Goldman Sachs

Top Projects 2017

Shale's short-cycle nature continues to reshape the industry, as our annual review of the largest oil & gas fields in the world shows. Shale oil resources have grown larger than Iraq's and well productivity keeps improving. Yet shale breakevens are now stabilizing, due to cyclical inflation, while the rest of the industry continues to improve. Near term, we see shale driving oil abundance, coinciding with record delivery of long lead-time mega-projects, but it may build long-term tightness. We estimate that by 2022, shale will require US$50 bn+ pa maintenance capital and would decline by 3 mln b/d pa without investment.

Shale keeps gaining scale, but the Rest of the World regains cost leadership

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Top Projects 2017

This report is our annual review of the world's top energy assets. For the complete series visit our New Oil Order portal.

Global Energy: Oil market rebalancing: Focus on credit, not OPEC, May 15, 2017

LNG vs. pipeline gas: Europe's New Gas Order, Apr. 11, 2017

Top Projects 2016: The Battle for Capital - A Flatter Cost Curve Drives OPEC Growth and Non-OPEC Deflation

TOP PROJECTS landscape in numbers

SHALE SCALE KEEPS GROWING…

50% vs. 16%

Percentage of short-cycle projects making up the Top Projects oil resource base today vs. in 2010. Overall, shale has added 190 bn barrels of oil resources (more than Iran or Iraq) and currently has 73 years' worth of production. (p. 13-16)

…YET INFLATION KICKS IN...

30%

The cyclical increase seen in shale well costs from trough, which should put an end to shale's cyclical deflation. At the same time, the share of non-shale Top Projects with a breakeven below shale has been growing, from 46% to 54% in the past year. (p. 28-30)

…WHILE OFFSHORE GETS CHEAPER

-63%

Cost deflation for Statoil's Johan Castberg development, an example of how the offshore oil industry is changing and adapting to this new era of oil abundance and cost focus. The budget was reduced from US$16 bn in 2014 to US$6 bn currently. (p. 22)

COST CONVERGENCE LEADS TO SUBSTITUTION & TIGHTER BREAKEVEN RANGE

40-50

The number of complex giant oil fields under development that shale substitutes the need for at any given time. (p. 20)

US$52-59/barrel

Today's range of breakevens between key development areas, vs. the US$57-$90/barrel range five years ago. (p. 14)

NEAR-TERM ABUNDANCE, LONG-TERM TIGHTNESS

4 mn barrels

The production growth from long lead-time mega-projects we expect between 2017 and 2019. This is poised to be the largest delivery of such projects in history. (p. 19)

US$50 bn+

The yearly maintenance capex we expect shale will require by 2022, without which we'd see a yoy production decline of 3 mn barrels per day. That's 2x the level of annual global demand growth. (p. 17)

NEW GAS ORDER, TOO

125 mn tonnes

Estimated LNG supply hitting the market in the next five years, or an additional 40% of current LNG capacity. This is likely to overwhelm the European gas market, the LNG buyer of last resort, and create market share competition with Russia. (p. 33)

PROJECT PROFILE – 2017 EDITION

US$2.4 tn

Total investment in Top Projects between 2017 and 2026E, projects which will collectively account for 58% of global supply by 2026. (p. 9)

432

Number of oil and gas field models in the Top Projects database in 2017 vs. 50 field models in 2003. This year we add eight new projects to our list. (p. 9)

PM Summary: Shale keeps gaining scale, but the RoW regains cost leadership

We have updated our analysis of the industry's legacy assets in this 14th edition of our Top Projects report. Shale resources continue to drive industry transformation and grow in scale and well productivity. Short-cycle projects now make up 50% of Top Projects reserves, up from only 16% in 2010, as the industry's capital spend becomes more cyclical and OPEC loses its role in balancing supply and demand. Shale breakevens fell the most through the downcycle, thanks to the short-term nature of its capital commitments and productivity improvements. However, costs are now normalizing, with 30% cyclical cost inflation from the trough, and shale breakevens now stabilizing. In the meantime, the rest of the industry is still lowering costs through simplification, deflation, strong delivery and taxes. As a consequence, we see deepwater and traditional developments becoming competitive again, with over half of their developments sitting below shale on the cost curve. In this environment, we see the Top Projects winners as well positioned - companies that have above-average exposure to Top Projects on materiality, profitability and growth. This year, the winners are the Big Oils that have moved lower on the cost curve (TOTAL, ENI), the international E&Ps that can benefit from the deflation in offshore (Lundin, Tullow, GALP, Anadarko), the NOC with access to low-cost basins (Petrobras), the US shale oil E&Ps with scale and contiguous acreage (EOG, Concho, Devon) and the low-cost gas producers (Range).On the M&A front, we have seen NOCs disappearing, creating a buyers' market for assets outside of US shale. In US shale, we estimate that contiguity of acreage has driven 90% of M&A this year, vs. 40% in 2015.

- **Top Projects are the key drivers of future oil & gas supply and investment.** Top Projects in this 14th edition will account for 58% of global supply in 2026 (86 mn boe/d of production), on our estimates, requiring cumulative investment of US$2.4 tn (2017-26E).
- **Shale scale keeps growing, increasing the industry's resource life**. Shale has added 190 bn bls of oil resources (more than Iran or Iraq total reserves), on our estimates, and currently has a 73-year resource life. We expect peak shale production of 13 mn b/d by 2030.
- **Short-cycle projects are becoming the backbone of Top Projects, changing the industry's dynamics.** Short-cycle projects make up 50% of the Top Projects oil resources today, up from 16% in 2010, transforming the industry in three ways: (1) global oil supply should react within 6-9 months to any supply-demand mismatch through a price incentive mechanism, without the need for OPEC to balance the market; (2) SEC proved reserves are likely to understate the actual resource life for the industry; and (3) maintenance capex is likely to increase dramatically.
- **Shale is back to the cost curve's upper half.** A 30% cyclical increase in shale well costs from the trough put an end to cyclical shale deflation, with breakeven prices stable yoy at US$54/bl. But shale productivity gains, particularly in the Permian basin, should continue. Meanwhile, the RoW keeps adapting, with both secular and cyclical cost deflation. Over the past year, we have seen the percentage of non-shale Top Projects with a breakeven below shale grow from 46% to 54%.
- **The primary driver of shale-well productivity is service intensity, driven by increases in well lateral lengths and a rise in frac stages**. Since 2014, a single horizontal rig is drilling 15% more wells per year, and generating 106% higher demand for pressure pumping and 152% increased demand for frac sand. This increase in service intensity has driven an 88% increase in liquids production per rig.

- **Deflation and convergence: Shale's scale and low technical risk has stranded the more complex developments (US$640 bn/65 bn boe)**, and refocused the industry on manufacturing efficiency from resource hunt. This has tightened the range of breakevens between the different development areas, from US$57-90/bl in 2012 to US$52-59/bl, reducing uncertainty and volatility in the long-end of the oil forward curve.
- **Offshore regains competitiveness,** an example: Johan Castberg. The budget was reduced from US$16 bn in 2014 to US$6 bn (-63%) through: (1) project simplification, which accounted for a 25%-30% cost reduction; and 2) c.20% oil services cost deflation; c.15% from NKr depreciation.
- **Near-term abundance… in 2017-19, we expect the largest production increase from long-cycle mega-projects in history,** with 4 mn b/d of incremental production from long lead-time projects (excluding shale) as the industry delivers the record 2010-13 wave of sanctions.
- **…vs. long-term tightness.** By 2022, when we expect shale production to be at c.10 mn b/d, we believe a sudden stop to investment could lead to a yoy production decline of 3 mn b/d, 2x the current level of global annual oil demand growth and maintenance capex will require US$50 bn+ pa.
- **OPEC is cutting production and growing capacity.** We estimate that OPEC will increase its production capacity by 3 mn b/d over the next 3 years, led by Iraq, Iran and Saudi Arabia.
- **Decline rates have moderated over the past 20 years.** We have analysed production declines of three mature basins, through 5,000 wells over time. The outcome is that underlying decline rates have improved since the 1990s, while uptime has remained stable and incremental activity is highly cyclical.
- **A wave of LNG oversupply is coming.** We expect a 40% increase in LNG capacity by 2020 to overwhelm the LNG spot market, leading to market share competition with Russia for the buyer of last resort, Europe. Much like OPEC in its battle with US shale for the oil market, we see little choice for Russia but to defend its market share, leading to lower-for-longer prices.
- **M&A: It's all about contiguity in US shales.** NOCs drove two-thirds of asset M&A in 2010-15, but stopped buying assets in 2016, creating a buyers' market. In shale, as longer laterals become increasingly important, contiguity has driven 90% of M&A this year, vs. 60%/40% in 2016/15.
- **Oil services: Focus on cost savings and shale well productivity enablers.** We expect the level of sanctions in the industry to start recovering in 2017, as offshore projects move lower in the cost curve, but contracts are likely to be smaller and less profitable than in the past. Therefore, we would focus on companies where additional cost saving measures could be implemented in order to adapt their cost base to smaller contract sizes and mitigate the impact on margins stemming from cost deflation. We identify the following companies which fall in this category: Saipem and TechnipFMC. We like Schlumberger for breadth of services and leadership in innovation. The primary driver of shale-well productivity is service intensity and we identify the following companies as key E&P productivity enablers: Hunting, Vallourec, Schlumberger, Halliburton, Propetro Holding and Emerge Energy Services.

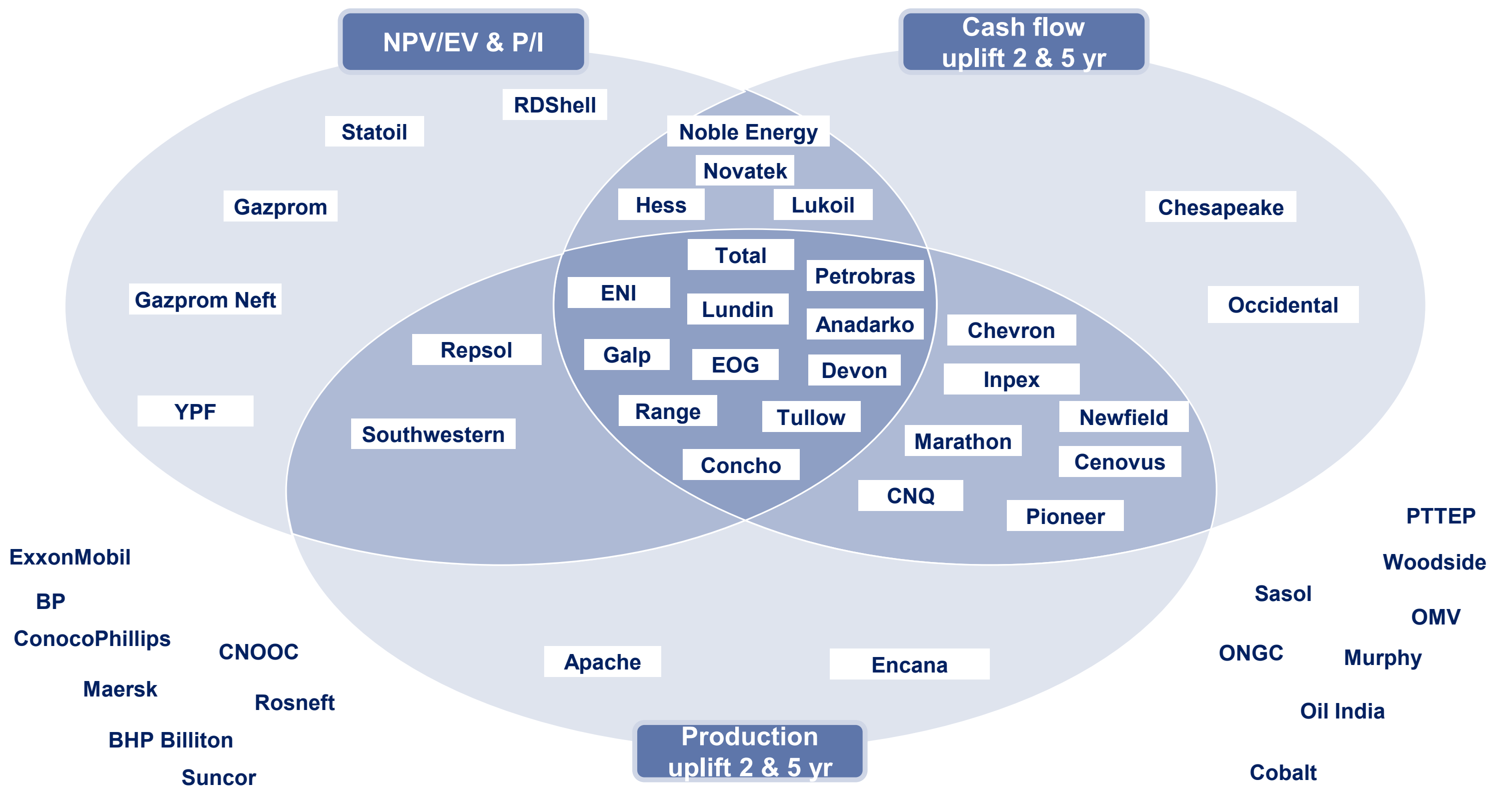
Top Projects winners: High profitability, strong growth in a lower-for-longer world

From our analysis of the 432 Top Projects in the global oil industry, we have identified 11 industry winners. These companies hold a diversified portfolio of projects (at least two growth projects) that are above average on three key factors: (1) materiality and profitability, (2) cash flow uplift, and (3) production uplift – see Exhibit 1. The “Winners” therefore own material new projects that represent a large component of their market value, are highly profitable and will materially lift their future cash flows and production in both the short and medium term, on our estimates, at a Brent oil price in the US$50-60/bl range. This set of metrics only reflects the companies’ Top Projects portfolio and does not take into consideration the rest of their business or their valuation.

In Europe, the Top Projects winners are Total, ENI, GALP, Lundin, Tullow.

In the Americas, they are: EOG, Range Resources, Devon, Concho, Anadarko, Petrobras.

Exhibit 1: In our analysis from the Top Projects, we view the companies below as holding some of the highest-quality growth assets



Source: Company data, Goldman Sachs Global Investment Research.

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Contents

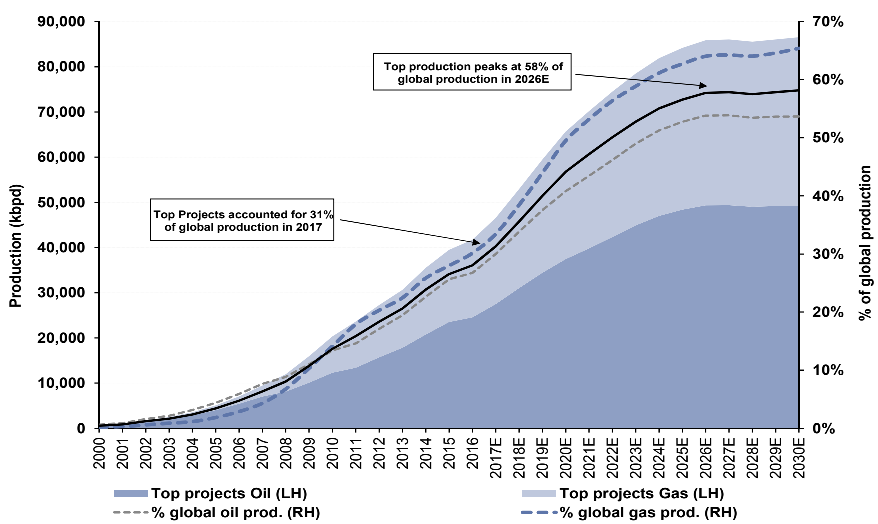
Top Projects to account for 58% of global oil & gas production within a decade

This is the 14th annual iteration of our Top Projects report. In these reports, we independently model the industry's largest new oil & gas developments. We draw conclusions on how the industry cost curve is changing, forecasting cash flow, capex and production, and assess delivery for the industry as a whole and on a company-by-company basis. This proprietary analysis informs our macro views, as well as company recommendations and forecasts.

The Top Projects database has evolved from 50 field models in 2003 to 432 models today, encompassing oil & gas fields both in traditional development areas (offshore and onshore) and unconventional (shale, heavy oil, GTL). We include all new fields with at least 300mnboe of recoverable resources. Combined, we forecast these projects will account for 58% of global supply in 10 years' time (86mnboe/d of production), requiring cumulative investment of US$2.4 tn (2017-2026E).

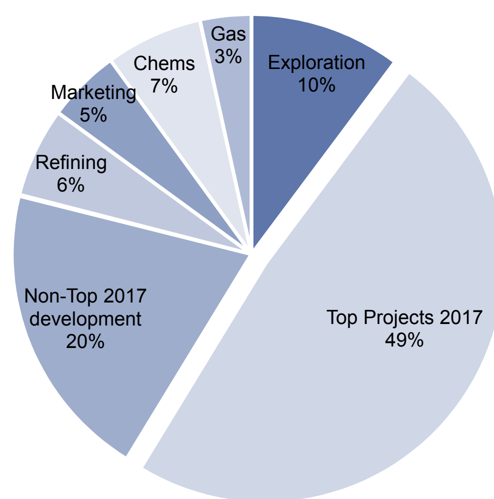
This year, we add eight new projects: Pikka, Trion, Lancaster (oil), Nooros, Tortue, Fortuna FLNG, Corpus Christi LNG and Atoll Gas (gas). Interestingly, only three new oil projects have been added. Conventional exploration remains disappointing, although the continuous increase in shale resources means that the industry's resource life keeps lengthening.

Exhibit 2: Top Projects to reach 58% of global oil & gas production by 2026E



Source: Goldman Sachs Global Investment Research, BP Statistical Review 2016.

Exhibit 3: Top Projects 2017 capex represents around half of Big Oils total capex (2017-19E)



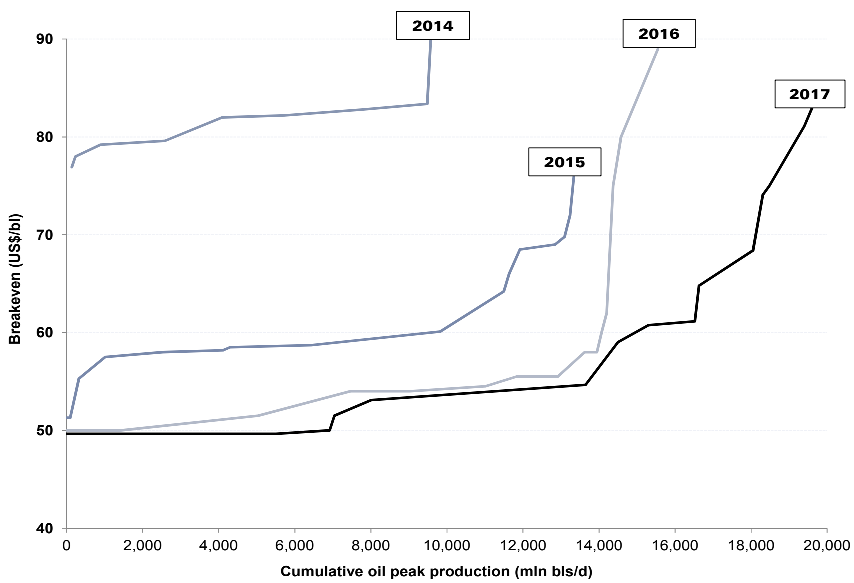
Source: Company data, Goldman Sachs Global Investment Research.

Shale moved down the cost curve first, but is now facing cyclical cost inflation

Shale led the industry's cost deflation in 2014-16, thanks to productivity gains and a short-cycle supply chain. Currently, onshore US costs are normalizing and cyclical inflation is coming back, temporarily offsetting further productivity gains. We estimate that shale breakevens are stabilizing, with the current level at US$54/bl.

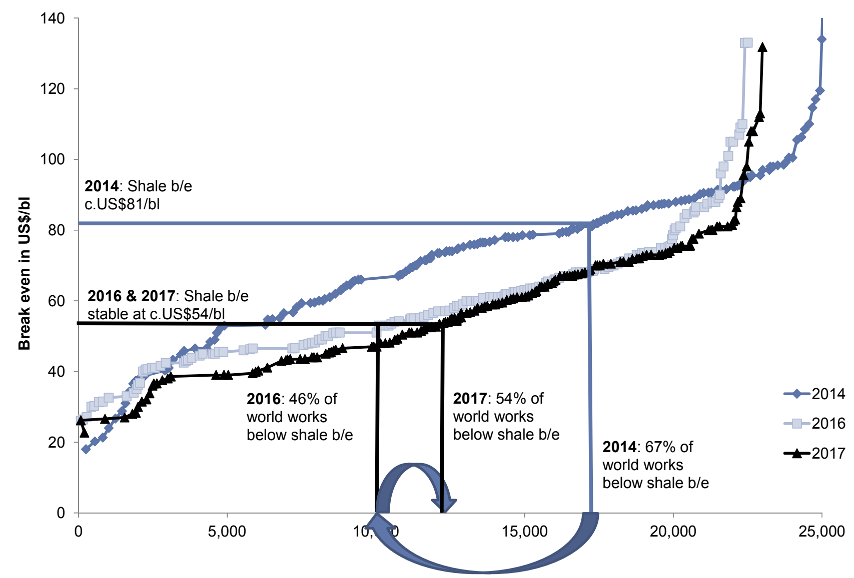
Exhibit 4 shows that the shale oil cost curve from our Top Projects models is broadly flat yoy, for the first year since 2014. The deflationary phase of the shale revolution is, at least temporarily, over, in our view. Instead, deflation is continuing in the RoW (deepwater, heavy oil, traditional) through standardization, simplification, strong delivery and lower taxes, while we see no signs yet of inflation through the supply chain. This deflation is bringing non-shale developments back to a competitive level with shale. Over the past year, we have seen the percentage of non-shale Top Projects with a breakeven below shale grow to 54% from 46%. Effectively shale has lost its short-lived cost leadership and is back on the upper half of the cost curve. Shale, however, continues to win on volumes, with a 26% expansion in its resource base over the past year, vs. an 11% increase for the non-shale Top Projects. Shale is, on our analysis, the industry's marginal producer (as it sits on the upper part of the cost curve), its swing producer (due to its short-cycle nature) and its key source of reserve replacement.

Exhibit 4: The shale resource base keeps growing, but its breakevens are stabilizing after falling rapidly in 2015-16...
Shale cost curves between 2014 and 2017



Source: Goldman Sachs Global Investment Research.

Exhibit 5: ...while the RoW is regaining cost leadership, but not scale
Non-shale cost curves between 2014 and 2017 vs. median shale breakeven (b/e) and peak liquid production in kb/d

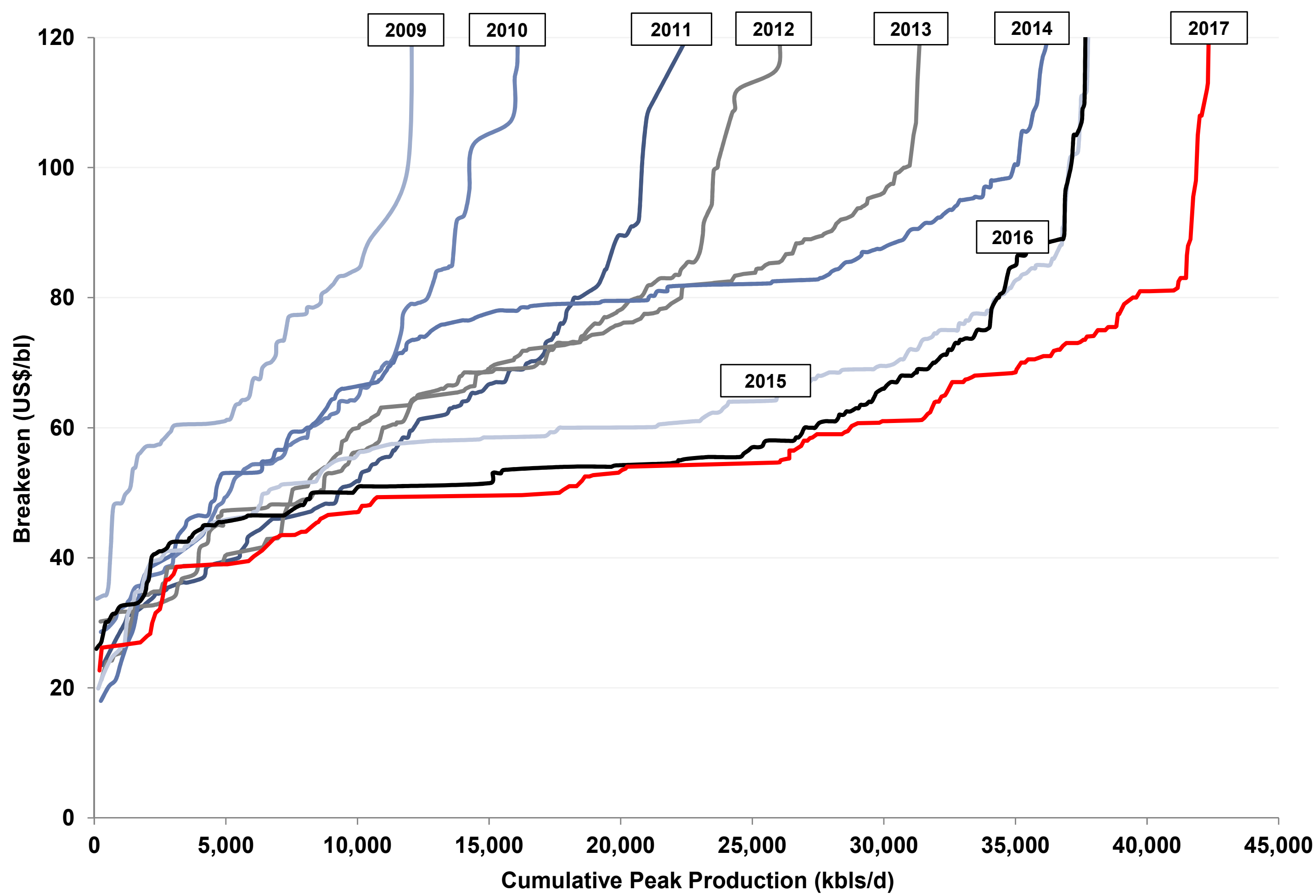


Source: Goldman Sachs Global Investment Research.

The Top Projects oil cost curve shows continued success in growing resources

The industry continues to successfully add resources, with a doubling in future peak production from Top Projects in today's pipeline vs. the pipeline in 2011. More importantly, the cost curve has flattened and shifted lower, with a tripling of resources with breakevens below US$60/bl over the same period. The cost curve in this report is calculated on a life-of-project basis and includes an IRR of 10%-15% according to the country risk.

Exhibit 6: The Top Projects cost curve shows continued success in growing resources, while cost deflationary forces are slowing
Top Projects cost curve of pre-plateau projects through the years



Source: Goldman Sachs Global Investment Research.

Squeezed between low-cost OPEC and prolific shale, RoW is fighting back with lower costs

Exhibit 7 shows the industry's cost curve for incremental projects, including OPEC. The low-cost producer remains OPEC, while US shale keeps increasing the scale of its short-cycle resources, now larger than Iraq's, on our estimates. In this environment, we believe that the rest of non-OPEC can only compete if it can reduce its breakeven below shale. We see clear signs that this is happening, with several large projects coming back into the lower part of the cost curve, fostering a (moderate) revival of project sanctions. Non-OPEC ex-US deflation is driven by five key factors:

1) Lower service costs – although we believe we are now seeing clear signs that costs have troughed.

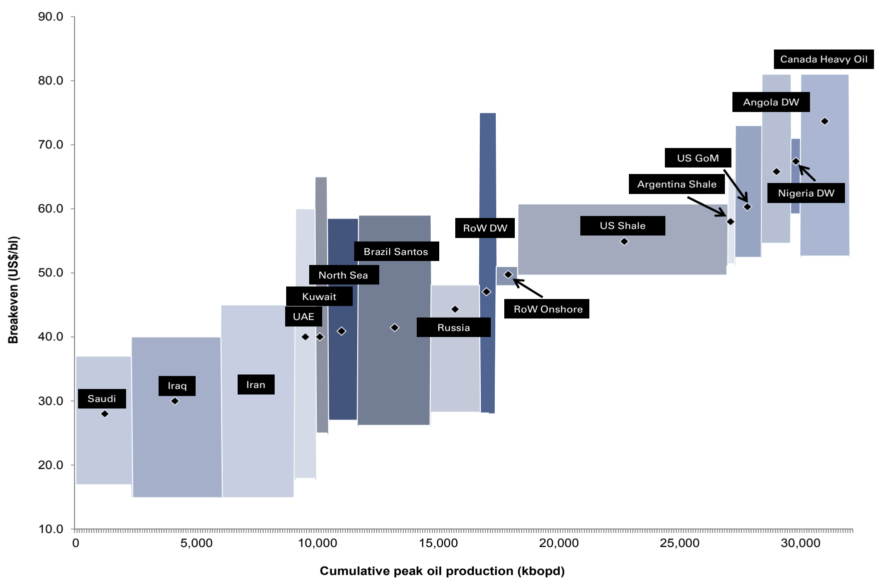
2) Simplified developments – Johan Castberg is one example of this: 30%-40% less equipment for only 11% less oil production.

3) FX – for countries with large locally denominated cost bases (e.g. Russia, Norway, Canada), a weaker local FX rate was a significant benefit in 2014-16. However, Russia's strengthening Ruble in 2017 is reversing part of the benefit.

4) Fiscal renegotiations – a number of countries such as the UK and Angola have reduced tax rates to incentivize investment.

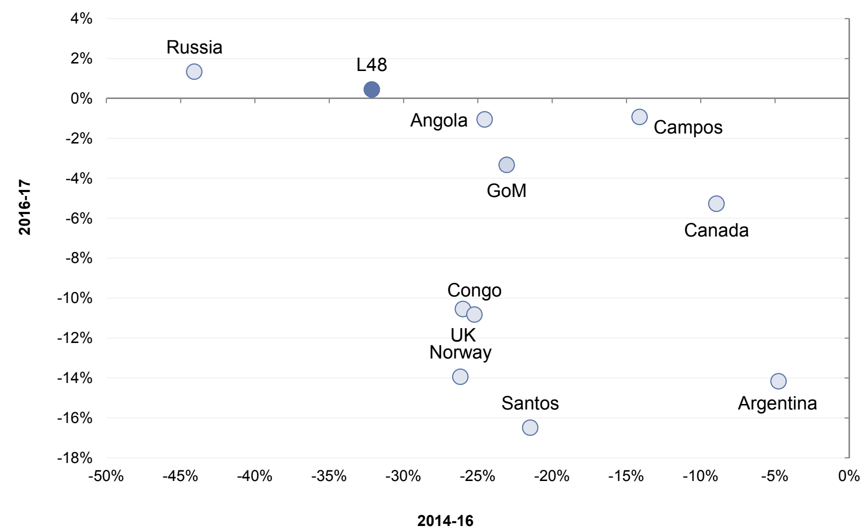
5) Better delivery – as the industry focuses on fewer, simpler projects, we have seen delivery improve dramatically.

Exhibit 7: OPEC producers are at the bottom of the cost curve; US shale keeps increasing its scale...
Cumulative peak oil production with range of breakevens for new developments



Source: Goldman Sachs Global Investment Research.

Exhibit 8: ...while the rest of the world continues to improve its cost positioning
Reserve weighted change in breakeven seen between 2014-16 and 2016-17



Source: Goldman Sachs Global Investment Research.

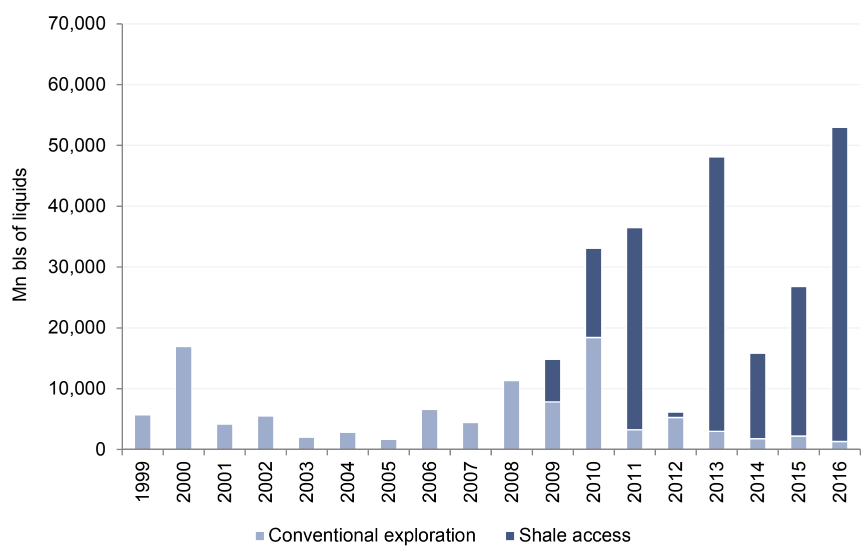
The hunt for resources is over: Focus can move from exploration to production efficiency

Shale's short time to market and ongoing productivity improvements have provided an efficient answer to the industry's decade-long search for incremental hydrocarbon resources in technically challenging, high-cost areas. On our estimates, shale has added 190 bn bls of oil resources since the start of the boom in the late 2000s (more than Iran or Iraq, and only behind Saudi Arabia or Venezuela) that can be developed through a technically simple supply chain which can be expanded with a 12-24 month lead time. This effectively ends the industry's great resource hunt in increasingly complex areas and re-focuses the industry's resources on development efficiency, rather than resource maximization. The E&P industry effectively shifts from 'E' to 'P', and in doing so rediscovers tremendous ability to standardize, simplify and reduce costs.

This success in finding new resources has led to a broadly constant resource life of c.45 years from our Top Project models, even as Top Projects oil production has doubled since 2010. Much of the 2016 additions has come from the Permian through both increased well locations in the Delaware (heading North into New Mexico) and improved expected ultimate recoveries (EURs – seen by large well type curves).

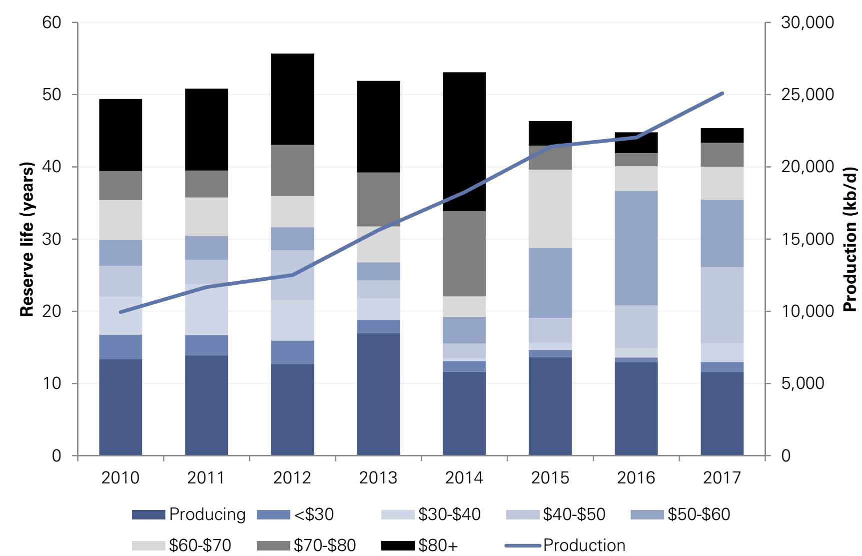
The result of this shale revolution, and the consequent broad industry deflation, is a continuous improvement in the cost curve. In the past three years, we have seen the proportion of reserves working at under US$60/bl almost doubling to 36 years from 19 years.

Exhibit 9: Shale access has dwarfed conventional exploration volumes...
Volume of liquid reserves discovered/accessed year by year that made the Top Projects



Source: Company data, Goldman Sachs Global Investment Research.

Exhibit 10: ...while Top Projects oil resource life has remained constant at c.45 years even as production doubled
Top Projects reserve life, by year of report and breakeven



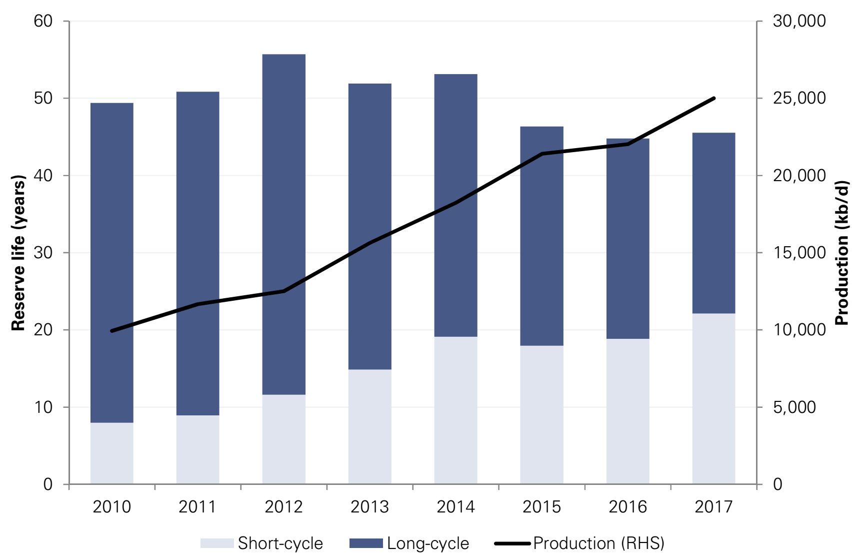
Source: Company data, Goldman Sachs Global Investment Research.

The rise of short cycle in scale leads to cost convergence

Exhibit 11 shows that the industry has shifted from long-cycle projects to short-cycle. While short-cycle projects made up only 16% of the Top Projects resource life in 2010, they make up 50% of the total today. This seismic change implies three consequences, in our view: (1) global oil supply should react within 6-9 months to any supply-demand mismatch through a price incentive mechanism, without the need for OPEC to correct the market imbalances through cuts beyond a 6-9 month timeframe; (2) the SEC rules about booking proved reserves imply that the industry will only be able to book short-cycle resources as they get drilled over time and therefore proved reserve life will likely fall and understate the actual resource life for the industry; and (3) maintenance capex for the industry is likely to increase. As we highlight on page 17, shale alone will have maintenance capex of over US$50 bn pa by 2022.

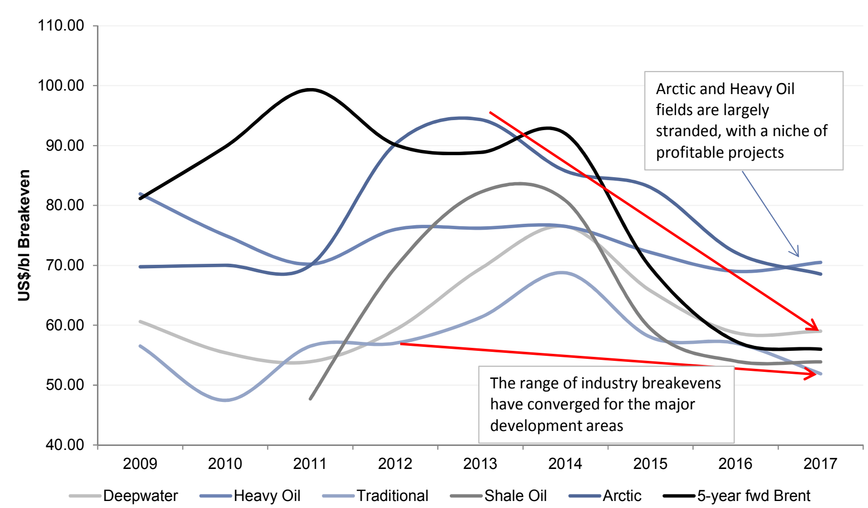
The scale and flexibility of the supply chain and low technical risk has stranded the industry's more complex developments (Exhibit 12), such as Arctic and heavy oil. It has also de-bottlenecked the supply chain for offshore developments, while creating competition for capital that has led to improved tax terms in marginal countries. The result is deflation and convergence, as shown in Exhibit 12. While the range of breakevens between the industry's required investment areas (we now consider heavy oil and Arctic as broadly stranded, with the exception of some small, profitable niches) was an exceptionally wide US$57-90/bl in 2012, it is now a much tighter US$52-59/bl, reducing uncertainty and volatility in the long-end of the Brent forward curve.

Exhibit 11: The Top Projects oil resources are now evenly split between short-cycle and long-cycle...
Short-cycle vs long-cycle reserve life and Top Projects production



Source: Goldman Sachs Global Investment Research.

Exhibit 12: ...driving a convergence of breakevens between different developments
Top Project breakeven median by development area over time



Source: Goldman Sachs Global Investment Research.

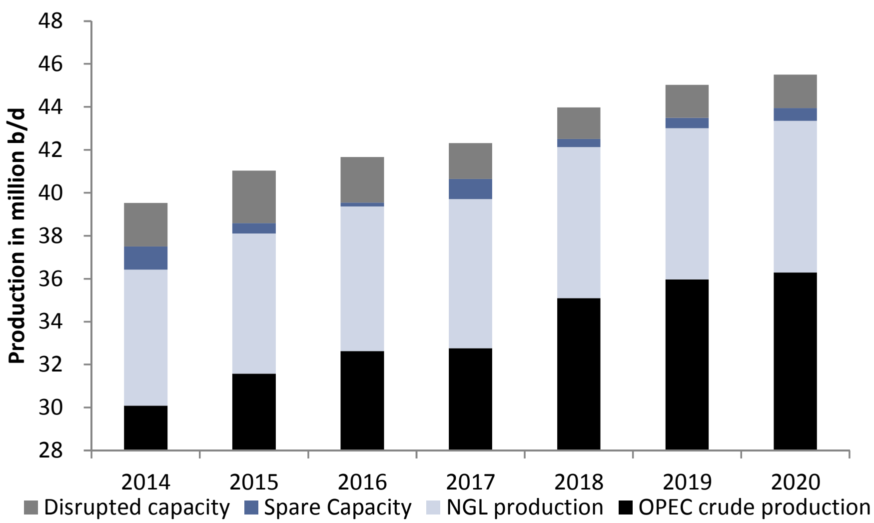
OPEC – increasing capacity, while cutting production. The dichotomy of the New Oil Order

OPEC decided to take 1.2mn b/d off the market at the beginning of this year, increasing its spare capacity and bringing the oil market from extreme contango (spot price at a discount to the forward oil price) towards backwardation. As OPEC producers tend to sell their oil at spot prices, while the US E&Ps tend to sell 30%+ of their production 12-18 months forward, this decision was rationale, in our view, and created a level-playing field on oil price realizations between OPEC and shale.

However, as the low-cost producer in the industry, OPEC has the incentive, in our view, to keep increasing its capacity and keep the market in backwardation through a strategy of future abundance (increased production capacity) and near-term tightness (lower inventories through production restraint). Exhibit 14 shows that OPEC has several major projects that are expected to ramp up through the rest of the decade.

