EAGLE FORD REALITY CHECK

THE NATION'S TOP TIGHT OIL PLAY AFTER MORE THAN A YEAR OF LOW OIL PRICES

J. DAVID HUGHES

post carbon institute

FALL 2015

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About the Author

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

Over the past decade, Hughes has researched, published and lectured widely on global energy and sustainability issues in North America and internationally. His work with Post Carbon Institute includes: a series of papers (2011) on the challenges of natural gas being a "bridge fuel" from coal to renewables; *Drill, Baby, Drill* (2013), which took a far-ranging look at the prospects for various unconventional fuels in the United States; *Drilling California* (2013), which critically examined the U.S. Energy Information Administration's (EIA) estimates of technically recoverable tight oil in the Monterey Shale, which the EIA claimed constituted two-thirds of U.S. tight oil (the EIA subsequently wrote down its resource estimate for the Monterey by 96%); *Drilling Deeper* (2014), which challenged the U.S. Department of Energy's expectation of long-term domestic oil and natural gas abundance with an in-depth assessment of all drilling and production data from the major shale plays through mid-2014; and *Shale Gas Reality Check* (2015), *Tight Oil Reality Check* (2015) and *Bakken Reality Check* (2015), updates to *Drilling Deeper*. 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.

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

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Eagle Ford Reality Check: The Nation's Top Tight Oil Play After A Year Of Low Oil Prices
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In association with Post Carbon Institute
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1 Eagle Ford Production Overview

Oil production in the Eagle Ford Play of southern Texas, the largest tight oil play in the U.S., is now falling after more than a year of low oil prices—but it has proven more resilient than many observers expected. This paper reviews the latest developments in the Eagle Ford Play and provides an update of the assessment in my *Drilling Deeper* report,[1] which was published in October 2014 just as the turmoil in the oil markets began.

Figure 1 illustrates Eagle Ford production through July 2015. Production peaked in March 2015, at 1.61 million barrels per day (mbd) and has fallen 149,000 barrels per day, or 9.1%, since then. As of July there were 13,930 producing wells in the play, compared to 13,384 in March 2015 at peak production (production data in this paper are from Drillinginfo[2]).

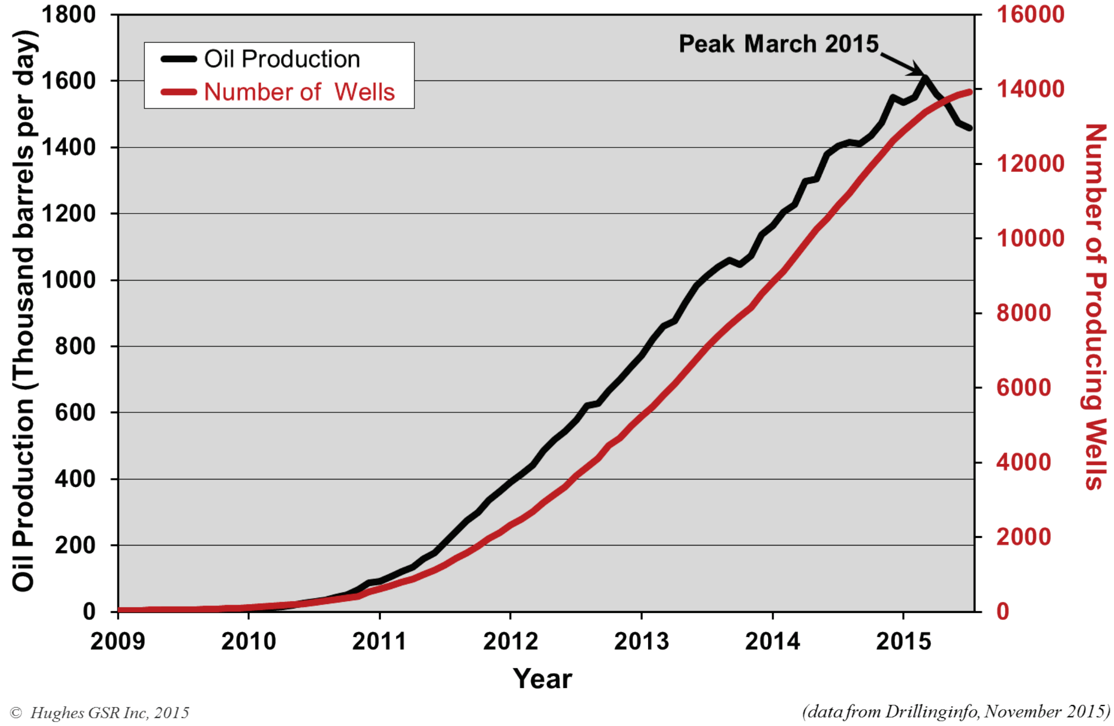


Figure 1. Oil production and producing well count in the Eagle Ford Play from 2009 through July 2015.

[1] David Hughes, *Drilling Deeper: A Reality Check on U.S. Government Forecasts for a Lasting Tight Oil & Shale Gas Boom* (Santa Rosa, CA: Post Carbon Institute, 2014); http://shalebubble.org.

[2] Drillinginfo data for Texas includes pending data that have not yet been fully processed by the Texas Railroad Commission, hence is more complete for recent months than production data published by the Texas Railroad Commission.

The Eagle Ford Play is also a prolific shale gas producer, ranked second only to the Marcellus, and accounts for nearly 12% of U.S. shale gas production. Figure 2 illustrates gas production in the Eagle Ford through July 2015 in comparison to oil production. Although gas production also peaked in March 2015, at 6 billion cubic feet per day (bcf/d), it has declined much less than oil since then.

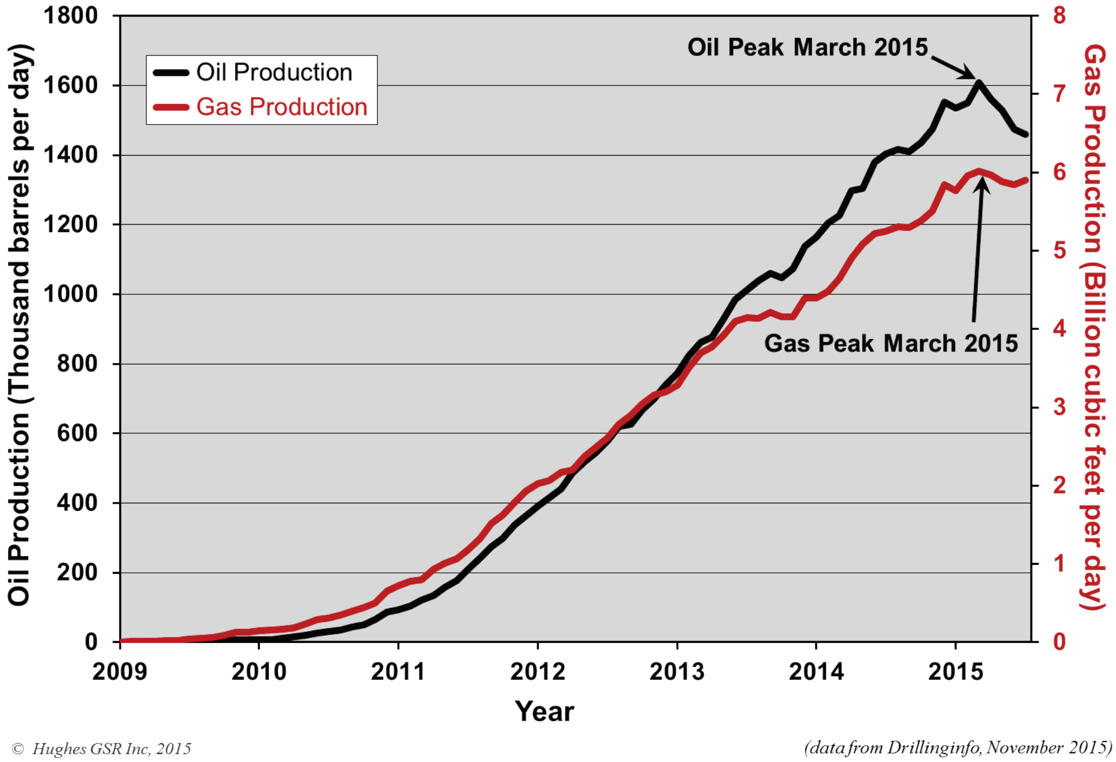


Figure 2. Gas production relative to oil production in the Eagle Ford Play from 2009 through July 2015.

More than 80% of the Eagle Ford's cumulative oil production has come from 6 of 31 counties, and half has come from three: Karnes, Dewitt and Lasalle (Figure 3). Oil production is concentrated in the up-dip "oil window", along the northwestern edge of the play, whereas gas production is concentrated in the down-dip "gas window", hence distribution of oil and gas production depends on which window a county is overlying. Webb County, for example, has produced 29% of the play's cumulative gas production yet just 4% of cumulative oil production.

