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## Breaking Up Is Hard to Do: Creating Hydraulic Fracture Complexity in the Bakken Central Basin

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### Abstract

The Bakken drilling boom in North Dakota has seen a frenzy of activity over the past several years as operators sought to hold acreage and create value with the drill bit. This has been particularly true in the Central Basin portion of the Williston Basin where initial wells drilled prior to 2008 were uneconomic. However, advances in completion technology caused such a fundamental shift in economics that the whole Central Basin area of over 2500 square miles has been opened to economic development with ~100 rigs currently drilling in the region.

The most fundamental change in completion design has been the incorporation of “high-intensity” multi-stage fracturing. What makes Bakken completion design fundamentally different from recent shale gas developments has been the widespread use of uncemented liners with external packers in the open-hole lateral in order to create the multi-stage zonal isolation.

As operators have advanced the application of multi-stage completion techniques there has been a wide variety of completion equipment used and stimulation designs that have been pumped. This operator decided to employ a completion design that comprised:

- (i) An open-hole “uncemented” liner section;
- (ii) Annular zonal isolation created by swell packers;
- (iii) The use of “plug and perf” technology to individually open successive zones to stimulation;
- (iv) The pumping of slickwater fracture treatment fluids at high rate;
- (v) The use of high-quality ceramic proppant to generate the required fracture conductivity.

Production data are presented from 58 wells in which this completion and stimulation design has been conducted, which show that the use of this approach has resulted in well performance that is 25-45% superior to any other Bakken completion technique.

### Geology

The Bakken Formation (highlighted in red in **Figure 1**) is located within the Williston Basin, which spans southern Saskatchewan and Manitoba in Canada as well as North Dakota and Montana in the United States. The basin was formed as a subtle downwarping between the Superior Craton to the northeast and the Wyoming Craton to the southwest.<sup>2</sup> The Williston Basin is a gently dipping basin with very little structural deformation, with the exception of a small number of structural features including the Nesson Anticline and the Cedar Creek Anticline, as shown in Figure 1.

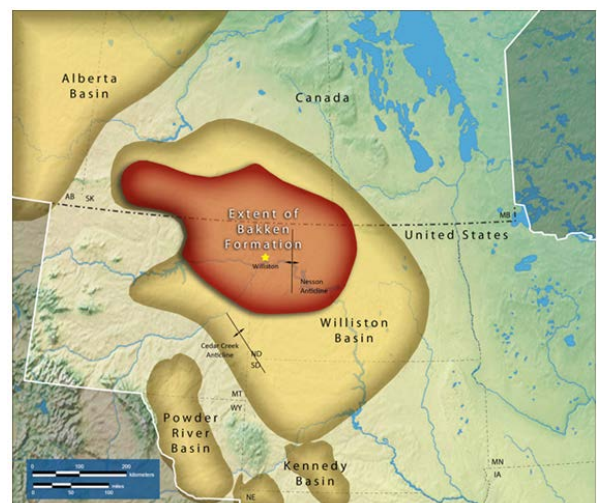
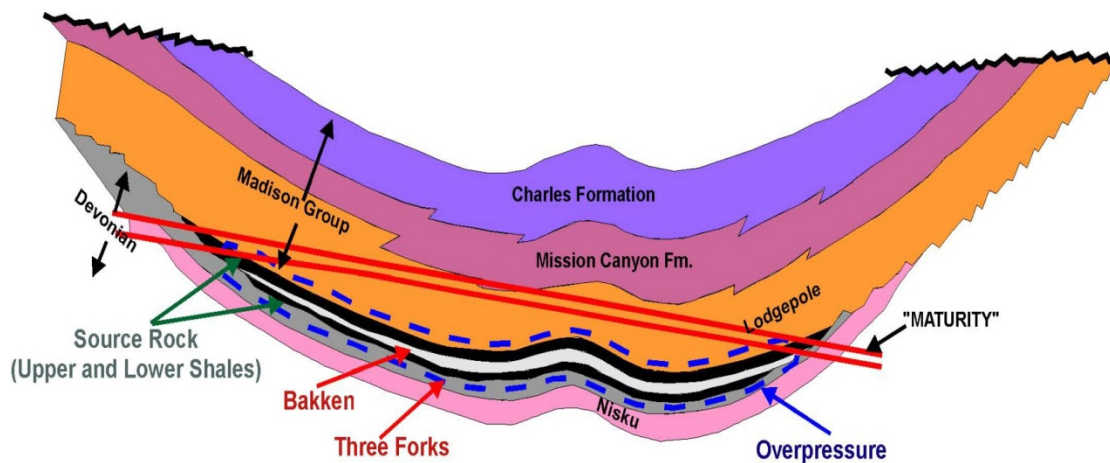


Figure 1—Location of the Williston Basin.<sup>1</sup>

The stratigraphic column (**Figure 2**) shows that the Bakken Formation is Mississippian and Devonian in age. It consists of the Upper, Middle and Lower Members of the formation. The focus of this paper is the Middle Bakken Member. As shown in **Figure 3**, the Bakken does not outcrop at the surface, making it a completely contained petroleum system. The Bakken petroleum system, which includes the underlying Three Forks Formation, has a top seal in the Lodgepole Formation, and a bottom seal in the Nisku Formation. Bakken oil saturations are highest in the deep center of the basin where thermal maturity was greatest, and in stratigraphic traps on the flanks of the basin.

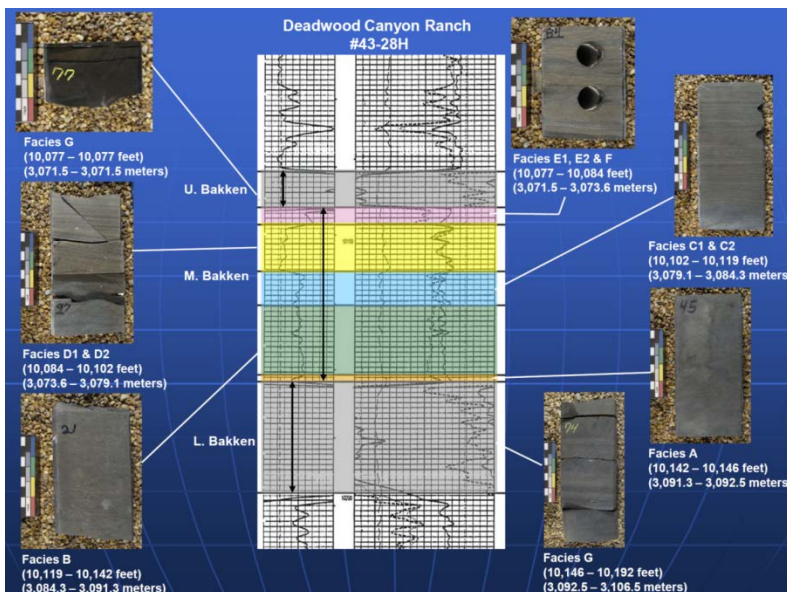
Mississippian	Lodgepole Formation	"False Bakken"
		Scallion
Devonian	Bakken Formation	Upper
		Middle
		Lower (Pronghorn)
	Three Forks Formation	

**Figure 2—Bakken stratigraphic chart.**



**Figure 3—Cross-section of Williston Basin formations.<sup>4</sup>**

**Figure 4** depicts the Bakken lithofacies using a compensated neutron-density log from the Sanish Field area on the east flank of the basin and core photos of the various lithologic facies. The Upper and Lower Bakken shales are the prolific source rocks for the petroleum system. The Middle Member consists of 5-7 distinct lithofacies that range from silty sandstone on the east flank of the basin to silty dolomite on the west flank of the basin. Porosities in the Middle Member range from 4-10% and permeabilities are generally less than 0.1 md.

