U.S. Shale Oil is Plentiful and Competitive, New Research Suggests

The emergence of U.S. shale oil has expanded the global supply of oil. New research notes that the long-run impact of shale oil will depend on how much can be produced and how much it will cost. Few have good answers. In recent research, finance professor and energy expert James Smith of SMU Cox with co-author Thomas Lee determine what portion of known shale resources are economically viable at various price points and how many wells are likely to be drilled. Their paper, "The price elasticity of U.S. shale oil reserves," was recently published in *Energy Economics*.

In the summer of 2014, U.S. oil prices reached $107 per barrel, then descended to a low of $26 in early 2016. The harsh boom to bust period softened and prices have recovered in the $50 range during late 2017. Oil prices are now rising beyond $50 per barrel, largely because OPEC has chosen to support prices through production quotas and the laws of supply and demand are rebalancing the market.

Each shale basin is like its own economic ecosystem, with unique geological features and breakeven costs which dictate how much of the resource can be exploited profitably. The research focuses on four major shale oil-producing basins: the Permian's Midland Wolfcamp; the Williston Basin's Bakken core; the Eagle Ford, and the Anadarko Basin's Marmaton. Four combination plays, comprised of both shale oil and gas, are also analyzed to determine how much might be produced at various price levels.

Very large resource

For shale observers, the research reveals several notable results. From the findings, Smith offers, "The remaining volume of shale oil in all basins is very large and much of that resource can be produced at prices of $50 per barrel or lower. In addition to the economic wells that remain to be drilled, there are vastly more uneconomic drilling locations remaining that would only be drilled at prices of $100 per barrel or higher."

Though there are a large number of these potential uneconomic wells, they would not markedly contribute to future production or overall supply. They are simply low productivity wells, notes Smith. These wells would only become economic if prices rise substantially. Importantly, by play, basin or well, the heterogeneity, or variation, in the productivity of shale oil wells lies at the core of finding out how much will get produced and estimating how sensitive future supply will be to price variations.

The research is based on the technologies available at mid-year 2015. In a related research paper about the future supply in the Bakken Shale, Smith updates technological assumptions. He accounts for how changes in production from drillers' experience, applied learning, and the use of technologies impacts the volumes extracted and investment decisions. However, Smith notes that producers continue to experiment and try out new technologies and fracking schemes to recover more of the shale oil in place. "This means that future costs are likely to be lower than I have assumed," he explains. "It also means the volume of recoverable reserves is likely to be higher than I have estimated." His results are purposely constructed to provide conservative estimates of future supply, which is true of the results reported in both papers.

More to Drill

So far, only a small portion of drilling sites have factored into the shale oil boom, according to Smith, and we have only depleted a fraction of U.S. shale resources. The Bakken paper suggests there are very large amounts yet to be tapped. He estimates that "50% of remaining technically recoverable resources located in the Bakken play—roughly 8 billion barrels—could be developed economically if the oil price remains near $50 per barrel." The case study is based on drilling results observed in the North Dakota portion of the Bakken play during 2006-2015. During that period, a total of 12,376 horizontal fractured shale oil wells were drilled in North Dakota.

The remaining volume of technically recoverable shale oil resources in North Dakota is estimated to be roughly 17 billion barrels, notes the Bakken paper. The U.S. Geological Survey announced the total volume of technically recoverable oil resources in the Midland Wolfcamp play is estimated to be 20 billion barrels. By applying Smith and Lee's model, at oil prices of $20 per barrel the estimated volume of Midland Wolfcamp oil reserves that could be economically recovered would be approximately 10.6 billion barrels. But that volume rises to 13.8 billion barrels at $40 oil, and 17 billion barrels at $100.

Importantly, the research points to the gift of geology as a primary influence for a well's economic potential. In Texas with its large Permian Basin resource, many company investor presentations talk about relatively low breakeven prices in the Midland area's Spraberry/Wolfcamp Shale. Smith's research suggests that most of the Wolfcamp Shale wells need a $100 oil price to breakeven, which on the surface seems surprisingly high. "Every well has its own breakeven price depending on its depth, specific rock formations, richness of the shale, etc.," says Smith. "Within a single basin, potential drill sites range from good, ie., high productivity/low cost, to bad, low productivity/high cost. I agree that many available drill sites in the Spraberry/Wolfcamp have low breakevens and that is reflected in the research." However, *most* drill sites have breakeven prices that are higher than the average for the basin because the distribution of well productivity is "skewed" to the low productivity side.

Middle (median) ground

The shale resource base is heavily "skewed" toward lower productivity, marginal wells, offers Smith. The productivity of wells located in the "sweet spots" is very high; but there are relatively few of those wells to weigh against the many lower productivity potential drill sites. The "average" productivity of all wells is elevated sharply by the few best wells, but most wells will not reach that level. "In other words," says Smith, "most wells are below average. For this reason, the median productivity presents a more representative picture of what operators will experience — not the average, or mean. Exactly 50% of drill sites will perform at the median productivity level or better, and 50% will perform worse."

The study also considers the impact of geology and prices for shale basins that are called "combo plays," holding a combination of shale oil and gas. "Higher gas prices would benefit shale oil production because many drill sites located in the gas/natural gas liquids portion of shale basins would become attractive; and these sites also produce oil," offers Smith. "Either higher gas or oil prices are needed to incentivize production."

But higher oil prices come at a cost. Higher oil prices increase oil development activity, which increases drilling rig rates and other costs, Smith explains. Higher costs, when incurred in the gas plays, tend to reduce drilling activity. The research finds a "backward bending supply curve" as evidence of a counter-intuitive result: higher oil prices suppress oil production in the gas basins where relatively little oil is produced. "Remember, little oil is produced from the gas plays, so the higher oil price we are talking about provides little additional revenue to the operator," he offers.

Contrary to some opinions, there is a long way to go before shale production peaks. Smith's research suggests this is so. "Most drill sites may not be economic at $50 — but the good ones are," says Smith. And the good wells' aggregate reserves constitute most of the potentially recoverable resource even though they constitute less than 50% of the viable drill sites.

"The price elasticity of U.S. shale oil reserves," by James Smith, Cary M. Maguire Chair in Oil & Gas Management at Southern Methodist's University's Cox School of Business and Thomas Lee of the U.S. Energy Information Administration was recently published in *Energy Economics.* The second related paper titled "Estimating the Future Supply of Shale Oil: A Bakken Case Study" is authored by James Smith. Smith's research was supported by research grants from the U.S. Energy Information Administration and the MIT Center for Energy and Environmental Policy Research.

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