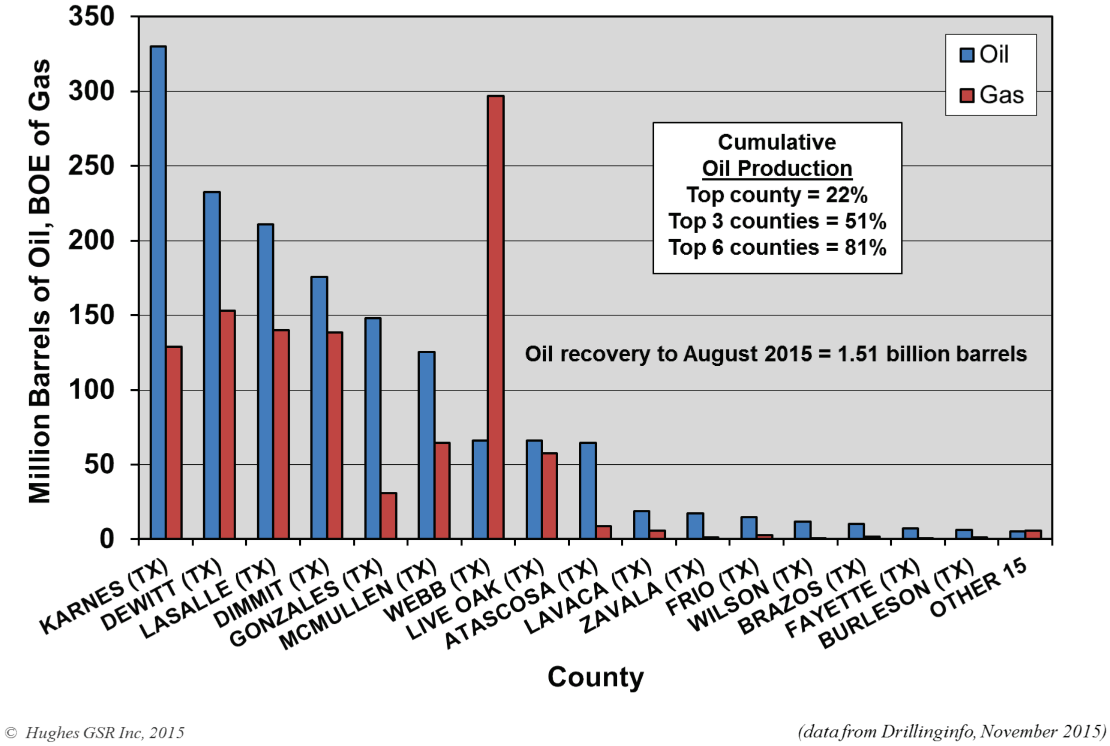


Figure 3. Cumulative oil and gas production in the Eagle Ford Play by county through August 2015.

Natural gas production is expressed in "barrels of oil equivalent" at a conversion rate of 6,000 cubic feet of gas to one barrel of oil.

The trend in the concentration of production within top counties has continued. In July 2015, 52% of production came from Karnes, Dewitt and Lasalle counties, and 81% came from the top six counties (Figure 4).

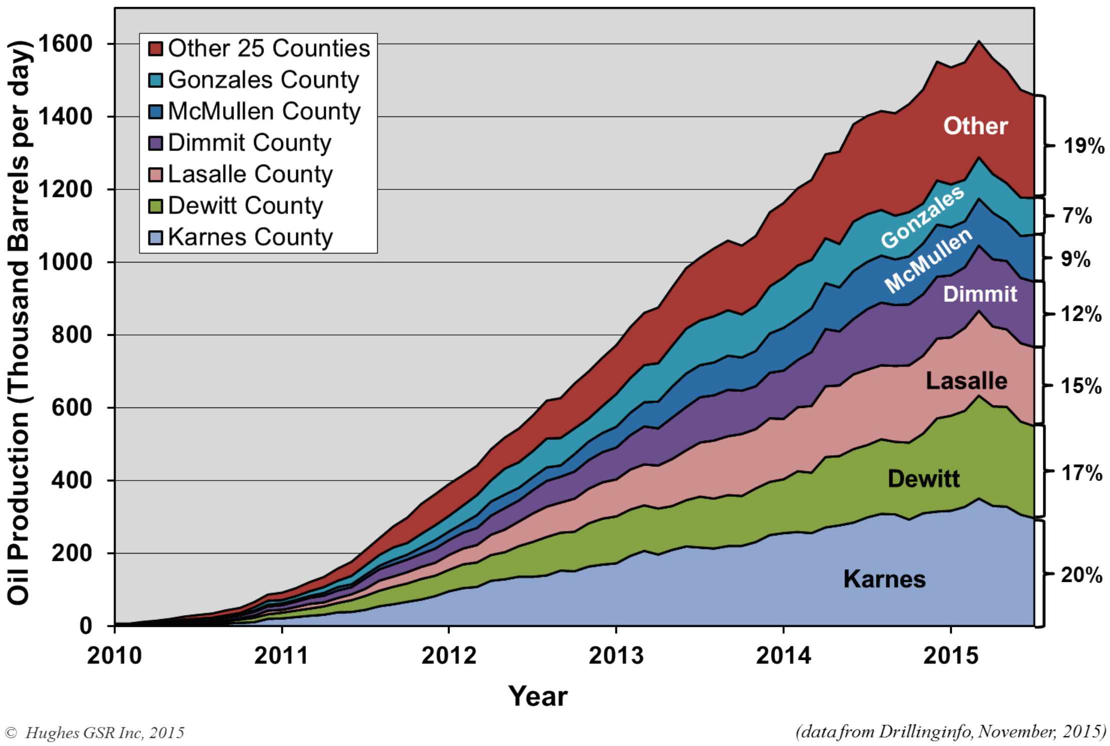
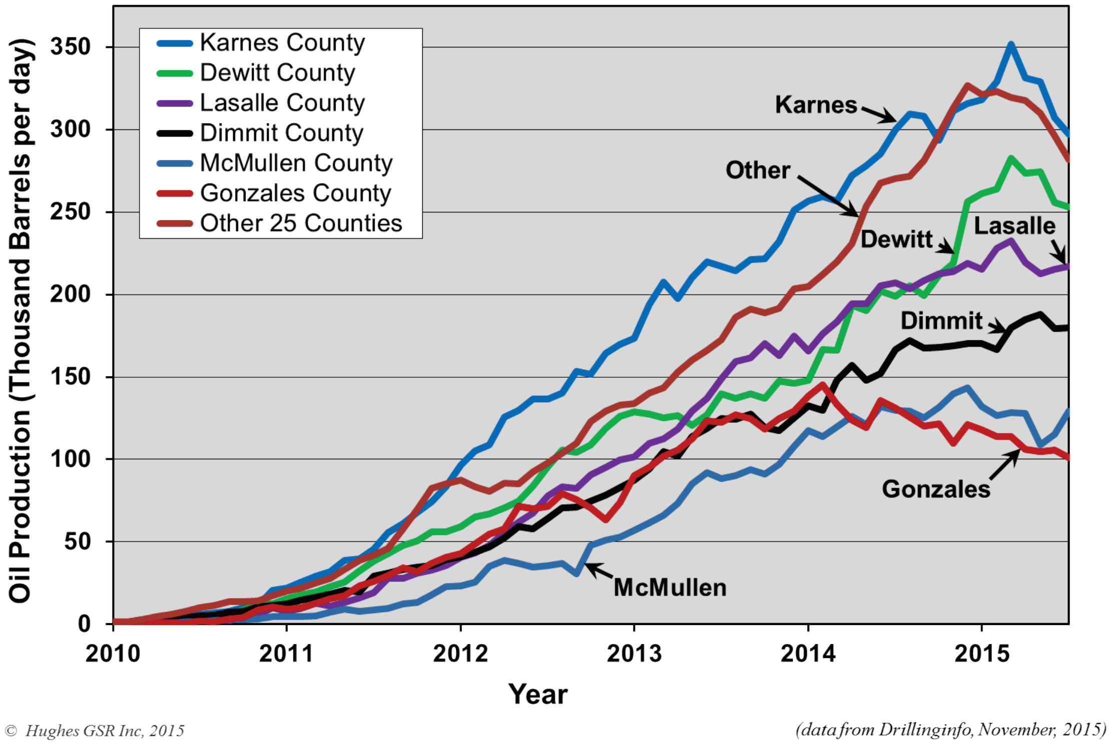


Figure 4. Eagle Ford Play oil production by county from 2010 through July 2015.

Oil production peaked in all counties between June 2014 and May 2015 (Figure 5). Karnes County, the top producer, has experienced the largest decline at 54.4 thousand barrels per day or a 15.5% reduction from peak. Dimmit County, with the fourth highest production, has declined the least. This is somewhat counterintuitive as conventional wisdom suggests that companies are focusing drilling efforts on their best acreage, which is in top counties such as Karnes, and withdrawing from more marginal parts of the play in order to maximize economics in a low oil price environment. The reason for the steeper decline in Karnes County is likely that it is the most heavily drilled and high quality locations are running out, which is evidenced by the decline in average well productivity (see "Technology Improvement Meets Geology", page 12) and the 80% decline in the rate of well completions (Figure 18). Dimmit County, on the other hand, has experienced a slight iimprovement in well quality and a lesser decline in the rate of well completions (Figure 16).



