Energy Transition Advisors
ETA

Carbon Tracker Initiative

Executive Summary

- **Rising capex, falling capex productivity**: From 2000-2013, worldwide capital expenditures (capex) related to oil and gas production increased from $250 billion in 2000 to nearly $700 billion (both figures in 2012 dollars). Rising investment, however, has been yielding progressively smaller increases in the global oil supply; from 1999-2013 industry-wide exploration and production capex per barrel increased at a compound annual growth rate (CAGR) of 10.9% - or roughly 10X faster than during the period from 1985-1999 (0.9% CAGR).

- **Shift to higher-cost resources and uneven project execution**: Declining capex productivity reflects in part the rise in production of "unconventional" oil (e.g. shale oil, tight liquids, oil sands), as well as a shift in production of "conventional" oil toward deepwater and ultra-deepwater projects. On average, these resources (especially in certain areas, such as oil sands) tend to have higher per-barrel production costs than do existing conventional oil assets that account for ~90% of the current global oil supply. Other sources of declining capex productivity include, uneven project execution and general inflation in industry costs (both partly a result of sustained capex growth straining supply chains).

- **Company-level cash returns below 30-year averages**: After reaching a peak of 21% in 2008, average returns on upstream projects have since declined to the industry's estimated long-term hurdle rate of 12-13%. Rising project costs, moderating oil price growth, increased maintenance expenditures on existing assets, and high-priced acquisitions have all played a role in the decline of upstream returns. Falling upstream profitability has brought company-level cash returns below the 30-year industry average of ~11%, raising questions as to whether many companies can generate sufficient cash to fund existing dividend and investment commitments. Though the cash position of producers may improve over the coming years as capex growth stabilizes and new assets come online, current trends highlight (1) the current economic incentive for companies to exercise cost-control and capital discipline; and (2) potential short-term vulnerability of financial returns to volatility in oil prices, industry costs and exchange rates.

From Capex Growth to Capital Discipline? - Cost, Risk, and Return Trends in the Upstream Oil Industry

To complement our recent report on carbon asset risk in the oil industry (Carbon Supply Cost Curves – Evaluating Financial Risk to Oil Capital Expenditures), this note examines recent trends in the upstream oil industry related to project costs, financial returns, and technical/geopolitical risks.

Given that oil companies in the private sector are planning to invest $1.1 trillion in new production over the next decade, it is instructive to examine the industry's recent performance at delivering projects on time and within budget. This analysis finds the period 2008-2013 to have seen widespread delays and cost-overruns across a range of projects (with negative impacts on shareholder returns). Moreover, over the coming years the challenges to project execution – in the form of technical and geopolitical risk – appear to be generally increasing, rather than decreasing.

As the transition to a low-carbon world is likely to bring increasing structural pressure on future oil demand and prices, cost-control and capital discipline will be essential strategies for oil companies to protect shareholders from carbon asset risk. The analysis in this note is intended to further the dialogue between investors and industry on that topic.

Analysts

CTI:
Reid Capalino

ETA:
Paul Spedding
Mark Fulton

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- **Potential for technical risk to rise to "never-before-seen" levels**: As the industry prepares for continued (albeit declining) capex growth, there is heightened awareness of the technical risks to project execution. Excluding certain "de-risked" asset types (e.g. US shale oil plays), some market observers detect the technical risk of new projects rising to "never-before-seen levels" and potentially jeopardizing project delivery. Examples of such risk include the significant (>1500 meter) water depth for Brazilian "pre-salt" wells, harsh operating conditions in the Arctic, and pipeline bottlenecks in Alberta and Kurdistan. Views are mixed on how well-prepared the industry is to manage these risks. Whereas some emphasize increased measures to mitigate technical risk (e.g. via more investment in front-end engineering), others point to recent incidents – for example, the latest two-year delay (as a result of a pipeline leaking toxic gas) at the massive Kashagan oil field in the northern Caspian Sea – as evidence that the delays and cost-overruns of recent years are likely to continue.

- **As geopolitical risk resumes its prominent role in world oil markets**: Recent years have seen a lull in geopolitical risk as production growth occurred chiefly in low-risk countries such as the United States and Canada. Countries that post greater challenges for investors, however, are expected to receive a large share of future oil industry investment; through 2025, we find $300 billion of potential capex (from private-sector companies) in countries with significant geopolitical risk. Noteworthy recent reminders of such risk include economic sanctions against Russia, attacks against oil infrastructure in Kurdistan, and Spanish oil major Repsol's $5 billion settlement with the government of Argentina's owing to expropriation of assets in 2012. More mundane (but no less relevant) examples include the potential for corruption, lack of due process, and political instability in countries such as Nigeria, Kazakhstan, Angola, and Madagascar. How industry succeeds at handling the combination of geopolitical and technical risks will largely determine whether the actual costs of new projects are in line with projections.

Acknowledgements
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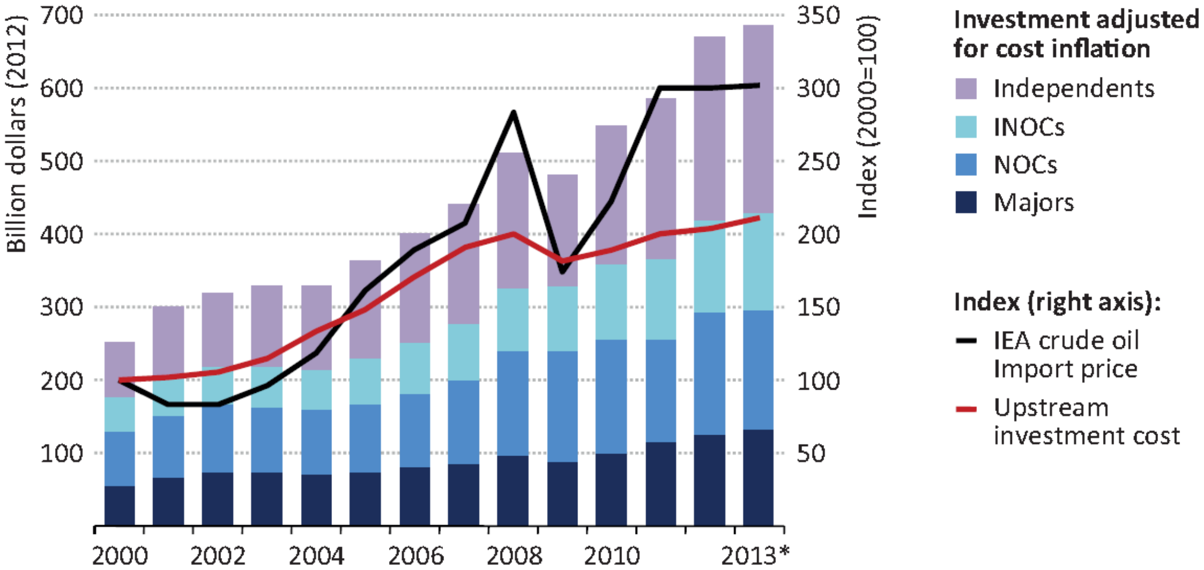
1. Rising capex and changing sources of supply growth

The oil industry has been increasing investment in exploration and production. In response to rising oil prices and technological advances, global upstream oil investment (capex) increased from roughly $250 billion in 2000 to nearly $700 billion in 2013 (both figures in 2012 dollars).[1]

Figure 1 Worldwide upstream oil and gas investment and the IEA Upstream Investment Cost Index



* Budgeted spending. Notes: The IEA Upstream Investment Cost Index, set at 100 in 2000, measures the change in underlying capital costs for exploration and production. It uses weighted averages to remove the effects of spending on different types and locations of upstream projects. Note that in our *Carbon Supply Cost Curves* report we combine INOCs and NOCs into a category we term "National Oil Companies"; we combine Majors and Independents into a category we term "Private Oil Companies." When separating out the Majors, however, our definition is the same as that of the IEA. **Source:** IEA databases and analysis based on industry sources.

Growth in capex over recent years has coincided with a changing composition of how this money is being invested. Since 2004 Goldman Sachs has compiled an annual database of all major new (i.e. recently producing, under development, or pre-sanction) oil and gas projects that (1) have estimated recoverable reserves of at least 300 million barrels of oil equivalent); and (2) have at least one "investable entity" as an equity participant (i.e. are not fully-owned by the subset of National or International Oil Companies with no degree of private ownership).[2] The table below shows the breakdown of annual capex related to these projects by various categories of resource type (i.e. traditional, US unconventional liquids[3], heavy oil) and method of production (i.e. onshore, offshore, deepwater, ultra-deepwater). Though capex increased across all of these categories, note the particular surge from 2006-2012 in capex related to US unconventional

[1] International Energy Agency (IEA), *World Energy Outlook 2013 (WEO 2013)*, Paris: OECD/IEA, 2013, 499 http://www.worldenergyoutlook.org/publications/weo-2013/IEA

[2] Goldman Sachs, *380 Projects to Change the World: From Resource Constraint to Infrastructure Constraint,* April 12, 2013, 131. Their most recent survey of top projects amounted to 45% of total capex for major oil companies from 2013-2016. Moreover, note that the result of the inclusion criteria is to exclude some projects (particularly from national oil companies) that might otherwise qualify based purely on the estimated recoverable reserves threshold.

[3] The term "unconventional liquids" here includes shale oil, tight liquids, and natural gas liquids (NGLs). For definitions of these terms see Appendix A.

liquids (i.e. tight oil and natural gas liquids, or NGLs), which grew at a 63% compound annual growth rate (CAGR) from 2006-2012 (chiefly due to investment from mid-sized US Independents). Another area of strong (and continuing) growth in capex has been in ultra-deepwater production (in Brazil, the Gulf of Mexico, and elsewhere), with most of this investment coming from the majors.[4]

Table 1 Capex spend and growth rates for major oil projects, 2010-2016E ($MM) – recent growth drivers include US unconventional liquids, ultra-deepwater

	2010	2011	2012	2013E	2014E	2015E	2016E	CAGR 2006-2012	CAGR 2012-2018
Total Top 380 Capex	148,671	178,143	233,896	275,073	310,662	323,568	361,645	21.0%	8.0%
Total Offshore	57,649	63,793	78,301	107,165	115,800	136,717	160,622	11.6%	14.1%
% of Total Top 380 Capex	*39%*	*36%*	*33%*	*39%*	*37%*	*42%*	*44%*		
Traditional	19,408	20,495	22,322	20,883	23,070	26,889	30,635	22.3%	1.6%
% of Total Top 380 Capex	*13%*	*12%*	*10%*	*8%*	*7%*	*8%*	*8%*		
Deepwater 750m - 1500 m	17,732	19,839	23,329	27,928	25,072	26,037	29,759	7.6%	2.0%
% of Total Top 380 Capex	*12%*	*11%*	*10%*	*10%*	*8%*	*8%*	*8%*		
Ultra deepwater > 1500 m	9,656	11,768	15,662	25,589	29,904	41,996	56,807	27.0%	29.8%
% of Total Top 380 Capex	*6%*	*7%*	*7%*	*9%*	*10%*	*13%*	*16%*		
Total Onshore	91,022	114,360	155,596	167,908	194,861	186,851	201,024	28.9%	4.1%
% of Total Top 380 Capex	*61%*	*64%*	*67%*	*61%*	*63%*	*58%*	*56%*		
US Unconventional liquids	10,397	24,825	47,542	54,728	66,536	62,838	62,358	63.4%	3.8%
% of Total Top 380 Capex	*7%*	*14%*	*20%*	*20%*	*21%*	*19%*	*17%*		
Heavy Oil	14,465	13,579	17,624	19,966	20,415	22,190	29,955	10.8%	12.6%
% of Total Top 380 Capex	*10%*	*8%*	*8%*	*7%*	*7%*	*7%*	*8%*		

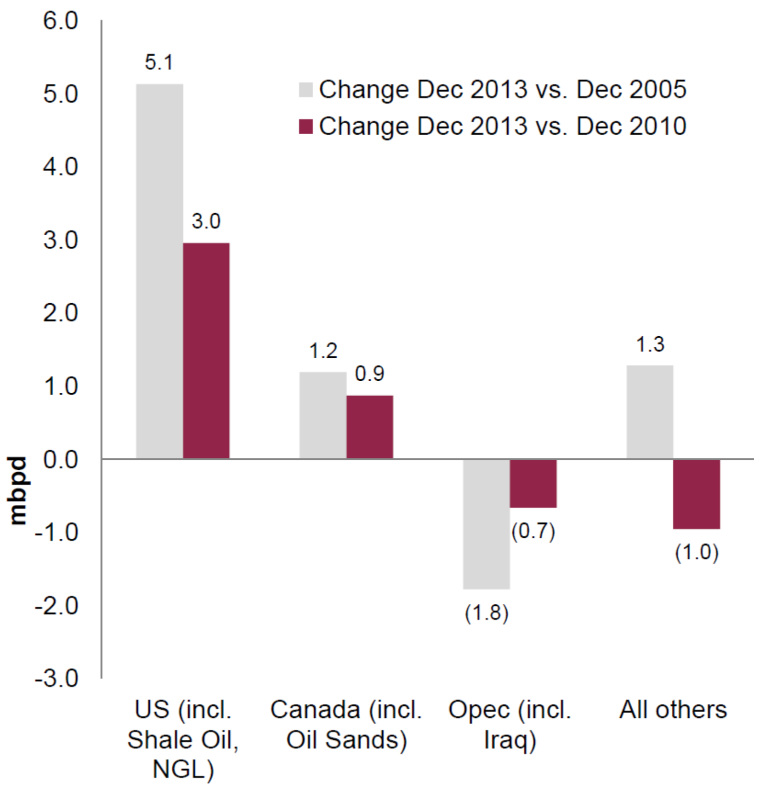
Figures for all except heavy oil and unconventional liquids also include some portion of capex devoted to natural gas production.
Source: Company data, Goldman Sachs research analysis, Carbon Tracker analysis 2014

[4] Goldman Sachs, *380 Projects*, 87.

