SHALE REALITY CHECK

DRILLING INTO THE U.S. GOVERNMENT’S ROSY PROJECTIONS FOR SHALE GAS & TIGHT OIL PRODUCTION THROUGH 2050
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Drilling Into the U.S. Government’s Rosy Projections for Shale Gas & Tight Oil Production Through 2050

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About the Author

David Hughes is an earth scientist who has studied the energy resources of Canada for four decades, including 32 years with the Geological Survey of Canada as a scientist and research manager. He developed the National Coal Inventory to determine the availability and environmental constraints associated with Canada’s coal resources. As Team Leader for Unconventional Gas on the Canadian Gas Potential Committee, he coordinated the publication of a comprehensive assessment of Canada’s unconventional natural gas potential.

Over the past decade, Hughes has researched, published and lectured widely on global energy and sustainability issues in North America and internationally. His work with Post Carbon Institute includes a series of papers (2011) on the challenges of natural gas being a “bridge fuel” from coal to renewables; *Drill, Baby, Drill* (2013), which took a far-ranging look at the prospects for various unconventional fuels in the United States; *Drilling California* (2013), which critically examined the U.S. Energy Information Administration’s (EIA) estimates of technically recoverable tight oil in the Monterey Shale, which the EIA claimed constituted two-thirds of U.S. tight oil (the EIA subsequently wrote down its resource estimate for the Monterey by 96%); and *Drilling Deeper* (2014), which challenged the U.S. Department of Energy’s expectation of long-term domestic oil and natural gas abundance with an in-depth assessment of all drilling and production data from the major shale plays through mid-2014. Separately from Post Carbon, Hughes authored *A Clear View of BC LNG* in 2015, which examined the issues surrounding a proposed massive scale-up of shale gas production in British Columbia for LNG export, and *Can Canada increase oil and gas production, build pipelines and meet its climate commitments?* in 2016, which examined the issues surrounding climate change and new export pipelines.

Hughes is president of Global Sustainability Research, a consultancy dedicated to research on energy and sustainability issues. He is also a board member of Physicians, Scientists & Engineers for Healthy Energy (PSE Healthy Energy) and is a Fellow of Post Carbon Institute. Hughes contributed to *Carbon Shift*, an anthology edited by Thomas Homer-Dixon on the twin issues of peak energy and climate change, and his work has been featured in *Nature*, *Canadian Business*, *Bloomberg*, *USA Today*, as well as other popular press, radio, and television.

About Post Carbon Institute

Post Carbon Institute’s mission is to lead the transition to a more resilient, equitable, and sustainable world by providing individuals and communities with the resources needed to understand and respond to the interrelated environmental, energy, economic, and equity crises of the 21st century.

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Executive Summary

Shale gas and tight oil from low permeability reservoirs have provided a new lease on life for U.S. oil and gas production. Tight oil has allowed U.S. oil production to double from its 2005 lows, and shale gas has similarly allowed a major increase in U.S. gas production. However, the nature of these reservoirs is that they decline quickly, such that production from individual wells falls 70–90% in the first three years, and field declines without new drilling typically range 20–40% per year. Continual investment in new drilling is therefore required to avoid steep production declines. Older fields like the Barnett, where drilling has nearly ceased, are in terminal decline. Shale plays also exhibit variable reservoir quality, with “sweet spots” or “core areas” containing the highest quality reservoir rock typically comprising 20% or less of overall play area. In the post-2014 era of low oil prices drilling has focused on sweet spots which provide the most economically viable wells.

How sustainable is shale production in the long term given optimistic government and industry forecasts of robust production through 2050 and beyond? This report endeavors to answer that question by assessing the viability of the projections of the U.S. Energy Information Administration (EIA), which are widely used by policymakers, industry, and investors to make long-term plans. The report is based on an analysis of well production data for all major shale gas and tight oil plays in the U.S. These plays make up 88% of the EIA’s Annual Energy Outlook 2017 (AEO2017) reference case cumulative production forecast for shale gas and tight oil for the period 2015–2050. The data source is Drillinginfo, a commercial database of well-level production data which is utilized by the EIA and most major oil and gas companies.

For each play, this report assesses:

- Current and historical production.
- Total- and producing-well count by county, well type and vintage.
- Well- and field-declines by county, well type and vintage.
- Distribution of wells in terms of quality, as defined by production of oil or gas in the highest month (initial productivity), in order to delineate sweet spots.
- Density of wells in sweet spots.
- Cumulative oil and gas production by county.
- Average productivity of all wells drilled in each year from 2012 to 2017 by county, well type and play average, in order to determine the impact of enhanced technology.
- Production history in sweet spot counties and in the remainder of the play area.
- Prospective drilled area to determine the area which might reasonably contribute to future production.
- The optimism bias for the EIA AEO2017 play-level forecast based on play fundamentals determined from the assessment.

This analysis finds that EIA projections of production through 2050 at the play-level are highly to extremely optimistic, and are therefore very unlikely to be realized. EIA play forecasts count on recovering all proven reserves plus a high percentage of unproven resources—in some cases over 100%—by 2050. (Proven reserves have been demonstrated by drilling to be technically and economically recoverable. Unproven resources are thought to be technically recoverable but have not been demonstrated to be economically viable; as such they are much less certain than proven reserves.) Furthermore, most of these play-level projections assume that production will exit

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1 Drillinginfo, https://info.drillinginfo.com/
2050 at high levels compared to current rates, implying that there are vast additional resources to be recovered beyond 2050.

Key findings:

- **Well productivity**
  - Better technology—including longer horizontal laterals, a tripling of water and proppant injection since 2012, and more fracking stages—has resulted in increased average well productivity in most plays.
  - A significant portion of the increased average well productivity is a result of “high-grading” sweet spots: focusing drilling on the highest quality reservoir rocks (which form a relatively small portion of most plays).
  - Average well productivity in some counties and plays has declined in 2017, indicating technology there has reached the point of diminishing returns. This is a result of drilling outside of sweet spots and/or drilling wells too close together, resulting in “frac hits” and well interference which compromises individual well production.

- **Tight oil plays**
  - The Permian Basin plays are the main driver for tight oil production growth. In Permian plays such as the Wolfcamp and Spraberry production is increasing rapidly, although Bone Spring production has flat-lined recently. EIA estimates for production through 2050 for these plays are rated as highly to extremely optimistic.
  - Production in older tight oil plays like the Bakken and Eagle Ford, which were among the first tight oil plays developed, is down substantially from peak. EIA projections for these and other tight oil plays, including the Niobrara and Austin Chalk, are rated as highly to extremely optimistic.

- **Shale gas plays**
  - The Appalachian plays are the main driver for shale gas production growth - the Marcellus and Utica now account for 48% of U.S. shale gas production. EIA forecasts for the Marcellus and Utica, which project these will provide 52% of cumulative production of U.S. shale gas through 2050, are rated as extremely optimistic.
  - Production in older shale gas plays—including the Barnett, Haynesville, and Fayetteville, which were among the first to be developed—is now down more than 40% from peak. EIA projections for these plays—along with the Woodford, which is down 25% from peak—are rated as highly to extremely optimistic.

- **All plays**
  - The EIA AEO2017 reference case projects that 1.29 million wells will be drilled to recover oil and gas from both conventional and unconventional reservoirs in the period 2015–2050. At $6 million per well, this amounts to $7.7 trillion. Shale plays reviewed herein, which account for 88% of the EIA’s estimated shale oil and gas production through 2050, would require 1.04 million wells using EIA assumptions—at an estimated cost of $5.7 trillion. Recovering the remaining 12% of shale resources would require an additional .68 million wells at a cost of $4.1 trillion. Given the EIA’s overestimates of future shale production and recoverable resources, it is unlikely that all of these wells will be drilled.

There is no doubt that the U.S. can produce substantial amounts of shale gas and tight oil over the short- and medium-term. Unrealistic long-term forecasts, however, are a disservice to planning a viable long-term energy strategy. The very high to extremely optimistic EIA AEO2017 projections impart an unjustified level of comfort for
long-term energy sustainability. As sweet spots are exhausted, the reality is likely to be much higher costs and higher drilling rates to maintain production and/or stem declines.

The "shale revolution" has provided a reprieve from what just 13 years ago was thought to be a terminal decline in oil and gas production in the U.S. It has sparked calls for "American energy dominance"—despite the fact that the U.S. is projected to be a net oil importer through 2050, even given EIA forecasts. This reprieve is temporary, and the U.S. would be well advised to plan for much-reduced shale oil and gas production in the long term based on this analysis of play fundamentals.

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1. Introduction

As recently as 2005, U.S. oil and gas production were thought to be in terminal decline. The advent of high-volume hydraulic fracturing (fracking) in combination with horizontal drilling changed all that, as it allowed access to oil and gas resources in impermeable source rocks that were previously inaccessible. This technology was first developed and applied by George Mitchell\(^3\) to gas in the Barnett shale of east Texas in the late 1990s, and quickly spread to other regions. It was later applied to tight oil, beginning with the Bakken shale of North Dakota, and has resulting in the doubling of U.S. oil production.

Shale has raised expectations for U.S. oil and gas production and has underpinned calls for U.S. “energy dominance” by the Trump Administration,\(^4\) after decades of being a net importer of oil and gas. International exports of gas via LNG and of crude oil have begun over the past three years. The optimism has been bolstered by the U.S. Department of Energy’s Energy Information Administration (EIA), which has issued optimistic forecasts projecting U.S. oil and gas abundance due to shale through 2050 at least.

But how reliable are these forecasts? They have recently been questioned by oil magnate Harold Hamm as overly optimistic,\(^5\) and MIT has released a study of the Bakken play suggesting the same thing.\(^6\) I have also pointed this out in reports over the past several years.\(^7\) The answer to this question is very important, as the prospect of cheap, abundant oil and gas for the foreseeable future discourages investment in alternative energy and the adoption of policies to reduce consumption which would enhance long-term sustainability. Incorrect assumptions about future oil and gas availability also increases vulnerability to price shocks and supply disruptions.

Shale plays share several common characteristics:

1. Although each play may cover several hundred to thousands of square miles, well productivity and ultimate recovery (EUR) per well are highly variable. Core areas or “sweet spots,” where well productivity and EUR are high, generally comprise only 10–20% of total play area. Industry has focused on sweet spots with the downturn in oil and gas prices, but for full development higher prices and higher drilling rates will be required as sweet spots are exhausted.

2. Production decline for a typical shale well averages 70–90% over the first three years, with much of the decline in the first year. This means payback of well drilling costs must be achieved in the first few years, and that new wells must continually be drilled to maintain production.

3. Field declines, made up of older wells declining at lower rates and new wells declining at higher rates, typically average 20–40% per year, meaning that this much production must be replaced each year by new drilling to keep production flat.

4. Technology has made a big difference in well productivity over the past few years. This has been achieved through higher levels of water and proppant injection, and longer horizontal laterals. Average water use per foot of horizontal lateral has tripled since 2012, to nearly 50 barrels (2100 gallons per foot), and proppant use has also tripled, to nearly 2000 pounds per foot.\(^8\) This means a well with a 10,000 foot lateral (typical in the Bakken but normally somewhat less elsewhere) will use 21 million gallons of water and 20 million pounds of proppant. Some wells use even more, such as a well in the Haynesville of

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\(^7\) J.D. Hughes, Drilling Deeper: A Reality Check on U.S. Government Forecasts for a Lasting Tight Oil & Shale Gas Boom (Santa Rosa, CA: Post Carbon Institute, 2014); http://shalebubble.org.

Louisiana which used 50 million pounds of proppant in a horizontal lateral of nearly 10,000 feet, or 5,000 pounds per foot. An excellent review of water use in the Permian Basin reports that water use there can go as high as 124 barrels per foot (5208 gallons per foot). More aggressive technology, coupled with longer horizontal laterals, allows each well to drain more reservoir area, but reduces the number of drilling locations and therefore does not necessarily increase the total recovery from a play—it just allows the resource to be recovered more quickly at lower cost from fewer wells. Well locations in sweet spots are limited and placing wells too close together has resulted in well interference and lower per well recoveries, as documented by Rystad Energy in the Eagle Ford, and others in shale plays more generally.

5. Although well quality as measured by initial productivity has risen due to more aggressive technology and the high-grading of sweet spots in most plays, it has plateaued in the top counties of some plays and is declining in others. This is a result of geological limits and the exhaustion of drilling locations which will ultimately be experienced in all plays.

EIA forecasts of oil production published in its Annual Energy Outlook (AEO) are viewed by industry and government as the best available assessment of what to expect in the longer term, with the EIA’s reference case typically viewed as the most likely scenario for future production. This report assesses the viability of the EIA’s Annual Energy Outlook 2017 (AEO2017) reference case projections at the play level, using well production data from the Drillinginfo database (which is also a key input to EIA data collection). Plays are reviewed in terms of overall production, county-level production, well productivity trends, and well- and field-decline rates. EIA assumptions, including play area, drilling density and wells needed, are then assessed in the context of this data analysis to determine the credibility of EIA play-level production forecasts.

On average, EIA projections are highly to extremely optimistic when reviewed at the play level. These play-level forecasts are then aggregated by the EIA and presented in its AEO as an overall rosy outlook. As noted above, rosy forecasts discourage investment in alternative energy and the adoption of policies to reduce consumption—which would enhance long-term sustainability—and increases vulnerability to price shocks and supply disruptions.

13 Drillinginfo, https://info.drillinginfo.com/
2. Tight Oil Plays

Figure 1 illustrates tight oil production from the seven major plays assessed in AEO2017, as well as “other” plays\(^{14}\), as of November 2017. Production from tight oil plays is at an all-time high, although the two largest plays—the Eagle Ford and the Bakken, which constituted 44% of tight oil production in November 2017—are down 30% and 8% from peak, respectively (the last two months are estimates; Drillinginfo data show the Bakken down 16% as of September 2017). Including “other” plays, 51% of tight oil production was down 19% from a March 2015 peak. The Permian Basin, which produced 39% of U.S. tight oil in November 2017, has been responsible for most of the growth in U.S. tight oil production. The Permian Basin has been producing oil and gas for nearly a century, but industry has proven adept at accessing unconventional resources in the basin.

![Figure 1. U.S. tight oil production by play, 2008 through November 2017\(^{15}\)](https://www.eia.gov/energyexplained/data/U.S.%20tight%20oil%20production.xlsx)

Note the last two months are estimated. The Spraberry, Wolfcamp, and Bone Spring lie within the Permian Basin.

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\(^{14}\) “Other” plays include the Monterey, Granite Wash, Yeso, Glorieta, Delaware, and liquids from mainly gas plays including the Woodford, Haynesville, Marcellus and Utica.

\(^{15}\) EIA, December, 2017, How Much Tight Oil is Produced in the U.S.? https://www.eia.gov/energyexplained/data/U.S.%20tight%20oil%20production.xlsx
Figure 2 illustrates the AEO2017 reference case for U.S. oil production by source with price projections. Tight oil constitutes by far the largest source of supply overall, and is forecast to make up 63% of 2050 production. Production from other major sources, such as onshore and offshore conventional oil, is projected to decline, while overall U.S. production is projected to grow to an all-time high of 10.5 million barrels per day (mbd) in 2029. Prices are projected to remain below $100/barrel until 2031, and 2050 production is projected to meet 56% of projected crude oil demand—meaning that despite the aggressive production growth forecast for tight oil, the U.S. will remain a large net importer of oil.

Figure 2. EIA AEO2017 reference case forecast of oil production by source, 2012–2050. Also shown is projected price (West Texas Intermediate and Brent in 2016 dollars per barrel).
The importance of tight oil in the EIA’s reference forecast is illustrated in Figure 3. Tight oil is projected to provide 58% of total crude oil production of 133 billion barrels over the 2015–2050 period. That is more than triple proven U.S. crude oil reserves of 35.2 billion barrels at year-end 2015\textsuperscript{16}, and half of U.S. proven reserves plus unproven resources.\textsuperscript{17} The tight oil portion is forecast to recover 6.7 times proven U.S. tight oil reserves and 76% of proven reserves plus unproven technically recoverable resources. This is an extremely aggressive forecast and is based on some tenuous assumptions, as will be shown in the following play-by-play review of major tight oil plays.

\textbf{Figure 3. EIA AEO2017 reference case forecast of cumulative oil production by source, 2015–2050.}

\textsuperscript{16} EIA, Table 1, U.S. proved reserves, and reserves changes, 2014-15, https://www.eia.gov/naturalgas/crudeoilreserves/.

\textsuperscript{17} EIA, Assumptions to the Annual Energy Outlook 2017, https://www.eia.gov/outlooks/aeo/assumptions/
The EIA’s reference case AEO2017 forecast by play is illustrated in Figure 4. Tight oil is not expected to peak until 2046, and to produce 79 billion barrels of oil by 2050, when production is projected to be considerably higher than today. The Bakken is forecast to produce 30% of 2014–2050 tight oil production and the Bakken, Eagle Ford, and the Permian Basin’s Spraberry play to collectively produce 63%.

Figure 4. U.S. tight oil production by play in EIA AEO2017 projection compared to AEO2015 and AEO2016.
The changes in EIA AEO production projections by play from 2014 to 2017 are illustrated in Figure 5. In general, these forecasts have become more optimistic from year to year, with the most aggressive increases occurring in the Bakken and Eagle Ford, as well as the Permian Basin plays including the Bone Spring, Wolfcamp, and Spraberry.

2.1 Bakken Play

The Bakken Play in North Dakota and eastern Montana was the first major tight oil play to be developed. Production is both from the Bakken and underlying Three Forks formations. Figure 6 illustrates the production rise from nothing in 2003 to one of the largest plays in the U.S. in 2014, when it peaked. More than 13,000 wells have been drilled, of which more than 12,000 are still producing.

Figure 6. Bakken Play oil production and number of producing wells, 2000–2017.
Production peaked in December 2014 and was down 12% as of October 2017.
Figure 7 illustrates the distribution of wells by quality as defined by peak production month (usually month 1). In common with all shale plays, the most productive and economic wells occupy a relatively small part of the total play area. In the case of the Bakken, the highest productivity wells occupy parts of McKenzie, Mountrail, Williams, and Dunn counties.

Figure 7. Bakken Play well locations showing peak oil production in the highest month. The highest productivity wells are concentrated in parts of Dunn, Mountrail, McKenzie, and Williams counties.18

18 Drillinginfo, September, 2017; EIA, March, 2016, play area outline from https://www.eia.gov/maps/map_data/TightOil_ShaleGas_Plays_Lower48_EIA.zip
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Figure 8 illustrates cumulative recovery of oil and gas by county. Over half of oil production has come from two counties—Mountrail and McKenzie—and 84% from these plus Dunn and Williams counties. These “sweet spots” constitute a small part of the total play area assumed by the EIA in Figure 7.

![Figure 8: Cumulative production of oil and gas from the Bakken Play by county.](data:image/png;base64,iVBORw0KGgoAAAANSUhEUgAAAUAAAACgCAYAAABQZC6YAAAAAXNSR0IArs4c6QAAAARn笔耕不辍

**Figure 8. Cumulative production of oil and gas from the Bakken Play by county.**

Production is highly concentrated in sweet spot counties, with 84% of cumulative recovery in the top 4 counties.

Table 1 shows the number of wells drilled, cumulative and current production, and well- and field-decline rates for the Bakken as a whole and for individual counties. Three-year well decline rates average 85% and field decline rates average 40% per year without new drilling, which is at the high end for shale plays analyzed in this report.

<table>
<thead>
<tr>
<th>County</th>
<th>Total Well Count</th>
<th>Producing Well Count</th>
<th>Cumulative Oil Production (billion bbls)</th>
<th>Cumulative Gas Production (tcf)</th>
<th>Oil Production May 2017 (Kbbls/day)</th>
<th>Gas Production May 2017 (bcf/day)</th>
<th>3-year well decline (%)</th>
<th>Field decline (%)</th>
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<td>Williams</td>
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<td>83.6</td>
<td>0.12</td>
<td>84.4</td>
<td>29.5</td>
</tr>
</tbody>
</table>

**Table 1. Well count, cumulative production, most recent production, and well- and field-decline rates for the Bakken Play and counties within it.**

The degree of development of the Bakken core area to date is illustrated in Figure 9. Horizontal laterals are typically on the order of 10,000 feet in length (although some wells have exceeded 15,000 feet) and spaced as little as 500 feet apart. At such close spacings wells are typically separated vertically to develop both the Bakken
and the underlying Three Forks. It has been shown that wells begin to exhibit interference in the Bakken at spacings of less than 2000 feet. Spacing wells closer than 2000 feet in a single horizon sacrifices production from infill wells but serves to recover the resource more quickly.

**Figure 9. Horizontal well development in the core area of the Bakken Play, October 2017.**

Upper: overview of core area; lower: close-up view.

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20 https://www.dmr.nd.gov/OaGIMS/viewer.htm
Figure 10 illustrates production from the top four counties compared to the overall play. All counties have peaked beginning with Mountrail and McKenzie in December 2014, followed by Dunn and Williams in September and October 2015, respectively. The eleven counties outside the top four peaked in February 2015, and are now down 43%. The top four counties make up 92% of current production.

Figure 10. Oil production in the Bakken Play by county showing peak dates and percentage decline from peak, 2000–2017.

© Hughes GSR Inc, 2017
(data from Drillinginfo, September 2017)
In evaluating the credibility of the EIA reference case production projection for the Bakken, it is instructive to look at the EIA’s assumption of the total area that ultimately will be developed with viable wells. Figure 11 illustrates the EIA’s assumptions for the play areas of the Bakken Formation and underlying Three Forks Formation compared to the actual area that has been developed by drilling to date (the "prospective drilled area" in Figure 11). As can be seen, the prospective drilled area—at 12,754 square miles—is half of the EIA’s 25,853 square mile assumed play area of the Bakken, and an even smaller proportion of the EIA’s 30,965 square mile assumed play area of the Three Forks.

In its assumptions document for AEO2017, the EIA assumes there are 14,966 square miles of remaining drillable Bakken Formation at an average well density of 2.75 wells per square mile, and 21,439 square miles of remaining drillable Three Forks Formation at 3.5 wells per square mile (for unproven resources as of year-end 2014). In comparison, the existing prospective drilled area has an average effective well density of 2.1 wells per square mile (given that each well effectively accesses two square miles), with higher well densities in sweet spots. Thus, the EIA appears to have overestimated the economically viable areal extent of the Bakken Play, and hence the number of economically viable wells that can be drilled, given that there have been several uneconomic wells drilled outside of the prospective drilled area.

