The History of a Supply-Driven Bear Market: Part 2 of 2 Oil Price Surprises from 2016 Onwards

Jan-Hein Jesse
Founder, JOSCO Energy Finance and Strategy Consultancy (Amsterdam); and Editorial Advisory Board Member, *Global Commodities Applied Research Digest*

Introduction

This article is the second in a two-part series. This series of articles provides insights into the complex dynamics of oil price formation from 2014 onwards. Part 1, which was in the last issue of *GCARD*, focused on the events influencing the oil markets from 2014 through 2015 while Part 2 covers (a) oil-market-moving events from 2016 through the present and near future and (b) JOSCO Energy Finance and Strategy's field-by-field oil production analysis through 2025.

Oil price formation is characterized by highly dynamic interactions amongst a wide set of drivers, each one sometimes dormant, and at other times, hyperactive. These drivers can be clustered into four overarching categories: (1) Supply & Demand Fundamentals, (2) Geopolitics, (3) Geo-Finance, and (4) Technology & Innovation. The reader will recognize them all in this article. The latter captures climate change and the energy transition. The third, Geo-finance, includes two branches: the first around macroeconomic parameters such as the dollar exchange rate, interest rates, inflationary expectations, trade balances, and debt levels. The Fed, ECB, Bank of Japan, Bank of China and Bank of England all play a pivotal role in this. The second branch includes fast-cycle money invested in oil through futures and options traded on the New York Mercantile Exchange (NYMEX) and the Intercontinental Exchange (ICE), as well as on the Dubai Mercantile Exchange and as of March 26 of this year, also on the Shanghai International Energy Exchange.

Oil, like all commodities, is not an anticipatory asset, and pricing expectations typically prove self-negating. Hence, in contrast to equities, oil does not have much expectation value and is thus, far more of a spot asset class. For that reason, big structural changes, such as we witnessed in 2014, always seem to come as a surprise, as did the recent spike in Brent oil prices from $47 a barrel in mid-June of last year to $61 in early December and $70 in late January 2018, only to fall back to $62 a barrel in the second week of February 2018. With the arrival of shale oil in the U.S., trading in paper oil (futures contracts) has exploded since 2010 and brought a new group of macro funds, hedge funds and other speculators to the market in recent years.

The oil price went through a full cycle during the years 2014 through 2017. During this time, the oil curve went from backwardation in the first months of 2014 to a situation where spot prices started to fall in the 2nd half of 2014 when the curve shifted in contango. Subsequently, long-dated prices started to fall as well while the front of the curve went into even steeper contango. Halfway through the cycle, the curve started to flatten at which point spot prices started to recover. Finally, in the 2nd half of 2017, the curve flipped back into backwardation while long dated prices also started to rise, signaling a normalization of the market. The big question now is whether the "New Oil Order" brought on by the

North American shale oil revolution is on hiatus. Moreover, who are the winners? And who are the losers? And have price discovery and the price formation process really changed?

2016

Oil prices were falling fast in 2016. Energy option prices were outpacing the decline in oil prices, showing that investors were increasingly concerned about the potential for oil price declines to accelerate. The oil market appeared to be approaching the end game. The resilience of non-OPEC production ex U.S. continued to be a major factor in oil market oversupply while OPEC production remained close to the highs of the year at 31.7 million barrels per day (mb/d). Moreover, the International Atomic Energy Agency had announced on January 16 that it had verified that Iran had implemented its nuclear-related measures described in the Joint Comprehensive Plan of Action, which allowed Iran to resume oil exports to all non-U.S. destinations. There was a rising probability that storage would run out of capacity soon. The Brent 1-6 month time spreads widened to incentivize floating storage, a very bearish scenario; and the possibility of oil prices hitting cash costs came into sight.

The supply response was now resting on two short-cycle sources of supply: U.S. shale and OPEC. Mid-January, it was estimated that U.S. shale production would decline 500-600 thousand barrels per day (kb/d), driven by tighter financial conditions at lower oil prices. This would be much more than the extremely modest -150,000 b/d decline year-over-year as of year-end 2015. Meanwhile the cost deflationary spiral continued, not only in the U.S. but elsewhere. The key theme for 2016 was a real fundamental adjustment occurring, which would rebalance markets and eventually create the birth of a new bull market. Spot oil prices shot below $30/barrel (bbl) to $27/bbl. With spot prices reaching a bottom, the next step would be for participants in the futures market to sell off the back-end of the futures curve in the coming months, and then shrug off the bear market that had been going on since the summer of 2014. A flat curve near cash costs is historically the buy signal for passive investors, and it was plausible that this bear market would end in the same way. While we already noted at that time that "you should never catch a falling knife," we now saw the moment that "the knife had landed ... and that it was the best time to enter the market again."

