Industry Top Trends 2019

Oil and Gas

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Key Takeaways

- **Ratings Outlook:** The S&P Global Ratings' outlook for the oil and gas sector is broadly stable with a somewhat negative slant for the oilfield services (OFS) and contract drilling segments. The ratings outlook largely reflects our assessment of the sector's improved balance sheets and cash flow metrics and a generally range-bound outlook for hydrocarbon prices.
- **Forecasts:** Our forecasts show slightly improving credit metrics compared with last year due to higher oil and gas production and improved non-North American pricing and volumes for OFS equipment.
- **Assumptions:** Our 2019 hydrocarbon price assumptions are broadly flat, mirroring the futures curve trends. We expect global capital expenditures (capex) to increase nominally, with the U.S. demonstrating more substantial increases as steep decline curves warrant high investment. We don't expect North American OFS to improve much more due to regional takeout capacity restraints in the U.S., flattening rig counts, and product-line oversupply in some sectors of the OFS segment. We believe the offshore deepwater market has bottomed and won't experience a significant rebound anytime soon because the oil prices outlook doesn't support many greenfield projects and there's still too much rig supply in the market.
- **Risks:** Hydrocarbon price risk remains the number one risk in the sector. Slowing demand, regulatory issues delaying regional capacity pipeline construction, and regional price differentials remain the near-term threats. Over the medium to longer term, the sector has a significant amount of debt maturing over the next couple of years and any substantial drop in prices could lead to another round of defaults and bankruptcies. Acquisition activity has picked up but the use of equity has been more prevalent than debt funding.
- **Industry Trends:** The 2019 outlook for many of the sector's industries is one of general stability and largely reflects the range-bound price environment for hydrocarbon prices. Many companies have reduced debt through asset sales or equity offerings. The industry has had capital market access but a pervasive shift has occurred in the equity markets that are now demanding companies grow but live within cash flow and not overspend. Over the long term, energy transitions could be a key theme—including, for example the adoption rate of electric vehicles. The effects on strategy vary significantly by company.

