HIGH YIELD ENERGY SECTOR

Pacific Income Advisers

January 15, 2015

History

In the early 2000s, the energy component of the high yield market was 7% of the universe, of which half was oil and gas exploration and production ("E&P") companies. Starting in 2007, issuance picked up, and today the energy component of the broad market is 16%, of which 9% is E&P. The remaining energy subsectors are oil services (such as drilling, pressure pumping or "fracking," and helicopter transport of offshore production crews) and "midstream" (which is principally pipelines), each with 3% to 3.5% of the total high yield market, and refining at a little under 1%. In dollar terms, the increase in issuance was large: during 2001 to 2010, energy issuance averaged $10 billion per year, and, in 2012 and 2013, it averaged $54 billion per year. So energy has indeed been the fastest growing part of the index, and the energy sector is now the second largest industry (behind media and telecom) in the high yield universe.

Is the Energy Sector a Bubble Ready to Burst?

There is a temptation to say that large issuance in an industry is ipso facto evidence of a "bubble." We do not agree with that characterization in the case of the expansion of energy companies in the high yield market. A bubble arises when speculative overcapacity is built, especially in advance of an increase in demand which may be merely hypothetical or which may exist only because of some market anomaly such as a subsidy (e.g., the ethanol bubble) or some other market distortion (e.g., mandated cheap credit for subprime housing.) Examples of true bubbles in our market have been the media/telecom and merchant utility build-outs of the late 1990s and early 2000s, which generated massive overcapacity of a non-exportable service. The US oil and gas expansion, on the other hand, is based on a genuine supply side revolution in engineering, and demand is growing today (not in the future) in the end markets: natural gas competes successfully with coal in the huge US utility sector, and gas also has a ready market as a chemical feedstock to the US petrochemical industry, which with new and cheaper gas supplies has re-emerged as a newly competitive exporter to world markets. The oil market is a steadily growing world market as well, with a still massive amount of oil imports to be backed out of the US. We think what we are seeing today is not the unraveling of a bubble, but simply another (predictable) cycle proving the inherent, structural volatility of the oil market. For years, the price of oil has been kept above its competitive market level due to OPEC's strategic role as the swing (price-setting) supplier. Since short term price elasticity on both the supply and demand sides is low and the supply curve is quite steep at the high cost end, relatively small imbalances were always capable of causing huge price declines, and indeed some of those have historically been deliberately engineered by OPEC (as in 1986) to disrupt the emergence of new fields and new technologies. We have seen this price volatility before, and it is the reason we as managers have never invested in any E&P companies: markets which are driven by strategic or cartel behavior are capable of far greater price instability than markets where all competitors are price takers and something closer to a competitive equilibrium exists. Our presence in the energy markets has therefore been entirely confined to service companies or materials suppliers whose direct economic linkage is to the (much more stable) volume of hydrocarbon produced rather than the price and profitability of producing it, and especially the much more volatile economics of exploring for it. The most obvious example of this is in pipelines, whose tariffs and physical throughput are far less volatile than oil prices and which in many cases enjoy a logistical monopoly position. A second example is the helicopter transport companies, which shuttle crews to offshore platforms: at any oil price we will see, the pure variable cost of producing from an already existing production platform is so low that the platform will almost never be shut down prior to its end-of-life decommissioning, and as long as the platform operates, transporting the crews back and forth between it and its land base is a nondiscretionary expense. None of these service companies is invulnerable to a decline in oil prices; sustained low prices won't kill an existing platform, but they will ultimately curtail the deployment of new ones or the hiring of floating production facilities which come off long-term leases at the end of a given field's production. But part of our job as high yield managers is to recognize that there are highly variable degrees of sensitivity.

There has not been a trend towards increasing financial leverage in the issuance of energy bonds in the high yield market. There are anecdotes of more highly leveraged issuance, as there will always be in a large market sector, but the credit metrics at issuance for the energy sector as a whole are very consistent with the past. The high and rising leverage that exists today in the average E&P credit is entirely due to the drop in oil prices after the bonds were issued – indeed, before the drop in the second half of 2014, issuance in the sector had gotten so large precisely because several years of historically high (and relatively stable) oil prices had incorrectly caused investors who had not lived through past price drops to believe that the E&P sector was lower risk than the market as a whole.

