Industry Top Trends 2017

Oil and Gas

Overview

- **Ratings Outlook:** Rating trends across the energy sector continue to stabilize. The subsectors with the highest percentage of negative outlooks primarily are oilfield services and offshore contract drilling. The tremendous number of downgrades and bankruptcies we saw over the past two years will not likely be repeated.

- **Forecasts:** Credit ratios for many upstream companies are improving materially owing to the rebound in hydrocarbon prices. Going forward, we expect credit ratios to improve nominally as volumes and oilfield-service (OFS) prices increase and more cost efficiencies are achieved upstream.

- **Assumptions:** Our hydrocarbon price decks for oil and natural gas are flat owing largely to relatively flat futures curves and reduced production costs. We expect capital expenditures (capex) to begin increasing along with an increase in OFS costs of about 10% in 2017, led by North America. We expect offshore drilling to remain weak and still vulnerable to additional new supply entering the market. We also think gasoline demand will likely increase modestly with a more robust response in distillate. There could also be some modest improvement in overall industry crack spreads.

- **Risks:** Hydrocarbon price risk is of great concern mainly because we don’t know whether OPEC will continue with its six-month production-cut agreement at the end of June. Also, there is a high degree of uncertainty regarding sweeping GOP tax reforms and what the implications could be for the energy sector.

- **Industry Trends:** The industry should remain relatively stable for at least the next six months while the oil and gas markets catch their breaths following the prolonged downturn and 2016 upturn. The near-term oil price driver is the market perception of the effectiveness and longevity of the OPEC cuts and the production response from U.S. shale. In 2017, the extent to which the global oil market shifts away from oversupply will be key for the sector’s incipient recovery to become a rebound.

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The overall distribution of outlooks in the oil and gas sector has improved over the past six months along with the recovery and stabilization of oil and gas prices. Many negative outlooks translated into defaults in early 2016 but there have been fewer downgrades in late 2016. Although balance sheets remained stretched, many companies have adapted to the expectation of lower oil prices for longer by meaningfully lowering their cost structures, cutting capex, and becoming more efficient. Liquidity risks have largely abated and capital market access appears to have returned to the deep speculative-grade issuers with yields and spreads tightening significantly. The majority of our investment-grade ratings are on U.S. companies, largely due to a significant number of new issuers from 2011 to the end of 2014, stemming from the shale explosion, high oil prices, and low interest rates. Bifurcating this further, approximately two-thirds of the speculative-grade ratings on U.S. companies fall in the ‘B’ and below ratings category. Despite oil prices stabilizing, our rating outlook on OFS companies are largely negative due to the inability to pass through price increases sufficient enough to garner improved credit metrics and Internal rates of return that cover their capital costs.
Industry forecasts

Global Oil and Gas

Chart 7 – Revenue growth (local currency)

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.

As expected with any rebound in commodity prices, industry credit metrics and profitability measures were largely improved in 2016. With our price deck slightly increasing in the latter years, we think the sector will remain mostly relatively stable. Over the longer term, we expect margins in the exploration and production (E&P) segment to remain relatively flat given our generally flat price deck, companies’ limited ability to squeeze further efficiencies, and prospects for modest increases in OFS costs. However, we project that near-term cash flow measures will improve based on the rebound in hydrocarbon prices with longer-term metrics sustained or improving due to higher production as companies ramp up capex.
Key assumptions

Exploration and Production

1 Oil prices
Our base case price deck for West Texas Intermediate (WTI) and Brent is relatively flat at $50 per barrel (bbl) for 2017 and 2018, and $55/bbl for 2019 and beyond. We believe the recent OPEC production cuts provided a floor to oil prices at least temporarily. An oil price above $55/bbl is bound to lead to a meaningful production response in U.S. shale because breakeven prices were significantly lowered as producers became much more efficient. We believe shale is the new swing producer, one based on economics and not politics and, over the medium term, will provide a cap on oil prices over the next couple of years. We expect demand to remain relatively stable with the supply-side of the equation, ultimately determining the direction of oil prices.

