Shale Gas Production Decline Trend Comparison Over Time and Basins
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Abstract

Production from shale gas reservoirs has formed an increasingly large part of the U.S. natural gas mix in the last few years. More than half of the rigs in onshore U.S. will be drilling horizontal wells with a large majority in shale plays. Within the last year, shale gas plays have dominated the onshore U.S. natural gas drilling activity, with this boom occurring during a time of economic uncertainty. However, skepticism has recently been placed on shale gas production decline trends from consultants and investment firms, where estimated ultimate recoveries (EURs) and the overall economic feasibility of shale gas plays have been brought into question.

EURs of shale gas wells have been forecast in a number of ways within the industry. Some entities have been calculating EURs based on initial production rates (IPs). Others are applying the decline trends established in one basin to a different newer basin with less production history. In other cases, two different operators may use different trend types in wells that are in the same location.

This paper seeks to more accurately assess the decline trends and EURs of these shale plays, if the decline trends are improving, and what returns are required to make a well economically feasible. This study compares the production trends of horizontal wells in the Barnett, Fayetteville, Woodford, Haynesville and Eagle Ford shale plays, analyzing each over time to determine if there have been improvements to production. Where applicable we address the impact that technology has made in this enhanced production. Furthermore, the decline trends of horizontal shale to horizontal tight gas sandstone plays are examined to look for differences and shed some light on potential EURs.

The results of the analysis helped establish which decline trends could be used to determine the EUR of these horizontal shale wells, or if a better methodology may exist. A basic economic analysis to estimate breakeven gas price for an average (P50) horizontal well in each play was performed.

Introduction

Natural gas production from shale gas formations has shown a rapidly growing trend in recent years. The Barnett Shale formation is already producing 6% of all natural gas onshore in the lower 48 states of the U.S. The two major enablers for the emergence of shale gas plays in the U.S. have been technological advances and process time efficiency gains in both horizontal drilling, completions, and stimulation operations. The boom has also been aided by higher energy prices and declining production from conventional reservoirs from 2004 until 2008. The last couple of years have seen lower natural gas prices, and a correspondingly greater interest in estimating shale gas reserves as some U.S. shale plays have become marginally economical.

Many papers have been written and prophecies have been made about U.S. shale gas plays. The long term production viability of horizontal shale wells has been debated by some in the industry. More specifically the decline trends of the various shale plays
have come under contention. The time to reach an abandonment rate has also been questioned. The most heavily contested point among industry experts is the EUR and resultant economics for various shale plays. The principal techniques used for EUR determination are material balance analysis, numerical simulation, decline curve analysis (DCA), volumetric analysis and analogy. These methods add fodder to the EUR debate. Material balance OGIP calculations are rarely used on shale gas reservoirs because of the difficulty of obtaining accurate values of reservoir pressure due to prohibitively long shut-in times required on wells. Volumetric analysis has uncertainties of the recovery factor parameter and the actual drainage area. Analog methods in shale gas reservoirs predict reserves from correlations between production and reservoir and completion parameters. The large number of variables and parameters in this method causes high degree of uncertainties in predicted reserves. Numerical simulation in data-rich wells has provided robust estimations of future well production where the physics of shale gas reservoir production mechanisms is well known. DCA is probably the most frequently used production forecasting tool for shale gas reservoirs due to its relative simplicity and speed. The method for production comparisons between shale basins used in this analysis is the DCA technique.

There are six objectives for this paper:
1. Examine trends in historical horizontal gas production for a given shale gas basin over time, from 2003 to 2009.
2. Compare trends in historical horizontal gas production across different shale basins for a given time.
3. Compare the historical production trends of vertical Barnett Shale wells with horizontal Barnett wells to determine what differences and similarities exist.
4. Evaluate horizontal and vertical tight gas sandstone wells within a basin. This diagnostic is performed on two separate tight sandstone basins and the results are compared to each other. Furthermore, information from long term production of vertical wells in tight gas sands is used as an indicator to assess long term production of horizontal wells in the same basin. The results from the third and fourth objectives can be linked together to estimate the long term production behavior of horizontal shale gas wells.
5. Assess the impact of length of production history on predicted EUR and decline parameters.
6. Perform a basic economic analysis of the average (P50) horizontal well in each of the shale basins analyzed to determine at what gas prices various plays are economically viable.

The shale gas basins analyzed in this study were the Barnett, Fayetteville, Woodford, Haynesville, and Eagle Ford. With thousands of wells drilled in these plays the study was limited to a core area, or ‘sweet spot’ in each play. This was done in order to limit the size of the study to a manageable well count that could be properly quality assured and quality checked (QA/QC). Furthermore, this core area would help reduce the petrophysical heterogeneity and to minimize the effect of changes in production operations that would play a bigger role over an entire basin. These areas were also chosen as they have production histories on horizontal wells from the exploration phase of the field through to the present. Finally, selecting core areas with the highest production in each play allows for the conclusion to be made that wells outside the core area will be uneconomic if the wells in the core area are uneconomic (generally speaking, it is assumed that laterals outside the core area have less production than laterals inside the core area).