Figure 11. EIA play areas for the Bakken and Three Forks compared to the prospective area that has been demonstrated by drilling.

The improvement in well productivity over time in most plays is undeniable. As noted earlier, this is partly due to vastly increasing the amount of water and proppant used per well, and the use of longer horizontal laterals, both of which effectively expand the volume of reservoir rock drained by each well. This reduces the number of available drilling locations as wells must be spaced further apart to avoid interference. Thus, a play can be drained with fewer wells, but the ultimate recovery is unchanged. A second major reason for the improvement in well productivity is that operators have defined the sweet spots and are concentrating drilling in the most geologically favorable parts of the field. This is clearly evident in the Bakken Play.

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22 EIA play area outlines from https://www.eia.gov/maps/map_data/TightOil_ShaleGas_Plays_Lower48_EIA.zip; prospective drilled area digitized based on well distribution as of June 2017 from Drillinginfo.
Figure 12 illustrates the change in average well productivity in the Bakken Play over the past six years. All counties have increased substantially since 2012. These gains in average well productivity are entirely due to rising productivity in McKenzie and Dunn counties. There has been no improvement in Mountrail and Williams counties or in the 11 counties outside the core area. This indicates that well spacing in the best parts of these counties is reaching saturation and well productivity is likely to fall in the future as more infills are drilled with resulting well interference. Well productivity is still rising in McKenzie and Dunn counties as operators continue to focus on sweet spots. Assuming that “technology learning” will continue to improve well productivity in the future, as the EIA does, ignores the fact that much of the improvement is due to high-grading sweet spots, and that sweet spots have limited areal extent and are rapidly becoming exhausted.

Figure 12. Average well productivity over the first four months of oil production by county in the Bakken Play, 2012–2017.

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Figure 13 illustrates the EIA’s AEO2017 reference case production projection for the Bakken Play through 2050, together with earlier projections. The EIA expects production to double by 2029, and to recover 24.1 billion barrels over the 2014–2050 period. This is more than triple the recent USGS assessment of undiscovered technically recoverable resources from the Bakken (including Three Forks) of 7.4 billion barrels. Furthermore, the EIA’s projection exits 2050 at nearly double current production. Given the fundamentals outlined above, to say this is an extremely optimistic forecast is an understatement.

Figure 13. AEO2017 reference case Bakken Play oil production estimate through 2050. Also shown are earlier AEO estimates to 2040.

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Table 2 illustrates assumptions in the EIA AEO2017 reference case projection. If realized, the EIA projection would have to recover 83% of the EIA’s estimate of proven reserves plus unproven resources, and would require 120,258 wells, nearly ten times the current total, at a cost of $722 billion.

<table>
<thead>
<tr>
<th>EIA AE02017 Reference Case Projection</th>
<th></th>
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</thead>
<tbody>
<tr>
<td>Proven Reserves 2015 (Bbbls)</td>
<td>5.0</td>
</tr>
<tr>
<td>Unproven Resources 2015 (Bbbls)</td>
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</tr>
<tr>
<td>Total Potential 2015 (Bbbls)</td>
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<tr>
<td>2015-2050 Recovery (Bbbls)</td>
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</tr>
<tr>
<td>% of total potential used 2015-2050</td>
<td>83.0%</td>
</tr>
<tr>
<td>Wells needed 2015-2050</td>
<td>120,258</td>
</tr>
<tr>
<td>Well cost 2015-2050 ($billions)</td>
<td>$722</td>
</tr>
</tbody>
</table>

Table 2. EIA assumptions for Bakken Play oil in the AE02017 reference case.

Well costs of $722 billion for full development are estimated assuming a well cost of $6 million each. Wells needed were determined using EIA drilling density and “area with potential” for unproven resources, and wells needed for proven reserves assuming EUR per well would be twice as high for proven reserves as unproven resources.

Synopsis

The EIA’s reference case production estimate is extremely optimistic. Key points include:

- The EIA has overestimated the prospective play area by 100% (Bakken) to 140% (Three Forks) compared to the current prospective drilled area.

- Assuming 120,258 wells can be drilled to develop unproved resources plus proven reserves (per the EIA AE02017 assumptions and 2015 proven reserves), plus the 13,165 wells already drilled, would increase well density in the prospective play area to 10.5 per square mile. This would result in an effective density of 21 wells per square mile, given that each well accesses two square miles with a 10,000-foot horizontal lateral. This is highly unlikely to be economic given well interference already evident; resources can likely be effectively recovered with a much lower well density, which suggests that ultimate recoverable resources are far less than the EIA estimates.

- Well productivity improvements have flat-lined or decreased in all but two counties, indicating available well locations are running out.

- Given a considerably higher drilling rate, production may again approach the 2014 peak; but sweet spots are running out and lower productivity wells outside of the core area will require considerably higher prices to be economic.

- Assuming that 83% of proven reserves and unproven resources (which together are more than triple USGS estimates) will be recovered by 2050 and that the 2050 exit rate will be nearly double current production strains credibility to the limit. The only way that the EIA reference case projection could be realized is if the vast largely undrilled area assumed in its play area were to prove to be economically viable, which seems unlikely given several uneconomic wells drilled in this area.

26 Unproved technically recoverable resources are from EIA, Assumptions to the Annual Energy Outlook 2017, https://www.eia.gov/outlooks/aeo/assumptions/; Proven reserves are from U.S. Crude Oil and Natural Gas Proved Reserves, Year-end 2015, https://www.eia.gov/naturalgas/crudeoilreserves/.
2.2 **Eagle Ford Play**

The Eagle Ford Play of southern Texas rose from nothing in 2008 to the largest tight oil play in the U.S., when it peaked in March 2015. Figure 14 illustrates production from 2008 through May 2017. The Eagle Ford is also a prolific gas producer with most production downdip of oil production in the southeast and southern portions of the play (the formation dips southeastward towards the Gulf of Mexico). Nearly 18,000 wells have been drilled of which more than 17,000 are still producing.

![Figure 14. Eagle Ford Play oil production and number of producing wells, 2008–2017. Production peaked in March 2015 and was down 34% as of October 2017.](image)

© Hughes GSR Inc., 2018

*(data from DrillBarInfo, February, 2018)*
Figure 15 illustrates the distribution of wells by quality as defined by peak production month (usually month 1). In common with all shale plays, the most productive and economic wells occupy a relatively small part of the total play area. In the case of the Eagle Ford, the highest productivity wells occupy parts of Karnes, Dewitt, La Salle, Dimmit, Gonzales, and McMullen counties. The 14,644 square miles outlined in the EIA play area of Figure 15 is 65% larger than the prospective drilled area of 8,887 square miles. The EIA AEO2017 assumptions suggest that 14,780 square miles can be drilled at a density of 6.26 wells per square mile to recover unproved resources, which does not include wells needed to recover proven reserves.

Figure 15. Eagle Ford Play well locations showing peak oil production in the highest month.

The highest productivity wells are concentrated in parts of Karnes, Dewitt, La Salle and Dimmit counties. “Excluded” wells are on leases with multiple wells where the initial productivity (IP) of individual wells cannot be differentiated.

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26 EIA play area outline from https://www.eia.gov/maps/map_data/TightOil_ShaleGas_Plays_Lower48_EIA.zip; prospective drilled area digitized from well distribution in Figure 14 from Drillinginfo.
27 EIA, Wells need for unproved technically recoverable resources are from Assumptions to the Annual Energy Outlook 2017, https://www.eia.gov/outlooks/aio/assumptions/; Proven reserves are from U.S. Crude Oil and Natural Gas Proved Reserves, Year-end 2015, https://www.eia.gov/naturalgas/crudeoilreserves/
28 EIA, March, 2016, play area outline from https://www.eia.gov/maps/map_data/TightOil_ShaleGas_Plays_Lower48_EIA.zip
Figure 16 illustrates cumulative recovery of oil and gas by county. Over one-third of oil production has come from two counties—Karnes and Dewitt—and 82% from the top six counties. These “sweet spots” constitute a relatively small part of the total play area assumed by the EIA in Figure 15.

![Graph showing cumulative production of oil and gas by county.](image)

**Figure 16. Cumulative production of oil and gas from the Eagle Ford Play by county.**
Production is highly concentrated in sweet spot counties, with 82% of cumulative recovery in the top 6 counties.

Table 3 shows the number of wells drilled, cumulative and current production, and well- and field-decline rates for the Eagle Ford as a whole and for individual counties. Three-year well decline rates average 81% and field decline rates average 34% per year without new drilling, which is in the middle of the range for shale plays analyzed in this report.

<table>
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<tr>
<th>County</th>
<th>Well type</th>
<th>Vintage</th>
<th>Total Well Count</th>
<th>Producing Well Count</th>
<th>Cumulative Oil Production (billion bbls)</th>
<th>Cumulative Gas Production (tcf)</th>
<th>Oil Production May 2017 (Kbbls/day)</th>
<th>Gas Production May 2017 (bcf/day)</th>
<th>3-year well decline (%)</th>
<th>Field decline (%)</th>
</tr>
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<tbody>
<tr>
<td>All</td>
<td>All</td>
<td>All</td>
<td>17,951</td>
<td>17,042</td>
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<td>All</td>
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<td>Dimmit</td>
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<td>All</td>
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<td>0.72</td>
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<td>Karnes</td>
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<td>La Salle</td>
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<td>380.5</td>
<td>2.52</td>
<td>83.6</td>
<td>31.4</td>
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</table>

**Table 3. Well count, cumulative production, most recent production, and well- and field-decline rates for the Eagle Ford Play and counties within it.**
The degree of development of the Eagle Ford core area to date is illustrated in Figure 17. Some recent horizontal laterals are over 10,000 feet in length, although the average is considerably less. Most well pads have multiple wells. Well interference has been noted at close well spacings between early “parent” wells and later infill “child” wells—which suggests, as in other plays, that production is compromised by crowding wells too closely together.29

![Figure 17. Core area of the Eagle Ford Play in Karnes County showing well locations and degree of development as of mid-2017.](image-url)

Figure 18 illustrates production from the top four counties compared to the overall play. All counties have peaked, beginning with counties outside the core area in December 2014, and followed by the top four counties between March and May 2015. The top four counties now make up 64% of production.

The improvement in well productivity over time in most plays is undeniable, and the Eagle Ford is no exception. As noted earlier, this is due to vastly increasing the amount of water and proppant used per well and increasing the length of horizontal laterals, as well as crowding wells into sweet spot areas. This has enabled operators to drain reservoir rocks at higher rates with fewer wells, and thus increase economic viability. There is no free lunch, however, and eventually sweet spots will become depleted and drilling will have to move to lower productivity reservoir rocks which will require higher prices to be economic. The practice of high-grading a play by focusing on sweet spots using better technology will not necessarily increase the ultimate recovery from the play.
Figure 19 illustrates the change in average well productivity in the Eagle Ford Play over the past six years. Although average well quality was relatively flat in the 2012–2016 period, with the exception of Dewitt County, all counties increased somewhat in 2017. Dewitt has emerged as the top county, followed by Karnes, in terms of the highest productivity wells.

Figure 19. Average well productivity over the first four months of oil production by county in the Eagle Ford Play, 2012–2017.
Figure 20 illustrates the EIA’s AEO2017 reference case oil production projection for the Eagle Ford Play through 2050, together with earlier projections. The EIA expects production to decline gradually overall, producing 12.2 billion barrels over the 2014–2050 period. Given current drilling rates, the well interference already observed in sweet spots, and the overestimate of play area, this is a highly optimistic forecast (although less so than the EIA’s Bakken forecast).

Figure 20. EIA AEO2017 reference case Eagle Ford Play oil production estimate through 2050.
Also shown are earlier AEO estimates to 2040.
Table 4 illustrates assumptions in the EIA AEO2017 reference case projection.\textsuperscript{30} If realized, the EIA projection would have to recover 59% of the EIA’s estimate of proven reserves plus unproven resources, and would require 63,461 additional wells, for a total well count of more than four times the current number, at an estimated cost of $381 billion.

<table>
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<th>EIA AE02017 Reference Case Projection</th>
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</thead>
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<td>Proven Reserves 2015 (Bbbls)</td>
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<tr>
<td>Unproven Resources 2015 (Bbbls)</td>
</tr>
<tr>
<td>Total Potential 2015 (Bbbls)</td>
</tr>
<tr>
<td>2015-2050 Recovery (Bbbls)</td>
</tr>
<tr>
<td>% of total potential used 2015-2050</td>
</tr>
<tr>
<td>Wells needed 2015-2050</td>
</tr>
<tr>
<td>Well cost 2015-2050 ($billions)</td>
</tr>
</tbody>
</table>

Table 4. EIA assumptions for Eagle Ford Play oil in the AEO2017 reference case.

Well costs of $381 billion for full development are estimated assuming a well cost of $6 million each. Wells needed were determined using EIA drilling density and play area for unproven resources, and wells needed for proven reserves assuming EUR per well would be twice as high for proven reserves as unproven resources.

Synopsis

The EIA’s reference case production estimate is highly optimistic. Key points include:

- The EIA has overestimated play area by 65% compared to the current prospective drilled area.

- Assuming 63,461 wells can be drilled to develop unproved resources plus proven reserves (per the EIA AE02017 assumptions and 2015 proven reserves), plus the 17,951 wells already drilled, would increase well density in the prospective play area to 9.2 per square mile. This is highly unlikely to be economic given well interference already evident. Well interference would reduce EURs such that ultimate recovery would be considerably less than the 11.7 billion barrels the EIA assumes will be recovered from 2015-2050.

- Although well productivity has improved significantly in three of the top four counties in the past year, sweet spots are likely to become saturated with wells in a few years at most.

- The steep decline observed since the March 2015 peak can be slowed or even temporarily reversed with increased drilling rates. As sweet spots are exhausted, maintaining production or even stemming decline will require considerably higher prices and higher drilling rates as drilling moves into less productive parts of the play.

- The EIA’s projection of only slow decline with production only modestly below current levels in 2050 implies that there would be considerable remaining resources to be recovered after 2050. This is highly optimistic given the above and play fundamentals.

\textsuperscript{30} EIA, Unproved technically recoverable resources are from Assumptions to the Annual Energy Outlook 2017, https://www.eia.gov/outlooks/aeo/assumptions/; Proven reserves are from U.S. Crude Oil and Natural Gas Proved Reserves, Year-end 2015, https://www.eia.gov/naturalgas/crudeoilreserves/
2.3 **Permain Basin**

The Permian Basin of northwest Texas and southeast New Mexico is a very large oil producing region that has produced large quantities of oil and gas for nearly a century. Some 418,000 wells have been drilled into conventional and unconventional reservoirs within the basin, of which 146,000 are still producing. The Permian Basin is comprised of several sub-basins, the most prolific of which are the Delaware and Midland, as illustrated in Figure 21 along with other tectonic features.

![Tectonic features and areal extent of the Permian Basin](https://www.eia.gov/maps/map_data/PermianBasin_Boundary_Structural_Tectonic.zip)

**Figure 21. Tectonic features and areal extent of the Permian Basin.**

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Production from the Permian basin, which had been in slow decline from a peak of 2.2 mbd in October 1973, has more than doubled since 2009 due to the application of horizontal drilling and modern hydraulic fracturing. Figure 22 illustrates Permian Basin production in the 1990–2017 period. Although the overall producing well count is falling due to the retirement of older wells that have ended their productive life, the increase in much higher productivity horizontal wells is driving production higher.

Figure 22. Permian Basin oil production and number of producing wells, 1990–2017.
Figure 23 illustrates the distribution of all Permian Basin wells by quality as defined by peak production month. The most productive wells are concentrated in the Delaware and Midland basins but considerable amounts of conventional production have occurred outside these areas.

Figure 23. Permian Basin well locations showing peak oil production in the highest month.32

The highest productivity wells are concentrated in the Delaware and Midland basins. “Excluded” wells are on leases with multiple wells where the initial productivity (IP) of individual wells cannot be differentiated.

32 Permian Basin area outline from EIA, December, 2017. https://www.eia.gov/maps/map_data/PermianBasin_Boundary_Structural_Tectonic.zip
The game-changing impact of hydraulic fracturing coupled with horizontal drilling is illustrated in Figure 24 for wells drilled since 2011. Post-2011 horizontal wells accounted for 58% of Permian Basin production in May 2017, even though they account for just seven per cent of producing wells. Post-2011 vertical and directional wells, which made up eight per cent of producing wells, accounted for just 5% of production. The remaining 37% of production came from 124,894 wells older wells which constitute 85% of the producing well count.

Figure 24. Permian Basin oil production by well type and vintage, 1990–2017.
Post 2011 horizontal wells accounted for 58% of Permian Basin production in May 2017.
Figure 25 illustrates cumulative recovery of oil and gas by county. The Permian Basin is large and encompasses many counties with multiple plays which have been exploited for nearly a century. Nonetheless, production tends to be concentrated in certain parts of the basin. One-quarter of cumulative production has come from three counties and two-thirds from 12 counties.

**Figure 25. Cumulative production of oil and gas from the Permian Basin by county.**

Due to the size of the basin, and the fact that it contains multiple plays, production is more spread out than in plays like the Bakken and Eagle Ford. Nonetheless, two-thirds of production has come from 12 counties and one-quarter from 3 counties.
Much of the 32 billion barrels of oil and 116 trillion cubic feet of gas that have been recovered from the Permian Basin over the past century has come from prolific conventional reservoirs that have depleted gradually since the basin peaked in 1973. New production from unconventional plays using fracking technology has been responsible for most of the production increase since 2009. Production from unconventional plays is concentrated in a much smaller portion of the basin than earlier conventional production, as illustrated in Figure 26.

Figure 26. Post-2011 Permian Basin wells showing peak oil production in the highest month.

The highest productivity wells are concentrated in the Delaware and Midland basins. “Excluded” wells are on leases with multiple wells where the initial productivity (IP) of individual wells cannot be differentiated.
Cumulative production by county for post-2011 wells differentiated by well type is illustrated in Figure 27. Post-2011 production is concentrated in fewer, and different, counties than historical production, with 31% in the top two counties for horizontal drilling, and 66% in the top six counties. The difference in cumulative production between horizontal and vertical/directional wells is starkly evident, given the fact that overall well count is similar for the two well types. Eddy County in New Mexico, the top county for post-2011 cumulative production for all well types, peaked in December 2014 and is now down 32% from peak. All other counties, however, are in growth mode.

Figure 27. Cumulative production of oil and gas by county from post-2011 Permian Basin wells by well type.

Production is largely from unconventional reservoirs and the distribution of production by county is quite different compared to historical production in the basin illustrated in Figure 25.
Table 5 shows the number of wells drilled, cumulative and current production, and well- and field-decline rates for the Permian Basin as a whole, and for major counties, by well type and vintage. Three-year well decline rates average 88%, but are lower, at 65%, for pre-2012 wells, many of which were drilled for conventional resources, and are as high as 91% in Eddy County in New Mexico (the top county for post-2011 cumulative production). Field declines average 16% per year for the basin as a whole, but are just 6% for pre-2012 wells, given that they are older and in the lower decline portion of the typical well decline curve. Field declines in post-2011 horizontal wells average 29%, but range up to 42% in Lea County (the current top producer) and 38% in Eddy County, which are at the high end of the range observed in major shale plays and require high drilling rates to keep production flat.

<table>
<thead>
<tr>
<th>County</th>
<th>Well type</th>
<th>Vintage</th>
<th>Total Well Count</th>
<th>Producing Well Count</th>
<th>Cumulative Oil Production (billion bbls)</th>
<th>Cumulative Gas Production (tcf)</th>
<th>Oil Production May 2017 (Kbbls/day)</th>
<th>Gas Production May 2017 (bcf/day)</th>
<th>3-year well decline (%)</th>
<th>Field decline (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>All</td>
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<td>All</td>
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</tr>
<tr>
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<td>All</td>
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<td>870.6</td>
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<td>74.6</td>
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<td>Eddy</td>
<td>Horizontal</td>
<td>Post-2011</td>
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<td>128.5</td>
<td>0.60</td>
<td>91.3</td>
<td>37.5</td>
</tr>
<tr>
<td>Lea</td>
<td>Horizontal</td>
<td>Post-2011</td>
<td>1,266</td>
<td>1,188</td>
<td>0.172</td>
<td>0.393</td>
<td>185.4</td>
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<td>41.8</td>
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<td>Loving</td>
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<td>Post-2011</td>
<td>949</td>
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<td>144.7</td>
<td>0.52</td>
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<td>26.2</td>
</tr>
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<td>Midland</td>
<td>Horizontal</td>
<td>Post-2011</td>
<td>728</td>
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<td>0.088</td>
<td>0.150</td>
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<td>89.5</td>
<td>21.7</td>
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<tr>
<td>Reagan</td>
<td>Horizontal</td>
<td>Post-2011</td>
<td>576</td>
<td>552</td>
<td>0.061</td>
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<td>69.0</td>
<td>0.24</td>
<td>84.4</td>
<td>36.9</td>
</tr>
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<td>Reeves</td>
<td>Horizontal</td>
<td>Post-2011</td>
<td>1,177</td>
<td>1,090</td>
<td>0.147</td>
<td>0.520</td>
<td>196.2</td>
<td>0.79</td>
<td>81.7</td>
<td>20.9</td>
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<tr>
<td>Upton</td>
<td>Horizontal</td>
<td>Post-2011</td>
<td>487</td>
<td>461</td>
<td>0.057</td>
<td>0.104</td>
<td>89.6</td>
<td>0.17</td>
<td>90.9</td>
<td>28.9</td>
</tr>
<tr>
<td>Other counties</td>
<td>Horizontal</td>
<td>Post-2011</td>
<td>4,027</td>
<td>3,737</td>
<td>0.335</td>
<td>1.230</td>
<td>392.4</td>
<td>1.33</td>
<td>85.0</td>
<td>30.7</td>
</tr>
</tbody>
</table>

Table 5. Well count, cumulative production, most recent production, and well- and field-decline rates for the Permian Basin and counties within it by well type and vintage.33

33 From Drillinginfo September, 2017. Note that total well count in line 1 includes 129,299 wells that have never had any production.
The concentration of post-2011 horizontal well oil production in sweet spots is illustrated in Figure 28. Seventy-one percent of production from horizontal wells, which constitute 58% of Permian Basin production, now comes from seven counties, the largest cumulative producer of which (Eddy County) peaked in December 2014, and is now down 32% from peak.