New sources of supply growth

The changing composition of capex has led to a change in the sources of growth in the global oil system. Since 2005 net global oil production has increased by 5.8 MBPD. Of this, the largest source of new supply has come from US unconventional liquids (shale oil, tight liquids[5], NGLs), which have increased by 5.1 MBPD since 2005. Other notable sources of recent supply growth have been Canada (chiefly from oil sands) and production of NGLs within OPEC (up 1.7 MBPD since 2005, but not shown on the chart below).

Figure 2 World Liquids Production Growth, 2005-2013, Oct-Dec averages, excludes OPEC NGLs



Source: Douglas-Westwood based on EIA STEO.

Looking forward, analysts estimate that recent capex will enable annual net growth in non-OPEC oil supply of roughly 1 MBPD through 2017-2020. US unconventional liquids are expected to remain the chief source of new non-OPEC supply (~3 MBPD of new supply by 2017-2020), followed by ultra-deepwater production in Brazil (3 MBPD by 2020), and Canada (0.84 MBPD by 2017).[6] Within OPEC, until recently Iraq (including Kurdistan) had been projected to be the only significant source of new supply (2.7 MBPD by 2017, 3.4 MBPD by 2020[7]), although continuing sabotage of pipelines/refineries and investment bottlenecks in related infrastructure projects (discussed in the "Geopolitical risk" section below) raise questions as to whether Iraq's production targets will in fact be met. Production from Kurdistan has been also been constrained by political disagreements with Baghdad.

[5] For definitions of these terms, see Appendix A.

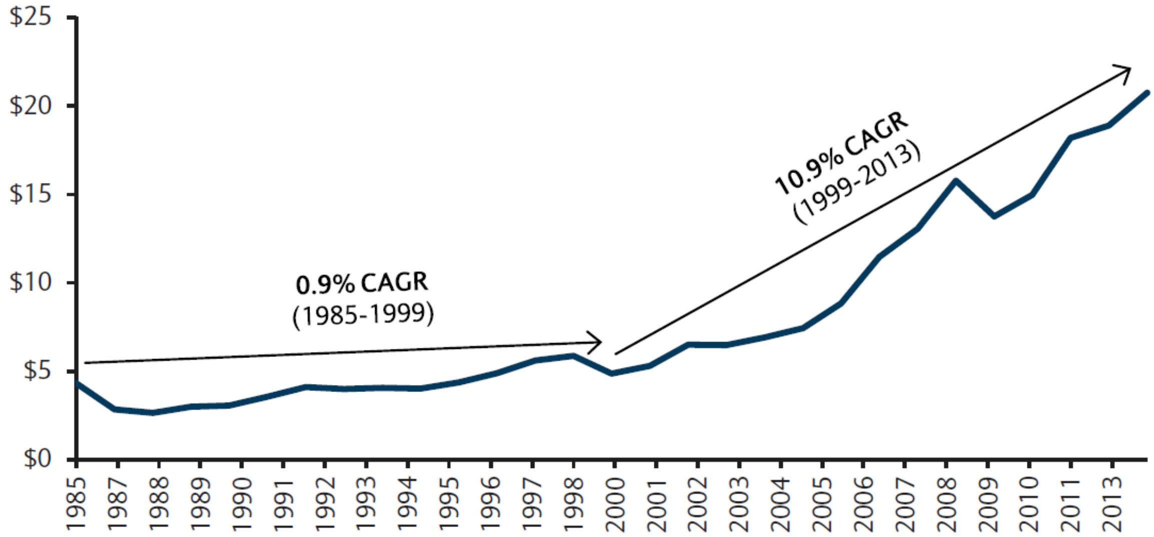
[6] Goldman Sachs, *380 Projects*, 30. Citi, *Global Oil Vision: Stand and Deliver - Global Energy Enters a New Cycle*, March 11 2014, 17.

[7] Goldman Sachs, *380 Projects*, 30. Citi, *Global Oil Vision*, 17.

2. Falling capex productivity

Note that rising investment has been yielding progressively smaller increases in the global oil supply. Industry-wide, Barclays estimates that from 1999-2013 E&P capex per barrel increased at a compound average annual growth rate (CAGR) of 10.9% - or roughly 10X faster than in the period from 1985-1999 (0.9% CAGR).[8]

Figure 3 E&P Capex per barrel

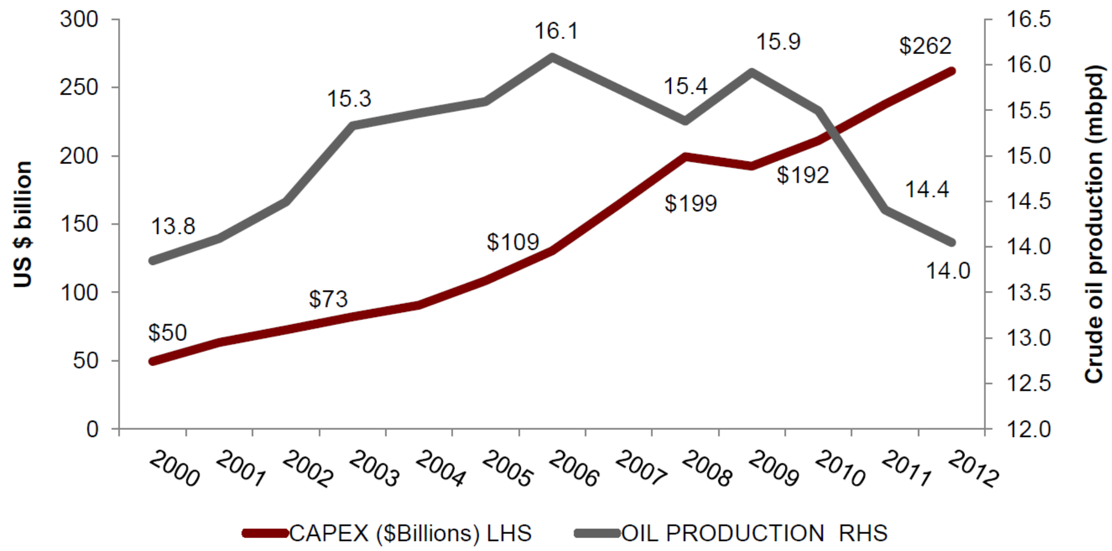


Source: Barclays based on IEA data

The rising capital intensity (capex/barrel) of new oil developments is particularly evident in the sample below of 11 of the largest publicly-traded oil companies.[9] From 2000-2012 these companies increased capex more than five-fold and yet cumulative 2012 production was at roughly the same level as in 2000.[10] One industry consultant interprets this trend to mean that capex productivity (in the sense of barrel of production capacity per capex dollar invested) has fallen by a factor of five since 2000.[11]

[8] IEA and Barclays Research data, cited in Steven Kopits, "Oil and economic growth: a supply-constrained view," presentation to Columbia University Center on Global Energy Policy, 11 February 2014, 43, http://tinyurl.com/mhkju2k.
[9] Relative to the IEA classification of companies in Figure 1, these eleven companies contain all seven oil majors (, ConocoPhillips, Chevron, ENI, Royal Dutch Shell, Total, and ExxonMobil), two international oil companies (Petrobras and Statoil), or INOCs, and two independents (Occidental Petroleum and BG).
[10] Note, though, that over the same period global oil production increase at a CAGR of only 1%, meaning that the trend of limited production increases is global, rather than limited just to largest oil companies. Moreover, that many of these 11 companies are (or had been) substantially under-invested in US unconventional liquids – which, as noted, have been the largest source of new world oil supply – is also part of the story.
[11] Kopits, 40.

Figure 4 Combined capex data for BG, BP, COP, CVX, ENI, OXY, PBR, RDS, STO, TOT, XOM



Data for Majors (BP, ConocoPhillips, Chevron, ENI, Royal Dutch Shell, Total, and ExxonMobil) as well as two International Oil Companies (Petrobras and Statoil) and two Independents (BG and Occidental Petroleum). Includes capex on non-production and downstream assets. **Source:** Bloomberg via Phibro Trading LLC .

Reserves vs. Production

On the other hand, it is important to note that companies invest not only to increase current *production* but also to increase *reserves* (the source of future production). To the extent that companies have been spending to grow reserves rather than to grow production, the trend observed above would appear less troubling. The post-2000 period has indeed seen some major discoveries, in particular the ultra-deepwater "pre-salt" fields of Brazil and the giant Kashagan field in the northern Caspian Sea (both discussed below). With respect to non-OPEC reserves of conventional crude oil, the IEA observes "a clear ramp up in proven reserves since 2002, as higher oil prices moved reserves from a non-commercial to a commercial category and stimulated an increase in appraisal activities."[12] The lion's share of reserve growth over this period, however, has occurred in a single region – the former Soviet Union (chiefly Kazakhstan and Russia) – which has seen a 39% increase in proven reserves since 2002.[13] Excluding the former Soviet Union, since 2000 non-OPEC proven reserves (including both conventional and unconventional oil) are essentially flat. Moreover, capex relating to "proving up reserves" accounts for a minority of overall industry capex; for example, Goldman Sachs estimated that from 2013-2016 exploration capex will account for only 15% of total capex for global oil Majors.[14] Hence, while reserve growth in lieu of production growth is certainly a relevant part of the discussion on capex productivity[15] (and while exploration success may increase in coming years), it explains only a portion of the decline in capex productivity noted above.

Given that context, the paragraphs below survey the major drivers of declining capex productivity.

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[12] IEA, *WEO 2013*, 432

[13] BP Statistical Review of World Energy June 2013, "Oil: proved reserves – barrels (from 1980)", 2013, http://www.bp.com/statisticalreview As discussed above, the US has also seen notable growth (though on an absolute basis far less than in the former Soviet Union) via shale oil and tight liquids.