2 Natural gas prices
Our price for natural gas is stable at $3.00 per Btu over the next three years. Natural gas prices have had a nice rebound owing to declines in the gas-directed rig count and associated natural gas production from liquids drilling reductions, as well as an unseasonably warm summer. This has led to inventory levels finally declining below the five-year average. Going forward, we expect production growth to come from the prolific and low-cost Marcellus and Utica shale plays. Significant take-out capacity will alleviate any bottlenecks and further tighten the regional gas differentials. Demand will get a boost from utilities switching to natural gas from coal, growing demand for liquid natural gas (LNG), and exports to Mexico. Still, we believe that long-term natural gas prices are unlikely to remain at well-above $3, due to low-cost Marcellus and Utica output effectively capping prices.

3 Capital expenditure
While we haven’t gathered our preliminary capex budget data yet, it’s clear that spending will be higher this year than last, especially in the U.S. as producers in these higher-cost basins look to take advantage of the rebound in energy prices and replenish reserves and augment production. Some industry research firms are projecting capex will increase globally by an average of 6%-10% with U.S. capex increasing over 20%.

Oilfield Services

1 Spending
The growth engine for oilfield services is undoubtedly E&P spending. After years of significant declines in production, which decreased at a compound annual growth rate (CAGR) of 37% in 2015 and 2016, we expect capex to increase along with the rebound in hydrocarbon prices. Any increase in spending is sure to give service companies a lifeline. We generally anticipate a slower recovery outside the U.S.

2 Margins
The sector’s revenue and margins have been severely hurt by the significantly lower volumes stemming from the declining rig count and price concessions companies have had to give up to the E&P companies. We believe that in 2017, OFS companies, on average, and depending on their geographic position, could achieve price increases anywhere between 8% and 12%, with certain subsectors like pressure pumping achieving higher returns in the neighborhood of 15%-20%. Nevertheless, despite such initial price recovery, additional price and volume increases will be necessary for these companies to achieve internal rates of return (IRR) that will sustain value.

3 Rig count/recovery
The rig count decline had been unprecedented, with rig counts in the U.S. declining more severely and rapidly than at any other point in history. Oil rig count declined 80% from a peak of 1,609 in October 2014 to a low of 316 at end of May 2016. However, with the increase in oil prices, rig count activity has rebounded nicely especially in the Permian basin. Total rig counts currently stand at 712, an increase of 125% from the low. Oil-directed rigs account for most of the rigs with 583. We expect nominal increases in rig counts from current levels both globally and domestically because we expect oil and natural gas prices to remain flat.
Refining

Gasoline demand

Global gasoline demand and demand growth, as for other oil products, are likely to remain driven by emerging economies as demand from the Organization for Economic Cooperation and Development members moderates further. China consumes about one-third of the gasoline volumes consumed by the U.S., but the International Energy Agency (IEA) estimates China’s gasoline demand is likely to continue growing at 7.2% in 2017. According to the EIA, U.S. gasoline demand is expected to moderate from 2016's 1.1% growth, mainly due to slower growth in highway travel. Lower growth in highway travel reflects forecasts for slower employment growth and rising gasoline prices. Our demand forecasts are generally in line with the EIA, with gasoline demand growing about 0.5% in 2017 and by 1% in 2018.

Distillate demand

Industrial activity is likely to support demand for diesel, even if growth rates across major markets globally are estimated to be in the low-single-digit range. In the U.S. we expect diesel and other distillate demand to strengthen in 2017, driven by stronger expected economic growth, increasing oil and natural gas drilling activity, and an assumption of normal temperatures. Our forecast for distillate demand growth is about 3% in 2017 and 2% in 2018.

Crack spreads and utilization

We are forecasting 2017 crack margins to be only modestly better than 2016, but to exhibit a fair amount of volatility if Congress approves the Trump Administration’s plan to tax exports. Higher U.S. gasoline production and inventory levels in 2016 contributed to refinery margin compression. Despite an increase in gasoline production and high inventory levels, rising exports provided some support for gasoline margins, which we expect to continue into 2017. Diesel margins should be somewhat better, driven by higher crude oil prices and stronger demand. We expect average utilization for U.S. refining capacity to be in the low- to mid-90% area. On the contrary, refining margins in Europe and Asia have broadly declined as oil prices rose in late 2016. We currently anticipate broadly flat margins outside the U.S. in 2017.