Newspapers were suggesting that OPEC producers and Russia would meet in February to discuss a potentially coordinated cut in production. However, such a cut was also seen as a self-defeating action given the short-cycle of shale production and therefore was not given a high possibility of occurring. But only signaling the market resulted in a 7% price rally, which took 1-month oil price volatility to 70%, its highest level since April 2009. According to one report, "OPEC was best off to sustain production and let the market do its work, as that would maximize revenues medium term." But should a cut occur, oil prices would only get support from such a step once inventories stopped building. With oil prices approaching stress levels, this was expected to pressure U.S. shale producers into restraining production, which would thereby prevent storage tanks from overflowing.

Different from expected, Saudi Arabia, Russia, Qatar and Venezuela announced on February 16 that they had agreed to freeze oil production at their January level, but only if other producers would commit as well. This was the first coordinated production decision between OPEC and non-OPEC members in fifteen years and it was said that "other steps to stabilize and improve markets" could follow. However, this announcement did not immediately have an impact on prices. By March 11, the average price for West Texas Intermediate (WTI) year-to-date was still $32/bbl driven by new records for storage utilization close to a saturation point. Fortunately for stabilizing the price of oil, U.S. Lower-48 production was further declining and supply disruptions within OPEC were rising to more than 2 mb/d in unplanned outages, mainly due to Libya, Iraq and Nigeria, while Venezuela's production was in structural decline. Also, only a modest increase in Iranian production of 280 kb/d was foreseen (much lower than the 600 to 800 kb/d this author personally forecasted at that time.) Meanwhile, time spreads in WTI and Brent had strengthened, indicating that inventories were drawn more than seasonally during the winter months. Taking all things together and highlighting that this remains a supply-driven bear market, price forecasts were lowered to $35/bbl for 2Q2016, gradually rising to $40/bbl in 4Q2016 and $50-60/bbl in 2017. "Such price improvement in the next 18 months would be driven by near-dated prices with a return to backwardation by late 2016. Sequential U.S. production growth would be required, but only from 2Q2017 onwards," according to one investment bank report. However, based on curve movements in the 1998-2000 period and the time it took to move from deep contango back to backwardation - a sign of a normalization in the oil markets - a prediction of a return to backwardation by late 2016 was extremely optimistic, perhaps even unrealistic. Normalization in the oil markets would definitely take longer, most likely not earlier than the 2nd half of 2017. Only a coordinated action by OPEC could accelerate such process. Meanwhile high demand growth stimulated by lower oil prices, quantitative easing, and a gradual improvement of world economies would do their work.

On April 17, OPEC and non-OPEC producers met again in Doha. The biggest hurdle to reaching any meaningful agreement was the conflicting Saudi and Iranian stances with Iran repeatedly having stated that it would continue to grow production and regain market share. No positive surprises came out of the meeting. Nevertheless, oil prices continued to recover to $50/bbl in June. However, fundamental volatility as a result of unplanned outages continued to create an uncertain path for oil rebalancing. While the physical barrel rebalancing had started, the industry was still adjusting, which led to a lower 2017 forecast with prices in 1Q2017 at $45/bbl and only reaching $60/bbl by 4Q2017. In the last week of May, the U.S. oil rig count reached its lowest level at 316 rigs (vs. a peak of 1,609 reached on October 10, 2014.) As in previous downturns, the crude oil glut had also become an oil product glut, as refineries were incentivized to run higher than normal utilization.

