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**OCTAVIA'S OUTLOOK**
**VOLUME 4: WINTER 2017**

The current Octavia's Outlook evaluates the energy industry. The objective of this letter is to consider the factors influencing financial securities. For the energy industry, this means we need to understand what forces influence oil and gas prices. While some companies are better operators than others within a given sector of the energy industry, commodity prices supersede all. A sustained environment of $30 oil and $2 natural gas would bankrupt the entire US energy industry (other than the refiners). So, first and foremost energy investors must forecast the commodity price environment. With that, then energy investors can determine which sectors and companies are best suited to succeed in such an environment. You will notice that we are focusing on oil and gas as it relates to the energy industry because while alternative and renewable energies matter in the long-run, over the next 20 plus years they are quite inconsequential. The fact is that oil and gas are the energy sector.

Finally, to fully share Octavia's investment perspectives and theses on the energy industry would likely require a 100+ page letter, which obviously is not practical. So, we have elected to only focus on the areas we think are of greatest importance or interest. To the extent we have excluded something, it does not mean we are not considering it in our investment decisions.

This letter includes three sections. Section 1 starts on page 2 and provides an oil and gas primer. Section 2 starts on page 4 and discusses the forces that impact oil and gas prices. And, Section 3 starts on page 17 and lays out Octavia's investment theses. While the document seems long, charts comprise about 70% of the pages, so please don't be scared off by the page length.

## Section 1: An Oil and Gas Primer

If you have a solid understanding of oil and gas, please move on Section 2 on page 4. Quick disclaimer for the petroleum engineers reading this letter. We are going to way, way over-simply things since most of our clients and other readers are not energy experts. We are writing in a way that we believe is the easiest to understand.

***What are Oil and Gas?***

Oil and gas are made by the earth "cooking" organic matter (plants mostly) for millions of years under the earth's surface. By being hundreds to thousands to tens of thousands of feet below the earth's surface, plant matter is under high levels of pressure and heat. These combine to "cook" the plant matter and turn it into oil and gas. The higher the level of pressure and/or the higher the level of heat, the more likely natural gas is created. Conversely, the lower the level of pressure and/or heat, the more likely crude oil is created.

Oil and gas are basically the same thing (chains of hydrogen and carbon atoms) and basically only vary in their density. And, by density we mean how many carbon atoms and hydrogen atoms are in a molecule. This is why oil and gas are called hydrocarbons. Natural gas, the stuff you use to heat your stove or run your heater to heat your home is the least dense of the hydrocarbons and contains 1 carbon atom and 4 hydrogen atoms (for every carbon atom there are 2xC + 2 hydrogen atoms). Crude oil from west Texas is considered "light" oil and is mostly comprised of varying densities of oil with 6 to 8 carbon atoms and thus 14 (2x6 + 2) to 18 (2x8 +2) hydrogen atoms. Conversely, oil from Canadian tar sands is considered "heavy" oil and has 20 carbon atoms or more per molecule.

Hydrocarbons follow a continuum of densities. Natural gas has 1 carbon. Ethane, which is used to make plastics, has 2 carbons. Propane, which is used also to make plastics or to fuel your BBQ, has 3 carbons. Butane, which is used as a fuel additive, has 4 carbons. As we start getting to hydrocarbons with 6 carbons and more, they are mostly used as fuels to run motors. Also, when you say crude oil, that could mean hydrocarbons with 7 carbons or more than 20 carbons per molecule. This is an important point to remember later in the letter because when we talk about crude oil, not all crude oil is the same and its value to a refiner can vary widely, thus impacting prices for various grades of crude oil. In summary, at atmospheric pressure and temperature (i.e., the world in which we live), since natural gas is less dense it is a gas and since oil is denser it is a liquid.

There are three primary categories of hydrocarbons: natural gas, natural gas liquids ("NGLs") and crude oil. Natural gas' primary uses are to generate electricity and generate heat. Natural gas needs to be chilled to minus 259 degrees Fahrenheit (minus 161 Celsius) to change to a liquid state. To do this is a very expensive process. As a result, natural gas is typically transported within pipelines as a gas, as opposed to liquefied, put on ships and transported (this is what LNG is – liquefied natural gas). Since natural gas is mostly shipped via pipeline, its pricing can vary widely by geography. Natural gas liquids (hydrocarbons with 2 to 5 carbon atoms) are primarily used to make plastics, as a heat source and as a component in fuels. Crude oil (hydrocarbons of 6 carbon atoms and above) are primarily used to make transportation fuels (gasoline for cars; diesel for trucks, buses, trains; jet fuel for airplanes; bunker fuel for ships; as well as asphalt for roofing and streets).

The liquid products into which crude oil (and to a lesser extent select NGLs) is converted (components to make gasoline, diesel, jet fuel, etc.) are called Refined Products. Refined products are produced by Refineries, which are basically giant chemistry sets of varying complexity. The US has the most sophisticated refineries in the world that can take varying densities of crude oil and convert them into refined products. For example, a refinery with basic capabilities can take light oil (think 6 to 8 carbons) and make gasoline quite easily. But, if this refinery had to process heavy oil (think 20 carbons), it would not be able to create gasoline because it would lack the ability to "break" the carbon chains and make products with 6 to 8 carbons. But, a sophisticated refinery does have this capability. As a result, heavier oil typically trades at a price discount to light oil because fewer refineries can process the heavier oil. At the same time, refineries having the capability to process heavier oil can make larger profits by buying heavy oil at discounts to light oil. Understand, though, that the ability to process heavy oil is due to billions of dollars in capital expenditures on these special capabilities.

Regarding units of measure. Oil is measured in barrels. NGLs are measured in either gallons or barrels (42 gallons per barrel). Natural gas is measured in cubic feet, with thousands of cubic feet the measure when you see natural gas prices. Thus, when we say natural gas costs $3, we mean that it costs $3 for one thousand cubic feet.

Finally, regarding energy equivalence, 1 barrel of oil has the energy equivalence of 6,000 cubic feet of natural gas. So, when we want to discuss a company's combined oil and gas volumes, we typically quote them in Barrel of Oil Equivalents ("BOE"), where every 6,000 cubic feet of natural gas is converted into 1 barrel of oil for measurement purposes. While the ratio of energy equivalence follows this 6:1 ratio, commodity prices are quite different. At $50 oil and $3 natural gas, the ratio is 16.7:1, meaning the oil is far more valuable than natural gas on an energy equivalent basis. This is an important factor to keep in mind in evaluating companies (i.e., one company could produce 1 million barrels of oil while another could produce 6 billion cubic feet of natural gas, and while they are the energy equivalent, the oil production is far more valuable given the pricing differences – assuming production costs are comparable).

***What is Fracing?***

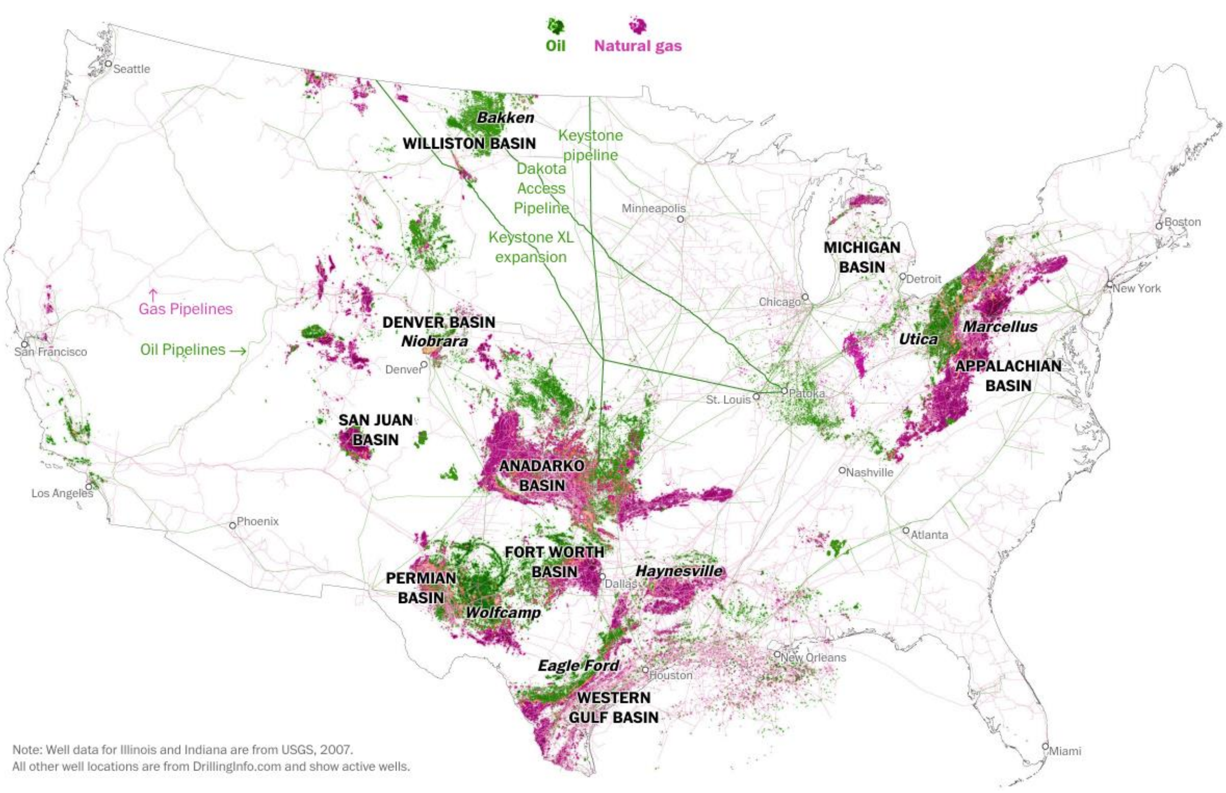
There are two primary methods to drill for oil and gas (ignoring Canadian tar sands mining): conventional and unconventional. In conventional drilling, you drill to an area where the oil and gas are suspended in sand or it has pooled. Since the oil and gas is under incredible pressure being below the earth's surface and since sand is porous and thus oil and gas can move within it, when you drill to where the oil and gas are they naturally want to rise to the surface. That is how oil and gas have historically been extracted.

In unconventional drilling (otherwise known as fracing), the oil and gas is trapped in shale rock instead of sand or in pools. But, shale rock is not porous and the oil and gas can't freely flow when you drill down to it. So, what the exploration and production companies do is drill down to where the shale layer is and then turn the drill-bit sideways and drill horizontally for thousands of feet through the shale layer. They then pump water and sand (and a smidge of chemicals) using tremendous pumping pressure to fracture the shale rock, with the sand that was pumped staying behind to keep the factures open and allow the oil and gas that was trapped in the shale to flow.

***Where Does Fracing Occur?***

Some shale basins have a higher weighting to oil while others are weighted to natural gas. The following graphic in Chart 1 can help you get a perspective for where shale oil and gas are drilled (FYI, not all listed basins are shale basins).

**Chart 1**



As it relates to nomenclature. A Basin is the geography where drilling occurs, while the Shale is the layer of rock within the Basin under the surface. For example, in the Permian Basin (west Texas), there are about 11 shale layers which can be drilled, one of which is called the Wolfcamp Shale. Or, in the Appalachian Basin of Pennsylvania, West Virginia, Ohio and New York, the Marcellus Shale is a layer of rock beneath the surface.
Regarding productivity from the seven primary shale basins, Charts 2 and 3 provide some perspective on production levels (conventional drilling in Alaska and the Gulf of Mexico are also included).

**Chart 2**

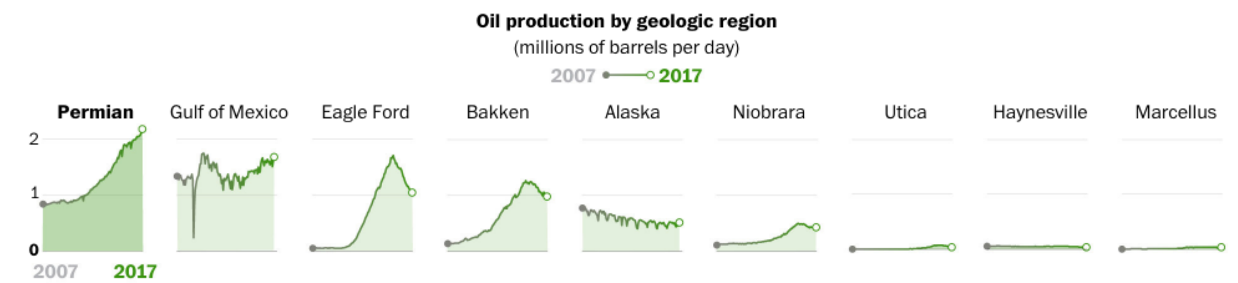
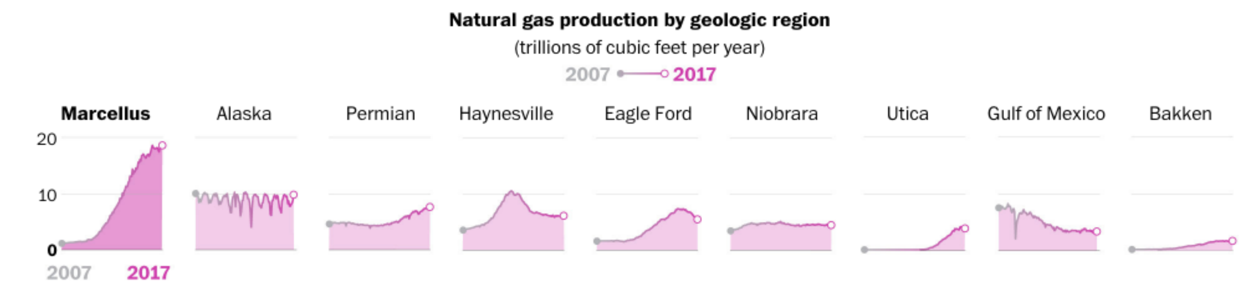



**Chart 3**




***What Sectors Comprise the Oil and Gas Industry?***

There are four sectors in oil and gas:

1. Exploration and Production ("E&Ps"): these companies find, extract and then sell the oil and gas. Sector also referred to as "Upstream".
2. Oilfield Services ("OFS"): these companies provide services to the E&P companies to help them extract the oil and gas.
3. Pipelines: these companies provide the pipeline services to transport the oil and gas and the refined products made from oil, as well as provide processing plants to process NGLs (take a stream of NGLs and separate them into ethane, propane, butane, and pentane; a process called fractionation). Sector also referred to as "Midstream".
4. Refiners: these companies convert oil into the components to make refined products (gasoline, diesel, jet fuel, etc.). Sector also referred to as "Downstream".

