SHALE REALITY CHECK 2019

DRILLING INTO THE U.S. GOVERNMENT'S OPTIMISTIC FORECASTS FOR SHALE GAS AND TIGHT OIL PRODUCTION THROUGH 2050

J. DAVID HUGHES

post carbon institute

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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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Shale Reality Check 2019: Drilling into the U.S. Government's Optimistic Forecasts for Shale Gas & Tight Oil Production Through 2050
By J. David Hughes
In association with Post Carbon Institute with support from PSE Healthy Energy.

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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 by 96%);
- *Drilling Deeper* (2014), which challenged the EIA's expectation of long-term domestic oil and gas abundance with an in-depth assessment of all drilling and production data from major shale plays;
- Various updates to *Drilling Deeper*, most recently *Shale Reality Check* (2018); and
- *How Long Will the Shale Revolution Last?* (2019), an in-depth assessment of likely future production in the top ten tight oil and shale gas plays in the United States.

Separately from Post Carbon, Hughes authored *BC LNG: A Reality Check in 2014 and 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, *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, and *Canada's Energy Outlook: Current realities and implications for a carbon-constrained future* in 2018.

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, and USA Today, as well as other popular press, radio, and television.

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Each year, the U.S. Department of Energy's Energy Information Administration (EIA) publishes its Annual Energy Outlook which reviews U.S. energy sources and forecasts supply through 2050, the latest version of which was released in early 2019.[1] Although several scenarios based on different assumptions are included, the EIA's reference case is widely used by industry and government as an authoritative forecast of what to expect for long-term energy supply.

In the case of oil and gas, which is expected to provide a major share of U.S. energy supply through 2050, the so-called "Shale Revolution" has revolutionized domestic U.S. oil and gas production over the past decade. Tight oil (also known as shale oil) and shale gas from low permeability reservoirs has allowed U.S. oil production to more than double from its 2005 lows and shale gas has similarly led to 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 75–90% in the first three years, and first-year field declines without new drilling typically range from 25–50% per year. High rates of capital investment in new drilling are therefore required to avoid steep production declines. Older plays like the Barnett and Fayetteville, which are close to saturated with wells and drilling has nearly ceased, have declined 50% or more from peak production levels of just a few years ago. 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. Sweet spots will inevitably become saturated with wells, and drilling outside of sweet spots will require higher rates of drilling and capital investment to maintain production, along with higher commodity prices to justify them.

Given that shale plays are forecast to provide the major share of U.S. domestic oil and gas production through 2050, it is crucial for future planning and policy development to understand the long-term viability of shale plays and the reliability of long-term forecasts. This report assesses the credibility of EIA forecasts of future shale production on a play-by-play basis in terms of likelihood of meeting forecast production levels and what it would take to meet them in terms of new wells drilled and capital investment. 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 90% of the EIA's *Annual Energy Outlook 2019* (AEO2019) reference case production forecast for shale gas and tight oil for the period 2017–2050. Along with references from the literature, the key data source is Drillinginfo,[2] 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 and cumulative oil and gas production by county.
- Total- and producing-well count by county, well type, and vintage.
- Three-year well decline and first-year field decline 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.
- Average productivity of all wells drilled in each year from 2012 to 2018 by county, well type, and play, in order to assess the impact of improved technology.
- Definition of prospective drilled area to determine the area which might reasonably contribute to future production.
- Projected number of wells, well density, and capital investment required to meet production forecasts.

[1] Energy Information Administration, *Annual Energy Outlook 2019*, https://www.eia.gov/outlooks/aeo/
[2] Drillinginfo, https://info.drillinginfo.com/

- Comparison of forecast production to EIA estimates of proven reserves plus unproven resources.
- The optimism bias for the EIA AEO2019 play-level forecasts based on play fundamentals determined from the assessment.

This report finds that EIA reference case play-level production forecasts through 2050 are extremely optimistic for the most part, and are therefore highly unlikely to be realized.

Key findings include:

- Of the 13 shale plays analyzed, nine are rated as extremely optimistic, three highly optimistic, and one moderately optimistic.
- In some cases, EIA play-level production forecasts through 2050 exceed the EIA's own estimates of proven reserves plus unproven resources, and all plays are forecast to recover all proven reserves and a high percentage of unproven resources by 2050.
- The EIA's reference case cannot deliver its forecast production requirement by 2050 if production from plays is limited to the EIA's estimated proven reserves plus unproven resources. The overall forecast falls short by nearly ten billion barrels of oil, or 10% of the required production volume.
- In most cases, forecasts exit 2050 at high production levels, often significantly higher than current production rates, implying that vast additional resources would remain after 2050.
- Oil is the most sought-after resource given that it sells for three times the price of gas on an energy equivalent basis. More than 70% of capital investment and drilling is directed at tight oil plays.
- Well drilling and completion costs using the EIA's estimated ultimate recovery (EUR) of wells is less than $50 per barrel in the Bakken, Eagle Ford, and Permian Basin plays, and is less than $40 per barrel on an oil equivalent (BOE) basis (as these plays also produce large amounts of associated gas). Costs are much higher in plays like the Niobrara and Austin Chalk and exceed $500 per barrel for oil in the EIA's "other" play category (and more than $160 on a BOE basis).
- Given the EIA's forecast of requiring production from "other" plays outside of the major plays analyzed in this report, 1,558,910 additional wells would be required for shale plays over 2017-2050 at a cost of $11 trillion, due to the low estimated ultimate recovery of wells outside of major plays. If wells required for conventional on- and off-shore production are included, a total of 1,892,854 additional wells would be needed by 2050 to meet the forecast, at an overall cost of $13 trillion.
- An alternative to the EIA's forecast of significant production from its high cost, low productivity, "other" plays, would be to make up the required production from the Permian Basin Wolfcamp Play and the Denver-Julesburg Basin Niobrara Play. ***However, doing so would totally exhaust all of the EIA's estimated proven reserves and unproven resources of tight oil in major plays by 2050, leaving nothing for later***. This would reduce the well requirement for shale plays to 1,117,827 additional wells over 2017-2050 at a cost of $7.5 trillion. Coupled with required conventional on- and off-shore wells, a total of ***1,451,771 new wells would be needed to meet the forecast, for a total expenditure of $9.5 trillion*** (this is 16% higher than the 1,247,058 new wells estimated by the EIA).
- Well productivity has increased in most plays through focusing on sweet spots and due to longer horizontal laterals and increased volumes of water and proppant, as well as more fracking stages. The limits of technology and exploiting sweet spots are becoming evident, however, as in some plays new wells are exhibiting lower productivities.

Although 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 are a disservice to planning a viable long-term energy strategy. The best-case scenario to meet the EIA AEO2019 reference case forecast requires drilling 1,451,771 wells at a cost of $9.5 trillion over the 2017-2050 period.

The fact that all U.S. tight oil resources would be consumed by 2050 in this best-case scenario, assuming that the EIA estimates of proven reserves plus unproved resources are correct, should be extremely troubling for long term energy security planning and policy development. And given the extremely optimistic nature of most of the EIA's play-level forecasts, it is by no means assured that even this much oil and gas can be produced. Assuming that production will remain at high levels after 2050 is wishful thinking.

The "shale revolution" has sparked calls for "American energy dominance"[3]—despite the fact that the U.S. is projected to be a net oil importer through 2050, even given EIA forecasts. Although the "shale revolution" has provided a reprieve from what just 15 years ago was thought to be a terminal decline in oil and gas production in the U.S., 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. That is without factoring in any mandates to reduce greenhouse gas emissions or the economics of renewable energy sources. If U.S. energy policy actually reflected the need to mitigate climate change—which the international community mandated in 2016 through the Paris Agreement[4]—the EIA's forecasts for tight oil and shale gas production through 2050 make even less sense.

[3] Time, June 29, 2017, *President Trump Says He Wants 'Energy Dominance.' What Does He Mean?* http://time.com/4839884/energy-dominance-energy-independence-donald-trump/

[4] "The Paris Agreement," United Nations Framework Convention on Climate Change, retrieved November 7, 2019; https://unfccc.int/process-and-meetings#:a0659cbd-3b30-4c05-a4f9-268f16e5dd6b.

1. Introduction

As recently as 2005, U.S. oil and gas production were thought to be in terminal decline. Oil production, which peaked in 1970 at ten million barrels per day (mbd), had declined to five mbd[5], and dry natural gas production, which peaked in 1973 at 60 billion cubic feet per day (bcfd), had declined to 50 bcfd[6]. 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[7] 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 Play of North Dakota. Since 2008, U.S. crude oil production has increased 117%, to 12.1 mbd, and gas production has increased 85% to 91 bcfd since 2008.

Shale has raised expectations for U.S. oil and gas production and has underpinned calls for U.S. "energy dominance" by the Trump Administration,[8] after decades of being a net importer of oil and gas. Exports of crude oil and LNG have commenced over the past five years and expectations of continued production growth are high. This optimism has been bolstered by the U.S. Department of Energy's Energy Information Administration (EIA), which issues annual forecasts of future oil and gas production, the latest of which was the *Annual Energy Outlook 2019* (AEO2019) released in January 2019.[9] AEO2019 projects tight oil production to grow 38% above 2018 levels by 2050, and shale gas production to grow 81% over the same period.

But how reliable are these forecasts? They have been questioned by shale oil magnate Harold Hamm[10] and others[11] as overly optimistic. I have also pointed this out in reports over the past several years.[12] 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 estimated ultimate recovery (EUR) per well are highly variable. Core areas or "sweet spots," where well productivity and EUR are highest, 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 become exhausted.

2. Production decline for a typical shale well averages 75–90% 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 of well-life, and that new wells must continually be drilled to maintain production.

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[5] Energy Information Administration, *U.S. Field Production of Crude Oil*, October, 2019, https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=MCRFPUS2&f=M
[6] Energy Information Administration, *Natural Gas Gross Withdrawals and Production*, https://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_FPD_mmcf_m.htm
[7] The Economist, August 3, 2013, *The Father of Fracking*, https://www.economist.com/news/business/21582482-few-businesspeople-have-done-much-change-world-george-mitchell-father
[8] Time, June 30, 2017, *President Trump Says He Wants 'Energy Dominance.' What Does He Mean?*, http://time.com/4839884/energy-dominance-energy-independence-donald-trump/
[9] Energy Information Administration, *Annual Energy Outlook 2019*, https://www.eia.gov/outlooks/aeo/
[10] Bloomberg, November 17, 2017, *Shale King Hamm Wants to Give Oil Forecasters a Reality Check*, https://www.bloomberg.com/news/articles/2017-11-16/shale-king-hamm-wants-to-give-oil-forecasters-a-reality-check
[11] Wall Street Journal, March 3, 2019, *Shale Companies, Adding Ever More Wells, Threaten Future of U.S. Oil Boom*, https://www.wsj.com/articles/shale-companies-adding-ever-more-wells-threaten-future-of-u-s-oil-boom-11551655588?mod=searchresults&page=2&pos=6&mod=article_inline
[12] J.D. Hughes, *Shale Reality Check,* Post Carbon Institute, 2018*,* http://shalebubble.org.

3. First-year field declines, which are made up of older wells declining at lower rates and new wells declining at higher rates, typically average 25–50% 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 (2,100 gallons per foot), and proppant use has also tripled, to nearly 2,000 pounds per foot.[13] 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 Louisiana which used 50 million pounds of proppant in a horizontal lateral of nearly 10,000 feet, or 5,000 pounds per foot.[14] An excellent review of water use in the Permian Basin reports that water use there can go as high as 124 barrels per foot (5,208 gallons per foot).[15] 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[16], and others in shale plays more generally.[17]

   In 2019 I published an in-depth review of trends in horizontal lateral lengths and water and proppant injection in the ten major tight oil and shale gas plays.[18] The increase in well productivity has been impressive in most plays. In the Permian Basin, for example, an average 2018 well is able to access four times the reservoir volume of an average 2012 well. Although this has increased well productivity and hence economics, it has reduced available drilling locations must faster, raising serious questions about the EIA's forecasts for production in 2050 if not much sooner.

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.

6. As sweet spots are exhausted drilling will of necessity have to move into lower quality parts of plays, meaning higher prices will be required to break even. Drilling rates will also have to increase to maintain production, which will consume drillable locations faster and increase the rate of collateral environmental impacts.

EIA forecasts of oil and gas production published in its Annual Energy Outlooks (AEOs) 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 AEO2019 reference case projections at the play level, using well production data from the Drillinginfo[19] 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

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[13] C. Cross, November 14, 2017, Completion Trends: Proppant and Fluid Concentrations on the Upswing Across All Basins, https://info.drillinginfo.com/completion-trends-proppant-and-fluid-concentrations-on-the-upswing-across-all-basins/
[14] World Oil, October 21, 2016, *Chesapeake declares 'propageddon' with record frac job*, http://www.worldoil.com/news/2016/10/21/chesapeake-declares-propageddon-with-record-frac-job
[15] B. R. Scanlon et al., 2017, *Water Issues Related to Transitioning from Conventional to Unconventional Oil Production in the Permian Basin*, *Environ. Sci. Technol.*, 2017, *51* (18), pp 10903–10912
[16] Rystad Energy, December, 2017, *Empirical evidence for collapsing production rates in Eagle Ford*, https://communications.rystadenergy.com/acton/rif/12327/s-04e3-1712/-/l-0044:4dab/q-005a/showPreparedMessage?sid=TV2:x1Eq3cVo4
[17] 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
[18] J.D. Hughes, 2019, *How long will the shale revolution last? Technology versus Geology and the Lifecycle of Shale Plays*, Post Carbon Institute, https://www.postcarbon.org/publications/how-long-will-the-shale-revolution-last/
[19] Drillinginfo, https://info.drillinginfo.com/

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 forecasts 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 AEOs 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 decrease vulnerability to price shocks, supply disruptions, and environmental impacts including climate change.

2. Tight Oil Plays

Figure 1 illustrates tight oil production from the seven major plays assessed in AEO2019, as well as "Other" plays[20], as of July 2019. Production from tight oil plays is at an all-time high, although one of the largest plays—the Eagle Ford, which constituted 16% of tight oil production in July 2019—is down 24% from its early 2015 peak. The Permian Basin, which consists of the Spraberry, Wolfcamp, and Bone Spring plays, has been responsible for much of the growth in U.S. tight oil production—producing 48% of total U.S. tight oil in July 2019. Although the Permian Basin has been producing oil and gas for nearly a century, industry has proven adept at accessing unconventional resources in the basin.

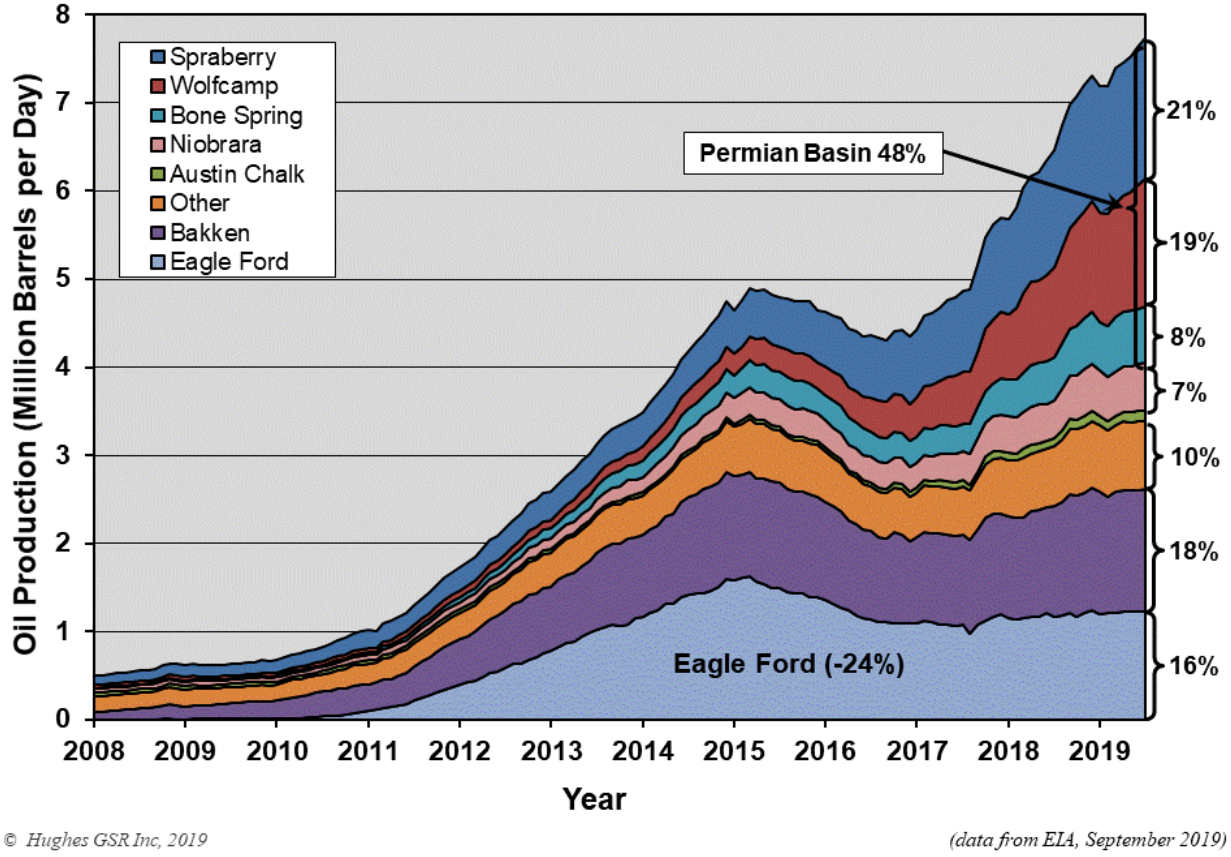


Figure 1. U.S. tight oil production by play, 2008 through July 2019.[21]

The Spraberry, Wolfcamp, and Bone Spring lie within the Permian Basin. Eagle Ford production is currently down 24% from its peak in March 2015.

[20] 'Other" plays include the Monterey, Granite Wash, Yeso, Glorieta, Delaware, and liquids from mainly gas plays including the Woodford, Haynesville, Marcellus and Utica.

[21] EIA, September, 2019, *How Much Tight Oil is Produced in the U.S.?*, https://www.eia.gov/tools/faqs/faq.php?id=847&t=6

Figure 2 illustrates the AEO2019 reference case for U.S. oil production by source with price projections. Tight oil constitutes by far the largest source of oil supply overall, and is forecast to make up 71% 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 14.5 mbd in 2031. West Texas Intermediate (WTI) prices are projected to remain below $100/barrel until 2040, and 2050 production is projected to meet 69% of projected crude oil demand—meaning that despite the aggressive production growth forecast for tight oil, the U.S. will remain a large importer of oil.

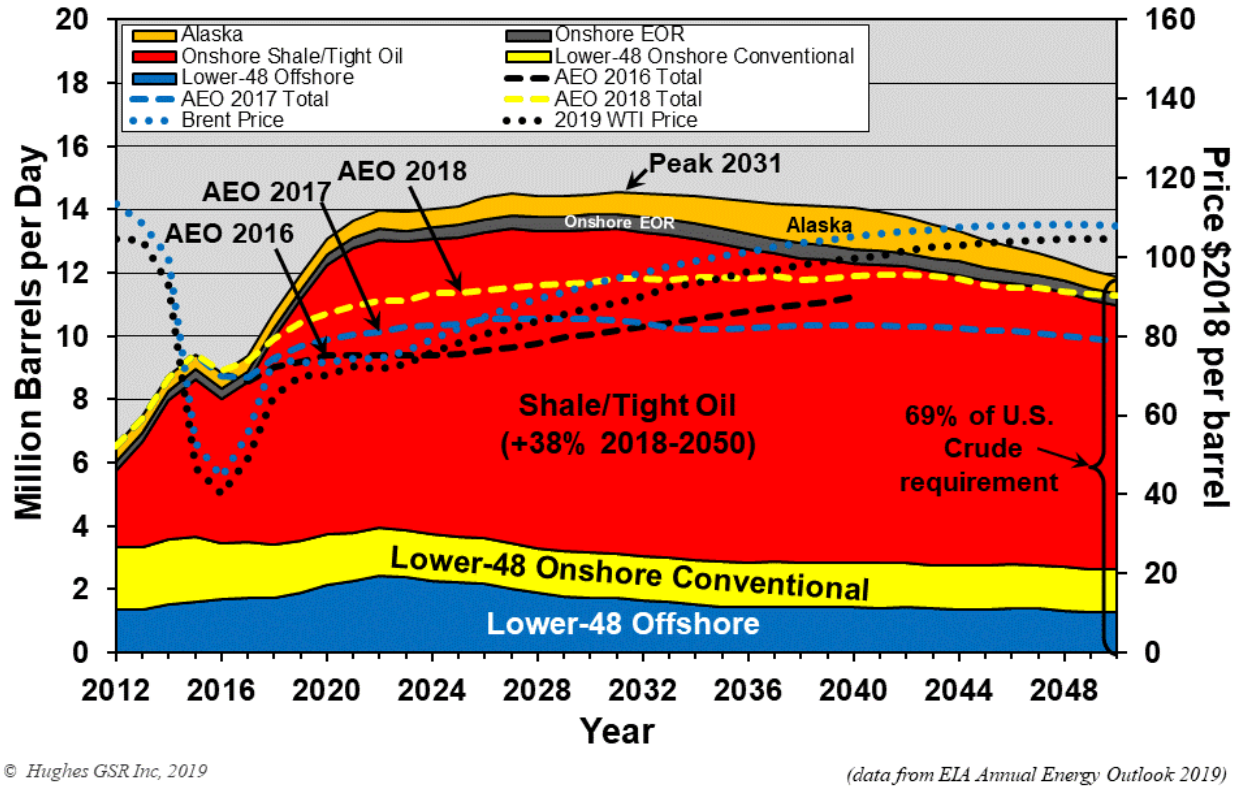


Figure 2. EIA AEO2019 reference case forecast of U.S. oil production by source, 2012–2050.

Also shown are earlier forecasts and projected price (West Texas Intermediate and Brent in 2018 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 68% of total crude oil production of 164 billion barrels over the 2018–2050 period. That is more than triple proven U.S. crude oil reserves of 42 billion barrels at yearend 2017[22], and half of U.S. proven reserves plus unproven resources.[23] (Proven reserves have been demonstrated to be technically and economically recoverable, whereas unproven resources are thought to be technically recoverable but have not been demonstrated to be economically recoverable.)

The tight oil portion of the EIA's reference forecast is expected to recover 5.6 times proven U.S. tight oil reserves and 85% 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. Moreover, the EIA's forecast that oil production will exit 2050 at high production levels assumes that there are large additional resources yet to be recovered.

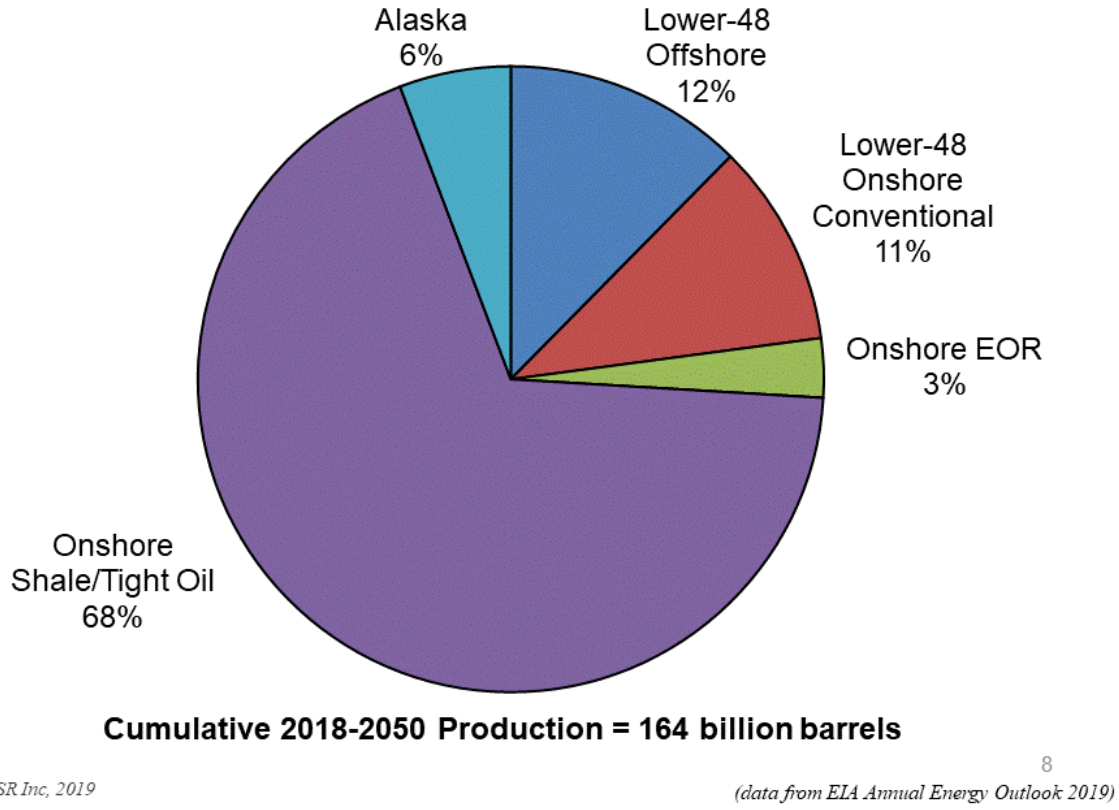


Figure 3. EIA AEO2019 reference case forecast of cumulative oil production by source, 2018–2050.

[22] EIA, Table 1. U.S. proved reserves, and reserves changes, yearend 2017, https://www.eia.gov/naturalgas/crudeoilreserves/.
[23] EIA, Assumptions to the Annual Energy Outlook 2019, https://www.eia.gov/outlooks/aeo/assumptions/

The EIA's reference case AEO2019 forecast by play is illustrated in Figure 4. Tight oil is expected to peak in 2031, and to produce 119 billion barrels of oil from 2014 through 2050, when production is projected to be considerably higher than today. The Permian Wolfcamp play is forecast to produce 25% of this, and with the Bakken, Eagle Ford and Spraberry, the top four plays are forecast to collectively produce 75%.

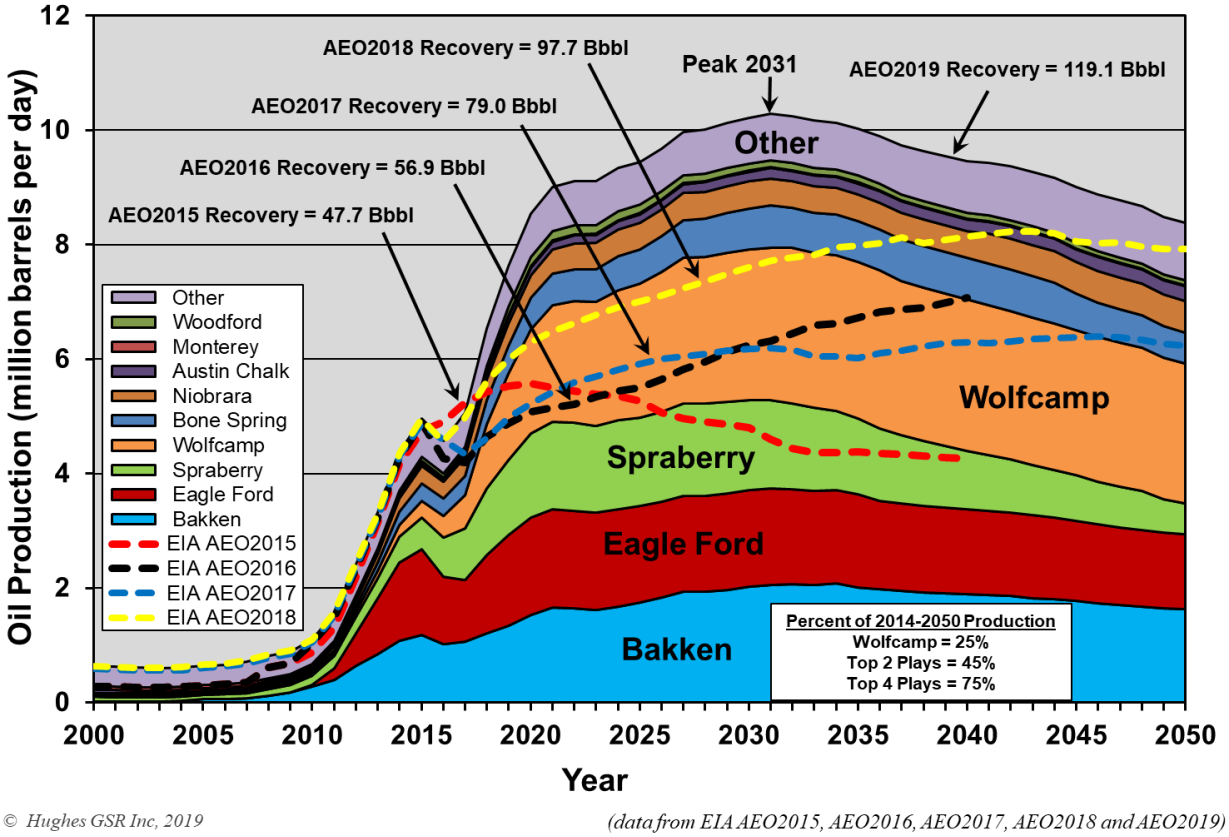
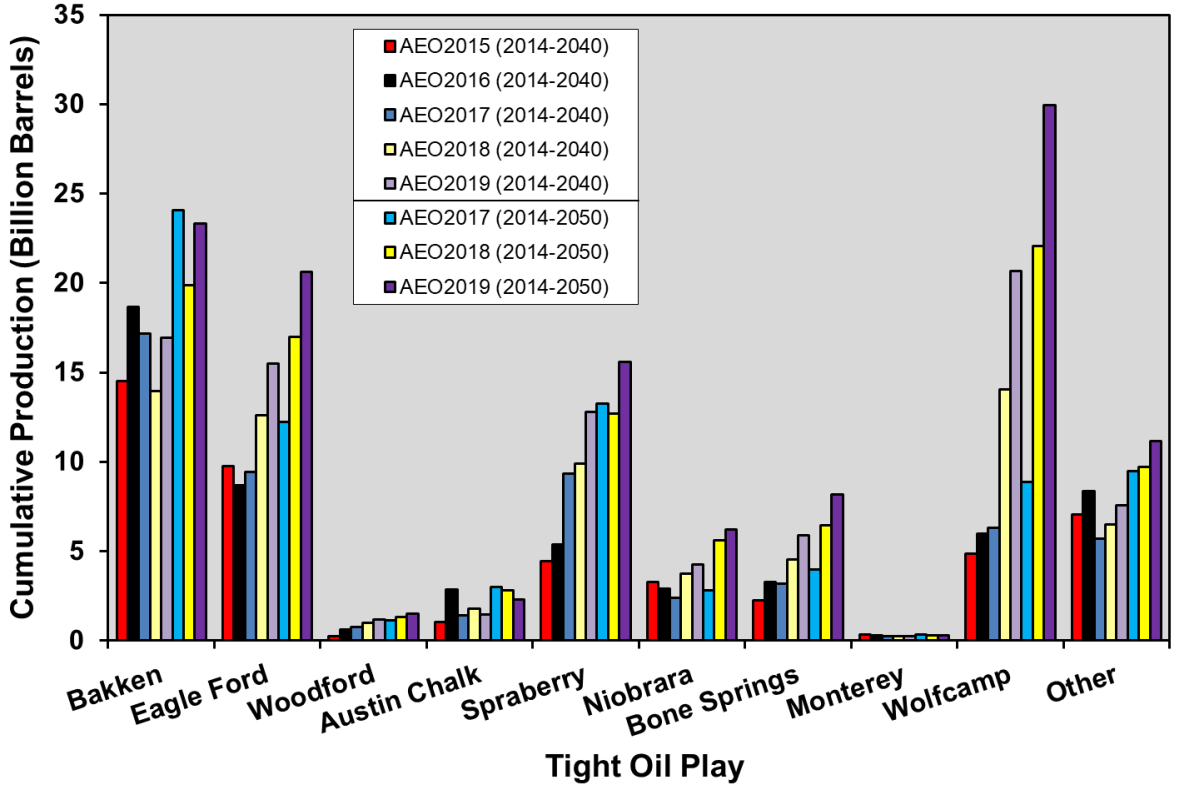


Figure 4. U.S. tight oil production by play in EIA AEO2019 reference case forecast compared to earlier forecasts.

AEO2015 and AEO2016 forecasts are for the period 2014-2040. AEO2017, AEO2018, and AEO2019 forecasts are for the period 2014-2050. Bbbl=billion barrels.

The changes in EIA AEO production forecasts by play from 2014 to 2019 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.



© Hughes GSR Inc, 2017 (EIA reference case cumulative production from AEO2014, AEO2015, AEO2016, AEO2017, AEO2018 and AEO2019)

Figure 5. Cumulative oil production forecasts by play for 2014–2040 and 2014–2050 in the AEO2019 reference case compared to AEO2014 through AEO2018 forecasts.

A summary of the total number of wells, total well cost, and total cumulative production through 2050 based on the EIA's reference case can be found in Table 29, page 159.

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 reached a temporary peak due to a falloff in the drilling rate. With an increase in drilling the Bakken resumed growth in 2017 and reached a second peak in December, 2018, followed by a slight decline due to a falloff in drilling. More than 15,500 wells have been drilled, of which more than 14,100 are still producing.

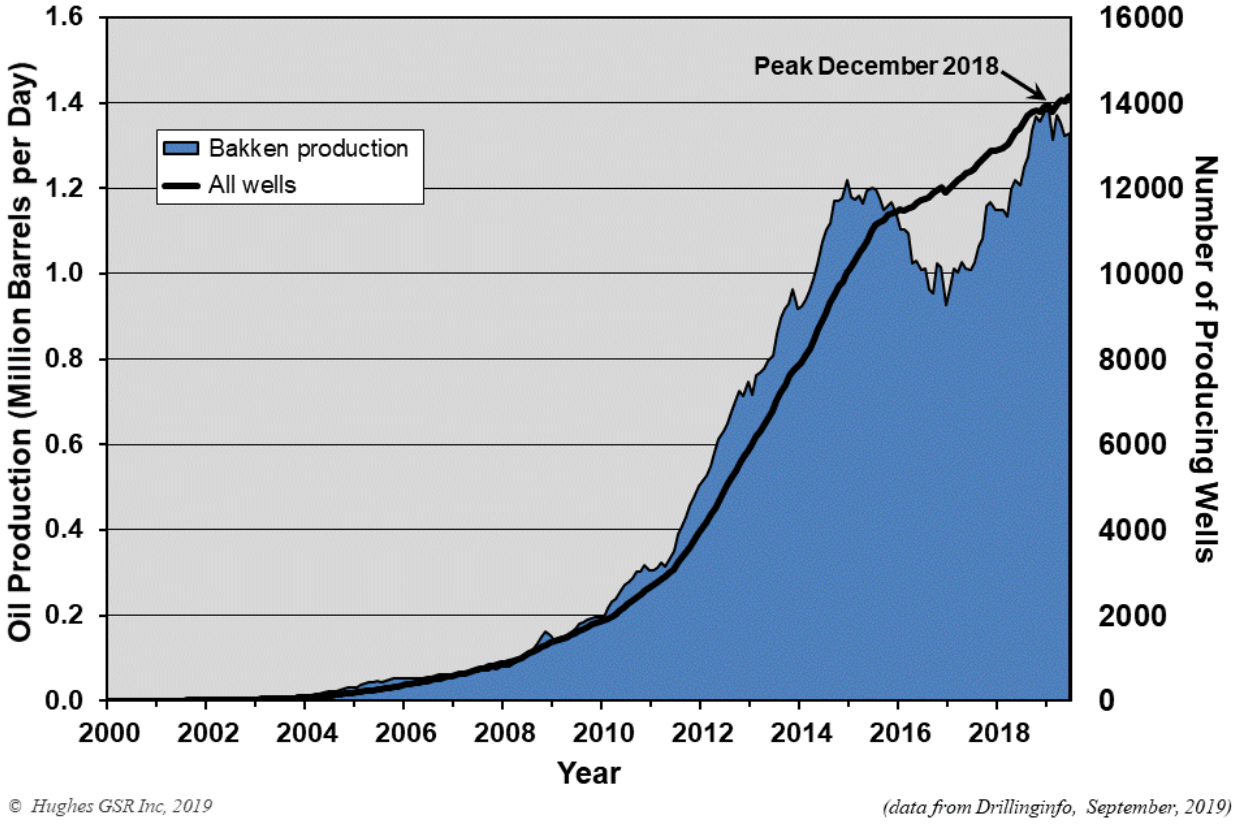
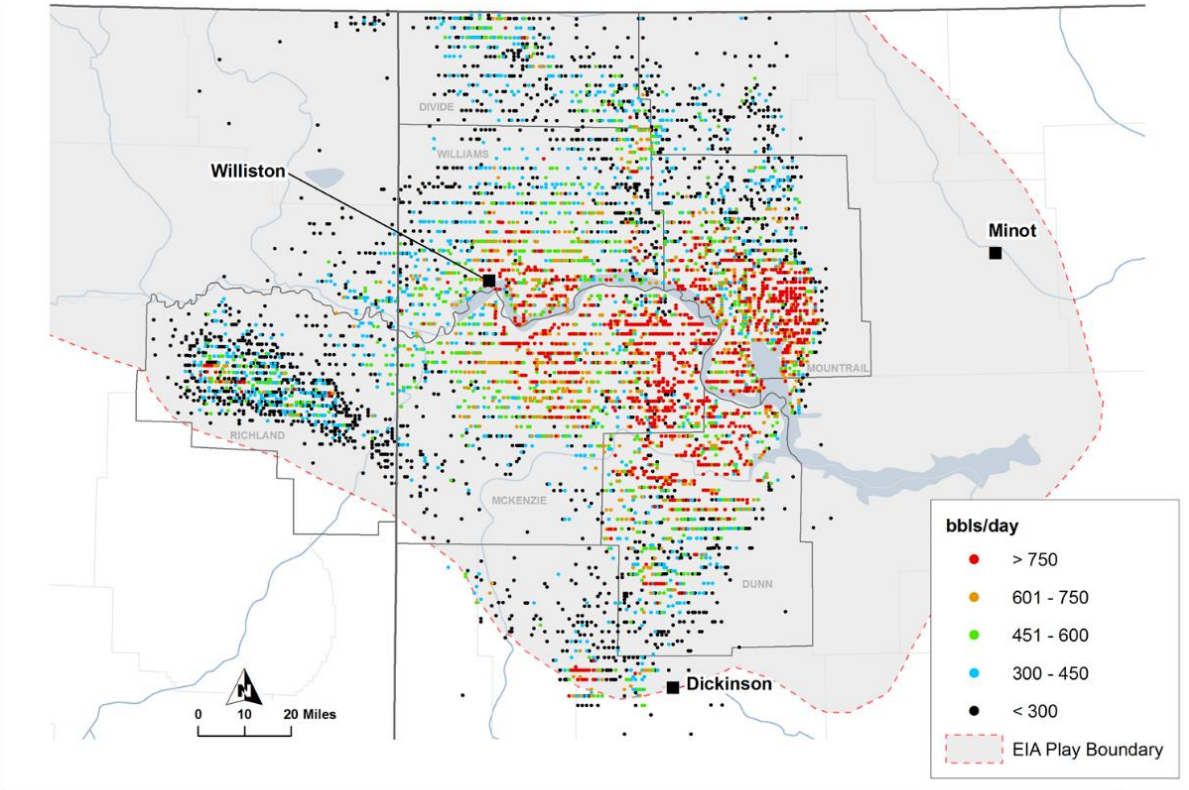


Figure 6. Bakken Play oil production and number of producing wells, 2000–2019.
Production peaked in December 2018 and was down 4% as of June 2019.

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 occur in 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.



© Van Hoesen and Hughes, 2017 (data from Drillinginfo September, 2017; EIA shapefile March 2016)

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.[24]

[24] Drillinginfo, September, 2017; EIA, March, 2016, play area outline from https://www.eia.gov/maps/map_data/TightOil_ShaleGas_Plays_Lower48_EIA.zip

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 87% 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.

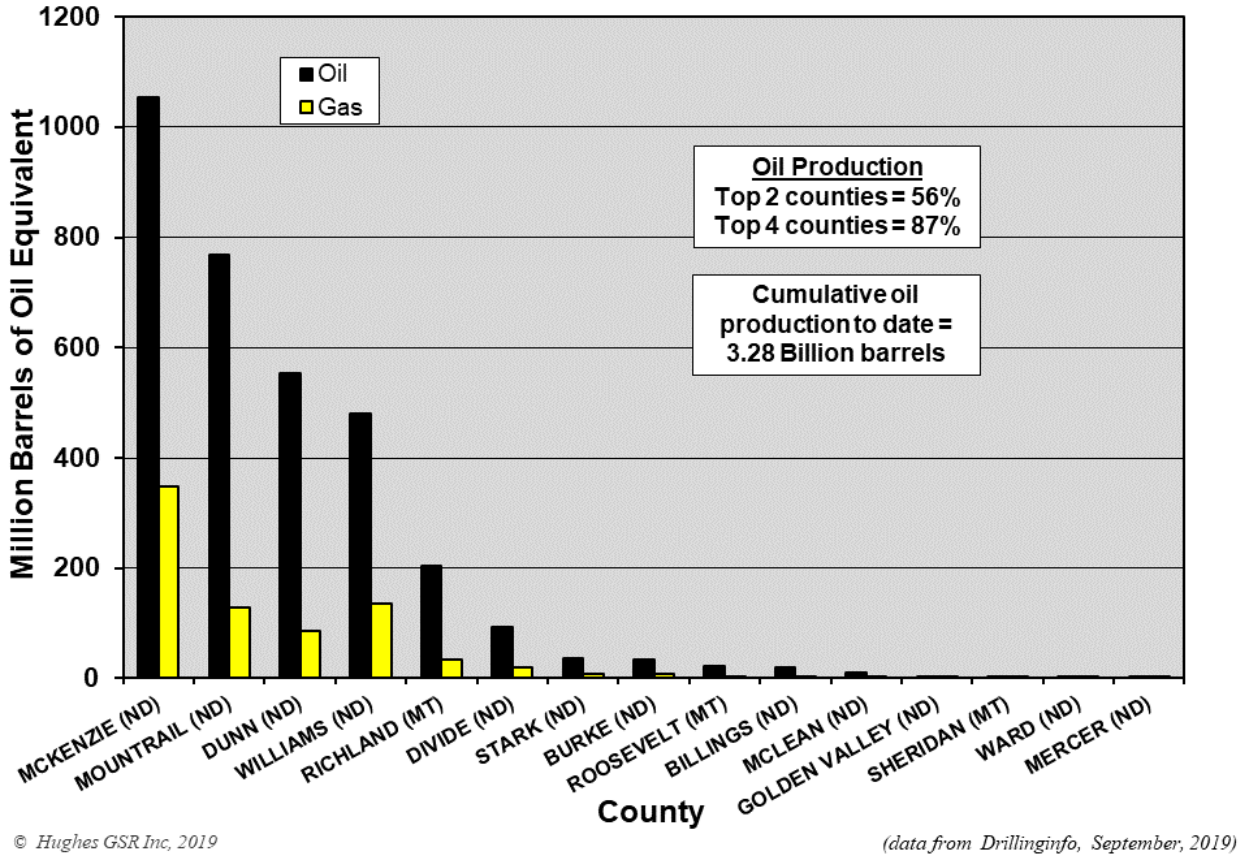


Figure 8. Cumulative production of oil and gas from the Bakken Play by county.

Production is highly concentrated in sweet spots, with 87% of cumulative production from the top 4 counties.

Table 1 shows the number of wells drilled by vintage, cumulative and current production, and well- and first-year field-decline rates for the Bakken as a whole and for individual counties. Three-year well decline rates average 88.7% and first-year field decline rates average 40.6% per year without new drilling, which is at the high end for shale plays analyzed in this report. Field declines are highest in counties that have undergone a lot of new drilling, given the high decline rates of new wells. Counties outside of the top four have lower field decline rates as most wells are older and past the high decline early years of production (but are producing at 20% or less of initial production rates).

County	Total Well Count	Producing Well Count	Cumulative Oil Production (billion bbls)	Cumulative Gas Production (tcf)	Oil Production June 2019 (Kbbls/day)	Gas Production June 2019 (bcf/day)	3-year well decline (%)	First-year field decline (%)
All	15,552	14,156	3.279	4.655	1327.6	2.79	88.7	40.6
Dunn	2,418	2,204	0.555	0.519	270.0	0.33	86.4	33.8
McKenzie	4,567	4,154	1.053	2.082	524.5	1.46	89.7	47.9
Mountrail	3,073	2,764	0.767	0.771	248.3	0.38	89.3	34.7
Williams	2,700	2,522	0.480	0.809	219.6	0.49	87.2	39.8
Other counties	2,794	2,512	0.366	0.380	65.3	0.12	85.1	19.0

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

(bbls=barrels. tcf=trillion cubic feet. bcf=billion cubic feet.)

The degree of development of the Bakken core area to date is illustrated in Figure 9. Horizontal lateral lengths have increased 7% since 2012 and averaged 9,864 feet in 2018 (although some wells have exceeded 15,000 feet) and are spaced as little as 500 feet apart.[25] 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.[26] Spacing wells closer than 2,000 feet in a single horizon may sacrifice production from infill wells but serves to recover the resource more quickly.

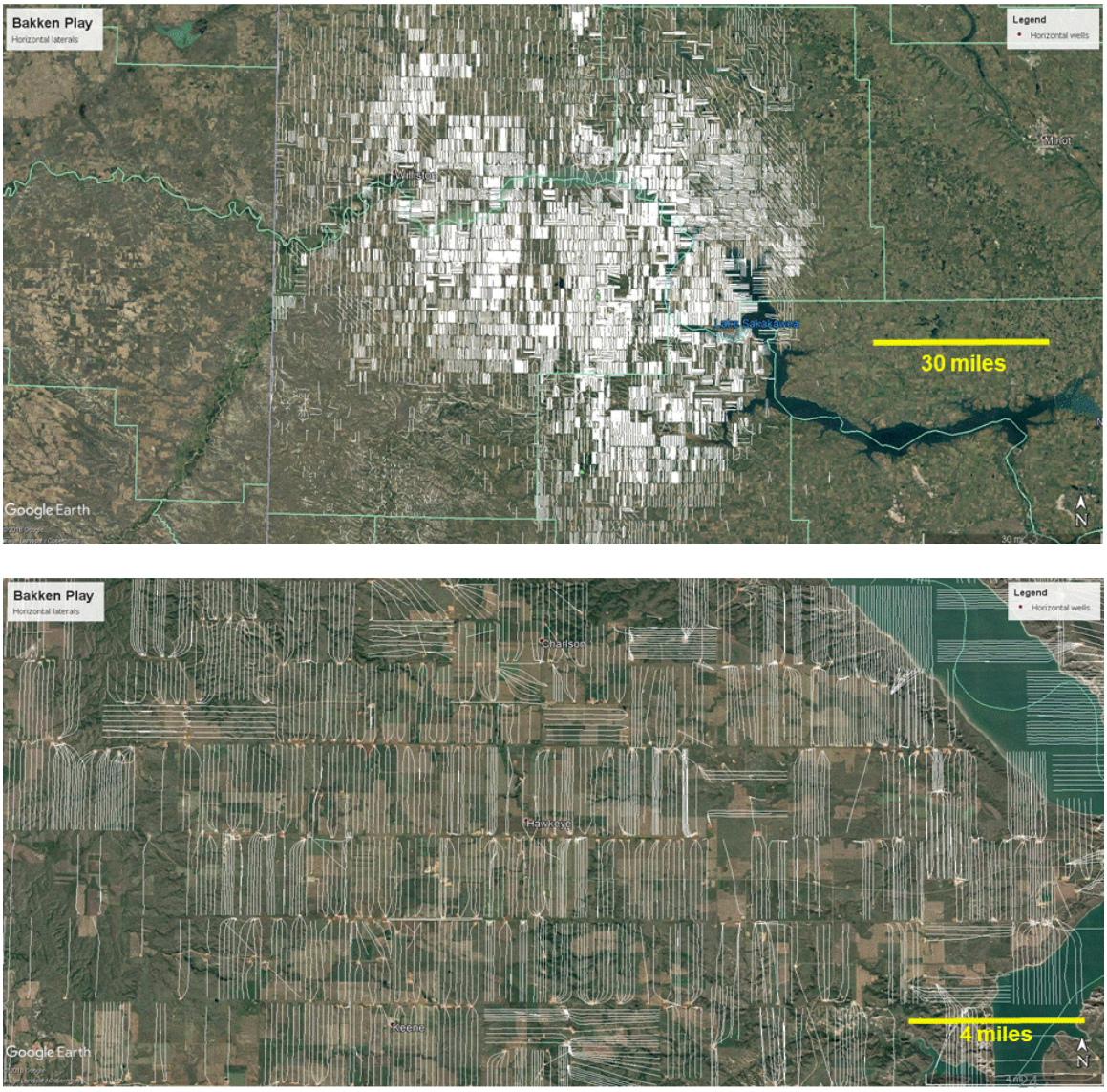


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Figure 9. Horizontal well development in the Bakken Play.

Upper: overview of play. Lower: core area view.[27]

[25] J.D. Hughes, 2019, *How long will the shale revolution last? Technology versus Geology and the Lifecycle of Shale Plays*, Post Carbon Institute, https://www.postcarbon.org/publications/how-long-will-the-shale-revolution-last/

[26] Thuot, K., 2013, There Will Be Blood: Well Spacing & The Bakken Shale Oil Milkshake, https://info.drillinginfo.com/well-spacing-bakken-shale-oil/

[27] North Dakota Department of Mineral Resources, Oil and Gas: ArcIMS Viewer, data retrieved October 2019; https://www.dmr.nd.gov/OaGIMS/viewer.htm.

Figure 10 illustrates production from the top four counties compared to the overall play. Mountrail County peaked in December 2014, and McKenzie and Williams counties peaked in early 2019. Counties outside of the top four peaked in February 2015, and are now down 56%. The top four counties make up 95% of production in June 2019.

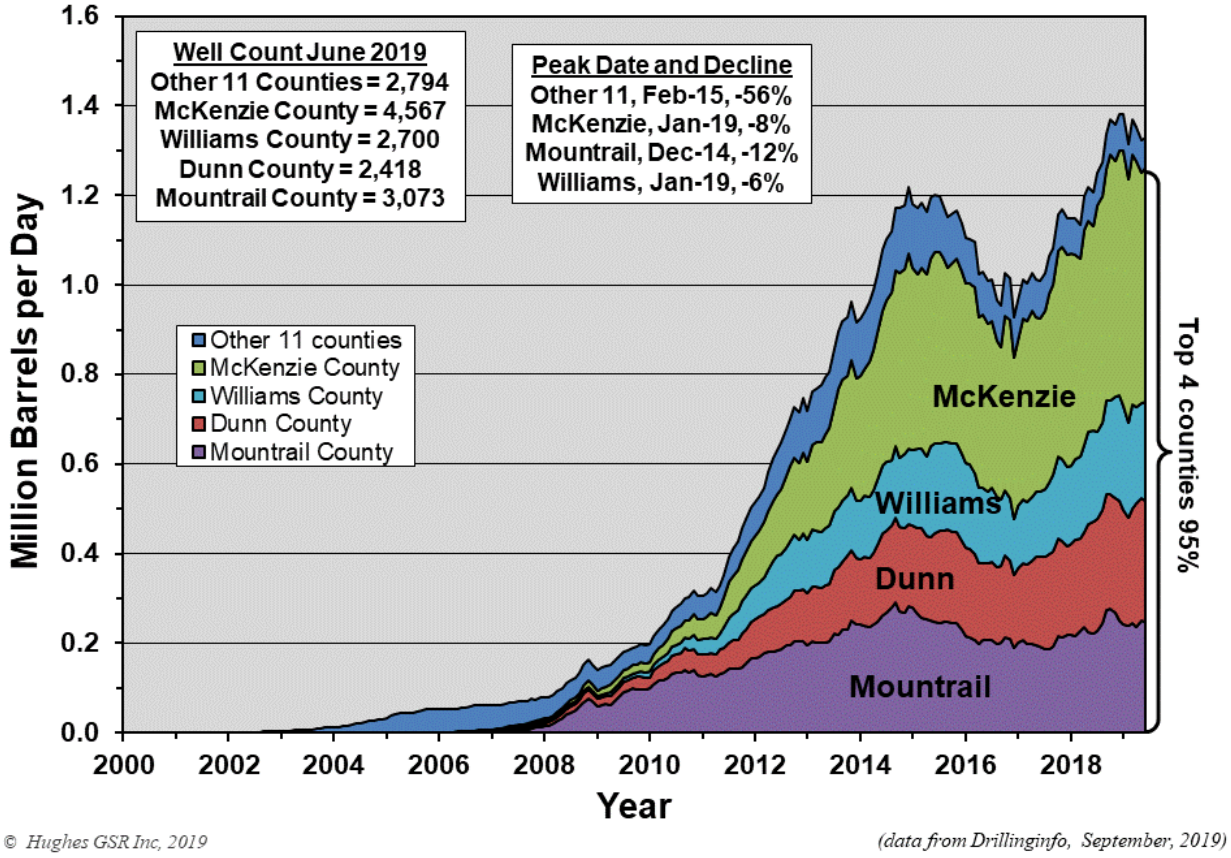
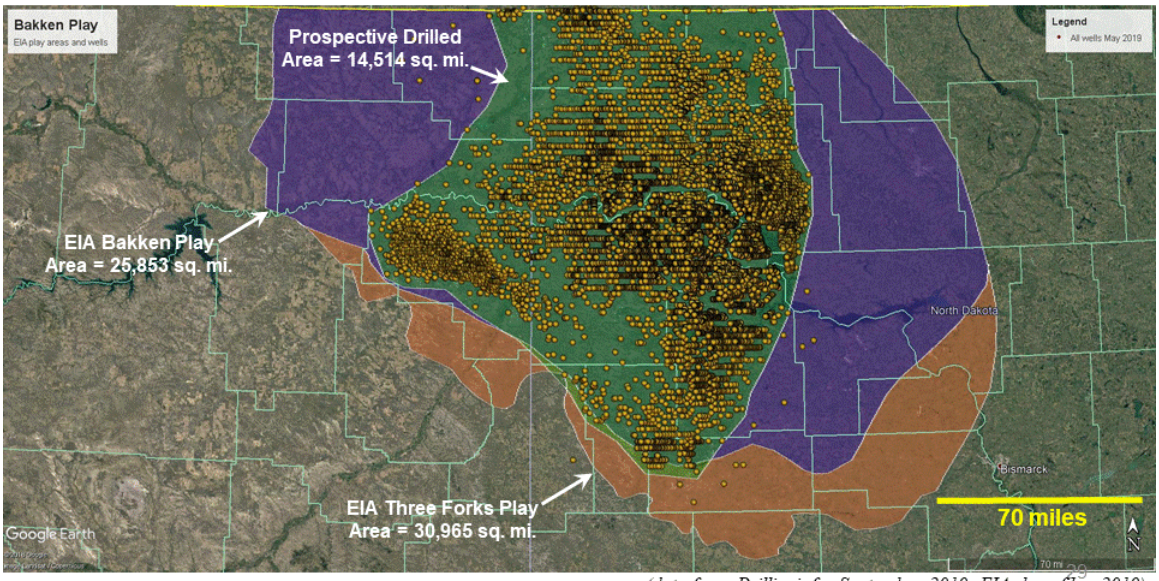


Figure 10. Oil production in the Bakken Play by county from 2000 through June 2019 showing well count, peak dates, and percentage decline for counties that have peaked.

In evaluating the credibility of the EIA reference case production forecast 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 14,514 square miles—is just over 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 AEO2019, the EIA assumes there are 13,793 square miles of remaining drillable area in the Bakken Formation in which "unproven resources" would be developed at an average well density of 3.9 wells per square mile, and 7,971 square miles of remaining drillable Three Forks Formation at 4.5 wells per square mile (as of year-end 2016).[28] This estimate for "unproven resources" is presumably mostly in addition to the area already drilled and the area needed to recover the EIA's estimated 5.45 billion barrels of "proven reserves". In comparison, the existing prospective drilled area already has an average effective well density of 2.14 wells per square mile (given that each well with a 10,000 foot lateral 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.

Should the developable extent of the Bakken/Three Forks prove to be limited to the existing prospective drilled area, well density would have to be increased to at least 8.3 wells per square mile to recover the EIA's estimated 16 billion barrels of "unproved resources" and 5.45 billion barrels of "proved reserves" (including the existing 15,552 wells), for an effective well density of 16.6 wells per square mile (assuming 10,000 foot laterals). It is highly unlikely that wells spaced this close together would be economically viable due to interference with one another via "frac hits". Hence the EIA's estimate of oil remaining to be recovered from the Bakken/Three Forks appears to be extremely optimistic.



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(data from Drillinginfo, September, 2019; EIA shapefiles, 2019)

Figure 11. EIA play areas for the Bakken and Three Forks compared to the prospective area that has been demonstrated by drilling.[29]

[28] EIA, Assumptions to the Annual Energy Outlook 2019, https://www.eia.gov/outlooks/aeo/assumptions/

[29] 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 August, 2019, from Drillinginfo.

The improvement in well productivity over time in most plays is undeniable. As noted earlier, this is partly due to the vastly increased 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.[30] 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 substantially 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.

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. With the exception of McKenzie County, which is the top producer, productivity improvements are evident through 2018. In McKenzie County, however, well productivity declined slightly in 2018, suggesting that well spacing in the best parts of this county is reaching saturation and well productivity is likely to fall in the future as more infills are drilled, with resulting well interference. Assuming that technology will continue to improve well productivity for the foreseeable future, as the EIA apparently does, ignores the fact that much of the improvement is due to high-grading sweet spots,[31] and that sweet spots have limited areal extent and are rapidly becoming saturated with wells. This will inevitably happen in all counties, necessitating higher drilling rates to maintain production and higher prices to justify them.

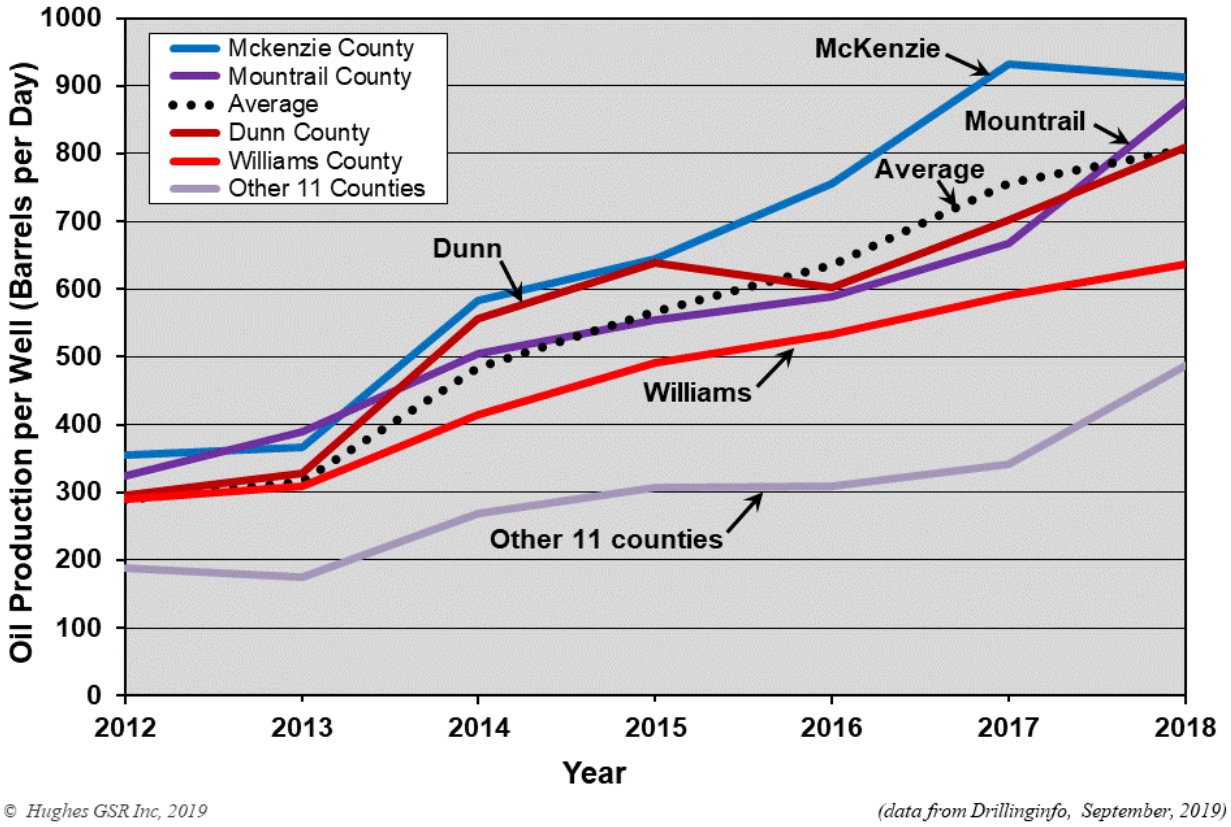

Figure 12. Average well productivity over the first four months of oil production by county in the Bakken Play, 2012–2018.

[30] J.D. Hughes, 2019, *How long will the shale revolution last? Technology versus Geology and the Lifecycle of Shale Plays*, Post Carbon Institute, https://www.postcarbon.org/publications/how-long-will-the-shale-revolution-last/
[31] J.B. Montgomery and F.M. O'Sullivan, *Spatial variability of tight oil well productivity and the impact of technology*, Applied Energy, 2017, http://dx.doi.org/10.1016/j.apenergy.2017.03.038

Figure 13 illustrates the EIA's AEO2019 reference case production forecast for the Bakken Play through 2050, together with earlier forecasts. The EIA expects production to grow 55% from 2019 levels by 2034 and exit 2050 at 22% above current levels. This implies the recovery of 22.1 billion barrels over the 2017–2050 period, which is more than triple the 2013 U.S. Geological Survey (USGS) assessment of 7.4 billion barrels of undiscovered technically recoverable resources from the Bakken/Three Forks.[32] As well, neither the USGS estimate of undiscovered technically recoverable resources nor the EIA's estimate of unproven resources have been demonstrated to be economically recoverable. The EIA's estimate of unproven resources alone is 116% higher than the USGS estimate. Moreover, the EIA's forecast exits 2050 at 1.6 mbd, implying that there will be considerable additional volumes of oil remaining for recovery after 2050. Given the above, the EIA's forecast for the Bakken Play is rated as extremely optimistic.

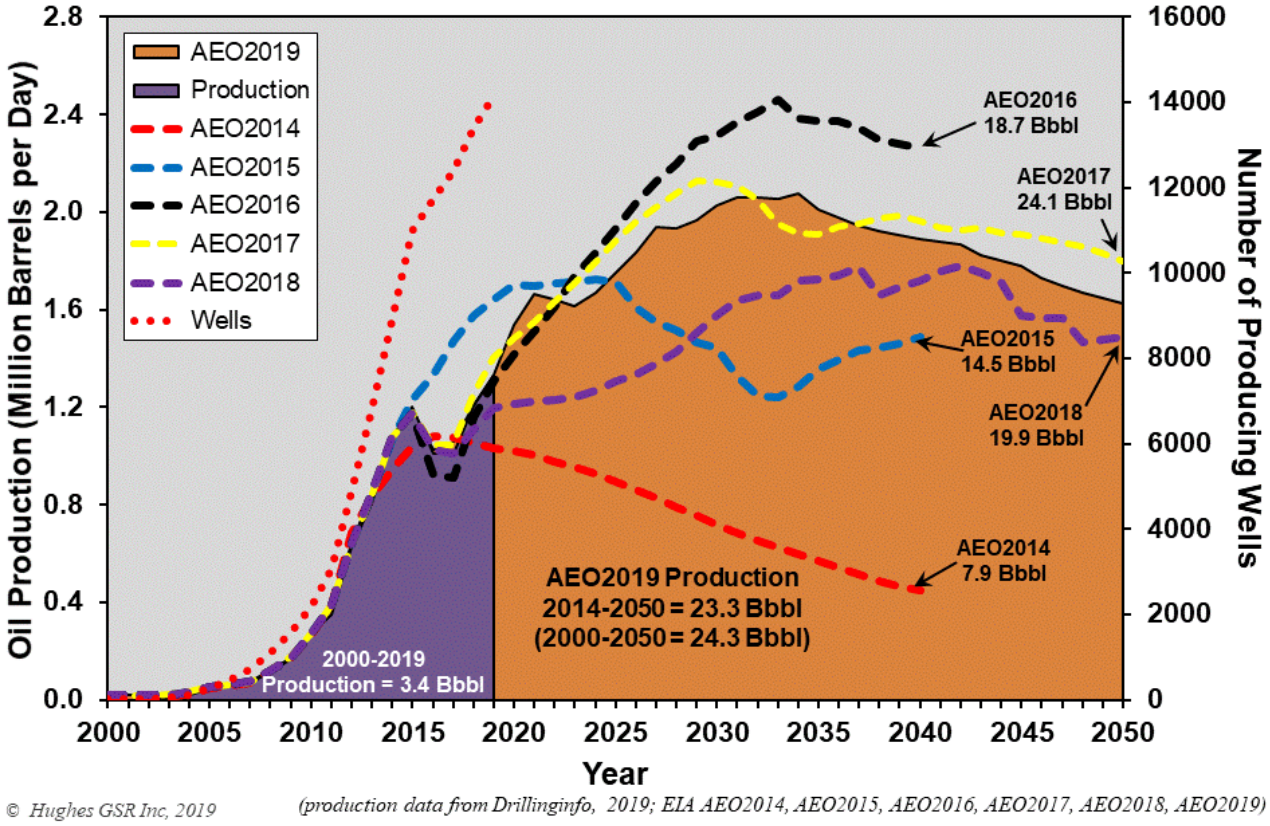

Figure 13. AEO2019 reference case Bakken Play oil production forecast through 2050.

Also shown are earlier AEO forecasts through 2040 and 2050, and cumulative 2000-2019 production. Bbbl=billion barrels.

[32] USGS, 2013, *Assessment of Undiscovered Oil Resources in the Bakken and Three Forks Formations, Williston Basin Province, Montana, North Dakota, and South Dakota, 2013*, U.S. Geological Survey, http://pubs.usgs.gov/fs/2013/3013/

Table 2 illustrates assumptions in the EIA AEO2019 reference case forecast.[33] If realized, the EIA forecast would have to recover 103% of the EIA's estimate of proven reserves plus unproven resources, and would require 105,058 wells—seven times the current total—at a drilling and completion cost of $819 billion.

EIA AEO2019 Reference Case Forecast	
Proven Reserves year-end 2017 (Bbbls)[34]	5.45
Unproven Resources 2017 (Bbbls)[35]	16.0
Total Potential 2017 (Bbbls)	21.45
2017-2050 Recovery (Bbbls)	22.11
% of total potential used 2017-2050	103.1%
Wells needed for available potential 2017-2050	105,058
Well cost 2017-2050 ($billions)	$819

Table 2. EIA assumptions for Bakken Play oil in the AEO2019 reference case.

Well costs of $819 billion for full development are estimated assuming an average well cost of $7.8 million.[36] The number of wells needed was determined using EIA EUR estimates for unproven resources assuming EUR per well would be twice as high for proven reserves as for unproven resources. Total well costs are to extract 100% of proven reserves and unproven resources – available proven reserves and unproven resources fall short of AEO2019 forecast extraction requirement through 2050 by 0.66 billion barrels.

[33] Unproved technically recoverable resources are from EIA, *Assumptions to the Annual Energy Outlook 2019*, https://www.eia.gov/outlooks/aeo/assumptions/; Proven reserves are from *U.S. Crude Oil and Natural Gas Proved Reserves, Yearend 2017*, https://www.eia.gov/naturalgas/crudeoilreserves/.
[34] EIA, 2018, U.S. Crude Oil and Natural Gas Proved Reserves, Yearend 2017, https://www.eia.gov/naturalgas/crudeoilreserves/
[35] EIA, 2019, Oil and Gas Supply Module for AEO2019, https://www.eia.gov/outlooks/aeo/assumptions/pdf/oilgas.pdf
[36] EIA, 2016, Trends in U.S. Oil and Natural Gas Upstream Costs, https://www.eia.gov/analysis/studies/drilling/pdf/upstream.pdf

Synopsis

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

- The EIA has considerably overestimated the prospective play area compared to the current prospective drilled area. The few low productivity wells drilled outside the current prospective drilled area suggest that the viable extent of the play has been fairly well defined.
- The EIA reference case forecast requires recovering 103% of its estimates of remaining proven reserves plus unproven resources by 2050, so the EIA forecast cannot be met with its current reserve/resource estimates. Yet, its forecasts projects production levels 22% higher than at present in 2050, implying that there will be vast additional resources remaining to be recovered after 2050.
- Drilling the 105,058 new wells required to extract all of the EIA's estimated unproved resources plus proven reserves (per the EIA AEO2019 assumptions and 2017 proven reserves), in addition to the 15,552 wells already drilled, would increase the effective well density in the prospective play area to 16.6 wells per square mile (given that each well with a 10,000-foot horizontal lateral accesses two square miles). This is highly unlikely to be economic given well interference already evident at some locations. Available resources can likely be recovered with a much lower well density, which suggests that ultimate recoverable resources are far less than the EIA estimates.
- Well productivity improvements in the top producing county have flat-lined, indicating that better technology is reaching the law of diminishing returns, and drillable sweet-spot well locations are running out.
- Considerably higher drilling rates will be required to maintain production once sweet spots become saturated with wells and drilling moves into lower productivity reservoir rocks. Higher prices will be required to justify this drilling.
- Given the above, the EIA production forecast is rated as extremely optimistic.

2.2 Eagle Ford Play

The Eagle Ford Play in southern Texas rose from nothing in 2008 to become the largest tight oil play in the U.S. when it peaked in March 2015. Figure 14 illustrates production from 2008 through April 2019. 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 21,400 wells have been drilled, of which more than 20,300 are still producing.