County	Peak Month	% Below Peak	Decrease (kbbl/d)
Karnes	Mar-15	15.47%	54.4
Dewitt	Mar-15	10.56%	29.9
Lasalle	Mar-15	6.70%	15.6
Dimmit	May-15	4.44%	8.3
McMullen	Dec-14	9.54%	13.7
Gonzales	Jun-14	22.87%	34.6
Other 25	Dec-14	13.76%	44.9

Figure 5. Oil production in individual counties from 2010 through July 2015.

Also shown is the month oil production peaked and the percentage and actual production decline from peak.

The drop in rig count, from 218 in July 2014 to 73 today (November 2015)[3], should by now, in theory, have resulted in a precipitous collapse in the rate of addition of new producing wells. This has been somewhat muted, however, owing to the completion of wells drilled earlier (termed DUCs: drilled but uncompleted wells), and to greater efficiencies allowing more wells to be drilled by a single rig per unit of time (although such improvements are likely to have been marginal over the past 12 months compared to earlier gains).

Figure 6 illustrates the rate of drilling on an annual basis and the amount of production added to the play from each new well. As can be seen, on an annual basis the rate of drilling has declined from over 4,000 wells per year in late 2014 to just over 3,000 in July 2015. Production added to the play with each new well has declined from 180 barrels per day, when the play's production was growing rapidly in 2011, to less than 25 barrels per day. A drilling rate of 2,900 wells per year drilling is required to offset static field decline and keep production flat.

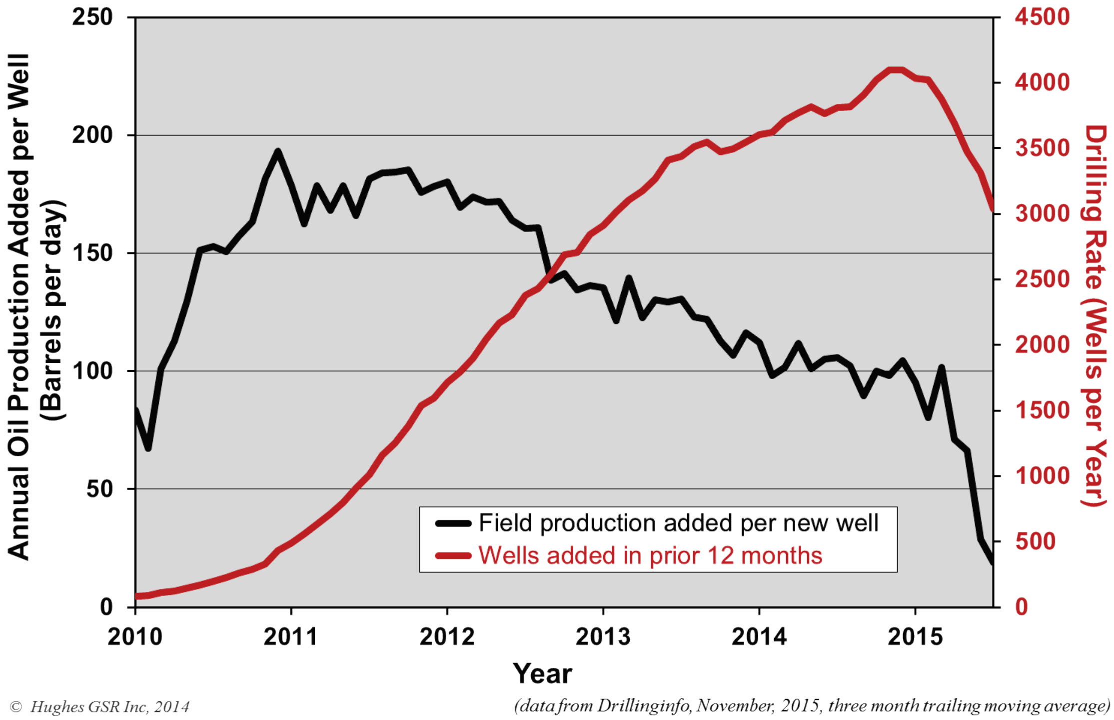


Figure 6. Annual drilling rate versus annual production added per new well from 2010 through July 2015.

A three-month trailing moving average has been fitted to the data.

[3] Baker-Hughes rig count for the week of November 27, 2015, http://phx.corporate-ir.net/phoenix.zhtml?c=79687&p=irol-reportsother.

Figure 7 illustrates the correlation between drilling rate and production on a monthly basis. In order to maintain production at the peak rate of 1.6 mbd, 242 new producing wells need to be added each month to overcome the static field production decline of the play, which in 2014 was 25% per year. The rate of well additions fell below this threshold in March and production began to fall, although the rate of producing well additions remained much higher than implied by the drastic drop in rig count given that many of the wells being added in recent months were drilled during the period of high rig counts. The drop in rig count will manifest itself in steeper production declines in future months as DUC wells are worked out of the system.

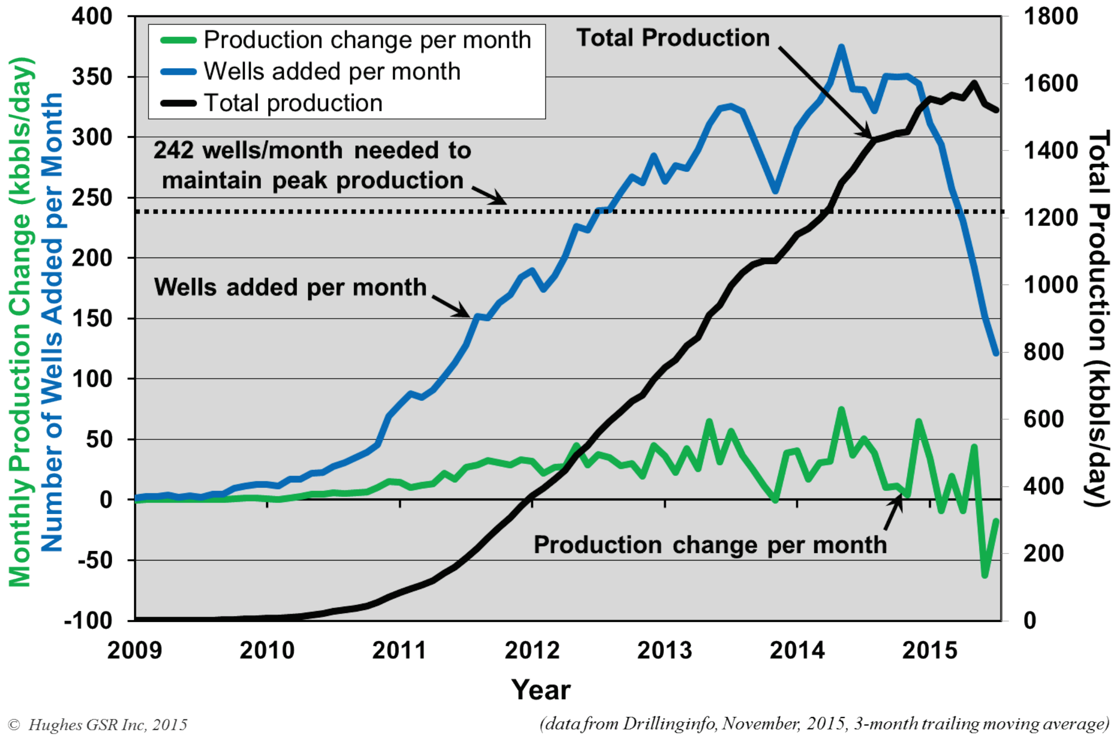


Figure 7. Eagle Ford Play oil production change per month versus new producing wells added per month from 2009 through July 2015.

A three-month trailing moving average has been fitted to the data.

Figure 7 indicates that to maintain production at the peak rate of 1.6 mbd, 242 wells must be drilled each month (2,904 wells each year). At a cost of $8 million per well, this necessitates investment of $23 billion per year, not including operating, leasing and other ancillary costs. Stories of negative cash flows within shale producers have been rampant in the media,[4] even at much higher oil prices. Many tight oil producers, depending on the quality of their land holdings, cannot break even at oil prices of $50-$60 per barrel, hence the prospect of attracting the level of investment needed to maintain Eagle Ford production is slim indeed, unless oil prices rise substantially. Operators have been able to continue to complete and/or drill new wells in the Eagle Ford thanks in large measure to debt, but those days may be nearing an end.[5]

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[4] Bradley Olson, "U.S. Shale Drillers Are Drowning in Debt," *Bloomberg*, September 17, 2015; http://www.bloomberg.com/news/articles/2015-09-17/an-oklahoma-of-oil-at-risk-as-debt-shackles-u-s-shale-drillers.

[5] Stephen Gandel, "Frackers could soon face mass extinction," *Fortune*, September 26, 2015; http://fortune.com/2015/09/26/frackers-could-soon-face-mass-extinction.

Figure 8 illustrates the average production per well by county. Average production is dropping in all counties, which is to be expected as new wells comprise a smaller and smaller proportion of the total complement of producing wells. A decline in the rate of addition of new producing wells will accelerate this trend.