Ratings trends and outlook

Global Oil and Gas

Chart 1

Ratings distribution by region

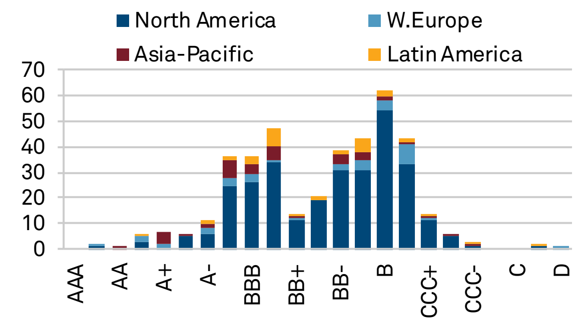


Chart 2

Ratings distribution by subsector

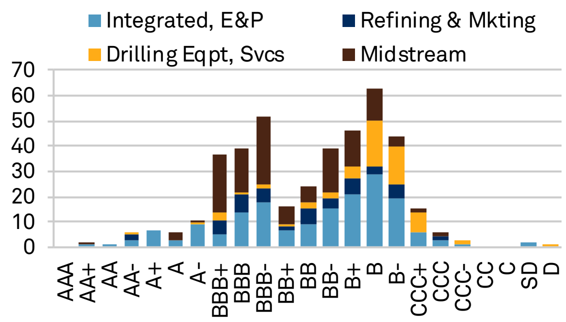


Chart 3

Ratings outlooks

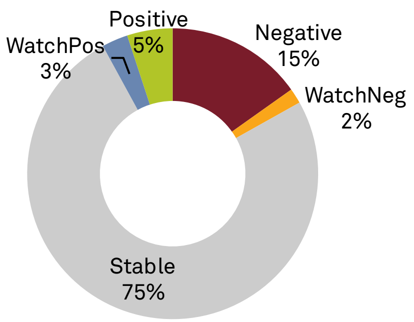


Chart 4

Ratings outlooks by subsector

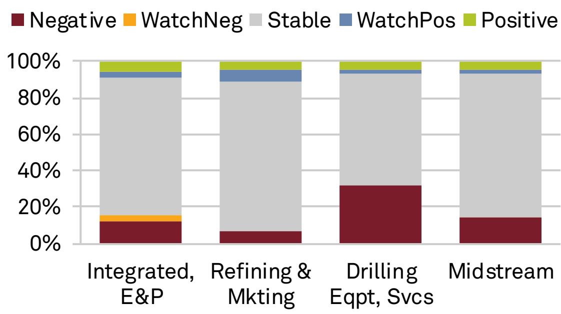


Chart 5

Ratings outlook net bias

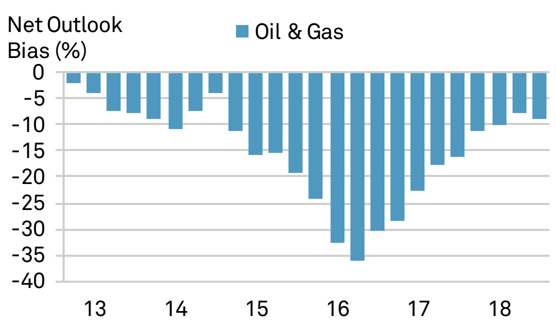
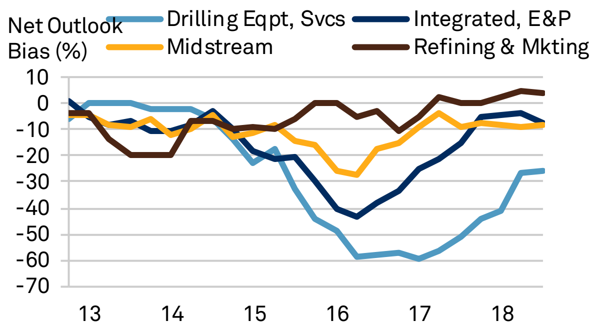


Chart 6

Ratings net outlook bias by subsector



Source: S&P Global Ratings. Ratings data measured quarterly with last shown quarter ending September 30, 2018

Ratings improvement has largely been driven by the general improvement in hydrocarbon prices, actions taken by companies to improve balance sheets, financial policy discipline, and improved cost and productivity profiles. The rating spectrum is still highly weighted toward high yield because most issuers are in the U.S. and we rated them during the four-year period prior to the November 2014 OPEC meeting. The OFS industry has the preponderance of negative outlooks in the sector, largely reflecting recovery prospects for the offshore contract-drilling segment and the difficulty OFS companies have recapturing their pre-oil collapse margins. Despite the improvement we've seen in the sector and the overall price increases they've initiated, price increases and volumes are insufficient to garner adequate rates of return and healthy credit ratios. Liquidity in the sector remains healthy because of robust debt markets, with attractive rates and covenant-lite loans being the norm. The banking environment and borrowing bases are stable and we don't expect any declines in borrowing bases during upcoming redeterminations.

Industry forecasts

Global Oil and Gas

Chart 7

Revenue growth (local currency)

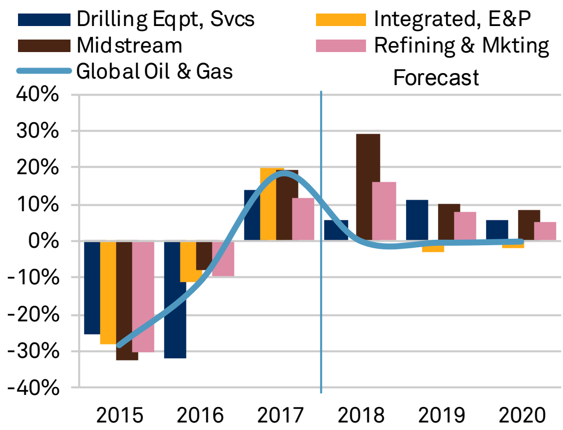


Chart 8

Capex growth (adjusted)

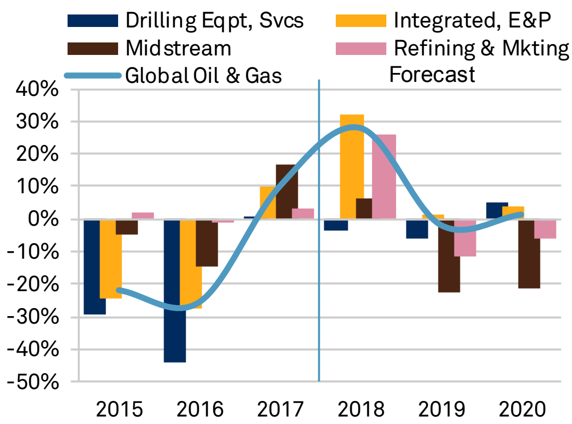


Chart 9

Debt / EBITDA (median, adjusted)