A detailed analysis of production data was performed in this study incorporating hundreds of horizontal wells in each basin. Due to the low well count in the Eagle Ford basin, the sweet spot has not yet been determined, so all of the producing horizontal Eagle Ford Shale wells were incorporated in the study. Fig. 1 shows the location of the horizontal wells used in the study, color-coded by basin. A total of 1,957 shale gas horizontal wells were selected for the study, of which 839 were from the Barnett, 468 from the Fayetteville, 309 from the Woodford, 275 from the Haynesville, and 66 from the Eagle Ford. The production and completion data used in the study was obtained from publically available sources. This study was primarily focused on production data; although petrophysical, geophysical, and geomechanical properties are different for each basin, these were not considered in an attempt to keep the study manageable. However, discussions were made where necessary and references are cited for additional information.
Methodology

Monthly production data from the horizontal wells in each basin was captured and placed in a database. A quality control of this data was performed. This involved rejecting any well that had any abrupt changes in monthly gas rate during the production history. Following this all monthly production rate data was shifted with respect to time so that the production data on all wells had the same start date or ‘time zero’. This reference ‘time zero’ was the earliest year of production of any well in the database (2002). All wells were then grouped by their date of first production (DOFP) which is the year in which the first production was reported. Therefore, wells in the DOFP 2009 group had less than a year of production whereas wells in the DOFP 2004 group had less than five years of production. The monthly rate data was then converted into an equivalent daily production rate of an average well by dividing the monthly rate by the number of days in the corresponding month, and then dividing the result by the number of producing wells for that particular month. The production analysis software that was used in this study allowed for a specific filtering of wells by shale gas basin and DOFP criteria. Combinations of these criteria allowed for various scenarios to be analyzed.

At this point, a second, careful QA/QC was performed on each well’s gas production data before incorporating it into the analysis. When a given DOFP group of wells completed in the same year was less than eight, the data was not analyzed as it would lead to a poor statistical correlation. For example, there were only four wells in the Woodford Shale data set with a DOFP of 2005, and this data set was eliminated. Next, wells that had considerably different gas production rates (for example an order of magnitude difference in production rate from the group in which they were a part of) were highlighted and examined carefully. This was a major issue for the Eagle Ford Shale wells incorporated in the study. As the Eagle Ford has a large area producing condensate and oil, wells with an oil-gas ratio (OGR) greater than 80 bbl/MMscf were excluded in the analysis. Other suspect laterals that had low production rate issues compared to their peers comprised wells that were found to be vertical or had known pipeline constraints.

The third QA/QC that was performed examined the behavior of the producing gas well count over time for each group. While analyzing production data from a group of wells it was necessary to ensure that the producing well count remains near constant.
over time. The well count was used in the calculation of the averaged daily production rate variable and when this count changed dramatically then the resultant calculated rate is no longer a suitable representation of the original group of wells. It was observed that when the well count started to drop there would be an associated change in decline behavior that was unrelated to the production decline of the area studied. Well count was observed to start constant and to decrease dramatically after a period of time. Following this the calculated rate often had anomalous behavior. Fig. 2 shows such an example (Barnett wells with DOFP 2007). TimeN in Fig. 1 is the normalized time in months, from ‘time zero’. The thin blue line represents the number of producing gas wells. At around 27 months, the number of producing wells declines dramatically. This is accompanied by a sharp decrease in the normalized gas production rate (red line). Filtering out data after 27 months ensured that the data could be analyzed during a time in which the number of producing wells remained near constant. The filtered (QC Corr) data is shown by the thick black line and the final normalized well count is shown by the thick green line. This decrease in well count at 27 months and thereafter can be explained by wells starting their producing life at different months in 2007. The production data in our study ends in February 2010. Therefore, wells starting production in January 2007 would have 38 months of production and December 2007 wells would have only 27 months of production history while both belong to DOFP 2007. A drop in the number of producing wells can cause the calculated rate to be erratic, increase, or decrease (which is the case in Fig. 2 since the wells that started production at later stages in 2007 were producing better at a given TimeN than wells that started their producing life in early 2007.) Without this correction, it may be erroneously concluded that the wells studied are declining exponentially.

After the QA/QC measures were taken, a total of 1,931 wells existed in the database of which 838 wells were from the Barnett, 467 from the Fayetteville, 305 from the Woodford, 275 from the Haynesville and 46 from the Eagle Ford.

Fig. 2 – Barnett Shale production rate and active producing well count for DOFP 2007 data series
Following this QA/QC step, the data was analyzed in two ways:

a) The data was plotted out to compare trends in each shale gas basin through time, and to compare trends between different shale gas basins. This is presented in “Intra Shale” and “Inter Shale” production sections.

b) Decline curve analysis (DCA) was performed on various scenarios incorporating all of the vetted horizontal shale gas well production data, and vertical and horizontal tight gas sandstone data. The result of this was presented in the “Tight Gas Sandstone and Shale Basin Production Comparisons” section, and in the “Economic Analysis” section.

The DCA was performed using the well known empirical Arps\textsuperscript{5} equation:

\begin{equation}
q_g(t) = \frac{q_{gi}}{[1 + bD_i t]^{1/b}}
\end{equation}

Where \(q_g\) is the gas production rate at time \(t\), \(q_{gi}\) is the gas production rate at initial time, \(D_i\) and \(b\) are empirical parameters determined by fitting a curve mapped out by this equation onto a production rate versus time plot. \(D_i\) is the decline rate at initial time and the \(b\) exponent controls the ‘curvature’ of the decline trend. Where \(b = 0\) an exponential decline curve results and the equation is approximated to the following formula:

\begin{equation}
q_g(t) = q_{gi} e^{-D_0 t}
\end{equation}

where \(D_0\) is the decline rate and is constant.

The Arps equation was designed for conventional reservoirs and primarily vertical wells where boundary-dominated flow is the norm with associated constant bottom-hole pressure. Shale gas reservoirs are characterized by transient production behavior and in general boundary-dominated flow is rarely observed in the data\textsuperscript{6}. Production rates generally have steep initial decline trends as production is dominated by flow from hydraulic fractures to the wellbore. At later times, gas production rate decline is often small. This ‘long tail’ in the production profile at later times is due to matrix dominated, transient flow which is a reflection of low permeability. The resulting DCA can often yield \(b\) values greater than 1.0.