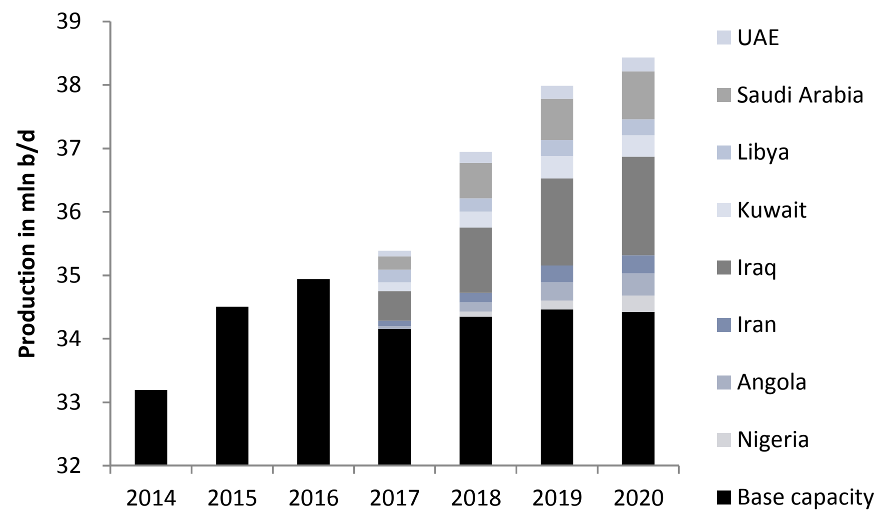
Some of the largest projects include Upper Zakum in the UAE, which is heading towards 750kb/d and has the potential to go to 1,100kb/d (if the expansion project is approved). Meanwhile, Saudi Arabia is in the process of ramping up several completed expansion phases at Khurais and Shaybah, and is considering further expansions at Manifa (possibly taking the field from 900kb/d to 1,500 kb/d) and capacity maintenance at the super-giant Safaniyah. Iraq also has strong near-term growth prospects as new production capacity is installed and existing processing capacity is backfilled. We think Iraq will have over 5mn b/d of capacity by mid-late 2017.

Exhibit 13: OPEC keeps adding production capacity, although growth may slow towards the end of the decade...
OPEC crude and NGL/condensate production/spare capacity



Source: IEA, Goldman Sachs Global Investment Research.

Exhibit 14: ...with most new field capacity being added in the Persian Gulf
OPEC crude production capacity showing new major field additions, shut in capacity and legacy production

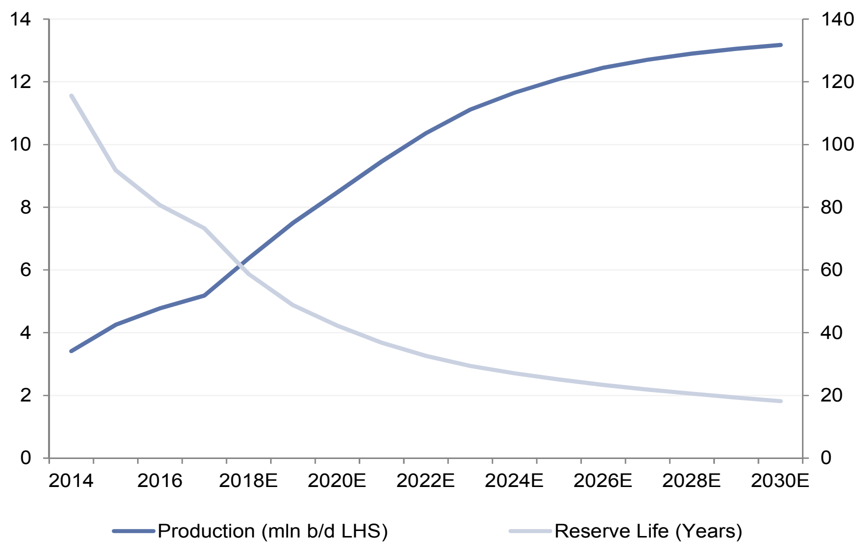


Source: IEA, Goldman Sachs Global Investment Research.

Shale has a 73-year resource life in 2017

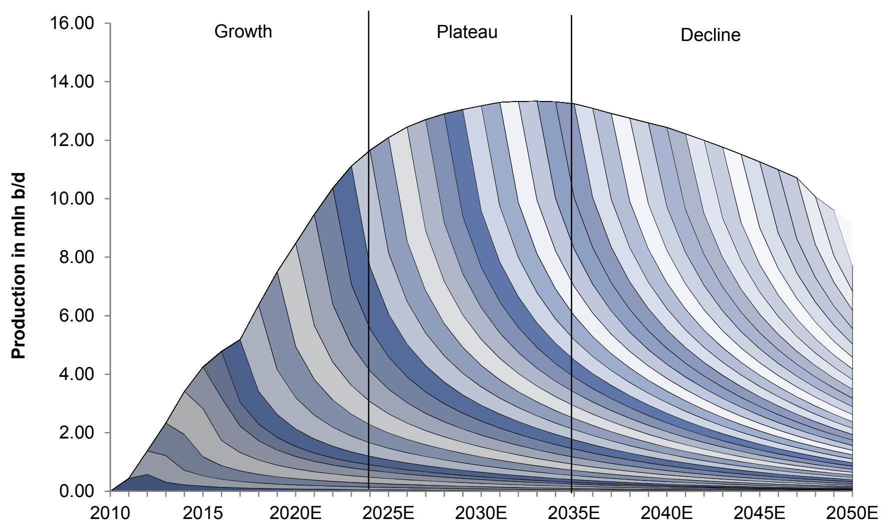
Shale presents a clear dichotomy, in our view: it is a very long-life resource with very short-life single well production. This is exemplified in Exhibit 16 that shows 20 years of growth followed by 15 years of slow decline for the Big 4 shale plays in aggregate (Bakken, Eagle Ford, Delaware, Midland), but also shows how quickly each vintage year of wells declines. The consequence of this dichotomy is that shale can provide many years of stable growth, provided there is an investment of US$50 bn+ pa. However, ever more of this would be spent to counter the decline of maturing wells. If capital availability were to be curtailed, the decline in shale oil production would be larger, the higher the total shale production is. By 2022, when we expect shale production to be at c.10mnb/d, we believe a sudden stop to investment could lead to a yoy production decline of 3mnb/d, 2x the current level of global oil demand growth.

Exhibit 15: The shale industry still has a large resource life…
Big 4 shale players production in mn b/d (LHS) and reserve life (RHS)]



Source: Goldman Sachs Global Investment Research.

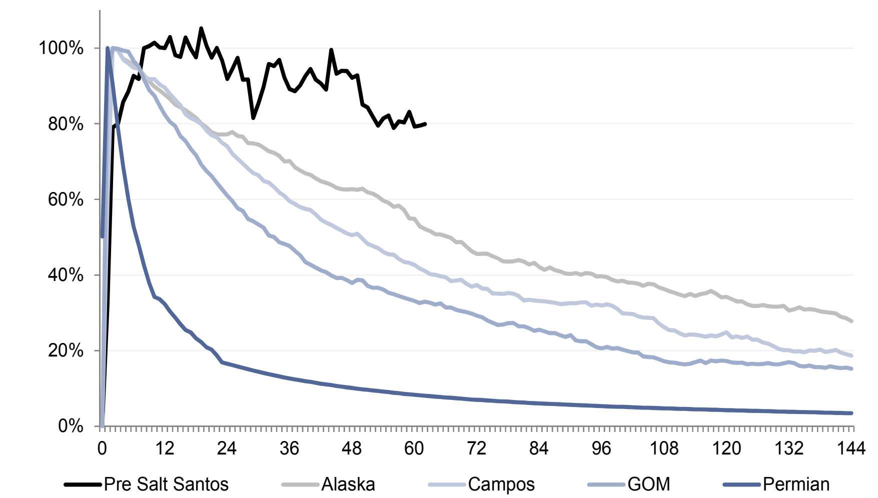
Exhibit 16: … but continued drilling is needed in the shale treadmill
Cumulative shale production by year of wells drilled



Source: Goldman Sachs Global Investment Research.

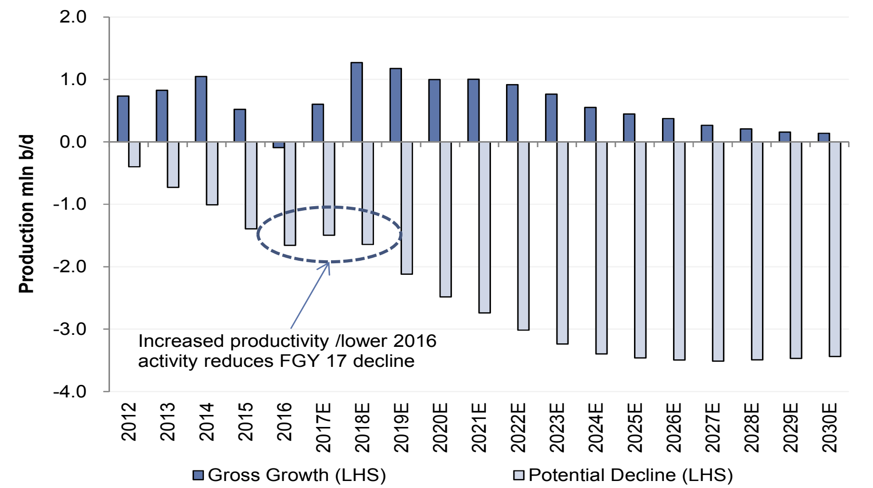
Shale provides near-term oil abundance, but also the risk of long-term tightness

Exhibit 17: Shale has a very steep rate of decline, compared to offshore…
Decline rates seen in 5 basins with peak prod in 1st 6mths rebased to 100%



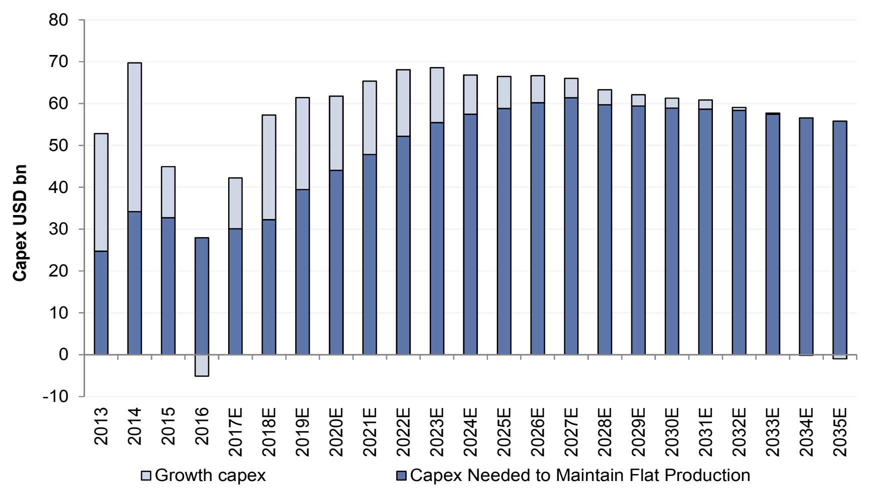
Source: ANP, Alaska DoE, BOEM, Goldman Sachs Global Investment Research.

Exhibit 18: ...meaning that the larger it grows, the steeper the declines…
Big 4 prod increase/decrease in mn b/d at our base case and at no spending



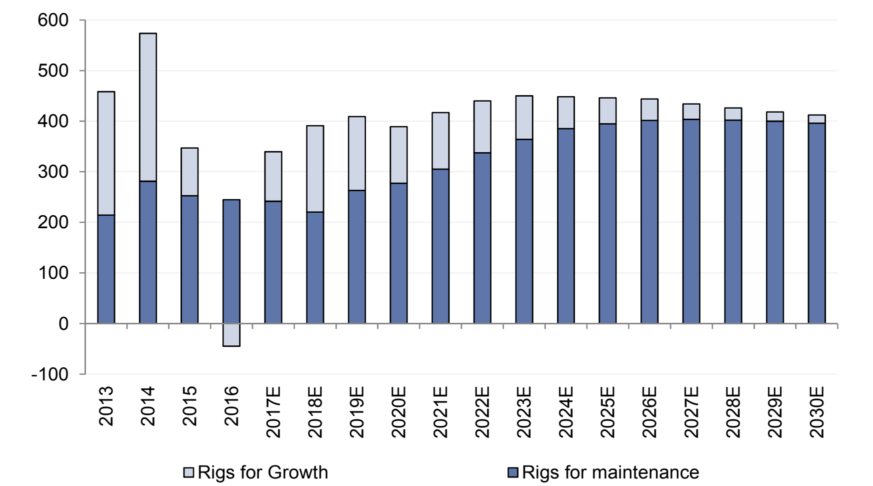
Source: Goldman Sachs Global Investment Research.

Exhibit 19: …the higher the necessary maintenance spend…
Our capex profile and amount spent on growth/maintenance in the Big 4



Source: Goldman Sachs Global Investment Research.

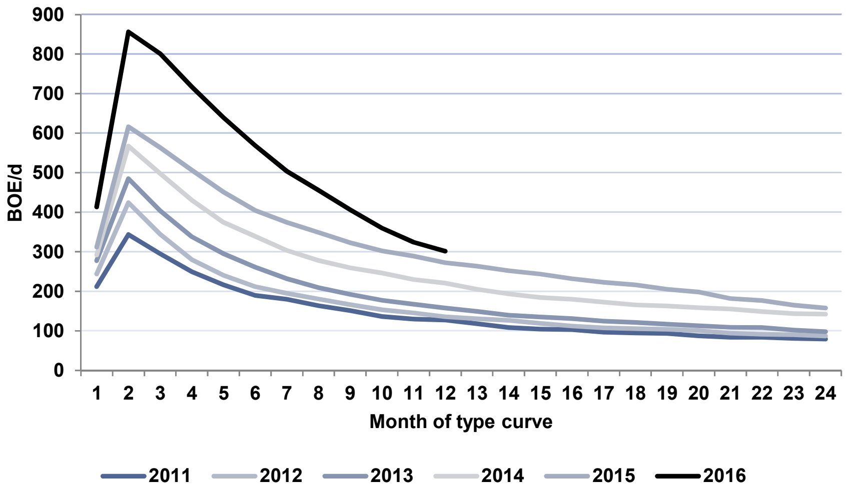
Exhibit 20: …and the number of rigs required to maintain production
Rig Count in Big 4 (Delaware, Midland, Eagle Ford, Bakken)



Source: Goldman Sachs Global Investment Research.

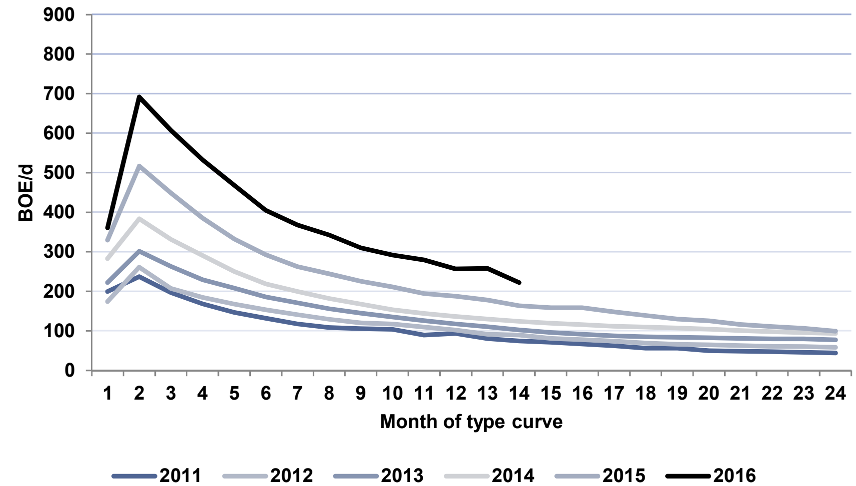
Shale well productivity continues to improve in all basins

Exhibit 21: Delaware wells are now the most productive shale wells…
Type curve from the Permian Delaware over the years



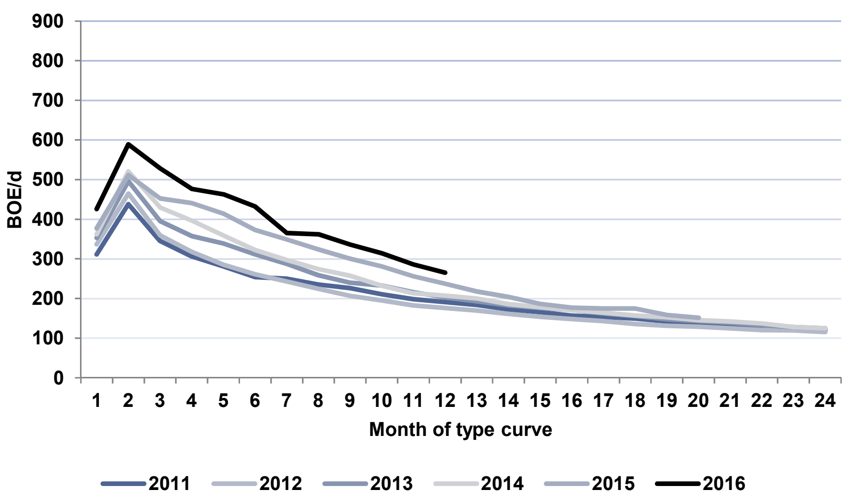
Source: IHS, Goldman Sachs Global Investment Research.

Exhibit 22: ...followed by the Midland
Type curve from the Permian Midland over the years



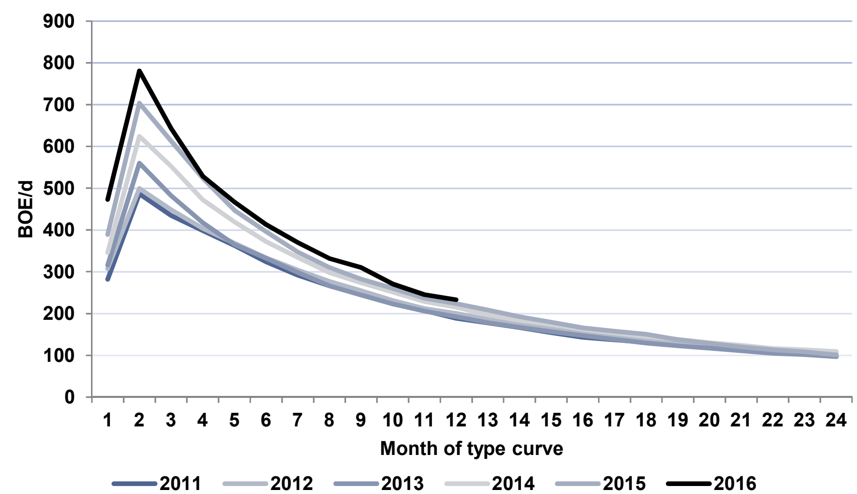
Source: IHS, Goldman Sachs Global Investment Research.

Exhibit 23: The Bakken continues to improve…
Type curve from the Bakken over the years



Source: IHS, Goldman Sachs Global Investment Research.

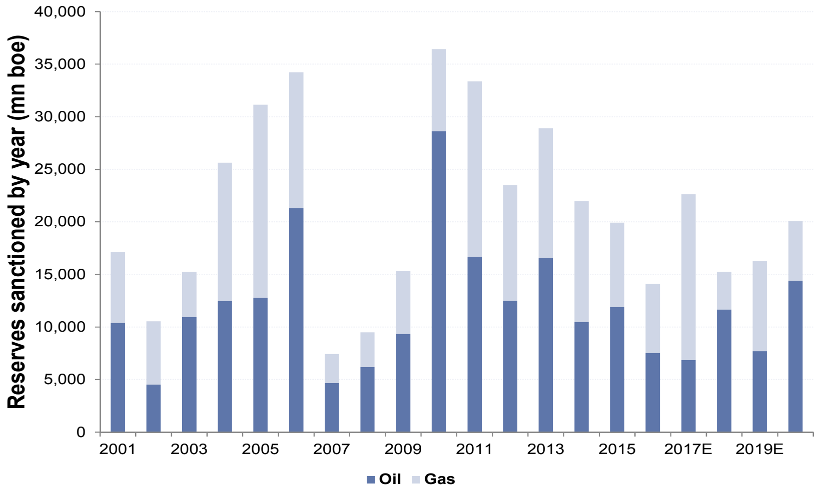
Exhibit 24: … but the Eagle Ford may be nearing peak productivity
Type curve from the Eagle Ford over the years



Source: IHS, Goldman Sachs Global Investment Research.

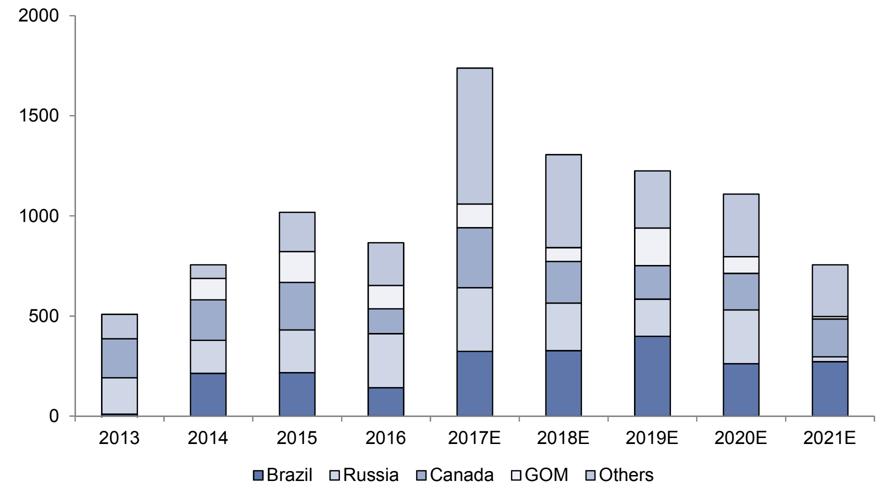
Non-OPEC ex-US: 2017-19 could see the largest delivery of mega-projects in history

Exhibit 25: 2010-13 saw the largest pipeline of project sanctions in history…
Non-OPEC oil and gas project sanctions by year (excluding shale)



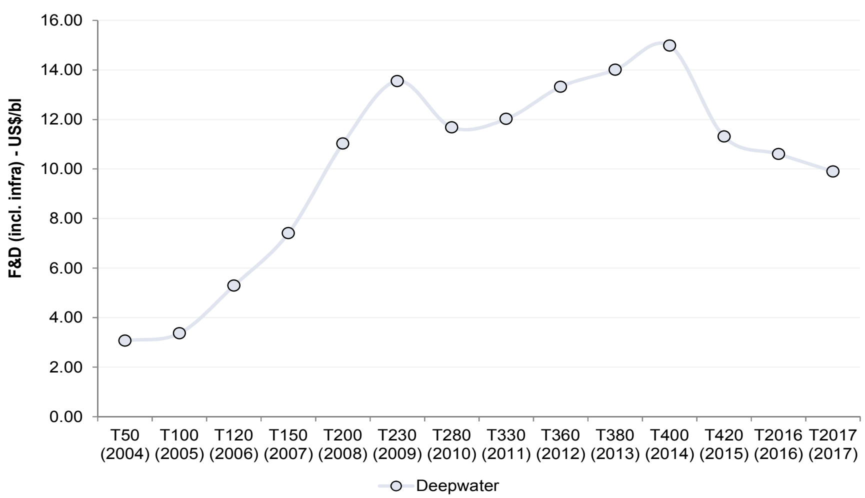
Source: Goldman Sachs Global Investment Research.

Exhibit 26: … driving significant production growth through to 2020
YoY production growth (kboe/d) from non-OPEC, excluding shale projects



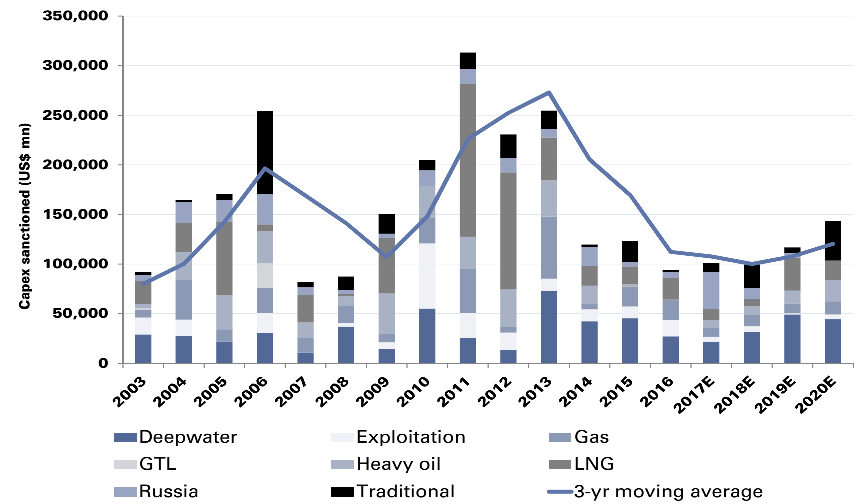
Source: Company data, Goldman Sachs Global Investment Research.

Exhibit 27: Costs are now back down to 2008 levels…
F&D cost per barrel of pre-sanction deepwater Top Projects through the years



Source: Goldman Sachs Global Investment Research.

Exhibit 28: …incentivizing the industry to start investing again
Capex sanction per annum in non-OPEC (excluding shale)



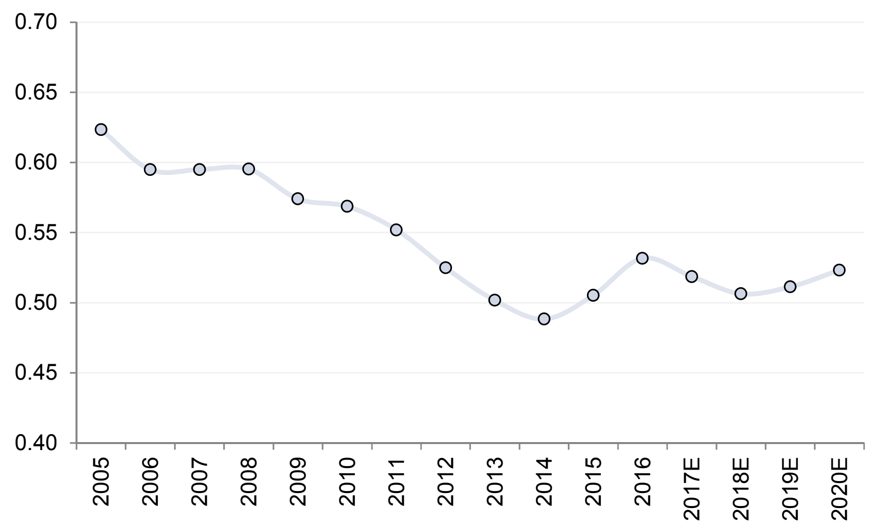
Source: Company data, Goldman Sachs Global Investment Research.

Technical and country risk are falling in the industry, allowing for better delivery

The vast resource base provided by shale substitutes the need for some of the higher-cost, more technically complex developments in the industry. At a rate of growth of c.1mnb/d, shale effectively substitutes the need for c.10 giant fields each year. These giant fields would take 4-5 years to develop and so effectively shale substitutes the need for 40-50 giant fields under development at any point in time. This de-bottlenecks the global oil services supply chain and substantially de-risks the delivery of incremental oil supply, through lower technical and political risk.

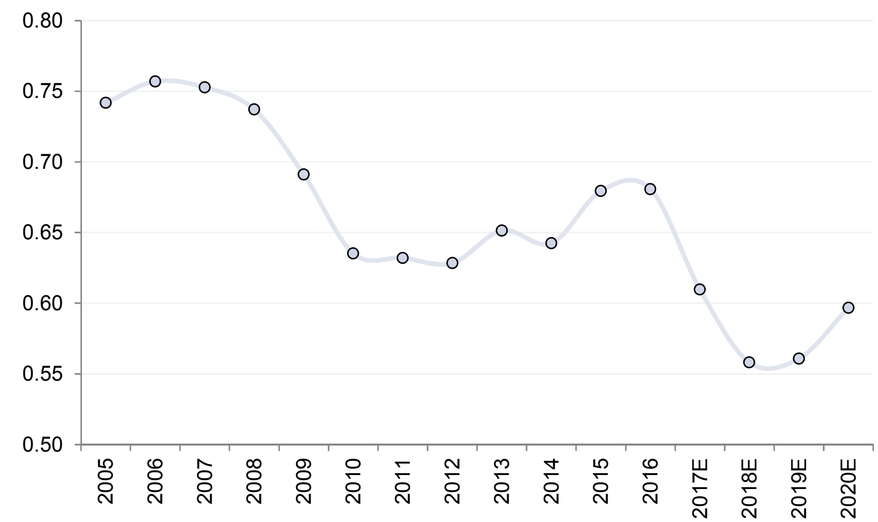
Exhibits 29 and 30 shows that the combination of low country risk in the US, combined with the short-cycle manufacturing nature of shale, means that we have seen both country risk and technical risk reducing over the past 10 years (with the brief exception of 2015-16, when shale investments were temporarily curtailed). We assess the risk of each Top 400 field with reference to two risk types – technical (i.e. those related to the complexity of extracting hydrocarbons from the ground) and political (the risk of doing business in a particular location).

Exhibit 29: Country risk has reduced over time, driven largely by increased US production...
Capex weighted country risk for the Top Projects developments 2005-20E



Source: Goldman Sachs Global Investment Research.

Exhibit 30: ...as has technical risk, with more shale investments and less investments in the technical frontiers of the industry (Arctic, ultra-deepwater, etc.)
Capex weighted technical risk for the Top Projects developments 2005-20E



Source: Goldman Sachs Global Investment Research.

The sector's project delivery has consistently improved since 2012

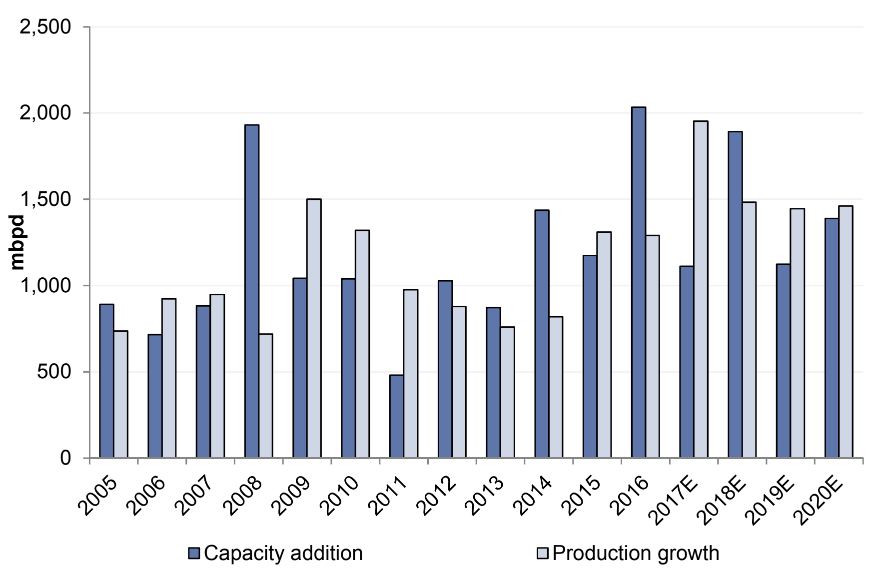
2016 was the best year in history for Top Project start-ups (capacity additions). Numerous mega-projects came on line, including Kashagan Phase-1, three Brazilian Pre-salt FPSOs, Suzunskoye, Messoyakhaneftegaz, Bolshet Depression Project, TEN, Ivar Aasen and Stones. We see a slight drop in capacity additions in 2017, before another strong year in 2018 (with multiple Brazilian FPSOs and a new region in East Siberia starting up). This is consistent with the record sanctions in 2010-13 given the average 5-year lag from sanction to start-up.

It takes 12 months for an average oil project to reach full capacity from start-up, and therefore despite the record volume of capacity added in 2016, the impact on production growth will only be fully felt in 2017-18 and the full impact from the 2010-13 mega-projects sanctioned will not materialise until 2019. In the meantime, the industry is improving its delivery, as typical in a downturn, further enhancing the oversupply risk.

2016 actual production only missed our estimates by 1%, confirming a structural improvement in Top Project delivery. This is a significant improvement from the 11% miss only six years ago, and shows how the shift from exploration to production combined with the spare capacity across the oil services supply chain has improved deliverability in the industry.

Exhibit 31: 2016 saw the largest ever capacity addition from mega-projects – 2017 sees the volume growth as those projects ramp up...

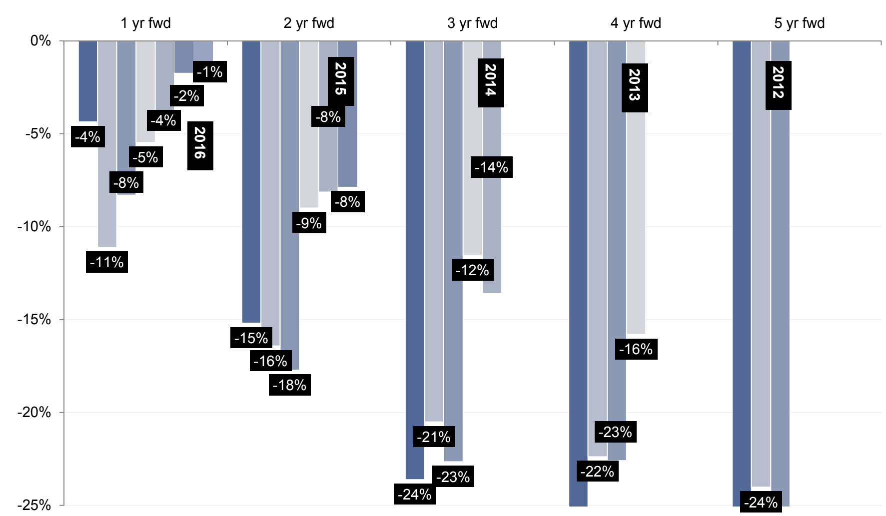
Non-OPEC capacity and production additions in kb/d by year (excluding shale). These additions are calculated before the impact of decline rates on mature fields.



Source: Goldman Sachs Global Investment Research.

Exhibit 32: ...while delivery relative to our expectations keeps improving and was only -1% in 2016

% miss of non-OPEC production vs our expectations over the previous seven years. Excluding Shale and Kashagan.



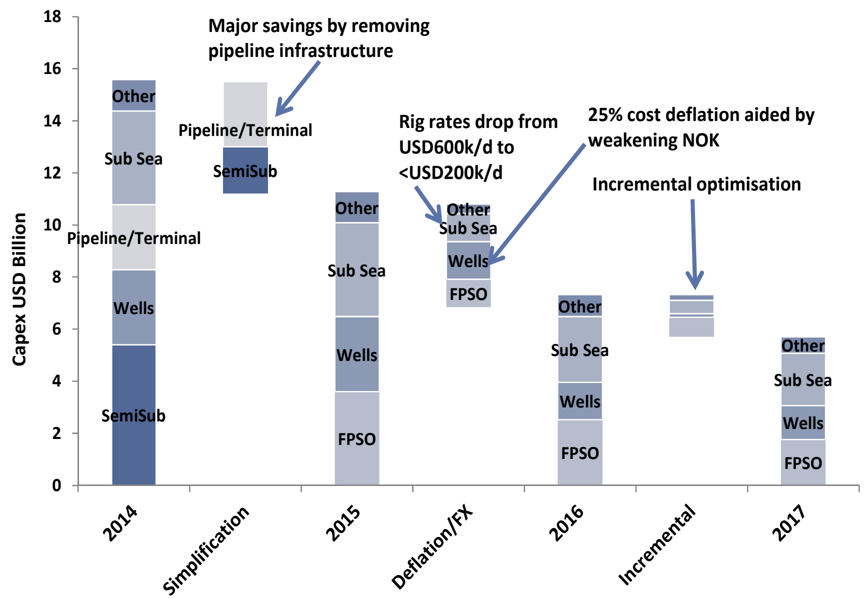
Source: Goldman Sachs Global Investment Research.

Johan Castberg – an example of why the RoW will continue to see cost deflation

We believe that Statoil's Johan Castberg development in the Barents Sea provides a good example of how the offshore oil industry is changing and adapting to this new era of oil abundance and cost focus. The breakeven for the project has fallen from US$86/bl in 2014 to US$43/bl currently, bringing it down to the first quartile of the Top Projects cost curve, US$10/bl lower that the average shale oil project, on our estimates. We identify three key drivers for the 63% reduction in total costs: (1) Project simplification achieved a 25%-30% cost reduction, by only sacrificing 11% of peak production with no meaningful change to recoverable resources; (2) c.20% came through oil services cost deflation; and (3) c.15% came through NKr depreciation (from 6.0 Nkr/US$ to c.8.5 Nkr/US$).

We think this is a clear example of how the industry is adapting to the new oil order. Two of the impacts (deflation, FX) are one-off cyclical adjustments, but the largest driver (simplification and standardization) is structural and acts as a permanent reset for the oil services industry. We believe that project sanctions in offshore are going to resume, but the projects will be smaller and simpler, leading to smaller packages for the oil services. For example, the SURF contract for Mad Dog II, awarded to Subsea7 by BP in March 2017, came in at US$300-500 mn, versus expectations of US$700 mn based on our discussions with investors.

Exhibit 33: Johan Castberg budget has been reduced to US$6 bn from US$16 bn in 2014
Capex estimates for Johan Castberg through the years with key drivers for cost reduction



Source: Statoil, Goldman Sachs Global Investment Research.

Exhibit 34: Project simplification was the key reason for the capex reduction
Johan Castberg capex drivers: Current vs. 2014 estimates

	2014	2017	% change
Number of Wells	40	31	-23%
Number of Templates	15	10	-33%
Number of Risers	18	11	-39%
Length of Pipeline/Umbilicals (km)	170	116	-32%
Days of Marine Installation	2490	1740	-30%
Number of Rig and Vessel Days	3200	2200	-31%
FPSO Topside Weight ('000t)	22	17	-23%
Storage (mln bl)	1.3	1.1	-15%
Water Injection (kb/d)	290	252	-13%
Liquid capacity (kb/d)	283	252	-11%
Capex (Nkr bn)	95	50	-47%
Capex (USD bn)	15.8	5.9	-63%

Source: Statoil, Goldman Sachs Global Investment Research.

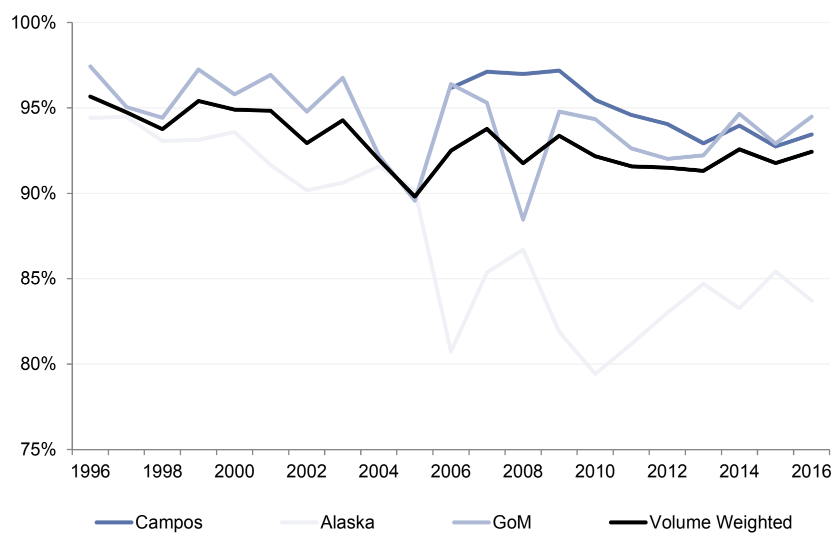
Brownfields: Stable decline rates and uptime – the legacy assets are not deteriorating

We have analysed over 5,000 wells spread across three mature basins, Campos (Brazil), Prudhoe Bay/Alaska (US), Gulf of Mexico (US), and the Santos growth basin (Brazil). With monthly data going back as far as 1969, we have analyzed all wells in these basins that have produced an equivalent of 1,000 b/d of total production for at least one year. We have dissected the legacy fields' production decline in these basins into its three key drivers: physical decline rates (well-by-well yoy decline, adjusted for maintenance and shut-downs), uptime (maintenance and shut-downs) and brownfield activity (new wells drilled on legacy fields). The outcome of this analysis is that physical decline rates have been stable over the past five years and have improved vs. the 1990s; uptime deteriorated in the early 2000s, but has stabilized; brownfield activity remains cyclical and has troughed in 2016.

The data shows that well-by-well decline rates (Exhibit 36) have been on a downward trend since the late 1990s, with the average falling from c.25% to 10%-15%, and have been stable since 2007. This is contrary to common knowledge indicating higher decline rates in mature basins.

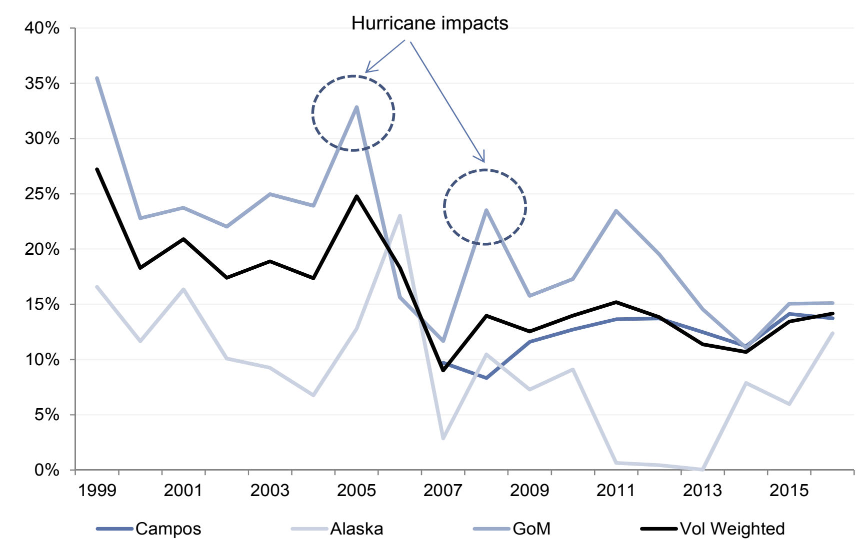
Uptime has been broadly stable over the past decade and is only slightly down from 1990s levels. To identify downtime, we looked at months in which individual wells declined more than 20%, but then recovered. We then calculate "lost production" by comparing the well's actual production to the production it could have achieved without downtime, which we calculate as the average production of that well in the previous and subsequent 3-6 months.

Exhibit 35: Uptime has been stable over the past decade...
Well level uptime calculated on production lost through maintenance, where production falls more than 20% in a month but then recovers, on a well-by-well basis



Source: ANP, Alaska DoE, BOEM, Goldman Sachs Global Investment Research.