Another OPEC meeting took place in Algiers on September 26-28. After six failed attempts, and a new Saudi Arabian energy minister, a deal to curb production later in the year became more likely than at any point in the past two years. After having given up the price formation role during the last two years and after having recognized that some market orchestration would be required for inventories to decline to normal levels, and preferably at a faster pace, Saudi Arabia was determined to force the others into a deal that it could live with, knowing that it most likely had to give major players an exemption. The Kingdom played hard ball this time, determined to earn back its reputation as the "central bank for oil." Instead of just walking out of the meeting without any consequences for the other members as happened in November 2014, this time it threatened to blow up OPEC completely if no deal would be reached at the next Ministerial meeting in November. Moreover, Saudi Arabia was sufficiently motivated by its price-volume elasticity advantage to agree to an OPEC deal. More precisely, market volatility associated with OPEC meetings gave them confidence that if a deal could be structured, the lost production would result in higher revenues without losing market share. This was the turning point. However, this was not leaked to the outside world at that time, and some analysts saw prices still skewed to the downside. In some cases, year-end forecasts were lowered materially at the time of the Algiers meeting on the back of potentially fewer disruptions and the relatively high speculative long positions. Low cost production continued to surprise to the upside, at that time in Saudi Arabia and the UAE, previously in Iraq and Iran, and next in Russia. Also, the ramp-up in new production outside of OPEC was set to accelerate with 2017 additions from new projects sanctioned before the summer of 2014 expected to be 30 percent higher than in 2016. In addition, legacy production declines had remained limited outside of China, Venezuela, Columbia and Mexico as producers were seeking to maximize cash flow from existing production. In turn, U.S. production declines were set to slow with the oil rig count up 31 percent since the trough, and the aging U.S. shale well profile showing stabilizing production.

Nevertheless, the post-Algiers rally in oil prices continued, fueled by comments by Saudi Arabia and Russia that pointed to a greater probability of reaching a deal to cut production. But as usual, risks of disagreement were not negligible with Iran, Iraq, Nigeria and Libya the most vocal opponents. All were aiming to grow production in 2017 and were disputing the usual measures of its production as too low. But ultimately Saudi Arabia had a strong incentive to cut production to achieve a normalization in inventories in anticipation of the Saudi Aramco IPO and in light of its deteriorating budget. Moreover, an agreement with Russia would (hopefully) end the highly competitive battle for market share in Asia, notably in China. This was mainly driven by the following three important factors. First, a sharp devaluation of the rouble vs. the dollar from about 34 in June 2014 to a peak of 81 early in 2016 before stabilizing around 60 for the year had improved oilfield economics in Russia fabulously, as most operational and conventional drilling costs are predominantly or completely set in roubles. Saudi Arabia, with its currency pegged to the dollar, was harmed by dollar strength, and thus saw its relative competitive position vs. Russia deteriorating. Second, the imposition of Western financial and other sanctions, which were levied as a result of events in the Ukraine and Russia's retaking of Crimea, resulted in China stepping in to provide pre-export finance to Russian oil companies to replace Western credits that had to be refinanced. Third, these credits backed by oil export flows enabled Russia to leapfrog over Saudi Arabia to become the dominant provider of oil to China, using in the best possible way its expanded network of pipelines from Eastern Siberia to China and from Western Siberia via Kazakhstan to China. The combination of these factors helped Russia achieve its longstanding goal of moving from a lumpy passive supplier of oil and gas to Europe to assume a much more active role in influencing world oil markets economically as well as politically. Thus for Saudi Arabia, accommodating U.S. shale was already a formidable challenge, but now it was also being challenged by the 2nd largest producer.

On November 30, OPEC members agreed to cut OPEC production by 1.2 million b/d from October levels to 32.7 mb/d for six months starting in January. The deal achieved a broad consensus with Libya, Nigeria and Indonesia exempted, a modest growth allowance for Iran based on secondary sources and a 4.6% cut across other producers. Discussions with other non-OPEC producers would continue and indeed on December 10, eleven non-OPEC producers agreed to join eleven OPEC members to reduce production by 558 kb/d in 1H2017. Russia agreed to contribute 300 kb/d. The goal would be the normalization in inventories rather than achieving much higher oil prices, which would instead unleash a sharp production response in the U.S. The big question became in how far participating countries would comply. In general compliance levels were set quite high by market analysts, in the order of 85% to the headline cut of -1.6 million b/d (-1,164 kb/d announced by OPEC and -458 kb/d by non-OPEC participants), and much higher than historically achieved. The biggest issues were the possibility of a potential ramp up in Libya and Nigeria. But overall, it was expected that the global market imbalance would finally turn into a deficit in every quarter of 2017. After inventories normalized in 2017, the common view was - and still is - that OPEC and Russia would return to high production levels. However, one could argue, also on the abovementioned factors, that Core Gulf OPEC and Russia ("ROPEC") will be a much stronger bond than currently foreseen, and would stay there for much longer.