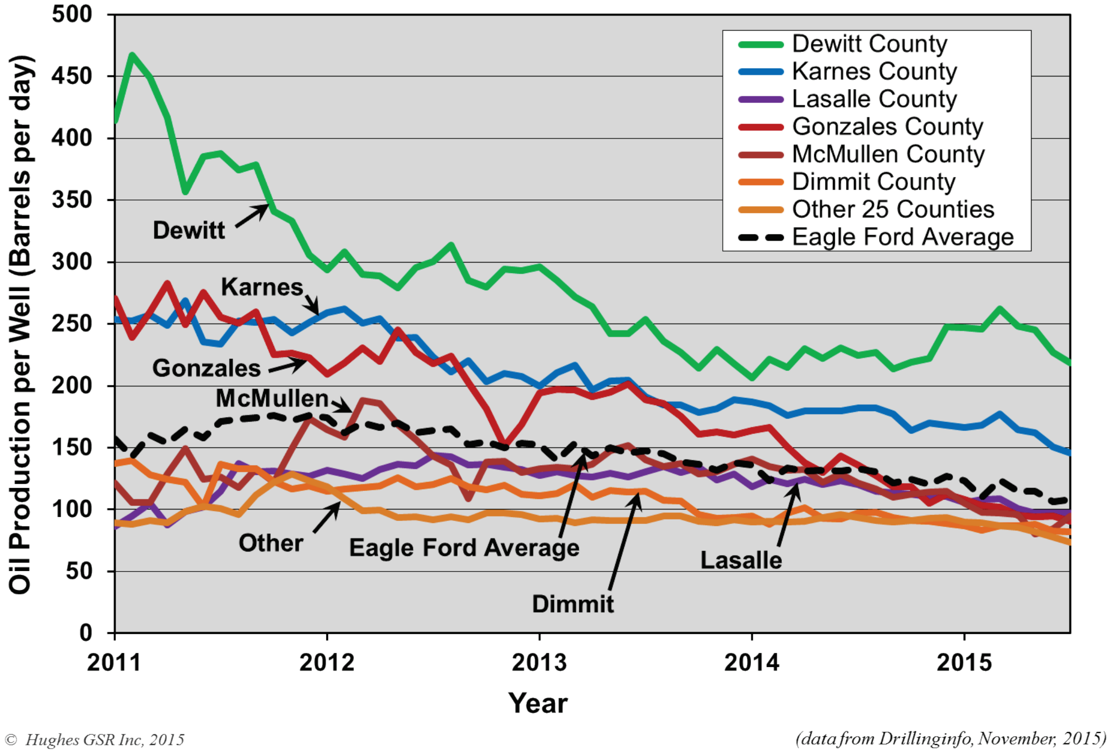
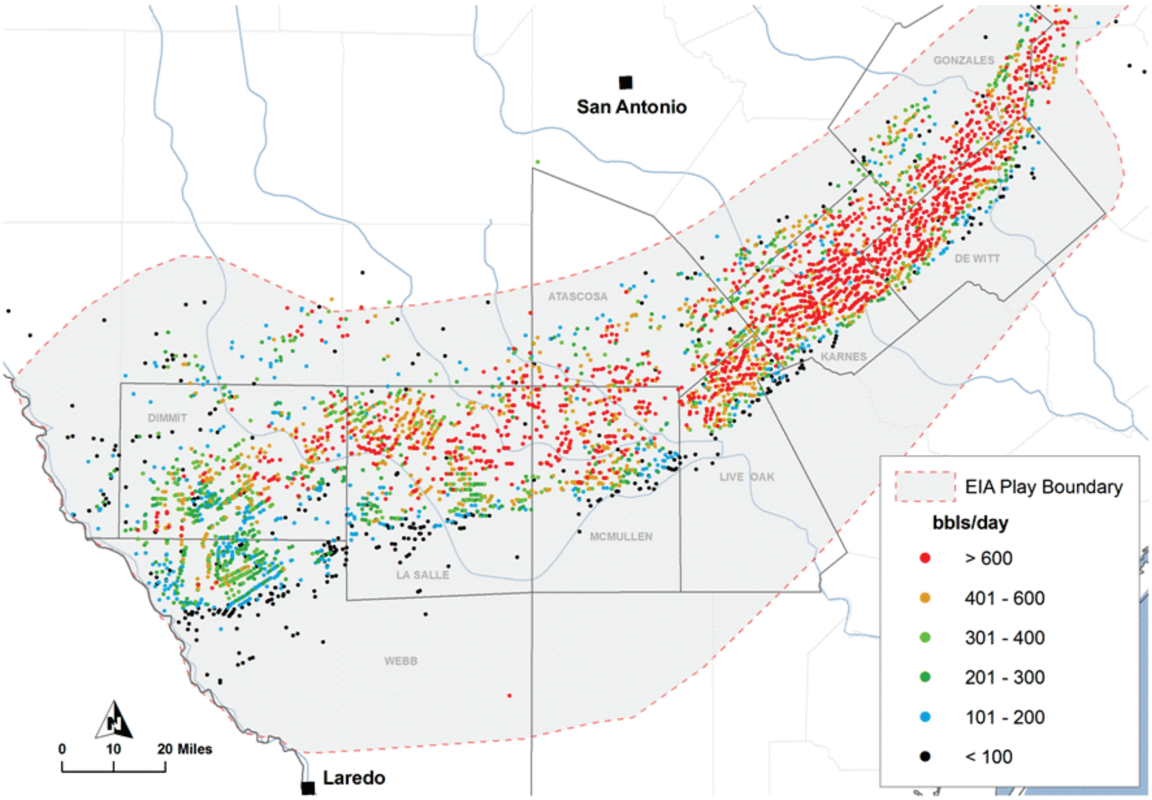


Figure 8. Average production of Eagle Ford wells by county from 2011 through July 2015.

2 Dominance of Sweet Spots

Sweet spots—core areas of high well productivity—produce most of the oil, as indicated by the fact that 81% of Eagle Ford oil in July 2015 was produced from six of 31 counties, and 52% came from three counties. Figure 9 illustrates the distribution of producing wells in the Eagle Ford categorized by well quality, as defined by initial oil production. As can be seen, the actual area of highest quality wells constitutes a small proportion of the total play area and, even within the top six counties, the area of highest quality wells is only a portion of the total county area.



(data from Drillinginfo, August 2014)

Figure 9. Distribution and initial oil production (highest month) of wells in the Eagle Ford as of June 2014.

Figure 10 illustrates average type well decline curves by county and Figure 11 illustrates average oil EUR (estimated ultimate recovery). The average well declines 77% in its first three years and between 43% and 48% of a well's ultimate recovery, assuming a 25-year life, is produced in the first three years. Given the difference in production between the sweet spots and the rest of the play, it is easy to see why drilling has been focused on the best parts of the top counties. In the longer term, however, drilling will have to move into lower quality parts of the play as sweet spots become saturated with wells. Higher prices will be required to justify this.

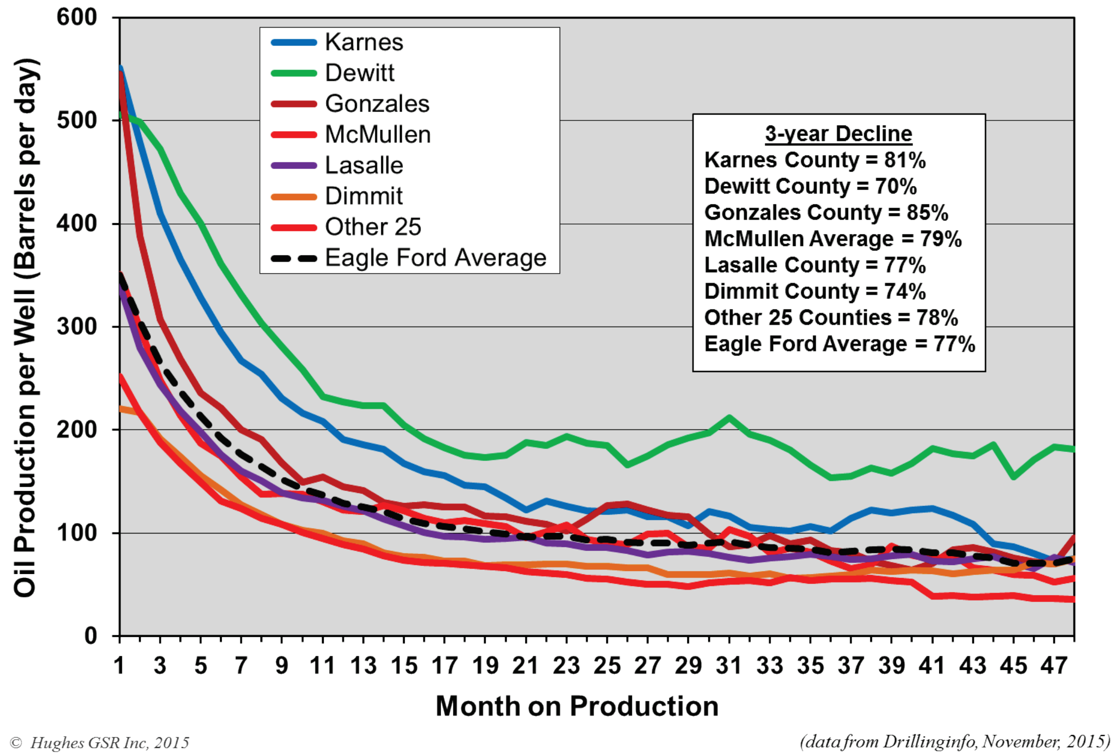


Figure 10. Type well decline curves by county for the Eagle Ford Play using data to year-end 2014.