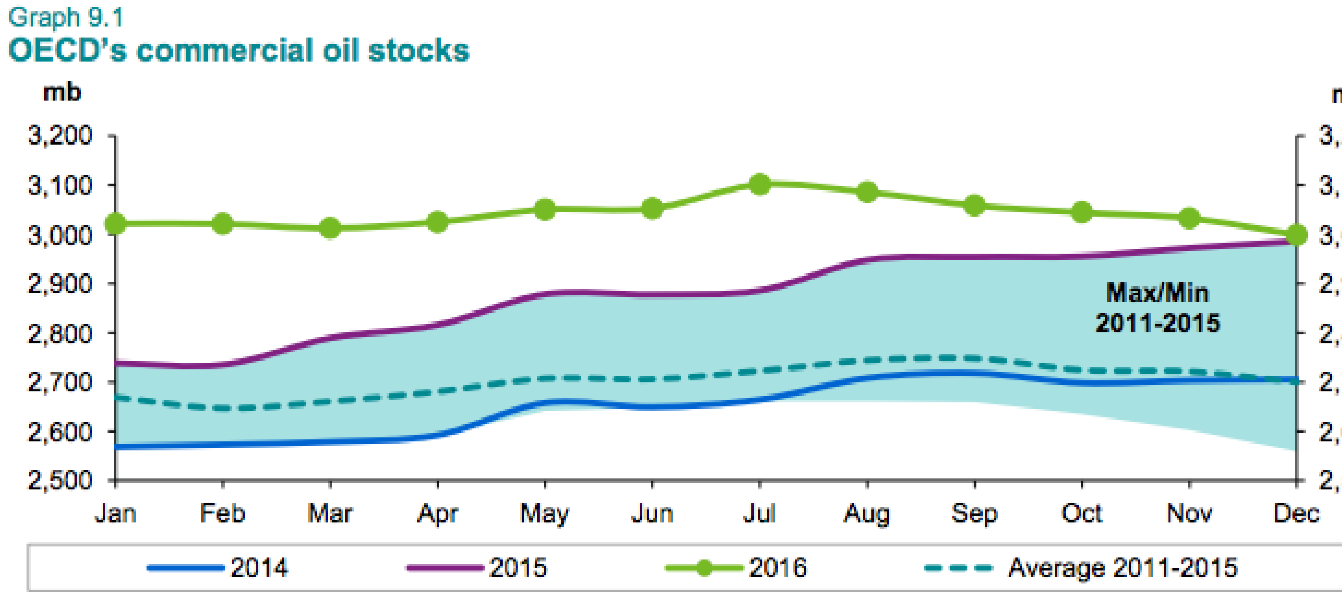
## <u>Section 2: What Forces Impact Oil and Gas Prices?</u>

Let's start with oil. We believe there are three factors that drive the price of oil: scarcity premium, variable cost and trading sentiment.

***Scarcity Premium***

Simply put, crude oil is the most important commodity in the world, full stop. Without crude oil, the global economy would come to a halt because transportation would come to a halt. No driving cars to work, no transporting goods on trucks, trains, ships or airplanes. No flying anywhere. Therefore, the negative consequences of not being able to access crude oil are so dire that there is a huge "scarcity premium" in the price of crude oil. This scarcity premium can vary depending on the amounts of crude oil and refined products in storage. The more in storage, the more time before the world would run out of transportation fuels in the event of a crude oil supply disruption (think, war in the middle east). Chart 4 on the next page provides the most commonly followed data on crude oil and refined products stocks in inventory.

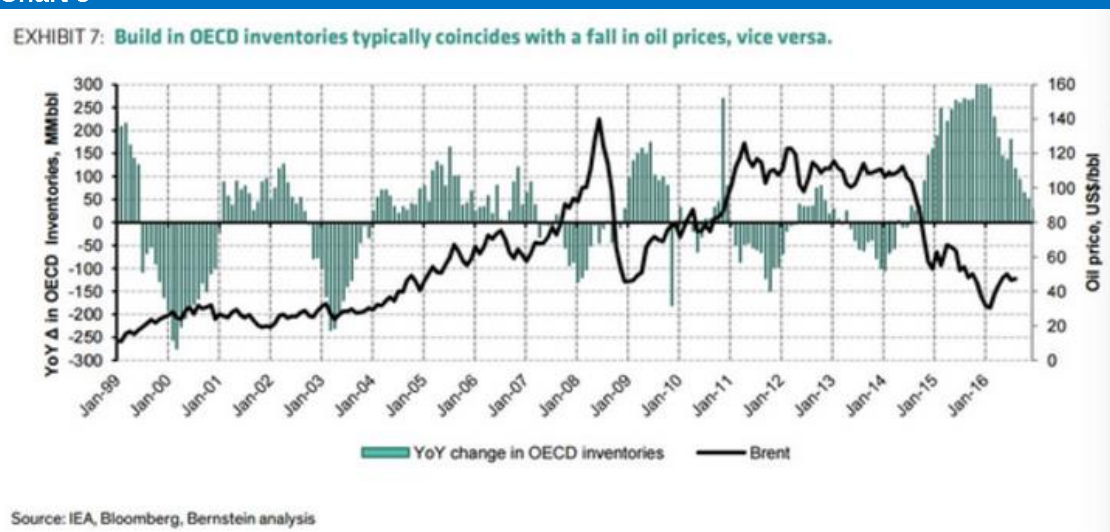
**Chart 4**




*Sources: Argus Media, Euroilstock, IEA, METI, OPEC Secretariat and US Energy Information Administration.*

In 2014 inventories covered 58.3 days of consumption and oil prices were $100 per barrel (or thereabouts). Today, inventories cover 63.8 days of consumption and oil prices are about $55 per barrel. And, in Q1 2016 when oil was around $30 per barrel, inventories covered 65.1 days of consumption. Looking at it another way, when stocks were 2.6 billion barrels, oil was $100 per barrel, but with stocks now at 3 billion barrels, oil is $50 per barrel. It seems strange to us that such small changes in inventories can have such a huge impact on price, but these differences in inventory drive the perception of scarcity or excess. The correlation between inventories and oil prices is very strong, per Chart 5.

**Chart 5**

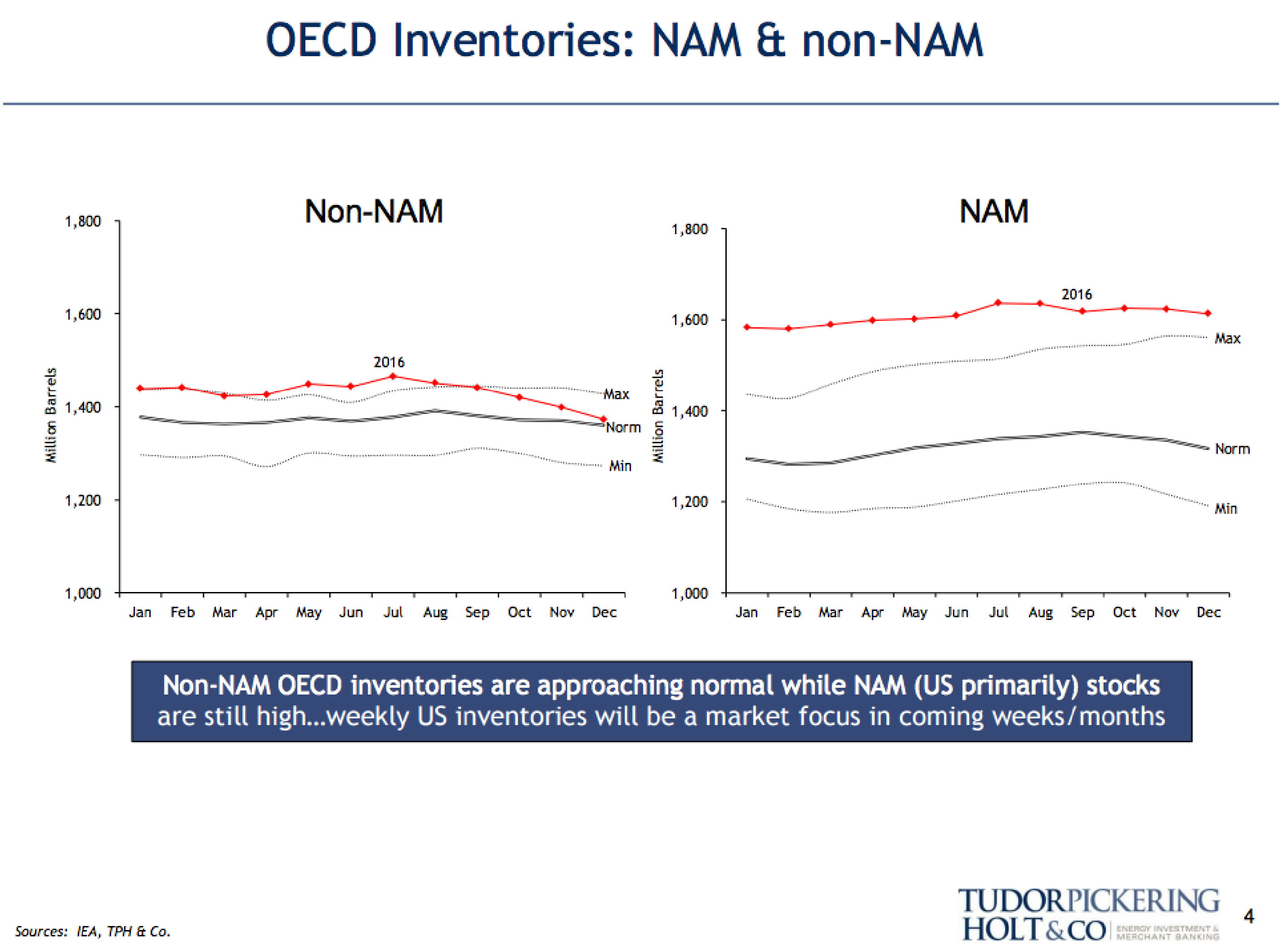



Source: Bernstein, @NickatFP, @joshdigga

That said, one caveat. The OECD inventory data is not total global inventory. It is only the inventory reported by developed countries. We don't know, for example, exactly how much oil and refined product are in storage in China and many other emerging economies. The industry performs analysis to try to determine the stocks, but they are only educated guesses. Thus, we don't know what global inventory data truly is. We can see period-over-period changes in OECD data, but it's possible that non-OECD inventories are moving in the opposite direction. We try to track oil tankers to see where oil is moving, but we can't track all the on-land pipelines moving oil. The point being that the data is inexact and could be misleading, thus we must consider it with a broader perspective.

One final thought. You will notice we have not mentioned US oil and refined product stocks. This is because oil is fungible and easy to transport, and thus pricing is based on global supply and demand, not US supply and demand. Each week, the US Energy Information Association (EIA) publishes US inventory data, which typically impacts oil prices. The problem we have with this is that just because US inventories go up or down, it does not mean global inventories have gone up or down. Maybe a trader is simply storing oil in the US instead of storing it in Singapore or Rotterdam or Okinawa. Its cost about $1-$2 per barrel to ship oil from the Middle East to the US. We are not saying the cost is inconsequential, but we are saying that the reasons that US inventories are going up or down from week to week can be due to factors other than global supply and demand, and therefore while we consider the weekly EIA inventory numbers, we believe they require deeper understanding than simply did they go up or down and thus global inventories are higher or lower. On this topic, we find Chart 6 interesting.