Exhibit 36: ...while decline rates have improved since the 1990s
GoM, Alaska (onshore), Campos, Santos annual well-by-well declines, adjusted for uptime



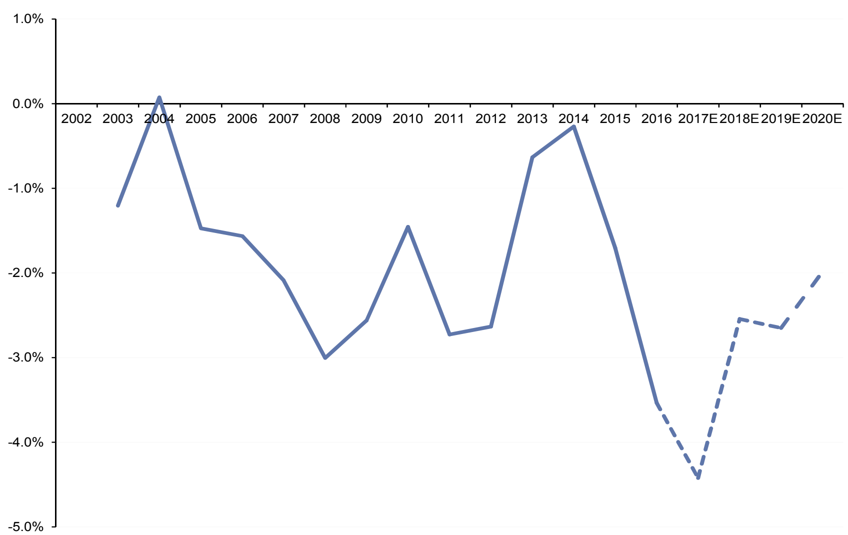
Source: ANP, Alaska DoE, BOEM, Goldman Sachs Global Investment Research.

2016-17 non-OPEC declines should be seen as unusually severe

Exhibit 37 shows the non-OPEC production decline rate ex-Top Projects. It is calculated including all the incremental drilling on brownfields, small fields and satellites. It only excludes the positive impact of giant fields (Top projects) start-ups. Under these assumptions, 2016 saw the largest decline rates in more than a decade, at 3.5%. This was due to falling drilling activity and some one-off factors (disruptions such as the wildfires in Canada). We expect declines to peak in 2017 before moderating to 2%-3% through 2020, as drilling activity resumes.

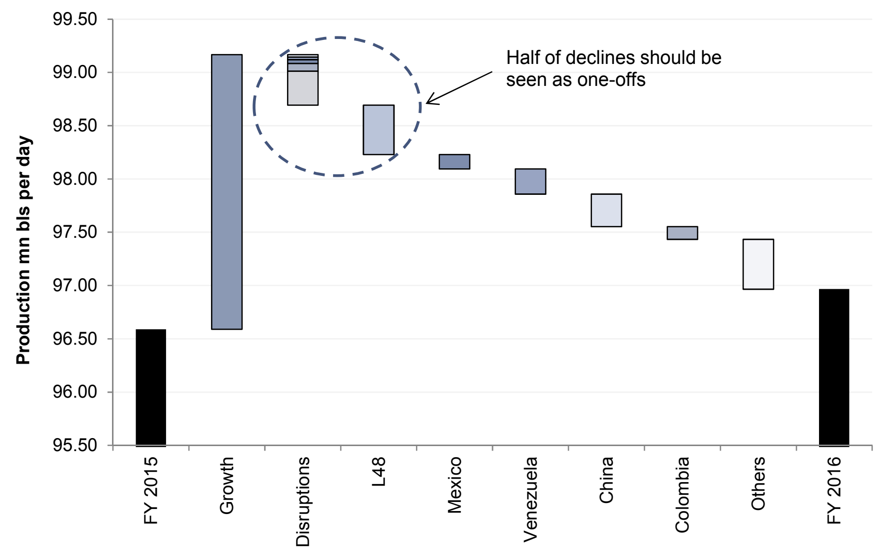
Activity has seen a broad-based pick-up as the oil price bounced off the trough. While rig additions in the US have taken centre stage, the rig count has also increased globally (ex-US) through 1Q17, with additions in Latin America (Colombia, Mexico, Venezuela – Exhibit 42), but also China and Russia. Declines in high-cost, short-cycle countries – both onshore (China, Colombia) and offshore (Mexico) – have moderated accordingly (Exhibit 41), a trend which we expect to continue, although we do see these countries as mature and in the declining phase.

Exhibit 37: We expect 2017 to mark the peak in non-OPEC decline rates
Non-OPEC production decline rates, excluding Top Projects



Source: ANP, BOEM, Alaska DoE, Goldman Sachs Global Investment Research.

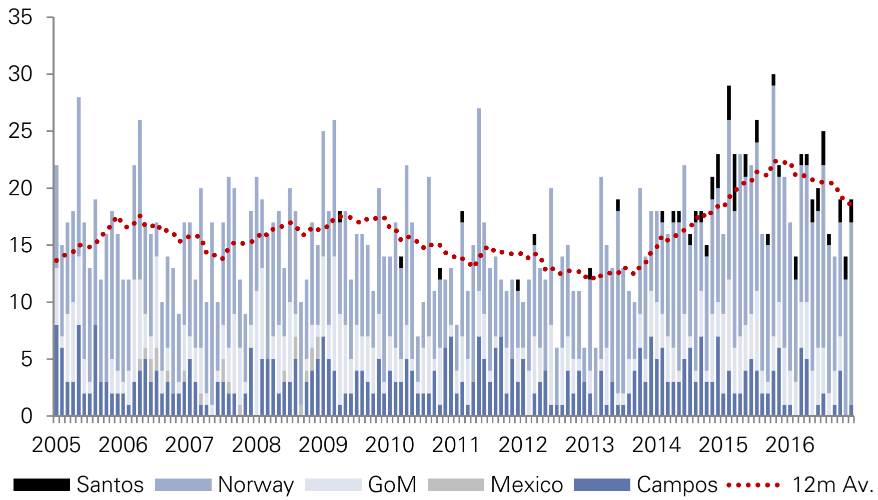
Exhibit 38: Half of the 2016 declines should be seen as temporary
2016 global oil production in mn b/d, highlighting key countries which declined



Source: IEA, Goldman Sachs Global Investment Research.

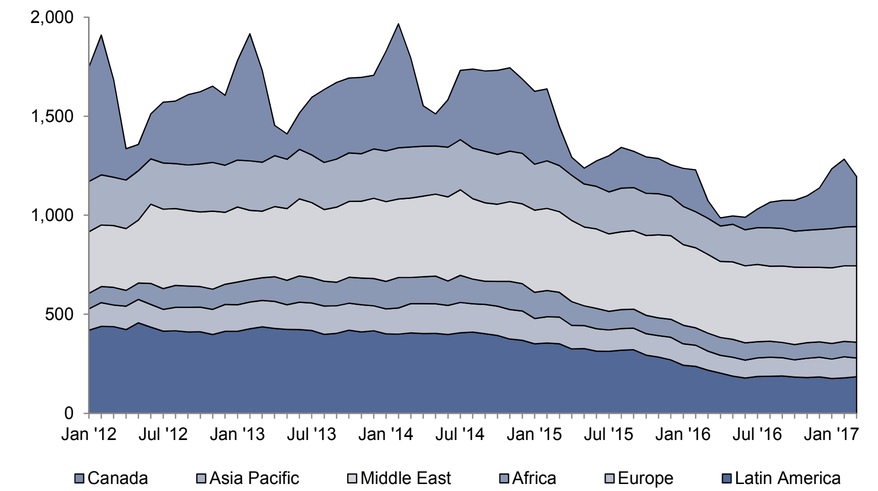
We expect non-OPEC declines to moderate as drilling activity recovers

Exhibit 39: Offshore activity is off the highs, but is holding up...
Monthly number of new offshore wells.



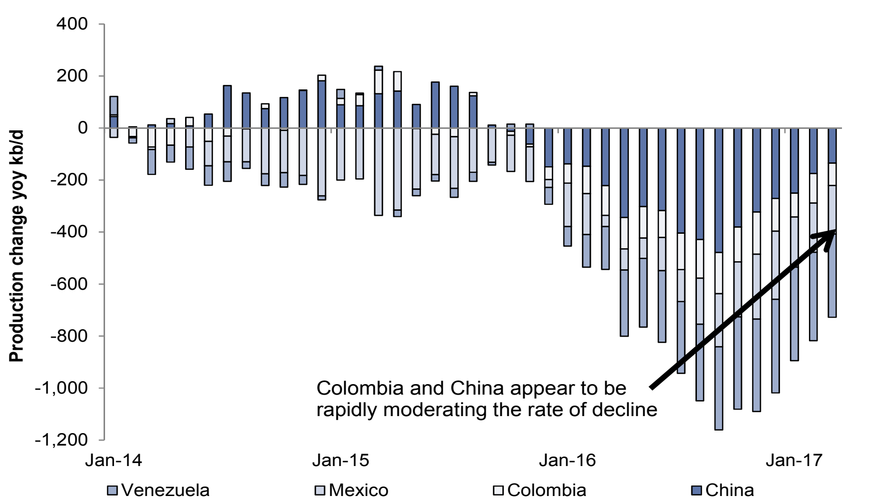
Source: ANP, Alaska DoE, BOEM, Pemex, NPD, Goldman Sachs Global Investment Research.

Exhibit 40: ...while rig count starts to recover from the lows of mid-2016
Ex US, China, Russia, Global rig count monthly



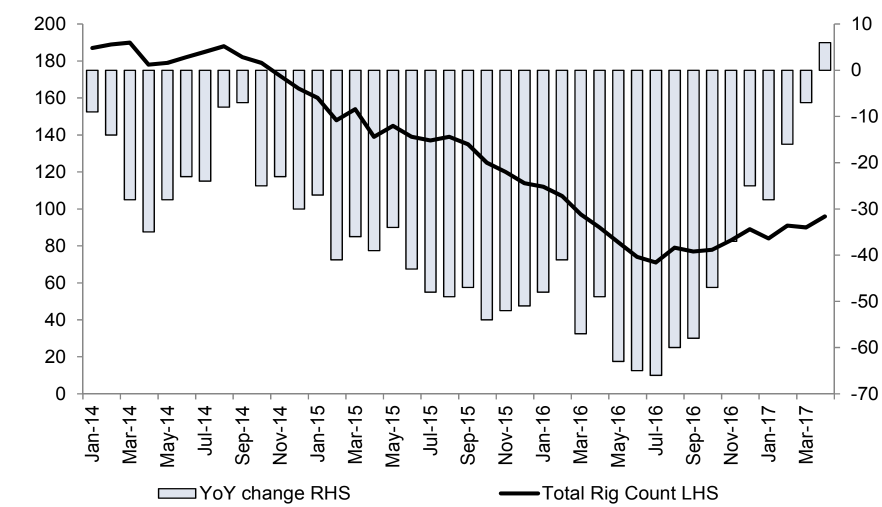
Source: BHI.

Exhibit 41: In short-cycle, high-cost countries, declines are moderating...
Oil production increase/decrease yoy in kb/d



Source: IEA, Goldman Sachs Global Investment Research.

Exhibit 42: ...while April 2017 saw the first yoy growth in three years
YoY change in rigs in Venezuela, Colombia and Mexico



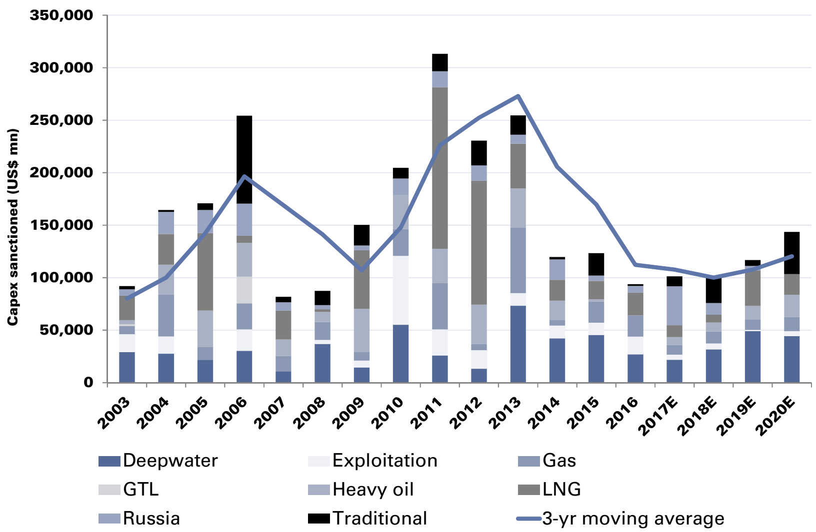
Source: BHI, Goldman Sachs Global Investment Research.

Oil services: Sanctioned capex troughed in 2016 and we expect a moderate improvement

Capex sanctioned covered by the Top Projects reached a trough in 2016 and we expect a gradual improvement from 2017. We expect deepwater to trough in 2017 and then almost double in 2018, driven by the expected sanction of the Bonga SW Aparo, Vito and Sangomar projects.

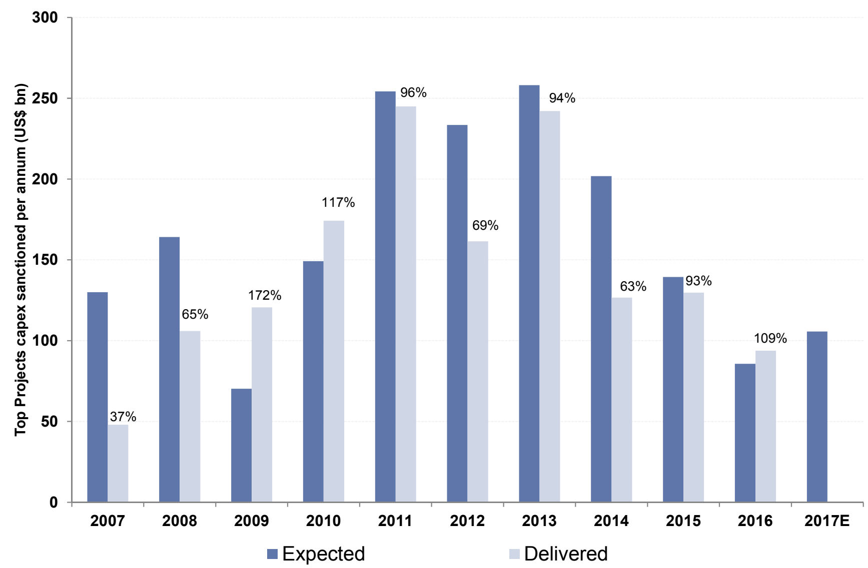
Exhibit 44 shows delivered capex sanctioned vs. our initial expectations in each year back to 2007. Sanctioning of projects was particularly disappointing in years of sharp oil price corrections (2008, 2014), or extreme cost inflation (2007, 2014). The big years of disappointment were 2007/08, when constraints emerged across most parts of the oil services chain; combined, with a high degree of fiscal re-negotiation, this led to the most disappointing period for project awards, at 37% and 65% of our 2007 and 2008 expectations, respectively. In contrast, 2009 saw several large, complex project sanctions, with Gorgon, Kearl and Goliat all moving ahead, contrary to our expectations, and possibly indicating that some operators looked to take advantage of falling oil services costs. This was repeated in the 2016 downcycle, which again surpassed our initial expectations, driven by Tangguh Tr3, Mad Dog 2 and Tengiz, with operators benefiting from falling oil service costs as well as simplified engineering scopes. With respect to 2017, our expectations stand at c.US$106 bn, driven by Liza, Coral FLNG, Fortuna LNG and Kovykta.

Exhibit 43: Capex sanctioned in 2016 reached a trough, and we expect a gradual improvement from 2017
Top Projects capex sanctioned by year, split by win zone



Source: Company data, Goldman Sachs Global Investment Research.

Exhibit 44: Actual FIDs exceeded our expectations in 2016 by 9%
Expectations for capex sanctioned vs. that which was ultimately delivered (each year represents an edition of the Top Projects report)



Source: Company data, Goldman Sachs Global Investment Research.

Diverging trends: US shale to ramp up while other investment areas continue to contract in 2017/18E

Our Top Projects database shows at an aggregate level that 2015 and 2016 capex deployment fell 16%/17%, respectively. We expect capex to increase by 5% in 2017 and continue to rise at a CAGR of 1% over 2017/20E. The muted increase is due to diverging capex trends: while we anticipate a sharp pick-up in short-cycle capex for US shales, we expect all other win zones (long-cycle) to show a decline in 2017/18E before picking up from 2019.

Exhibit 45: US 'shales' to lead the recovery while long-cycle areas continue to contract
Aggregate capex from Top Projects in US$ mn

Total capex spend US$ mn	2010	2011	2012	2013	2014	2015	2016	2017E	2018E	2019E	2020E
Win zones											
Total capex	145,975	177,386	244,119	300,094	326,393	275,400	228,615	239,135	244,629	246,409	245,163
yoy % growth		*22%*	*38%*	*23%*	*9%*	*-16%*	*-17%*	*5%*	*2%*	*1%*	*-1%*
Total Offshore	52,499	61,380	77,150	100,000	111,186	113,657	105,575	98,069	87,103	83,335	82,130
yoy % growth		*17%*	*26%*	*30%*	*11%*	*2%*	*-7%*	*-7%*	*-11%*	*-4%*	*-1%*
Traditional	16,876	18,401	20,836	19,528	21,515	23,829	19,792	15,245	14,649	15,808	18,171
yoy % growth		*9%*	*13%*	*-6%*	*10%*	*11%*	*-17%*	*-23%*	*-4%*	*8%*	*15%*
Deep water (>750m)	25,682	32,519	40,122	46,582	49,648	50,764	49,618	49,375	45,148	46,762	54,249
yoy % growth	*10%*	*27%*	*23%*	*16%*	*7%*	*2%*	*-2%*	*0%*	*-9%*	*4%*	*16%*
LNG	18,119	19,803	33,649	57,381	62,956	50,513	43,790	36,585	32,782	26,708	26,277
yoy % growth	*166%*	*9%*	*70%*	*71%*	*10%*	*-20%*	*-13%*	*-16%*	*-10%*	*-19%*	*-2%*
Total Onshore	93,476	116,006	166,970	200,094	215,207	161,743	123,039	141,066	157,526	163,074	163,033
yoy % growth		*24%*	*44%*	*20%*	*8%*	*-25%*	*-24%*	*15%*	*12%*	*4%*	*0%*
US Unconventional gas	16,365	18,607	19,721	15,645	16,130	12,899	7,329	11,483	13,991	15,304	15,007
yoy % growth	*9%*	*14%*	*6%*	*-21%*	*3%*	*-20%*	*-43%*	*57%*	*22%*	*9%*	*-2%*
US Unconventional liquids	14,305	30,061	56,328	67,293	86,890	57,759	34,891	53,887	74,702	81,088	83,101
yoy % growth	*162%*	*110%*	*87%*	*19%*	*29%*	*-34%*	*-40%*	*54%*	*39%*	*9%*	*2%*
All US Unconventional	30,670	48,669	76,049	82,939	103,020	70,658	42,219	65,370	88,692	96,392	98,108
yoy % growth	*50%*	*59%*	*56%*	*9%*	*24%*	*-31%*	*-40%*	*55%*	*36%*	*9%*	*2%*
Heavy Oil	14,581	15,108	19,433	27,166	26,143	23,018	14,559	12,092	9,575	10,223	11,079
yoy % growth	*626%*	*4%*	*29%*	*40%*	*-4%*	*-12%*	*-37%*	*-17%*	*-21%*	*7%*	*8%*

Source: Goldman Sachs Global Investment Research.

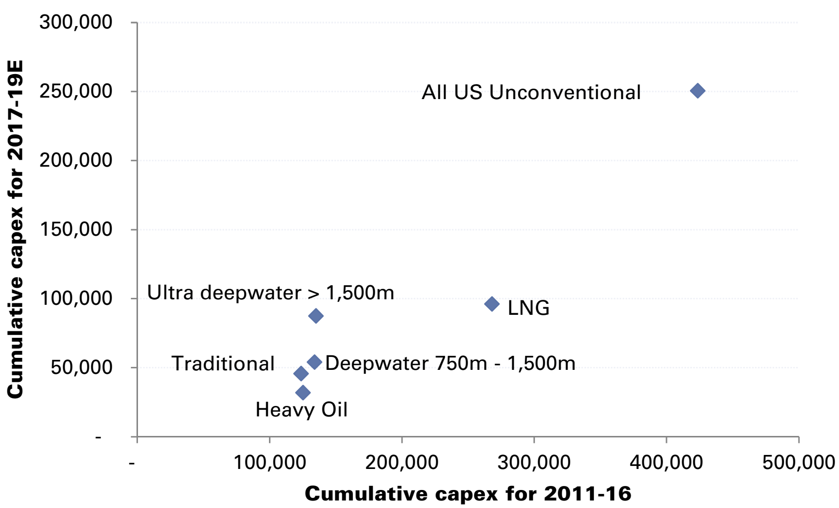
US shale activity levels already in recovery mode, both in terms of volumes and prices

We have already started to see a recovery in US onshore activity levels, with sustained increases in the US rig count which troughed in May 2016 at 380. We note that since the end of last year, companies exposed to US activity levels have highlighted a return of cost inflation as a result of improving activity levels. Well costs in US shales have declined by about 30% since 2014 owing to service price deflation and rig efficiency, with well costs declining on average from c.US$7 mn to US$5 mn between 2014 and 2016.

We now expect service price inflation of about 20%-30% in the coming years, with well costs rising to c.US$6.4 mn by 2018, though this is still 8% lower versus 2014. The increase in well costs is a function of service price inflation and higher service intensity, which primarily means increases in the volume of frac sand pumped. Higher service intensity is also leading to improvement in well productivity, and we estimate that since 2014, the industry's finding and development costs have fallen by about 36% when adjusted for increases in well EUR. We now project a 24% increase in per barrel finding and development costs by 2018, even as well costs rise by about 30%. Nonetheless, despite the cyclical increase, finding and development costs should still be about 20% lower structurally versus US$14.00/b in 2014.

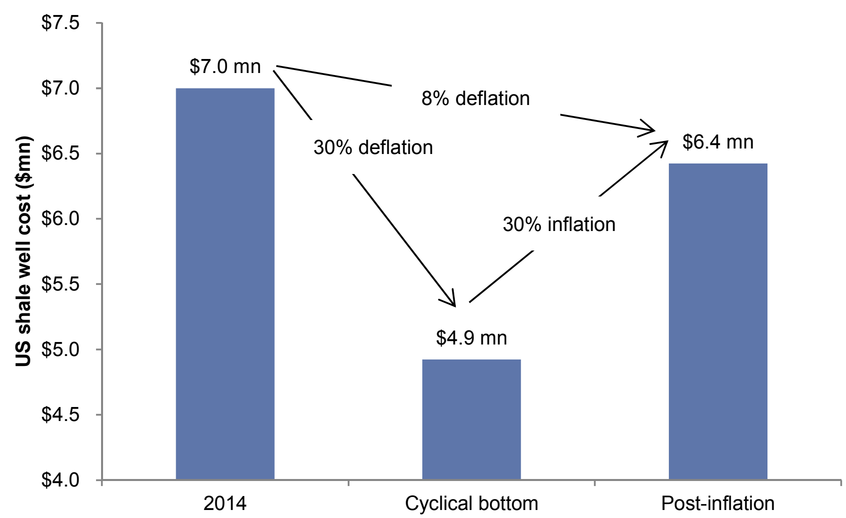
In Exhibit 46, we show cumulative capex in US$ mn for 2011/16 and 2017/19E, with US shales clearly standing out in terms of capex deployment. We note that both LNG and ultra-deepwater (water depth>1500m) follow. We expect ultra-deepwater capex to be driven predominantly by Brazilian projects, and LNG to be driven by Australia and North America.

Exhibit 46: Capex deployments in 2017/19E period to be driven by US shale
Cumulative capex growth forecast vs. history



Source: Company data, Goldman Sachs Global Investment Research.

Exhibit 47: Well costs have down by 30% since 2014, but should increase by about 30% off the bottom
US shale well costs in US$ mn, which does not account for well productivity changes (cyclical bottom in 2016; post inflation in 2018)



Source: Company data, Goldman Sachs Global Investment Research.

Unequal service recovery in shales: Completion services to outperform drilling rigs

The primary driver of well productivity growth in US shales is growth in service intensity, driven by increases in well lateral lengths and a rise in frac stages. Since 2014, a single horizontal rig is drilling 15% more wells per year, and generating 106% higher demand for pressure pumping and 152% increased demand for frac sand. This increase in service intensity has driven an 88% increase in liquids production per rig. Service intensity growth trends are still continuing, and frac stages per well and frac sand pumped per well, which have increased 36%/120% since 2014, are projected to grow another 30%/35% through 2020, on our estimates. Demand for pressure pumping is highly correlated to frac stages too, and as such we expect demand for pumping to be up by about 35%.

For most services, we do not expect service pricing to reach peak levels seen in 2014, although service pricing is increasing off the bottom for most services. Given the increased consumption per well that we see for frac sand and pressure pumping in particular, we project E&P spend on these services to be up 10% and 86% by 2018 versus their spend in 2014.

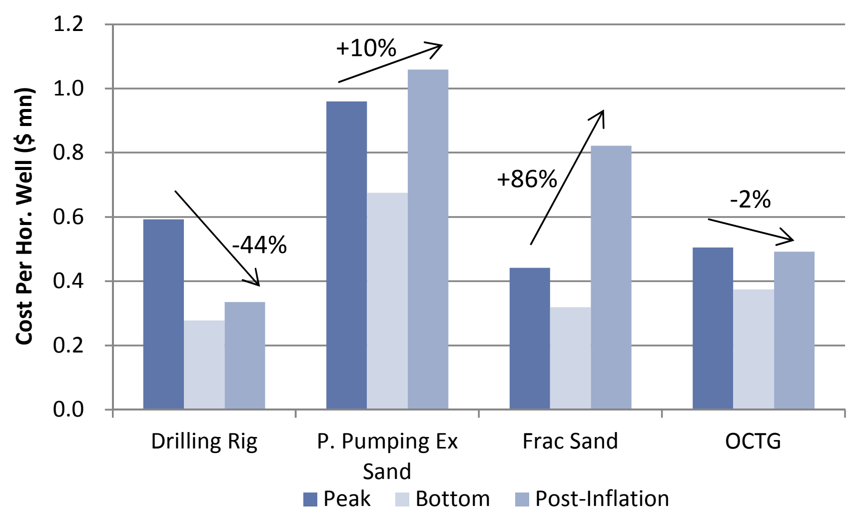
Overall drilling rig associated costs are projected to be only about 5% of a well's cost in 2018, versus 9% of the cost in 2014. On the other hand, we project pressure pumping to be 29% of a well's cost versus 20% in 2014. We expect pressure pumping prices to increase to newbuild economics, as our supply/demand analysis shows that in addition to all idle equipment, industry will need to build 3.5-5.0mn HHP of new capacity.

Exhibit 48: Changes in service consumption/pricing in horizontal shale well
Completion oriented segments seeing significant increase in consumption

	Units	2014	2018	Change
Service consumption				
Rigs	Days per well (days)	22.9	19.7	-14%
Pressure Pumping	Demand per well (HHP)	35,000	42,000	20%
Pressure Pumping	Job duration (days)	5.2	7.8	50%
Frac Sand	Demand per well (mn T)	2,462	5,406	120%
OCTG	Feet of casing per well	18,100	21,000	16%
Water	Demand for fracking (bbls)	30,000	500,000	1567%
Service prices				
Drilling rigs	Dayrate ($K/day)	$25-$28	$18-$22	-25%
Pressure Pumping	Price per frac stage ($K/day)	$80-$90	$60-$65	-27%
Frac Sand	Price per ton at wellsite ($/T)	$140	$112.50	-20%
OCTG	Cost per foot ($/ft)	$28	$23	-16%

Source: Goldman Sachs Global Investment Research.

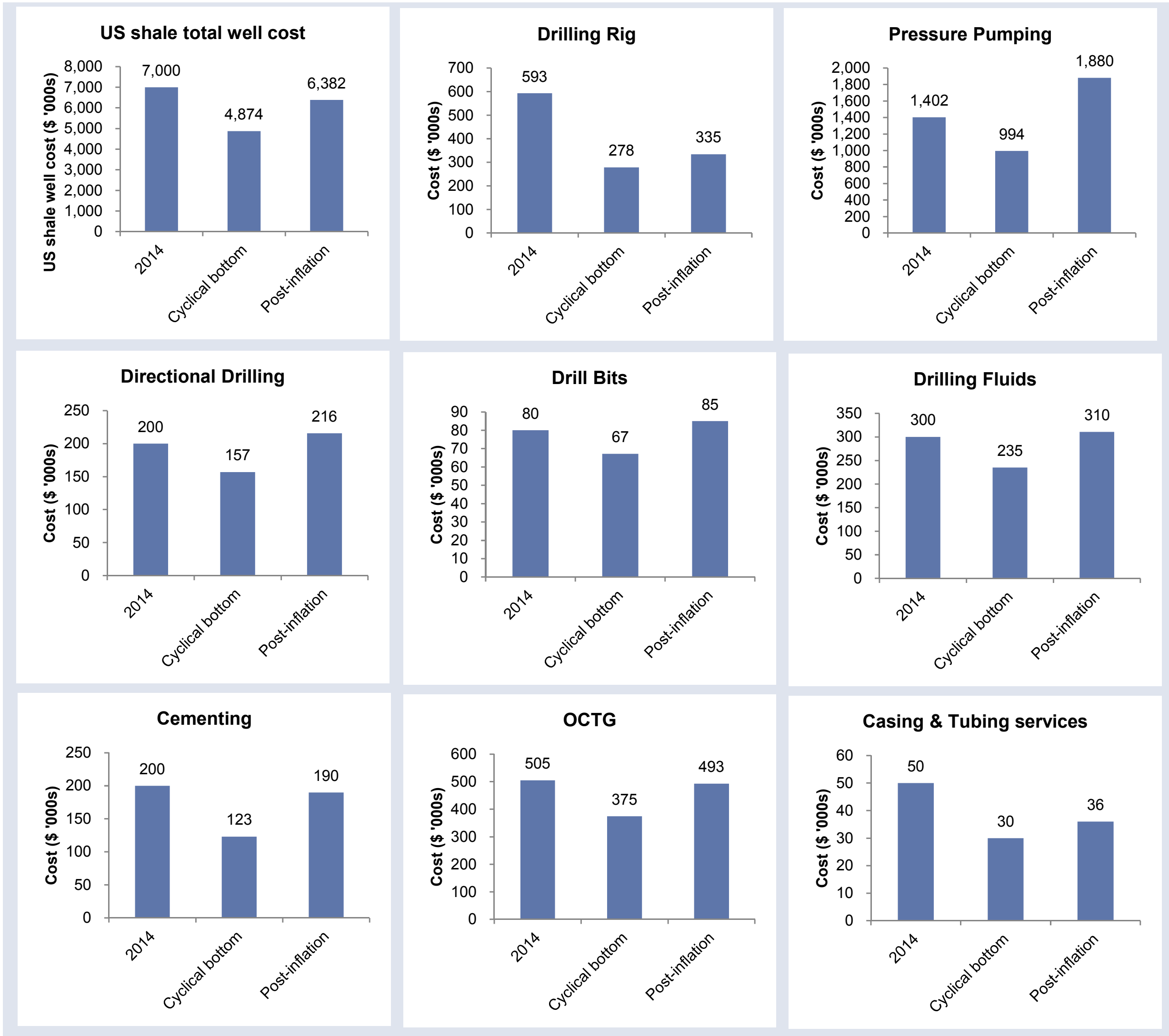
Exhibit 49: 10%/86% higher take for PP/sand post-inflation vs prior peak
Drilling rig take per well should fall by about 44% versus 2014 levels (peak in 2014, cyclical bottom in 2016; post inflation in 2018)



Source: Goldman Sachs Global Investment Research.

Exhibit 50: Various business segments should see different uplifts off the bottom

Changes in service intensity and pricing to drive revenue recovery off the bottom (peak in 2014, cyclical bottom in 2016; post inflation in 2018)



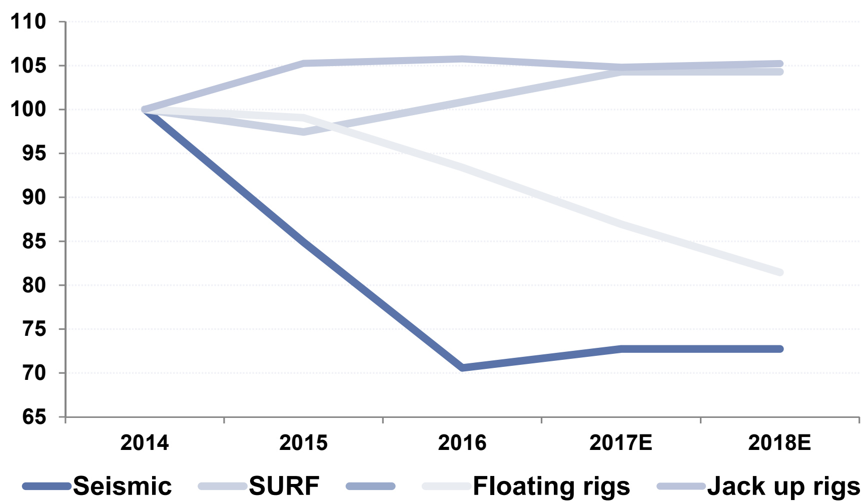
Source: Goldman Sachs Global Investment Research.

Offshore utilization to trough this year with a gradual pick-up from 2018E

In Exhibit 51, we show supply growth in offshore vessels by subcategories, rebased to 100 for 2014. We note that the seismic segment has seen the most asset rationalization, with numerous vessels being retired – by Schlumberger, CGG and PGS, among others. In the offshore drilling space, we have started to see some vessels being stacked but believe further restructuring is necessary, particularly in the jackups segment where we still expect significant newbuild additions that will need to be balanced with more retirements. We do not expect any additional increases in SURF supply; however, if there is insufficient pick-up in offshore investments, companies will need to further adjust their vessels fleets to mitigate the impact on margins stemming from lower fixed cost absorption on the back of deteriorating vessel utilization.

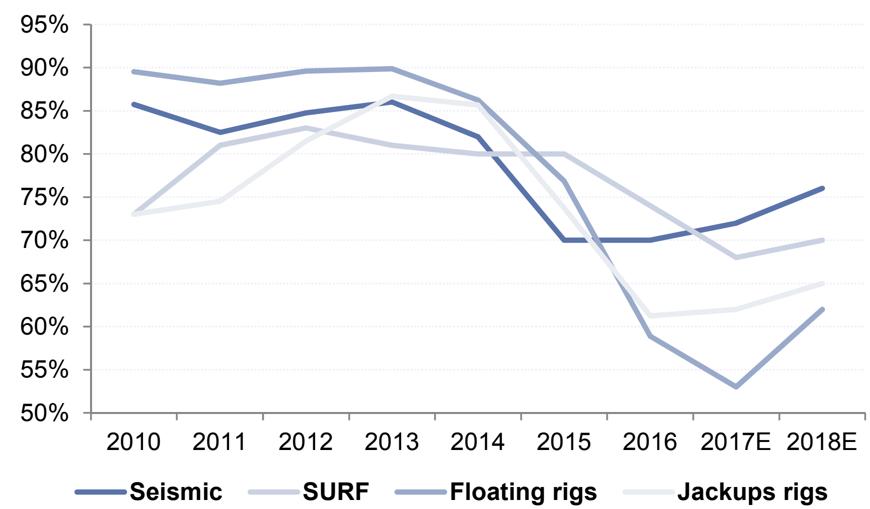
In Exhibit 52, we show our assumptions for vessel utilization rates, based on our assumptions for capex as well as number of vessels. The only segment where we anticipate a muted recovery from 2017 is seismic, which we believe troughed in 2016. We expect all other segments to see some level of recovery from 2018, driven by the increase in capex sanctioned we foresee. We also note that several offshore-exposed E&C companies highlighted in their 1Q17 earnings results that they expect some subsea contracts to be sanctioned this year, with a level of inflection expected to materialize in 2018. We anticipate the pick-up in contracts being awarded to be driven, to a certain extent, by cost deflation along the oil services supply chain, and as such would anticipate pressure on companies' margins.

Exhibit 51: SURF and jackups seeing less asset rationalization
Supply growth by offshore segments rebased to 100 in 2014



Source: Baker Hughes, Goldman Sachs Global Investment Research.

Exhibit 52: Utilization troughs in 2017E on our assumptions
Utilization rates in different offshore asset categories



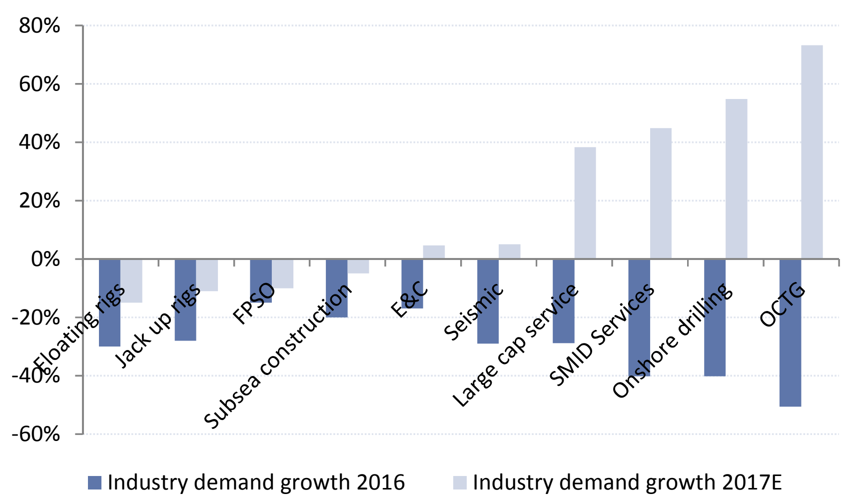
Source: Company data, Goldman Sachs Global Investment Research.

Oil services winners have exposure to the following themes: E&P productivity enablers, M&A targets and self-help

We highlight the Top Projects oil services winners below. We have calculated the estimated industry demand growth for 2016 as well as the estimated industry demand growth for 2017E. The data shows a clear divergence between offshore and US onshore-exposed companies. We also note that we expect a slight improvement in seismics, where we expect exploration volumes to pick up even if at modest levels. We have then chosen the Buy-rated stocks under coverage that are exposed to the key themes identified in Exhibit 54. In mapping the growth rates to different sub-sectors, we have made the following assumptions. For large cap services, we assume 70% exposure to US onshore and 30% exposure to deepwater developments. We base the SMID service growth purely on US unconventional growth. For OCTG, we use our US rig count assumptions. For seismic, we use our industry revenue forecasts for growth, with an implied base for uncovered companies. The key areas of growth are the segments which are exposed to the onshore segment. Aside from exposure to US onshore, we believe the other key areas to be E&P productivity enablers, self-help as well as companies that we have identified as potential M&A targets. The winners are:

- US: Schlumberger, Halliburton, Nabors Industries, TechnipFMC, Emerge Energy Services, Propetro Holdings, U.S Silica Holdings and Oceaneering International.
- Europe: Hunting, TechnipFMC, Vallourec and Saipem.

Exhibit 53: Highest growth rates for those with exposure to US shale
Industry demand growth for 2016 and 2017E



Source: Company data, Goldman Sachs Global Investment Research.

Exhibit 54: The Top Projects oil services winners all have material exposure either to US shale, self-help or potential M&A* targets

	Top projects winners		
	Potential M&A targets	Self-help	E&P productivity enablers
Europe	Hunting	TechnipFMC Saipem	Hunting Vallourec
Americas	Oceaneering International	Schlumberger TechnipFMC Nabors Industries Emerge Energy Services	Schlumberger Halliburton Propetro Holding U.S. Silica Holdings

Rating and pricing information (as of May 24, 2017). Emerge Energy Services LP (B/A, $12.15), Halliburton Co. (B/A, $47.71), Hunting Plc (B/N, 553.00p), Nabors Industries Ltd. (B/A, $9.87), Oceaneering International Inc. (B/C, $26.22), Propetro Holding (B/A, $13.72), Saipem (B/N, €3.93), Schlumberger Ltd. (B/A, $71.36), TechnipFMC Plc (B/A, €28.30), U.S. Silica Holdings (B/A, $38.39) and Vallourec (B/N, €6.06)

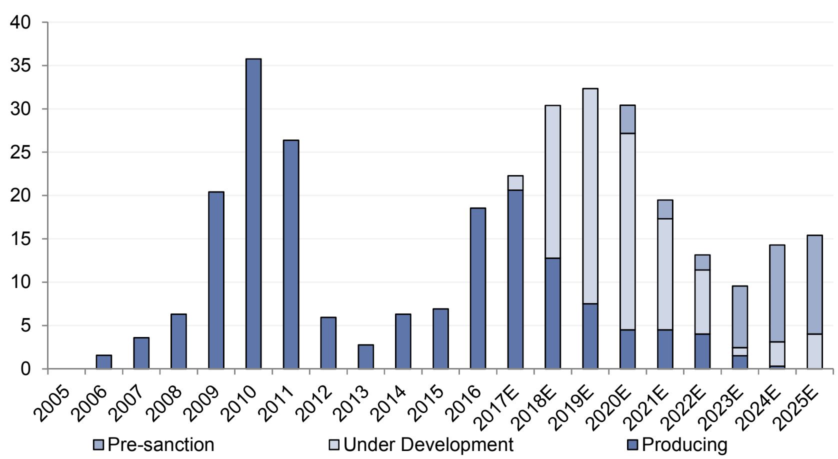
*Source: Goldman Sachs Global Investment Research. * To identify targets, we assess stocks in our coverage using an M&A framework, considering both qualitative factors and quantitative factors. Hunting and Oceaneering rank 2 on this framework, representing 15%-30% probability of M&A activity; we incorporate a 15% weighting to an M&A value into our price targets to account for this optionality, in line with our standard departmental guidelines.*

LNG: A wave of oversupply to hit the market in 2018-20E

After the wave of LNG FIDs in 2011-14, we expect a large number of LNG projects to come online in 2017-20, adding 125mnt of LNG supply in the next five years (Exhibit 55), or c.40% of current LNG capacity. Most of these projects are already at an advanced stage of development, and are thus unlikely to be shelved. We expect this wave of LNG to tip the market into oversupply in 3Q17, and estimate 19-60 mtpa of excess supply in 2018-20 could head to Europe.