The shale revolution and the ensuing flattening of the oil cost curve with no imminent need for sanctioning "Most Expensive Oil" projects has driven important shifts in the sources of future supply, as covered in Part 1 of this series. While historically during the investment phase, large "Cheap Oil" producers like Saudi Arabia and other Gulf OPEC countries could impact the long-term oil price when the oil cost curve was steep (by choosing a value strategy instead of a volume strategy), they become price takers once the cost curve flattens and new "Most Expensive Oil" developments are no longer necessary. This would lead them to develop new strategies around actively managing inventories and to maximize revenues through rising volumes. As a consequence, the Goldman Sachs and Citi camp lowered their WTI forecast for 2017 and 2018 further to $55/bbl for both years, and $57/bbl and $61/bbl respectively.

2017

The optimistic mood created after the ROPEC decision to cut oil production led to unprecedented long net speculative positions in the futures market in January 2017. Hedge funds and other money managers had accumulated a record net long position in the main Brent and WTI futures and options contracts equivalent to 885 million barrels by January 31. Stock markets had also rallied in November and December 2016 on the back of the election of Donald Trump as the new president, and the general view that the U.S. was now in an optimistic phase. Also a new type of fund was entering the oil markets. Beside the traditional investors, who are primarily focused on fundamentals and geopolitics, this time the length was also driven by large-scale macro funds, machine traders (having developed their own proprietary algorithm trading models) and momentum traders. This new breed of financial oil traders is more focused on macroeconomic and geo-finance factors and less on oil specific drivers, and thus is responsible for material inflows and outflows resulting in more short-term cycles in speculative length. Moreover, their behavior worked against more traditional trading schemes, having arguably put the funds trading the oil specific drivers on a wrong footing in 2017. That said, in the long run, market fundamentals of supply, demand and inventories are (arguably) likely to win over those who are trading primarily on macroeconomic themes and momentum.

In February 2017 funds had long positions equivalent to almost 1 billion barrels across the three major contracts while short positions amount to just 111 million barrels. The ratio of long-to-short positions reached almost 9:1, the most bullish since May 2014, when Islamic State fighters were racing across northern Iraq, and the Libyan civil war had halted crude exports. Analogous to August 2015, the crude market was starting to resemble the classic crowded trade in which speculators attempt to position themselves in the same direction in anticipation of a big price move. Fund managers apparently believed output reductions by ROPEC would succeed in draining excess global inventories rapidly, which would push oil prices higher. Managers were also discounting the threat from renewed drilling in the U.S. and a likely increase in output from shale producers, at least in the near term. But every successful trade needs an exit strategy and in this case it remained unclear how and at what price fund managers would manage down positions and try to take profits.

Due to stretched oil production by OPEC and non-OPEC countries in the last months of 2016, in anticipation of the cut, weekly inventories further increased well beyond their seasonal pattern in January and February, especially in the U.S. At the same time, prices rallied, a good example of the new interplay between the different types of investors described earlier. These higher imports were not the result of lower demand nor of higher domestic production, but due to increased imports. The surplus production in 4Q2016 was estimated at about 0.5 mb/d over demand. Moreover, optimistic guidance from U.S. E&P companies during the earning release period created worries over increased U.S. shale output. This was also given by strong hedging in the first months of the year when oil prices were (relatively) high, having secured their cash flows, and a large increase in mega projects coming on stream and ramping up in 2017-2019. By the end of the first quarter, producers had already added 346 oil rigs in the U.S., a 109% increase since its trough on May 27, 2016. However, with very high compliance by OPEC and participating non-OPEC countries, helped by cold weather in Russia, greater production cuts by Saudi Arabia, and further field production declines in Venezuela, it was expected that oil supplies to markets, especially to those West of Suez, would decrease as of March. Only a higher supply from Nigeria and Libya could spoil the party. All together the consensus WTI price outlook was surprisingly increased for 2Q2017 in late February. Instead, and not illogical, the oil price for WTI went down from $54.58/bbl on February 23 in three cycles to a new low on June 21 of $42.48/bbl. The main driver behind this price fall was caused by stubbornly high inventories around the world with June levels still materially higher than in January, irrespective of high compliance by OPEC and participating non-OPEC producers to their agreement. As a consequence, there was no alternative but for them to roll over their agreement to cut production, which they did at their May 25 meeting. In hindsight, the U.S. equity market had taken a pause in the first five months of the year, and thus did not deliver strong momentum either. Going forward, inventories needed sustained cuts to normalize and generate backwardation of the futures curve. Meanwhile, more investors in the energy space were increasingly throwing their towels in the ring in May. Clearly, oil bulls were nearing capitulation. Once inventories normalized, the view was that low cost producers would ramp up quickly again. With growing evidence of the ability of U.S. shale to lower their break-even costs at the well even further, the upside was increasingly seen as capped with WTI flat prices of $55/bbl for years to come. However, what was not clearly recognized was the return of reflation, in combination with an unexpected and rapidly weakening of the U.S. dollar from 1.05 to the euro at the start of the year to 1.14 on July 3 to 1.20 on September 4, giving a strong signal that oil prices should rise. These were the ingredients that the new breed of financial oil traders was looking for.

