractive investment-grade credit ratings and thus pay low interest rates on their debt (ExxonMobil has maintained a triple-A credit rating, uninterrupted, for 90 years), although they are not immune to downgrades in the event of large risks materializing. Shell, for example, lost its AAA credit rating for the first time in 2004 as it was forced to take significant write-downs in the aftermath of a reserves accounting scandal. BP also saw two high profile downgrades in the past decade - one involving risks related to its 50% share in the Russian venture TNK-BP, and another in the midst of the Deepwater Horizon oil spill in the Gulf of Mexico.

Smaller and newer companies - as are common in the shale oil sector - traditionally bear non investment grade credit ratings, higher interest premiums (if they are able to access conventional bond markets at all), and generally start with a strategic disadvantage in securing financing. Of the E&P firms that are tracked by Moody's and S&P, the share possessing non-investment grade credit reached approximately 70% and 80%, respectively, as of the end of June 2014.

For non-investment grade companies involved in upstream (exploration and production, or E&P) activities that lack the means or desire to access equity finance (e.g., for fear of equity share dilution), high-yield bonds and leveraged loans offer a way forward. These options have seen on an increasingly important role in sustaining U.S. oil production as tight oil, produced largely by independent E&P companies, comprises a larger and larger share of this overall production. An indication of the growing interest premiums being paid to finance U.S. oil production can be found in the "net debt per barrel of oil equivalent" metric which, according to industry consultancy IHS CERA, grew from $28.84/boe in 2007 to over $39/boe in 2013.

Many companies involved in shale hydrocarbons utilize a revolving credit facility, secured against the borrower's reserves of oil and/or gas. Critically, the upward borrowing limits of such facilities are most often set by a calculation based upon the firm's producing reserves, with comparatively little credit provided for undeveloped or speculative reserve assets. Other conventional financing mechanism employed by many companies include

23 Jewell and Livingston, A Comparison of Bond Ratings from Moody's S&P and Fitch IBCA, Financial Markets, Institutions and Instruments, 8 (4), 1999

leveraged loans, such as second lien term loans. These loans are issued with a secondary priority claim to the underlying assets securing the loan, and as such they also demand higher interest rate premiums. In the oil sector, second lien loan issuance has traditionally been counter-cyclical to high yield bond market activity, such that as one accelerates, the other typically slows. Second lien loans are commonly used as bridge finance to pay off previous liabilities until the company can access capital markets or issue high-yield bonds. Chesapeake Energy, for example, obtained a five-year, $2 billion term loan in 2012 with proceeds used to pay off previously-incurred debt with more punitive interest rates.[24]

7.3. Recent innovations and trends

In addition to the mechanisms listed above, a number of new, innovative options are being employed with increasing frequency. The possible attributions for this trend are many, including regulatory changes, broader market conditions such as historically low interest rates, and the shifting preferences of various investor classes. However, the net impact of all of these factors is clear: borrowers have found themselves in a historically advantageous position over the past few years, be it through record low high yield interest rates or "borrower-friendly" features.

These features include, inter alia, "amend-and-extend" provisions (allowing borrowers to extend the maturity of loans, even if lenders do not elect the option), "accordion" or "incremental" credit facilities (allowing borrowers to increase the size of the credit facility at given intervals), and loan buy-back provisions (allowing borrowers to buy back their loans, such as through reverse auctions).[25] Moreover, high yield bonds issued by independent E&P companies have begun, in some instances, to be issued without the negative covenants that traditionally worked to restrict company payments (dividends, distributions, or investments) or the incurrence of further debt.[26] Broadly speaking, the aggregate impact of these more recent innovations has been to empower the debtors - in this case the drillers - and to weaken traditional control mechanisms afforded to lenders.