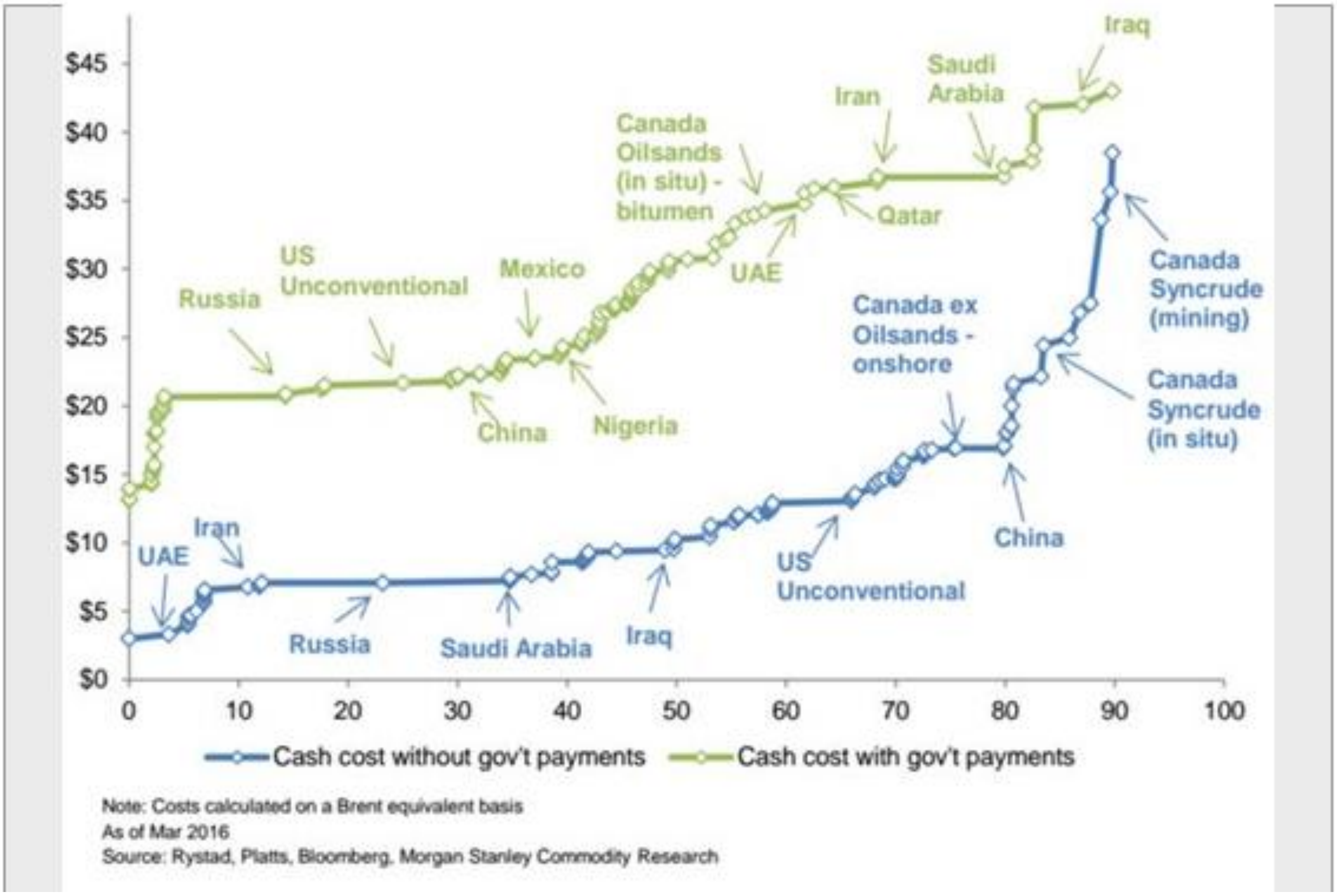
**Chart 6**



***Variable Cost***

Which takes us to the next factor, the variable cost to lift oil. Once an oil well has been drilled and is producing hydrocarbons (often oil, NGLs and natural gas all come up at the same time, the weightings varying by the level of "cooking"; some wells are ~100% oil, some are ~100% natural gas, some are 1/3 oil, 1/3 NGL and 1/3 natural gas; it varies widely depending on the geology), the variable cost to continue to produce the hydrocarbons ranges from $3 to $20+ per barrel for a well that predominantly produces oil, per Chart 7.

**Chart 7**




What this means is that in a world where there is little to no scarcity premium built into the price of oil, which we believe is the world in which we lived in 2015 and 2016, then the price of oil could fall to variable lifting cost, since producers generate positive cash flow up to their variable cost. Yes, at $20 oil, producers could decide to shut in wells, waiting for prices to rise. And, if enough producers shut in their wells, then supply would fall, which would likely cause prices to rise. At the same time, though, if an oil company has huge debt levels it must service or a national oil company produces 75% of the country's revenues which are needed to fund social programs (healthcare, education, infrastructure, etc.), then such producers are hard pressed to shut in production when some cash flow is better than no cash flow. And, that is the world in which we currently live. Oil producers do not have the luxury of shutting in their oil wells. They must service their high debt levels or, in the case of national oil companies, pay for social welfare programs, and thus can't shut the oil valves. What this tells us is there is no reason why oil could not fall to $20 per barrel, if that is where sentiment took it.

That said, it's not quite that simple and we are not forecasting $20 oil prices. While oil may be over-supplied today, it's possible it could be in balance or even under-supplied in the future. And, if someone believes that the world will be in such a situation, then they would buy oil today, put it in storage, and sell it at the higher price in the future. This demand would keep current prices elevated. For oil to fall to $20 per barrel, we would need two things. First, inventories would need to stay elevated at current levels or higher. Second, current production would need to be greater than current demand with no prospect for supply reductions in the future. In that scenario, oil would likely fall to variable cost. The reason oil is $55 today is that OPEC has agreed to a supply cut and its possible inventories could fall materially in the second half of 2017, bringing inventories back down to the 2.8 billion barrels level. This scenario is competing with the current excess inventory situation, putting oil at its current $55 level; above $20 variable cost breakeven but below the $100 scarcity scenario.

Given the importance of OPEC's recent supply cut, we want to spend a bit of time sharing our thoughts on this. In October 2016, OPEC and a group of 11 non-OPEC countries agreed to cut production on average 1.8 million barrels per day (OPEC 1.2 / non-OPEC 0.6) during the January to June 2017 period. The question we ask is what impact would this have on inventories in the best-case scenario of full compliance. First let's look at global oil demand and global oil supply ex-OPEC in Chart 8.

## Chart 8

**World oil demand and supply balance, *mb/d***

| | 2013 | 2014 | 2015 | 1Q16 | 2Q16 | 3Q16 | 4Q16 | 2016 | 1Q17 | 2Q17 | 3Q17 | 4Q17 | 2017 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **World demand** | | | | | | | | | | | | | |
| **OECD** | 46.1 | 45.8 | 46.4 | 46.8 | 46.2 | 47.2 | 47.0 | 46.8 | 47.0 | 46.4 | 47.5 | 47.1 | 47.0 |
| Americas | 24.2 | 24.2 | 24.6 | 24.6 | 24.7 | 25.1 | 24.8 | 24.8 | 24.8 | 24.8 | 25.4 | 24.9 | 25.0 |
| Europe | 13.6 | 13.5 | 13.7 | 13.6 | 13.9 | 14.4 | 13.9 | 14.0 | 13.7 | 14.0 | 14.4 | 13.9 | 14.0 |
| Asia Pacific | 8.3 | 8.1 | 8.0 | 8.6 | 7.6 | 7.7 | 8.3 | 8.1 | 8.5 | 7.6 | 7.7 | 8.2 | 8.0 |
| **DCs** | 29.1 | 29.9 | 30.6 | 30.7 | 31.0 | 31.5 | 31.1 | 31.1 | 31.3 | 31.6 | 32.1 | 31.8 | 31.7 |
| **FSU** | 4.5 | 4.6 | 4.6 | 4.5 | 4.4 | 4.7 | 5.0 | 4.7 | 4.6 | 4.4 | 4.8 | 5.1 | 4.7 |
| **Other Europe** | 0.6 | 0.7 | 0.7 | 0.7 | 0.6 | 0.7 | 0.8 | 0.7 | 0.7 | 0.7 | 0.7 | 0.8 | 0.7 |
| **China** | 10.3 | 10.7 | 11.1 | 11.0 | 11.5 | 11.4 | 11.7 | 11.4 | 11.2 | 11.7 | 11.6 | 11.9 | 11.6 |
| **(a) Total world demand** | **90.7** | **91.7** | **93.3** | **93.6** | **93.7** | **95.5** | **95.6** | **94.6** | **94.8** | **94.9** | **96.8** | **96.8** | **95.8** |
| **Non-OPEC supply** | | | | | | | | | | | | | |
| **OECD** | 22.2 | 24.3 | 25.3 | 25.3 | 24.2 | 24.6 | 25.1 | 24.8 | 25.2 | 24.8 | 24.8 | 25.2 | 25.0 |
| Americas | 18.2 | 20.1 | 21.1 | 21.0 | 20.1 | 20.5 | 20.7 | 20.6 | 20.9 | 20.6 | 20.8 | 21.0 | 20.8 |
| Europe | 3.6 | 3.6 | 3.8 | 3.9 | 3.7 | 3.6 | 3.9 | 3.8 | 3.8 | 3.7 | 3.5 | 3.8 | 3.7 |
| Asia Pacific | 0.5 | 0.5 | 0.5 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.5 | 0.4 | 0.4 | 0.4 |
| **DCs** | 11.8 | 12.0 | 12.2 | 12.0 | 12.0 | 12.2 | 12.3 | 12.1 | 12.2 | 12.2 | 12.3 | 12.4 | 12.3 |
| **FSU** | 13.6 | 13.5 | 13.7 | 14.0 | 13.7 | 13.7 | 14.2 | 13.9 | 13.9 | 13.8 | 13.9 | 14.0 | 13.9 |
| **Other Europe** | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| **China** | 4.2 | 4.3 | 4.4 | 4.2 | 4.1 | 4.0 | 4.0 | 4.1 | 3.9 | 3.9 | 3.9 | 3.9 | 3.9 |
| **Processing gains** | 2.1 | 2.2 | 2.2 | 2.2 | 2.2 | 2.2 | 2.2 | 2.2 | 2.2 | 2.2 | 2.2 | 2.2 | 2.2 |
| **Total non-OPEC supply** | **54.1** | **56.4** | **57.9** | **57.9** | **56.4** | **56.7** | **57.8** | **57.2** | **57.6** | **57.0** | **57.3** | **57.8** | **57.4** |
| **OPEC NGLs + non-conventional oils** | 5.6 | 5.8 | 5.9 | 6.1 | 6.1 | 6.1 | 6.1 | 6.1 | 6.2 | 6.2 | 6.3 | 6.3 | 6.2 |
| **(b) Total non-OPEC supply and OPEC NGLs** | **59.7** | **62.2** | **63.8** | **63.9** | **62.5** | **62.8** | **64.0** | **63.3** | **63.8** | **63.3** | **63.5** | **64.2** | **63.7** |
| **OPEC crude oil production (secondary sources)** | 30.5 | 30.3 | 31.5 | 31.9 | 32.2 | 32.6 | 33.1 | 32.5 | | | | | |
| **Total supply** | 90.2 | 92.5 | 95.3 | 95.9 | 94.6 | 95.5 | 97.1 | 95.8 | | | | | |

A key takeaway from Chart 8 is that oil demand is seasonal, with low demand in 2017 Q1 and Q2 of an estimated 94.9 million barrels per day and high demand in 2017 Q3 and Q4 of an estimated 96.8 million barrels per day. Another key takeaway is that the OPEC supply numbers that balance world demand are 31.0, 31.6, 33.3 and 32.6 million barrels per day in 2017 Q1 through Q4, respectively. In Chart 9 we provide the OPEC production targets for 1H 2017.

**Chart 9**

## OPEC Crude Production

(million barrels per day)

| | Dec 2016 Supply | Jan 2017 Supply | Supply Baseline[1] | Agreed Cut | Actual Cut[2] | January Compliance |
|---|---|---|---|---|---|---|
| Algeria | 1.12 | 1.05 | 1.09 | -0.05 | -0.04 | 78% |
| Angola | 1.64 | 1.64 | 1.75 | -0.08 | -0.11 | 142% |
| Ecuador | 0.54 | 0.525 | 0.55 | -0.03 | -0.02 | 88% |
| Gabon | 0.21 | 0.20 | 0.20 | -0.01 | 0.00 | 22% |
| Iran[3] | 3.75 | 3.75 | 3.71 | 0.09 | 0.04 | NA |
| Iraq | 4.66 | 4.45 | 4.56 | -0.21 | -0.11 | 53% |
| Kuwait | 2.81 | 2.71 | 2.84 | -0.13 | -0.13 | 98% |
| Qatar | 0.63 | 0.61 | 0.65 | -0.03 | -0.04 | 127% |
| Saudi Arabia | 10.45 | 9.98 | 10.54 | -0.49 | -0.56 | 116% |
| UAE | 3.14 | 2.96 | 3.01 | -0.14 | -0.05 | 38% |
| Venezuela | 2.10 | 2.05 | 2.07 | -0.10 | -0.02 | 18% |
| **Total OPEC 11** | **31.05** | **29.93** | **30.97** | **-1.16** | **-1.04** | **90%** |
| Libya[4] | 0.62 | 0.69 | | | | |
| Nigeria[4] | 1.39 | 1.44 | | | | |
| **Total OPEC** | **33.06** | **32.06** | | | | |

1 Based on October 2016 OPEC secondary source figures, except Angola which is based on September 2016.
2 From OPEC supply baseline.
3 Iran was given a slight increase.
4 Libya and Nigeria are exempt from cuts.

Based on the numbers in Chart 9, if OPEC and non-OPEC achieve 100% of its targeted 1.8 million barrels per day, then inventories will stay roughly constant during 1H 2017. But, if OPEC and non-OPEC continue their targeted production levels for another six months into 2H 2017, inventories would decline by about 1 million barrels per day, or about 180 million barrels. Given oil prices were $100 at 2.6 billion barrels in storage, it is possible that oil could be $60 to $65 with 2.8 billion barrels in storage. We are not going to try to determine the exact inventory levels required to achieve some form of equilibrium but an approximately 200 million barrel reduction in inventories by the end of 2017 feels like a number that should generate some incremental scarcity premium.

Our view is that oil prices will follow an iterative process where inventory reductions will lead to rising prices, which lead to increased production, which leads to lower prices, which leads to production cuts, which leads to higher prices, etc. etc. The key, which we describe next, is that OPEC will be playing the key role in setting production targets to iterate to a long-term sustainable oil price, which we believe is about $60 per barrel.

While US shale oil gets much press as the new “swing” producer and is feared will flood the world with oil, we think this narrative is wrong. US shale is not the swing producer because US shale does not act in concert. US shale does not increase and decrease production to impact price but instead increases and decreases production in reaction to price. By definition, that is not the behavior of a swing producer. US shale is made up of hundreds of private companies deciding to drill based on prevailing prices. No individual shale E&P can influence oil prices and shale E&Ps do not collude to set production levels. While US shale can act as a gate on rising or falling prices because US shale can bring production up or down quickly, US shale is reacting to price signals, not setting them. In addition, US shale is simply too small to be a swing producer. At around 4.5 million barrels of oil per day, US shale is small relative to 80 million barrels of oil per day globally or Saudi Arabia at around 10 million barrels of oil per day. Now, to the extent US shale increases production by 1 million barrels per day in a short time period, that would most likely push global supply-demand out of balance and drive down prices, but at current prices, US shale does not have the collective balance sheets to grow that fast. In 2017, US shale E&Ps appear to be increasing capital expenditures on drilling and completing wells by over 50% versus 2016 spending and most companies will be cash flow negative, yet for the year 2017 US shale is forecast to only grow production by 300,000 to 400,000 barrels per day. Given the capital markets want US shale companies to live more within their cash flows and not use outside financing to fund growth, while $60 oil is quite profitable, it is not profitable enough to enable US shale to massively invest in drilling and the resulting production growth. In the near-term, fear of rapid US shale production growth is over-blown, in our opinion. Over time, we can easily see a scenario where US shale is producing 10 or 15 million barrels per day, but that will take five to ten years and require other production (global conventional and offshore) to come off significantly, such the US shale would be taking market share as opposed to increasing total global production. We will describe this further later in this letter.