Finally, during the summer when prices hit their trough, ongoing inventory draws gave rise to an improved outlook. This was not only as a result of ROPEC living up to their promise, but perhaps even more due to very strong demand growth of 1.7 mb/d for the year. While the U.S. stock market was already in the optimistic phase - the final part of the cycle - since the election of President Trump, Europe was also on the brink of shifting to this phase. The bull market was finally in full swing. Some even started to point to a possibility that inventories should not fall too low in a too short period, as that would take prices towards $65/bbl, making the extended ROPEC cuts self-defeating. As things were moving forward into the 2nd half of the year, it became increasingly more likely that the oil market would finally enter the last phase of the cycle that had started in the summer of 2014 with the futures forward curve shifting into backwardation (which actually happened for Brent in the 3rd week of September), a signal of the normalization of the oil market. This would reflect a market that recognized near-term physical tightness while at the same time the lower forward price further out curtailed the market's ability to grow future production through forward sales. This thus means that fear of long-term surpluses could reinforce near-term shortages. The sharp increase in oil prices in November, which was pushed by robust oil fundamentals followed by the return of geopolitical risks in the Middle East, Nigeria and Venezuela ($57.34/bbl WTI, a new high for the year), raised the question of what to expect for the coming years.

2018

December 2017 and January 2018 were extremely good months for oil prices. Strong and simultaneous global economic growth, higher oil demand against limited supply growth due to ROPEC curtailments and a further weakening of the U.S. dollar to a recent euro-dollar rate of 1.25 on January 29 and rising inflationary concerns were the key drivers behind the rally. On the back of a new all-time high in net speculative length - money managers and hedge funds amassed a record net long position in Brent futures and option contracts equivalent to 600 million barrels and in WTI to 500 million barrels - Brent reached a new peak of $70 a barrel and WTI just over $66 a barrel in late January. Meanwhile, in January, the U.S. Energy Information Administration (EIA) announced that U.S. crude oil production had passed the 10 million barrels a day mark, just 6,000 bpd below the record set in November 1970. Basically, U.S. shale and prolific deep water developments in the U.S. Gulf of Mexico helped the United States to double production over the last ten years with a remarkable growth in crude oil of 850,000 barrels a day in just three months to November 2017. From an output perspective, the U.S. shale sector has fully recovered from the price and output slump that started in 2014. The wildcat nature of the early days of shale was unsustainable, but has now passed. But good rocks are good rocks and through forced discipline, efficiency gains, reduced costs and improved recovery, U.S. production has proved itself to be resilient and is poised to grow materially in the coming years. Consolidation is still lagging compared to the other segments in the oil sector, but that might eventually come in due course. Late January, ROPEC's Joint Ministerial Monitoring Committee also made it clear that at this point in time the agreement is more about oil price and near-term revenues than reducing inventories to their five-year average, which have been realized or are close to this depending on the way this is calculated.