The high degree of capital availability for the shale sector has also been internalized in industry decision making, as reflected by a compilation of results from a regular survey of E&P company leadership carried out by Barclays that shows steadily decreasing significance afforded to capital availability as the key determinant of E&P capital expenditures (see table 1):

One large question mark for the future of the shale sector and the financing of shale operations is the future role of actors other than independent E&P companies. For example, private equity groups were responsible for substantial activity in the oil and gas industry in 2012, amounting to 1,590 deals worth $152.3 billion.[27] Private equity funds can take traditional equity stakes, but also regularly utilize other transaction structures such as joint ventures, sale-leaseback transactions, farm-out agreements, overriding royalties, and other arrangements.[28]

Another potential growth area is represented by producer-user joint ventures, in which the user of a commodity (in this case oil or NGLs) will take a working interest in shale wells in order to ostensibly hedge future prices. For example, this approach has been utilized by U.S. utilities investing directly in shale gas wells[29], and could be explored in the future by petrochemical plants or other manufacturers investing directly in NGL-rich tight

24 Chesapeake Energy Corporation Form 8K, 13 November 2012

25 For further discussion of these trends, see: Theresa Einhorn, Developments and Trends in Oil and Gas Financing 2013, Haynes & Boone, LLP, Presentation to the American Bar Association Business Law Section Spring Meeting 2013, Houston, Texas, 2013

26 Moody's, High-Yield Bond Covenant Protections Hit New Low in January, Moody's Global Credit Research, 12 February 2013

27 Haynes & Boone, LLP, Presentation to the American Bar Association Business Law Section Spring Meeting 2013, Houston, Texas, 2013

28 Segal Rogerscasey, Investing in Infrastructure through Private Equity, May 2012

29 Alexander Osipovich, US utilities invest in shale gas wells as long term hedges, Risk.net, 31 July 2014

***Table 1** - Key Determinants of E&P Spending, Self-Reported by Industry. (source: Barclays Research, Global 2013 E&P Spending Outlook)*

Factor	2014	2013	2012	2011	2010	2009	2008	2007	2006	2005	2004	2003	2002	2001	2000
Oil Prices	63%	70%	54%	49%	45%	49%	39%	39%	51%	50%	44%	43%	51%	47%	59%
Cash Flow	60%	64%	46%	53%	48%	48%	47%	42%	36%	60%	54%	53%	59%	65%	68%
Drilling Success	37%	39%	31%	25%	21%	26%	39%	35%	34%	43%	43%	30%	30%	44%	41%
Natural Gas Prices	30%	42%	47%	42%	54%	55%	51%	53%	61%	52%	73%	55%	67%	66%	68%
Prospect Availability	27%	30%	32%	22%	18%	23%	45%	42%	53%	58%	51%	55%	39%	60%	45%
Drilling Costs	27%	24%	29%	24%	24%	31%	36%	37%	40%	41%	38%	35%	49%	35%	31%
Capital Availability	**20%**	**24%**	**32%**	**26%**	**35%**	**29%**	**23%**	**28%**	**23%**	**32%**	**39%**	**36%**	**37%**	**43%**	**52%**

oil plays.

Finally, there exists great uncertainty over the future role that foreign (primarily Asian) investors will play in U.S. shale production moving forward. A number of North American oil companies have entered into joint ventures with Asian investors that have seen investors fund exploration and production costs in exchange for an interest in the underlying tight oil reserves. Some large oil-sector transactions, including CNOOC's $5.2 billion acquisition of Canadian oil sands firm Nexen in 2013 - China's largest single overseas transaction to date - have precipitated concern over the strategic and geopolitical implications of such deals, and any ensuing restrictions on foreign investment in the U.S. oil and gas sector would likely have repercussions for U.S. tight oil financing.

7.4. Interest rates and shale production

The link between monetary policy and unconventional hydrocarbon production has been given little coverage in both academic and grey literature. To the extent that insights can be garnered by existing analysis, such insights must be extrapolated from broader work on the relationship between monetary policy and global oil prices, or on the fiscal impact of unconventional hydrocarbon production.