An important factor with US shale is the speed with which production can increase or decrease. If an oil company wants to develop a field in deep waters in the Gulf of Mexico, it can take 5 years or more from discovery to first oil and gas production. With shale, the industry knows the oil and gas is there; there is almost never a dry hole. And, a well takes as short as a week to drill. So, from the time a producer decides to drill a well, they can be producing oil and gas a few months later. This means that US shale producers can react very quickly to price signals. At the same time, shale wells deplete very quickly. In a conventional well, maybe they produce 7% of the resource in year 1, declining slowly over 20 to 30 years (as the pressure declines). US shale wells produce 20% to 30% of the entire well in the first year (because they are under massive pressure), with a heavy decline rate from there, such that half the well is produced in four to five years. What this means is that if shale producers stop drilling because of low prices, their production levels will fall off very quickly (as we saw in 2015 and 2016 where total US shale oil production declined about 20%). Conversely, with conventional wells, even if the E&Ps stop drilling, annual production declines will only be in the 3% to 5% level in the global aggregate. These two factors are very important to global oil supply-demand balancing.

OPEC, and more specifically Saudi Arabia, are still the swing producer and what they do matters most to oil prices. OPEC produces 38-ish million of the 95 million barrels of oil and NGLs produced daily (32-ish million of the 80 million barrels of oil produced daily). If the OPEC country members, which have national oil companies to which they can dictate policy, want to coordinate supply levels, they can. And, if they can get some non-OPEC countries, such as Russia and its 11 million barrels per day of oil production, to use their influence to moderate oil and gas production, all the better.

Thus, it is very important to understand the situation of OPEC countries, since that will dictate their supply strategy. There are two factors at work: fiscal budgets and Saudi Arabia's planned IPO of its national oil company ("Aramco").

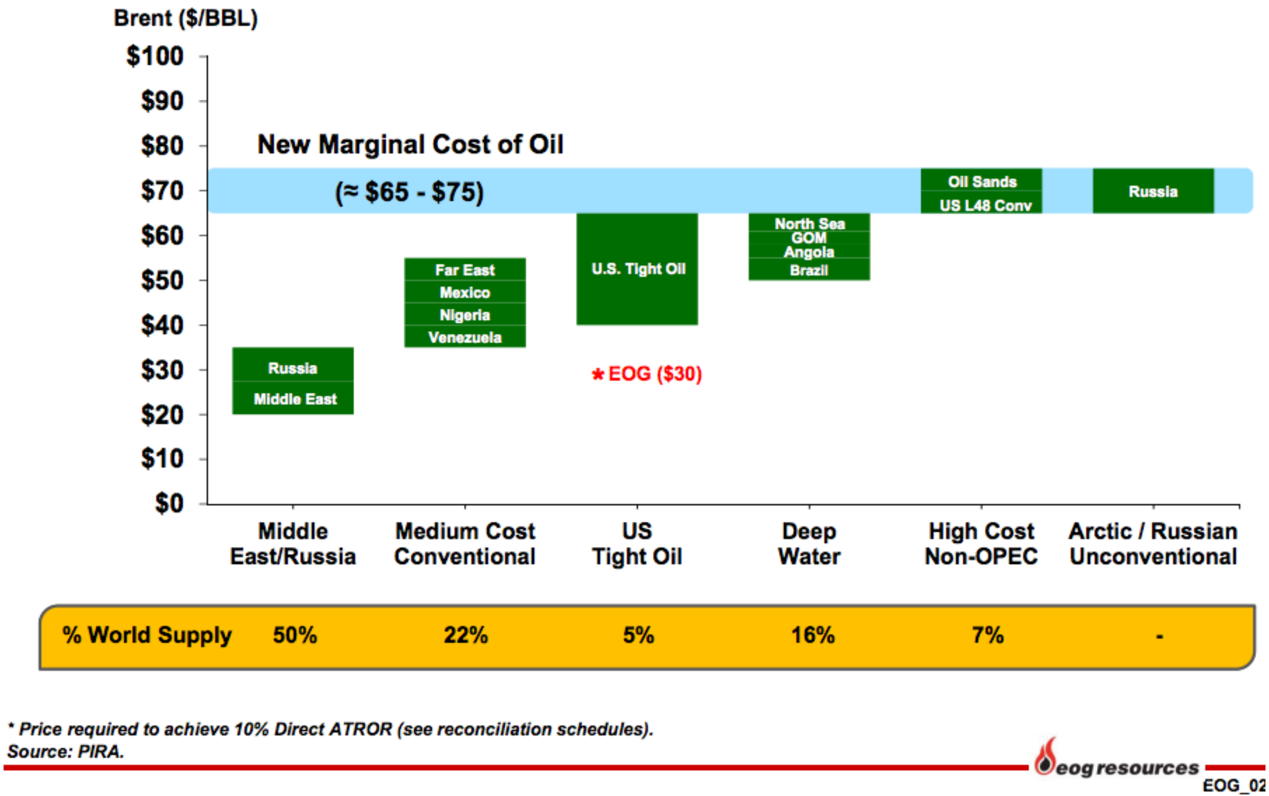
Crude oil exports are the primary source of revenues for most OPEC member countries (and many non-OPEC countries also). The oil companies are owned by the government or taxed heavily by the government and thus the profits fill the national treasuries. These profits are then used to pay for social benefits, such as health care, schooling, infrastructure, etc. While the US relies on taxes (and borrowing) to fund government spending, OPEC countries rely on oil export sales to fund government spending (although they recently began debt funding to fill budget shortfalls, as exemplified by Saudi Arabian government debt issues). At $100 oil, most OPEC countries ran budget surpluses, but at $50 oil, most OPEC countries are running large deficits. Chart 10 approximates the oil price at which certain countries' budgets are balanced.

**Chart 10**

The fact of the matter is that many OPEC countries need $60 to $90 oil to run balanced budgets. But, this creates a huge issue for OPEC. The problem with $100 oil was that it encouraged too much production since most oil resources can be economically produced when sold at $100 per barrel.

Chart 11 should be referenced in thinking about five oil producing groups and their break-even oil prices:

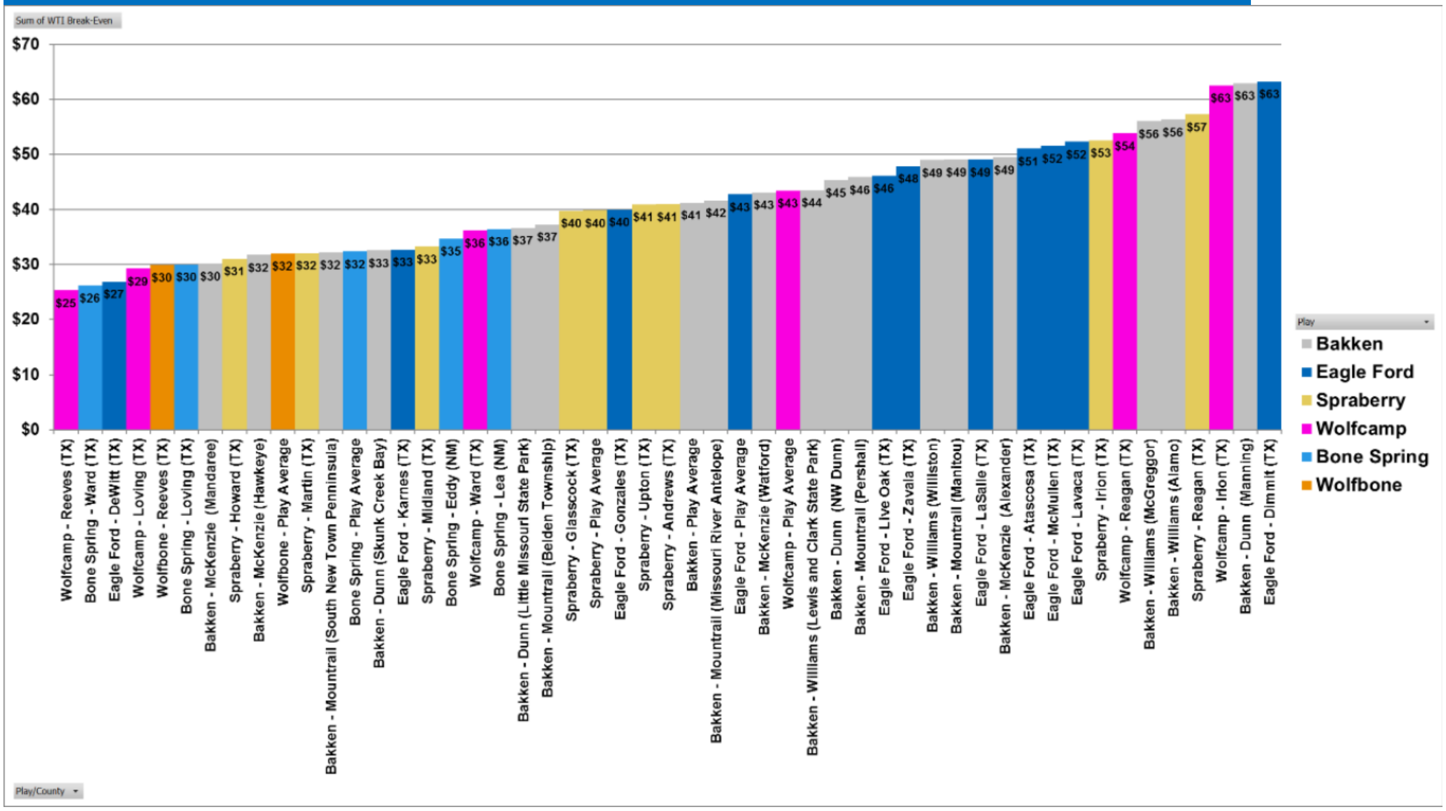
**Chart 11**




1. Middle East gulf states: while numbers are not known, best estimates are that Saudi Arabia, Iran, Iraq, UAE, etc. can drill and lift oil at project level break-even prices in the $20 area. Thus, they can make great project level profits at $50 oil, but when you layer on the overhead of government programs to support, they need $60-$90 oil to "break even".

2. US Shale: US shale economics have improved materially in the past three years. Today, many oil-weighted US shale wells can be drilled and completed for less than $10 per barrel of oil equivalent (BOE) in the ground. Add on $5 to $10 per BOE for on-going lifting costs and the expense of getting the oil from the well to market, and total project level cost for US shale is about $15 to $20 per BOE. Remember, though, that no US shale well is 100% oil. It's quite normal for the weighting to be 50% to 80% oil, 10% to 25% NGL and 10% to 30% natural gas for a US shale "oil" well. Since natural gas prices are quite low currently, this means that oil prices need to be higher than $15 to $20 to breakeven on a cash basis. Add on time value of money, and US shale has abundant locations that break even in the $25 to $45 per barrel of oil level (assuming $3 per thousand cubic feet for natural gas). You may wonder why we claim $25 to $45 break even oil prices for US shale when Chart 11 implies it is more like $50 to $65 per barrel of oil. Its exemplified in Chart 11 from EOG Resources, which claims its break-even is $30 oil. And, it is not just EOG. In numerous US Shale E&P company presentations, break-evens are well below $50 to $65. The following Chart 12 provides break-even oil prices across various US Shale basins.

## Chart 12




3. On-shore Conventional: Conventional on-shore oil wells can vary dramatically in cost based on the amount of oil and gas the wells will produce. Some conventional wells can breakeven at $20 oil (i.e., Russia) while others require $65 or higher oil prices.

4. Canadian Tar Sands: Canadian tar sands produce a very heavy oil. Ignoring costs, Canada has the third highest oil reserves in the world because of the tar sands in Alberta, per Chart 13. But, a new tar sands facility breaks even around $70 oil prices. Canadian tar sands produce only about 3% of global oil today, although given the large reserves could grow materially if the economics permitted.

## Chart 13

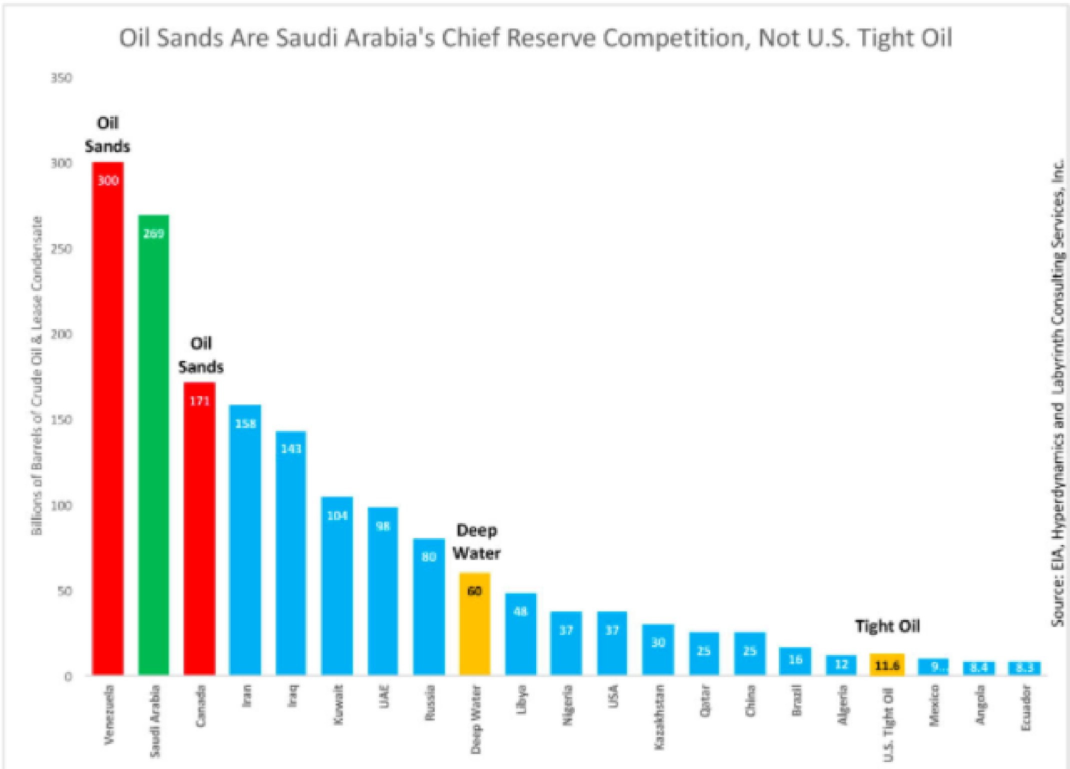



Figure 3. Oil Sands Are Saudi Arabia's Chief Reserve Competition, Not U.S. Tight Oil. Source: EIA, Hyperdynamics and Labyrinth Consulting Services, Inc.