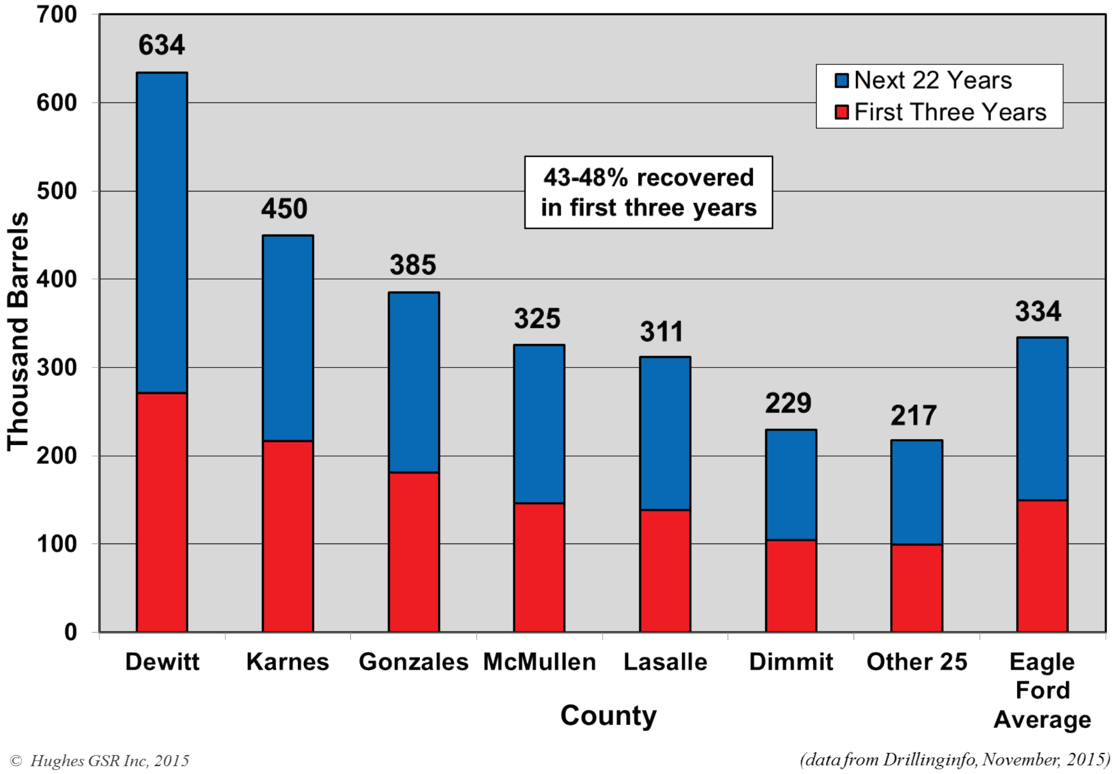


Figure 11. Estimated ultimate oil recovery (EUR) of average wells by county in the Eagle Ford Play.

This average reflects the concentration of recent wells in the best parts of these counties.

3 Technology Improvement Meets Geology

A major theme in investor presentations is that wells are getting ever more productive through the use of longer horizontal laterals, more fracking stages, and larger volumes of water, chemicals and proppants in the fracking process. Figure 12 illustrates the average production rate over the first six months for new Eagle Ford wells by county from 2010 through 2015. Average productivity for the Eagle Ford increased by 27% from 2012 to 2015, through both better technology and focusing drilling on sweet spots. However in Karnes County, which has so far been the most productive, average well productivity peaked in 2013 and has declined by 9% since then. Well productivity declined in Lasalle and McMullen counties in 2015 as well. Improved technology and focusing on the highest quality locations is still making a difference in other counties, however it is only a matter of time before well productivity declines there also as drilling saturates available high-quality locations.

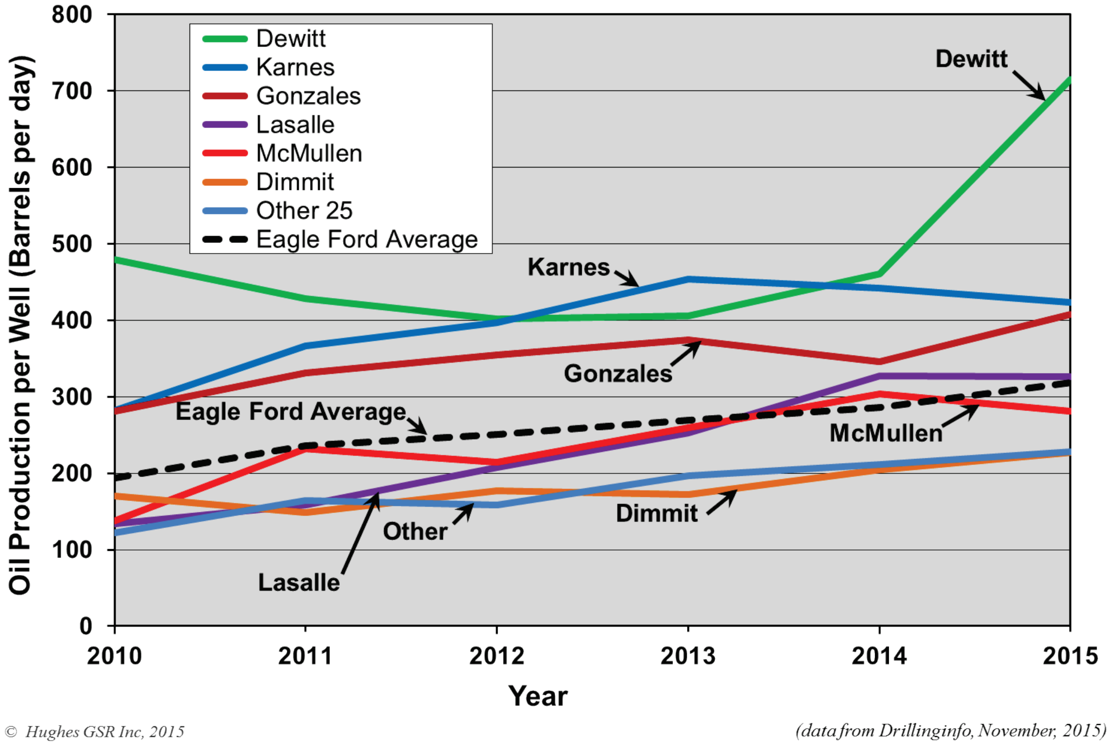


Figure 12. Average production rate of Eagle Ford wells by county over the first six-months of production from 2010 through 2015.

The failure of technology to boost average well productivity in Karnes, Lasalle and McMullen counties, which collectively account for 44% of Eagle Ford production, is due to:

- Well saturation in sweet spots causing interference between wells.
- Exhaustion of the best drilling locations in sweet spots, necessitating drilling in lower-quality parts of these counties.

A further consideration is that although these improved technologies have allowed an individual well to drain more of the reservoir at higher production rates, and hence have allowed the recoverable oil to be produced with fewer wells, they will not necessarily increase the ultimate oil recovery of the play. Wells with interference will allow the oil to be produced faster, but ultimately will represent higher capital cost inputs than necessary to recover the resource.

The Eagle Ford Play still has enough drilling locations available to nearly triple the number of producing wells that have been drilled to date, but these locations are increasingly in poorer quality rock. Thus the drilling rate will have to be increased substantially as well productivity decreases, in order to stem the steep intrinsic field decline rate. These wells will also require progressively higher oil prices to be economic as well productivity declines.