In addition to the above limitations of the Arps equation as a forecasting tool in shale gas reservoirs, the methodology may suffer from inconsistency of historical data regression by the interpreter which may be highly subjective. Therefore, in this study, ‘auto-decline’ functionality from production analysis software was performed on data from each basin with careful consideration of whether or not to include outlying data points. This helped achieve consistency across the different basins and DOFP categories.

Following this, the formulation of a decline type curve for each shale gas basin was possible allowing for a higher-level analysis comparing production decline trends and economics between shale gas basins. The final production type curves for each basin presented in this study used historical decline curve regression data instead of the actual production data. This yielded smoother production profiles. This was beneficial when comparing results from different basins.

**Intra Shale Basin Production Overview**

The following subsections discuss the actual production for each of the shale plays (Figs. 3-11). Data is organized by DOFP allowing for an examination of shale gas production over time for each shale gas basin.

**Barnett Shale Production Overview**

The selected area for the Barnett Shale study was located in Tarrant, Wise, Denton and Parker counties and consisted of 838 horizontal wells drilled from 2003 to 2009. Figs. 3 and 4 show the averaged daily production rate per well for wells grouped by DOFP from 2003 through 2009. Time\(N\) is the producing time in months, from ‘time zero’. Unlike all other shale gas basins in this
study, there was no production improvement over time in the Barnett since the IPs are similar for the seven DOFP. It appears that wells are not interfering with one another as production trends are parallel and have similar slopes over the years (fig. 4). This implies that wells are not too tightly spaced. However, in a few cases newer hydraulic fracture operations have created direct communications with older offset wells.

Initially operators were pumping on average two fracture stages, increasing to six by 2008. In addition, the total fluid and proppant volumes have also increased but not proportionally. Initial designs were primarily slickwater with 40/70 sand which were modified to include linear or cross-linked tail-in with 30/50 or 20/40 sand (hybrid treatment) by a few operators. One study performed showed the total volume of proppant pumped had a good positive correlation to resultant production in the Barnett. However, in many wells total proppant volume per stage decreased over time. The completion and stimulation practices have changed over time but may not be optimized resulting in no obvious additional gain in production.

The Barnett Shale is believed to contain natural fractures, some of which may be re-opened by the drilling process. Furthermore, the extensional basin environment results in little horizontal stress anisotropy allowing easier dilation of mineralized natural fractures contacted during stimulation. The curvature of the Barnett Shale may also have an impact on the natural fracture orientation, and the magnitude of the horizontal in-situ stresses. The curvature and natural fractures may act in tandem to dictate the ultimate hydraulic fracture geometry, reducing the impact of hydraulic fracture size, staging, and design.

Another cause of similar IPs and decline trends over time is pipelines transporting gas out of the study area have been running at capacity. This is unlikely to be occurring consistently over time, but still needs to be considered.

Finally, the chosen core area is likely to have more consistent rock properties than a play-wide analysis would show.

Fig. 3 (left) and Fig 4 (right): Barnett shale averaged daily production rate per well Mscf/d (y-axis), grouped by DOFP and shifted to time zero. Left plot shows first 12 months; right plot shows the entire production history.
**Fayetteville Production Overview**

The core area for the Fayetteville Shale study was selected in Conway and Van Buren counties and consisted of 467 horizontal wells drilled from 2005 to 2009. Fig. 5 shows the average daily gas production rate per well for the first twelve months of production from wells grouped by DOFP from 2005 through 2009. The initial production rate ranged from 1.0 to 2.6 MMscf/d for the five data sets. The plots show three distinct groups: one with 2005 DOFP wells, another with 2006 and 2007 DOFP wells, and the third with the 2008 and 2009 DOFP wells. The average initial production rates have consistently improved over time: there is a 50 – 60% increase in initial production rate from DOFP 2005 until DOFP 2006/2007, followed by a further increase of 40 – 60% from DOFP 2007 until DOFP 2008/2009.

This increase in production can be attributed to the evolution of horizontal well length from 1,800 to 4,300 ft during this timeframe. As the lateral length increased, the number of stages were doubled from 3-4 in 2005 to 6-8 in 2009. The total stimulation fluid volume also doubled, the proppant volume per well nearly tripled, and stimulation designs were evolved to accommodate these additional volumes over the same time frame. Over this period, production trends are parallel and have similar slopes for all five data sets. Although other factors may play a part, because production increases in a step-like function between DOFPs, the changes in drilling, completion, and stimulation practices discussed above are most likely causes.

The entire productive history was analyzed for the Fayetteville Shale to examine how the production changed in the longer term. Fig. 6 shows the long term production with the data categorized by DOFP. Similar to the one year production data sets, all of the historical data sets had very similar decline trends.

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**Fig. 5 (left) and Fig 6 (right):** Fayetteville Shale averaged daily production rate per well MScf/d (y-axis), grouped by DOFP and shifted to time zero. Left plot shows first 12 months; right plot shows the entire production history.
Woodford Production Overview

The core area for the Woodford Shale study was selected in Hughes and Coal counties (Arkoma Basin) and consisted of 305 wells drilled from 2006 to 2009. Fig. 7 shows the average daily gas rate per well for the first twelve months of production for wells drilled from 2006 through 2009, and fig. 8 for the first 40 months of production. The initial production rate ranged from 2.1 to 3.6 MMscf/d for the four data sets. The plots show three distinct groups similar to Fayetteville Shale: one with 2006 and 2007 DOFP wells, another with 2008 DOFP wells, and the third with the 2009 DOFP wells. There is a dramatic increase in the initial production rate of about 35% from 2006 and 2007 DOFP wells to 2008 DOFP wells which further increased by 20% to 2009 DOFP wells.