Of course, the focus will soon shift to the principal risk that U.S. shale drilling will accelerate too fast, compliance in ROPEC will decline, production from non-OPEC non-shale sources will increase, and demand will decelerate owing to rising prices. Geo-finance elements are also starting to play a bigger role, as markets are entering a new era of volatility as the world adjusts to higher interest rates after a decade of ultra-loose monetary policy. But for the time being, none of these risks, with the exception of higher (but still modest) interest rates, appear likely to materialize imminently although the latest forecasts predict that U.S. Lower-48 onshore crude oil will grow by 1 million bpd in 2018 and only slightly less in 2019 with corresponding NGL production growth of 0.44 and 0.39 million bpd respectively. However, investors in shale are now much more focused on returns than on growth, and punish companies by pushing stock prices lower for those shale producers who do not give enough attention to dividend payments and buy-backs. In addition, OPEC and non-OPEC ex U.S. Lower-48 could add another 900,000 and over 1.1 million barrels a day in 2018 and 2019 respectively, pending the exact exit route of ROPEC. For the time being, they have communicated maintaining production restraint until the end of this year. Most shale producers have been in an excellent position to hedge their 2018 drilling campaigns in the last couple of months in case of a temporary fall in prices if too much new OPEC and non-OPEC supply comes on the market simultaneously. Given that we are now entering a new macroeconomic environment, oil price forecasts for 2018 and 2019 vary in a big way again. Where, for instance, Barclays and Citi had a $66 and $65 a barrel outlook for 1Q2018 respectively and no higher quarterly average prices this year and next year, Goldman Sachs raised its 3-, 6- and 12-month Brent oil price forecast to $75.0, $82.5 and $75.0/bbl, resulting in an annual average price for Brent of $77.5/bbl for 2018 while having raised the price for 2019 and 2020 to $70 and $60/bbl respectively. J.P. Morgan sees an average quarterly price of $70, $75, $70 and $65/bbl this year. And finally, Bernstein sees the oil price softening over the first half of 2018 to an average of $55/bbl in 2018, basically not much different than the actual average price of 2017. They also see a gradual increase of $60 and $65/bbl in 2019 and 2020 respectively. The higher price outlook by Goldman Sachs is given by the expectation of (a) reflation where higher oil prices are driving inflationary pressure back up across the board, (b) releveraging in emerging markets (EM) due to strengthening balance sheets and strengthening EM FX (vs. the U.S. dollar), (c) reconvergence where EM growth catches up with developed market (DM) growth, and (d) each of these three factors reinforcing each other. In addition, capacity constraints in the midstream sector and timely availability of first-tier fracking crews could temper future production growth.

The consensus thus shows a higher oil price this year than in 2019. This is predominantly based on a view that markets will not further tighten because of ample supply from U.S. shale, ongoing production growth in non-OPEC countries from new fields coming on stream and others still ramping up, and the gradual return of ROPEC volumes currently constrained by the production curtailment agreement. On the demand side, growth may slow down, especially as the U.S. might shift into a recession. But oil fundamentals for 2018-2019 do not indicate any reasons to panic because of an emerging supply gap.

Field-by-Field Production Analysis through 2025

Having conducted a full field-by-field production study for 72 oil producing countries around the world for the period 1995-2025 in the fourth quarter of 2017, we see world oil liquids production peaking in 2020 under a rather conservative demand growth scenario if no new final investment decisions (FIDs) ex U.S. Lower-48 are taken as of today. This analysis included (a) all known sanctioned projects currently still ramping up or under construction, (b) known brownfield developments, (c) normal ongoing investments in producing fields, and (d) ongoing growth in tight oil as per EIA scenarios for the U.S. Lower-48. However, in the years thereafter, a supply-demand gap starts growing rapidly in the order of either 9.5 mb/d or 11.5 mb/d in 2025 under two different EIA scenarios.

In other words, during the rest of this decade, there seems to be no reason to be concerned about any shortfall. However, for the first half of the next decade, the big question arises if “Cheap Oil” and

"Medium Priced Oil" can close the gap beyond the projects included in our analysis. That is, can shale oil grow technologically and operationally faster than what has been projected in the EIA's scenarios, together with more new oil developments from countries such as Saudi Arabia, Iran and Iraq? (We included all Libyan oil currently offline due to the civil war as coming back on stream by 2020.) Will shale oil continue to be the swing producer that sets the overall price of oil, as covered in Till and Jesse (2016)? Or will the world be faced with a structural shortage in supply, which would trigger fast rising oil prices that would stimulate upstream investments in the "Most Expensive Oil" projects? In such a situation we basically return to the 1999 ($10 Oil World) through 2004 - 2006 period, when differently from foreseen, the oil market rapidly ended the "Demand-Led Oil World" of the 1990s and entered the "Supply-Constrained Oil World" of the 2000s. And thus that we could face another and most likely final "Supply-Constrained Oil World" before entering into an "Oil-Substitution World" in the 2030s.