4 Future Outlook

Figure 13 illustrates historical production and the number of producing wells over time, as well as forecasts of future production from the Energy Administration's (EIA) *Annual Energy Outlook 2015* (AEO2015)[6], and my "Most Likely" forecast from *Drilling Deeper*. Also shown is the number of new wells required through 2021 in order to meet the production forecast from *Drilling Deeper*, and the EIA's historical production data and short-term forecast from its *Drilling Productivity Report* for November 2015.[7]

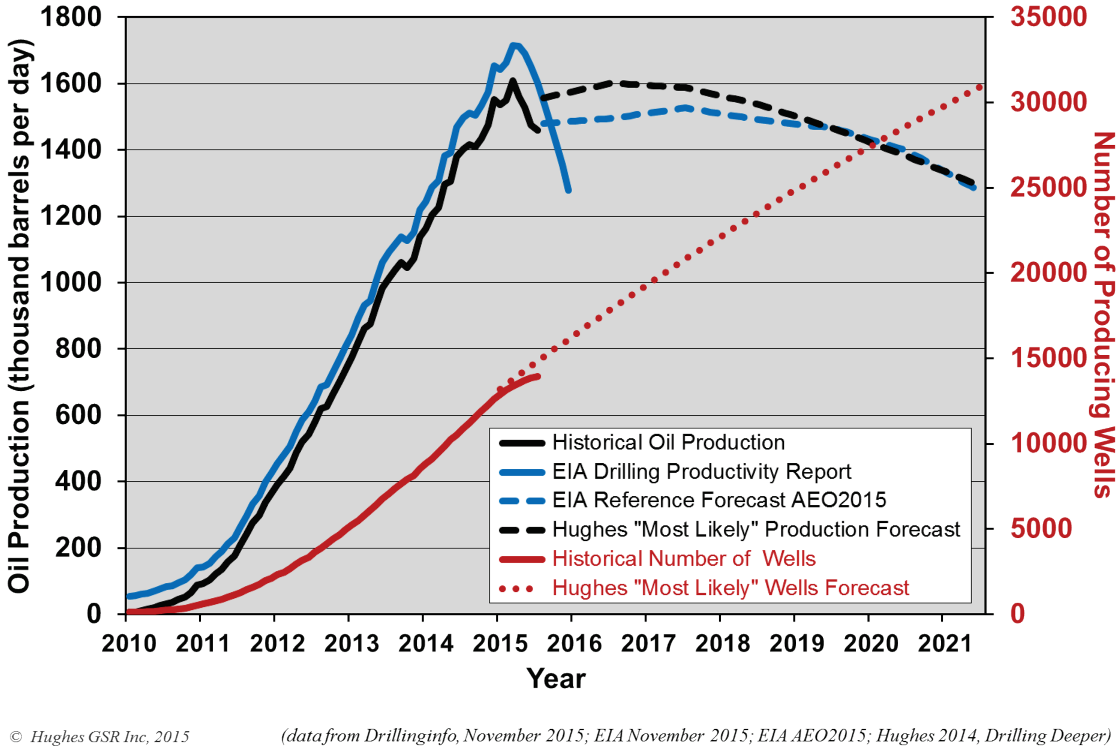


Figure 13. Historical production from the Eagle Ford Play using Drillinginfo and EIA *Drilling Productivity Report* (DPR) data.

Also shown are the "Most Likely" production forecast and number of wells required from *Drilling Deeper*, and the production forecast from the EIA AEO2015 reference case. DPR data refers to the "Eagle Ford Region" which includes non-Eagle Ford production.

Some observations:

- Drilling rates have dropped below those assumed in the *Drilling Deeper* forecast, hence production is currently slightly lower than projected.
- There are hundreds of DUC wells in the play, the completion of which will mitigate the otherwise steep decline in the rate of drilling new wells implied by the drastically reduced rig count. This will serve to stem production decline in the play as a whole. Once the DUC wells are worked off, however, production will fall to the level at which new drilling can offset the static field decline rate.

[6] Energy Information Administration, *Annual Energy Outlook 2015* , April 14, 2015; http://www.eia.gov/forecasts/aeo.
[7] Energy Information Administration, *Drilling Productivity Report*, November 9, 2015; http://www.eia.gov/petroleum/drilling.

- The EIA AEO2015 reference case forecast parallels the *Drilling Deeper* forecast very closely out to 2025 (Figure 13 and Figure 14), at which point the 37,000 locations available will have been drilled. Beyond 2025 production will fall at the static field decline rate. The EIA, however, assumes a much lower rate of production decline beyond 2025, although it provides no rationale for this and the geological fundamentals do not support it.

- The "Most Likely" forecast from *Drilling Deeper* looks slightly optimistic in the near term, as drilling rates have fallen below assumed levels due to low oil prices. The *Drilling Deeper* forecast assumes that an additional 23,000 producing wells can be added to the 14,000 already drilled by 2025. Lower drilling rates will reduce production levels and extend drilling beyond 2025, although the ultimate recovery will not change.

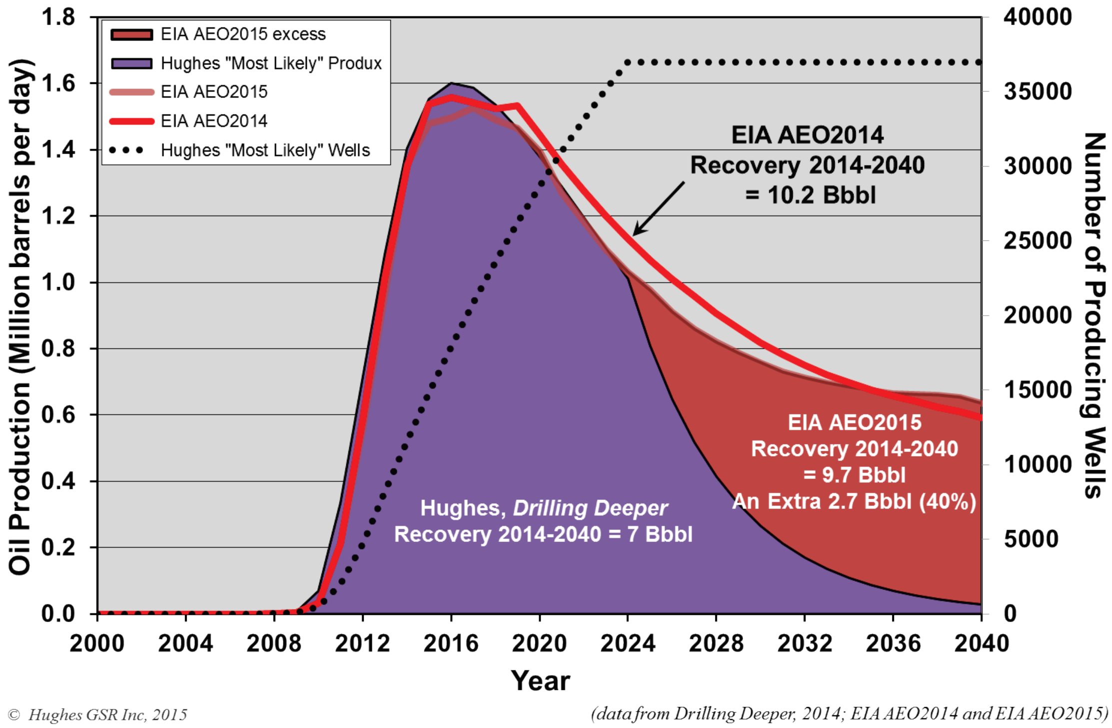


Figure 14. Comparison of "Most Likely" Drilling Deeper forecast for the Eagle Ford Play to forecasts by the EIA in its AEO2014 and AEO2015.

Also shown is the number of wells required to meet the "Most Likely" *Drilling Deeper* forecast.

5 Summary and Implications

Eagle Ford production is falling, which is a result of the decline in the rate of well completions to levels insufficient to offset the static 25% yearly decline rate of the play (2,900 well completions per year are required to maintain production at the peak level of 1.6 mbd). The glory days of the Eagle Ford are behind it, at the ripe old age of six years.

The rig count has dropped by 67% since July 2014, and is paralleled by a 65% drop in well completions over the same period. The current rate of well completions is far below that necessary to offset static field decline hence a continued steep drop in production can be expected. There are several hundred drilled but uncompleted (DUC) wells in the play which could slow the production decline should prices go higher, even if the rig count does not recover.

Well productivity gains due to better technology have stopped and are declining in three of the six top counties, which account for 44% of the play's production. This is a harbinger of what will happen in all counties as high quality drilling locations are used up. Well productivity is dropping due to both exhaustion of the highest quality drilling locations and well interference from spacing wells too close together.

The observation that new well quality is declining in top counties, despite every incentive to maximize individual well production, is key. Pundits such as Morningstar, while bearish on the short term, are convinced that rig counts and production will rise dramatically at prices of $60-$70 per barrel.[8] They miss the point that the best quality parts of the play are being exploited now, and that lower quality geology going forward will dictate lower well productivities, with worse economics, which will require higher prices to justify drilling. Thus even to maintain the peak rate of 1.6 mbd, the drilling rate would have to increase from the 2,900 wells per year currently required (needing $23 billion per year of capital input exclusive of leasing and other ancillary costs). To substantially increase production above the March peak would require a return to rig count levels of triple current rates or higher, which would accelerate the consumption of the finite number of remaining drilling locations. As noted in *Drilling Deeper*, high drilling rates serve to recover the resource sooner, but do not result in a significantly higher ultimate recovery.

Both the *Drilling Deeper* and EIA AEO2015 forecasts for Eagle Ford production are likely too high in the short term given the drastic drop in the rate of well completions. Lower well completion rates now, however, will save drilling locations for later, which will serve to extend drilling in the field beyond 2025 when the 37,000 drilling locations in the play were forecast to be exhausted. The EIA's assumption that production can continue at relatively high levels after drilling locations are exhausted and exit 2040 at 0.6 mbd is highly optimistic, however, and is unsubstantiated by the data.

The hype surrounding tight oil as a means to bolster global oil production over the long term is not justified. Geological fundamentals clearly show that high decline rates, limited sweet spots, and finite numbers of drilling locations will limit long term contributions to production. The Eagle Ford and Bakken plays have peaked after only a few years, and although they have made a significant short term impact, their best days are behind them. The Bakken and Eagle Ford are unique in that they were developed from scratch, whereas other plays in the Permian Basin, Niobrara and elsewhere are redevelopments of old plays (which have been producing for decades) with new technology. The optimistic tight oil forecasts of the EIA,[9] and even more optimistic forecasts of some industry watchers,[10] are unhelpful abstractions in developing energy policy for a more sustainable future.