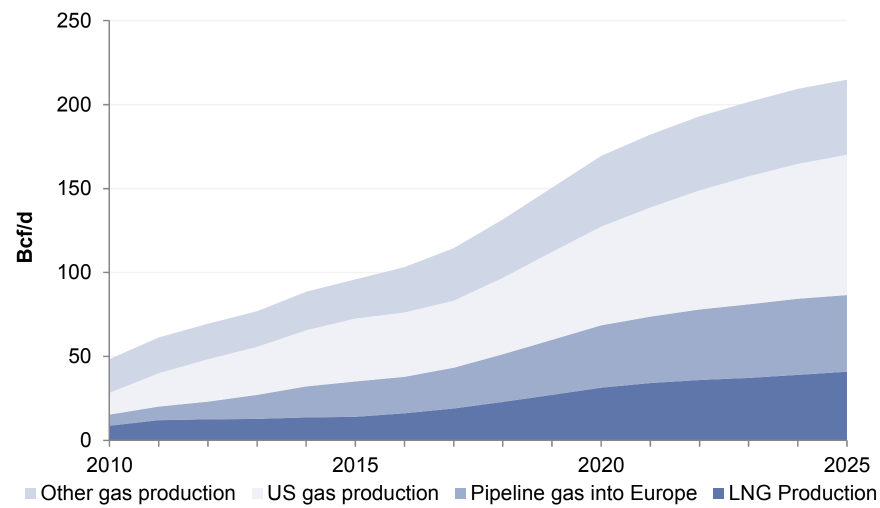
In addition to the wave of LNG, piped gas supply is also growing (Exhibit 56) – we estimate c.60 bcf/d of growth from Top Projects in 2017-21, with more than half of this coming from the US and Europe (including Russia and Azerbaijan). This, coupled with growth in LNG volumes, increases competition in markets where both pipeline gas and LNG are available, driving growth in spot gas trading. We have already witnessed this in Europe, where the share of spot trading volumes reached c.33% in 2015, vs. only c.3% in 2005. We expect the renewed competition between pipeline gas and LNG to impact the European gas market in particular (as the largest most liquid market and with the most spare regasification capacity), depressing prices as pipeline gas suppliers fight for market share – more on pg. 48).

Exhibit 55: LNG Supply is increasing at 2x the historical rate of LNG demand growth in 2018-20E...
LNG volume additions in mtpa by development status



Source: Goldman Sachs Global Investment Research.

Exhibit 56: ...while piped gas is also accelerating rapidly and eating into LNG demand in countries such as Egypt and Argentina
Top Projects gas supply in bcf/d

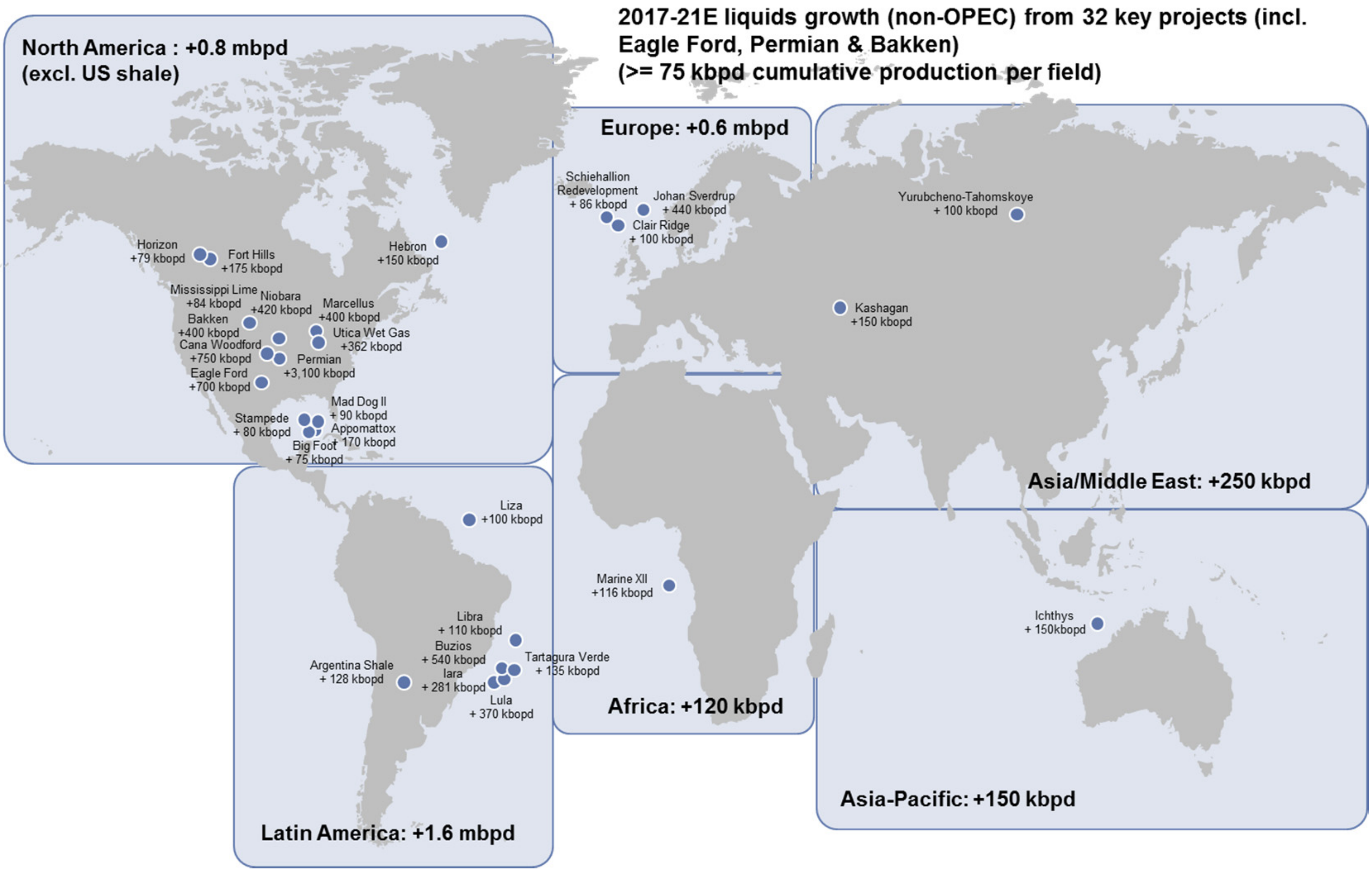


Source: Goldman Sachs Global Investment Research.

Growth Map: 32 key projects that drive non-OPEC growth to 2021

Exhibit 57: 2017-2021 key non-OPEC growth projects

Non-OPEC projects that contribute at least 75 kbpd of growth by 2021



Source: Goldman Sachs Global Investment Research.mn

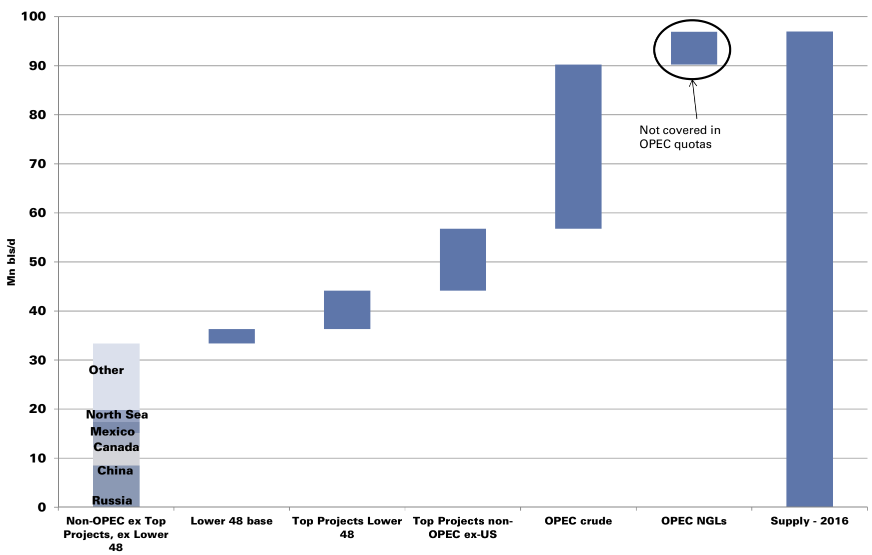
OPEC, Top Projects and Shale make up two-thirds of global supply

Global liquid production was 97mn b/d in 2016. Of this, 70% came from OPEC, the US, Russia and the rest of the FSU (mainly Kazakhstan). We see these regions as being generally short-cycle, as production can be raised within 6-12 months with increasing drilling activity, or it can be severely curtailed through cuts (OPEC, Russia) or lower oil prices (US). Having seen a steady erosion of market position between 1965 and 2000, the resurgence first of Russia (2000-10), then the US (2010-20) has once again increased their share of the market. We would expect these countries to continue to capture market share through the end of the decade, creating a stronger adjustment mechanism to demand-supply miss-matches.

OPEC produces around 40mn b/d of liquids, of which 33mn b/d is oil and covered by OPEC quotas, while 7mn b/d is NGLs/condensates which have historically been exempt from OPEC quotas. The US Lower 48 accounts for around 11mn b/d, of which 8mn b/d is captured in our Top Project analysis.

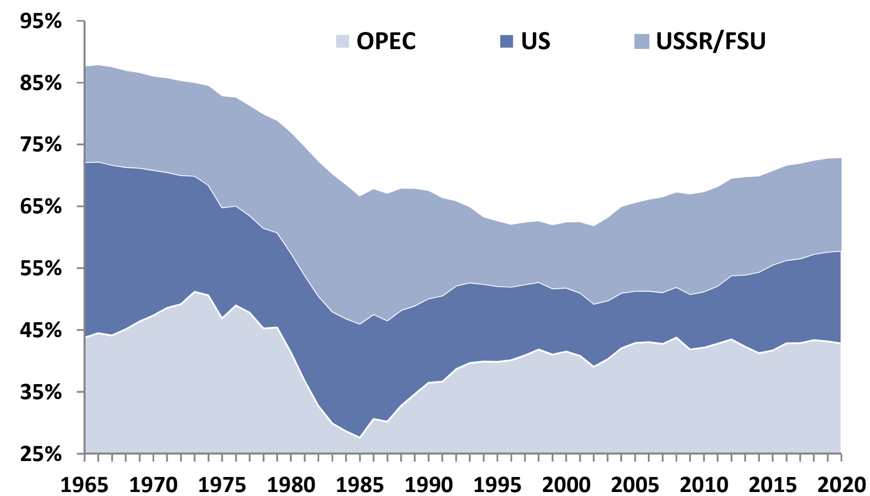
The rest of our Top Projects 2016 production (ex-Lower 48/OPEC) accounts for 13mn b/d. This leaves outside of the Top Projects scope 33mn b/d of non-OPEC, non US production. The bulk of this comes from Russia (9mn b/d), China (4mn b/d), Canada (3mn b/d), Mexico (2mn b/d) and the North Sea (2mn b/d) and constitutes the declining, mature legacy part of non-OPEC.

Exhibit 58: Top Projects accounted for c.25% of global production in 2016
Make-up of global liquids supply in mn b/d in 2016



Source: IEA, Goldman Sachs Global Investment Research.

Exhibit 59: Short-cycle producers are regaining market share
Share of global liquids supply from 1965-15 per OPEC, US and FSU

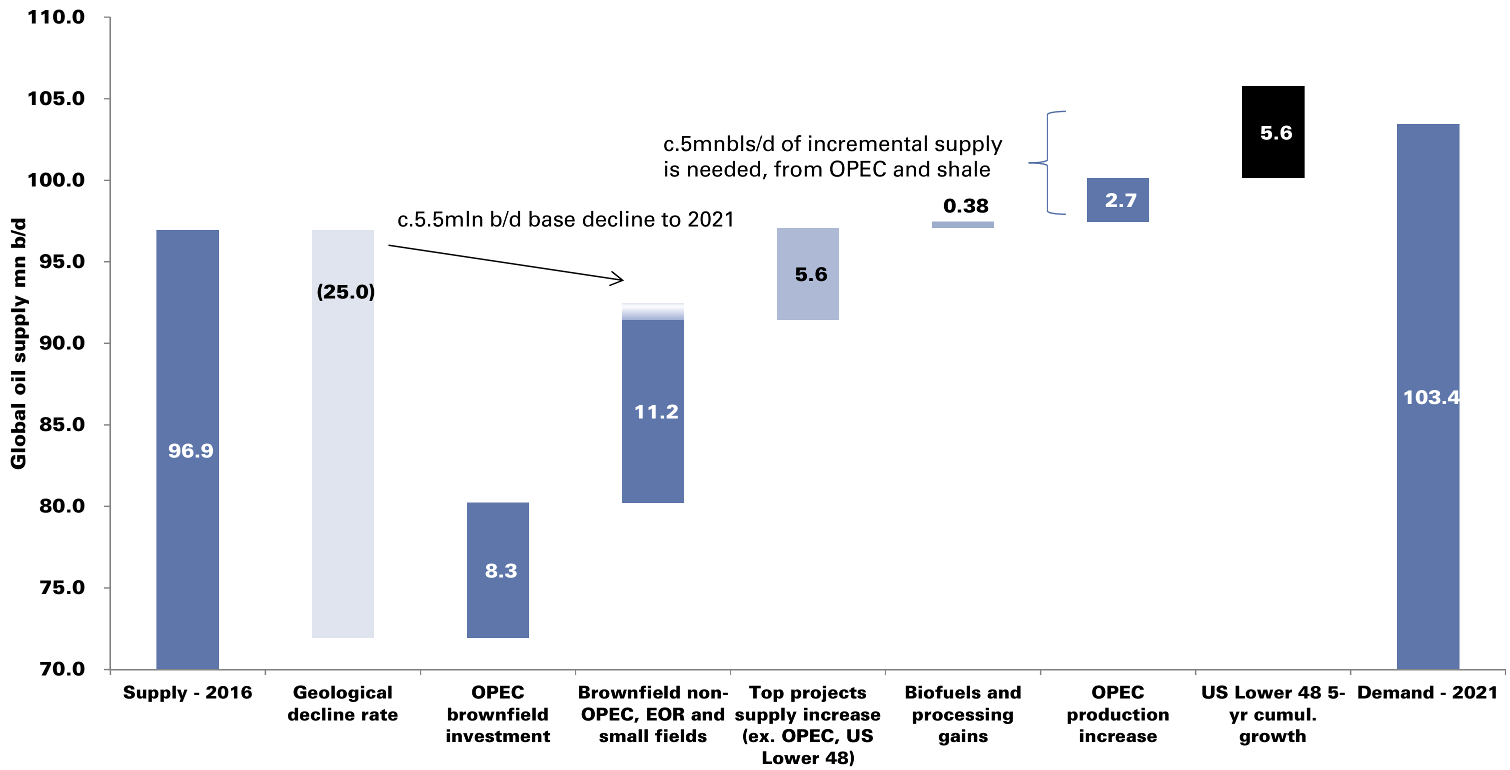


Source: BP Statistical Review of the Year, Goldman Sachs Global Investment Research.

The oil market looks well supplied through 2021, unless shale investment slows

While we remain relatively bullish on our medium-term demand forecast (seeing a 6.5mn b/d increase between 2016-21), we think underlying declines mean that there will be a c.10mn b/d gap to fill. Of this, we see 4.2mn b/d filled by our Top Projects, another 0.4mn b/d of biofuels/processing gains allowing for shale and OPEC to compete for the last 5mnb/d.

Exhibit 60: The oil supply and demand model to 2021 suggests no shortage, unless shale investments slow
Key drivers of supply growth to 2021



Source: IEA, Goldman Sachs Global Investment Research.

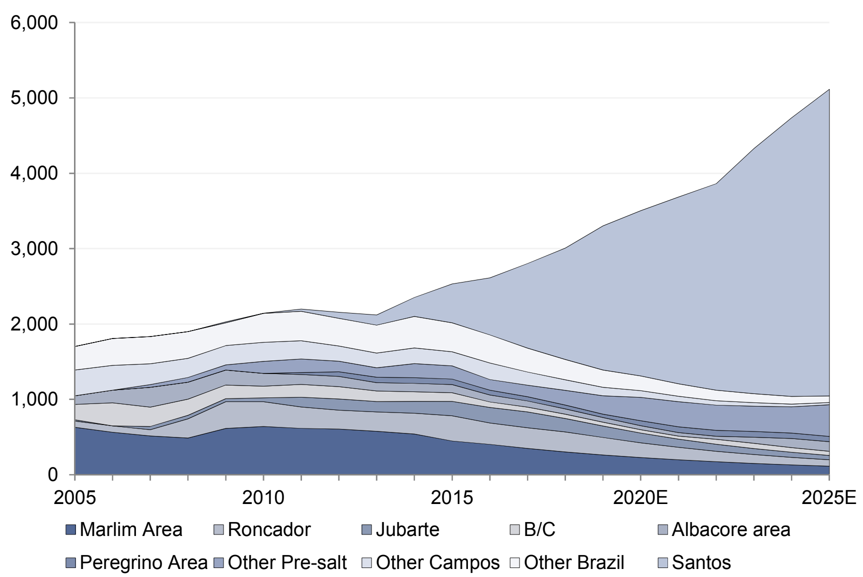
The Brazilian pre-salt Santos basin: Non-OPEC's lowest cost new production with scale

Brazil has two major producing basins, the Campos basin (accounting for c.1.5mn b/d), which is currently in decline, and the Santos basin, accounting for c.1mn b/d and growing through the development of its pre-salt fields, with the remainder (c.300kb/d) in a variety of small legacy basins including onshore.

We expect a rapid 15% pa decline in the Campos basin (excluding new pre-salt wells at select fields such as Jubarte), driven by physical decline and low investment. Our analysis of well declines suggests a maximum decline rate of 10%-15%, while we think FPSO retirement may increase this rate.

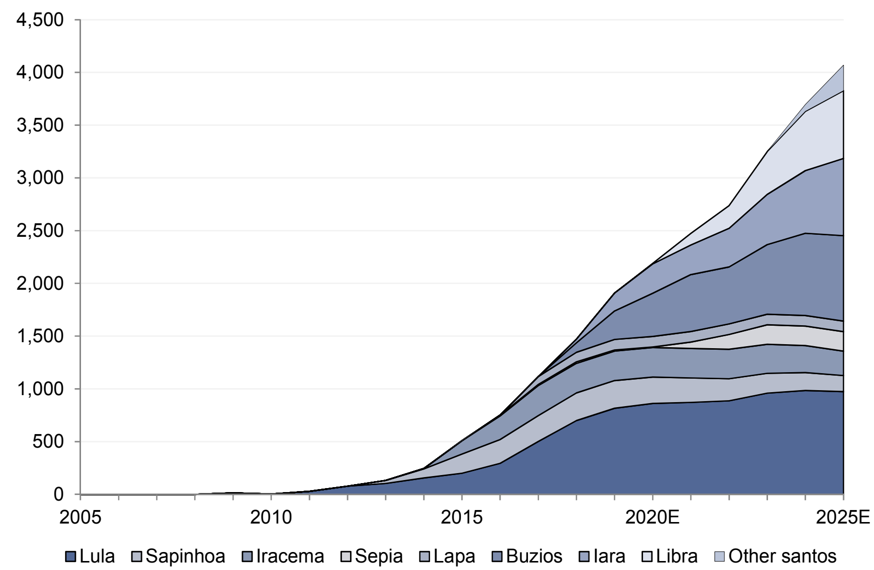
Filling in this decline and fueling growth for the country as a whole, the Santos basin will see growth accelerate as new FPSOs start up through the next four years. While there is some risk to the post 2020 profile (as FID has not been taken on a number of the giant projects such as Libra, Carcara, Sepia etc), we think the near-term ramp is relatively de-risked and our estimates may prove to be conservative. Should FPSOs be delivered on schedule (vs. our expectations of some delays in fitting out), the 2018-20 ramp-up could be much more aggressive. We currently expect the pre-salt Santos basin fields to produce >2mnb/d by 2020 and >4mnb/d by 2025, from c.0.5mnb/d in 2015.

Exhibit 61: We expect Brazilian legacy production to decline rapidly, but still grow in aggregate thanks to the Santos pre-salt
Forecast of Brazilian legacy production (kboe/d)



Source: ANP, IEA, Goldman Sachs Global Investment Research.

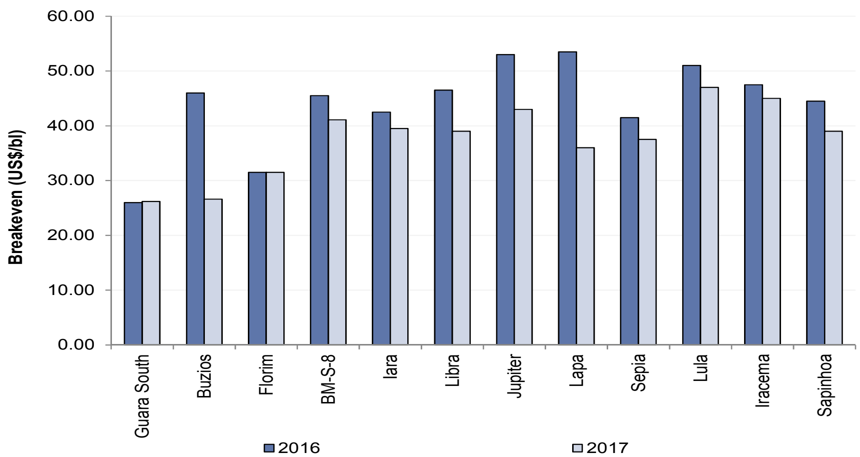
Exhibit 62: We expect the Santos basin pre-salt production to reach 4mnb/d by 2025
Forecast of production from Santos basin pre-salt fields (kboe/d)



Source: ANP, Goldman Sachs Global Investment Research.

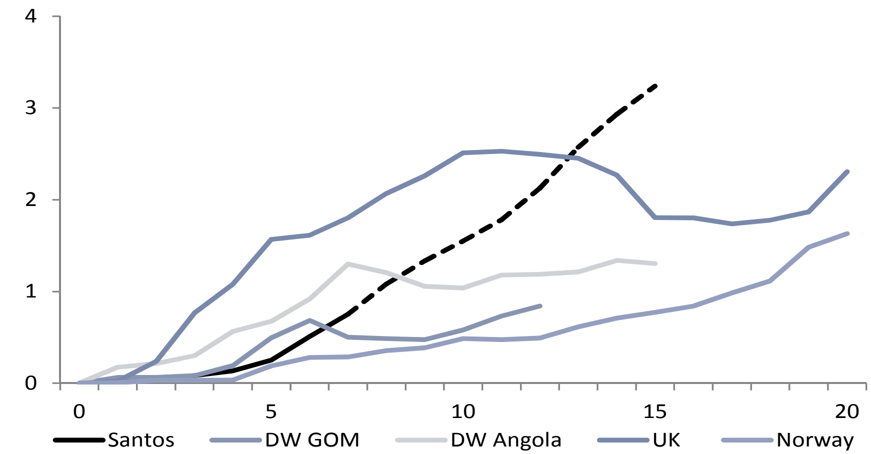
…while the Santos keeps getting better…

Exhibit 63: Breakeven prices keep falling year after year …
Santos pre-salt breakevens in 2016 vs 2017



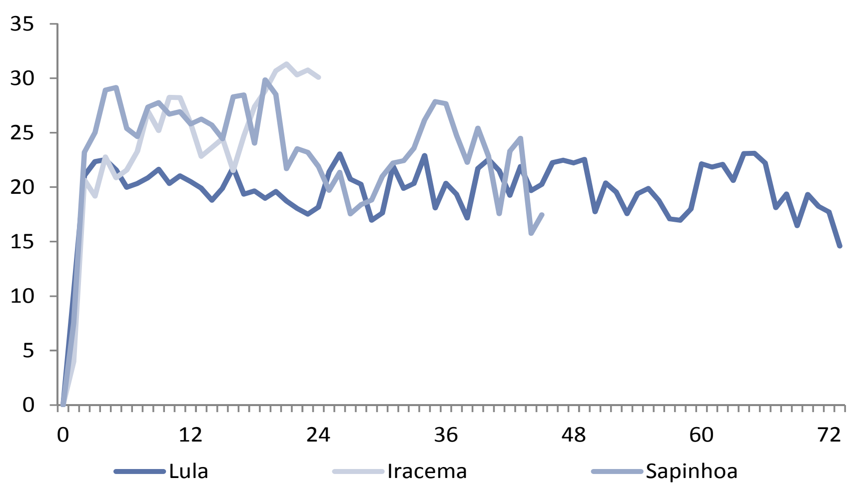
Source: Goldman Sachs Global Investment Research.

Exhibit 64: … while the Santos basin enters a major period of growth…
Production profile in mn b/d vs time from first oil in years for various basins



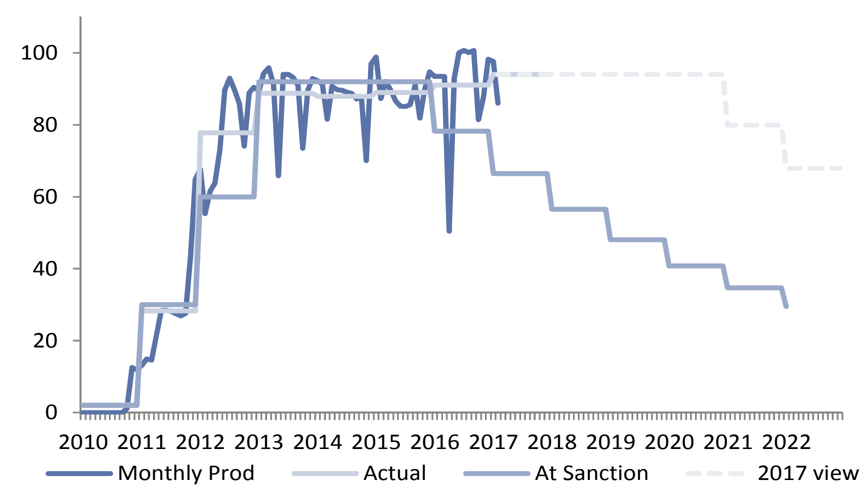
Source: ANP, NPD, OGA, BOEM, Company data, Goldman Sachs Global Investment Research.

Exhibit 65: …pre salt well performance is constantly strong…
Average monthly pre-salt well production by field in kb/d of oil



Source: ANP, Goldman Sachs Global Investment Research.

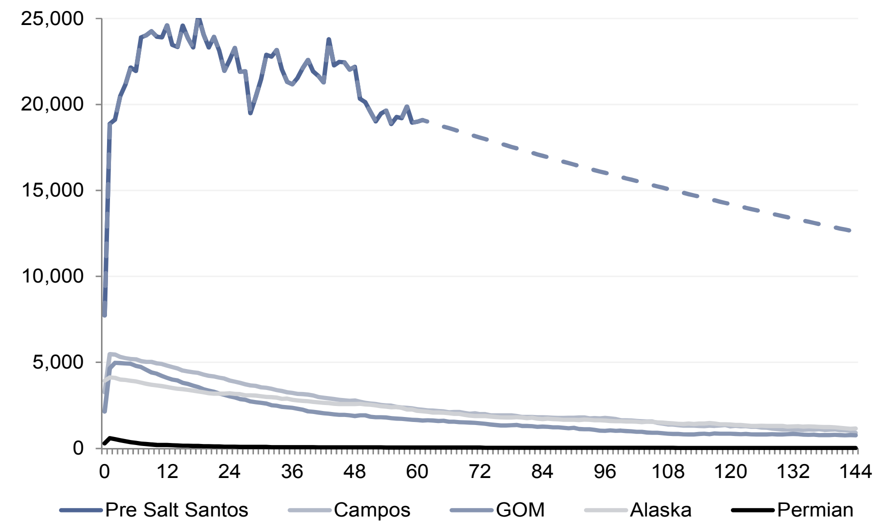
Exhibit 66: …extending plateaus and producing 360mn bbl more per FPSO
Angra Dos Reis (1st Lula FPSO) production profile at FID, actual and forecast



Source: ANP, Goldman Sachs Global Investment Research.

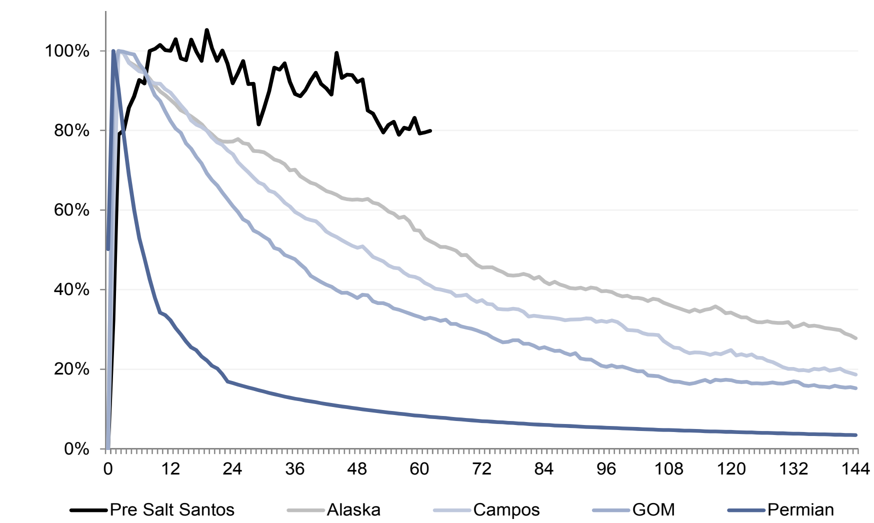
…as the pre-salt Santos wells are showing exceptional productivity and longevity

Exhibit 67: The pre-salt Santos wells show exceptional productivity…
Average oil well production per month in b/d



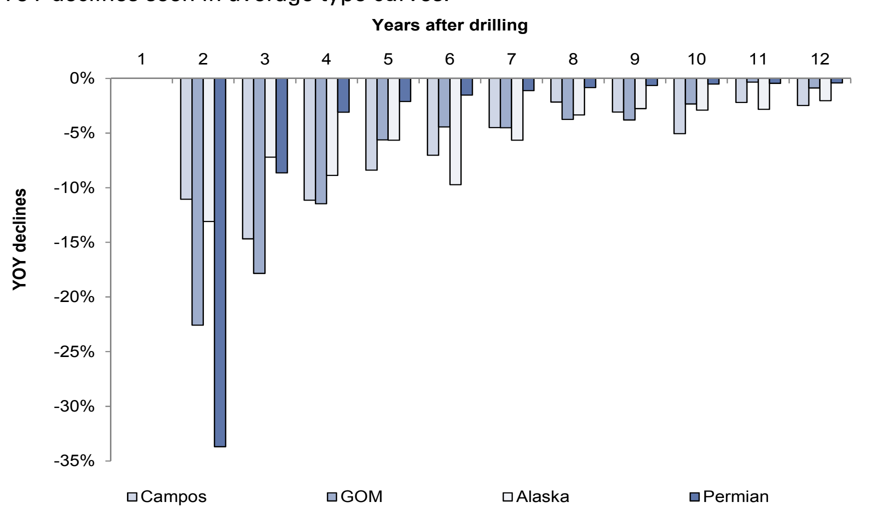
Source: ANP, BOEM, Alaska DoE, Goldman Sachs Global Investment Research

Exhibit 68: …and longevity, with low decline rates….
Average oil well production rebased to 100% at peak prod in first six months



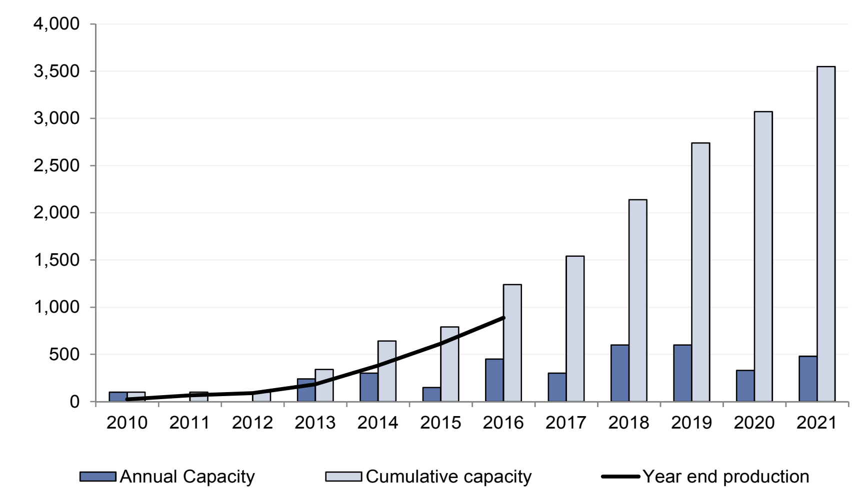
Source: ANP, BOEM, Alaska DoE, Goldman Sachs Global Investment Research

Exhibit 69: …compared with other basins
YoY declines seen in average type curves.



Source: ANP, BOEM, Alaska DoE, Goldman Sachs Global Investment Research

Exhibit 70: Over 4 years, the Santos is adding more prod. capacity than Norway
Santos pre-salt FPSO capacity additions



Source: ANP, Goldman Sachs Global Investment Research.

There are 8 FPSOs currently under construction, taking us to 2020

But Sepia, Libra and Caracara need to be sanctioned to fill in post 2020.

Exhibit 71: Brazil FPSO ramp ups
FPSOs ranked by field deployment and status, showing the number of FPSOs currently under construction.

Name	Field	Number	Oil Capaclty	Gas Capacity	Owner	% Local Content	Status	Date Sanctioned	First Oil	Notes
Angra Dos Reis	Lula		100	177	Modec	65%	Plateau	Aug-08	Oct-10	1st Pre-salt Santos FPSO
Paraty	Lula		120	177	SBM	65%	Plateau	Jul-11	Jun-13	
Marica	Lula		150	212	SBM	65%	Ramp up	Jul-13	Feb-16	
Saquarema	Lula		150	212	SBM	65%	Ramp up	Jul-13	Jul-16	
Lula Sul	Lula	P-66	150	212	Petrobras	65%	Ramp up	2010	May-17	1st Replicant
Lula North	Lula	P-67	150	212	Petrobras	65%	Construction	2010	-	Should be concluded in 4Q2017
Lula Extreme South	Lula	P-69	150	212	Petrobras	65%	Construction	2010	-	In integration process; to finish in 1H2018
Lula West	Lula		150	212		65%	Feasability			Difficult reservoir
Mangaratiba	Iracema		150	283	Modec	65%	Plateau	Sep-11	Dec-14	
Itaguai	Iracema		150	283	Modec	65%	Plateau	Mar-12	Jul-15	
Atapu	Iara	P-70	150	212	Petrobras	65%	Construction	2010	-	Hull is being constructed in China; to be ready in 2H2017
Atapu South	Iara		150	212						
Berbigao	Iara	P-68	150	212	Petrobras	65%	Construction	Aug-12	-	Hull delivered in Dec-16 to start integration
Sururu	Iara		150	212			Feasability			Tight reservoir needing further work
Sao Paulo	Sapinhoa		120	177	Modec	55%	Plateau	Aug-10	Jan-13	
Ilha Bela	Sapinhoa		150	212	SBM	55%	Plateau	Mar-12	Nov-14	
Caraguatatuba	Lapa		100	177	Modec	40%	Ramp up	Dec-13	Dec-16	Ramping
Buzios I	Buzios	P-74	150	245	Petrobras	65%	Construction	Apr-13	-	FPSO scheduled to come to Brazil late 2017
Buzios III	Buzios	P-75	150	245	Petrobras	65%	Construction	Sep-13	-	Undergoing integration process in Asia
Buzios III	Buzios	P-76	180	245	Petrobras	65%	Construction	Apr-13	-	Undergoing integration; to end in 2H2017
Buzios IV	Buzios	P-77	150	245	Petrobras	65%	Construction	Sep-13	-	Undergoing first integration process
Buzios V	Buzios		150	245						Tender expected to be awarded Sept.2017
	Sepia		150	245		80%	Pre-sanction			Tender expected to be awarded mid 2017
	Libra		180	245		70%	Pre-sanction			ANP reduced local content demand by 50%
	Libra		180	245		70%	Pre-sanction			ANP reduced local content demand by 50%
	Libra		180	245		70%	Pre-sanction			ANP reduced local content demand by 50%
	Carcara		150	245			Pre-sanction			Pending unitisation of BM-S-8 with unlicenced acreage

Source: Company data, Goldman Sachs Global Investment Research.

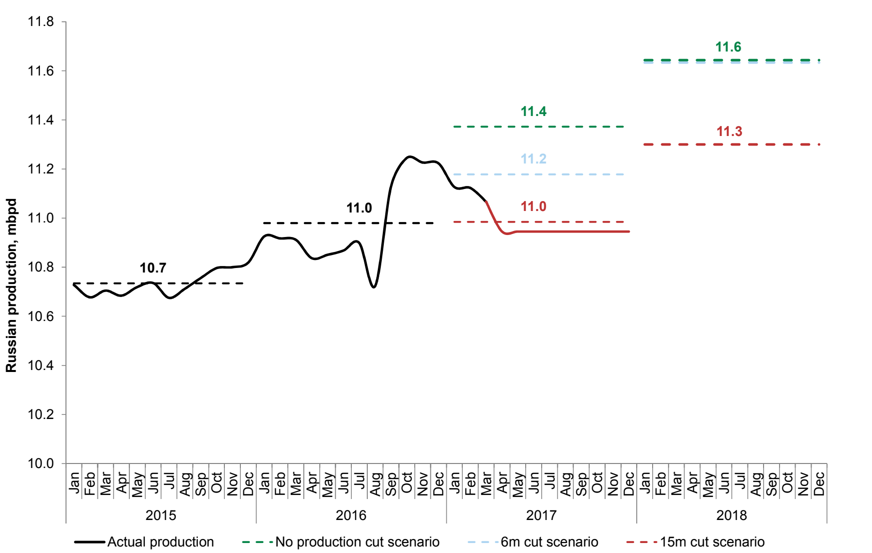
Russian production potential remains significant, but ramp-up post the cut might be slow

Russian production growth potential remains significant, in our view, once the cuts end. This is due to improving brownfield mechanics and additional greenfield start-ups in East Siberia. Without the production cuts, we think production capacity in Russia would reach c.11.4 mbpd in 2017 (+3.2% YoY) and 11.6 mbpd in 2018 (+2.4% YoY). Despite this, once the production cut is cancelled, we do not believe Russia production will immediately return to the level it would be if there was no cut. Due to companies' internal planning, budget allocations and speed of response, we believe that production recovery will be gradual and relatively slow. With production staying at current levels till March 31, 2018, we estimate Russian production to average 11.3 mbpd in 2018, c.300 kbpd lower than our estimated 2018 production potential if there was no cut.

The Khanty Mansiisk Autonomous Okrug accounts for 44% of Russian production – over 4.8mnb/d. It is home to two of Russia's four largest fields (Priobskoye and Samotlor) as well as Russia's largest production subsidiary, Rosneft's Yuganskneftegaz. In aerial terms, Khanty Mansiisk is larger than Spain or Thailand. While it is mature (production peaked in the mid-1980s), it holds c.60% of Russia's oil reserves in generally thin, laterally extensive reservoirs. Production should be seen as a function of number of wells.

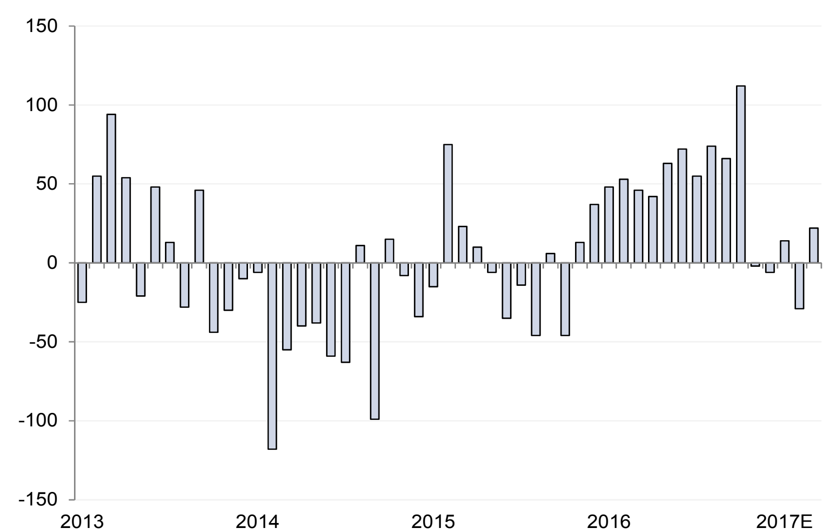
The intensity of drilling at Khanty Mansiisk increased sharply through 2016, reaching record levels in Autumn, before falling over winter 2016-17 (due to an unusually cold winter). However, recent months again show an uptick in drilling activity, leading to renewed year on year increases, as seen in Exhibit 73. Consequently, we think Khanty Mansiisk is unlikely to see an acceleration in declines, and could potentially trend back to mom growth (as was seen through the second half of 2016 and March 2017).

Exhibit 72: Russia's production outlook remains robust, though recovery post the cut might be relatively slow…
Russian production paths by scenario in mn b/d



Source: CDU TEK, Goldman Sachs Global Investment Research.

Exhibit 73: …and will depend largely on how quickly Russian oil companies ramp up drilling activity at brownfields
YoY change in number of wells drilled monthly in Khanty Mansiisk



Source: CRRU, Goldman Sachs Global Investment Research.

Russia: Tax developments support upstream but are negative for refining

We expect the tax reform for the Russian oil industry (so called "tax maneuver") to continue. The tax maneuver increases the tax burden on refining as well as reducing the domestic subsidy (through reducing the export duty). At the same time, the tax maneuver keeps flat or reduces the tax burden on the upstream industry (see *Blessing in disguise v.2: Production growth, tax reforms accelerate,* October 19, 2016 for more detail).

Historically, refining and consumers were indirectly subsidized by lower taxes (i.e. lower net backs), effectively funded by the upstream industry. Refining was subsidized via lower export duty rates for oil products vs crude oil, and consumer through lower domestic fuel prices, determined as the international price net of export duty for product. However, tax reform eliminating this misbalance has started and will continue, in our view.

Removal of the refining and consumer tax subsidies and the simultaneous reduction of the upstream tax burden could boost upstream profitability, while keeping the government's take from the industry unchanged; consumers and refining, not the government, would therefore fund the expected increase in upstream profitability. A lower upstream tax burden would make currently stranded reserves commercially recoverable, which would boost production and export volumes, helping the country to sell more oil on international markets.