5. Offshore: Most offshore new oil discoveries are in deep waters. But, deep water oil breaks even in the $60 to $80 oil price area. And, new projects can take five to ten years before they are producing first oil and gas, making it hard to do project planning given the unknown price for oil and gas at that time. Offshore oil today contributes about 30% of global oil production, per Chart 14, and about a third of that is deep water or ultra deepwater, per Chart 15.

## Chart 14

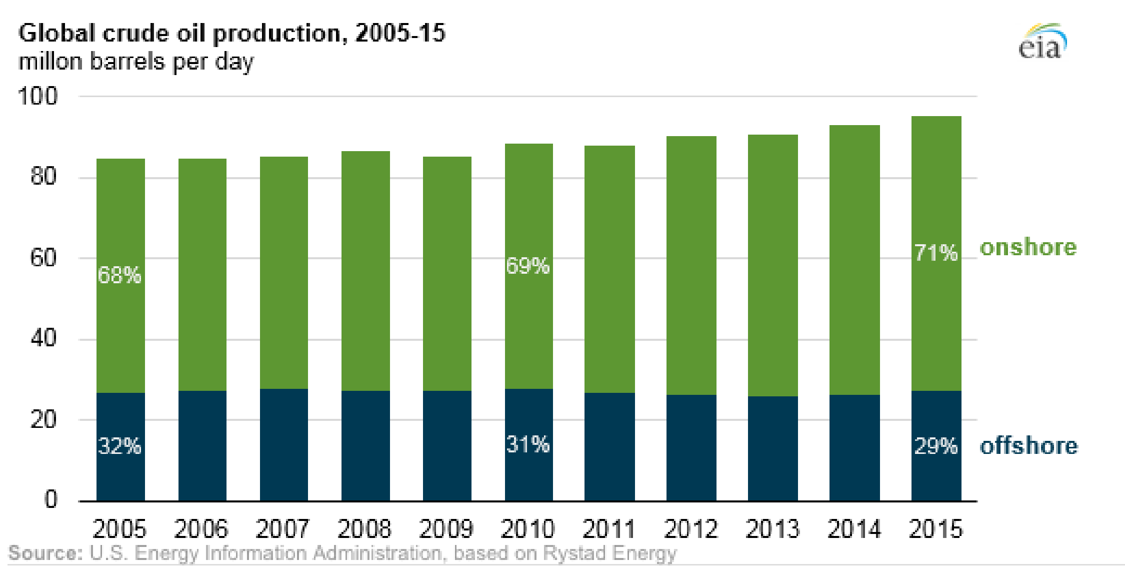
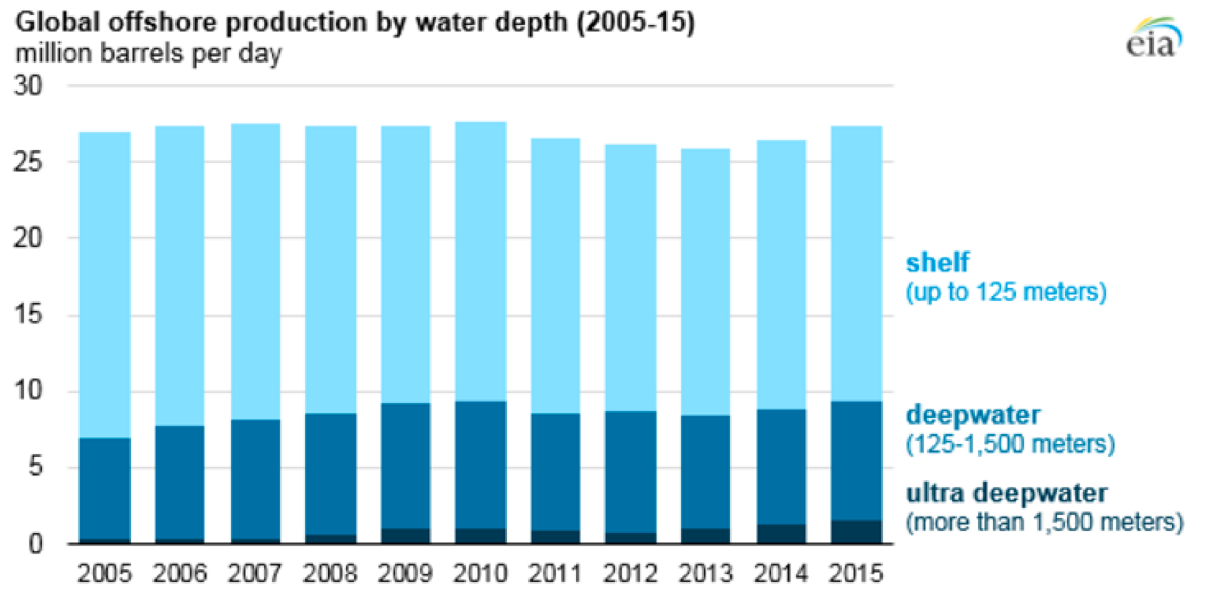


**Chart 15**



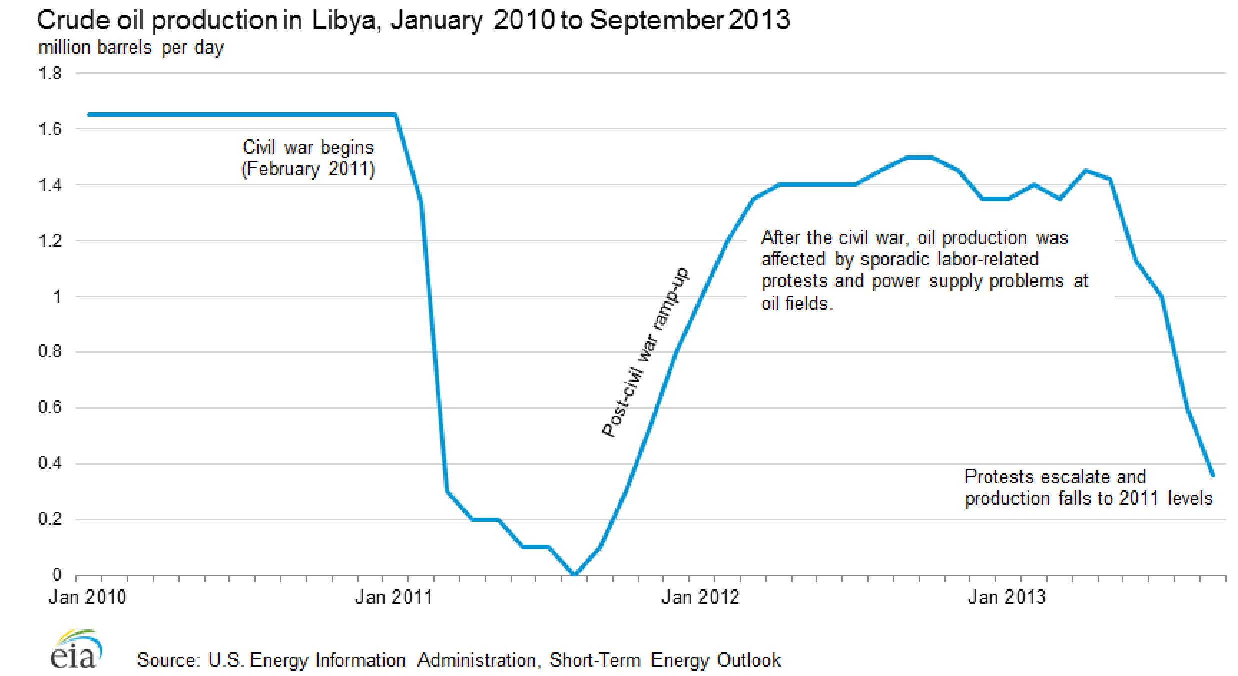

**Source:** U.S. Energy Information Administration, based on Rystad Energy
**Note:** Includes lease condensate and hydrocarbon gas liquids.

So, this is the dilemma for OPEC. If oil prices are too high, too many projects will be initiated, flooding the world with oil and driving down prices. But, if oil prices are too low, they don't have the revenues to fund government spending. We believe that the magic number for OPEC is about $60 per barrel. At this price, offshore is not economic, nor are Canadian tar sands. Conversely, OPEC, US shale and selective onshore conventional producers (i.e., Russia) are all highly economic at $60 oil. That said, several OPEC countries will need to trim their government spending in a $60 oil world (and forget Venezuela, since it needs $150 oil), but it's the price that keeps the world from being flooded with new oil and enables a smaller group to gain market share.

In the scenario we provide above, oil inventories need to fall in order for oil to get to the $60 area. And, this requires production cuts since for the past few years oil production has been in excess of demand. As already discussed, OPEC commenced oil production cuts in January 2017 to achieve such an inventory reduction. The question remains, though, whether they will stick to their production targets or will they cheat. We believe that OPEC, in the aggregate, will succeed in reducing production and thus bring down inventories to levels commensurate with $60 oil. We believe this because Saudi Arabia wants to IPO its national oil company, Aramco, raising an estimated US$100 billion to fund a sovereign wealth fund and start the transition away from being solely a petro state. For Saudi Arabia to have a successful IPO, it will need a strong and stable oil price environment. Thus, Saudi Arabia will do whatever it takes to push up oil prices over the next few years to make Aramco look as good as possible at the time of the IPO (after that, all bets are off). The Aramco IPO is looking like a second half 2018 or first half 2019 event, so for the next two years Saudi Arabia will support oil prices through whatever production cuts are necessary. We saw this in January 2017 with the Saudis cutting production MORE THAN their allocation target. If the Saudi's are committed to oil price increases and stability, we are generally confident they will achieve it.

Regarding risks to our $60 oil forecast, the one that concerns us the most is production from Libya and Nigeria. Libya and Nigeria have experienced significant production disruptions over the past few years due to civil unrest. As a result, they were excluded from the OPEC production cuts. In 2015, Nigeria produced 2 million barrels of oil per day but in 2016 Nigeria produced 1.6 million barrels of oil per day. Thus, we could see an extra 400 thousand barrels per day (72 million barrels over six months) if Nigeria resolves its internal strife. But, the bigger concern is Libya. Chart 16 provides perspective on their production trends. Prior to civil war in 2011, Libya produced over 1.6 million barrels of oil per day. In 2016, Libya produced about 400,000 and as of January 2017 is producing 675,000. If Libya gets back to 2011 production levels, it will bring on an additional 1 million barrels per day. This will wreak havoc on OPEC's desire to bring down inventories. We are closely following this situation but for now are not forecasting a rapid rise in Libyan oil production.

**Chart 16**




### *Trading Sentiment*

Inventory levels and variable costs are the fundamental factors that influence oil prices, but over short time periods trading sentiment can have a powerful influence over oil prices. The world consumes about 80 million barrels per day of crude oil. Trading of Brent and WTI oil on exchanges averages around 2 billion barrels per day. Adjusting for weekend days, this means that for every 1 barrel of oil consumed about 18 barrels are traded. Thus, trading sentiment is far more important to the price of oil than fundamental demand. In theory, trading of oil is supposed to enable producers of oil and consumers of oil to hedge their risks. But, in reality, oil trading is about speculation by financial parties and therefore sentiment is far more important to the short-term price of oil than actual underlying fundamentals.

### *Oil - Key Takeaways*

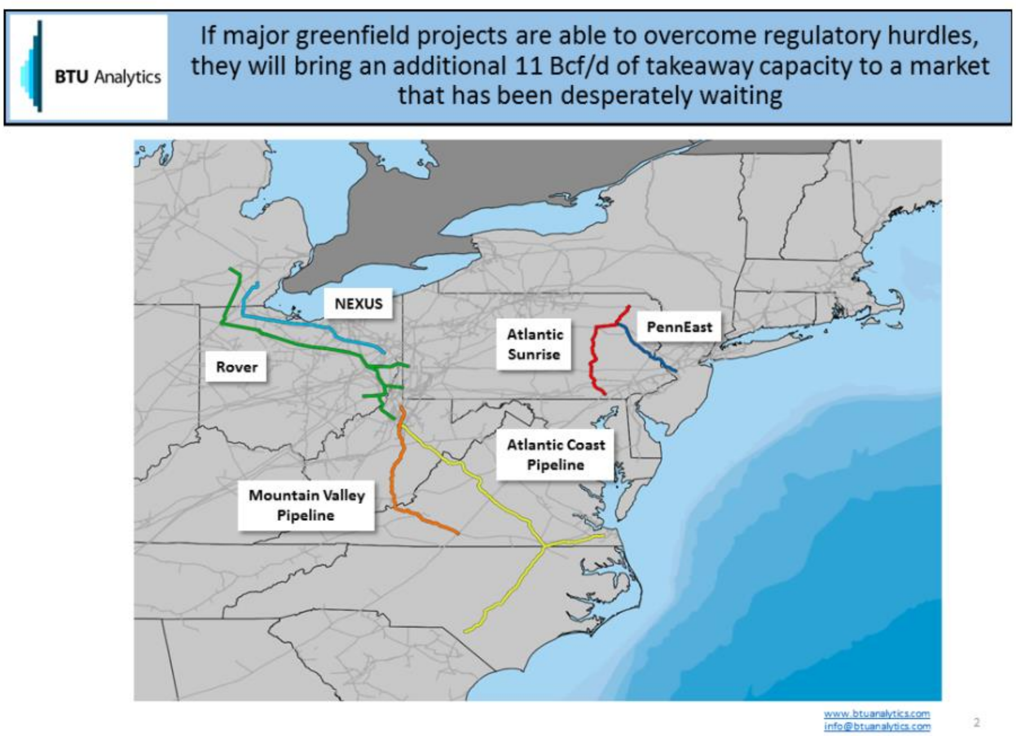
Closing out on oil prices, here are our summary conclusions. Current oil prices assume OPEC maintains it production cuts to bring inventory levels down. If OPEC waivers in its production cuts, oil prices could fall materially. But, given Saudi Arabia's goal of a successful Aramco IPO, we believe Saudi Arabia will do whatever it takes to achieve OPEC's production targets and bring down inventory levels. While increased US shale production is not to be ignored, it is unlikely that US shale will increase production enough to counteract OPEC cuts. At $60 oil, US shale is profitable but not profitable enough to fund a massive increase in new production investment. And, we did not mention it before, but understand that without new investment in production, global oil production would decline by about 5% per year. That means that 80 million barrels per year would become 76 million barrels per year. Thus, if new investment is not going into deep water offshore or Canadian tar sands, then OPEC, US shale and Russia can gain market share simply by growing production to make up for the natural production declines from offshore production which is 30% of global oil production.

