Focusing on short term economics and production gains from increased stage counts, Jason Baihly, Raphael Altman and Isaac Aviles, Schlumberger, USA, explain the performance of selected groups of Bakken wells in the Williston Basin.

Has the economic stage count been reached in Bakken wells? The answer depends on numerous factors in six well groupings in North Dakota selected by well density, activity, geology, well orientation and multistage well fracture stimulation.

Despite differences in payout, net present value (NPV) and the discounted profitability index (DPI) of the groupings, one thing remains constant throughout the play: activity in the Williston Basin continues at a frenetic pace as operators exploit the Middle Bakken and Three Rivers formations and help drive a resurgence in US oil production.

North Dakota’s active rig count remains near 200. Production has soared six fold - from 100 000 bpd in 2005 to 600 000 bpd in 2012 - as operators continue to employ horizontal drilling technology and more hydraulic fracture stages.

Economics
Economic factors influencing the Bakken boom include takeaway prices at roughly US$ 85/bbl. The economic floor ranges from US$ 55 to US$ 60/bbl. A more conservative estimate places the limit at US$ 75/bbl.

In 2011 and 2012, Bakken wells typically cost US$ 6 - 10 million, depending on lateral length, fracture stage count, fracture stage size and proppant materials. Completion costs account for 25 – 50% of well cost.

Costs per stage range from US$ 50 000 to US$ 200 000 or more. The average is US$ 125 000. Operating costs vary from less than US$ 5/bbl. to US$ 14/bbl., and finding and development (F&D) costs US$ 10 to US$ 27/bbl., with a median value of approximately US$ 18.
The study determined economic stage count groups geographically to reflect changes in natural fractures, reservoir quality, net pay and lateral length.

The model well cost was US$ 4.7 million, per stage treatment cost US$ 125,000, base case oil price US$ 80/bbl., royalty 20%, state tax rate 11.5%, discount rate 10%, and oil gravity 41˚ API. Using today’s dollars in each case, the operating cost was US$ 6/bbl.

Although well economics vary by operator, most wells should generate positive cash flow and/or payout in one to five years.

Each grouping contained at least 30 single-leg horizontal wells completed with multistage stimulation isolation systems. System types were not considered because most consisted of open hole cased laterals with external casing packers.

**Analysis method**

Public available data from North Dakota wells were used for this analysis. Wells were selected based on five parameters: 1) well density, 2) drilling activity, 3) geology, 4) well orientation, and 5) multistage well activity. To account for statistical significance, groups were required to have no less than 30 wells in them. To account for reservoir and production considerations, no major geological structures were allowed to cut through the geographical area of each group.

The objective was to evaluate the production impact of stage count within a given group. For this purpose, production data was normalised, with respect to time, to generate production type curves.

Production data was quality assured/quality controlled. A well was removed if it presented one of the following: a) an indeterminate stage count, b) it was re-fractured or it had more than one lateral leg, or c) its production decline trend was not well characterised (such as production rate increasing with time, dramatic variations in production rate over small time periods) and the root cause could not be identified.

**Well groupings**

Six well groups were identified, which included the Parshall field (PAR), Sanish field (SAN), Stanley, Robinson Lake, and Alger fields (SRA), Murphy Creek and Fayette fields (MKF), Elidah, Silverston, North Tobacco Garden, South Tobacco Garden fields (EST), and Dollar Joe, Wheelock, and Brooklyn fields (DWB).

The PAR and SAN groups were the only two that exhibited a positive NPV within three years.

**PAR**

PAR included 96 wells (Table 1). All but one had 25 stages or fewer. Laterals extended from 4700 to 9600 ft.

Wells with 13 stages or fewer were optimum, although individual production declines varied widely. Wells with fewer than 10 stages and 10 - 13 stages broke even in 12 months and 18 months, respectively.

The Parshall Field’s extremely conductive fracture fairway likely explains why lower stage counts have equivalent or more production. Wells with fewer than 10 stages had the best overall production, followed closely by wells with 10 - 13 stages and 22 - 25 stages. Each had similar decline behaviours and the greatest amount of proppant per stage.