Exhibit 74: We expect tax reform to continue, supporting upstream and eliminating the tax subsidy to refining

Estimated effects of the tax maneuver 2015-17 and our expected end point for Russian oil & gas economics and taxation (US$/bbl)

	2015	2016	2017E	End point
Upstream economics per bbl				
Crude price	51.6	42.2	50.0	50.0
US$/Rub	61.0	63.0	60.0	60.0
Crude ED	*15.2*	*11.2*	*11.5*	*0.0*
Marginal ED rate, as % of oil price	42%	42%	30%	0%
Crude MET	*14.7*	*12.2*	*17.6*	*29.1*
Base MET rate, Rub/ton	766	857	919	1,585
Total taxes	29.9	23.4	29.1	29.1
OPEX & SG&A	3.1	3.0	3.2	3.2
Transport	4.0	3.9	3.9	3.9
EBITDA upstream	**14.6**	**11.9**	**13.8**	**13.8**
Downstream economics per bbl				
Products basket price	52.5	43.1	50.9	50.9
Crude netback	32.5	27.1	34.6	46.1
OPEX & SG&A	2.8	2.7	2.9	2.9
Transport	4.5	4.4	4.4	4.4
Products ED	10.4	7.2	7.2	0.0
EBITDA downstream	**2.4**	**1.7**	**1.8**	**-2.5**
Government take				
MET taxable crude production, mnt	490.0	487.8	487.8	487.8
Additional taxable crude production, mnt	-	-	-	19.0
Taxable crude export, mnt	202.1	202.1	202.1	202.1
Taxable products export, mnt	169.7	155.0	155.0	155.0
MET, US$ bn	52.6	43.6	62.6	103.7
MET on additional taxable crude production, US$ bn	-	-	-	1.6
Crude export duty, US$ bn	22.4	16.6	17.0	0.0
Products export duty, US$ bn	12.8	8.2	8.1	0.0
Government take, US$bn	**87.9**	**68.3**	**87.7**	**105.3**

ED eliminated which is compensated by higher MET

Upstream profitability remains the same

Refineries require upgrades in order to remain profitable (will make loss at current slate)

Government take increases which can partially be used to reduce tax burden on upstream

Source: Russian Ministry of Finance, Russian Tax Code, Goldman Sachs Global Investment Research.

Russia: FX a blessing which has already played out

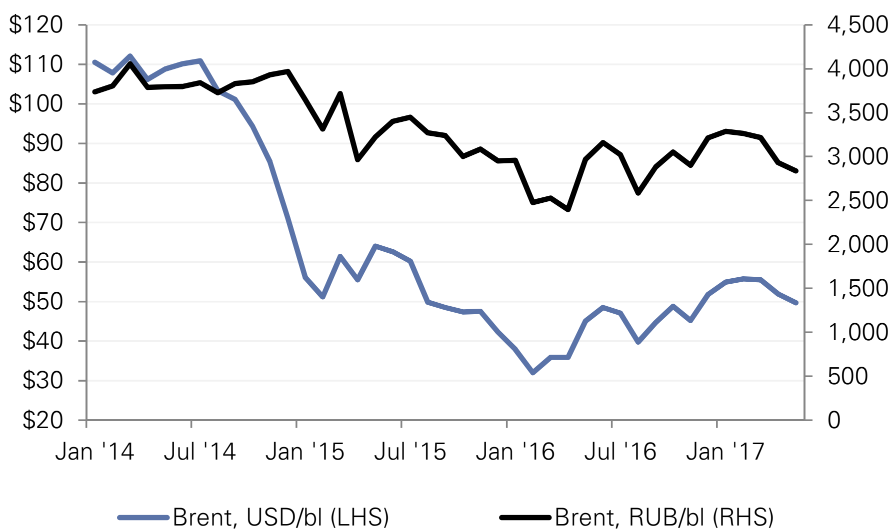
Russia has a predominantly rouble-denominated cost base. Consequently, the sector saw an extraordinary reduction in costs in 2014-16 along with the currency's sharp depreciation. However, since the OPEC production cuts, the rouble has strengthened, partially eroding some of the gains.

Despite the recent strengthening, Russian well costs are down c.45% since 2014, and this has helped underpin continued high levels of activity across the industry.

When the rouble's correlation to the oil price is taken into account alongside the Russian tax regime, we see the Russian upstream industry as broadly unaffected by oil price changes from US$15/bl-US$100/bl, consistently earning around US$4-6/bl after costs.

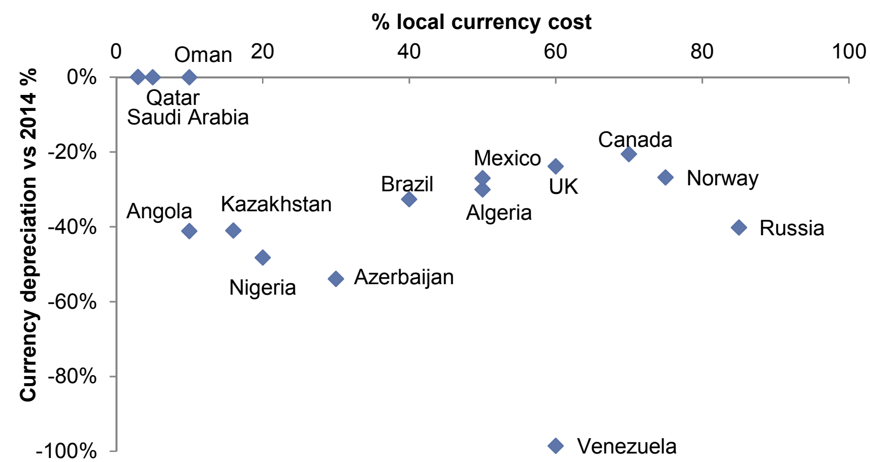
This has enabled the Russian industry to continue to invest in both brownfield activity and frontier greenfield regions.

Exhibit 75: While Brent is down c.55% since 2014, a barrel in rouble terms is only down 25%, cushioning the impact
Brent price (US$/bl) in USD (LHS) and in roubles (RHS)



Source: Datastream

Exhibit 76: Russia has one of the largest domestic cost-based operations, but has also seen a sharp currency depreciation
% local cost vs currency depreciation



Source: Goldman Sachs Global Investment Research.

Russia: East Siberia – scale overlooked

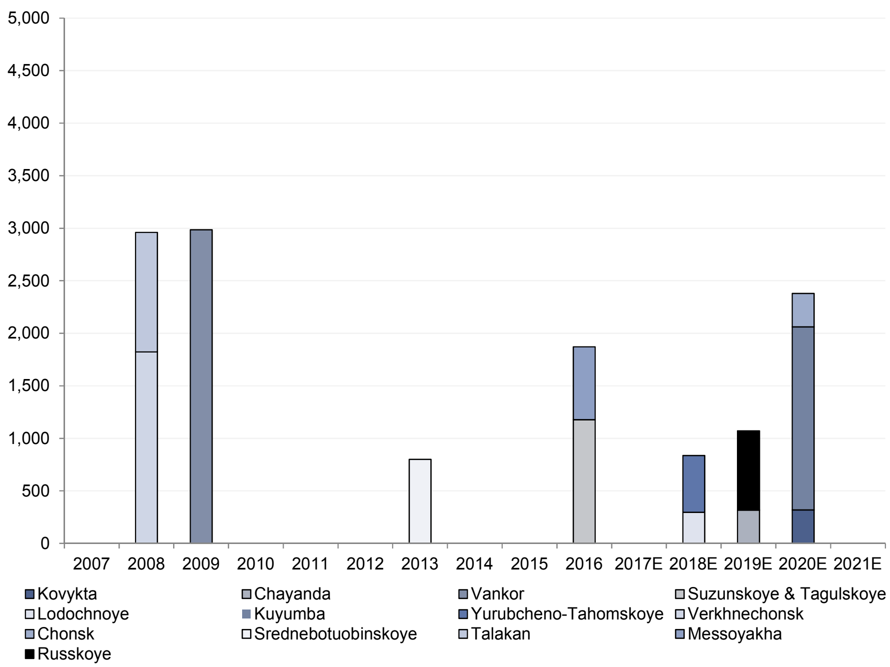
Since the opening of the ESPO pipeline in 2009, two areas of East Siberia have been opened to production. In 2018, we expect a third – the Evenkia cluster containing the potentially super-giant Yurubcheno Tokhomskoye and Kuyumba fields.

With the Vankor cluster broadly at plateau (Vankor in slight decline while Suzun ramping, and Tagul, Russkoye and Lodochnoye are under development), we think the next stage of growth will come from the Irkutsk cluster (Verkhnechonsk, Talakan, Srednebotuoba, Chayanda oil) and the new Evenkia cluster.

These newer fields are technically challenging but hold vast upside. Russkoye and Tagul both have heavy oil, while Yurubcheno Tokhomskoye and Kuyumba have ancient, highly fractured reservoirs. However, all of these fields can be developed with domestic Russian technology.

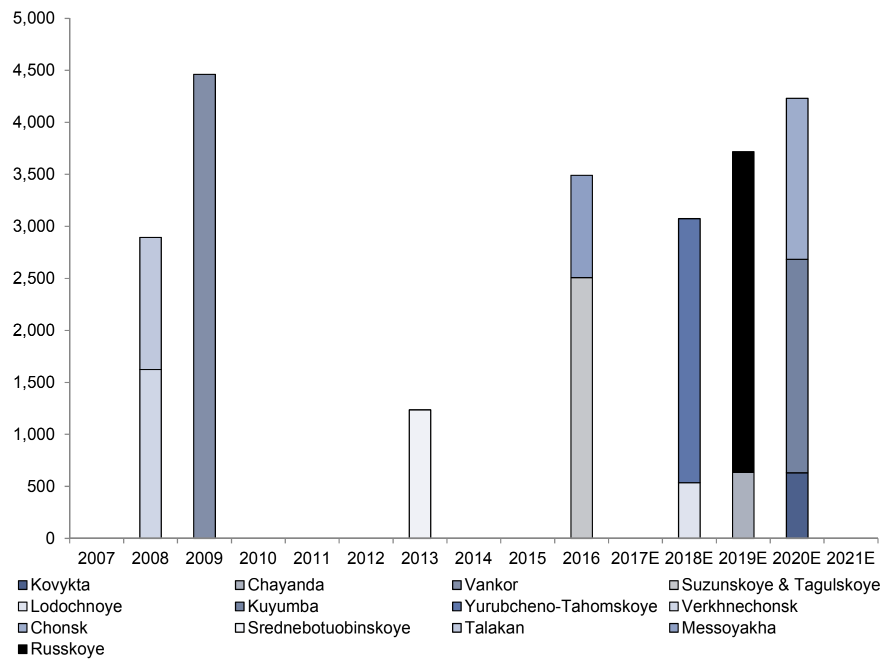
This is best illustrated by our Top Project reserve figures seen in Exhibit 77; we try to align these with what we think can be recovered commercially. However, when we look at the same fields under the Russian ABC1+C2 classification – a measure of what could be technically recovered – the figure is 10bn bls greater. Consequently, we think there could be upside to these new fields.

Exhibit 77: We estimate liquid reserves of 12.9bn bls in East Siberia
East Siberian field reserves in mnbls per Top Projects close to 2P reserves, listed by year of first oil



Source: Goldman Sachs Global Investment Research.

Exhibit 78: But using ABC1+C2 classifications, reserves could be 23bn bls
East Siberian field reserves inmnbls per ABC1+C2 classifications, listed by year of first oil



Source: Company Data, IEA, Goldman Sachs Global Investment Research.

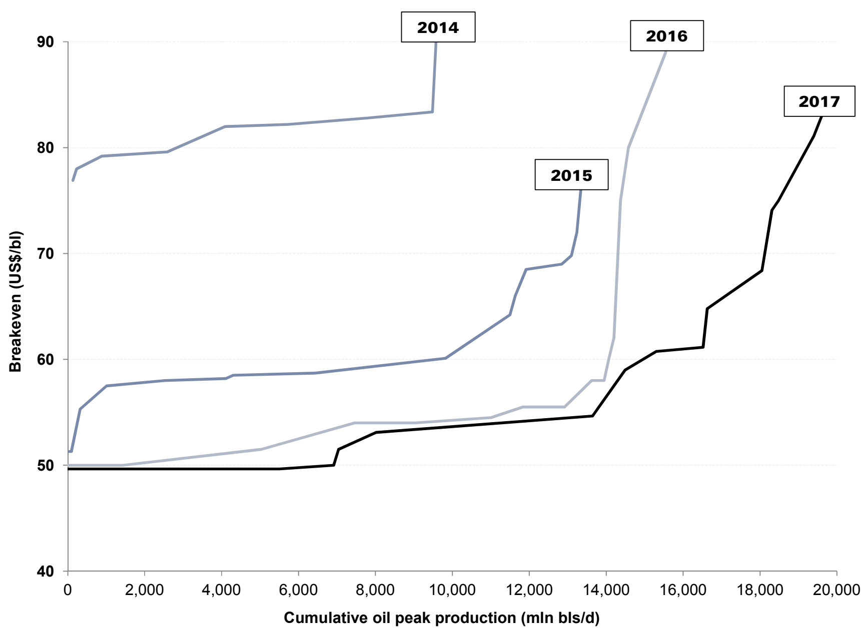
Shale oil to more than double production, even as breakevens flatten out...

On our estimates, shale has added 190 bn bls of oil resources in the past decade, providing US producers a resource base above major OPEC members such as Iran or Iraq. With such an abundance of resource, we expect the four major shale plays (Delaware, Midland, Bakken and Eagle Ford) to grow rapidly, tripling production between 2017 and 2025 to almost 12mnb/d of liquids.

This growth will be underpinned by the Permian basin and its two major sub-basins, the Delaware (in the west) and Midland (in the east). While around 30bln bls have already been produced from conventional reservoirs in the Permian since the 1920s, the majority of this has been on the central high, which separates the Delaware and Midland.

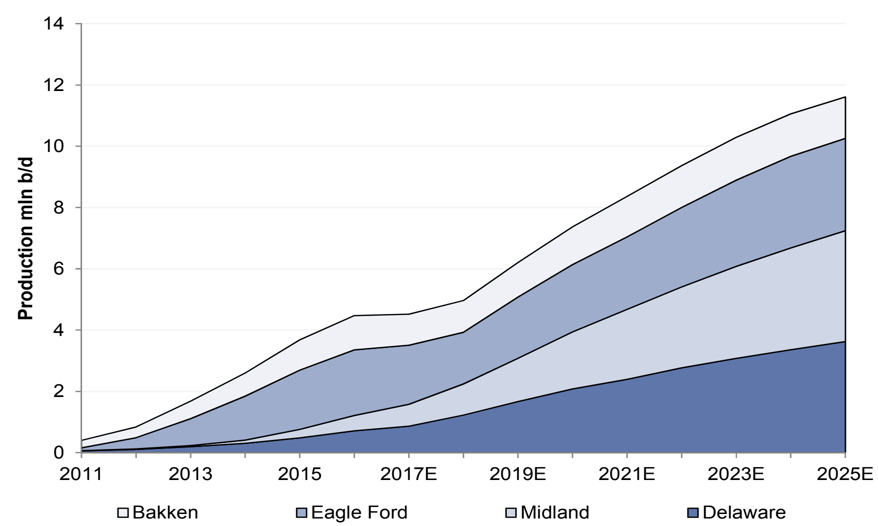
Over the coming years, we expect horizontal fractured wells in the Midland and Delaware to target a number of low permeability but oil saturated formations such as the Wolfcamp A,B,C,D,XY, Bone Spring, Spraberry and Avalon, amongst others. While all of these will not necessarily work in the same location, several likely will. This stacked structure is what sets the Permian apart from the Eagle Ford or Bakken (where generally there is one major target (e.g. Eagle Ford and the Middle Bakken) and potentially another minor target (e.g. the Austin Chalk in Texas and the Three Forks in North Dakota).

Exhibit 79: Shale cost curve has flattened and lengthened...
Shale cost curve through time



Source: Goldman Sachs Global Investment Research.

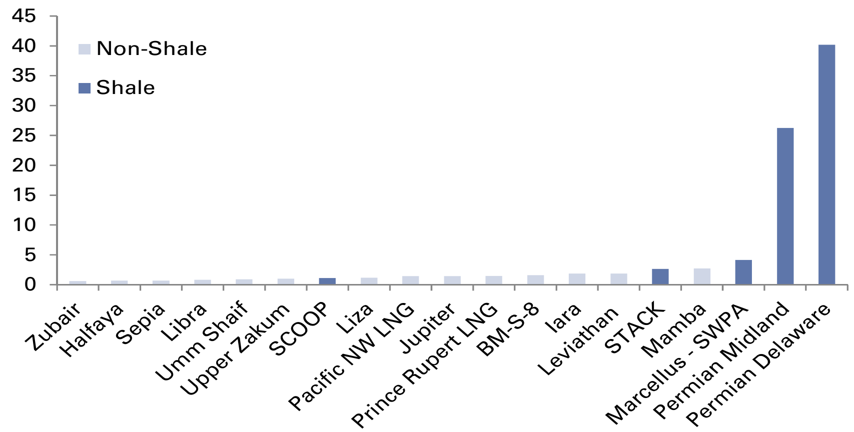
Exhibit 80: ... as the Big 4 shale plays keep increasing in scale and production
Eagle Ford, Bakken, Midland, Delaware oil+NGL production inmnb/d



Source: Goldman Sachs Global Investment Research.

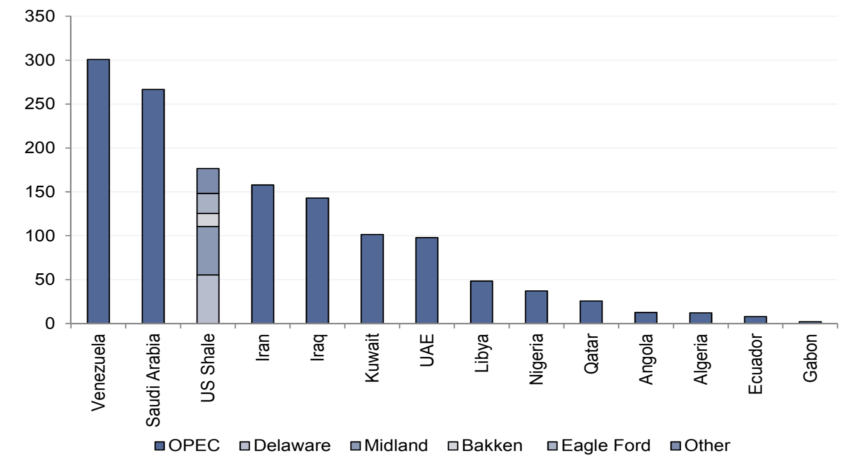
…as shale is underpinned by a resource base above most OPEC members

Exhibit 81: Shale has led the way in yoy volume additions
YOY resource increases in Top Projects in bn bls, 2017 vs 2016



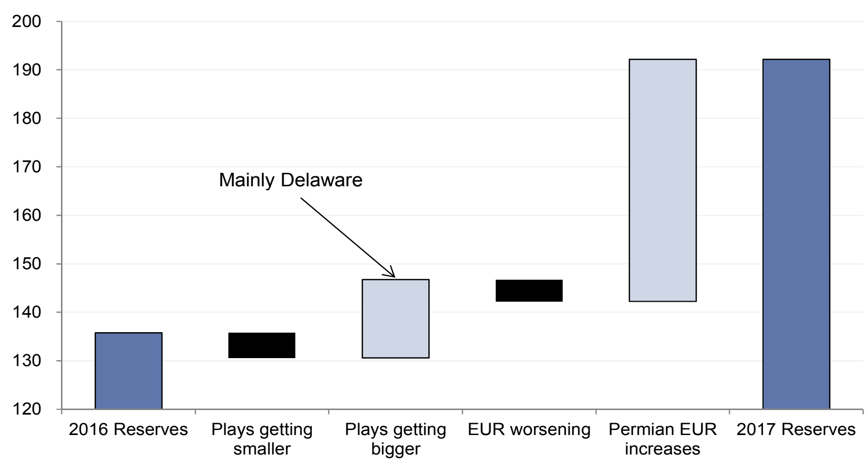
Source: Goldman Sachs Global Investment Research.

Exhibit 82: Shale resources would now constitute a major OPEC country
Reserves of OPEC members and our estimate of shale resources, bn bls (2016)



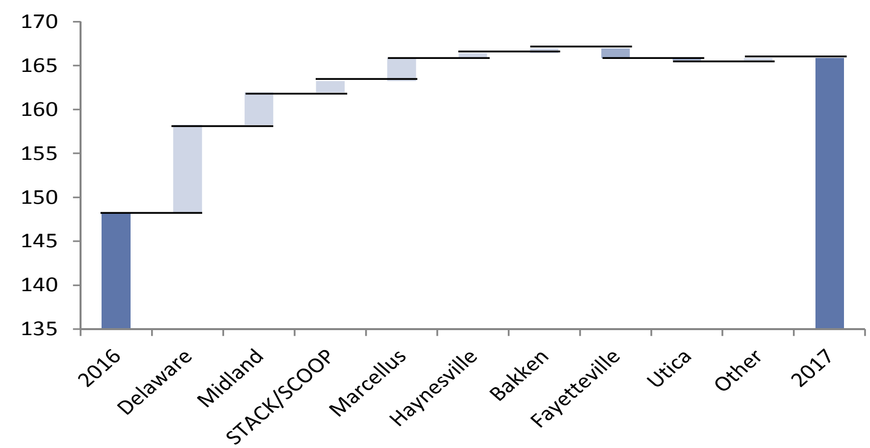
Source: BP Statistical Review of the Year, Goldman Sachs Global Investment Research.

Exhibit 83: Increased recovery rates per well in the Permian have driven…
Total recoverable volume in billion boe from the Big 4 liquid plays (includes associated gas)



Source: Goldman Sachs Global Investment Research.

Exhibit 84: ... the bulk of the increase in shale oil resources vs. last year
Causes of change in liquid reserves 2017 vs 2016 by play in bn bl



Source: Goldman Sachs Global Investment Research.

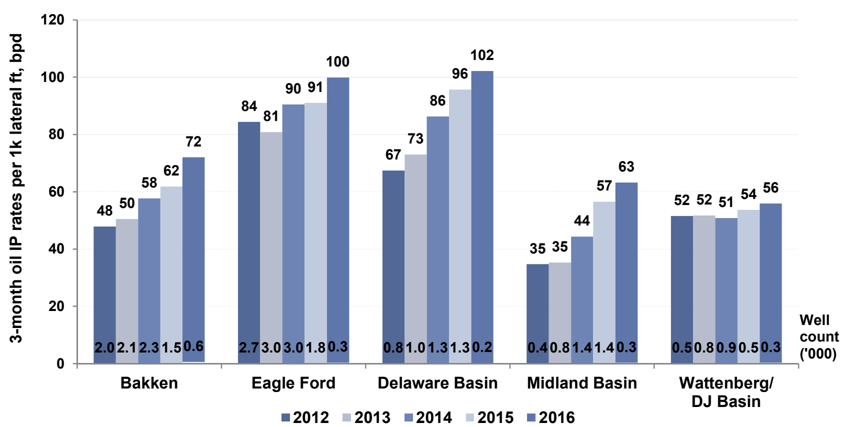
Productivity improvements in shale show little sign of slowing, outside the Eagle Ford

Our most recent analysis of well type curves shows 33%-35% improvements yoy (2016 vs 2015) in the Permian Basin. The Delaware sub-basin has been a true stand-out and continues to shows 6% improvements in 3-month IP rates (post lateral length adjustment), and more impressively 13% yoy improvements in the 9-month IP rates (again post lateral length improvements), showing growth for the fifth year running. We view the Delaware as the least mature of the major shale basins, and as such we think it has potentially the greatest upside. Even the relatively mature Bakken saw c.12% improvements in year 1 EURs (2016 vs 2015).

In our view, this improvement across the board is driven by both structural factors (longer laterals [although we strip them out in the charts below], better fracture placement) and non-secular productivity gains such as high grading (which may unwind if activity ramps up significantly).

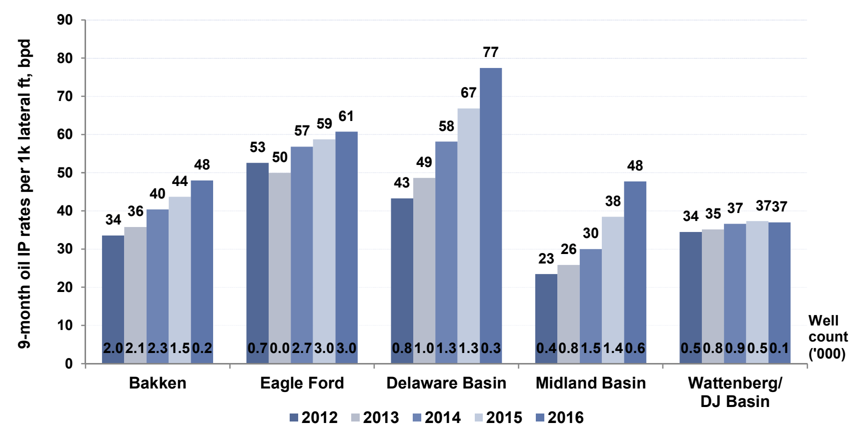
In the case of the Eagle Ford, we think that excluding high grading and lateral length extension, the EUR's degraded between 2014 and 2016 is due to the operators with the highest quality acreage and most advanced completions reducing operations. In our view, 2017 should see some of these operators return, and if EURs do not increase, it could suggest that the play is significantly more mature than we expect.

Exhibit 85: Delaware Basin lateral-adjusted oil rates continue to stand out
3-month oil IP rates adjusted for lateral length by play; note our analysis does not take into account potential differentiation in cost structure among plays, or the impact of high grading



Source: Goldman Sachs Global Investment Research.

Exhibit 86: Both Delaware and Midland Basin productivity accelerated in 2015
9-month oil IP rates adjusted for lateral length by play; note our analysis does not take into account potential differentiation in cost structure among plays, or the impact of high grading



Source: Goldman Sachs Global Investment Research.

LNG: With capacity being added, the ramp will now start…

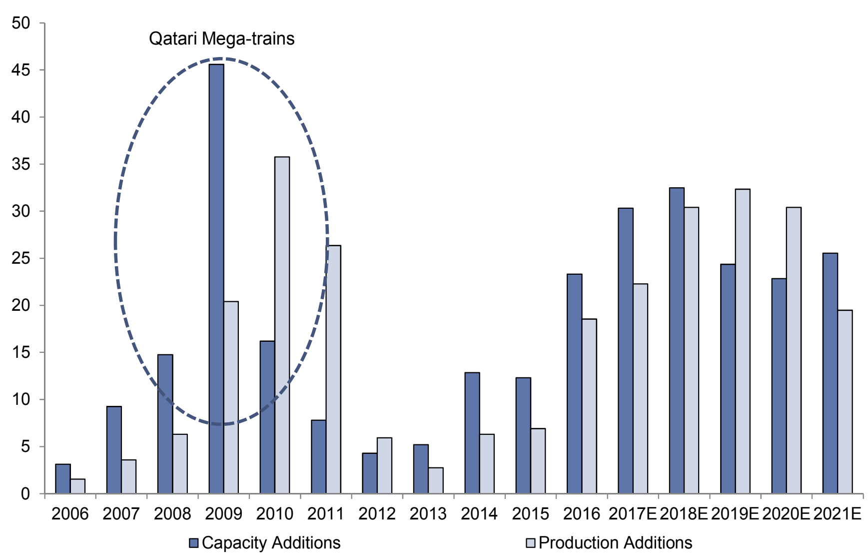
Following on from the successful Qatari LNG mega-projects, 2010-15 saw a boom in LNG sanctioning. Australian players sanctioned c.62mtpa of LNG capacity in 2009-14, while the US saw c.55mtpa sanctioned (2012-15).

After a number of delays and cost over-runs, these mega-projects are now being delivered and ramping up. We expect the LNG market to tip into oversupply in 3Q17, bringing 20-40mtpa of surplus LNG in 2018 and 2019, respectively. We expect ramp-ups to add c.16mtpa, start-ups (including Sabine Pass T3, Gorgon T3, Prelude and Wheatstone T1) a further 9mtpa in 2017. This will, on our estimates, outstrip demand growth by c.8mtpa. We expect the imbalance in supply/demand growth to worsen in 2018, with 19mtpa of additional supply from ramp-ups and 12mtpa of new starts, almost double our expected demand growth.

The bulk of additions through 2020 will come from Australia and the US, with lesser volumes from Russia (Yamal) and the eponymous Angola LNG. In Australia, we expect Wheatstone, Prelude and Ichthys (all starting up in 2017/18E) to add 44mtpa of supply through 2020.

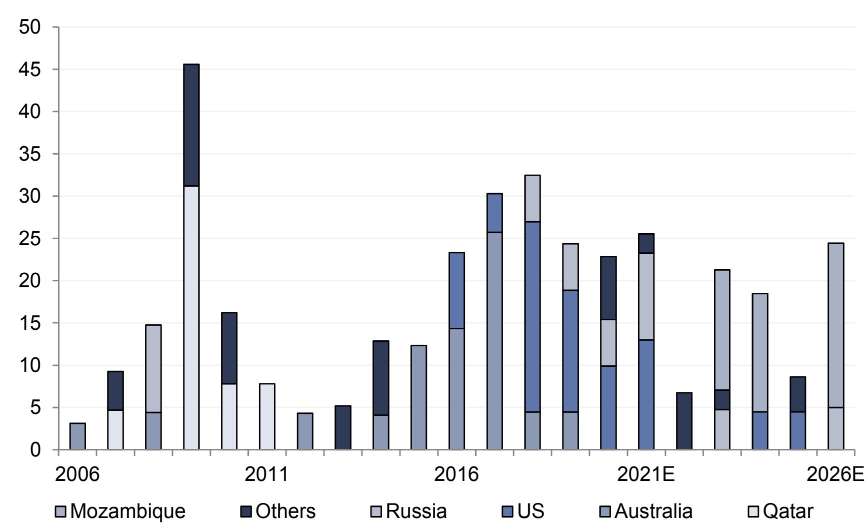
With huge capital costs behind them, and relatively low cash costs from first production, these Australian projects are incentivized to run at capacity to maximize cash flow. We also note numerous LNG projects have seen debottlenecking. In the US, the ramp-up of Sabine Pass, Cameron LNG, Cove Point, and Freeport LNG between 2016 and 2021, will add a cumulative 73mtpa of LNG. We believe most excess LNG will be sent to Europe due to availability of spare regasification capacity.

Exhibit 87: The LNG capacity has arrived and is now being filled
Annual increase in LNG production/capacity in mtpa



Source: Company Data, Goldman Sachs Global Investment Research.

Exhibit 88: Australia has added the volume to date, but the focus will switch to the US for the rest of a decade
LNG capacity additions by country in mtpa



Source: Company Data, Goldman Sachs Global Investment Research.

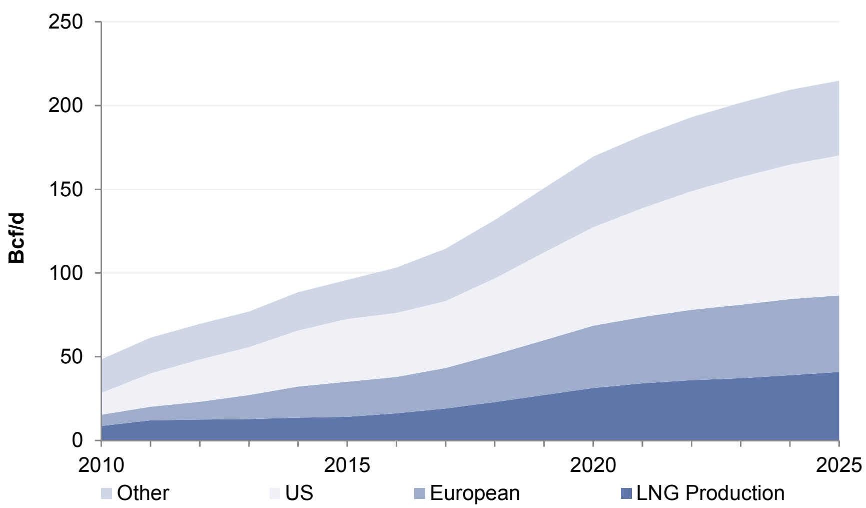
...while the pipeline of piped gas keeps increasing the pressure...

In a situation not entirely different to that faced by OPEC in 2014, we see major pipeline gas producers having to make a choice in the near future: do they reduce production to maximize the value per molecule or maintain or increase production to reduce prices while keeping LNG out of key markets?

Historically, the companies have rarely exported at full capacity, instead trying to balance the market and achieve the best pricing per molecule. The expansion of LNG will, in our view, force low-cost gas producers to choose between maintaining volumes or restricting shipments to maintain higher prices. We believe it is most likely that low-cost producers will defend their market share, as higher prices might incentivize further LNG capacity additions.

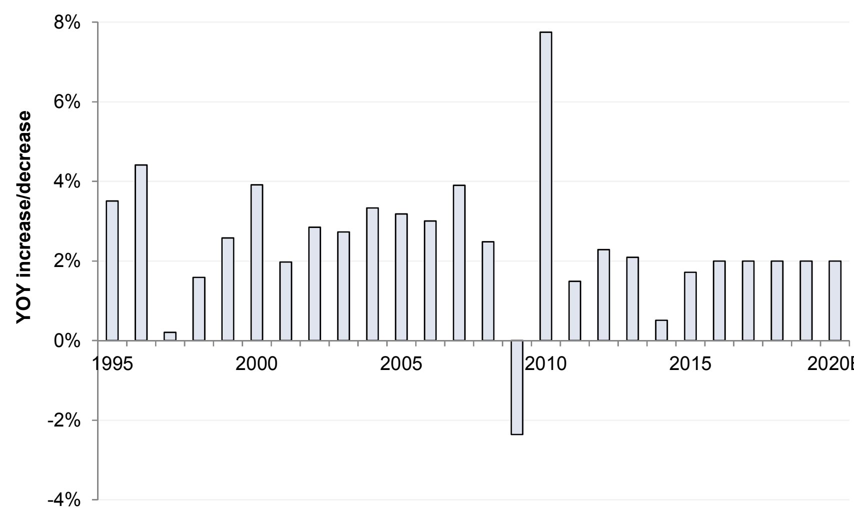
This comes against a backdrop of major piped gas producers significantly increasing capacity. We expect the bulk of volume growth to come from Russia, Egypt and the US. Russia is expanding its gas export capacity to Europe by >30% by North Stream 2 and Turkish Stream, expected to come onstream in 2019-20. Planned pipeline gas additions from Algeria and central Asia will add an additional c.40 bcm capacity to Europe. New gas projects in the Mediterranean, such as Zohr, Nooros and Tortue, will expand gas supply in Egypt and meet demand in the region, which we expect to lower imports of LNG. Additional gas developed in South Pars we believe will be used in the domestic market due to the current lack of export infrastructure.

Exhibit 89: While LNG production is increasing rapidly, we also see conventional resources accelerating
Growth seen from Top Projects



Source: Goldman Sachs Global Investment Research.

Exhibit 90: Over the past few years, we have rarely seen demand growth of more than 2.5% below historical levels
Annual global gas consumption yoy increase/decrease in %



Source: BP Statistical Review of the Year, GIIGNL, Goldman Sachs Global Investment Research

…which means more volumes at lower prices

Since 2010, the gas cost curve has lengthened significantly, but not seen the lowering observed in the oil cost curve. There are several reasons for this:

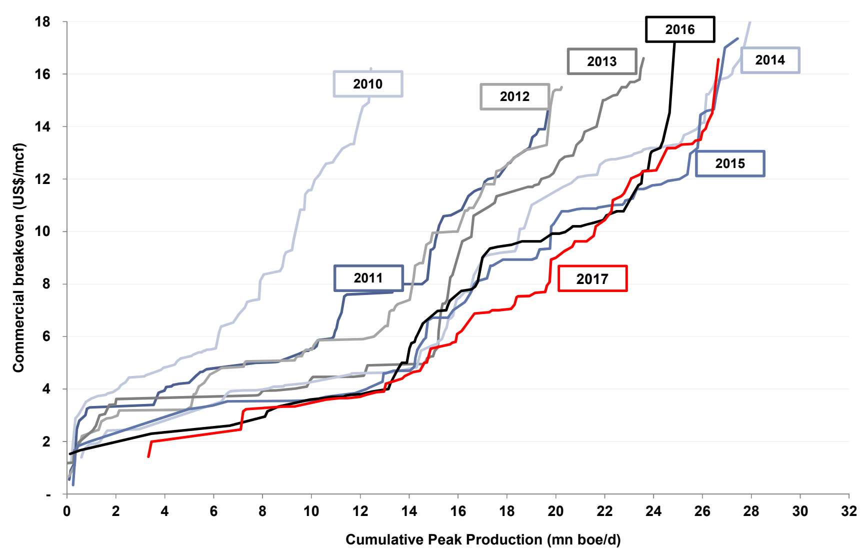
1) The US shale gas boom occurred earlier (from 2005 onwards), so is already partially captured in the 2010 curve. Of the improvements seen recently, most have come from the Marcellus which now breaks even at US$2/mcf.

2) Gas markets are less connected, meaning regional gas prices (many of which are still regulated) vary significantly and do not have the international benchmarks seen in oil. It also means regional supply and demand can be out of kilter to a much greater degree.

3) Two new projects were added in Egypt this year – Atoll and Nooros – which, along with Zohr, are attractive greenfield opportunities with regulated gas prices.

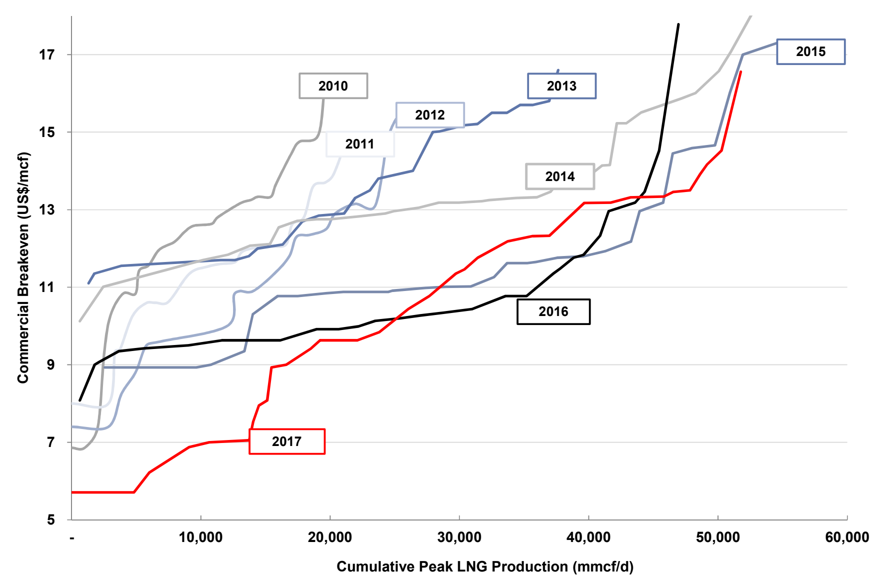
The LNG cost curve has improved more materially over time, driven by the addition of low cost US brownfield LNG projects. This year, we saw material improvement in breakeven from non-US projects such as Mamba and Golfinho-Atum, and from the addition of new projects, such as Tortue, at the bottom of the cost curve. On the other hand, delays and cost overruns increased the breakevens of a number of already high-cost projects in Australia and Canada, such as Scarborough, Evans Shoal and Kitimat LNG. We expect lower-cost LNG supply growth to come from the US.

Exhibit 91: The gas cost curve has lengthened….
Piped gas cost curve in US$/mcf



Source: Goldman Sachs Global Investment Research.

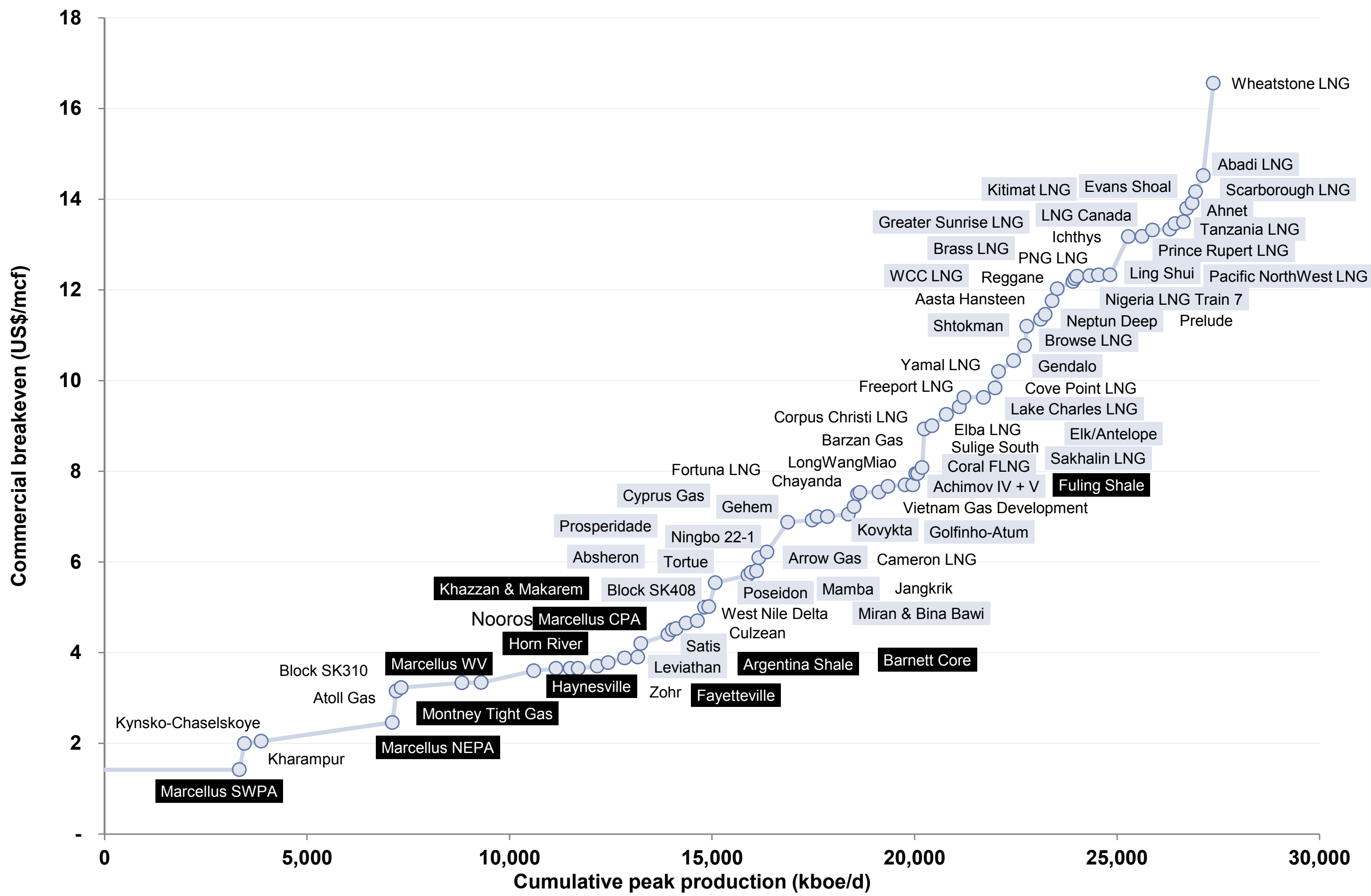
Exhibit 92: …while the LNG cost curve has come down
LNG cost curve in US$/mcf



Source: Goldman Sachs Global Investment Research.