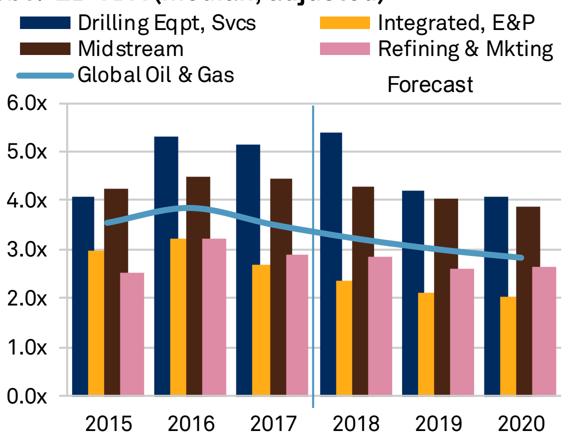
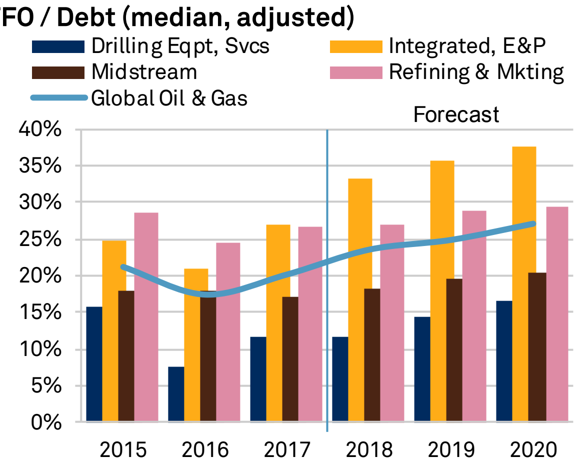


Chart 10

FFO / Debt (median, adjusted)



Source: S&P Global Ratings. Revenue growth shows local currency growth weighted by prior-year common-currency revenue-share. All other figures are converted into U.S. Dollars using historic exchange rates. Forecasts are converted at the last financial year-end spot rate. FFO--Funds from operations.

Credit metrics continue to improve owing largely to improved hydrocarbon prices, increasing production and midstream throughput, better non-North American OFS prices, and a healthy outlook for refining margins. In aggregate, companies in the exploration and production (E&P) segment are increasing production but managing to live within cash flows and are maintaining healthier balance sheets.

Key assumptions

Exploration and Production

1. Oil prices

Our base case price deck for Brent and West Texas Intermediate (WTI) is in a slight backwardation, mirroring the futures curve. Our price deck assumes Brent and WTI prices are per barrel (bbl) $65 and $60 for 2019, $60 and $55 for 2020, and $55 and $55 for 2021 and beyond, respectively. Oil fundamentals remain reasonably favorable owing to the 1.8 million bbl per day (d) of production cuts from OPEC and several other nations. The supply cuts helped to reduce global oversupply and record high global inventory levels to five-year, normalized ranges. Despite OPEC slowly unwinding those production cuts, we aren't too concerned about oversupply because it's possible Iranian exports could be lower by 1 million bbl/day by mid-summer 2019 and Venezuela's production continues to decline. Moreover, North American takeout capacity restraints, particularly in the Permian Basin, have limited production growth at least for now. Moreover, U.S. producers, yielding to investor sentiment, are curtailing aggressive spending and production, opting to live within cash flows, which limits rampant production growth**.** OPEC has signaled their support to keep oil prices somewhat range-bound with Saudi Arabia pointing to their spare capacity in the event of a significant reduction in production.

2. Natural gas prices

Our natural gas price deck is stable at $3.00 per Btu over the next three years. Our premise hasn't changed from last year. We believe there is ample natural gas supply in the U.S., particularly from the Northeast where the prolific and low-cost Marcellus and Utica shale plays will continue to supply much of the growth in natural gas demand. The slow rise in long-term natural gas demand is primarily driven by coal-fired utilities switching to natural gas, increased liquid natural gas (LNG) use, and exports to Mexico. Northeast regional differentials relative to the Henry Hub, continue to recover due to the significant amount of takeout capacity that was added and being built in the region. A lot of associated gas comes from extensive oil drilling occurring in the Permian Basin.

3. North American oil and natural gas differentials

North American regional differentials, which we factor into our credit analysis, are more problematic for oil and gas producers. The price for oil at the Midland, Texas oil price hub, which is more reflective of Permian oil fundamentals, is trading well below the price of WTI Cushing, Okla., due to limited takeout pipeline capacity. We believe this well be alleviated sometime in the first quarter of 2020 when additional pipeline capacity begins to come online. Similarly, Western Canadian Select, the Canadian oil benchmark, is also trading well-below WTI due to takeout capacity limitations. However, it's difficult at this juncture to ascertain when this will be alleviated because of ongoing Canadian regulatory and court battles that have delayed or cancelled pipeline additions. For natural gas, the Waha gas hub in Texas is trading below the benchmark Henry Hub. While there is sufficient takeout capacity from the region to move the bi-product (from oil drilling) gas, delayed infrastructure demand from Mexico has caused the differential to collapse. Permian gas is finding its way into the Denver-Julesburg basin and has caused differentials there to widen as well. Additionally, the price for natural gas at the AECO storage facility in Alberta, Canada, is trading well below Henry Hub due to lack of takeout capacity basically from the NOVA Gas Transmission System, but we expect that to be alleviated in early 2020 barring further legal or regulatory delays.