Figure 28. Oil production in the Permian Basin from post-2011 horizontal wells by county, 2012–2017.
As in most other shale plays, the application of better technology has increased well productivity markedly over the 2012–2017 period. Figure 29 illustrates average horizontal well productivity over the first four months of production for the basin as a whole and for individual counties. Horizontal wells were 7 to 15 times more productive than vertical/directional wells in 2017, and well productivity was highest in Lea County, the current top producer. Despite the overall improvement, well productivity has flat-lined or fallen in three of the top seven counties between 2016 and 2017—including Eddy County, the top post-2011 cumulative producer.

This is an indication that technology has reached the point of diminishing returns, and that wells are being crowded too closely together causing “frac hits” or well interference, which lowers the productivity of infill “child” wells and may reduce the productivity of earlier “parent” wells. Frac hits are becoming an increasing concern of operators as sweet spots reach maximum development. Over-drilling is already occurring in the Permian Basin, but is just the beginning compared to what is likely to occur given the drilling rates that will be required for optimistic forecasts of future production increases, and the fact that drilling locations in sweet spots are limited.

Figure 29. Average horizontal well productivity over the first four months of oil production by county in the Permian Basin, 2012–2017.

---

Seventy percent of Permian Basin production comes from three plays, the Spraberry, Wolfcamp, and Bone Spring. These plays have had some production for decades, but the advent of modern fracking has vastly increased their production. Most of the rest of production comes from legacy conventional wells and some smaller unconventional plays. Figure 30 illustrates Permian Basin production by play. Each of these plays is assessed in the following sections, along with the EIA’s estimates of future production from them.

Figure 30. Permian Basin oil production by play, 1990–2017.

Seventy percent of production now comes from three unconventional plays which are assessed in the following section.
2.3.1 Spraberry Play

The Spraberry Play of the Midland sub-basin of the Permian Basin has produced oil and gas for decades. The application of fracking at scale in 2009 revolutionized the development of the Spraberry, however, and oil production has increased seven-fold since then. It is now the single largest producing play in the Permian Basin. Figure 31 illustrates production from 1990 through October 2017. Nearly 44,000 wells have been drilled of which more than 30,000 were still producing as of mid-2017.

Figure 31. Spraberry Play oil production and number of producing wells by type, 1990–2017.
Figure 32 illustrates the distribution of Spraberry wells. Post-2011 wells are highlighted by quality as defined by peak production month. New drilling with high well productivities is concentrated in a relatively small part of the overall play extent.

Figure 32. Spraberry Play well locations showing peak oil production of post-2011 wells in the highest month.35

The highest productivity wells are concentrated in relatively small parts of the total play extent. “Excluded” wells are on leases with multiple wells where the initial productivity (IP) of individual wells cannot be differentiated.36

35 Note that the “Trend area” reservoir is included with the “Spraberry” reservoir in this discussion. Together these reservoirs are mainly included in the “Spraberry” field but the Trend area reservoir also occurs in the “Wolfbone” field in the southwest portion of the map and the Spraberry reservoir occurs in fields other than the “Spraberry” field in the northern portion of the map area.
36 EIA, March, 2016, play area outline from https://www.eia.gov/maps/map_data/TightOil_ShaleGas_Plays_Lower48_EIA.zip
Figure 33 illustrates cumulative recovery of oil and gas by county. Over half of oil production has come from three counties—Midland, Martin, and Reagan—and 83% from the top six counties. These “sweet spots” constitute a relatively small part of the total play area indicated by older drilling in Figure 32.

**Figure 33. Cumulative production of oil and gas from the Spraberry Play by county.**

Production is concentrated in sweet spot counties, with 54% of cumulative oil recovery in the top three counties and 83% in the top six.
Post-2011 production has migrated somewhat from earlier production, although Midland County has remained the top producer. Figure 34 illustrates cumulative production by well vintage. Reeves, Howard, and Upton counties have increased their rank in post-2011 production at the expense of Reagan, Borden, and Martin counties. In both older and younger vintage wells, however, production remains concentrated with 84% or more from the top six counties.

**Figure 34. Cumulative production of oil and gas from the Spraberry Play by county and well vintage.**

Production in post-2011 remains concentrated in sweet spot counties, with 36% in the top two counties, and 84% in the top six.
The importance of horizontal drilling and hydraulic fracturing in the Spraberry Play is illustrated in Figure 35. Post-2011 horizontal wells make up less than 10% of producing wells, yet they accounted for 62% of May 2017 production. Although there were nearly twice as many post-2011 vertical/directional wells, they accounted for just 6% of production. Future production growth will therefore be heavily weighted to horizontal drilling with the latest fracking technology.

![Figure 35. Spraberry oil production by well type and vintage.](image)

Post 2011 horizontal wells accounted for 62% of Spraberry Play production in May 2017.
The counties focused on by horizontal versus vertical/directional drilling are different, which is not surprising given variations in geology and the suitability of one well type over the other. Although Midland County remains the top county for post-2011 production from horizontal wells, it ranks fifth for vertical/directional wells. Figure 36 illustrates post-2011 production by county and well type. Seven counties provide 96% of horizontal production whereas a different mix of seven counties provides 89% of vertical/directional production. The superior productivity of horizontal wells is evident in Figure 36.

Figure 36. Post-2011 cumulative production of oil and gas from the Spraberry Play by county.
Horizontal is concentrated in seven counties which account for 96% of production.
Table 6 summarizes the number of wells drilled, cumulative and current production, and well- and field-decline rates for the Spraberry Play as a whole and for individual counties. Three-year well decline rates average 91% and field decline rates average 13% per year without new drilling, given the preponderance of older wells declining at slower rates. Post-2011 wells have a field decline between 24% and 26%.

Table 6. Well count, cumulative production, most recent production, and well- and field-decline rates for the Spraberry Play and counties within it by well type and vintage.37

<table>
<thead>
<tr>
<th>County</th>
<th>Well type</th>
<th>Vintage</th>
<th>Total Well Count</th>
<th>Producing Well Count</th>
<th>Cumulative Oil Production (billion bbls)</th>
<th>Cumulative Gas Production (tcf)</th>
<th>Oil Production May 2017 (Kbbls/day)</th>
<th>Gas Production May 2017 (bcf/day)</th>
<th>3-year well decline (%)</th>
<th>Field decline (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>All</td>
<td>All</td>
<td>All</td>
<td>42,919</td>
<td>30,421</td>
<td>2.617</td>
<td>6.277</td>
<td>888.1</td>
<td>2.183</td>
<td>91.3</td>
<td>12.5</td>
</tr>
<tr>
<td>All</td>
<td>All</td>
<td>Pre-2012</td>
<td>32,346</td>
<td>22,921</td>
<td>2.137</td>
<td>5.164</td>
<td>280.0</td>
<td>0.86</td>
<td>65.8</td>
<td>10.7</td>
</tr>
<tr>
<td>All</td>
<td>Horizontal</td>
<td>Post-2011</td>
<td>2,976</td>
<td>2,753</td>
<td>0.346</td>
<td>0.659</td>
<td>552.9</td>
<td>1.08</td>
<td>87.9</td>
<td>23.6</td>
</tr>
<tr>
<td>All</td>
<td>Vertical</td>
<td>Post-2011</td>
<td>5,003</td>
<td>4,747</td>
<td>0.134</td>
<td>0.454</td>
<td>55.1</td>
<td>0.24</td>
<td>79.9</td>
<td>26.4</td>
</tr>
<tr>
<td>Howard</td>
<td>Horizontal</td>
<td>Post-2011</td>
<td>314</td>
<td>283</td>
<td>0.037</td>
<td>0.039</td>
<td>76.0</td>
<td>0.09</td>
<td>92.0</td>
<td>55.3</td>
</tr>
<tr>
<td>Martin</td>
<td>Horizontal</td>
<td>Post-2011</td>
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<td>256</td>
<td>0.036</td>
<td>0.051</td>
<td>66.0</td>
<td>0.09</td>
<td>91.2</td>
<td>37.4</td>
</tr>
<tr>
<td>Midland</td>
<td>Horizontal</td>
<td>Post-2011</td>
<td>642</td>
<td>584</td>
<td>0.085</td>
<td>0.143</td>
<td>154.6</td>
<td>0.30</td>
<td>84.1</td>
<td>15.6</td>
</tr>
<tr>
<td>Reeves</td>
<td>Horizontal</td>
<td>Post-2011</td>
<td>408</td>
<td>398</td>
<td>0.051</td>
<td>0.102</td>
<td>50.3</td>
<td>0.11</td>
<td>80.9</td>
<td>12.0</td>
</tr>
<tr>
<td>Upton</td>
<td>Horizontal</td>
<td>Post-2011</td>
<td>473</td>
<td>445</td>
<td>0.055</td>
<td>0.104</td>
<td>88.4</td>
<td>0.17</td>
<td>90.7</td>
<td>27.7</td>
</tr>
<tr>
<td>Other counties</td>
<td>Horizontal</td>
<td>Post-2011</td>
<td>854</td>
<td>787</td>
<td>0.082</td>
<td>0.219</td>
<td>117.7</td>
<td>0.31</td>
<td>89.3</td>
<td>39.8</td>
</tr>
</tbody>
</table>

37 From Drillinginfo October, 2017. Note that total well count in line 1 includes 2,594 wells that have never had any production.
The degree of development of the Spraberry core area to date is illustrated in Figure 37. Some recent horizontal laterals have exceeded 15,000 feet in length, although the average is considerably less. Most well pads have multiple wells. Well interference has been noted at close well spacings between early “parent” wells and later infill “child” wells which suggests, as in other plays, that production is sacrificed by crowding wells too closely together.\footnote{T. Jacobs, November, 2017, Frac Hits Reveal Well Spacing May be too Tight, Completion Volumes too large, Journal of Petroleum Technology, http://www.slb.com/~/media/Files/stimulation/industry_articles/201711-jpt-frac-hits-tight-spacing-large-completion-volumes.pdf}

\begin{figure}[h]
\centering
\includegraphics[width=\textwidth]{spraberry-core-area.png}
\caption{Core area of the Spraberry Play in Midland County showing well locations and degree of development as of mid-2017.}
\end{figure}
The evolution of production by county for post-2011 horizontal wells is illustrated in Figure 38. As of mid-2017, Midland County accounted for 28% of production, and the top five counties accounted for 79%.

Figure 38. Oil production from horizontal post-2011 wells in the Spraberry Play by county.
Horizontal drilling in all counties has exhibited a marked improvement in productivity in the 2012–2017 period, as illustrated in Figure 39. Vertical/directional drilling, on the other hand, has declined in productivity over this period, and on average was less than 10% of the productivity of horizontal drilling in 2017. As noted earlier, this improvement is due to the vastly increased amounts of water and proppant used per well and increased length of horizontal laterals, as well as crowding wells into sweet spot areas.

It appears, however, that better technology has reached its limits in improving well productivity in the top two counties. Average well productivity has flat-lined in Midland County since 2015, and well quality has declined since 2016 in Upton County, the second most productive county. Together these counties accounted for 44% of mid-2017 Spraberry production. This is a symptom of reaching the law of diminishing returns on technology as well as crowding wells too close together, causing well interference and reducing per well production and oil recovery.

**Figure 39.** Average horizontal well productivity over the first four months of oil production by county in the Spraberry Play, 2012–2017.
Figure 40 illustrates the EIA’s AE02017 reference case production projection for the Spraberry Play through 2050, together with earlier projections. The EIA expects production to keep increasing to a peak in 2041 before gradually declining to exit 2050 at a higher production rate than current levels. This would require producing 13.2 billion barrels of oil in the 2014–2050 period, which is five times as much oil as has been recovered from the Spraberry since the 1950s. It is also would require recovering 17% more oil than the EIA’s estimates show exist, in terms of proven reserves and unproven resources. The fact that the estimate exits 2050 at very high production levels implies much more oil would be recovered after 2050. Given this, and the fact that well interference is already evident in the top counties, the IEA’s projection is rated as extremely optimistic.

Figure 40. EIA AE02017 reference case Spraberry Play oil production estimate through 2050.
Also shown are earlier AE0 estimates to 2040.
Table 7 illustrates assumptions in the EIA AEO2017 reference case projection.\textsuperscript{39} If realized, the EIA projection would have to recover 118% of the EIA’s estimate of proven reserves plus unproven resources, and would require 130,830 additional wells, for a total well count of more than three times the current 42,919, at an estimated cost of $785 billion.

<table>
<thead>
<tr>
<th>EIA AE02017 Reference Case Projection</th>
</tr>
</thead>
<tbody>
<tr>
<td>Proven Reserves 2015 (Bbbls)</td>
</tr>
<tr>
<td>Unproven Resources 2015 (Bbbls)</td>
</tr>
<tr>
<td>Total Potential 2015 (Bbbls)</td>
</tr>
<tr>
<td>2015-2050 Recovery (Bbbls)</td>
</tr>
<tr>
<td>% of total potential used 2015-2050</td>
</tr>
<tr>
<td>Wells needed 2015-2050</td>
</tr>
<tr>
<td>Well cost 2015-2050 ($billions)</td>
</tr>
</tbody>
</table>

Table 7. EIA assumptions for Spraberry Play oil in the AE02017 reference case.
Well costs of $785 billion for full development are estimated assuming a well cost of $6 million each. Wells needed were determined using EIA estimates of EUR, assuming EUR would not be compromised by over-drilling, and wells needed for proven reserves would have an EUR twice as high as unproven resources.

\textsuperscript{39} EIA, Unproved technically recoverable resources are from Assumptions to the Annual Energy Outlook 2017, https://www.eia.gov/outlooks/aeo/assumptions/; Proven reserves are from U.S. Crude Oil and Natural Gas Proved Reserves, Year-end 2015, https://www.eia.gov/naturalgas/crudeoilreserves/
Synopsis

The EIA’s reference case production estimate is extremely optimistic. Key points include:

- The Spraberry is an old play being re-developed with new technology. New horizontal drilling has shifted areas of highest production from historic locations. As of May 2017, 42,919 wells had been drilled.

- The EIA has tripled its estimate of the size of the prospective Spraberry play area to 15,684 square miles, compared to the 5,297 square mile play-area in Figure 32. The EIA assumes this revised area can be drilled at 6.9 wells per square mile to recover unproved resources. This revised area is 45% larger than the current drilled extents of the play.

- In its reference case, the EIA assumed that 13.1 billion barrels of oil would be recovered over the 2015-2050 period, which is 118% of its estimated proven reserves plus unproven resources. This would require 130,830 wells, assuming that the EIA’s EUR for unproven resources per well is correct, and assuming that proven reserves will have an EUR per well of double that of unproven resources. At $6 million per well this would cost $785 billion.

- Drilling 130,830 wells would raise the existing well density by 8.3 wells per square mile (if the EIA’s new play area is correct and assuming EUR would not be reduced by well interference), for a total of 11.1 wells per square mile, if existing wells are included. Given that there are already signs of well interference, it is highly unlikely that such a well density would be economic, or would recover the 13.1 billion barrels the EIA has assumed. It would likely amount to vastly over-drilling without expanding the recoverable resource significantly. If the new EIA’s play area is overestimated by 45%, as it appears to be based on the current drilled area, the well density would have to be increased even more (in the unlikely event that well EURs would not be reduced by over-drilling). This suggests that the EIA’s estimate of unproven resources is significantly overestimated.

- The EIA assumes that production will exit 2050 at above current rates, which implies that vast additional, as-yet-unknown, resources will be recovered beyond 2050.

- Taken together, along with play fundamentals, the above strains the credibility of the EIA reference case projection for the Spraberry to the limit.

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41 EIA, March, 2016, play area outline from https://www.eia.gov/maps/map_data/TightOil_ShaleGas_Plays_Lower48_EIA.zip
2.3.2 Wolfcamp Play

The Wolfcamp Play, primarily in the Delaware sub-basin of the Permian Basin, has produced oil and gas for decades. The application of fracking at scale in 2009 revolutionized the development of the Wolfcamp, however, and oil production has increased fourteen-fold since then. It is now the second largest producing play in the Permian Basin. Figure 41 illustrates production from 1990 through October 2017. More than 14,600 wells have been drilled, of which 7,217 were producing as of mid-2017.

Figure 41. Wolfcamp Play oil production and number of producing wells by type, 1990–2017.
Figure 42 illustrates the distribution of Wolfcamp wells. Post-2011 wells are highlighted by quality as defined by peak production month. New drilling with high well productivities is concentrated in a relatively small part of the play extent drilled prior to 2012.

Figure 42. Wolfcamp Play well locations showing peak oil production of post-2011 wells in the highest month.42

The highest productivity wells are concentrated in relatively small parts of the total play extent defined by pre-2012 drilling. “Excluded” wells are on leases with multiple wells where the initial productivity (IP) of individual wells cannot be differentiated.

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42 Permian Basin area outline from EIA, December, 2017. https://www.eia.gov/maps/map_data/PermianBasin_Boundary_Structural_Tectonic.zip
Figure 43 illustrates cumulative recovery of oil and gas by county. Forty-three percent of oil production has come from four counties and 65% from the top six counties. These “sweet spots” constitute a relatively small part of the total play area indicated by older drilling in Figure 42.

**Figure 43. Cumulative production of oil and gas from the Wolfcamp Play by county.**

Production is concentrated in sweet spot counties, with 43% of cumulative oil recovery in the top four counties and 65% in the top six.
Post-2011 production has migrated somewhat from earlier production. Except for Ward County, none of the top six counties for post-2011 cumulative production is the same as the top six counties for pre-2012 production. This is not unexpected given the shift from conventional to unconventional reservoirs and variable geology. Figure 44 illustrates cumulative production by well vintage. Production is more widespread in older, pre-2012 wells, as only 66% is from the top six counties whereas in post-2011 wells 83% of production has come from six counties.

![Figure 44. Cumulative production of oil and gas from the Wolfcamp Play by county and well vintage.](image)

Production in post-2011 remains concentrated in sweet spot counties, with 25% in the top county, and 84% in the top six.
The importance of horizontal drilling and hydraulic fracturing in the Wolfcamp Play is illustrated in Figure 45. Although post-2011 horizontal wells made up less than half of producing wells, they accounted for 92% of production in mid-2017. Pre-2012 wells, which made up over half of producing wells, accounted for just seven percent of production.

**Figure 45. Wolfcamp oil production by well type and vintage.**

Post 2011 horizontal wells accounted for 92% of Wolfcamp Play production in May 2017.
Table 8 summarizes the number of wells drilled, cumulative and current production, and well- and field-decline rates for the Wolfcamp Play as a whole and for individual counties. Three-year well decline rates average 84% and field decline averages 25% per year without new drilling.

<table>
<thead>
<tr>
<th>County</th>
<th>Well type</th>
<th>Vintage</th>
<th>Total Well Count</th>
<th>Producing Well Count</th>
<th>Cumulative Oil Production (billion bbls)</th>
<th>Cumulative Gas Production (tcf)</th>
<th>Oil Production May 2017 (Kbbls/day)</th>
<th>Gas Production May 2017 (bcf/day)</th>
<th>3-year well decline (%)</th>
<th>Field decline (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>All</td>
<td>All</td>
<td>All</td>
<td>14,633</td>
<td>7,217</td>
<td>1.199</td>
<td>5.651</td>
<td>474.2</td>
<td>2.309</td>
<td>84.3</td>
<td>25.4</td>
</tr>
<tr>
<td>All</td>
<td>All</td>
<td>Pre-2012</td>
<td>8,061</td>
<td>3,681</td>
<td>0.824</td>
<td>4.007</td>
<td>33.8</td>
<td>0.20</td>
<td>58.0</td>
<td>16.9</td>
</tr>
<tr>
<td>All</td>
<td>Horizontal</td>
<td>Post-2011</td>
<td>3,349</td>
<td>3,024</td>
<td>0.365</td>
<td>1.595</td>
<td>435.9</td>
<td>2.08</td>
<td>84.6</td>
<td>26.5</td>
</tr>
<tr>
<td>All</td>
<td>Vertical</td>
<td>Post-2011</td>
<td>632</td>
<td>512</td>
<td>0.010</td>
<td>0.049</td>
<td>4.5</td>
<td>0.03</td>
<td>74.5</td>
<td>31.7</td>
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<tr>
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<td>Post-2011</td>
<td>222</td>
<td>208</td>
<td>0.030</td>
<td>0.331</td>
<td>40.3</td>
<td>0.43</td>
<td>88.3</td>
<td>21.8</td>
</tr>
<tr>
<td>Irion</td>
<td>Horizontal</td>
<td>Post-2011</td>
<td>416</td>
<td>413</td>
<td>0.033</td>
<td>0.211</td>
<td>16.7</td>
<td>0.18</td>
<td>89.2</td>
<td>33.4</td>
</tr>
<tr>
<td>Loving</td>
<td>Horizontal</td>
<td>Post-2011</td>
<td>571</td>
<td>516</td>
<td>0.076</td>
<td>0.221</td>
<td>108.9</td>
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<td>78.3</td>
<td>23.9</td>
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<td>Reeves</td>
<td>Horizontal</td>
<td>Post-2011</td>
<td>742</td>
<td>660</td>
<td>0.098</td>
<td>0.414</td>
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<td>0.62</td>
<td>83.6</td>
<td>27.3</td>
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<td>Ward</td>
<td>Horizontal</td>
<td>Post-2011</td>
<td>269</td>
<td>239</td>
<td>0.041</td>
<td>0.084</td>
<td>30.5</td>
<td>0.07</td>
<td>81.1</td>
<td>19.0</td>
</tr>
<tr>
<td>Other counties</td>
<td>Horizontal</td>
<td>Post-2011</td>
<td>1,129</td>
<td>988</td>
<td>0.086</td>
<td>0.334</td>
<td>97.5</td>
<td>0.47</td>
<td>83.7</td>
<td>30.3</td>
</tr>
</tbody>
</table>

Table 8. Well count, cumulative production, most recent production, and well- and field-decline rates for the Wolfcamp Play and counties within it by well type and vintage.43

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43 From Drillinginfo October, 2017. Note that total well count in line 1 includes 2,591 wells that have never had any production.
The degree of development of the Wolfcamp core area to date is illustrated in Figure 46. Some recent horizontal laterals are over 10,000 feet in length, although the average is considerably shorter. Most well pads have multiple wells. Some corridors appear saturated with wells although other areas appear able to accommodate more wells.

**Figure 46.** Core area of the Wolfcamp Play showing well locations and degree of development as of mid-2017.
The evolution of production by county for post-2011 horizontal wells is illustrated in Figure 47. As of mid-2017, Reeves and Loving counties accounted for 58% of production, and the top five counties accounted for 78%.