This increase in production can be primarily attributed to evolution of length of the horizontal wells of 1,800 to 4,800 ft over the time frame analyzed. Furthermore, as the lateral length increased the number of hydraulic fracturing stages also increased from three to ten. However the total stimulation fluid volume did not increase proportionally while the proppant volume remained the same over the same time frame. The decline profiles are quite similar during the first year of production for all years analyzed.

The entire productive history was analyzed for the Woodford Shale to examine production changed over time. Fig. 8 shows the long term production with the data categorized by DOFP. Similar to the Fayetteville Shale, all of the historical data sets had very similar decline trends.

Fig. 7 (left) and Fig 8 (right): Woodford Shale averaged daily production rate per well MScf/d (y-axis), grouped by DOFP and shifted to time zero. Left plot shows first 12 months; right plot shows the entire production history.
Haynesville Production Overview

The core area for the Haynesville Shale study was selected in Bienville, Bossier, Caddo, De Soto, Red River, Sabine Parishes. It consisted of 275 horizontal wells drilled from 2008 to 2009. Figs. 9 and 10 show the average daily gas rate per well. The IP has increased by 18% for 2009 DOFP wells compared to 2008 DOFP wells. Similar to other shale plays, the average lateral length was increased from 2,200 ft to 4,800 ft and the number of hydraulic fracturing stages from six to fourteen. The stimulation volumes also evolved proportionally to lateral length, more so than other shale plays. An average hydraulic fracturing stage pumped in Haynesville Shale consists of ~12,000 bbls of slickwater with 300,000 lbs of proppant

Eagle Ford Production Overview

The study area for the Eagle Ford Shale study was selected in Dimmit, De Witt, La Salle, Live Oak, McMullen, and Webb counties with 46 horizontal wells analyzed in 2009. The Eagle Ford shale play is evolving at a similar pace to the Haynesville shale play with the average lateral length eclipsing 5,000 ft and the number of stages currently at 12 to 14 per lateral. The stimulation volumes are also comparable to the Haynesville Shale.

Fig. 9 (left) and Fig 10 (right): Haynesville Shale averaged daily production rate per well MScf/d (y-axis), grouped by DOFP and normalized to time zero. Left plot shows first 12 months; right plot shows the entire production history.

Fig. 11 Eagle Ford Shale averaged daily production rate per well MScf/d (y-axis), grouped by DOFP and normalized to time zero.
Inter Shale Basin Production Comparison

Figs. 12 – 15 show the production trends of various basins analyzed. Each figure is for a different DOFP and allows the production behavior between all the basins to be compared. For DOFP 2009 there is a clear trend of increasing IP: Haynesville IP > Eagle Ford IP > Woodford IP > Fayetteville IP > Barnett IP. The Haynesville and Eagle Ford basins have greater IPs than the other basins mainly because their reservoir pressures are greater. Another cause for the increase could be that operators generally drill longer laterals with more stages and use greater fluid and proppant volumes per stage in the hydraulic fracturing treatments pumped on the Haynesville and Eagle Ford horizontals. These two reasons are more likely to have a greater impact in the IP difference than differences in petrophysical properties between basins. It was observed that in years prior to 2008, the Woodford, Fayetteville and Barnett have similar IPs. However, for wells with a DOFP of 2008 and 2009, a trend emerges with Woodford having the highest IP of the three, followed by Fayetteville and the Barnett. As discussed in the previous section, the increase in production of Fayetteville and Woodford with time is related to step changes in the drilling such as better understanding of lateral landing and steering the lateral in the target zone; completion practices such as manageable perforation clusters spaced close together and more stages; stimulation designs such as hybrid treatments, various fluid diverting options, microseismic monitoring of hydraulic fracturing treatments, etc. and overall knowledge gain as time passed.

Figs. 12 – 15 also show that regardless of the IP of the Barnett shale in comparison to the other shale gas basins, its decline is more gradual than the other Shales. The Barnett core area used in this study is believed to have rock properties that are favorable to maintain fracture conductivity over time. Firstly there is lesser vertical heterogeneity and moderate vertical stress variation in the Barnett in the study area than for the other shale basins. Secondly the Barnett Shale has greater siliceous content and high Young’s Modulus compared to the other plays analyzed. Other shale basins have greater clay volume and occurrence than the core area of the Barnett, leading to a greater intensity of “pinch points”, affecting hydraulic fracture conductivity with time. Thirdly there is a large network of open and healed natural fractures in the Barnett shale as observed in literature, which if retain their integrity over time, can help reduce gas production decline. Barnett also has very low stresses which lead to a lower effective stress on poorly/un-propped fractures during production9,10,11. While natural fractures may exist in all of the other shale gas basins, the rock fabric of the Barnett allows for better connectivity between natural fracture sets. For example, the Woodford is known to have natural fractures but these are concentrated in chert intervals and not in clay intervals14. These observations especially with regard to argillaceous reservoirs will cause fractures to close with time and ultimately lead to steeper production rate declines.

The Haynesville and Eagle Ford Shales have steeper decline rates compared to the other shale gas basins (figs. 12 and 13). This observation is seen more clearly in figs. 16 and 17 which show absolute averaged daily gas production rate per well and averaged IP-normalized daily gas production rate per well, respectively for each basin. Since the main mechanism for production in shale gas reservoirs is the creation of a ‘complex’ fracture system in the reservoir, it follows that any degradation of this network will cause gas production rates to decline. Preventing this degradation from occurring can become more challenging in higher pressured reservoirs with softer rock and/or lower Young’s Modulus such as the Haynesville, as proppant embedment and proppant crushing may occur, and to a lesser extent the Eagle Ford Shale. These two reservoirs produce at high initial gas rates that decrease fairly early in time as the reservoir pressure decreases. When this pressure decrease occurs, high stresses can impact open hydraulic fracture networks and cause their degradation with time, resulting in a decrease in the overall fracture conductivity of the system. Furthermore, greater reservoir pressures (particularly in the Haynesville) will cause steeper production rate declines initially as the gas from the fracture network is produced more quickly (with the high initial production rates) than gas fed from the matrix to the fracture network.