Oilfield Services

1. Rig count

The global rig count (not including North America) stands at 1,044 as of the date of this report, up 8% from last year and 9% from the cycle low of 920. International markets tend to be less volatile on both the downside and upside, incorporating the influence of national oil companies and lack of short-cycle development typical of shale. Venezuela continues to be a drag on the total rig count because of financial distress.

The U.S. rig count grew strongly in 2018 to reach 1,067 after recovering from the trough of 404 in May of 2016. The rebound has been driven primarily by the oil price rebound. Activity in the oil-focused Permian Basin in western Texas has been particularly intense, with 490 rigs operating now, up from a low of 132 in 2016. We expect growth to flatten in 2019 due to a plateau in oil prices and pipeline constraints in the Permian that are likely to continue until late in the year, undermining regional prices. The U.S. natural gas rig count has remained relatively flat--just under 200--over the past year because natural gas prices have hovered around $3. We expect gas to remain relatively flat for 2019, and we don't believe there will be a significant increase in the overall gas-focused rig count.

2. Margins

OFS companies captured margin gains in 2018, continuing to build from the 2016 bottom of the cycle. Costs of ramping up capacity to meet increased activity levels dampened profits, however. We expect excess capacity to be a drag on additional margin improvement in 2019. The slowdown in completion activity in the Permian, which is likely to continue until transportation constraints are resolved late next year, will also limit margin upside. On the cost side, we expect OFS companies to be able to largely pass increased prices for material such as steel (due to tariffs) and sand (due to supply and logistics issues) to customers. Increased labor costs due to the tight U.S. market, will likely be borne by service providers. Internationally, we expect stronger growth and less dynamic supply to give OFS providers somewhat more pricing power.

3. Spending

We expect E&P capital spending growth to be limited in 2019, consistent with moderating oil prices. U.S. companies are sensitive to investor aversion to outspending cash flow and focus on return of capital to shareholders. We also expect efficiency gains, while slowing, allow drillers to be more productive with less money. International spending will likely be incrementally stronger, in the range of 5% to 10%, driven by the major and international oil companies' need to improve reserve replacement and modest increase in offshore activity.

Refining

1. Gasoline and distillate demand

Emerging economies, especially China and India, will likely remain the drivers of global gasoline demand growth, as well as for other oil products. In contrast, demand from the Organization for Economic Cooperation and Development (OECD) members is likely to be flattish or only moderately positive in 2019, despite our base case view that global and OECD GDP growth will continue at a healthy rate. The U.S. may see stronger demand in line with its stronger GDP trajectory. We currently forecast U.S. demand growth of about 1.1%, generally in line with Energy Information Administration (EIA) estimates. Importantly, we see the higher prevailing crude and product prices in 2018 having a dampening effect on demand, especially for countries such as India and Brazil, where local currency depreciation against the U.S. dollar has meant domestic fuel prices have rebounded strongly.

2. Increasing crude oil production

The IEA estimates global crude oil supply growth of 2.2 million barrels per day (mm bbl/d) in 2018 moderating to a still robust 1.8mm bbl/d in 2019. The U.S. remains the largest single contributor to oil supply growth in 2019, with total production projected to increase to about 1mm bbl/d to 11.8mm bbl/d, although we also anticipate the agreed relaxation of OPEC cuts from June 2018 and growth from Brazil and Canada will be significant. Despite lower production from Venezuela and exports from Iran, as a result of U.S. sanctions, higher prices are supporting net production growth. The shifts in the quality and grades of the global mix of crude oil may become more significant for refiners. U.S. onshore tight oil production is typically lighter than Middle Eastern crudes, for example.

3. Refining margins

Our working assumption is that average 2019 refining margins are broadly in line or above 2018 levels. We see conflicting drivers for refining margins in most regions in 2019. In the latter half of 2019, the implications of the International Maritime Organization (IMO) 2020 changes may well be supportive for diesel cracks and refining margins overall. However, in the first half, as in late 2018, higher crude feedstock prices could undermine refining margins, especially if capacity additions and refinery runs outstrip product demand.