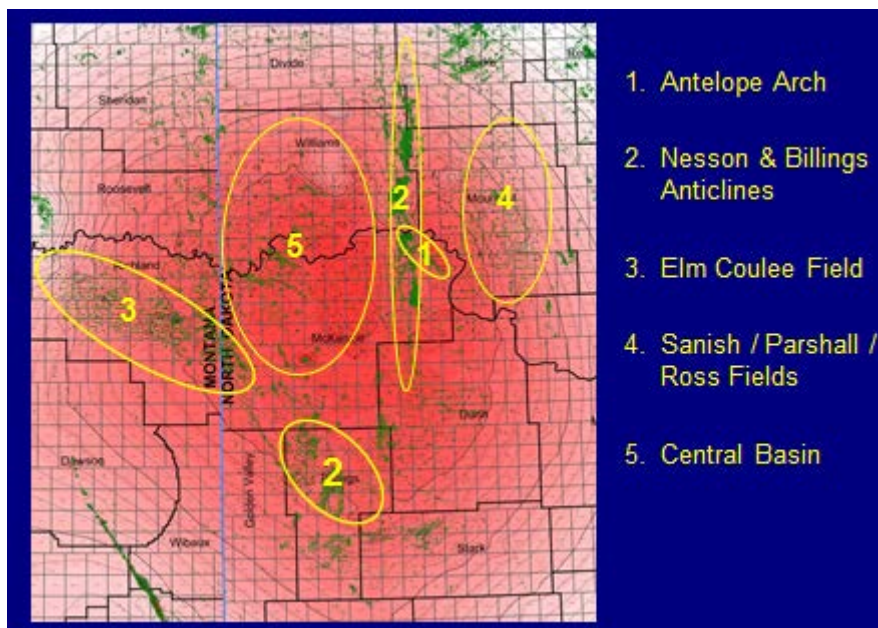


**Figure 4—Bakken lithofacies.<sup>5</sup>**

**Bakken Development History**

The first Bakken Formation well came on production in 1953 - just two years after first oil production in North Dakota. Drilling took place along the axis of the Antelope Arch - an anticlinal feature in eastern McKenzie County shown as the first development area in **Figure 5**. Over the next 15 years a total of 42 vertical wells were completed in the Middle Bakken and/or Three Forks formations. Commercial production was dependent on the existence of natural fractures associated with the uplift and could be correlated to the second derivative curvature in the formation.<sup>6</sup>

A second period of Bakken vertical well development occurred between 1970 and 1985 with wells drilled along two other structural features; the much larger Nesson and Billings anticlines. Drilling in the same areas occurred during the third period of development (1986 to 1999), which saw the first use of horizontal wells. These wells were typically completed with pre-perforated liners and generally consisted of single fracture treatments, often incorporating diversion materials in an attempt to generate multiple zones of stimulation.



**Figure 5—Structural Map with the main development areas in the Williston Basin.**

The discovery of a high porosity dolomitized carbonate shoal complex within the Middle Bakken at the Elm Coulee Field in Montana ushered in the next period of development in 2000. Horizontal drilling was used with open-hole single stage completions. The first ten wells all had cemented liners and some flowed after perforating without stimulation. The most significant productivity gains over the early years of Elm Coulee development came with the use of uncemented liners, and the drilling of many wells having multiple horizontal legs. Drilling of the dolomitized shoal facies also crossed the state line into North Dakota as shown in Figure 5.

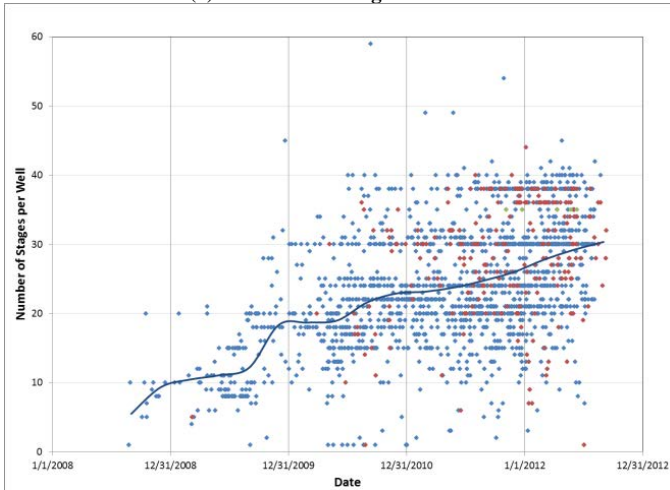
The broader significance of the Elm Coulee development was the realization that very large volumes of oil had been generated in the Upper and Lower Bakken shales and expelled into the Middle Bakken and Three Forks zones. This subsequently led in 2006 to the exploration and finding of higher porosity facies in the Ross, Parshall and Sanish fields on the east side of the Nesson Anticline. Well stimulation of these earliest wells typically involved the pumping of a single stage frac of ~2 million pounds of proppant and one million gallons of cross-linked gel. The first multi-stage fraced well was completed in the Parshall Field in 2007 and this technology was rapidly duplicated in other areas of the Williston Basin such that by 2008 the average stage count per well had reached ~10 fracs.<sup>7,8</sup>

**Figure 6** shows several plots with key completion parameters for wells completed since 2008. Hybrid and Cross-Linked gel fracture treatments are depicted for the Central Basin (red) and other areas of the Williston Basin (blue). Slickwater-only designs are shown in green. These data are all compiled from the North Dakota Industrial Commission public database<sup>9</sup>.