**Figure 47. Oil production from horizontal post-2011 wells in the Wolfcamp Play by county.**
Horizontal drilling in all counties has exhibited a marked improvement in productivity in the 2012–2017 period, as illustrated in Figure 48. Vertical/directional drilling, on the other hand, has declined in productivity over this period, and on average was less than 5% of the productivity of horizontal drilling in 2017. As noted earlier, this improvement is due to the vastly increased amounts of water and proppant used per well and increasing the length of horizontal laterals, as well as crowding wells into sweet spot areas.

Well productivity has increased in four counties from 2016 to 2017, but has flat-lined in Irion County since 2012, and has declined since 2016 in counties outside of the top five. On average, however, the productivity of horizontal wells in the play declined in 2017. This is a symptom of reaching the law of diminishing returns on technology and crowding wells too close together, causing well interference and reducing per well production and oil recovery.

Figure 48. Average horizontal well productivity over the first four months of oil production by county in the Wolfcamp Play, 2012–2017.
Figure 49 illustrates the EIA’s AEO2017 reference case production projection for the Wolfcamp Play through 2050, together with earlier projections. The EIA expects production to keep increasing to a peak in 2032, at 55% above current levels, and maintain a plateau thereafter, exiting 2050 at 45% above current levels. This would require producing 8.9 billion barrels of oil in the 2014–2050 period, which is seven times as much oil as has been recovered from the Wolfcamp since the 1950s. The fact that the projection exits 2050 at very high production levels implies much more oil would be recovered after 2050. Given this, and the fact that well interference is already evident in the basin, the IEA’s forecast is rated as highly optimistic.

Figure 49. EIA AEO2017 reference case Wolfcamp Play oil production estimate through 2050.

Also shown are earlier AEO estimates to 2040.
Table 9 illustrates assumptions in the EIA AEO2017 reference case projection.\textsuperscript{44} If realized, the EIA projection would have to recover 75% of the EIA’s estimate of proven reserves plus unproven resources, and would require 56,398 additional wells, for a total well count of five times the current 14,633, at an estimated cost of $338 billion.

<table>
<thead>
<tr>
<th>EIA AE02017 Reference Case Projection</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Proven Reserves 2015 (Bbbls)</td>
<td>0.7</td>
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<tr>
<td>Unproven Resources 2015 (Bbbls)</td>
<td>11.1</td>
</tr>
<tr>
<td>Total Potential 2015 (Bbbls)</td>
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</tr>
<tr>
<td>2015-2050 Recovery (Bbbls)</td>
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</tr>
<tr>
<td>% of total potential used 2015-2050</td>
<td>75.0%</td>
</tr>
<tr>
<td>Wells needed 2015-2050</td>
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</tr>
<tr>
<td>Well cost 2015-2050 ($billions)</td>
<td>$338</td>
</tr>
</tbody>
</table>

\textbf{Table 9. EIA assumptions for Wolfcamp Play oil in the AE02017 reference case.}

Well costs of $338 billion for full development are estimated assuming a well cost of $6 million each. Wells needed were determined using EIA drilling density and play area for unproven resources, and wells needed for proven reserves assuming EUR per well would be twice as high for proven reserves as unproven resources.

\textsuperscript{44} EIA, Unproved technically recoverable resources are from Assumptions to the Annual Energy Outlook 2017, https://www.eia.gov/outlooks/aeo/assumptions/; Proven reserves are from U.S. Crude Oil and Natural Gas Proved Reserves, Year-end 2015, https://www.eia.gov/naturalgas/crudeoilreserves/; Note that the EIA reports 0.8 Bbbl for Wolfcamp and Bone Spring proven reserves combined, 0.7 Bbbl of which was apportioned to the larger Wolfcamp and 0.1 Bbbl to the Bone Spring, based on the proportion of unproven resources in these plays.
Synopsis

The EIA’s reference case production estimate is highly optimistic. Key points include:

- The Wolfcamp is an old play being re-developed with new technology. New horizontal drilling has shifted areas of highest production from historic locations. As of May 2017, 14,633 wells had been drilled.

- The prospective area with high productivity wells drilled since 2011 is about 8,400 square miles, located mainly in the Delaware sub-basin. The EIA estimates that an area of 18,491 square miles can be drilled at a well density of four wells per square mile to recover unproven resources, which is 120% larger.\textsuperscript{45} This suggests that the EIA’s ultimately recoverable unproven resource may be overestimated by at least double.

- In its reference case, the EIA assumed that 8.8 billion barrels of oil will be recovered over the 2015–2050 period, which is 75% of its estimated proven reserves plus unproven resources. If unproven resources are overestimated by 120%, as suggested by the prospective drilled area, producing this amount by 2050 would require recovering 155% of unproven resources plus proven reserves. This would require 56,398 wells, assuming that the EIA’s EUR for unproven resources per well is correct and would not be reduced by well interference from over-drilling, and assuming that proven reserves will have an EUR per well of double that of unproven resources. At $6 million per well this would cost $338 billion.

- Drilling 56,398 wells would raise the existing well density, including wells already drilled, to 3.8 wells per square mile (if the EIA’s 18,491 drammable square mile area is correct). If the prospective area defined by high productivity wells drilled since 2011 is correct (8,400 square miles), well density would be increased to 8.4 wells per square mile. Given that there are already signs of well interference, it is unlikely that such a well density would be economic, as EURs would be reduced by over-drilling, and 55% more resources than are estimated to exist would have to be recovered.

- The EIA assumes that production will exit 2050 at above current rates, which implies that vast additional, as-yet-unknown, resources will be recovered beyond 2050.

- Although the optimism bias for the Wolfcamp is somewhat lower than for the EIA’s projection for the Spraberry, given the above considerations and play fundamentals it must be considered highly optimistic.

\textsuperscript{45} EIA, Assumptions to the Annual Energy Outlook 2017, https://www.eia.gov/outlooks/aeo/assumptions/
2.3.3 Bone Spring Play

The Bone Spring is a relatively small play located in the northern part of the Delaware sub-basin and has produced oil and gas for decades. The application of fracking at scale since 2009 has revolutionized its development, and oil production has increased seventeen-fold since then. It is now the third largest producing play in the Permian Basin. Figure 50 illustrates production from 1990 through October 2017. More than 8,000 wells have been drilled, of which 3,725 were still producing as of mid-2017. Production peaked in May 2015, and has declined slightly since then.

Figure 50. Bone Spring Play oil production and number of producing wells by type, 1990–2017.
Figure 51 illustrates the distribution of Bone Spring wells. Post-2011 wells are highlighted by quality as defined by peak production month. New drilling with high well productivities is concentrated in the New Mexico part of the play, although there are a few wells with high productivity as far south as Pecos in Texas.

Figure 51. Bone Spring Play well locations showing peak oil production of post-2011 wells in the highest month.\(^{46}\)

The highest productivity wells are concentrated in relatively small parts of the total play extent defined by pre-2012 drilling. “Excluded” wells are on leases with multiple wells where the initial productivity (IP) of individual wells cannot be differentiated.

\(^{46}\) Bone Spring area outline from EIA, March, 2016. https://www.eia.gov/maps/map_data/AboYeso_BoneSpring_Delaware_GlorietaYeso_Spraberry_Play_Boundary_EIA.zip
Figure 52 illustrates cumulative recovery of oil and gas by county. Eighty-five percent of oil production has come from two counties in New Mexico, and 95% from the top four counties. These “sweet spots” constitute a relatively small part of the total play area indicated by the EIA’s play boundary in Figure 51.

**Figure 52. Cumulative production of oil and gas from the Bone Spring Play by county.**

Production is concentrated in sweet spot counties, with 85% of cumulative oil recovery in the top two counties and 95% in the top four.
Post-2011 production has migrated somewhat from earlier production (Figure 53). Loving and Culberson counties in Texas have emerged as the third and fourth most productive counties, whereas previously they had little production. This reflects the ability to access parts of the play that were previously uneconomic with new technology. Lea and Eddy counties in New Mexico remain the top counties in the play, although Eddy County peaked in February 2016, and has since declined 23%.

**Figure 53. Cumulative production of oil and gas from the Bone Spring Play by county and well vintage.**

Production in post-2011 remains concentrated in sweet spot counties, with 46% in the top county, and 93% in the top three.
The importance of horizontal drilling and hydraulic fracturing in the Bone Spring Play is illustrated in Figure 54. Ninety-five percent of post-2011 wells were horizontal and accounted for 65% of all producing wells in the play. Post-2011 horizontal wells accounted for 92% of production in mid-2017.

Figure 54. Bone Spring oil production by well type and vintage.
Post 2011 horizontal wells accounted for 92% of Bone Spring Play production in May 2017.
Table 10 summarizes the number of wells drilled, cumulative and current production, and well- and field-decline rates for the Bone Spring Play as a whole and for individual counties. Three-year well decline rates average 90% and field decline averages 35% per year without new drilling.

<table>
<thead>
<tr>
<th>County</th>
<th>Well type</th>
<th>Vintage</th>
<th>Total Well Count</th>
<th>Producing Well Count</th>
<th>Cumulative Oil Production (billion bbls)</th>
<th>Cumulative Gas Production (tcf)</th>
<th>Oil Production May 2017 (Kbbls/day)</th>
<th>Gas Production May 2017 (bcf/day)</th>
<th>3-year well decline (%)</th>
<th>Field decline (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>All</td>
<td>All</td>
<td>All</td>
<td>8,055</td>
<td>3,725</td>
<td>0.497</td>
<td>1.860</td>
<td>254.7</td>
<td>1.037</td>
<td>90.4</td>
<td>34.8</td>
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<tr>
<td>All</td>
<td>All</td>
<td>Pre-2012</td>
<td>2,120</td>
<td>1,194</td>
<td>0.189</td>
<td>0.629</td>
<td>14.7</td>
<td>0.07</td>
<td>85.9</td>
<td>19.2</td>
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<tr>
<td>All</td>
<td>Horizontal</td>
<td>Post-2011</td>
<td>2,735</td>
<td>2,404</td>
<td>0.319</td>
<td>1.208</td>
<td>235.1</td>
<td>0.95</td>
<td>90.7</td>
<td>37.9</td>
</tr>
<tr>
<td>All</td>
<td>Vertical</td>
<td>Post-2011</td>
<td>163</td>
<td>127</td>
<td>0.009</td>
<td>0.023</td>
<td>4.9</td>
<td>0.02</td>
<td>87.2</td>
<td>31.5</td>
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<td>Eddy</td>
<td>Horizontal</td>
<td>Post-2011</td>
<td>1,073</td>
<td>896</td>
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<td>0.494</td>
<td>68.3</td>
<td>0.33</td>
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<td>Post-2011</td>
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<td>0.36</td>
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<td>39.2</td>
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<tr>
<td>Other counties</td>
<td>Horizontal</td>
<td>Post-2011</td>
<td>631</td>
<td>533</td>
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<td>0.371</td>
<td>41.6</td>
<td>0.26</td>
<td>86.6</td>
<td>29.3</td>
</tr>
</tbody>
</table>

Table 10. Well count, cumulative production, most recent production, and well- and field-decline rates for the Bone Spring Play and counties within it by well type and vintage.47

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47 From Drillinginfo October, 2017. Note that total well count in line 1 includes 3,037 wells that have never had any production.
The degree of development of the Bone Spring core area to date is illustrated in Figure 55. Some recent horizontal laterals exceed 10,000 feet in length although the average is considerably less. Most well pads have multiple wells. Some areas appear saturated with wells although other areas appear able to accommodate more wells.

Figure 55. Core area of the Bone Spring Play showing well locations and degree of development as of mid-2017.
The evolution of production by county for post-2011 horizontal wells is illustrated in Figure 56. As of mid-2017, Eddy and Lea counties accounted for 82% of production. The play as a whole peaked in May 2015, and Eddy County peaked in February, 2016, and is now down 23%.

Figure 56. Oil production from horizontal post-2011 wells in the Bone Spring Play by county.
Horizontal drilling in all counties has exhibited a marked improvement in productivity in the 2012–2017 period, as illustrated in Figure 57. Vertical/directional drilling, on the other hand, decreased markedly in 2017. As noted earlier, this improvement is due to the vastly increased amounts of water and proppant used per well and increasing the length of horizontal laterals, as well as crowding wells into sweet spot areas.

Figure 57. Average horizontal well productivity over the first four months of oil production by county in the Bone Spring Play, 2012–2017.
Figure 58 illustrates the EIA’s AEO2017 reference case production projection for the Bone Spring Play through 2050, together with earlier projections. The EIA expects production to keep increasing to a peak in 2022, at 86% above current levels, despite the fact that the play peaked in May 2016. This would require producing 3.95 billion barrels of oil in the 2014–2050 period, which is eight times as much oil as has been recovered from the Bone Spring since the 1960s. The fact that the projection exits 2050 at production levels just 12% below current production, implies that considerable additional volumes of oil would be recovered after 2050. Given this, the IEA’s forecast is rated as extremely optimistic.

Figure 58. EIA AEO2017 reference case Bone Spring Play oil production estimate through 2050.
Also shown are earlier AEO estimates to 2040.
Table 11 illustrates assumptions in the EIA AEO2017 reference case projection.\textsuperscript{48} If realized, the EIA projection would have to recover 184\% of the EIA’s estimate of proven reserves plus unproven resources, and would require 30,302 additional wells, for a total well count of five times the current 8,055, at an estimated cost of $182 billion.

<table>
<thead>
<tr>
<th>EIA AE02017 Reference Case Projection</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Proven Reserves 2015 (Bbbls)</td>
<td>0.1</td>
</tr>
<tr>
<td>Unproven Resources 2015 (Bbbls)</td>
<td>2.0</td>
</tr>
<tr>
<td>Total Potential 2015 (Bbbls)</td>
<td>2.1</td>
</tr>
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<td>2015-2050 Recovery (Bbbls)</td>
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<tr>
<td>% of total potential used 2015-2050</td>
<td>183.5%</td>
</tr>
<tr>
<td>Wells needed 2015-2050</td>
<td>30,302</td>
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<tr>
<td>Well cost 2015-2050 ($billions)</td>
<td>$182</td>
</tr>
</tbody>
</table>

\textbf{Table 11. EIA assumptions for Bone Spring Play oil in the AE02017 reference case.}

Well costs of $182 billion for full development are estimated assuming a well cost of $6 million each. Wells needed were determined using EIA estimates of EUR assuming EUR would not be compromised by over-drilling, and wells needed for proven reserves would have an EUR twice as high as unproven resources.

\textsuperscript{48} EIA, Unproved technically recoverable resources are from Assumptions to the Annual Energy Outlook 2017, https://www.eia.gov/outlooks/aeo/assumptions/; Proven reserves are from U.S. Crude Oil and Natural Gas Proved Reserves, Year-end 2015, https://www.eia.gov/naturalgas/crudeoilreserves/; Note that the EIA reports 0.8 Bbbl for Wolfcamp and Bone Spring proven reserves combined, 0.7 Bbbl of which was apportioned to the larger Wolfcamp and 0.1 Bbbl to the Bone Spring, based on the proportion of unproven resources in these plays.
Synopsis

The EIA’s reference case production estimate is extremely optimistic. Key points include:

- The Bone Spring is an old play being re-developed with new technology. Although the top two counties, Lea and Eddy in New Mexico, account for 82% of current production, new technology has increased production to the south in Texas. Eddy County peaked in February 2016, and the play as a whole peaked in May 2016. As of May 2017, 8,055 wells had been drilled.

- The prospective area with high productivity wells drilled since 2011 is about 4,400 square miles, located mainly in New Mexico but extending south into Texas (compared to the EIA play area in Figure 51 of 6,070 square miles). The EIA also estimated that an area of 3,769 square miles can be drilled at a well density of 4.2 wells per square mile, for a total of 15,830 wells, to recover 2 billion barrels of unproven resources.

- In its reference case, the EIA AEO2017 assumes that 3.9 billion barrels of oil will be recovered over the 2015-2050 period, which is 184% of its estimated proven reserves plus unproven resources. Recovering this much oil would require 30,302 wells, or approximately twice the number of wells as available drilling locations assumed by the EIA for its unproven resources (assuming EIA estimates of EUR for unproven resources are correct and would not change with over-drilling, and that proven reserves would have EURs of twice that of unproven resources). At $6 million per well this would cost $182 billion.

- Drilling 30,302 wells would raise the well density, including wells already drilled, to 10.2 wells per square mile (if the EIA’s 3,769 square mile drillable area is correct). If the prospective area defined by high productivity wells drilled since 2011 is correct (4,413 square miles), well density would be 8.7 wells per square mile. Crowding wells this close together would likely result in well interference and reduced EURs, making such a well density uneconomic. Doing so is highly unlikely to recover 84% more resources than the EIA estimates exist, as projected in AEO2017.

- The EIA assumes that production will exit 2050 at only 12% below current rates, which implies that large additional, as-yet-unknown, resources will be recovered beyond 2050.

- Given the above considerations and play fundamentals, the AEO2017 projection for the Bone Spring is considered to be extremely optimistic.
2.4 **Austin Chalk Play**

The Austin Chalk is an old play that extends over a broad swath from southern Texas into Louisiana. It has produced oil and considerable amounts of gas since the 1950s. Production peaked in 1991 as illustrated in Figure 59. The play is being redeveloped with horizontal drilling and hydraulic fracturing which has resulted in a reversal of its decline since 2014, but production is still far below its 1991 peak. More than 14,600 wells have been drilled, of which 4,896 were still producing as of mid-2017.

![Figure 59. Austin Chalk Play oil production and number of producing wells by type, 1990–2017.](image)
Figure 60 illustrates the distribution of Austin Chalk wells. Post-2011 wells are highlighted by quality as defined by peak production month. Although new drilling has been widespread, high quality wells have been confined to a relatively small area centered on Karnes County. The Austin Chalk underlies the Eagle Ford shale and there may be synergies and cost savings in developing both in Karnes County, which is one of the top producing counties of the Eagle Ford.

The highest productivity wells are concentrated in relatively small parts of the total play extent defined by pre-2012 drilling. “Excluded” wells are on leases with multiple wells where the initial productivity (IP) of individual wells cannot be differentiated.

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Figure 61 illustrates cumulative recovery of oil and gas by county. Production is mainly pre-2011 and is widespread over many counties. The highest cumulative recoveries have been in Texas but there has also been some production in Louisiana. As can be seen, the Austin Chalk has also been a significant natural gas producer.

**Figure 61. Cumulative production of oil and gas from the Austin Chalk Play by county.**
The top two counties have recovered 27% of total oil production and the top five have recovered 56%.
Post-2011 production shows that most of the counties which have in the past provided production are no longer prospective. Karnes County, which overall was the 13th-ranked in terms of cumulative production from the Austin Chalk, has moved into first place with 64% of post-2011 production, as illustrated in Figure 62. From the distribution of wells by quality in Figure 60, and production by county in Figure 62, it appears that most of the historical producing areas of the Austin Chalk are not amenable to fracking technology, and that only a relatively small area centered on Karnes County is prospective.

Figure 62. Cumulative production of oil and gas from the Austin Chalk Play by county and well vintage.
Production in post-2011 is concentrated in Karnes County, with 64%. The top five counties accounted for 82% of post-2011 production.
Table 12 summarizes the number of wells drilled, cumulative and current production, and well- and field-decline rates for the Austin Chalk Play as a whole and for individual counties. Three-year well decline rates average 95% and field decline averages 50% per year without new drilling. These are the highest decline rates observed of all plays analyzed in this report.

<table>
<thead>
<tr>
<th>County</th>
<th>Well type</th>
<th>Vintage</th>
<th>Total Well Count</th>
<th>Producing Well Count</th>
<th>Cumulative Oil Production (billion bbls)</th>
<th>Cumulative Gas Production (tcf)</th>
<th>Oil Production May 2017 (Kbbls/day)</th>
<th>Gas Production May 2017 (bcf/day)</th>
<th>3-year well decline (%)</th>
<th>Field decline (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>All</td>
<td>All</td>
<td>All</td>
<td>15,773</td>
<td>4,896</td>
<td>1.289</td>
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<tr>
<td>All</td>
<td>All</td>
<td>Pre-2012</td>
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<td>4,548</td>
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<td>15.6</td>
<td>0.13</td>
<td>92.5</td>
<td>15.5</td>
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<td>Horizontal</td>
<td>Post-2011</td>
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<td>326</td>
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<td>0.165</td>
<td>62.7</td>
<td>0.20</td>
<td>94.7</td>
<td>70.0</td>
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<tr>
<td>All</td>
<td>Vertical</td>
<td>Post-2011</td>
<td>41</td>
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<td>0.000</td>
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<td>Other counties</td>
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<td>0.060</td>
<td>4.2</td>
<td>0.03</td>
<td>89.6</td>
<td>41.2</td>
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</tbody>
</table>

Table 12. Well count, cumulative production, most recent production, and well- and field-decline rates for the Austin Chalk Play and counties within it by well type and vintage.50

50 From Drillinginfo October, 2017. Note that total well count in line 1 includes 1,126 wells that have never had any production.
The degree of development of the Austin Chalk with new wells in the Karnes County core area to date is illustrated in Figure 63. Although some recent horizontal laterals exceed 8,000 feet in length, the average is considerably less. Most well pads have multiple wells. Current development is relatively sparse and there appears to be a substantial area for infill wells.

**Figure 63. Core area of the Austin Chalk Play showing well locations and degree of development as of mid-2017.**

Pre-2012 wells are black and post-2011 wells are gold in color.
Drilling in the Austin Chalk since 2011 has been focused on Karnes County, due to the high well productivities found there. There has been a large improvement in well productivity in Karnes County from 2012 through 2016 with advancing technology, however, average well productivity declined slightly in 2017. As noted earlier, this improvement is due to the vastly increased amounts of water and proppant used per well, and the increased length of horizontal laterals. Outside of Karnes County, average well productivity has declined since 2012, with average production in 2017 a fifth or less of the average well in Karnes County, as illustrated in Figure 64. This suggests that the economically viable extent of the Austin Chalk play that can be redeveloped with fracking is quite small compared to the earlier extent of the play.

Figure 64. Average horizontal well productivity over the first four months of oil production by county in the Austin Chalk Play, 2012–2017.
Figure 65 illustrates the EIA’s AEO2017 reference case production projection for the Austin Chalk Play through 2050, together with earlier projections. The EIA expects production to keep increasing to a peak in 2050, at 6.5 times current production levels and nearly triple the all-time peak rate of the play in 1991. This would require producing 2.97 billion barrels of oil in the 2014–2050 period, which is 2.3 times as much as the play has produced since the 1960s. The fact that the projection exits 2050 at levels of 6.5 times current production implies vast, as yet unknown, resources will be recovered after 2050. Given play fundamentals, which suggest the economically viable extent of the play is quite limited compared to historic production, the IEA’s forecast is rated as extremely optimistic.