Our ratings are underpinned by our base case assumptions, but also generally factor in some headroom for short-term volatility and longer-term cyclicality of prices and margins. This is particularly true when prevailing prices and our assumptions are relatively high in a historical context.

Contract Drilling (Offshore)

1. Utilization may have stabilized for floaters, and is increasing for jack-ups

After reaching a peak of more than 80% in 2013, utilization for floaters dropped to around 50% in 2017, and we expect levels to remain essentially flat until 2020. Although tenders and bidding activity for ultra-deepwater and deepwater floaters have recently picked up, we expect any new fixtures to essentially offset contracts that are rolling off over the next 12 months. Meanwhile, utilization for jack-ups has increased from around 50% in 2015 to nearly 65%, given the lower breakeven costs and shorter payment periods associated with shallow water wells.

2. We expect low day-rates until 2021

Although we expect utilization for floaters to improve in 2020, we don’t expect it to reach 85% until year-end, which is typically the level at which dayrates begin rising. We assume new contracts on ultra-deepwater rigs will be in the $200,000 to $225,000 per day range, on average, in 2019, increasing to about $250,000 per day in 2020, with some variation depending on the rig quality and location.

3. There are still too many rigs

Although we do expect an uptick in offshore drilling demand starting in 2020 from about 145 floaters today, there are still 30 to 50 new floaters under construction, and--assuming these are all delivered--we estimate the industry will need to scrap additional rigs to balance the market. Although we have a negative outlook on the offshore contract drilling sector for the next two years, we believe the long-term need for E&P companies and majors to replace offshore reserves after years of significant under-investment will drive increased demand for offshore rigs.

Midstream

1. Commodity prices

Our base case price assumptions for WTI and Brent crude oil is $60/bbl and $65/bbl, respectively, for 2019. We then have WTI decreasing to $55/bbl for 2020 and beyond. Our Brent crude oil price is $60/bbl in 2020 and $55/bbl in 2021 and beyond. Our price assumption for natural gas is unchanged at $3 per million through 2021. We are forecasting that natural gas liquid (NGL) prices average about 80 cents per barrel for the first half of 2019 and about 70 cents per barrel in the second half after fractionation capacity constraints are addressed. Under these price assumptions, we don't expect commodity prices to substantially damage midstream companies' credit profiles because most already have largely fee-based contract profiles. However, we think the flat-price environment could cause a slowdown in organic growth projects, especially if upstream companies slow down their production spending.

2. Widening crude oil differentials to persist

We expect crude oil differentials to persist, mainly due to pipeline infrastructure constraints in Western Canada and West Texas. While we believe West Texas crude differentials could narrow by the end of 2019 as pipelines are placed into service, constraints in Western Canada are more complex, with regulatory roadblocks that may require more time to resolve than the typical construction time to build a long-haul pipeline. Other infrastructure projects will address the need for takeaway capacity for natural gas and natural gas liquids, along with more export capacity, which should start yielding results by the end of 2019.

3. Capital allocation discipline

With most midstream equities yet to recover from the last commodity price cycle, capital discipline will be more important than ever. We believe most midstream companies will maintain robust distribution coverage ratios of at least an average 1.2x and use excess cash flow to fund the equity portion of organic projects instead of on common preferred equity. This "self-funding" model will become more prominent, as will an increase in joint-venture projects among strategic players in the most highly competitive basins like the Delaware.

Key risks and opportunities

Exploration and Production

1. IMO 2020 (see side panel)

With the International Maritime Organization requiring ships to reduce their sulfur emissions on Jan. 1, 2020, from 3.5% to 0.5%, we could see demand and prices for 3.5mm bbl of “sour” grade crudes, which are high in sulfur content, immediately collapse. Producers who can produce “sweet” (low in sulfur) oil should realize higher prices as refineries that lack the necessary complexity (equipment) to process sour crudes into light distillate/low-sulfur fuel oil--a product that will be demanded by shipping companies to comply with the new regulation--will increase demand for sweeter crude. Producers in the U.S., North Sea, and West Coast of Africa who produce light/sweet crude, stand to benefit from higher prices for their crude. Producers of heavy/sour based crudes, such as producers in Canada, the Middle East, and Mexico to name a few, will likely immediately see lower prices for their crude as lower demand from refineries hurts pricing. Depending on how long this lasts and how wide the differentials are, it’s possible we could raise the credit ratings on some producers if they use excess cash flow for debt reduction.