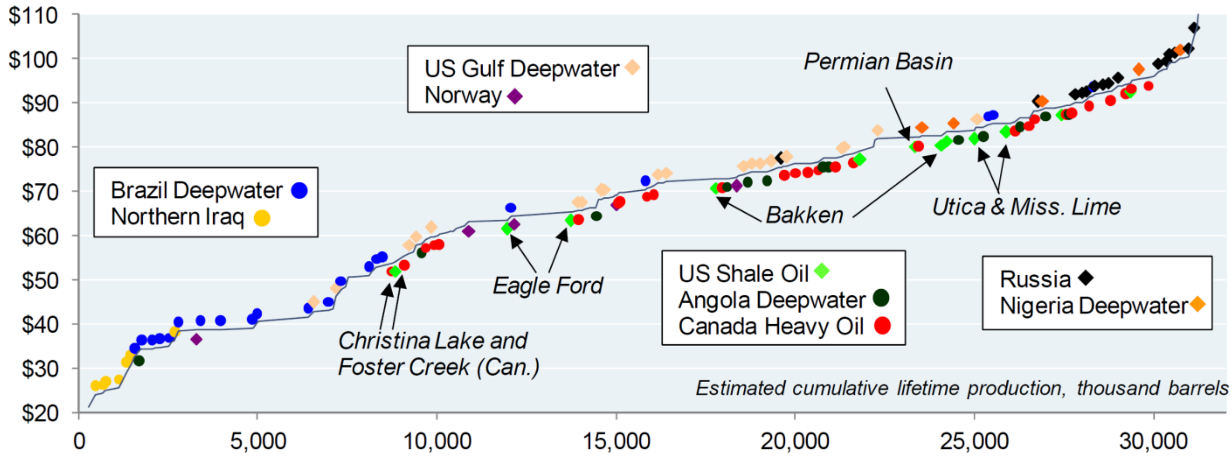
[14] Goldman Sachs, *380 Projects*, 4.

[15] Particularly for companies with a history of recent exploration success, such as Petrobras, BG, and several of the North American Independents. Goldman Sachs, *380 Projects*, 69.

Development of higher-cost resources

Through the late 1990s (when the price of Brent crude) in 2012 dollars, dipped below $20/bbl, oil companies approved projects that had to be competitive in a world of $20-30/bbl oil.[16] The subsequent rise in oil prices has spurred a shift to higher-cost resources.[17] In an April 2013 update to the Goldman Sachs' new project survey, half of the cumulative lifetime production was projected to come from projects with a Brent-equivalent breakeven oil price (BEOP) above $70/bbl.[18] Moreover, among projects added within the past two years (which are a subset of the projects shown in the chart below), none had a BEOP below $70/bbl and most had BEOPs within the $80-100/bbl band. The latter group includes higher-cost US shale oil and deepwater projects as well as majority of Canadian oil sands projects, which Goldman estimate to be the current marginal source of new non-OPEC supply (with the top quintile of production having a Brent-equivalent BEOP of $88-105/bbl, including 2.4 MBPD of future production that requires over $100/bbl).[19] This recent trend is a departure from the 2009-2011 period, during which many new additions to the Goldman database had BEOPs below $80/bbl (including Brazilian deepwater, lower-cost Canadian oil sands sites, and US shale plays in the Bakken and Eagle Ford formations).

Figure 5 Cost curve for new projects (recently producing, under development or pre-sanction) USD per barrel



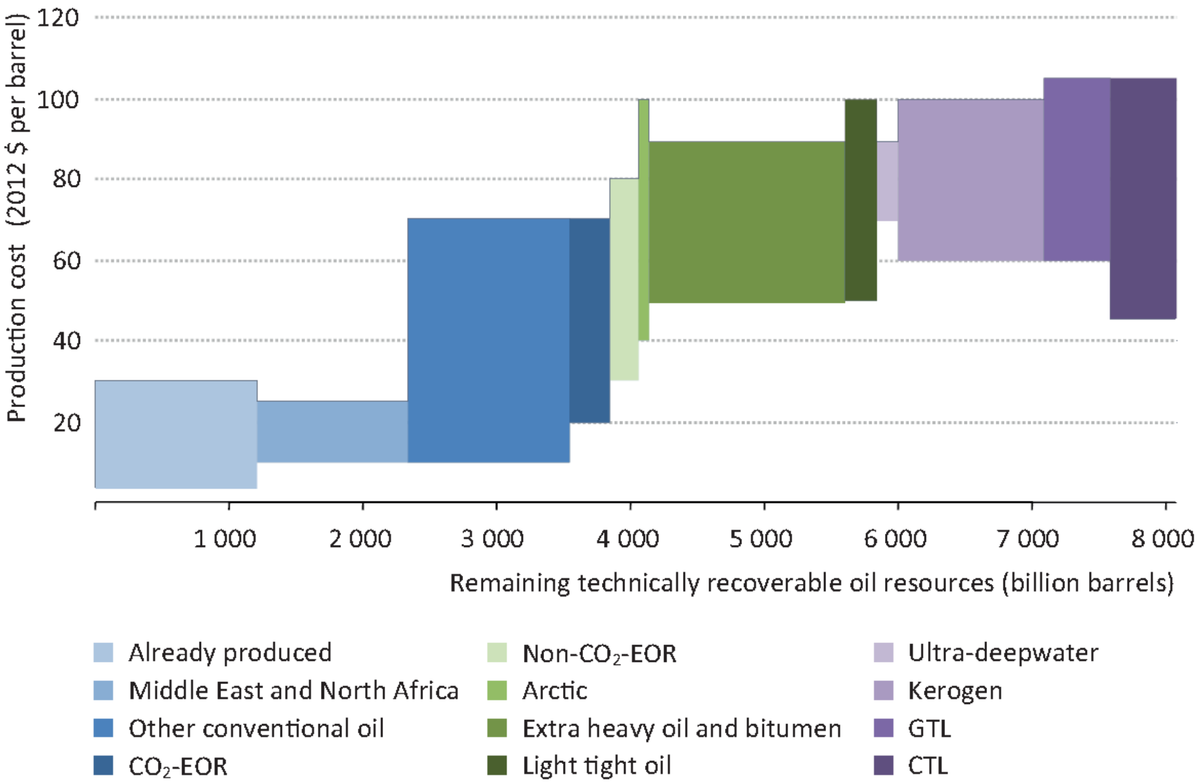
Source: JPM based on Goldman Sachs,"380 projects to change the world". April 2013. Note: Russian breakeven costs shown are high primarily due to heavy taxation

[16] Citi, 13.
[17] Note that a portion of the increase in E&P capex per barrel is also attributable to a move toward "mega-projects" (e.g. the Kashagan project in Kazahkstan or several Canadian oil sands projects) that have high capex-to-production ratios as a result of high costs and very long reserve lives.
[18] Goldman Sachs, *380 Projects*, 11.
[19] Goldman Sachs, *Top 380 Global Oil Price Update - Higher long-term prices required by a troubled industry*, April 12, 2013, 2, 5. The range of $88-105/bbl reflects the assumption that future heavy crude differentials will decline due to expanded transport infrastructure in Western Canada.

Uneven Execution of Recent Projects

The trend toward higher BEOP project costs largely reflects the nature of the resources being developed. For example, the figure below suggests that the focus of recent capex – tight oil, extra heavy oil and bitumen, ultra-deepwater – has higher BEOPS than oil that has already been produced and (on average) tends to have higher BEOPs than much of the remaining supply of conventional oil.

Figure 6 Supply costs of liquid fuels



Note: Figures in the chart above differ from those displayed in our main document because the figure above is displaying "remaining technically recoverable resources", whereas we focus on Estimated Ultimate Recovery (EUR). For more discussion see Appendix C in our *Carbon Supply Cost Curves* study.
Source: Resources to Reserves (IEA, 2013).

These projected cost differences are due to many factors including complex geology, increasing water depths and harsher conditions. Several recent projects have seen delays with actual spends significantly above budget. This reflects the difficulty of managing increasingly complex developments at a time of strained supply chains and tight labor markets. In many cases, this harmed project economics. For example, in the case of an Angolan deepwater project, Citi estimate that a one-year delay and 25% cost-overrun would diminish a projected 15.5% post-tax internal rate of return (IRR) to an 11% IRR. In the Gulf of Mexico, which has a traditional fiscal regime (rather than a concession-based production sharing contract or PSC) the negative effect of such a delay and cost-overruns is amplified, with the projected IRR declining from 21% to 13.5%. Citi attribute recent examples of flawed project execution in part to "the industry's focus on a land-grab of resources" and "targets and management incentives increasingly aligned around growth rather than return on investment."[20] Accordingly, improving the quality of project execution has become a major industry focus.[21]

[20] Citi, 31.
[21] For more discussion, see the "Technical Risk" section below.

General Cost Inflation

Moving from project-level to industry-level considerations, any assessment of the recent developments in the upstream oil industry must examine the trend shown in Figure 1 above, the steady increase in the IEA Upstream Investment Cost Index (which measures changes in underlying capital costs for exploration and production).[22] It suggests that underlying capital costs for exploration and production to have roughly doubled in real terms since 2000 (i.e. a 5.5% CAGR). This real rate of increase hurts project economics and creates uncertainty as to how such costs will evolve in the future. Increases after 2000 largely reflect an industry ramping up after more than a decade of retrenchment, and hence may not be relevant in future. This argument, however, does not explain the continued increase in costs in recent years; a recent study of the US, for example, found exploration and development costs to have increased by 20 percent in 2012 alone.[23] Uncertainty over trends driving the rise in upstream costs (rising rig rates, increased seismic, deeper water depths, rising wage costs and increased complexity), is likely to make forecasting future costs difficult for oil companies. At present, we believe the risks lie towards continued increases in industry inflation - unless, of course, the industry decides to scale back investment to improve returns.[24]

Feedback effects between the oil price and upstream investment costs

Though a full discussion of upstream cost trends is beyond the scope of this study, it is worth briefly exploring the interaction between oil prices and upstream investment costs.[25] Other things being equal, a higher oil price will make a given upstream investment look to be more profitable. In practice, however, part of these excess profits will over time be eroded as higher oil prices feed their way back through the upstream supply chain or fiscal changes (a process that can also work in reverse when oil prices decline). This reflects in part the extensive use of oil as an input throughout the upstream supply chain. More generally, it reflects rent-seeking activity by supply companies (of cement, steel, materials), oil field services companies, and governments that grant drilling licenses and institute various production-sharing agreements. The IEA observes that “it is reasonable to expect that all industry participants… will always try to capture their share of higher oil prices, de facto pushing costs up proportionally.”[26]

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[22] This index measures changes in underlying capital costs for exploration and production.
[23] Ernst and Young, “US oil and gas reserves study,” 2013, http://www.ey.com/Publication/vwLUAssets/US_oil_and_gas_reserves_study_2013/$FILE/US_oil_and_gas_reserves_study_2013_DW0267.pdf
[24] For pre-sanction and under-development projects, Goldman Sachs (*380 Projects*, 44) estimates the all-in capital costs of deepwater and heavy oil projects to have increased from under $4/bbl in 2005 to $10.5-12/bbl in 2013. Owing to higher costs for onshore rigs, steel, and labor, 2011-2013 costs for “greenfield” oil sands projects (and LNG projects) have been particularly notable.
[25] As for developments that put *downward* pressure on costs, technology learning is by far the most important.
[26] IEA, *WEO 2013*, 454.

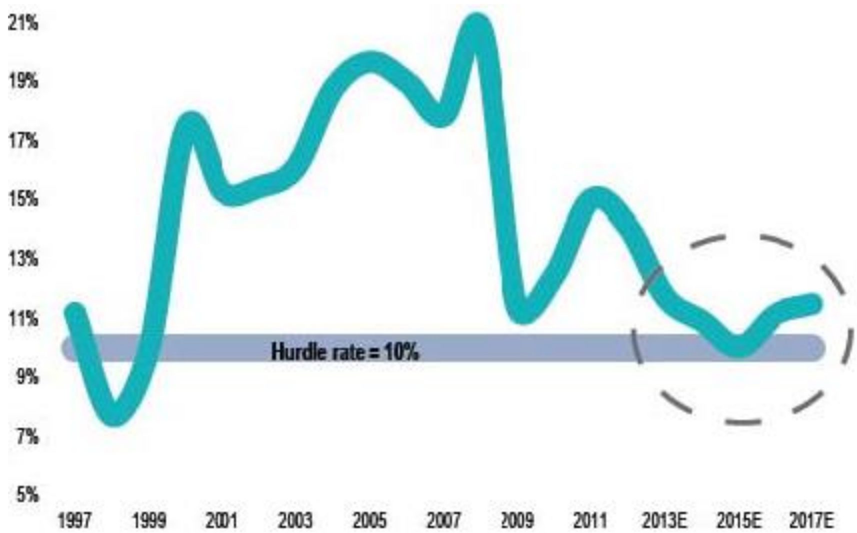
3. Impact on Shareholder Returns

Recognizing the recent trends of rising capex and falling capex productivity, the paragraphs below examine how such trends have affected financial returns at the both the project and company levels.