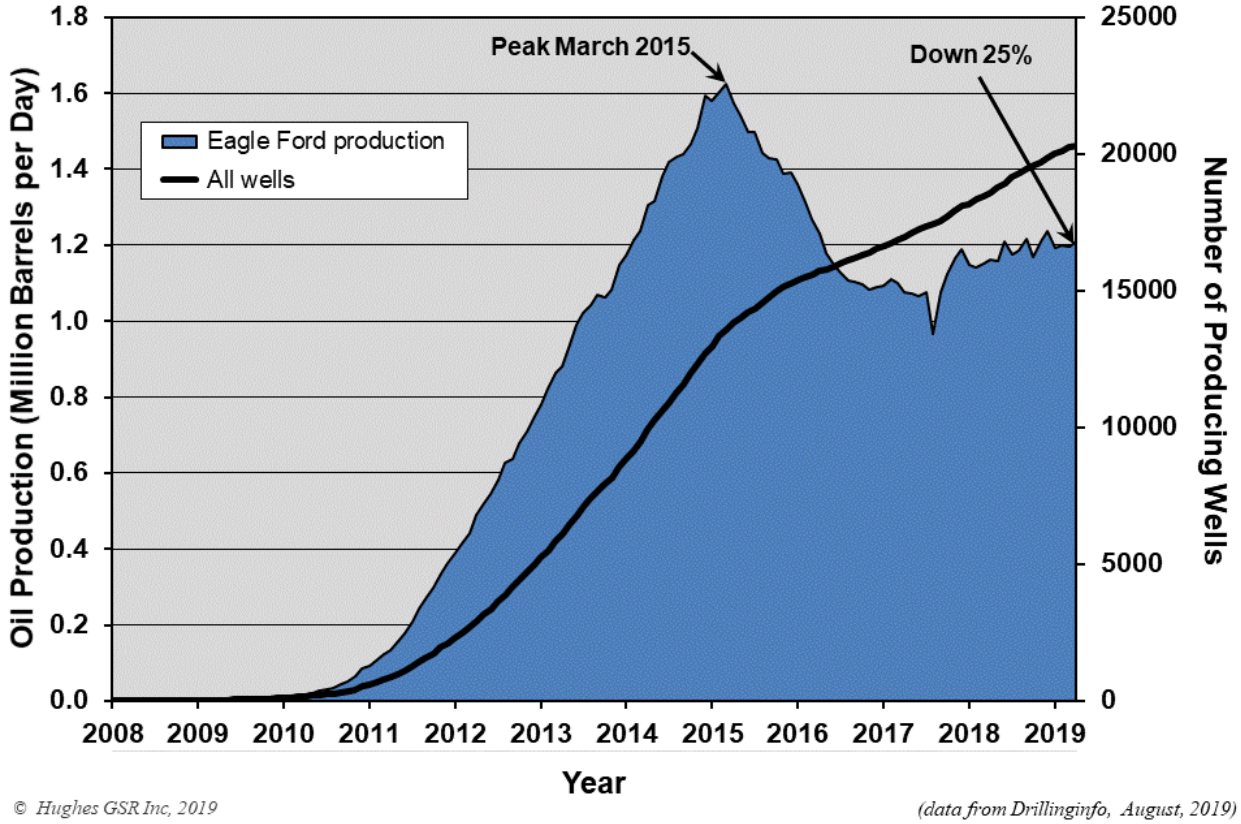

Figure 14. Eagle Ford Play oil production and number of producing wells, 2008–2019.
Production peaked in March 2015 and was down 25% as of April 2019.

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, and Dimmit 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.[37] The EIA AEO2019 assumptions suggest that 13,772 square miles can be drilled at a density of 6.95 wells per square mile to recover unproved resources, which does not include wells needed to recover proven reserves or the wells drilled to date.[38]

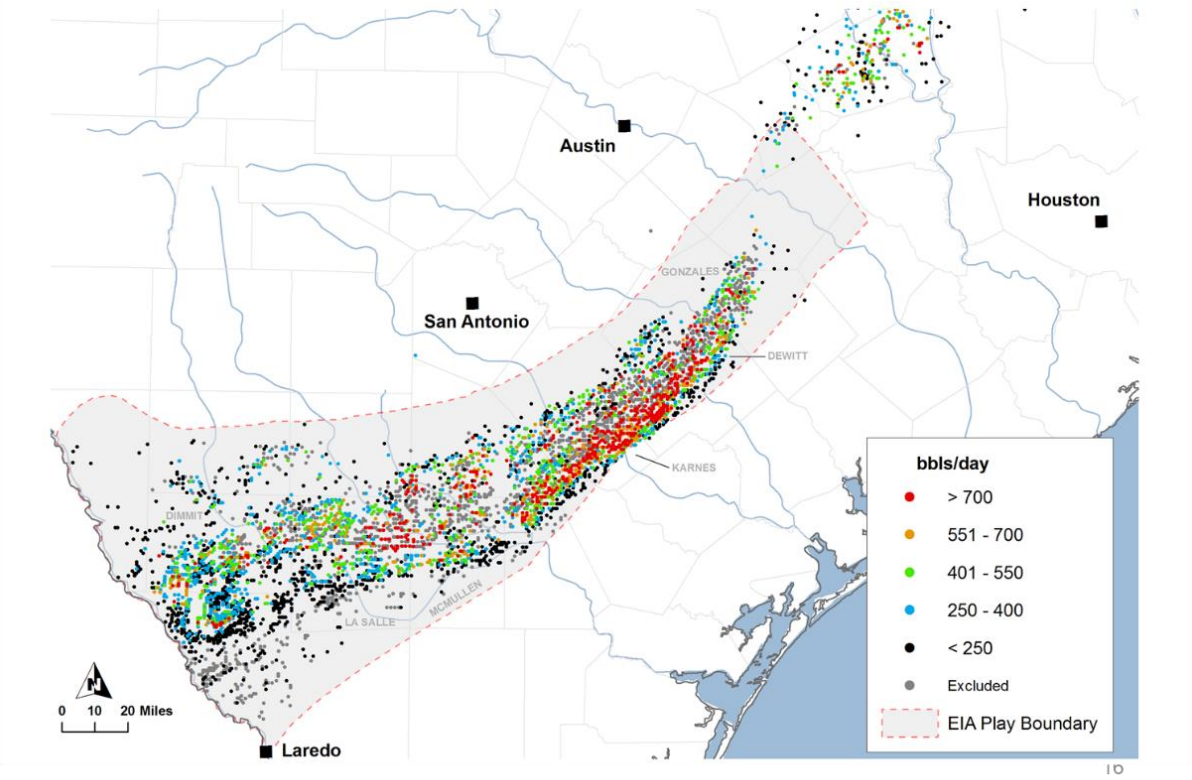

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Figure 15. Eagle Ford Play well locations showing peak oil production in the highest month.

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.[39]

[37] 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.
[38] EIA, Wells need for unproved technically recoverable resources are from *Assumptions to the Annual Energy Outlook 2019*, https://www.eia.gov/outlooks/aeo/assumptions/; Proven reserves are from *U.S. Crude Oil and Natural Gas Proved Reserves, Yearend 2017*, https://www.eia.gov/naturalgas/crudeoilreserves/
[39] 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 81% 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.

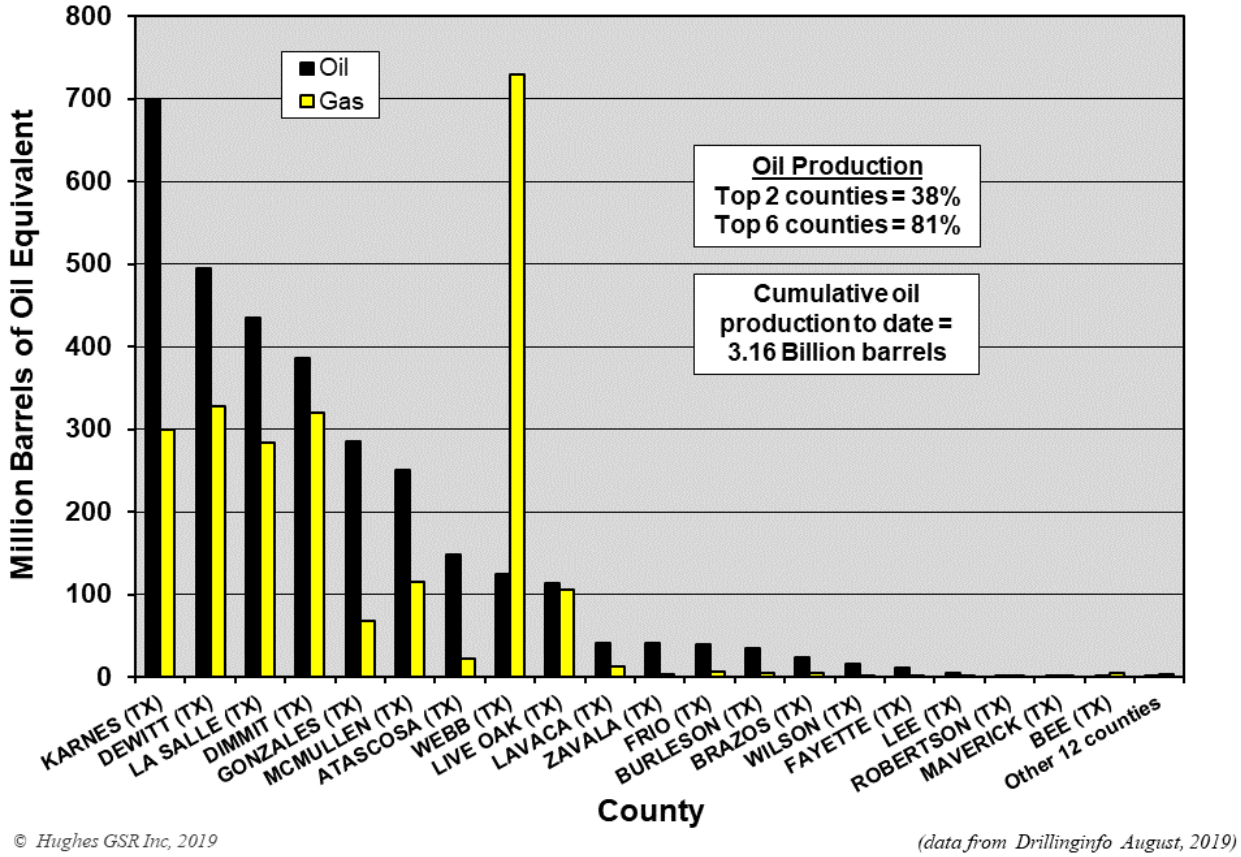

Figure 16. Cumulative production of oil and gas from the Eagle Ford Play by county.

Production is highly concentrated in sweet spots, with 81% of cumulative production from the top 6 counties.

Table 3 shows the number of wells drilled by vintage, cumulative and current production, and well- and first-year field-decline rates for the Eagle Ford as a whole and for individual counties. Three-year well decline rates average 88.6% and first-year field decline rates average 23.3% per year without new drilling, which is at the lower end of the range for shale plays analyzed in this report.

County	Well type	Vintage	Total Well Count	Producing Well Count	Cumulative Oil Production (billion bbls)	Cumulative Gas Production (tcf)	Oil Production April 2019 (Kbbls/day)	Gas Production April 2019 (bcf/day)	3-year well decline (%)	First-year Field decline (%)
All	All	All	21,391	20,302	3.161	13.952	1201.1	5.522	88.6	23.3
Dewitt	All	All	1,873	1,762	0.494	1.972	163.8	0.74	92.2	15.6
Dimmit	All	All	3,396	3,263	0.386	1.918	160.2	0.79	90.0	32.6
Karnes	All	All	3,359	3,235	0.699	1.798	256.8	0.74	86.0	15.1
La Salle	All	All	3.348	3,211	0.435	1.707	183.3	0.64	88.6	36.1
Other counties	All	All	9.415	8,836	1.146	6.557	445.1	2.66	89.1	21.7

Table 3. Well count, cumulative production, most recent production, and well- and first-year 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 in 2018 was 7,736 feet. Most well pads have multiple wells. Well interference has been noted at close well spacings between early "parent" wells and later infill "child" wells. This suggests, as in other plays, that production is compromised by crowding wells too closely together.[40] Moreover, although 6-month production of wells has increased somewhat overall due to increased proppant and water injection in the Eagle Ford play, 12-month and 24-month production has decreased, suggesting improved technology has front-loaded production, but that ultimate well recovery is falling.[41]

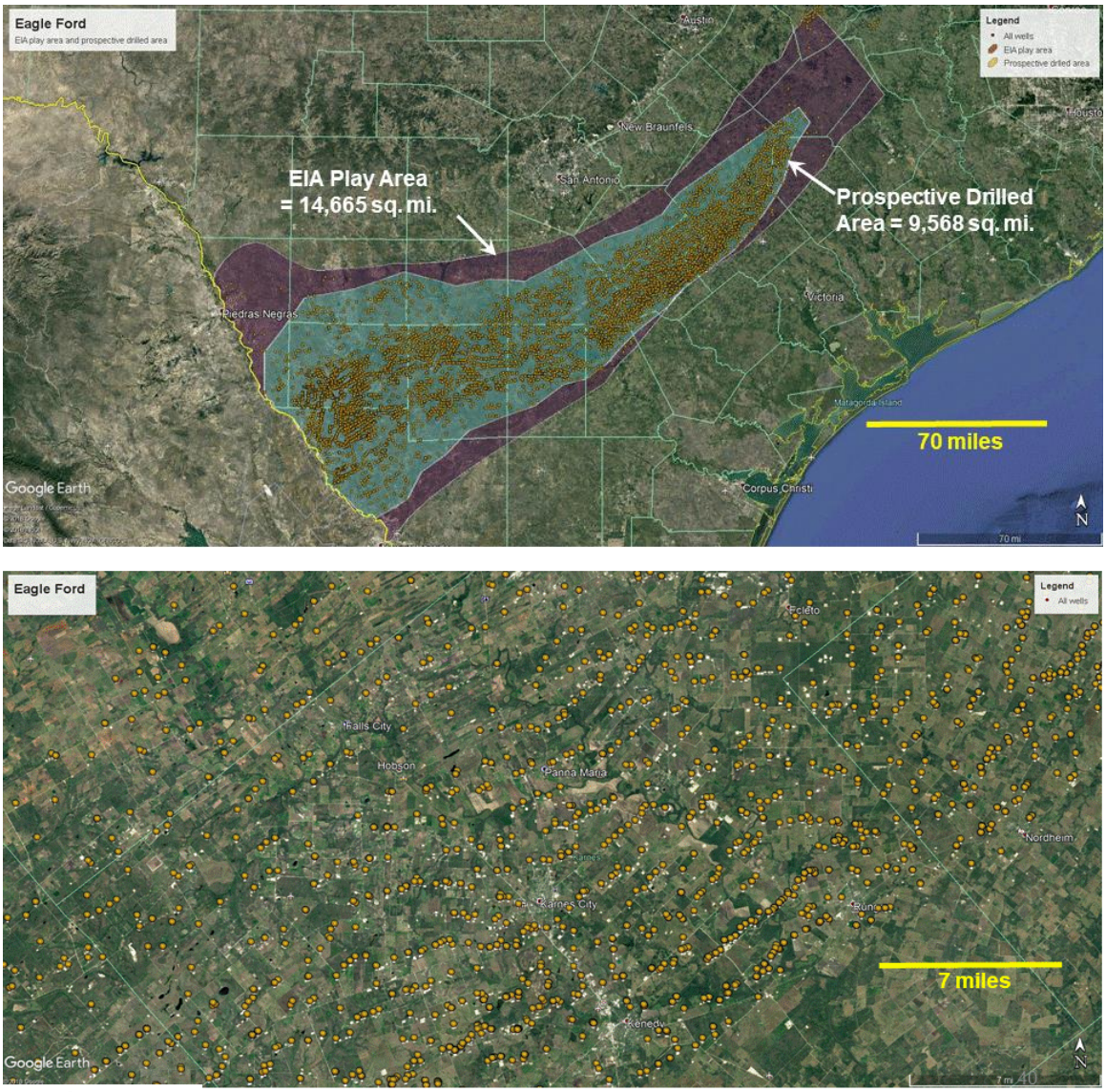

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Figure 17. Drilling density in the core area of the Eagle Ford Play.

Upper: EIA Eagle Ford play area and prospective drilled area. Lower: Core area of the Eagle Ford Play in Karnes County showing well locations and degree of development as of April 2019.

[40] Rystad Energy, December, 2017, *Empirical evidence for collapsing production rates in Eagle Ford*, https://communications.rystadenergy.com/acton/rif/12327/s-04e3-1712/-/l-0044:4dab/q-005a/showPreparedMessage?sid=TV2:x1Eq3cVo4

[41] J.D. Hughes, 2019, *How long will the shale revolution last? Technology versus Geology and the Lifecycle of Shale Plays*, Post Carbon Institute, https://www.postcarbon.org/publications/how-long-will-the-shale-revolution-last/

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, followed by the top four counties between March and May 2015. The top four counties now make up 63% of production.

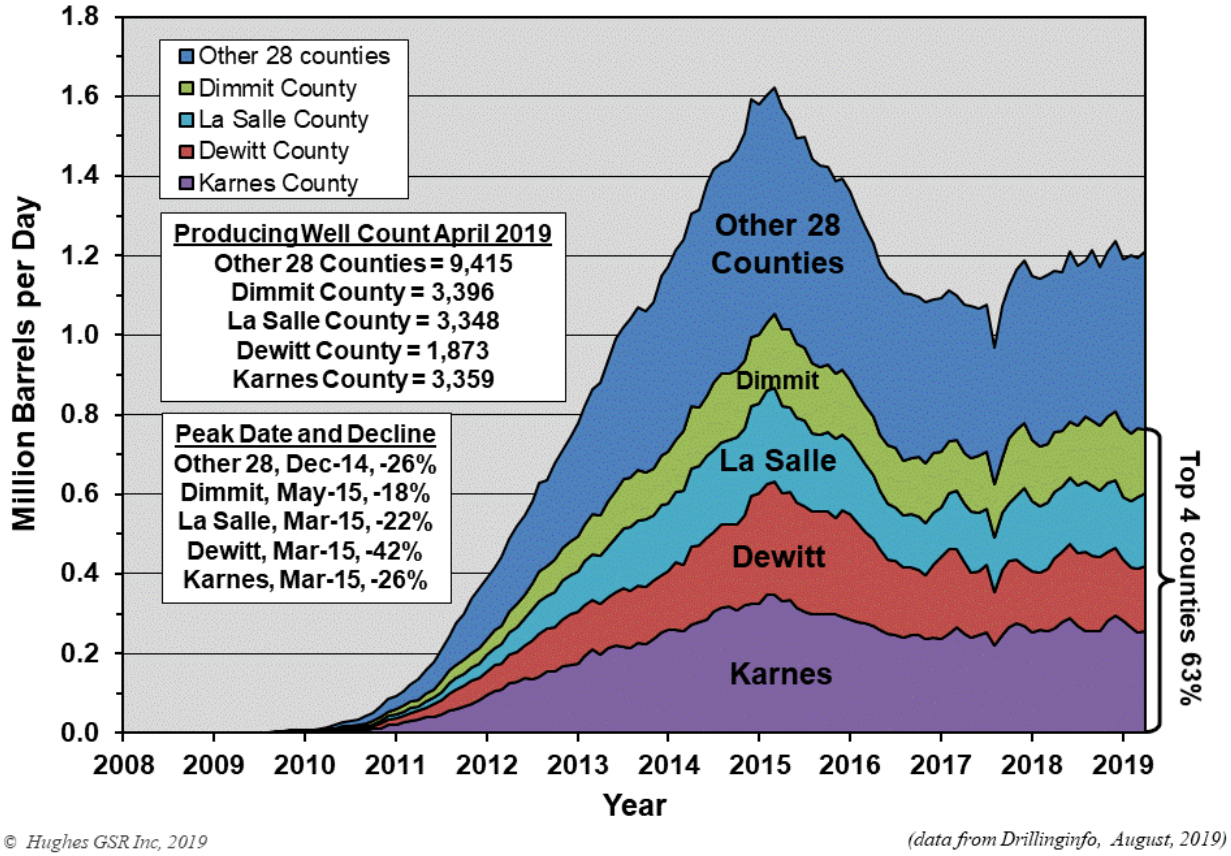


Figure 18. Oil production in the Eagle Ford Play by county showing peak dates and percentage decline from peak, 2008–2019.

Figure 19 illustrates the change in average well productivity in the Eagle Ford Play over the past six years. Although average well productivity increased somewhat in the 2012–2017 period, it flat-lined in 2018 despite more advanced technology, and well productivity in three of the top four counties declined. Only Karnes County demonstrated a productivity increase. As noted earlier, increasing proppant and water injection volumes has increased overall 6-month well production somewhat, but 12-month and 24-month production has fallen, suggesting technology has reached the law of diminishing returns and that drilling is moving out of sweet-spots. Exhaustion of sweet-spots will require higher drilling rates and prices to maintain production.

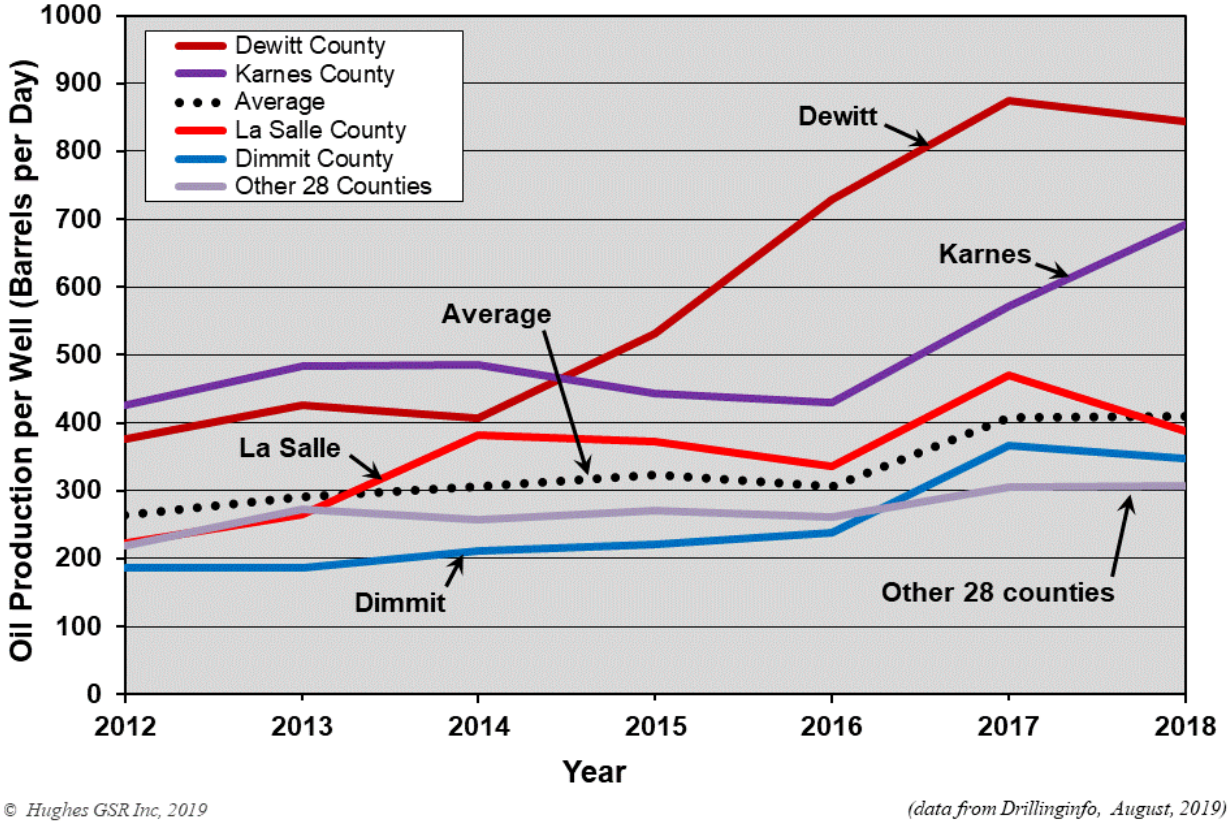


Figure 19. Average well productivity over the first four months of oil production by county in the Eagle Ford Play, 2012–2018.

Figure 20 illustrates the EIA's AEO2019 reference case oil production forecast for the Eagle Ford Play through 2050, together with earlier forecasts. The EIA expects production to increase 41% over current levels by 2021, despite production already having declined 25% from its peak in 2015, and to still be producing at 9% above current levels in 2050. Production over the 2014-2050 period is forecast to be 20.6 billion barrels, or more than six times production to date. This would require production of 106% of the EIA's own estimate of proven reserves plus unproven resources by 2050.

The USGS completed an assessment of continuous resources in the Eagle Ford Play in 2018.[42] Mean, undiscovered, technically recoverable resources were estimated at 8.5 billion barrels (note that neither the USGS undiscovered technically recoverable resources nor the EIA's unproven resources have been demonstrated to be economically recoverable). This means that the EIA's estimate of unproven resources is 55% higher than the USGS estimate, rendering the 106% overshoot of the EIA's own estimates even more unrealistic. Moreover, the EIA's forecast exits 2050 at 1.3 mbd, 9% above current levels, implying that there will be considerable additional oil recovered after 2050. Given the above, the EIA's forecast for the Eagle Ford Play is rated as extremely optimistic.

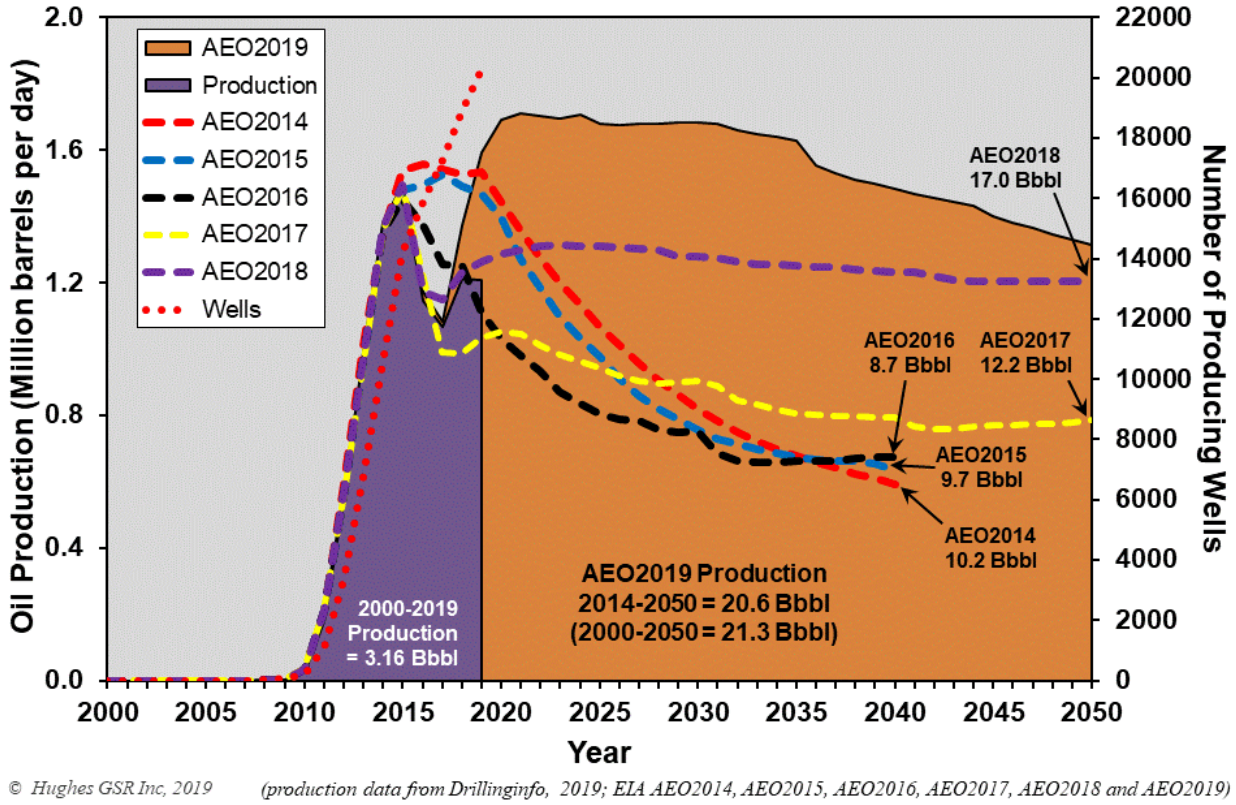


Figure 20. EIA AEO2019 reference case Eagle Ford Play oil production forecast through 2050.

Also shown are earlier AEO forecasts to 2040 and 2050, and cumulative 2000-2019 production.

[42] USGS, 2018, *Assessment of Undiscovered Oil and Gas Resources in the Eagle Ford Group and Associated Cenomanian–Turonian Strata, U.S. Gulf Coast, Texas, 2018,* https://pubs.usgs.gov/fs/2018/3033/fs20183033.pdf

Table 4 illustrates assumptions in the EIA AEO2019 reference case forecast.[43] If realized, the EIA forecast would, as mentioned above, have to recover 106% of the EIA's estimate of proven reserves plus unproven resources by 2050, and would require 112,123 additional wells, for a total well count of more than six times the current number, at an estimated cost of $841 billion.

EIA AEO2019 Reference Case Forecast	
Proven Reserves year-end 2017 (Bbbls)[44]	4.82
Unproven Resources 2017 (Bbbls)[45]	13.2
Total Potential 2017 (Bbbls)	18.02
2017-2050 Recovery (Bbbls)	19.13
% of total potential used 2017-2050	106.2%
Wells needed for available potential 2017-2050	112,123
Well cost 2017-2050 ($billions)	$841

Table 4. EIA assumptions for Eagle Ford Play oil in the AEO2019 reference case.

Well costs of $841 billion for full development are estimated assuming an average well cost of $7.5 million.[46] The number of wells needed was determined using EIA EUR estimates for unproven resources, assuming EUR per well would be twice as high for proven reserves as for unproven resources. Total well costs are to extract 100% of proven reserves and unproven resources. Available resources fall short of the AEO2019 forecast extraction requirement through 2050 by 1.11 Bbbls.

[43] EIA, Unproved technically recoverable resources are from *Assumptions to the Annual Energy Outlook 2019*, https://www.eia.gov/outlooks/aeo/assumptions/; Proven reserves are from *U.S. Crude Oil and Natural Gas Proved Reserves, Yearend 2017*, https://www.eia.gov/naturalgas/crudeoilreserves/

[44] EIA, 2018, U.S. Crude Oil and Natural Gas Proved Reserves, Yearend 2017, https://www.eia.gov/naturalgas/crudeoilreserves/

[45] EIA, 2019, Oil and Gas Supply Module for AEO2019, https://www.eia.gov/outlooks/aeo/assumptions/pdf/oilgas.pdf

[46] EIA, 2016, Trends in U.S. Oil and Natural Gas Upstream Costs, https://www.eia.gov/analysis/studies/drilling/pdf/upstream.pdf

Synopsis

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

- The Eagle Ford Play grew from nothing beginning in 2008 to reach a peak in early 2015, when it was the largest tight oil producer in the U.S. Production in April 2019 was down 25% from its peak. As of April 2019, 21,391 wells have been drilled.

- The Eagle Ford play area is estimated by the EIA at 14,665 square miles compared to a prospective drilled play area of 9,568 square miles (see Figure 17). At the EIA's assumed well density of 6.8 wells per square mile, 16,488 square miles would be required to accommodate the 112,123 new wells needed to meet the EIA's forecast production by 2050. At the assumed well density, the area required for the EIA's production estimate exceeds the EIA's own Eagle Ford play area estimate by 11% and the prospective drilled area by 42%.

- If existing wells are included, 133,514 wells would be needed by 2050 to meet the EIA production forecast. This would still leave the cumulative production needed to meet the forecast short by 1.11 billion barrels. Unless substantial production could be obtained outside of currently prospective areas, well density would need to rise to 14 wells per square mile. Effective well density—given that horizontal laterals in the Eagle Ford now average 7,736 feet and therefore each well accesses more than one square mile—would rise to 20.4 wells per square mile. This is highly unlikely to be economic given the well interference already evident from spacing wells too close together. Well interference will reduce EURs such that ultimate recovery is extremely likely to be much less than the 19.1 billion barrels the EIA assumes will be recovered in the 2017–2050 period.

- Well productivity has flat-lined or declined in all counties except Karnes, despite increasing injections of proppant and water and longer horizontal laterals. This indicates sweet spots are already becoming saturated and drilling will have to move into lower quality reservoir rocks, necessitating a higher drilling rate to maintain production and higher prices to justify it.

- The EIA's assumption that production will increase 47% above 2019 levels by 2021 and be 9% above current levels in 2050, after recovering more than the EIA's own estimates of proven reserves and unproven resources, are inexplicable as noted above. How can production remain higher than current levels in 2050 after all resources have been exhausted?

- Given the above, the EIA's AEO2019 production forecast for the Eagle Ford is rated as extremely optimistic.

2.3 PERMIAN 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. More than 428,600 wells have been drilled into conventional and unconventional reservoirs within the basin, of which more than 145,300 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.

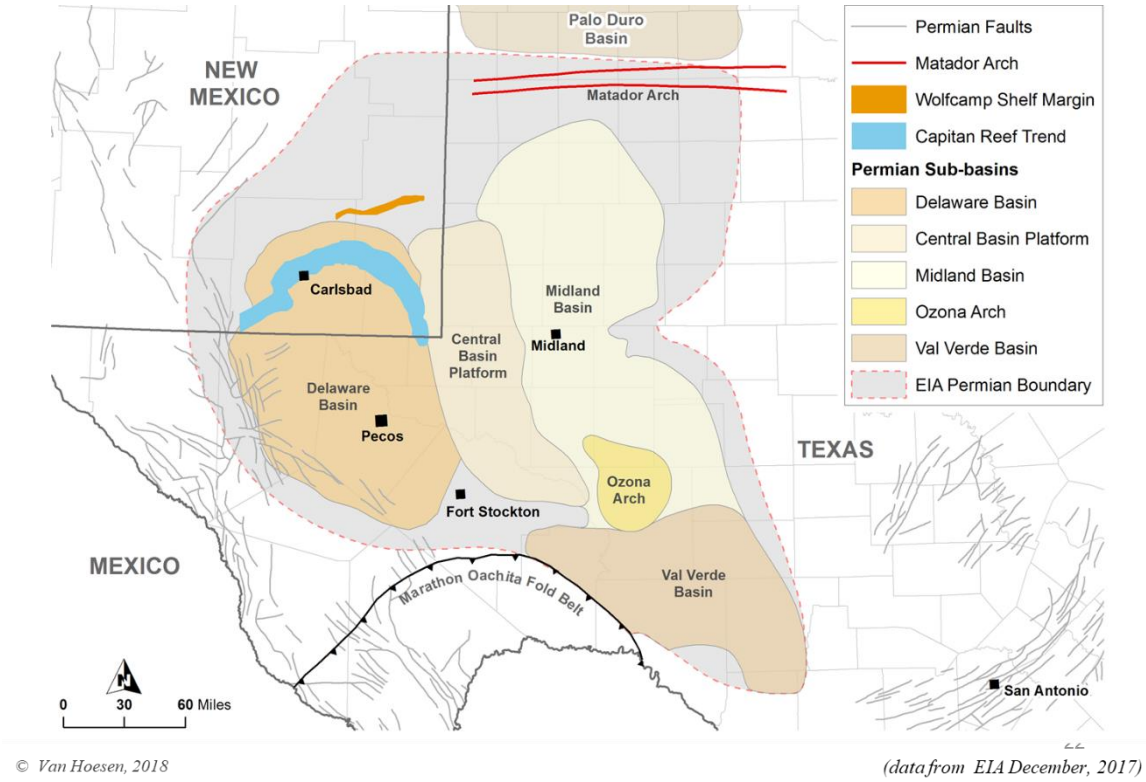


Figure 21. Tectonic features and areal extent of the Permian Basin.[47]

[47] Prepared by Van Hoesen from EIA, December 21 2017, *Permian Basin: boundary, structure and tectonic features*, https://www.eia.gov/maps/map_data/PermianBasin_Boundary_Structural_Tectonic.zip

Production from the Permian basin, which had been in slow decline from a peak of 2.2 mbd in October 1973, has quadrupled since 2011 due to the application of horizontal drilling and modern hydraulic fracturing. Figure 22 illustrates Permian Basin production over the 1990–2019 period. Although the overall producing well count has declined since 2015 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.

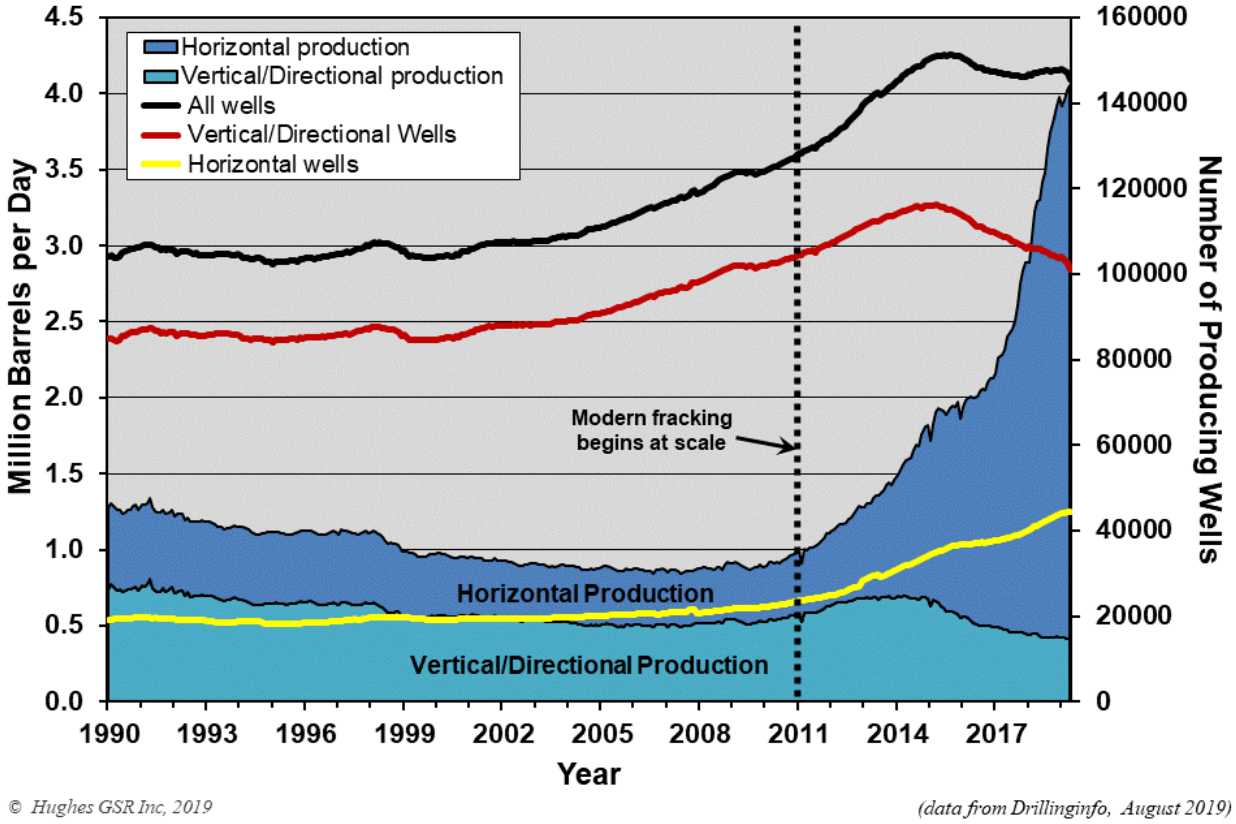


Figure 22. Permian Basin oil production by well type and number of producing wells, 1990–2019.

Figure 23 illustrates the distribution of all Permian Basin wells by quality as defined by production in peak month. The most productive wells are concentrated in the Delaware and Midland basins (see Figure 21) but considerable amounts of conventional production have occurred outside these areas.

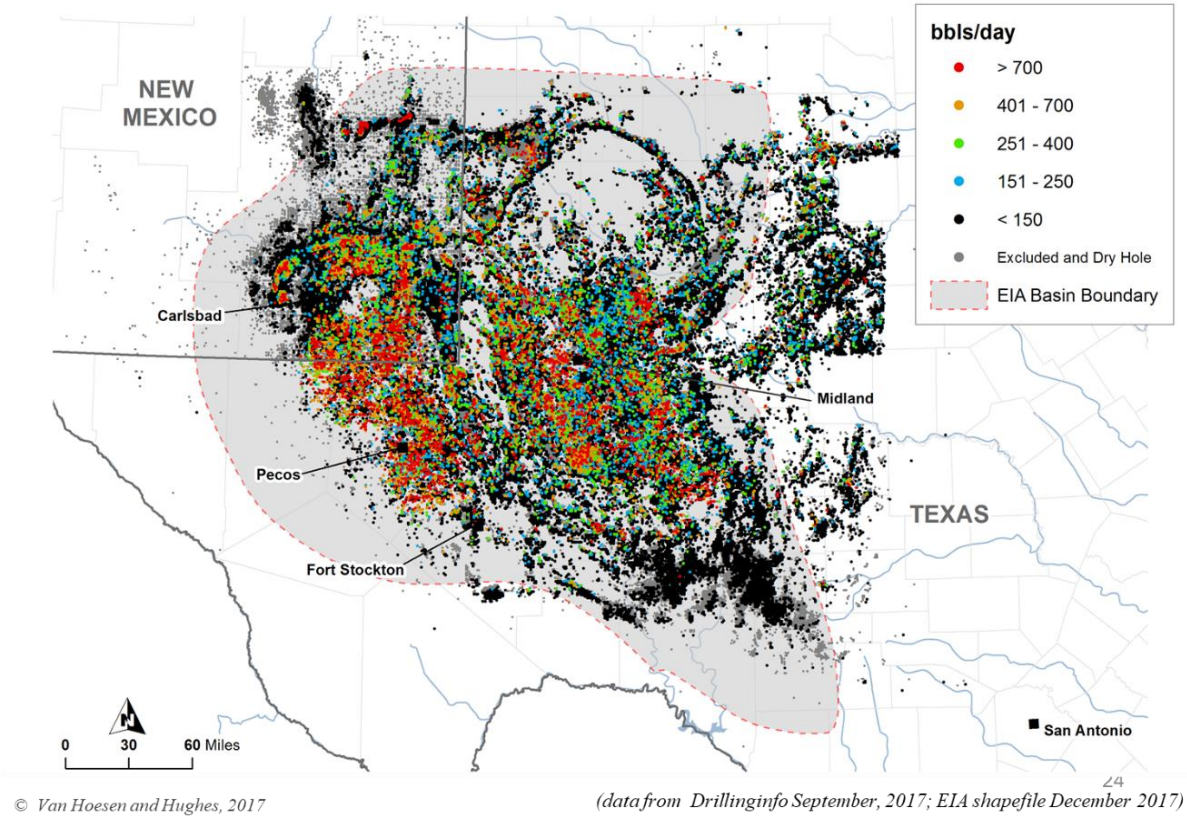


Figure 23. Permian Basin well locations showing peak oil production in the highest month.[48]

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.

[48] Production data from Drillinginfo September, 2017: 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 78% of Permian Basin production in April 2019, even though they account for just 12% of producing wells. Post-2011 vertical and directional wells, which made up eight percent of producing wells, accounted for just three percent of production. The remaining 19% of production came from 112,326 older wells, which constitute 80% of the producing well count.

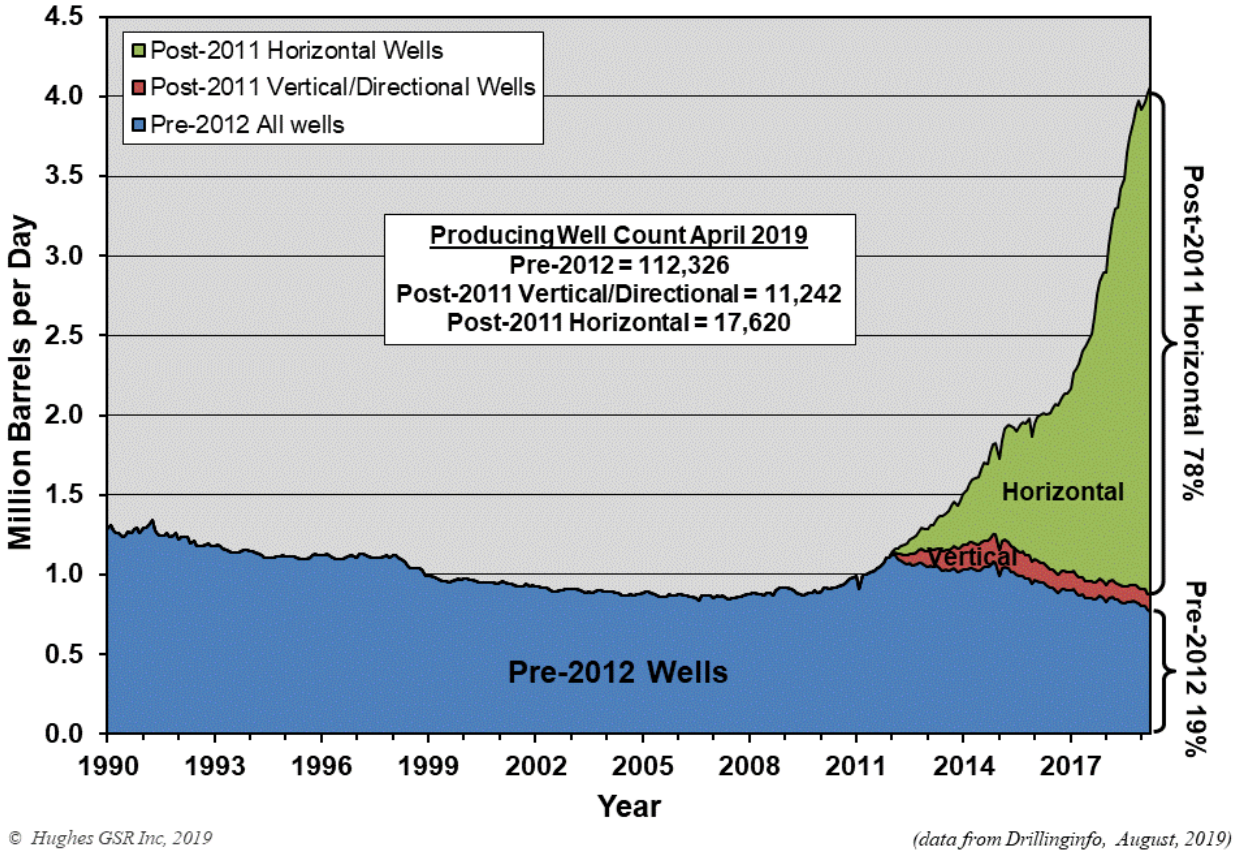


Figure 24. Permian Basin oil production by well type and vintage, 1990–2019.

Post 2011 horizontal wells accounted for 78% of Permian Basin production in April 2019.

Figure 25 illustrates cumulative recovery of oil and gas by county. The Permian Basin is large and encompasses many counties with multiple plays that 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.

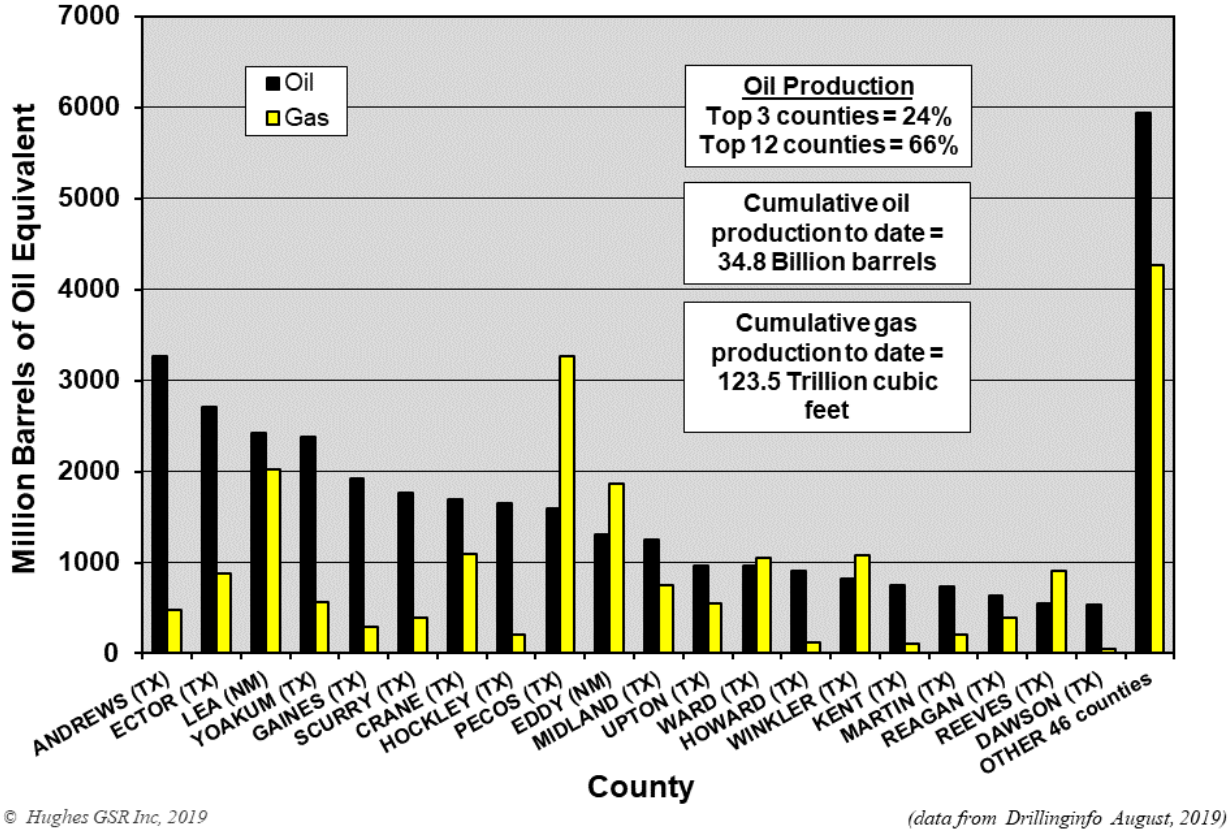


Figure 25. Cumulative production of oil and gas from the Permian Basin by county through 2019.

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 the top three counties.

Much of the 35 billion barrels of oil and 124 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 first peaked in 1973. New production from unconventional plays using fracking technology has been responsible for virtually all of the production increase since 2011. Production from unconventional plays is concentrated in a much smaller portion of the basin than earlier conventional production, as illustrated in Figure 26.

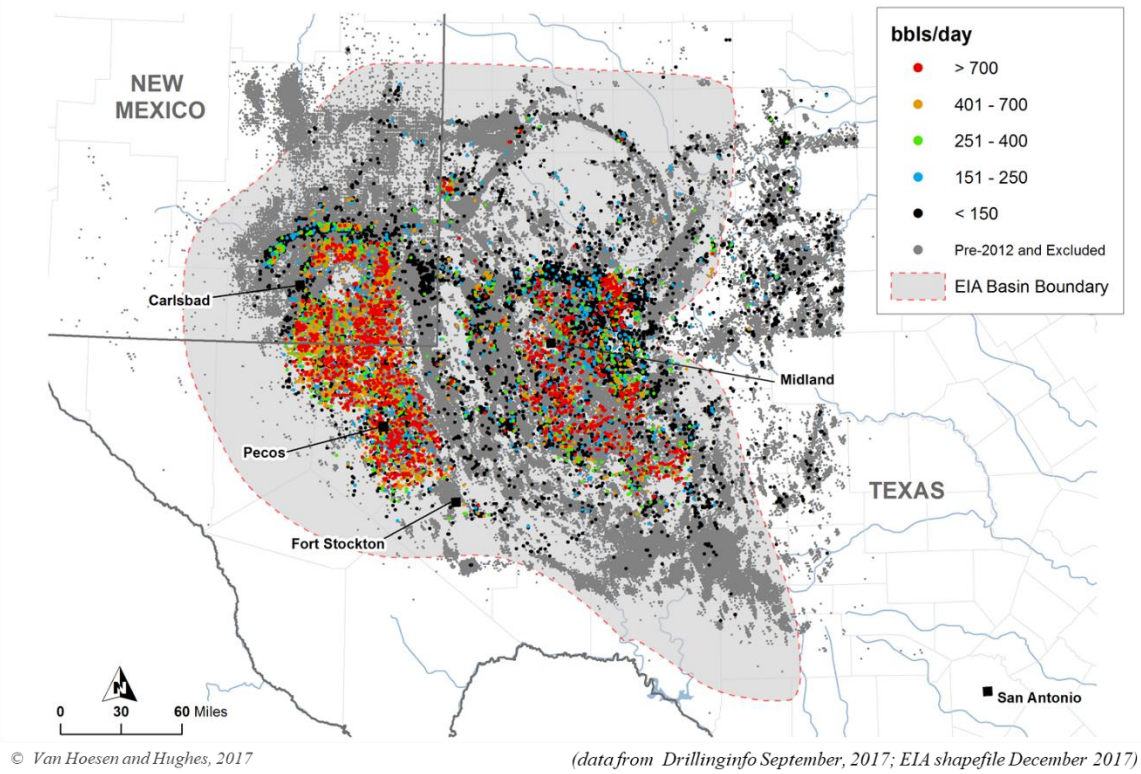


Figure 26. Post-2011 Permian Basin wells showing peak oil production in the highest month.

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.

Figure 27 illustrates cumulative production by county for post-2011 wells, differentiated by well type. Post-2011 production is concentrated in fewer, and different, counties than historical production (Figure 25). The top two counties accounted for 28% of cumulative production from post-2011 horizontal wells, with 67% in the top six counties. The high productivity of horizontal wells compared to vertical/directional wells is starkly evident.

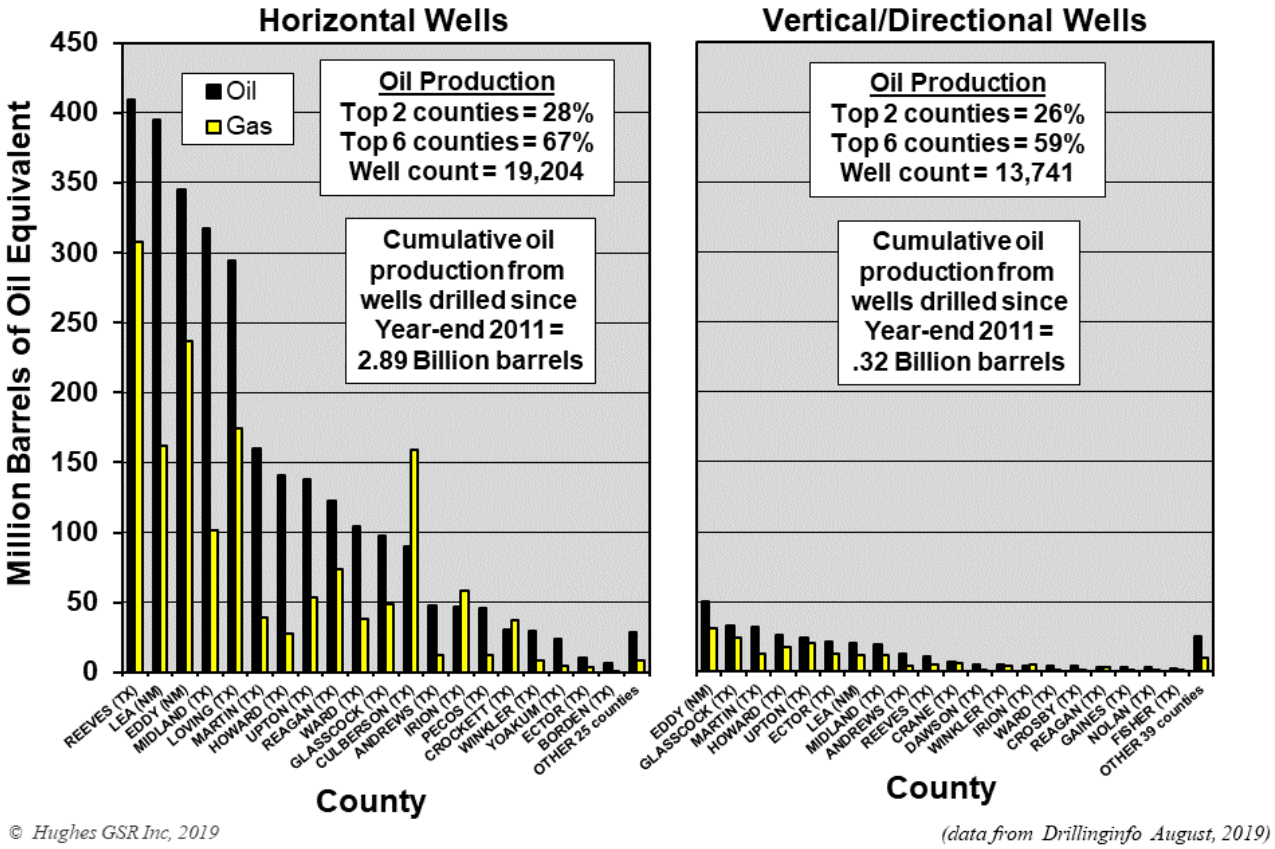


Figure 27. Cumulative production of oil and gas by county from post-2011 Permian Basin wells by well type through 2019.

Production is largely from unconventional reservoirs and the distribution of production by county is quite different compared to historical production in the basin as shown in Figure 25. Total well count is also shown, which is a superset of the producing well count noted in Figure 24.

Table 5 shows the number of wells drilled, cumulative and current production, and well- and first-year 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 87.3%, but are lower, at 61.8%, for pre-2012 wells, many of which were drilled for conventional resources, and are as high as 91.1% in Eddy County in New Mexico (one of the top counties for post-2011 cumulative production). First-year field declines average 22.4% per year for the basin as a whole, but are just 4.8% for pre-2012 wells, given that they are older and in the lower decline portion of the typical well decline curve. First-year field declines in post-2011 horizontal wells average 30.5%, but range up to 52.6% in Eddy County and 47.1% in Lea County (both in the top three counties for post-2011 cumulative production), which are at the high end of the range observed in major shale plays and require high drilling rates to keep production flat.

County	Well type	Vintage	Total Well Count	Producing Well Count	Cumulative Oil Production (billion bbls)	Cumulative Gas Production (tcf)	Oil Production April 2019 (Kbbls/day)	Gas Production April 2019 (bcf/day)	3-year well decline (%)	First-year field decline (%)
All	All	All	428,655	145,388	34.805	123.554	4062.0	13.80	87.3	22.4
All	All	Pre-2012	395,385	116,230	31.536	112.796	822.1	2.86	61.8	4.8
All	Horizontal	Post-2011	19,529	17,709	2.949	9.640	3140.1	10.52	86.1	30.5
All	Vertical	Post-2011	13,741	11,449	0.320	1.118	99.8	0.42	69.6	14.7
Eddy	Horizontal	Post-2011	2,666	2,320	0.350	1.443	320.1	1.41	91.1	52.6
Lea	Horizontal	Post-2011	2,293	2,129	0.403	0.992	417.9	1.11	91.7	47.1
Loving	Horizontal	Post-2011	1,655	1,403	0.301	1.070	325.9	1.03	78.4	12.6
Midland	Horizontal	Post-2011	1,517	1,407	0.321	0.618	389.0	0.85	78.4	10.1
Reeves	Horizontal	Post-2011	2,618	2,381	0.421	1.919	496.7	2.48	82.5	30.4
Other counties	Horizontal	Post-2011	8,780	8,069	1.153	3.598	1190.5	3.64	87.1	11.6

Table 5. Well count, cumulative production, most recent production, and well- and first-year field-decline rates for the Permian Basin and counties within it, by well type and vintage.[49]

[49] From Drillinginfo September, 2019. Note that total well count in line 1 includes 129,299 wells that have never had any production.

Production from post-2011 horizontal wells by county is illustrated in Figure 28. These wells account for 78% of overall Permian Basin production, of which 62% are concentrated in five sweet spot counties, which have garnered more than half of all post-2011 horizontal drilling. Remaining Permian Basin production is scattered over 40 counties.

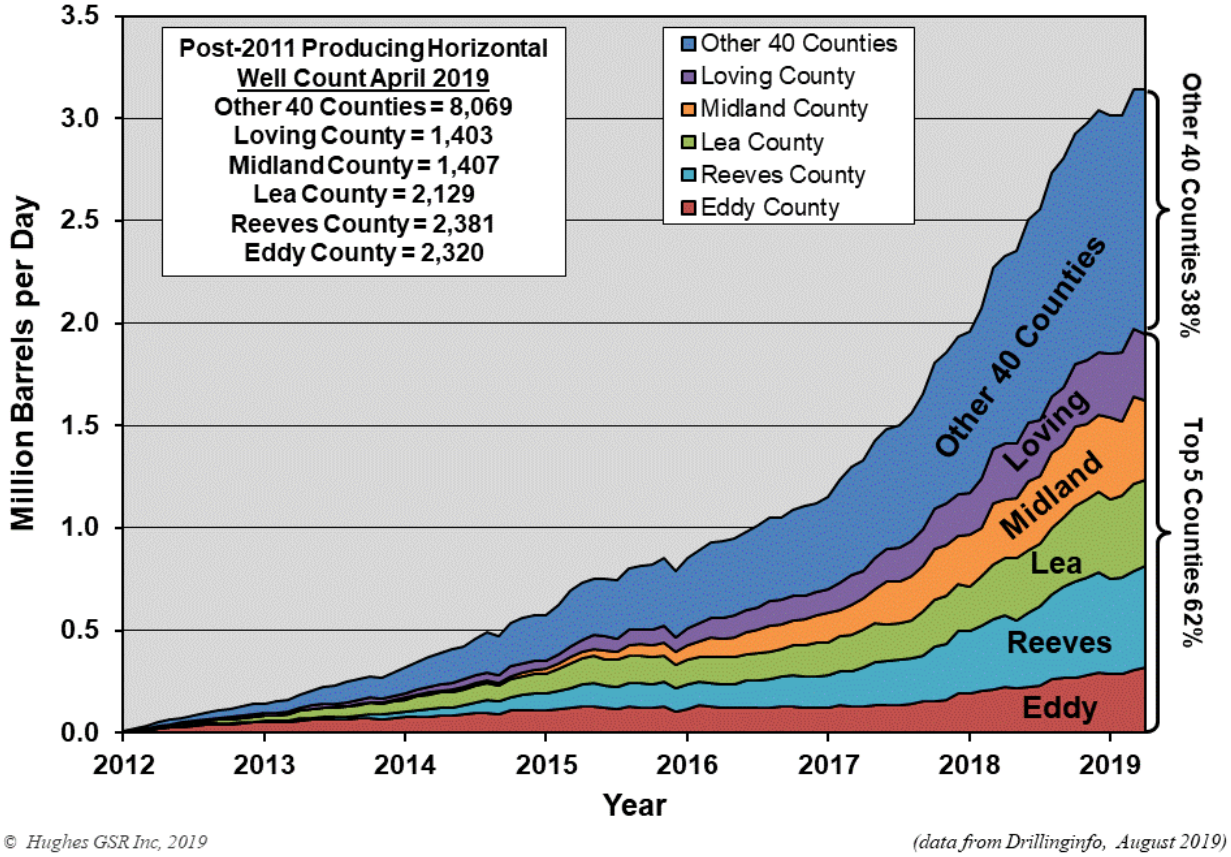


Figure 28. Oil production in the Permian Basin from post-2011 horizontal wells by county, 2012–2019.

As with most other shale plays, the application of better technology has increased well productivity markedly over the 2012–2018 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. Average horizontal well productivity has more than tripled from 2012 levels through 2018, through both better technology and the focus on drilling in sweet spots. Horizontal wells were 30 times more productive on average than vertical/directional wells in 2018, with well productivity highest in Lea and Midland counties (the second and third highest producers in April 2019, respectively).

However, in Reeves County, which was the top producing county in the Permian Basin as of April 2019, well productivity appears to have flat-lined in 2018. Reeves County has seen the most horizontal wells drilled since 2011 of any county, and the flat-lining of productivity gains suggests sweet spots there may be reaching their limits and over-drilling may be taking its toll. 'Frac hits'—well interference due to spacing wells too close together—are becoming an increasing concern in the Permian Basin and other shale plays.[50,51] Frac hits result from spacing infill "child" wells too close to "parent" wells, which can lower production and EUR in both wells, damaging economics and wasting capital. Over-drilling will not increase ultimate recovery, although it may allow resources to be recovered sooner.

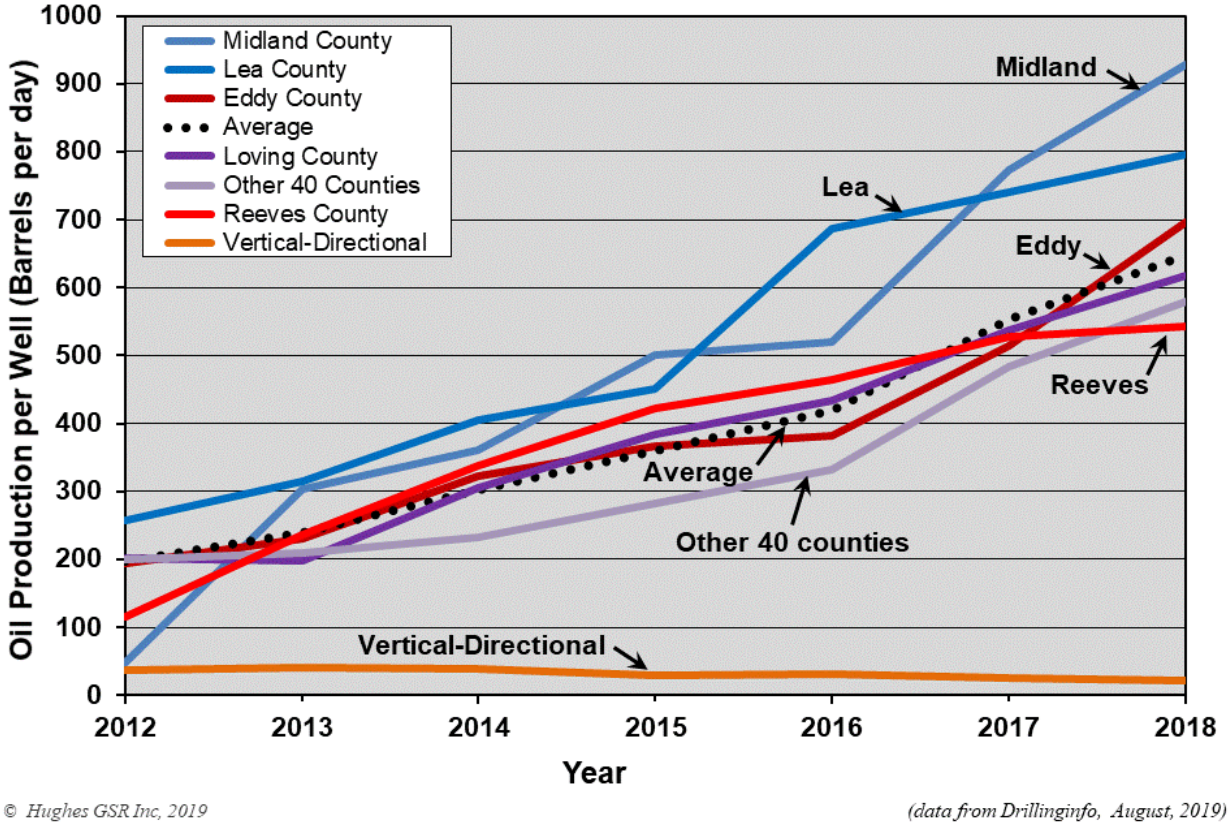


Figure 29. Average horizontal well productivity over the first four months of oil production by county in the Permian Basin, 2012–2018.

[50] Journal of Petroleum Technology, November, 2017, *Frac hits reveal well spacing may be too tight, volumes too large*, https://pdfs.semanticscholar.org/7d1c/9673632be9676556390ab683f8299220a1d8.pdf
[51] J. Triepke, Alphasense, June 9, 2017, *The Fracking Problem with Over Drilling*, https://www.alpha-sense.com/blog/the-fracking-problem-with-over-drilling/

Seventy-seven 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.

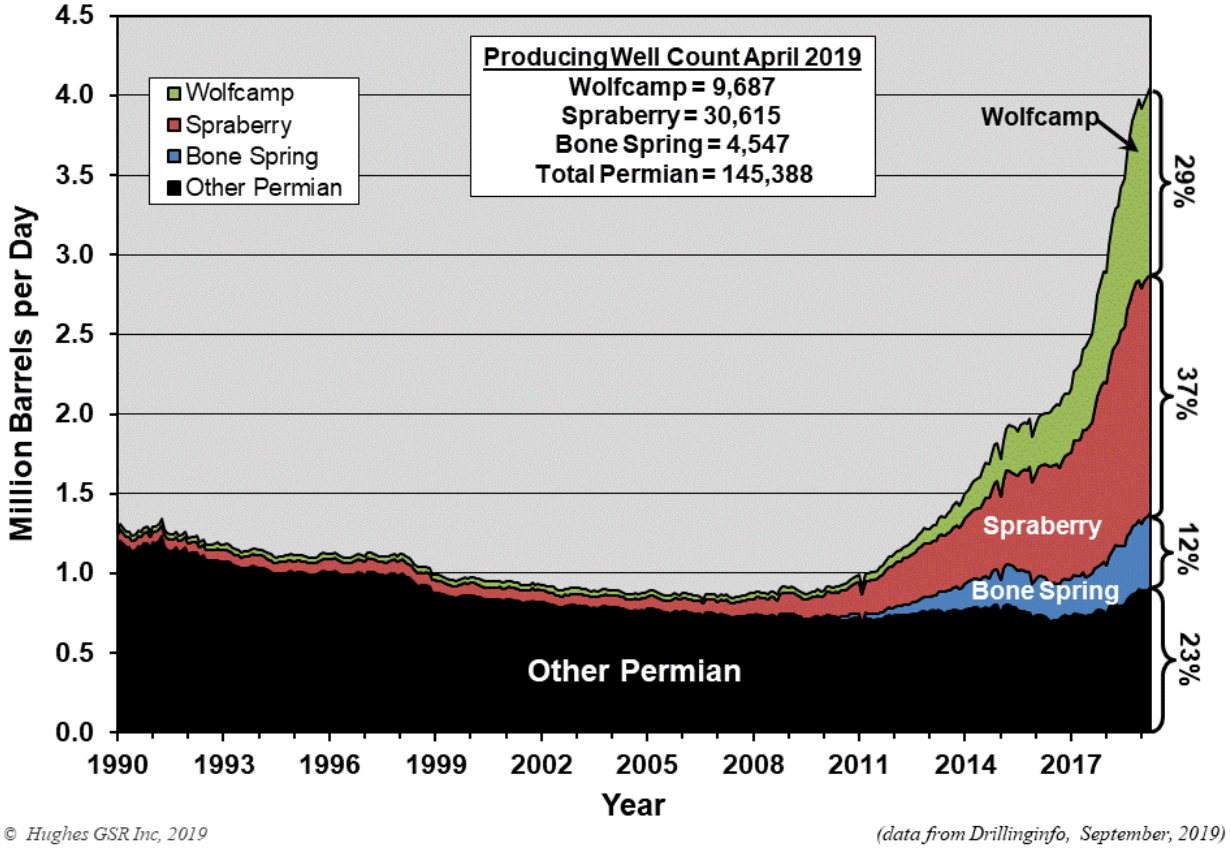


Figure 30. Permian Basin oil production by play, 1990–2019.