Wells with 14 - 17 stages, 18 - 21 stages and 22 - 25 stages had highly variable production.

**SAN**

The Sanish Field grouping, with the highest DPI and NPV, contained 189 wells (Table 2). Stage counts ranged from five to 40 and lateral lengths from 2000 to 10 600 ft.
With the exception of wells with fewer than 10 stages, the lateral length average was 8500 - 9400 ft. Stage spacing decreased as the stage count increased.

Stage spacings of 500 ft experienced greater production. Long laterals of 8000 ft or more were also good producers. The 18 - 21 stage dataset had the highest production, followed by wells in the 30 - 33 set and those with more than 37 stages. Just behind were wells in the datasets of 10 - 13 stages, 14 - 17 stages and 22 - 25 stages. Wells with fewer than 10 stages and 26 - 29 stages were the lowest producers.

Pay out was two years or sooner for wells with fewer than 10 stages, 10 - 13 stages, and 18 - 21 stages. The 18 - 21 stage dataset had the highest NPV of any group analysed. The 26 - 29 and greater than 37 stage datasets had the lowest economics.

**SRA**

The SRA group contained 95 wells with eight to 39 stages per lateral and lateral lengths from 4500 to 11 100 ft. For the most part, wells with fewer than 22 stages had an average lateral length of 5700 - 6600 ft. Wells with stage counts of 22 or more averaged 9500 – 10 200 ft.

The 12 month DPI and NPV is comparable among the SRA datasets. The optimum stage range appears to be 22 - 37, followed by wells in the 10 - 13 range.

### Table 1. PAR field dataset well completion summary

<table>
<thead>
<tr>
<th>Stage interval</th>
<th>Well count</th>
<th>Avg. lateral length (ft)</th>
<th>Avg. stage spacing (ft)</th>
<th>Avg. proppant amount per stage (lbs/stg)</th>
<th>Avg. proppant amount per lateral foot (lbs/ft)</th>
<th>Avg. fluid volume per stage (bbls)</th>
<th>Avg. fluid volume per lateral foot (bbls/ft)</th>
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<td>413</td>
<td>147 144</td>
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<td>314</td>
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<td>18 - 21</td>
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<td>6326</td>
<td>319</td>
<td>126 754</td>
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<td>22 - 25</td>
<td>7</td>
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<td>386</td>
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### Table 2. SAN field dataset well completion summary

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<tr>
<th>Stage interval</th>
<th>Well count</th>
<th>Avg. lateral length (ft)</th>
<th>Avg. stage spacing (ft)</th>
<th>Avg. proppant amount per stage (lbs/stg)</th>
<th>Avg. proppant amount per lateral foot (lbs/ft)</th>
<th>Avg. fluid volume per stage (bbls)</th>
<th>Avg. fluid volume per lateral foot (bbls/ft)</th>
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<td>696</td>
<td>163 426</td>
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<td>934</td>
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<tr>
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ranging from 1800 – 2000 bbls per stage, with the exception of the 10 – 13 stage dataset.

Average fluid pumped per lateral foot ranged from 2.8 to 7.2 bbl./ft. Higher stage count wells tended to have more fluid pumped per lateral foot.

**MKF**

The MKF group contained 48 wells with stage counts ranging from 10 to 54. Laterals overall ranged from 6600 to 10 400 ft with average laterals confined to a fairly small band between 9300 – 10 100 ft.

The 22 – 25 stage dataset is the most economic across six, 12 and 18 months. This is followed closely by the 14 – 17 stage dataset, which is catching up because the average decline rate is less severe.

The lowest and highest stage count groups have the worst economics. Small alterations in fracture stage costs can alter the results. The 10 – 13 stage grouping is the most economical, followed by the 18 – 21 stage dataset. Stage counts greater than 21 and less than 10 have poor economics.

Laterals with lower stage counts were the poorest producers. The well grouping with greater than 37 stages had the second lowest production in the area. The 22 – 25 stage dataset was the highest producer. Production declines are similar in datasets with 30 - 33 stages, 18 - 21 stages and 14 - 17 stages.