First and foremost, monetary policy can have impacts through the oil price mechanism: at the most basic level, the circulation of money can impact demand for, and nominal prices of, commodities. Recent examples are plentiful. For example, Gilje (2012) examined the phenomenon of shale exploration creating local credit supply shocks through the vector of bank deposits associated with the large payments made to mineral rights owners in return for access to resources.[30] Masson (2014) examined the inter-linkages in a petro-state, Nigeria, between oil prices, inflation, and the policy stance of the Central Bank of Nigeria.[31] At a higher level of analysis, Ano-Sujithan et al. (2013) found an implicit inverse relationship between commodity prices and short-term interest rates across a heterogeneous sample of countries.[32]

Though less-studied, linkages may also exist between monetary policy (interest rates) and the production function for unconventional hydrocarbons. As alluded to earlier, perhaps the largest single factor behind the affordability and availability of capital for the E&P sector - and the broader junk bond market - has been the historically-low interest rate environment in the U.S. in the wake of the 2008-2009 financial crisis and subsequent global economic recession.

Low interest rates on U.S. treasuries and other investments indexed to treasures have driven aggressive, yield-seeking investors into the high yield bond and the leveraged loan market. From 2012 onwards, these markets have been the recipients of large inflows from institutional investors as well, including pension funds, university endowments, and insurance companies. The demand-supply imbalance for non investment grade credit has driven the interest rate for even the highest-risk bond tranches to historic lows. This, in turn, has provided an accommodating financing environment for the coincident shale revolution in North America.

There are indications that the financing environment may prove less accommodating in the near future. A recent analysis by Sanford C. Bernstein found that over the three year period from early 2011 to 2014, the upstream oil sector averaged revenues of $56 per barrel, with interest expenses deducting only $2 from this amount (approximately 3.6%). This ratio appears to be trending upward, as it is an increase over the 2.3% interest expense share of revenue seen in 2010, and was lifted further to 4.1% in the first quarter of 2014.[33] This is corroborated by another recent study from analysis firm Energy Aspects, which found that between Q2 2012 and Q2 2013, companies added $13 billion of debt while increasing production by only 200,000 barrels of oil equivalent per day. With cumulative interest payments increasing at a compound annual growth rate (CAGR) of 21% in the six years between 2007 and 2013, companies are indeed having to "spend more just to stand still". [34]

What remains to be well-documented is the full response of the shale sector to a rising interest rate environment - whether driven by the Federal Reserve or by endogenous industry or firm-level factors. An initial analysis by Bloomberg of 61 companies revealed that 26 had reduced spending in response to recent increases in interest rates, with a concomitant fall in production expected. When the Federal Reserve begins to increase benchmark interest rates, interest rates on less risky debt are likely to rise, and depending upon broader market conditions this safer debt may become more attractive to investors.

With less producing reserves against which to secure new lines of credit, some firms' financial leverage may

30 Erik Gilje, Does Access to Finance Matter? - Evidence from U.S. Oil and Natural Gas Shale Booms, University of Houston, Bauer College of Business, Presented at Department of Finance Seminar Series, 25 January 2013, 12 November 2012

31 Paul Masson, Macroprudential policies, commodity prices and capital inflows, 2014

32 Ano-Sujithan et al., Does Monetary Policy Respond to Commodity Price Shocks?, Dauphine Université, 2013

33 Bloomberg, 2014

34 Virendra Chauhan, The other tale of shale, Energy Aspects, October 2013

shrink further and drive a positive feedback loop of shrinking shale activity. In any case, the need for continual borrowing to ward off natural production declines will, given sufficient time, likely end up bifurcating those that can endure higher capital costs and those that cannot.

On the other hand, it is crucial to account for recent shifts in the aggregate temporal debt structure in the U.S. generally, as well as in the oil and gas sector specifically. Companies have been taking advantage of the anomalous credit market conditions of the past few years to lock in low fixed rates with long maturities.