While the initial decline rates are due to changes in the conductivity of the fracture system with time, later decline rates are more related to matrix/fracture coupling and matrix properties as the production becomes more matrix-dominated. At this later stage, similar decline rates are related to matrix-dominated flow which does not have as much variability between basins as ‘complex’ fracture dominated flow. Figs. 13 – 15 and Figs. 16 – 17 show a tendency for production rate declines to be the same across the different basins at later times.

Fig. 18 shows a sensitivity plot of simulated gas production rate for three different shale gas reservoir scenarios: a base case, a case with an abundance of natural fractures and a case in which the reservoir pressure has been doubled. A numerical simulator was run in dual porosity compositional mode with the same generic properties for all three scenarios. The same bottom-hole pressure was used in all three cases. The natural fracture case shows slightly higher IPs and more gradual production rate decline than the base case while the increased reservoir pressure case shows a considerably higher IP and a much steeper production rate decline. This is consistent with the observations from Figs. 12 – 15 as discussed above in this section.
Fig. 12 (top left), fig 13 (top right), fig 14 (bottom left), fig15 (bot right): Averaged daily production rate per well MScf/d (y-axis), per basin for a given DOFP
Fig. 16: Absolute averaged daily gas production rate per well for each shale gas basin

Fig. 17: IP-Normalized gas production rate for each shale gas basin
Tight Gas Sandstone and Shale Basin Production Comparisons

The sections that follow compare the production behavior of IP-normalized gas rates per well (gas production rate is normalized using the highest production point, i.e. the highest production point will have a value of 1.0) and absolute gas rates per well for: vertical and horizontal tight gas sandstones, vertical and horizontal Barnett Shale wells and horizontal shale gas and tight gas sandstones. The production curves in each case were generated using the methodology outlined earlier with the exception that all wells from a particular basin, regardless of DOFP, were grouped together and shifted with respect to time so that the first month of production for each basin was set at “time zero”. A rigorous QA/QC was performed on the resulting profiles to observe when wells start to come on production through time as mentioned above in the methodology section. DCA were performed on the resulting profiles. The curves from the various DCAs are presented in Figs. 19 – 26.

The results of this DCA exercise are summarized in Table 1.

Table 1: Decline curve analysis results from production profiles of various shale gas and tight gas sandstone basins used in the study

<table>
<thead>
<tr>
<th>Case</th>
<th>Reservoir Type</th>
<th>Well Type</th>
<th>History Months</th>
<th>Total Wells</th>
<th>EUR @ 30 Years M.M</th>
<th>b</th>
<th>Di M.n</th>
<th>Current Cumulative Gas Production M.M</th>
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</thead>
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<tr>
<td>Barnett</td>
<td>Shale Gas</td>
<td>Horizontal</td>
<td>64</td>
<td>731</td>
<td>2,989</td>
<td>1.5933</td>
<td>0.0089</td>
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<td>Fayetteville</td>
<td>Shale Gas</td>
<td>Horizontal</td>
<td>37</td>
<td>467</td>
<td>1,390</td>
<td>0.6377</td>
<td>0.0325</td>
<td>883</td>
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<td>Woodford</td>
<td>Shale Gas</td>
<td>Horizontal</td>
<td>45</td>
<td>305</td>
<td>1,696</td>
<td>0.8436</td>
<td>0.0227</td>
<td>996</td>
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<td>Haynesville</td>
<td>Shale Gas</td>
<td>Horizontal</td>
<td>12</td>
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<td>5,915</td>
<td>1.1852</td>
<td>0.0632</td>
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<td>Eagle Ford</td>
<td>Shale Gas</td>
<td>Horizontal</td>
<td>7</td>
<td>59</td>
<td>3,793</td>
<td>1.694</td>
<td>0.0826</td>
<td>548</td>
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<tr>
<td>Cotton Valley</td>
<td>Tight Gas</td>
<td>Horizontal</td>
<td>48</td>
<td>96</td>
<td>1,926</td>
<td>0.7259</td>
<td>0.0248</td>
<td>1,341</td>
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<td>Cleveland</td>
<td>Tight Gas</td>
<td>Horizontal</td>
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<td>824</td>
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<td>0.0149</td>
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<td>Cotton Valley (1980)</td>
<td>Tight Gas Sandstone</td>
<td>Vertical</td>
<td>354</td>
<td>445</td>
<td>2,703</td>
<td>1.2778</td>
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<td>0.0175</td>
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Tight Gas Sandstone Horizontal and Vertical Well Comparison

The Cotton Valley Sandstone of East Texas and North Louisiana and the Cleveland Sandstone of North Texas were included in the study as multi-stage fracturing treatments are required to make economic horizontal wells, which are similar to shale gas reservoirs. In addition, these sandstone plays have some of the longest production histories of horizontal hydraulically fractured sandstone gas wells.

In the study a total of 96 horizontal wells drilled from 2005 to date were incorporated from the Cotton Valley sand, and 388 horizontal wells from 2000 to date were incorporated from the Cleveland sand. Also, 445 vertical Cotton Valley wells drilled in the year 1980 were incorporated (providing 30 years of actual production data), together with 967 vertical Cleveland wells drilled during the 1980s. In addition to this, 4401 vertical Cotton Valley wells drilled after 2005 were also included.