Seventy-seven 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.

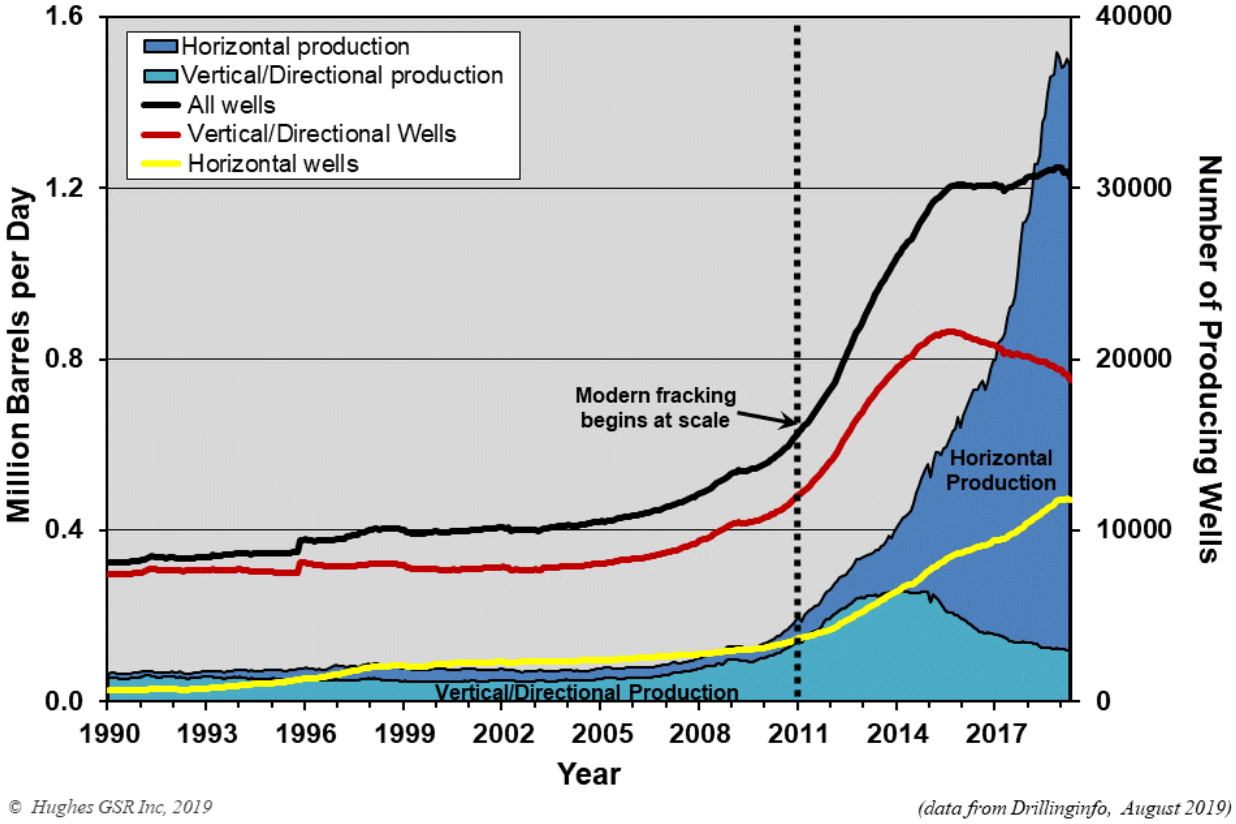


Figure 31. Spraberry Play oil production and number of producing wells by type, 1990–2019.

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.

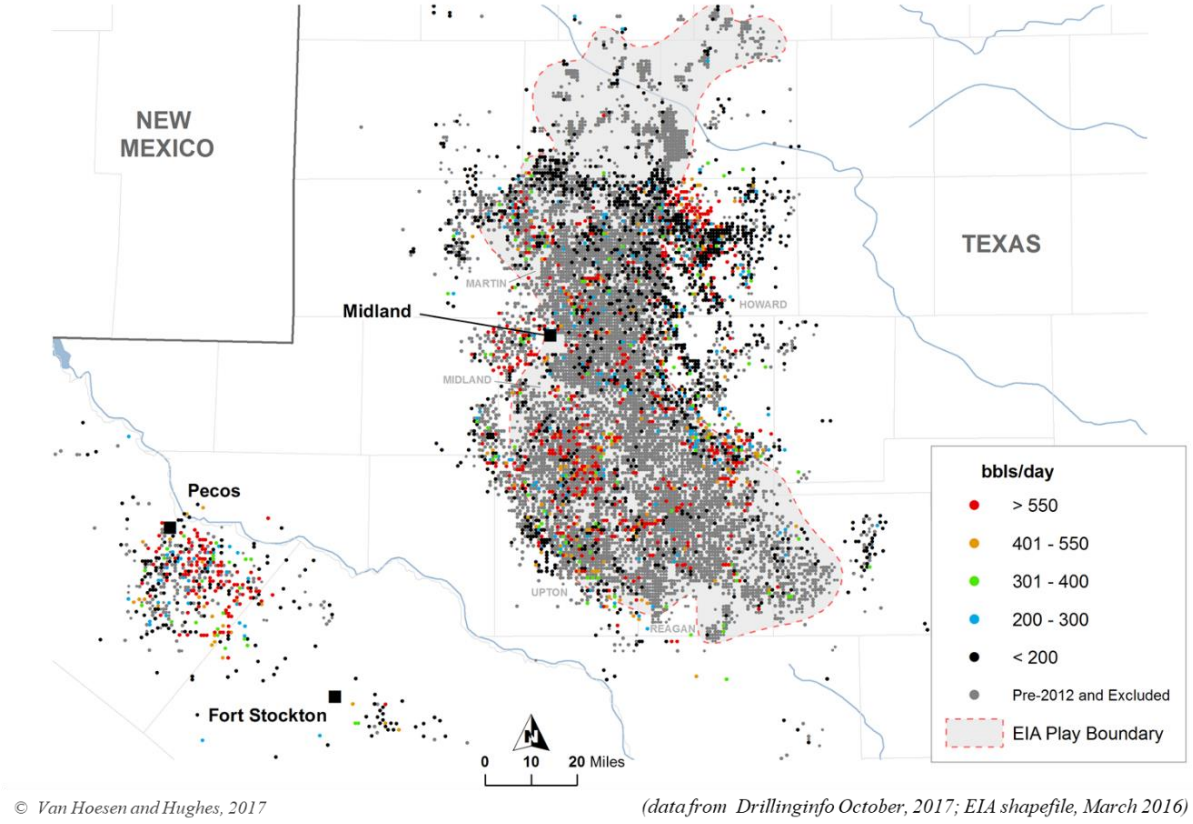


Figure 32. Spraberry Play well locations showing peak oil production of post-2011 wells in the highest month.[52]

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.[53]

[52] 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.
[53] 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 Upton—and 81% 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.

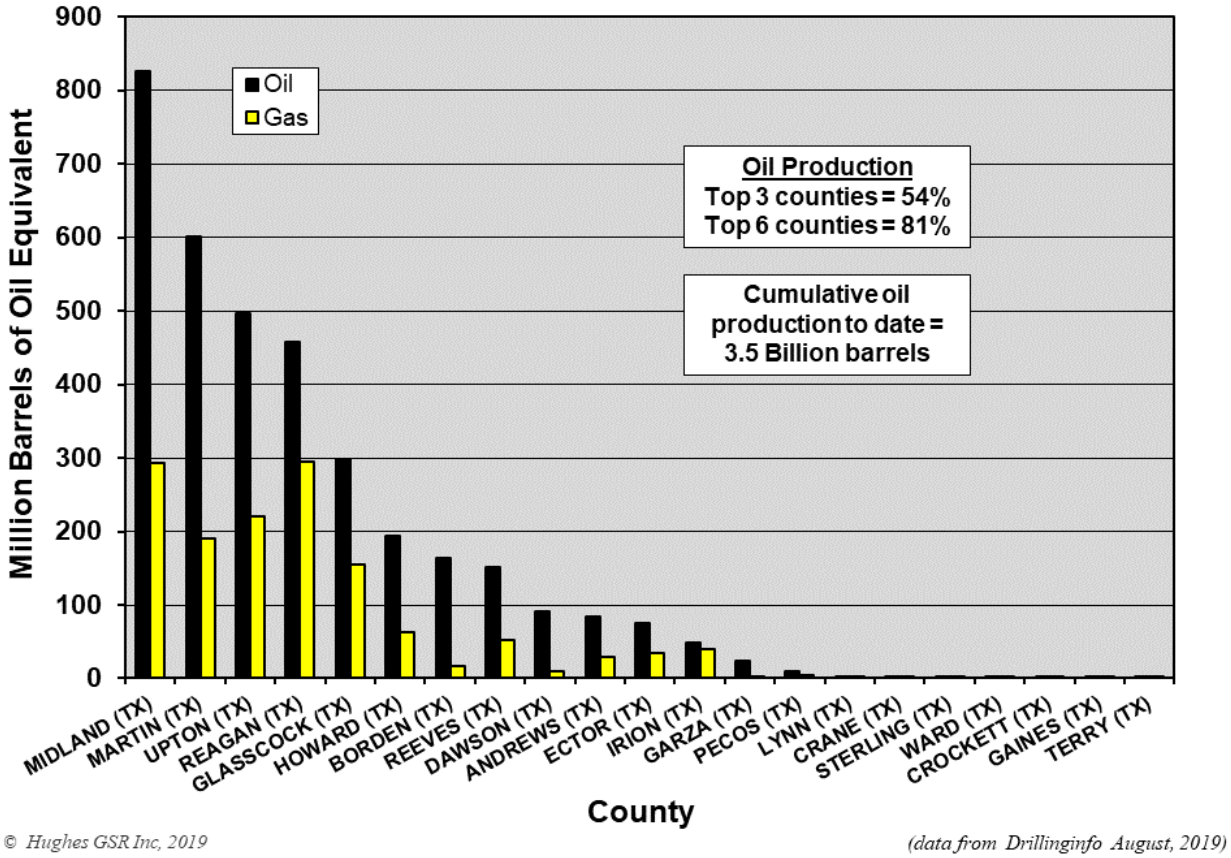


Figure 33. Cumulative production of oil and gas from the Spraberry Play by county through 2019.

Production is concentrated in sweet spot counties, with 54% of cumulative oil recovery in the top three counties and 81% in the top six.

Figure 34 illustrates cumulative production by well vintage and county. Post-2011 production has migrated somewhat from earlier production, although Midland County has remained the top producer. In both older and younger vintage wells, however, production remains concentrated, with 40% from the top two counties and 87% from the top six.

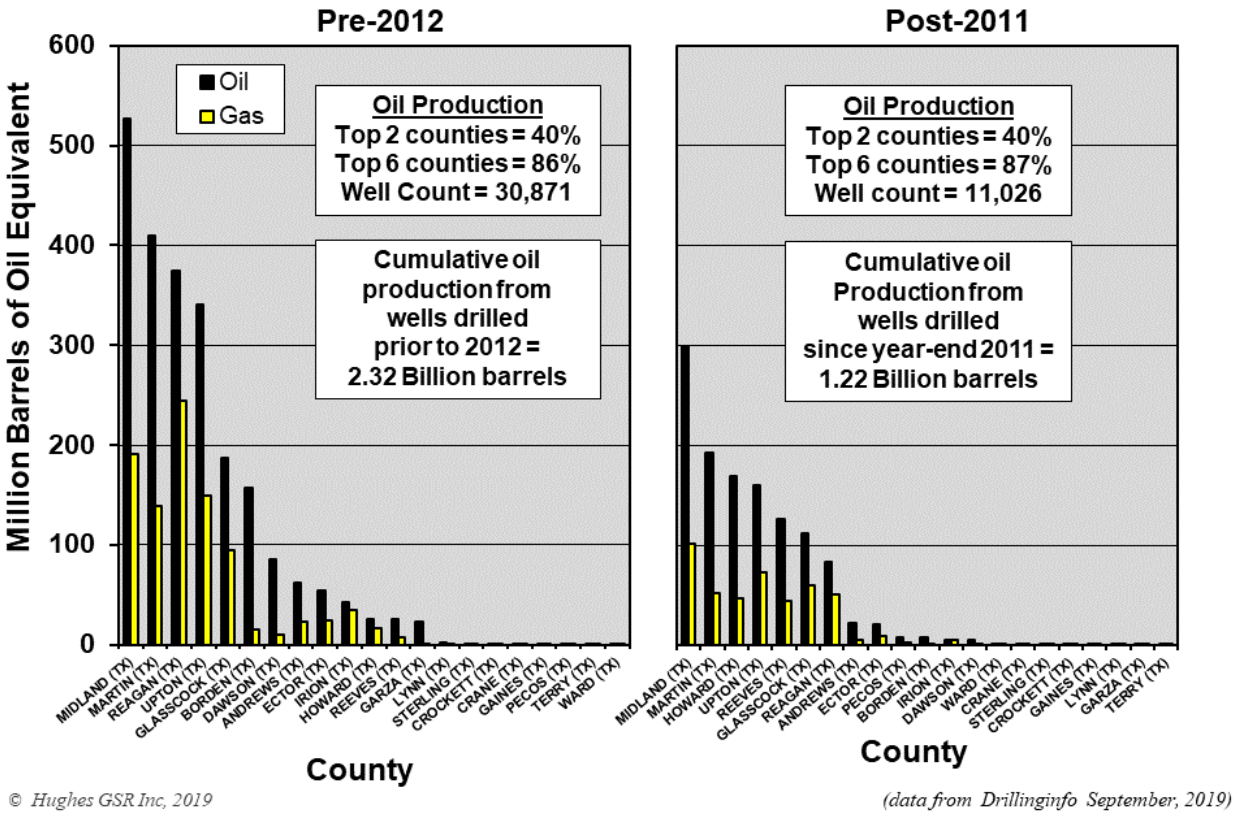


Figure 34. Cumulative production of oil and gas from the Spraberry Play by county and well vintage through 2019.

Production in post-2011 remains concentrated in sweet spot counties, with 40% in the top two counties, and 87% in the top six. Total well count is also shown, which is a superset of the producing well count noted in Figure 31. Pre-2012 production came primarily from conventional wells, while post-2011 production has been dominated by horizontal, hydraulically fractured wells.

The importance of horizontal drilling and hydraulic fracturing in the Spraberry Play is illustrated in Figure 35. Post-2011 horizontal wells made up just 18% of producing wells as of April 2019, yet they accounted for 81% of production. Post-2011 vertical/directional wells made up 16% of the total producing well count, yet accounted for just 3% of production. Future production growth will therefore be heavily weighted to horizontal drilling, employing the latest fracking technology.

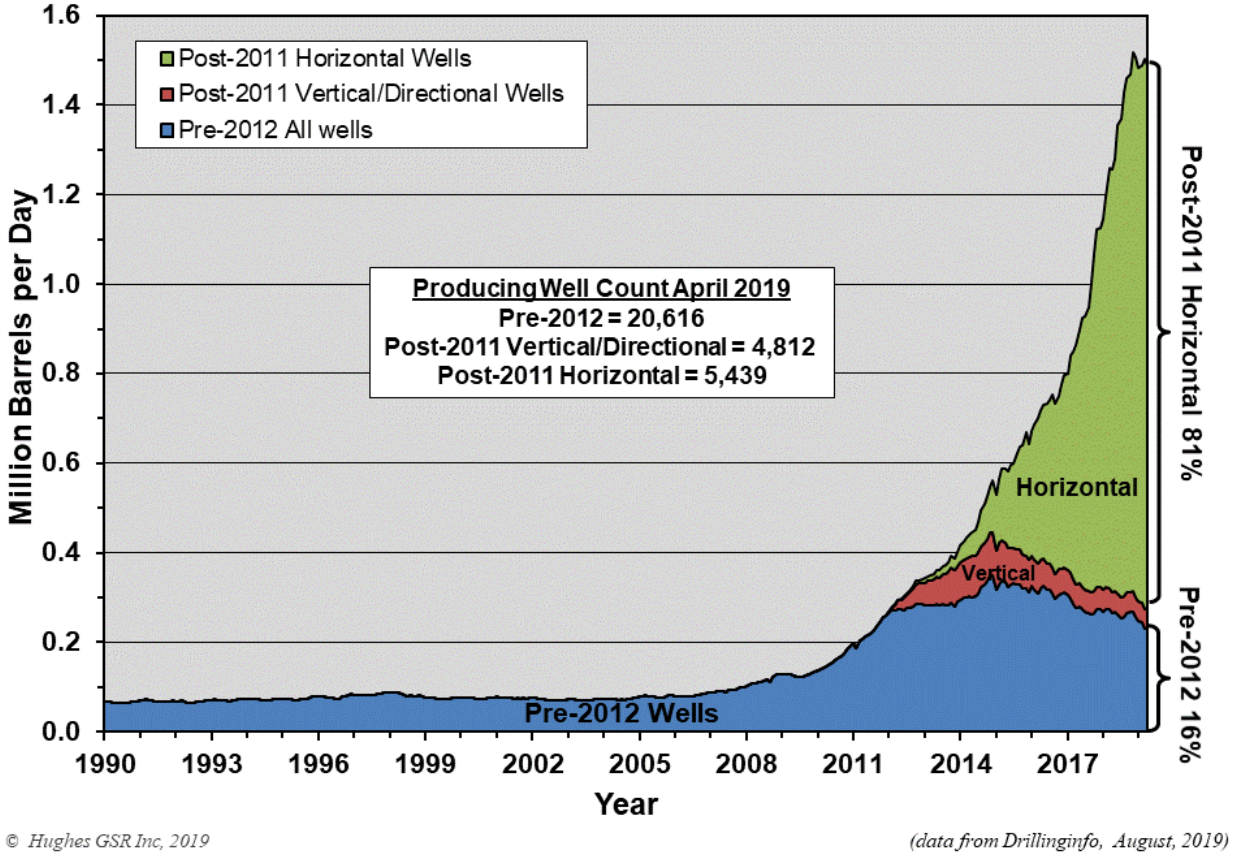


Figure 35. Spraberry oil production by well type and vintage through 2019.

Post-2011 horizontal wells accounted for 81% of Spraberry Play production in April 2019.

Figure 36 illustrates post-2011 production by county and well type. 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 Country remains the top county for post-2011 production from horizontal wells, it ranks fifth for vertical/directional wells. Six counties provide 88% of horizontal production, whereas a different mix of six counties provides 86% of vertical/directional production. The superior productivity of horizontal wells is evident in Figure 36.

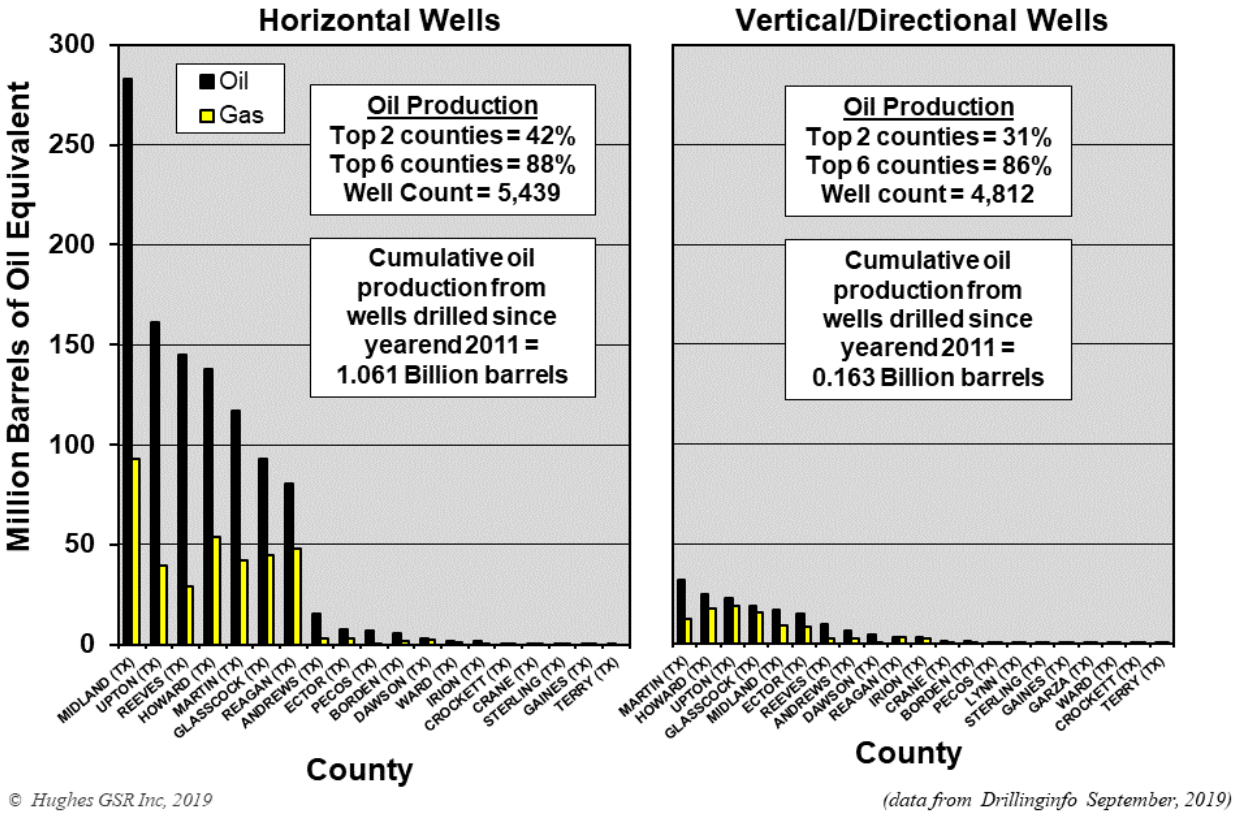


Figure 36. Post-2011 cumulative production of oil and gas from the Spraberry Play by county through 2019.

Horizontal production is concentrated in six counties which account for 88% of cumulative production through April 2019.

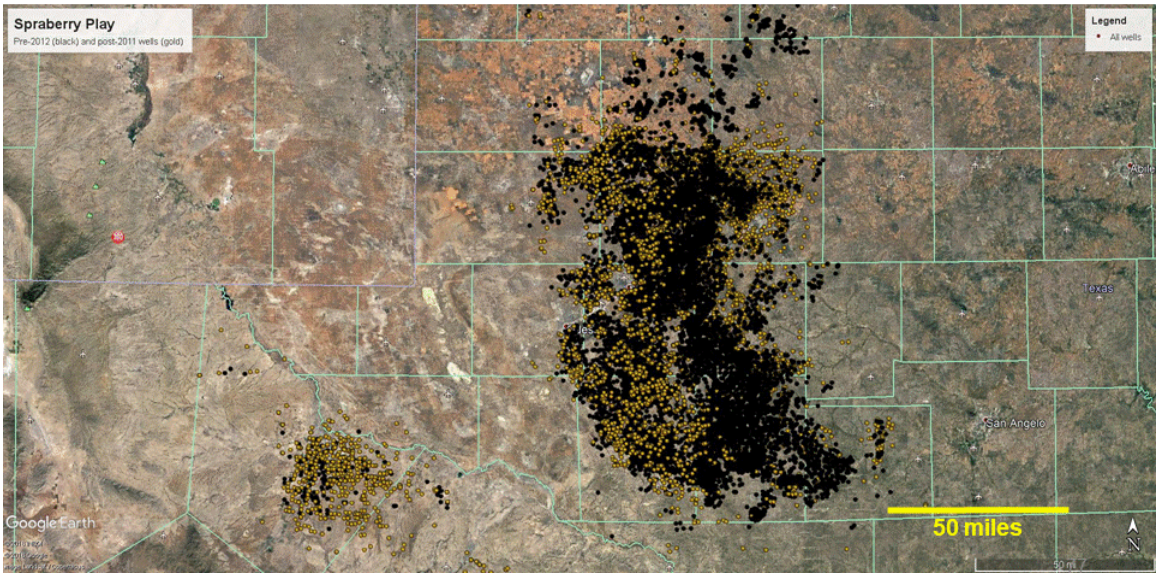
Table 6 summarizes the number of wells drilled by vintage, cumulative and current production, and well- and first-year field-decline rates for the Spraberry Play as a whole and for individual counties and well types. Three-year well decline rates average 87.3% and first-year field decline rates average 24.5% without new drilling. Wells drilled before 2012 are collectively declining at just 6.3%, as they have already gone through the early steep decline years but are producing at 10% or less of their initial productivity, whereas first-year field decline in post-2011 horizontal wells averages 31.2%.

County	Well type	Vintage	Total Well Count	Producing Well Count	Cumulative Oil Production (billion bbls)	Cumulative Gas Production (tcf)	Oil Production April 2019 (Kbbls/day)	Gas Production April 2019 (bcf/day)	3-year well decline (%)	First-year field decline (%)
All	All	All	44,922	30,871	3.544	8.478	1488.0	3.80	87.3	24.5
All	All	Pre-2012	33,717	20,616	2.320	5.727	234.4	0.77	58.5	6.3
All	Horizontal	Post-2011	6,012	5,439	1.107	2.282	1209.7	2.86	83.8	31.2
All	Vertical	Post-2011	5,193	4,816	0.163	0.575	43.9	0.17	74.5	16.0
Howard	Horizontal	Post-2011	843	755	0.152	0.185	180.6	0.27	81.0	29.3
Martin	Horizontal	Post-2011	803	725	0.171	0.252	226.6	0.38	87.8	43.1
Midland	Horizontal	Post-2011	1281	1137	0.295	0.586	336.4	0.79	77.9	20.1
Reeves	Horizontal	Post-2011	698	659	0.121	0.261	113.4	0.27	83.7	20.7
Upton	Horizontal	Post-2011	792	736	0.142	0.337	125.6	0.40	88.8	42.2
Other counties	Horizontal	Post-2011	1,595	1,427	0.226	0.661	227.1	0.75	87.6	37.6

Table 6. Well count, cumulative production, most recent production, and well- and first-year field-decline rates for the Spraberry Play and counties within it, by well type and vintage.[54]

[54] From Drillinginfo August, 2019.

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 for the Permian in 2018 was 6,860 feet[55]. Most well pads have multiple wells. Well interference has been noted at close well spacings between early "parent" wells and later infill "child" wells. This suggests, as in other plays, that production is sacrificed by crowding wells too closely together.[56]



© Hughes GSR Inc, 2019 (data from Drillinginfo October, 2019)

Figure 37. Drilling density in the core area of the Spraberry Play.

Upper: Overview of drilling in Spraberry Play. Lower: Core area of the Spraberry Play in the Midland sub-basin showing degree of development as of April 2019.

[55] J.D. Hughes, 2019, *How long will the shale revolution last? Technology versus Geology and the Lifecycle of Shale Plays*, Post Carbon Institute, https://www.postcarbon.org/publications/how-long-will-the-shale-revolution-last/

[56] 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

The evolution of production by county for post-2011 horizontal wells is illustrated in Figure 38. As of April 2019, Midland County accounted for 28% of production, and the top five counties accounted for 81%.

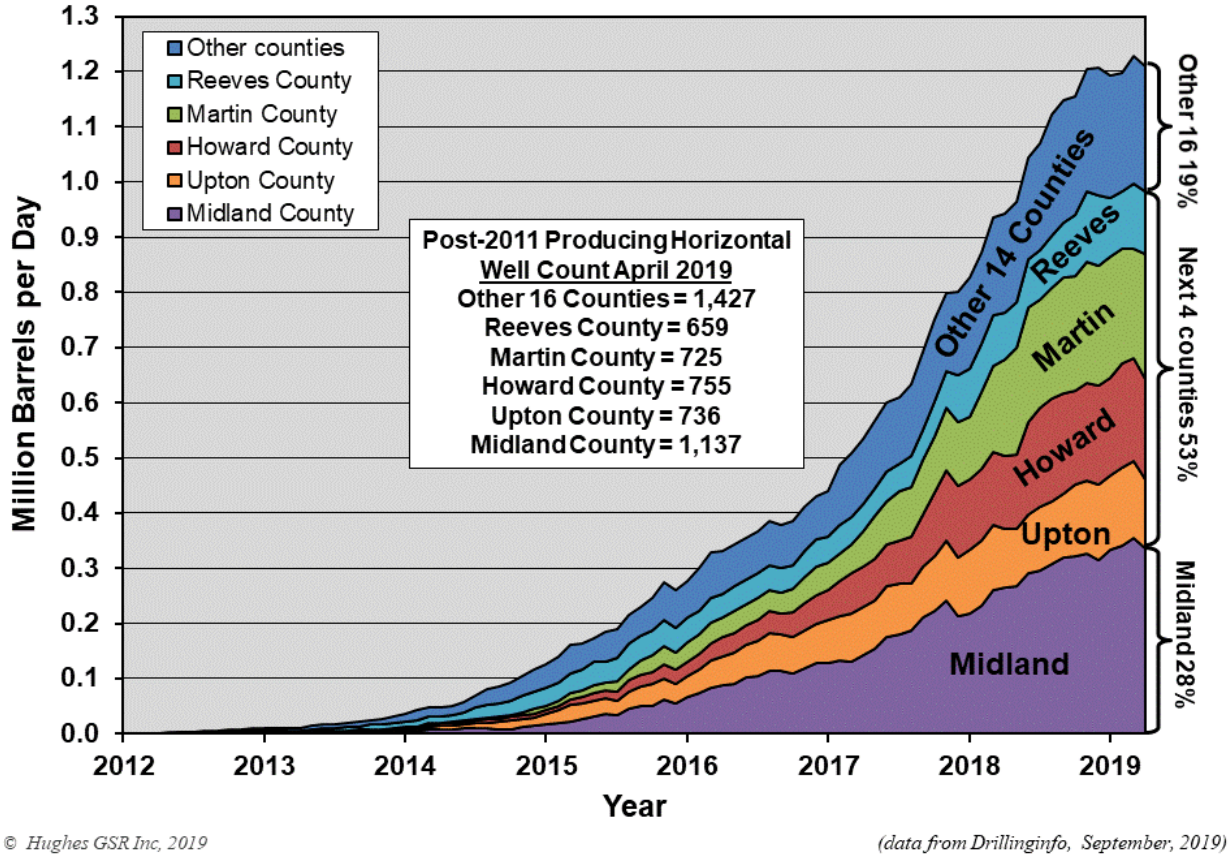


Figure 38. Oil production from horizontal post-2011 wells in the Spraberry Play by county through 2019.

Horizontal drilling in top five counties has exhibited a marked improvement in productivity over the 2012–2018 period as illustrated in Figure 39, although productivity has flat-lined in counties outside of the top five since 2016. Vertical/directional drilling, on the other hand, has declined in productivity over this period. Horizontal wells were on average 37 times as productive as vertical wells in 2018. 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 spots.

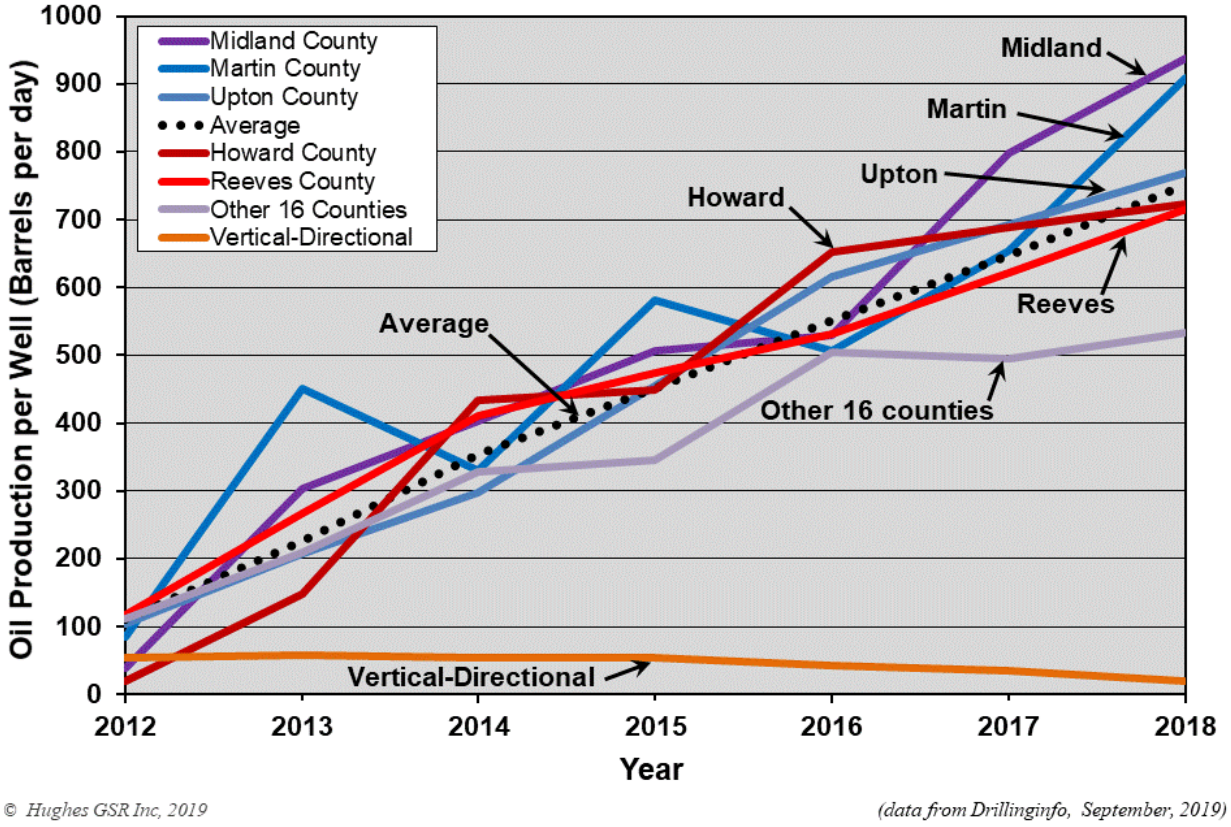


Figure 39. Average horizontal well productivity over the first four months of oil production by county in the Spraberry Play, 2012–2018.

Figure 40 illustrates the EIA's AEO2019 reference case production forecast for the Spraberry Play through 2050, together with earlier forecasts. The EIA expects production to keep increasing to a peak in 2028 at 8% above current levels before gradually declining to exit 2050 at 36% of current levels. This would require producing 15 billion barrels of oil over the 2017–2050 period, which is more than four times as much oil as has been recovered from the Spraberry since the 1950s. It would also require recovering 225% of the EIA's own estimates of proven reserves and unproven resources.

The USGS completed an assessment of remaining conventional and continuous resources in the Spraberry Play in 2017.[57] Mean, undiscovered, technically recoverable resources in the Spraberry were estimated at 4.2 billion barrels. This means that the EIA estimate of unproven resources is 46% higher than the USGS estimate, rendering the 225% overshoot of the EIA's own estimates even more unrealistic. Moreover, the EIA's forecast exits 2050 at 0.54 mbd, implying that there will be considerable additional oil recovered after 2050. Given the above, the EIA's forecast for the Spraberry Play is rated as extremely optimistic.

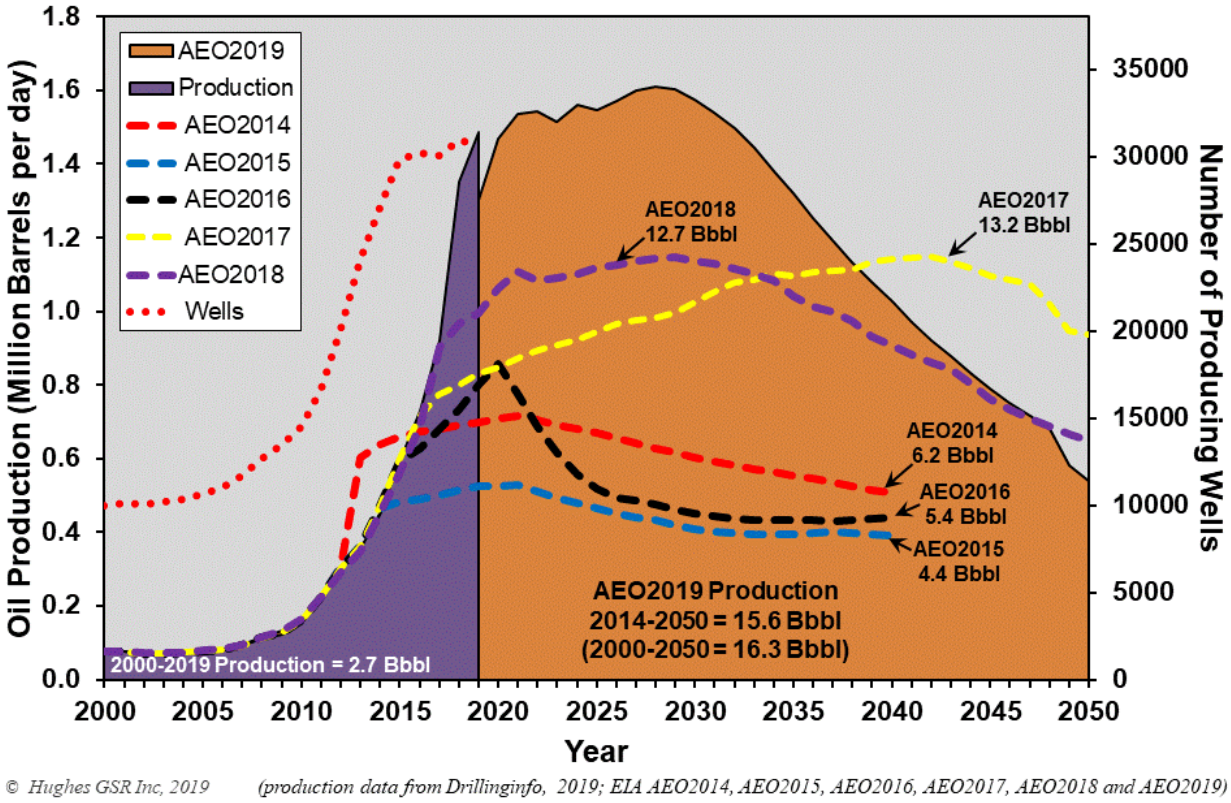


Figure 40. EIA AEO2019 reference case Spraberry Play oil production forecast through 2050.

Also shown are earlier AEO forecasts to 2040 and 2050, and cumulative 2000-2019 production.

[57] USGS, 2017, *Assessment of Undiscovered Oil and Gas Resources in the Spraberry Formation of the Midland Basin, Permian Basin Province, Texas, 2017,* https://pubs.usgs.gov/fs/2017/3029/fs2017173029%20.pdf

Table 7 illustrates assumptions in the EIA AEO2019 reference case forecast.[58] If realized, the EIA forecast would have to recover 225% of the EIA's own estimate of remaining oil. Recovering just the EIA's estimated proven reserves plus unproven resources would require 42,748 additional wells, for a total well count of roughly double the current count of 44,922, at an estimated cost of $321 billion. Producing 100% of proven reserves plus unproven resources would leave total production 8.33 billion barrels short of the EIA's AEO2019 production forecast.

EIA AEO2019 Reference Case Forecast	
Proven Reserves year-end 2017 (Bbbls)[59]	0.45
Unproven Resources 2017 (Bbbls)[60]	6.2
Total Potential 2017 (Bbbls)	6.65
2017-2050 Recovery (Bbbls)	14.98
% of total potential used 2017-2050	225.2%
Wells needed for available potential 2017-2050	42,748
Well cost 2017-2050 ($billions)	$321

Table 7. EIA assumptions for Spraberry Play oil in the AEO2019 reference case.

Well costs of $321 billion for full development are estimated assuming a well cost of $7.5 million.[61] The number of wells needed was determined using EIA EUR estimates for unproven resources, assuming EUR per well would be twice as high for proven reserves as for unproven resources. Total well costs are to extract 100% of proven reserves and unproven resources. Available resources fall short of AEO2019 forecast extraction requirement through 2050 by 8.33 Bbbls, more than three times the total amount of oil produced since 2000.

[58] EIA, Unproved technically recoverable resources are from *Assumptions to the Annual Energy Outlook 2019*, https://www.eia.gov/outlooks/aeo/assumptions/; Proven reserves are from *U.S. Crude Oil and Natural Gas Proved Reserves, Yearend 2017*, https://www.eia.gov/naturalgas/crudeoilreserves/

[59] EIA, 2018, *U.S. Crude Oil and Natural Gas Proved Reserves, Yearend 2017*, https://www.eia.gov/naturalgas/crudeoilreserves/. Note that the EIA does not report reserves for the Spraberry in the Permian (it only reports the Wolfcamp and Bone Spring plays), hence Spraberry reserves reported here are from the EIA's 'other' tight oil category.

[60] EIA, 2019, *Oil and Gas Supply Module for AEO2019*, https://www.eia.gov/outlooks/aeo/assumptions/pdf/oilgas.pdf

[61] EIA, 2016, *Trends in U.S. Oil and Natural Gas Upstream Costs*, https://www.eia.gov/analysis/studies/drilling/pdf/upstream.pdf

Synopsis

The EIA's reference case production estimate for the Spraberry Play is extremely optimistic. Key points include:

- The Spraberry is an old play being re-developed with new technology. Horizontal drilling and hydraulic fracturing technology have shifted areas of highest production from historic locations. As of April 2019, 44,922 wells have been drilled.

- The EIA's estimate of unproved resources and proven reserves assumes wells can be drilled over an area of 6,679 square miles at a density of 6.4 wells per square mile[62]. This assumed drilling area is 21% larger than the EIA's Spraberry play area of 5,301 square miles in Figure 32[63]. If the EIA's play area is correct, well densities of 8.1 per square mile would be required, and effective well density would be higher still, as the average horizontal lateral in the Permian is nearly 7000 feet and hence accesses more than one square mile[64]. Even if these well densities could be achieved without well interference, and 100% of the EIA's proven reserve plus unproven resource estimates could be recovered by 2050, 8.33 billion barrels are missing to meet the EIA production forecast.

- The EIA's reference case production forecast is not consistent with its own estimates of proven reserves plus unproven resources—6.65 billion barrels are available from its estimates, whereas its production forecast requires recovery of 14.98 billion barrels over 2017–2050. Recovering the 6.65 billion barrels of proven reserves and unproven resources would require 42,748 wells at a cost of $321 billion.

- The EIA assumes that production will exit 2050 at 0.54 mbd, which implies that there would be considerable additional resources remaining in 2050, rendering the 225% overshoot of its own estimates of proven resources plus unproven reserves in its production forecast even less credible.

- Taking the above together, along with play fundamentals, the AEO2019 production forecast for the Spraberry is rated as extremely optimistic.

[62] EIA, *Assumptions to the Annual Energy Outlook 2019*, https://www.eia.gov/outlooks/aeo/assumptions/
[63] EIA, March, 2016, play area outline from https://www.eia.gov/maps/map_data/TightOil_ShaleGas_Plays_Lower48_EIA.zip
[64] J.D. Hughes, 2019, *How long will the shale revolution last? Technology versus Geology and the Lifecycle of Shale Plays*, Post Carbon Institute, https://www.postcarbon.org/publications/how-long-will-the-shale-revolution-last/

2.3.2 Wolfcamp Play

The Wolfcamp Play is located in the Delaware and Midland sub-basins of the Permian Basin (see Figure 21) and has produced oil and gas for decades. The application of fracking at scale in 2011 revolutionized the development of the Wolfcamp and oil production has increased twenty-six-fold since then. It is now the second largest producing play in the Permian Basin. Figure 41 illustrates production from 1990 through April 2019. More than 15,187 wells have been drilled, of which 9,711 were producing as of April 2019.

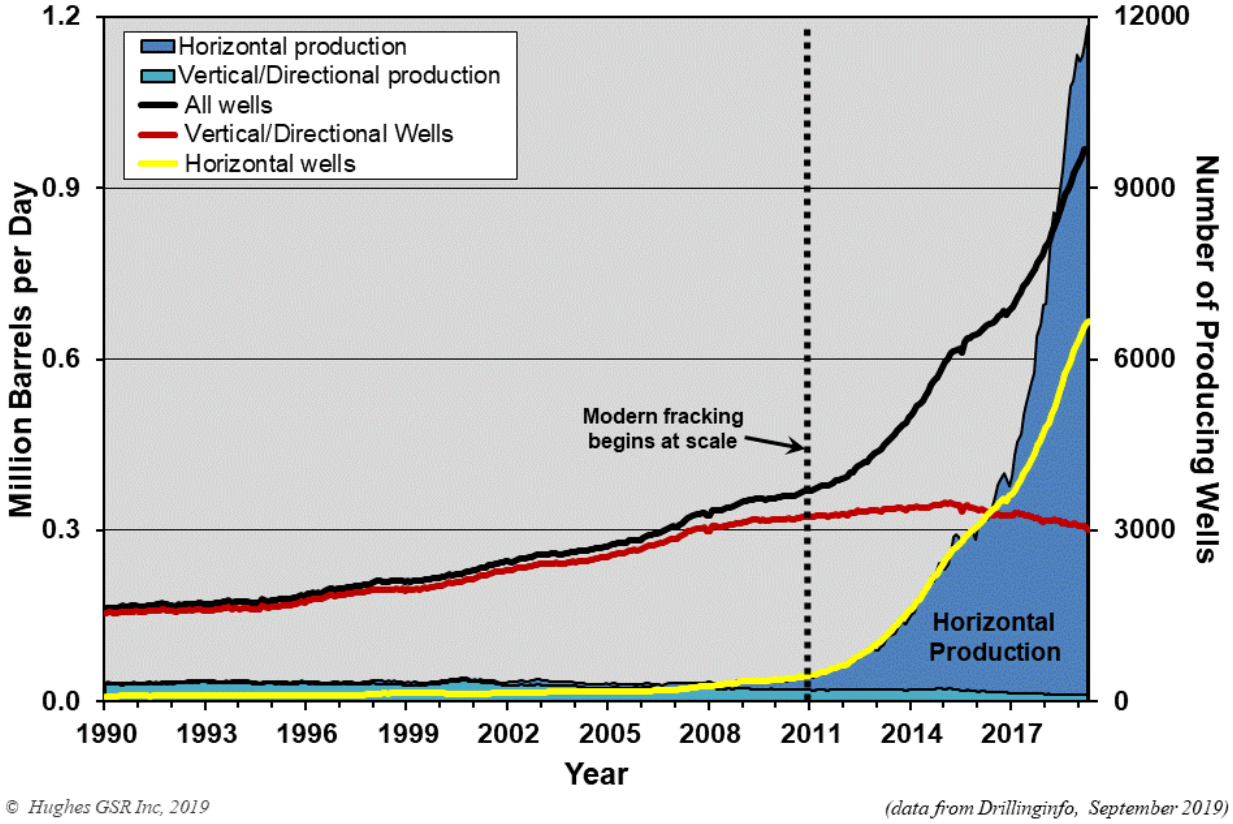


Figure 41. Wolfcamp Play oil production and number of producing wells by type, 1990–2019.

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.

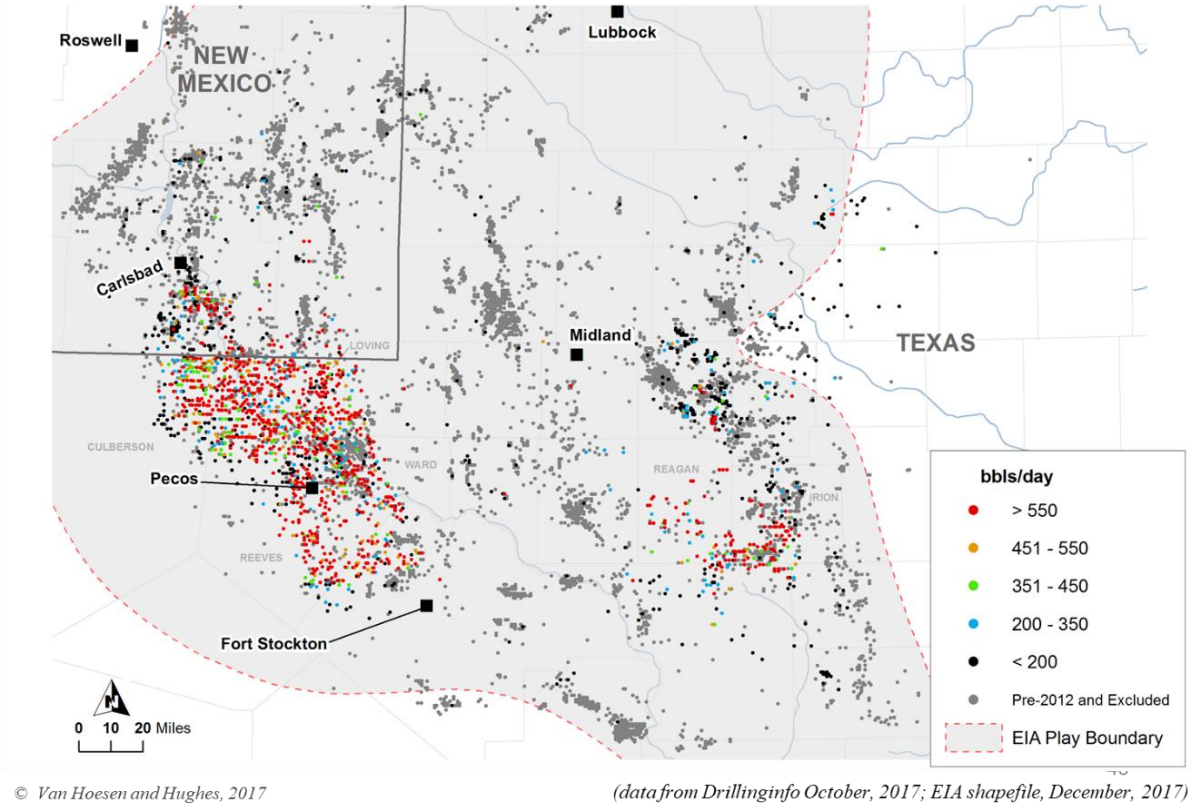


Figure 42. Wolfcamp Play well locations showing peak oil production of post-2011 wells in the highest month.[65]

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.

[65] Map by John Van Hoesen from Drillinginfo data as of December, 2017; 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. Fifty-one percent of oil production has come from four counties and 61% from the top six. These "sweet spots" constitute a relatively small part of the total play area indicated by older drilling in Figure 42.

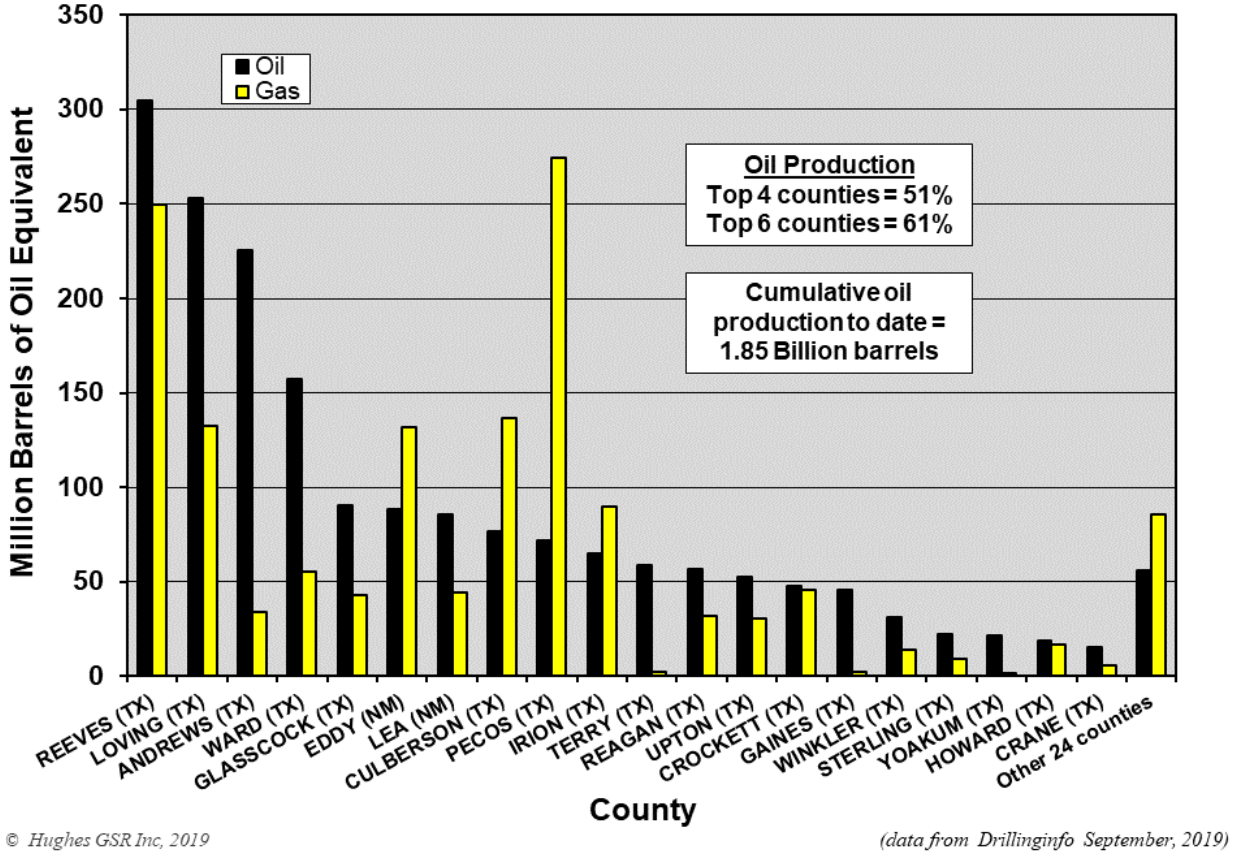


Figure 43. Cumulative production of oil and gas from the Wolfcamp Play by county.

Production is concentrated in sweet spots, with 51% of cumulative oil production from the top four counties and 61% from the top six.

Figure 44 illustrates cumulative production by well vintage and county. Post-2011 production has migrated from earlier production. Except for Ward County, none of the top six counties for post-2011 cumulative production are 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. Cumulative production is more widespread in older, pre-2012 wells, as only 65% is from the top six counties, whereas in post-2011 wells 83% has come from the top six counties.

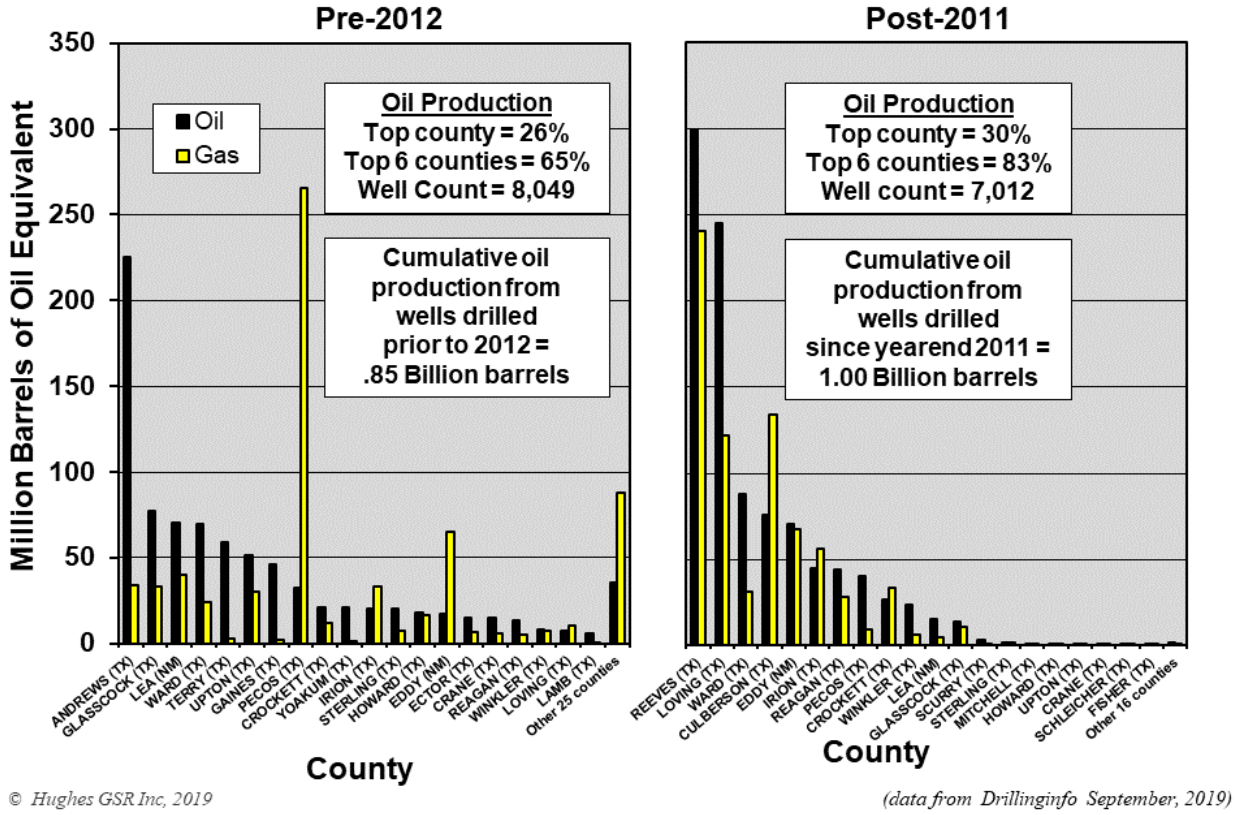


Figure 44. Cumulative production of oil and gas from the Wolfcamp Play by county and well vintage through 2019.

Production from post-2011 wells remains concentrated in sweet spot counties, with 30% in the top county, and 83% in the top six.

The importance of horizontal drilling and hydraulic fracturing in the Wolfcamp Play is illustrated in Figure 45. Post-2011 horizontal wells made up 59% of producing wells yet accounted for 97% of production in April 2019. Pre-2012 producing wells, which made up 36% of the total, accounted for just three percent of production, and vertical/directional wells accounted for just 0.25% of production.

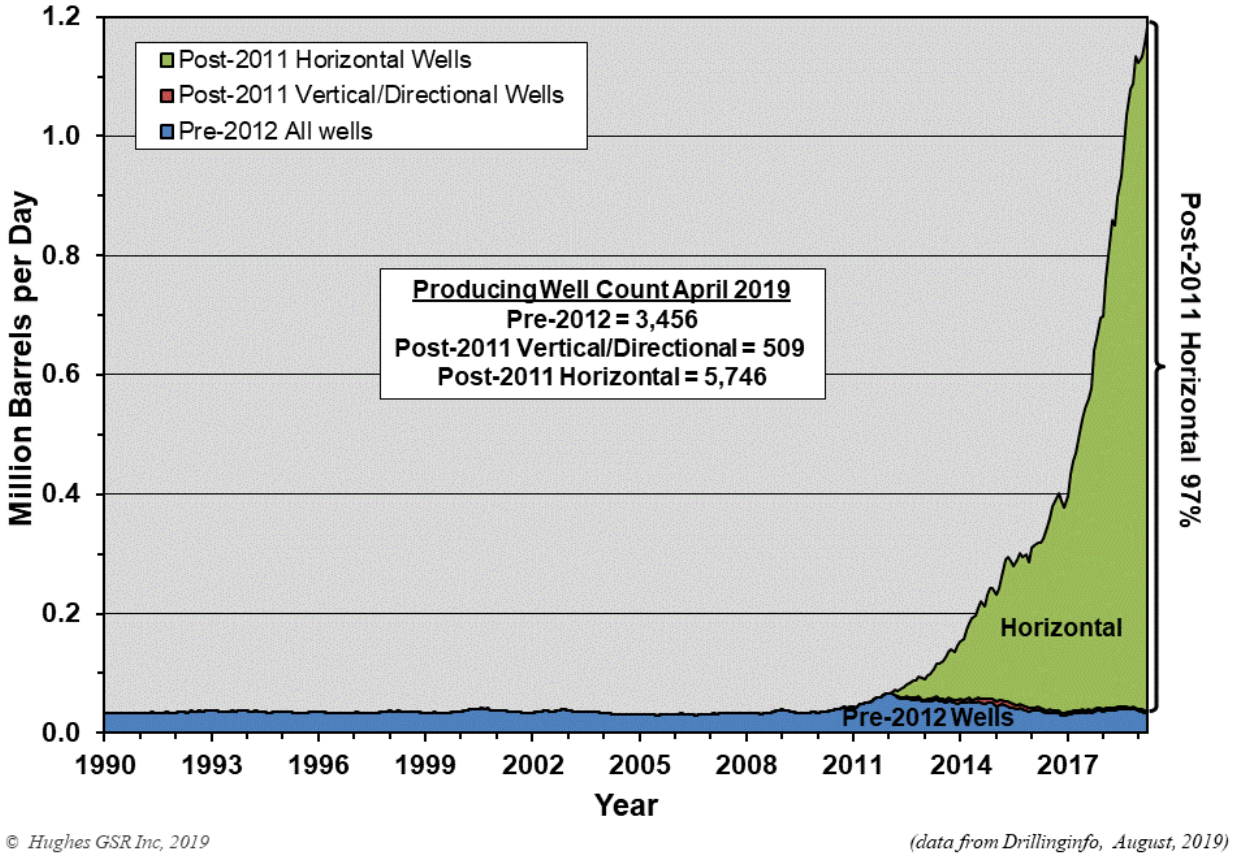


Figure 45. Wolfcamp oil production by well type and vintage.

Post-2011 horizontal wells accounted for 97% of Wolfcamp Play production in April 2019.

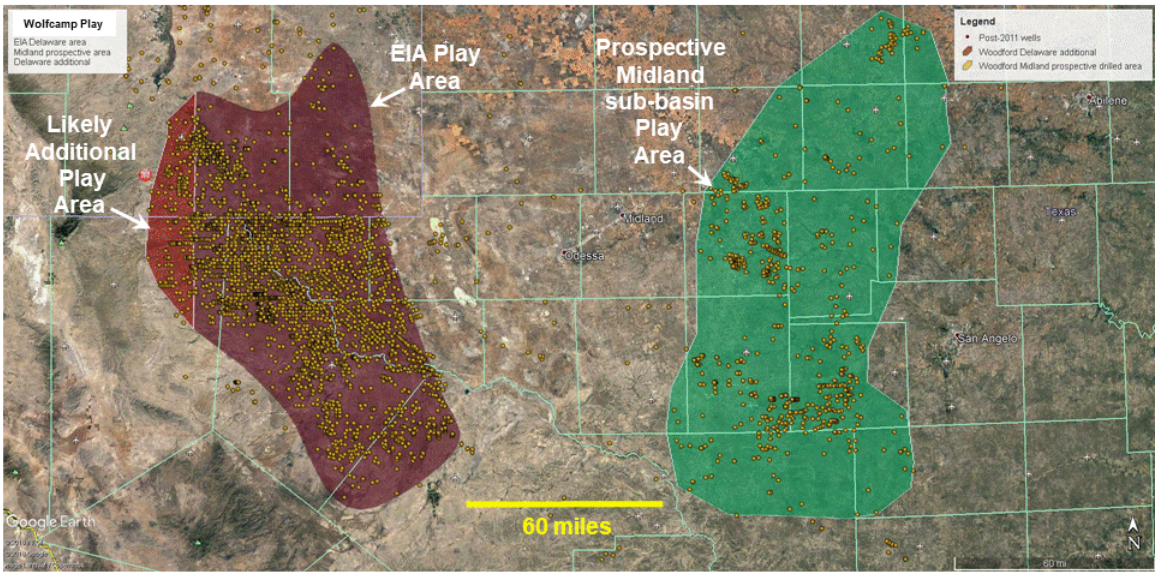
Table 8 summarizes the number of wells drilled by vintage, cumulative and current production, and well- and first-year field-decline rates for the Wolfcamp Play as a whole and for individual counties. Three-year well decline rates average 83.4% and first-year field decline averages 24% per year without new drilling.

County	Well type	Vintage	Total Well Count	Producing Well Count	Cumulative Oil Production (billion bbls)	Cumulative Gas Production (tcf)	Oil Production April 2019 (Kbbls/day)	Gas Production April 2019 (bcf/day)	3-year well decline (%)	First-year Field decline (%)
All	All	All	15,187	9,711	1.772	8.647	1184.8	5.26	83.4	24.0
All	All	Pre-2012	8,175	3,456	0.850	4.152	32.4	0.19	71.8	5.0
All	Horizontal	Post-2011	6,328	5,746	0.909	4.431	1149.5	5.05	83.1	25.5
All	Vertical	Post-2011	684	509	0.013	0.064	2.9	0.02	67.5	16.4
Culberson	Horizontal	Post-2011	409	369	0,078	0.803	70.0	0.76	80.5	24.7
Eddy	Horizontal	Post-2011	585	495	0.070	0.391	135.0	0.68	90.7	63.8
Loving	Horizontal	Post-2011	1,180	1,055	0.245	0.730	291.2	0.85	75.2	9.5
Reeves	Horizontal	Post-2011	1,734	1,567	0.299	1.440	370.1	1.88	84.1	34.4
Ward	Horizontal	Post-2011	495	433	0.088	0.186	87.0	0.21	84.6	27.0
Other counties	Horizontal	Post-2011	1,925	1,787	0.207	0.880	196.2	0.67	87.1	11.6

Table 8. Well count, cumulative production, most recent production, and well- and first-year field-decline rates for the Wolfcamp Play and counties within it by well type and vintage.[66]

[66] Data from Drillinginfo September, 2019.

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 for the Permian Basin is 6,860 feet. Most well pads have multiple wells. Some corridors appear saturated with wells although other areas appear able to accommodate more wells.



© Hughes GSR Inc, 2019 (data from Drillinginfo October, 2019)

Figure 46. Drilling density in the core area of the Wolfcamp Play

Upper: EIA Wolfcamp Play area[67], potential additional Delaware sub-basin play area, and prospective drilled play area in the Midland sub-basin. Lower: Core area of the Wolfcamp Play in the Midland Basin (both showing post-2011 well locations).

[67] EIA, 2018, https://www.eia.gov/maps/map_data/Wolfcamp_Play_Boundary.zip

The evolution of production by county for post-2011 horizontal wells is illustrated in Figure 47. As of April 2019, Reeves and Loving counties accounted for 58% of production and the top five counties accounted for 83%.

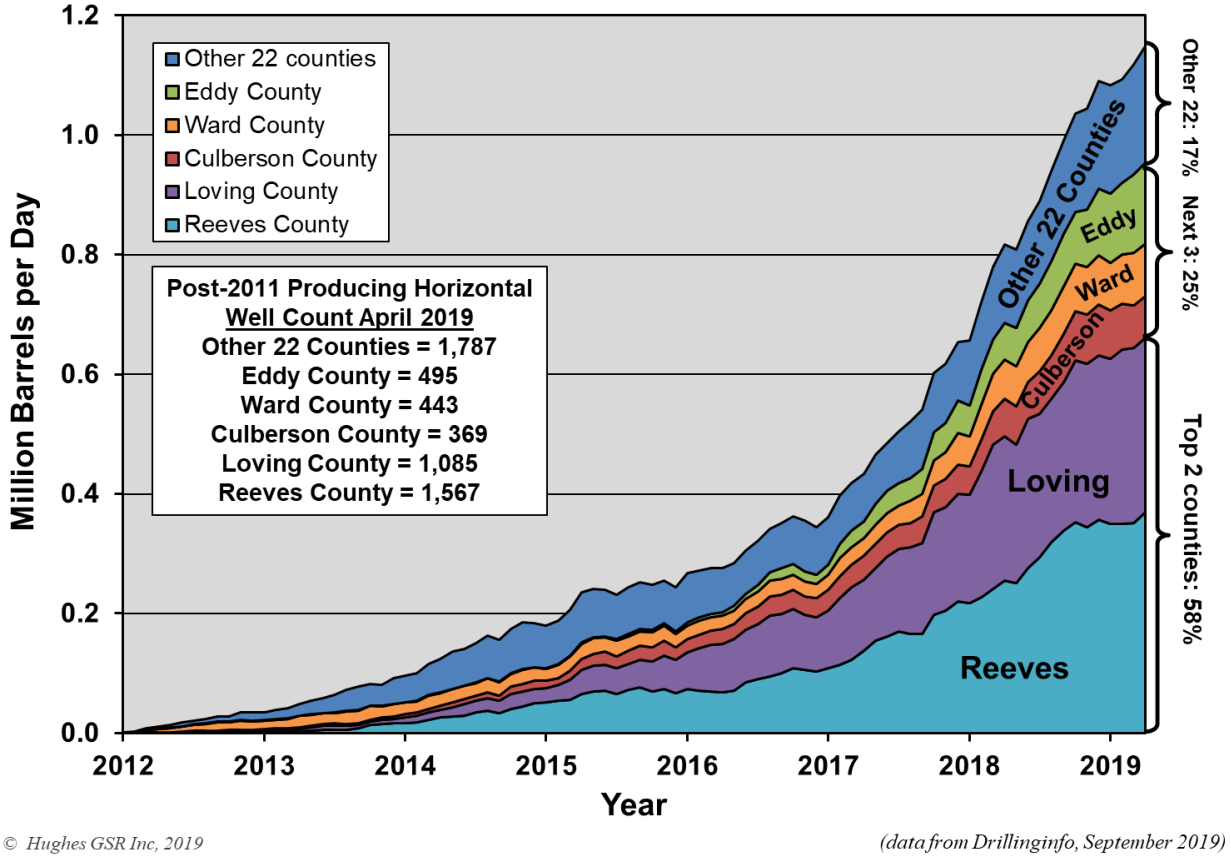


Figure 47. Oil production from horizontal post-2011 wells in the Wolfcamp Play by county.