"The involvement of independent companies has been critical for the tight oil production growth given the unique economics of shale"

Between 2007 and mid-2014, long-term fixed rate debt increased from 55% to 65% of total debt outstanding in the United States, while floating rate debt (vulnerable to interest rate shocks) has shrank from 42% to 30%.[35]

These trends are even more lucid in the E&P sector, where it has been suggested that as much as 90% of outstanding debt carries fixed rates, with approximately 60% possessing maturities beyond the year 2020.[36] The contrast is also pronounced when comparing investment grade and non investment grade E&P debt. While 27% (~$130 billion) of the former will mature prior to the end of 2018, only 13% (~$17 billion) of the latter will mature by that time.[37]

However, new borrowing by E&P companies will see significant constraints as debt-servicing costs rise, with high-yield issuers particularly likely to be impacted. The importance of new borrowing is not trivial given the continued investment necessitated by steep decline rates witnessed thus far in tight oil wells.

8. Conclusion

Estimates of the aggregate capital expenditure associated with shale oil and gas vary, but all point to rapid growth. One industry analyst suggests that annual capital expenditures associated with shale oil and gas in the United States have escalated from approximately $5 billion in 2006 to $80 billion in 2013.[38] Another estimate has put cumulative capital expenditure in the Appalachian and Permian basins alone at over $1.5 trillion as of late 2013, based upon a simple extrapolation of the number of wells drilled multiplied by average well costs. [39]

A tremendous amount of additional capital will be required over coming years to not only conduct the drilling necessary to maintain existing production levels, but to also increase total production levels and to build the requisite infrastructure of storage facilities, pipelines, processing plants, refinery units, and distribution terminals needed to bring such production to market. IHS, the industry consultancy, has estimated that annual capital expenditures on unconventional oil and gas are expected to average approximately $200 billion per year, for a cumulative expenditure total exceeding $5 trillion by the year 2035.[40]

Capital has flowed into the unconventionals sector from both traditional and nontraditional sources, and the future volume and composition of these flows will be shaped by key determinants including interest rates, government policy, as well as the articulation of real and perceived risks in the sector. Environmental risks, including - inter alia - induced seismicity, water contamination, and methane leakage, are of critical importance here. It is highly likely that increased regulation will be seen in various U.S. jurisdictions in coming years to address these concerns, and this may increase operating costs for many firms involved in shale exploration. While it is not in the purview of this article to address these important risks and to assess the appropriate regulatory frameworks, it is sufficient to say that the framework in which these risks are addressed will have a material impact on the shale sector's continued financial sustainability.

These considerations will have implications for regions around the world that are currently evaluating the compatibility of tight oil production with each region's political, financial, and industry environment. Many

35 Bank of America Merrill Lynch, The Rate Debate, 18 August 2014

36 Brian Gibbons of Credit Insights as cited in: Liam Denning, Shale's Big Spenders Needn't Fight the Fed, Wall Street Journal, 4 August 2014

37 Ibid.

38 Oswald Clint, Director Bernstein, The Dark Side of the Golden Age of Shale and Tight Oil, May 2013

39 TPH Global Shale Conference, 21 November 2013; as reported in: Ivan Sandrea, U.S. shale gas and tight oil industry performance: challenges and opportunities, Oxford Institute for Energy Studies, March 2014

40 IHS, America's New Energy Future: The Unconventional Oil and Gas Revolution and the US Economy, October 2012.

European shale plays, for example, may not have internal rates of return that beat the corporate hurdle rate (15%), and/or may display negative NPV. The availability and sustainability of financing flows for European projects has not been adequately considered to date, and is one of the reasons - along with disappointing geology - behind the slow start to shale exploration in geographies such as Poland.

Of course, each company is different. Exposure to interest rates, for example, depends on each company's balance sheet and income statement. The more strung out the company – less attractive acreage, higher cost, lower production yields, etc. – the more sensitive that the company will be. The best companies control the best acreage, with the preponderance of shale oil and gas production coming from a small cluster of leading operators. For the others, the question is clear: what entity will have the capacity or desire to continue funding the acquisition of new acreage and the drilling of new wells at an ongoing loss? The vagaries of finance and the mechanics of cyclical bubbles must be heeded. In the timeless words of Mark Twain, "A banker is a fellow who lends you his umbrella when the sun is shining, but wants it back the minute it begins to rain."