Figure 65. EIA AEO2017 reference case Austin Chalk Play oil production estimate through 2050.
Also shown are earlier AEO estimates to 2040.
Table 13 illustrates assumptions in the EIA AEO2017 reference case projection.\textsuperscript{51} If realized, the EIA projection would have to recover 60% of the EIA’s estimate of proven reserves plus unproven resources, and would require 41,543 additional wells, for a total well count of 3.6 times the current 15,733, at an estimated cost of $249 billion.

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<thead>
<tr>
<th>EIA AE02017 Reference Case Projection</th>
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<td>Proven Reserves 2015 (Bbbls)</td>
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<tr>
<td>Unproven Resources 2015 (Bbbls)</td>
<td>4.7</td>
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<tr>
<td>Total Potential 2015 (Bbbls)</td>
<td>4.9</td>
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<tr>
<td>2015-2050 Recovery (Bbbls)</td>
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<td>% of total potential used 2015-2050</td>
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<td>Wells needed 2015-2050</td>
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</tr>
<tr>
<td>Well cost 2015-2050 ($billions)</td>
<td>$249</td>
</tr>
</tbody>
</table>

Table 13. EIA assumptions for Austin Chalk Play oil in the AE02017 reference case.
Well costs of $249 billion for full development are estimated assuming a well cost of $6 million each. Wells needed were determined using EIA drilling density and play area for unproven resources, and wells needed for proven reserves assuming EUR per well would be twice as high for proven reserves as unproven resources.

\textsuperscript{51} EIA, Unproved technically recoverable resources are from Assumptions to the Annual Energy Outlook 2017, https://www.eia.gov/outlooks/aeo/assumptions/; Proven reserves are from U.S. Crude Oil and Natural Gas Proved Reserves, Year-end 2015, https://www.eia.gov/naturalgas/crudeoilreserves/
Synopsis

The EIA’s reference case production estimate is extremely optimistic. Key points include:

- The Austin Chalk is an old play being re-developed with new technology. Although the play has been broadly tested with wells drilled since 2011, most post-2011 production has come from Karnes County. Considering post-2011 wells only, Karnes County accounted for 64% of cumulative production and 92% of mid-2017 production. This suggests that the most prospective part of the Austin Chalk for redevelopment is in a relatively small part of the play’s original extent. As of May 2017, 15,733 wells have been drilled, 449 of which were drilled since 2011.

- The prospective area with high productivity wells drilled since 2011 is about 3,800 square miles, located in Karnes and surrounding counties in the southern part of the original play extent. The EIA has estimated that an area of 11,447 square miles can be drilled at a well density of 6 wells per square mile, for a total of 68,682 wells, to recover 4.7 billion barrels of unproven resources.

- In its reference case, the EIA AEO2017 assumes that three billion barrels of oil will be recovered over the 2015-2050 period, which is 60% of its estimated proven reserves plus unproven resources. Recovering this much oil would require 41,543 wells (assuming EIA estimates of EUR for unproven resources are correct and that proven reserves would have EURs of twice that of unproven reserves). At $6 million per well this would cost $249 billion.

- Drilling 41,543 wells would raise the well density, including wells already drilled, to 5 wells per square mile (if the EIA’s 11,447 square mile drillable area is correct). If the prospective area defined by high productivity wells drilled since 2011 is correct (3,800 square miles), well density would need to be 15.1 wells per square mile. At six new wells per square mile, the prospective area could support only 22,800 wells, which would still be more than double the total number of wells in the play. Assuming the prospective play area of 3,800 square miles is correct, along with the EIA’s EUR assumption for unproven resources, the actual unproven resources are only one-third of those estimated by the EIA. This reduces the total potential of the play to 1.8 from 4.9 billion barrels, which means the EIA production projection would have to recover 66% more oil than actually exists.

- The EIA assumes that production will exit 2050 at 6.5 times the current rate, which implies that large additional, as-yet-unknown, resources will be recovered beyond 2050.

- Given the above considerations and play fundamentals, the AEO2017 projection for the Austin Chalk must be considered extremely optimistic.
2.5 **Niobrara Play**

The Niobrara is an old play that extends over several basins in Colorado, Wyoming and southwestern Nebraska. Niobrara production is found in the Piceance, Powder River, Green River and Park basins, although the Denver-Julesburg basin contributes by far the largest proportion of production. In addition to oil, the Niobrara has produced significant amounts of natural gas since the 1950s.

Figure 66 illustrates production in the 1990–2017 period. The advent of modern horizontal drilling and hydraulic fracturing has increased production dramatically since 2009, however the play peaked in March 2015. Production has since fallen by 25%. More than 34,700 wells have been drilled, of which 12,964 were still producing as of mid-2017.

![Graph showing oil production and number of producing wells by type, 1990–2017.](image)

*Figure 66. Niobrara Play oil production by well type and number of producing wells by type, 1990–2017.*
Figure 67 illustrates the distribution of Niobrara wells in the Denver-Julesburg basin. Post-2011 wells are highlighted by quality as defined by peak production month. Although some new drilling has covered counties in southern Wyoming and other basins, most has been focused on the Weld County core area (Wattenberg Field) in Colorado. Although Niobrara wells generally have lower productivity than plays like the Bakken or Eagle Ford, they are also lower in cost ($3.6 million for a 6,000 foot horizontal lateral), which has improved overall economics.

“Excluded” wells are on leases with multiple wells where the initial productivity (IP) of individual wells cannot be differentiated.

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53 EIA, March, 2016, play area outline from https://www.eia.gov/maps/map_data/TightOil_ShaleGas_Plays_Lower48_EIA.zip
Figure 68 illustrates cumulative recovery of oil and gas by county over the full life of the play. Eighty-one percent of cumulative production has come from Weld County and 95% from the top four counties, which include two counties in southern Wyoming. As can be seen, the Niobrara has also been a very significant natural gas producer, and has produced more gas than oil on an oil equivalent basis.

Figure 68. Cumulative production of oil and gas from the Niobrara Play by county. Eighty-one percent of total oil production has been recovered from Weld County and the top four counties have recovered 95%.
Production from new drilling has been concentrated even more in Weld County, which had 87% of production of post-2011 production. Ninety-nine percent of post-2011 production came from four top counties, including two counties in Wyoming. The second-tier counties have shifted somewhat in cumulative production between older and newer wells, as illustrated in Figure 69. Weld County has been the focus of most new drilling and high-quality drilling locations are running out.

Figure 69. Cumulative production of oil and gas from the Niobrara Play by county and well vintage.

Production from post-2011 wells has been concentrated in Weld County, with 87%. The top four counties accounted for 99% of post-2011 production.
Table 14 summarizes the number of wells drilled, cumulative and current production, and well- and field-decline rates for the Niobrara Play as a whole and for Weld and other counties. Three-year well decline rates average 91% and field decline averages 43% per year without new drilling. These are at the high end of decline rates observed for plays analyzed in this report.

<table>
<thead>
<tr>
<th>County</th>
<th>Well type</th>
<th>Vintage</th>
<th>Total Well Count</th>
<th>Producing Well Count</th>
<th>Cumulative Oil Production (billion bbls)</th>
<th>Cumulative Gas Production (tcf)</th>
<th>Oil Production May 2017 (Kbbls/day)</th>
<th>Gas Production May 2017 (bcf/day)</th>
<th>3-year well decline (%)</th>
<th>Field decline (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>All</td>
<td>All</td>
<td>All</td>
<td>34,707</td>
<td>12,964</td>
<td>0.647</td>
<td>5.427</td>
<td>193.5</td>
<td>1.207</td>
<td>91.4</td>
<td>43.4</td>
</tr>
<tr>
<td>All</td>
<td>All</td>
<td>Pre-2012</td>
<td>25,479</td>
<td>8,491</td>
<td>0.345</td>
<td>3.924</td>
<td>8.2</td>
<td>0.15</td>
<td>92.9</td>
<td>24.7</td>
</tr>
<tr>
<td>All</td>
<td>Horizontal</td>
<td>Post-2011</td>
<td>3,926</td>
<td>3,524</td>
<td>0.291</td>
<td>1.401</td>
<td>183.0</td>
<td>1.04</td>
<td>90.5</td>
<td>46.1</td>
</tr>
<tr>
<td>All</td>
<td>Vertical</td>
<td>Post-2011</td>
<td>2,128</td>
<td>949</td>
<td>0.015</td>
<td>0.102</td>
<td>2.3</td>
<td>0.02</td>
<td>86.6</td>
<td>26.9</td>
</tr>
<tr>
<td>Weld</td>
<td>Horizontal</td>
<td>Post-2011</td>
<td>3,424</td>
<td>3,083</td>
<td>0.251</td>
<td>1.244</td>
<td>156.1</td>
<td>0.97</td>
<td>90.28</td>
<td>45.8</td>
</tr>
<tr>
<td>Other counties</td>
<td>Horizontal</td>
<td>Post-2011</td>
<td>502</td>
<td>441</td>
<td>0.040</td>
<td>0.157</td>
<td>26.9</td>
<td>0.08</td>
<td>91.5</td>
<td>47.7</td>
</tr>
</tbody>
</table>

Table 14. Well count, cumulative production, most recent production, and well- and field-decline rates for the Niobrara Play and counties within it by well type and vintage.\(^{54}\)

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\(^{54}\) From Drillinginfo October, 2017. Note that total well count in line 1 includes 3,174 wells that have never had any production.
The degree of development of the Niobrara with old and new wells in the Weld County core area to date is illustrated in Figure 70. Some recent horizontal laterals exceed 10,000 feet in length all the average is considerably shorter. Most post-2011 well pads have multiple wells. New wells include limited infills and wells drilled along the periphery of the core area.

Figure 70. Niobrara Play showing well locations in Weld County core area of the Denver-Julesburg basin and the degree of development as of mid-2017.

Pre-2012 wells are black and post-2011 wells are gold in color. Upper: north portion; lower: south portion.
Well productivity from horizontal drilling in the Niobrara Play has declined overall since 2016 as illustrated in Figure 71. Although new technology in terms of increased amounts of water and proppant per well, and increased length of horizontal laterals, has certainly been applied, this has reached the point of diminishing returns, likely due to over-crowding of wells with resultant well interference. Wells outside of Weld County have exhibited improvement in productivity with better technology in 2017, however, and likely represent the main opportunity for maintaining or growing production and/or stemming declines from the Niobrara.

Figure 71. Average horizontal well productivity over the first four months of oil production by county in the Niobrara Play, 2012–2017.
Figure 72 illustrates the EIA’s AEO2017 reference case production projection for the Niobrara Play through 2050, together with earlier projections. The EIA expects production to increase to a peak in 2024, at 89% above current production levels, and then decline and exit 2050 at about half of current production levels. This would require producing 2.81 billion barrels of oil in the 2014–2050 period, which is 4.3 times as much as the play has produced since the 1950s. It also assumes that the play will produce 316% of the EIA’s estimate of proven reserves plus unproven resources. This, along with the fact that the core area is almost saturated with wells, means the EIA’s forecast must be rated as extremely optimistic.

Figure 72. EIA AEO2017 reference case Niobrara Play oil production estimate through 2050.

Also shown are earlier AEO estimates to 2040.
Table 15 illustrates assumptions in the EIA AEO2017 reference case projection. If realized, the EIA projection would have to recover 316% of the EIA’s estimate of proven reserves plus unproven resources, and would require 228,657 additional wells, for a total well count of 7.6 times the current 34,707, at an estimated cost of $823 billion.

<table>
<thead>
<tr>
<th>EIA AE02017 Reference Case Projection</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Proven Reserves 2015 (Bbbls)</td>
<td>0.5</td>
</tr>
<tr>
<td>Unproven Resources 2015 (Bbbls)</td>
<td>0.4</td>
</tr>
<tr>
<td>Total Potential 2015 (Bbbls)</td>
<td>0.9</td>
</tr>
<tr>
<td>2015-2050 Recovery (Bbbls)</td>
<td>2.7</td>
</tr>
<tr>
<td>% of total potential used 2015-2050</td>
<td>316.3%</td>
</tr>
<tr>
<td>Wells needed 2015-2050</td>
<td>228,657</td>
</tr>
<tr>
<td>Well cost 2015-2050 ($billions)</td>
<td>$823</td>
</tr>
</tbody>
</table>

Table 15. EIA assumptions for Niobrara Play oil in the AE02017 reference case.
Well costs of $823 billion for full development are estimated assuming a well cost of $3.6 million each. Wells needed were determined using EIA estimates of EUR assuming EUR would not be compromised by over-drilling, and wells needed for proven reserves would have an EUR twice as high as unproven resources.

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55 EIA, Unproved technically recoverable resources are from Assumptions to the Annual Energy Outlook 2017, https://www.eia.gov/outlooks/aeo/assumptions/; Proven reserves are from U.S. Crude Oil and Natural Gas Proved Reserves, Year-end 2015, https://www.eia.gov/naturalgas/crudeoilreserves/
Synopsis

The EIA’s reference case production estimate is extremely optimistic. Key points include:

- The Niobrara is an old play being re-developed with new technology. Although the play has been tested with wells drilled outside the core area since 2011, most post-2011 production has come from the Wattenberg Field in Weld County. Considering post-2011 wells only, Weld County accounted for 87% of cumulative production and 85% of mid-2017 production. Weld County has been extensively drilled and cannot accommodate the tens of thousands of additional wells needed to meet the EIA’s projection. As of May 2017, a total of 34,707 wells had been drilled in the play as a whole, of which 26,985 were in Weld County.

- The EIA has estimated that an area of 7,463 square miles can be drilled at a well density of 5 wells per square mile, for a total of 37,315 wells, to recover 0.4 billion barrels of unproven resources. If one assumes that 5 wells per square mile is the optimal well density, that proven reserves of 0.5 billion barrels will be recovered before unproven resources, and that proven reserves will have an EUR per well of twice that of the EIA’s estimate for unproven resources, proven reserves would require 17,828 wells over an area of 3,566 square miles. To recover the remaining 2.2 billion barrels in the EIA AEO2017 reference case projection by 2050 would require an additional 210,830 wells over an area of 42,166 square miles, assuming the EIA estimate of EUR per well for unproven resources is correct, for a total of 228,657 wells. This vastly exceeds the drillable area available and is therefore extremely unlikely.

- In assuming 2.7 billion barrels will be recovered from the Niobrara from 2015-2050, the EIA appears to have ignored its own estimates of 0.9 billion barrels of total potential.

- If the 228,657 wells required to fulfil the EIA reference case forecast of 2.7 billion barrels by 2050 were drilled, it would cost an estimated $823 billion, assuming an average well cost of $3.6 million.

- The EIA assumes that production will exit 2050 at half the current rate, which implies that significant additional, as-yet-unknown, resources will be recovered beyond 2050.

- Given the above considerations and play fundamentals, the AEO2017 projection for the Niobrara must be considered extremely optimistic.
3. Shale Gas Plays

Figure 73 illustrates shale gas production from major plays assessed in AEO2017, as well as “other” plays, as of November 2017. Production of shale gas is at an all-time high, although production from five legacy plays—including the Barnett, where shale gas was first successfully produced, and the Haynesville, which was once the largest shale gas play in the U.S.—peaked in August 2012 and has since fallen by 25%. The Marcellus and Utica plays of Pennsylvania, Ohio, and West Virginia, along with associated gas from the Permian Basin, have dominated production growth in recent years, and currently provide 60% of shale gas production.

Figure 73: U.S. shale gas production by play, 2008 through November 2017

Note the last two months are estimated.56

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Figure 74 illustrates the AEO2017 reference case for U.S. gas production by source with price projections. Shale gas production is expected to double and constitutes by far the largest source of supply overall, making up 68% of 2050 production. Production from other major sources, such as onshore and offshore conventional gas, with the exception of tight gas (the recovery of which is improved by fracking technology), is projected to decline. Overall U.S. production is projected to grow by 49% to an all-time high of 40.3 trillion cubic feet per year (tcf/year), or 110.3 billion cubic feet per day (bcf/day), in 2050. Exports via LNG to international markets and by pipeline to Canada and Mexico are projected to account for 14% of production in 2050. Prices are projected to remain below $6/MMBtu until 2032.

Figure 74. EIA AEO2017 reference case forecast of gas production by source, 2012–2050.

Also shown is projected price (Henry Hub in 2016 dollars per barrel).
The importance of shale gas in the EIA’s reference forecast is illustrated in Figure 75. Shale gas is projected to provide 64% of total natural gas production of 1,257 trillion cubic feet (tcf) over the 2015–2050 period. Production through 2050 is projected to be nearly quadruple proven U.S. natural reserves of 323 tcf at year-end 2015, and half of U.S. proven reserves plus unproven resources. The shale gas portion is forecast to recover 4.6 times proven U.S. shale gas reserves and 81% of proven reserves plus unproven resources. This is an extremely aggressive forecast and is based on some tenuous assumptions, as will be shown in the following play-by-play review of major shale gas plays.

Figure 75. EIA AEO2017 reference case forecast of cumulative natural gas production by source, 2015–2050.
The EIA’s reference case AEO2017 shale gas production forecast by play is illustrated in Figure 76. Production is projected to grow continuously, exiting 2050 at levels of nearly double current shale gas production, suggesting vast additional resources are available for recovery after 2050. The majority of production is forecast to be confined to relatively few plays, however, with two-thirds of the total 2014–2050 recovery of 819 tcf coming from three plays: the Marcellus, Utica, and Haynesville. The Marcellus alone is expected to account for 34% of production.

Figure 76. U.S. shale gas production by play in the EIA AEO2017 reference case projection compared to AEO2015 and AEO2016.
The changes in EIA AEO reference case production projections over the past four years are illustrated in Figure 77 compared to cumulative production to date.

**Figure 77.** Cumulative shale gas production projections by play for 2015–2050 in the AEO2017 reference case compared to AEO2014, AEO2015, AEO2016 and AEO2017.
3.1 **Barnett Play**

The Barnett Play was the first major shale gas play to be developed, and it was here that George Mitchell perfected fracking technology. Production began in the mid-1990s and grew to a peak in November 2011 as illustrated in Figure 78. Production has since fallen by 44%. More than 20,000 wells have been drilled, of which 15,000 are still producing. Drilling in the play has slowed to a near standstill, as the most productive parts of the play are saturated with wells.

![Figure 78. Barnett Play gas production and number of producing wells, 2000–2017. Production peaked in November 2011 and was down 44% as of September 2017.](image)

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Figure 79 illustrates the distribution of wells by quality as defined by peak production month (usually month 1). In common with all shale plays, the most productive and economic wells occupy a relatively small part of the total play area. In the case of the Barnett, the highest productivity wells occupy parts of Tarrant, Johnson, Denton, and Wise counties.

6.25

Figure 79. Barnett Play well locations showing peak gas production in the highest month.

The highest productivity wells are concentrated in parts of Tarrant, Johnson, Denton, and Wise counties.61

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61 Drillinginfo, December, 2017; EIA, March, 2016, play area outline from https://www.eia.gov/maps/map_data/TightOil_ShaleGas_Plays_Lower48_EIA.zip
Figure 80 illustrates cumulative recovery of oil and gas by county. One-third of cumulative gas production has come from Tarrant County and 84% has come from the top four counties. These “sweet spots” constitute a small part of the total play area assumed by the EIA in Figure 79.

**Figure 80.** Cumulative production of oil and gas from the Barnett Play by county.
Production is highly concentrated in sweet spot counties, with 84% of cumulative recovery in the top 4 counties.
Table 16 shows the number of wells drilled, cumulative and current production, and well- and field-decline rates for the Barnett as a whole and for individual counties. Three-year well decline rates average 72% and field decline rates average 16% per year without new drilling, which is at the low end for shale plays analyzed in this report.

<table>
<thead>
<tr>
<th>County</th>
<th>Well type</th>
<th>Vintage</th>
<th>Total Well Count</th>
<th>Producing Well Count</th>
<th>Cumulative Oil Production (billion bbls)</th>
<th>Cumulative Gas Production (tcf)</th>
<th>Oil Production August 2017 (Kbbls/day)</th>
<th>Gas Production August 2017 (bcf/day)</th>
<th>3-year well decline (%)</th>
<th>Field decline (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>All</td>
<td>All</td>
<td>All</td>
<td>20,218</td>
<td>15,011</td>
<td>0.072</td>
<td>20.649</td>
<td>5.1</td>
<td>3.34</td>
<td>71.9</td>
<td>16.0</td>
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<tr>
<td>Denton</td>
<td>All</td>
<td>All</td>
<td>3,225</td>
<td>2,705</td>
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<td>3.083</td>
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<td>0.49</td>
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<td>Johnson</td>
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<td>All</td>
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<td>Other counties</td>
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<td>5,338</td>
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<td>3.7</td>
<td>0.60</td>
<td>56.1</td>
<td>14.6</td>
</tr>
</tbody>
</table>

Table 16. Well count, cumulative production, most recent production, and well- and field-decline rates for the Barnett Play and counties within it by well type and vintage.62

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62 From Drillinginfo September, 2017
The degree of development of the Barnett core area to date is illustrated in Figure 81. Horizontal laterals are typically average 5,000 feet or more in length (although a few exceed 10,000 feet), and drilling has reached a density of eight wells per square mile in core areas, which is close to or at saturation. Additional drilling would increase the chances of “frac hits” and well interference.

Figure 81. Drilling density in the central core area of the Barnett Play as of September 2017.
Upper: overview of core area; lower: close-up view of Tarrant County.63

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63 From Drillinginfo December, 2017
Figure 82 illustrates production from the top four counties compared to the overall play. All counties have peaked beginning with Johnson in 2009 and ending with Wise in 2013, such that the play as a whole peaked in November 2011. The top four counties have made up 84% of cumulative production and made up 82% of September 2017, production.

Figure 82. Gas production in the Barnett Play by county showing peak dates and percentage decline from peak.
The improvement in well productivity over time in most plays is undeniable, and on average, the Barnett is no exception. Figure 83 illustrates the change in average well productivity in the Barnett Play over the past six years. The improvement in well productivity in the case of the Barnett, however, has been confined to one county: Denton. Other counties show a decline, meaning that improved technology has reached the point of diminishing returns, and in the case of Johnson and Tarrant counties there have been too few wells drilled in recent years to draw conclusions.

The Barnett is an example of a shale play that has seen its better days and new drilling will of necessity need to focus on lower productivity rock requiring higher prices to be economic, and higher drilling rates to stem overall field decline. It is the oldest shale play and a harbinger of what is to come for all shale plays.