The horizontal well decline trend was compared to the vertical well decline trends to estimate if the decline trends were similar or different over time in a given basin. Figs. 19 and 20 show the comparison of Cotton Valley horizontal wells, Cotton Valley vertical wells drilled in 1980 and Cotton Valley vertical wells drilled after 2005 for IP-normalized gas production rates and absolute gas production rates respectively. Interestingly, vertical wells drilled after 2005 have lower IPs and sharper decline rates than older vertical wells analyzed. This may be attributed to depletion in the Cotton Valley Sandstone over time. Many recent wells were drilled on tighter spacings. Furthermore, many newer wells have been drilled in areas outside of the initial economic core areas, and recent completions include slickwater with less proppant compared to earlier crosslink gels with massive proppant volume in the 1980s.

Fig. 20 shows that Cotton Valley Horizontal well IPs are approximately four times greater than Cotton Valley vertical wells. However, horizontal wells show much sharper decline rates than the vertical wells. This could be related to the following factors: 1) vertical and lateral heterogeneity along horizontal Cotton Valley wells have a greater effect on horizontal production than in the case of the vertical well; 2) The high water gas ratios (WGRs) of the Cotton Valley cause unfavorable flow dynamics in horizontal wells with poorer production results than vertical wells; 3) Hydraulic fractures are not evenly spaced in horizontal wells and in many cases are overlapping causing inefficient drainage patterns compared to vertical wells as observed using microseismic monitoring; and 4) Horizontal wells may be affected by depletion more as they oftentimes intersect depleted areas, especially from offset older vertical wells (drilled in 1980). These four factors can explain the observations shown in Fig. 20 which gives an insight to the expected production behavior of an average horizontal well drilled in the Cotton Valley Sandstone. The horizontal wells are likely to have sharper decline trends than the verticals, crossing the production profile of old vertical wells (drilled in 1980). However, horizontal wells are likely to maintain their production rate above the newer vertical wells (i.e. drilled from 2005 to date).

A similar exercise was performed for the Cleveland Sandstone. Figs. 21 and 22 compare the decline trends of horizontal wells (drilled from year 2000 to date) and vertical Cleveland tight gas sandstone wells (drilled in the 1980s). Similar behavior was observed for the Cleveland Sandstone normalized gas production curves as the Cotton Valley Sandstone discussed above. On average, horizontal wells have steeper decline trends than older verticals. This is likely due to the same factors affecting Cotton Valley Sandstone.

The vertical Cotton Valley wells with almost 30 years of production history (effectively the EUR ‘life’ of the well) allow for the determination of decline curve parameters such as the highly debated ‘b’ with greater confidence. It follows that a ‘b’ value of 1.28 for the Cotton Valley wells drilled in 1980 (as shown in table 1) means that ‘b’ values greater than 1.0 for other tight gas sandstone and shale gas cases may be realistic, especially since the tendency is for the decline rate to be much lower after the first five years until the economic limit is reached.
Fig. 19: IP-Normalized gas production rate for Cotton Valley horizontal wells, Cotton Valley vertical wells drilled during the year 1980 and Cotton Valley vertical wells drilled from 2005 to the present day

Fig. 20: Absolute gas production rate for Cotton Valley horizontal wells, Cotton Valley vertical wells drilled during the year 1980 and Cotton Valley vertical wells drilled from 2005 to the present day
Fig. 21: IP-Normalized gas production rate for Cleveland horizontal wells and Cleveland vertical wells drilled during the 1980s

Fig. 22: Absolute gas production rate for Cleveland horizontal wells and Cleveland vertical wells drilled during the 1980s
Vertical and Horizontal Well Barnett Shale Comparison

Fig. 23 shows Barnett Shale vertical and horizontal well IP-normalized production rate curves superimposed on the same plot. The horizontal type curve was generated from 731 wells and the vertical type curve from 56 wells. The criteria used to determine the vertical well Barnett Shale data set was wells in the core area (mentioned in the introduction) that had a DOFP in the 1980s. Fig. 24 shows the absolute averaged well daily production rates where the IP of the horizontal well (~2.0 MMSCF/D) is five times greater than the IP of the vertical well (~0.4 MMSCF/D). A striking observation is the similar decline behaviors between these horizontal and vertical Barnett type curves for the first 24 months despite their IP ratios, as shown in Fig. 23. After the first 24 months, horizontal wells show slightly higher decline than vertical wells. The corresponding calculated EURs for horizontal Barnett wells was 2.99 BCF and 0.74 BCF for vertical Barnett wells. This ratio of IPs is slightly lower than the horizontal and vertical tight gas sandstones analyzed above.

This similarity in decline behavior early in the time could indicate some important differences between the Barnett Shale and the Cotton Valley Sandstone, such as greater lateral heterogeneity and water production issues affecting the horizontal Cotton Valley wells. The Barnett Shale may have open natural fractures and more complex hydraulic fractures compared to the planar fractures of the Cotton Valley Sandstone. The trend shows that the factors affecting a horizontal Barnett well’s decline behavior are also affecting a Barnett vertical well decline trend. The plots show that the Barnett vertical wells only have approximately nine years of production history despite coming online in the 1980s. In the late 1990s a large number of Barnett vertical wells were re-stimulated, so all production subsequent to this was eliminated from the analysis as this would skew the results.4

Fig. 23: IP-Normalized gas production rate for Barnett vertical wells (drilled during 1980s) and Barnett horizontals (drilled after 2003)
Horizontal Tight Gas Sandstone versus Horizontal Shale Comparison

As mentioned in the previous section, Cotton Valley sandstone verticals with DOFP of 1980 and Cleveland sandstone vertical wells (DOFP in 1980s) have gradual decline rates after five years of production. Furthermore, the 4 – 5 years of horizontal well production data in both sandstones show flattening decline behavior in their later production time similar to the vertical wells. This trend can be used as a benchmark for production behavior in horizontal shale gas basins. For example, Cotton Valley Sandstone horizontal wells are likely to decline more sharply than all shale gas basins in this study. This can be observed in Fig. 25 where the normalized plot shows the orange Cotton Valley horizontal production type curve crossing the decline type curves of all of the shale gas basins. This holds true as long as Cotton Valley horizontal wells are not re-stimulated. Over time the Cotton Valley horizontal production type curve starts to dip below many of the shale basin type curves. Therefore, the horizontal Cotton Valley type curve and ‘b’ exponent acts as a lower limit for the horizontal shale gas production forecast for all basins studied.