2. Capital market access

The oil and gas industry faces a significant amount of debt maturities over the next couple of years. This is due to many companies issuing or refinancing debt during the high oil prices of 2012-2014. Any severe declines in the price of oil or a capital market liquidity crisis, would result in a significant amount of companies being unable to refinance their debt and could lead to another wave of bankruptcies. Equity investors are also becoming less patient with companies that continually outspend cash flow to increase and use debt to fund the difference. They are placing a premium on issuers that can grow within cash flow. We expect borrowing bases, which are the life blood for many high yield companies, to remain stable. However, a distressed pricing environment coupled with the impact of reduced drilling budgets, could constrain liquidity.

3. A sharp downturn in the global economy in 2019

A sharp downturn in the global economy clearly would result in a significant decline in demand and thus oil prices. Recent history suggests oil prices could decline severely in a recession. During the industry trough of 2015-2016, the price of WTI and Brent averaged $43.15 and $43.55 per bbl, respectively. Trading actually saw both Brent and WTI fall from more than $100 to below $30 per bbl in early 2016 although prices didn’t stay there very long. In the previous industry down turn in 2008, oil prices retreated from a high of more than $145 per bbl, bottoming out at $32 spurred on by the financial crisis, a stronger U.S. dollar, and lower global demand. Predicting oil prices through a recession is difficult but just as difficult is how long oil prices will stay low. In 2009, we saw a rapid rebound in prices. Given this rapid increase, few oil and gas companies defaulted because they were able to weather the brief downturn. However, with shale production growing in significance since then, the recent downturn lasted more than two years, resulting in a significant amount of bankruptcies and defaults. If the recent downturn in oil prices is any indication of what oil prices could look like and for how long during a 2019 recession, we think there could be another significant wave of bankruptcies

IMO 2020

From Jan. 1, 2020, the sulfur limit will be reduced to 0.5% mass by mass (m/m) from 3.5% currently.

This change has major implications for refiners, because they are producers of the currently used high-sulfur fuel oil (HSFO) and also as producers of most of the lower-sulfur substitutes from 2020.

The majority of the international shipping fleet will need low-sulfur fuels in the short run from Jan. 1, 2020, because the number of LNG-fueled vessels and ships with chemical scrubbers (to remove sulfur) are likely to still be in the minority.

In 2020, demand for and relative prices of HSFO are likely to drop while demand for low-sulfur diesel and other blending components could rise significantly, at least for a period until markets adjust.

We don’t anticipate a substantial increase in investments in 2019 to address these changes in oil product demand, because we believe it’s too late for refinery upgrades that are not already underway. The benefits to refining margins could also be relatively short-lived. See additional

Oilfield Services

1. Hydrocarbon Prices

We view a sudden drop in commodity prices as the main risk to the credit quality of OFS companies. Under our assumptions, development levels should be robust in 2019. We note that regional price differentials due to infrastructure constraints such as those in the Permian may affect spending decisions even if index prices are strong. E&P companies, and U.S. shale producers in particular, have lowered costs since the last downturn, and we believe operators are capable of maintaining activity at lower oil and gas prices than previously. Part of the gains have been due to lower service prices, however, and as prices rise we expect E&P breakeven levels to creep back up.

2. Limited Price Improvements

Prices for most services haven't recovered to the level before the last downturn. This is partly due to excess industry capacity. E&P companies are also sensitive to investor sentiment against outspending cash flow. Increased efficiency means that E&P companies can drill and complete more wells with fewer rigs and less time than previously, resulting in lower demand. We expect pricing gains to be limited next year, though certain markets with tight dynamics such as the Permian may outperform others.

3. A sharp downturn in the global economy in 2019

A slowdown in economic activity almost always leads to falling commodity prices, which, in turn, leads to lower E&P spending. OFS companies would see a drop in revenue and tighter margins, leading to weaker credit measures. E&P companies, especially shale drillers, have improved efficiencies since the last downturn and demand for services may be somewhat more resilient but still highly cyclical. We also note that OFS companies haven't regained all of the margin lost in the last trough, meaning that the expected drop in prices in a hypothetical 2019 downturn may not be as severe as experienced two years ago.

Refining

1. IMO 2020 (stricter low-sulfur marine fuel requirements)

In general, IMO 2020 presents a risk to low-complexity refineries with limited crude and product flexibility, but an opportunity for complex refiners. The IMO is further tightening the limit on sulfur in "bunker" fuel for ships. This change has engendered significant uncertainty about the implications for marine-fuel product demand patterns, particularly in 2020, with respect to the flexibility of refiners and traders to produce and supply the necessary volumes of these products and the consequences for pricing of both products and different crude feedstock grades. U.S. refining equity prices have been hurt by calls from the current U.S. administration to have a phase-in plan to minimize the IMO's impact on fuel prices during a presidential election year. While we view this as unlikely, it's worth monitoring in 2019 because it can affect U.S. refiners' decision-making if equity prices remain weak.