Figure 83. Average well productivity over the first six months of gas production by county in the Barnett Play, 2012–2017.
Figure 84 illustrates the EIA’s AEO2017 reference case production projection for the Barnett Play through 2050, together with earlier projections. The EIA expects production to decline through 2030 and then grow to a secondary peak in 2047. This is considerably more realistic that the EIA’s 2014, 2015 and 2016 forecasts, but still strains credibility given the degree of well saturation in sweet spots, and that 50% more gas would have to be recovered by 2050 than has been recovered from the play so far. The fact that the production exits 2050 at 2.4 bcf/d, which is 71% of current levels, implies that there would still be considerable volumes of recoverable resources remaining at that time. A more likely scenario is that the play continues its long descent, stemmed perhaps if higher prices allow an increase in drilling. Given these fundamentals, the AEO2017 has to be rated as highly optimistic.

Figure 84. EIA AEO2017 reference case Barnett Play gas production estimate through 2050.

Also shown are earlier AEO estimates to 2040.
If realized, the EIA projection would have to recover 95% of the EIA’s estimate of proven reserves plus unproven resources, and would require 60,346 wells, nearly three times the current total, at a cost of $272 billion.

<table>
<thead>
<tr>
<th>EIA AE02017 Reference Case Projection</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Proven Reserves 2015 (tcf)</td>
<td>17.0</td>
</tr>
<tr>
<td>Unproven Resources 2015 (tcf)</td>
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</tr>
<tr>
<td>Total Potential 2015 (tcf)</td>
<td>29.9</td>
</tr>
<tr>
<td>2015-2050 Recovery (tcf)</td>
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<tr>
<td>% of total potential used 2015-2050</td>
<td>94.7%</td>
</tr>
<tr>
<td>Wells needed 2015-2050</td>
<td>60,346</td>
</tr>
<tr>
<td>Well cost 2015-2050 ($billions)</td>
<td>$272</td>
</tr>
</tbody>
</table>

Table 17. EIA assumptions for Barnett Play gas in the AE02017 reference case.

Well costs of $362 billion for full development are estimated assuming a well cost of $4.5 million each. Wells needed were determined using EIA estimates of EUR assuming EUR would not be compromised by over-drilling, and wells needed for proven reserves would have an EUR twice as high as unproven resources.

Synopsis

The EIA’s reference case production estimate is highly optimistic. Key points include:

- The EIA play area (26,311 square miles) overestimates the prospective drilled area (8,682 square miles) by 200%. Wells drilled outside of the prospective drilled area have very low levels of production and in some cases no production.

- Assuming 60,346 wells can be drilled to develop unproved resources plus proven reserves (per the EIA AE02017 assumptions and 2015 proven reserves), plus the 20,218 wells already drilled, would increase well density in the prospective play area to 9.3 per square mile. This is unlikely to be economic given that well density is already 8 wells per square mile in the highest quality parts of the play.

- The average well productivity of new drilling is declining in counties other than Denton, suggesting well interference and/or drilling outside of sweet spots, which constitute only a portion of the prospective drilled area. Well interference indicates that more wells are unlikely to increase ultimate recovery, although over-crowding wells will increase the short-term rate of resource extraction resulting in steeper long-term field declines, and increase overall cost.

- Given the depletion of drilling locations in sweet spots, the drilling rates that would be required to raise production after 2030 are highly unlikely without very high prices.

- Assuming that 95% of proven reserves and unproven resources will be recovered by 2050, and that the 2050 exit rate will be 71% of current production levels is highly optimistic. The Barnett play is mature and is likely in terminal decline.

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64 EIA, Unproved technically recoverable resources are from Assumptions to the Annual Energy Outlook 2017, https://www.eia.gov/outlooks/aeo/assumptions/; Proven reserves are from U.S. Crude Oil and Natural Gas Proved Reserves, Year-end 2015, https://www.eia.gov/naturalgas/crudeoilreserves/
3.2 Haynesville Play

The Haynesville Play in western Louisiana and eastern Texas grew from nothing in 2007 to the largest shale gas play in the U.S. when it peaked in November 2011, as illustrated in Figure 85. Production has since fallen by 44%, although has increased in recent months due to an uptick in drilling. Haynesville wells are much more productive than Barnett wells but are also twice as expensive, at $9 million each.65 More than 4,000 wells have been drilled, of which 3,746 are still producing. Drilling in the play has increased four-fold from a recent low in mid-2016.66

Figure 85. Haynesville Play gas production and number of producing wells, 2007–2017.

Production peaked in November 2011 and was down 44% as of September 2017.

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Figure 86 illustrates the distribution of wells by quality as defined by peak production month. In common with all shale plays, the most productive and economic wells occupy a relatively small part of the total play area. In the case of the Haynesville, the highest productivity wells occupy parts of De Soto, Red River, and Caddo counties, all of which are in Louisiana.

Figure 86. Haynesville Play well locations showing peak gas production in the highest month.
The highest productivity wells are concentrated in parts of De Soto, Caddo, and Red River counties of Louisiana.67

67 Drillinginfo, December, 2017; EIA, March, 2016, play area outline from https://www.eia.gov/maps/map_data/TightOil_ShaleGas_Plays_Lower48_EIA.zip
Figure 87 illustrates cumulative recovery of oil and gas by county. Forty percent of cumulative gas production has come from De Soto County and 77% has come from the top five counties. These “sweet spots” constitute a small part of the total play area assumed by the EIA in Figure 86.

Figure 87. Cumulative production of oil and gas from the Haynesville Play by county.

Production is highly concentrated in sweet spot counties, with 40% of cumulative gas recovery in De Soto County and 77% in the top 5 counties.
Table 18 shows the number of wells drilled, cumulative and current production, and well- and field-decline rates for the Haynesville as a whole and for individual counties. Three-year well decline rates average 89% and field decline rates average 36% per year without new drilling, which is at the high end for shale plays analyzed in this report.

<table>
<thead>
<tr>
<th>County</th>
<th>Well type</th>
<th>Vintage</th>
<th>Total Well Count</th>
<th>Producing Well Count</th>
<th>Cumulative Oil Production (billion bbls)</th>
<th>Cumulative Gas Production (tcf)</th>
<th>Oil Production August 2017 (Kbbls/day)</th>
<th>Gas Production August 2017 (bcf/day)</th>
<th>3-year well decline (%)</th>
<th>Field decline (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>All</td>
<td>All</td>
<td>All</td>
<td>4,098</td>
<td>3,746</td>
<td>0.002</td>
<td>14.179</td>
<td>0.5</td>
<td>4.24</td>
<td>89.0</td>
<td>35.7</td>
</tr>
<tr>
<td>Caddo</td>
<td>All</td>
<td>All</td>
<td>422</td>
<td>383</td>
<td>0.000</td>
<td>1.540</td>
<td>0.0</td>
<td>0.50</td>
<td>84.4</td>
<td>33.4</td>
</tr>
<tr>
<td>De Soto</td>
<td>All</td>
<td>All</td>
<td>1,505</td>
<td>1,396</td>
<td>0.000</td>
<td>5.681</td>
<td>0.0</td>
<td>1.72</td>
<td>91.2</td>
<td>41.9</td>
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<tr>
<td>Red River</td>
<td>All</td>
<td>All</td>
<td>469</td>
<td>427</td>
<td>0.000</td>
<td>2.051</td>
<td>0.0</td>
<td>0.72</td>
<td>88.3</td>
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<tr>
<td>Other counties</td>
<td>All</td>
<td>All</td>
<td>1,702</td>
<td>1,540</td>
<td>0.000</td>
<td>4.907</td>
<td>0.5</td>
<td>1.30</td>
<td>86.8</td>
<td>27.6</td>
</tr>
</tbody>
</table>

Table 18. Well count, cumulative production, most recent production, and well- and field-decline rates for the Haynesville Play and counties within it by well type and vintage.68

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68 From Drillinginfo September, 2017
The degree of development of the Haynesville core area to date is illustrated in Figure 88. Horizontal laterals in recent wells have exceeded 10,000 feet in length but the average is considerably less. Most well pads have multiple wells.

Figure 88. Drilling density in the central core area of the Haynesville Play as of September 2017.

Upper: overview of core area; lower: close-up view of De Soto County.69

69 From Drillinginfo December, 2017
Figure 89 illustrates production from the top three counties compared to the overall play. All counties have peaked, beginning with De Soto and Red River in 2011 and ending in 2012 with counties outside of the top three, such that the play as a whole peaked in November, 2011. The top three counties make up 64% of cumulative production and accounted for 69% of September 2017 production. Counties outside of the top three have declined 53% since peaking.

Figure 89. Gas production in the Haynesville Play by county showing peak dates and percentage decline from peak.
Figure 90 illustrates average well productivity over the first six months for the play as a whole and for individual counties. Although improved technology, along with focusing on sweet spots, has increased average well productivity markedly in the Haynesville since 2012, since 2016 productivity has declined on average, and for all counties except De Soto. Technology improvements include extending horizontal laterals up to 10,000 feet, and extreme frack jobs (“mega-fracks”) that have used up to 50 million pounds of proppant per well, or 5,000 pounds per foot. As noted earlier, better technology allows access to more reservoir rock per well, so the resource can be recovered with fewer wells at lower average cost. The drop in average well productivity suggests, however, that more aggressive technology has reached its limits.

Figure 90. Average well productivity over the first six months of gas production by county in the Haynesville Play, 2012–2017.
Figure 91 illustrates the EIA’s AE02017 reference case production projection for the Haynesville Play through 2050, together with earlier projections. The EIA expects production to rise to a new peak in 2040 of triple current production levels and exit 2050 at 2.5 times current levels. This is an extremely aggressive forecast that would require recovering eight times as much gas by 2050 as the play has recovered to date. It also requires producing more gas by 2050 than the EIA’s own estimates of proven reserves plus unproven resources. There is no doubt that the Haynesville contains considerable additional resources, and with higher drilling rates may exceed its 2011 production peak for short periods, but given the play fundamentals the AE02017 projection strains credibility to the limit and this forecast must be rated as extremely optimistic.
Table 19 illustrates assumptions in the EIA AEO2017 reference case projection. If realized, the EIA projection would have to recover 134% of the EIA’s estimate of proven reserves plus unproven resources by 2050, and would require 30,498 wells, more than seven times the current total, at a cost of $274 billion.

<table>
<thead>
<tr>
<th>EIA AE02017 Reference Case Projection</th>
<th></th>
</tr>
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<tbody>
<tr>
<td>Proven Reserves 2015 (tcf)</td>
<td>12.8</td>
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<tr>
<td>Unproven Resources 2015 (tcf)</td>
<td>76.8</td>
</tr>
<tr>
<td>Total Potential 2015 (tcf)</td>
<td>89.6</td>
</tr>
<tr>
<td>2015-2050 Recovery (tcf)</td>
<td>119.7</td>
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<tr>
<td>% of total potential used 2015-2050</td>
<td>133.5%</td>
</tr>
<tr>
<td>Wells needed 2015-2050</td>
<td>30,498</td>
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<tr>
<td>Well cost 2015-2050 ($billions)</td>
<td>$274</td>
</tr>
</tbody>
</table>

Table 19. EIA assumptions for Haynesville Play gas in the AE02017 reference case.

Well costs of $274 billion for full development are estimated assuming a well cost of $9 million each. Wells needed were determined using EIA estimates of EUR assuming EUR would not be compromised by over-drilling, and wells needed for proven reserves would have an EUR twice as high as unproven resources.

Synopsis

The EIA’s reference case production estimate is extremely optimistic. Key points include:

- The EIA play area (11,167 square miles) overestimates the prospective drilled area (6,571 square miles) by 70%. Wells drilled outside of the prospective drilled area have low levels of production and in some cases no production.

- The EIA assumes that 134% of its estimate of a total remaining potential of 89.6 tcf as of 2015 will be recovered by 2050. This corresponds to a play recovery of 129.8 tcf (including production prior to 2015), and a play EUR far higher given the 2050 exit rate. By contrast, the University of Texas Bureau of Economic Geology (BEG) predicted a play EUR of 56.9 tcf at $6/mcf and 72.3 tcf at $10/mcf. So even the EIA’s estimate of proven reserves plus unproven resources is overestimated compared to the BEG estimate at high prices, let alone the EIA assumption that 134% of it will be recovered by 2050.

- The EIA assumes that production will exit 2050 at levels of 2.5 times current rates, implying that there are vast additional remaining resources to be recovered beyond its overestimated assumption of recovery through 2050.

- Assuming 30,498 wells can be drilled to develop unproven resources plus proven reserves (per the EIA AE02017 assumptions and 2015 proven reserves), plus the 4,098 wells already drilled, would increase well density in the prospective play area to 5.3 per square mile, for an effective well density of over 10 per square mile, given that new wells with 10,000 foot laterals access two square miles each. This is unlikely to be economic, given the recent decline in well productivity already observed in most counties which suggests well interference is already occurring. It would represent far more wells than are needed to recover a resource which is likely far smaller than the EIA assumes to exist.

- Given the depletion of drilling locations in sweet spots, and the relatively high field decline, the drilling rates that would be required to raise production above the 2011 peak for long are unlikely without much higher prices.

- Given these fundamentals, the AE02017 projection for the Haynesville is, at best, extremely optimistic.

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71 EIA, Unproved technically recoverable resources are from Assumptions to the Annual Energy Outlook 2017, https://www.eia.gov/outlooks/aeo/assumptions/; Proven reserves are from U.S. Crude Oil and Natural Gas Proved Reserves, Year-end 2015, https://www.eia.gov/naturalgas/crudeoilreserves/
72 J. Browning et al, December, 2015, Study forecasts gradual Haynesville production recovery before final decline, Oil and Gas Journal
3.3 Marcellus Play

The Marcellus is a very large play that accounts for 38% of current U.S. shale gas production and is projected by the EIA to account for 34% of cumulative shale gas production through 2050. Most production is from Pennsylvania and West Virginia, but the play extends into eastern Ohio and southern New York State (where there is a moratorium on fracking). Production peaked in February 2017, as illustrated in Figure 92, but is likely to grow somewhat owing to the availability of new pipeline takeaway capacity. More than 11,600 wells have been drilled, of which 10,826 are still producing.

Figure 92. Marcellus Play production and number of producing gas wells, 2005–2017.73
Production peaked in February 2017 and was down slightly as of September 2017. West Virginia production and well count are estimated for 2017.

73 Drillinginfo, December, 2017.
Figure 93 illustrates the distribution of wells by quality as defined by peak production month. In common with all shale plays, the most productive and economic wells occupy a relatively small part of the total play area. In the case of the Marcellus, the highest productivity wells occupy a northeast sweet spot in Susquehanna and Bradford counties of Pennsylvania, and a southwest sweet spot in Washington and Greene counties of Pennsylvania as well as northern West Virginia.

The highest productivity wells are concentrated in Susquehanna and Bradford counties in the northeast, and Washington and Green counties, along with northern West Virginia, in the southwest.74

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74 Drillinginfo, December, 2017; EIA, March, 2016, play area outline from https://www.eia.gov/maps/map_data/TightOil_ShaleGas_Plays_Lower48_EIA.zip
Figure 94 illustrates cumulative recovery of oil and gas by county. Thirty-six percent of cumulative gas production has come from the top two counties and 65% has come from the top five. These “sweet spots” constitute a small part of the total play area assumed by the EIA in Figure 93.

**Figure 94. Cumulative production of oil and gas from the Marcellus Play by county.**

Production is concentrated in sweet spot counties, with 36% of cumulative gas recovery in Susquehanna and Bradford counties and 65% in the top 5 counties.
Table 20 shows the number of wells drilled, cumulative and current production, and well- and field-decline rates for the Marcellus as a whole and for individual counties. Three-year well decline rates average 72% and field decline rates average 20% per year without new drilling, which is at the low end for shale plays analyzed in this report.

Table 20. Well count, cumulative production, most recent production, and well- and field-decline rates for the Marcellus Play and counties within it by well type and vintage.75

<table>
<thead>
<tr>
<th>County/State</th>
<th>Well type</th>
<th>Vintage</th>
<th>Total Well Count</th>
<th>Producing Well Count</th>
<th>Cumulative Oil Production (billion bbls)</th>
<th>Cumulative Gas Production (tcf)</th>
<th>Oil Production August 2017 (Kbbls/day)</th>
<th>Gas Production August 2017 (bcf/day)</th>
<th>3-year well decline (%)</th>
<th>Field decline (%)</th>
</tr>
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<tbody>
<tr>
<td>All</td>
<td>All</td>
<td>All</td>
<td>11,651</td>
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<td>16.93</td>
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<td>All</td>
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<td>23.772</td>
<td>14.1</td>
<td>13.47</td>
<td>70.5</td>
<td>19.9</td>
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<td>All</td>
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<td>3,303</td>
<td>0.034</td>
<td>4.480</td>
<td>17.7</td>
<td>4.85</td>
<td>79.4</td>
<td>18.8</td>
</tr>
<tr>
<td>OH and NY</td>
<td>All</td>
<td>All</td>
<td>68</td>
<td>38</td>
<td>0.001</td>
<td>0.016</td>
<td>0.4</td>
<td>0.02</td>
<td>49.5</td>
<td>26.4</td>
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<td>Bradford</td>
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<td>All</td>
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<td>4.436</td>
<td>0.0</td>
<td>1.858</td>
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<tr>
<td>Lycoming</td>
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<td>All</td>
<td>768</td>
<td>749</td>
<td>0.000</td>
<td>2.400</td>
<td>0.0</td>
<td>0.89</td>
<td>71.4</td>
<td>45.1</td>
</tr>
<tr>
<td>Susquehanna</td>
<td>All</td>
<td>All</td>
<td>1,219</td>
<td>1,166</td>
<td>0.000</td>
<td>5.675</td>
<td>0.0</td>
<td>3.35</td>
<td>72.9</td>
<td>26.5</td>
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<tr>
<td>Washington</td>
<td>All</td>
<td>All</td>
<td>1,377</td>
<td>1,238</td>
<td>0.023</td>
<td>3.208</td>
<td>13.2</td>
<td>2.57</td>
<td>76.0</td>
<td>26.1</td>
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<td>Other counties</td>
<td>All</td>
<td>All</td>
<td>6,309</td>
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<td>0.035</td>
<td>9.969</td>
<td>18.9</td>
<td>6.76</td>
<td>73.5</td>
<td>16.9</td>
</tr>
</tbody>
</table>

75 From Drillinginfo December, 2017
The degree of development of the Marcellus northeast and southwest core areas to date is illustrated in Figures 95 and 96, respectively. Horizontal laterals in recent wells have been up to 15,000 feet in length although the average is considerably less. Most well pads have multiple wells.

Figure 95. Drilling density in the northeast core area of the Marcellus Play as of September 2017.

Upper: overview of core area in Bradford and Susquehanna counties; lower: close-up view of Susquehanna County near the town of Dimock.

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77 From Drillinginfo December, 2017
Figure 96. Drilling density in the southwest core area of the Marcellus Play in Washington County south of Pittsburgh as of September 2017.78
Upper: overview; lower: close-up.

78 From Drillinginfo December, 2017
Figure 97 illustrates production from the top five counties compared to the overall play. All counties have peaked, beginning with Bradford County in 2014 and ending with Washington County in 2017, such that the play as a whole peaked in February 2017. As noted earlier, production in the play is likely to grow somewhat overall with the recent completion of additional takeaway pipelines. The top five counties make up 65% of cumulative production and accounted for 65% of September 2017 production. Counties outside of the top five have declined 6.5% since peaking in February 2017.

Figure 97. Gas production in the Marcellus Play by county showing peak dates and percentage decline from peak.
Figure 98 illustrates average well productivity over the first four months for the play as a whole and for individual counties. Improved technology, along with focusing on sweet spots, has increased average well productivity markedly in the Marcellus since 2012. Technology improvements include extending horizontal laterals in recent wells up to 15,000 feet, along with significantly increasing volumes of water and proppant injection and the number of frack stages. As noted earlier, better technology allows access to more reservoir rock per well, so the resource can be recovered with fewer wells at a lower average cost. The increase in well productivity suggests there is still room for further technology improvement as well as room for more wells in sweet spots.

Figure 98. Average well productivity over the first six months of gas production by county in the Marcellus Play, 2012–2017.
Figure 99 illustrates the EIA’s AEO2017 reference case production projection for the Marcellus Play through 2050, together with earlier projections. The EIA expects production to keep rising through 2050 and exit 2050 at 41% above current production levels. Although the Marcellus is a very large play, this is an extremely aggressive forecast that would require recovering nine times as much gas by 2050 as the play has recovered to date. It also requires producing nearly all of the EIA’s own estimates of proven reserves plus unproven resources (unproven resources have not been demonstrated to be economic) and more than three times the U.S. Geological Survey (USGS) mean estimate of recoverable resources.79 There is no doubt that the Marcellus contains considerable additional gas, and higher drilling rates coupled with more aggressive technology will likely grow production somewhat in the short-term, but given the play fundamentals the AEO2017 projection must be rated as extremely optimistic.


Figure 99. EIA AEO2017 reference case Marcellus Play gas production estimate through 2050.
Also shown are earlier AEO estimates to 2040.
Table 21 illustrates assumptions in the EIA AEO2017 reference case projection. If realized, the EIA projection would recover 96% of the EIA’s estimate of proven reserves plus unproven resources by 2050, and would require 132,163 wells, more than eleven times the current total, at a cost of $793 billion.

<table>
<thead>
<tr>
<th>EIA AE02017 Reference Case Projection</th>
</tr>
</thead>
<tbody>
<tr>
<td>Proven Reserves 2015 (tcf)</td>
</tr>
<tr>
<td>Unproven Resources 2015 (tcf)</td>
</tr>
<tr>
<td>Total Potential 2015 (tcf)</td>
</tr>
<tr>
<td>2015-2050 Recovery (tcf)</td>
</tr>
<tr>
<td>% of total potential used 2015-2050</td>
</tr>
<tr>
<td>Wells needed 2015-2050</td>
</tr>
<tr>
<td>Well cost 2015-2050 ($billions)</td>
</tr>
</tbody>
</table>

Table 21. EIA assumptions for Marcellus Play gas in the AEO2017 reference case.
Well costs of $793 billion for full development are estimated assuming a well cost of $6 million each. Wells needed were determined using EIA estimates of EUR assuming EUR would not be compromised by over-drilling, and wells needed for proven reserves would have an EUR twice as high as unproven resources.