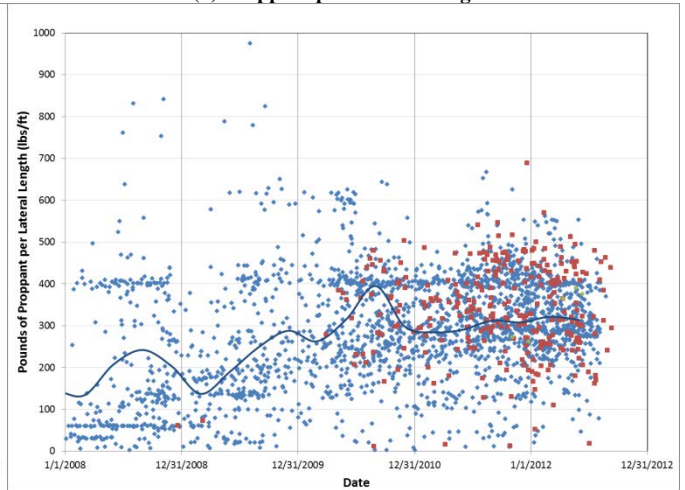
As can be seen from Figure 6a, the number of stages per well has steadily increased with time from an average of ~10 stages per well in 2008 to an average of ~30 stages per well by mid-2012. Part of this tripling in the number of stages per well is a consequence of the change in North Dakota spacing rules. Prior to 2010, operators could elect to permit either a single section 640-acre well or a dual section 1280-acre well, but in March 2010 the NDIC spaced the remaining extent of the Bakken reservoir on 1280-acre spacing; effectively requiring operators to drill ~9,500 feet laterals in order to hold a Drilling Spacing Unit (DSU). The effect of this can be seen in Figure 6f, where the average lateral length has increased from ~7,500 ft in 2008 to 9,500 ft in mid-2012 as the majority of current drilling is now occurring in 1280-acre spaced DSU's.