After robust growth, upstream returns have compressed toward hurdle rates

The trend toward higher costs has pulled upstream returns back towards the industry's long-term hurdle rate. Average returns on upstream projects have declined from a peak of 21% in 2008 to just under 12% in 2013 (in line with the industry's estimated long-term hurdle rate of 12-13%).[27] Given the industries ramping up of capex and the replacement of declining high-return legacy assets with higher cost, higher taxed projects, a reduction of returns was to be expected. Still, some analysts argue that the recent decline in returns has exceeded expectations. Analysts at Citi, for example, argue that post-2008 the industry had expected upstream returns to decline to 17-18%, rather than falling 600 basis points to 12-13%. This may be a reflection of a build in inventories of assets yet to begin production but we believe that escalating costs, tighter fiscal terms, and project delays are also key factors.

Figure 7 Industry-level upstream returns



Source: Citi Research estimates based on company reports

The paragraphs above covered the role that rising costs played in the recent decline in returns; both the *expected* increase in costs (as a result of declining low-cost existing assets being replaced by higher-cost new projects) and the *unexpected* increase in costs as a result of poor project execution. Two related trends that have contributed to declining post-2008 upstream returns include a leveling off of oil price growth and a record of costly acquisitions (discussed below):

- *Decelerating oil price growth*: Whereas from 2000 to 2008 the Brent oil price increased by nearly $70 or 240% ($65 and 170% in real terms), from 2008-2013, however, it increased by only 15% (8% in real terms). Comparing the price data in Figure 8 below with the IEA's Upstream Investment Cost Index in Figure 1 above, from 2005-2012 upstream costs (in real terms) has increased at a faster rate than has the Brent oil price (a ~90% overall increase for upstream costs vs. a ~75% overall increase

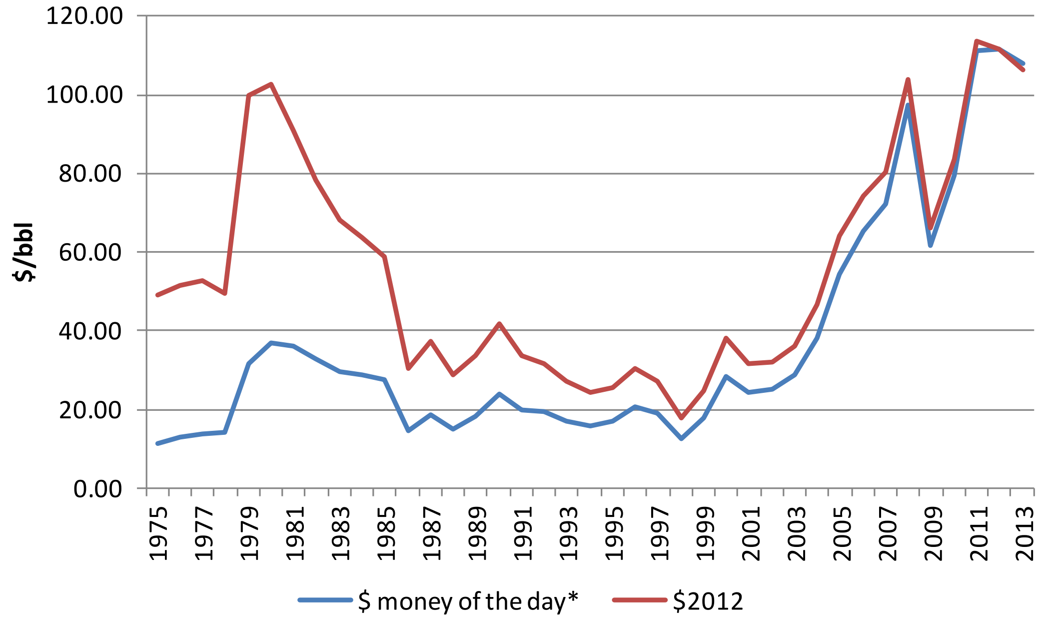
[27] Citi, 11.

for the Brent price). Moreover, from 2011-2013 the IEA estimates a 20% increase in upstream costs versus a decline 6% decline in the real Brent price over this period.[28]

- *Over-priced acquisitions*: For 2008-2012 Citi analysts estimate industry-wide acquisitions of $360 billion (equal to 17% of end-2007 upstream invested capital), many of which have begun to look highly questionable (examples include Total's investments in the Joslyn Canadian oil sands project and Royal Dutch Shell investments in Ohio's Utica shale).[29]

[28] Mark Lewis, "Toil for oil means industry sums do not add up," *Financial Times*, Nov 25 2013, http://www.ft.com/intl/cms/s/0/5e923e3a-51d3-11e3-8c42-00144feabdc0.html#axzz30tJZ5vct
[29] Citi, 13.

Figure 8 Price of Brent crude in nominal and real terms, 1982-2013 ($/bbl)



Source: BP, Shell, ETA analysis 2014

… Lowering company-level cash returns below 30-year averages

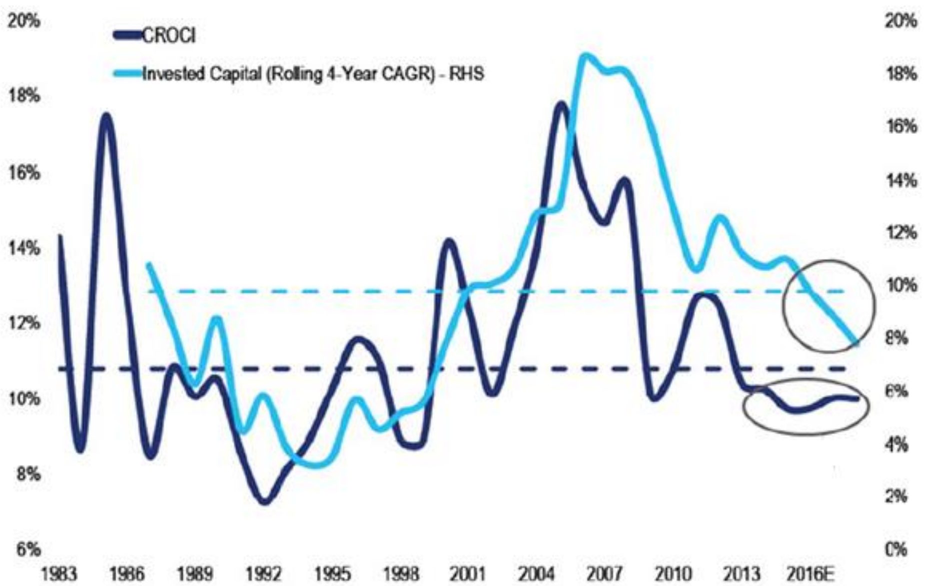
For most major oil companies, the upstream segment accounts for around 75% of earnings - meaning that, generally speaking, company returns mirror upstream returns.[30] One measure of cash returns is Cash Return on Capital Invested (CROCI), which compares a company's cash return against its equity.[31] As of April 2014, Citi notes that returns have fallen below the 30-year industry average of ~11%, commenting "for most players ... cash generation is not enough to support current investment and dividends needs."[32] Its analysts project cash returns to remain flat through 2017-2018, after which there is the potential for them to increase as a result of decelerating capex growth, new production from recently sanctioned/developing projects, and better project execution.

[30] Though beyond the scope of this paper, average returns in the downstream segment improved in the immediate years following 2008 to above the hurdle rate, but have since compressed back downward.

[31] CROCI = EBITDA/Total Value of Equity

[32] Citi, 31.

Figure 9 Financial outlook for oil companies - returns below 30-year average, projected to remain that way through 2018



Source: Cit research estimates based on company data

Super-majors fall close to 40 year lows

Focusing on the three largest "super majors" (Exxon, Shell, and BP), earnings for these firms fell by 16-23% in 2013 relative to 2012.[33] In April 2013 Goldman Sachs projected the 2017 CROCI of this group to be around 9% - below the 16% CROCI for 2004 and roughly the same as in 1965. This is despite a projected 2017 Brent price of $100/bbl that (in real terms) is 5X higher than in 1965.[34] One interpretation of these results is that (in response to recent record-high oil prices) the super majors have been building new reserves at a cost to overall profitability. That said even a 9% 2017 CROCI would be above the super majors' cost of capital and returns beyond 2017 may increase as a result of new cash generation from recently-producing assets.

Company-level cash-flow neutral oil prices

Ultimately returns to shareholders in oil companies depend on free cash flow at the company level, rather than just the return profile of new upstream projects. But breakeven oil prices for *companies* to be free cash flow neutral after capex and dividends can at times be higher than those for their projects. April 2013 estimates from Goldman Sachs suggest that for the "vast majority" of major oil companies this price is over $100/bbl. Moreover, for half of the industry (including Western oil majors such as Chevron, Eni, and Statoil) this price is over $120/bbl, up from ~$80/bbl in 2008-2011.[35] Goldman attribute the recent increase in company-level breakeven oil prices to (1) increasing decline rates from existing assets (~two percentage

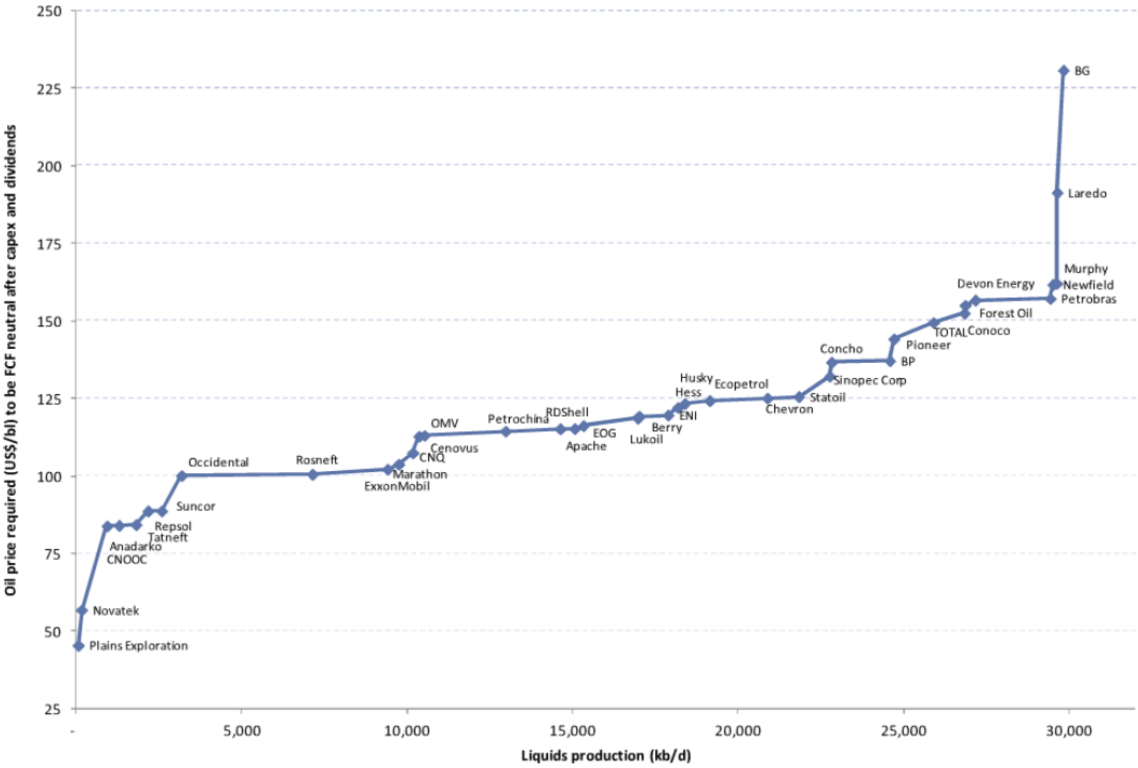
[33] Clifford Kraus and Stanley Reed, "Quarterly Earnings Fall at Exxon Mobil and Shell," *New York Times*, Jan 30 2014, http://www.nytimes.com/2014/01/31/business/fourth-quarter-earnings-fall-at-exxon-mobil-and-shell.html. Stanley Reed, "Profit Drops for BP, but Still Beats Analysts' Forecasts," *New York Times*, Feb 4 2014, http://www.nytimes.com/2014/02/05/business/international/lower-bp-profit-still-beats-analysts-forecasts.html

[34] Goldman Sachs, *Top 380 Global Oil Price Update,* 3

[35] Goldman Sachs, *Top 380 Global Oil Price Update,* 4-6. Within this half is a segment of firms (those in the fourth-quartile of the total distribution) whose cash-flow neutrality requires an oil price above $130/bbl; firms in this segment include many US E&Ps, Petrobras, and a few European integrated companies (BG, Total, BP).

points higher over the past five years; (2) higher maintenance capex costs for these existing assets; and (3) declining cash generation from downstream and other business units.