2. Increasing refining capacity

We note that global refining capacity additions in 2019 at about 2mm bbl/d are likely to be the greatest since 2009, according to the IEA. These are mostly in non-OECD countries: half in China and most of the rest in Saudi Arabia, Brunei, and Malaysia. Some of this Asian capacity is focused on petrochemicals, a key driver of oil demand outside transportation. Nonetheless, the trend of high refinery utilization in recent years in North

America and Europe, (with declines in Latin America and Africa) could change as competing capacity comes online--particularly in 2019--or margins could come under some pressure.

3. A sharp downturn in the global economy in 2019

A significant deviation from our base case view of global GDP growth would likely affect our assumptions for oil product demand. Crude and product prices in local currencies have a bearing on demand, but S&P Global Platts Analytics has noted that shifts in GDP growth can have a more significant impact. A downward revision in demand expectations, as a result of tariffs and trade wars or other reasons, even if accompanied by a downward move in crude prices, could severely compromise refining margins, especially if capacity continues to increase and utilization levels decline.

Contract Drilling

1. Costs continue to drop for offshore production and development

Although breakeven costs have come down considerably over the past three years for offshore developments, we estimate the long-term oil price required for a greenfield offshore project is still in excess of $60/bbl. This compares with the breakeven costs of many unconventional onshore shale projects at about $30/bbl. If offshore producers are able to continue to reduce costs, for example by using existing infrastructure or standardizing equipment, demand for offshore rigs and equipment would likely increase earlier than we currently anticipate.

2. Faster rate of rig scrapping

Although we estimate that nearly 115 floaters have been retired since 2014, there are about 100 stacked rigs and 35 to 50 newbuilds expected to be delivered over the next two years, putting pressure on overall utilization even as demand grows. More rapid retirement or scrapping of rigs across fleets could address market oversupply and improve utilization and therefore dayrates sooner. We note that recent mergers and acquisitions in the sector could result in increased rig retirement, as drillers optimize their fleets.

3. A sharp downturn in the global economy in 2019

A sharp downturn in the global economy would likely result in lower demand for crude oil and, as a result, lower crude oil prices. This would hurt E&P companies' cash flow generation and thus their ability and willingness to spend on long-term deepwater projects, which do not typically generate cash flow for several years. In this scenario, we would expect the recovery in offshore-rig demand to be pushed out further, into late 2020 or 2021.

Midstream

1. Simplification leading to improving credit profiles

Most midstream master limited partnerships have simplified their corporate structures, which we view as a generally positive credit factor. The elimination of high-cost incentive distribution rights and distribution cuts should result in improved equity costs and less reliance on equity funding in general. In some instances, a corporate simplification can burden the balance sheet with higher leverage and more limited financial flexibility initially, particularly if the general partner had its own debt. However, we expect most midstream companies that have gone through a simplification transaction to improve their credit profile within the next 12-18 months through higher EBITDA, while keeping absolute debt levels relatively flat.

2. Regulatory pressure

Regulatory hurdles present the biggest unknown in 2019, but based on past experience could have a significant impact on ratings and outlooks if the effect is a substantial project delay or cancellation. We've already seen this with the Trans Mountain Pipeline expansion, and Keystone XL, and we expect it to continue to the types of ballot initiatives that we've seen in Colorado and permitting decisions for the Mountain Valley Pipeline project. Generally, a small or moderate delay won't lead to an adverse ratings outcome, but extended delays that push EBITDA out for a year or longer, or increased costs, are greater risks.

3. A sharp downturn in the global economy in 2019

A significant deviation from our base case view of global GDP growth would likely have an impact on our assumptions for oil product demand and commodity prices generally. A downward revision in demand expectations, along with lower prices for crude oil, natural gas, and natural gas liquids, would likely affect production plans for E&P companies, including lower rig counts and volume forecasts. This, in turn, would have the greatest impact on midstream companies with commodity price exposure because they would also experience volume losses as would those companies that primarily only have fee-based contract profiles.