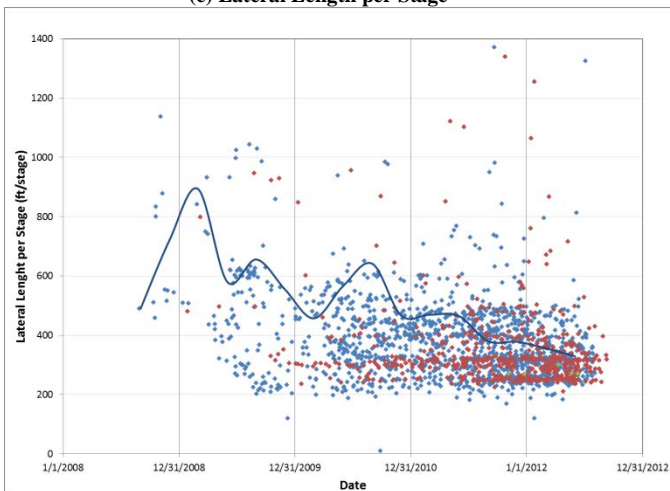
(a) Number of Stages



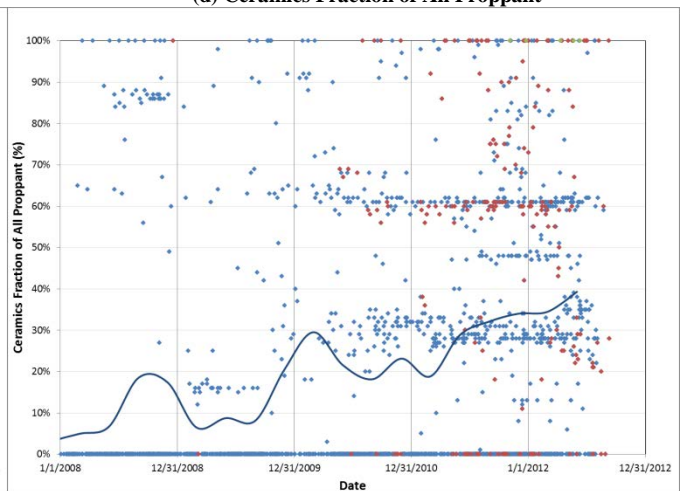
(b) Proppant per Lateral Length



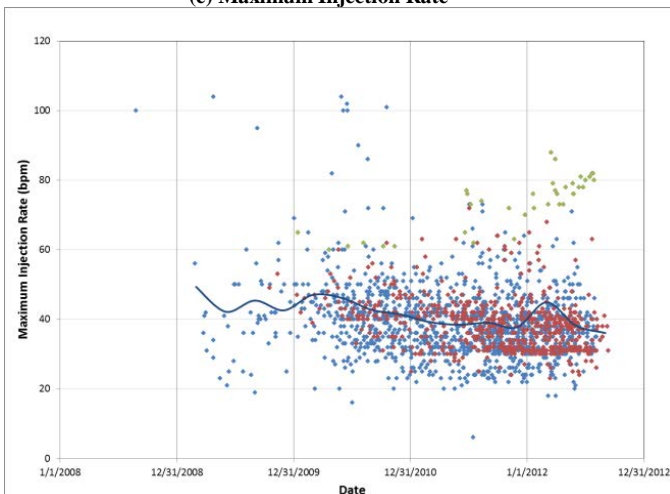
(c) Lateral Length per Stage



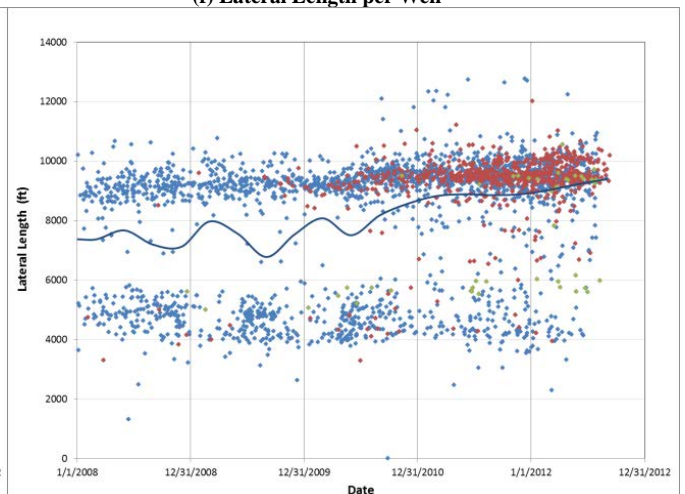
(d) Ceramics Fraction of All Proppant

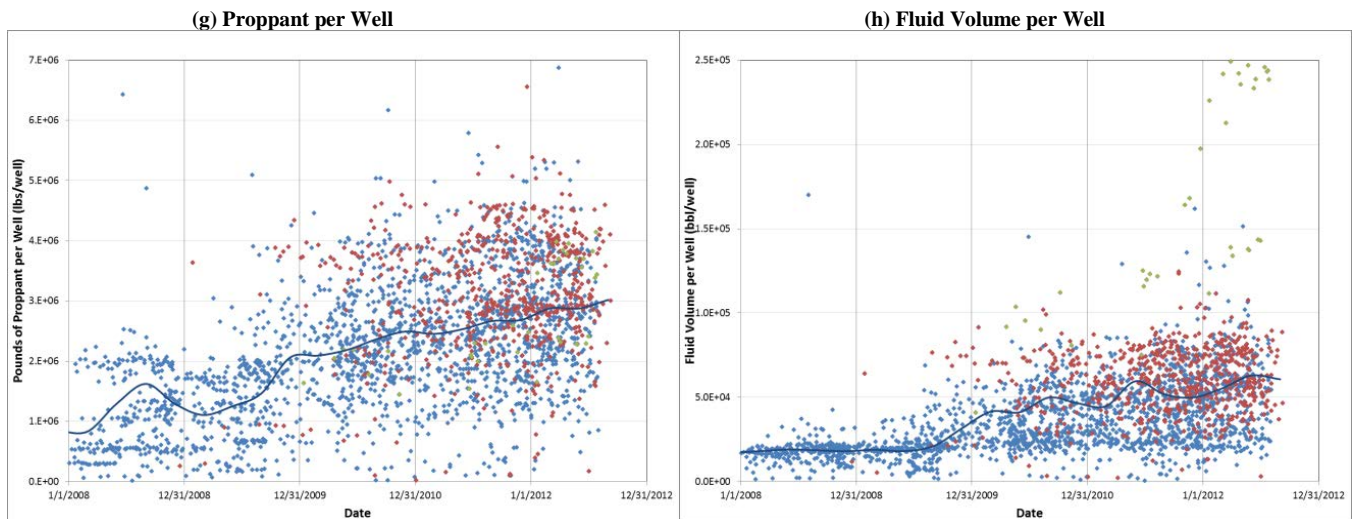


(e) Maximum Injection Rate



(f) Lateral Length per Well





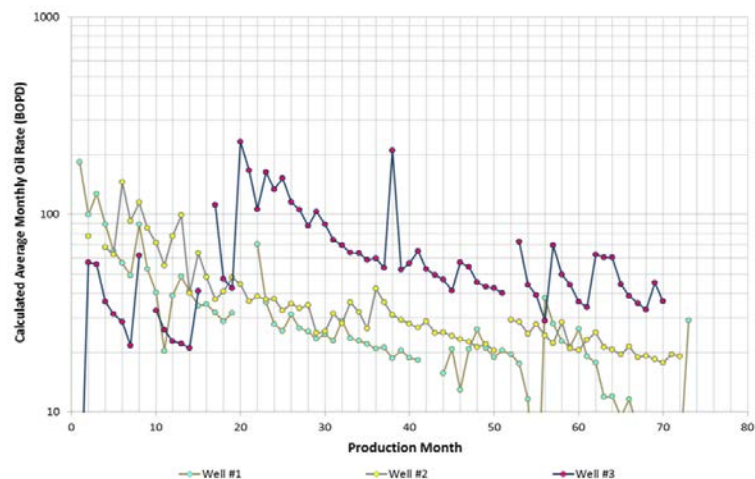
**Figure 6—Historical perspective for completion practices for all horizontal wells in the Williston Basin since 2008. Hybrid and Cross-Linked gel fracture treatments are depicted for the Central Basin (red) and other areas of the Williston Basin are shown in blue. Slickwater-only designs are shown in green.**

A number of other observations can be made from the data:

- (i) The total amount of proppant pumped per well (Figure 6g) has increased significantly with proppant placed per lateral foot increasing from ~100 lbs/ft to more than 300 lbs/ft (see Figure 6b).
- (ii) Proppant usage on a per stage basis has been slightly reduced over the last few years from about 150,000 lbs/stage to the current 100,000 lbs of proppant per stage (see Figure 6c).
- (iii) In most well stimulation the proppant used has been sand (see Figure 6d). Use of ceramic proppant, however, has increased from a very low base to a current average of about 40% of all proppant placed.
- (iv) Injection rate trends have decreased over time with most jobs treated in the range of 30 to 40 bpm (see Figure 6e). A notable exception to this is the slickwater-only stimulations which are typically pumped at rates in excess of 70 bpm.
- (v) Treatment volumes per well have gradually increased from 20,000 bbl per well in 2008 to about 60,000 bbl per well in 2012. The slickwater-only stimulations are significantly larger at about 230,000 bbl per well (see Figure 6h).

While the use of uncemented liner completions is standard practice in the Bakken, a number of other key completion design parameters need to be decided by operators on an individual well-by-well basis:

- (i) The number of completion stages;
- (ii) The method to access the reservoir in each completion stage – Plug and Perf or Sliding Sleeve, or a hybrid completion;
- (iii) The use of multiple perforation clusters or multi-port sleeves;
- (iv) The type of stimulation; Cross-linked gel, Slickwater or Hybrid;
- (v) Fluid volume to be pumped;
- (vi) Injection rate;
- (vii) Proppant types and amounts;
- (viii) The fracture treatment scheduling.



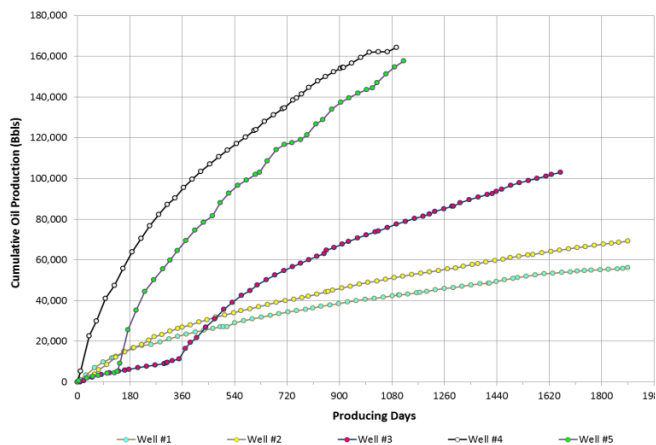
**Figure 7—Operator A – Production from the first three wells drilled in the Central Basin in 2006.**

### Initial Completions in the Central Basin

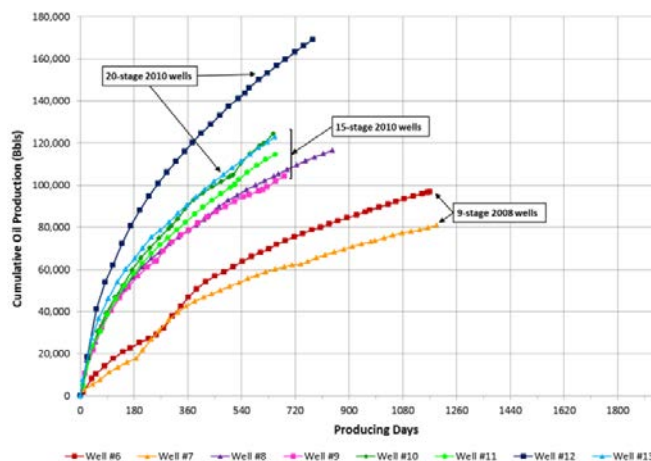
The first three wells in the Central Basin were drilled and completed in 2006. Completion and stimulation design mirrored common practices of the day using pre-perforated liners and single-stage stimulation treatments incorporating fluid diversion materials. Production results are shown in **Figure 7**; with early production of <100 bopd and average first-year production rates averaging <50 bopd these wells were uneconomic.