### *Natural gas*

Oil is a liquid that is extremely easy to transport across the world via tanker ship. A barrel of oil can be transported from the middle east to the US for about $1 to $2 per barrel. As a result, oil is a global commodity with global competition. Natural gas is much more difficult and expensive to transport because it is a gas (at atmospheric pressure and temperature). For example, natural gas in the US costs about $3 per thousand cubic feet ("mcf"). If you wanted to transport it to Asia, it would cost another $3 to liquefy it to put in on a ship and another couple dollars more to transport it and convert it back from liquid to gas state at the destination point. So, $3 natural gas in the US would cost about $8-$10 delivered to Asia. Where a $50 barrel of US oil would cost $51-$52 (after $1-$2 for shipping) delivered to Asia. As a result, natural gas pricing ends up being a local market where prices can vary dramatically from geography to geography. To the extent a country does not have domestic natural gas production and no access to gas via pipelines (think Russia transporting natural gas to Europe), then their price will depend on global LNG (liquefied natural gas) prices (think Japan, the largest purchaser of LNG in the world).

So, in the US, the price of natural gas is mostly impacted by domestic supply and demand factors and resulting inventory levels (same as oil). In 2016, the US produced 71.4 billion cubic feet (bcf) per day of natural gas. On the demand side, currently 2 bcf per day are exported as LNG and 4 bcf per day are exported via pipelines to Mexico. The rest is consumed domestically. Over the next few years, LNG exports should increase to around 9 bcf per day and Mexico exports to maybe 6 to 8 bcf per day, or an incremental 10 bcf per day. And, regarding electricity power generation, which used about 27 bcf per day during 2016, as natural gas continues to displace coal, its usage continues to increase. All these factors bode well for natural gas, except for one thing. The US Appalachia region (Pennsylvania and West Virginia specifically) is to natural gas what Saudi Arabia is to oil. US Appalachia can drill and complete natural gas wells for as little as $0.25 per mcf. It costs another $0.06 per mcf in on-going operating expenses. US Appalachia is the low cost natural gas producer by orders of magnitude versus the other natural gas producing basins (Barnett in North Texas, Powder River basin in Wyoming, Anadarko basin in Western Oklahoma, Haynesville shale in Northeast Texas/Northwest Louisiana, etc.). These basins drill and complete wells at over $1 per mcf. So, why then are gas prices $3 per mcf if US Appalachia gas is so cheap and plentiful? It's because the pipelines are not in place to get the gas out of market. The transportation constraint limits how much US Appalachia shale gas can be produced, and the fact that all the pipelines are full leads to very high prices for pipeline transportation. In numerous areas within Appalachia, E&Ps sell their natural gas for less than $1 per mcf even when the market price outside of Appalachia is closer to $3 per mcf. But, that situation is finally changing. There are four pipelines expected to come online over the next 12 to 18 months adding 6.5 bcf per day of new takeaway capacity (total natural gas production in Appalachia is about 23-24 bcf per day). And, there are more pipelines in the works behind that. Over the next few years, with the benefit of new pipelines, US Appalachia gas production will grow faster than US demand growth and in the process do two things: drive down the price of natural gas and put pure-play natural gas E&Ps located outside of Appalachia into bankruptcy. We believe that starting in 2018, the price for natural gas will be permanently below $3 per mcf, and at that price the non-Appalachia pure-play natural gas producers can't survive; they won't have enough asset value relative to their debt levels. Charts 17 and 18 provide more details on the pipeline projects.

**Chart 17**




Source: BTU Analytics (as of 2/2/2017)

**Chart 18**

BTU Analytics

## Summary of Key Pipeline Takeaway Projects

| Project Timing and State/Federal Progress | | | | | | |
|---|---|---|---|---|---|---|
| Projects | Capacity (MMcf/d) | Current Official ISD | FERC Application | FERC Final EIS | FERC Certificate Approval | Notes |
| ET Rover | 3,250 | Jun-17 (Ph 1)<br>Nov-17 (Ph 2) | 2/20/2015 | 7/29/2016 | (10/27/2016) | Awaiting its FERC Certificate approval; following a positive decision intervenors have 30 days to apply for re-hearings |
| TCO Leach Xpress | 1,500 | Nov-17 | 6/8/2015 | 9/1/2016 | (11/30/2016) | EPA requested a headquarters level meeting to discuss how FERC addressed green house gas emissions during its review process of this project |
| Nexus | 1,500 | Nov-17 | 11/20/2015 | 11/30/2016 | (2/28/2017) | Received FEIS on schedule in November |
| Atlantic Sunrise | 1,700 | Mid-18 | 3/31/2015 | (12/30/2016) | (3/30/2017) | In-service delayed: partial in-service 2H 2017, full in-service mid 2018. Delay due to an extended comment period centering around the evaluation of a possible re-route. |
| PennEast | 1,000 | Nov-18 | 9/25/2015 | (2/17/2017) | (5/18/2017) | Received Draft Environmental Impact Statement in July, FERC delayed the scheduled FEIS by two months due to new route modifications; project facing heavy regulatory resistance from both state and federal agencies |
| Mountain Valley Pipeline | 2,000 | Nov-18 | 10/23/2015 | (3/10/2017) | (6/8/2017) | Received Draft Environmental Impact Statement in September; US Forest Service and VA Dept of Conservation suggesting reroutes |
| Atlantic Coast Pipeline | 1,500 | Nov-19 | 9/18/2015 | (6/30/2017) | (9/28/2017) | Official ISD delayed from Q4 2018 to Q4 2019 due to prolonged FERC review process |

Note: Dates within parentheses are scheduled dates published by FERC. These dates are subject to revision as project timelines change.
Source: FERC, Company Presentations, BTU Analytics Northeast Gas Outlook

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2

On a fundamental level, oil prices are a function of supply and demand and the resulting impact on storage levels, as discussed above. We have already discussed supply dynamics, so now a bit on the demand side. We have done significant analysis on global oil demand but it's too dense and will take too long for this letter. Instead, our key conclusions are that:

1. Electric cars are not a threat to oil demand in the near future. Maybe in 20 years but not in the near term.
2. Demand does seem to be steadily growing at 1+ million barrels per year.
3. Our biggest concern regarding growth comes from China. First, China has potential economic troubles given its credit lead growth and resulting heavy debt loads. If the credit bubble bursts and China goes into recession, that will be a big hit to demand. Second, China is building a strategic petroleum reserve. Its target is about 100 days of consumption, or about 1 billion barrels. Currently, it has about 240 million barrels in reserve. Remember, this is the government's inventory and independent of Chinese refiners that buy oil to convert to refined products, who also store oil for future use. Estimates are that the Chinese government is buying about 1 million barrels per day for the strategic reserve. If for some reason the Chinese government stopped buying (because the storage tanks are full until new ones are built or any other reason), that would be a huge hit to demand.
4. US and European demand is on the uptrend as economic activity is increasing, which given their size, is supportive to global annual demand increases in excess of 1 million barrels per day.

Outside of the risk to Chinese demand, global demand does not appear to be a major risk. The primary issue as it relates to oil prices is supply.

## Section 3: Investment Strategies

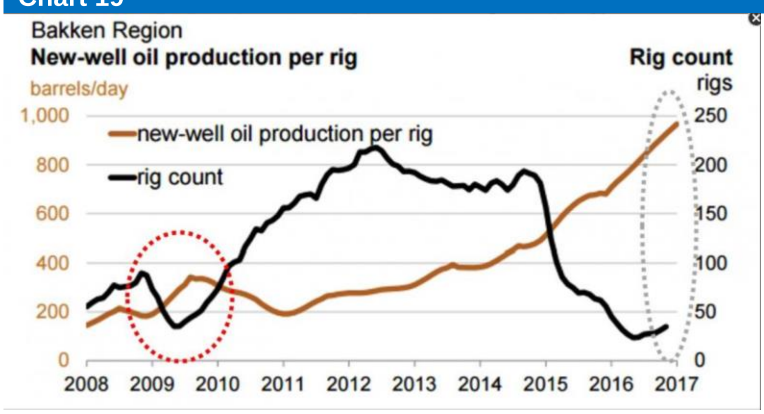
In sections 1 and 2, we provided the context for how we think about the oil and gas industry. With this, we then make specific investment decisions. Among the various sectors, in 2016 we believed the E&P sector was the most attractive because it had an asynchronous return profile. If oil and gas prices were low and E&Ps went bankrupt, then the entire food chain of OFS (oil field services) and pipeline companies would be brought down with them. But, if oil and gas prices strengthened, E&P companies' profitability were most highly levered to these rising prices. During 2016, we invested almost exclusively in the E&P sector. Currently, we are invested 75% E&P and 25% OFS with all our OFS holdings being shale well completions levered. While we still see selective value in E&P, the massive run in security prices in 2016 has resulted in many E&Ps being wildly over-valued based on our $60 oil / $30 NGL / $2.75 natural gas long-term price assumptions. At these prices, though, E&Ps can sustain solid production growth, benefiting OFS and Midstream. E&P is still our favorite sector, just not to the degree it was in 2016. Specifically within E&P, we like the fundamentals of US shale but are negative on conventional offshore. Within US shale E&Ps, it's a company by company analysis. We do not have any investments in Pipelines but it is an area into which we plan to do a deep dive in 2017. We also have not analyzed the Refining sector and thus have no positions (the dynamics of US refining are far removed from the macro oil and gas environment, thus our research is not applicable to refining, where it is to E&P, OFS and Pipelines).

Before we go into investment thesis specifics on each oil and gas sector, we want to describe a bit why we are so positive on US shale and by extension the companies that are tied to it.

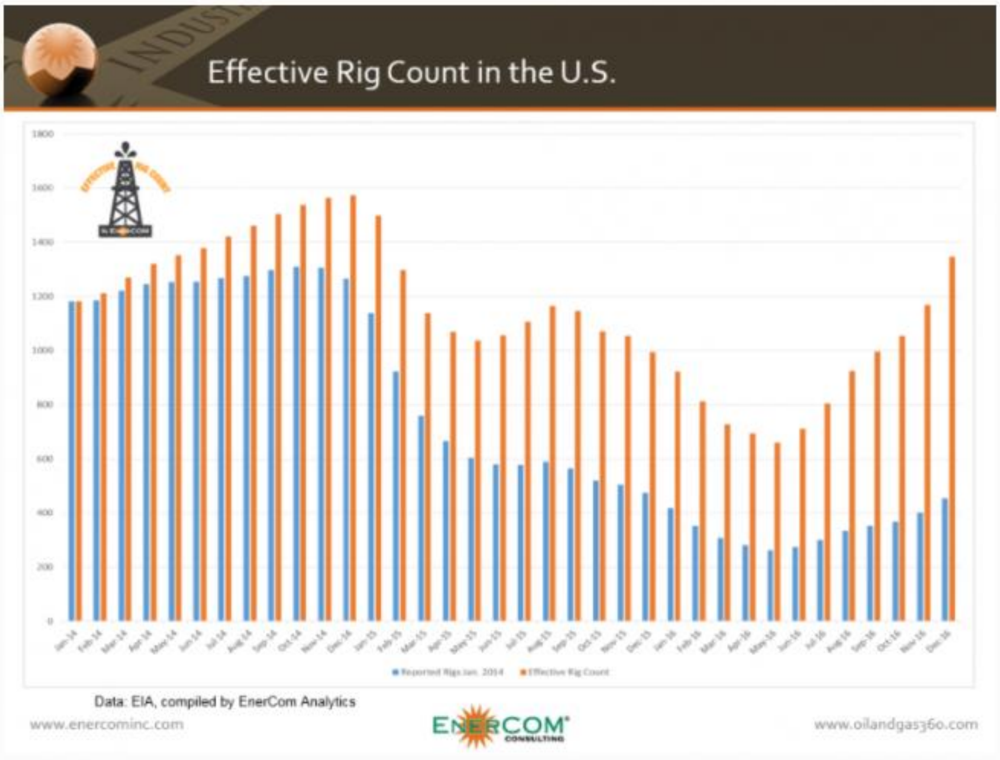
When we evaluate US shale, we see traits similar to the semiconductor industry and Moore's Law. US shale is a manufacturing process and it keeps getting more and more efficient. Where four years ago, the estimated ultimate recovery ("EUR") on a well might be 250,000 BOE, today the EUR in the same location is more like 1 million BOE. Oh, and the well costs $6 million to drill and complete versus $10 million back then. So, four years ago the cost to drill and complete a well was around $40 per BOE, where today it's more like $6! While some of this improvement is because US shale E&Ps are drilling in better locations, its more about the technological improvements. Laterals (the horizontal drilling within the shale rock) have gone from 4,000 feet to over 10,000 feet, yet the cost to drill has not increased by 2.5x. And, the wells can be drilled in 7 days, where it used to take 30 days. Since E&Ps rent the drilling rigs, the faster they can drill a well and the longer the laterals they can drill result in lower cost per BOE. E&Ps are also doing Pad Drilling, where on a single pad site the E&Ps drill four or six or eight or more wells, instead of just one well. By doing this, they can leverage on-site infrastructure to serve eight wells instead of just one. And, the time to move the drilling rig to the next well-site is materially reduced. Again, adding efficiency and driving down cost. Regarding the actual fracing of the wells, the E&Ps are utilizing many more frac stages (the location where they fracture the shale rock to release the oil and gas) and are pumping orders of magnitude more sand (enabling more oil and gas to be released). All of these factors together, and many more we did not mention, lead to greater amounts of oil and gas production per well and thus lower costs per BOE. Charts 19, 20, 21 and 22 show graphically some of these improvements.