Figure 10 Oil price required by oil companies to be free cash flow neutral after capex and dividends (2013E)



Source: Goldman Sachs research estimates based on company data

Caveat – returns likely to improve as new assets begin producing

Note that the above findings are for a single year. For many companies, breakeven prices could fall as the growth in invested capital slows and cash-flow from recently-producing projects increases.[36] To wit, despite estimated cash-flow neutral prices near or above $125/bbl, Shell, BP, and Total have all recently increased dividends. *The above discussion, however, still highlights (1) the current economic incentive for companies to exercise cost-control and capital discipline; and (2) potential vulnerability of short-term financial returns to short term volatility in oil prices*, industry costs and exchange rates.

[36] The positive impact on returns from cash generation as a result of new production becomes evident if one adjusts the percentage of capital employed for (1) assets under construction; and (2) exploration and evaluation assets. For example, in the case of Shell, from 2008-2012 its Return on Average Capital Employed (ROCE, or EBIT/Capital Employed) after such adjustments was consistently five to seven percentage points higher than before such adjustments (i.e. for 2012 17.7% versus 12.7%). Royal Dutch Shell, 2013 Annual Report.

4. Rising technical risk for new projects

The combination of rising costs and flat oil prices has led to project cancellations and delays. Recent examples of this trend include:[37]

- Shell, which expects capex down 20% for 2014
- Chevron 5% decrease in 2014 from $42 billion in 2013
- BG expects 2015-16 capex to fall to $8-10 bn from $12 bn in 2013
- Hess (largely due to shareholder activism) capex down 30% over two years
- Statoil - beginning in 2016, will cut costs by $1.3 billion per year
- Exxon will reduce annual spend by $5.5 billion from 2015-2017 versus 2013 levels

These examples notwithstanding, some observers project that overall annual upstream capex will continue to increase over the next several years (albeit at a slower rate than during the 2006-2012 period).[38] Investment for some majors may come back from recent peaks but will still remain well above 10-year averages. New projects are being added with a wide range of breakeven prices, and many analysts cite the potential for attractive economics,[39] particularly in emerging deepwater and ultra-deepwater plays (with ultra-deepwater, among all resource types, set to see the largest relative increase in annual capex).[40] That said, the projected economics of new projects are increasingly uncertain due to (1) rising levels of technical risk; and (2) a return, for some projects, of significant geopolitical risk. Looking ahead to next wave of upstream investment, the success of companies in managing such risks will largely determine whether actual project economics are in line with projections.

Increasing technical risk for new oil projects, even at the lower end of the cost-curve

Technical complexity can harm project economics by (1) necessitating repeated changes to initial design and engineering plans; and (2) increasing the time before project sanction and initial production. Relative to the existing global base of conventional oil production, new barrels coming online in future years (whether in the form of conventional or unconventional oil) could require greater levels of capital, involve more technical complexity and expertise, as longer lead times initial production.[41] Commentators frequently note this in reference to high-cost mega-projects such as the Kashagan oil field in the northern Caspian Sea or oil sands projects in Canada.[42] For example, as a result of leaking toxic gas from a pipeline, the Kashagan oil field has recently been forced to shut down production for at least two years.[43] Leaking pipelines are only

[37] Kopits 49.

[38] As of January 2014 (*Analyzing Key Geographic and Operator Type E&P Capex Trends into 2014*, p. 2) Morgan Stanley project global upstream oil and gas spending to grow ~$40 billion in 2014 and ~$50 billion in 2015 (i.e. significantly less than the annual growth of $120 billion in 2012). In their April 2013 *380 Projects* report (87), Goldman Sachs projects for 2012-2018 total capex related to their Top 380 oil and gas projects to grow at an 8% CAGR (versus a 21% CAGR for 2006-2012), as shown in Table 1 above.

[39] Across major oil and gas projects to 2020, Citi (15) estimates "portfolios geared to deliver a weighted average IRR of 17%" (assuming flat a $90/bbl Brent price in real terms)."

[40]Goldman Sachs, *380 Projects,* 87.

[41] Exceptions to the "longer lead time" would include tight oil

[42] The Kashagan project, for example, is employing new subsea technology in harsh operating conditions (sea ice, extreme temperature variation); strong pricing for output from many oil sands projects in Western Canada depends on development of new pipelines or rail transport infrastructure.

[43] Mark Lewis, "Giant Kashagan oilfield could be out of production for two years", Kepler Chevreux, Apr 7 2014, http://www.jeremyleggett.net/2014/04/giant-kashagan-oilfield-could-be-out-of-production-for-two-years/

the latest in a long of list of setbacks for Kashagan, which was to have entered into production nearly a decade ago but only came online in September 2013 before being forced to quickly shut down again.

Technical risk, however, is also an issue for many projects estimated to be low-cost, such as the ultra-deepwater pre-salt[44] and sub-salt fields off the coasts of Brazil and in the Gulf of Mexico. In assessing the technical complexity of its Top 380 projects, Goldman Sachs enumerates five key criteria for technical risk: water depth, environment/geography/climate, technology dependence, geological issues, and infrastructure dependence.[45]

Table 2 Categories of Technical Risk for Oil Projects

Category	Description	Example fields
Water depth	Fields in greater water depths are assumed to have higher risk profiles	Jack, Stones, Lula
Environment, geography & climate	Fields subject to hostile operating conditions, e.g. Arctic operations, environmentally sensitive areas, planning permission, high civil unrest or other complex geographies, e.g. sub--salt or hostile weather patterns.	US GoM, Newfoundland
Technology dependence	Greater than average dependency on new or complex production technologies, e.g. subsea systems, early generation deepwater developments, heavy oil, unconventional production technologies	Kashagan
Geological issues	Risks regarding complex reservoirs, heavy oil, HPHT, sour liquids or unconventional reservoirs	Kristin Tyrihans, Kashagan
Infrastructure dependence	Infrastructure required to develop and monetize produced hydrocarbons	Uganda, Iraq, Caspian

Source: Goldman Sachs.

Excluding (generally low-risk) projects related to tight liquids (i.e. shale) in North America as well as Caspian Sea projects, Goldman found technical risk of new projects had risen "...to never-before-seen levels... presenting a potential danger to delivery"[46] Largely this is as a result of a surge of investment in ultra-deepwater production (Table 1 above).

[44] Chevron ("Glossary of Energy and Financial Terms", March 2013, http://www.chevron.com/documents/pdf/GlossaryOfEnergyAndFinancialTerms.pdf) define these terms as follows: "*Post-salt* refers to crude oil and natural gas reservoirs lying above and deposited after an autochthonous (deposited in its present position) salt layer. *Pre-salt* refers to reservoirs lying beneath and deposited prior to an autochthonous salt layer. *Subsalt* refers to reservoirs lying beneath allochthonous (deposited at a distance from its present position) salt layers. The distinction is that, as salt deforms, older sediments below the original position of the salt are called 'pre-salt', whereas younger sediments over which salt has been squeezed are more narrowly called 'subsalt'."

[45] Goldman Sachs, *380* Projects, 120

[46] Goldman Sachs, *380* Projects, 123

Case study: technical risks of Brazil's ultra-deepwater pre-salt fields

Many major new projects are exposed to technical risk across several of the criteria listed above. One clear example is the ultra-deepwater pre-salt reserves of Brazil, which Citi analysts describe as the "single-most important source of new low-cost world oil supply."[47] Brazil pre-salt deposits contain an estimated 50+ billion barrels of oil equivalent beneath an active (i.e. shifting) layer of cretaceous salt across an area 112 thousand km in size (roughly the size of New York State).[48] Since discovery of the massive pre-salt Tupi (now called Lula) field in 2007, Brazil's offshore pre-salt basins have been the global epicenter of new oil discoveries. Through 2017, Petrobras plans to invest $73 billion in pre-salt exploration and production activities[49]; by 2020, Petrobras and other operators in Brazil's pre-salt fields (including Shell, Chevron, and Statoil)[50] aim to begin extracting as much as 2 MBPD.

Projects in the pre-salt fields must grapple with multiple technical challenges:

- *Water depth*: The oil sits beneath a dense layer of rock that is itself 2-3km down into the Atlantic Ocean. For reference, the water depth of the Tupi field (2.2 km) is nearly 50% greater than the water depth of the Macondo Prospect in the Gulf of Mexico (1.5km), site of the Deepwater Horizon accident. Managing production at this level of depth and extremely high pressure can add cost as well as accident risk.

- *Environment, Geography, and Climate*: Brazil's pre-salt oil deposits happen to exist amid diverse Atlantic Ocean ecosystems that contain, among other things, coral reefs and mating areas for whales. Discussion of this became more prominent when, in November 2011, 2400 barrels of oil spilled over the course of two weeks at Chevron's Frade field (in March 2012 Chevron detected another seep at the same field).[51]

- *Technology Dependence*: Companies intend to receive oil from Brazil's pre-salt deposits using floating production, storage, and offloading (FPSO) facilities. New materials or equipment, however, will have to at least partly comply with Brazil's strict local content requirements.[52] Note also that "integrating the subsea architecture"[53] proved challenging for initial producers in the pre-salt formations of Brazil's Santos Basin due to the use of a new type of riser, showing the potential for increased risk or project delays as a result of new technology.

- *Geological Issues*: Even ignoring the water depth, oil still resides deep beneath unusually thick layers of salt and rock (i.e. up to 1.9 km of salt and nearly 5 km of rock). Mapping (i.e. "seismically resolving") oil deposits in such conditions is tremendously challenging, particularly because salt complicates the use of imaging technology. Moreover, even assuming that the deposits have been

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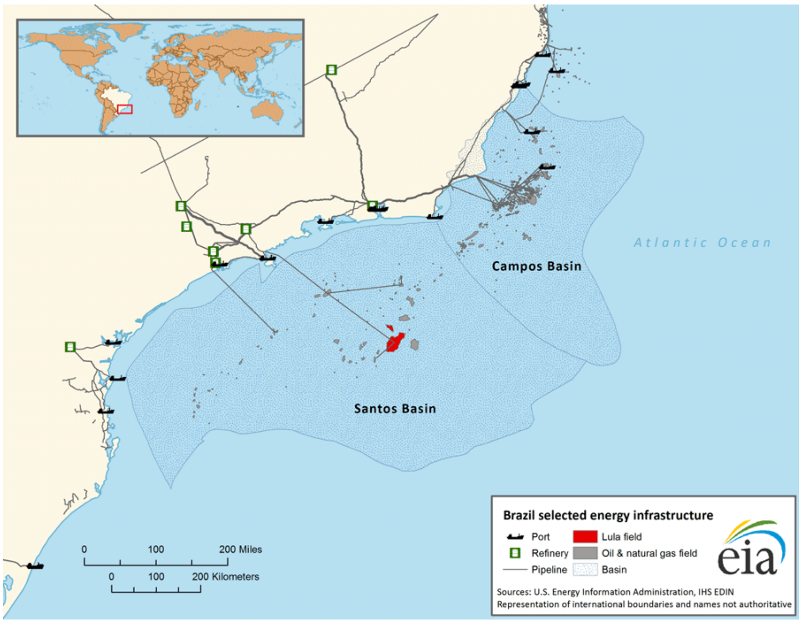
[47] Citi, 14.
[48] US Energy Information Administration (EIA), "Brazil," October 1, 2013, http://www.eia.gov/countries/cab.cfm?fips=br
[49] EIA, "Brazil."
[50] Royal Dutch Shell was the first foreign crude oil producer in the country, and it has now been joined by Chevron, Repsol, BP, Anadarko, El Paso, Galp Energia, Statoil, BG Group, Sinopec, ONGC, and TNK-BP. Brazilian oil company OGX
[51] EIA, "Brazil."
[52] Which holds true even as some local FPSOs have been replaced by leased international FPSOs.
[53] Goldman Sachs, *380* Projects, 37.

properly mapped, accessing them remains extremely challenging as drill stems and pipe have to hold up under tremendous pressures (from the water depth and rock), high temperatures (up to 198 degrees C), and the abrasive effects of salt.