Gas cost curve

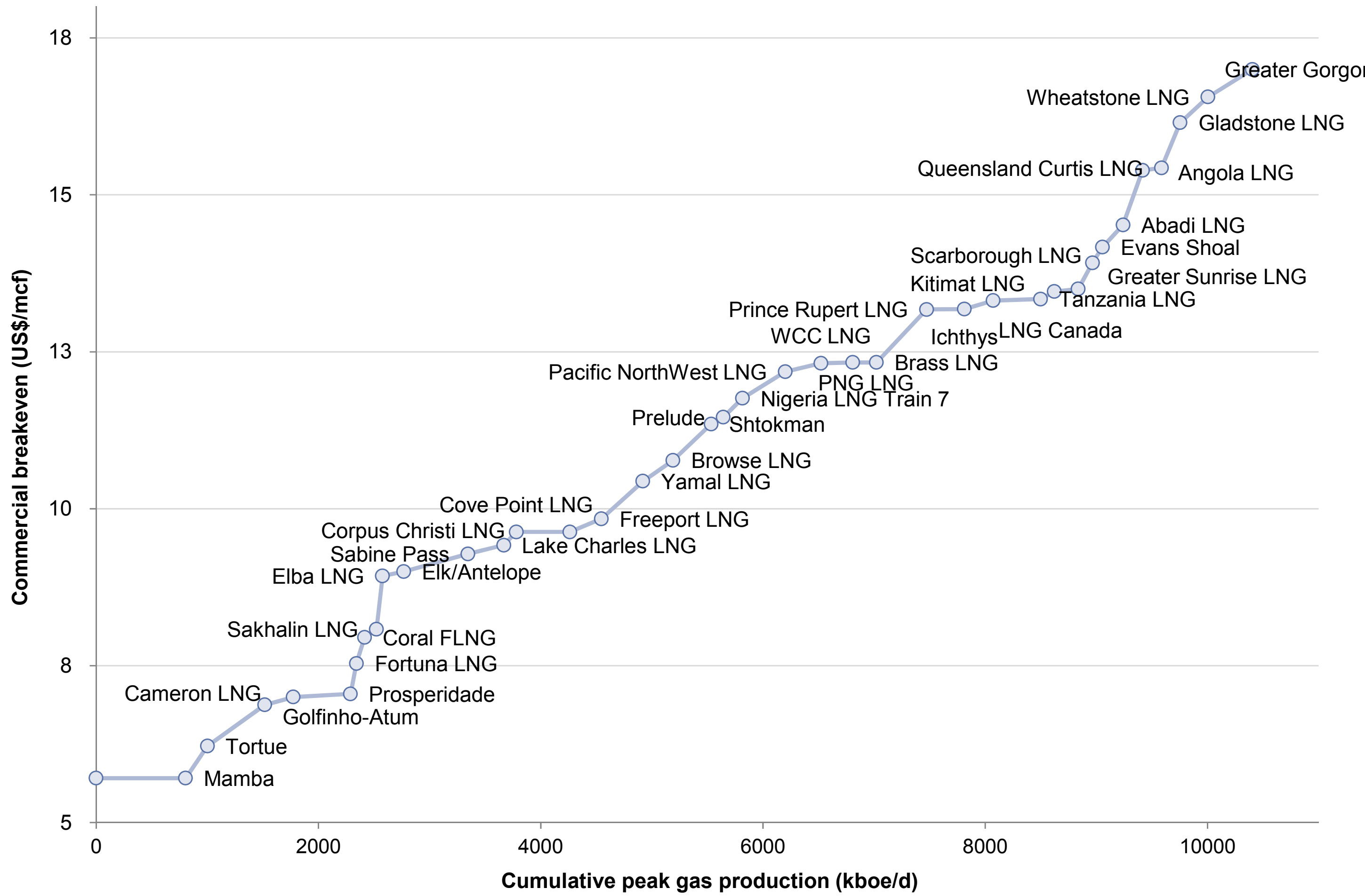
Exhibit 93: Unlike shale oil, shale gas is at the bottom of the cost curve
Shale gas cost curve with pre-sanction projects highlighted in light blue and shale plays in black



Source: Goldman Sachs Global Investment Research.

LNG cost curve

Exhibit 94: Mozambique dominates at the bottom of the cost curve
LNG cost curve by project



Source: Goldman Sachs Global Investment Research

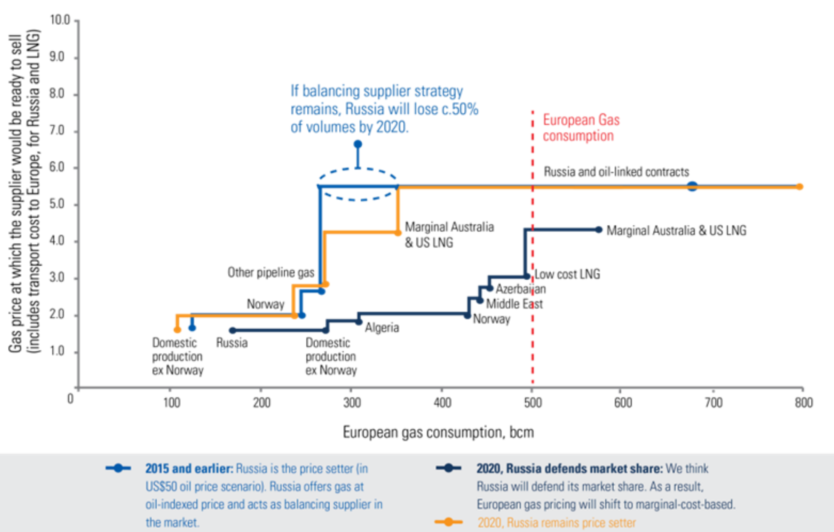
Russia’s response to LNG means lower-for-longer gas prices in Europe

With the rise of LNG capacity around the world, we expect to see substantial surplus of supply over demand. In our view, this surplus will be directed to Europe, the only region where LNG can attract consumers by competing with pipeline gas and which also has vast spare LNG regasification capacity, equivalent to >20% of European gas consumption. The reaction of pipeline gas producers (specifically in Russia) to rising LNG supply will determine the future of gas pricing in Europe.

Russia, Europe’s largest gas supplier (historically 35% of European consumption), has historically been the balancing supplier in the European gas market. Gas pricing in its contracts is based on oil-indexation, and effectively Russia has set the marginal price of gas supply to Europe. In our view, Russia has held a de-facto quasi-OPEC position in the European gas market. Its production and pipeline transportation capacity is substantially underutilized, supplying far less gas to Europe than it is physically and economically able to.

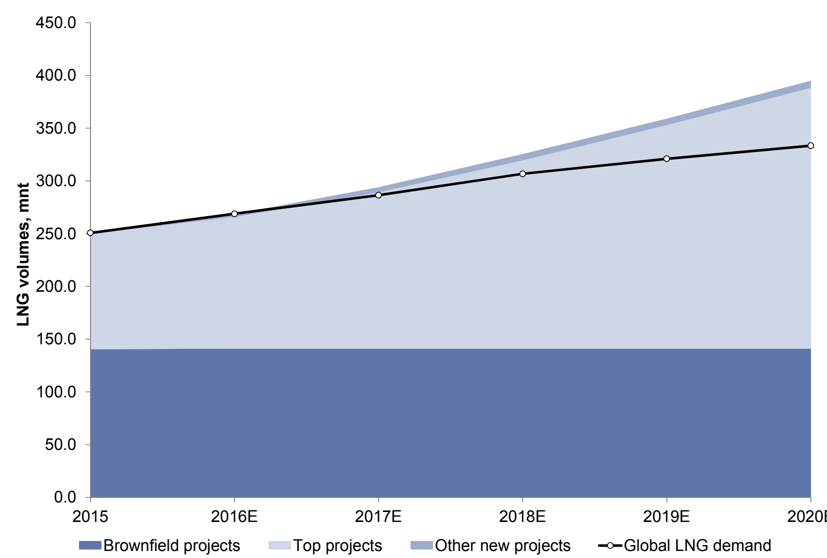
The shale revolution in the US led to a boost of gas production in the country, turning it from an LNG importer in the mid-2000s to a LNG exporter today. As a result, shale gas is transforming the global gas market and disrupting Russia’s balancing supplier role in Europe. With the rise of LNG supply, Europe will be presented with an alternative supplier, and Russia will be faced with a choice: whether to lower supply and help keep European gas prices aligned with oil-indexation, or to defend its market share and accept a lower price (we estimate that this price would be at less than US$4.5/mcf). We believe Russia will have to choose the second option. In this context, gas prices will likely decouple from oil, staying low enough to keep incremental LNG out of the European market.

Exhibit 95: Russia has been acting as the balancing supplier in the European gas market; we expect the European gas market pricing mechanism to move to a marginal cost-based one…
Cost curve for marginal gas suppliers to Europe



Source: IEA, IHS, Goldman Sachs Global Investment Research

Exhibit 96: …as a rise of LNG supply from Australia and US will keep the LNG market oversupplied starting from 2017-18 with the excess volumes heading to Europe
Global LNG supply/demand dynamics, mnt



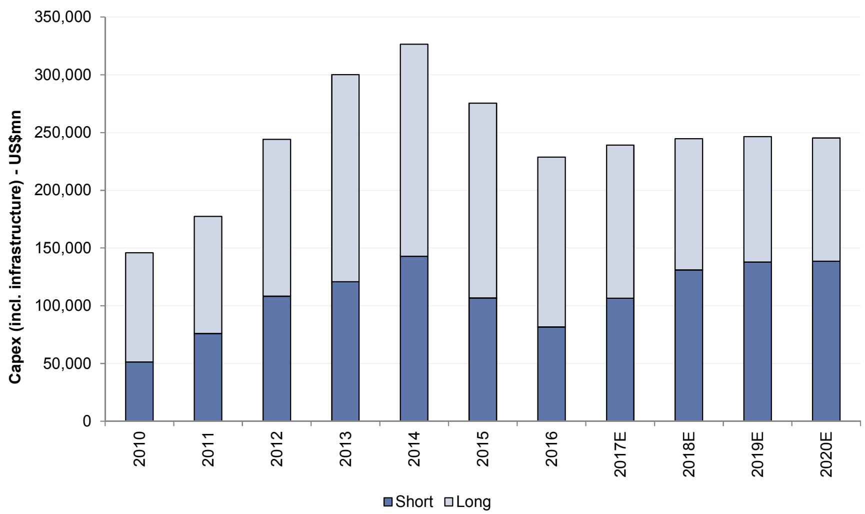
Source: IEA, IHS, Goldman Sachs Global Investment Research

Adapting to the New Oil Order: Short-cycle developments drive incremental activity

The shale revolution has altered the capex make-up of the oil & gas industry. We have seen short-cycle capex (up to two years from FID to first oil, and unconventional) double since 2010, while long-cycle capex has risen only 40% in the same timeframe. Short-cycle investment in oil & gas fell sharply with the oil price in 2014-16, reaching a trough in 2016, according to Top Projects. With the oil price increases, we have seen a huge rise in rig usage and activity is recovering at a rate which may push the market into oversupply in 2018.

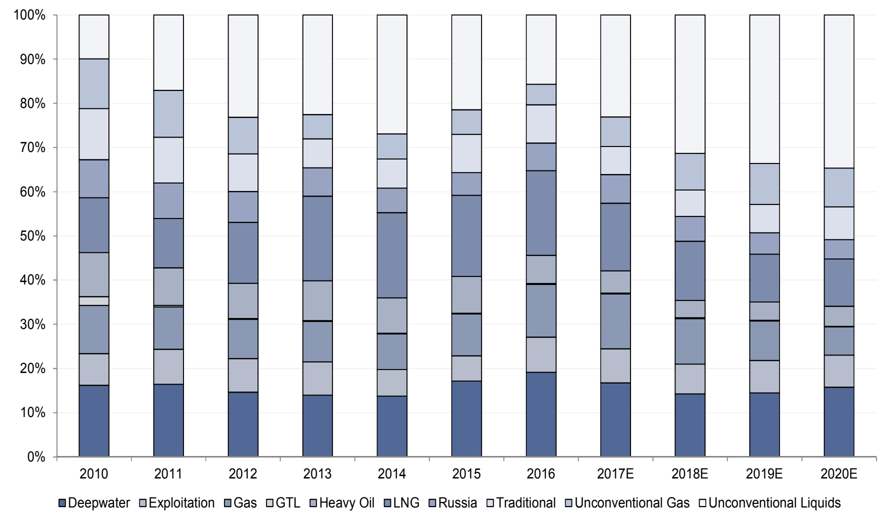
Comparing 2010 and 2020E, we expect investments towards unconventional projects to increase from 10% of global capex to c.35% based on our Top Projects database. Meanwhile, the portion of capex on LNG and heavy oil has dropped materially over the past years, as major building projects in Canada (heavy oil) and Australia (LNG) have reached completion. As a result of a lower-for-longer oil price environment, we do not expect a return to the previous levels of LNG and heavy oil spending, although the best projects will continue to be sanctioned and built.

Exhibit 97: Investments towards short-cycle projects expected to almost double by the end of the decade
Top Projects capex (incl. infrastructure), split by short/long cycle, over time



Source: Goldman Sachs Global Investment Research.

Exhibit 98: Investments in unconventional projects set to take more weight in the industry mix
Top Projects capex (incl. infrastructure), split by winzone, over time



Source: Goldman Sachs Global Investment Research.

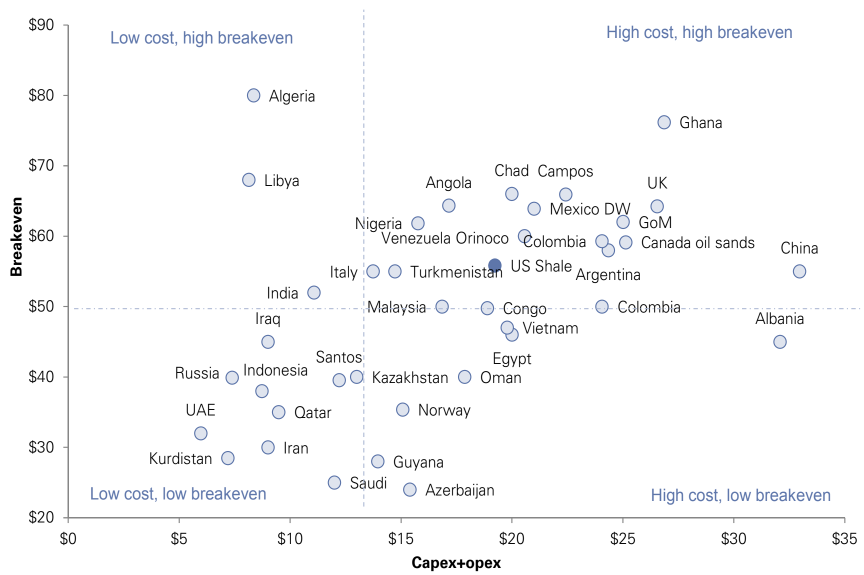
Low-cost countries may become ever more important for IOCs in the medium term

We have seen an extraordinary evolution of the global cost curve. This is the result of the industry's race to make projects competitive with shale. Today even select projects in the Arctic (albeit not ice-covered Arctic) can compete with shale and display breakevens of below US$50/bl.

The scale of the shale resource, potentially yielding 20mn b/d of liquid production (and 75% economic at below US$60/bl), dwarfs all else. Even global deepwater projects "only" get to 12.5mn b/d, with only 54% economic at US$50/bl, and 4mn b/d uneconomic at US$60/bl.

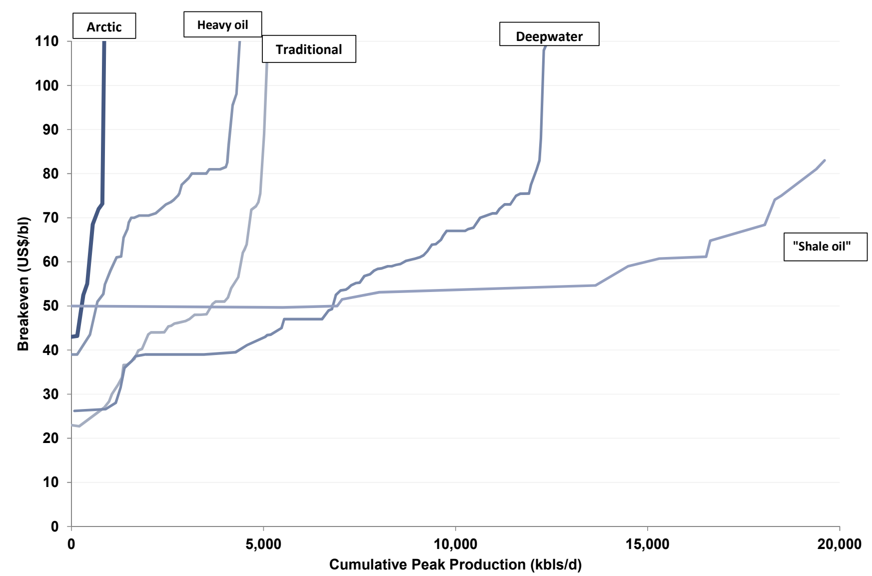
A number of countries such as Angola and Nigeria have lower costs than US Shale, but show higher breakevens. This is predominantly down to higher rates of tax. Consequently, we think these countries have a lot to gain by lowering taxes to make them cost competitive with shale. We have seen early signs of this, but think there is much further to go should prices remain in the US$50-60 range.

Exhibit 99: Much of the world has costs below shale but not necessarily breakevens
Capex+opex costs vs post tax breakeven



Source: Goldman Sachs Global Investment Research.

Exhibit 100: Every winzone now has at least one competitive project vs shale
Top project cost curve by Winzones

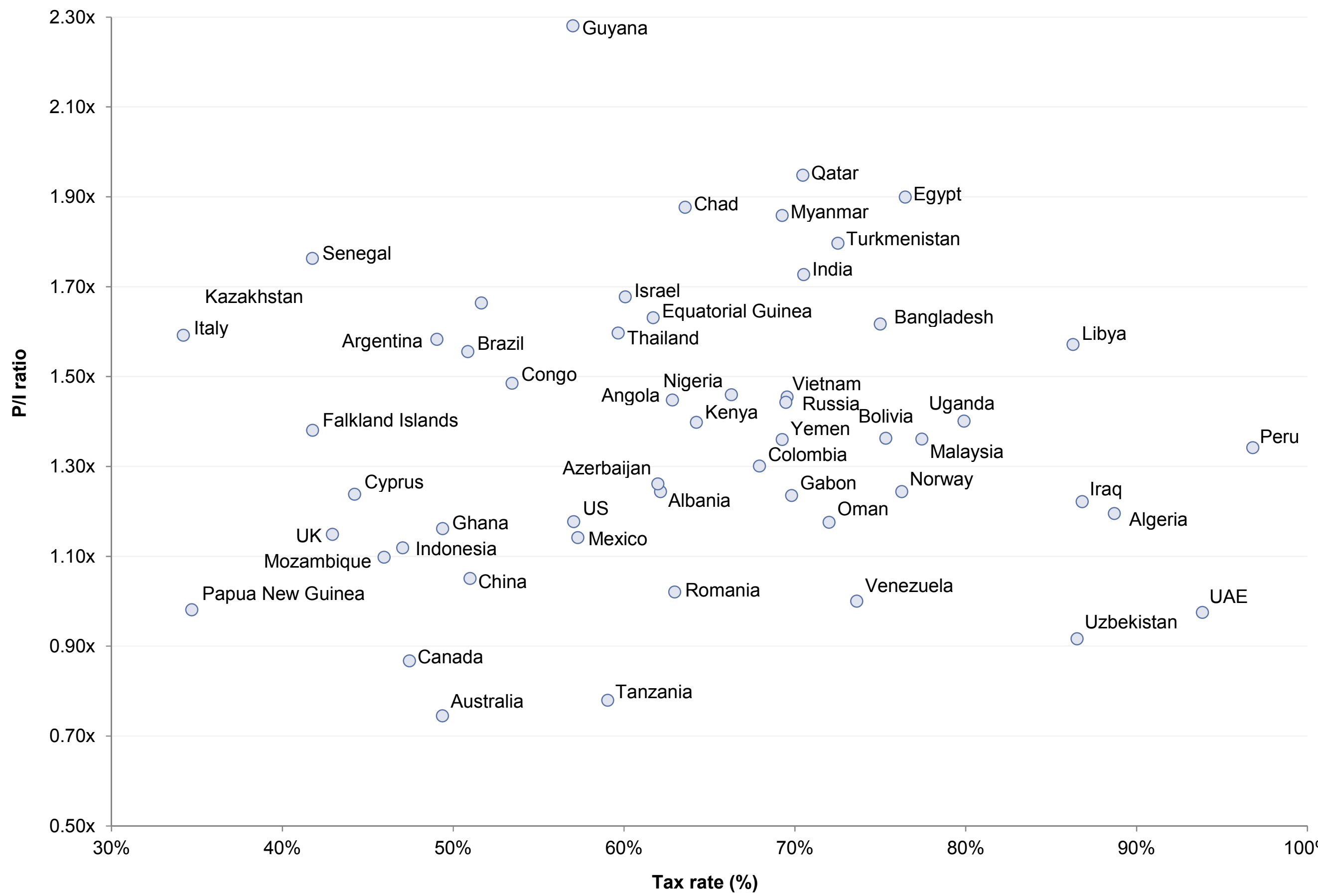


Source: Goldman Sachs Global Investment Research.

Fiscal reform is key for countries to remain competitive, as investment shifts towards short-cycle

We view countries with high tax rates and low P/I ratios as least likely to see significant new investment from a purely fiscal standpoint. Meanwhile, these countries likely also have the incentive to reduce tax rates to promote new investment. We highlight Iraq, Algeria and Venezuela as chief among these.

Exhibit 101: Countries with low profitability and high tax takes have a greater opportunity for fiscal change to make a difference
Overall government take vs. P/I (profit to investment ratio) by country (countries where uneconomic projects are located highlighted in blue)



Source: Goldman Sachs Global Investment Research

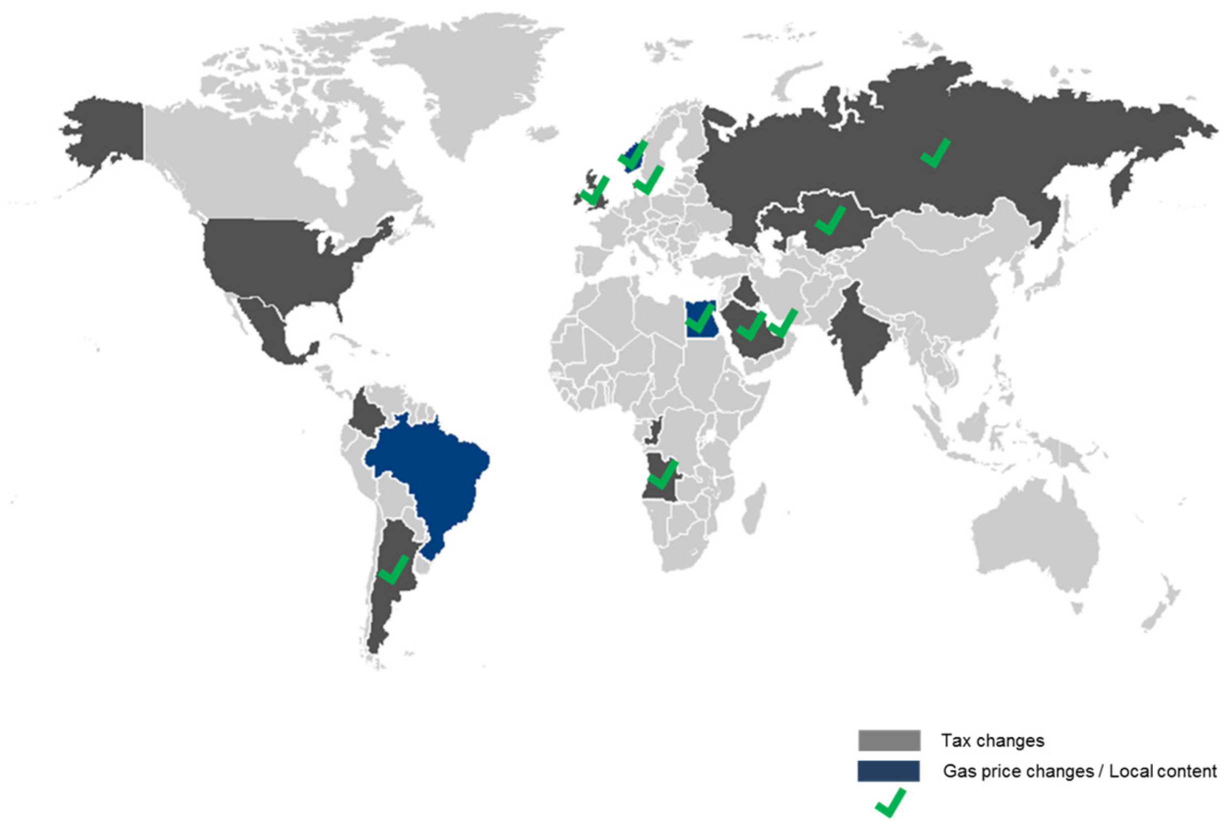
Countries showing major tax changes: The process of adaptation continues

Over the past couple of years, we have seen numerous fiscal changes to incentivize new investment. These include tax reductions in places like the UK, Saudi Arabia, Denmark, Kazakhstan and Angola. Meanwhile, we have seen talk of reduction of local content requirements in countries such as Brazil, or the abandonment of large regional infrastructure projects (Norway).

On the other side, we have seen increases in domestic gas prices in Egypt and Argentina to incentivize new investment in Zohr and shale gas in the Neuquen basin, respectively. In addition, the US has talked of a Border Adjusted Tax which could have significant impacts on the industry if approved and depending on conditions.

We expect the rate of fiscal reform to accelerate as countries and companies push to make more projects work in the New Oil Order.

Exhibit 102: We have seen improving fiscal/regulatory terms across the globe
Map showing locations of announced and approved regulatory/fiscal changes



Source: Goldman Sachs Global Investment Research.

Project sanctions: Several mega-projects have adapted and are ready for sanction...

We are seeing the industry respond to lower prices by sanctioning fewer, larger projects. There is now a greater weighting towards mega-projects such as Libra, Mozambique LNG, Leviathan etc, at the expense of mid-sized projects with more marginal economics.

Exhibit 103: We are seeing a shift to progressively larger mega-projects with fewer mid-scale projects relative to history
Projects expected to be sanctioned through to 2020

Project	Operator	Win zone	Country	Production start	Total reserves (mn boe)			Total capex ($mn)
					Oil	Gas	Total	
2017 sanctions								
Libra	Petrobras	Deepwater	Brazil	2020	9,172	1,192	10,364	$52,491
Liza	ExxonMobil	Deepwater	Guyana	2020	1,570	0	1,570	$10,912
Johan Castberg	Statoil	Traditional	Norway	2022	517	0	517	$5,250
Aspen	Imperial Oil	Heavy oil	Canada	2020	1,157	0	1,157	$7,938
Kovykta	Gazprom	Russia	Russia	2020	320	4,447	4,767	$22,192
Achimov IV + V	Gazprom Neft	Russia	Russia	2019	601	1,603	2,204	$2,704
Coral FLNG	ENI	LNG	Mozambique	2021	0	784	784	$4,950
Fortuna LNG	Ophir	LNG	Equatorial Guinea	2020	0	417	417	$3,455
Leviathan domestic	Noble Energy	Gas	Israel	2020	0	3,855	3,855	$9,475
Block SK408	SapuraKencana	Gas	Malaysia	2020	0	365	365	$1,696
2018 sanctions								
Bonga SW Aparo	RDShell	Deepwater	Nigeria	2022	823	0	823	$11,950
Sangomar	Cairn Energy	Deepwater	Senegal	2021	437	0	437	$4,518
Vito	RDShell	Deepwater	US	2022	312	17	329	$5,650
Buckskin	LLOG	Deepwater	US	2021	235	20	255	$2,937
Uganda, blocks 1, 2 & 3	TOTAL	Traditional	Uganda	2021	1,537	0	1,537	$7,851
Pikka	Repsol	Traditional	US	2021	1,318	0	1,318	$8,173
Kuyumba	Rosneft	Russia	Russia	2020	1,741	407	2,148	$9,055
Chonsk	Gazprom Neft	Russia	Russia	2020	319	15	334	$1,918
Golfinho-Atum	Anadarko	LNG	Mozambique	2023	0	4,463	4,463	$29,058
Tortue	Kosmos Energy	LNG	Senegal	2022	0	1,769	1,769	$10,850
Elk/Antelope	TOTAL	LNG	Papua New Guinea	2022	126	1,484	1,611	$12,208
Absheron	TOTAL	Gas	Azerbaijan	2020	188	561	750	$5,850
Ningbo 22-1	CNOOC	Gas	China	2021	0	470	470	$3,542
2019 sanctions								
Greater Orca Lontra Development	Cobalt	Deepwater	Angola	2023	820	195	1,015	$12,643
North Platte	Cobalt	Deepwater	US	2022	520	29	549	$7,742
Trion	BHP Billiton	Deepwater	Mexico	2023	486	0	486	$7,531
Cameia	Cobalt	Deepwater	Angola	2022	481	0	481	$6,257
Anchor	Chevron	Deepwater	US	2023	412	22	434	$6,391
Kenya onshore	Tullow	Traditional	Kenya	2021	754	0	754	$5,650
Mamba	ENI	LNG	Mozambique	2023	0	8,808	8,808	$44,396
Miran & Bina Bawi	Genel	Gas	Iraq	2023	78	745	824	$3,220
Nyonie Deep	ENI	Gas	Gabon	2023	143	214	357	$2,684
Neptun Deep	ExxonMobil	Gas	Romania	2022	0	316	316	$2,597
2020 sanctions								
Block 18 West	BP	Deepwater	Angola	2024	518	0	518	$7,888
Itaipu	Anadarko	Deepwater	Brazil	2024	371	0	371	$5,115
OPL 245	ENI	Deepwater	Nigeria	2024	305	0	305	$4,497
Alta Gohta	Lundin	Traditional	Norway	2024	424	0	424	$5,720
Sea Lion	Premier Oil	Traditional	Falkland Islands	2023	385	0	385	$5,315
Al Ghubar	PDO	Heavy Oil	Oman	2024	300	0	300	$2,024
Gendalo	Chevron	Gas	Indonesia	2023	113	509	621	$5,158
Ling Shui	CNOOC	Gas	China	2024	0	402	402	$5,506

Source: Goldman Sachs Global Investment Research

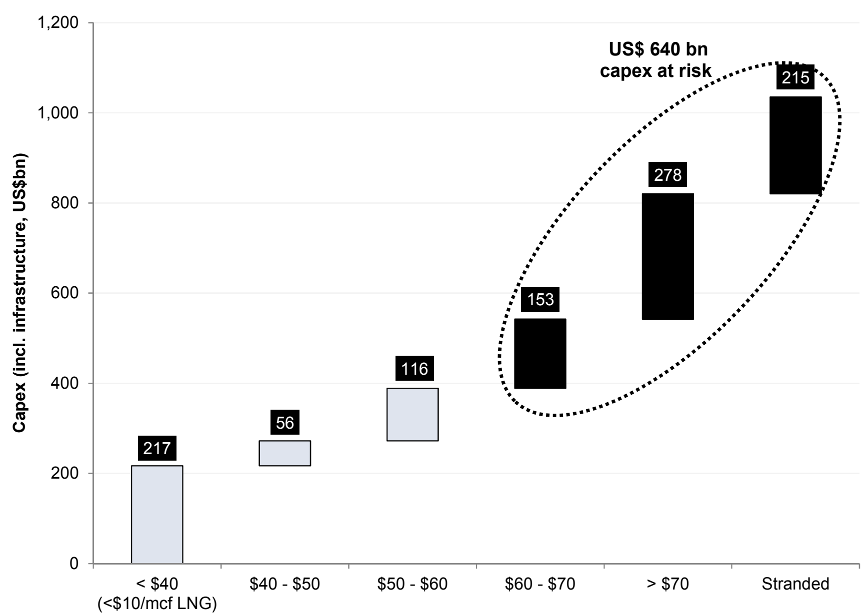
…pushing US$640 bn/65 bn boe of high-cost long-cycle capex towards cancellation

The large portfolio of oil and LNG projects which break even at <US$50/bl or <US$10.00/mcf (LNG) means we see oil prices capped in a US$50-60 range for at least the medium term. In our view, this means many projects may not be sanctioned due to positions on the cost curve above our expected long-term oil price. We think 53 projects require further technical or fiscal improvements to become competitive. Among these, we view 16 projects as "stranded", indicating very remote, high cost or technically challenging projects.

The bulk of the projects breaking even above US$60/bl or US$10mcf are high-cost LNG, heavy oil and marginal deepwater projects. We see regional concentrations in Canada, the US and West Africa. These hold some 65 bn boe of reserves, in our view. The majority of the "stranded" projects (holding c.24bn boe) have been specifically identified by their operators as unlikely to be sanctioned in the near future and have average breakevens of c.US$84/bl. These projects will require significant cost deflation in order to be economic.

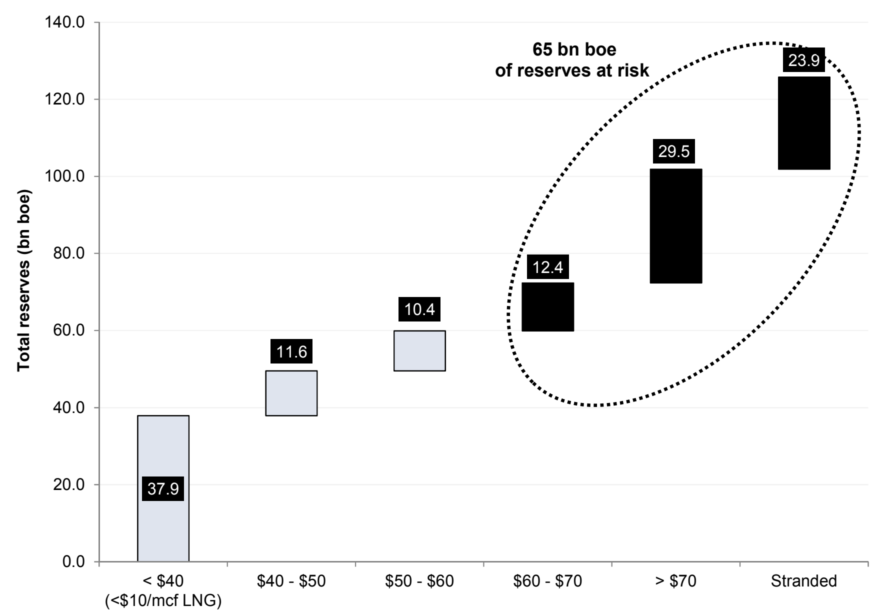
We split out the capex of pre-sanction projects by breakeven and highlight that more than US$640 bn of capex (equivalent to 65 bn boe) is at risk of not being sanctioned in a lower-for-longer oil price world. We think countries with large exposure to uneconomic projects will likely be incentivized to flex fiscal terms to try and make these projects viable in a lower oil price environment.

Exhibit 104: More than US$640 bn of capex could potentially never come through…
Capex breakdown of oil-levered pre-sanction projects by breakeven



Source: Company data, Goldman Sachs Global Investment Research.

Exhibit 105: …which represents c.65 bn barrels of reserves
Reserves breakdown of oil-levered pre-sanction projects by breakevens



Source: Company data, Goldman Sachs Global Investment Research.

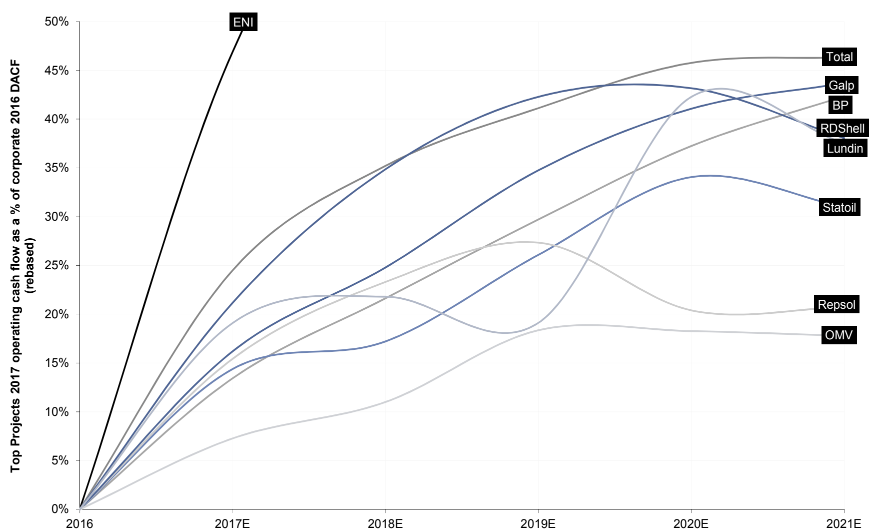
Top Projects remain a significant driver of cash flow growth, production and capex

ENI, TOTAL and Shell stand out with superior near-term cash flow growth

In our view, Top Projects will drive material cash flow uplift for a number of global upstream companies. In Europe, ENI and TOTAL and Shell stand out and will see the largest cash flow uplift from Top Projects by the end of the decade. We note that in 2016, ENI faced a number of operational challenges, including the shut-in of Val D'Agri and Goliat impacting production and ultimately cash flow generation. We do not expect the shut-ins to last and believe production will ramp back up to peak in the near term. ENI's solid cash generation will be driven by the ramp-up of a wide range of fields including Sankofa (Ghana), Zohr (Egypt), Jangkrik (Indonesia) and Kashagan (Kazakhstan). The largest contributors to TOTAL's cash flow uplift are the start-up and ramp-up of projects like Ichthys (Australia), Egina (Nigeria), Kashagan (Kazakhstan), Block 32 (Angola) and Yamal LNG (Russia). With the exception of Kashagan, the majority of the fields mentioned above were sanctioned during 2011-14, which saw the largest number of FIDs in the history of the oil & gas industry.

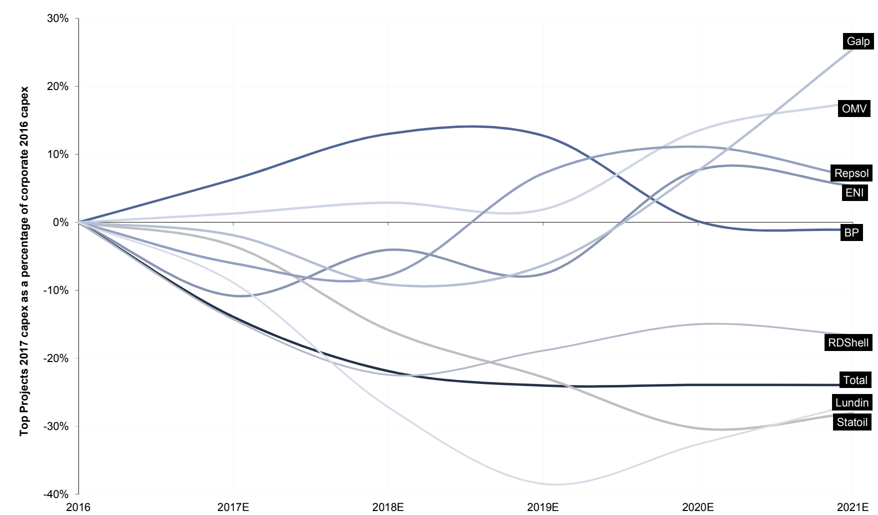
Owing to the low levels of project sanctioning from 2014 onwards, we expect capex to fall for most companies as projects come into production and are replaced with cheaper developments. Statoil and Lundin will see the biggest drop relative to corporate capex as the giant field Johan Sverdrup (Norway) is expected to come on-stream in 2019E. Spending remains elevated for Galp, growing towards the end of the decade due to large investments required for the giant LNG project in Mozambique.

Exhibit 106: ENI and TOTAL are expected to see material cash flow growth by 2021E from Top Projects
Top Projects 2017 operating cash flow as % of 2016 corporate DACF (rebased); ENI reaches 85% by 2021E



Source: Company data, Goldman Sachs Global Investment Research.

Exhibit 107: Spending remains elevated for Galp owing to large investments required for Mozambique
Top Projects 2017 capex as % of 2016 corporate capex (rebased)



Source: Company data, Goldman Sachs Global Investment Research.

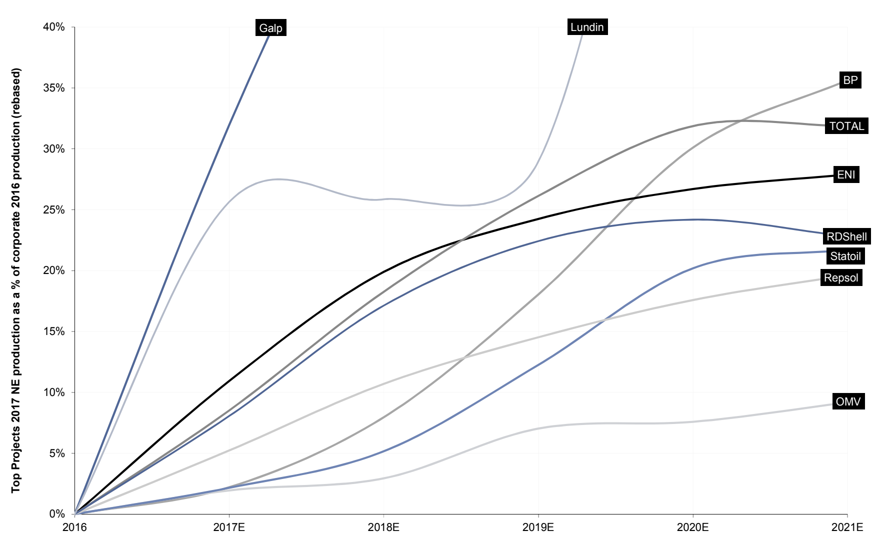
Galp and Lundin set to deliver material production growth

Although we prefer cash flow as a metric to assess a company's potential, we note that production remains an important metric to the market and thus look at the likely net entitlement production growth from each company. Galp and Lundin clearly stand out among the European companies, partly driven by the expected delivery/ramp-up of large projects relative to the size of their current production base, including Lula (Brazil) for Galp and Edvard Grieg (Norway) for Lundin. We note that from 2018, BP displays one of the most attractive production growth profiles among its European peers, due to a large number of predominantly gas projects ramping up, particularly in Egypt with Zohr, Nooros, West Nile Delta and Atoll.

We have also assessed the materiality of each company's leverage to oil & gas prices and their net entitlement Top Projects reserve life vs. the overall 2016 production to determine the longevity of each company's asset base. We have split oil & gas reserves into three categories: producing (projects currently on stream), high-return (non-producing oil projects with breakeven < US$55/bl, gas projects with P/I > 1.2x) and others (low-return new projects, including stranded projects).