A hot topic in 2017 is rising service costs and the impact on E&P costs to drill and complete wells. We think these concerns are overblown. For one, even 25% in added cost is only a few dollars per BOE. But, more importantly, as with Moore's law, even if costs are rising, the EURs and production rates will be increasing even faster, thus resulting in steadily declining costs on a per BOE basis (even if there are short-term cost bumps along the way).

**Chart 19**

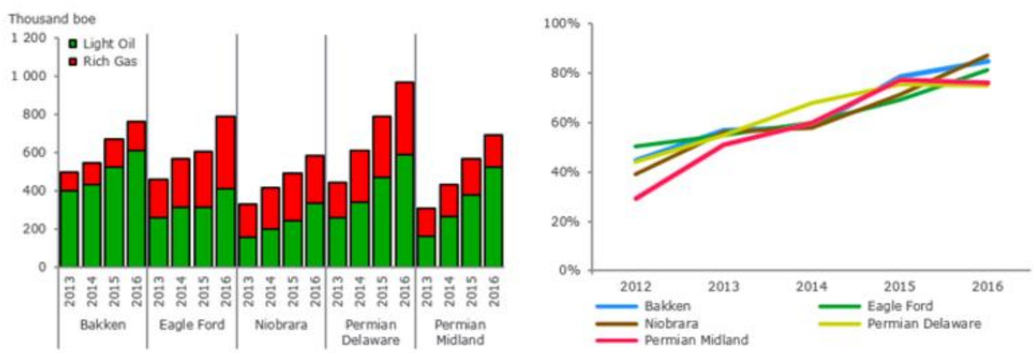


## Chart 20




## Chart 21

*Figure 3. Well performance: Average EUR per well (LHS) and share of core drilling per play (RHS)*




Source: NASWellCube

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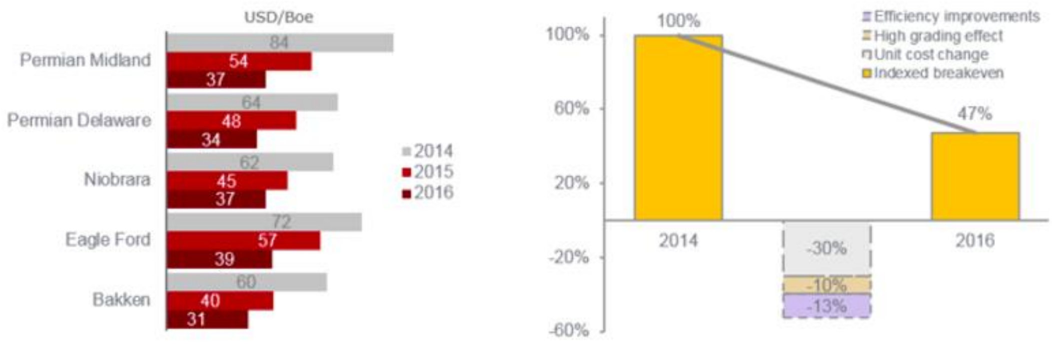
## Chart 22

*Figure 4. Well economics: Average breakeven price (LHS) and indexed breakeven by factors (RHS)*




Source: Rystad Energy Research and Analysis, NASReport, NASWellCube

And with that, here is a summary of our investment theses in each sector.

***US Shale E&P Companies***

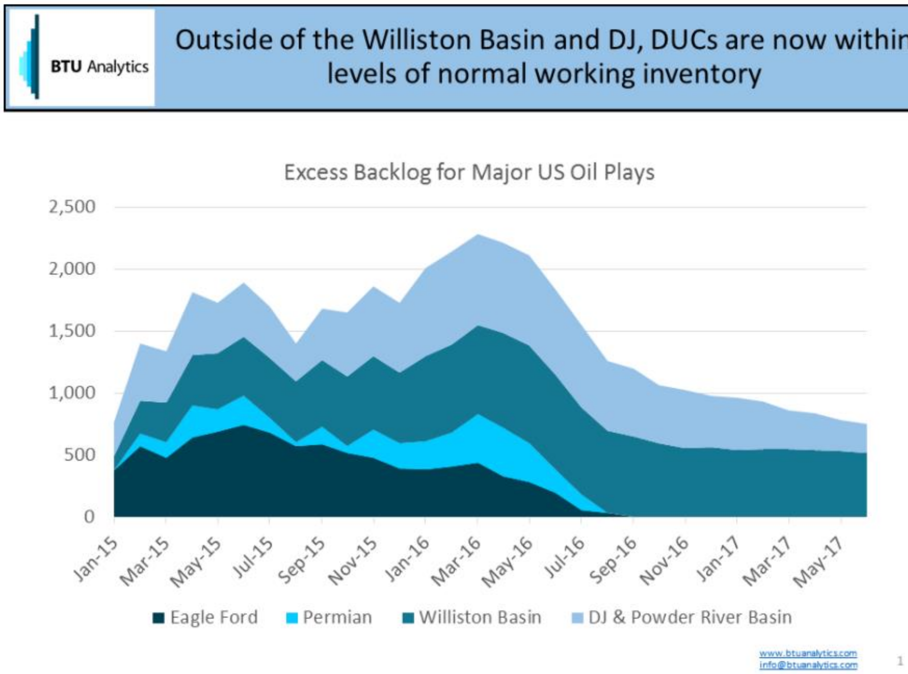
At Octavia, we are fundamental value investors. Therefore, we forecast cash flows derived from assets to determine the net present value and resulting equity values. This lends itself very well to US E&P companies. We have extensive financial models where we forecast for about 50 companies how much oil and gas each has the rights to produce, the rate at which they will produce it, for how much they can sell this oil and gas and at what cost. Sounds simple, but the model is over 3,500 excel rows of inputs and formulas for each company. Determining the amount of producible oil and gas and the costs varies tremendously (by geography) and requires many, many assumptions and detailed analyses.

The key takeaway is that assuming $60 long-term oil, $30 long-term NGL and $2.75 long-term natural gas prices, the intrinsic values of these 50 E&P companies can vary dramatically from their current share prices. Of the 50, a few are meaningfully undervalued (we own these companies in the Atlas Energy strategy), about half have implied equity values 50% or more below current levels, and some even have zero equity value. What this means is that the market is pricing in $70+ oil to justify current E&P share prices. But, even at $60 oil, there are some companies that we believe the market does not properly value. Primarily, this is because the market often focuses on multiples of 2018 EBITDA, but we think that using EBITDA multiples for E&P companies is IDIOTIC!!! E&P companies are worth the NPV from the production of their resource reserves. If a company has a huge asset base, a 2018 EBITDA multiple does not capture this.

Another factor that the market seems to confuse is project level returns versus overall asset values. There are many US shale E&Ps that can generate 50% to 100% IRRs at the well project level. Sounds great, right. But, the next question is, “how many drilling sites do you have?”. It is very possible that an E&P has amazing assets, but they simply do not have enough of them relative to their debt and/or enterprise value, which is the problem for many E&Ps. When you tally the aggregate value from extracting all the oil and gas to which they have the right to produce, sometimes you see that even at 100% project level IRRs the asset value is less than the debt they incurred securing those drilling rights in the past. This is why some of the US shale E&Ps we analyze have negative equity values.

And, another factor we believe the market has gotten wrong is the read-through from production growth. During 2016, many US shale E&Ps demonstrated strong growth in oil and gas production without commensurate high levels of capital expenditures. The assumption was that it was from increased productivity improvements. And, while productivity has definitely increased, there was also the drawing down of DUC inventories. DUCs are drilled but uncompleted wells, where a well was drilled but then set aside and not completed to commence production. Typically, 1/3 of the well cost is for drilling and 2/3 is for completing the well. During 2015 and through early 2016, US shale E&Ps were building up an inventory of wells to drill, per Chart 23.

**Chart 23**




Source: BTU Analytics' February Upstream Outlook. Underlying data from RigData and DrillingInfo.

But, then, the E&Ps started completing the DUCs. This made production growth relative to capital expenditures look artificially strong. And, while Q4 2016 earnings and 2017 guidance announcements for US shale E&Ps are just now kicking off, the initial guidance is troubling. In order to achieve their production growth targets, many (OK, most) companies are forecasting 2017 capital expenditures well in excess of 2017 operating cash flows. We believe this is a key reason why US shale E&P share performance has been so weak in 2017 (most US shale E&Ps are down 15-30% from recent highs). The market wants US shale E&Ps to live within cash flow, but instead the companies are prioritizing production growth over cash flow. This is something we are watching very closely and taking into account with our security selection.

Finally, in evaluating US shale E&Ps, you need to understand how much of their production and extractable resource is oil, how much is NGLs and how much is natural gas. The economics for each is very different given the pricing differences. Likewise, geography is also important given the amount of available pipeline takeaway capacity and the related cost to get the oil, NGL and gas to market. As mentioned earlier, natural gas in some locations in Appalachia can be sold by the E&P company for less than $1 per mcf even when the "market" price is $3 per mcf because pipeline capacity is not available to transport it out of market.

Regarding the natural gas weighted US shale E&Ps, we currently do not own any. We are negative on natural gas longer-term and would like to see how things shake out regarding Appalachia pipeline capacity and the impact on pricing in and out of basin. We are tempted to want to short the non-Appalachia natural gas E&Ps but don't because in a rising market, all boats can be lifted, but there could come at time... If we had to buy a natural gas weighted US shale E&P, we would consider select Appalachia focused E&Ps given their superior drilling economics.

Throughout this letter, we have focused on crude oil and natural gas and have mostly ignored NGLs. Yet, NGLs are a large market. The US produced 13.6 million barrels per day of liquids (crude oil and NGLs) in 2016, of which 3.5 million (25%) were NGLs. And, between oil, NGLs and natural gas, we are the most positive on US NGLs and by extension US shale E&Ps exposed to NGLs. Between all the steam cracker facilities being built that will sole source ethane as a feedstock to produce ethylene (used to make plastics) and all the propane and butane export facilities being built to allow the US to export LPGs (liquid petroleum gases, which include propane and butane), the US NGL market has been tightening dramatically, especially propane and butane prices. Given that ethane makes up around 40% of an NGL barrel, ethane prices are very important. Currently, a significant amount of ethane is rejected into the natural gas stream because it's worth more used in the same applications as natural gas versus the cost of separating it and selling it to a chemical plant to make plastics. But, in the near future, we believe ethane rejection will mostly end as US steam crackers will gobble up the excess ethane. And, US ethane is also being exported via new export facilities, creating another source of demand to prevent ethane rejection. This incremental demand will push up NGL prices. This is why we are forecasting long-term $30 per barrel NGL prices (50% of oil prices versus the current 30% to 35% of oil prices).

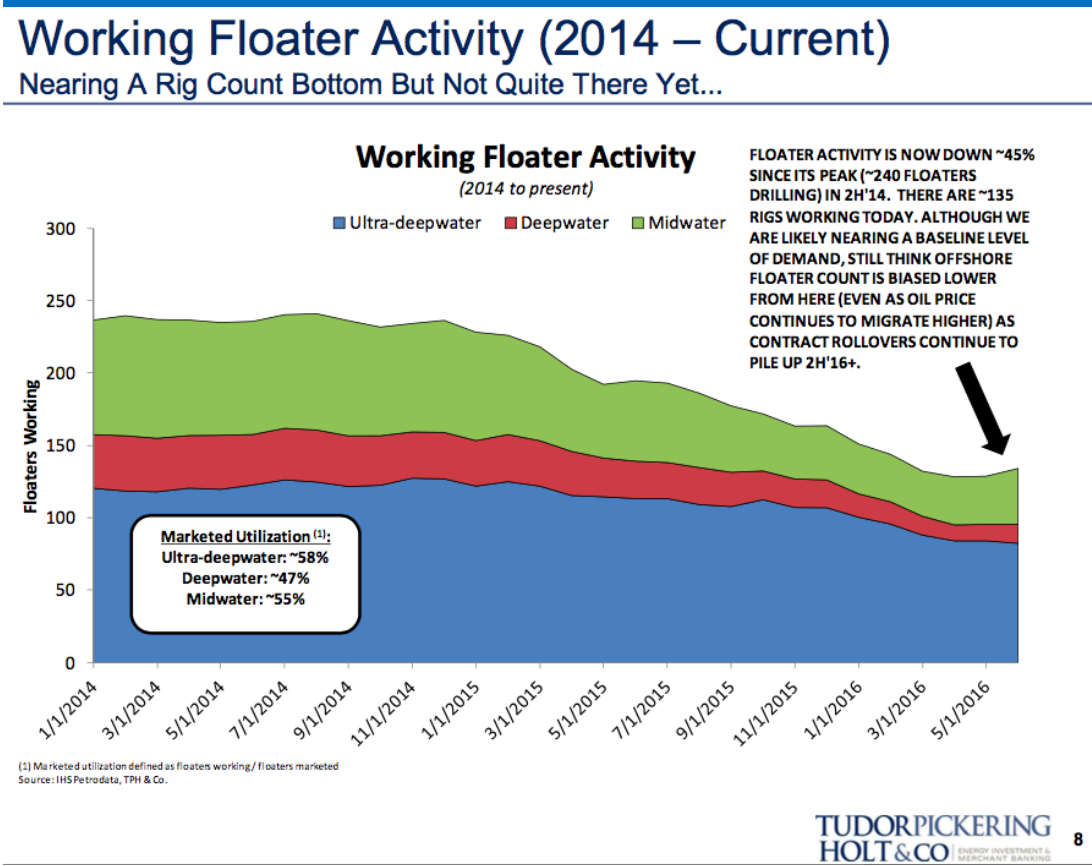
Finally, regarding conventional offshore E&Ps, given our negative stance on offshore, it's not a sector we have spent time researching (we have finite resources/time and thus don't have the bandwidth to analyze all the sectors we'd like to research). As a result, there could be individual companies that are undervalued, but we would not know.