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80 EIA, Unproved technically recoverable resources are from Assumptions to the Annual Energy Outlook 2017, https://www.eia.gov/outlooks/aeo/assumptions/; Proven reserves are from U.S. Crude Oil and Natural Gas Proved Reserves, Year-end 2015, https://www.eia.gov/naturalgas/crudeoilreserves/
Synopsis

The EIA’s reference case production estimate is extremely optimistic. Key points include:

- The EIA play area (58,326 square miles) overestimates the prospective drilled area (41,531 square miles) by 40%. Wells drilled outside of the prospective drilled area have low levels of production and in some cases no production. The northeast and southwest sweet spot areas comprise less than 20% of the prospective drilled area.

- The EIA assumes that 96% of its estimate of a total remaining potential of 284 tcf as of 2015 will be recovered by 2050. This corresponds to a total play recovery of 286 tcf (including production prior to 2015) by 2050. This is more than triple the estimate of the USGS that predicted a mean recoverable resource of 84 tcf. The play EUR would be higher still, given that the EIA’s projection exits 2050 at all-time highs.

- The EIA assumes that production will exit 2050 at levels 41% above current rates, implying that there are vast additional resources remaining to be recovered over and above its estimate of proven reserves and unproven resources.

- Assuming 132,163 wells can be drilled to develop unproven resources plus proven reserves (per the EIA AEO2017 assumptions and 2015 proven reserves), plus the 11,651 wells already drilled, would increase average well density in the prospective drilled area to 3.6 per square mile, and considerably higher in sweet spot areas. Depending on lateral lengths, which have reached over 15,000 feet, effective well density would be over 7 per square mile (assuming an average lateral length of 10,000 feet), given that new wells would access two square miles each. This is likely far more wells than necessary to cost-effectively recover the resource.

- The Marcellus is a very large play and represents a huge resource, however drilling has focused on sweet spot areas which are becoming saturated with wells. In order to fully develop the play drilling rates will have to be considerably higher in later years owing to lower quality rock outside sweet spots, and prices will have to be correspondingly higher to maintain production and/or stem declines.

- The profile of the AEO2017 projection for the Marcellus, which assumes recovery of 96% of proven reserves and unproven resources, and assumes that after these resources are recovered production will still be 41% above current levels, is rated as extremely optimistic.

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3.4 UTICA PLAY

The Utica play has emerged since 2012 to become a second, potentially very large, addition to the Marcellus play in the eastern U.S. Most Utica production comes from Ohio, but the play underlies the Marcellus over parts of Pennsylvania, northern West Virginia and southern New York state. The Utica accounts for 10% of current U.S. shale gas production and is projected by the EIA to account for 18% of cumulative shale gas production in the 2014–2050 period. That means that together with the Marcellus, these two plays alone are projected to account for 52% of U.S. shale gas production through 2050. Production has grown rapidly, as illustrated in Figure 100, although the rate of growth has slowed in recent months. More than 2,200 wells have been drilled, of which 1,790 are still producing.

Figure 100. Utica Play gas production and number of producing wells, 2010–2017.83

83 Drillinginfo, December, 2017.
Figure 101 illustrates the distribution of wells by quality as defined by peak production month. In common with all shale plays, the most productive and economic wells occupy a relatively small part of the total play area. In the case of the Utica, the highest productivity wells occupy a sweet spot centered on Belmont County in Ohio, although some high productivity wells have been drilled in Bradford County in Pennsylvania and in other scattered locations in southwest Pennsylvania and northern West Virginia.

**Figure 101.** Utica Play well locations showing peak gas production in the highest month.

The highest productivity wells are concentrated in Belmont, Carroll, Monroe, and Harrison counties of Ohio.84

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84 Drillinginfo, December, 2017; EIA, March, 2016, play area outline from https://www.eia.gov/maps/map_data/TightOil_ShaleGas_Plays_Lower48_EIA.zip
Figure 102 illustrates cumulative recovery of oil and gas by county. Thirty-one percent of cumulative gas production has come from Belmont County, and 83% has come from the top five. These “sweet spots” constitute a small part of the total play area assumed by the EIA in Figure 101. Carroll, Harrison, and Guernsey counties have also produced significant amounts of associated liquids.

**Figure 102. Cumulative production of oil and gas from the Utica Play by county.**
Production is concentrated in sweet spot counties, with 31% of cumulative gas recovery in Belmont County and 83% in the top 5 counties.
Table 22 shows the number of wells drilled, cumulative and current production, and well- and field-decline rates for the Utica as a whole and for individual counties. Three-year well decline rates average 86% and field decline rates average 41% per year without new drilling, which is at the high end for shale plays analyzed in this report.

<table>
<thead>
<tr>
<th>County</th>
<th>Well type</th>
<th>Vintage</th>
<th>Total Well Count</th>
<th>Producing Well Count</th>
<th>Cumulative Oil Production (billion bbls)</th>
<th>Cumulative Gas Production (tcf)</th>
<th>Oil Production June 2017 (Kbbls/day)</th>
<th>Gas Production June 2017 (bcf/day)</th>
<th>3-year well decline (%)</th>
<th>Field decline (%)</th>
</tr>
</thead>
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<tr>
<td>All</td>
<td>All</td>
<td>All</td>
<td>2,248</td>
<td>1,790</td>
<td>0.065</td>
<td>3.956</td>
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<td>4.76</td>
<td>85.8</td>
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<tr>
<td>Belmont</td>
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<td>All</td>
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<td>299</td>
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<td>1.211</td>
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<td>1.98</td>
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<td>44.4</td>
</tr>
<tr>
<td>Carroll</td>
<td>All</td>
<td>All</td>
<td>463</td>
<td>435</td>
<td>0.017</td>
<td>0.699</td>
<td>8.7</td>
<td>0.39</td>
<td>70.9</td>
<td>35.3</td>
</tr>
<tr>
<td>Harrison</td>
<td>All</td>
<td>All</td>
<td>324</td>
<td>308</td>
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<td>19.5</td>
<td>1.13</td>
<td>85.3</td>
<td>40.1</td>
</tr>
</tbody>
</table>

Table 22. Well count, cumulative production, most recent production, and well- and field-decline rates for the Utica Play and counties within it by well type and vintage.\(^{85}\)

\(^{85}\) From Drillinginfo December, 2017
The degree of development of the Utica core area in Belmont County to date is illustrated in Figure 103. Horizontal laterals in some recent wells have been over 17,000 feet in length although the average is considerably shorter. Most well pads have multiple wells with up to ten wells per pad.

---

Figure 103. Drilling density in the Belmont County core area of the Utica Play as of September 2017.

---

87 From Drillinginfo December, 2017
Figure 104 illustrates production from the top four counties compared to the overall play. The top four counties account for 83% of cumulative production and 76% of September 2017 production. Two of the top four counties have already peaked—Carroll County in November 2015, and Harrison County in June 2016—and are down 41% and 26%, respectively.

**Figure 104. Gas production in the Utica Play by county showing peak dates and percentage decline from peak.**

© Hughes GSIR Inc, 2017

*(data from Drillinginfo, December 2017)*
Figure 105 illustrates average well productivity over the first six months for the play as a whole and for individual counties. Improved technology, along with focusing on sweet spots, has increased average well productivity markedly in the Utica since 2012. Technology improvements include extending horizontal laterals in recent wells to more than 18,000 feet, along with significantly increasing volumes of water and proppant injection and the number of frack stages. All counties, however, have seen a decline in average well productivity in 2017, suggesting technology has reached the point of diminishing returns. This is likely due to drilling lower quality rock outside of sweet spots and perhaps to spacing wells too close together, although the Utica has relatively few wells to date, compared to other plays that have demonstrated “frac hits”.

Figure 105. Average well productivity over the first six months of gas production by county in the Utica Play, 2012–2017.
Figure 106 illustrates the EIA’s AEO2017 reference case production projection for the Utica Play through 2050, together with earlier projections. The EIA expects production to keep rising through 2050 and exit 2050 at 3.6 times current production levels. Although the Utica is potentially a very large play, the prospective drilled area is far smaller than estimated by the EIA in Figure 101. This is an extremely aggressive forecast that would require recovering 37 times as much gas by 2050 as the play has recovered to date. It also requires producing four times the U.S. Geological Survey (USGS) mean estimate of recoverable resources.88 There is no doubt that the Utica contains considerable additional gas and that it is its early phase of development, but most production so far is confined to a relatively small core area in Ohio, and it remains to be seen how much of the play’s extent in Pennsylvania can be profitably developed. Production will certainly grow, but given the play fundamentals and uncertainties the AEO2017 projection must be rated as extremely optimistic.

Figure 106. EIA AEO2017 reference case Utica Play gas production estimate through 2050.

Also shown are earlier AEO estimates to 2040.

---

Table 23 illustrates assumptions in the EIA AEO2017 reference case projection. If realized, the EIA projection would recover 70% of the EIA’s estimate of proven reserves plus unproven resources by 2050, and would require 111,212 wells, more than forty-nine times the current total, at a cost of $667 billion.

<table>
<thead>
<tr>
<th>EIA AE02017 Reference Case Projection</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Proven Reserves 2015 (tcf)</td>
<td>12.4</td>
</tr>
<tr>
<td>Unproven Resources 2015 (tcf)</td>
<td>199.2</td>
</tr>
<tr>
<td>Total Potential 2015 (tcf)</td>
<td>211.6</td>
</tr>
<tr>
<td>2015-2050 Recovery (tcf)</td>
<td>147.7</td>
</tr>
<tr>
<td>% of total potential used 2015-2050</td>
<td>69.8%</td>
</tr>
<tr>
<td>Wells needed 2015-2050</td>
<td>111,212</td>
</tr>
<tr>
<td>Well cost 2015-2050 (billions)</td>
<td>$667</td>
</tr>
</tbody>
</table>

Table 23. EIA assumptions for Utica Play gas in the AE02017 reference case.

Well costs of $667 billion for full development are estimated assuming a well cost of $6 million each. Wells needed were determined using EIA estimates of EUR assuming EUR would not be compromised by over-drilling, and wells needed for proven reserves would have an EUR twice as high as unproven resources.

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89 EIA, Unproved technically recoverable resources are from Assumptions to the Annual Energy Outlook 2017, https://www.eia.gov/outlooks/aeo/assumptions/; Proven reserves are from U.S. Crude Oil and Natural Gas Proved Reserves, Year-end 2015, https://www.eia.gov/naturalgas/crudeoilreserves/
Synopsis

The EIA’s reference case production estimate is extremely optimistic. Key points include:

- The EIA play area (59,054 square miles) overestimates the prospective drilled area (14,123 square miles) by 300%. Wells drilled outside of the prospective drilled area have low levels of production and in some cases no production. The sweet spot areas in Ohio and northeast Pennsylvania comprise less than 20% of the prospective drilled area.

- The EIA assumes that 70% of its estimate of a total remaining potential of 212 tcf as of 2015 will be recovered by 2050. This corresponds to a total play recovery of 216 tcf (including production prior to 2015) by 2050. This is nearly six times the estimate of the USGS that predicted a mean recoverable resource of 37 tcf. The play EUR would be higher still, given that the EIA’s projection exits 2050 at all-time highs.

- The EIA assumes that production will exit 2050 at levels 3.6 times current rates, implying that there are vast additional resources remaining to be recovered over and above its estimate of proven reserves and unproven resources.

- Assuming 111,212 wells can be drilled to develop unproven resources plus proven reserves (per the EIA AEO2017 assumptions and 2015 proven reserves), plus the 2.248 wells already drilled, would increase average well density in the prospective drilled area to 8 per square mile, and considerably higher in sweet spot areas. Depending on lateral lengths, which have reached over 15,000 feet, effective well density would be 16 per square mile (assuming an average lateral length of 10,000 feet), given that new wells would access two square miles each. This is far more wells than necessary to cost-effectively recover the resource, which is likely only a fraction of that estimated by the EIA.

- Although the Utica is potentially a large play, two of the core area counties have already peaked, and average well productivity fell in all counties in 2017, indicating improved technology has reached its limits. The amount of the prospective drilled area that can be economically developed is uncertain, given that much of it has very few wells to date. Even if all the prospective drilled area can be profitably developed, the EUR of the play is likely far smaller than estimated by the EIA.

- The AEO2017 projection for the Utica, which assumes recovery of 70% of its estimate of proven reserves and unproven resources, and assumes that after these resources are recovered production will still be 3.6 times current levels, is rated as extremely optimistic.

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3.5 **Fayetteville Play**

The Fayetteville is a relatively small play located in north-central Arkansas. Production peaked in November 2012 and is down 44% from peak. The limits of the play have been well defined by extensive drilling and production is highly concentrated in a few counties. The Fayetteville accounts for 3.3% of current U.S. shale gas production and is projected by the EIA to account for 4.3% of cumulative shale gas production in the 2014–2050 period. More than 5,900 wells have been drilled, of which 5,354 are still producing. Rig count has dropped to zero in recent months and without more drilling the Fayetteville is in terminal decline.

![Figure 107. Fayetteville Play gas production and number of producing wells, 2005–2017](image)

*Figure 107. Fayetteville Play gas production and number of producing wells, 2005–2017.*

---

92 Drillinginfo, December, 2017.
Figure 108 illustrates the distribution of wells by quality as defined by peak production month. In common with all shale plays, the most productive and economic wells occupy a relatively small part of the total play area. In the case of the Fayetteville, the highest productivity wells occupy four counties in the eastern part of the EIA play area.

Figure 108. Fayetteville Play well locations showing peak gas production in the highest month.93

93 Drillinginfo, December, 2017; EIA, March, 2016, play area outline from https://www.eia.gov/maps/map_data/TightOil_ShaleGas_Plays_Lower48_EIA.zip
Figure 109 illustrates cumulative recovery of oil and gas by county. Thirty percent of cumulative gas production has come from Van Buren County, and 92% has come from the top four. These “sweet spots” constitute a small part of the total play area assumed by the EIA in Figure 108. The Fayetteville produces exclusively gas with no associated liquids.

**Figure 109. Cumulative production of oil and gas from the Fayetteville Play by county.**

Production is concentrated in sweet spot counties, with 31% of cumulative gas recovery in Belmont County and 83% in the top 5 counties.
Table 24 shows the number of wells drilled, cumulative and current production, and well- and field-decline rates for the Fayetteville as a whole and for individual counties. Three-year well decline rates average 79% and field decline rates average 25% per year without new drilling, which is in the medium range for shale plays analyzed in this report.

<table>
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<tr>
<th>County</th>
<th>Well type</th>
<th>Vintage</th>
<th>Total Well Count</th>
<th>Producing Well Count</th>
<th>Cumulative Oil Production (billion bbls)</th>
<th>Cumulative Gas Production (tcf)</th>
<th>Oil Production August 2017 (Kbbls/day)</th>
<th>Gas Production August 2017 (bcf/day)</th>
<th>3-year well decline (%)</th>
<th>Field decline (%)</th>
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<td>All</td>
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<td>1.63</td>
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<td>All</td>
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<td>0.36</td>
<td>78.7</td>
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<tr>
<td>Other counties</td>
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<td>514</td>
<td>0.000</td>
<td>0.657</td>
<td>0.0</td>
<td>0.16</td>
<td>80.5</td>
<td>31.0</td>
</tr>
</tbody>
</table>

Table 24. Well count, cumulative production, most recent production, and well- and field-decline rates for the Fayetteville Play and counties within it by well type and vintage.94

---

94 From Drillinginfo December, 2017
The degree of development of the Fayetteville core area to date is illustrated in Figure 110. Horizontal laterals average just over 5,000 feet in length. Most well pads have multiple wells.

Figure 110. Drilling density in the core area of the Fayetteville Play as of September 2017.

---

96 From Drillinginfo December, 2017
Figure 111 illustrates production from the top four counties compared to the overall play. All counties have peaked, beginning with White County in 2012 and ending with Cleburne County in 2014, such that the play as a whole peaked in November, 2012. The top four counties make up 92% of cumulative production and accounted for 76% of September 2017 production.

Figure 111. Gas production in the Fayetteville Play by county showing peak dates and percentage decline from peak.
Figure 112 illustrates average well productivity over the first six months for the play as a whole and for individual counties. Improved technology, along with focusing on sweet spots, has increased average well productivity in the Fayetteville since 2012. Although well productivity has increased in most counties since 2015, there has been so little drilling in Van Buren, Conway and White counties that it is not possible to determine the trend there for 2017. This lack of drilling, even considering the relatively low well costs, suggests the Fayetteville is getting close to the saturation point in terms of wells and resultant economics, and needs higher gas prices to make additional wells economic.

![Figure 112. Average well productivity over the first six months of gas production by county in the Fayetteville Play, 2012–2017.](image)

(data from Drillinginfo, December, 2017)
Figure 113 illustrates the EIA’s AEO2017 reference case production projection for the Fayetteville Play through 2050, together with earlier projections. The EIA expects the current decline to reverse and production to keep rising and exit 2050 at 87% above current production levels. Although higher prices and resultant higher drilling rates could temporarily reverse the current production decline, the EIA’s projection is highly unlikely given the size of the play, the current level of well saturation, and the fact that the prospective drilled area is far smaller than estimated by the EIA in Figure 108. The EIA projection would also require producing twice as much gas as the Bureau of Economic Geology’s base case play EUR.\(^{97}\) Given the play fundamentals the AEO2017 projection must be rated as extremely optimistic.

\(^{97}\) J. Browning et al., 2014, *Study develops Fayetteville shale reserves, production forecast*, Oil and Gas Journal, http://www.beg.utexas.edu/files/content/beg/research/shale/Fayetteville%20Shale%20OGJ%20article.pdf
EIA AEO2017 Reference Case Projection

<table>
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<th>2015 (tcf)</th>
<th>2015-2050 Recovery (tcf)</th>
<th>% of total potential used 2015-2050</th>
<th>Wells needed 2015-2050</th>
<th>Well cost 2015-2050 ($billions)</th>
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<td>Total Potential 2015</td>
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<td>2015-2050 Recovery</td>
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<tr>
<td>% of total potential used</td>
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</tr>
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<td>Wells needed 2015-2050</td>
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<tr>
<td>Well cost 2015-2050 ($billions)</td>
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<td></td>
<td></td>
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<td></td>
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</table>

Table 25. EIA assumptions for Fayetteville Play gas in the AEO2017 reference case.

Well costs of $54 billion for full development are estimated assuming a well cost of $3 million each. Wells needed were determined using EIA estimates of EUR assuming EUR would not be compromised by over-drilling, and wells needed for proven reserves would have an EUR twice as high as unproven resources.

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98 EIA, Unproved technically recoverable resources are from Assumptions to the Annual Energy Outlook 2017, https://www.eia.gov/outlooks/aeo/assumptions/; Proven reserves are from U.S. Crude Oil and Natural Gas Proved Reserves, Year-end 2015, https://www.eia.gov/naturalgas/crudeoilreserves/
Synopsis

The EIA’s reference case production estimate is extremely optimistic. Key points include:

- The EIA play area (5,852 square miles) overestimates the prospective drilled area (2,280 square miles) by 157%. Wells drilled outside of the prospective drilled area have low levels of production and in some cases no production.

- The EIA assumes that 74% of its estimate of a total remaining potential of 43 tcf as of 2015 will be recovered by 2050. This corresponds to a play recovery of 39.5 tcf (including production prior to 2015) by 2050. This is more than double the base case play EUR estimate of the Bureau of Economic Geology of 18.2 tcf. The EIA play EUR would be higher still given that its projection exits 2050 at levels 87% above current production.

- The EIA assumes that the current production decline will reverse and production will grow through 2050 to above peak levels, implying that there are large additional resources remaining to be recovered over and above its estimate of proven reserves and unproven resources.

- Assuming 17,786 wells can be drilled to develop unproven resources plus proven reserves (per the EIA AEO2017 assumptions and 2015 proven reserves), plus the 5,903 wells already drilled, would increase average well density in the prospective drilled area to 10.4 per square mile. This is far more wells than necessary to cost-effectively recover the resource, which is likely much smaller than that estimated by the EIA.

- The Fayetteville is a relatively small play that has been extensively drilled. All counties are past peak and Van Buren County, which has the highest cumulative gas recovery, is down 56% from its December 2012 peak. Assuming that there will be a reversal of this trend and production from the play will grow through 2050 is extremely optimistic. With considerably higher prices and higher drilling rates the production decline could be temporarily reversed, but the EIA scenario is highly unlikely.

- The EIA AEO2017 projection for the Fayetteville, which assumes recovery of 74% of its estimate of proven reserves and unproven resources, and assumes that after these resources are recovered production will still be at high levels, is rated as extremely optimistic.

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99 J. Browning et al., 2014, Study develops Fayetteville shale reserves, production forecast, Oil and Gas Journal, http://www.beg.utexas.edu/files/content/beg/research/shale/Fayetteville%20Shale%20OGJ%20article.pdf
3.6 **Woodford Play**

The Woodford Play includes parts of the Anadarko, Ardmore, and Arkoma basins of Oklahoma, as well as some production on the intervening Chautauqua Platform. The play has emerged since 2005 to become a major shale gas producer along with considerable amounts of associated liquids. The Woodford accounts for 5% of current U.S. shale gas production and is projected by the EIA to account for 3.7% of cumulative shale gas production in the 2014–2050 period. Production has grown rapidly, as illustrated in Figure 114, but peaked in January, 2016. More than 5,000 wells have been drilled, of which 3,976 are still producing.

![Figure 114. Woodford Play gas production and number of producing wells, 2005–2017.](image)

© Hughes GSR Inc. 2017  
(date from Drillinginfo, December 2017)

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100 Drillinginfo, December, 2017.
Figure 115 illustrates the distribution of wells by quality as defined by peak production month. In common with all shale plays, the most productive and economic wells occupy a relatively small part of the total play area. In the case of the Woodford, the highest productivity wells occupy four sweets spots: two in the Anadarko basin, one in the north part of the Ardmore Basin and one in the south-central Arkoma Basin.

Shaded EIA play areas include the Anadarko Basin on the northwest, the Ardmore Basin on the south, and the east-central Arkoma Basin.

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101 Drillinginfo, December, 2017; EIA, March, 2016, play area outline from https://www.eia.gov/maps/map_data/TightOil_ShaleGas_Plays_Lower48_EIA.zip
Figure 116 illustrates cumulative recovery of oil and gas by county. Thirty-nine percent of cumulative gas production has come from Pittsburg and Canadian counties, and 73% has come from the top five.

Figure 116. Cumulative production of oil and gas from the Woodford Play by county.
Production is concentrated in sweet spot counties, with 31% of cumulative gas recovery in Belmont County and 83% in the top 5 counties.
Table 26 shows the number of wells drilled, cumulative and current production, and well- and field-decline rates for the Woodford as a whole and for individual counties. Three-year well decline rates average 76% and field decline rates average 23% per year without new drilling, which is at the low end for shale plays analyzed in this report.