After ~18 months of production the liner was pulled from Well #3 and replaced with a 7-stage completion incorporating external packers. Figure 7 shows that after stimulation of all intervals the well's production was increased over five-fold. This paved the way for the drilling of two wells in 2008, which were completed with 20-stage completions. After stimulation of all zones, Wells #4 and #5 produced at 30-day rates of ~600 bopd and as shown in the cumulative production plot in **Figure 8** they had 90-day cumulative production in excess of 40,000 BO (note Well #5 was initially produced from a single stage due to a mechanical problem, but after stimulation of all 20 intervals it had similar production to Well #4). Similar results in the same general area were obtained by a second operator as they moved from 9 to 15 and then 20 stages per well as shown in **Figure 9**. **Figure 10**, the cumulative production plots from the first 13 wells completed by these two operators clearly shows the impact of increasing the number of stages from a single-stage to twenty stages per well with first year cumulative production increasing from <20,000 BO to over 100,000 BO.

A 2010 study<sup>11</sup> utilizing the early results from the Central Basin generated optimization curves for stage count per well for the then-current conditions and incremental production expectations for each stage at that time. For the given economics used in the study (including a WTI oil price of \$67.50, \$75 & \$90 per barrel in years 1, 2, 3+ and service costs existing in 2009) a peak Internal Rate of Return (IRR) was shown to be 25% for a well with 22 stages, while EUR per well leveled off at about 550 Mboe. The study, which was conducted across all Bakken development regions of the Williston Basin, gave correlations of  $R^2 = 0.91$  and  $0.96$  between 30-day and 90-day cumulative production and forecast EUR's predicted from later historical well production.



**Figure 9—Operator A – Cumulative production versus time from the first five wells drilled in the Central Basin in 2006 & 2008.**



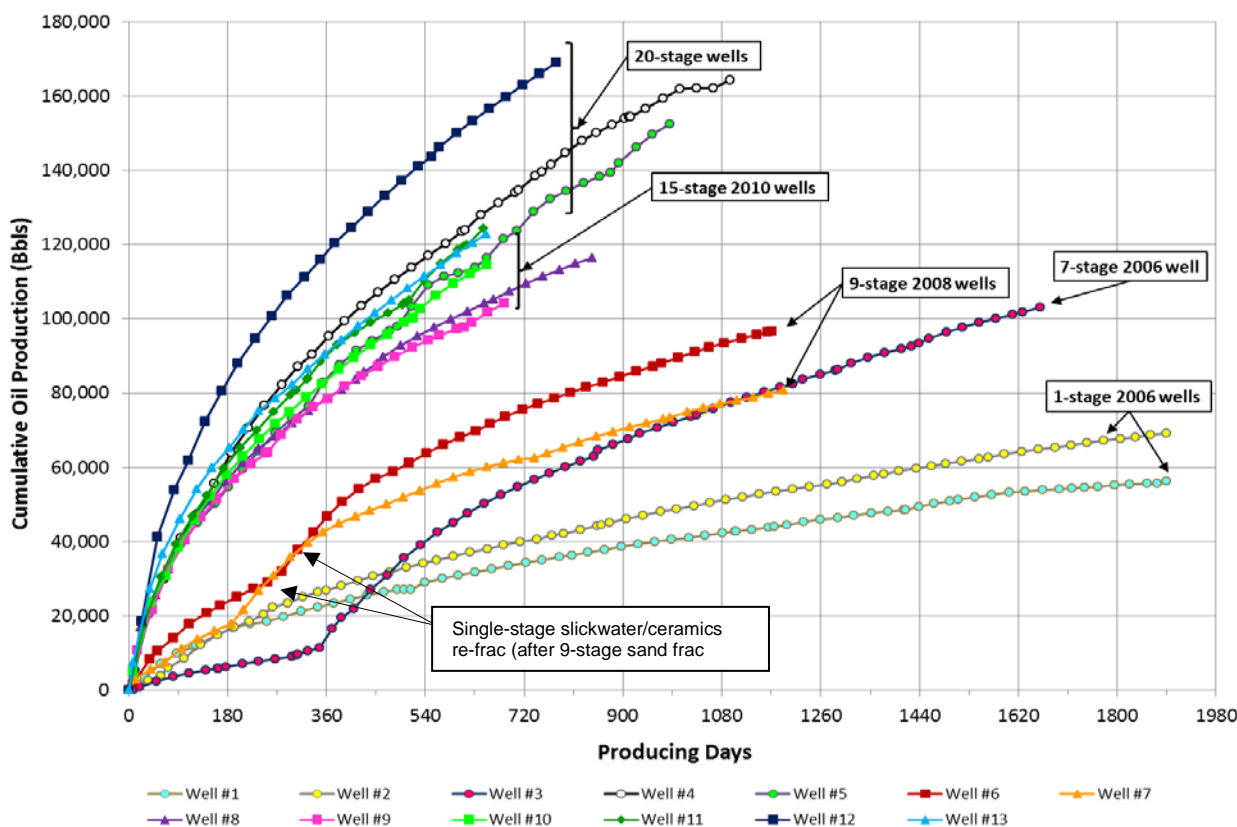
**Figure 8—Operator B – Cumulative production versus producing days for Central Basin wells 2008-2010.**

### Considerations for a Slickwater-Only Design

There are three critical completion and fracture stimulation design parameters affecting production from an unconventional resource formation:<sup>12-14</sup>

- (i) Stimulated Reservoir Volume (SRV),
- (ii) Fracture contact area within the SRV, and
- (iii) Fracture conductivity.

SRV is a measure of the extent of the reservoir coverage by the induced hydraulic fracture system and will define the total hydrocarbon in place contained within the stimulated volume. However, this does not quantify the degree of coverage, or density of hydraulic fractures, within the covered volume. Since early- and middle-time oil and gas flow will be controlled by the created fracture contact area and fracture conductivity both of these parameters are critical design parameters.