Outlook

One thing that is immediately clear from recent performance data is that the common refrain that security prices react "indiscriminately" in a moment of dislocation caused by an event such as the refusal of OPEC to cut its output is a myth. The market recognizes that different sectors (and, within each sector, each issuer's bonds) have different sensitivities to oil prices, different exposures to gas versus oil, different exposures to exploration versus production versus processing versus distribution, different reliance on continued access to high yield financing, and so on, and the market does allow for each of those, albeit imperfectly, in repricing each individual bond.

We believe the biggest exposure to bankruptcies lies in the E&P sector. Some oil service assets can be redeployed to more productive fields (such as drilling rigs, transport helicopters, and the like,) and distribution via pipeline is inherently locally priced and is not in excess supply. But the physical features which render an oilfield field high cost are, so to speak, set in stone. They are features like resource depth, the thickness of the pay zone, the permeability and porosity of the host rock, proximity to markets, and the like. For a period of four years since the last significant decline in oil prices during the recession, the high yield market has become comfortable with the notion that oil prices over $100 represented a stable equilibrium (rather than a very fragile cartel-administered price which was far above the competitive market price, and therefore highly vulnerable to even a small oversupply un-countered by a lowering of OPEC production.) And so during those four years, the high yield market financed over 80 independent US E&P companies - some with multiple issues, so the number of bonds is over 190 and their face value exceeds $100 billion. The average coupon on these bonds was about 7.75% and the average spread to Treasuries at issue was about 560 bp – about 60 bp tighter than the rest of the high yield market, showing that the market viewed these bonds as comparatively safe. Crucially, only 20% of these companies are free cash flow positive after their large capital expenditures – they are mostly young companies embarking on business plans which will require continued access to low cost high yield debt financing. Investors in these bonds have now learned what they never should have forgotten after price declines caused in the past by the development of new supply frontiers like the North Sea and ultra-deepwater fields – that as non-OPEC producers exploit the OPEC price umbrella to increase supplies of high-cost oil, prices are vulnerable to multiyear declines as the cartel (and, today, notably Saudi Arabia, the UAE, and Kuwait within the cartel) responds strategically to the new supply. Therefore, even if oil prices do recover from here, it is very unlikely that the newly chastened high yield market will continue to lend to these highly price-sensitive companies at the low rates which they have based their business plans on. Today, the average E&P bond yields in excess of 11% and the average spread, at 1,000 bp, has almost doubled.

The market knows that most of these companies will easily survive during 2015 – as past investments come online, the US industry will actually increase its production in 2015 despite reducing capital expenditures. In addition, many of the E&P companies have hedged some portion of their sales at much higher prices (but mostly only for one year) and most of them will have access to undrawn revolvers to fund themselves during 2015. The real crunch will hit in 2016. JPMorgan estimates that if West Texas Intermediate oil prices (which are about 10% less than Brent) stabilize at $65 and the Henry Hub gas price is $2.50, 20% of the E&P universe will default in 2016 and another 15% will default in 2017. These numbers are by no means unprecedented. In 1987, 28% of the high yield energy universe defaulted a year after the WTI price dropped by 50%, and in 1991, 19% defaulted a year after the WTI price fell by 40%. As they try to avoid default, companies will be forced to sell assets, and those sale prices will disappoint because many of the assets will be only marginally profitable, if at all, from the point of view of a buyer who is investing new capital on which a return must be earned. This will be particularly so when the buyer's own cost of capital will be much higher than what the E&P sector has faced in many years.