Contract Drilling

Supply/demand

We believe that the deep water offshore market will continue to remain oversupplied through 2017 as more rigs need to be retired or cold stacked in order to balance supply and demand. Fundamentals are incredibly weak due to all the newbuilds that flooded the market over the past couple of years and the lack of demand given low oil prices. We recently revised our estimate of the start of a recovery in the sector from late 2018 to late 2019 resulting in numerous recent downgrades. We are broadly assuming there will be no new contracts until late 2019. Still, any recovery will be tepid and we remain uncertain whether oil prices will be sufficient to garner a sustained level of capex for greenfield deep water projects. We believe the jackup market has bottomed and with the sector needing lower oil prices to recover, we expect modest improvement with demand slated for newer, higher-specification rigs.

Utilization and day rates

Utilization rates will remain low and pricing power will not return to rig operators until industry utilization rates climb to at least 85% in the deep water segment. We’ve assumed that contract drillers will not be replacing contracts that expire through 2019. Pressure remains on day-rates because the market remains oversupplied and non-contracted newbuilds continue to apply pressure on rates.
### Midstream

#### Commodity prices

We believe commodity prices will provide a floor for most midstream companies' credit measures in 2017, but will not be a meaningful driver of improved credit profiles. Our price assumptions for WTI crude oil is $50/bbl in 2017 and 2018, and $55/bbl in 2019 and beyond. Our price assumption for Brent crude oil is the same, with currently no differential from WTI. Our natural gas price assumption is $3 per million Btu, held flat from 2017-2019. Natural gas liquids prices are 60 cents per barrel in 2017. We believe these assumptions will result in relatively stable to growing throughput depending on the basin, but should encourage at least a modest pickup in drilling activity.

#### Throughput will vary

We expect throughput for gathering and processing companies will vary somewhat, depending on where midstream companies are located. We believe companies that have strong acreage dedications in the Marcellus, South Central Oklahoma Oil Province (SCOOP) and Sooner Trend Anadarko Basin Canadian and Kingfisher Counties (STACK), and Permian basins will have the best economic results and see growing throughput to support organic expansion plans. Midstream companies that are less diversified and have significant systems in dry-gas plays like the Haynesville or parts of the Uinta or Powder River basins will see less favorable throughputs but some base level if natural gas prices in those areas can stay above $3/million (mm) Btu. The Northeast region could get a boost from stranded natural gas due to a lack of takeaway capacity, as several pipeline projects, like the Atlantic Sunrise, received approvals to move ahead. But in-service dates for some projects are more than a year away.

#### Financing

Capital markets should be much more cooperative for midstream players compared with the first half of 2016. We believe there’s a lot of pent-up demand for new debt offerings for investment-grade issuers. The equity markets are also open for midstream companies, particularly those that have reset distributions to a more sustainable level because equity investors realize that the rest was necessary for long-term growth to continue. A shift by many companies to retain more excess cash flow for reinvestment in the business will also help alleviate public equity requirements, but many diversified investment-grade companies still have significant needs and will have to be somewhat aggressive in the use of at-the-market programs to meet their targets.
### Key risks and opportunities

#### Exploration and Production

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<th>Oil/natural gas prices</th>
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<td>1</td>
<td>The recent agreement by OPEC members to cut production has, at a minimum, set a floor on prices. However, depending on how closely demand matches supply, should OPEC not continue production cuts after the agreement is up in six months, we could see oil prices begin to retreat. Furthermore, there is uncertainty regarding proposed GOP tax bills and the implications they could have on oil prices. The implementation of a plan that taxes imports but not exports would lead to an immediate increase in WTI, rising to a tax-adjusted level. The higher price garnered by U.S. producers would result in them quickly increasing production, which could lead to lower oil prices globally. Moreover, the tax plan could lead to a rising U.S. dollar, thus lowering demand for oil.</td>
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<th>Mergers and acquisitions</th>
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<td>We’re expecting the pace of M&amp;A to increase somewhat due to the return of the capital markets and issuer accessibility to the energy sector. Interest rates still remain low and oil prices appear to have stabilized at least temporarily. Moreover, with so many issuers having emerged from bankruptcy and eliminated much of their debt, one of the hurdles to acquisitions over the past couple of years, the need for a purchaser to redeem debt at full value (due to make-whole clauses in bond indentures), were eliminated. Valuations, while improved, still remain relatively low in comparison to when oil was trading above $100. Nevertheless, we have recently seen transactions in mature provinces such as the North Sea.</td>
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<th>Proposed U.S. corporate tax changes</th>
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<td>In an industry that relies heavily on capital-market access, especially debt markets, to fund capex, a proposed tax plan that would eliminate the interest-expense deductible, could clearly be detrimental. The loss of deductible interest for tax purposes would affect companies’ cost of capital and could stem project development, especially during periods of rising interest rates. However, for 2017, given our expectation of a relatively low interest rate environment, we would expect the impact on project development to be marginal.</td>
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#### Oilfield Services