- *Infrastructure Dependence*: Monetizing oil from pre-salt fields will require moving oil from FPSOs onto tankers or into pipelines for sale into world markets. The planned ramp up in production from 0.1 MBPD in 2012 to 2 MBPD by 2020[54] may strain Brazil's infrastructure network, particularly its network of pipelines. Delays adding infrastructure may cause bottlenecks in production independent of the other technical issues outlined above.

Figure 11 Location of Brazil's pre-salt fields



Source: U.S. Energy Information Administration

[54] EIA, "Brazil."

Implications of technical risk dynamics in deepwater/ultra-deepwater oil projects

Note that the dynamics around technical risk are particular challenging for current deepwater/ultra-deepwater projects. The ideal oil project will have (1) a low break-even price (i.e. below ~$65/bbl); (2) low technical risk; and (3) low geopolitical risk, particularly in the sense of being located in a country with a fiscal regime that is both stable and shareholder-friendly. Surveying current deepwater projects, however, suggest very few project categories to satisfy all three of these criteria (the major exceptions being fields in Brazil "post-salt" and French Guiana.[55] Generally, fields with low break-even prices (Brazil pre-salt, low-cost Gulf of Mexico) tend to have higher technical risk as a result of water depth, hurricane risk, and environmental sensitivity; fields with low technical risk, however, tend to have higher break-even prices (e.g. $75-100/bbl) and to be located in countries such as Nigeria, Congo, and Angola whose fiscal terms tend to put a tight limit on project returns.[56] The multiple risks confronting deepwater/ultra-deepwater projects highlight the challenges companies face in implementing these projects on time and within budget.

Industry ability to handle more technical risk

How rising levels of technical risk will affect future project execution is uncertain. In response to recent cost overruns the industry has redoubled its focus on controlling project costs. Analysts at Citi, for example, cite implementation of several measures that they predict will improve project execution, including greater investment in front-end engineering, more "modularized" projects, and better-developed supply-chains and supply-chain management practices.[57] In the short term this may prove true. Over the medium term, however, the IEA highlights shortages of skilled personnel as a significant risk to project implementation.

Human capital challenges as a barrier to handling more technical risk

The global oil industry is confronting serious shortages of skilled personnel such as geologists, geophysicists, reservoir engineers, drilling and completion engineers, and production engineers.[58] Such shortages are particularly acute in Australia, North America, Africa, and the Middle East. Among other reasons, such shortages are the result of (1) the retirement of older and more experienced employees; (2) the industry's nearly two-decade long retrenchment period amid low oil prices (1984-2000), during which hiring "skipped a generation of employees'); (3) difficulties recruiting younger workers, owing to both limited pools of specialized expertise and (in some markets) a reluctance of graduates to work in the fossil fuel industry; and (4) the long lead time (10-15 years on average) necessary to train new recruits before they can assume leadership positions. The IEA observes that the consequences of staffing shortages "can be felt in higher costs or in project delays – or, potentially, in the quality of project implementation", with the latter having "potentially very serious consequences for an industry under increasingly strict scrutiny for its environmental performance."[59]

[55] This discussion draws on Goldman Sachs, "All deepwater projects are not created equal," *380* Projects, 147
[56] The fiscal terms often have tiered bands of tax that rise as cash flow from a given project increases. The marginal rate of tax can hit in excess of 90%, so that little of any incremental return goes to the oil industry.
[57] Citi, 23. Citi also note that, at the early stages of a project, some companies are increasing the level of built-in contingency from 15% to 20%.
[58] This discussion draws on IEA, "Staffing the oil and gas business," *WEO 2013*, 500.
[59] IEA, *WEO 2013*, 500.

5. Geopolitical risk resumes a prominent place in world oil markets

The recent surge of production and investment in the US and Canada has diminished attention to how geopolitical risk can affect industry returns or impede production. Such risk, however, remains pervasive, and is poised to become more salient as the next round of major capex projects ramps up over the rest of this decade. To measure geopolitical risk, we draw on data from the Worldwide Governance Indicators (WGI) project.[60] The four measures we focus on are:

- *Control of corruption*: the magnitude of public corruption, which can undermine the conditions necessary for international competitiveness

- *Political stability and absence of violence/terrorism*: the likelihood that the government "will be destabilized or overthrown by unconstitutional or violent means, including politically motivated violence and terrorism"

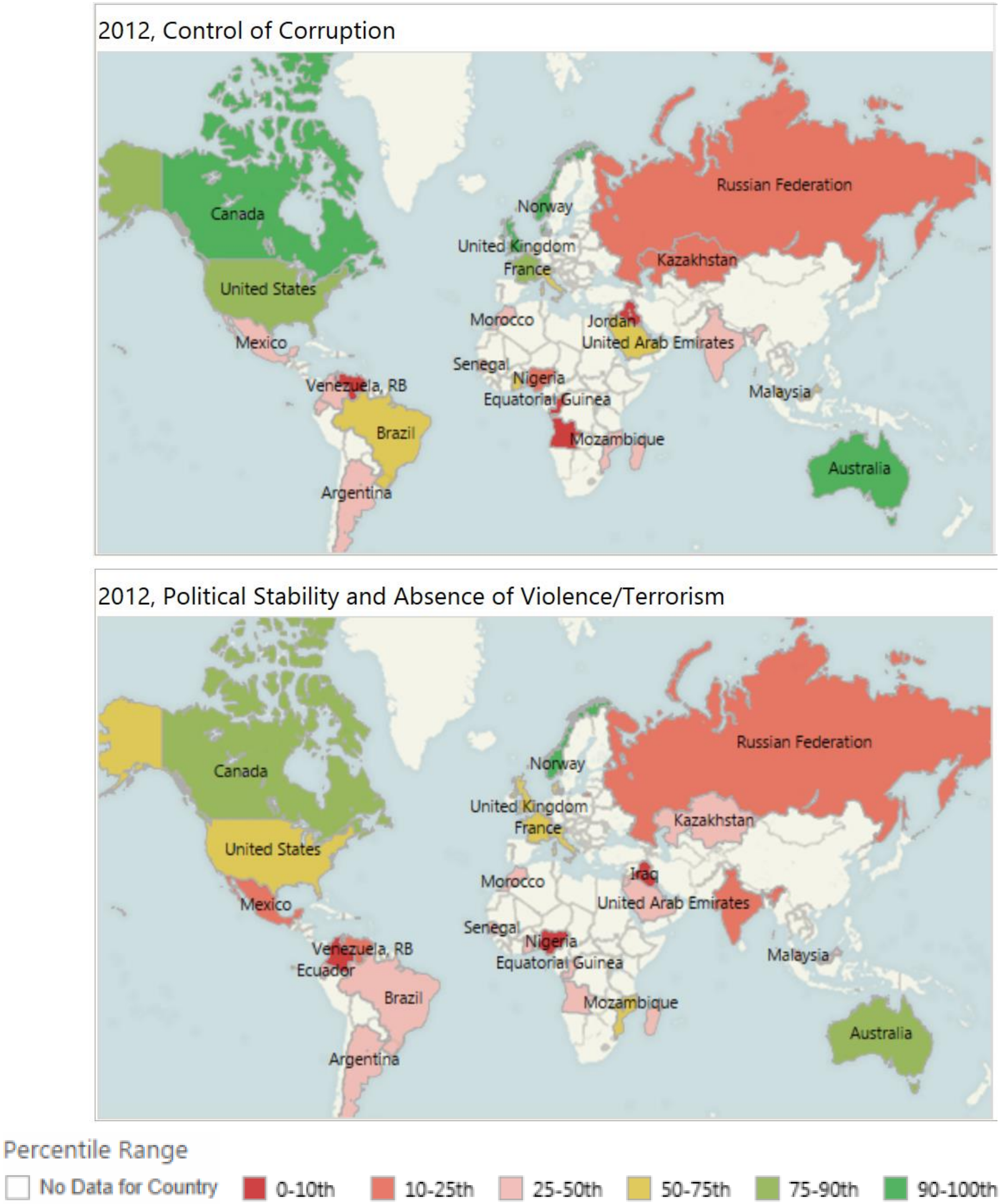
- *Rule of law*: extent to which individuals and businesses have confidence in and abide by the rules of society and in particular the quality of contract enforcement, property rights, the police, and the courts, as well as the likelihood of crime and violence

- *Regulatory quality*: "ability of the government to formulate and implement sound policies and regulations that permit and promote private sector development"

Focusing on countries that are the focus of major planned capex projects over the coming years, the figures below illustrate performance on each of these four dimensions. Oil production is a global business, and, continuing the trend noted at the start of this section, a sizeable share of planned capex is likely to occur in countries where geopolitical risk is low (e.g. US, Canada, Norway, Australia, United Kingdom, France) or moderate (e.g. Brazil, Mexico, India, Morocco, Malaysia, Qatar, Mozambique). That leaves, however, a remaining (and very significant) share of capex in high-risk countries such as Russia, Kazakhstan, Venezuela, Nigeria, Angola, and – given its recent history of expropriating foreign-owned oil assets - Argentina.[61] The paragraphs below review key geopolitical risk factors in high-risk countries that are set to see the largest amount of new capex from privately-owned companies. For more detail on capex commitments in countries with potentially high geopolitical risk – which we tally at $300 billion for private-sector companies through 2025 – see our companion report on *Carbon Supply Cost Curves.*

[60] Daniel Kaufmann, Aart Kraay, and Massimo Mastruzzi, "Worldwide Governance Indicators," The World Bank Group, 2013, http://info.worldbank.org/governance/wgi/index.aspx#home. For 215 economies over the period 1996–2012, the WGI project assembles aggregate measures of six dimensions of governance. These aggregate indicators combine the views of a large number of enterprise, citizen and expert survey respondents in industrial and developing countries. They are based on 31 individual data sources produced by a variety of survey institutes, think tanks, non-governmental organizations, international organizations, and private sector firms.
[61] For detailed data on capex by country and province, see Tables 8-11 in our *Carbon Supply Cost Curves* repot.

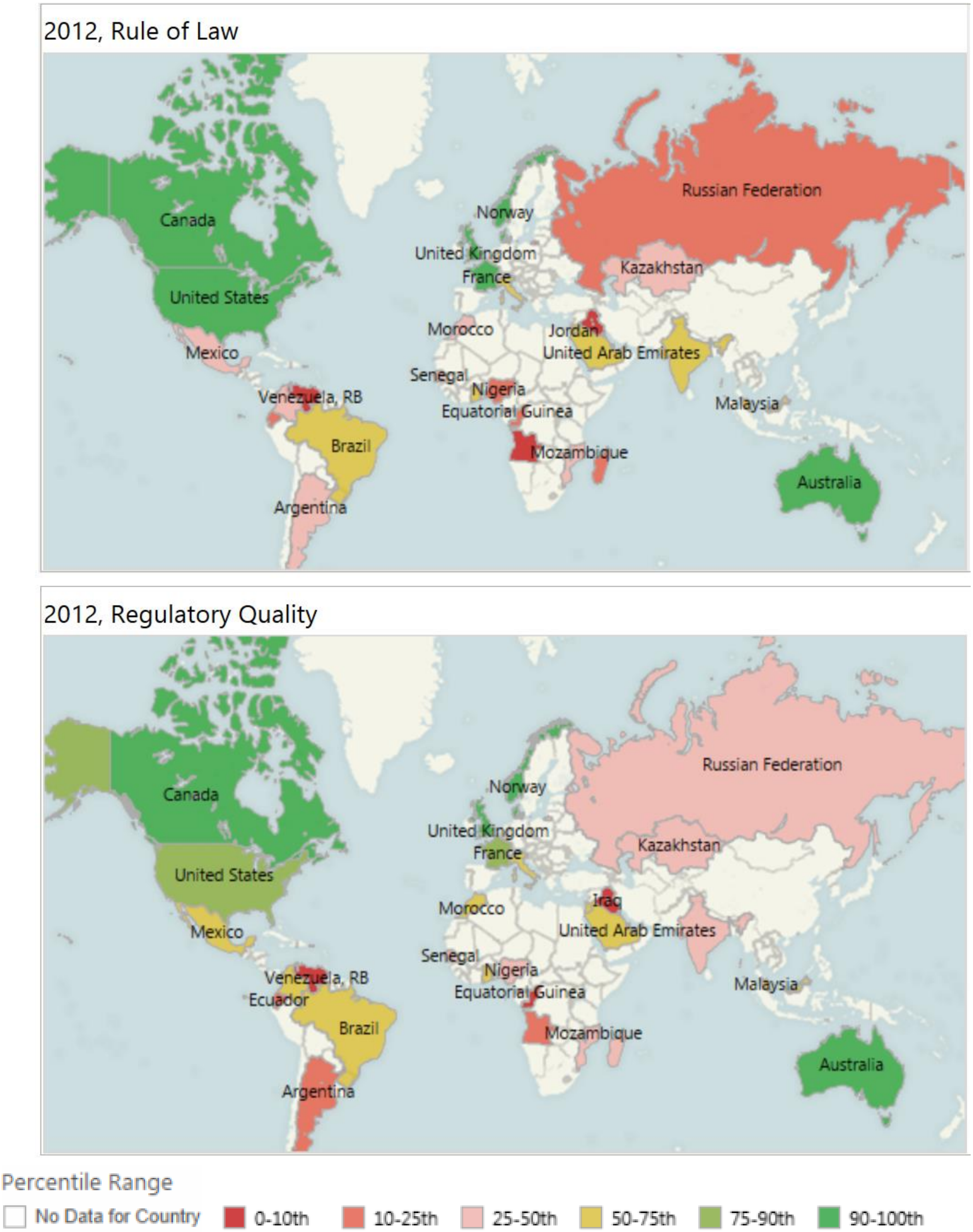
Figure 12 Corruption and political stability in countries containing key oil basins