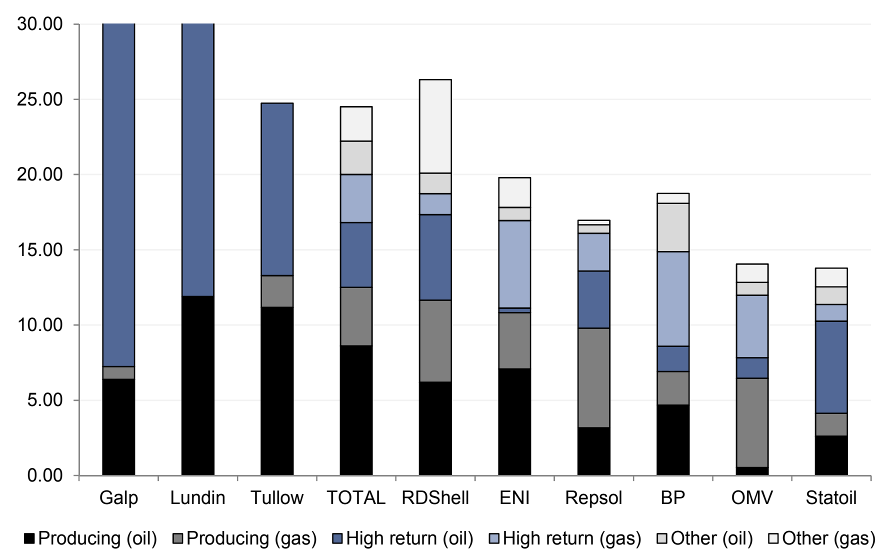
Galp and Lundin stand out with the best reserve life in the sector, with TOTAL, RDShell and ENI the best placed among the European majors.

Exhibit 108: Galp and Lundin will see material production growth…
Top Projects 2017 net entitlement production as % of corporate 2016 production (Rebased)



Source: Company data, Goldman Sachs Global Investment Research.

Exhibit 109: …and lead on Top Projects reserves life; TOTAL scores best out of the European Majors
Based on remaining net entitlement volumes vs. 2016 production; high return oil projects breakeven below US$55/bl; high return gas projects have P/I > 1.2x



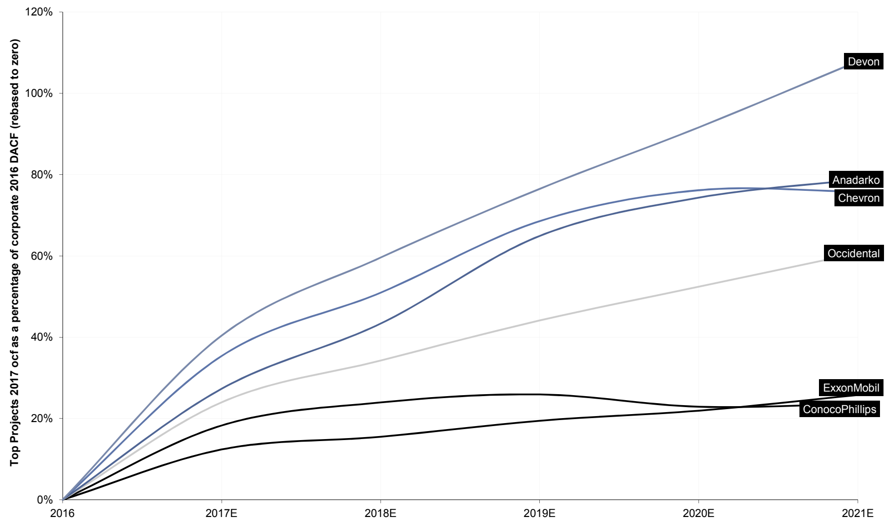
Source: Company data, Goldman Sachs Global Investment Research.

Chevron shows the strongest cash flow growth among US Big Oils

We see Chevron as a clear leader among the larger US companies in terms of both Top Projects cash flow growth and falling capex profile over the coming years. Chevron's cash flow uplift is dominated by LNG near term (Gorgon, Wheatstone and the return of Angola LNG) and offshore with Stampede, Clair Ridge, Hebron and Big Foot all adding growth, with the Permian contributing long-term growth. As projects are expected to progressively come on-stream, we expect Chevron to continue reducing its capex by the end of the decade, relative to 2016 levels.

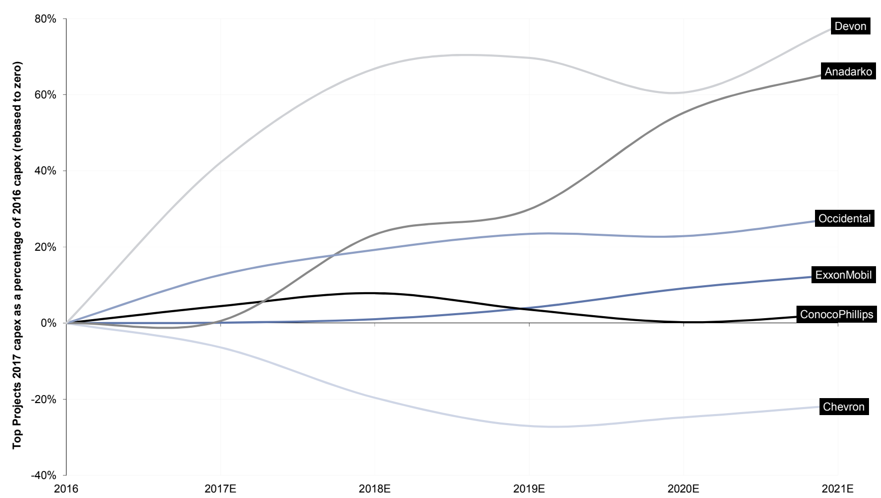
We note the attractive cash flow growth profile of Devon (balanced by ongoing capex requirements) is primarily driven by the higher activity levels expected in US onshore, particularly in the Permian and Cana Woodford (Stack and Scoop). Anadarko's cash flow uplift is supported by a number of offshore projects ramping up (i.e. Holstein, Jubilee and Heidelberg) and its exposure to the Permian. We expect Golfinho-Atum (Anadarko operated, Mozambique) to be sanctioned in 2018 and add a significant portion of capex to Anadarko (27% stake), alongside the ongoing high investment required for its stake in the Permian and the Niobara.

Exhibit 110: Chevron displays one of the most attractive cash flow growth…
Top Projects 2017 operating cash flow as % of 2016 corporate DACF (rebased)



Source: Company data, Goldman Sachs Global Investment Research.

Exhibit 111: …and capex profiles, suggesting the best FCF inflection
Top Projects 2017 capex as % of 2016 corporate capex (rebased)

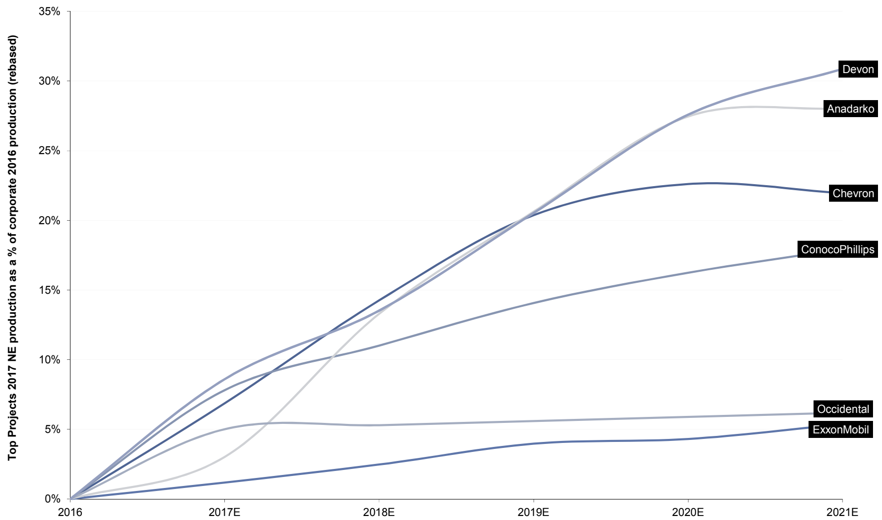


Source: Company data, Goldman Sachs Global Investment Research.

Devon and Anadarko couple high production growth and high reserves life

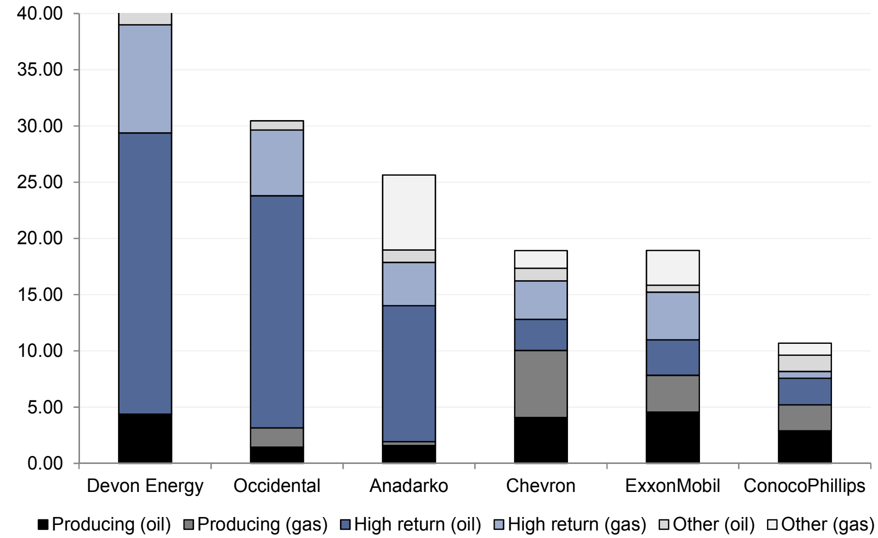
Although Chevron displays an attractive growth profile until the end of the decade as offshore projects start up/ramp up in 2018-20, we view the US onshore exposed names such as Devon and Anadarko as having the most attractive production long-term resource base, driven mainly by the Permian and the Niobara. While Occidental's production growth lags the rest of the group, its reserve life is one of the most attractive, with high exposure to high-return oil potential in the Permian.

Exhibit 112: Among the US large caps, Chevron shows the most attractive combination of production growth in the medium term…
Top Projects 2017 net entitlement production as % of corporate 2016 production (rebased)



Source: Company data, Goldman Sachs Global Investment Research.

Exhibit 113: …while Devon displays the highest reserves life owing to its attractive exposure to the Permian basin
Based on remaining net entitlement volumes vs. 2016 production; high return oil projects breakeven below US$55/bl; high return gas projects have P/I > 1.2x



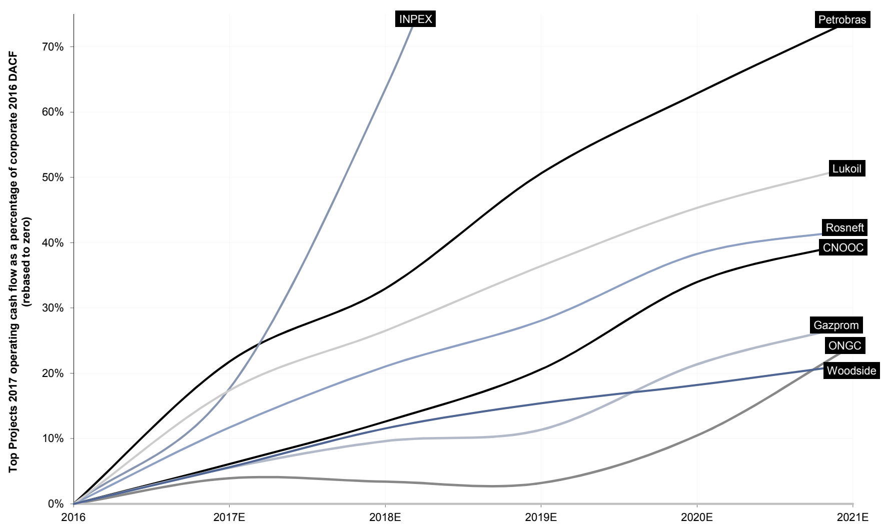
Source: Company data, Goldman Sachs Global Investment Research.

INPEX and Petrobras see biggest cash flow uplift in the RoW

INPEX and Petrobras see the largest cash flow uplift from the Top Projects among the large cap producers outside of Europe and the US. INPEX sees a rapid cash flow uplift from mega- projects including Kashagan, Ichthys and Prelude, while Petrobras continues to benefit from the continued ramp-up of giant projects in the Santos basin.

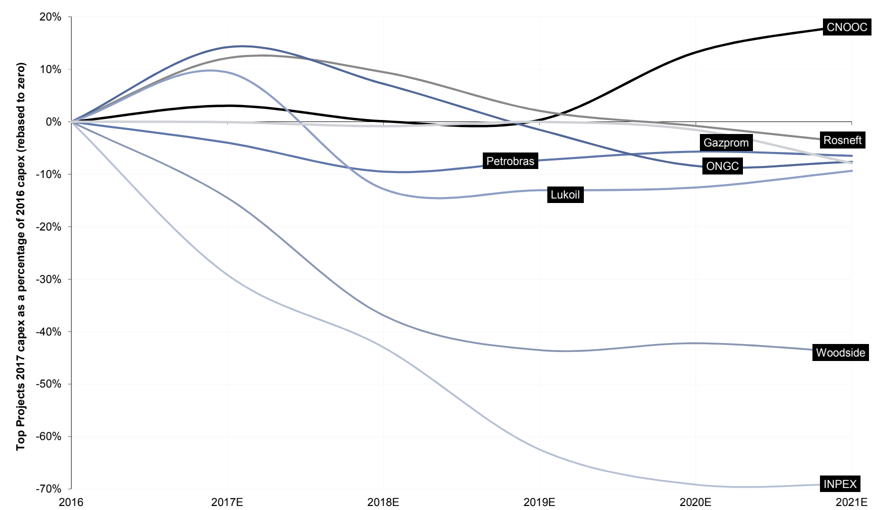
There is a relatively wide range of capex outlooks for the EM oils, with the Russian oils Top Projects capex continuing to grow until 2018, while the more LNG geared players, INPEX and Woodside, see a material fall in Top Projects capex. Given Petrobras' balance sheet constraints, we believe that the company may look to reduce this capex burden through further disposals/asset sales.

Exhibit 114: INPEX appears with the most attractive cash flow growth…
Top Projects 2017 operating cash flow as % of 2016 corporate DACF (rebased)



Source: Company data, Goldman Sachs Global Investment Research

Exhibit 115: …further supported by a falling capex profile
Top Projects 2017 capex as % of 2016 corporate capex (rebased)

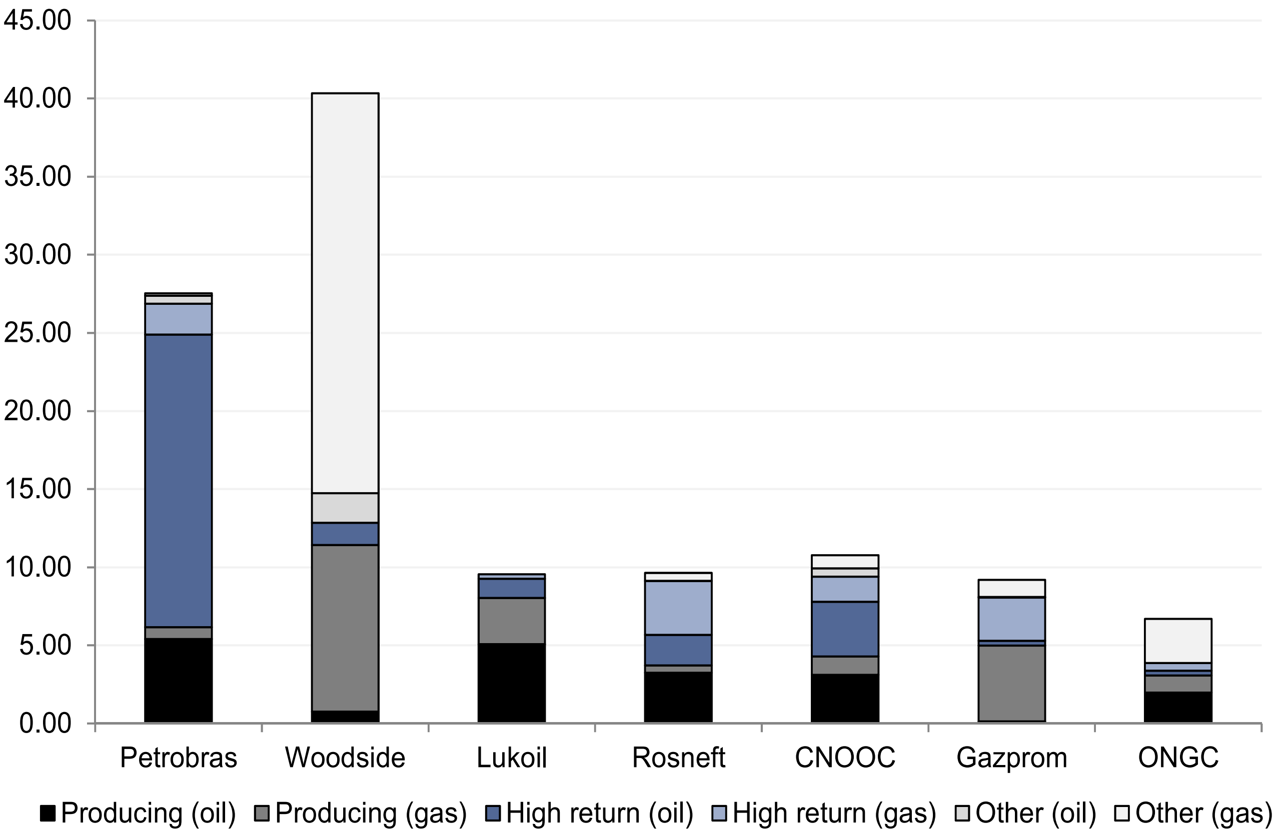


Source: Company data, Goldman Sachs Global Investment Research

Petrobras has the longest Top Projects reserve life; Russian exposure is high return

There is a significant divergence in the materiality of Top Projects exposure among the global players. Woodside and Petrobras are by far the most exposed to Top Projects and have a Top Projects reserves life in excess of 20 years, while the others all have a reserves life of c.10 years or less. Petrobras' long reserves life is a result of its exceptional exploration success offshore Brazil, with a leadership position in what we believe to be the most profitable non-OPEC basin with scale: the pre-salt Santos basin. Other EM players have less exposure, partly as a result of high levels of legacy asset production not included in the Top Projects analysis (such as for Gazprom) and partly as a result of a relatively small absolute exposure to the Top Projects dataset (such as ONGC). It is worth noting, however, that the vast majority of reserves for the Russian oils are high return.

Exhibit 116: Adjusted for field profitability, Petrobras stands out as having the longest high-quality Top Projects reserve life
Based on remaining net entitlement volumes vs. 2016 production; high return oil projects breakeven below US$55/bl; high return gas projects have P/I > 1.2x



Source: Company data, Goldman Sachs Global Investment Research.

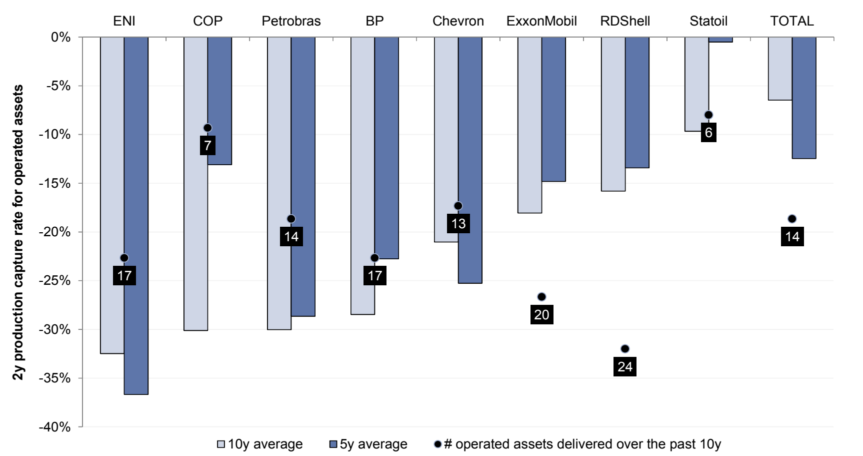
Delivery continues to get better; Statoil/TOTAL maintain their strong track records

The oil & gas industry has a poor record of project delivery in the last decade, but is showing notable signs of improvements in the downcycle. We believe that a fair assessment of operator effectiveness should consider both the delivery of sanctioned projects and also the ability to get projects sanctioned. Although poor project delivery tends to be well flagged, the negative impact of failing to sanction projects also has a negative material effect on NAV. As a result, we look at capture rates for both two (operational delivery) and five years (ability to move projects from discovery to production).

We have analysed companies with more than five operated projects to assess how effective each company has been in bringing production online over the past five years and two years. To do this, we have looked back to each of the previous iterations of the Top Projects report (starting with Top 50 in 2003). We have taken the volumes that we predicted the fields operated by each company would produce in five years and two years from the date of publication and we compare it with the production that we currently expect from those fields, thereby giving an idea of the capture rate for each company. We believe that low levels of lost production are an indication of effective operatorship, both in terms of effective development and prompt sanctioning. We note that these data points are based on our estimates and do not necessarily reflect companies' guidance at the time of writing and that companies with a large proportion of assets already in production tend to be favoured by this analysis. Also, the overall improvement that we have seen in delivery over the past few editions of the report partially reflects the fact that we are still judging these companies against our estimates, rather than versus actual delivery.

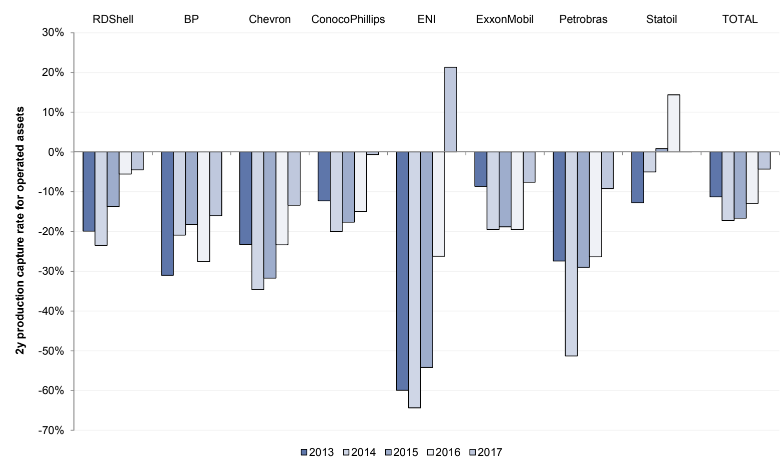
In general we see an improving trend of delivery, with two-year and five-year production rates on operated assets improving in recent performance (last five years) compared to the average over all vintages of the Top Projects. Averaging the results across all versions of the report, TOTAL has had the best track record of physically delivering projects (two-year forward delivery), further supported by recent performance (over the last five years) which has meaningfully improved.

Exhibit 117: TOTAL has the best 10y prod. capture rate on operated assets
Two-year production capture rate for operated assets, 10y vs. 5y average



Source: Company data, Goldman Sachs Global Investment Research.

Exhibit 118: ...and has materially improved delivery over the past five years
Two-year production capture rate for operated assets, over the past five years

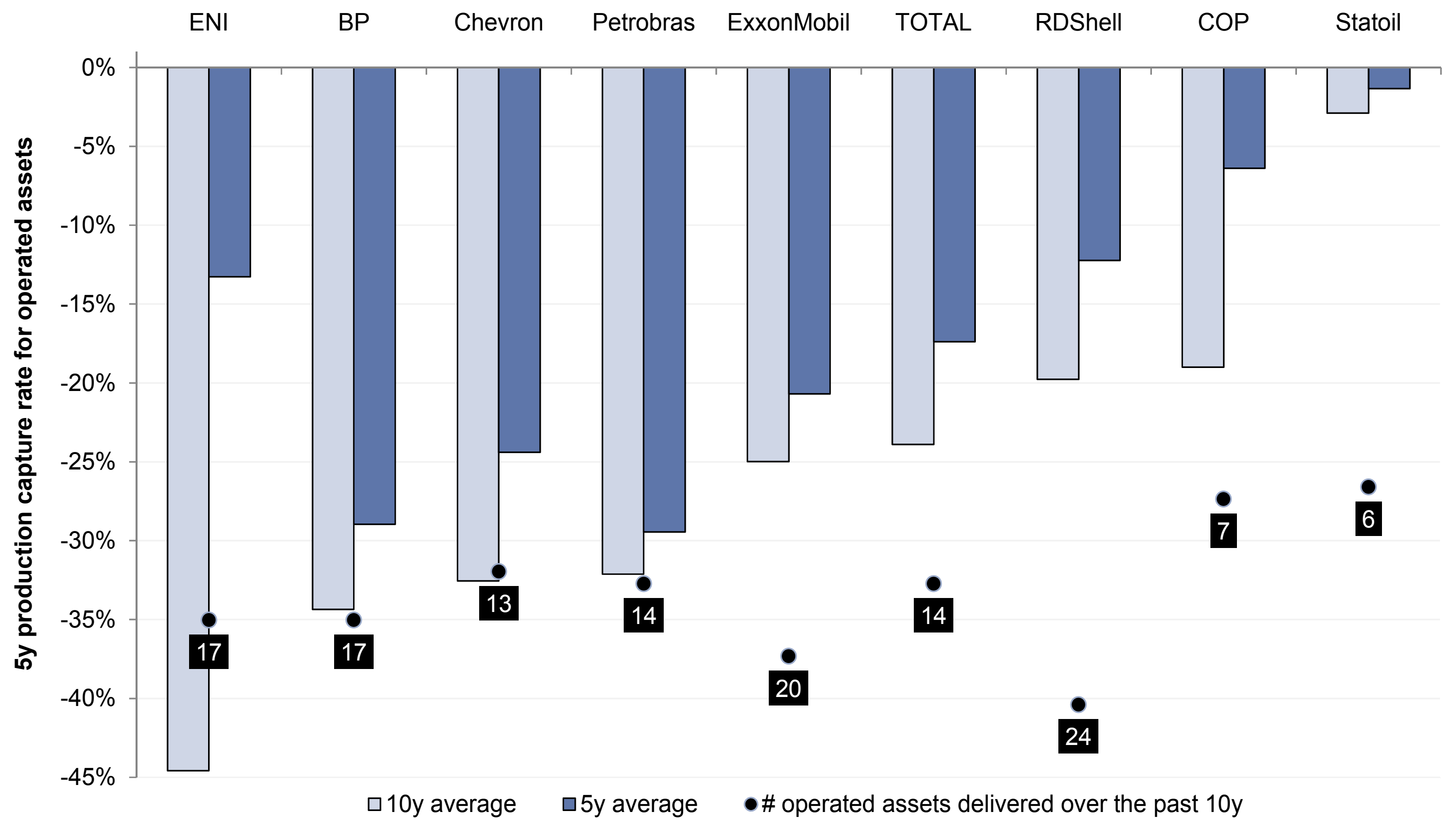


Source: Company data, Goldman Sachs Global Investment Research.

Statoil stands out on a 5-year production capture rate for operated assets owing to satellite tie-backs at the Gjoa, Grane & Kristin Tyrihans fields in the Norwegian Continental Shelf. ENI and Petrobras are weaker on most timeframes, although ENI has improved materially, particularly on five-year production capture rates over the past few years, reflecting an improvement in speed to market of upstream assets (i.e. Zohr in Egypt), in our view. We also highlight the high number of projects the company has managed to deliver over the past 10 years vs. its global peers (17 operated-fields delivered).

While Statoil and ConocoPhillips both stand out on a 5-year production capture rate, the number of projects delivered over the past 10 years, based on our Top Projects analysis, appears well below the peer group average (Statoil 6, ConocoPhillips 7 vs. 15 on average). We note that RDShell has managed to bring on-stream 24 operated-projects with a noticeable improvement in delivery over the past five years.

Exhibit 119: Statoil stands out as having the best 5-year production capture rate on operated assets; TOTAL has improved materially
Five-year production capture rate for operated assets, 10y vs. 5y average



Source: Company data, Goldman Sachs Global Investment Research.

Competitive Positioning framework: Superior legacy assets, higher return growth opportunity, lower risk

In our report "*Global Energy: Death & rebirth v2: A deep dive into Competitive Positioning*", October 8, 2013, we identified a new group of global industry winners by looking at six factors that we believe will drive superior value creation in the coming years. We percentiled each of these factors, resulting in a total score that allowed us to compare and rank the companies. We looked at the following factors:

- **Production growth**: Estimated production growth over the coming five years (2017-21E), which takes into account decline rates, growth from the Top Project fields, PSC effects and other changes to the portfolio.
- **Cash-flow growth from new start-ups**: Cash flow growth from Top Projects over the coming five years.
- **Quality of the portfolio of growth projects**: We estimated the NPV (as a % of GCI) and PI (Profit to Investment ratio) of each company's Top Projects portfolio of new legacy projects.
- **Opportunity set**: We added the NPV from exploration success over the past six years plus the NPV in shale oil as a percentage of current GCI. This sums up exposure to the two most important new business opportunities in the industry, in our view.
- **Risk**: We measured each company's country and technical risk using objective metrics from our Top Projects report.

Exhibit 120 shows the ranking of the global oil & gas companies on our six metrics, using the new Top Projects data, with the overall percentile calculated as the average of each metric's percentile. We take the first six companies (75th percentile) in the list as the winners in this analysis, although this draws an arbitrary line in a continuous data series. We include in this analysis only companies that display in our Top Projects database at least two projects in a "ramp up" stage. ("ramp-up includes pre-sanction and under development projects, alongside unconventional oil and gas fields).

Overall our analysis suggests the US companies are best placed, with c. 50% of the entries in the first quartile, including shale-scale winners Concho, Continental, Pioneer, Range Resources and EOG. Offshore winners Aker BP, Lundin and Tullow also screen well, while YPF is now the best positioned LatAm company in our view, following continued improvement in cost and productivity in the Vaca Muerta. From the international majors, second quartile ENI and Galp screen best with the rest in Q3/Q4. Elsewhere, Russian oils generally screen well in the second quartile, while the fourth quartile is dominated by LNG and Canadian heavy oil exposed companies.

We also compare competitive positioning with the Top 420, published in 2015. We look at profitability and risk of the companies' Top Projects portfolios, and also look at a variety of valuation metrics and recent performance to see whether the change has been fully reflected. Here, the US shale winners continue to screen well, owing to largely positive NPV revisions related to productivity and efficiency gains, improving materially the economics. YPF continues to rank among the best owing to improved costs and largely unchanged realisations given fixed pricing in Argentina. ENI is once again the highest scoring of the Majors, although interestingly BP also screens well as having improved its portfolio on a relative basis over the last two years.

Exhibit 120: Competitive Positioning: US E&Ps continue to score strongly
Competitive Positioning metrics by company (companies with 2 growth assets)

	5-yr pa Top 2017 cash flow growth as % of 2016 corporate cash flow	2017-21E production CAGR	NPV of 10 years of exploration success and shale access as a % of GCI	PI of Top 2017 fields not yet at plateau	NPV of Top 2017 fields not yet at plateau as % GCI	Top 2017 technical + political risk	Overall percentile
Concho Resources	28%	24%	16%	1.19x	47%	0.55	88%
Continental Resources	34%	26%	10%	1.10x	48%	0.55	87%
Pioneer	29%	22%	10%	1.11x	40%	0.55	84%
Lundin	8%	15%	66%	1.45x	53%	0.37	83%
Range Resources	31%	25%	0%	1.38x	57%	0.65	77%
Aker BP	8%	7%	19%	1.46x	17%	0.46	76%
EOG Resources	25%	18%	7%	1.07x	32%	0.55	76%
Noble Energy	22%	17%	8%	1.11x	26%	1.03	70%
Hess	26%	8%	8%	1.18x	16%	1.09	69%
Tullow	17%	7%	62%	1.40x	6%	1.16	68%
YPF	30%	1%	3%	1.47x	14%	0.83	68%
Marathon	30%	9%	2%	1.03x	17%	0.63	66%
Devon Energy	22%	5%	3%	1.12x	10%	0.64	66%
Occidental	12%	7%	3%	1.19x	10%	0.75	65%
Petrobras	15%	3%	12%	1.60x	33%	1.64	65%
Galp	9%	14%	21%	1.34x	29%	1.72	65%
Anadarko	16%	14%	6%	1.10x	11%	1.02	65%
Southwestern Energy	14%	18%	0%	1.18x	19%	0.65	63%
Novatek	21%	4%	5%	1.09x	105%	1.39	60%
Apache	7%	12%	2%	1.11x	7%	0.57	57%
ENI	17%	2%	10%	1.34x	4%	1.61	52%
Chesapeake	26%	9%	0%	0.89x	5%	0.56	49%
Encana	11%	17%	0%	1.02x	2%	0.56	49%
Rosneft	8%	2%	0%	1.54x	8%	1.03	47%
CNOOC	9%	2%	2%	1.18x	7%	1.50	46%
Lukoil	10%	3%	1%	1.13x	3%	1.24	43%
INPEX	34%	9%	0%	0.74x	29%	1.79	43%
BP	8%	2%	1%	1.12x	5%	1.27	43%
Gazprom Neft	10%	5%	0%	1.32x	4%	1.31	43%
Statoil	6%	2%	4%	1.08x	7%	1.19	42%
TOTAL	10%	2%	1%	1.08x	8%	1.60	39%
RDShell	8%	2%	1%	1.20x	5%	1.63	37%
OMV	4%	0%	0%	1.19x	3%	0.78	36%
Gazprom	5%	1%	0%	1.27x	5%	1.03	35%
Chevron	15%	2%	1%	1.07x	4%	1.62	35%
Cenovus	21%	4%	0%	0.88x	0%	0.91	34%
ExxonMobil	5%	2%	1%	1.11x	4%	1.58	34%
ONGC	4%	5%	0%	1.09x	2%	1.19	33%
ConocoPhillips	5%	1%	1%	1.04x	2%	0.93	31%
Murphy	3%	3%	0%	1.01x	5%	0.86	30%
Suncor	9%	5%	0%	0.93x	2%	1.15	29%
Repsol	4%	1%	3%	1.10x	2%	1.42	29%
PTTEP	2%	-1%	2%	1.06x	1%	0.96	26%
Woodside	4%	2%	0%	0.97x	0%	1.00	20%
Canadian Natural Resources	14%	0%	0%	0.77x	0%	1.38	17%
Oil India	0%	2%	1%	1.05x	1%	1.85	17%
SASOL	1%	0%	0%	0.65x	-4%	0.68	15%
BHP Billiton	1%	-9%	0%	0.96x	1%	1.54	13%

Source: Company data, Goldman Sachs Global Investment Research.

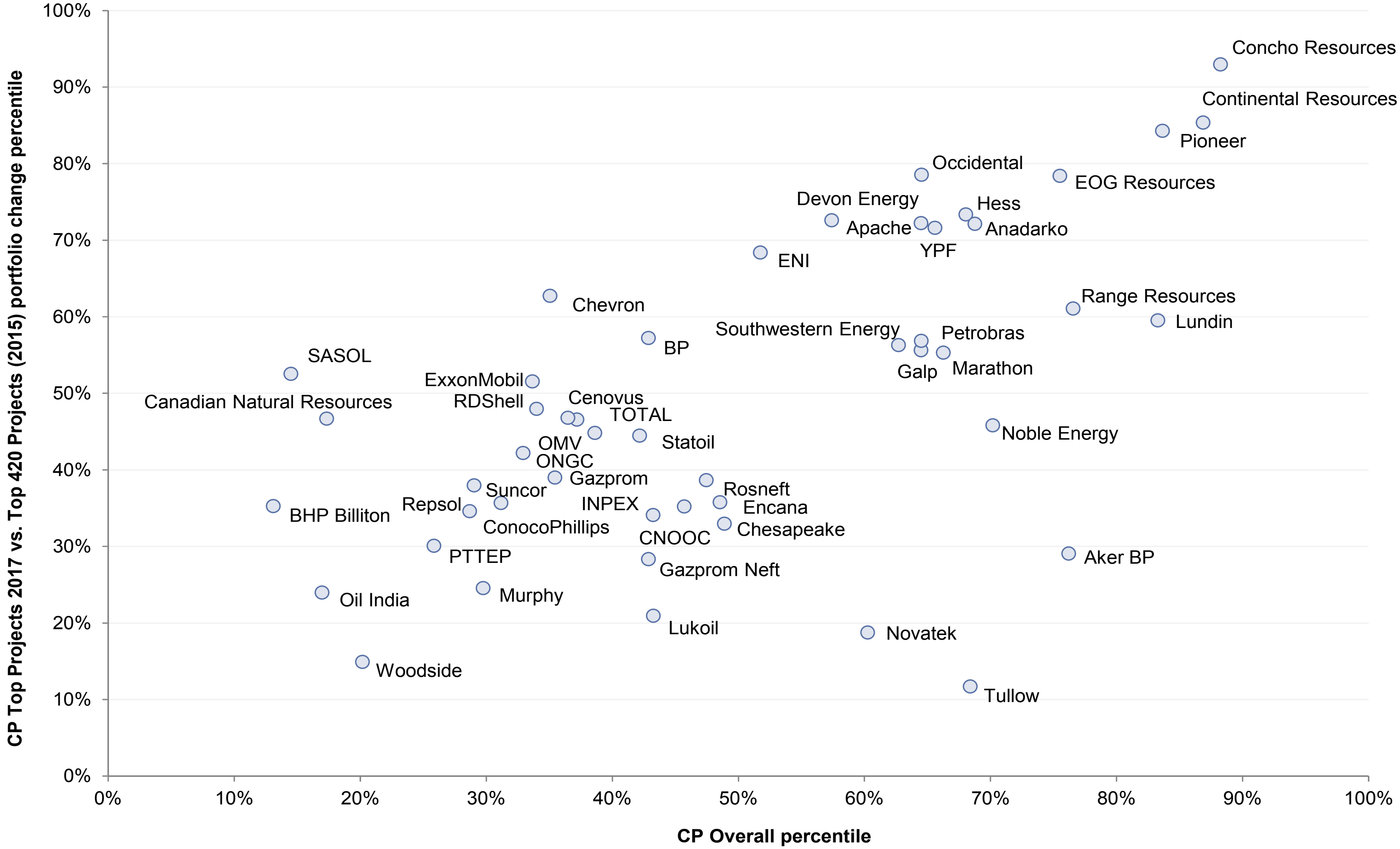
Exhibit 121: US E&Ps have improved the most over the past two years, driven by productivity and efficiency gains in US onshore which translated into better economics

Changes in the portfolio of growth projects since Top 420 publication in May 2015

vs. Top 420, published May 2015	PI % change	NPV as % GCI change	10 yr Exploration + shale success as % of GCI change	Risk factor % change	Overall percentile	US$ Share price performance since Jan 2016	Valuation percentile
Concho Resources	1%	35%	16%	-48%	93%	43%	16%
Continental Resources	-3%	17%	10%	-48%	85%	84%	38%
Pioneer	-5%	22%	10%	-48%	84%	39%	27%
Occidental	0%	6%	3%	-28%	79%	-10%	28%
EOG Resources	-6%	15%	7%	-48%	78%	33%	33%
YPF	7%	-3%	3%	-36%	73%	55%	56%
Apache	-5%	5%	2%	-43%	73%	15%	39%
Anadarko	2%	1%	2%	-25%	72%	7%	44%
Hess	-3%	8%	8%	-7%	72%	1%	30%
Devon Energy	-3%	2%	3%	-37%	72%	19%	22%
ENI	-3%	9%	5%	-4%	68%	11%	57%
Chevron	13%	4%	0%	3%	63%	19%	38%
Range Resources	2%	3%	0%	-25%	61%	2%	50%
Lundin	9%	35%	0%	11%	60%	45%	80%
BP	-3%	0%	1%	-8%	57%	16%	47%
Petrobras	4%	8%	0%	-3%	57%	143%	66%
Southwestern Energy	2%	-1%	0%	-25%	56%	2%	56%
Galp	-3%	7%	0%	-11%	56%	39%	41%
Marathon	-15%	0%	2%	-47%	55%	15%	49%
SASOL	-1%	-5%	0%	-39%	53%	15%	54%
ExxonMobil	6%	-3%	1%	18%	52%	6%	25%
Cenovus	-10%	32%	0%	-7%	48%	-24%	51%
OMV	48%	4%	0%	41%	47%	82%	65%
Canadian Natural Resources	1%	16%	0%	19%	47%	45%	36%
RDShell	-5%	2%	0%	9%	47%	23%	39%
Noble Energy	-12%	-4%	2%	-25%	46%	-4%	44%
TOTAL	-8%	3%	0%	2%	45%	20%	52%
Statoil	-3%	1%	0%	-4%	44%	29%	41%
ONGC	-6%	2%	0%	-17%	42%	18%	57%
Gazprom	-6%	-3%	0%	-13%	39%	25%	72%
Rosneft	-2%	-12%	0%	-8%	39%	59%	85%
Suncor	-5%	5%	0%	19%	38%	24%	47%
Encana	-9%	-4%	0%	-35%	36%	119%	43%
ConocoPhillips	-16%	-11%	0%	-13%	36%	1%	31%
BHP Billiton	-8%	-2%	0%	14%	35%	38%	35%
CNOOC	-9%	-3%	2%	16%	35%	14%	75%
Repsol	-15%	3%	0%	-12%	35%	51%	59%
INPEX	-12%	3%	0%	-2%	34%	-6%	39%
Chesapeake	-19%	-6%	0%	-45%	33%	23%	65%
PTTEP	-3%	-7%	-1%	-6%	30%	76%	74%
Aker BP		2%	0%	38%	29%	183%	86%
Gazprom Neft	-7%	-9%	0%	-3%	28%	61%	86%
Murphy	-11%	-11%	-1%	-16%	25%	17%	53%
Oil India	-14%	-6%	0%	-3%	24%	14%	53%
Lukoil	-6%	-12%	0%	-2%	21%	60%	88%
Novatek	-8%	-37%	0%	8%	19%	48%	42%
Woodside	-18%	-15%	0%	1%	15%	15%	36%
Tullow	-21%	-8%	-11%	-3%	12%	25%	50%

Source: Company data, Goldman Sachs Global Investment Research.