Horizontal drilling in all counties has exhibited a marked improvement in productivity in the 2012–2018 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 2% 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.

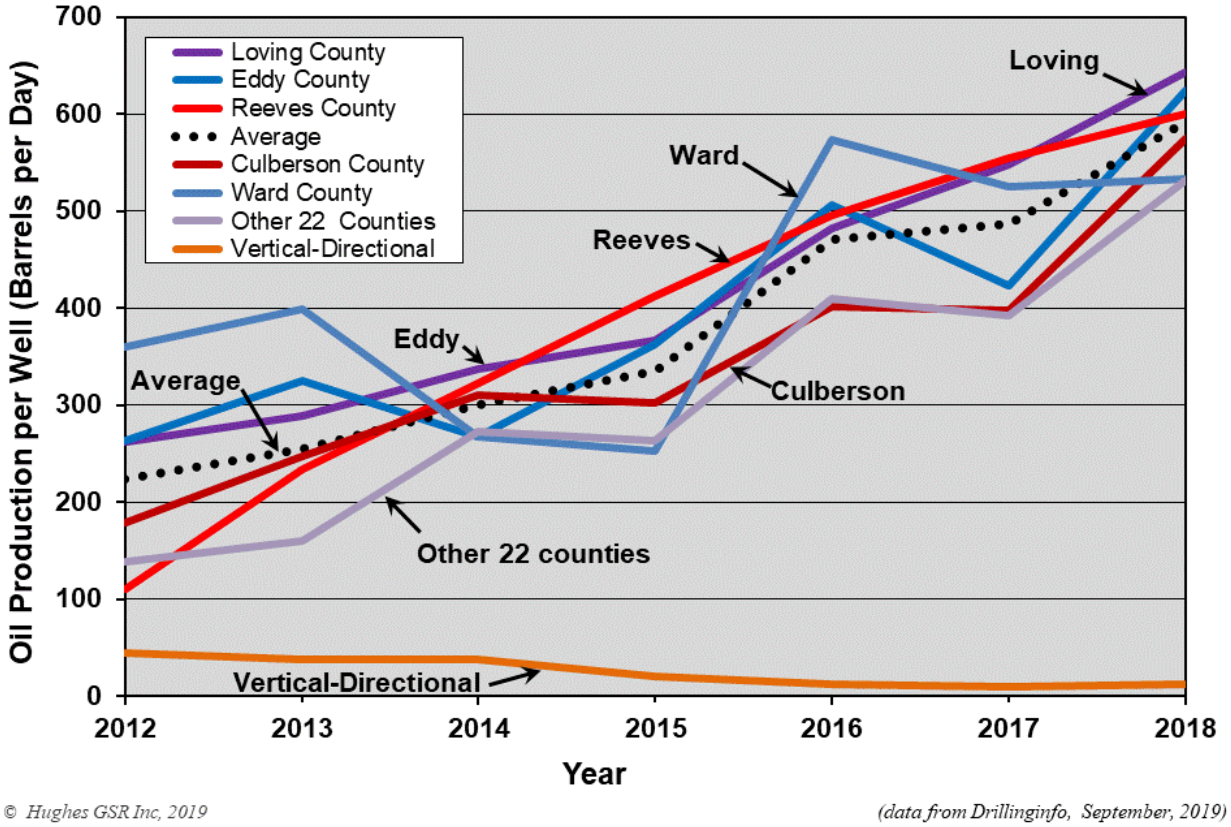


Figure 48. Average horizontal well productivity over the first four months of oil production by county in the Wolfcamp Play, 2012–2017.

Figure 49 illustrates the EIA's AEO2019 reference case production forecast for the Wolfcamp Play through 2050, together with earlier forecasts. The EIA expects production to keep increasing to a peak in 2036, at 133% above current levels, and gently decline thereafter, exiting 2050 at 106% above current levels. This would require producing 29.6 billion barrels of oil over the 2017–2050 period, which is seventeen times as much oil as has been recovered from the Wolfcamp since the 1950s.

The USGS has completed two assessments of continuous resources in the Wolfcamp Play—the 2016 Midland sub-basin assessment[68] and the 2018 Delaware sub-basin assessment[69]. Mean, undiscovered, technically recoverable resources in the Wolfcamp were estimated at 19.9 billion barrels for the Midland sub-basin and 29.5 billion barrels for the Delaware sub-basin, for a total of 49.4 billion barrels. The USGS states, however, that "whether or not it is profitable to produce these resources has not been evaluated" (similarly, the EIA estimates of unproven resources have not been demonstrated to be economically recoverable). If the USGS resources were economically recoverable, the EIA forecast would recover 60% of the mean USGS estimate by 2050. The fact that the EIA forecast exits 2050 at more than double current production levels implies that much more oil would be recovered after 2050. Given that the USGS estimates are probabilistic (at a 95% probability there are only 27.5 billion barrels in both sub-basins), and are not necessarily economically recoverable, the EIA's forecast is rated as highly optimistic.

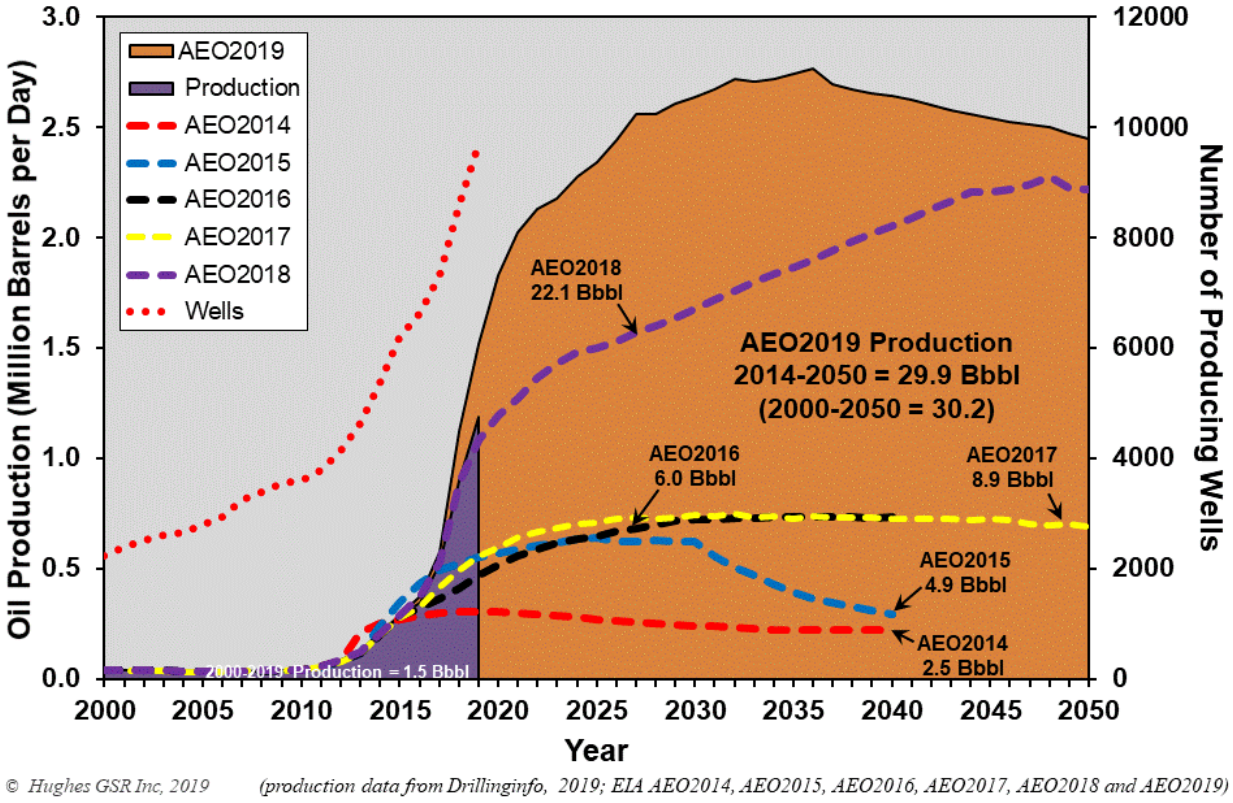


Figure 49. EIA AEO2019 reference case Wolfcamp Play oil production forecast through 2050.

Also shown are earlier AEO forecasts to 2040 and 2050, and cumulative 2000-2019 production.

[68] USGS, 2016, *Assessment of Undiscovered Continuous Oil Resources in the Wolfcamp Shale of the Midland Basin, Permian Basin Province, Texas, 2016,* https://pubs.usgs.gov/fs/2016/3092/fs20163092.pdf

[69] USGS, 2018, *Assessment of Undiscovered Continuous Oil and Gas Resources in the Wolfcamp Shale and Bone Spring Formation of the Delaware Basin, Permian Basin Province, New Mexico and Texas, 2018,* https://pubs.usgs.gov/fs/2018/3073/fs20183073.pdf

Table 9 illustrates assumptions in the EIA AEO2019 reference case forecast.[70] If realized, the EIA forecast would recover 68% of the EIA's estimate of proven reserves plus unproven resources, and would require 175,841 additional wells, for a total well count of twelve times the current 15,187, at an estimated cost of over $1.3 trillion.

EIA AEO2019 Reference Case Forecast	
Proven Reserves year-end 2017 (Bbbls)[71]	6.57
Unproven Resources 2017 (Bbbls)[72]	37
Total Potential 2017 (Bbbls)	43.57
2017-2050 Recovery (Bbbls)	29.62
% of total potential used 2017-2050	68.0%
Wells needed 2017-2050	175,841
Well cost 2017-2050 ($billions)	$1,319

Table 9. EIA assumptions for Wolfcamp Play oil in the AEO2019 reference case.

Well costs of $1,319 billion (over $1.3 trillion) for full development are estimated assuming a well cost of $7.5 million.[73] The number of wells needed was determined using EIA EUR estimates for unproven resources, assuming EUR per well would be twice as high for proven reserves as for unproven resources.

[70] EIA, Unproved technically recoverable resources are from *Assumptions to the Annual Energy Outlook 2019*, https://www.eia.gov/outlooks/aeo/assumptions/; Proven reserves are from *U.S. Crude Oil and Natural Gas Proved Reserves, Yearend 2017*, https://www.eia.gov/naturalgas/crudeoilreserves/

[71] EIA, 2018, *U.S. Crude Oil and Natural Gas Proved Reserves, Yearend 2017*, https://www.eia.gov/naturalgas/crudeoilreserves/. Note that the EIA does not report reserves for the Wolfcamp separately – it reports the Permian Wolfcamp and Bone Spring together at 8.32 Bbbls which have been apportioned between the Wolfcamp and Bone Spring according to the EIA's assumed 2017-2050 recovery - 6.57 Bbbl was apportioned to the Wolfcamp and 1.75 Bbbl to the Bone Spring.

[72] EIA, 2019, *Oil and Gas Supply Module for AEO2019*, https://www.eia.gov/outlooks/aeo/assumptions/pdf/oilgas.pdf

[73] EIA, 2016, *Trends in U.S. Oil and Natural Gas Upstream Costs*, https://www.eia.gov/analysis/studies/drilling/pdf/upstream.pdf

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 drilling has shifted areas of highest production from historic locations. As of April 2019, 15,187 wells have been drilled.
- Wolfcamp resources occur in five benches (A, B-lower, B-upper, C and D), of which the A and B benches contain the most unproven resources according to USGS assessments.
- The EIA's unproven resource estimate of 37 billion barrels is reasonable for the Wolfcamp as it falls within the USGS mean unproven resource estimate of 49.5 billion barrels. However, neither estimate evaluated whether these resources are economically recoverable. Moreover, the USGS estimates are probabilistic; at a 95% probability, for example, USGS unproven resources drop 44% to 27.5 billion barrels.
- Recovering 68% of the EIA's estimates of proven reserves plus unproven resources by 2050, as required in its forecast, would require 27,475 square miles drilled at the EIA's assumed density of 6.4 wells per square mile, for a total of 175,841 wells.[74] This compares to the EIA's Wolfcamp play area in the Delaware sub-basin of 6,946 square miles, plus a rough estimate of the prospective drilled area in the Midland sub-basin of 8,119 square miles, and an additional 672 square miles of prospective area missed by the EIA in the Delaware sub-basin, for a total play area of 15,737 square miles (see Figure 46). This is 43% smaller than the area required for the EIA's production forecast, which means that well density would have increase to 12.1 wells per square mile to accommodate the required drilling (if a well's influence was confined with a square mile). Given that the average lateral length in the Permian Basin has increased to nearly 7,000 feet in 2018[75], however, the effective well density would increase to 15.8 per square mile if 175,841 more wells were drilled. Given that there has already been some evidence of well interference in the Permian, it is highly unlikely that well density could increase 15-fold without substantially degrading well productivity and EUR, and hence economics.
- Notwithstanding the well over-crowding required to meet the EIA production forecast, the EIA assumes that Wolfcamp production will be more than double current rates in 2050, after 175,841 new wells have been drilled at a cost of $1.32 trillion.
- Given the above considerations and play fundamentals, the EIA's production forecast for the Wolfcamp is rated as highly optimistic.

[74] Using the EIA's assumptions of well EUR for unproven resources from *Assumptions to the Annual Energy Outlook 2019*https://www.eia.gov/outlooks/aeo/assumptions/; and assuming the EUR of proven reserves would be twice as high as for unproven resources.
[75] J.D. Hughes, 2019, *How long will the shale revolution last? Technology versus Geology and the Lifecycle of Shale Plays*, Post Carbon Institute, https://www.postcarbon.org/publications/how-long-will-the-shale-revolution-last/

2.3.3 Bone Spring Play

The Bone Spring is a relatively small play located in the northern part of the Delaware sub-basin that has produced oil and gas for decades. The application of fracking at scale since 2011 has revolutionized its development, and oil production has increased twenty-six-fold since then. It is now the third largest producing play in the Permian Basin. Figure 50 illustrates production from 1990 through April 2019. More than 10,000 wells have been drilled, of which 4,547 were still producing as of April 2019.

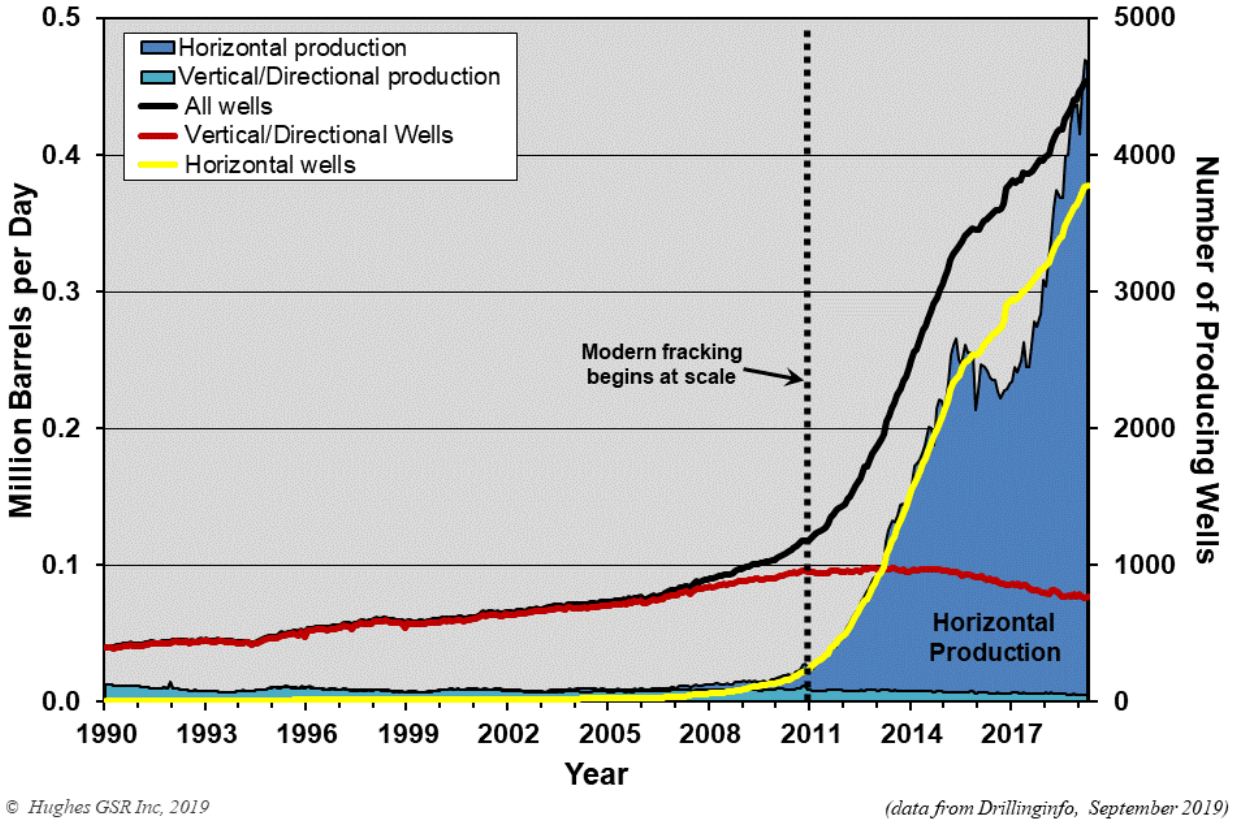


Figure 50. Bone Spring Play oil production and number of producing wells by type, 1990–2019.

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.

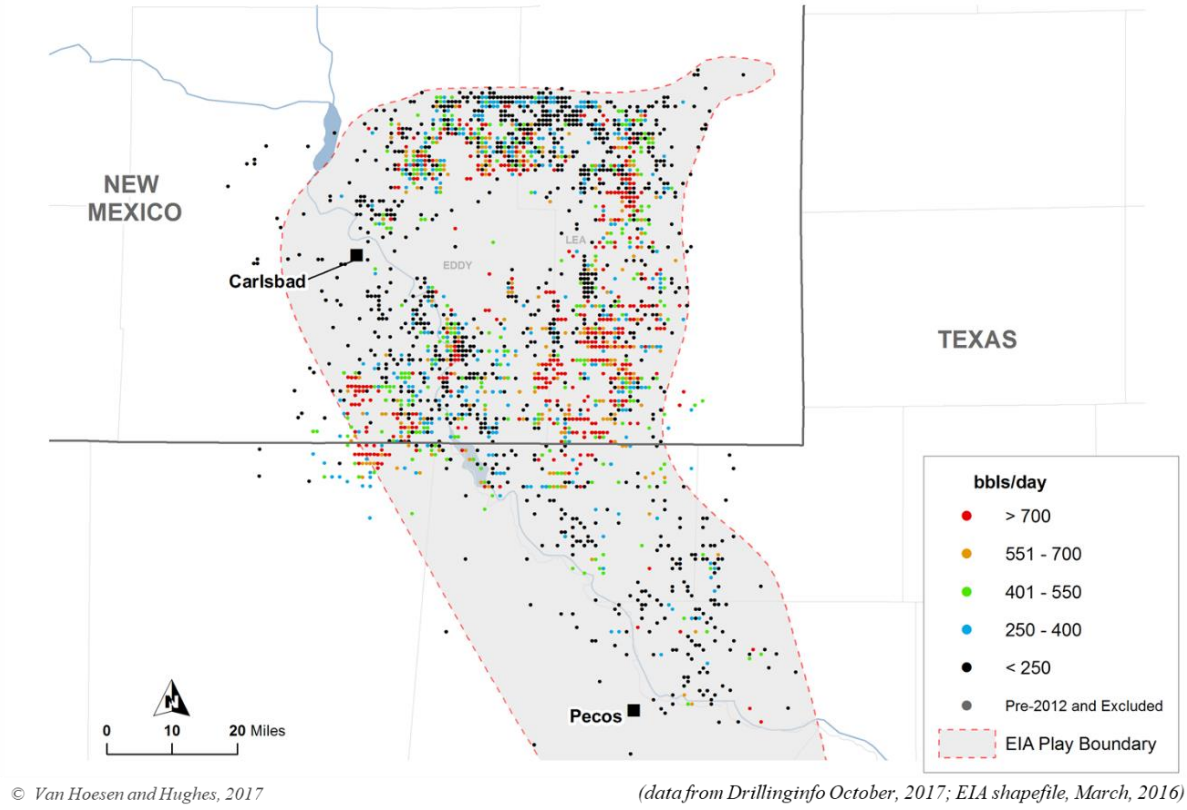


Figure 51. Bone Spring Play well locations showing peak oil production of post-2011 wells in the highest month.[76]

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.

[76] 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.

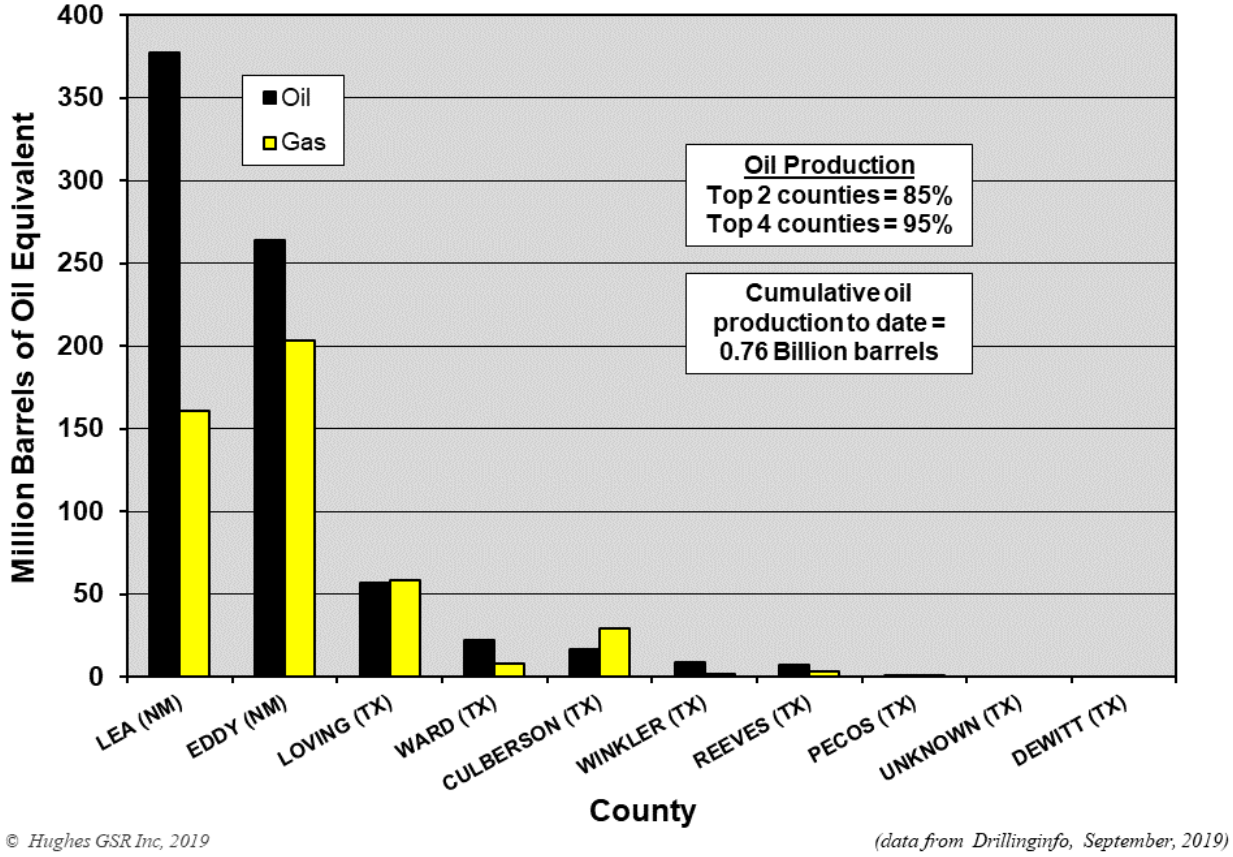


Figure 52. Cumulative production of oil and gas from the Bone Spring Play by county through 2019.

Production is concentrated in sweet spots, with 85% of cumulative oil recovery from the top two counties and 95% from 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%. Seventy-six percent of cumulative Bone Spring production is from post-2011 wells.

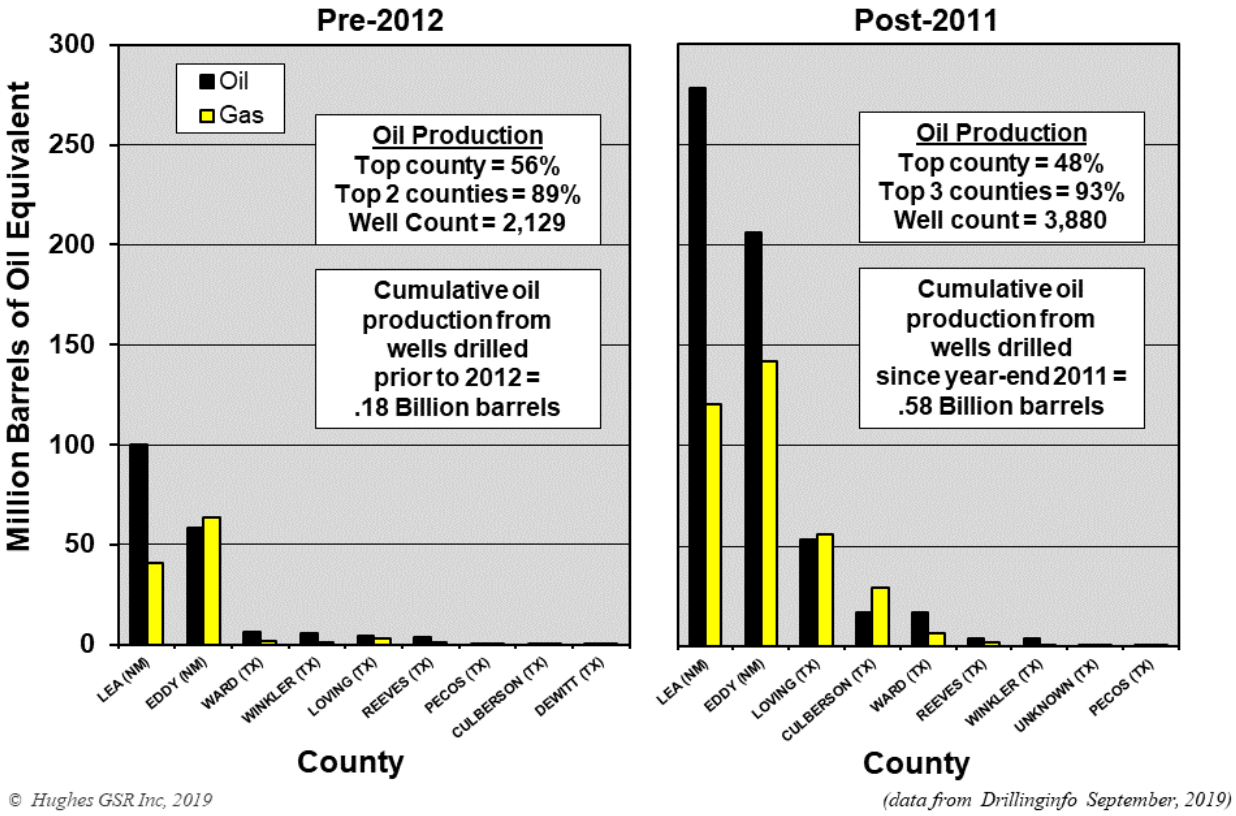


Figure 53. Cumulative production of oil and gas from the Bone Spring Play by county and well vintage through 2019.

Cumulative production in post-2011 remains concentrated in sweet spot counties, with 48% from the top county, and 93% from the top three.

The importance of horizontal drilling and hydraulic fracturing in the Bone Spring Play is illustrated in Figure 54. Ninety-eight percent of wells drilled post-2011 were horizontal and account for 73% of all producing wells in the play. Post-2011 horizontal wells accounted for 97% of production in April 2019.

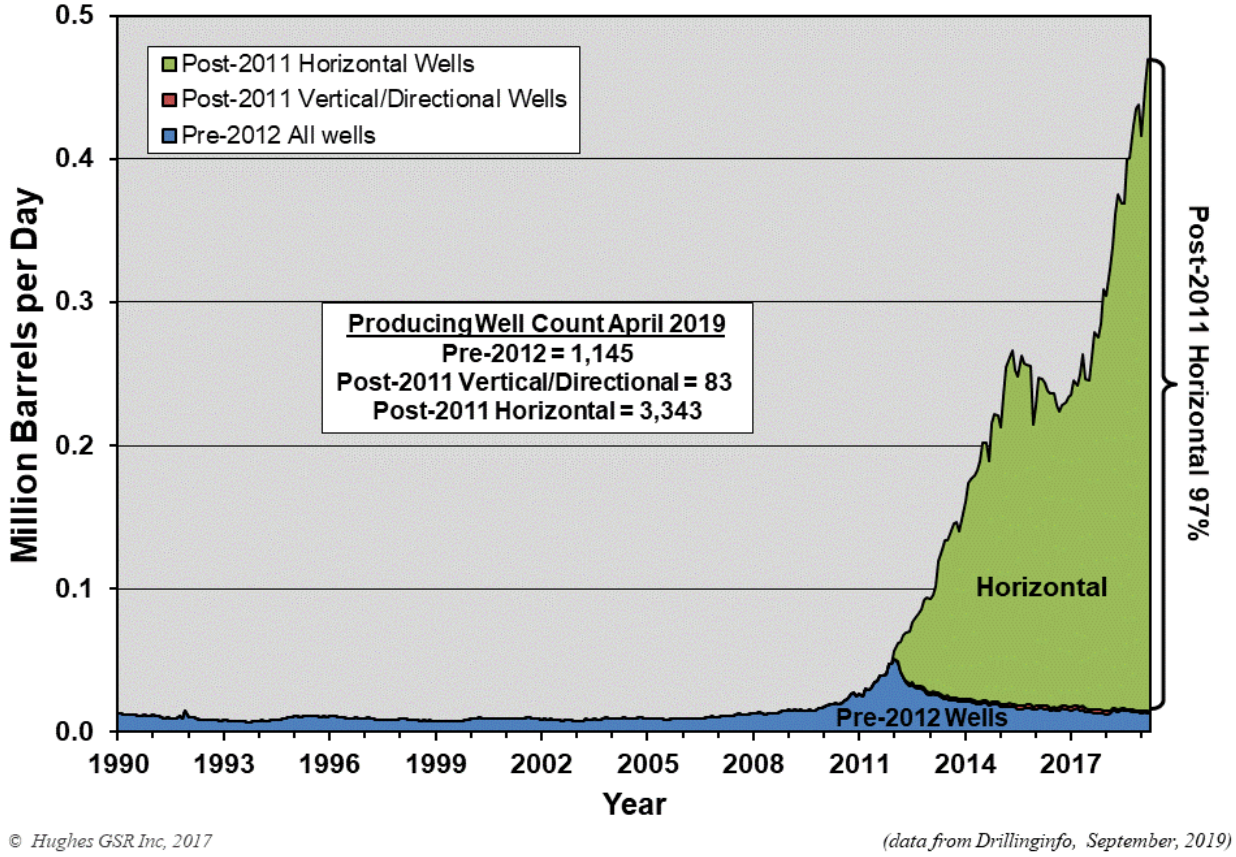


Figure 54. Bone Spring oil production by well type and vintage.

Post-2011 horizontal wells accounted for 97% of Bone Spring Play production in April 2019.

Table 10 summarizes the number of wells drilled by vintage, cumulative and current production, and well- and first-year field-decline rates for the Bone Spring Play as a whole and for individual counties. Three-year well decline rates average 91% and field decline averages 42.3% per year without new drilling.

County	Well type	Vintage	Total Well Count	Producing Well Count	Cumulative Oil Production (billion bbls)	Cumulative Gas Production (tcf)	Oil Production April 2019 (Kbbls/day)	Gas Production April 2019 (bcf/day)	3-year well decline (%)	First-year field decline (%)
All	All	All	10,176	4,547	0.756	2.795	467.4	1.71	91.0	42.3
All	All	Pre-2012	6,378	1,204	0.167	0.618	13.7	0.06	n/a	n/a
All	Horizontal	Post-2011	3,798	3,343	0.589	2.177	453.7	1.65	91.0	44.1
All	Vertical	Post-2011	130	83	0.005	0.012	1.1	0.003	79.3	50.7
Eddy	Horizontal	Post-2011	1,406	1,256	0.209	0.864	159.4	0.66	92.2	52.0
Lea	Horizontal	Post-2011	1,580	1469	0.283	0.739	233.6	0.69	90.7	42.6
Other counties	Horizontal	Post-2011	812	618	0.097	0.574	60.7	0.30	88.3	28.5

Table 10. Well count, cumulative production, most recent production, and well- and first-year field-decline rates for the Bone Spring Play and counties within it, by well type and vintage.[77]

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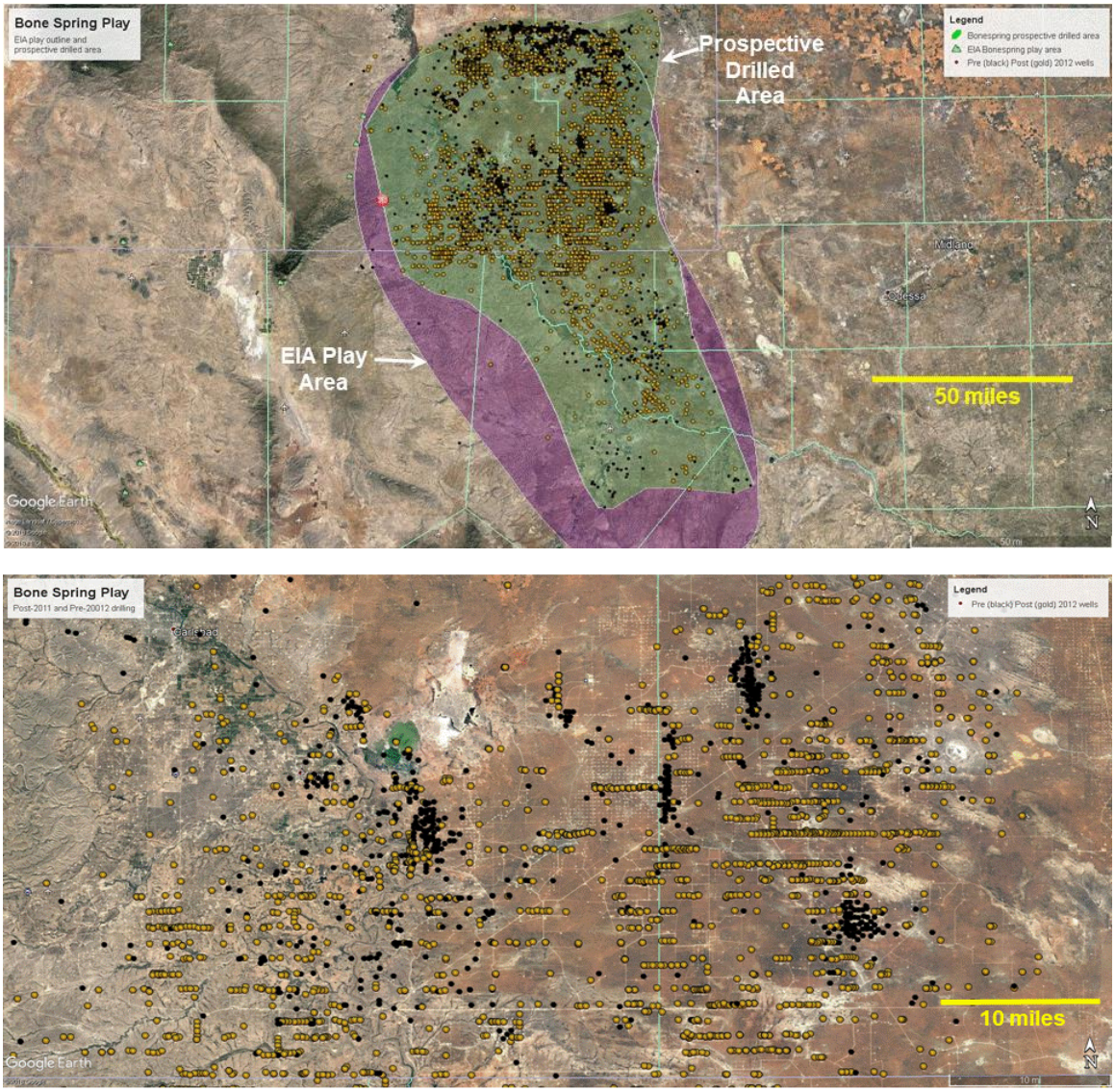
[77] From Drillinginfo August, 2019.

The degree of development of the Bone Spring core area to date is illustrated in Figure 55, along with the EIA Bone Spring play area and the prospective drilled area. Although these areas extend far into Texas, New Mexico has accounted for 86% of production. Most well pads have multiple wells and laterals average 7,000 feet. Some areas appear close to saturated with wells, although other areas appear able to accommodate many more.



© Hughes GSR Inc, 2019 (data from Drillinginfo October, 2019)

Figure 55. Drilling density in the core area of the Bone Spring Play.

Upper: EIA Bone Spring play area[78] and prospective drilled area. Lower: Core area of the Bone Spring Play, showing well locations and degree of development as of April 2019. Pre-2012 Bone Spring wells shown in black; post-2011 wells shown in gold.

[78] EIA, 2019, *Bone Spring and Avalon Bone Spring play extents (3/26/2019)*, https://www.eia.gov/maps/map_data/BoneSpring_AvalonBoneSpring_Boundary_EIA.zip

The evolution of production by county for post-2011 horizontal wells is illustrated in Figure 56. As of April 2019, Eddy and Lea counties accounted for 87% of production. The seven Texas counties accounted for just 13% of post-2011 horizontal production.

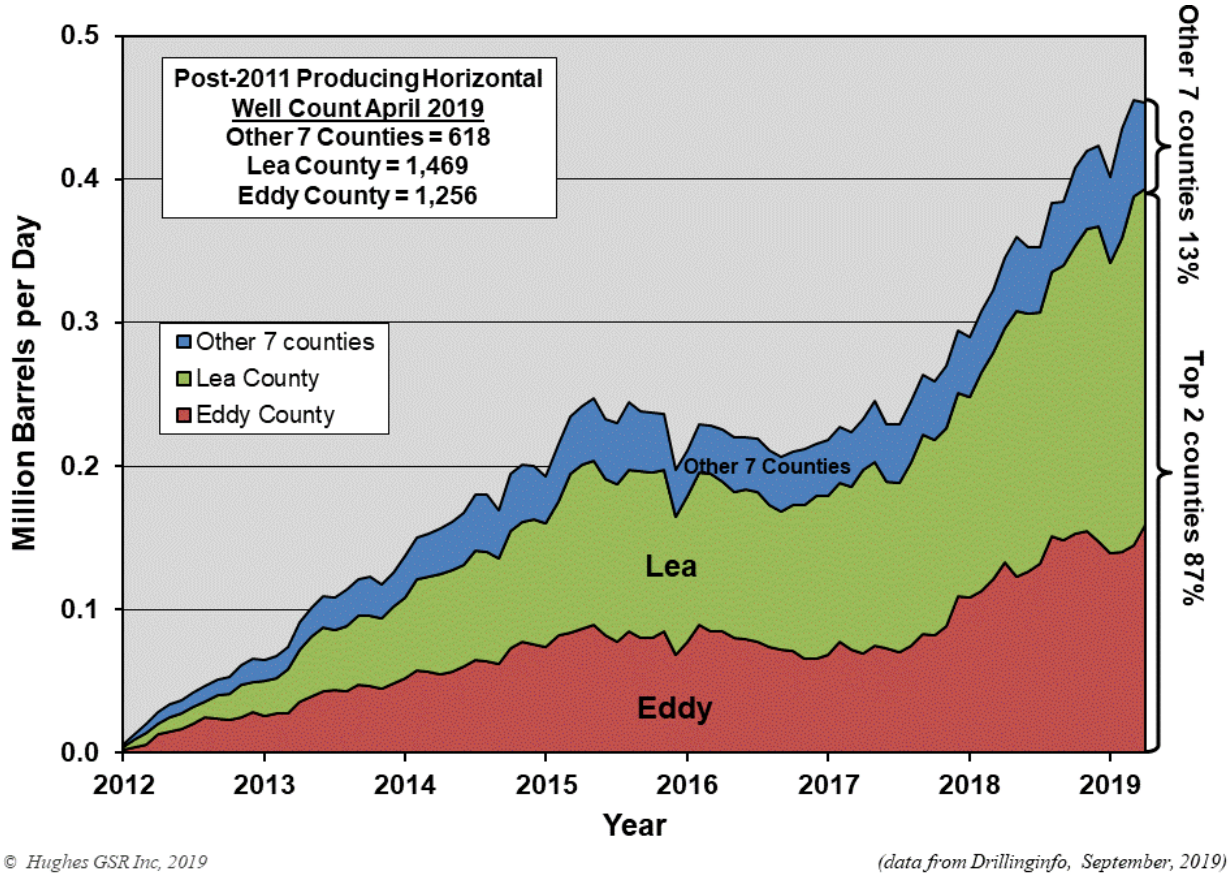


Figure 56. Oil production from horizontal post-2011 wells in the Bone Spring Play by county through 2019.

Horizontal drilling in all counties has exhibited a marked improvement in productivity in the 2012–2018 period, as illustrated in Figure 57. Vertical/directional drilling, on the other hand, decreased markedly since 2016. 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. Horizontal wells in the Texas part of the play, however, have flat-lined in 2018, in terms of productivity gains.

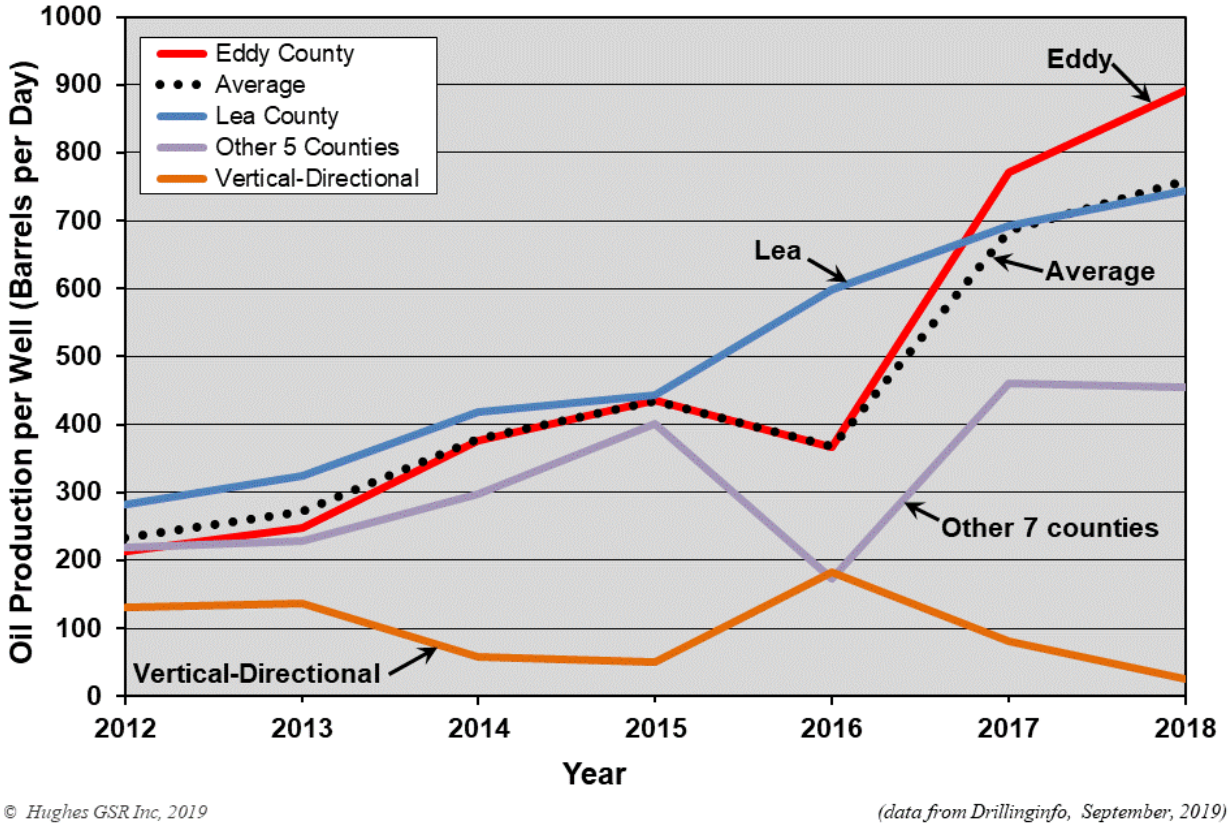


Figure 57. Average horizontal well productivity over the first four months of oil production by county in the Bone Spring Play, 2012–2018.

Figure 58 illustrates the EIA's AEO2019 reference case production forecast for the Bone Spring Play through 2050, together with earlier forecasts. The EIA expects production to keep increasing to a peak in 2031, at 59% above current levels, and exit 2050 at 15% above current levels. This would require producing 7.88 billion barrels of oil over the 2017–2050 period, which is ten times as much oil as has been recovered from the Bone Spring since the 1960s[79]. The EIA production forecast requires producing 130% of its estimate of proven reserves plus unproven resources by 2050. The fact that the EIA forecast exits 2050 at production levels 15% above current levels implies that considerable additional volumes of oil would be recovered after 2050. Given the above, the EIA's forecast is rated as extremely optimistic.

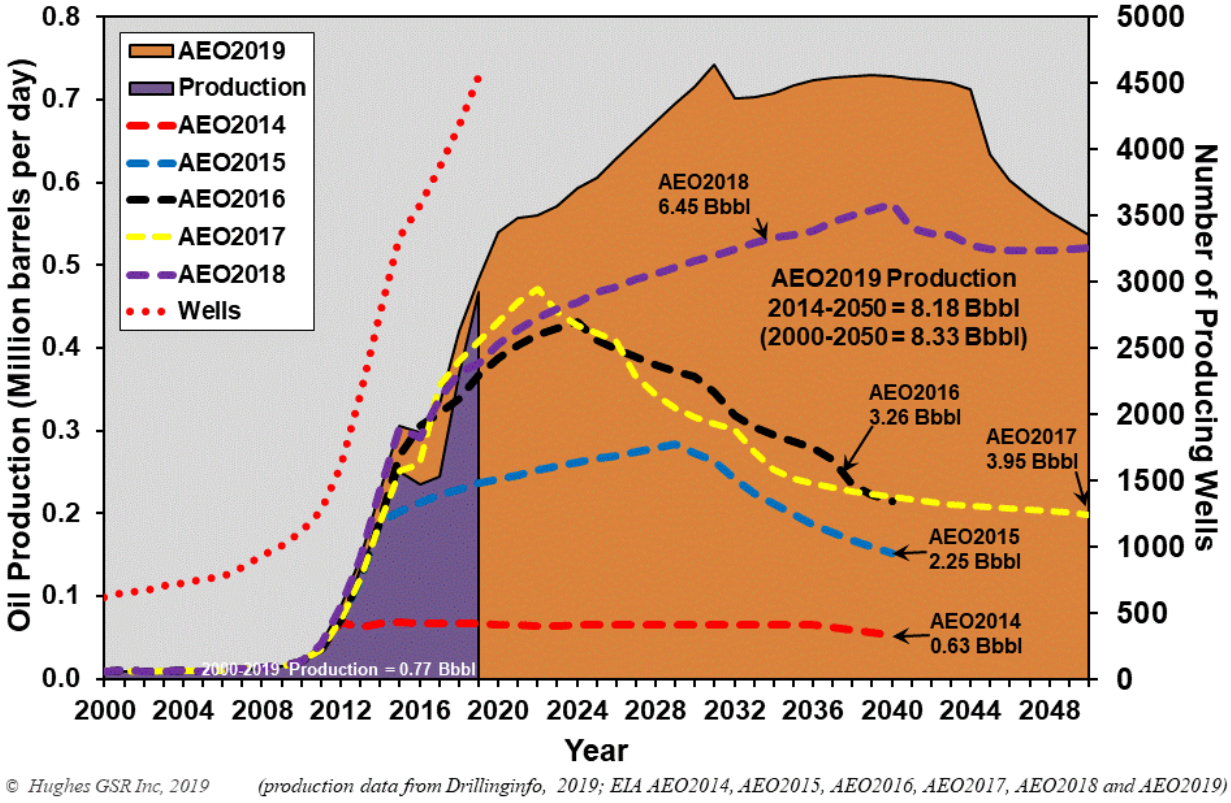


Figure 58. EIA AEO2019 reference case Bone Spring Play oil production forecast through 2050.

Also shown are earlier AEO forecasts to 2040 and 2050, and cumulative 2000-2019 production.

[79] Production data from Drillinginfo. The USGS completed an assessment of continuous resources in the Bone Spring Play in 2018. Mean, undiscovered, technically recoverable resources in the Bone Spring were estimated at 14 billion barrels. The USGS states, however, that "whether or not it is profitable to produce these resources has not been evaluated", https://pubs.usgs.gov/fs/2018/3073/fs20183073.pdf

Table 11 illustrates assumptions in the EIA AEO2019 reference case forecast.[80] If realized, the EIA forecast would have to recover 130% of the EIA's estimate of proven reserves plus unproven resources, and would require 30,087 additional wells, for a total well count of four times the current 10,176, at an estimated cost of $226 billion.

EIA AEO2019 Reference Case Forecast	
Proven Reserves year-end 2017 (Bbbls)[81]	1.75
Unproven Resources 2017 (Bbbls)[82]	4.3
Total Potential 2017 (Bbbls)	6.05
2017-2050 Recovery (Bbbls)	7.88
% of total potential used 2017-2050	130.3%
Wells needed for available potential 2017-2050	30,087
Well cost 2017-2050 ($billions)	$226

Table 11. EIA assumptions for Bone Spring Play oil in the AEO2019 reference case.

Well costs of $226 billion for full development are estimated assuming a well cost of $7.5 million.[83] The number of wells needed was determined using EIA EUR estimates for unproven resources, assuming EUR per well would be twice as high for proven reserves as for unproven resources. Total well costs are to extract 100% of proven reserves and unproven resources. Available resources fall short of the AEO2019 forecast extraction requirement through 2050 by 1.83 Bbbls.

[80] EIA, Unproved technically recoverable resources are from *Assumptions to the Annual Energy Outlook 2019*, https://www.eia.gov/outlooks/aeo/assumptions/; Proven reserves are from *U.S. Crude Oil and Natural Gas Proved Reserves, Yearend 2017*, 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.

[81] EIA, 2018, U.S. Crude Oil and Natural Gas Proved Reserves, Yearend 2017, https://www.eia.gov/naturalgas/crudeoilreserves/. Note that the EIA does not report reserves for the Bone Spring separately – it reports the Permian Wolfcamp and Bone Spring together at 8.32 Bbbls which have been apportioned between the Wolfcamp and Bone Spring according to the EIA's assumed 2017-2050 recovery

[82] EIA, 2019, Oil and Gas Supply Module for AEO2019, https://www.eia.gov/outlooks/aeo/assumptions/pdf/oilgas.pdf

[83] EIA, 2016, Trends in U.S. Oil and Natural Gas Upstream Costs, https://www.eia.gov/analysis/studies/drilling/pdf/upstream.pdf

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 post-2011 wells have accounted for 78% of cumulative production, almost all of it from horizontal wells. The top two counties, both in New Mexico, account for 87% of current production. As of April 2019, 10,176 wells have been drilled.

- The prospective drilled area is about 6,330 square miles, located mainly in New Mexico but extending south into Texas (compared to the EIA play area in Figure 55 of 8,427 square miles). The EIA has also estimated that an area of 4,701 square miles can be drilled at a well density of 6.4 wells per square mile, to recover 6.05 billion barrels of unproven resources plus proven resources by 2050.

- In its reference case, the EIA AEO2019 assumes that 7.88 billion barrels of oil will be recovered over the 2017–2050 period, which is 130% of its estimated proven reserves plus unproven resources. Recovering 100% of the EIA estimates of proven reserves plus unproven resources would require 30,087 wells, but would still leave production 1.83 billion barrels short of the 7.88 billion barrels required to meet its forecast. At $7.5 million per well this would cost $226 billion.

- Although the EIA estimate of unproven Bone Spring resources is less than the USGS estimate, most of the potential area for extension of the play is in Texas, where wells have exhibited much lower productivities than wells in New Mexico and have not increased in productivity in 2018 despite higher injection volumes of water/proppant. Neither the EIA nor USGS estimates of unproven resources have been demonstrated to be economically recoverable.

- The EIA assumes that production will exit 2050 at 15% above current rates, after recovering 30% more oil than its own estimates of proven reserves and unproven resources suggest exist, which implies that large additional, as-yet-unknown, resources will be recovered beyond 2050.

- Given the above considerations and play fundamentals, the AEO2019 forecast for the Bone Spring is rated as 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 16,200 wells have been drilled, of which 4,940 were still producing as of April 2019.

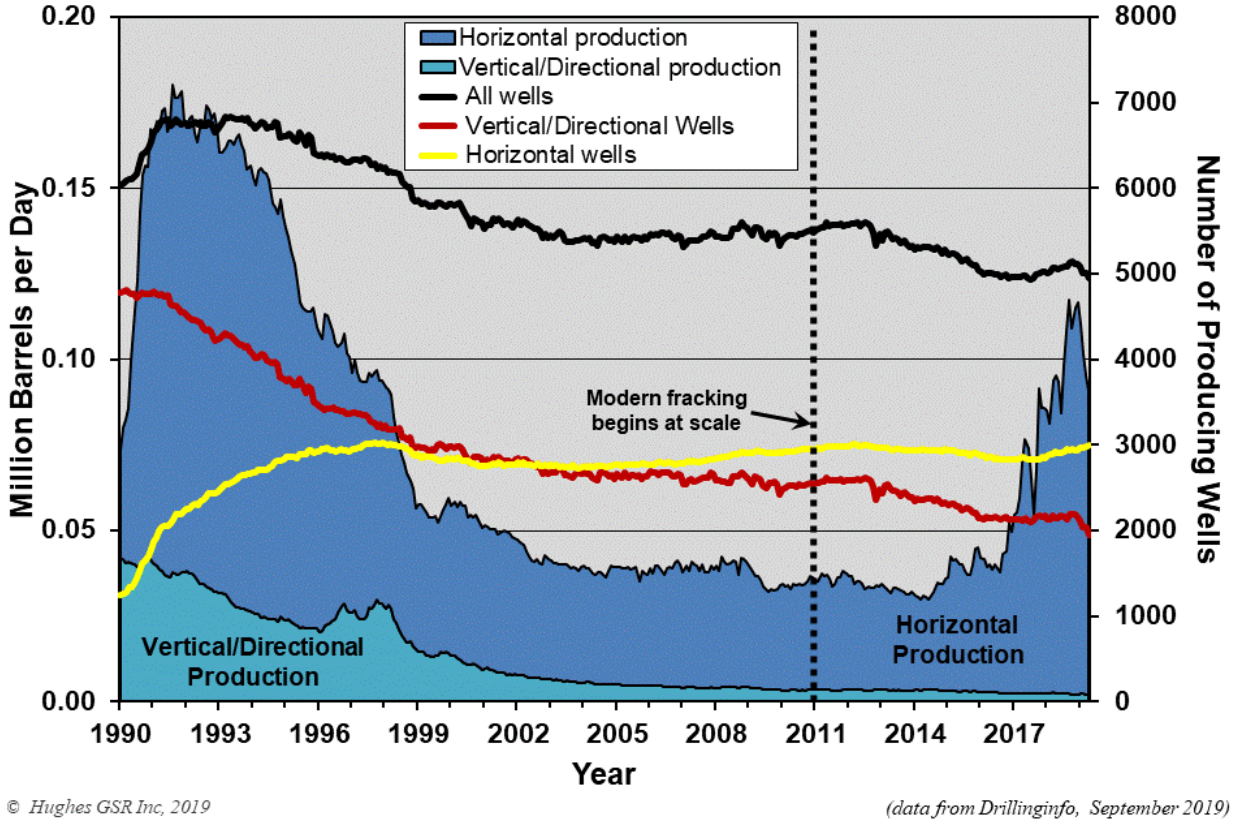


Figure 59. Austin Chalk Play oil production and number of producing wells by type, 1990–2019.

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 also one of the top producing counties of the Eagle Ford.

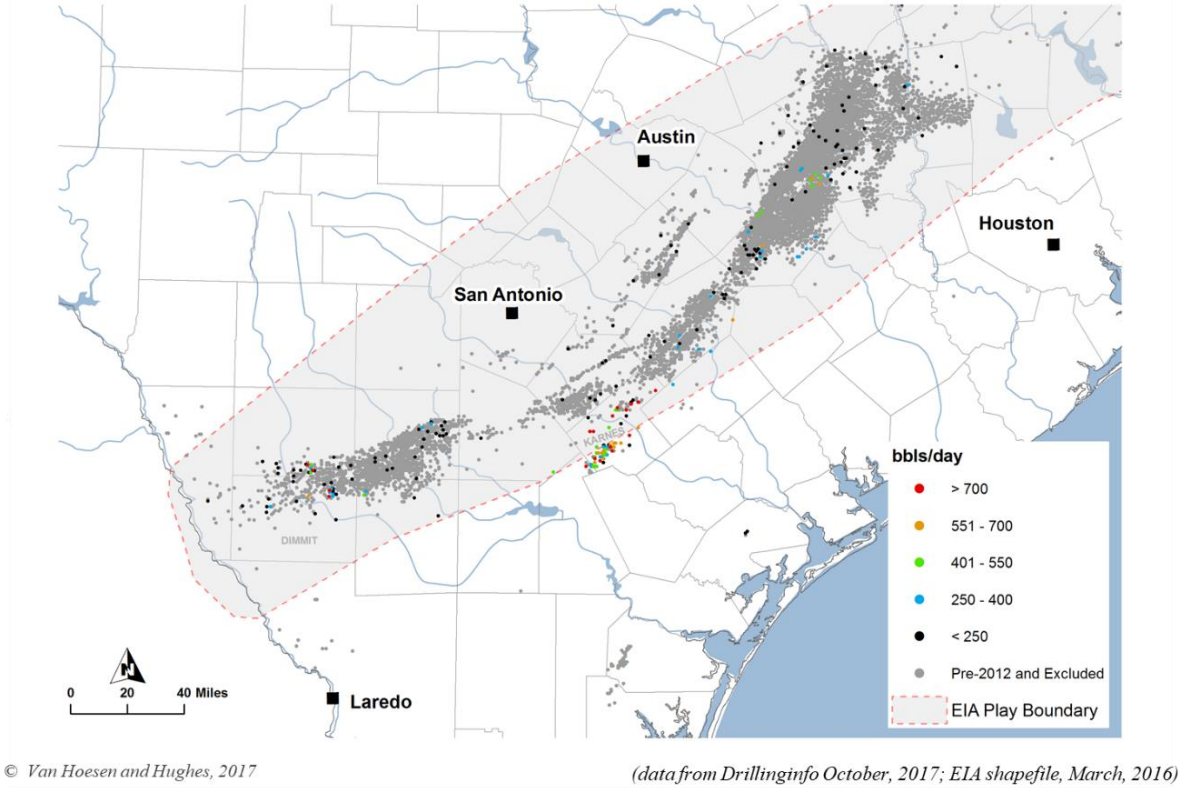


Figure 60. Austin Chalk Play well locations showing peak oil production of post-2011 wells in the highest month.[84]

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.

[84] EIA, *Shapefiles for the Tight Gas Plays Map*, March, 2016, https://www.eia.gov/maps/map_data/tightgasbasinplay.zip

Figure 61 illustrates cumulative recovery of oil and gas by county. Production has been mainly from pre-2011 wells and is widespread over many counties. The highest cumulative recoveries of oil 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.

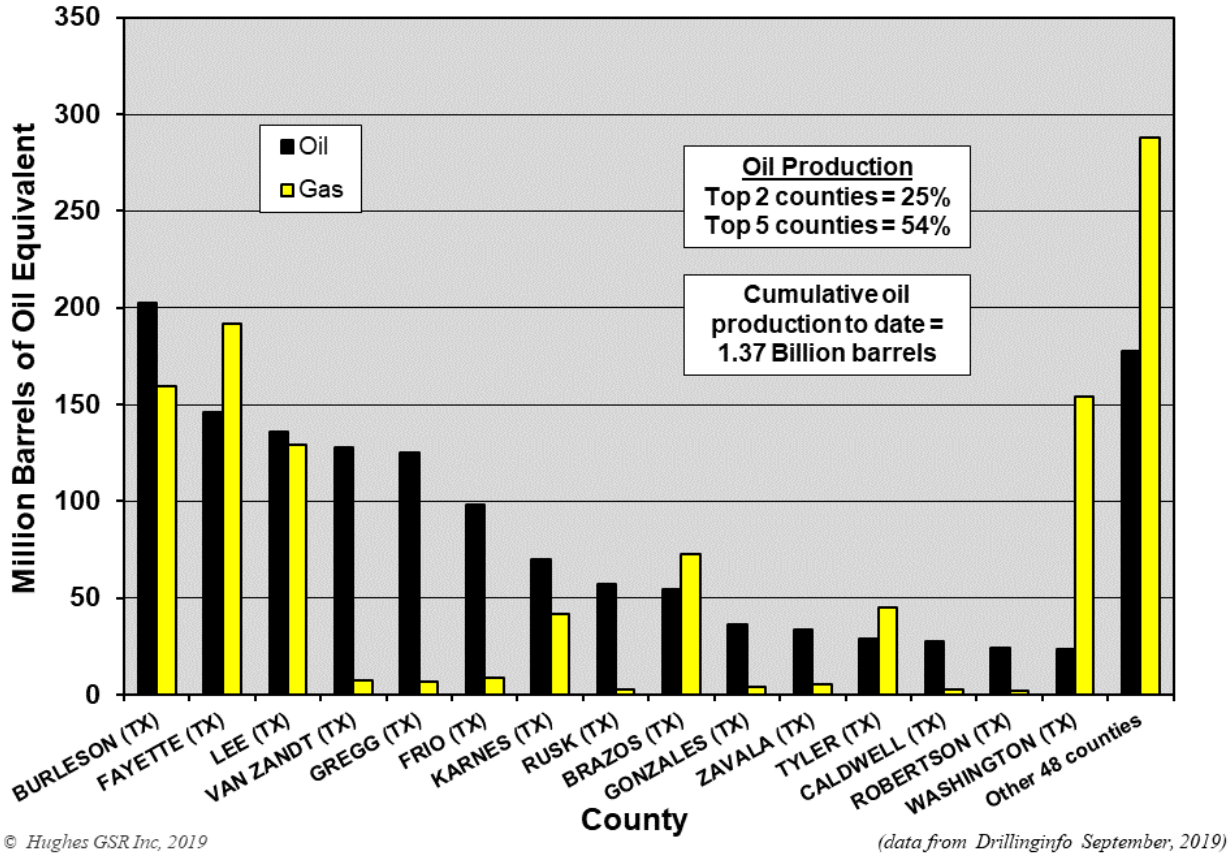


Figure 61. Cumulative production of oil and gas from the Austin Chalk Play by county through 2019.

The top two counties have recovered 25% of total oil production and the top five have recovered 54%.

Post-2011 production shows that most of the counties which have in the past provided production are no longer prospective. Karnes County, which was not even in the top 16 producing counties before 2012, has moved into first place with 77% 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.

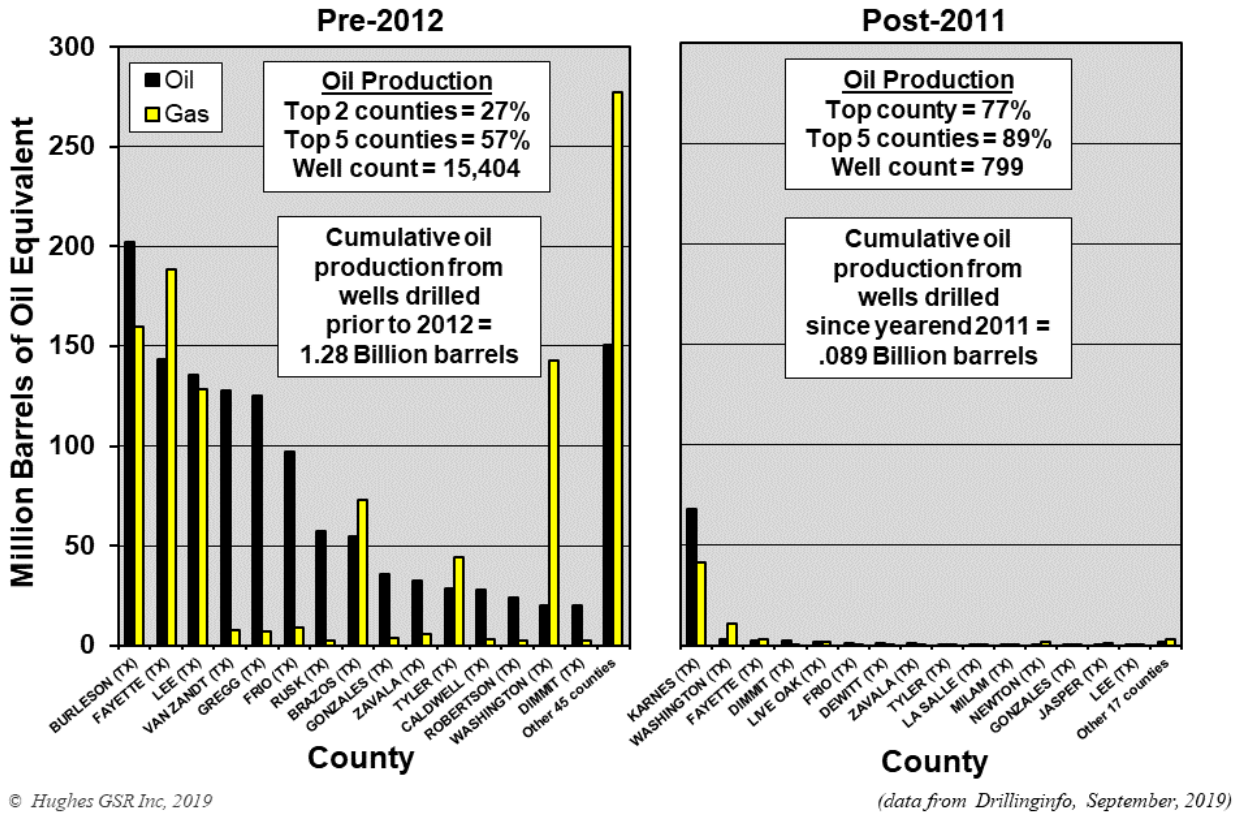


Figure 62. Cumulative production of oil and gas from the Austin Chalk Play by county and well vintage through 2019.

Production in post-2011 is concentrated in Karnes County, with 77% of the total. The top five counties accounted for 89% of post-2011 production.

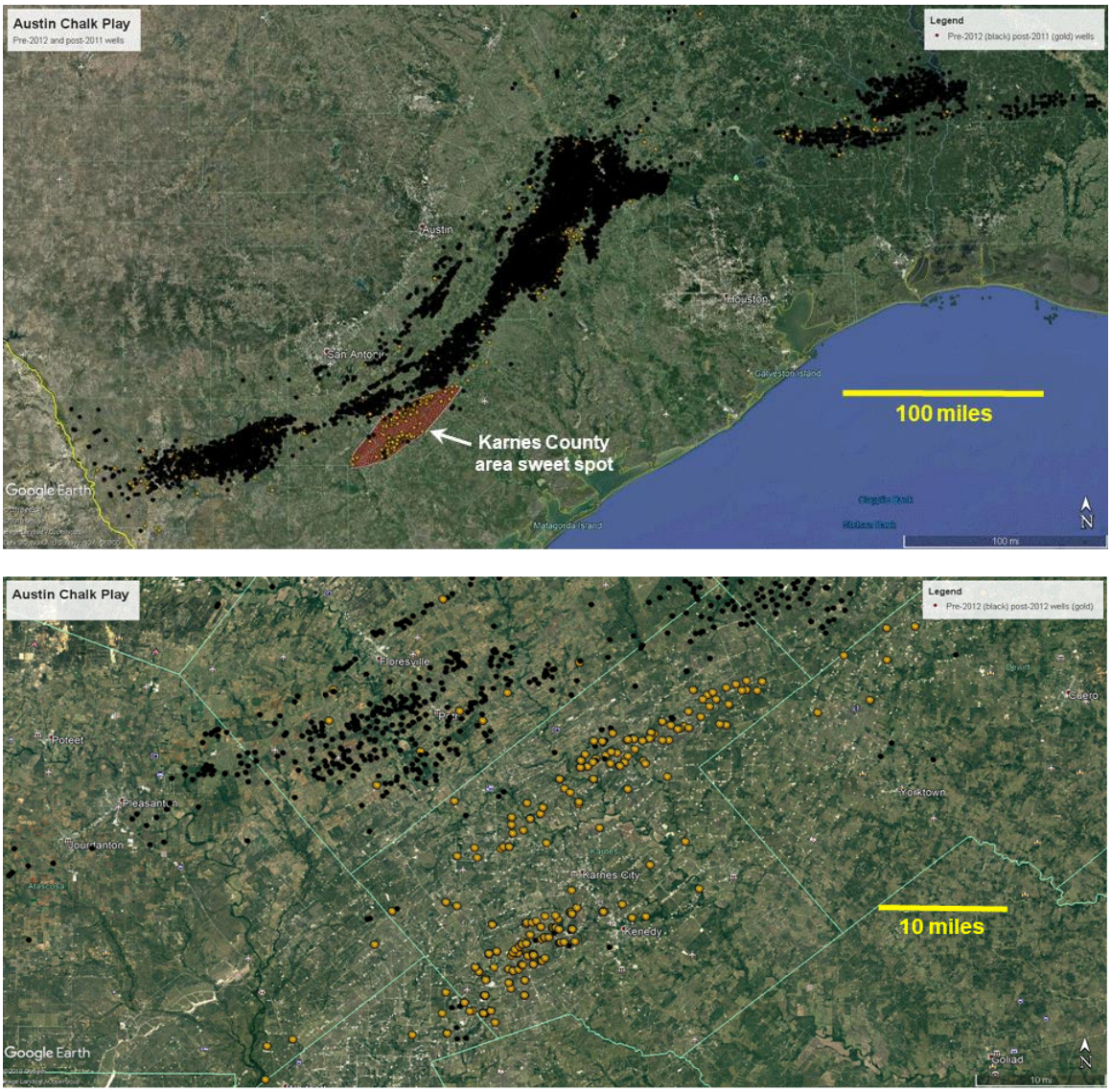
Table 12 summarizes the number of wells drilled by vintage, cumulative and current production, and well- and first-year field-decline rates for the Austin Chalk Play as a whole and for individual counties. Three-year well decline rates average 91% and first-year field decline averages 23.2% per year without new drilling.