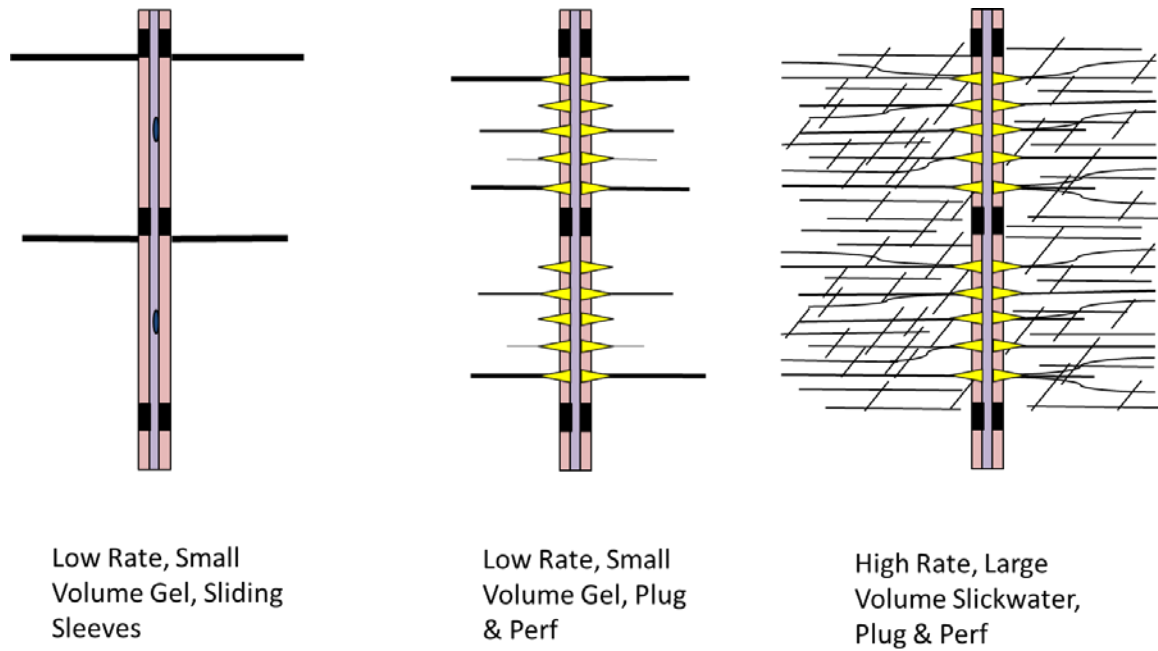


**Figure 10—Impact on cumulative production for Operator A and B initial wells (2006-2010). Note Well #5 production is time-offset until the stimulation of all zones was carried out.**

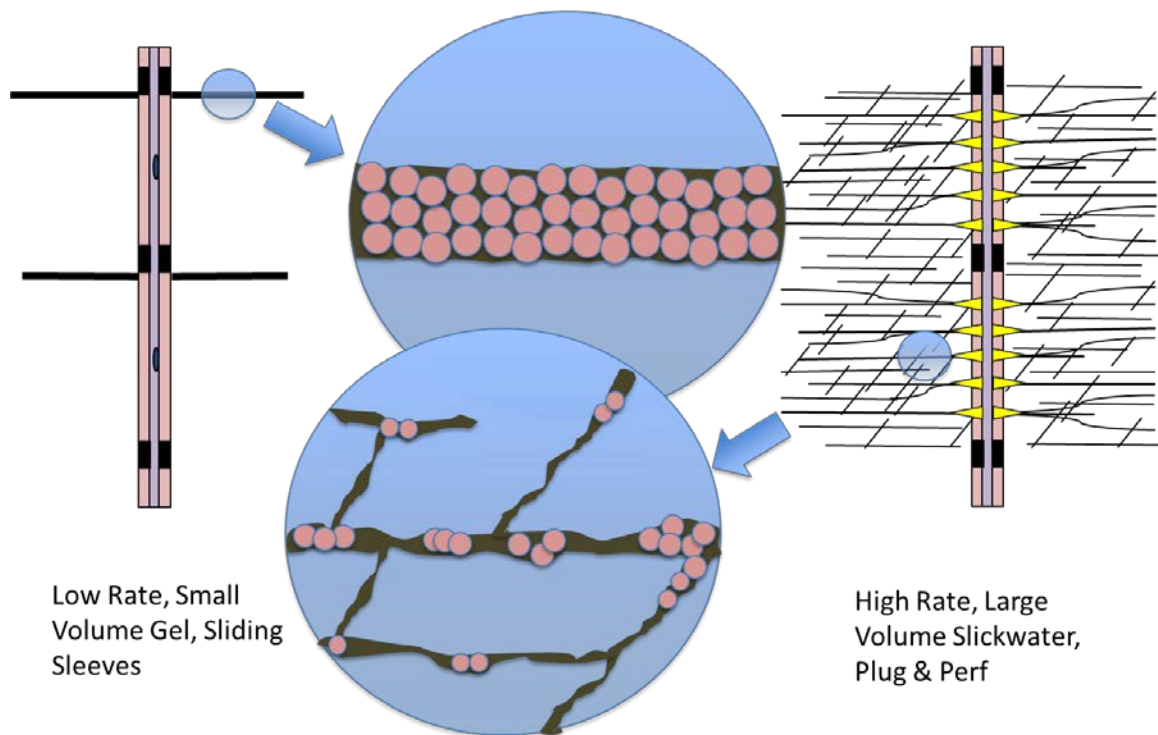
**Figure 11** shows the ability to create complexity and reservoir contact area through a fracture system depends on the well completion and the fracture treatment design. Low rate, high viscosity fracture fluids injected into an unperforated wellbore are likely to activate only a few pre-existing natural fractures which act as points of weakness. Alternatively, in the absence of natural fractures, basic rock mechanics dictates that a longitudinal fracture will be created axially along the wellbore. In contrast, a similar fluid system injected into a perforation cluster is likely to initiate new artificial fractures – as well as opening existing natural fractures. However, due to viscosity effects and stress shadowing it is likely that only a few dominant fractures will be extended into the reservoir. By contrast, as schematically shown in Figure 11, if the injection fluid is changed to a high-rate, low viscosity fluid such as slickwater there is both the likelihood of multiple fracture initiation points and the stimulation of a much more complex set of natural fractures. The ability to create more complexity with slickwater was first documented in re-fracture treatments in the Barnett Shale, where original fractures completed with gel showed both lower contact area as observed with micro-seismic mapping and lower production response than the slickwater re-fracs<sup>15</sup>. The ability of the Plug and Perf technique to act as points of fracture initiation has been documented in the field using micro-seismic mapping.<sup>16,17</sup>

As described in **Figure 12**, the fracture geometry created in a low-rate gel treatment in the absence of new fracture initiation points from perforations is most likely in the form of a single or a few dominant fractures having a fracture width several proppant grains wide.<sup>18,19</sup> In contrast, the fracture geometry for a high-rate slickwater treatment contains significantly more contact area, as the low-viscosity fluid may create more fractures in the preferred fracture plane, but possibly also penetrate into pre-existing weaknesses or natural fractures present in the rock outside this preferred fracture plane. Conservation of mass would suggest that a 10,000 bbl slickwater treatment, with perhaps 90% fluid efficiency and creating fractures of only 0.1" width, has the capacity to generate several million square feet of contact area within the Stimulated Reservoir Volume. In such a scenario, as proppant is distributed over a fracture network with significantly larger surface area, the proppant distribution per fracture is significantly less, and most likely only a partial monolayer. Due to the high complexity of the natural fracture system in the Bakken, and despite the larger amount of proppant which settles in the fractures due to poor proppant transport, the creation of partial proppant monolayers is probably more the rule than the exception in these treatments. Use of small-mesh proppant and stronger proppant helps transport these proppants deeper in the fracture system and provide more strength to provide the required fractured conductivity to sustain long-term enhanced productivity.