Source: The Worldwide Governance Indicators, ETA analysis 2014

Source: The Worldwide Governance Indicators, ETA analysis 2014

Figure 13 Rule of law and regulatory quality in countries containing key oil basins



Source: The Worldwide Governance Indicators, ETA analysis 2014

Russia – a difficult market for foreign companies (even prior to recent diplomatic tensions)

- Focus of capex: conventional/unconventional oil in western Siberia, south Russia, and the Arctic
- Companies: Shell, Exxon
- WGI data has Russia in the least attractive decile for corruption, political stability/violence, and rule of law
- Goldman Sachs ranks as "high risk" (score of 0.93 out of 1.30)

At the time of writing, recent economic sanctions imposed by the United States and other nations on Russia (in response to its military intervention in the Ukraine) are highlighting the geopolitical risks of doing business in the former Soviet republic.[62] Well before this current diplomatic crisis, however, the risks for foreign investors in Russia's oil sector have been very clear. The US Energy Information Administration (EIA) notes that "foreign operators experience difficulty operating in Russia" and mentions in particular the troubled history of BP's Russian activities. As a result of disagreements with its Russian partners, BP exited a planned Arctic partnership with Rosneft (Russia's largest oil producer); in 2013 BP divested its Russian assets, including its share in TNK-BP, a joint venture between BP and Russian investors that had been Russia's third-largest oil producer and among the world's ten largest private oil companies. The politically fraught unraveling of the TNK-BP partnership included, among other things, an armed raid on BP's Moscow offices in August 2011.[63] TNK-BP assets are now owned by Rosneft (though, it should be noted, BP retains a significant presence in Russia's oil and gas sector).

The TNK-BP saga illustrates the perils for foreign investors posed by the re-emergence of state control over Russia's oil industry (oil production having been privatized following the dissolution of the Soviet Union). Successfully producing oil in Russia requires working with four different Ministries and three different regulatory Commissions, this in a country where in 2012 oil and gas revenues generated 52% of total revenues to the federal budget.[64] Adding to the challenge is Russia's fiscal regime, in the form of its mineral extraction tax (MET) and export tax. The financial burden related to these taxes poses a substantial risk to development of Russia's unconventional oil reserves, such as those in western Siberia currently being explored by Shell and others. As a result of high tax rates, the IEA estimates that Russian oil production have full life-cycle costs below $25/bbl in order to be competitive on international oil markets (an unlikely prospect for many unconventional reserves). Though Russia recently amended its tax regime for select unconventional formations, even under the new regime the IEA estimates 2035 production from Russia's largest shale oil resource (the Bazhenov Formation) at only 0.450 MBPD in 2035.[65]

Though partnership with or shareholding in Russian companies may afford a degree of protection for the majors, they must still contend with significant geopolitical risks.

[62] Andrew E. Kramer, "New Complications in Russia: Sanctions Over Ukraine Cause Headaches in the Energy Sector," *New York Times*, April 29, 2014, http://www.nytimes.com/2014/04/29/business/international/sanctions-over-ukraine-cause-headaches-in-the-energy-sector.html?_r=0
[63] Andrew E. Kramer, "Memo to Exxon: Business with Russia Might Involve Guns and Balaclavas," *New York Times*, August 31, 2011, http://www.nytimes.com/2011/09/01/business/global/bp-russia.html
[64] EIA, "Russia," November 26 2013, http://www.eia.gov/countries/analysisbriefs/Russia/russia.pdf
[65] IEA, *WEO 2013*, 479.

Kazakhstan – growing role for the state oil company, growing demands on foreign operators

- Focus of capex: conventional production in the Caspian Sea
- Companies: Chevron, ExxonMobil, Shell, Total, ConocoPhillips, Eni, CNPC, BG Group, PetroChina
- WGI data has in bottom quartile for corruption
- Goldman Sachs ranks as "high risk" (score of 0.92 out of 1.30)

Since the dissolution of the Soviet Union, the chief barriers to expanding Kazakhstan's oil production have been technical rather than geopolitical (as the above discussion of the Kashagan project illustrates). Relative to many of its neighbors, Kazakhstan has made significant progress in resolving territorial disputes related to the Caspian Sea (e.g. via its treaty with Russia) and arranging the participation of foreign oil companies (mostly via joint ventures). That said, recent regulatory trends within Kazakhstan pose challenges for foreign-based private operators. These include:

- Growing role of KMG: Kazakhstan's national oil and gas company (KMG) is playing an increasingly prominent role in the country's oil industry. Since its formation in 2002, KMG's role has expanded to the point where it is now by law entitled to majority ownership of all new projects and joint ventures. This is a significant departure from conditions in the 1990s and early 2000s, where foreign oil companies played a leading role in Kazakhstan's oil sector.

- Pre-emption rights and retro-active contractual changes: A 2005 amendment to Kazakhstan's Law on Subsoil and Subsoil Use authorized the state to apply "pre-emption rights" on any oil assets being sold within the country (i.e. gives KMG the option to acquire them); as a result of this change KMG has become a partial owner of Kazakhstan's largest projects oil projects.[66] A 2007 amendment to the law authorized the state to retro-actively alter the terms of oil contracts, or even to repudiate such contracts entirely if the state deems them a risk to national security.

- Local content requirements: In 2011 Kazakhstan adopted legislation setting minimum requirements for the percentage of a project's goods and services that must be procured from within Kazakhstan (with a goal of 85% local content by 2020, relative to the current 50%).[67] Moreover, as of January 2012 at least 90% of an oil company's employees must be Kazakh nationals (at least 70% for management teams), making work permits for foreign workers significantly harder to secure.

- Oil export duties: After a series of back-and-forth moves between 2008 and 2011, all oil exporters within Kazakhstan must now pay an export duty (the only exception being operators whose contracts include a tax stabilization clause.

The above trends do not grab international headlines in the same way as sectarian violence in Iraq or outright expropriation of foreign oil assets in Argentina do. That said, their cumulative impact is to add cost and risk to the production of oil within Kazakhstan. Combined with the technical complexity of the country's largest new oil field (Kashagan), the evolving regulatory climate is an added challenge for private oil companies to navigate.

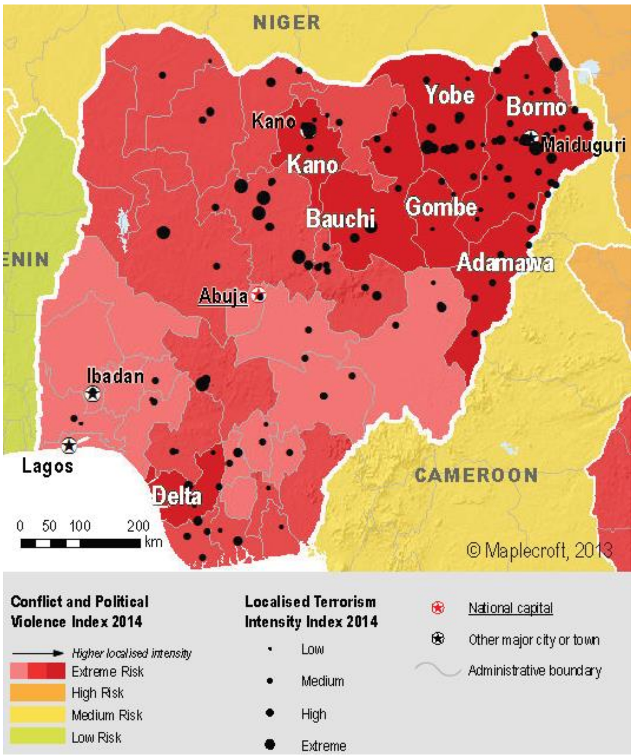
[66] The EIA ("Kazakhstan," http://www.eia.gov/countries/analysisbriefs/Kazakhstan/kazakhstan.pdf) notes that "KMG holds equity interests in Karachaganak (10%), Kashagan (16.8%), and Tengiz (20%), as well as interests ranging between 15% and 100% in many of the onshore projects. It holds at least 50% interest in most of the offshore blocks."
[67] EIA, "Kazakhstan."

Nigeria – as production moves offshore, concerns shift from pipeline attacks to contract renegotiations

- Focus of capex: deepwater
- Companies: Shell, ExxonMobil, Chevron, Total, and Eni
- WGI data has in bottom decile for corruption and political stability/violence and terrorism, bottom quartile for rule of law
- Goldman Sachs ranks as "very high risk" (score of 1.11 out of 1.30)

Among the countries reviewed here, Nigeria stands out for the extent to which oil production has been disrupted as a result of civil unrest, political instability, theft, and acts of terrorism (which have caused unplanned outages as high as 500 kb/d).[68] Surveying the situation in the Niger Delta (Nigeria's main oil-producing province), the EIA notes that "lack of transparency of oil revenues, tensions over revenue distribution, environmental damages from oil spills, and local ethnic and religious tensions created a fragile situation."[69] Oil theft is estimated to have cost Nigeria $10.9 billion in lost revenues from 2009-2011[70]; at the same time, Nigeria's onshore and shallow water production has had to contend with a raft of attacks.

Figure 14 Conflict and Political Violence Intensity Index for Nigeria – Multiple Incidents in the Oil-Producing Delta Region



Sources: Maplecroft, 2013; MTD, 2013

[68] EIA, "Nigeria." http://www.eia.gov/countries/analysisbriefs/Nigeria/nigeria.pdf
[69] EIA, "Nigeria."
[70] Nigeria's Extractive Industries Transparency, "Core Audit Report of Oil & Gas – 2009 to 2011," March 2012, http://www.neiti.org.ng/index.php?q=documents/audit-report-2009-2011

Going forward, conflict within the Niger Delta region may become less relevant for the international oil players as much of the capex for new projects will be devoted to deepwater projects that are miles offshore. Here, however, there is another obstacle in the form of regulatory ambiguity and Nigeria's large government take of private company oil revenues. Much of this involves the ultimate contents of Nigeria's long-awaited Petroleum Industry Bill (PIB). First proposed in 2008 (currently awaiting approval by the Nigerian National Assembly), this legislation is intended to revise the structure and fiscal arrangements of Nigeria's oil and gas industries. The US EIA notes that[71]:

> Some of the most contentious areas of the PIB are the potential renegotiation of contracts with IOCs, changes in tax and royalty structures, deregulation of the downstream sector, restructuring of NNPC [Nigeria's national oil company], a concentration of oversight authority in the Minister of Petroleum Resources, and a mandatory contribution by IOCs of 10% of monthly net profits to the Petroleum Host Communities Fund.