As we ponder whether this is an opportune point for investment in the oil sector, we must grapple with the future trajectory of oil prices. This is an enormously complicated issue on which many very well informed industry specialists disagree, and we are skeptical of our ability to forecast better than anyone else. However, as debt investors, we need not have a judgment about the specific new equilibrium trading range for oil. We only need to have a feel for probabilities and direction. The average price of energy bonds is still in the low 80s, so the upside for the sector if prices rise enough to stave off a wave of defaults is 20 points. If bonds default, they will likely fall to 40 or below. So, ignoring coupon income for the moment, with a downside twice or larger than the upside, we would need to be at least 67% confident that oil prices will rise substantially from today's level by 2016 to find the sector as a whole attractive for bond investment today. Now, there may be individual E&P issuers which will do well even if commodity prices do not rise – either because they have reserves which are unusually low cost to produce, or because they can cut costs better than others with changes in technology. But in our experience, if an entire sector is stricken with an exogenous and (we believe) continuing shock like what has just occurred in the oil sector, there will be very few opportunities for individual bonds to outperform the index as a whole, especially on a risk-adjusted basis. The headwinds in a stricken industry, and the sudden increase in the industry's cost of capital when it requires continued financing to fund cash flow deficits, are just too strong at dollar prices in the 80s.

Some potential drivers for a quick recovery in the price of oil are 1) a major new crisis in the Mideast or 2) an unexpected resurgence of demand growth from major markets like China, Europe, and Japan, all of whose macro economies are now suffering multiyear slowdowns, or 3) a complete reversal of OPEC's November decision not to reduce output, which would require painful cutbacks by countries that are in a very poor fiscal position to participate in voluntary output reductions. It must be said that a change of heart by OPEC, given the further steep drop during December, cannot be ruled out – it has happened in the past. But we believe that it is most likely that "this time is different." Many OPEC producers have become reliant on prices of $100 and even above to balance their budgets, notably Venezuela, Nigeria and Libya. Outside of OPEC, the position of Russia is the most parlous of all. Saudi Arabia, the only member with significant capacity already idled by past output restrictions, does seem determined to enforce cuts by the non-OPEC suppliers, who have been acting as if they can cannibalize Saudi Arabia's market share without limit, and Saudi Arabia can withstand low prices for several years due to its large financial reserves. In the popular press, this stand by OPEC has been cast as a "war on US shale" because shale has very visibly generated the biggest increase in supply for the last several years. But in reality, Saudi Arabia is challenging all high cost suppliers to cut their production by about 2 million barrels not just now but, even more importantly, by more than that amount in the future, so that OPEC can then exploit tightness to raise prices again for a sustained period.

So the questions facing the market are: which producers will back down to bring the market back into balance, when will they do it, and how long will it take before OPEC can raise prices again? Nobody really knows the answers to these questions – there are simply too many variables, especially demand growth, and the game theory aspects of the cartel's dynamics are unanalyzable. There is a great deal of focus on and disagreement about the short term marginal and full cycle (capital return included) production costs faced by shale producers, with most analysts now lowering their view of those breakeven costs as technology (increasing length of laterals, more frack stages per well) makes recovery more economic. But most experts say that about two thirds of US shale remains economic (including a return on capital) at $60 WTI, and the short term marginal cost per barrel for a field which has already been leased and has access to a gathering system and distribution pipeline can be as low as $25 per barrel. Furthermore, most 2015 drilling in the three main shale fields (the Bakken, Eagle Ford, and Permian) has already been contractually committed to. Therefore, shale should grow, not decrease, its production during 2015, and even if future drilling is reduced only to wells which are economic at current prices, post-2015 shale output reductions alone, which will be less than 1% of world production, will not be enough to bring the world market into balance.

Furthermore, shale is much cheaper (in terms of capital costs) and more granular than the "lumpy" supply provided by large, complex deepwater fields. Shell has just commenced producing from a deepwater project called Jack-St. Malo in 7,000 feet of water 280 miles from New Orleans, and the initial phase has cost approximately $7.5 billion dollars and required ten years to bring online. Other sizable fields on the majors' capital commitment schedules cost $10 billion to $20 billion each. In contrast, a horizontally drilled land-based shale well can be drilled for as little as $1.5 million in a matter of weeks. The hardware of shale development is not technologically complex – the assets are ordinary drilling rigs which need not float or even drill very deep, very powerful pumps, tanks, pipes and manifolds, trucks, and crews whose skill level is nowhere near what is found in a large offshore field. Unlike an offshore drilling rig or production facility, these simple fracking assets can be mothballed during periods of low prices without losing their physical performance capabilities. Therefore, a shale field can be "turned on and off" much more readily in response to price changes than an offshore project, so that potential shale capacity cannot be permanently killed off or even placed out of the supply picture for a period of several years by a decline in prices forced by OPEC. Even if E&P producers were forced into insolvency, their reserves would remain in place (now owned by new owners after the quite efficient US bankruptcy and asset sale process,) and those fields would be ready to resume production with relatively low restart costs whenever OPEC tried to initiate the next leg up on a pricing cycle. In a competitive market, therefore, it would be shale which could act as the real "swing capacity" in the world, and OPEC's very low cost production would be base capacity, tending to produce at its maximum deliverable level. What this implies is that even if OPEC does force shale producers to absorb a large part of the required output cuts to balance supply and demand, that supply will be ready to quickly re-ramp its production as soon as OPEC attempts to materially raise prices again.