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[8] Stephen Simko, "US Oil Production Fall Will be Worse than Markets Expect," *Morningstar*, September 24, 2015; http://www.morningstar.co.uk/uk/news/142447/us-oil-production-fall-will-be-worse-than-markets-expect.aspx.

[9] David Hughes, 2015, "Tight Oil Reality Check", Post Carbon Institute, http://www.postcarbon.org/wp-content/uploads/2015/09/Hughes_Tight-Oil-Reality-Check.pdf.

[10] PIRA, November 2015, tight oil production versus price, slide 28, http://phx.corporate-ir.net/External.File?item=UGFyZW50SUQ9NjAyMjQ1fENoaWxkSUQ9MzEyNzQzfFR5cGU9MQ==&t=1.

6 Appendix: Well Addition Rate Versus Production Change and Total Production by County

The following charts provide county-level detail on rates of well completions and production change for the top six counties as well as the group of other counties that make up the Eagle Ford Play. Also noted are the number of new wells that need to be added each month to offset the static field decline in each county.

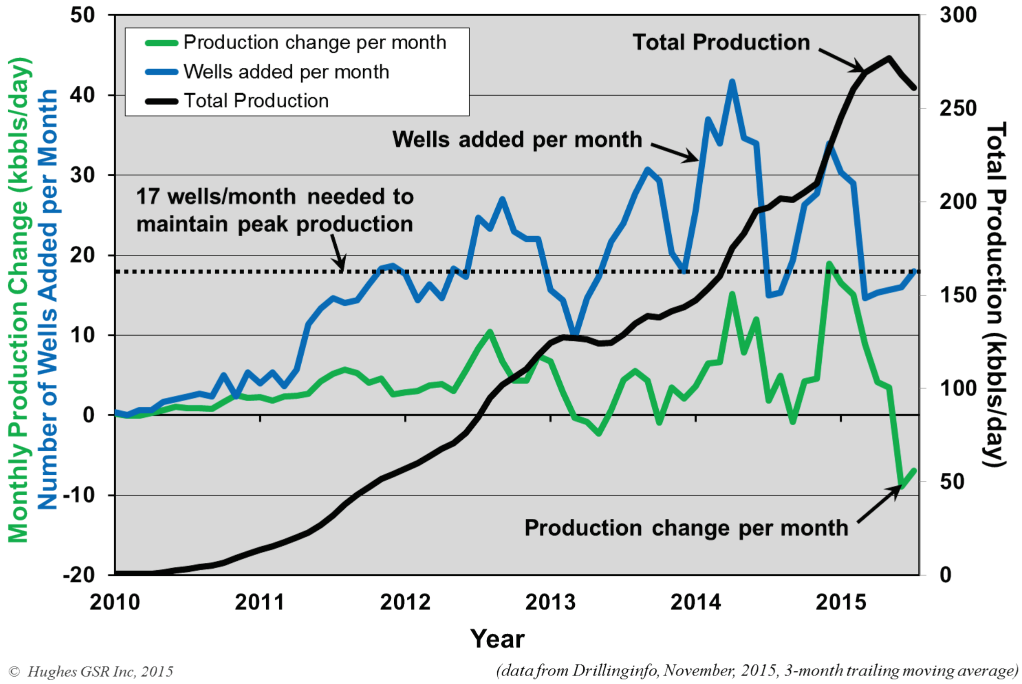

Figure 15. Dewitt County oil production change per month versus new producing wells added per month from 2010 through July, 2015.

A three-month trailing moving average has been fitted to the data.

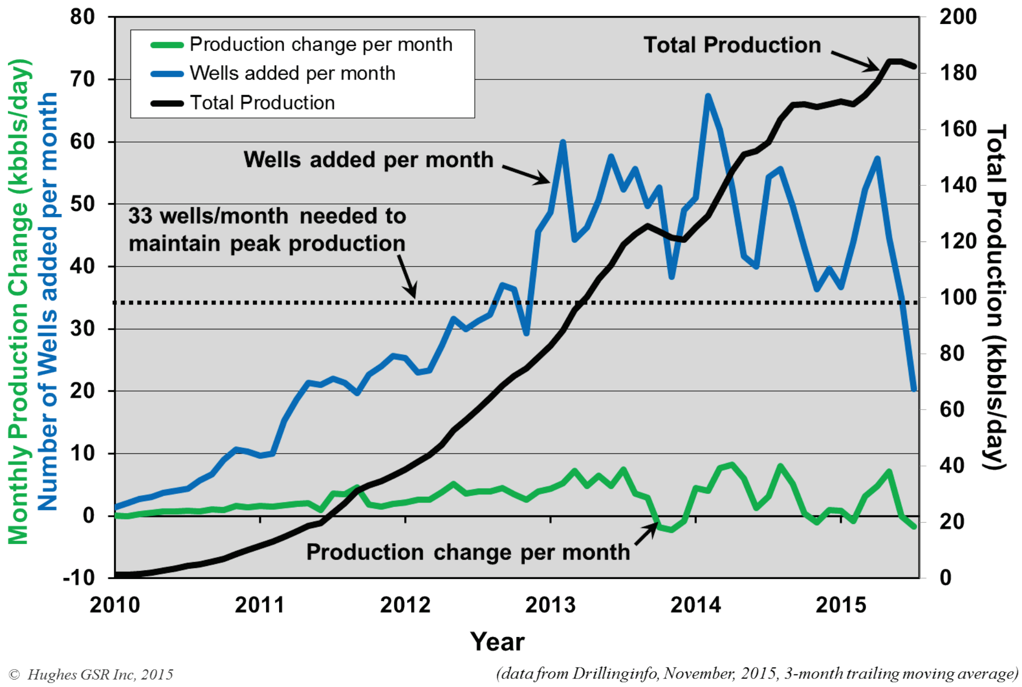

Figure 16. Dimmit County oil production change per month versus new producing wells added per month from 2010 through July, 2015.

A three-month trailing moving average has been fitted to the data.

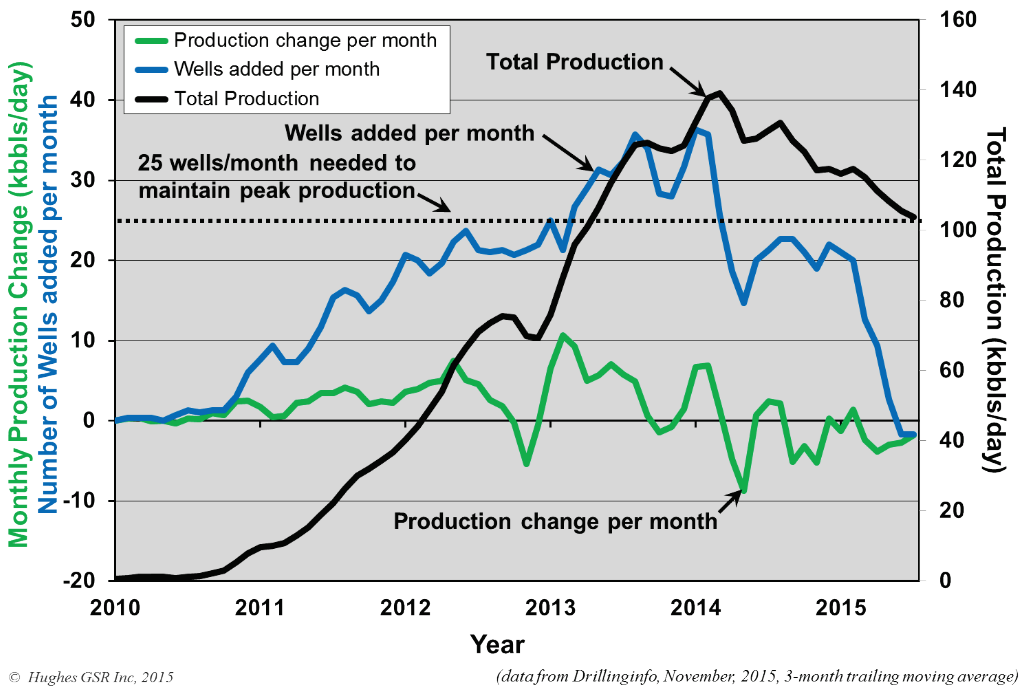

Figure 17. Gonzales County oil production change per month versus new producing wells added per month from 2010 through July, 2015.

A three-month trailing moving average has been fitted to the data.