County	Well type	Vintage	Total Well Count	Producing Well Count	Cumulative Oil Production (billion bbls)	Cumulative Gas Production (tcf)	Oil Production April 2019 (Kbbls/day)	Gas Production April 2019 (bcf/day)	3-year well decline (%)	First-year Field decline (%)
All	All	All	16,203	4,940	1.371	6.739	90.9	0.52	91.0	23.2
All	All	Pre-2012	15,404	4,269	1.280	6.332	16.96	0.05	n/a	n/a
All	Horizontal	Post-2011	723	627	0.091	0.406	73.9	0.47	91.1	32.1
All	Vertical	Post-2011	76	44	0.00003	0.0008	0.04	0.00	54.9	20.3
Karnes	Horizontal	Post-2011	361	330	0.071	0.258	53.0	0.28	91.3	30.3
Washington	Horizontal	Post-2011	49	48	0.003	0.067	4.26	0.13	92.2	49.0
Other counties	Horizontal	Post-2011	313	249	0.017	0.081	16.66	0.06	91.8	46.0

Table 12. Well count, cumulative production, most recent production, and well- and first-year field-decline rates for the Austin Chalk Play and counties within it, by well type and vintage.[85]

[85] From Drillinginfo August, 2019.

The areal extent of the Austin Chalk Play and the degree of development in the Karnes County core area through April 2019, is illustrated in Figure 63. Although some recent horizontal laterals exceed 8,000 feet in length, the average is considerably less. Most post-2011 well pads have multiple wells. Current development is relatively sparse and there appears to be substantial area for additional wells.



© Hughes GSR Inc, 2019 (data from Drillinginfo September, 2019)

Figure 63. Drilling density in the core area of the Austin Chalk Play

Upper: extent of Austin Chalk Play, illustrating wells drilled through April 2019, and sweet spot in and near Karnes County. Lower: core area in Karnes County and surroundings, showing well locations and degree of development as of April 2019. Pre-2012 wells are black and post-2011 wells are gold in color.

Figure 64 illustrates well productivity by county in the Austin Chalk over 2012–2018. Drilling in the play since 2011 has been focused on Karnes County, where there has been a large improvement in well productivity through 2016 due to advancing technology (although average well productivity has flat-lined since then). 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 Karnes County, average well productivity drops to a third or less, which suggests that the economically viable extent of the Austin Chalk that can be redeveloped with fracking is quite small compared to the earlier extent of the play. The average productivity of the play as a whole has declined since 2017.

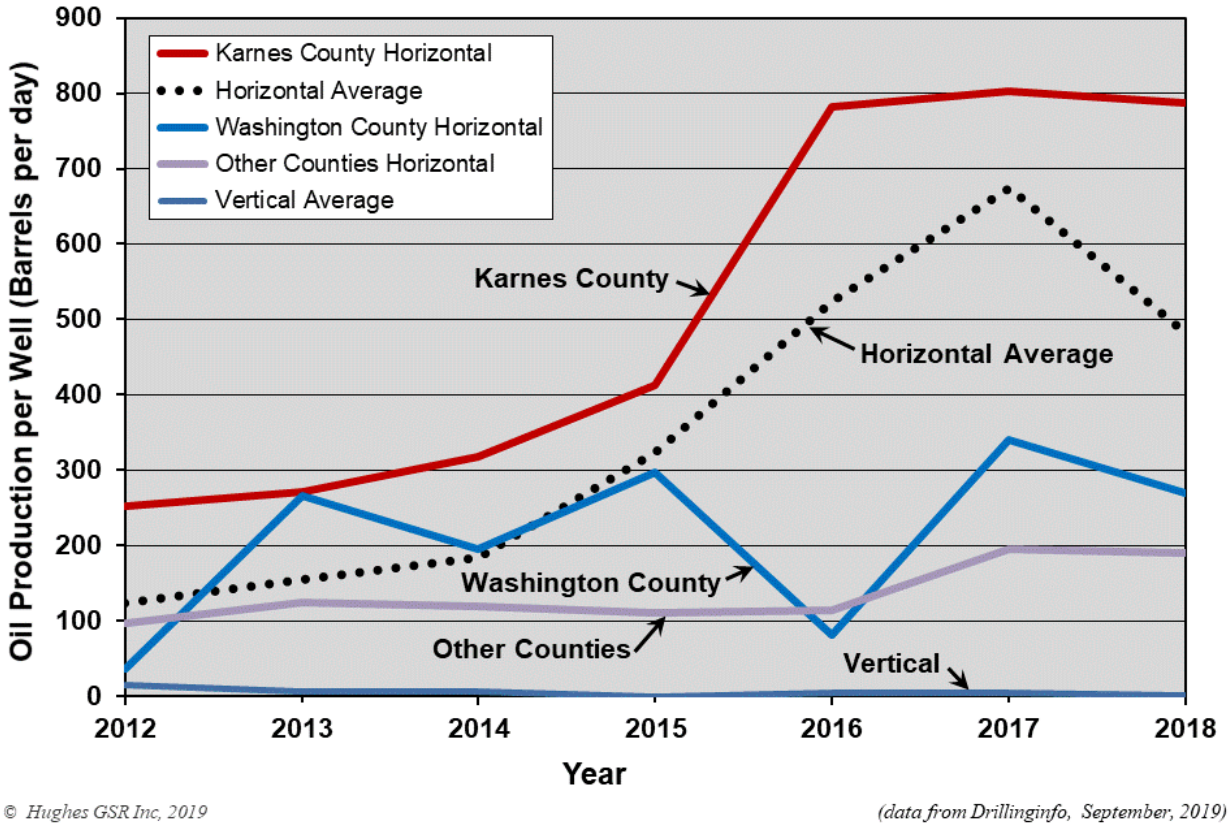


Figure 64. Average horizontal well productivity over the first four months of oil production by county in the Austin Chalk Play, 2012–2018.

Figure 65 illustrates the EIA's AEO2019 reference case production forecast for the Austin Chalk Play through 2050, together with earlier forecasts. The EIA expects production to keep increasing through 2050, which would require producing 2.26 billion barrels of oil over the 2017–2050 period. This is nearly twice as much as the play has produced since the 1960s. The fact that the EIA forecast exits 2050 at levels more than double current production implies large 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 EIA's forecast is rated as extremely optimistic.

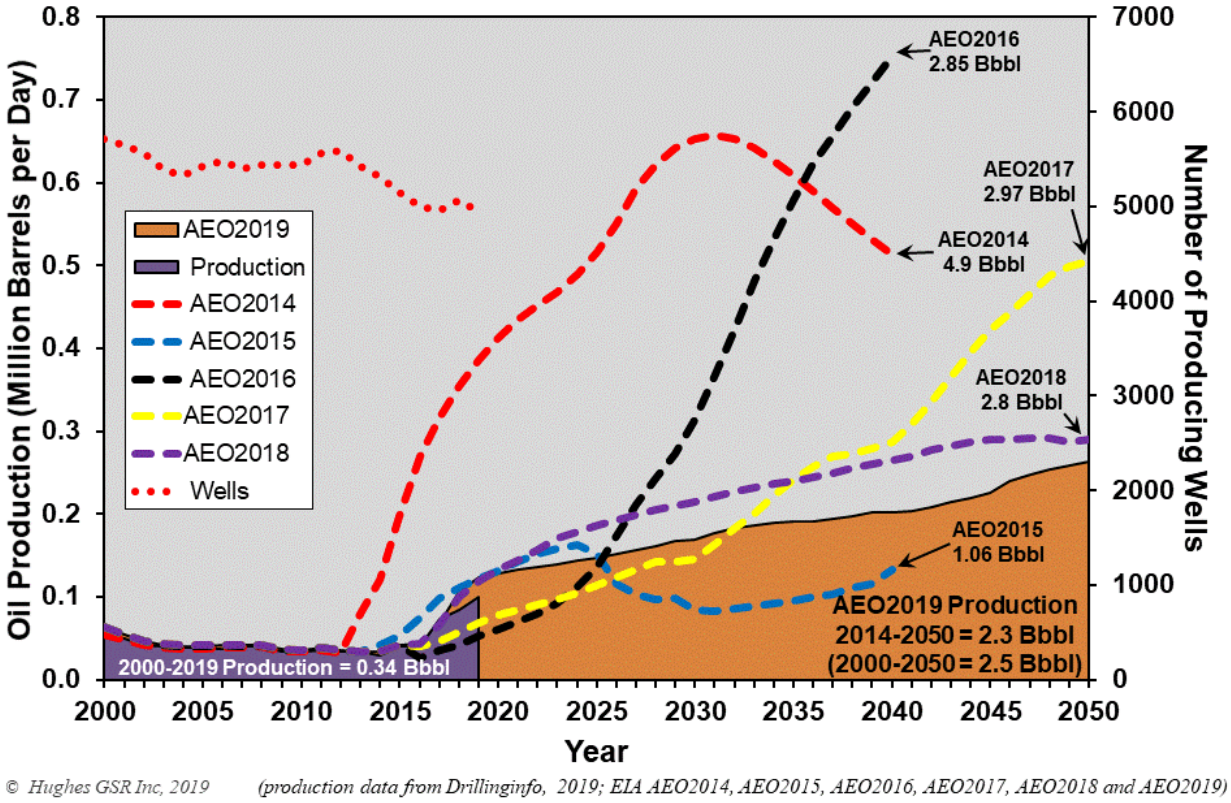


Figure 65. EIA AEO2019 reference case Austin Chalk Play oil production forecast through 2050.

Also shown are earlier AEO forecasts to 2040 and 2050, and cumulative 2000-2019 production.

Table 13 illustrates assumptions in the EIA AEO2019 reference case forecast.[86] If realized, the EIA forecast would have to recover 64.5% of the EIA's estimate of proven reserves plus unproven resources, and would require 47,717 additional wells, for a total well count of nearly four times the current 16,203, at an estimated cost of $358 billion.

EIA AEO2019 Reference Case Forecast	
Proven Reserves year-end 2017 (Bbbls)[87]	0.0
Unproven Resources 2017 (Bbbls)[88]	3.5
Total Potential 2017 (Bbbls)	3.5
2017-2050 Recovery (Bbbls)	2.26
% of total potential used 2017-2050	64.5%
Wells needed 2017-2050	47,717
Well cost 2017-2050 ($billions)	$358

Table 13. EIA assumptions for Austin Chalk Play oil in the AEO2019 reference case.

Well costs of $358 billion for full development are estimated assuming a well cost of $7.5 million.[89] The number of wells needed was determined using EIA EUR estimates for unproven resources, assuming EUR per well would be twice as high for proven reserves as for unproven resources.

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 (see Figure 63), most post-2011 production has come from Karnes County. Considering post-2011 wells only, Karnes County accounted for 77% of cumulative production and 72% of April 2019, 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 April 2019, 16,203 wells have been drilled, 799 of which were drilled since 2011.

- The sweet spot with high productivity wells drilled since 2011 in Karnes County and surrounding area is only about 773 square miles in area (see Figure 63). The EIA has estimated that an area of 7,456 square miles can be drilled at a well density of 6.4 wells per square mile, for a total of 41,543 new wells, to recover 2.26 billion barrels of unproven resources plus proven reserves to meet its forecast.[90] This area is roughly ten times the size of the Karnes County sweet spot, and although this much area exists in the original play extent, the low well productivity of wells outside the sweet spot area suggests the oil there would be difficult or impossible to economically extract.

- In its reference case, the EIA AEO2019 forecast assumes that nearly twice as much oil will be recovered by 2050 from the Austin Chalk as has been recovered since the early 1960s, that the well count will be nearly quadrupled at a cost of $358 billion, and that production will exit 2050 at near three times current levels.

- Given the above, along with play fundamentals, the AEO2019 forecast for the Austin Chalk Play is rated as extremely optimistic.

[86] EIA, Unproved technically recoverable resources are from *Assumptions to the Annual Energy Outlook 2019*, https://www.eia.gov/outlooks/aeo/assumptions/; Proven reserves are from *U.S. Crude Oil and Natural Gas Proved Reserves, Yearend 2017*, https://www.eia.gov/naturalgas/crudeoilreserves/

[87] EIA, 2018, U.S. Crude Oil and Natural Gas Proved Reserves, Yearend 2017, https://www.eia.gov/naturalgas/crudeoilreserves/. Note that the EIA does not report reserves for the Austin Chalk, hence they are listed here as zero.

[88] EIA, 2019, Oil and Gas Supply Module for AEO2019, https://www.eia.gov/outlooks/aeo/assumptions/pdf/oilgas.pdf

[89] EIA, 2016, Trends in U.S. Oil and Natural Gas Upstream Costs, https://www.eia.gov/analysis/studies/drilling/pdf/upstream.pdf

[90] EIA, 2019, *Assumptions to the Annual Energy Outlook 2019*, https://www.eia.gov/outlooks/aeo/assumptions/; the number of wells has been calculated using the EURs in this document for unproven resources and assuming EURs for proven reserves would be twice as high.

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 2011. More than 37,800 wells have been drilled, of which 13,568 were still producing as of April 2019.

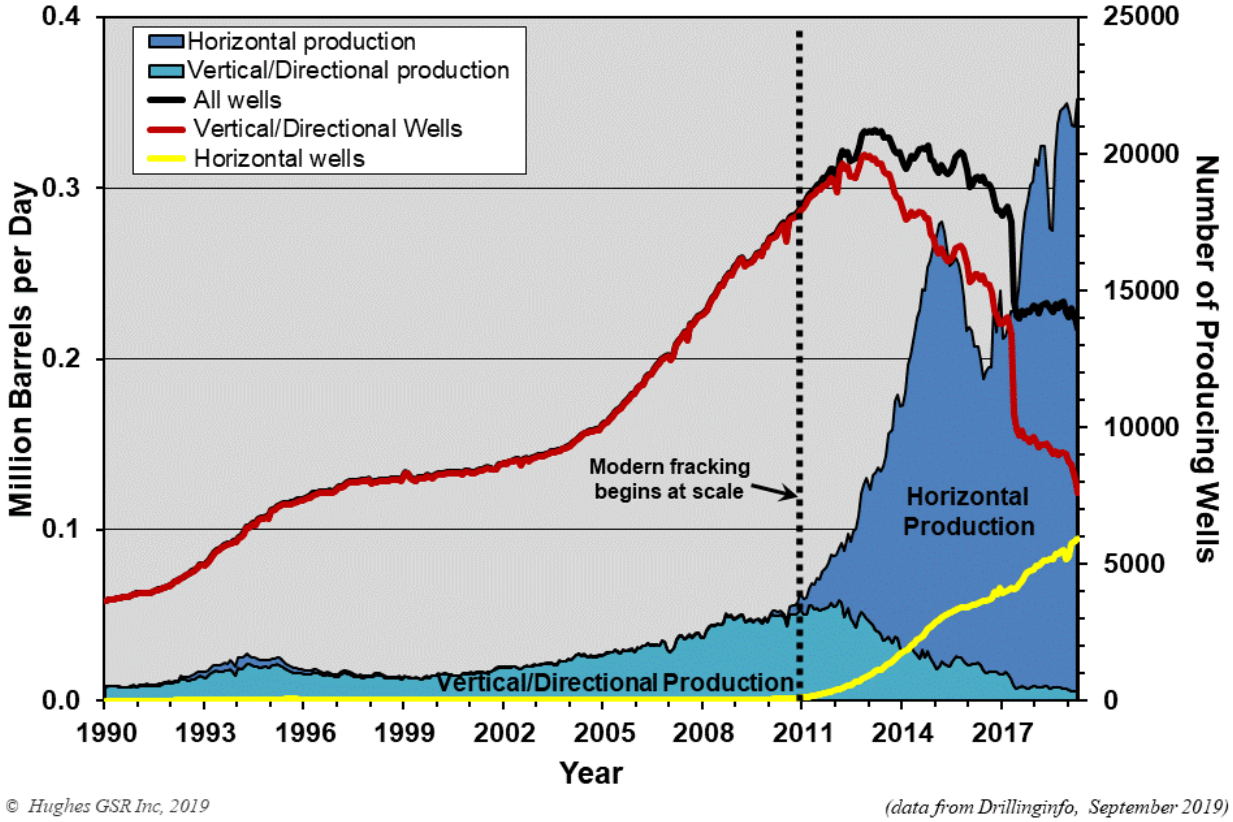


Figure 66. Niobrara Play oil production by well type and number of producing wells by type, 1990–2019.

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 ($5 million for a 6,600 foot horizontal lateral[91], compared to $7.8 million for an average well in the Bakken), which has improved overall economics.

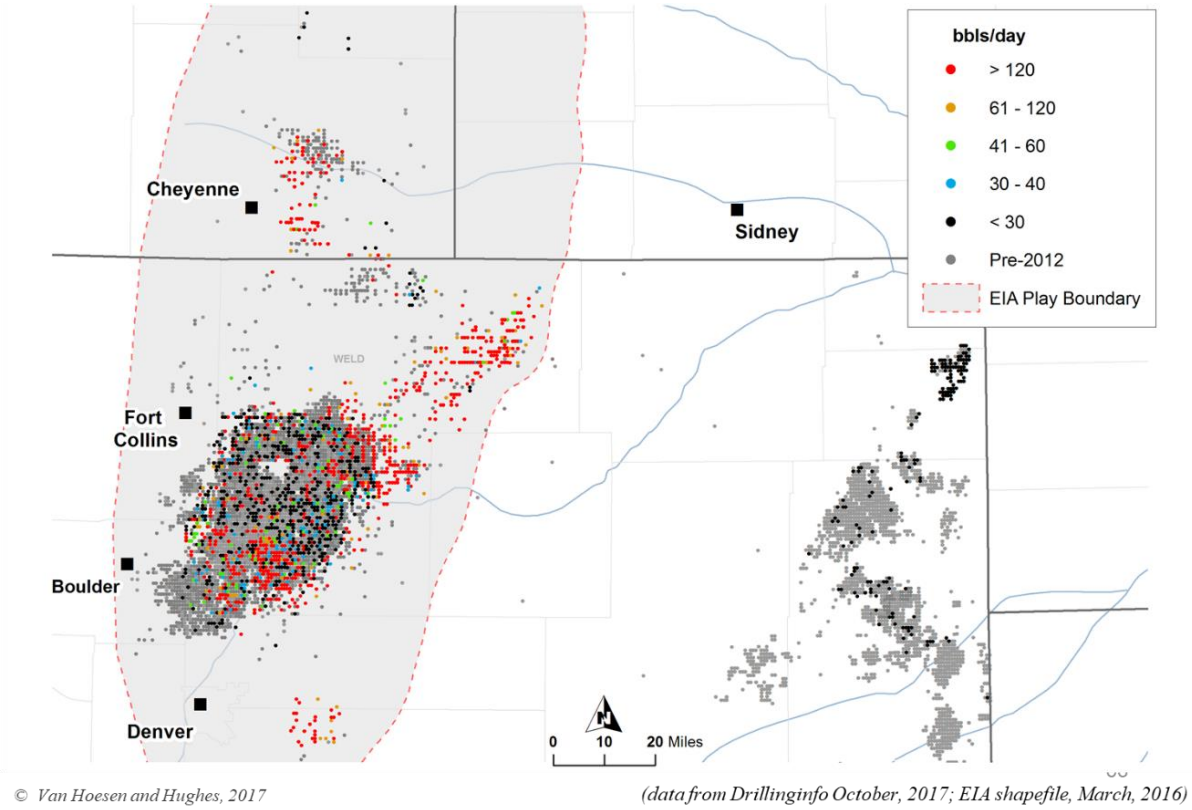


Figure 67. Niobrara Play in the Denver-Julesburg Basin well locations showing peak oil production of post-2011 wells in the highest month.[92]

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

[91] EIA, 2016, Trends in U.S. Oil and Natural Gas Upstream Costs, https://www.eia.gov/analysis/studies/drilling/pdf/upstream.pdf
[92] EIA, March, 2016, play area outline from https://www.eia.gov/maps/map_data/TightOil_ShaleGas_Plays_Lower48_EIA.zip p

Figure 68 illustrates cumulative recovery of oil and gas by county over the full life of the play. Eighty-three percent of cumulative production has come from Weld County and 96% 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.

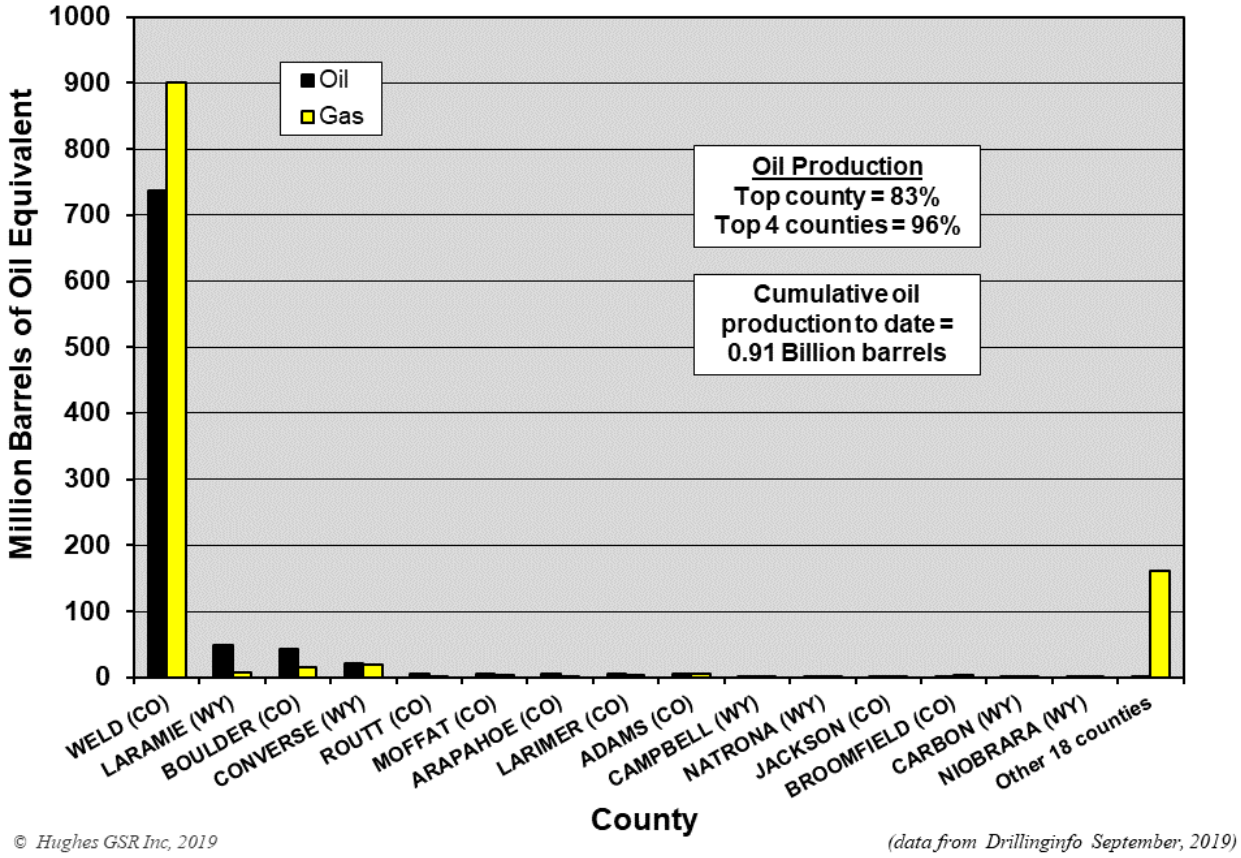


Figure 68. Cumulative production of oil and gas from the Niobrara Play by county through 2019.

Eighty-three percent of total oil production has been recovered from Weld County and the top four counties have recovered 96%.

Production from new drilling has been concentrated even more in Weld County, which had 87% of post-2011 production. Ninety-eight 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.

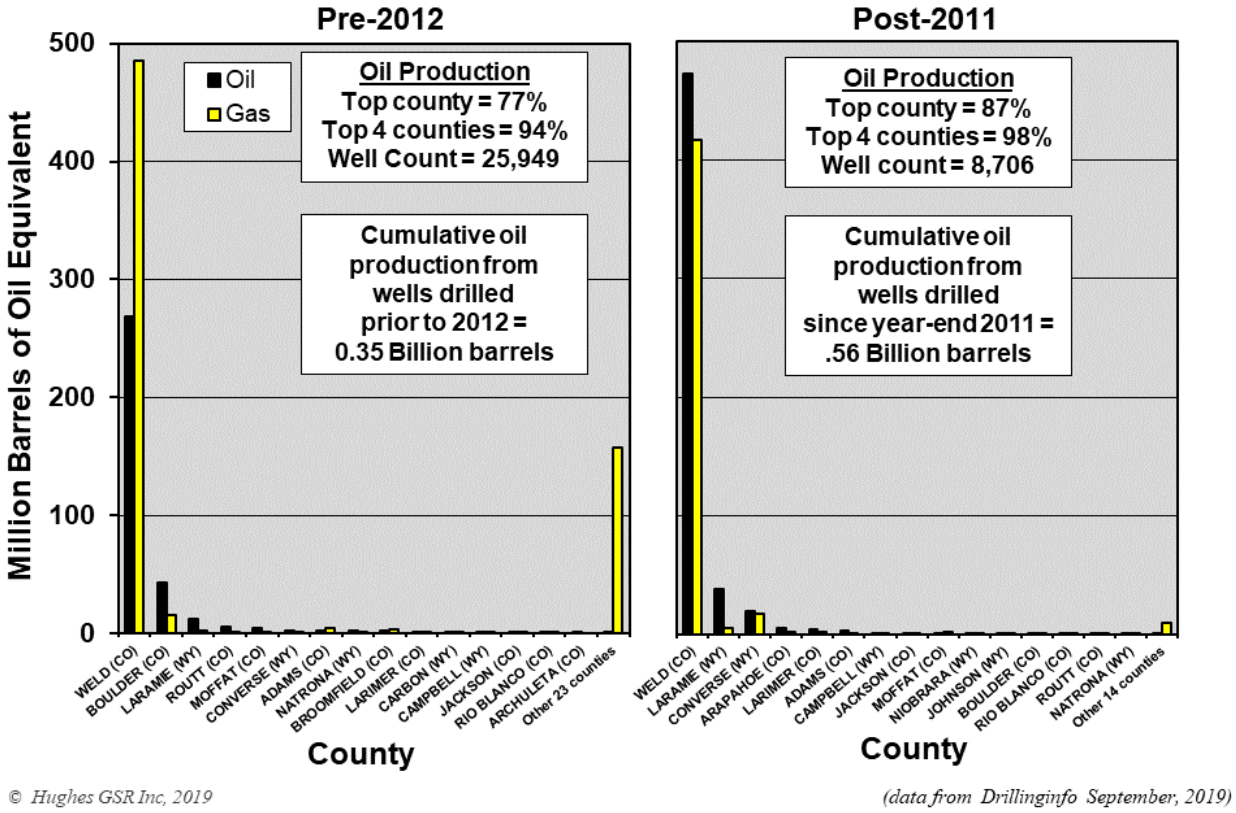


Figure 69. Cumulative production of oil and gas from the Niobrara Play by county and well vintage through 2019.

Production from post-2011 wells has been concentrated in Weld County, with 87%. The top four counties accounted for 98% of post-2011 production.

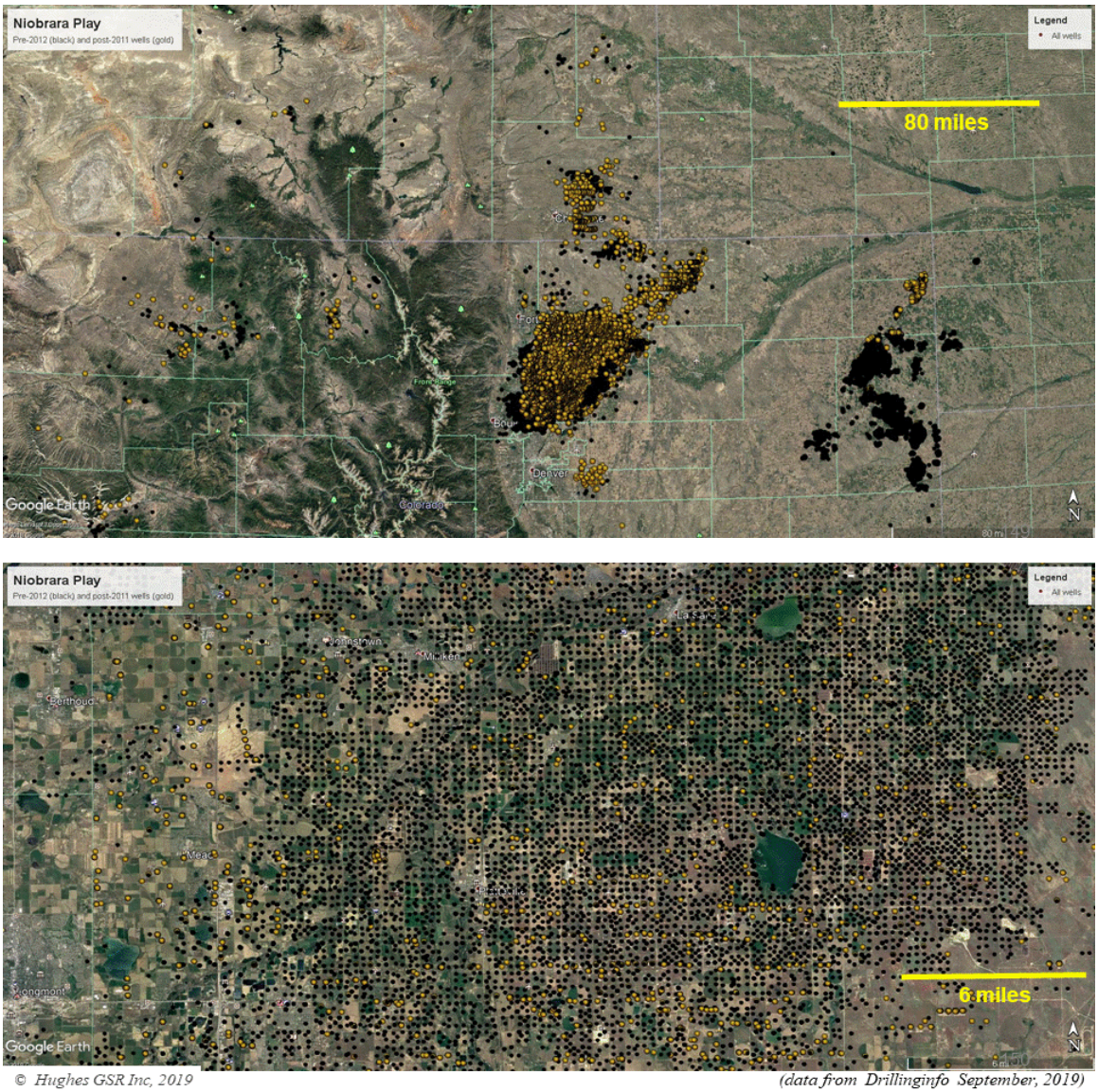
Table 14 summarizes the number of wells drilled by vintage, cumulative and current production, and well- and first-year field-decline rates for the Niobrara Play as a whole and for Weld and other counties. Three-year well decline rates average 91% and first-year field decline averages 51% per year, without new drilling. These are at the high end of decline rates observed for plays analyzed in this report.

County	Well type	Vintage	Total Well Count	Producing Well Count	Cumulative Oil Production (billion bbls)	Cumulative Gas Production (tcf)	Oil Production April 2019 (Kbbls/day)	Gas Production April 2019 (bcf/day)	3-year well decline (%)	First-year field decline (%)
All	All	All	37,863	13,568	0.908	6.873	353.1	2.05	90.8	50.8
All	All	Pre-2012	29,157	6,996	0.362	4.126	7.0	0.11	-	8.4
All	Horizontal	Post-2011	6,533	5,708	0.529	2.63	344.4	1.92	90.8	52,5
All	Vertical	Post-2011	2,173	864	0.017	0.117	1.7	0.02	80.4	43.2
Weld	Horizontal	Post-2011	5,764	5,029	0.457	2.403	273.2	1.80	90.6	53.4
Other counties	Horizontal	Post-2011	769	679	0.072	0.226	71.2	0.12	91.9	45.7

Table 14. Well count, cumulative production, most recent production, and well- and first-year field-decline rates for the Niobrara Play and counties within it by well type and vintage.[93]

[93] From Drillinginfo October, 2019.

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. Although some recent horizontal laterals have exceeded 10,000 feet in length, the average was 6,565 feet in 2018.[94] Most post-2011 well pads have multiple wells. New wells include limited infills and wells drilled along the periphery of the core area.



© Hughes GSR Inc, 2019 (data from Drillinginfo September, 2019)

Figure 70. Drilling density in the core area of the Niobrara Play.

Upper: Niobrara Play overview with well locations. Lower: Weld County core area of the Denver-Julesburg basin and the degree of development as of April 2019. Pre-2012 wells are black and post-2011 wells are gold in color.

[94] J.D. Hughes, 2019, *How long will the shale revolution last? Technology versus Geology and the Lifecycle of Shale Plays*, Post Carbon Institute, https://www.postcarbon.org/publications/how-long-will-the-shale-revolution-last/

Well productivity growth from horizontal drilling in the Niobrara Play has flat-lined since 2017 in the Weld County core area, but has increased outside of Weld County, as illustrated in Figure 71. On average, well productivity has increased somewhat since 2012 but remains much lower than in the Bakken, Eagle Ford or Permian Basin. As mentioned previously, increased productivity is due to increased amounts of water and proppant per well and longer horizontal laterals. The lack of improvement in Weld County suggests that improved technology has reached the point of diminishing returns due to over-crowding of wells and resultant well interference. Wells outside of Weld County likely represent the main opportunity for maintaining or growing production from the Niobrara.

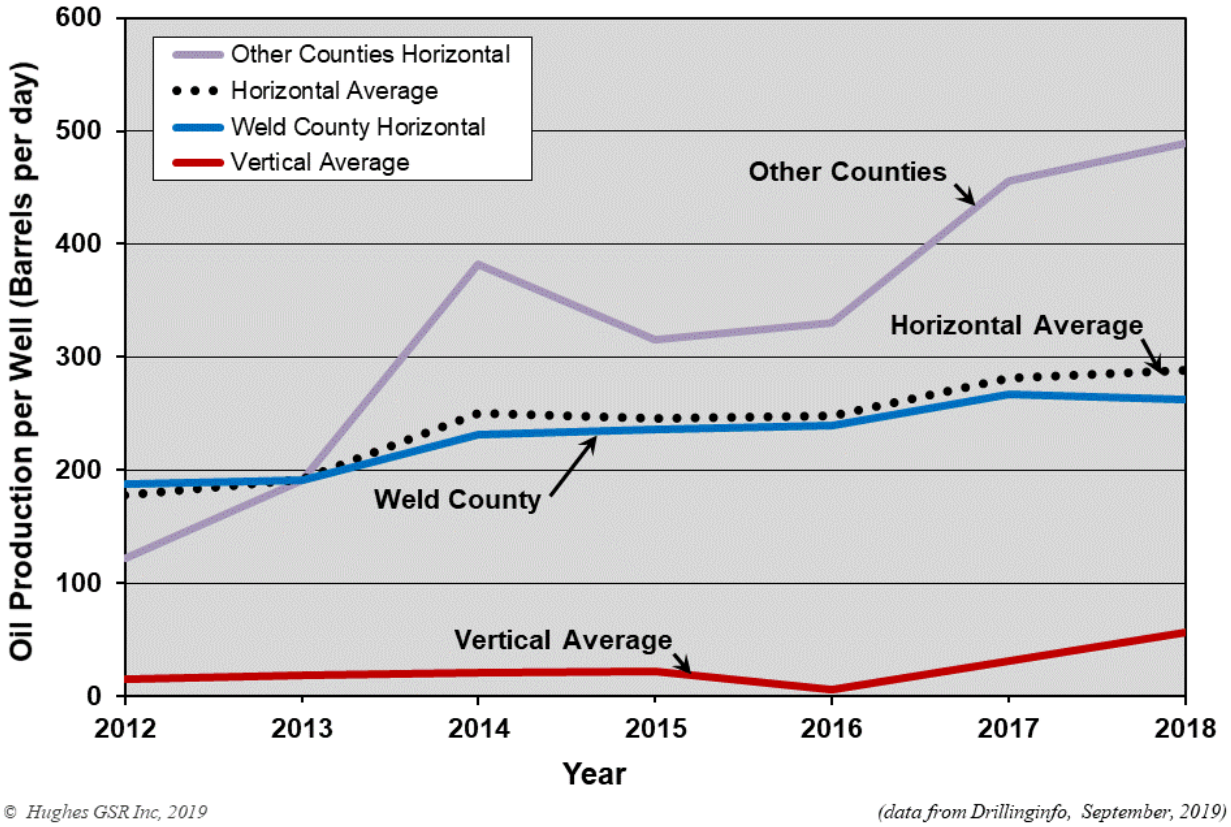


Figure 71. Average horizontal well productivity over the first four months of oil production by county in the Niobrara Play, 2012–2018.

Figure 72 illustrates the EIA's AEO2019 reference case production forecast for the Niobrara Play through 2050, together with earlier forecasts. The EIA expects production to rise to an all-time high in 2043 and remain there through 2050. This would require producing 5.92 billion barrels of oil over the 2017–2050 period, which is 6.5 times as much as the play has produced since the 1950s. At the EIA's assumed well density of 7.2 wells per square mile and its assumed average EUR, 112,260 wells would be needed to meet its forecast—requiring 15,592 square miles of productive area.[95] This is 20% larger than the entire area of the Denver-Julesburg Basin in Colorado and Wyoming, so presumably this would include some of the smaller basins with Niobrara rocks, which have thus far produced very little.[96] Given that the core area in the Denver-Julesburg Basin, which has produced 83% of the oil to date, is almost saturated with wells, and that the 112,260 wells needed would quadruple the well count at a cost of $561 billion, the EIA's production forecast for the Niobrara is rated as highly optimistic.

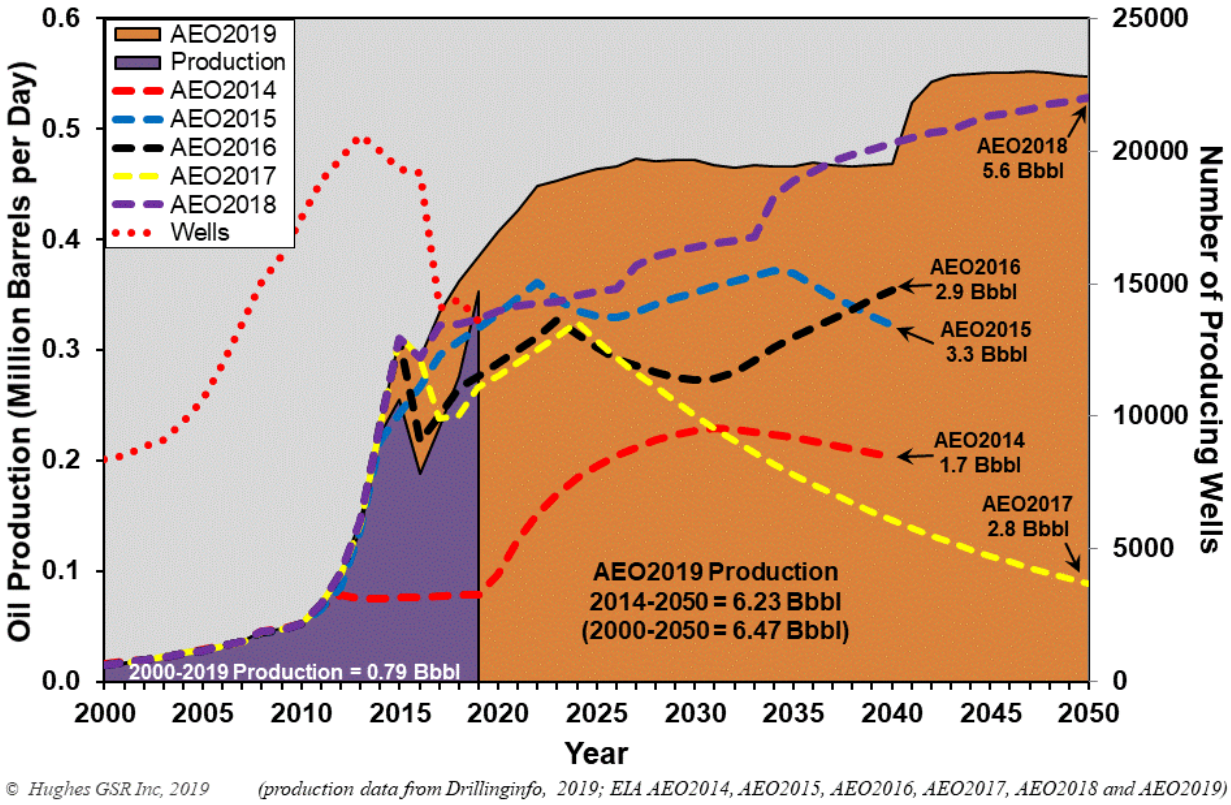


Figure 72. EIA AEO2019 reference case Niobrara Play oil production forecast through 2050.

Also shown are earlier AEO forecasts to 2040 and 2050, and cumulative 2000-2019 production.

[95] EUR for unproven resources is from *Assumptions to the Annual Energy Outlook 2019*, https://www.eia.gov/outlooks/aeo/assumptions/; the number of wells has been calculated using the EURs in this document for unproven resources and assuming EURs for proven reserves would be twice as high; the area needed was determined using the average well density of 7.2 wells per square mile assumed in this document.
[96] Denver-Julesburg Basin area from EIA, 2019, *Low permeability oil and gas play boundaries in Lower 48 States* (10/8/2019), https://www.eia.gov/maps/map_data/TightOil_ShaleGas_Plays_Lower48_EIA.zip

Table 15 illustrates assumptions in the EIA AEO2019 reference case forecast.[97] If realized, the EIA forecast would have to recover 58% of the EIA's estimate of proven reserves plus unproven resources, and would require 112,260 additional wells, for a total well count of four times the current, at an estimated cost of $561 billion.

EIA AEO2019 Reference Case Forecast	
Proven Reserves year-end 2017 (Bbbls)[98]	0.23
Unproven Resources 2017 (Bbbls)[99]	10.0
Total Potential 2017 (Bbbls)	10.23
2017-2050 Recovery (Bbbls)	5.92
% of total potential used 2017-2050	57.9%
Wells needed 2017-2050	112,260
Well cost 2017-2050 ($billions)	$561

Table 15. EIA assumptions for Niobrara Play oil in the AEO2019 reference case.

Well costs of $561 billion for full development are estimated assuming a well cost of $5 million.[100] The number of wells needed was determined using EIA EUR estimates for unproven resources, assuming EUR per well would be twice as high for proven reserves as for unproven resources.

Synopsis

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

- The Niobrara is an old play being re-developed with new technology. As of April 2019, a total of 37,863 wells have been drilled in the play. 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 79% of production in April 2019. Weld County has been extensively drilled and the Denver-Julesburg Basin as a whole is not large enough to accommodate the tens of thousands of additional wells needed to meet the EIA's forecast.

- The EIA has estimated that an area of 15,592 square miles can be drilled at a well density of 7.2 wells per square mile, for a total of 112,260 wells, to recover 5.92 billion barrels of proven reserves and unproven resources. As noted above, this is 20% larger than the entire extent of the Denver-Julesburg Basin so it would require drilling in outlying basins that so far have had little production. This would also quadruple the Niobrara well count at a cost of $561 billion.

- Given the above considerations and play fundamentals, the AEO2019 forecast for the Niobrara is rated as highly optimistic.

[97] EIA, Unproved technically recoverable resources are from *Assumptions to the Annual Energy Outlook 2019*, https://www.eia.gov/outlooks/aeo/assumptions/; Proven reserves are from *U.S. Crude Oil and Natural Gas Proved Reserves, Yearend 2017*, https://www.eia.gov/naturalgas/crudeoilreserves/
[98] EIA, 2018, U.S. Crude Oil and Natural Gas Proved Reserves, Yearend 2017, https://www.eia.gov/naturalgas/crudeoilreserves/.
[99] EIA, 2019, Oil and Gas Supply Module for AEO2019, https://www.eia.gov/outlooks/aeo/assumptions/pdf/oilgas.pdf
[100] EIA, 2016, Trends in U.S. Oil and Natural Gas Upstream Costs, https://www.eia.gov/analysis/studies/drilling/pdf/upstream.pdf

3. Shale Gas Plays

Figure 73 illustrates shale gas production from major plays assessed in AEO2019 as of September 2019. Production of shale gas is at an all-time high, although production from three legacy plays—including the Barnett, where shale gas was first successfully produced, along with the Fayetteville and Eagle Ford—collectively peaked in December, 2014, and is now down 32%. 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 57% of total shale gas production.

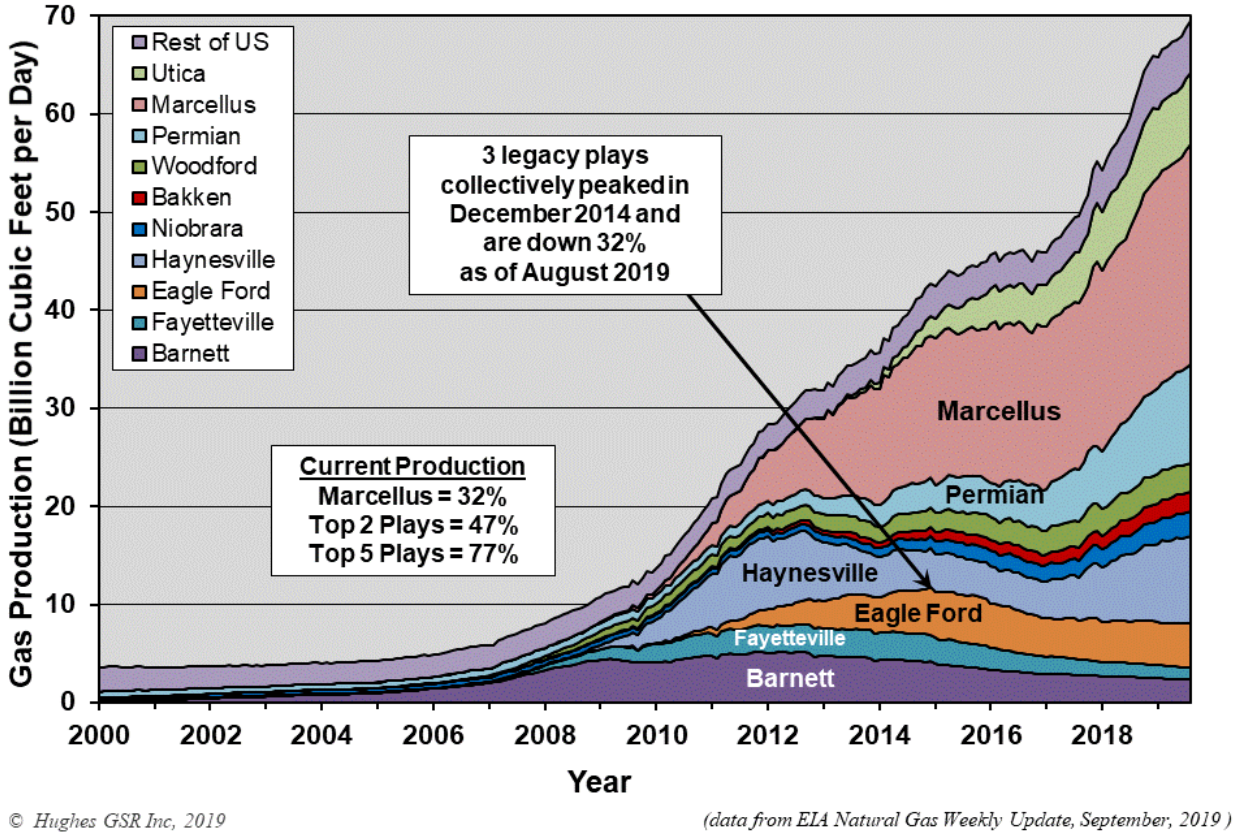


Figure 73. U.S. shale gas production by play, 2000 through August 2019.[101]

[101] EIA, September, 2019, *Natural Gas Weekly Update*, https://www.eia.gov/naturalgas/weekly/

Figure 74 illustrates the AEO2019 reference case for U.S. gas production by source, with price forecasts. Shale gas production is expected to nearly double from 2018 levels by 2050 and constitutes by far the largest source of supply overall, making up 77% 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 48% to an all-time high of 43.1 trillion cubic feet per year (tcf/year), or 119 billion cubic feet per day (bcfd), in 2050. Exports via LNG to international markets and by pipeline to Canada and Mexico are projected to consume 20% of production in 2050. Prices are projected to remain below $5/MMBtu through 2050.

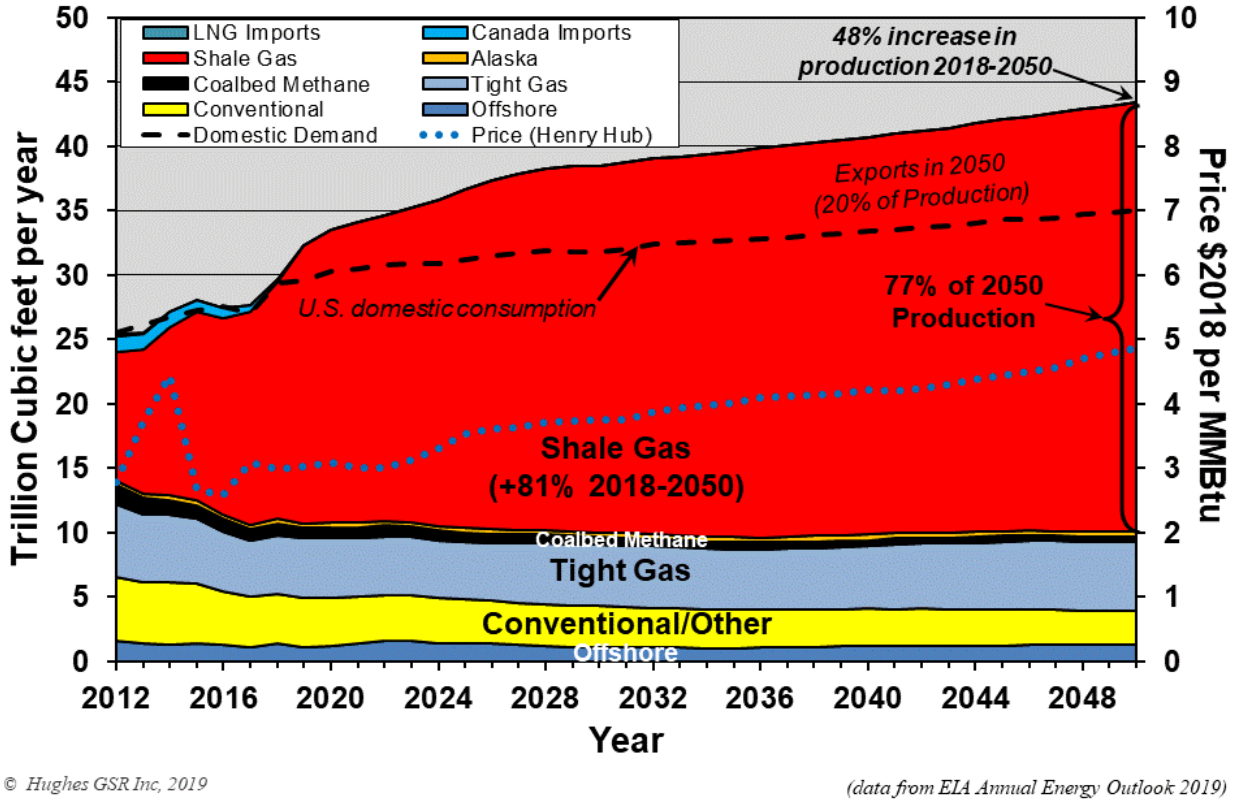
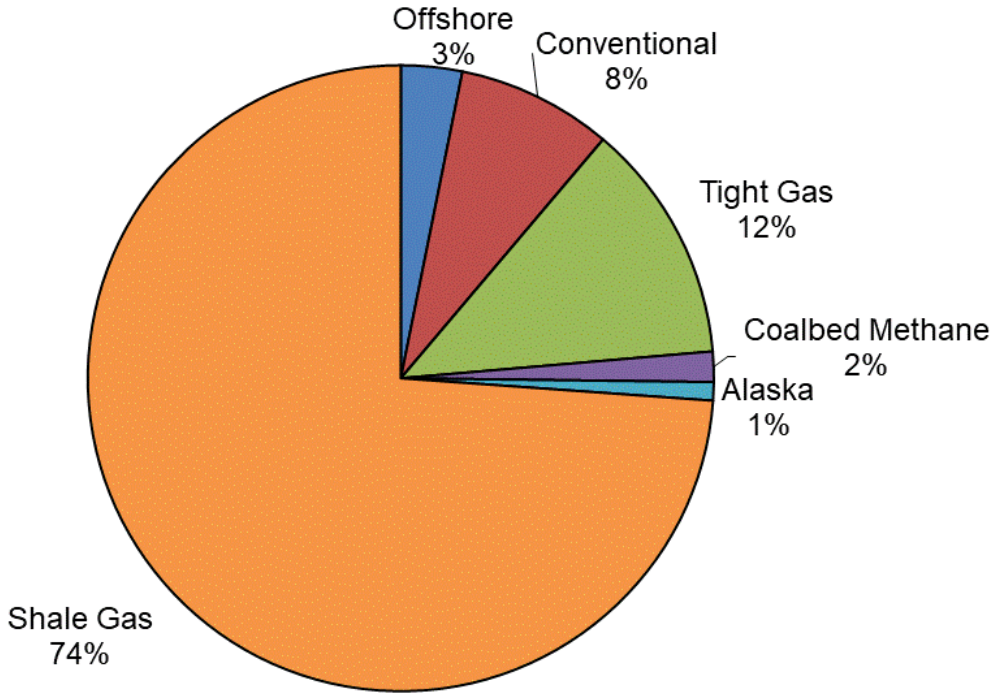


Figure 74. EIA AEO2019 reference case forecast of gas production by source, 2012–2050.

Also shown is projected price (Henry Hub in 2018 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 1,281 trillion cubic feet (tcf) over the 2018–2050 period. Production through 2050 is projected to be nearly triple proven U.S. natural reserves of 464 tcf at yearend 2017[102], and half of U.S. proven reserves plus unproven resources.[103] (Proven reserves have been demonstrated to be technically and economically recoverable, whereas unproven resources are thought to be technically recoverable but have not been demonstrated to be economically recoverable.)

The shale gas portion of the EIA's reference forecast is expected to recover 3.1 times proven U.S. shale gas reserves and 61% of proven reserves plus unproven resources.[104] 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.



Cumulative 2018-2050 Production = 1281 trillion cubic feet

150

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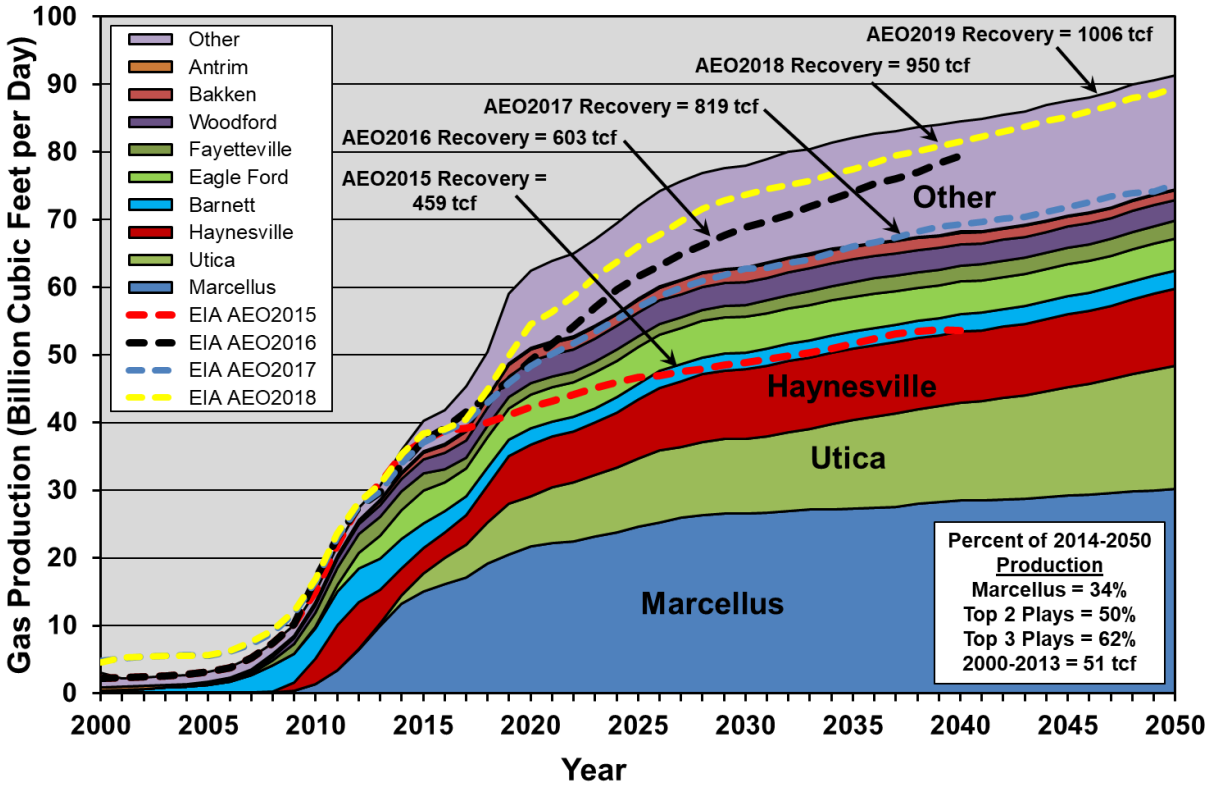
(data from EIA Annual Energy Outlook 2019)

Figure 75. EIA AEO2019 reference case forecast of cumulative natural gas production by source, 2018–2050.

[102] EIA, Table 1. *U.S. proved reserves, and reserves changes, 2016-17*, https://www.eia.gov/naturalgas/crudeoilreserves/.
[103] EIA, Assumptions to the Annual Energy Outlook 2019, https://www.eia.gov/outlooks/aeo/assumptions/; unproven resources were 1,986 tcf as of January 1, 2015.
[104] EIA, shale gas proven reserves were 307.9 tcf at yearend 2017, https://www.eia.gov/naturalgas/crudeoilreserves/, and unproven resources were 1279.9 tcf as of January 1, 2017, https://www.eia.gov/outlooks/aeo/assumptions/.

The AEO2019 reference case forecast for shale gas production 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 62% of total 2014–2050 shale gas production of 946 tcf coming from three plays: the Marcellus, Utica, and Haynesville. The Marcellus alone is expected to account for 34% of production.

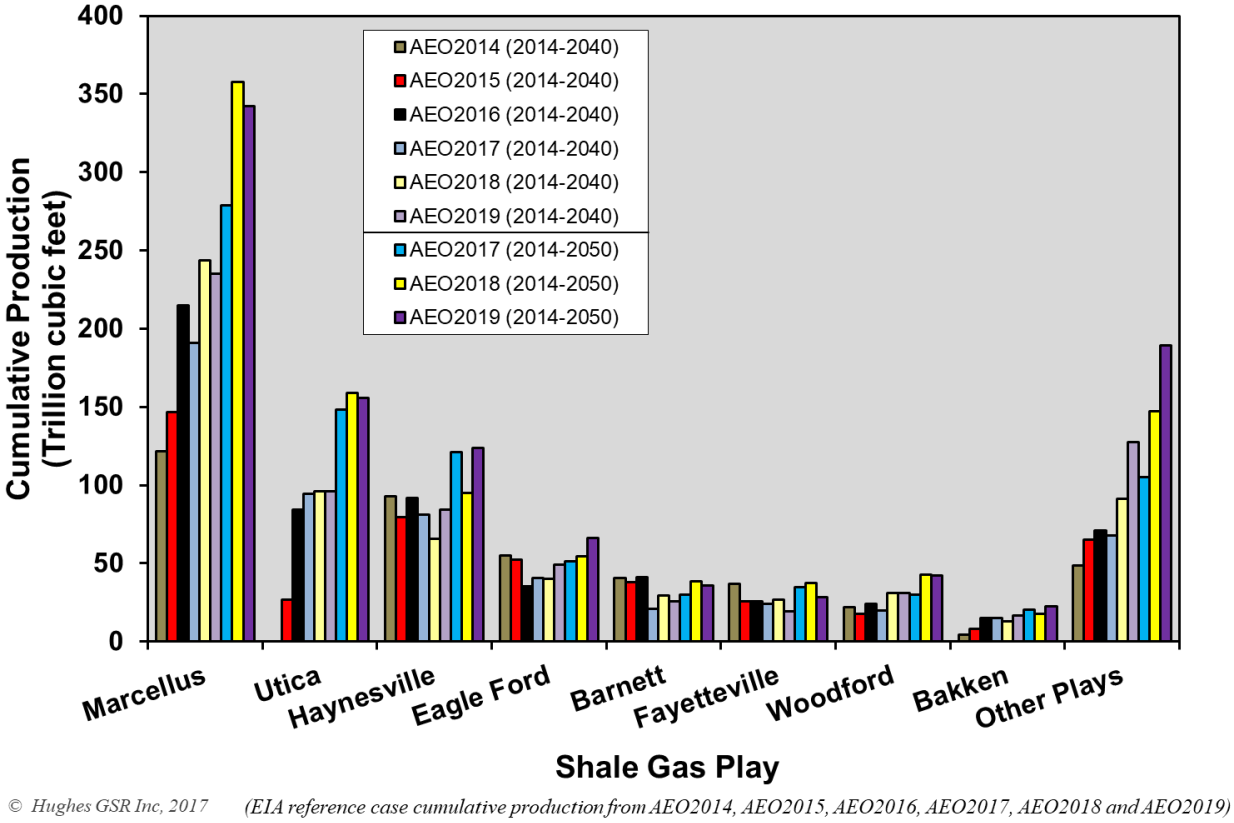


© Hughes GSR Inc, 2019 (data from EIA AEO2015, AEO2016, AEO2017, AEO2018 and AEO2019)

Figure 76. U.S. shale gas production by play in the EIA AEO2019 reference case forecast compared to earlier forecasts.

AEO2015 and AEO2016 forecasts are for the period 2014-2040. AEO2017, AEO2018, and AEO2019 forecasts are for the period 2014-2050.

EIA AEO reference case production forecasts over the past six years are illustrated in Figure 77. In general, production forecasts have become ever more optimistic, with AEO2019 projecting production of 56 tcf more shale gas by 2050 than AEO2018 and 187 tcf more than AEO2017. Shale gas production during 2018-2050 in AEO2019 is forecast to be nine times what the cumulative shale gas production was during 2000-2017.



© Hughes GSR Inc, 2017 (EIA reference case cumulative production from AEO2014, AEO2015, AEO2016, AEO2017, AEO2018 and AEO2019)

Figure 77. Cumulative shale gas production forecast by play in the AEO2019 reference case through 2040 and 2050 compared to the AEO2014, AEO2015, AEO2016, AEO2017, and AEO2018 forecasts.

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.[105] Production began in the mid-1990s and grew to a peak in November 2011, as illustrated in Figure 78. Production in the last eight years has fallen by 51%. More than 20,300 wells have been drilled, of which 14,615 were still producing as of April 2019. Drilling in the play has slowed to a near standstill, as the most productive parts of the play are saturated with wells. The lifecycle of the Barnett Play should serve as a cautionary consideration when forecasting what will eventually happen to all plays.

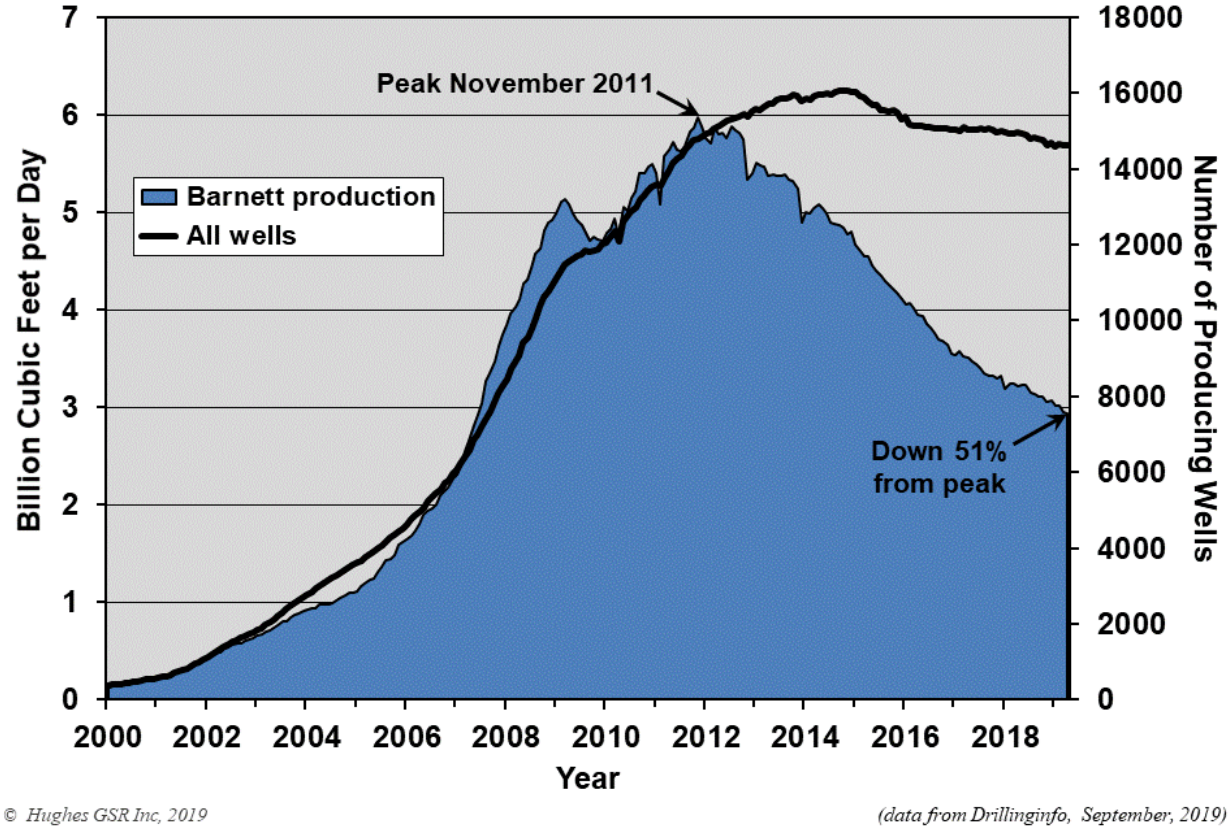


Figure 78. Barnett Play gas production and number of producing wells, 2000–2019.
Production peaked in November 2011 and was down 51% as of April 2019.

[105] The Economist, August 3, 2013, *The Father of Fracking*, https://www.economist.com/news/business/21582482-few-businesspeople-have-done-much-change-world-george-mitchell-father

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.

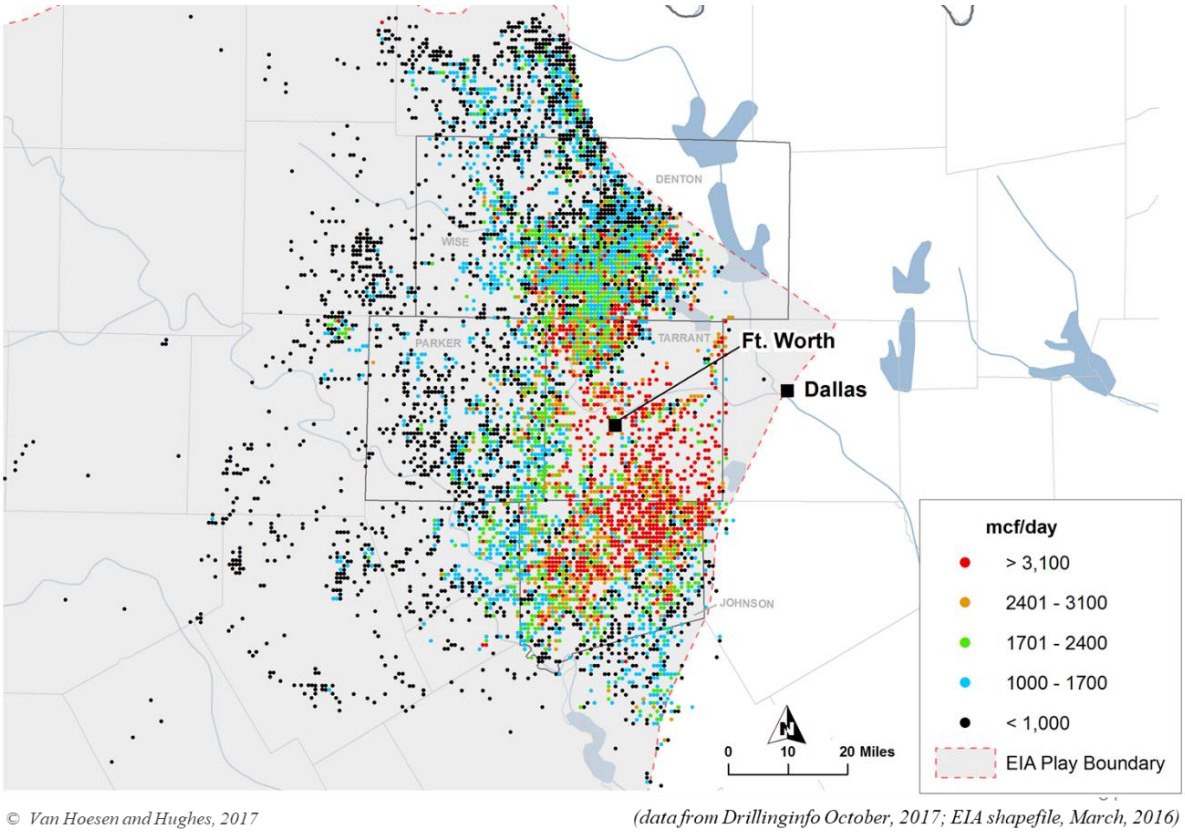


Figure 79. Barnett Play well locations showing peak gas production in the highest month.