In the medium to long term, therefore, OPEC can raise prices only if it can convince major producers that the risk of investing in very large fields with long build-outs (but then very long lives) is too high. Since most land-based large reserves outside the Mideast have already been found and exploited, this means that new provinces in the deepwater or ultra deepwater, or in the Arctic, or in the Canadian oil sands, must have their developments cancelled or postponed for multi-year periods for prices to rise and remain higher for several years. But the sponsors of those large projects also think strategically – they know that OPEC may cut prices from time to time but will always seek to maximize price over the entire future, and they therefore make their own capital decisions using a long-term vector of prices which is relatively insensitive to spot prices at any one time. An offshore field committed to today, for example, cannot produce any oil for at least 5 years. Those large projects are the greatest long-term threat to OPEC because once the capital has been spent, marginal costs are very low and therefore the capacity will not be swing capacity, volume decline curves are much slower than in a shale well, and it is those projects which must be taken out of play for prices to again contain a large element of monopoly profit for a sustained period.

As noted above, the recent behavior of Saudi Arabia suggests that it is no longer willing to absorb the swing capacity producer role, and the remaining players in OPEC are less inclined and less able to cut output than ever before in OPEC's history. We believe that Saudi Arabia will have to keep prices low for at least two years if it wants to force shale producers to act as the swing producers in the short run, which it can do by forcing a decline in shale producers' capital expenditures. A shale well's natural flow decreases by a stunning 70 percent in the first year, so diminished capital expenditures in shale will quickly reduce supply. But more important, it will have to keep prices low enough, long enough, to keep new large offshore fields from being developed – because unlike a shale play, once an offshore field is delayed, starting its production in response to a later OPEC price increase will take many years. There are also some mature provinces like the North Sea where two or more years of low prices (below $80) will cause existing platforms to be decommissioned, thus permanently eliminating the ability of that field to re-ramp. Seven percent of the infrastructure in the North Sea has already been decommissioned, and that will increase rapidly from this point.

What this suggests to us is that in order for Saudi Arabia and OPEC to achieve their goals, the price environment must remain depressed for several years – that prices will not, as the market seems to expect, rebound to $80 in 2015 or 2016. Anatole Kaletsky points out that from 1986 to 2004, oil prices were set in a competitive market, with price being close to the marginal cost of the most expensive producers and with a correspondingly low part of the price being due to the price umbrella of a cartel. During those years, the price was, with two brief exceptions, between $21 and $48 in 2014 dollars. If there is a 25–50% chance that we are at the cusp of another period of competitive pricing behavior, then on an expectational basis E&P investment in high yield will be unwise for several years at today's bond prices. We do believe the price scenario envisioned above, with WTI averaging below $70 for several years, is likely enough to make the sector unattractive for investment in the US high yield market today.

Bob Sydow is a Senior Vice President and High Yield Portfolio Manager at Pacific Income Advisers. Bob has been a High Yield Portfolio Manager for over 25 years and has covered the energy industry his entire career. Prior to joining PIA, Bob founded Grandview Capital in 1999. From 1989 to 1999, he was VP, SVP, and Co-Portfolio Manager for SunAmerica Investments' High Yield Bond Department, which grew tenfold to $4 billion during his tenure. Previously, he spent three years as Treasurer, Asset/Liability Manager, and High Yield Portfolio Manager at First Interstate Bancorp and five years in various financial positions at Atlantic Richfield Company (ARCO).

Sources: JP Morgan, OilPrice.com, Reuters and Bloomberg