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<td>We think the primary risk to the OFS segment is if OPEC doesn’t extend its production-cut agreement. Without an extension and a rebound in shale production due to the higher oil price, the industry could see a return to the trough we just experienced. Clearly, this would lead to significant declines in OFS services and goods and possibly more downgrades and bankruptcies. A declining rig count would be the initial impact.</td>
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<th>Limited price improvements</th>
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<td>Overall, we believe prices will increase on average approximately 10% in 2017. However, this level is still insufficient to garner sufficient IRRs to cover many of the small companies’ cost of capital. The industry will need further price improvements to achieve some stability. Most of the issuers in this segment have negative outlooks largely due to the sustainability of price increases.</td>
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<th>Aggressive competition</th>
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<td>As companies fight to win the limited tenders and work available, in part to keep employees and equipment in operation, we continue to see some at- or below-cost pricing. In addition, companies could target new or different markets, such as the Middle East, where investments have been cut back much less. This can impact the price points and margins for incumbent OFS companies that might have to renegotiate terms to retain business.</td>
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**Refining**

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<td>1</td>
<td>U.S. merchant refiners continue to face headwinds in 2017, and could experience even stronger gales if certain federal tax policies are implemented. Recent discussions in Washington, D.C. on an import tax, which we assume would include oil imported into the U.S., could lead to more volatility, margin pressure, and weaker credit profiles. Refiners would have incentive to buy domestically produced crude that they would still be able to deduct for tax purposes, thus driving up the price of WTI. U.S. producers would require a tax-adjusted price from domestic buyers (largely refiners) to compensate them for not shipping oil overseas tax free. WTI would rise to a tax-adjusted price relative to Brent and ultimately trade at a level that would make refiners indifferent as to whether they imported or bought oil domestically.</td>
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<td>U.S. refining margins and profitability will continue to be under some pressure because of narrow crude differentials and global capacity additions that could somewhat limit export opportunities. A narrow spread between Brent- and WTI-based crudes would most likely lead to increased international competition for U.S. refineries and pressure profitability. Refineries will try to pass any increase in oil prices from tax reforms to the U.S. consumer (as prices could increase anywhere from 30-36 cents/gallon) However, the companies might not be able to pass it all on and volatility and margin pressure would be a likely result. Depending on the refineries' crude slate, the overall impact could be neutral unless they import a significant portion of feedstock, like the refiners located on the East and Gulf coasts. Many of these refiners have little flexibility to switch to light sweet WTI because the assets are configured to run heavy sour, mostly imported crude. Refineries that predominantly run crude oil sourced from Canada, could also see a margin impact. The reduced tax rate, however, could spur higher utilization and lead to potential oversupply of product without a strong demand response, which would pressure margins.</td>
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<td>Weaker profitability in 2016 has mostly led to higher leverage and less liquidity, which has eroded the large cushion in credit ratios refineries built up from 2011-2015. Larger diversified refineries with a full backlog of midstream or retail assets will fare much better than their smaller less-diversified peers. Refiners that have growing midstream master-limited partnerships, have some options and flexibility to monetize assets, which could help reduce consolidated debt and weather a difficult operating environment.</td>
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**Contract Drilling**