The US EIA further notes a concern among IOCs that implementation of the PIB's fiscal terms would undermine the commercial viability of new projects, particularly capital-intensive deepwater projects (note that oil industry analysts judge Nigeria's take of oil company profits under its existing fiscal regime to already be high relative to other countries).[72] Regulatory uncertainty as a result of the PIB has delayed investment in new projects (Nigeria held its last licensing round in 2007) and amplifies risk for new oil company capex within Nigeria.

Venezuela – dealing with a nationalized oil industry

- Focus of capex: extra heavy oil
- Companies: CNPC, Rosneft, Chevron, Shell, Repsol, ENI
- WGI data has in bottom decile for corruption, political stability/violence and terrorism, rule of law, and regulatory quality
- Goldman Sachs ranks as "very high risk" (score of 1.28 out of 1.30)

Private oil companies operating in Venezuela face a multitude of obstacles. In 2006, as part of a program to nationalize Venezuela's oil industry, the late President Hugo Chavez required a renegotiation of all existing contracts to grant a minimum 60% ownership stake to state-run Petroleos de Venezuela S.A. (PdVSA).[73] Firms that refused to comply with the new agreements, such as Eni and Total, had their assets forcibly expropriated (most firms, however, including Chevron and Shell, agreed to transfer majority ownership to PdVSA).

Since 2006, the share of PdVSA revenues being redirected to other purposes (e.g. social and humanitarian programs) has risen while investments to develop the country's massive unconventional oil reserves have stagnated or fallen. The result is that, as minority partners in joint ventures with PdVSA, foreign operators face increasing pressure to fund new investments even as export revenue from initial production related to such investments goes to PdVSA. Frustration over such arrangements has reportedly been a major reason for the recent departure of foreign firms such as Petronas and Lukoil from projects in Venezuela.[74] How

[71] EIA, "Nigeria."
[72] Goldman Sachs, *380 Projects*, 147.
[73] EIA, "Venezuela," http://www.eia.gov/countries/analysisbriefs/Nigeria/nigeria.pdf http://www.eia.gov/countries/analysisbriefs/Venezuela/venezuela.pdf
[74] Daniel Wallis and Marianna Parraga, "Venezuela's autocratic ways exasperate foreign oil firms," Reuters, October 11 2013, http://www.reuters.com/article/2013/10/11/venezuela-oil-idUSL1N0I011920131011

operators remaining in Venezuela will fare in ramping up billion dollar capex programs in the Orinoco Basin remains to be seen.

Argentina – oil industry's recent poster child for geopolitical risk

- Focus of capex: shale oil in the Vaca Muerta
- Companies: Chevron, BP, Petrobras, Sinopec
- WGI data has in bottom quartile for regulatory quality
- Goldman Sachs ranks as "very high risk" (score of 1.30 out of 1.30)

Perhaps the most striking example of oil-related geopolitical risk in recent years has come from Argentina. The Spanish firm Repsol had majority ownership of YPF (Argentina's former national oil company) since 1999. Alleging under-investment in the country's hydrocarbon sector, in early May 2012 Argentina's government passed legislation expropriating Repsol's 51 percent share of YPF.[75] This move explains why, despite rule of law, control of corruption, and political stability that otherwise suggest geopolitical risk in the country to be moderate, analysts such as Goldman Sachs judge geopolitical risk in Argentina's oil sector to be "very high." How such risk plays out for recent entrants into Argentina (such as Chevron, which recently entered into a partnership with YPF for joint exploitation of shale oil in the Vaca Muerta region) remains to be seen.
Aside from the Repsol expropriation, the EIA notes that "labor unrest has periodically shut-in Argentina's oil production," as "separate disruptions affecting up to 100,000 barrels of output per day (bbl/d) plagued the sector in late 2010 and early 2011."[76]

Spain's Repsol agrees to $5 billion settlement with Argentina over YPF

Angola – need for regulatory climate to keep pace with investment ramp-up

- Focus of capex: deepwater, ultra-deepwater
- Companies: Exxon Mobil, Chevron, BP, Total, Repsol, Cobalt, Maersk
- WGI data has in bottom decile for corruption and rule of law, bottom quartile for regulatory quality
- Goldman Sachs ranks as "medium risk" (score of 0.79 out of 1.30)

Angola has been one of the oil industry's recent success stories. From 2002-2008, initial production from multiple deepwater fields to more than double, reaching a peak of 2 MBPD in 2008. The country's success at orchestrating this production increase (despite having just emerged from a 27-year civil war) has reduced the perception of geopolitical risk beyond what one might expected based on Angola's rankings in the WGI data. Operators are now planning to greatly increase Angola's offshore oil production, with deepwater and ultra-deepwater projects totaling $60 billion in total capex.

There are, however, potential geopolitical obstacles that might impede, delay, or add costs to the implementation of planned projects. These include:

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[75] Repsol and the government of Argentina recently agreed to a $5 billion settlement over this issue. "Spain's Repsol agrees to $5 billion settlement with Argentina over YPF," Reuters, Feb 25 2014, http://www.reuters.com/article/2014/02/25/us-repsol-argentina-idUSBREA1O1LJ20140225
[76] EIA, "Argentina," http://www.eia.gov/countries/analysisbriefs/cabs/Argentina/pdf.pdf

- Local content requirements: Angolan regulations nominally require IOCs to hire Angolan nationals for 70% of local contractor and management positions. Commenting on this 70% "Angolanization threshold," however, the US EIA observes that "to date this figure has rarely – if ever – been met."[77] Stronger implementation of this program, however, could delay or complicate the execution of highly complex deepwater and ultra-deepwater projects.

- Delays in project approvals: Explaining recent changes to development timetables in Angola, Citi cites "political interference" as a cause of delayed approvals for new development. Given the financial losses that operators incur as a result of delays between project sanction and first oil, there is risk relating to how expeditiously Angola's regulators can administer the planned ramp-up in licensing and production.

- Government vulnerability to oil price volatility: Partly owing to its very high take of oil company profits under its existing fiscal regime, Angola has so far not demonstrated the propensity for retro-active contract changes noted in Kazakhstan, Venezuela, or Argentina. That said, in a country where oil revenue accounts for nearly 80% of total government revenue[78], the risk of political interference in the oil sector runs high. Should a plunge in oil prices lead to fiscal problems for the Angolan government, Angola's leaders may explore ways to increase the government's (already relatively high) take of oil revenues.

Madagascar – an oil industry novice with a recent history of political instability and prospective plans for major ultra-deepwater projects

- Focus of capex: ultra-deepwater
- Companies: Exxon Mobil, BG, Sterling Energy
- WGI data has in bottom quartile for rule of law
- Not ranked by Goldman Sachs

Of the countries reviewed here, the one with the least history of oil industry operating experience is Madagascar. Despite this, major oil companies are exploring for ultra-deepwater fields off the coast of Madagascar. Pursuit of those plans has gotten off to a shaky start as, following a coup in 2009 and several years of worsening political instability, Exxon Mobil and other operators invoked *force majeure* clauses in their contracts and exited the country.[79]

Following recent presidential and parliamentary elections, Exxon and other operators are planning to resume offshore exploration. Lingering uncertainty of the stability of Madagascar's political situation, however, adds risk to the multi-billion dollar commitments needed to successfully explore for and produce oil from ultra-deepwater formations.

[77] EIA, "Angola," http://www.eia.gov/countries/cab.cfm?fips=AO
[78] EIA, "Angola."
[79] African Energy, "Madagascar: IOCs return following elections," Issue 275, 11 April 2014, "http://archive.crossborderinformation.com/Article/Madagascar+IOCs+return+following+elections.aspx?date=20140411#

Iraq – legal ambiguity, pipeline bottlenecks, and sectarian violence

- Focus of capex: conventional and heavy oil
- Private Companies: Shell, Statoil, Eni, BP, Exxon Mobil, many independents
- WGI data has in bottom decile for control of corruption, political stability/violence, regulatory quality, and rule of law
- Goldman Sachs ranks as "very high risk" (score of 1.28 out of 1.30)

Though the country does not make our lists of Top 5 Conventional and Unconventional key provinces (as many of its fields are in the "discovery" or "not yet discovered" phase), no discussion of geopolitical risk in the oil industry would be complete without a word on Iraq.
A full review of the political risks in Iraq's oil sector is beyond the scope of this paper. It is, however, worth noting three high-level observations:

- Key legal issues regarding Iraq's oil sector remain unresolved: Roughly 17% of Iraq's oil reserves are in the north of Iraq, particularly in the semi-autonomous region of Kurdistan. Kurdistan has been the focus of oil industry activity in Iraq, with the Kurdistan Regional Government (KRG) having signed contracts with majors such as Exxon Mobil, Chevron, and Total, and these companies in turn planning $7 billion in capex in Kurdistan. Those contracts, however, are contested by Iraq's central government authorities, which insist that any oil contracts within Iraq can be signed only with the Iraqi Oil Ministry. The continuing absence of any comprehensive Hydrocarbons Law removes any clear way to resolve these disputes.[80]

- Impasse over pipelines from Kurdistan: Oil produced within Kurdistan is of little use without a way to export it to world markets. Unable to reach agreement with Iraq's central government on sending oil south via pipeline down through Iraq, Kurdistan had recently moved to start construction of its own 420,000 bbl/d pipeline - Kurdistan Iraq Crude Export (KICE) – to send oil from Kurdistan over the border into Turkey. Strong objections from the Iraqi oil ministry (which claim that this pipeline would violate a treaty between Iraq and Turkey) and recent political scandals in Turkey, however, raise questions as to whether this pipeline will be completed.[81]

- Recent attacks and kidnapping highlight risks for northern Iraqi production: northern Iraq's oil infrastructure is becoming the target of increasingly violent terrorist attacks. Anti-government militias recently sabotaged northern Iraq's largest refinery (by blowing up its receiving pipeline) and kidnapped the head of its second largest refinery.[82] Such incidents emphasize the continuing risks of violence and sabotage for oil companies doing business in Iraq. Though development of Iraqi oil projects has so far continued amid such risks, the specter of widespread sectarian violence – on top of infrastructure bottlenecks and regulatory ambiguity – could significantly disrupt development of Iraq's oil resources.

[80] Barbara Slavin, "Obama administration uses Anbar crisis to push Maliki on Iraqi oil law," *Al-Monitor*, January 9, 2014 http://www.al-monitor.com/pulse/originals/2014/01/oil-law-iraq-anbar-maliki-obama.html##ixzz30uEqvn7E
[81] Patrick Osgood, "Analysis: Iraq-Turkey treaty restricts Kurdistan exports," *Iraq Oil Report*, Apr 18 2014, http://www.iraqoilreport.com/politics/oil-policy/analysis-iraq-turkey-treaty-restricts-kurdistan-exports-12047/?utm_source=IOR+Email+Update+Subscribers&utm_campaign=6c65f28634-Email_Update&utm_medium=email&utm_term=0_f9870911e6-6c65f28634-192800481
[82] These are the Baiji and Haditha refineries. Kamaran al-Najar, Jamal Naji, and Ben Lando, "Kidnapping, attacks cripple northern Iraq oil sector," Iraq Oil Report, April 18th, 2014, http://www.iraqoilreport.com/security/energy-sector/kidnapping-attacks-cripple-northern-iraq-oil-sector-12039/

Appendix A – definition of shale oil and tight liquids

Given their increasing importance to the global oil supply, it is useful to understand the terms "shale oil" and "tight liquids." Rystad Energy defines each of these terms as follows:

- The term "shale oil" combines the following:
  - Oil shale is a petroleum source rock with a high content of immature hydrocarbons (kerogen), the rock is mined and can be burned like coal, or oil and gas but needs to be cooked out of the source rock by pyrolysis.

  - Shale oil is crude or condensate produced from petroleum source rock by horizontal drilling and hydraulic fracturing. The associated gas may also have a high yield of natural gas liquids (NGLs). Shale oil has recently become increasingly importance to US domestic oil supply thanks to breakthroughs on fracturing and drilling technologies

- "Tight liquids" include all the new unconventional plays that cannot be classified as shale (examples: emerging unconventional plays in the Permian and Anadarko basins). The tight liquids plays in the Permian basin are either drilled vertically as in the northern Midland sub-basin where they target several very thick formations with the same well (e.g. Wolfcamp+Spraberry="Wolfberry"), in most other cases the unconventional wells are horizontal. All these wells are fractured (fracked).

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