Additional analysis shows that on the basis of annual field declines of -2 percent for OPEC countries and -5 percent for the non-OPEC ex U.S. Lower-48, the gap would be twice as big, approximately 22 mb/d by 2025. This means that already some 12 mb/d will be delivered by brownfield developments (about 5 mb/d) and sanctioned greenfield developments currently still under construction (7 mb/d). Another interesting result from the study was that U.S. shale production growth plus brownfield production growth from all other countries from 2011 onwards was so strong in the following years that it is only by 2020 that the production from these fields would fall below the level these fields were producing in aggregate in 2011. In other words, U.S. shale and brownfield developments (i.e., more production from legacy fields that were already producing before 2011) from Saudi Arabia, Iraq, Canada, Kuwait, the UAE, Russia and Brazil delivered about 11.2 mb/d, having compensated for a material field decline in most of the other countries. This raises the question if and when these major producing countries could do this another time in the years ahead and can thus fill a major part of the supply gap. Our analysis shows that over the period 1995 – 2025, the Top-15 producers add 35.2 million b/d while the bottom 15 producers lose -12.3 million b/d and the remaining 42 producing countries lose -2 million b/d. Over 5-year intervals, the aggregate volume added by the first 10 of the Top-15 producers has changed and will change materially: these countries added for instance 3 mb/d between 1996 and 2000, 5.8 mb/d between 2001 and 2005, 2.8 mb/d between 2006 and 2010, and 11.9 mb/d between 2011 and 2015. The Top-10 producers are expected to add 8.8 mb/d between 2016 and 2020 and only 0.9 mb/d between 2021 and 2025 if no new fields or big brownfields developments are sanctioned. This pattern can also be seen from the decline in new greenfield developments sanctioned during the latter intervals: Ex US-Lower-48, 310 large greenfield projects were developed around the world between 2011 and 2016. In late 2017, the number of sanctioned greenfield developments stood at 190 projects, many of which will be bringing less new oil supplies. Finally, out of the 72 producing countries, 20 show positive growth between 2010 and 2018. However, for the period 2018 – 2025, this number will decline to 9 if no new major projects are sanctioned.

Looking to the individual non-OPEC greenfield developments, historically around 9 to 10 new fields with production of more than 40,000 b/d came on stream a year with an average production of 134,000 b/d. However, as of 2019, this number falls on average to 3 per year, also with lower average production.

The big question now is whether the industry is prepared to increase activity in the upstream segment of the oil industry in the near future so that a gap will not materialize post-2020. Clearly, post-2020, shale alone can't do it. It needs material help from many other players. However, the Western oil companies are currently working on different priorities. There has been pressure to shift their portfolios to much cleaner fuels. Secondly, most Western oil companies have dramatically lowered their expected oil price to below $50 a barrel for planning purposes, and will stick to that figure irrespective of an oil price of $50 a barrel or $100 a barrel. Thirdly, these companies are still working on improving their balance sheets and their return on capital. Growing the oil upstream business, which have all-time low reserve – production replacement ratios, is not (yet) on top of their mind. Fourthly, outside the U.S., many companies left several upstream segments all together, having fired many engineers and project managers. In this respect, a world of "More Upstream / Profitable Downstream" as was the mantra in the early 2000s when the oil market entered an "Oil Supply-Constrained World" is not likely to come back, whatever oil price we face. Figuratively, these big oil tankers can't be turned overnight back to an old-fashioned business model. Today they are squarely working on transforming their companies for a new world post-2030. Fifthly, with respect to financing, the major banks lending to the oil industry find it increasingly difficult to stay committed to the industry because of reputation risks, higher capital costs due to Basel IV, and the possibility of ending up with stranded assets if the energy transition accelerates and leads to peak oil demand by 2030. Reduced access to capital might become a bigger issue and will be positive for commodity carry, reinforcing tightness at that time. Finally, from a geopolitical point of view, the Middle East, the other OPEC countries, Russia, Canadian oil sands, or Arctic are currently not seen as favorable hotspots for making large upstream investments. The question is whether the local players can do it themselves technically and financially.

Of course, new projects will be sanctioned and history shows that the gap will ultimately be filled. In particular, productivity gains, lower tax rates and project redesign will continue to drive engineering cost deflation. However, this time, also taking into account that a major oil development easily takes 5 years to build, it seems to become increasingly challenging to fill the gap completely and to do so with projects that have break-even costs of say $50 a barrel or less. If so, and no "Most Expensive Projects" are needed, we could then expect a smooth energy transition into an "Oil Substitution World" by 2030. However, if not enough projects are sanctioned in the next couple of years, there is no alternative than demand destruction through (much) higher oil prices to balance future oil supply and demand. Such higher oil prices could ultimately force central banks to raise interest rates to fight inflation. It could also result in a much lower U.S. dollar. In turn this could start hitting credits where companies cannot rely on ultra-cheap money as they have done in the last couple of years. Financing would become more expensive at a time when many loans have to be refinanced. Finally, by then, one could expect ROPEC to produce flat out. Under this scenario, once the current volumes that have been closed in come back on the market, not much spare capacity will be left until a new recession has set in and demand has come down materially. Ultimately, the fear for this to happen longer term would normally lead to a pick-up in new project sanctions.