The sharper production decline for horizontal Cotton Valley sandstone wells compared to horizontal shale gas wells could be an indication of the greater amount of water production which adversely affects the production of a horizontal Cotton Valley sandstone gas well. Furthermore, depletion affects are magnified more in the higher permeability sandstone wells than in the nanodarcy permeability shale basins analyzed with their large storage capacity. An interesting note is the high IP of the average horizontal Cotton Valley wells (4 MMSCF/D) which exceeds the IP of three of the shale gas plays analyzed.
Fig. 25: Overlay of IP-normalized production type curves for horizontal sandstone and shale basins

Fig. 26: Overlay of absolute gas production rate type curves for horizontal sandstone and shale basins
Impact of Length of Production History on Predicted EUR and Decline Parameters

DCAs were performed on data from the following three scenarios: Barnett DOFP 2003, Woodford DOFP 2006 and Fayetteville DOFP 2005. For each scenario, different lengths of historical production data such as one year, two year, etc. was used to perform DCA, and an estimation of ‘b’ exponent and EUR was made accordingly. The DCA was performed using “auto-decline” functionality as mentioned in the introduction. A careful consideration was made whether or not to include outlying data points. The results of this time lapse analysis are shown in Figs 27 – 29.

For the Woodford DOFP 2006 and Fayetteville 2005, in general as the amount of historical production data available increased, the ‘b’ exponent from DCA also increased. This led to higher forecasted EUR values (Figs 27, 28) as time progressed. Conversely for the Barnett DOFP 2003 as the amount of historical production data available increased, the ‘b’ exponent decreased, leading to lower forecast EUR values (Fig 29).

These observations highlight the uncertainties in accurately predicting EUR where a small amount of production data exists. In the case of the Woodford DOFP 2006 and Fayetteville DOFP 2005, performing DCA too early in the production profile would lead to a lower bound estimation of ‘b’ exponent and EUR. This would be the case for the shale gas basins in our study with the exception of the Barnett; in other words, a high initial decline rate that was observed in Haynesville, Eagle Ford, Fayetteville and Woodford Shales would lead to an underestimation of EUR if DCA was performed too early in the well’s life.

The Barnett itself showed exceptional behavior compared with the other basins because of its gradual decline rates early in time. Performing DCA too early in a Barnett well’s life, from the core area of our study, is likely to cause an overestimation of reserves. Where production data exists for short timeframes it would be desirable to perform DCA for a different amount of this historical data to assess the variation of the ‘b’ exponent with this historical data and whether a trend can be established that will allow for a better estimation of gas reserves.

Fig. 27: Effect of differing number of years of historical production data for Woodford DOFP 2006 scenario
Fig. 28: Effect of differing number of years of historical production data for Fayetteville DOFP 2005 scenario

Fig. 29: Effect of differing number of years of historical production data for Barnett DOFP 2003 scenario
Economic Analysis

The gas production forecasts generated from the type curves for the various shale plays discussed above were used to perform a basic economic evaluation using economics software that allowed the input of gas volume, gas price, capital and operating costs, and royalties. Discount profitability indexes (DPI) and return on revenue (ROR) before tax (BT) and after tax (AT) were calculated for all shale gas basins for wells drilled in 2008 and 2009. Wells were chosen over this time frame as they are the most representative of the latest use of technology, efficiencies, production, and cost. DPI is defined as:

\[ DPI = \frac{NPV + I}{I} \]

Where I is the estimated investment over the well’s life discounted to the present and NPV is the net present value of the well assuming a gas price of $4/Mscf for the entire life of the well.

Table 2 shows the input data utilized to estimate economical parameters for each basin.

<table>
<thead>
<tr>
<th>Play</th>
<th>Well Cost</th>
<th>Royality</th>
<th>Operating Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Haynesville</td>
<td>8</td>
<td>25</td>
<td>2.5</td>
</tr>
<tr>
<td>Eagle Ford</td>
<td>5.8</td>
<td>25</td>
<td>1.5</td>
</tr>
<tr>
<td>Barnett</td>
<td>3</td>
<td>22</td>
<td>0.7</td>
</tr>
<tr>
<td>Fayetteville</td>
<td>2.8</td>
<td>17</td>
<td>1.1</td>
</tr>
<tr>
<td>Woodford</td>
<td>6.7</td>
<td>19</td>
<td>1.15</td>
</tr>
</tbody>
</table>

Discount rates of 0%, 10% and 15% were used to perform the basic economic analysis. The results of the economic analysis including DPI BT, ROR BT, and EUR are shown in table 3:

<table>
<thead>
<tr>
<th>Case</th>
<th>Before Tax @ $4/MScf</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>DPI @ 0%</td>
</tr>
<tr>
<td>Barnett_DOFP_2008</td>
<td>2.11</td>
</tr>
<tr>
<td>Barnett_DOFP_2009</td>
<td>2.09</td>
</tr>
<tr>
<td>Fayetteville_DOFP_2008</td>
<td>1.95</td>
</tr>
<tr>
<td>Fayetteville_DOFP_2009</td>
<td>2.69</td>
</tr>
<tr>
<td>Woodford_DOFP_2008</td>
<td>0.71</td>
</tr>
<tr>
<td>Woodford_DOFP_2009</td>
<td>0.94</td>
</tr>
<tr>
<td>Haynesville_DOFP_2008</td>
<td>0.29</td>
</tr>
<tr>
<td>Haynesville_DOFP_2009</td>
<td>0.38</td>
</tr>
<tr>
<td>Eagle Ford_DOFP_2009</td>
<td>0.83</td>
</tr>
</tbody>
</table>
For this analysis a given well is profitable if the DPI > 1.0 at given interest/discount rate. Therefore, the only cases showing profitability at $4/MScf gas were wells drilled in the Barnett and Fayetteville during 2008 and 2009. Despite having a very high initial production and relatively higher EUR, the Haynesville was calculated to be uneconomical at $4/MScf gas in this study. Table 4 shows the gas price required for a particular basin to break even assuming a discount rate of 10%.