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<th>Hydrocarbon prices and effect on demand</th>
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<td>The demand side of the equation here is ultimately driven by the industry view of the level and sustainability of oil prices. We think that for greenfield deepwater demand to return, oil prices, at a minimum, would need to be sustained at $60/bbl. And for a more sustained recovery, prices would have to stay near $75/bbl-$85/bbl. Without a higher oil price, the recovery necessary to restore day and utilization rates to a more normalized cycle, could be pushed out beyond our 2019 recovery assumption. If we were to assume that recovery is further delayed, it could result in more negative rating actions. Most of the offshore drillers currently have negative outlooks.</td>
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<td>Both the deepwater and jackup markets continue to remain oversupplied and subject to more new construction in 2017. Jackup utilization rates are still very low but with the recovery in oil prices, we expect day and utilization rates to improve marginally as lead times for this segment are much shorter than the deep and ultra-deepwater markets. Higher-specification jackup rigs could see higher utilizations compared with older jackups, which overall, have a limited market, primarily in Asia. If newbuilds find their way to market and the oil prices revert, both segments are ripe for much deeper declines in day and utilization rates.</td>
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# Midstream

## Cost of capital

This year presents a host of challenges for midstream companies: stretched balance sheets, weak coverage ratios, high-cost equity capital, and significant financing requirements for a healthy backlog of projects. While this somewhat tempers our cautiously optimistic view of the sector, some midstream companies have adjusted their financial strategies and corporate structures to better position themselves for sustainable long-term growth. Most midstream companies’ equity yields skyrocketed after crude prices plummeted in the first quarter of 2016, which made it much harder to finance organic growth. With many equity investors already pricing in a distribution cut, midstream companies took the opportunity to reset distributions and growth targets, eliminate the incentive distribution rights (IDR) structure, fix their cost of equity capital, improve liquidity, and reduce leverage. For these reasons, the consequences of a cut weren’t viewed to be as punitive to a company’s equity price as were the distribution cuts in 2008-2009.

## High leverage

We the midstream industry to focus on repairing balance sheets that have been stretched from large capital projects and reduced EBITDA from lower commodity prices and volume throughput in 2017. We expect investment-grade midstream companies to have improved leverage ratios (debt/EBITDA) of about 4.5x, down from about 5x in 2016. Leverage is declining for several reasons, but the biggest driver is that midstream companies are retaining more cash flow rather than distributing it and using the excess cash to pay down debt. The retained cash flow helps reduce equity needs and financing risk to some extent, but many large midstream players still need to raise a significant amount of equity in 2017 to bring leverage down, which we believe presents some execution risk.

## Lower capital expenditure

Lower commodity prices encouraged management teams to instill a level of spending discipline as they’ve tried to reduce costs and improve efficiency across their asset bases. While the level of volatility in commodity prices has subsided, management teams remain cautious on spending for 2017. We expect the amount of capital spending to be 25% to 30% less than during the 2013-2015 period but remain significant, particularly for most diversified investment-grade companies. For the investment-grade peer group (Buckeye Partners L.P., Boardwalk Pipeline Partners L.P., Energy Transfer Partners L.P., Kinder Morgan Inc., Magellan Midstream Partners L.P., Oneok Partners L.P., Plains All American Pipeline L.P., Spectra Energy Partners L.P., and Williams Partners L.P.), spending peaked at $23.2 billion in 2015 and came down to $17.3 billion in 2016. We expect spending in 2017 to be about 30% lower than the peak at roughly $16 billion.

## Related research

- Despite Obstacles, North American Midstream Energy Companies’ Outlook Is Stable For 2017, Jan. 31, 2017
- After The OPEC Decision, What’s Next? Dec. 21, 2016
- U.S. Shale-Oil Producers Continue To Suffer From OPEC Pressures, Nov. 22, 2016
- U.S. Oil And Gas E&P Buyers Aim To Increase Acreage While Sellers Seek To Shore Up Balance Sheets In Third Quarter 2016, Sep. 27, 2016
- To Drill Or Not To Drill: Can Spec-Grade E&P Companies Keep Up Production? Sep. 27, 2016
- International Oil Majors Test The Limits Of Integration In 2016, Sept. 15, 2016
- The Market For Liquefied Natural Gas: Staying Afloat In A Sea Of Supply, Apr. 12, 2016
- Why Reserve-Based Loan Lenders Have Experienced Strong Recoveries, Jan. 13, 2016
Cash, debt and returns

Global Oil and Gas

Chart 11 – Cash and equivalents / Total assets

Chart 12 – Total debt / Total assets

Chart 13 – Fixed versus variable rate exposure

Chart 14 – Long term debt term structure

Chart 15 – Cash flow and primary uses

Chart 16 – Return on capital employed

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