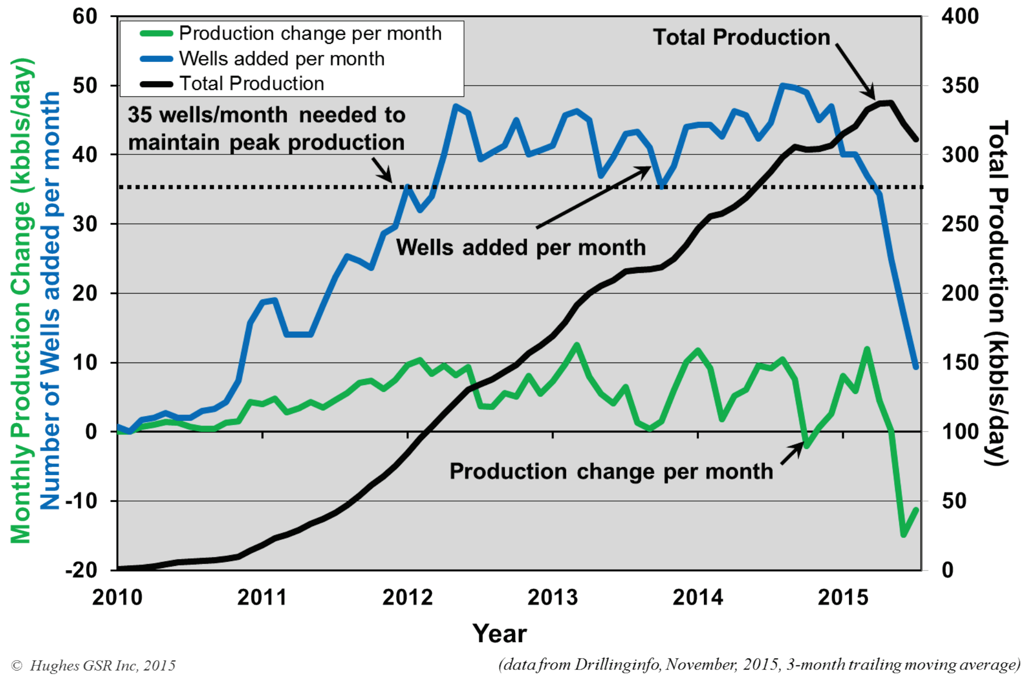

Figure 18. Karnes County oil production change per month versus new producing wells added per month from 2010 through July, 2015.

A three-month trailing moving average has been fitted to the data.

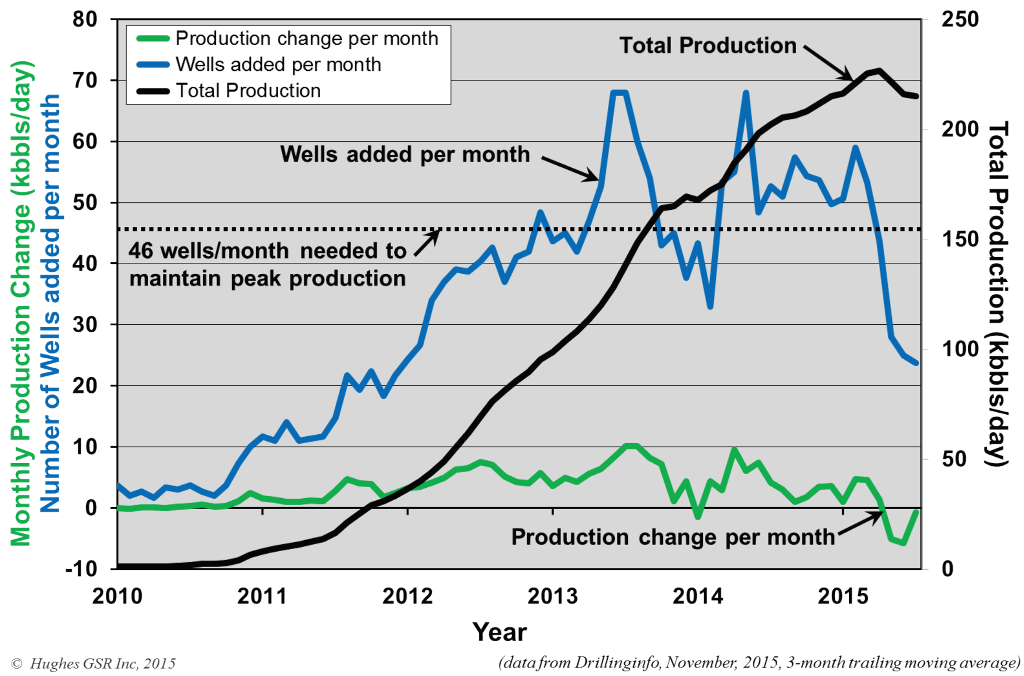

Figure 19. Lasalle County oil production change per month versus new producing wells added per month from 2010 through July, 2015.

A three-month trailing moving average has been fitted to the data.

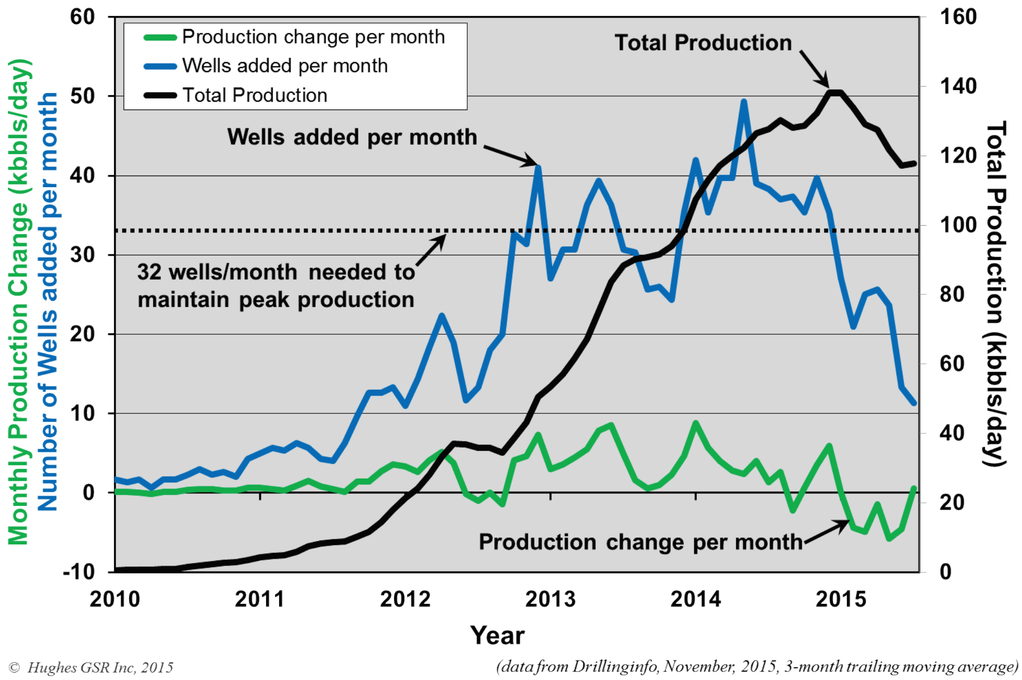

Figure 20. McMullen County oil production change per month versus new producing wells added per month from 2010 through July, 2015.

A three-month trailing moving average has been fitted to the data.

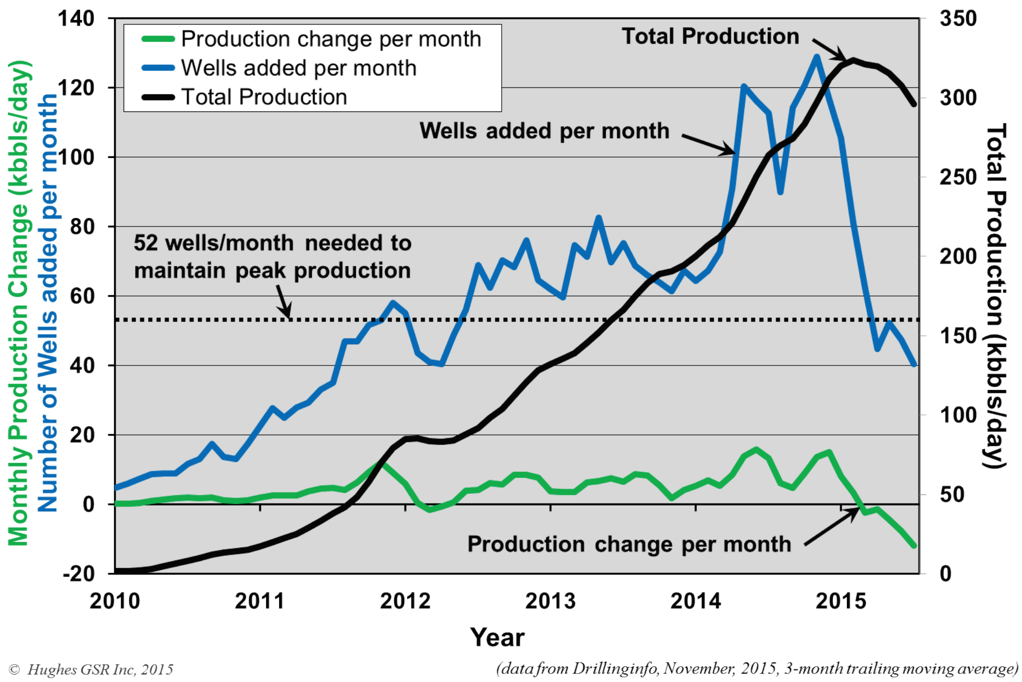

Figure 21. Other 25 counties oil production change per month versus new producing wells added per month from 2010 through July, 2015.

A three-month trailing moving average has been fitted to the data.