Stage spacing is a key. Wells need at least 600 ft spacings or lower to perform well. The optimum stage count could be more than 13 and less than 37.

Proppant and fluid metrics are not drivers. The average amount of proppant per stage was 86 000 – 100 000 lbs/stage, with the exception of the 10 – 13 stage dataset. Proppant per lateral foot was low compared with other groups, ranging from 170 to 380 lbs/ft.

There is a correlation between average proppant amount per lateral foot and stage count. As the stage count increases, the proppant per lateral foot increases. Average fluid volume per stage decreased as the stage count increased, with the exception of the wells with more than 37 stages.

The average fluid pumped per lateral foot ranged from 4.1 to 5.0 bbls/ft, with the dataset of more than 37 stages being the outlier.

**EST**

The EST group contained 46 wells. All but two had a stage count of 16 or more. Laterals ranged from 8900 to 9900 ft, with the exception of the wells in the 14 - 17 stage dataset. Similar to other groups, stage spacing decreased as the stage count increased, with the exception of the 14 - 17 stage dataset.

Small changes in fracture stage costs can alter results. Although production time is limited in the EST group, the 10 - 13 stage dataset is the most economical, followed by the wells with 18 - 21 stages. Stage counts more than 21 and less than 10 have poor economics.

The 30 - 33 stage dataset had the highest initial production and least decline, followed by a cluster with more than 37 stages, 18 - 21 stages, 26 - 29 stages, and 10 - 13 stages. Datasets with 14 - 17 stages and fewer than 10 stages had the lowest production.

Laterals longer than 8000 ft appear to be key to productive success. Stage spacing of 500 ft or less correlates to greater production.

Proppant and fluid factors had no correlation to production behaviour. The optimum stage count in this area could be between 26 and 37 stages.

Average proppant per stage was fairly consistent between 94 000 and 112 000 lbs/stage, with the exception of the 10 – 13 stage dataset. The average amount of proppant per lateral foot extended from 200 to 380 lbs/ft, with the exception of one well with fewer than 10 stages.

The average fluid volume per stage of 1650 - 2550 bbls and average fluid volume per lateral foot of 4.1 - 6.8 bbls/ft had no correlation.

**DWB**

The DWB group contained 30 wells. All but two had 22 stages or more. Laterals averaged from 9300 to 9900 ft, with the exception of wells with fewer than 10 stages.

Similar to the other groups, stage spacing decreased as the stage count increased, with the exception of wells with fewer than 10 stages.

Most datasets have either six or six and 12 month production results. DWB wells with a 26 – 33 stage count were the most economical. All wells outside the range have lower economic results.

Laterals longer than 8000 ft were necessary to achieve productive success. Stage spacing of less than 350 ft had more production.

Fluid volumes of 2000 bbls or less per stage resulted in greater production. The rest of the proppant and fluid factors had little correlation to production results. In this area it appears that a stage count of 26 to 37 stages may be optimum.

**Conclusion**

The evolution of key drilling and completion practices over time has allowed economic production in the Bakken to determine the proper landing zone, as well as lateral drilling, mechanically isolated fracture stages and favourable commodity prices.

Over the last decade lateral lengths in the Bakken have increased from 4000 ft to 9500 ft. For the majority of wells analysed within this study, lateral length was over 8000 ft. Fracture stage counts have increased from three to 30 in the last five years. In general, as lateral length increases, stage spacing becomes denser per lateral foot. Decreasing stage counts have initiated a declining trend in the amount of proppant used in most of the groups studied.

The highest producing stage count datasets are not always the most economical. None of the laterals that had 37 or more frac stages in any of the areas were the most economical.

With the exception of the PAR group, and the 10 - 13 stage dataset in the EST group, the optimum economic stage range varies from 18 to 37 stages, but more analyses would better determine a more exact count in each area.

Given the analyses and economic assumptions, it appears that the economic stage count has been reached and surpassed in some parts of the Bakken. But shifting costs and commodity prices will change economics. Still, examining economic stage counts provides insight into how other unconventional oil plays can evolve in the future. 

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