Cash, debt, and returns

Global Oil and Gas

Chart 11

Cash flow and primary uses

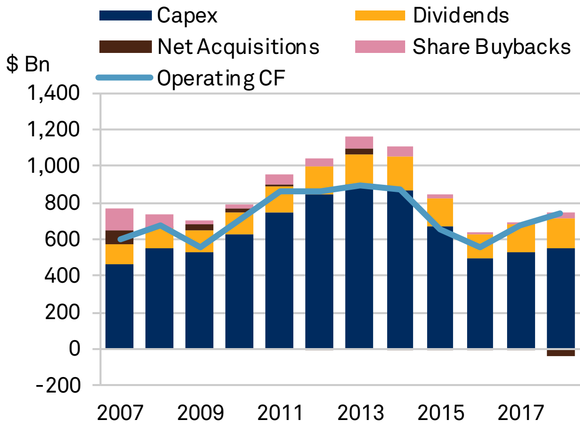


Chart 12

Return on capital employed

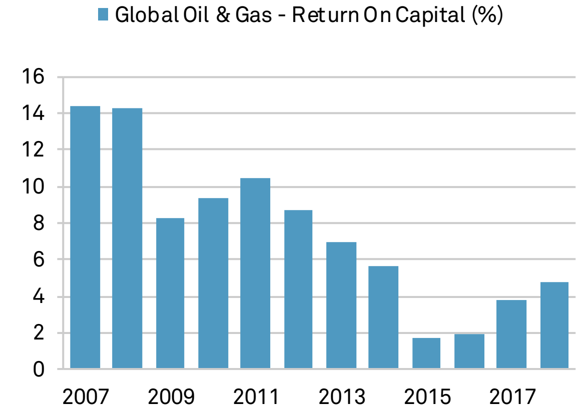


Chart 13

Fixed versus variable rate exposure

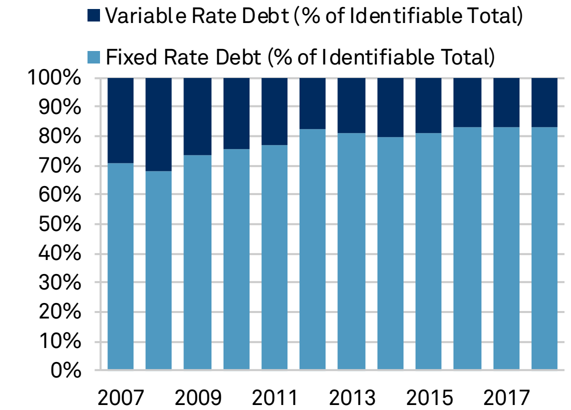


Chart 14

Long term debt term structure

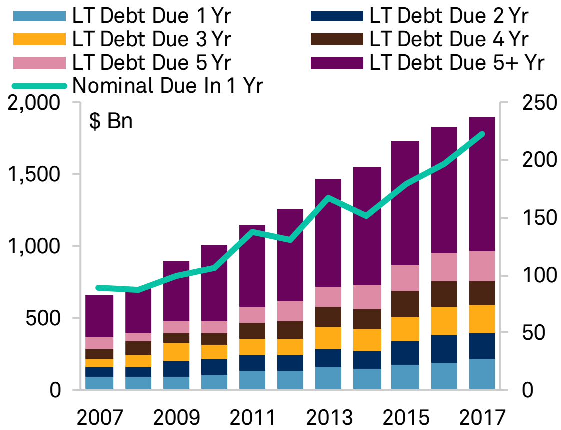


Chart 15

Cash and equivalents / Total assets

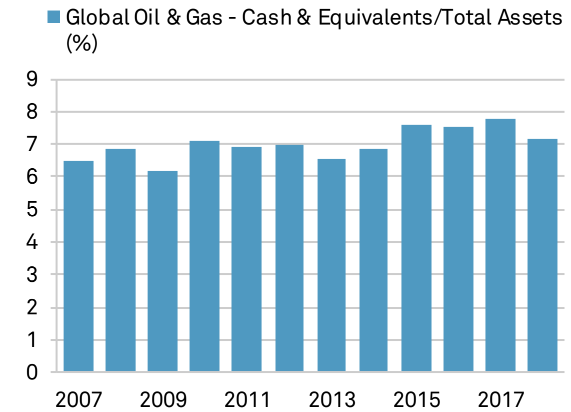
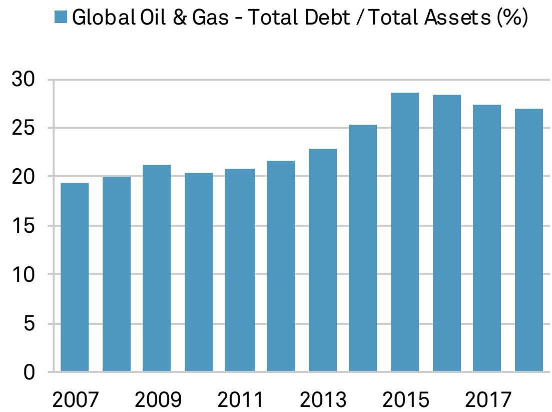


Chart 16

Total debt / Total assets



Source: S&P Global Market Intelligence, S&P Global Ratings calculations

spglobal.com/ratings