Exhibit 122: US E&Ps including Concho, Continental, Pioneer and EOG screen best on current CP and 2y change
CP overall percentile (x-axis) and percentile change in Top Projects 2017 vs. Top 420 (2015)

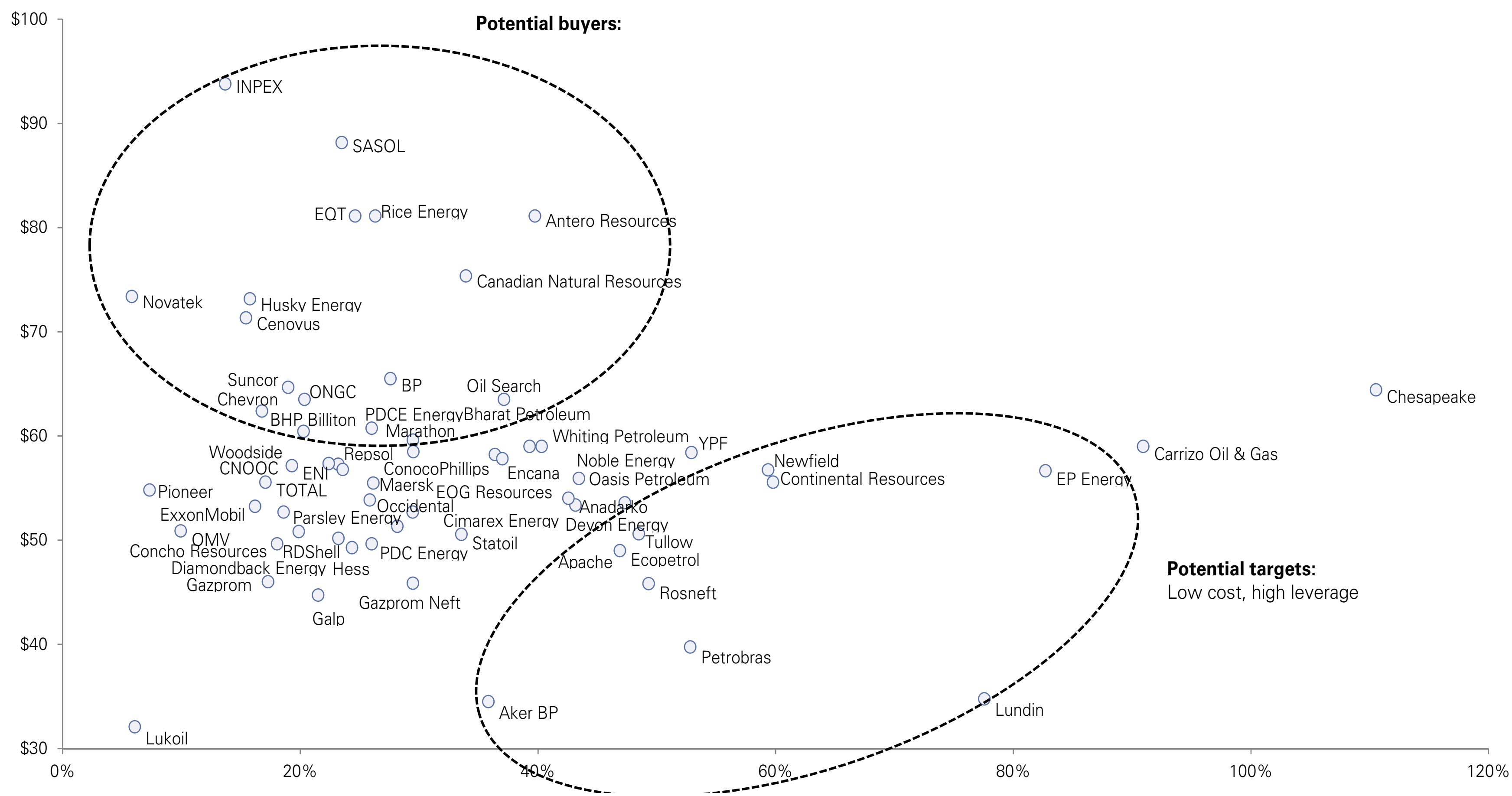


Source: Goldman Sachs Global Investment Research.

M&A could bridge the capital shortfall of poorly capitalized E&Ps with high quality assets

In Exhibit 123, we show the average corporate breakeven price and financial leverage. Companies with high leverage but low breakeven costs may make attractive targets for companies with low leverage but high breakeven costs. This is true for both companies and assets. As an example, we saw TOTAL gaining access to high-quality assets in 2016-17, by acquiring assets from highly financially leveraged companies such as Petrobras and Tullow. However, over the past two years, we have seen progressively fewer corporate M&A deals, while seeing more asset level deals.

Exhibit 123: Companies with robust balance sheets but higher breakevens could look to acquire low-cost projects from highly levered E&Ps
Top Projects 2017 breakeven vs. 2017 net debt/capital employed

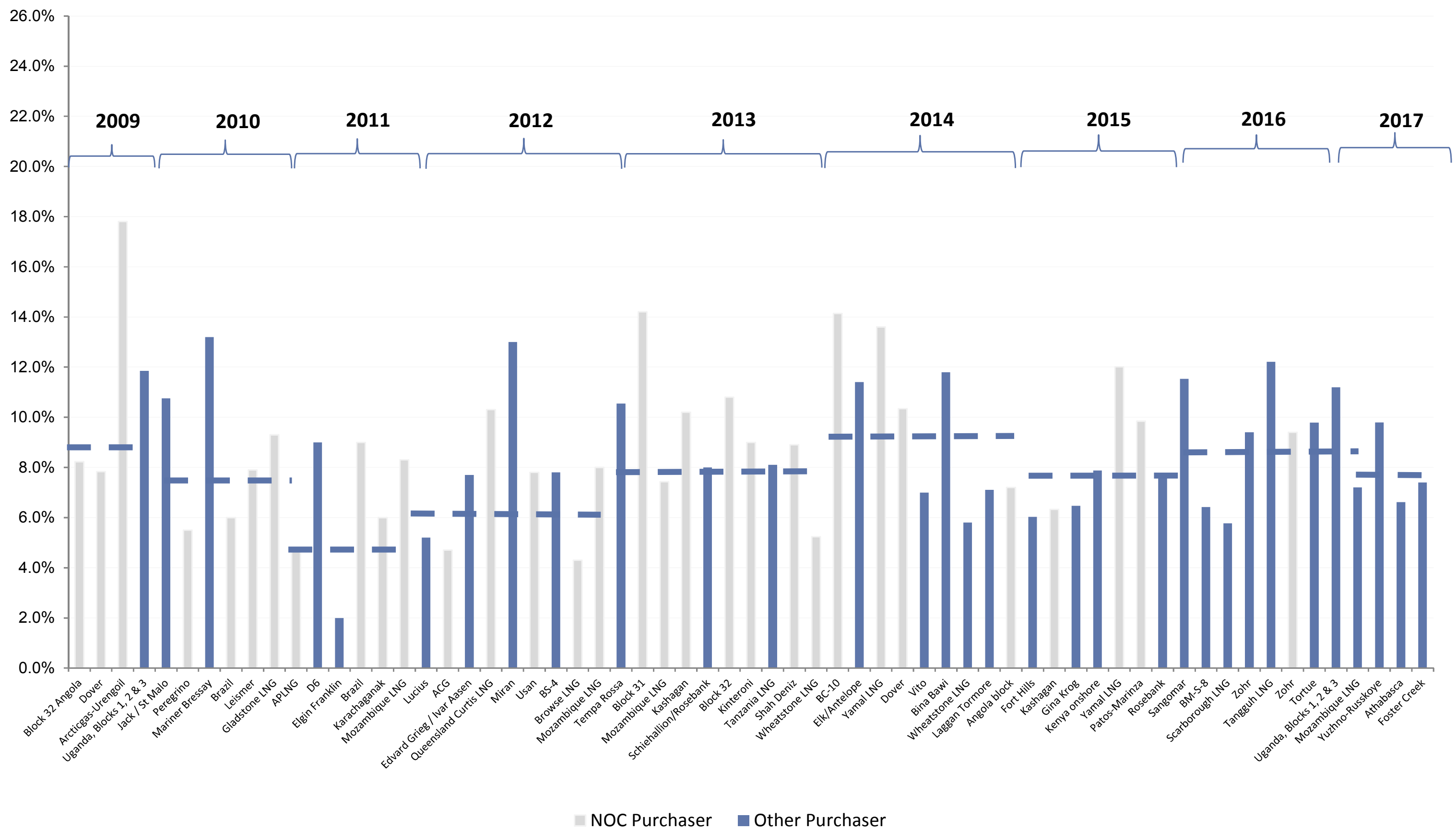


Source: Company data, Goldman Sachs Global Investment Research.

Recent deals show IOCs are becoming more active again, while NOCs fall away

We believe the size and scale of assets analyzed in the Top Projects are advantaged relative to the industry-wide opportunity set. Strategic assets remain scarce and as a result attract premiums, as shown by the lower discount rates that the deals around Top projects achieve. In an environment in which gaining access to low-cost reserves is critical, we have seen implied discount rates for strategic assets remain around 8% through 2015 and 2017. We continue to think that asset-level transactions remain attractive as the NOCs have left the market in 2016, allowing for more favourable negotiating positions for the IOC buyers.

Exhibit 124: Post oil price fall, NOC buyers have fallen away, while IOCs have returned
Implied discount rates of recent deals through time



Source: Goldman Sachs Global Investment Research.

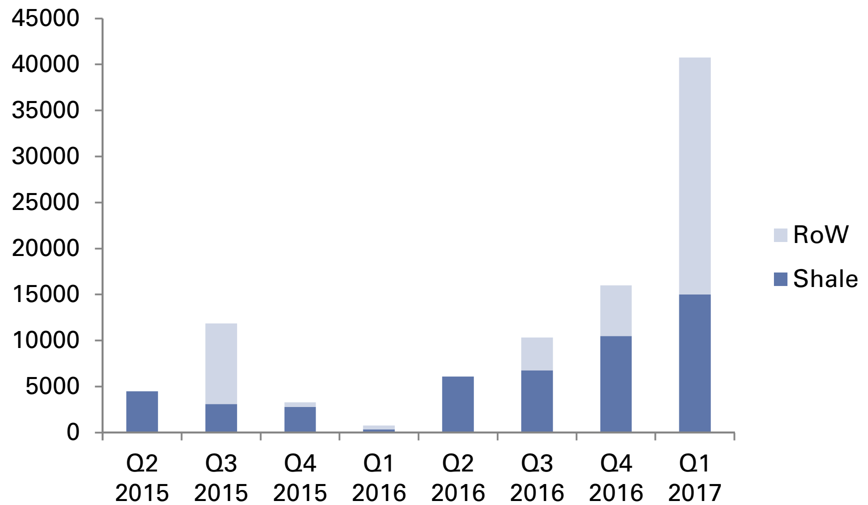
…but shale has seen the greatest volume of M&A deals…

Over the past two years, we have seen over US$49 bn of shale transactions involving GS covered companies. The rest of the world has only seen US$45 bn, even after accounting for US$21 bn of Canadian oil deals in 1Q2017. However, we know that the GS covered companies only cover a relatively small portion of the announced deals in the shale patch.

Within this, 61% (US$29.9 bn) of the deal value has been solely attributed to the Permian Basin in Texas/New Mexico. Interestingly, the much less mature Delaware sub-basin has seen US$21 bn of M&A, while the slightly more mature Midland sub-basin has seen only US$6.3 bn.

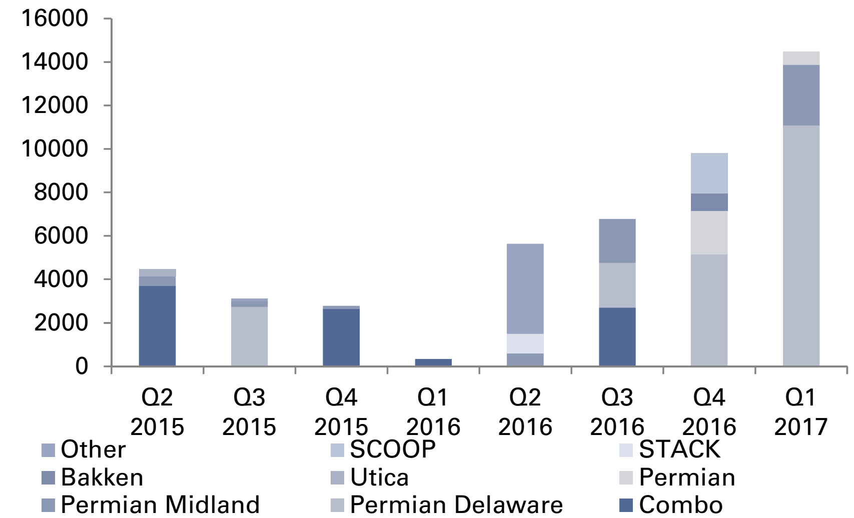
A further US$9.4 bn can be attributed to deals involving multiple plays (typically including the Permian), while the M&A in the Utica, Bakken and Eagle Ford is little more than US$1 bn in standalone deals.

Exhibit 125: Over the past two years, shale has seen more M&A activity than the conventional M&A scene…
M&A by quarter of companies covered by GS and Top Project assets (US$ mn)



Source: IHS, Factset, Company Data, Goldman Sachs Global Investment Research

Exhibit 126: …while the Permian has seen the bulk of M&A value
M&A value by shale basin per quarter (US$ mn)



Source: IHS, Factset, Goldman Sachs Global Investment Research

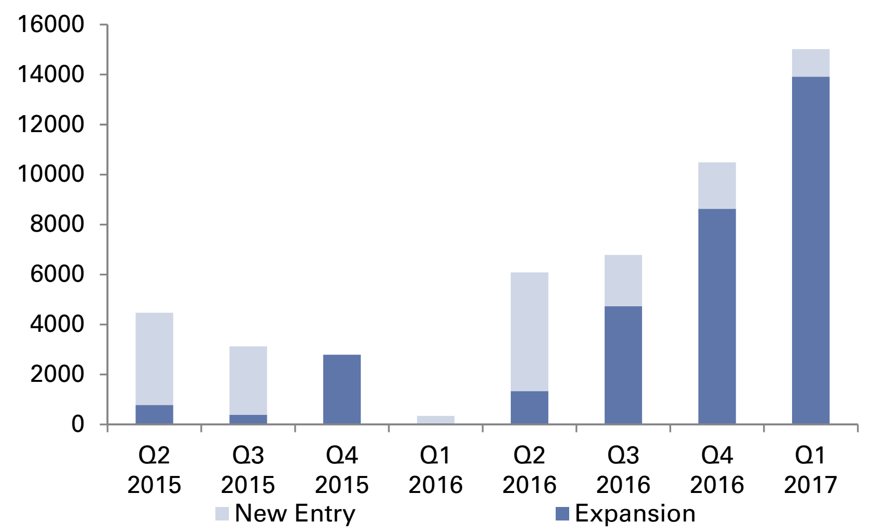
...with shale M&A deals prioritizing contiguous acreage

Over the past six months, we have seen a shift within shale M&A. The portion of companies buying into new plays (where at least one party has been covered by GS) has dropped, while the portion of companies expanding their position in one play has increased. We think this is partly as companies try to buy surrounding acreage to ensure that they can use longer laterals on their acreage, which deliver greater returns than shorter wells.

As seen in Exhibit 128, lateral lengths have increased rapidly over the past few years, a trend which we expect to continue. However, due to the unique land licencing in the US, plots of land can be relatively small. This can pose difficulties when trying to drill wells of over 3,000m. Increased lateral lengths are important for incremental well economics, keeping the well within the pay-zone of the reservoir for longer and enabling more frac stages to be placed, while minimizing the time required to drill down into the reservoir. This increases the recovery per well and can lower the whole well breakeven significantly.

Exhibit 127: M&A value has been driven by companies looking to expand acreage positions…

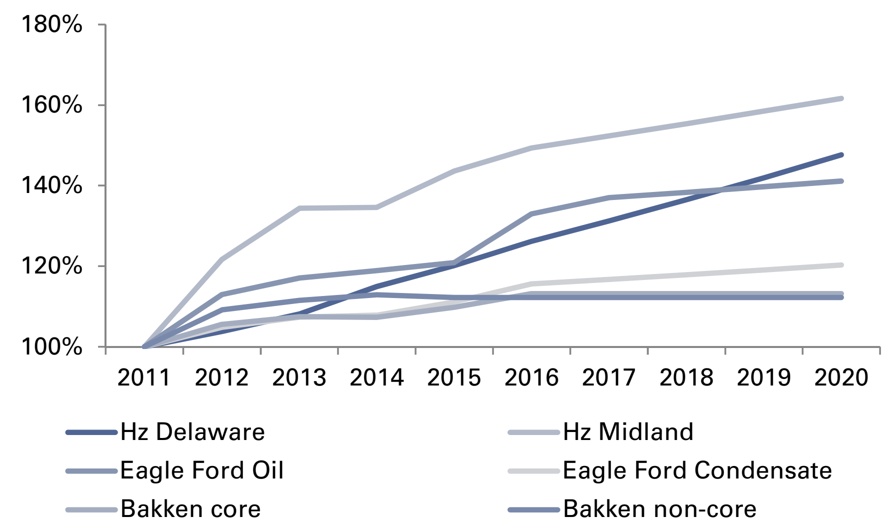
Value of M&A transactions by companies looking to expand acreage positions (“Expansion”) vs acquiring acreage in a new play (“New Entry”)



Source: IHS, Factset, Goldman Sachs Global Investment Research.

Exhibit 128: ...to help lengthen well laterals

Improvement in average lateral length per basin since 2011 (Rebased to 100% in 2011)



Source: IHS, Company data, Goldman Sachs Global Investment Research.

M&A: Companies with value and access to strategic assets

In Exhibit 129, we highlight the companies which have a high level of exposure to world-class material assets, accounting for a high percentage of the company's EV at the country's hurdle rate and at an 8% cost of capital. We note these valuations from Top Projects are unrisked and do not include any value for non-Top Project assets. This is not an M&A target list, as it includes companies with state ownership and blocking shareholders, but it shows pockets of value across the industry that may attract interest from buyers keen to increase their exposure to the industry's next generation of legacy assets.

Exhibit 129: A number of companies have a significant portion of their portfolios in areas which typically see higher discount rates
Strategic assets at commercial and 8% WACC

Company	2017 EV ($mn)	GS covered?	NPV of Top Projects 2017 assets at commercial WACC ($mn)	NPV of Top Projects 2017 assets at 8% WACC ($mn)	NPV of Top Projects 2017 assets at commercial WACC ($mn) vs. EV	NPV of Top Projects 2017 assets at 8% WACC ($mn) vs. EV	Breakeven in $/bbl (*)
Genel	433	y	359	1,186	83%	274%	NA
INPEX	18,346	y	16,090	23,683	88%	129%	93.79
Petrobras	148,084	y	131,400	179,902	89%	121%	39.74
Cenovus	21,283	y	17,070	25,031	80%	118%	71.34
Southwestern Energy	5,274	y	3,962	5,644	75%	107%	Gas-exposed
Kosmos Energy	3,839	y	1,738	3,850	45%	100%	Gas-exposed
Gazprom Neft	27,939	y	17,669	26,406	63%	95%	45.85
ENI	74,766	y	35,341	65,967	47%	88%	57.15
PTTEP	8,811	y	4,810	7,720	55%	88%	Gas-exposed
Lukoil	39,528	y	21,139	34,387	53%	87%	32.09
Cairn Energy	1,531	y	491	1,289	32%	84%	38.60
Canadian Natural Resources	44,969	y	27,815	36,636	62%	81%	75.35
Novatek	37,299	y	19,037	30,080	51%	81%	73.38
Devon Energy	23,543	y	10,972	16,850	47%	72%	53.37
Gazprom	93,768	y	29,734	64,312	32%	69%	46.00
Marathon	17,372	y	7,319	11,885	42%	68%	59.60
Tullow	7,910	y	3,597	5,255	45%	66%	50.60
Hess	20,036	y	8,462	13,054	42%	65%	49.28
Cimarex Energy	10,925	y	4,340	7,072	40%	65%	52.69
Laredo	4,529	y	1,595	2,796	35%	62%	54.65

(*) Oily Projects not yet at plateau only

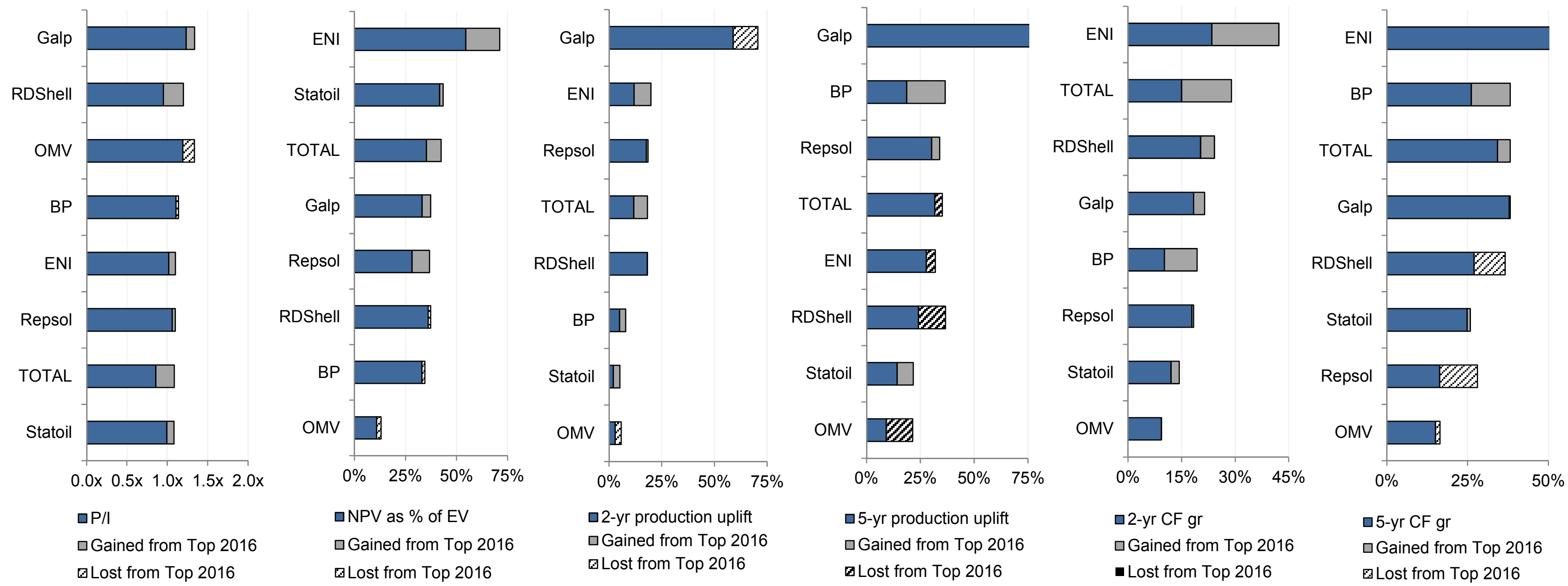
Source: Goldman Sachs Global Investment Research.

European integrated: Improving CF and production uplifts, Galp and ENI stand out

Exhibit 130 compares the European majors' exposure to Top Projects on a number of key metrics (profitability, cash flow and working interest production growth) and tracks how these metrics have changed vs. last year's report. The profitability and materiality of most companies' portfolios have marginally improved relative to last year. We note that all companies' 2-year cash flow uplift improved vs. last year, as 2017 appears as an inflection point with capex at a trough and production ramping up. The large wave of projects sanctions in 2011-14 start to deliver production in 2017 and drive a material ramp up over the next two years. However, due to the lack of investments over the past two years (driven by the fall in oil prices), we note that production and cash flow uplift by the end of the decade remains somehow limited. Galp screens very well across the board, both in the medium and long term, driven mainly by its exposure to the Santos basin (and a relatively low production and cash flow base). Our Top Projects analysis also suggests that ENI will benefit from a material cash flow uplift in the next 2/5 years, supported by a number of start-ups/ramp-ups (i.e. Kashagan, Zohr, Jangkrik, Sankofa) and a falling capex profile. We would highlight that BP screens better in the longer-term (5 year), in line with our view that the group's pipeline of new projects will deliver differentiated superior growth in 2019-21, but will lag its peers in the nearer term.

Exhibit 130: ENI and Galp screen well across the board, supported by a number of new start-ups and ramp-ups

Key Top Projects 2017 metrics and improvement/deterioration vs. Top Projects 2016

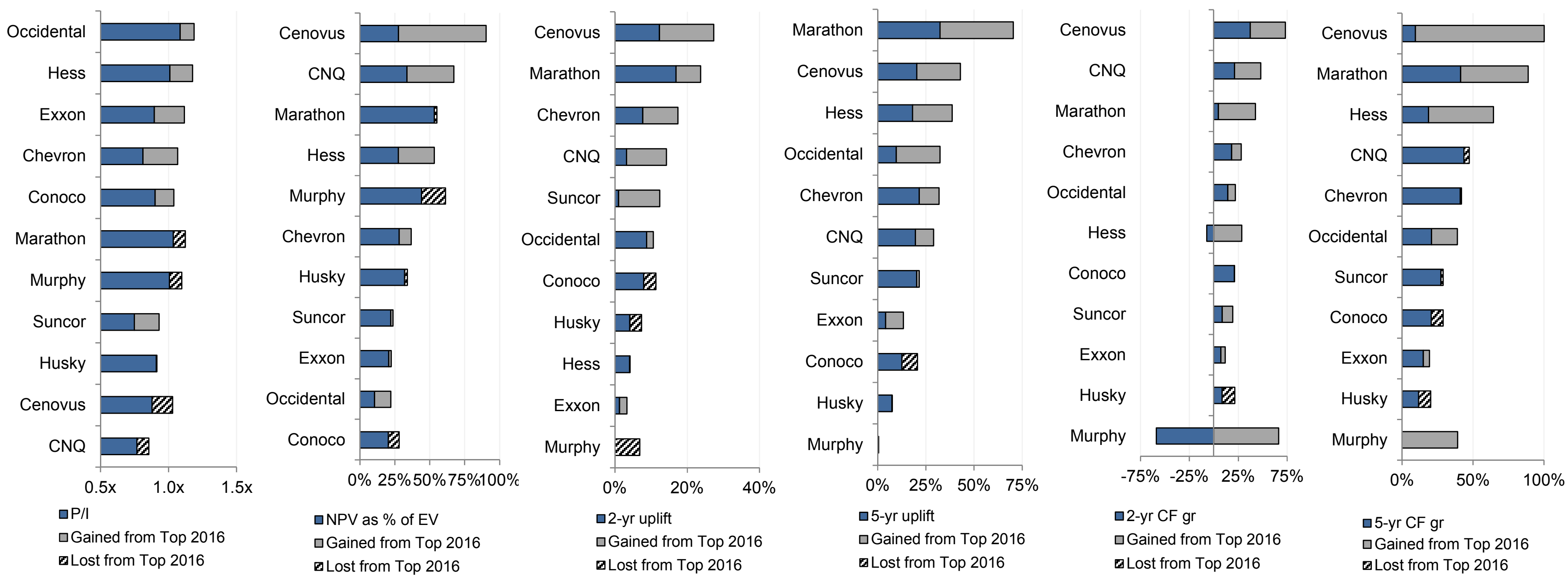


Source: Company data, Goldman Sachs Global Investment Research.

NAM large cap oils: Canadian Oil Sands players stand out

Exhibit 131 compares the North American large cap oils exposure to Top Projects on a number of key metrics (profitability, cash flow and working interest production growth) and tracks how these metrics have changed vs. last year's report. Here again we see a general trend of improvements both in terms of profitability and materiality of Top Projects portfolios. Chevron, Cenovus and Marathon are consistently leading the growth metrics, while Occidental, Hess and Exxon lead the group on profitability of their Top projects portfolio. Marathon continues to display attractive cash flow and production uplift both in the near and the long term owing to its higher-return international projects and robust production growth coming from its Eagle Ford and STACK/SCOOP exposure.

Exhibit 131: Cenovus shows meaningful production and cash flow improvements (vs. 2016), supported by a number of acquisitions
Key Top Projects 2017 metrics and improvement/deterioration vs. Top Projects 2016

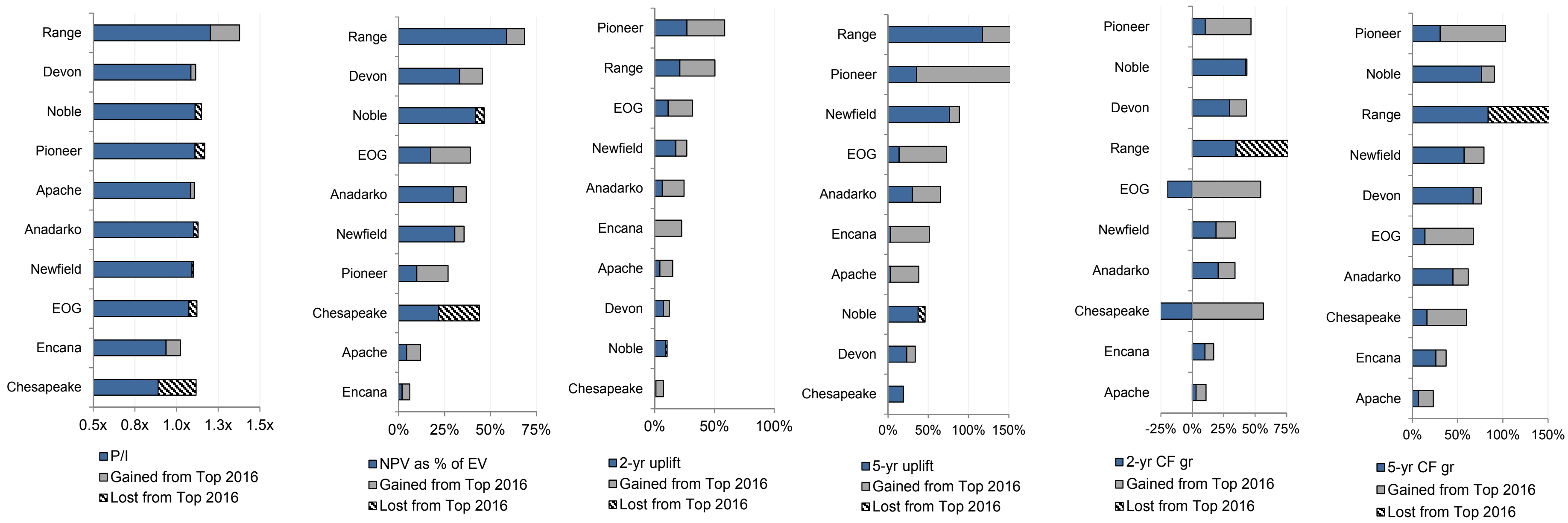


Source: Company data, Goldman Sachs Global Investment Research.

US E&Ps: Range, Pioneer and Noble screen best

Exhibit 132 compares the US E&Ps' exposure to Top Projects on a number of key metrics (profitability, cash flow and working interest production growth) and tracks how these metrics have changed vs. last year's report. Range, Pioneer and Noble dominate the tables; Range thanks to its high-quality exposure to the Marcellus shales, Pioneer to its leading position in the Permian basin and Noble from a wide range of international projects. Chesapeake, Apache and Encana are relative laggards in this analysis, particularly on growth metrics.

Exhibit 132: Range, Pioneer and Noble dominates the table across all metrics
Key Top Projects 2017 metrics and improvement/deterioration vs. Top Projects 2016

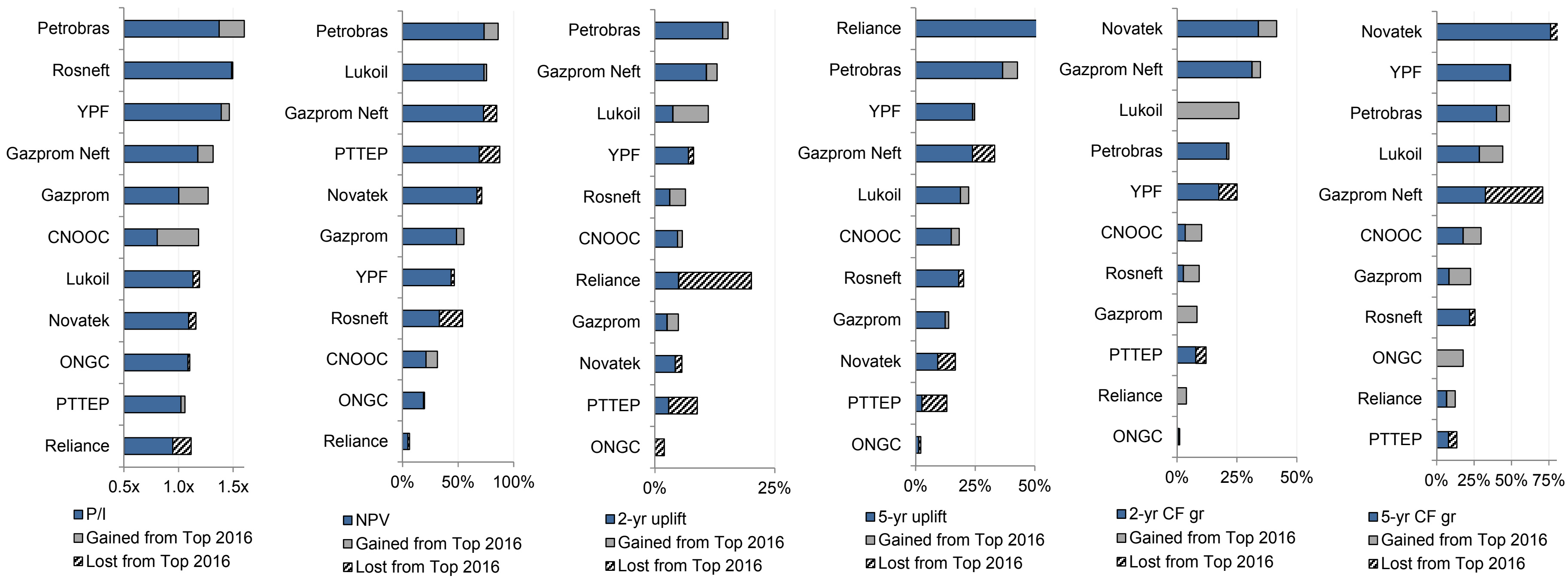


Source: Company data, Goldman Sachs Global Investment Research.

EM Integrated: Petrobras and Novatek stand out

Exhibit 133 compares the EM integrated oils exposure to Top Projects on a number of key metrics (profitability, cash flow and working interest production growth) and tracks how these metrics have changed vs. last year's report. Once again, portfolios' profitability has improved slightly vs. last year, owing to further cost deflation. Petrobras screens attractively given its large exposure to the Santos basin, offsetting deterioration in its Campos basin assets. Russian oils screen consistently well, with Novatek and Gazprom Neft the cash flow growth winners over both two and five years; Novatek' Top Projects portfolio will generate more than twice the company's 2016 DACF over the next five years, on our estimates. YPF appears in the first quartile across most metrics owing to its improving and growing Vaca Muerta assets.

Exhibit 133: Petrobras dominates all metrics owing to its exposure to the profitable Santos basin in Brazil
Key Top Projects 2017 metrics and improvement/deterioration vs. Top Projects 2016



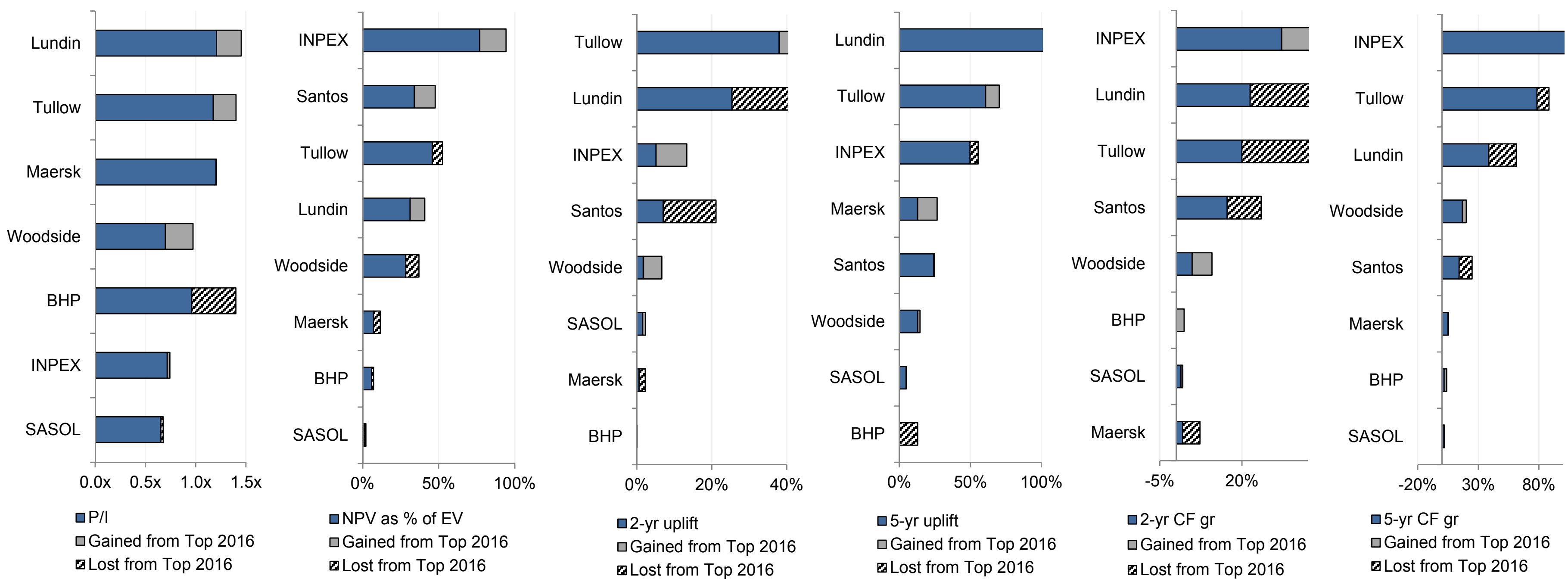
Source: Company data, Goldman Sachs Global Investment Research.

RoW E&Ps: Lundin and INPEX dominates the tables on production and cash flow growth

Exhibit 134 compares the RoW E&Ps' exposure to Top Projects on a number of key metrics (profitability, cash flow and working interest production growth) and tracks how these metrics have changed vs. last year's report. This is a very diverse group of companies, with exposure to different basins. The Australian LNG-focused companies, Woodside and Santos, both see reasonable production and cash flow growth as they ramp up Wheatstone and PNG LNG/Gladstone LNG, respectively. INPEX stands out on growth metrics as Kashagan, Prelude and particularly Ichthys drive material production and cash flow growth over the next two to five years. Lundin screens well in the longer term, particularly as Johan Sverdrup comes on-stream by the end of the decade.

Exhibit 134: Lundin and INPEX stand out with robust cash flow and production uplift

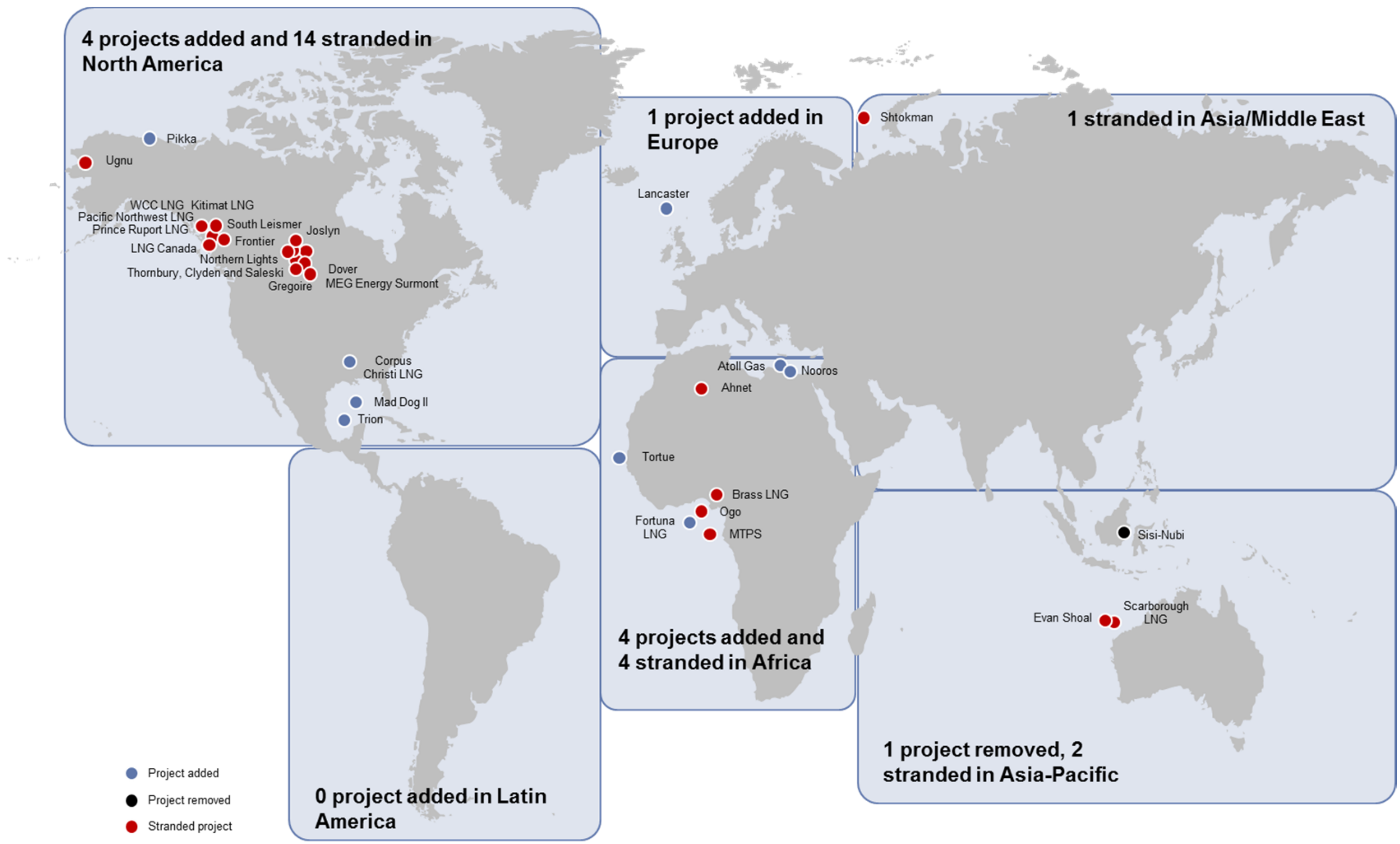
Key Top Projects 2017 metrics and improvement/deterioration vs. Top Projects 2016



Source: Company data, Goldman Sachs Global Investment Research.

New Top Projects – the additions remain limited and come mainly from gas projects

Exhibit 135: Map of changes made in the data set



Source: Company data, Goldman Sachs Global Investment Research.

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Reg AC

We, Michele Della Vigna, CFA, Duncan Milligan, Peter Hackworth, CFA, Maria-Laura Adurno, David Chreng, Kinga Darida, Waqar Syed, Neil Mehta, Brian Singer, CFA, Geydar Mamedov, Franklin Chow, CFA, Mark Wiseman, CFA, Bruno Pascon, Elena Malareva and Umang Choudhary, hereby certify that all of the views expressed in this report accurately reflect our personal views about the subject company or companies and its or their securities. We also certify that no part of our compensation was, is or will be, directly or indirectly, related to the specific recommendations or views expressed in this report.

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