***US Oilfield Services (OFS) Companies***

OFS is broken into a few sub-sectors: offshore drilling rigs and offshore vessels, onshore drilling rigs, consumables (both onshore and off-shore) and onshore completion services.

We consider offshore drilling rigs and offshore vessel companies a no touch and would not be surprised if several/many go bankrupt. At $60 oil, there are not enough greenfield offshore projects that work economically, especially relative to US shale as an alternative use of capital. As a result, utilization rates for offshore drilling rigs are abysmal, be it floating rigs or jackup rigs, per Charts 24 and 25 (these charts are from six to eight months ago; since then things have gotten much worse; there is not end in sight to the bleeding).

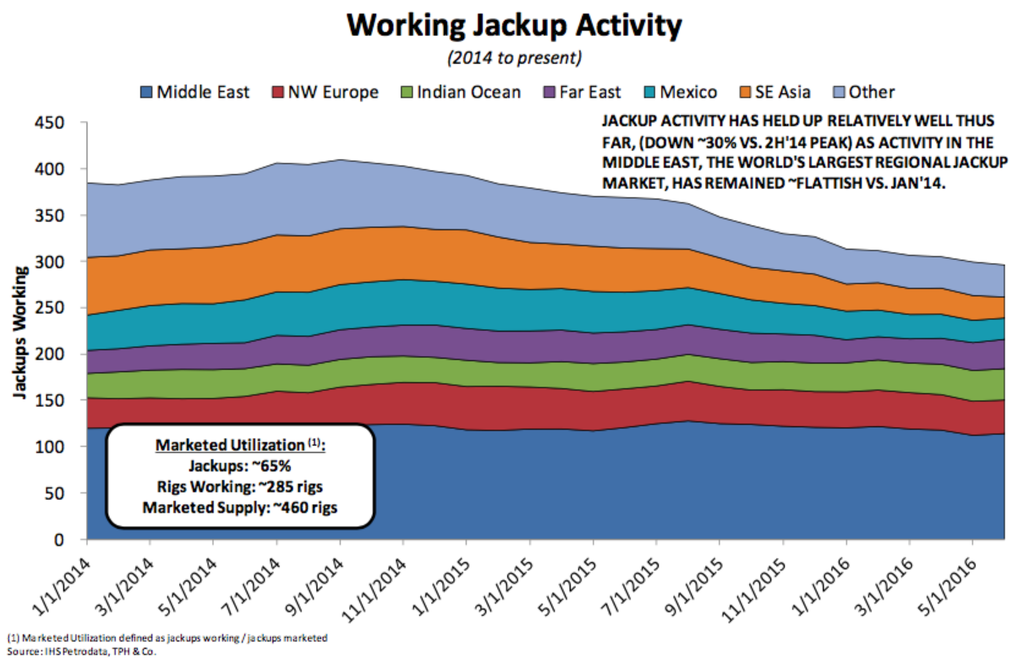
**Chart 24**



## Chart 25

# Working Jackup Activity (2014 – Current)

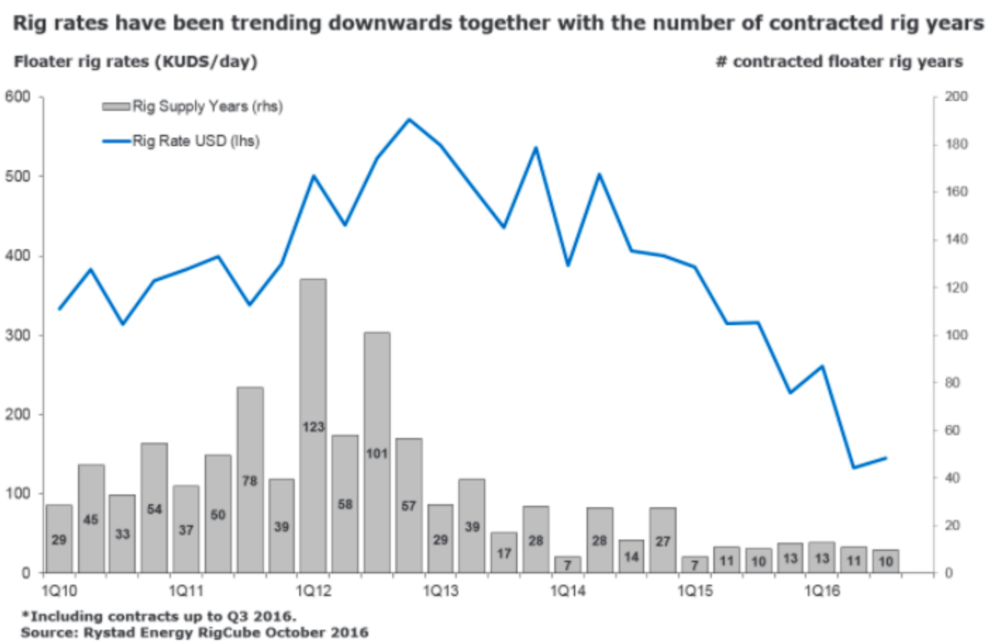
### Middle East Still An Island of Relative (and Absolute) Stability




TUDOR PICKERING HOLT & CO 15

Back in 2012 and 2013, deep water offshore drilling ships were charted for over $600,000 per day. Today, assuming they can even be re-chartered, daily rates are more like $175,000, which only covers cash operating costs and not interest expense on debt, corporate overhead, etc. Chart 26 shows the trend in offshore drilling rig day rates.

## Chart 26

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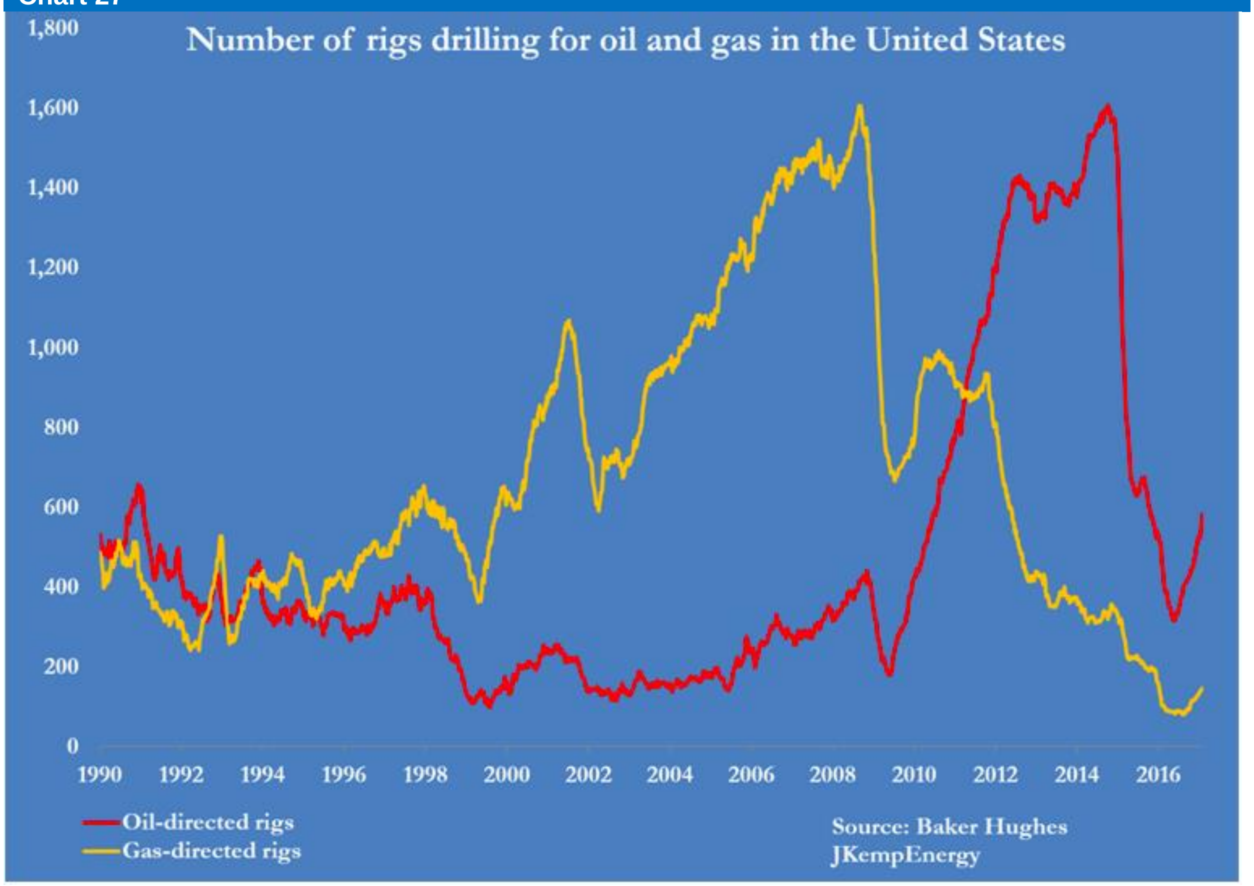
Given the debt that was incurred to build the offshore drilling rigs, current day rates equal to cash costs simply don't cut it and if sustained will eventually lead to bankruptcy. Many of the offshore drilling rig companies are still EBITDA positive because of legacy contracts from the days of $100 oil. But, as these contracts roll off, so will EBITDA. And, unless day rates move up meaningfully from the current levels, this sector is in trouble. Given our long-term $60 oil price forecast, we are negative on this sector.

To be fair, though, we must write that we have not modeled individual companies. There could be individual companies that are undervalued or will at least survive $60 oil. But, as written before, we simply lack the time and resources to model all the sectors in the oil and gas industry. That said, at a high level, we are negative on offshore drilling and thus are not invested in this sector.

Regarding onshore drilling rig companies, we are also negative (but not as negative as offshore drilling rig companies) and have no positions. While we believe that US shale production fundamentals are strong and thus the rig count will continue to increase, we believe there are simply too many drilling rigs in inventory and thus pricing will continue to be pressured. State of the art rigs currently lease for $15,000 per day, half of the rates of a few years ago. While the number of oil-focused rigs in use has increased from a low of around 300 in 2016 Q2 to around 600 currently, we are coming off a peak of around 1,600 oil-focused drilling rigs 2014 Q4. See Chart 27 on the next page for a graphical depiction.

As described earlier, because US shale E&Ps have so tremendously increased the amount of oil and gas produced per well and shortened the amount of time to drill a well, the industry can grow production significantly with fewer drilling rigs. In our experience, in most industries, suppliers do not have pricing power until industry-wide utilization rates move above 85%. This implies the US onshore oil-focused rig count would need to increase to around 1,300 before drilling rig rates increase meaningfully. And, we just don't see the number of working rigs getting anywhere close to that level in the foreseeable future because if it did, US production would be so high as to flood the markets with oil and/or gas and drive down prices accordingly.

**Chart 27**



As it relates to completion services, we are selectively positive. As E&Ps drill longer laterals, utilize more frac stages and pump more sand per frac stage, selective OFS companies can benefit. That said, as with the onshore drillers, it depends on how much capacity exists relative to demand and thus how fast pricing power can increase. It also depends on the companies' discipline not to build up capacity too fast relative to demand, or we fear they will crush pricing. Our largest fear in the OFS space is that management teams lack discipline and grow capacity in advance of higher prices, thus hurting prices. Many US onshore completions-oriented OFS companies are currently EBITDA break-even or negative. They need price increases, meaning they have to exhibit discipline on capacity increases, even in the face of growing demand. In our view, the frac sand sector is the best positioned to increase prices and volumes. And, as companies have started announcing 2016 Q4 earnings and providing 2017 guidance, our thesis has been playing out as sand prices and volumes have increased far faster than any other category of OFS. That said, if the frac sand sector starts investing heavily in production capacity, all bets are off.

***Pipelines (aka Midstream)***

We like the fundamentals of several midstream companies but currently have not invested in any for the following reason: disclosure is horrendous and they can't be modeled. In order to properly forecast cash flows, we need to understand how much pipeline capacity exists (which is disclosed), what the current utilization rates are (which companies do not disclose but certain 3rd parties do a good job of tracking), what pricing per barrel or mcf is for each pipeline (not disclosed) and finally what is the contract schedule for each pipeline so that we know when pricing may change (if this is available for all assets, we are not aware of it). Instead, pipeline companies simply give aggregate EBITDA guidance. But, as fundamental investors, that just does not work for us. It's very possible that midstream companies are cheap relative to intrinsic value, but based on the disclosure we have seen, we can't determine that on our own. As a result, currently we do not own any midstream companies. That said, midstream is a sector we would like to research more deeply, subject to time and resource availability. Maybe there is a way to track down the information we want and with a little more effort we can find it.

***Refining***

Because the factors influencing US refining companies are so different from E&P, OFS and Midstream companies, it is not a sector we have analyzed and thus do not have any thoughtfully developed opinions. With time and resources, Refining is a sector we would consider researching.

We hope you found this letter of value and welcome any feedback, especially from those that follow oil and gas. Our goal is to make good investment decisions, so we welcome the input.

Warmest Regards,
Octavia Investments LLC