Without doubt, the big winners in a higher-than-expected oil price world will be the big producers. U.S. shale producers and their service industry will do well. Only cost inflation could spoil the party to a certain extent. OPEC countries will do well too. Perhaps they will see this as their last and final opportunity to be quite profitable from their resource base before becoming a price taker in an "Oil Substitution World." Quite speculatively, the biggest winner could be Russia. Russia has not been hit by a depreciating dollar, and it already is well positioned to further build on its core strength to become a major influencer of world oil markets economically as well as politically. One could expect that Russia will make maximum use of its competitive advantage. Assuming a bigger role for itself versus OPEC countries, not only geopolitically, but also financially and economically, its ROPEC relationship could well be a crucial element in Russia's overall oil policy, enabling it to enforce power throughout the industry and to set the rules as a market maker.

Finally, it is plausible to assume that all incremental liquids production in the U.S. will leave the U.S., whether it is in light sweet crude, oil products or NGLs, as U.S refiners need imported sour crudes to run efficiently. Exports will thus rise rapidly from the U.S. Gross total exports already stood at 7 million b/d by the end of 2017. This figure is expected to increase. The U.S. is thus rapidly becoming a major oil hub. But this will not end in a physical hub alone. As described earlier, the way oil price discovery and price formation is changing with the arrival of new financially and macro-driven hedge funds, one could assume that this new model will also be exported to the rest of the world similarly to what is already happening in LNG, and will become a dominant influencer of oil prices. That said, Trade Wars in oil are very well possible, where the trend of liberalizing markets and reducing subsidies will stop and eventually reverse.

Conclusion

Clearly, the role of oil has not yet come to an end. So far demand has only grown this decade, the last years at an accelerated pace. The 100 million b/d demand mark will be achieved before 2020. It continues to be a spot asset class with little expectation value. The United States and Russia have definitely caught up and are now at par with Saudi Arabia. How they will work together and form bonds – especially between Saudi and Russia – will further determine the new rules of the game. The ever changing participants in the futures markets will also help in determining the new rules of the game as well. Whether the U.S. will continue to play the swing producer post-2020 is a big question. But it will definitely produce as much as it can to help avoid a growing supply/demand gap. In conclusion, assuming oil prices will never spike again is a rather risky assumption.

References

Barclays, 2018, "Between Scarcity and Abundance," Energy Market Outlook, February 8.

Bernstein Research, 2018, "European Oil Services & Equipment," January 11.

Citi, 2018, "Oil Price Forecast Pushed Higher," Energy Weekly, January 17.

Citi, 2018, "Misperceptions in the Oil Market Post Muscat," Energy Weekly, January 23.

Goldman Sachs, 2018, "Most Bullish in a Decade on the 3Rs," Commodity Watch, February 1.

Goldman Sachs, 2018, "Oil, the New Oil Order on Hiatus," Commodities Research, February 1.

International Energy Agency, 2018, "Long-Term Oil Liquids Supply Outlook."

J.P. Morgan, 2018, "Raising 2018 Price Forecasts by $10/bbl," Oil Market Weekly, January 25.

Kemp, J., 2018, "Hedge Funds Pile into Oil Despite Rising Risk of a Correction," *Reuters*, January 29.

Kemp, J., 2018, "Hedge Funds Continue to Exit Oil but OPEC Stems Rout," *Reuters*, February 27.

Till, H. and J.-H. Jesse, 2016, "Swing Oil Production and the Role of Credit," *Global Commodities Applied Research Digest*, Vol. 1, No. 2, Fall, pp. 70-88.

Author Biography

JAN-HEIN JESSE
Founder, JOSCO Energy Finance and Strategy Consultancy (Amsterdam); and Editorial Advisory Board Member, *Global Commodities Applied Research Digest*

Mr. Jan-Hein Jesse has been active in the oil and gas industry since 1980. Mr. Jesse is also an independent director and advisor of Centerbridge Partners (U.S.A., U.K.) and AT Capital (Singapore). He is the former head of Energy Finance at ING Bank, a former senior manager Mergers & Acquisitions at Shell, and the former CFO of Heerema Marine Contractors. He is an expert for the International Energy Agency, a visiting fellow of Clingendael International Energy Programme (CIEP, The Netherlands), and is a member of the Chief Economic Roundtable Group at the Ministry of Economic Affairs of The Netherlands. He lives in Amsterdam.