**Figure 11—The ability to create complexity and reservoir contact area through a fracture system depends on the well completion and the fracture treatment design.**



**Figure 12—The fracture geometry created in a low-rate gel treatment with sliding sleeves is most likely in the form of a single dominant fracture, whereas the fracture system created with a slickwater-only treatment through perforations results in significantly more surface area.**



Completion design parameters thus decided by the operator in order to maximize fracture contact area and complexity included:

- (i) Use of multiple limited-entry perforation clusters as a source of fracture initiation locations.
- (ii) To maximize fracture complexity through only pumping low-viscosity slickwater fluid.
- (iii) To pump at maximum rates as permitted by existing casing and liner designs (P-110 grade pipe with a 7" long-string and 4½" liner). This meant that friction effects limited injection rates to 70-80 bpm.

Stimulation design parameters to provide sufficient fracture conductivity included:

- (i) To define proppants which had the capacity to provide sufficient conductivity in partial monolayer or low concentration loadings of < 1 lb/ft<sup>2</sup>.
- (ii) To setup a test program for all potential proppants at actual stress and temperature conditions as exist in the formation through running a standardized long-term (50 hour) proppant conductivity test at 9,000 psi total stress and 250°F. This eliminated the potential for using sand proppants and dictated the need to run premium ceramic proppant in order to maintain effective conductivity.
- (iii) The use of surfactant and micro-emulsion additives to aid in the initial cleanup of the fracture face and propped fracture.

### Slickwater Implementation

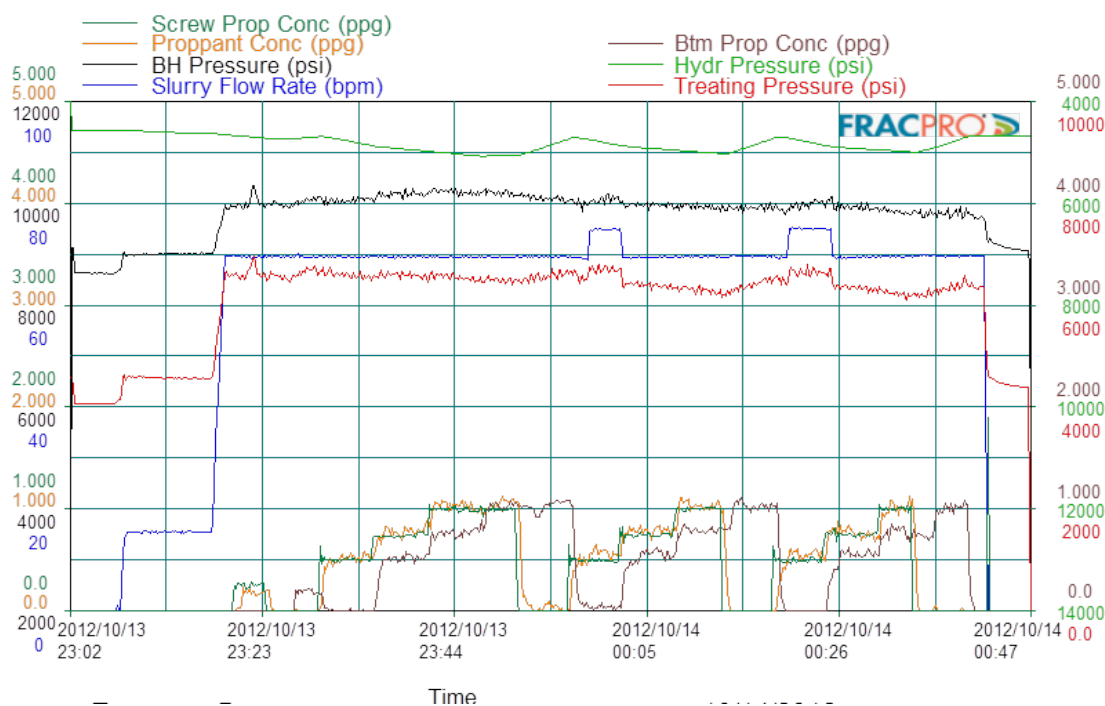
Bakken frac fleets are typically comprised of 6 to 8 pumping units since they were only required to pump at rates of 20 to 50 bpm (as shown in Figure 6). An 8-pump frac fleet injecting at 40 bpm and 7,500 psi has about 50% excess/standby pumping capacity. In order to inject slickwater fracs at up to 80 bpm and 9,500 psi it was required to have a minimum of 10 pumping units (12 with standby units) in the frac fleet.

While such a frac fleet is standard (and often significantly larger) in most of the gas shale areas which utilize slickwater fracturing, this was not standard in the North Dakota pumping service industry. For this reason, and also in part because of the lack of pumping service capacity in the basin during late 2010 and 2011, the operator developed its own capability to pump high-rate slickwater fracs through the launch of a service company with these capabilities. **Figure 13** shows these pumping services rigged up on location with 10 pumps in-line ready to pump a 35-stage stimulation on a well with a slickwater-only design.



**Figure 13—Bakken service company crew rigged-up for slickwater stimulation.**

The actual treating schedule for the slickwater fracs has undergone some changes over the past three years in order to get a design that can be routinely placed with minimal risk of screenout. While this may seem trivial given the large amount of slickwater fracturing that has gone on in gas shale formations, it should be noted that most of these stimulations occur in completions which are fully cemented. There is a significant difference with an uncemented liner where part of the slurry flow is travelling in the liner/open-hole annulus. Depending on the amount of flow in the annulus this has differing propensity to screenoff and can dramatically increase treating pressures. Due to the North Dakota ruling on 1280-acre spacing units, most new horizontal wells in the Central Basin are drilled in a north-south orientation. Given that the preferred fracture plane is oriented at N50°E in most of the Williston Basin, the fracture plane is therefore oriented at an oblique angle with the well orientation. This oblique orientation generally results in the most near-wellbore tortuosity challenges of any possible wellbore-to-fracture orientation<sup>10</sup>, thus providing an extra possible complication to the implementation of fracture treatments in general and slickwater treatments in particular. Recognizing this in real-time, and having a well-defined plan to deal with pressure increases is therefore key to risk mitigation and routinely placing slickwater fracs in short, uncemented completion intervals.