The highest productivity wells are concentrated in parts of Tarrant, Johnson, Denton, and Wise counties.[106]

[106] 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 85% 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.

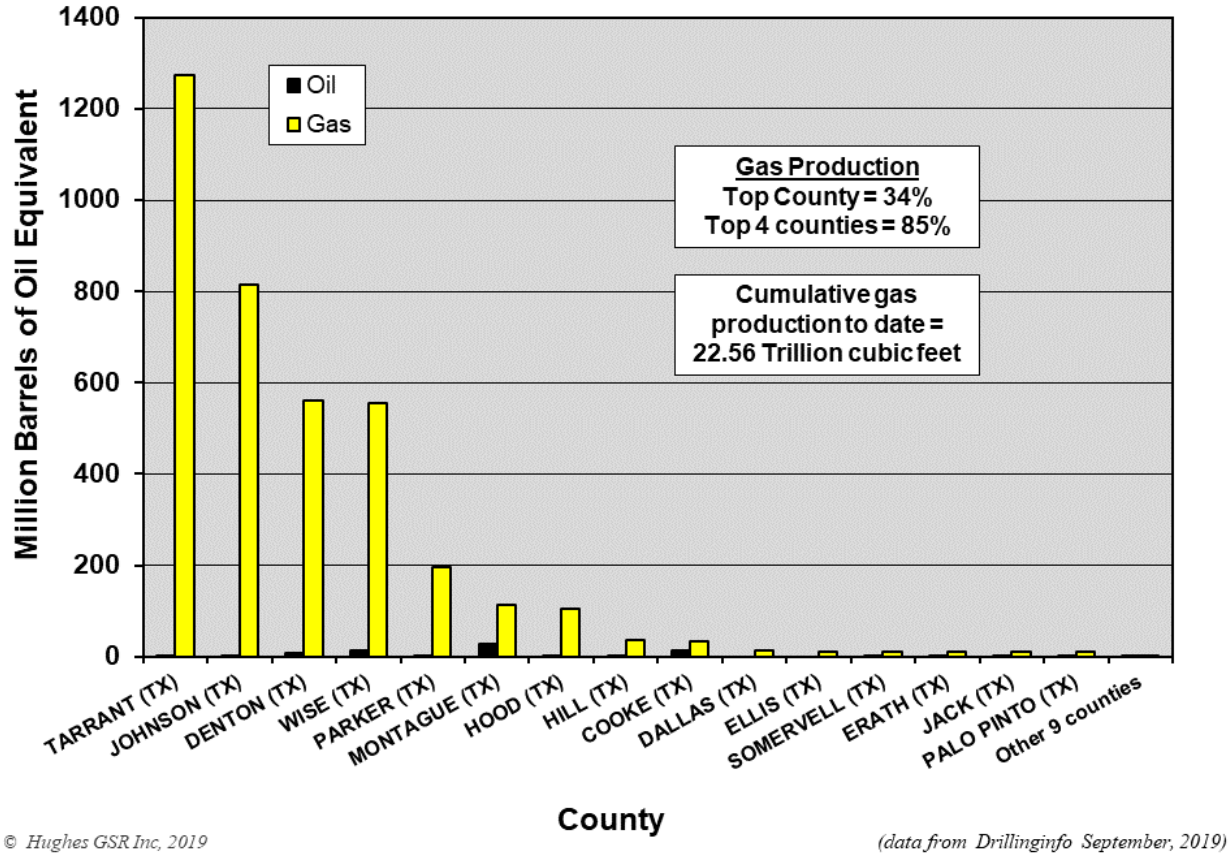


Figure 80. Cumulative production of oil and gas from the Barnett Play by county.

Production is highly concentrated in sweet spots, with 85% of cumulative production in the top four counties.

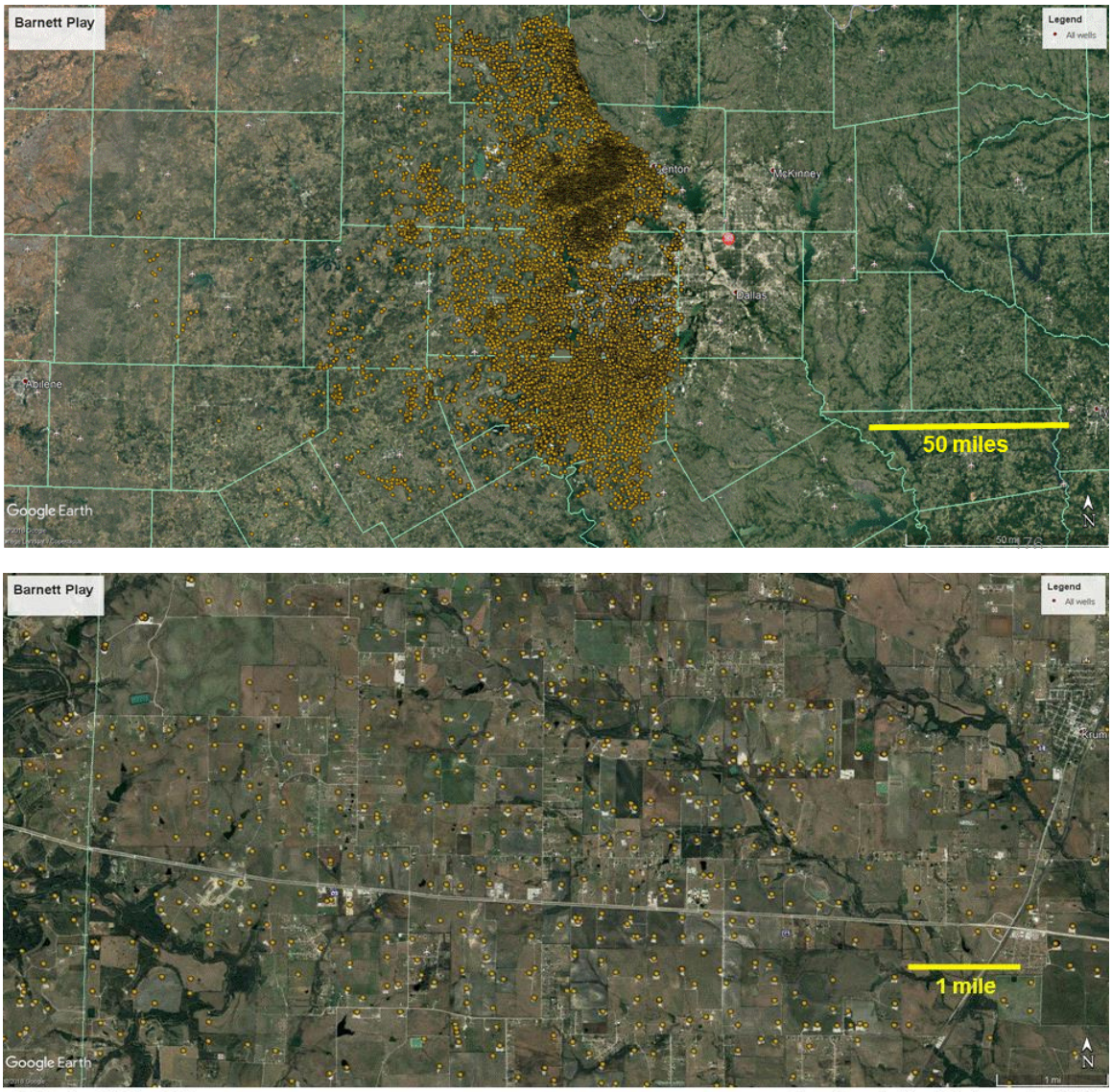
Table 16 shows the number of wells drilled, cumulative and current production, and well- and first-year field-decline rates for the Barnett as a whole and for individual counties. Three-year well decline rates average 73.5% and field decline rates average 10.8% per year, without new drilling (due to the fact that there have been very few new wells drilled recently and most wells have been through the first few high decline years). This is at the low end for shale plays analyzed in this report.

County	Well type	Vintage	Total Well Count	Producing Well Count	Cumulative Oil Production (billion bbls)	Cumulative Gas Production (tcf)	Oil Production April 2019 (Kbbls/day)	Gas Production April 2019 (bcf/day)	3-year well decline (%)	First-year field decline (%)
All	All	All	20,341	14,615	0.074	22.570	4.32	2.95	73.5	10.8
Denton	All	All	3,233	2,620	0.008	3.363	0.49	0.44	77.9	8.7
Johnson	All	All	3,853	2,537	0.00004	4.886	0.04	0.46	82.1	14.8
Tarrant	All	All	4,681	3,629	0.0004	7.641	0.03	1.11	74.9	11.5
Wise	All	All	3,225	2,518	0.014	3.338	1.12	0.46	71.2	7.7
Other counties	All	All	5,349	3,311	0.052	3.342	2.64	0.48	59.6	9.7

Table 16. Well count, cumulative production, most recent production, and well- and first-year field-decline rates for the Barnett Play and counties within it, by well type and vintage.[107]

[107] From Drillinginfo August, 2019.

The degree of development of the Barnett core area to date is illustrated in Figure 81. Horizontal laterals averaged 5,580 feet in length in 2018[108] (although a few exceeded 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.



© Hughes GSR Inc, 2019 (data from Drillinginfo September, 2019)

Figure 81. Drilling density in the central core area of the Barnett Play as of April 2019.

Upper: overview of core area. Lower: close-up view of core area.[109]

[108] J.D. Hughes, 2019, *How long will the shale revolution last? Technology versus Geology and the Lifecycle of Shale Plays*, Post Carbon Institute, https://www.postcarbon.org/publications/how-long-will-the-shale-revolution-last/

[109] From Drillinginfo September, 2019.

Figure 82 illustrates production from the top four counties compared to the overall play. All top counties have peaked, beginning with Johnson in 2009 and ending with Wise in 2013, and the play as a whole peaked in November 2011. The top four counties have made up 85% of cumulative production and 84% of production in April 2019.

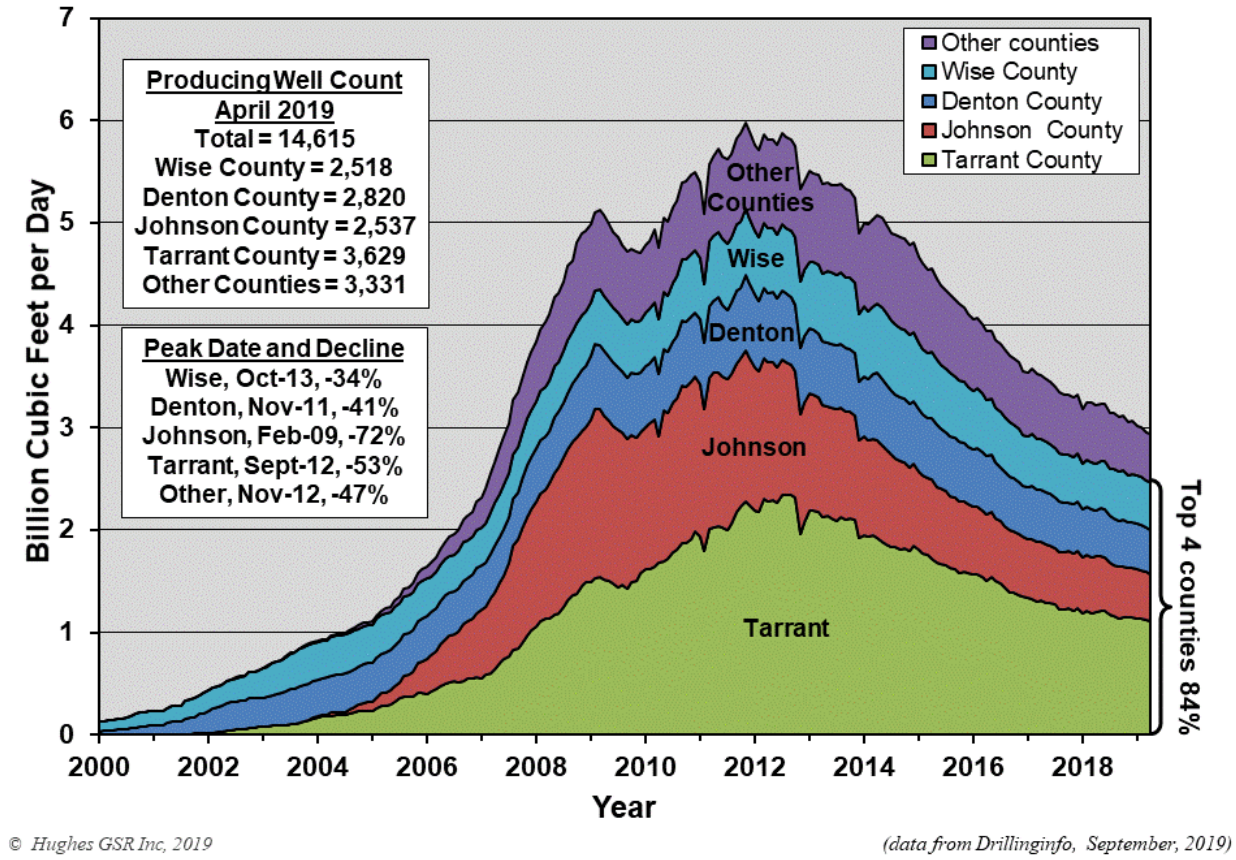


Figure 82. Gas production and producing well count in the Barnett Play by county through April 2019, showing peak dates and percentage decline from peak.

The Barnett Play is now in terminal decline, with few new wells being drilled. Even with longer laterals and increased water/proppant injection, well productivity declined in 2018 in the top three counties, as illustrated in Figure 83. These counties have reached maximum well densities and additional wells are compromised by frac hits and resultant well interference. Only in Wise County and counties outside of the top four were some improvements in productivity observed in 2018.

The Barnett is an example of a shale play that has nearly completed its life cycle. Sweet spots have been exhausted and drilling must now move into lower productivity rock which requires higher prices to be economic, and higher drilling rates to stem overall field decline. The Barnett is the oldest shale play and a harbinger of what is to come eventually in all shale plays.

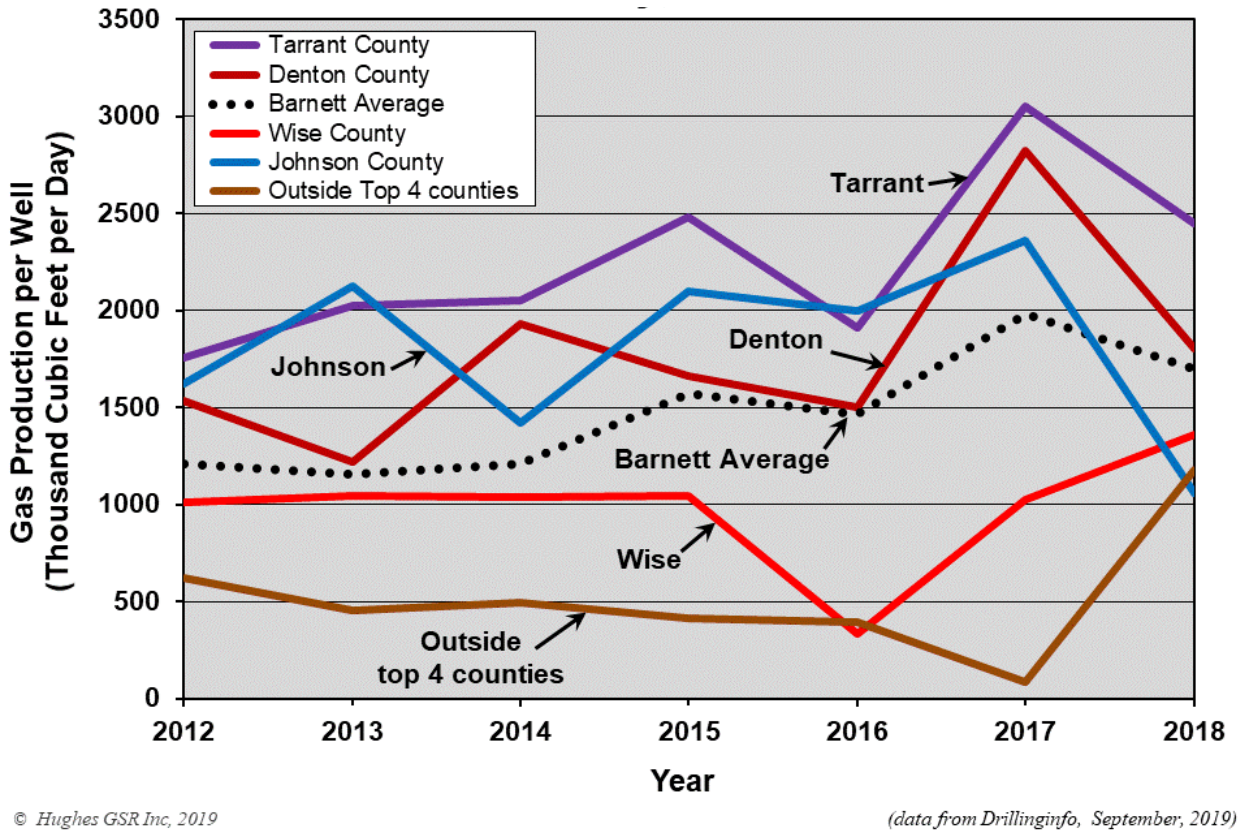


Figure 83. Average well productivity over the first six months of gas production by county in the Barnett Play, 2012–2018.

Figure 84 illustrates the EIA's AEO2019 reference case production forecast for the Barnett Play through 2050, together with earlier forecasts. The EIA expects production to decline to 27% below current levels in 2023, and then rebound and remain on a plateau exiting 2050 at 7% below current levels. This forecast is extremely unlikely, given the degree of well saturation in sweet spots, and that 31.5 tcf would have to be recovered over 2017-2050, which is 50% more gas than has been recovered from the play so far. The fact that production exits 2050 at just 7% below current levels implies that there would still be a considerable volume of recoverable gas remaining at that time. A more likely scenario is that the play continues its long descent, briefly stemmed, perhaps, if significantly higher prices allowed an increase in drilling. Given these fundamentals, the AEO2019 forecast has to be rated as extremely optimistic.

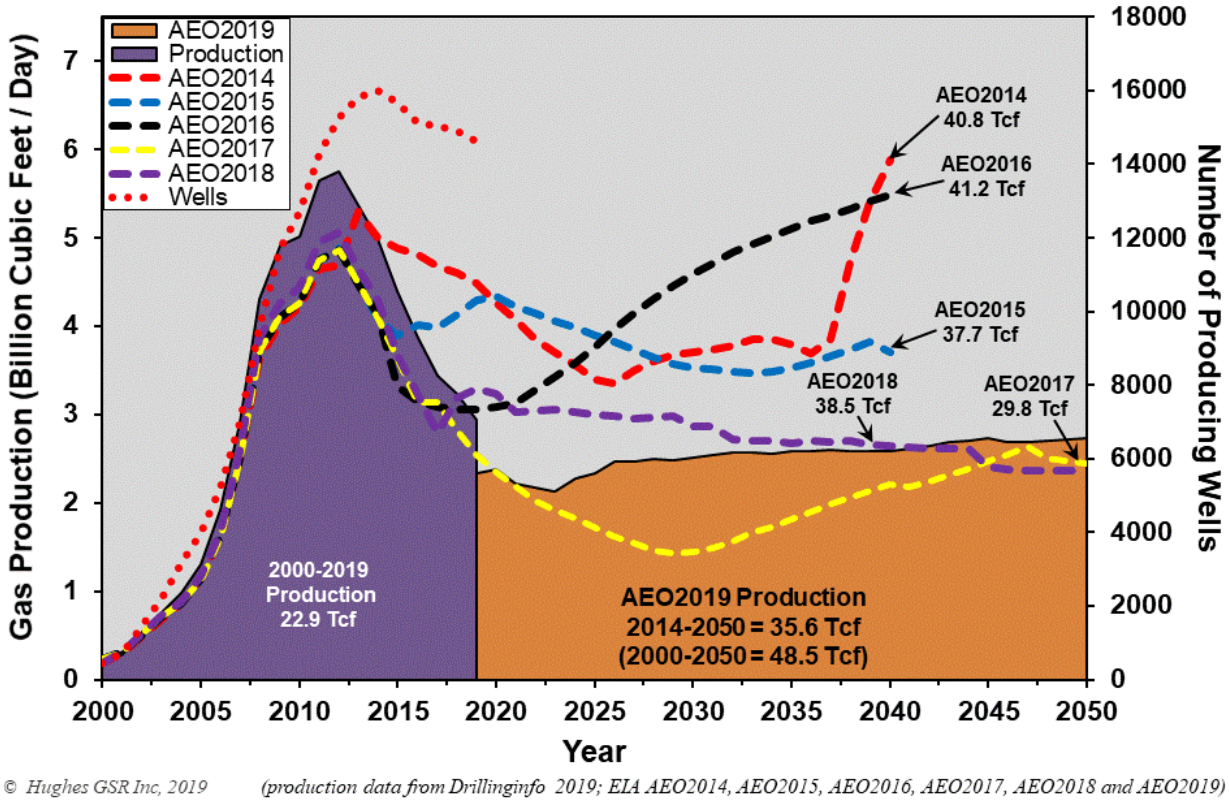


Figure 84. EIA AEO2019 reference case Barnett Play gas production forecast through 2050.

Also shown are earlier AEO forecasts to 2040 and 2050, and cumulative production from 2000-2019.

Table 17 illustrates assumptions in the EIA AEO2019 reference case forecast.[110] If realized, the EIA forecast would have to recover 77% of the EIA's estimate of proven reserves plus unproven resources, and would require 56,925 new wells, for a total well count of nearly four times the current 20,341, at a cost of $285 billion.

EIA AEO2019 Reference Case Forecast	
Proven Reserves year-end 2017 (tcf)[111]	19.2
Unproven Resources 2017 (tcf)[112]	22.0
Total Potential 2017 (tcf)	41.2
2017-2050 Recovery (tcf)	31.54
% of total potential used 2017-2050	76.6%
Wells needed 2017-2050	56,925
Well cost 2017-2050 ($billions)	$285

Table 17. EIA assumptions for Barnett Play gas in the AEO2019 reference case.

Well costs of $285 billion for full development are estimated assuming a well cost of $5 million each.[113] 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 (26,311 square miles) overestimates the prospective drilled area (8,682 square miles) by 200%. Wells drilled outside of the prospective drilled area have low levels of production and in some cases no production.
- Assuming 56,925 additional wells can be drilled to develop unproved resources plus proven reserves (per the EIA AEO2019 assumptions and 2017 proven reserves), in addition to the 20,341 wells already drilled, would increase well density over the entire prospective play area to 8.9 per square mile. This is unlikely to be economic given that well density is already eight wells per square mile in the highest quality parts of the prospective drilled area and new well productivity is falling.
- Well productivity of new drilling in the top three counties is declining, suggesting well interference and/or drilling outside of sweet spots, which constitute only a portion of these counties. Well interference indicates that more wells are unlikely to increase ultimate recovery, although they may increase the short-term production rate, resulting in steeper long-term field declines and higher costs. Quadrupling well count by 2050, at a cost of $285 billion, seems extremely unlikely.
- Although the USGS estimated a mean undiscovered technical recoverable resource in the Barnett of 53 tcf in 2016,[114] whether or not this resource could be economically recovered was not evaluated. The EIA's forecast requires recovering more than twice as much gas between 2017-2050 as has been extracted to date, and exiting 2050 at just 7% below current production levels, suggesting large additional resources will remain to be extracted after 2050. Without much higher prices to justify drilling lower productivity wells, this seems extremely unlikely.
- Given the above, and the fact that the Barnett is an extensively drilled mature play that appears to be in terminal decline, the EIA's forecast is rated as extremely optimistic.

[110] EIA, Unproved technically recoverable resources are from *Assumptions to the Annual Energy Outlook 2019*, https://www.eia.gov/outlooks/aeo/assumptions/; Proven reserves are from *U.S. Crude Oil and Natural Gas Proved Reserves, Yearend 2017*, https://www.eia.gov/naturalgas/crudeoilreserves/
[111] EIA, 2018, U.S. Crude Oil and Natural Gas Proved Reserves, yearend 2017, https://www.eia.gov/naturalgas/crudeoilreserves/.
[112] EIA, 2019, Oil and Gas Supply Module for AEO2019, https://www.eia.gov/outlooks/aeo/assumptions/pdf/oilgas.pdf
[113] EIA, 2016, Trends in U.S. Oil and Natural Gas Upstream Costs, https://www.eia.gov/analysis/studies/drilling/pdf/upstream.pdf
[114] USGS, 2016, *Assessment of Undiscovered Shale Gas and Shale Oil Resources in the Mississippian Barnett Shale, Bend Arch–Fort Worth Basin Province, North-Central Texas*, https://pubs.usgs.gov/fs/2015/3078/fs20153078.pdf

3.2 HAYNESVILLE PLAY

The Haynesville Play in western Louisiana and eastern Texas grew from nothing in 2007 to become the largest shale gas play in the U.S. when it peaked in November 2011, as illustrated in Figure 85. Drilling rates increased in late 2017 and since then production has risen to an all-time high. Haynesville wells are much more productive than Barnett wells but are also more expensive, ranging from $6.4 million[115] to $9 million[116] each. More than 4,700 wells have been drilled, of which 4,154 are still producing.

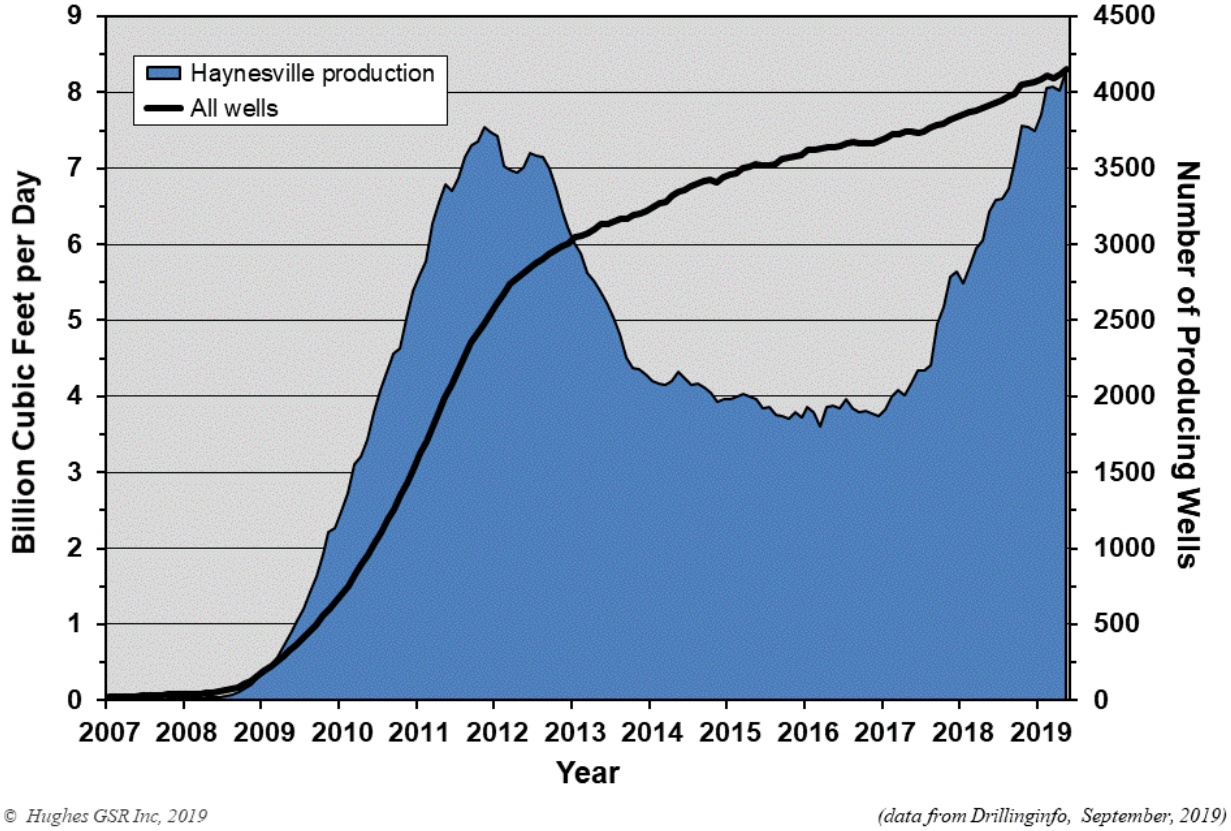


Figure 85. Haynesville Play gas production and number of producing wells, 2007–2019.

[115] EIA, 2016, *Trends in U.S. Oil and Natural Gas Upstream Costs*, https://www.eia.gov/analysis/studies/drilling/pdf/upstream.pdf
[116] Hart Energy, May 1, 2017, *Heyday in the Haynesville*, https://www.epmag.com/heyday-haynesville-1548121

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.

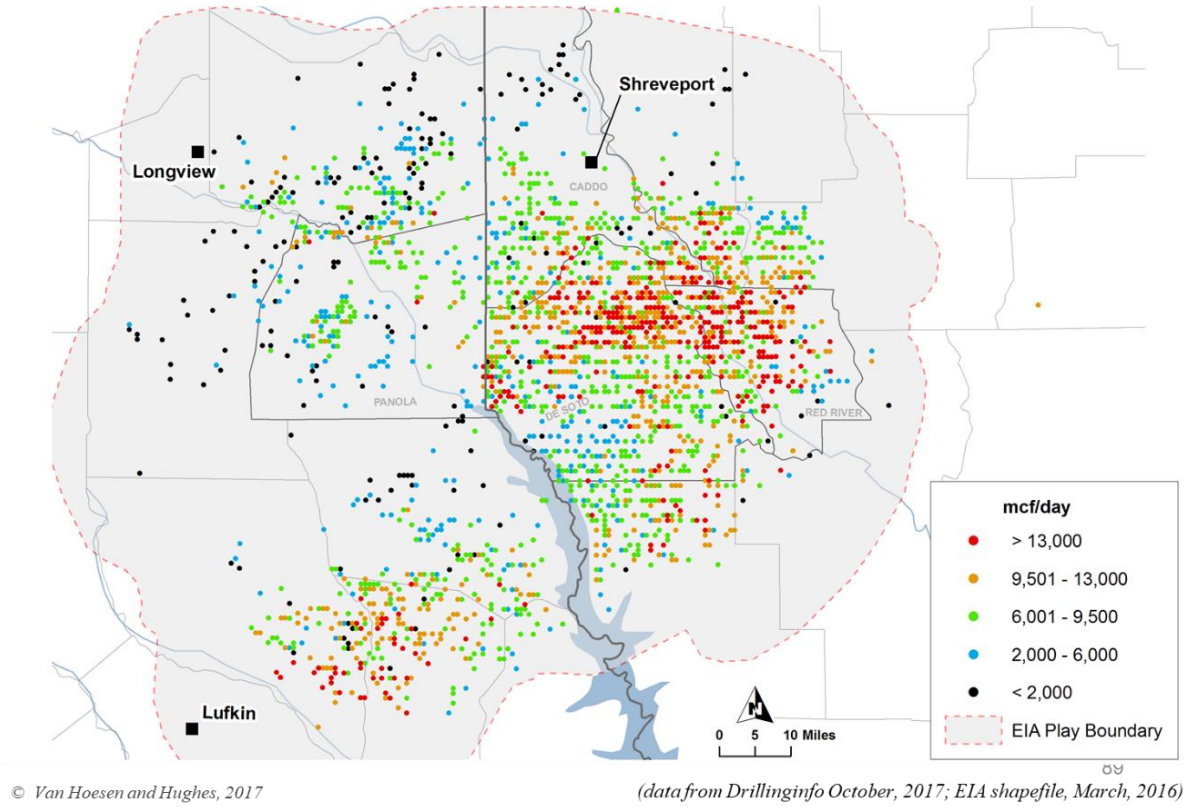


Figure 86. Haynesville Play well locations showing peak gas production in the highest month.

The highest productivity wells are concentrated in parts of De Soto, Caddo, and Red River counties of Louisiana.[117]

[117] 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 two-thirds has come from the top three counties. These "sweet spots" constitute a small part of the total play area assumed by the EIA in Figure 86.

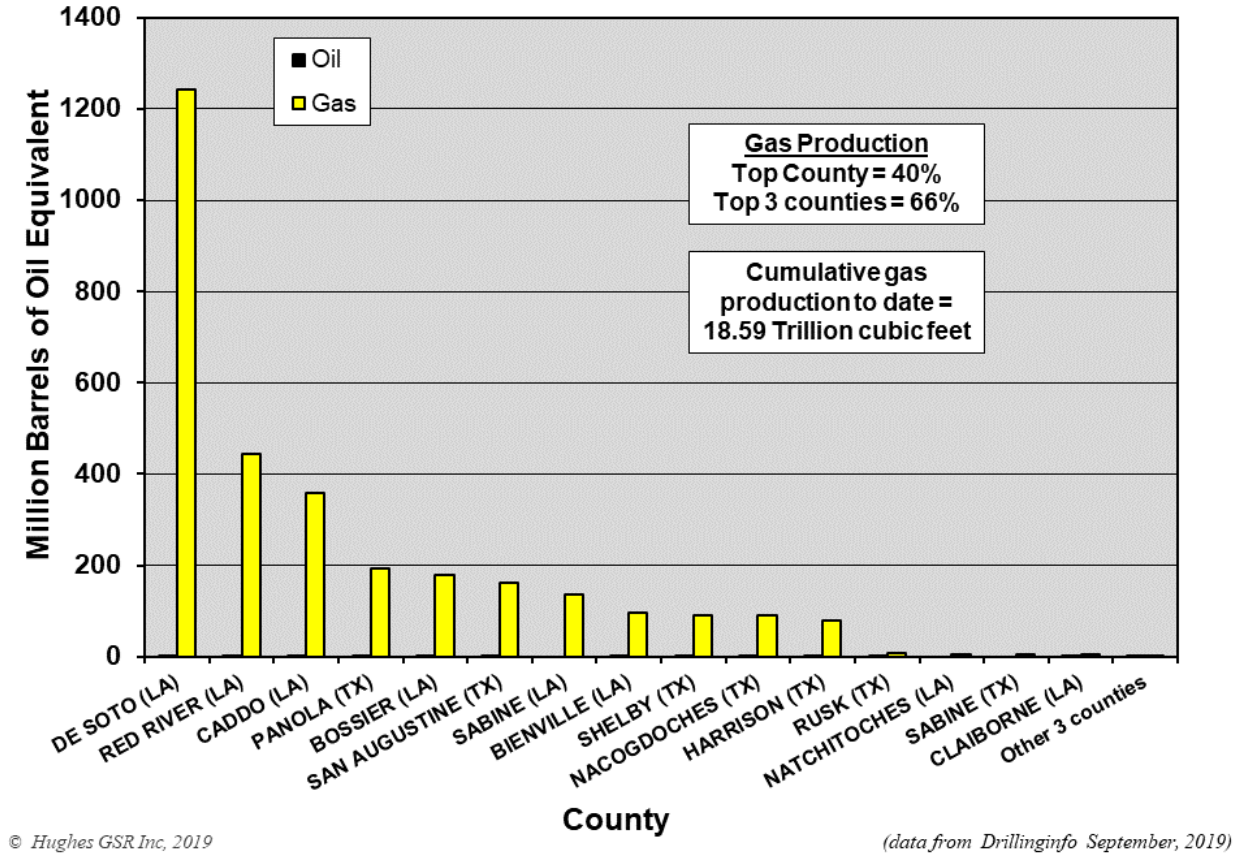


Figure 87. Cumulative production of oil and gas from the Haynesville Play by county.

Production is highly concentrated in sweet spots, with 40% of cumulative gas production in De Soto County and 78% in the top 5 counties.

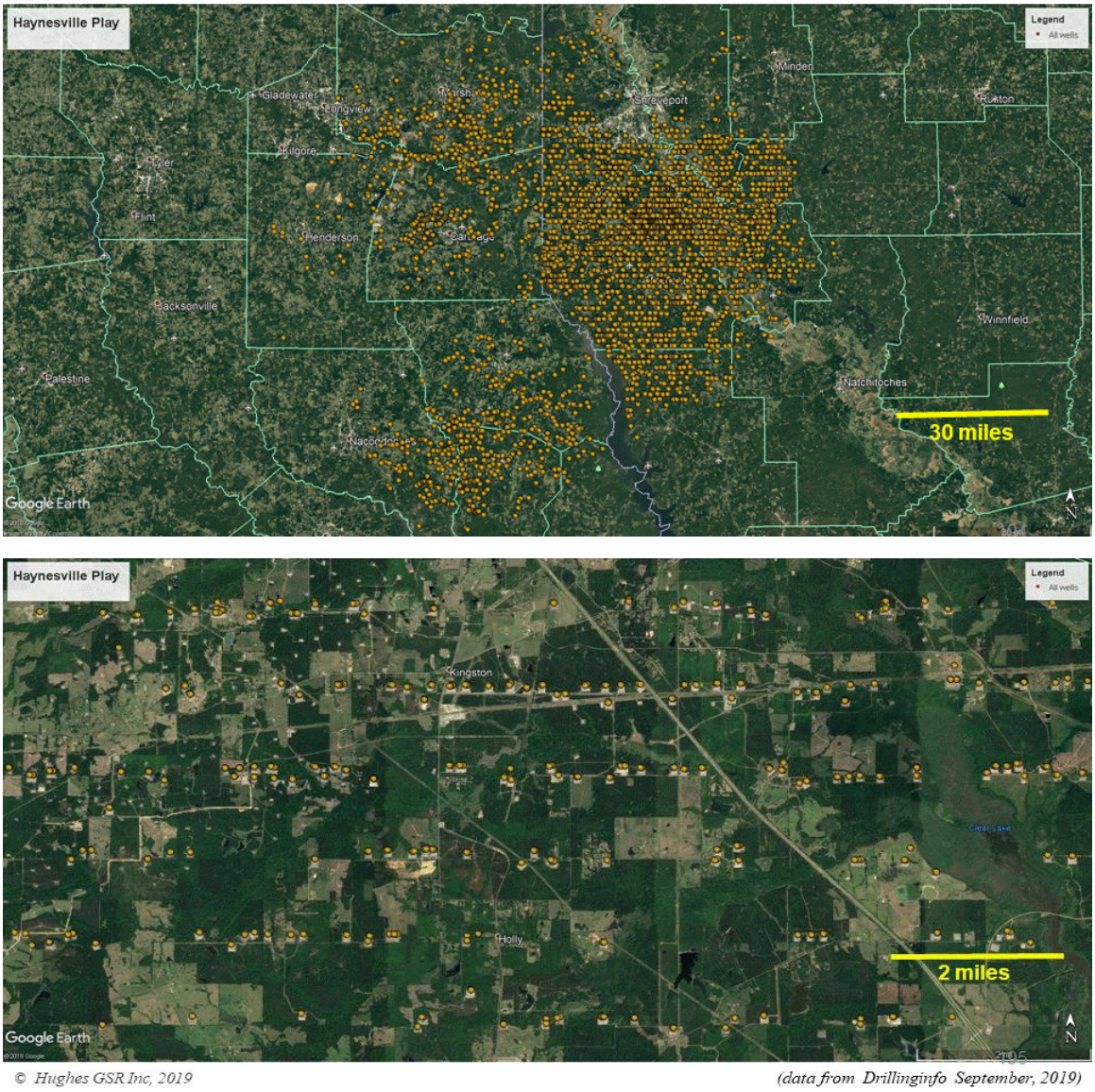
Table 18 shows the number of wells drilled, cumulative and current production, and well- and first-year field-decline rates for the Haynesville as a whole and for individual counties. Three-year well decline rates average 88% and field decline rates average 37.2% per year without new drilling, which is at the high end for shale plays analyzed in this report.

County	Well type	Vintage	Total Well Count	Producing Well Count	Cumulative Oil Production (billion bbls)	Cumulative Gas Production (tcf)	Oil Production May 2019 (Kbbls/day)	Gas Production May 2019 (bcf/day)	3-year well decline (%)	First-year field decline (%)
All	All	All	4,756	4,154	0.003	18.583	0.46	8.28	87.9	37.2
Caddo	All	All	505	454	0.00002	2.157	0.02	1.10	88.7	46.6
De Soto	All	All	1,770	1,541	0.000002	7.450	0.001	3.25	88.8	35.8
Red River	All	All	540	473	0.0000003	2.659	0.000	0.95	89.7	49.7
Other counties	All	All	1,941	1,686	0.003	6.317	0.44	2.98	85.2	27.9

Table 18. Well count, cumulative production, most recent production, and well- and first-year field-decline rates for the Haynesville Play and counties within it, by well type and vintage.[118]

[118] From Drillinginfo September, 2019.

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 was 6,381 feet in 2018[119]. Most well pads have multiple wells.



© Hughes GSR Inc, 2019 (data from Drillinginfo September, 2019)

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.[120]

[119] J.D. Hughes, 2019, *How long will the shale revolution last? Technology versus Geology and the Lifecycle of Shale Plays*, Post Carbon Institute, https://www.postcarbon.org/publications/how-long-will-the-shale-revolution-last/
[120] From Drillinginfo September, 2019.

Figure 89 illustrates production from the top three counties compared to the overall play. The top three counties make up 66% of cumulative production and accounted for 64% of May 2019, production.

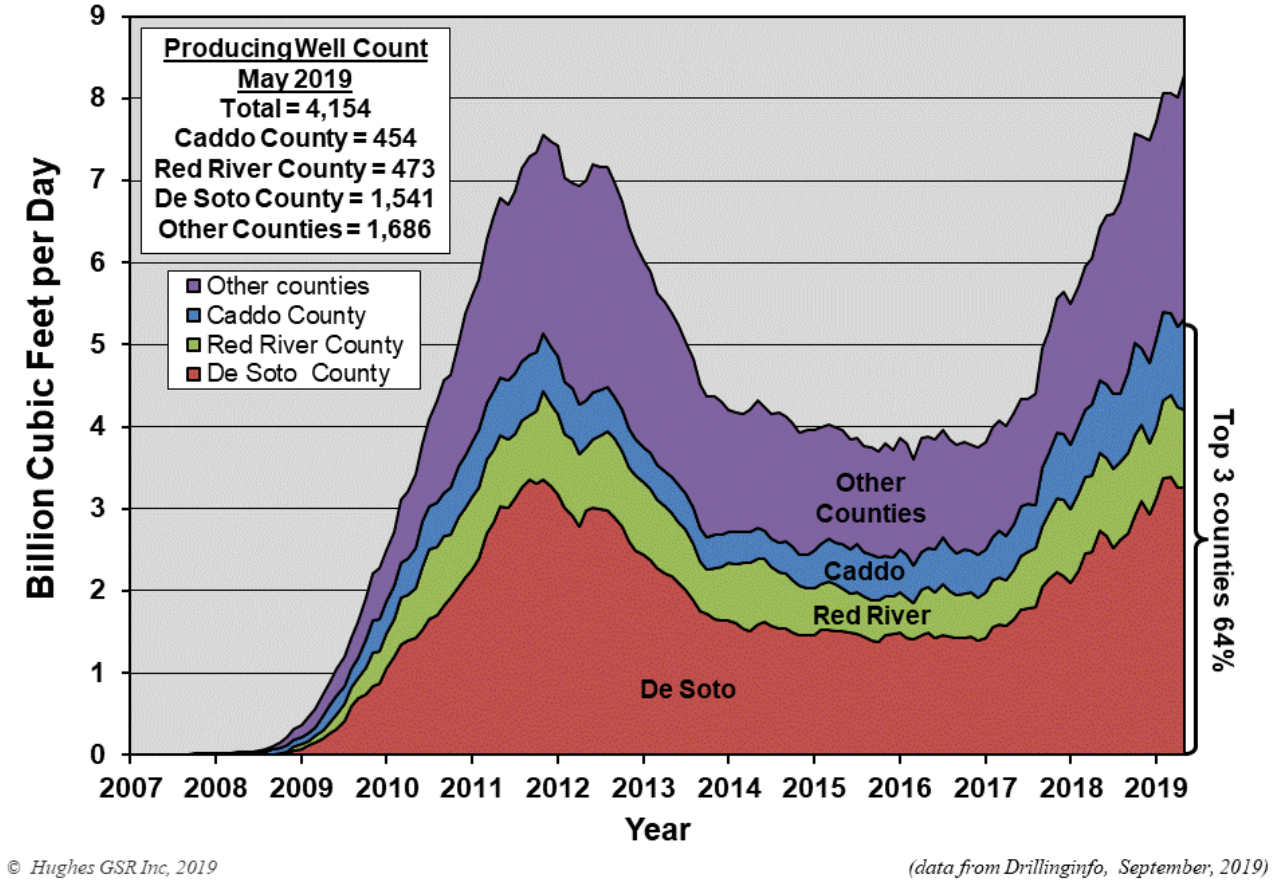


Figure 89. Gas production in the Haynesville Play by county through May 2019.

Figure 90 illustrates average well productivity over the first six months for the play as a whole and for individual counties over the 2012-2018 period. Although improved technology, along with focusing on sweet spots, has increased average well productivity markedly since 2012, productivity declined in two of the top three counties in 2018. Technology improvements include extending horizontal laterals[121], which have increased 37% since 2012 and now average 6,381 feet (some laterals have exceeded 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.[122] 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 drop in average well productivity in two sweet spot counties suggests, however, that more aggressive technology may be reaching its limits.

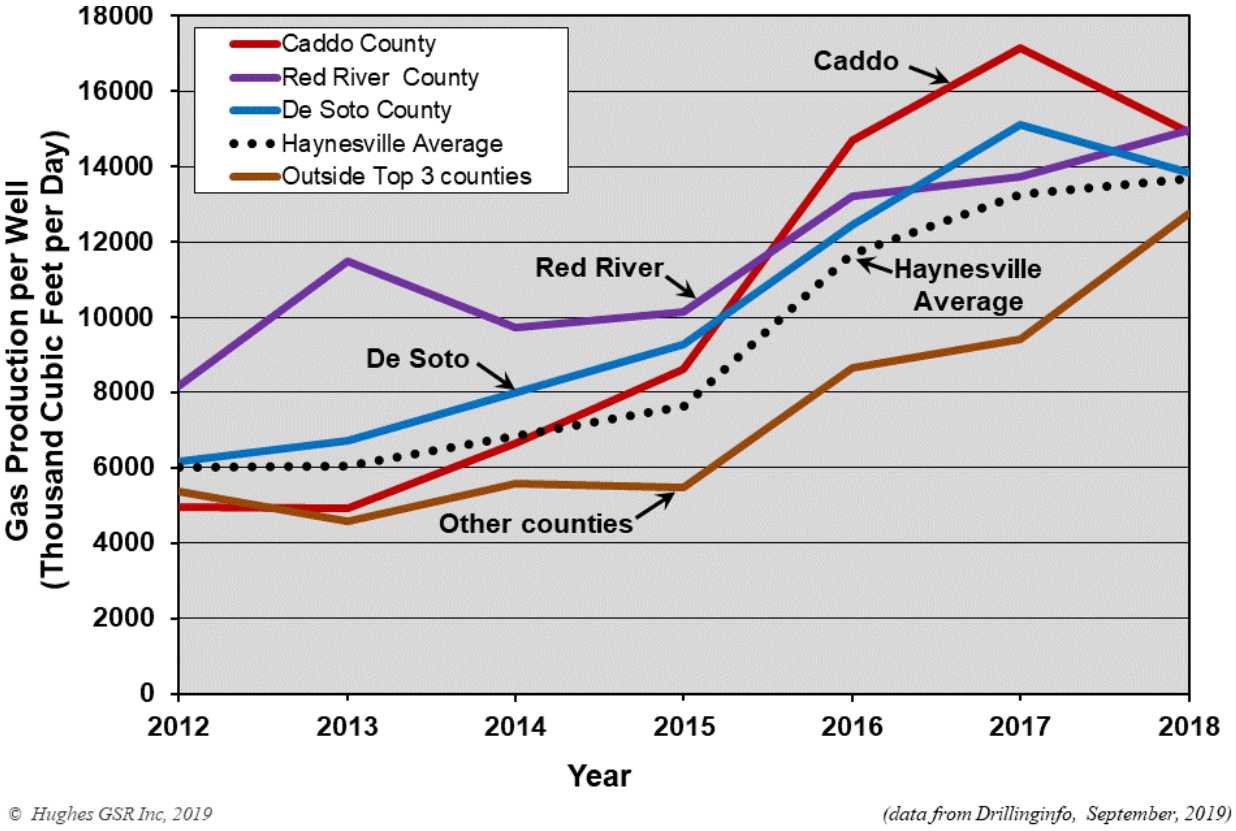


Figure 90. Average well productivity over the first six months of gas production by county in the Haynesville Play, 2012–2018.

[121] J.D. Hughes, 2019, *How long will the shale revolution last? Technology versus Geology and the Lifecycle of Shale Plays*, Post Carbon Institute, https://www.postcarbon.org/publications/how-long-will-the-shale-revolution-last/
[122] Investopedia, October 21, 2016, Chesapeake sets record with massive frack, https://www.investopedia.com/news/chesapeake-sets-record-massive-frack-chk/

Figure 91 illustrates the EIA's AEO2019 reference case production forecast for the Haynesville Play through 2050, together with earlier forecasts. The EIA expects production to keep rising and reach an all-time high in 2050 at 37% above current levels. This would require recovering 76% of the EIA's estimate of proven reserves and unproven resources of 119 tcf and 61% of the mean USGS estimate of undiscovered technical recoverable resources of 196 tcf[123]. This would mean producing 6.4 times as much gas by 2050 as the play has recovered to date. Given that the production forecast exits 2050 at all-time highs, it also implies that vast additional resources will remain to be recovered after 2050.

Although there is no doubt that large resources remain to be recovered in the Haynesville and well productivities are very high compared to plays like the Barnett, the unproven resource estimates of the EIA and USGS did not evaluate economic viability. By comparison, the University of Texas Bureau of Economic Geology (BEG) performed an economic analysis that determined just 57 tcf was recoverable at $6/mcf (a price 20% higher than the maximum assumed by the EIA), which is less than half of the EIA's 2017-2050 production forecast[124]. Given this, and the fact that well productivity is declining in two of the top three counties, which may be due to well overcrowding, the EIA forecast for the Haynesville is rated as highly optimistic.

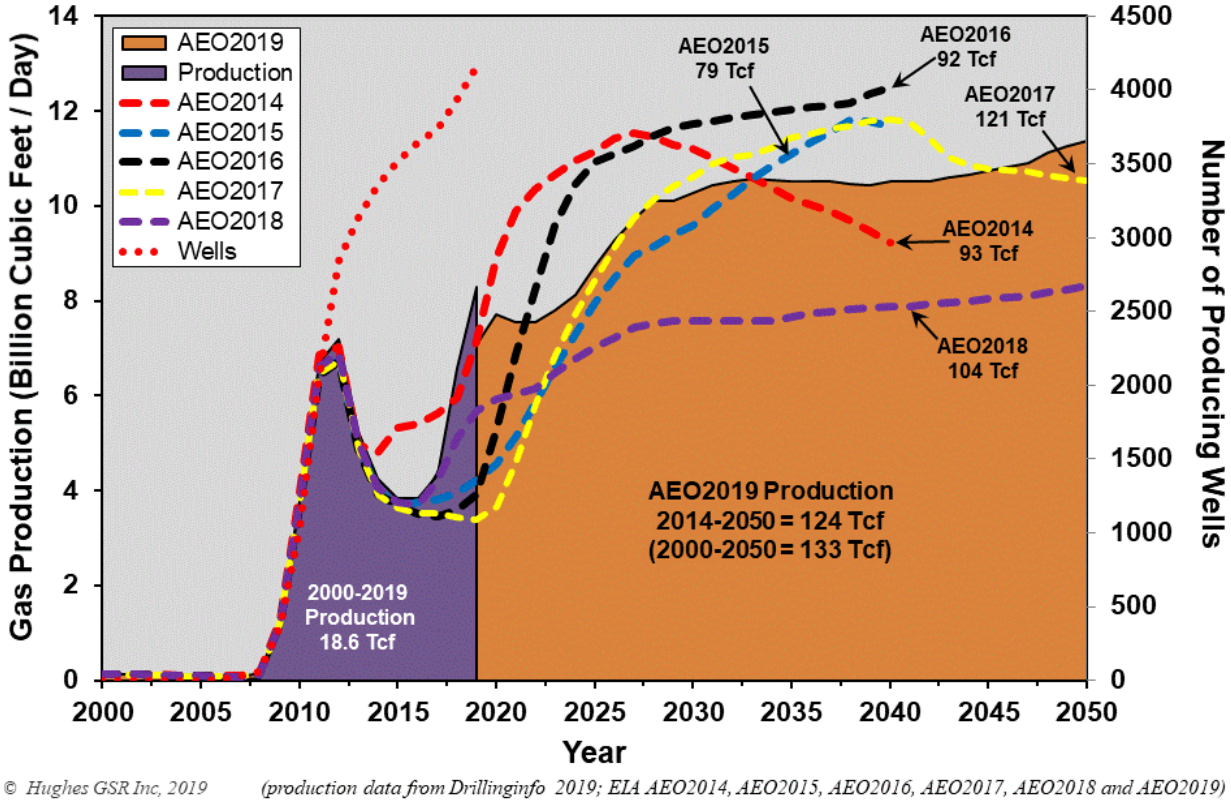


Figure 91. EIA AEO2019 reference case Haynesville Play gas production forecast through 2050.

Also shown are earlier AEO forecasts to 2040 and 2050, and cumulative production from 2000-2019.

[123] USGS, 2016, *Assessment of Undiscovered Oil and Gas Resources in the Haynesville Formation, U.S. Gulf Coast, 2016*, https://pubs.usgs.gov/fs/2017/3016/fs20173016.pdf

[124] J. Browning et al, December, 2015, *Study forecasts gradual Haynesville production recovery before final decline*, Oil and Gas Journal, https://www.ogj.com/general-interest/article/17236900/study-forecasts-gradual-haynesville-production-recovery-before-final-decline

Table 19 illustrates assumptions in the EIA AEO2019 reference case forecast.[125] If realized, the EIA forecast would have to recover 76% of the EIA's estimate of proven reserves plus unproven resources by 2050, and would require 14,461 wells, quadrupling the current well count of 4,756, at a cost of $93 billion.

EIA AEO2019 Reference Case Forecast	
Proven Reserves year-end 2017 (tcf)[126]	35.9
Unproven Resources 2017 (tcf)[127]	122.2
Total Potential 2017 (tcf)	158.1
2017-2050 Recovery (tcf)	119.47
% of total potential used 2017-2050	75.6%
Wells needed 2017-2050	14,461
Well cost 2017-2050 ($billions)	$93

Table 19. EIA assumptions for Haynesville Play gas in the AEO2019 reference case.

Well costs of $93 billion for full development are estimated assuming a well cost of $6.4 million each.[128] 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 (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.
- Although the EIA assumes that just 76% of its estimate of a total remaining potential of 158 tcf will be recovered over 2017-2050, it did not evaluate the economic viability of this potential. By comparison, BEG estimated just 56.9 tcf was recoverable at $6/mcf and 72.3 tcf at $10/mcf,[129] which is 48% and 61% of the EIA's projected 2017-2050 production, respectively.
- The EIA assumes that production will exit 2050 at an all-time high of 37% above current rates, implying that there are vast additional remaining resources to be recovered beyond 2050.
- Well productivity is dropping in two of the top three counties despite the application of better technology, suggesting that well overcrowding may already becoming an issue, which will lower well productivity and require higher prices and drilling rates to maintain and/or grow production. From the BEG analysis, it is unlikely that the EIA's production forecast could be met unless prices were much higher than $10/mcf (yet the EIA's reference case projects prices below $5/mcf through 2050).
- Given the above, the AEO2019 forecast for the Haynesville is rated as highly optimistic.

[125] EIA, Unproved technically recoverable resources are from *Assumptions to the Annual Energy Outlook 2019*, https://www.eia.gov/outlooks/aeo/assumptions/; Proven reserves are from *U.S. Crude Oil and Natural Gas Proved Reserves, Yearend 2017*, https://www.eia.gov/naturalgas/crudeoilreserves/
[126] EIA, 2018, U.S. Crude Oil and Natural Gas Proved Reserves, Yearend 2017, https://www.eia.gov/naturalgas/crudeoilreserves/.
[127] EIA, 2019, Oil and Gas Supply Module for AEO2019, https://www.eia.gov/outlooks/aeo/assumptions/pdf/oilgas.pdf
[128] EIA, 2016, Trends in U.S. Oil and Natural Gas Upstream Costs, https://www.eia.gov/analysis/studies/drilling/pdf/upstream.pdf
[129] J. Browning et al, December, 2015, *Study forecasts gradual Haynesville production recovery before final decline*, Oil and Gas Journal, https://www.ogj.com/general-interest/article/17236900/study-forecasts-gradual-haynesville-production-recovery-before-final-decline

3.3 Marcellus Play

The Marcellus is a very large play that accounts for 32% 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). More than 13,500 wells have been drilled, of which 12,469 are still producing.

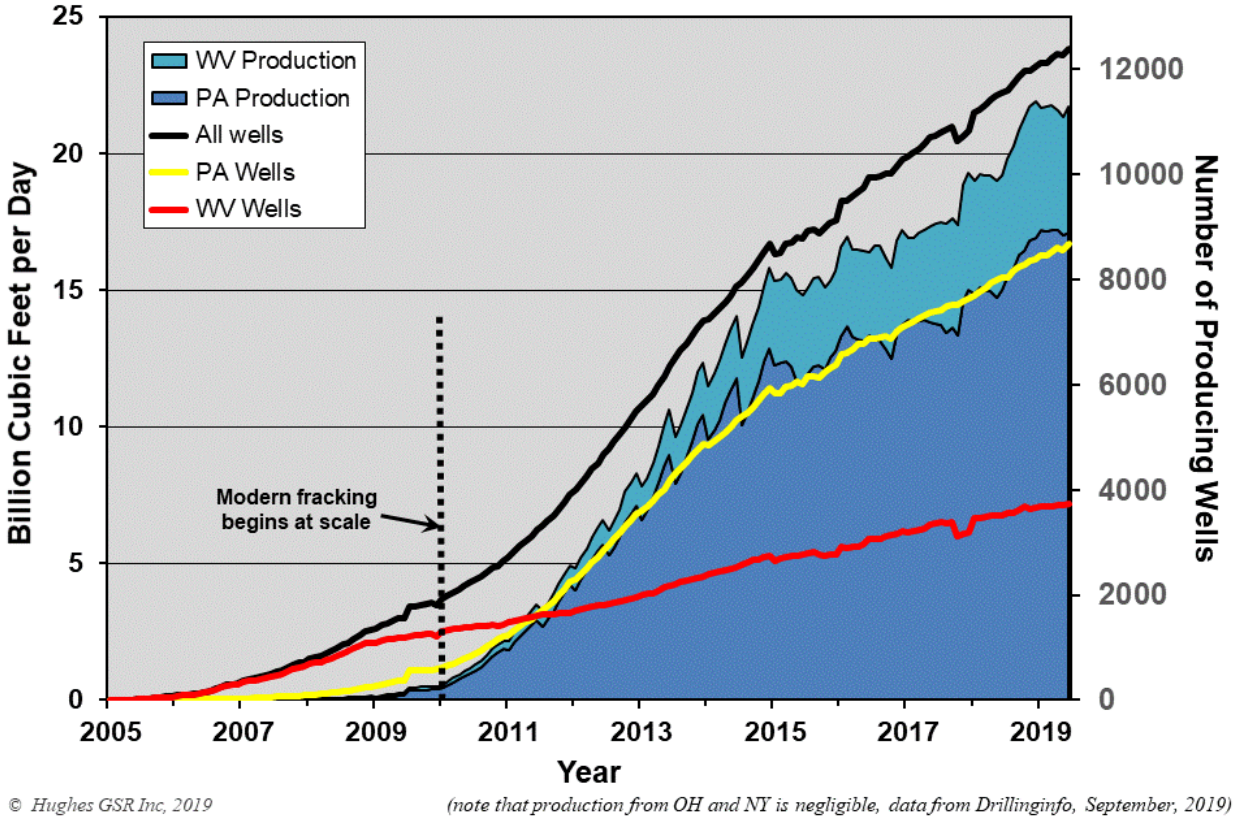


Figure 92. Marcellus Play production and number of producing gas wells, 2005–2019.[130]

West Virginia production and well count are estimated for 2019.

[130] Drillinginfo, September, 2019.

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.

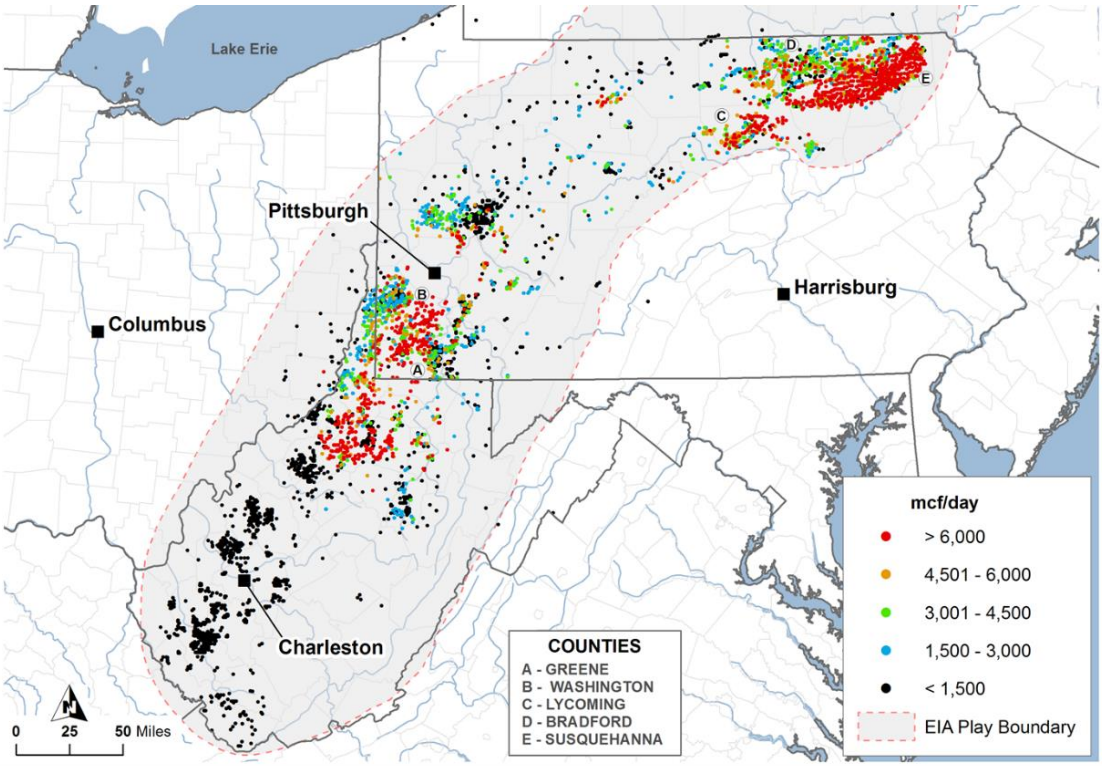


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Figure 93. Marcellus Play well locations showing peak gas production in the highest month.

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.[131]

[131] 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-three percent of cumulative gas production has come from the top two counties and 62% 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.

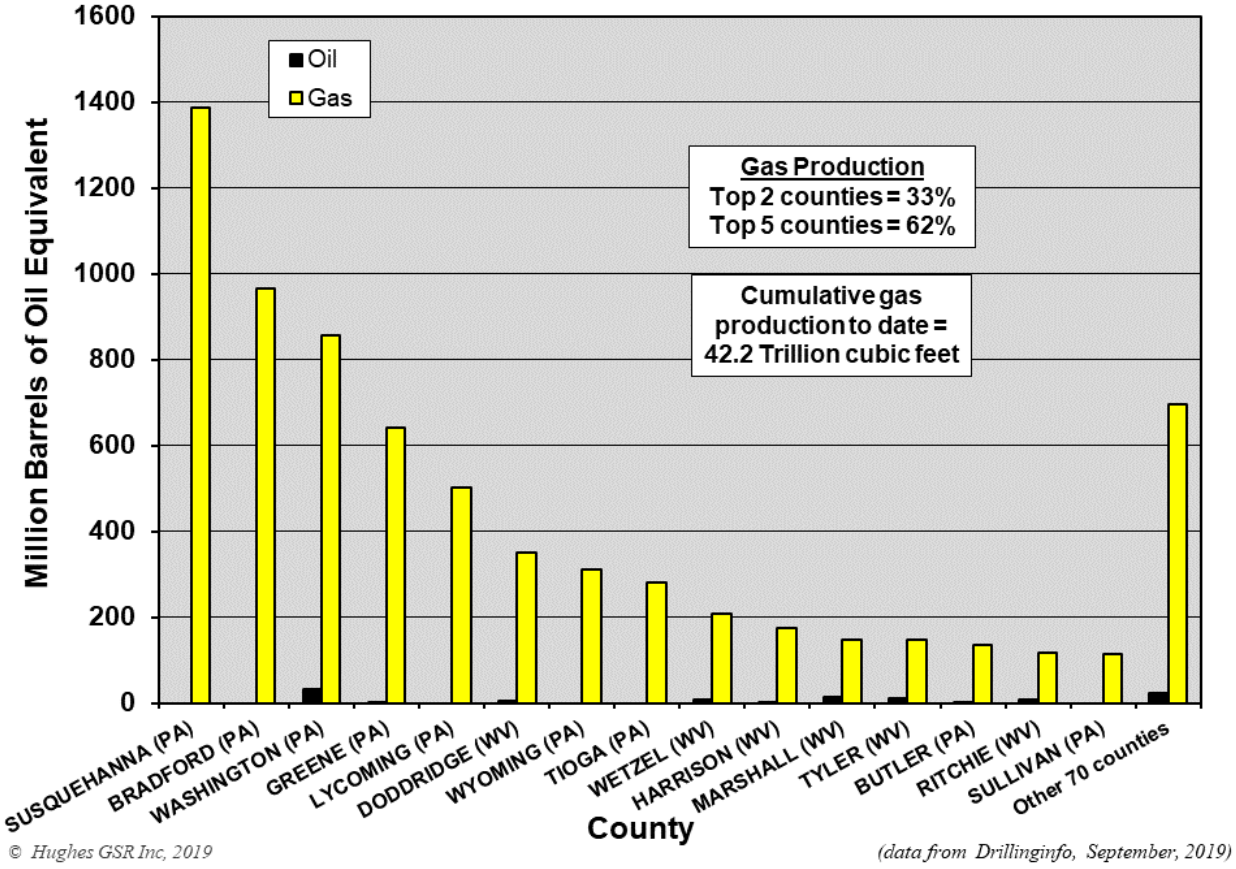


Figure 94. Cumulative production of oil and gas from the Marcellus Play by county through 2019.

Production is concentrated in sweet spots, with 33% of cumulative gas production in Susquehanna and Bradford counties and 62% in the top 5 counties, all of which are in Pennsylvania.

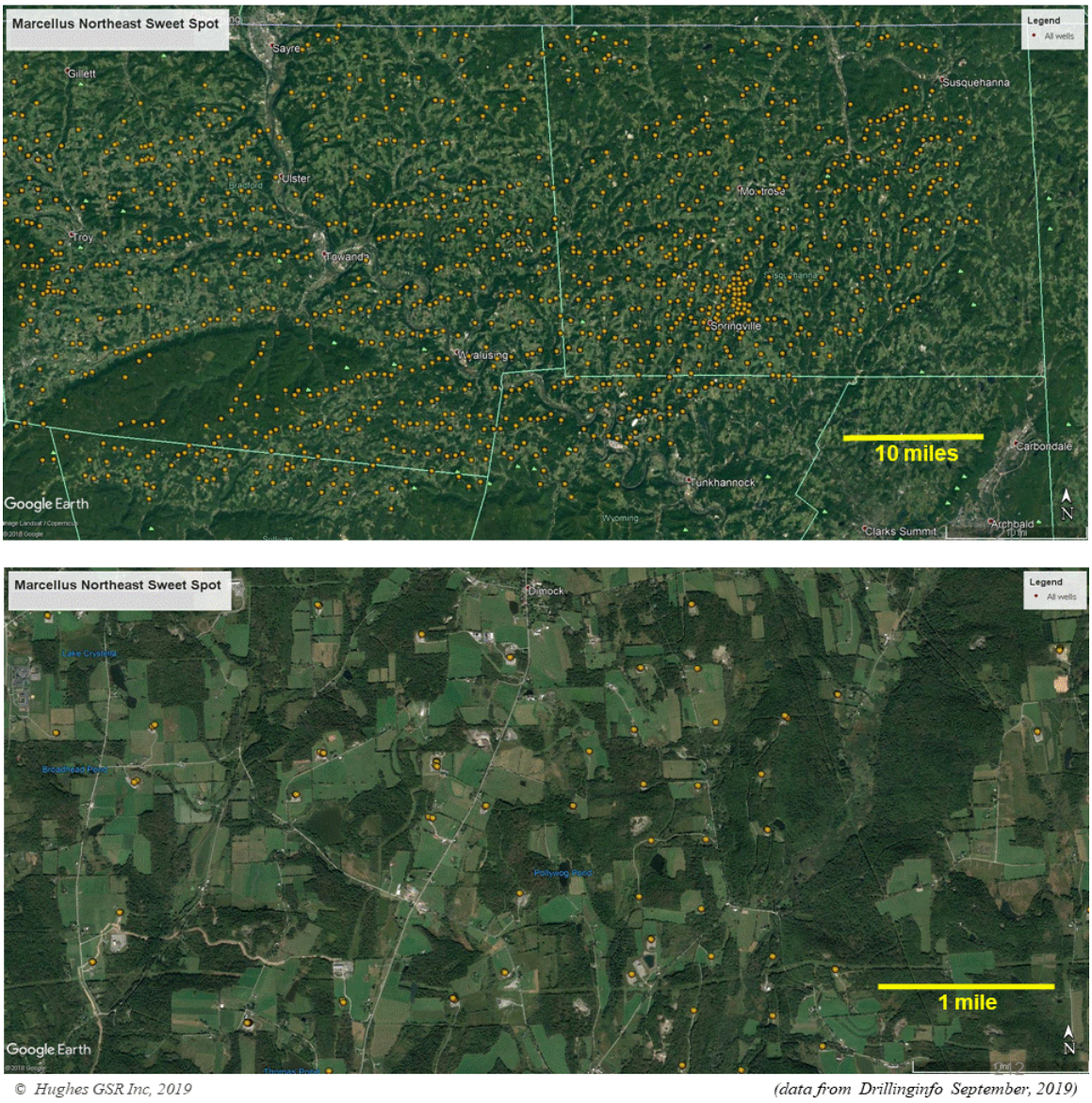
Table 20 shows the number of wells drilled, cumulative and current production, and well- and first-year field-decline rates for the Marcellus as a whole and for individual counties. Three-year well decline rates average 76.5% and first-year field decline rates average 30.4% per year, without new drilling.