### Table 4 – Break-even gas price per shale gas basin

<table>
<thead>
<tr>
<th>Case</th>
<th>EUR, Bcf</th>
<th>Gas Price (DPI @ 10% =1)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Barnett_DOFP_2008</td>
<td>2.895</td>
<td>3.7</td>
</tr>
<tr>
<td>Barnett_DOFP_2009</td>
<td>2.867</td>
<td>3.74</td>
</tr>
<tr>
<td>Fayetteville_DOFP_2008</td>
<td>2.463</td>
<td>3.65</td>
</tr>
<tr>
<td>Fayetteville_DOFP_2009</td>
<td>3.401</td>
<td>3.2</td>
</tr>
<tr>
<td>Woodford_DOFP_2008</td>
<td>2.544</td>
<td>7.35</td>
</tr>
<tr>
<td>Woodford_DOFP_2009</td>
<td>3.389</td>
<td>6.22</td>
</tr>
<tr>
<td>Haynesville_DOFP_2008</td>
<td>4.579</td>
<td>6.95</td>
</tr>
<tr>
<td>Haynesville_DOFP_2009</td>
<td>6.092</td>
<td>6.1</td>
</tr>
<tr>
<td>Eagle Ford_DOFP_2009</td>
<td>3.793</td>
<td>6.24</td>
</tr>
</tbody>
</table>

It is important to note that the actual drilling, completing, stimulating, and operating costs may vary greatly from operator to operator resulting in a large impact on overall economics. Some operators may have better production in a given core area versus others, further improving economics. In addition, nearly all operators have a portion of their gas prices hedged at levels that may make all or most of the shale plays analyzed economical. As the production continues to improve due to enhancements in technology (drilling, completion, and stimulation) and efficiency, the economics will continue to improve as long as costs remain in check. Due to the small number of wells and short production history of the Eagle Ford, the EUR and resultant economic analysis has greater uncertainty than for the other shale plays.

**Conclusions**

The data suggests that there is a clear distinction in the IPs across the shale basins for horizontal wells drilled in 2008 and 2009: Haynesville IP > Eagle Ford IP > Woodford IP > Fayetteville IP > Barnett IP. The Haynesville Shale IP is considerably higher than other Shales and is primarily due to higher reservoir pressure along with an aggressive drilling, completion, and stimulation approach.

An increase in IP was observed across all shale gas basins analyzed in this study (with the exception of the Barnett Shale) as DOFP increased from 2005 through 2009. This was due primarily to improvements in drilling, completion practices, stimulation designs, and knowledge gain over time.

For the Barnett Shale wells analyzed in this study, IP remained essentially the same from 2005 through 2009. During this timeframe, completion and stimulation practices have changed but may not be optimized resulting in no obvious additional gain in production. The curvature and natural fractures may act in tandem to dictate the volume of rock effectively stimulated during the hydraulic fracture propagation, reducing the impact of hydraulic fracture size, staging, and design.

The Barnett Shale also showed a distinctive flatter production decline trend in the study area compared to the other four basins. The Barnett would therefore not serve as a representing analog shale play for estimating production declines in other shale gas plays. The use of Barnett Shale ‘b’ exponent will cause predicted EURs to be overly optimistic and may reflect the upper bound or P90 of wells in other shale gas basins.
Decline curve analysis of tight gas sandstone vertical wells with almost 30 years of production data shows Arps ‘b’ exponent of 1.28 indicating that b exponents greater than 1.0 are realistic in unconventional gas reservoirs.

Decline curve analyses performed over different lengths of historical production data showed that the ‘b’ exponent increases with the length of available production data, reflecting the high initial decline rates in shale gas reservoirs, and the moderate decline rates at later times. The converse was true for the Barnett Shale with the ‘b’ exponent decreasing with the length of available production data. A great deal of uncertainty therefore exists in the estimation of EUR in shale gas reservoirs from decline curve analysis where a small amount of historical production data exists.

Horizontal Cotton Valley sandstone wells showed steeper declines than both vertical tight gas and horizontal shale gas wells. The Cotton Valley horizontal well production type curve and ‘b’ exponent formulated in this study could be used as a benchmark to provide a lower-limit or P10 for production in horizontal shale gas.

Similar declines in early time between vertical and horizontal Barnett wells despite a five-fold difference in their IPs implies that the factors affecting a horizontal Barnett well’s decline behavior are also affecting a Barnett vertical well decline trend.

Economic analysis of the data (DOFP 2008 and 2009) in this study showed that for $4/MScf gas price, only horizontal wells drilled in the Barnett and Fayetteville are economical. The Haynesville, Eagle Ford and Woodford shale gas plays require a gas price of just over $6/MScf to break even at 10% discount rate as seen from production profiles of wells drilled in 2009. This is an improvement over the economics of wells drilled in 2008 in these plays when break even gas price was around $7/MScf.

Acknowledgements

The authors wish to thank Schlumberger management for permission to publish this work. Special thanks to George Waters, Rick Lewis, Brian Clark, Shirley Indriati, Kevin Blankenburg and DJ White for providing valuable guidance. Finally, thanks to our entire team for their analyses and reviews.

References