<table>
<thead>
<tr>
<th>County</th>
<th>Well type</th>
<th>Vintage</th>
<th>Total Well Count</th>
<th>Producing Well Count</th>
<th>Cumulative Oil Production (billion bbls)</th>
<th>Cumulative Gas Production (tcf)</th>
<th>Oil Production August 2017 (Kbbls/day)</th>
<th>Gas Production August 2017 (bcf/day)</th>
<th>3-year well decline (%)</th>
<th>Field decline (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>All</td>
<td>All</td>
<td>All</td>
<td>5,025</td>
<td>3,976</td>
<td>0.138</td>
<td>6.154</td>
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<td>2.07</td>
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<tr>
<td>Pittsburg</td>
<td>All</td>
<td>All</td>
<td>650</td>
<td>573</td>
<td>0.000</td>
<td>1.237</td>
<td>0.0</td>
<td>0.31</td>
<td>79.1</td>
<td>23.5</td>
</tr>
<tr>
<td>Canadian</td>
<td>All</td>
<td>All</td>
<td>762</td>
<td>677</td>
<td>0.035</td>
<td>1.155</td>
<td>20.0</td>
<td>0.44</td>
<td>73.0</td>
<td>28.3</td>
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<td>All</td>
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<td>0.21</td>
<td>81.6</td>
<td>16.1</td>
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<td>Hughes</td>
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<td>All</td>
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<td>493</td>
<td>0.000</td>
<td>0.711</td>
<td>0.1</td>
<td>0.20</td>
<td>82.0</td>
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<tr>
<td>Other counties</td>
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<td>All</td>
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<td>1,764</td>
<td>0.102</td>
<td>2.162</td>
<td>46.8</td>
<td>0.91</td>
<td>78.1</td>
<td>19.9</td>
</tr>
</tbody>
</table>

Table 26. Well count, cumulative production, most recent production, and well- and field-decline rates for the Woodford Play and counties within it by well type and vintage.102

102 From Drillinginfo December, 2017
The degree of development in the Anadarko Basin core area of the Woodford to date is illustrated in Figure 117. Recent horizontal laterals extend to over 10,000 feet in length although the average is 5000-7000 feet. Most well pads have multiple wells.

Figure 117. Drilling density in the core area of the Woodford Play as of September 2017.\textsuperscript{103}

\textsuperscript{103} From Drillinginfo December, 2017
Figure 118 illustrates production from the top four counties compared to the overall play. All counties have peaked, beginning with Canadian County in May, 2016, and ending with counties outside of the top four in February 2017, such that the play as a whole peaked in January 2017. The top four counties make up 73% of cumulative production and accounted for 56% of September 2017 production.

Figure 118. Gas production in the Woodford Play by county showing peak dates and percentage decline from peak.
Figure 119 illustrates average well productivity over the first six months for the play as a whole and for individual counties. Improved technology, along with focusing on sweet spots, has increased average well productivity markedly in the Woodford since 2012. Technology improvements include extending horizontal laterals in recent wells to more than 10,000 feet, along with significantly increasing volumes of water and proppant injection and the number of frac stages. With the exception of Pittsburg and Hughes counties, however, other counties and the play as a whole experienced a decline in average well productivity in 2017, suggesting technology has reached the point of diminishing returns. This is due to drilling lower quality rock outside of sweet spots and perhaps to spacing wells too close together, resulting in “frac hits” and well interference.

Figure 119. Average well productivity over the first six months of gas production by county in the Woodford Play, 2012–2017.

Too few wells were drilled in Pittsburg County to determine a meaningful average in 2017.
Figure 120 illustrates the EIA’s AEO2017 reference case production projection for the Woodford Play through 2050, together with earlier projections. The EIA expects production to keep rising through 2050 and exit 2050 at 27% above current production levels. This is an aggressive forecast, but may be possible with high enough prices to justify the drilling rates required. However, given that the play as a whole and four core counties have peaked, along with the decline in average well productivity observed in recent wells, the EIA AEO2017 projection must be rated as highly optimistic.

Figure 120. EIA AEO2017 reference case Woodford Play gas production estimate through 2050.
Also shown are earlier AEO estimates to 2040.
Table 27 illustrates assumptions in the EIA AEO2017 reference case projection.\textsuperscript{104} If realized, the EIA projection would recover 80% of the EIA’s estimate of proven reserves plus unproven resources by 2050, and would require 17,914 wells, more than triple the current total, at a cost of $107 billion.

<table>
<thead>
<tr>
<th>EIA AEO2017 Reference Case Projection</th>
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<td>Proven Reserves 2015 (tcf)</td>
<td>18.6</td>
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<tr>
<td>Unproven Resources 2015 (tcf)</td>
<td>17.8</td>
</tr>
<tr>
<td>Total Potential 2015 (tcf)</td>
<td>36.4</td>
</tr>
<tr>
<td>2015-2050 Recovery (tcf)</td>
<td>29.2</td>
</tr>
<tr>
<td>% of total potential used 2015-2050</td>
<td>80.3%</td>
</tr>
<tr>
<td>Wells needed 2015-2050</td>
<td>17,914</td>
</tr>
<tr>
<td>Well cost 2015-2050 ($billions)</td>
<td>$107</td>
</tr>
</tbody>
</table>

Table 27. EIA assumptions for Woodford Play gas in the AEO2017 reference case.

Well costs of $107 billion for full development are estimated assuming a well cost of $6 million each. Wells needed were determined using EIA estimates of EUR assuming EUR would not be compromised by over-drilling, and wells needed for proven reserves would have an EUR twice as high as unproven resources.

Synopsis

The EIA’s reference case production estimate is highly optimistic. Key points include:

- The EIA play area (7445 square miles) underestimates the prospective drilled area (8,059 square miles) slightly. In addition, there are lower productivity producing wells outside of the Anadarko, Armena, and Arkoma basins as defined by the EIA (Figure 115). High productivity sweet spots occupy less than 20% of the prospective drilled area.

- The EIA assumes that 80% of its estimate of a total remaining potential of 36 tcf as of 2015 will be recovered by 2050. This corresponds to a play recovery of 33 tcf (including production prior to 2015) by 2050.

- The play peaked in January 2016, and was down 24% as of August 2017. The top two counties, which have accounted for 39% of cumulative production, have also peaked. Canadian County peaked in January, 2016, and Pittsburg County peaked in May, 2016, and are down 34% and 27%, respectively.

- The EIA assumes that production will exit 2050 at levels 27% above current rates, implying that there are large additional resources remaining to be recovered over and above its estimate of proven reserves and unproven resources.

- Assuming 17,914 wells can be drilled to develop unproven resources plus proven reserves (per the EIA AEO2017 assumptions and 2015 proven reserves), plus the 5,025 wells already drilled, would increase average well density in the prospective drilled area to 2.8 per square mile. This is not unreasonable and likely necessary to recover the resource.

- The Woodford is a moderately sized play that is now constrained by considerable amounts of drilling. Two of the core area counties have peaked, and average well productivity fell in 2017, indicating improved technology has reached its limits.

- The AEO2017 projection for the Woodford, which assumes recovery of 80% of its estimate of proven reserves and unproven resources, and assumes that after these resources are recovered production will still be 27% above current levels, is rated as highly optimistic.

\textsuperscript{104} EIA, Unproved technically recoverable resources are from Assumptions to the Annual Energy Outlook 2017, https://www.eia.gov/outlooks/aeo/assumptions/; Proven reserves are from U.S. Crude Oil and Natural Gas Proved Reserves, Year-end 2015, https://www.eia.gov/naturalgas/crudeoilreserves/
4. Play Comparisons

Table 28 summarizes the assumptions of the EIA for its AEO2017 projections by play and the optimism bias for each play based on the foregoing analysis. When the projections are reviewed on a play-by-play basis, the conclusion is that the overall projection for both tight oil and shale gas has a high to extreme optimism bias. Although proven reserves have been demonstrated to be technologically and economically recoverable, unproven resources are much less certain: they are thought to be technically recoverable but have not been demonstrated to be economically viable. This is because unproven resources are often extrapolated over broad areas without sufficient drilling control to prove economic viability. Certainly, some of these unproven resources will be converted to proven reserves with more drilling, but many of the EIA play forecasts count on recovering all proven reserves and a high percentage of unproven resources—in some cases over 100%—by 2050. Overall, the EIA’s AEO2017 projections assume the recovery of 100% of proven reserves, 73% of unproven tight oil resources and 60% of unproven shale gas resources by 2050. Furthermore, most of these play-level projections assume that production will exit 2050 at high levels compared to current rates, implying that there are vast additional resources to be recovered beyond 2050.

<table>
<thead>
<tr>
<th>Play</th>
<th>Proven Reserves</th>
<th>Unproven Resources</th>
<th>Total Potential</th>
<th>2015-2050 Recovery</th>
<th>% of total unproven resources recovered</th>
<th>Optimism Bias</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Bbbls oil</td>
<td>Tcf gas</td>
<td>Bbbls oil</td>
<td>Tcf gas</td>
<td>Bbbls oil</td>
<td>Tcf gas</td>
</tr>
<tr>
<td>Bakken</td>
<td>5.0</td>
<td>2.9</td>
<td>23.5</td>
<td>18.3</td>
<td>28.5</td>
<td>21.2</td>
</tr>
<tr>
<td>Eagle Ford</td>
<td>4.3</td>
<td>19.6</td>
<td>15.5</td>
<td>52.2</td>
<td>19.8</td>
<td>71.8</td>
</tr>
<tr>
<td>Permian: Spraberry</td>
<td>0.5</td>
<td>2.8</td>
<td>10.6</td>
<td>17.7</td>
<td>11.1</td>
<td>20.5</td>
</tr>
<tr>
<td>Permian: Wolfcamp</td>
<td>0.7</td>
<td>4.0</td>
<td>11.1</td>
<td>25.7</td>
<td>11.8</td>
<td>29.7</td>
</tr>
<tr>
<td>Permian: Bone Spring</td>
<td>0.1</td>
<td>0.9</td>
<td>2.0</td>
<td>5.6</td>
<td>2.1</td>
<td>6.5</td>
</tr>
<tr>
<td>Austin Chalk</td>
<td>0.2</td>
<td>2.8</td>
<td>4.7</td>
<td>17.9</td>
<td>4.9</td>
<td>20.7</td>
</tr>
<tr>
<td>Niobrara</td>
<td>0.5</td>
<td>0.4</td>
<td>0.4</td>
<td>2.7</td>
<td>0.9</td>
<td>3.1</td>
</tr>
<tr>
<td>Barnett</td>
<td>0.0</td>
<td>17.0</td>
<td>0.2</td>
<td>12.9</td>
<td>0.2</td>
<td>29.9</td>
</tr>
<tr>
<td>Haynesville</td>
<td>0.0</td>
<td>12.8</td>
<td>0.0</td>
<td>76.8</td>
<td>0.0</td>
<td>89.6</td>
</tr>
<tr>
<td>Marcellus</td>
<td>0.1</td>
<td>72.7</td>
<td>0.7</td>
<td>211.3</td>
<td>0.8</td>
<td>284.0</td>
</tr>
<tr>
<td>Utica</td>
<td>0.1</td>
<td>12.4</td>
<td>2.2</td>
<td>199.2</td>
<td>2.3</td>
<td>211.6</td>
</tr>
<tr>
<td>Fayetteville</td>
<td>0.0</td>
<td>7.1</td>
<td>0.0</td>
<td>35.9</td>
<td>0.0</td>
<td>43.0</td>
</tr>
<tr>
<td>Woodford</td>
<td>0.0</td>
<td>18.6</td>
<td>1.0</td>
<td>17.8</td>
<td>1.0</td>
<td>36.4</td>
</tr>
<tr>
<td>Antrim</td>
<td>0.0</td>
<td>1.9</td>
<td>0.0</td>
<td>12.3</td>
<td>0.0</td>
<td>14.2</td>
</tr>
<tr>
<td>Other</td>
<td>0.0</td>
<td>0.0</td>
<td>18.4</td>
<td>346.6</td>
<td>18.4</td>
<td>346.6</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>11.6</strong></td>
<td><strong>175.9</strong></td>
<td><strong>90.3</strong></td>
<td><strong>1052.9</strong></td>
<td><strong>101.9</strong></td>
<td><strong>1228.8</strong></td>
</tr>
</tbody>
</table>

Table 28. EIA AEO2017 reference case assumptions for all plays of proven reserves, unproven resources, total potential and the amount of cumulative oil and gas production, 2015–2050.\(^\text{105}\)

Also shown is the percentage of unproven resources assumed by the EIA to be recovered in its reference case, and an optimism bias rating based on the analysis of each play in this report. The percentage of unproven resources recovered assumes that 100% of proven reserves will be recovered before unproven resources are used. The overall optimism bias for AEO2017 is rated as high to extreme. “na” refers to estimates that are not provided by the EIA.

\(^\text{105}\) EIA. Unproved technically recoverable resources are from Assumptions to the Annual Energy Outlook 2017, https://www.eia.gov/outlooks/aeo/assumptions/; Proven reserves are from U.S. Crude Oil and Natural Gas Proved Reserves, Year-end 2015, https://www.eia.gov/naturalgas/crudeoilreserves/
Table 29 illustrates the number of wells and well costs to realize the AEO2017 forecasts by play based on the EIA’s assumptions of well EURs for unproven resources (and assuming wells to develop remaining proven reserves would have double the EUR of unproven resources). Including just the major plays analyzed in this report, which would meet 88% of the overall AEO2017 forecast for tight oil and shale gas, over one million wells would be required at a cost of $5.7 trillion. To meet the other 12% from plays not analyzed herein—“other” and “Antrim”—would require an additional 680,000 wells at a cost of $4 trillion. In practice, as outlined in the analysis of individual plays, drilling this many wells would represent more than what is needed to cost-effectively recover the resource which is likely considerably smaller than assumed by the EIA. By comparison, the EIA assumes that 1.29 million wells are needed to meet its reference case AEO2017 oil and gas projection (unconventional, conventional and offshore) which, at $6 million per well, represents an expenditure of $7.7 trillion by 2050.106

<table>
<thead>
<tr>
<th>Play</th>
<th>Total # of wells</th>
<th>Well cost (million)</th>
<th>Total cost 2015-2050 (million)</th>
<th>% of cost of plays analyzed</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bakken</td>
<td>120,258</td>
<td>$6</td>
<td>$721,546</td>
<td>12.6%</td>
</tr>
<tr>
<td>Eagle Ford</td>
<td>63,461</td>
<td>$6</td>
<td>$380,765</td>
<td>6.6%</td>
</tr>
<tr>
<td>Permian - Spraberry</td>
<td>130,830</td>
<td>$6</td>
<td>$784,978</td>
<td>13.7%</td>
</tr>
<tr>
<td>Permian - Wolfcamp</td>
<td>56,398</td>
<td>$6</td>
<td>$338,388</td>
<td>5.9%</td>
</tr>
<tr>
<td>Permian - Bone Spring</td>
<td>30,302</td>
<td>$6</td>
<td>$181,812</td>
<td>3.2%</td>
</tr>
<tr>
<td>Austin Chalk</td>
<td>41,543</td>
<td>$6</td>
<td>$249,258</td>
<td>4.3%</td>
</tr>
<tr>
<td>Niobrara</td>
<td>228,657</td>
<td>$3.6</td>
<td>$823,166</td>
<td>14.3%</td>
</tr>
<tr>
<td>Barnett</td>
<td>60,346</td>
<td>$6</td>
<td>$362,077</td>
<td>6.3%</td>
</tr>
<tr>
<td>Haynesville</td>
<td>30,498</td>
<td>$9</td>
<td>$274,484</td>
<td>4.8%</td>
</tr>
<tr>
<td>Marcellus</td>
<td>132,163</td>
<td>$6</td>
<td>$792,979</td>
<td>13.8%</td>
</tr>
<tr>
<td>Utica</td>
<td>111,212</td>
<td>$6</td>
<td>$667,275</td>
<td>11.6%</td>
</tr>
<tr>
<td>Fayetteville</td>
<td>17,786</td>
<td>$3</td>
<td>$53,359</td>
<td>0.9%</td>
</tr>
<tr>
<td>Woodford</td>
<td>17,914</td>
<td>$6</td>
<td>$107,486</td>
<td>1.9%</td>
</tr>
<tr>
<td>Total of plays analyzed</td>
<td>1,041,369</td>
<td></td>
<td>5,737,573</td>
<td>100.0%</td>
</tr>
<tr>
<td>Antrim</td>
<td>12,798</td>
<td>$6</td>
<td>$76,789</td>
<td></td>
</tr>
<tr>
<td>Other</td>
<td>668,337</td>
<td>$6</td>
<td>$4,010,020</td>
<td></td>
</tr>
<tr>
<td>Total of all shale plays</td>
<td>1,722,504</td>
<td>$9,824,381</td>
<td></td>
<td></td>
</tr>
<tr>
<td>EIA AEO2017 Total of shale and conventional plays</td>
<td>1,287,278</td>
<td>$6</td>
<td>$7,723,671</td>
<td></td>
</tr>
</tbody>
</table>

**Table 29. Number of wells required by play and well costs assuming EIA AEO2017 play-level production assumptions and well EURs.**

Also shown are the percentage of expenditures required for the major plays analyzed in this report, and EIA AEO2017 overall assumptions for all drilling including conventional, unconventional and offshore resources. Well costs are approximate.

Given play fundamentals, the EIA’s assumptions of tight oil and shale gas production through 2050 are highly overestimated. This has serious long-term energy sustainability implications. Policies for expanding natural gas and crude oil exports serve todeplete domestic resources sooner, setting up increased dependency on imports in the longer term (even with the EIA reference case AEO2017 projection the US will be a significant net importer of crude oil in 2050). At least a part of the multi-trillion-dollar investments needed to meet AEO2017 forecasts would be better invested in alternative energy sources to maximize future energy security.

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106 EIA AEO2017, Table 14, Oil and Gas Supply, https://www.eia.gov/outlooks/aeo/excel/yearbyyear.xlsx
5. Summary and Implications

Shale gas and tight oil from low permeability reservoirs have provided a new lease on life for U.S. oil and gas production. Tight oil has allowed U.S. oil production to double from its 2005 lows, and shale gas has similarly allowed a major increase in U.S. gas production. However, the nature of these reservoirs is that they decline quickly, such that production from individual wells falls 70-90% in the first three years, and field declines without new drilling typically range 20-40% per year. Continual investment in new drilling is therefore required to avoid steep production declines. Older fields like the Barnett, where drilling has nearly ceased, are in terminal decline. Shale plays also exhibit variable reservoir quality, with “sweet spots” or “core areas” containing the highest quality reservoir rock typically comprising 20% or less of overall play area. In the post-2014 era of low oil prices drilling has focused on sweet spots which provide the most economically viable wells.

This review of well-level production data for major US shale plays reveals that EIA projections of production through 2050 at the play-level are highly to extremely optimistic, and are therefore highly unlikely to be realized. EIA play forecasts count on recovering all proven reserves and a high percentage of unproven resources—in some cases over 100%—by 2050. Furthermore, most of these play-level projections assume that production will exit 2050 at high levels compared to current rates, implying that there are vast additional resources to be recovered beyond 2050.

The analysis considered drillable play area, well- and field-decline rates, change in average well productivity over time, well density, and recent production history. It contrasted these play fundamentals with the EIA AEO2017 reference case projections for each play. Key findings include:

- Well productivity
  - Better technology—including longer horizontal laterals, a tripling of water and proppant injection since 2012, and more fracking stages—has resulted in increased average well productivity in most plays.
  - A significant portion of the increased average well productivity is a result of “high-grading” sweet spots: focusing drilling on the highest quality reservoir rocks (which form a relatively small portion of most plays).
  - Average well productivity in some counties and plays has declined in 2017, indicating technology there has reached the point of diminishing returns. This is a result of drilling outside of sweet spots and/or drilling wells too close together, resulting in “frac hits” and well interference.

- Tight oil plays
  - The Permian Basin plays are the main driver for tight oil production growth. In Permian plays such as the Wolfcamp and Spraberry production is increasing rapidly, although Bone Spring production has flat-lined recently. EIA estimates for production through 2050 for these plays are rated as highly to extremely optimistic.
  - Production in older tight oil plays like the Bakken and Eagle Ford, which were among the first tight oil plays developed, is down substantially from peak. EIA projections for these and other tight oil plays, including the Niobrara and Austin Chalk, are rated as highly to extremely optimistic.

- Shale gas plays
  - The Appalachian plays are the main driver for shale gas production growth - the Marcellus and Utica now account for 48% of U.S. shale gas production. EIA forecasts for the Marcellus and Utica, which project these will provide 52% of cumulative production of U.S. shale gas through 2050, are rated as extremely optimistic.
- Production in older shale gas plays—including the Barnett, Haynesville, and Fayetteville, which were among the first to be developed—is now down more than 40% from peak. EIA projections for these plays—along with the Woodford, which is down 25% from peak—are rated as highly to extremely optimistic.

- All plays

- The EIA AEO2017 reference case projects that 1.29 million wells will be drilled to recover oil and gas from both conventional and unconventional reservoirs in the period 2015–2050. At $6 million per well, this amounts to $7.7 trillion. Shale plays reviewed herein, which account for 88% of the EIA’s estimated shale oil and gas production through 2050, would require 1.04 million wells using EIA assumptions—an estimated cost of $5.7 trillion. Recovering the remaining 12% of shale resources would require an additional .68 million wells at a cost of $4.1 trillion. Given the EIA’s overestimates of future shale production and recoverable resources, it is unlikely that all of these wells will be drilled.

There is no doubt that the U.S. can produce substantial amounts of shale gas and tight oil over the short- and medium-term. Unrealistic long-term forecasts, however, are a disservice to planning a viable long-term energy strategy. The high to extremely optimistic EIA AEO2017 projections impart an unjustified level of comfort for long-term energy sustainability. As sweet spots are exhausted, the reality is likely to be much higher costs and higher drilling rates to maintain production and/or stem declines.

The “shale revolution” has provided a reprieve from what just 13 years ago was thought to be a terminal decline in oil and gas production in the U.S. It has sparked calls for “American energy dominance”\textsuperscript{107}—despite the fact that the U.S. is projected to be a net oil importer through 2050, even given EIA forecasts. This reprieve is temporary, and the U.S. would be well advised to plan for much reduced shale oil and gas production in the long term based on this analysis of play fundamentals.