County/State	Well type	Vintage	Total Well Count	Producing Well Count	Cumulative Oil Production (billion bbls)	Cumulative Gas Production (tcf)	Oil Production June 2019 (Kbbls/day)	Gas Production June 2019 (bcf/day)	3-year well decline (%)	First-year field decline (%)
All	All	All	13,540	12,469	0.096	42.200	52.7	22.09	76.5	30.4
PA	All	All	9,273	8,682	0.032	33.874	11.1	17.98	76.4	30.2
WV	All	All	4,196	3,766	0.063	8.302	40.9	4.10	77.1	31.2
OH and NY	All	All	72	21	0.001	0.024	0.67	0.01	-	-
Bradford	All	All	1,249	1,229	0.000	5.800	0.00	2.34	68.3	18.0
Greene	All	All	1,070	1,027	0.00004	3.848	0.003	2.84	82.0	29.3
Lycoming	All	All	832	807	0.000	3.007	0.000	0.96	74.9	16.6
Susquehanna	All	All	1,470	1,422	0.000	8.314	0.000	4.48	79.7	33.3
Washington	All	All	1,609	1,438	0.030	5.141	10.19	3.10	77.4	38.7
Other counties	All	All	7,311	6,546	0.065	16.090	42.51	8.37	74.3	30.5

Table 20. Well count, cumulative production, most recent production, and well- and first-year field-decline rates for the Marcellus Play and counties within it, by well type and vintage.[132]

[132] From Drillinginfo October, 2019.

The degree of development of the Marcellus northeast and southwest core areas to date is illustrated in Figures 95 and 96, respectively. Horizontal laterals have increased 58% in length since 2012 to an average of 6,916 feet in 2018[133], although some wells have exceeded 14,000 feet.[134] Most well pads have multiple wells.

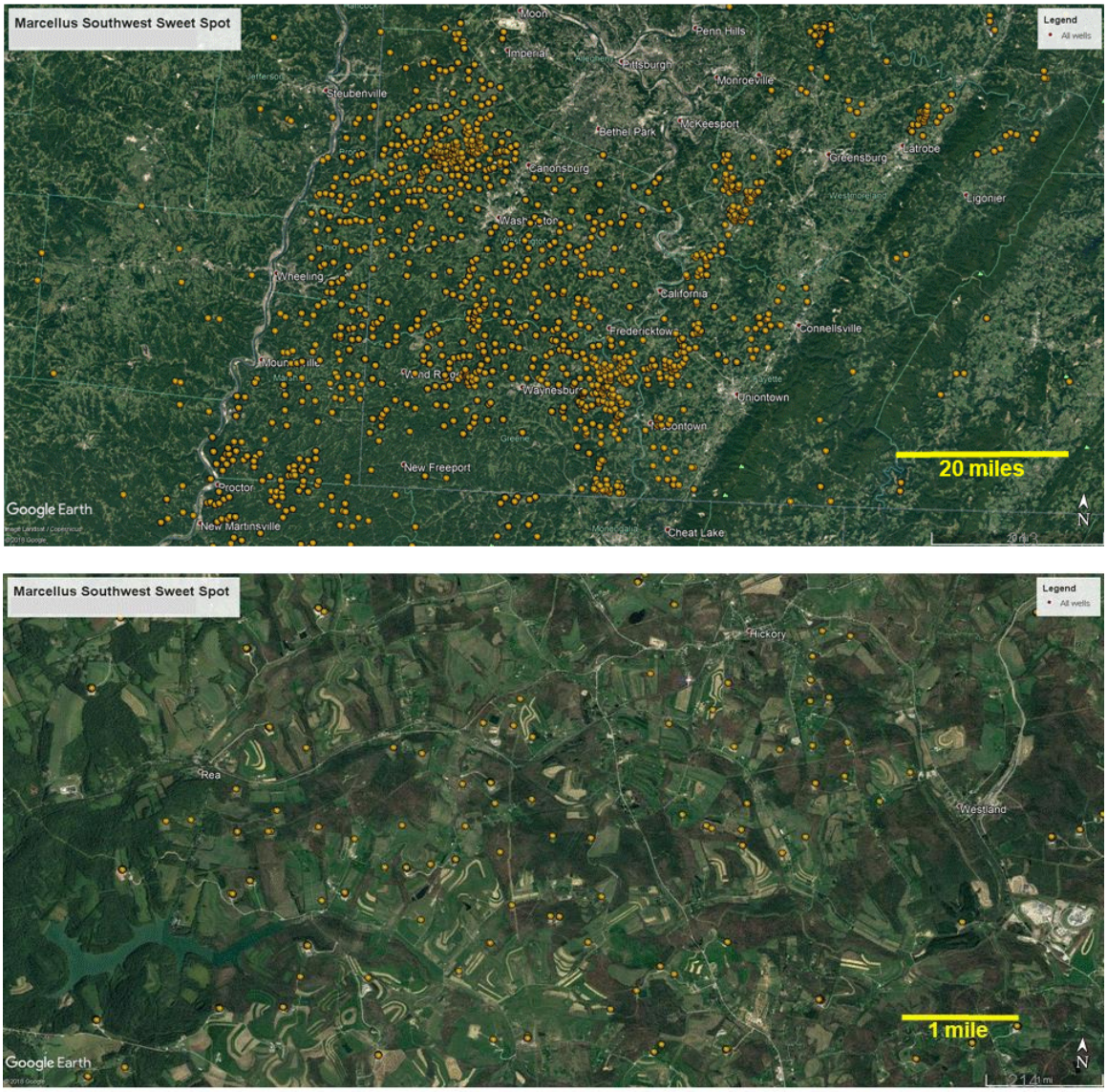


© Hughes GSR Inc, 2019 (data from Drillinginfo September, 2019)

Figure 95. Drilling density in the northeast core area of the Marcellus Play as of June 2019.

Upper: overview of core area in Bradford and Susquehanna counties. Lower: close-up view of Susquehanna County near the town of Dimock.[135]

[133] J.D. Hughes, 2019, *How long will the shale revolution last? Technology versus Geology and the Lifecycle of Shale Plays*, Post Carbon Institute, https://www.postcarbon.org/publications/how-long-will-the-shale-revolution-last/
[134] Shale gas reporter, June 20, 2017, *Range Resources sets record lateral length in Pa*., http://shalegasreporter.com/news/range-resources-sets-record-lateral-length-pa/60921.html
[135] From Drillinginfo September, 2019



© Hughes GSR Inc, 2019 (data from Drillinginfo September, 2019)

Figure 96. Drilling density in the southwest core area of the Marcellus Play in Washington County south of Pittsburgh as of June 2019.[136]

Upper: overview. Lower: close-up.

[136] From Drillinginfo September, 2019.

Figure 97 illustrates production from the top five counties compared to the overall play. Three of the top five counties have peaked, along with counties outside of the top five, however all but Lycoming County may exceed these peaks with more drilling. The top five counties make up 62% of cumulative production and 60% of June 2019 production. Counties outside of the top five have declined 4.4% since peaking in December 2018.

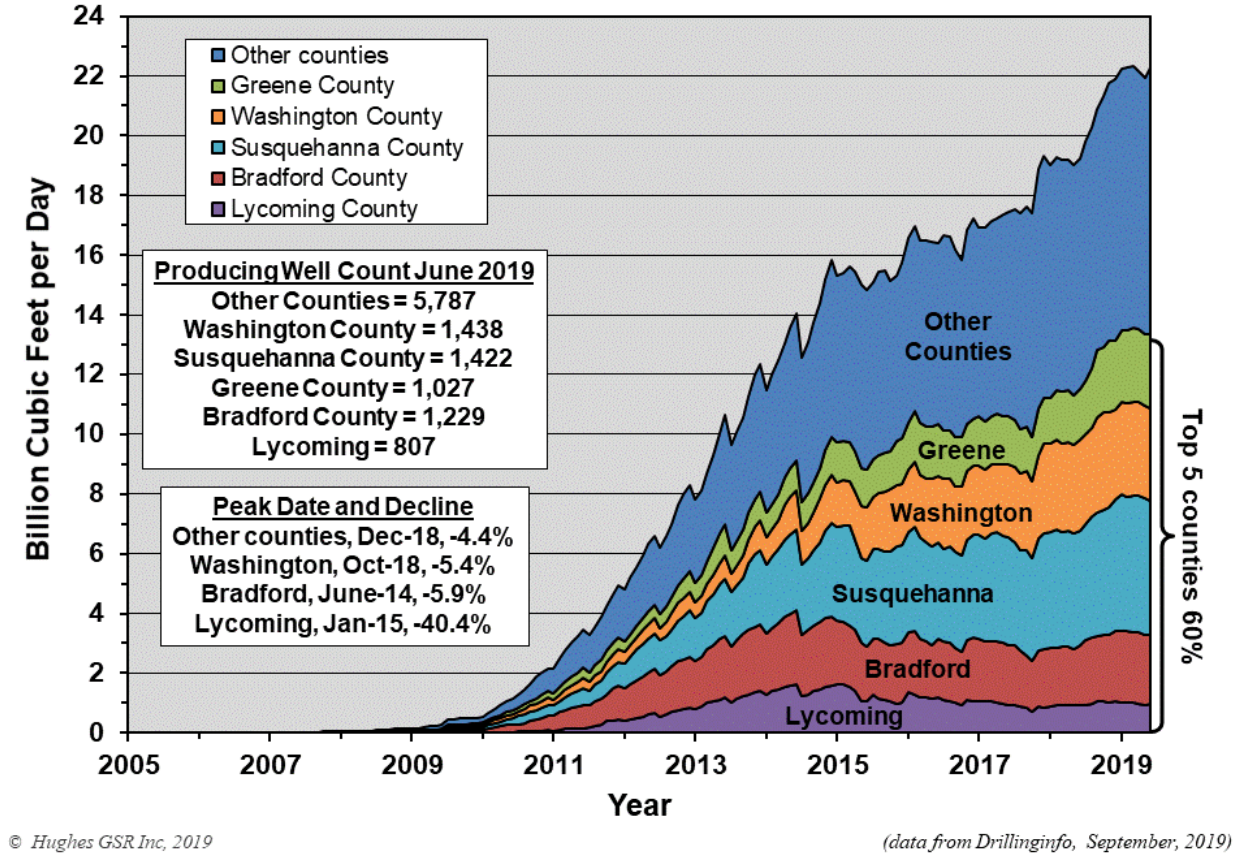


Figure 97. Gas production in the Marcellus Play by county through June 2019.

Also shown are peak dates and percentage decline from peak of three sweet-spot counties and collectively for counties outside of the top five. Production from West Virginia is estimated for 2019.

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. West Virginia wells on average have considerably lower productivity than Pennsylvanian wells. Lycoming County, which is well past peak, and other counties outside of the top five, have flat-lined in terms of productivity increases or increased very gradually. Technology improvements include extending horizontal lateral lengths. The average for the Marcellus has increased 58% since 2012 to 6,916 feet[137] (although some have exceeded 14,000 feet), as well as significantly increasing volumes of water/proppant injection. 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.

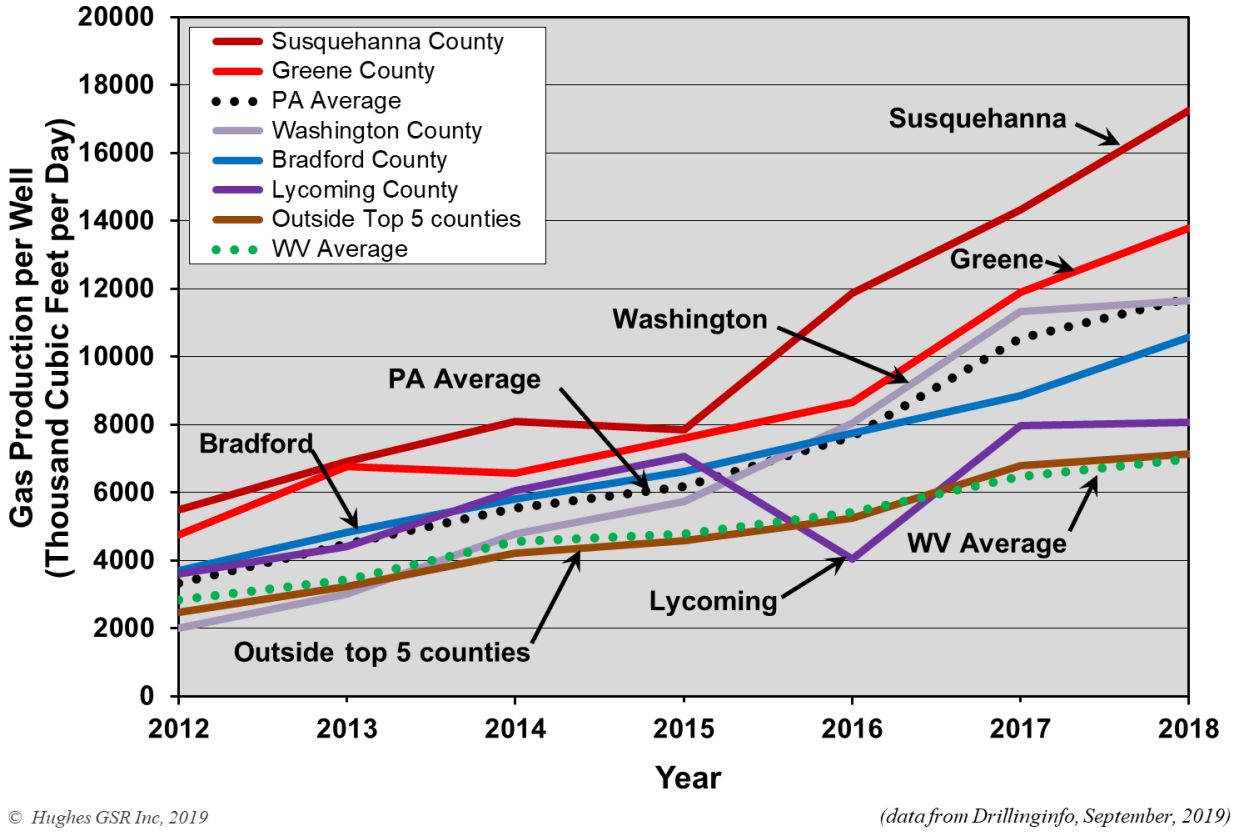


Figure 98. Average well productivity over the first six months of gas production by county in the Marcellus Play, 2012–2018.

[137] J.D. Hughes, 2019, *How long will the shale revolution last? Technology versus Geology and the Lifecycle of Shale Plays*, Post Carbon Institute, https://www.postcarbon.org/publications/how-long-will-the-shale-revolution-last/

Figure 99 illustrates the EIA's AEO2019 reference case production forecast for the Marcellus Play through 2050, together with earlier forecasts. The EIA expects production to keep rising through 2050 and exit 2050 at 41% above current levels. Although the Marcellus is a very large play, this is an extremely aggressive forecast that would require recovering eight times as much gas over 2017-2050 as the play has recovered to date. It also requires producing 84% of the EIA's estimates of proven reserves plus unproven resources. The EIA's estimate of unproven resources is more than three times the USGS mean estimate of undiscovered technically recoverable resources (unproven and undiscovered resources have not been demonstrated to be economically recoverable).[138] Although there is no doubt that the Marcellus contains very large remaining gas resources, and that higher drilling rates coupled with more aggressive technology will likely grow production somewhat in the short- and medium-term, the AEO2019 forecast must be rated as extremely optimistic.

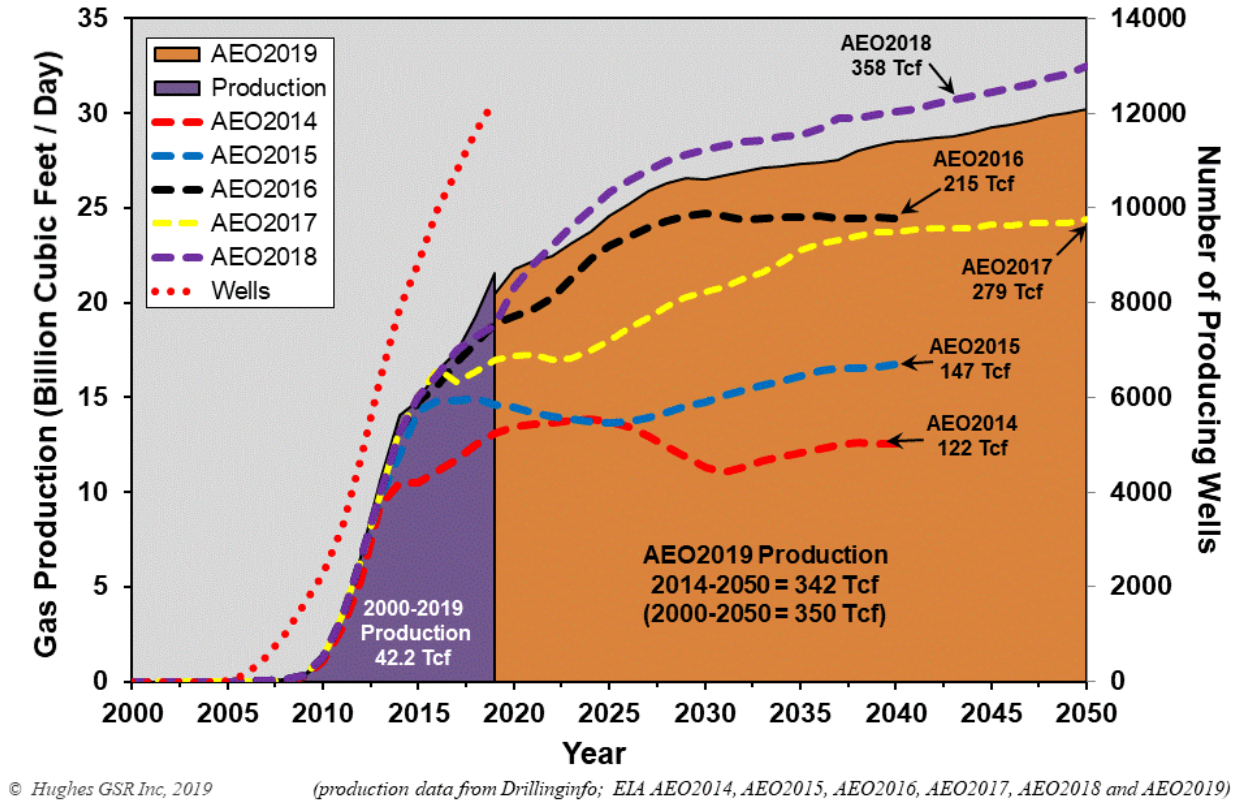


Figure 99. EIA AEO2019 reference case Marcellus Play gas production forecast through 2050.

Also shown are earlier AEO forecasts to 2040 and 2050, and cumulative production from 2000-2019.

[138] J.L. Coleman et al., 2011, *Assessment of Undiscovered Oil and Gas Resources of the Devonian Marcellus Shale of the Appalachian Basin Province, 2011*, U.S.G.S. https://pubs.usgs.gov/fs/2011/3092/pdf/fs2011-3092.pdf

Table 21 illustrates assumptions in the EIA AEO2019 reference case forecast.[139] If realized, the EIA forecast would recover 84% of the EIA's estimate of proven reserves plus unproven resources by 2050, and would require 124,767 wells, for a well count of ten times the current total at a cost of $799 billion.

EIA AEO2019 Reference Case Forecast	
Proven Reserves year-end 2017 (tcf)[140]	123.8
Unproven Resources 2017 (tcf)[141]	262.5
Total Potential 2017 (tcf)	386.3
2017-2050 Recovery (tcf)	326.0
% of total potential used 2017-2050	84.4%
Wells needed 2017-2050	124,767
Well cost 2017-2050 ($billions)	$799

Table 21. EIA assumptions for Marcellus Play gas in the AEO2019 reference case.

Well costs of $799 billion for full development are estimated assuming a well cost of $6.4 million each.[142] 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 forecast for the Marcellus is rated as 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 forecast assumes that 84% of its estimate of proven reserves plus unproven resources of 386 tcf will be recovered by 2050. The unproven resource portion of this estimate is more than triple the mean USGS estimate of 84 tcf of undiscovered technically recoverable resources.[143]

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

- Assuming 124,767 wells can be drilled to develop unproven resources plus proven reserves (per the EIA AEO2019 assumptions and 2017 proven reserves)—in addition to the 13,540 wells already drilled—this would increase average well density in the prospective drilled area to 3.3 per square mile (actual well density would be higher when off-limits areas such as metropolitan Pittsburgh are removed). The effective well density would be higher still given that the average horizontal lateral length has increased 58% to 6,916 feet over 2012–2018[144], and some laterals have reached over 14,000 feet.[145] Despite the increasing lateral lengths and higher volumes of proppant and water injection, well productivity gains have flat-lined in two of the top five counties, and one of them (Lycoming) peaked in 2015 and is now

[139] EIA, Unproved technically recoverable resources are from *Assumptions to the Annual Energy Outlook 2019*, https://www.eia.gov/outlooks/aeo/assumptions/; Proven reserves are from *U.S. Crude Oil and Natural Gas Proved Reserves, Yearend 2017*, https://www.eia.gov/naturalgas/crudeoilreserves/
[140] EIA, 2018, U.S. Crude Oil and Natural Gas Proved Reserves, Yearend 2017, https://www.eia.gov/naturalgas/crudeoilreserves/.
[141] EIA, 2019, Oil and Gas Supply Module for AEO2019, https://www.eia.gov/outlooks/aeo/assumptions/pdf/oilgas.pdf
[142] EIA, 2016, Trends in U.S. Oil and Natural Gas Upstream Costs, https://www.eia.gov/analysis/studies/drilling/pdf/upstream.pdf
[143] J.L. Coleman et al., 2011, *Assessment of Undiscovered Oil and Gas Resources of the Devonian Marcellus Shale of the Appalachian Basin Province, 2011*, U.S.G.S. https://pubs.usgs.gov/fs/2011/3092/pdf/fs2011-3092.pdf
[144] J.D. Hughes, 2019, *How long will the shale revolution last? Technology versus Geology and the Lifecycle of Shale Plays*, Post Carbon Institute, https://www.postcarbon.org/publications/how-long-will-the-shale-revolution-last/
[145] Shale gas reporter, June 20, 2017, *Range Resources sets record lateral length in Pa*., http://shalegasreporter.com/news/range-resources-sets-record-lateral-length-pa/60921.html

40% below peak. This suggests that increasing the well count 10-fold would likely result in far more wells than necessary to recover the economically viable portion of the resource.

- Although the Marcellus is a very large play, much of the drilling to date has focused on sweet spots that are becoming saturated with wells. In order to fully develop the play drilling rates will have to be considerably higher to maintain production and/or stem declines in later years as drilling moves into lower quality rock outside sweet spots, and prices will have to be correspondingly higher to justify them.

- Given the above, the AEO2019 forecast for the Marcellus, is rated as extremely optimistic.

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 10.5% of current U.S. shale gas production and is projected by the EIA to account for 16% of cumulative shale gas production over the 2014–2050 period. That means that together with the Marcellus, these two plays alone are projected to account for 50% of U.S. shale gas production through 2050. Production has grown rapidly, as illustrated in Figure 100, although it has declined slightly since December, 2018. More than 2,800 wells have been drilled, of which 2,466 are still producing.

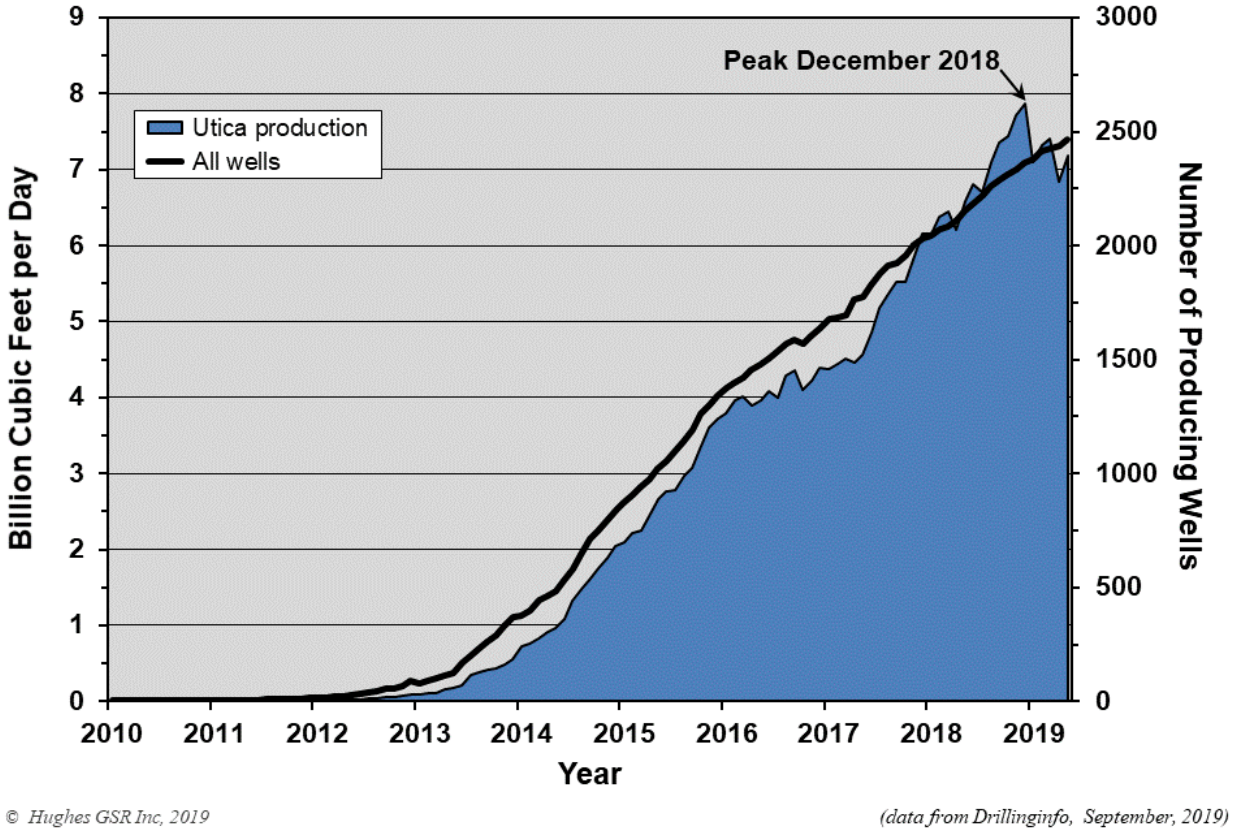


Figure 100. Utica Play gas production and number of producing wells, 2010–2019.[146]

[146] Drillinginfo, September, 2019.

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.

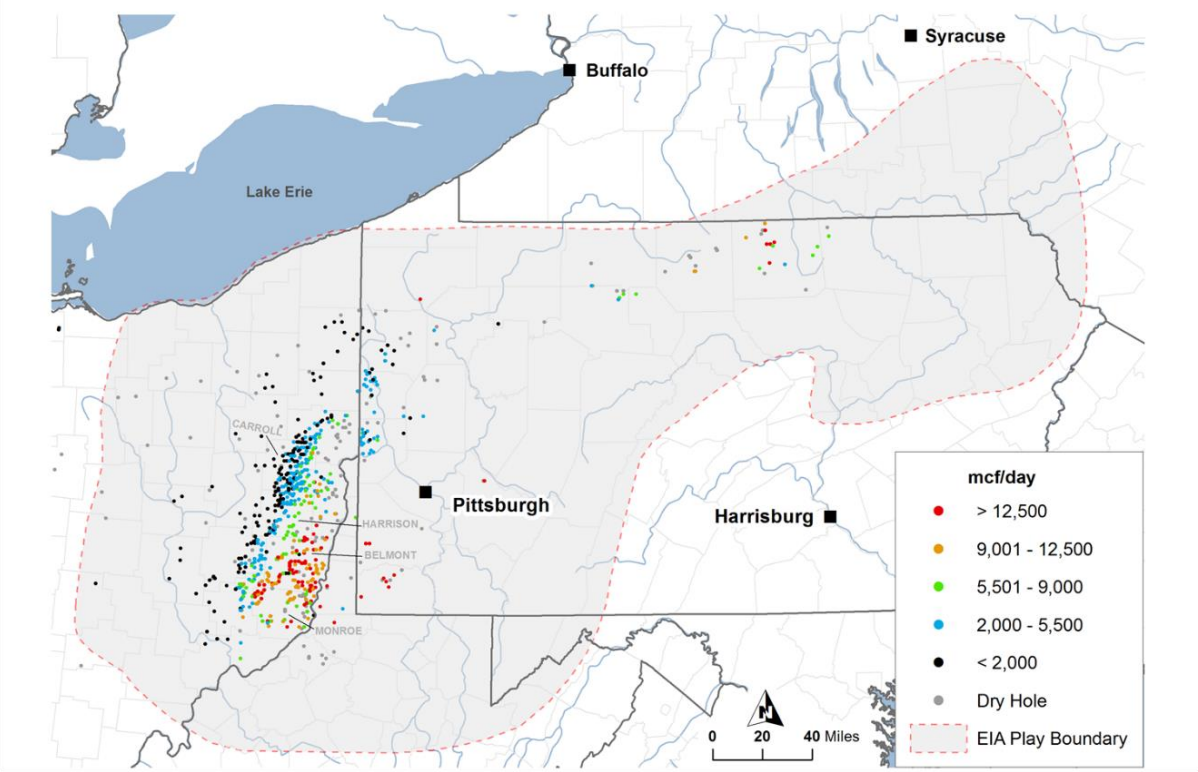


Figure 101. Utica Play well locations showing peak gas production in the highest month.

The highest productivity wells are concentrated in Belmont, Carroll, Monroe, and Harrison counties of southeast Ohio.[147]

[147] Drillinginfo, September, 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-five percent of cumulative gas production has come from Belmont County, and 81% 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.

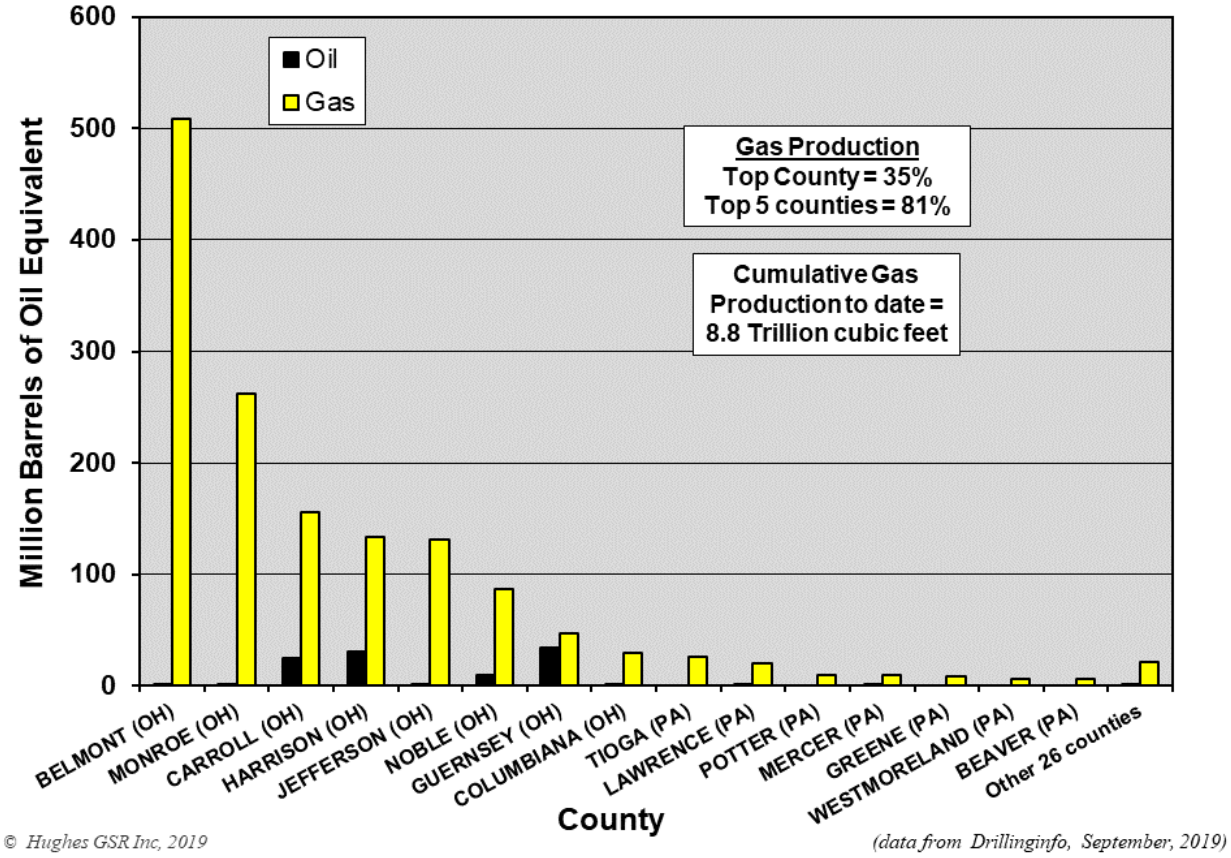


Figure 102. Cumulative production of oil and gas from the Utica Play by county through 2019.

Production is concentrated in sweet spots, with 35% of cumulative gas recovery in Belmont County and 81% in the top 5 counties.

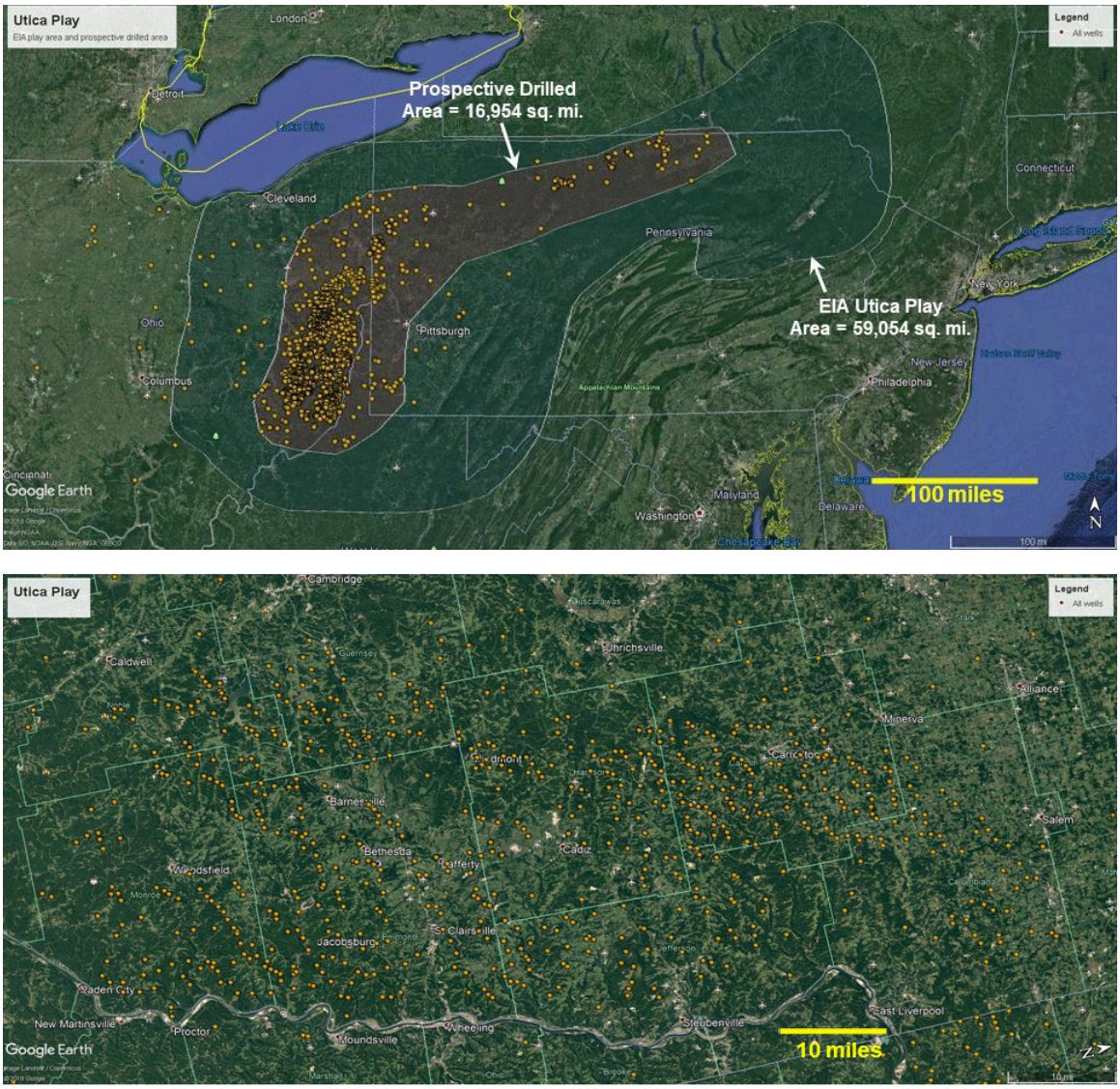
Table 22 shows the number of wells drilled, cumulative and current production, and well- and first-year field-decline rates for the Utica as a whole and for individual counties. Three-year well decline rates average 85.4% and first-year field decline rates average 42.3% without new drilling, which is at the high end for shale plays analyzed in this report.

County	Well type	Vintage	Total Well Count	Producing Well Count	Cumulative Oil Production (billion bbls)	Cumulative Gas Production (tcf)	Oil Production May 2019 (Kbbls/day)	Gas Production May 2019 (bcf/day)	3-year well decline (%)	First-year field decline (%)
All	All	All	2,893	2,466	0.104	8.795	60.36	7.17	85.4	42.3
Belmont	All	All	523	466	0.0007	3.051	0.05	2.38	84.3	43.9
Carroll	All	All	474	466	0.025	0.937	6.69	0.27	65.8	22.1
Harrison	All	All	390	356	0.030	0.803	17.37	0.53	76.7	32.1
Monroe	All	All	368	311	0.000014	1.570	0.03	1.63	88.0	43.1
Other counties	All	All	1,138	867	0.048	2.434	36.22	2.36	85.6	46.0

Table 22. Well count, cumulative production, most recent production, and well- and first-year field-decline rates for the Utica Play and counties within it, by well type and vintage.[148]

[148] From Drillinginfo September, 2019.

The degree of development of the Utica core area in Belmont County to date is illustrated in Figure 103. Horizontal laterals have increased 105% in length since 2012 to an average of 9,906 feet in 2018[149], although some recent wells have been over 18,000 feet.[150] Most well pads have multiple wells with up to ten wells per pad.



© Hughes GSR Inc, 2019 (data from Drillinginfo September, 2019)

Figure 103. Drilling density in the core area of the Utica Play.

Upper: EIA play and prospective drilling areas in the Utica Play. Lower: Core area of the Utica Play (north is to the right) with wells as of May 2019[151].

[149] J.D. Hughes, 2019, *How long will the shale revolution last? Technology versus Geology and the Lifecycle of Shale Plays*, Post Carbon Institute, https://www.postcarbon.org/publications/how-long-will-the-shale-revolution-last/

[150] The American oil and gas reporter, July, 2016, *Superlateral ushers in step-changes in well costs*, https://www.aogr.com/magazine/editors-choice/purple-hayes-no.-1h-ushers-in-step-changes-in-lateral-length-well-cost

[151] From Drillinginfo September, 2019.

Figure 104 illustrates production from the top four counties compared to the overall play. The top four counties account for 72% of cumulative production and 67% of production in May 2019. Three of the top four counties peaked between 2015 and 2018, and counties outside of the top four collectively peaked in early 2019.

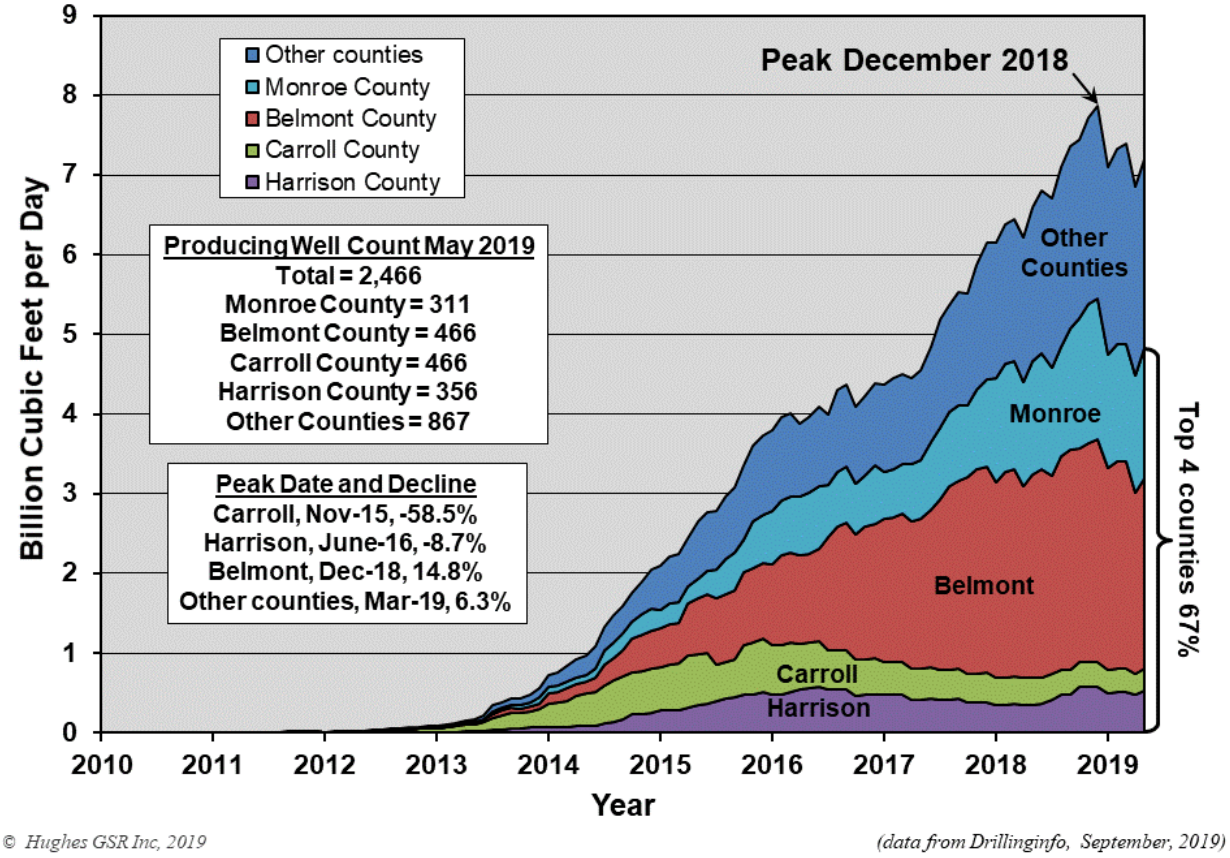


Figure 104. Gas production in the Utica Play by county through May 2019.

Also shown are peak dates and percentage decline from peak of three sweet-spot counties and collectively for counties outside of the top four.

Figure 105 illustrates average well productivity over the first six months for the Utica 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 longer horizontal laterals, which have increased 105% since 2012 to an average 9,906 feet in 2018[152], with some recent laterals of more than 18,000 feet[153], along with significantly increasing volumes of water and proppant injection and number of frack stages. With the exception of Carroll County, all counties have seen significant increases in average well productivity through 2018.

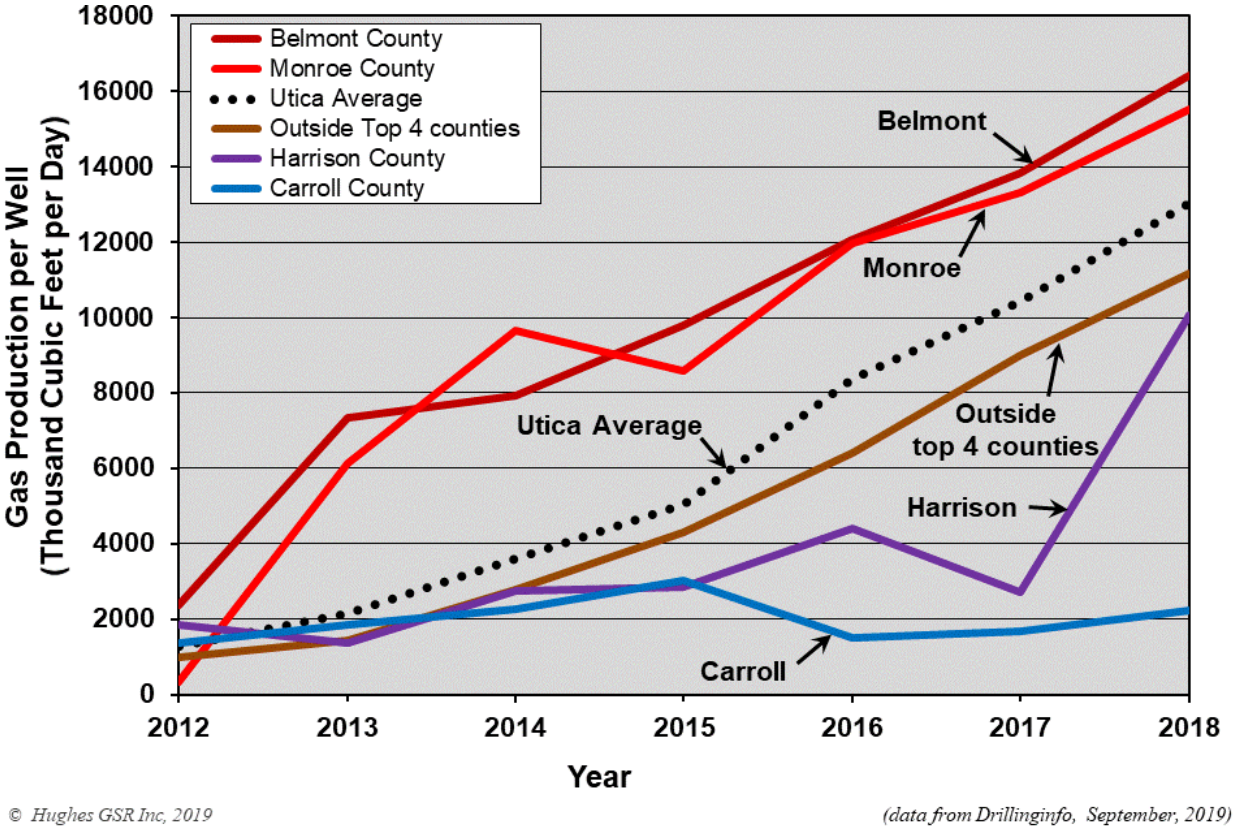


Figure 105. Average well productivity over the first six months of gas production by county in the Utica Play, 2012–2018.

[152] J.D. Hughes, 2019, *How long will the shale revolution last? Technology versus Geology and the Lifecycle of Shale Plays*, Post Carbon Institute, https://www.postcarbon.org/publications/how-long-will-the-shale-revolution-last/
[153] The American oil and gas reporter, July, 2016, *Superlateral ushers in step-changes in well costs*, https://www.aogr.com/magazine/editors-choice/purple-hayes-no.-1h-ushers-in-step-changes-in-lateral-length-well-cost

Figure 106 illustrates the EIA's AEO2019 reference case production forecast for the Utica Play through 2050, together with earlier forecasts. The EIA forecasts production to keep rising through 2050 and exit 2050 at 2.5 times current production levels. Although the Utica is potentially a very large play, the prospective drilled area is far smaller than the play area estimated by the EIA in Figure 101. This is an aggressive forecast that would require recovering 17 times as much gas by 2050 as the play has recovered to date. Although the EIA forecast over 2017-2050 requires production of just 69% of its estimate of proven reserves plus unproven resources, the EIA estimate of unproven resources is five times as large as the USGS mean estimate of undiscovered technically recoverable resources[154] (and neither estimate evaluated economic recoverability). The EIA forecast also exits 2050 at an all-time production high, implying there are vast additional resources remaining to be recovered after 2050.

Although there is no doubt that the Utica contains very large gas resources and that it is in its early stage of development, 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 AEO2019 forecast must be rated as extremely optimistic.

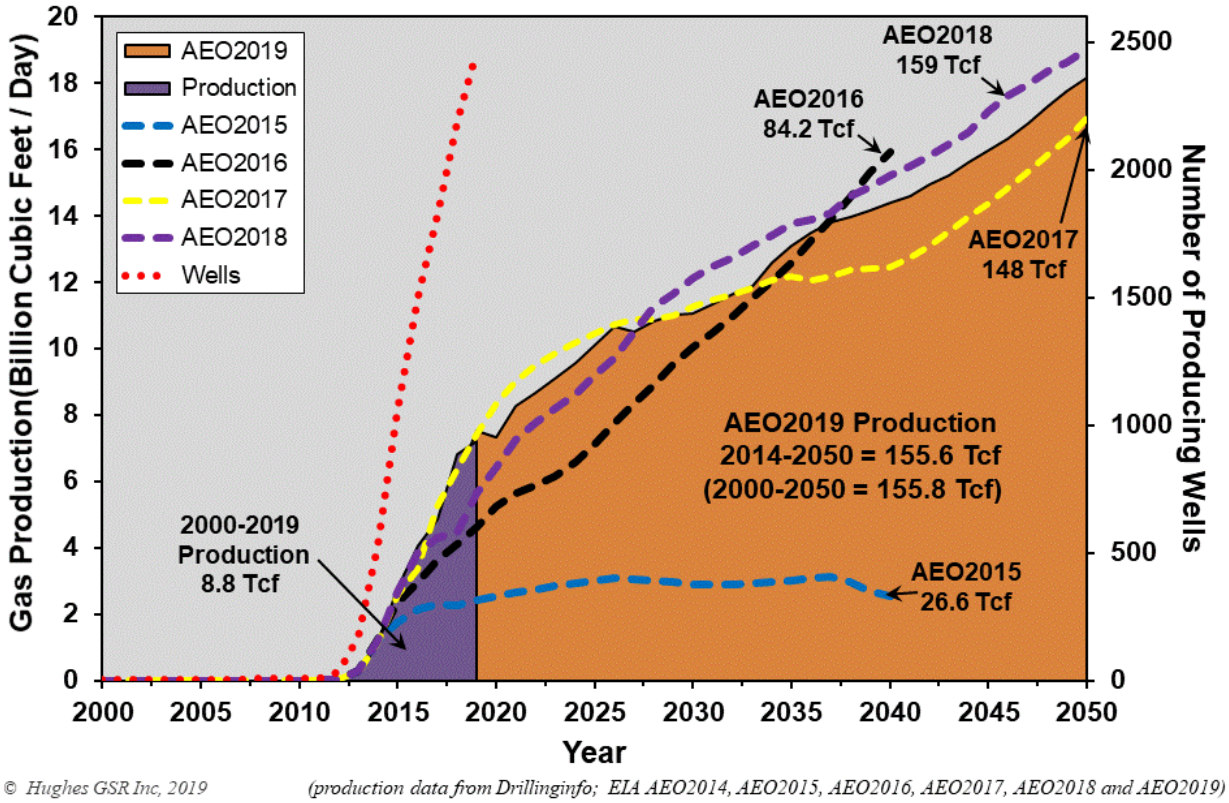


Figure 106. EIA AEO2019 reference case Utica Play gas production forecast through 2050.

Also shown are earlier AEO forecasts to 2040 and 2050, and cumulative production from 2000-2019.

[154] M.A. Kirschbaum, et al., 2012, *Assessment of Undiscovered Oil and Gas Resources of the Ordovician Utica Shale of the Appalachian Basin Province, 2012*, U.S.G.S. https://pubs.usgs.gov/fs/2012/3116/FS12-3116.pdf

Table 23 illustrates assumptions in the EIA AEO2019 reference case forecast.[155] If realized, the EIA forecast would recover 69% of the EIA's estimate of proven reserves plus unproven resources by 2050 (or 400% of the USGS estimate of undiscovered technically recoverable resources). This would require 88,731 wells, more than thirty times the current total, at a cost of $568 billion.

EIA AEO2019 Reference Case Forecast	
Proven Reserves year-end 2017 (tcf)[156]	26.5
Unproven Resources 2017 (tcf)[157]	193.9
Total Potential 2017 (tcf)	220.4
2017-2050 Recovery (tcf)	152.8
% of total potential used 2017-2050	69.3%
Wells needed 2017-2050	88,731
Well cost 2017-2050 ($billions)	$568

Table 23. EIA assumptions for Utica Play gas in the AEO2019 reference case.

Well costs of $568 billion for full development are estimated assuming a well cost of $6.4 million each.[158] 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.

[155] EIA, Unproved technically recoverable resources are from *Assumptions to the Annual Energy Outlook 2019*, https://www.eia.gov/outlooks/aeo/assumptions/; Proven reserves are from *U.S. Crude Oil and Natural Gas Proved Reserves, Yearend 2017*, https://www.eia.gov/naturalgas/crudeoilreserves/

[156] EIA, 2018, U.S. Crude Oil and Natural Gas Proved Reserves, Yearend 2017, https://www.eia.gov/naturalgas/crudeoilreserves/.

[157] EIA, 2019, Oil and Gas Supply Module for AEO2019, https://www.eia.gov/outlooks/aeo/assumptions/pdf/oilgas.pdf

[158] EIA, 2016, Trends in U.S. Oil and Natural Gas Upstream Costs, https://www.eia.gov/analysis/studies/drilling/pdf/upstream.pdf

Synopsis

The EIA's reference case production forecast is extremely optimistic. Key points include:

- The EIA play area (59,054 square miles) overestimates the prospective drilled area (16,954 square miles) by 250% (see Figure 103). 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 forecasts that 69% of its estimate of proved reserves and unproven resources of 220 tcf will be recovered by 2050. However, the EIA estimate of unproven resources is five times that of the USGS estimate of undiscovered technically recoverable resources. If the EIA estimate of proven reserves was added to the USGS estimate of unproven resources (a total of 65 tcf), the EIA production forecast of 153 tcf would require recovering 136% more gas than proven reserves plus the USGS estimate of unproven resources by 2050.

- The EIA forecasts that production will exit 2050 at levels 2.5 times current rates, implying that there are vast additional resources remaining to be recovered after 2050.

- The 88,731 new wells needed to recover the EIA production forecast by 2050, in addition to the 2,893 wells already drilled, would increase average well density in the prospective drilled area to 5.4 per square mile. The effective well density, given that horizontal laterals now average 9,906 feet, would be 10.1 wells per square mile. This is likely far more wells than necessary to cost-effectively recover the resources that exist. There is simply not enough prospective drilling area to recover the EIA's forecast production to 2050, let alone the resources it implies will remain to be recovered after 2050.

- Although the Utica is a large play, production in three of the four top counties has peaked, along with the play as a whole. Higher rates of drilling, and higher prices to justify them, will be needed to reverse these declines.

- Given the above, the EIA's AEO2019 forecast for the Utica is rated as extremely optimistic.

3.5 Fayetteville Play

The Fayetteville in a relatively small play located in north-central Arkansas. Production peaked in November 2012 and is down 57% 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 1.8% of current U.S. shale gas production and is projected by the EIA to account for 2.8% of cumulative shale gas production in the 2014–2050 period. More than 5,900 wells have been drilled, of which 5,345 are still producing. Rig count has dropped to zero in recent months and without more drilling the Fayetteville is in terminal decline. The Fayetteville, like the Barnett, is an example of a shale play at the end of its lifecycle.

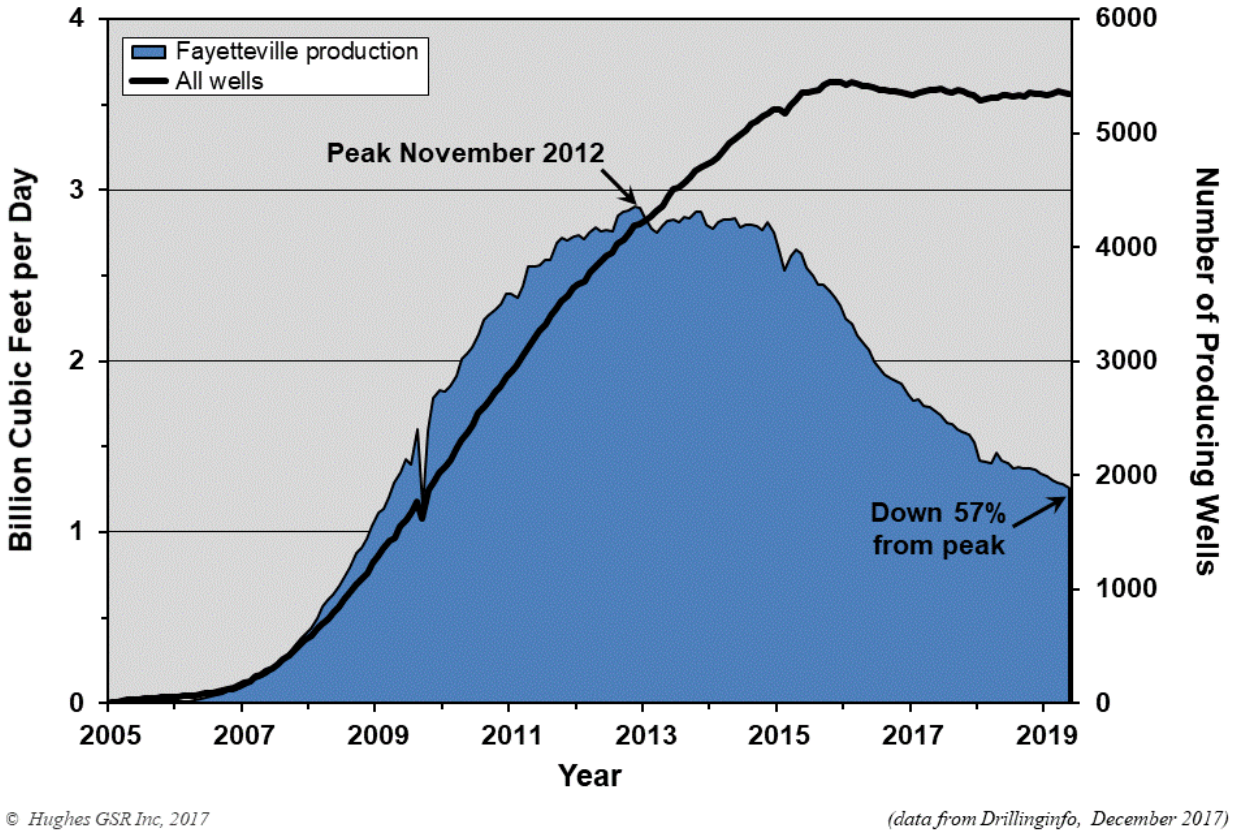


Figure 107. Fayetteville Play gas production and number of producing wells, 2005–2019.[159]

[159] Drillinginfo, September, 2019.

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.

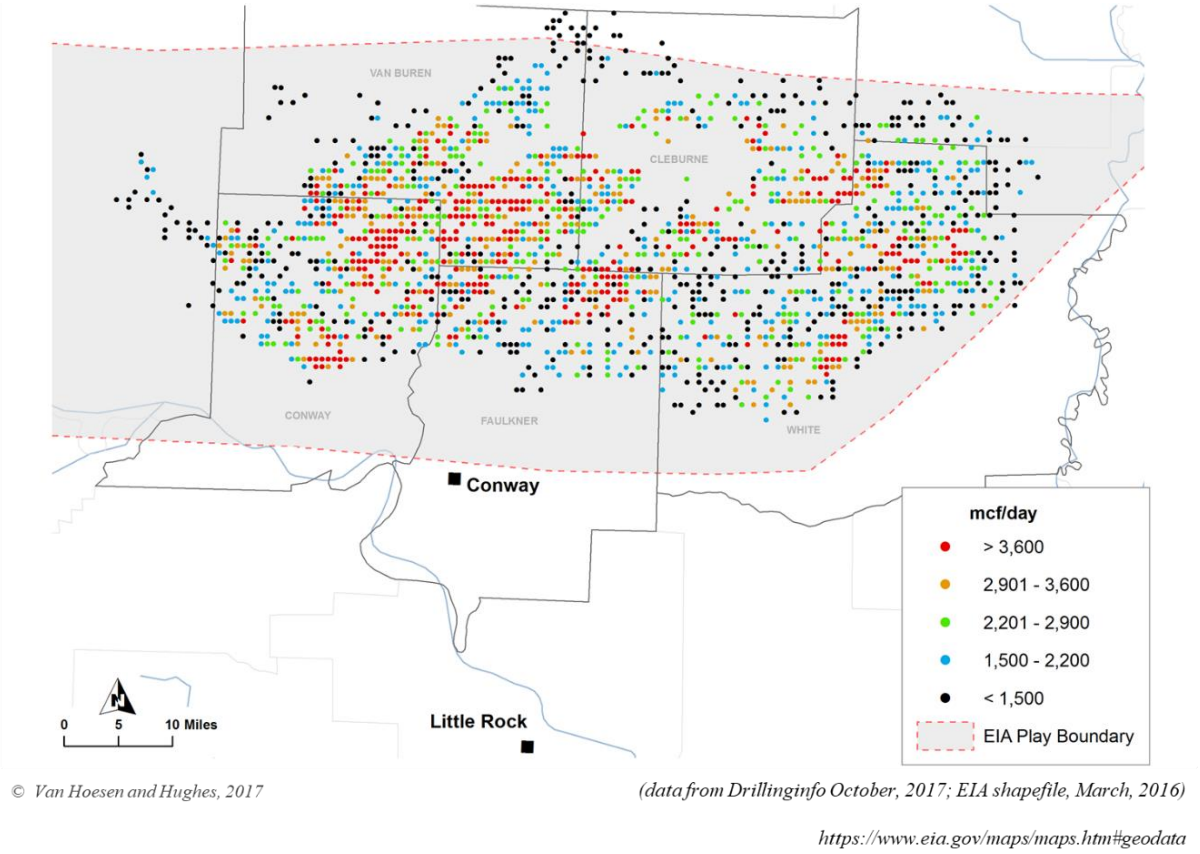


Figure 108. Fayetteville Play well locations showing peak gas production in the highest month.[160]

[160] 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 91% 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 exclusively produces gas with no associated liquids.

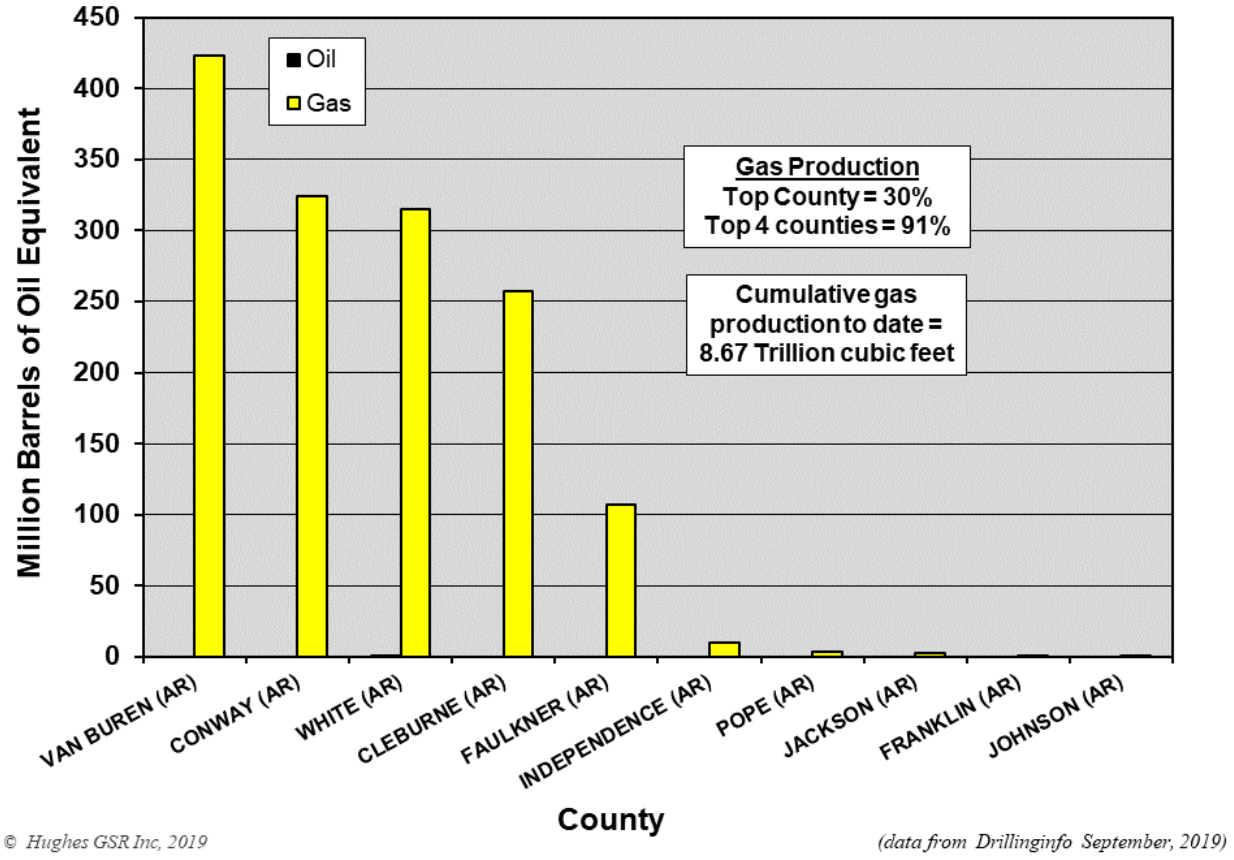


Figure 109. Cumulative production of oil and gas from the Fayetteville Play by county.

Production is concentrated in sweet spots, with 30% of cumulative gas production in Van Buren County and 91% in the top four counties.

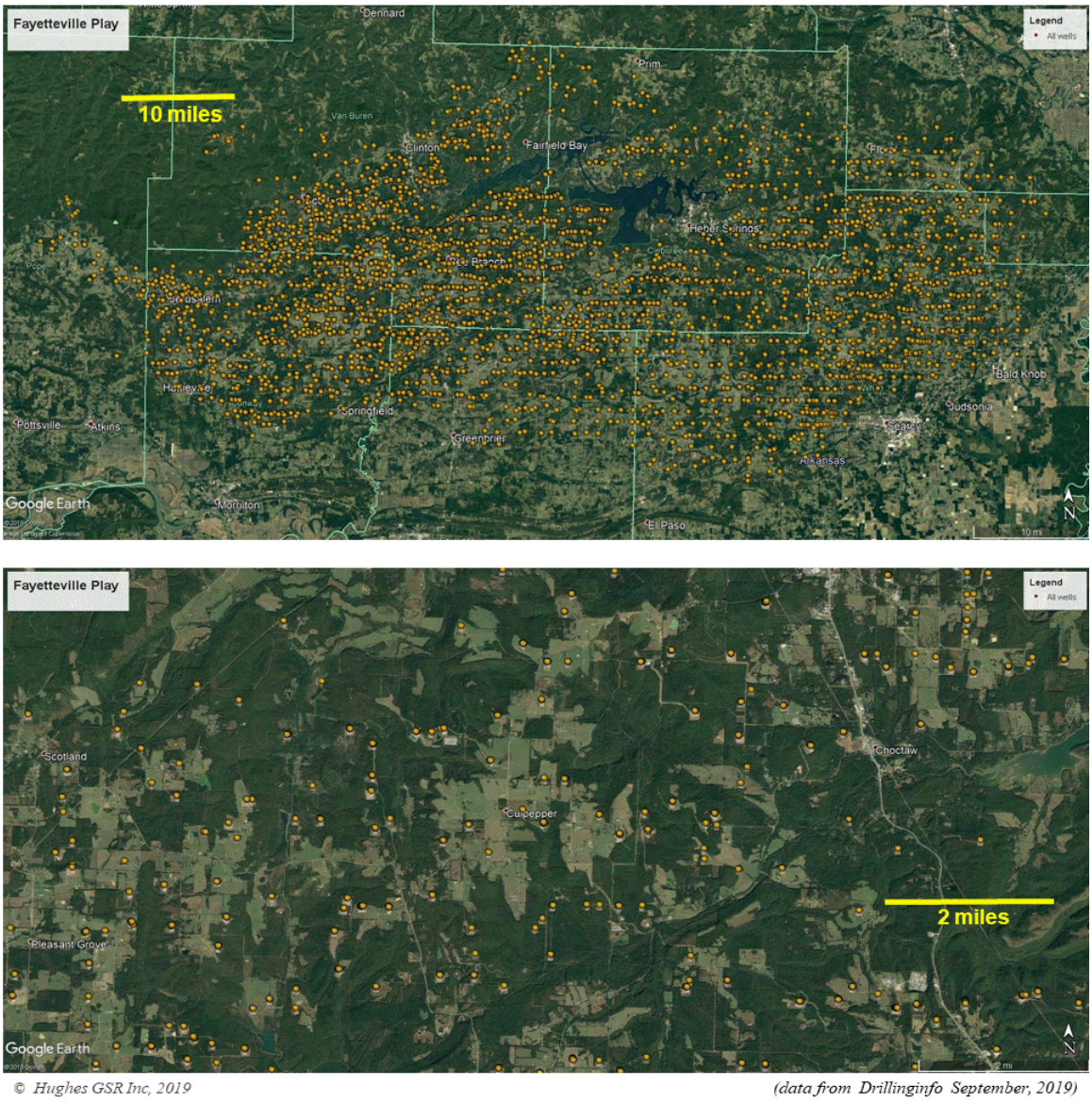
Table 24 shows the number of wells drilled, cumulative and current production, and well- and first-year field-decline rates for the Fayetteville as a whole and for individual counties. Three-year well decline rates average 82.1% and field decline rates average 12.2% per year without new drilling, which is in the medium range for shale plays analyzed in this report.

County	Well type	Vintage	Total Well Count	Producing Well Count	Cumulative Oil Production (billion bbls)	Cumulative Gas Production (tcf)	Oil Production May 2019 (Kbbls/day)	Gas Production May 2019 (bcf/day)	3-year well decline (%)	First-year Field decline (%)
All	All	All	5,906	5,345	0.000	8.668	0.00	1.26	82.1	12.2
Cleburne	All	All	1,109	1,077	0.000	1.546	0.00	0.28	81.2	14.8
Conway	All	All	1,229	1,082	0.000	1.945	0.00	0.28	81.1	13.2
Van Buren	All	All	1,630	1,451	0.000	2.541	0.00	0.32	82.6	7.4
White	All	All	1,303	1,229	0.000	1.890	0.00	0.26	81.9	12.1
Other counties	All	All	635	506	0.000	0,746	0.00	0,12	84.5	16,3

Table 24. Well count, cumulative production, most recent production, and well- and first-year field-decline rates for the Fayetteville Play and counties within it, by well type and vintage.[161]

[161] From Drillinginfo, September, 2019.

The degree of development of the Fayetteville core area to date is illustrated in Figure 110. Horizontal laterals averaged 6,793 feet in 2018, and have increased 49% in length since 2012.[162] Most well pads have multiple wells.



© Hughes GSR Inc, 2019 (data from Drillinginfo September, 2019)

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

Upper: Overview of Fayetteville Play drilling. Lower: Drilling density in the western core area of the play as of May 2019.[163]

[162] J.D. Hughes, 2019, *How long will the shale revolution last? Technology versus Geology and the Lifecycle of Shale Plays*, Post Carbon Institute, https://www.postcarbon.org/publications/how-long-will-the-shale-revolution-last/
[163] From Drillinginfo September, 2019

Figure 111 illustrates production from the top four counties compared to the overall play. All counties have peaked, beginning with White County in 2011 and ending with Cleburne County in 2014, such that the play as a whole peaked in November 2012. The top four counties make up 91% of cumulative production and accounted for 90% of production in May 2019.

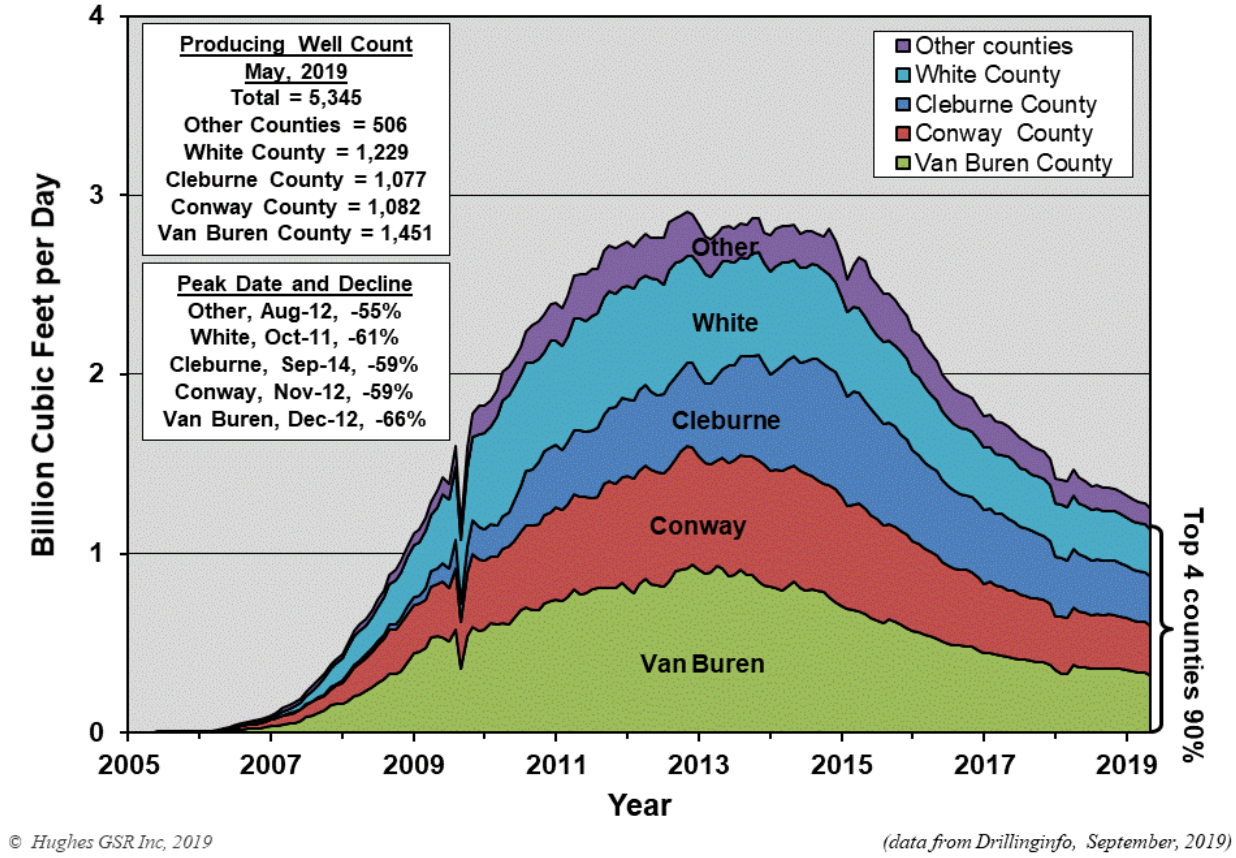


Figure 111. Gas production in the Fayetteville Play by county showing peak dates and percentage decline from peak.

Also shown are peak dates and percentage decline from peak of the four sweet-spot counties and collectively for counties outside of the top four.

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 2015, although there were too few wells drilled to have much confidence in 2017–2018 productivity data. Lack of drilling also precluded a productivity estimate for Van Buren County in 2016. Conway County, as well as counties outside of the top four, declined in 2017. This lack of drilling, even considering the relatively low well costs, suggests the Fayetteville is close to the saturation point in terms of wells and resultant economics. Without much higher gas prices, there will be little or no future drilling.

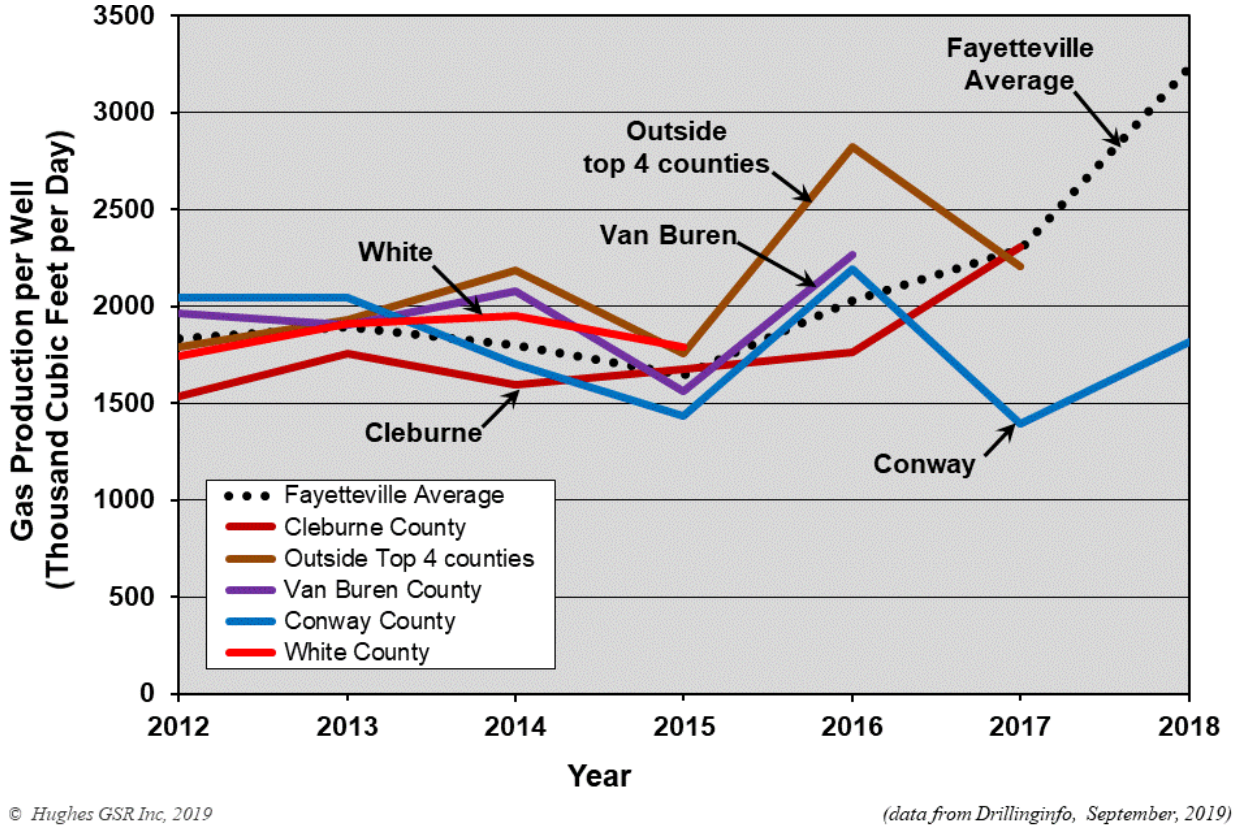


Figure 112. Average well productivity over the first six months of gas production by county in the Fayetteville Play, 2012–2018.

Note that the average for the play in 2018 is based on only two wells, hence is unreliable, and drilling had stopped in in Van Buren County in 2017 and some other counties in 2018.

Figure 113 illustrates the EIA's AEO2019 reference case production forecast for the Fayetteville Play through 2050, together with earlier forecasts. The EIA forecasts that the current decline will reverse beginning in 2028, and that production will rise to exit 2050 at 2.1 times the current production level. Although much higher prices and resultant higher drilling rates could temporarily reverse the current production decline, the play is nearly saturated with wells, making this forecast extremely unlikely. The EIA forecast would also require producing more gas over 2017-2050 (25.5 tcf) than the Bureau of Economic Geology's base case ultimate play recovery (18.2 tcf including production to date)[164]. Given the play fundamentals, the AEO2019 forecast must be rated as extremely optimistic.

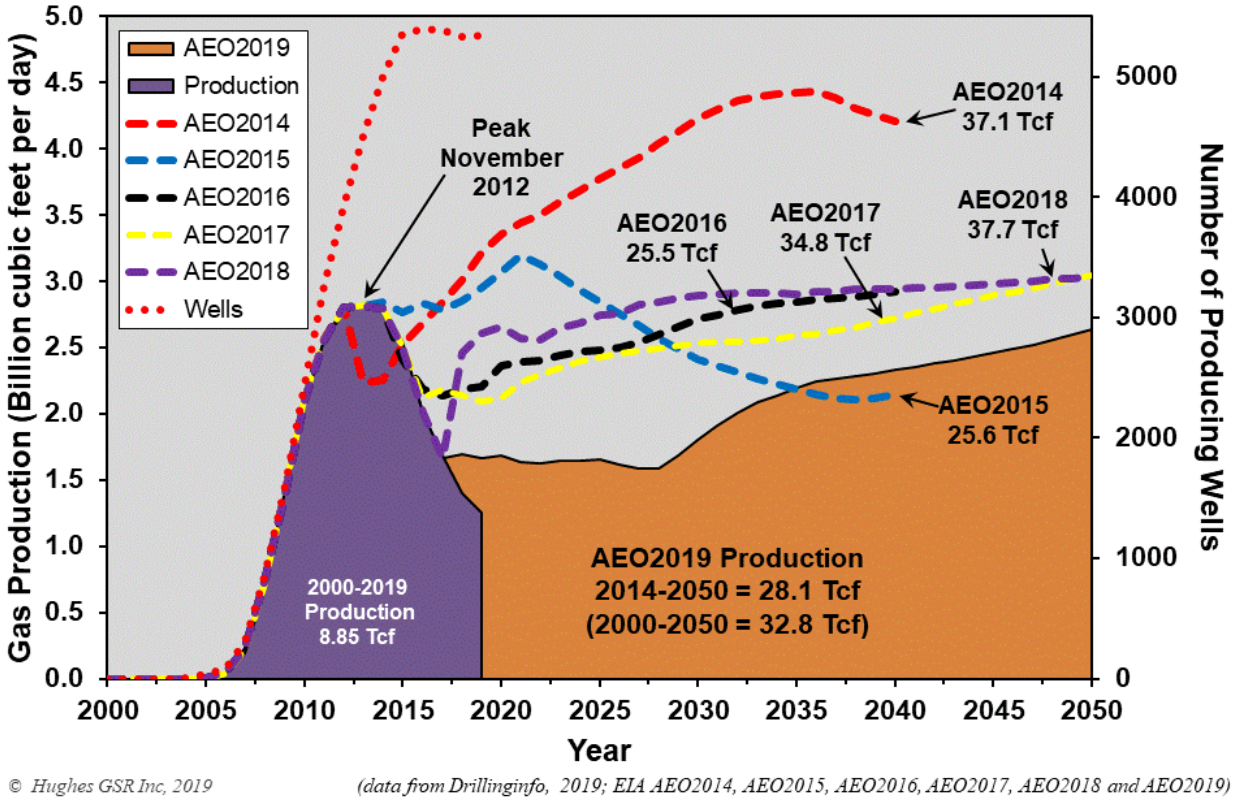


Figure 113. EIA AEO2019 reference case Fayetteville Play gas production forecast through 2050.

Also shown are earlier AEO forecasts to 2040 and 2050, and cumulative production from 2000-2019.

[164] 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 . The Bureau of Economic Geology's base case ultimate recovery is 18.2 tcf.

Table 25 illustrates assumptions in the EIA AEO2019 reference case forecast.[165] If realized, the EIA forecast would recover 57.5% of the EIA's estimate of proven reserves plus unproven resources by 2050. This would require 12,736 wells, for a well count of more than triple the current total, at a cost of $64 billion.

EIA AEO2019 Reference Case Forecast	
Proven Reserves year-end 2017 (tcf)[166]	7.1
Unproven Resources 2017 (tcf)[167]	37.2
Total Potential 2017 (tcf)	44.3
2017-2050 Recovery (tcf)	25.47
% of total potential used 2017-2050	57.5%
Wells needed 2017-2050	12,736
Well cost 2017-2050 ($billions)	$64

Table 25. EIA assumptions for Fayetteville Play gas in the AEO2019 reference case.

Well costs of $64 billion for full development are estimated assuming a well cost of $5 million each.[168] 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 (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 58% of its estimate of a total remaining potential of 44 tcf (as of 2017) will be recovered over 2017-2050. This corresponds to a play recovery by 2050 of 32.8 tcf (including production since 2000), which is nearly double the 18.2 tcf base case ultimate play recovery estimate of the Bureau of Economic Geology[169]. The EIA's forecast also exits 2050 at 2.1 times the current production level, implying vast additional resources remain to be recovered after 2050.
- The 12,736 wells required to recover the EIA's forecast through 2050, in addition to the 5,906 wells already drilled, would increase average well density in the prospective drilled area to 8.1 per square mile. Given that the average lateral length of 6,793 feet now exceeds one mile, the effective well density would be 10.5 wells 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 the play as a whole is down 57% from November, 2012. Assuming that production will grow to 2.1 times current levels by 2050 is extremely optimistic, even though the current production decline could be temporarily reversed with considerably higher drilling rates and higher prices to justify them.
- Given the above, the EIA AEO2019 forecast for the Fayetteville is rated as extremely optimistic.

[165] EIA, Unproved technically recoverable resources are from *Assumptions to the Annual Energy Outlook 2019*, https://www.eia.gov/outlooks/aeo/assumptions/; Proven reserves are from *U.S. Crude Oil and Natural Gas Proved Reserves, Yearend 2017*, https://www.eia.gov/naturalgas/crudeoilreserves/
[166] EIA, 2018, U.S. Crude Oil and Natural Gas Proved Reserves, Yearend 2017, https://www.eia.gov/naturalgas/crudeoilreserves/.
[167] EIA, 2019, Oil and Gas Supply Module for AEO2019, https://www.eia.gov/outlooks/aeo/assumptions/pdf/oilgas.pdf
[168] EIA, 2016, Trends in U.S. Oil and Natural Gas Upstream Costs, https://www.eia.gov/analysis/studies/drilling/pdf/upstream.pdf
[169] 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 4.2% of current U.S. shale gas production and is projected by the EIA to account for 4.2% of cumulative shale gas production over the 2014–2050 period. Production has grown rapidly, as illustrated in Figure 114. More than 5,800 wells have been drilled, of which 5,037 are still producing.

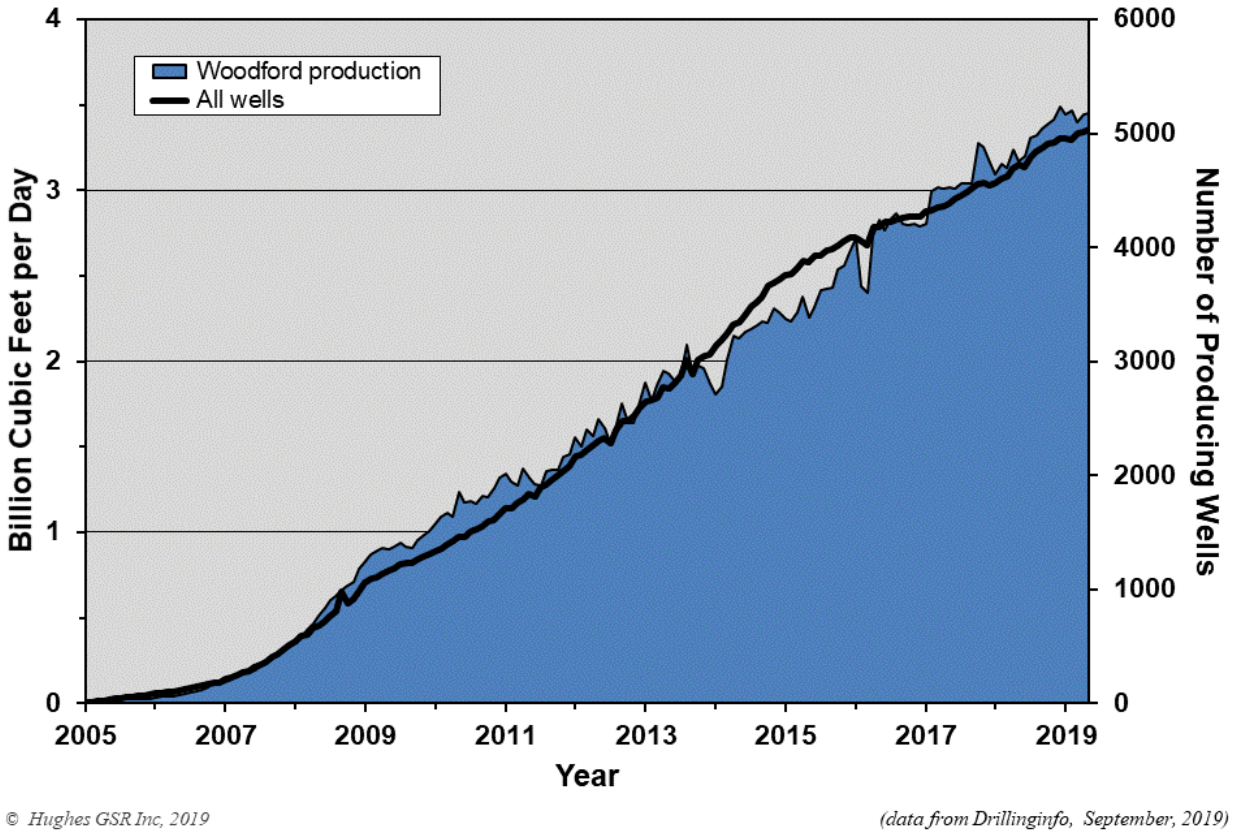
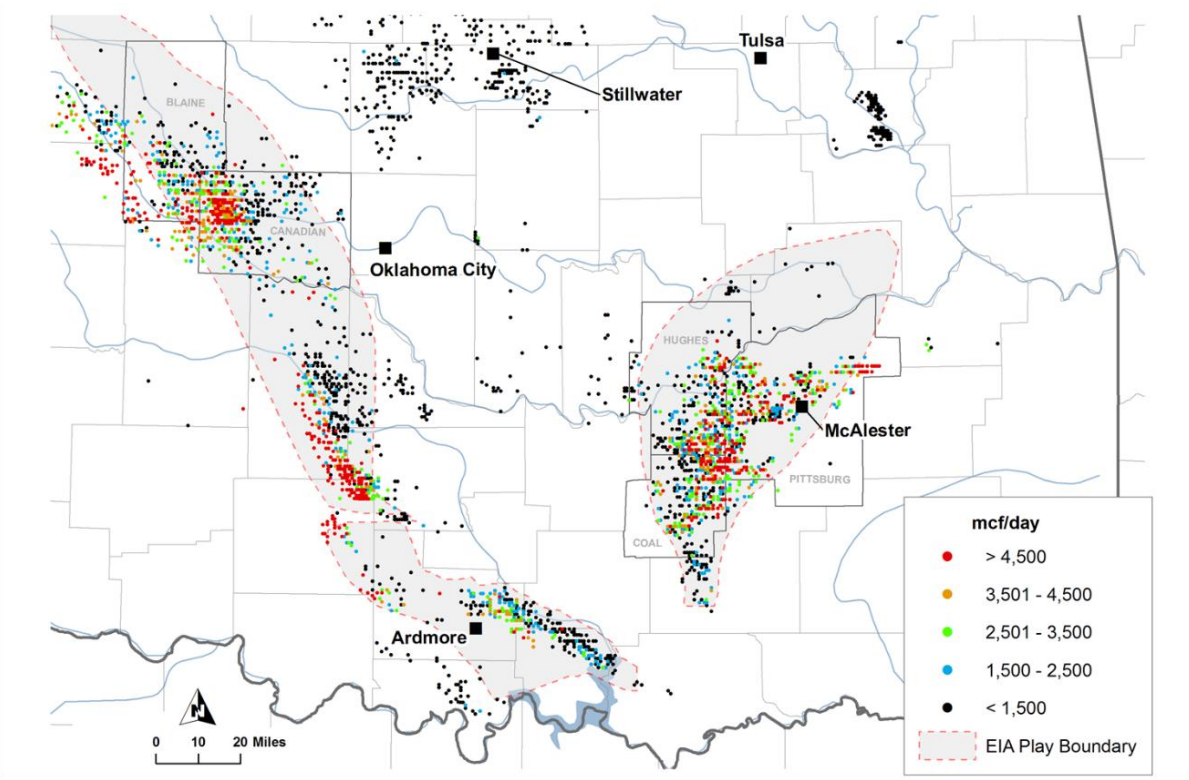


Figure 114. Woodford Play gas production and number of producing wells, 2005–2019.[170]

[170] Drillinginfo, September, 2019.

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.



© Van Hoesen and Hughes, 2017 (data from Drillinginfo October, 2017; EIA shapefile, March, 2016)

Figure 115. Woodford Play well locations showing peak gas production in the highest month.[171]

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

[171] 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-six percent of cumulative gas production has come from Pittsburg and Canadian counties, and 70% has come from the top five.

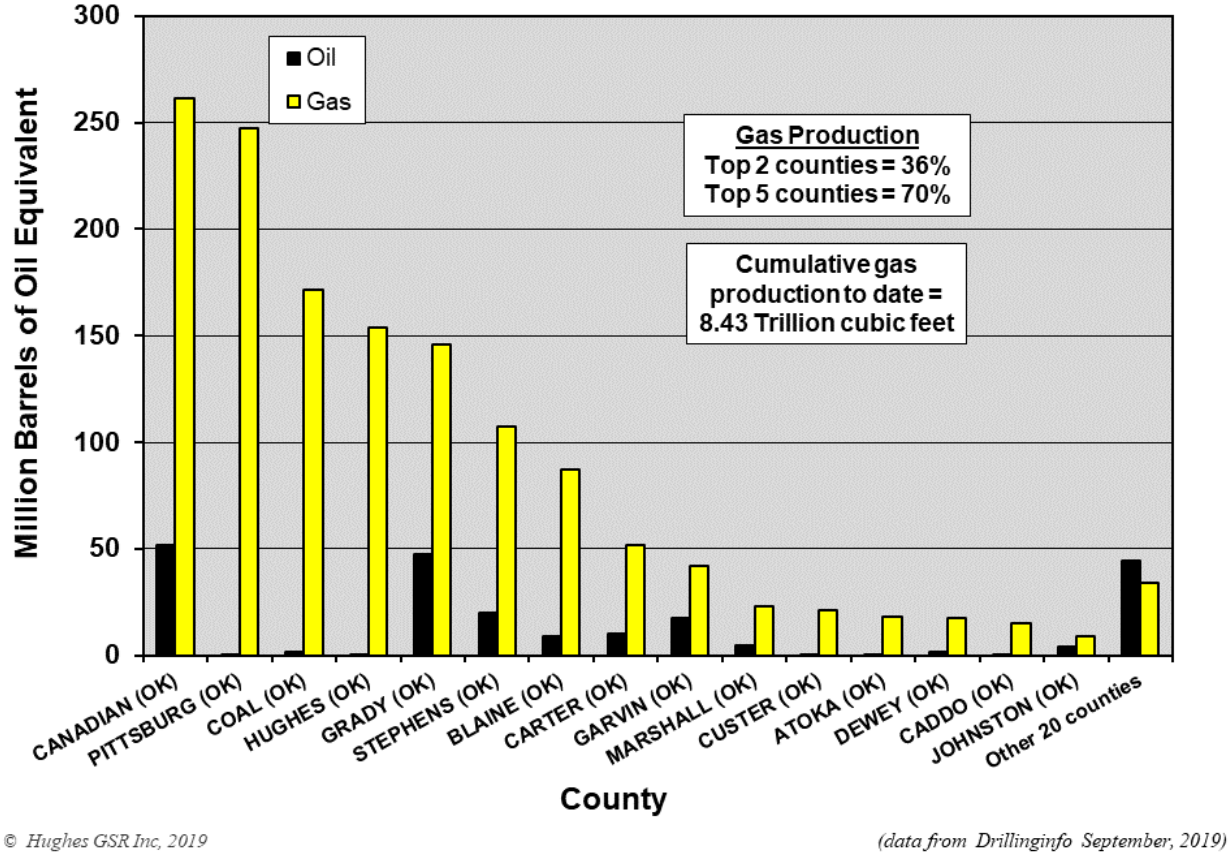


Figure 116. Cumulative production of oil and gas from the Woodford Play by county through 2019.

Production is concentrated in sweet spots, with 36% of cumulative gas production in the top two counties and 70% in the top five.

Table 26 shows the number of wells drilled, cumulative and current production, and well- and first-year field-decline rates for the Woodford as a whole and for individual counties. Three-year well decline rates average 74% and field decline rates average 25.4% per year without new drilling, which are both at the low end for shale plays analyzed in this report.

County	Well type	Vintage	Total Well Count	Producing Well Count	Cumulative Oil Production (billion bbls)	Cumulative Gas Production (tcf)	Oil Production May 2019 (Kbbls/day)	Gas Production May 2019 (bcf/day)	3-year well decline (%)	First-year field decline (%)
All	All	All	5,803	5,037	0.216	8.434	115.58	3.45	74.0	25.4
Pittsburg	All	All	697	647	0.0009	1.483	0.17	0.42	77.7	22.0
Canadian	All	All	882	850	0,052	1.567	21.80	0.54	64.1	21.7
Coal	All	All	549	507	0.002	1.030	0.35	0.21	75.3	20.1
Hughes	All	All	734	653	0.0005	0.924	0.43	0.33	81.4	25.2
Other counties	All	All	2,941	2,380	0.161	3.430	92.83	1.96	74.0	28.1

Table 26. Well count, cumulative production, most recent production, and well- and first-year field-decline rates for the Woodford Play and counties within it, by well type and vintage.[172]

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[172] From Drillinginfo September, 2019.

The degree of development in the Anadarko Basin core are of the Woodford to date is illustrated in Figure 117. Horizontal laterals have increased 60% in length since 2012 to 7,301 feet in 2018, although some recent wells have exceeded 10,000 feet[173]. Most well pads have multiple wells.

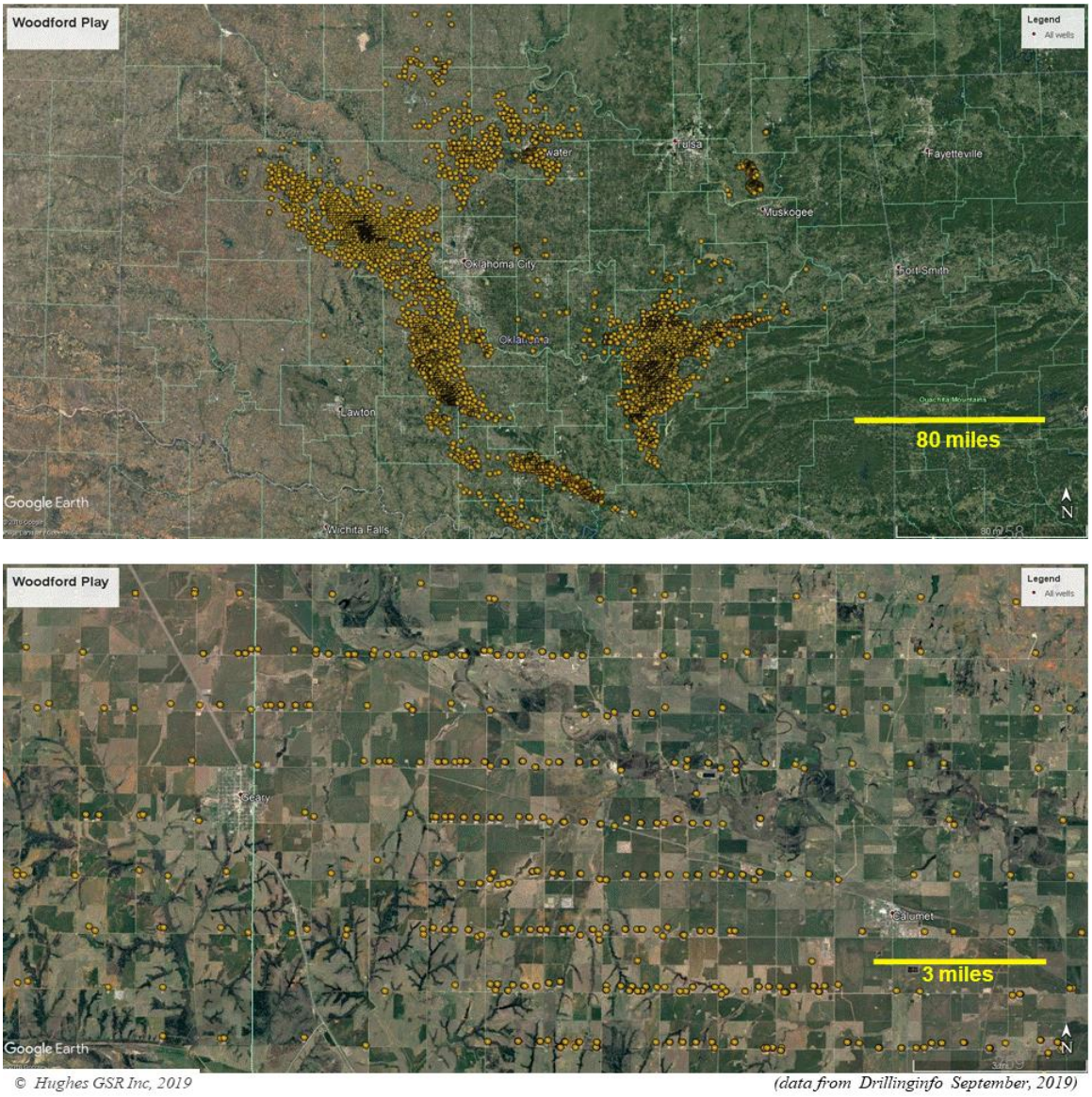

Figure 117. Drilling density in the core area of the Woodford Play.

Upper: Overview of drilling in Woodford Play. Lower: Drilling density in the core area of the play as of May 2019.[174]

[173] J.D. Hughes, 2019, *How long will the shale revolution last? Technology versus Geology and the Lifecycle of Shale Plays*, Post Carbon Institute, https://www.postcarbon.org/publications/how-long-will-the-shale-revolution-last/
[174] From Drillinginfo September, 2019.

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 59% of cumulative gas production and accounted for 43% of production in May 2019. All of the top four counties peaked in 2016 and 2017; hence production growth is from counties outside the top four, particularly those with liquids production (see Figure 116).

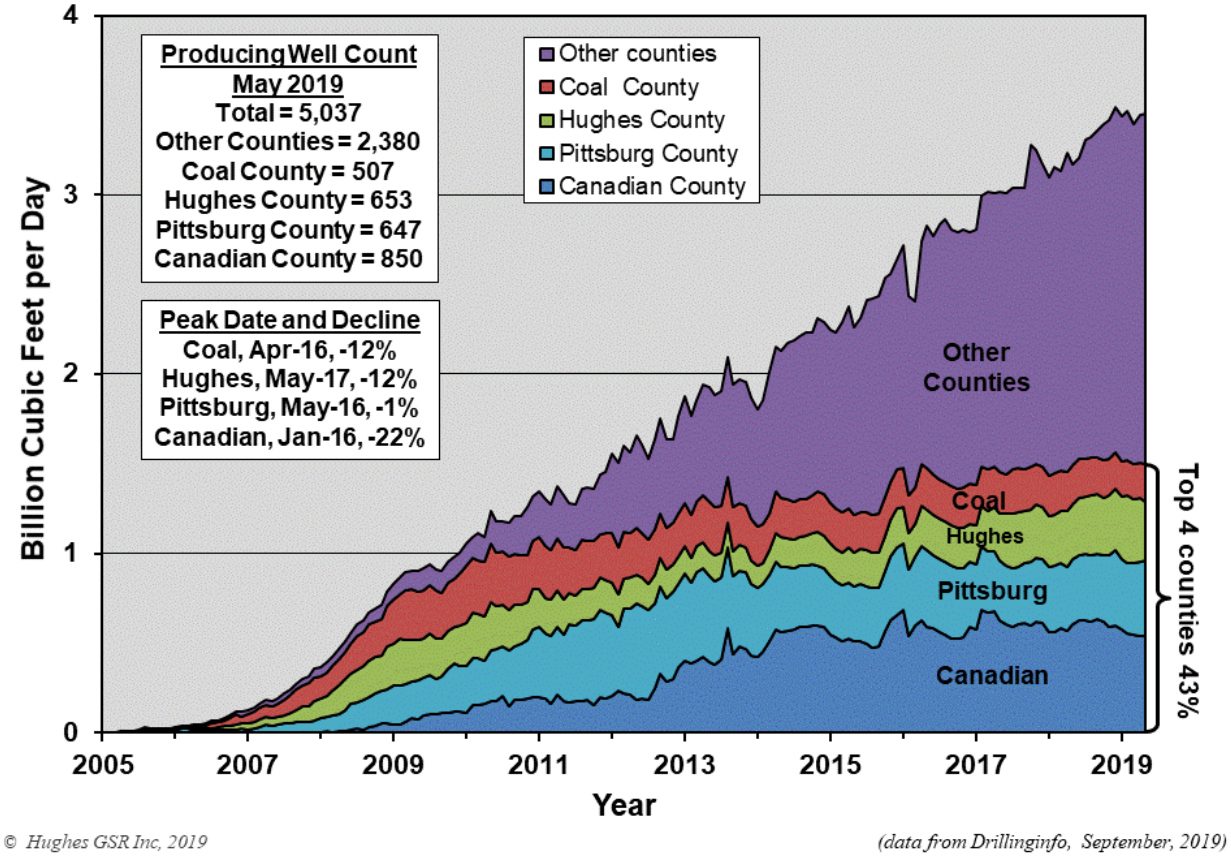

Figure 118. Gas production in the Woodford Play by county through May 2019, showing peak dates and percentage decline from peak for the four sweet spot counties.

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 from 2012 through 2017. Technology improvements include extending horizontal lateral length by 60% since 2012 to 7,301 feet in 2018, along with significantly increasing volumes of water and proppant injection and the number of frack stages. With the exception of Pittsburg County, however, all counties, and the play as a whole, experienced a decline in average well productivity in 2018. This suggests technology has reached the point of diminishing returns due to drilling lower quality rock, as sweet spots become saturated with wells, and spacing wells too close together in sweet spots, resulting in "frac hits" and well interference.

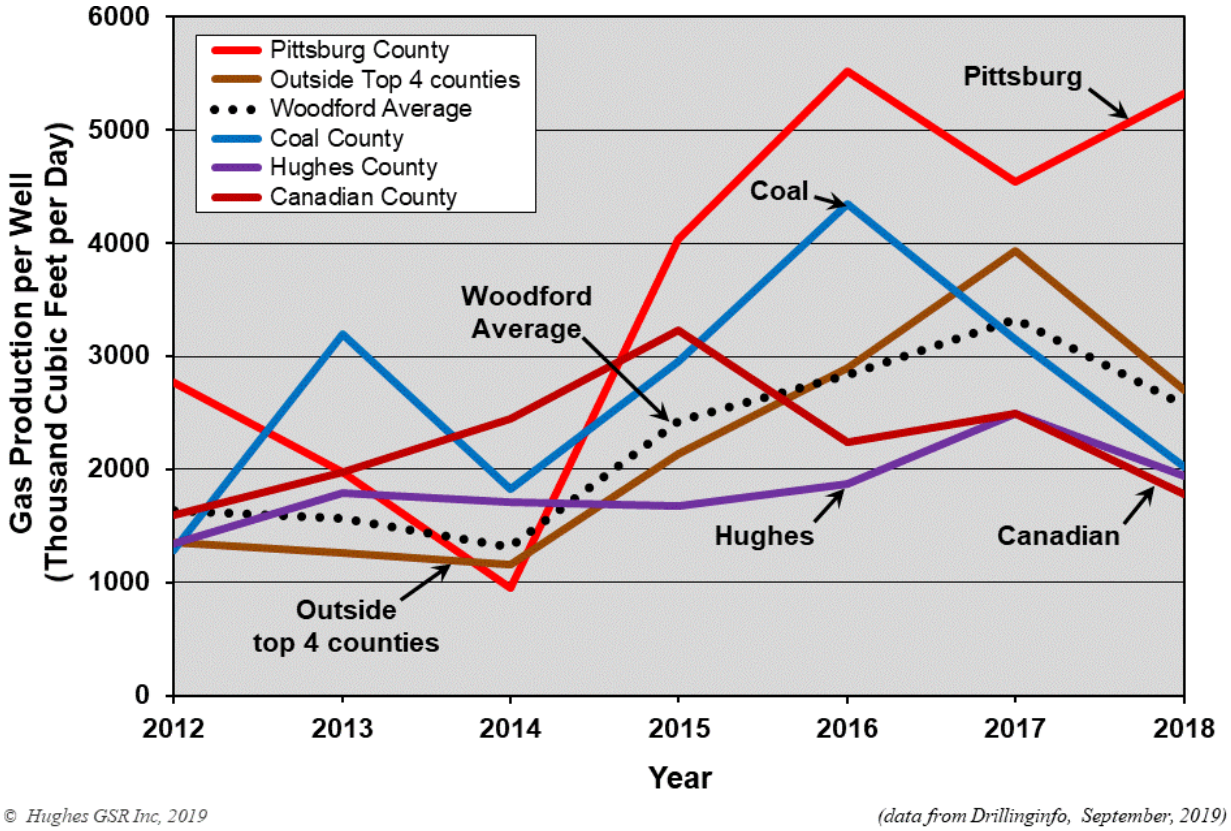

Figure 119. Average well productivity over the first six months of gas production by county in the Woodford Play, 2012–2018.

Figure 120 illustrates the EIA's AEO2019 reference case production forecast for the Woodford Play through 2050, together with earlier forecasts. The EIA forecasts production to remain roughly flat through 2035 before declining slightly to exit 2050 at 10% below current production levels. The EIA's forecast would consume 90% of the EIA's estimate of proven reserves plus unproven resources over 2017–2050. Exiting 2050 at 90% of current production implies that large resources will remain to be recovered after 2050. Although this is an aggressive forecast, it may be possible with high enough prices to justify the drilling rates required. However, given that the four top counties have already peaked, along with the decline in average well productivity observed in the play in 2018, the EIA AEO2019 forecast is be rated as moderately optimistic.

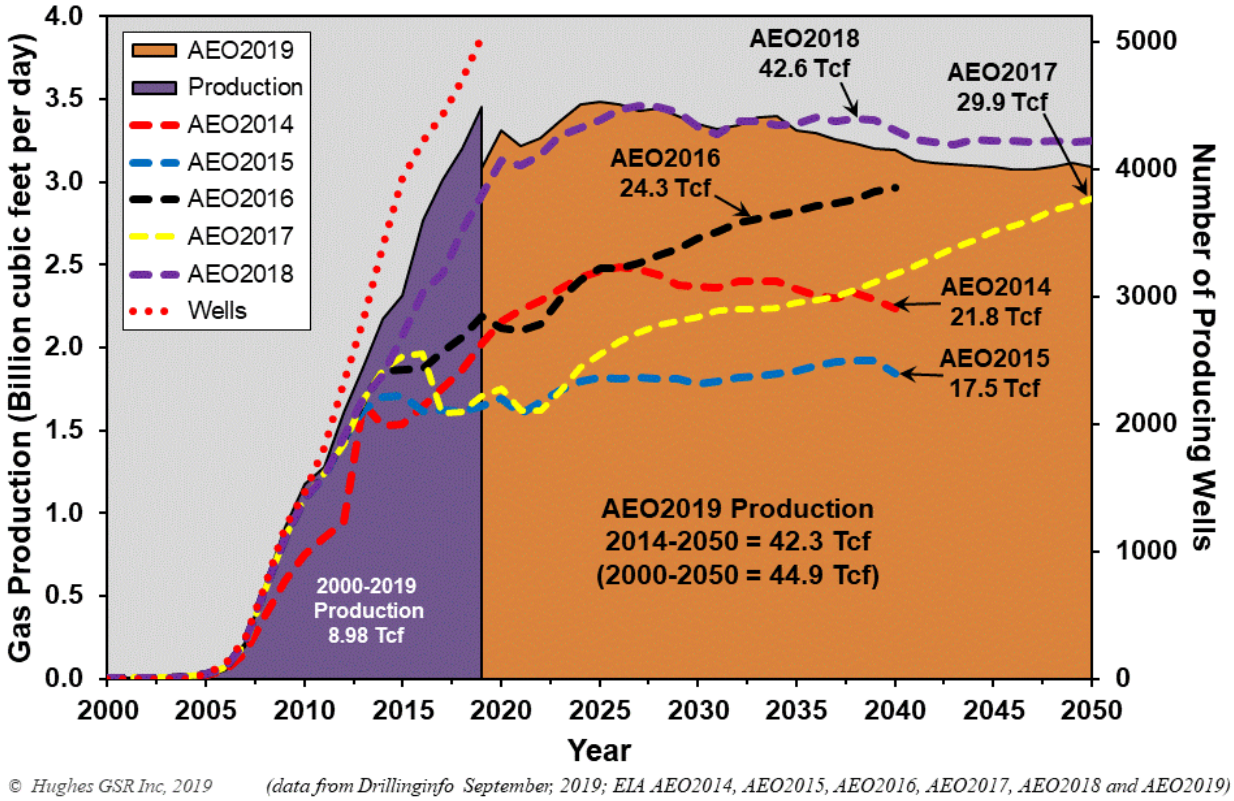

Figure 120. EIA AEO2019 reference case Woodford Play gas production forecast through 2050.

Also shown are earlier AEO forecasts to 2040 and 2050, and cumulative production from 2000-2019.

Table 27 illustrates assumptions in the EIA AEO2019 reference case forecast.[175] If realized, the EIA forecast would recover 90% of the EIA's estimate of proven reserves plus unproven resources by 2050. This would require 17,985 wells, for a well count of more than triple the current total, at a cost of $115 billion.

EIA AEO2019 Reference Case Forecast	
Proven Reserves year-end 2017 (tcf)[176]	22.5
Unproven Resources 2017 (tcf)[177]	21.8
Total Potential 2017 (tcf)	44.3
2017-2050 Recovery (tcf)	39.97
% of total potential used 2017-2050	90.2%
Wells needed 2017-2050	17,985
Well cost 2017-2050 ($billions)	$115

Table 27. EIA assumptions for Woodford Play gas in the AEO2019 reference case.

Well costs of $115 billion for full development are estimated assuming a well cost of $6.4 million each.[178] 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 moderately optimistic. Key points include:

- The EIA play area (7,445 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 forecasts that 90% of its estimated total remaining potential of 44 tcf (as of 2017) will be recovered by 2050. This corresponds to 4.7 times the cumulative production of the play since 2000.
- The top four counties peaked in 2015 and 2016, so potential growth will be outside of these particularly in liquids rich counties.
- The EIA forecasts that production will exit 2050 at 90% of current rates, implying that there are large additional resources remaining to be recovered after 2050.
- Three of the top four counties, along with the play as a whole, exhibited declines in well productivity in 2018. This indicates technology improvements may have reached a limit and/or that well over-crowding and drilling outside sweet spots is lowering productivity.
- Given the above, the EIA's AEO2019 forecast for the Woodford is rated as moderately optimistic.

[175] EIA, Unproved technically recoverable resources are from *Assumptions to the Annual Energy Outlook 2019*, https://www.eia.gov/outlooks/aeo/assumptions/; Proven reserves are from *U.S. Crude Oil and Natural Gas Proved Reserves, Yearend 2017*, https://www.eia.gov/naturalgas/crudeoilreserves/
[176] EIA, 2018, U.S. Crude Oil and Natural Gas Proved Reserves, Yearend 2017, https://www.eia.gov/naturalgas/crudeoilreserves/.
[177] EIA, 2019, Oil and Gas Supply Module for AEO2019, https://www.eia.gov/outlooks/aeo/assumptions/pdf/oilgas.pdf
[178] EIA, 2016, Trends in U.S. Oil and Natural Gas Upstream Costs, https://www.eia.gov/analysis/studies/drilling/pdf/upstream.pdf

4. Play Comparisons

Table 28 summarizes the assumptions of the EIA for its AEO2019 production forecasts by play and the optimism bias for each play based on the foregoing analysis. When the forecasts are reviewed on a play-by-play basis, nine out of the thirteen plays analyzed are rated as extremely optimistic, meaning they are extremely unlikely to be realized, three are rated as highly optimistic, and one is rated as moderately optimistic. Moreover, if it is assumed that no more resources can be recovered from a play than the sum of the EIA's estimates of proven reserves and unproven resources, the EIA's forecast is short nearly 10 billion barrels of oil from its required production through 2050. Notwithstanding this, the EIA forecasts that tight oil production will exit 2050 at considerably higher production levels than today, implying that vast unknown resources will remain to be recovered after 2050. The following section examines the number of wells and drilling and completion costs to meet the EIA's AEO2019 forecast, as well as an alternative scenario that would meet the required 2017-2050 production at lower cost.

Play	Proven Reserves		Unproven Resources		Total Potential		2017-2050 Recovery		% of total potential recovered		Optimism Bias
	Bbbls oil	Tcf gas	Bbbls oil	Tcf gas	Bbbls oil	Tcf gas	Bbbls oil	Tcf gas	Bbbls oil	Tcf gas	
Bakken	5.4	0.0	16.0	14.4	21.4	14.4	22.1	21.4	103%	149%	Extreme
Eagle Ford	4.8	27.4	13.2	54.7	18.0	82.1	19.1	61.5	106%	75%	Extreme
Permian: Spraberry	0.4	0.0	6.2	10.9	6.6	10.9	15.0	n/a	225%	n/a	Extreme
Permian: Wolfcamp	6.6	0.0	37.0	85.5	43.6	85.5	29.6	n/a	68%	n/a	High
Permian: Bone Spring	1.7	0.0	4.3	9.7	6.0	9.7	7.9	n/a	130%	n/a	Extreme
Austin Chalk	0.0	0.0	3.5	13.1	3.5	13.1	2.3	n/a	64%	n/a	Extreme
Niobrara	0.2	0.0	10.0	22.4	10.2	22.4	5.9	n/a	58%	n/a	High
Barnett	0.0	19.2	0.0	22.0	0.0	41.2	n/a	31.5	n/a	77%	Extreme
Haynesville	0.0	35.9	0.0	122.2	0.0	158.1	n/a	119.5	n/a	76%	High
Marcellus	0.3	123.8	0.8	262.5	1.1	386.3	n/a	326.0	n/a	84%	Extreme
Utica	0.0	26.5	1.6	193.9	1.6	220.4	1.8	152.8	n/a	69%	Extreme
Fayetteville	0.0	7.1	0.0	37.2	0.0	44.3	n/a	25.5	n/a	57%	Extreme
Woodford	0.4	22.5	0.8	21.8	1.2	44.3	1.45	40.0	n/a	90%	Moderate
Antrim	0.0	0.0	0.0	9.9	0.0	9.9	n/a	1.9	n/a	20%	Not evaluated
Other	0.0	45.5	18.9	399.8	18.9	445.3	8.6	182.6	45%	41%	Not evaluated
Total	**20.0**	**307.9**	**112.5**	**1280.0**	**132.5**	**1587.9**	**114.0**	**962.7**	**85%**	**61%**	**Moderate to Extreme**

Table 28. EIA AEO2019 reference case assumptions for all plays of proven reserves, unproven resources, total potential, and the amount of cumulative oil and gas production over 2017–2050.[179]

Also shown is the percentage of total potential forecasted 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 the AEO2019 forecast by play is provided: nine plays are rated as "extreme", three plays as "high", and one play as "moderate". ("n/a" refers to estimates that were not provided by the EIA. Bbbls = billion barrels. Tcf = trillion cubic feet.)

Although proven reserves have been demonstrated to be technologically and economically recoverable, unproven resources, which are the bulk of what is available to meet the 2017-2050 production forecast, are much less certain: they are thought to be technically recoverable but have not been demonstrated to be economically viable. 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

[179] EIA, Unproved technically recoverable resources are from *Assumptions to the Annual Energy Outlook 2019*, https://www.eia.gov/outlooks/aeo/assumptions/; proven reserves are from *U.S. Crude Oil and Natural Gas Proved Reserves, Yearend 2017*, https://www.eia.gov/naturalgas/crudeoilreserves/.

some cases over 100%—by 2050. Overall, the EIA's AEO2019 forecasts assume the recovery of 100% of proven reserves, 85% of unproven tight oil resources and 61% of unproven shale gas resources by 2050. Furthermore, most of these play-level forecasts 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 29 illustrates the number of wells and well costs to realize the AEO2019 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 89% of the AEO2019 forecast for tight oil and 91% for shale gas, 941,439 wells would be required at a cost of $6.37 trillion. To meet the "other" portion of the EIA's forecast, which is the remaining ten percent, 617,471 wells would be required at a cost of $4.63 trillion. This high cost is due to the low EURs assumed by the EIA for production outside of the major plays.

This compares to the EIA's estimate of a total of 1,247,058 wells to produce conventional and unconventional resources over the 2017-2050 period. Given that 73% of production over this period is forecast by the EIA to come from unconventional resources, conventional resources would require 333,944 wells, at a cost of $2 trillion, for a grand total of 1,892,854 wells at a cost of $13 trillion by 2050. As noted above, however, this leaves the EIA's forecast short by nearly 10 billion barrels of tight oil (tight oil is the constraining resource in the EIA forecasts as shale gas is sufficient).

Play	Total # of wells	Well cost (million)	Total well cost 2017-2050 (million)	% of cost of shale plays analyzed	% of cost of all plays
Bakken	105,058	$7.8	$819,452	12.87%	6.30%
Eagle Ford	112,123	$7.5	$840,920	13.21%	6.47%
Permian—Spraberry	42,748	$7.5	$320,612	5.04%	2.47%
Permian—Wolfcamp	175,841	$7.5	$1,318,809	20.71%	10.14%
Permian—Bone Spring	30,087	$7.5	$225,653	3.54%	1.74%
Austin Chalk	47,717	$7.5	$357,875	5.62%	2.75%
Niobrara	112,260	$5.0	$561,301	8.82%	4.32%
Barnett	56,925	$5.0	$284,626	4.47%	2.19%
Haynesville	14,461	$6.4	$92,549	1.45%	0.71%
Marcellus	124,767	$6.4	$798,508	12.54%	6.14%
Utica	88,731	$6.4	$567,879	8.92%	4.37%
Fayetteville	12,736	$5.0	$63,680	1.00%	0.49%
Woodford	17,985	$6.4	$115,107	1.81%	0.89%
Total of shale plays analyzed	**941,439**		**$6,366,969**	**100.00%**	**48.97%**
Other tight oil shale plays	617,471	$7.5	$4,631,029		35.62%
Total of all shale plays	**1,558,910**		**$10,997,999**		**84.59%**
Lower-48 conventional plays estimated from EIA	333,944	$6.0	$2,003,663		15.41%
Total wells needed	**1,892,854**		**$13,001,661**		**100.00%**

Table 29. Number of wells required by play and well costs, assuming EIA AEO2019 play-level production assumptions and well EURs.

Also shown are the percentage of total expenditures required by play for the major plays analyzed in this report, and EIA AEO2019 overall assumptions for all drilling for both conventional and unconventional resources. Well costs are from EIA estimates[180].

[180] EIA, 2016, Trends in U.S. Oil and Natural Gas Upstream Costs, https://www.eia.gov/analysis/studies/drilling/pdf/upstream.pdf

Figure 121 illustrates production by play for the EIA AEO2019 forecast. As noted above, gas supply is not a constraint to meeting the EIA gas production forecast, given that most tight oil plays produce significant amounts of associated gas.

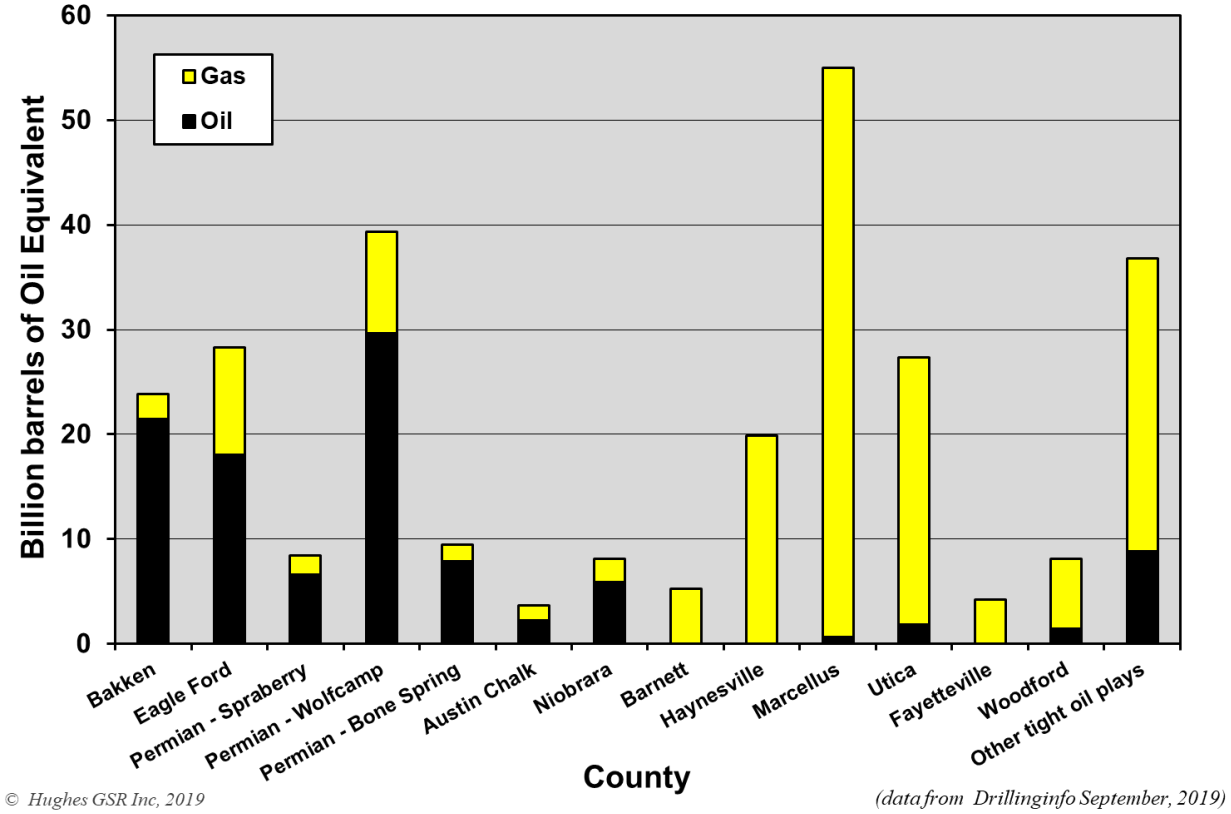

Figure 121. EIA AEO2019 reference case production forecast of oil and gas by play over 2017-2050.

Figure 122 illustrates the cost of extraction, considering well drilling and completion costs only (as illustrated in Table 29), given the EIA AEO2019 production forecast and assuming EIA estimates of well EUR[181]. The viability of the Permian Basin, Bakken, and Eagle Ford compared to the Austin Chalk and Niobrara is clearly evident. The viability of the major shale gas plays is also evident, however, as gas sells for only about a third of the price of oil on an energy equivalent basis. Thus a large proportion of exploration and development is directed to oil.

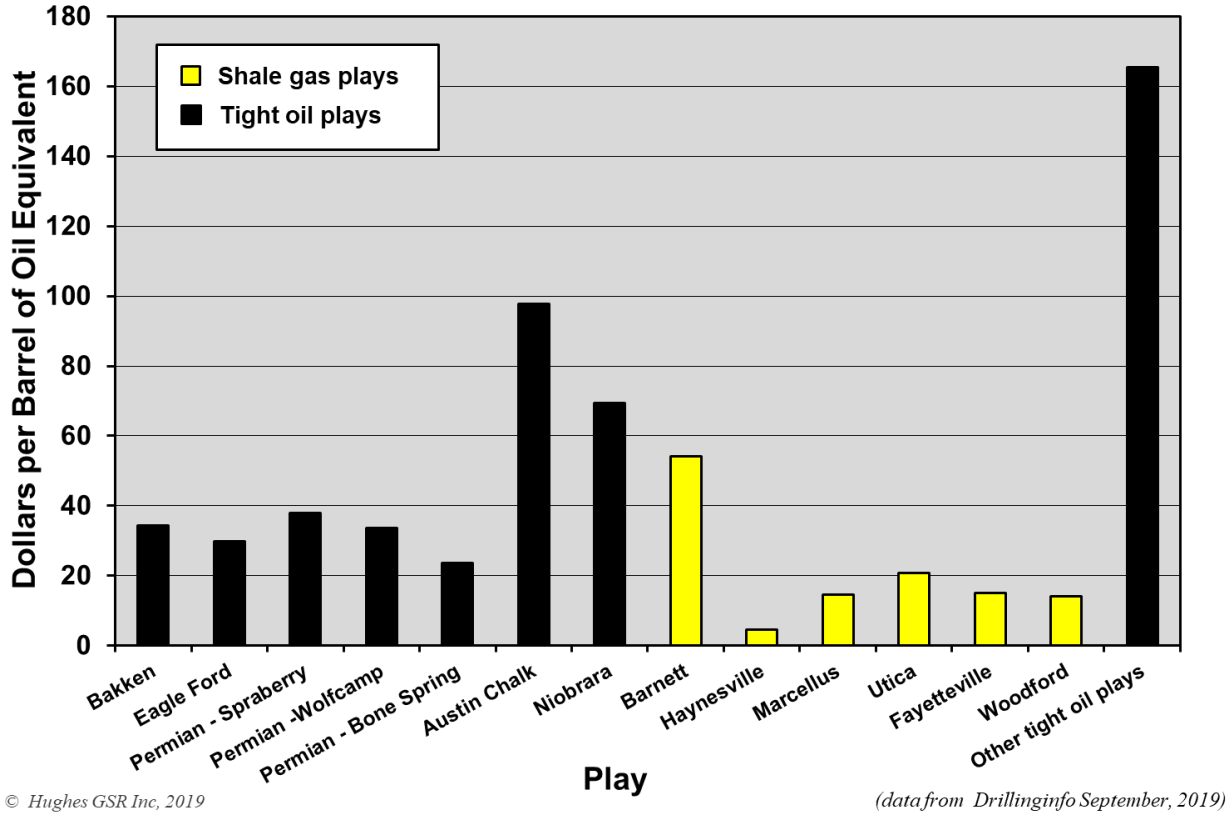

Figure 122. Drilling and completion costs for EIA AEO2019 reference case production forecast of oil and gas by play over 2017-2050 (dollars per barrel of oil equivalent).

Due to the low EUR's assumed by the EIA for unproven resources in "other" plays, recovering oil and gas from them costs over $160 per barrel of oil equivalent (BOE), and over $520 per barrel for oil only. This is uneconomic in any pricing scenario included in AEO2019. And as mentioned earlier, several plays in the EIA's forecast are projected to produce more oil and gas than the sum of the EIA's estimates of proven reserves and unproven resources, which leaves insufficient production to meet the EIA's reference case forecast.

[181] EIA, 2019, *Assumptions to the Annual Energy Outlook 2019*, https://www.eia.gov/outlooks/aeo/assumptions/

It is highly unlikely that producers would pursue oil at a cost exceeding $520 per barrel when lower cost resources remain in the major shale plays. A review of Table 28 reveals that, after recovering the EIA's production forecast through 2050, there remains sufficient unproven resources in the Wolfcamp and Niobrara plays to provide lower cost production to meet the EIA's production forecast. ***However, this would consume all of the EIA's estimated proven reserves and unproven tight oil resources in major shale plays in the lower-48 by 2050.*** Table 30 illustrates this scenario, in which case the total wells needed over 2017-2050 are reduced to 1,451,771 wells at a cost of $9.49 trillion, a reduction of nearly $4 trillion from the EIA's forecast with a well count only 16% higher that the EIA's estimate. However, even accepting the EIA's extremely optimistic play-level forecasts, this scenario would leave the U.S. with no tight oil after 2050, in contrast to the EIA forecasts of abundance.

Play	Total # of wells	Well cost (million)	Total well cost 2017-2050 (million)	% of cost of shale plays analyzed	% of cost of all plays
Bakken	105,058	$7.8	$819,452	10.95%	8.64%
Eagle Ford	112,123	$7.5	$840,920	11.24%	8.87%
Permian—Spraberry	42,748	$7.5	$320,612	4.29%	3.38%
Permian—Wolfcamp	268,949	$7.5	$2,017,116	26.96%	21.27%
Permian—Bone Spring	30,087	$7.5	$225,653	3.02%	2.38%
Austin Chalk	47,717	$7.5	$357,875	4.78%	3.77%
Niobrara	195,541	$5.0	$977,703	13.07%	10.31%
Barnett	56,925	$5.0	$284,626	3.80%	3.00%
Haynesville	14,461	$6.4	$92,549	1.24%	0.98%
Marcellus	124,767	$6.4	$798,508	10.67%	8.42%
Utica	88,731	$6.4	$567,879	7.59%	5.99%
Fayetteville	12,736	$5.0	$63,680	0.85%	0.67%
Woodford	17,985	$6.4	$115,107	1.54%	1.21%
Total of shale plays analyzed	**1,117,827**		**$7,481,679**	**100.00%**	**78.88%**
Other tight oil shale plays	0	$7.5	$0		0.00%
Total of all shale plays	**1,117,827**		**$7,481,679**		**78.88%**
Lower-48 conventional plays estimated from EIA	333,944	$6.0	$2,003,663		21.12%
Total wells needed	**1,451,771**		**$9,485,341**		**100.00%**

Table 30. Number of wells required by play and well costs assuming that remaining low-cost resources in major plays will be produced instead of consuming resources in very high-cost "other" plays (per Table 29). EIA AEO2019 play-level production assumptions and well EURs are assumed.

Also shown are the percentage of expenditures required for the major plays analyzed in this report, and EIA AEO2019 overall assumptions for all drilling including conventional and unconventional. Well costs are from EIA estimates[182].

The best-case scenario to meet the EIA AEO2019 reference case requires drilling 1,451,771 wells at a cost of $9.49 trillion over 2017-2050. Given the extremely optimistic nature of most of the EIA's play-level forecasts, it is by no means assured that this much oil and gas could be produced even if the EIA's estimates of proven reserves and unproven resources prove to be correct. The fact that all U.S. tight oil resources would be consumed by 2050, even if the EIA estimates are proven correct, should be extremely troubling for long term policy development. Assuming that production will remain at high levels after 2050 is, based on the play fundamentals analyzed in this report, wishful thinking.

[182] EIA, 2016, Trends in U.S. Oil and Natural Gas Upstream Costs, https://www.eia.gov/analysis/studies/drilling/pdf/upstream.pdf

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 more than double from its 2005 lows, and shale gas has more than doubled 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 first-year field declines without new drilling typically range from 25-50% per year. High rates of capital investment in new drilling are therefore required to avoid steep production declines. Older plays like the Barnett and Fayetteville, which are close to saturated with wells and where drilling has nearly ceased, have declined 50% or more from peak production levels of a few years ago. 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 that provide the most economically viable wells. Sweet spots will inevitably become saturated with wells, and drilling outside of sweet spots will require higher rates of drilling and capital investment to maintain production, along with higher commodity prices to justify them.

This review of play-level production data for major U.S. shale plays finds that EIA production forecasts through 2050 are extremely optimistic for the most part, 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 forecasts 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.

This 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 AEO2019 reference case forecasts for each play, and determined the number of wells and capital investment required to meet production forecasts. Key findings include:

- Of the 13 shale plays analyzed, nine were rated as extremely optimistic, three highly optimistic and one moderately optimistic.
- In some cases, EIA play-level production forecasts through 2050 exceed EIA estimates of proven reserves plus unproven resources, and all plays are forecast to recover all proven reserves and a high percentage of unproven resources by 2050.
- In most cases, forecasts exit 2050 at high production levels, often significantly higher than current production rates, implying that vast additional resources would remain after 2050.
- Oil is the most sought-after resource given that it sells for three times the price of gas on an energy equivalent basis. More than 70% of capital investment and drilling is directed at tight oil plays.
- The EIA's reference case cannot deliver its forecast production requirement by 2050 if production from plays is limited to the EIA's estimated proven reserves plus unproven resources. The overall forecast falls short by nearly ten billion barrels of oil, or 10% of the required production volume.
- Well drilling and completion costs using the EIA's estimated ultimate recovery (EUR) of wells is less than $50 per barrel in the Bakken, Eagle Ford, and Permian Basin plays, and is less than $40 per barrel on an oil equivalent (BOE) basis (as these plays also produce large amounts of associated gas). Costs are much higher in plays like the Niobrara and Austin Chalk, and exceed $500 per barrel for oil in the EIA's "other" play category (and more than $160 on a BOE basis).
- Given the EIA's forecast of requiring production from "other" plays outside of the major plays analyzed in this report, 1,558,910 additional wells would be required for shale plays over 2017–2050 at a cost of $11 trillion, due to the low estimated ultimate recovery (EUR) of wells outside of major plays. If wells required for conventional on- and off-shore production are included, a total of 1,892,854 additional wells would be needed by 2050 to meet the forecast, at an overall cost of $13 trillion.

- An alternative to the EIA's forecast of significant production from its high cost, low productivity, "other" plays, would be to make up the required production from the Permian Basin Wolfcamp Play and the Denver-Julesburg Basin Niobrara Play. ***However, doing so would totally exhaust all of the EIA's estimated proven reserves and unproven resources of tight oil in major plays by 2050, leaving nothing for later***. This would reduce the well requirement for shale plays to 1,117,827 additional wells over 2017-2050 at a cost of $7.5 trillion. Coupled with required conventional on- and off-shore wells, a total of ***1,451,771 new wells would be needed to meet the forecast, for a total expenditure of $9.5 trillion*** (this is 16% higher than the 1,247,058 new wells estimated by the EIA).

- Well productivity has increased in most plays through focusing on sweet spots and due to longer horizontal laterals and increased volumes of water and proppant, as well as more fracking stages. The limits of technology and exploiting sweet spots are becoming evident, however, as in some plays new wells are exhibiting lower productivities.

Although 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 are a disservice to planning a viable long-term energy strategy. The best-case scenario to meet the EIA AEO2019 reference case forecast requires drilling 1,451,771 wells at a cost of $9.5 trillion over the 2017-2050 period.

The fact that all U.S. tight oil resources would be consumed by 2050 in this best-case scenario, assuming that the EIA estimates of proven reserves plus unproved resources are correct, should be extremely troubling for long term energy security planning and policy development. And given the extremely optimistic nature of most of the EIA's play-level forecasts, it is by no means assured that even this much oil and gas can be produced. Assuming that production will remain at high levels after 2050 is wishful thinking.

The "shale revolution" has sparked calls for "American energy dominance"[183]—despite the fact that the U.S. is projected to be a net oil importer through 2050, even given EIA forecasts. Although the "shale revolution" has provided a reprieve from what just 15 years ago was thought to be a terminal decline in oil and gas production in the U.S., 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. That is without factoring in any mandates to reduce greenhouse gas emissions or the economics of renewable energy sources. If U.S. energy policy actually reflected the need to mitigate climate change—which the international community mandated in 2016 through the Paris Agreement[184]—the EIA's forecasts for tight oil and shale gas production through 2050 make even less sense.

[183] Time, June 29, 2017, *President Trump Says He Wants 'Energy Dominance.' What Does He Mean?* http://time.com/4839884/energy-dominance-energy-independence-donald-trump/

[184] United Nations Framework Convention on Climate Change, https://unfccc.int/process-and-meetings#:a0659cbd-3b30-4c05-a4f9-268f16e5dd6b