**Figure 14—Example Middle Bakken slickwater fracture treatment plot.**

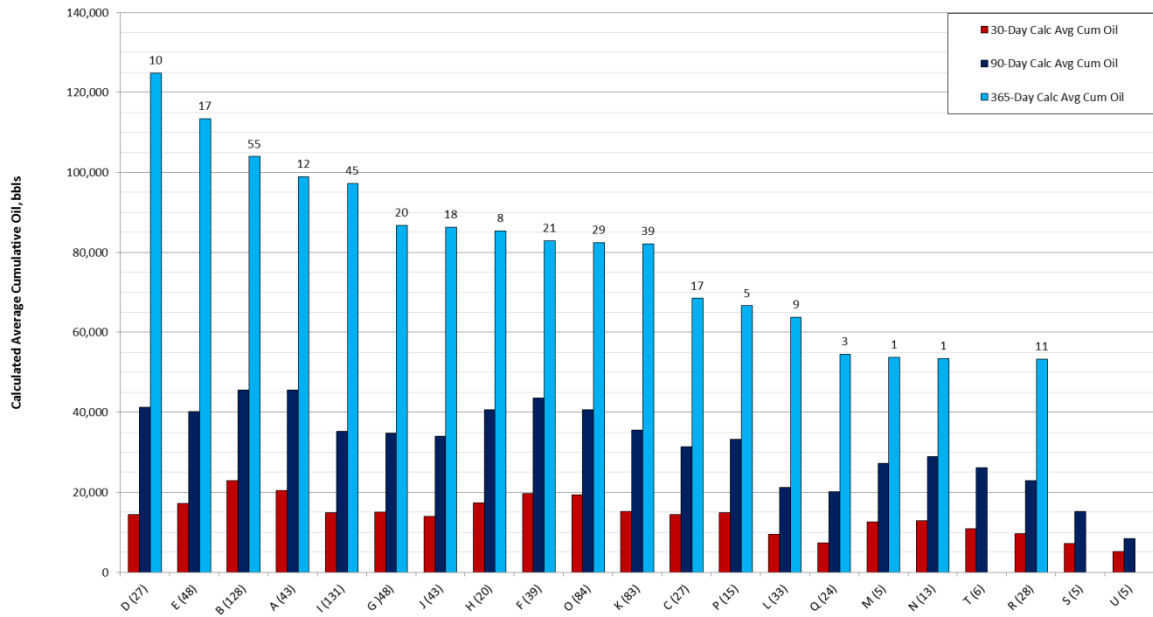
**Figure 14** is a typical treatment plot from a job in which no pressure anomalies due to annular flow effects or near-wellbore effects occurred. As shown, the current design includes limiting proppant ramps to only 1 ppa of proppant concentration and the use of 500 bbl sweep stages between ramps. We see varying levels of potential proppant placement problems in Bakken slickwater-only treatments, and we have evolved approaches to deal with these events, thus maximizing proppant placement while minimizing screen-outs. With more than 1,100 slickwater treatments performed in 2012 through the month of October, screen-outs have only occurred four times – and all in jobs pumped at the very beginning of the year, and not during the last 900 stages.

### Production Results

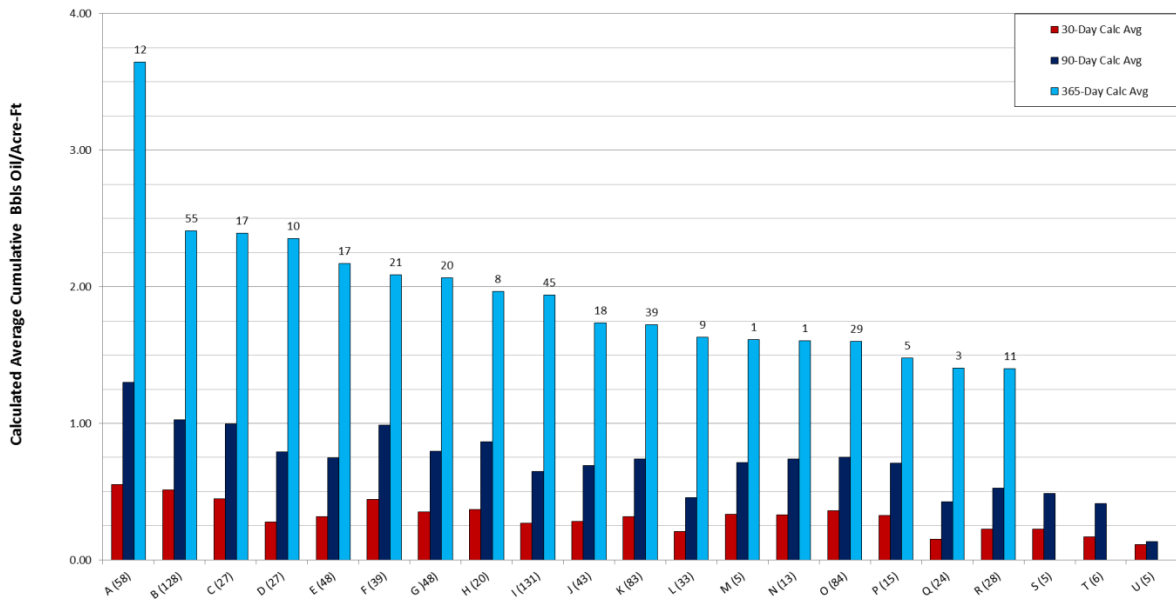
The Bakken is an over-pressured reservoir with pore pressure gradients in excess of 0.75 psi/ft in the deepest parts of the basin. As a consequence, post-frac flowback fluid volumes provide an almost immediate indication of stimulation effectiveness. It is not unusual to start cutting oil within the first 24 hours of flowback as formation fluids are produced in addition to the fracturing fluid.

Maximum production rates are typically generated during the plug or seat drillout phase since reservoir pressure is still charged by the injection of stimulation fluids. However, variation in drill-out procedures between operators does not make the initial flow data a suitable metric for direct comparison between different completion designs. Similarly, differences in flowback procedures and choke settings in the early-time operating philosophy of different operators can result in significant variation in 30-day cumulative production data.

**Central Basin Area - 870 Wells**  
(completions since 1/15/2009, production through Sep 2012)



**Operator Average Cumulative Bbls Oil/Acre-Ft - 870 wells**  
(completions since 1/15/2009, production through Sep 2012)

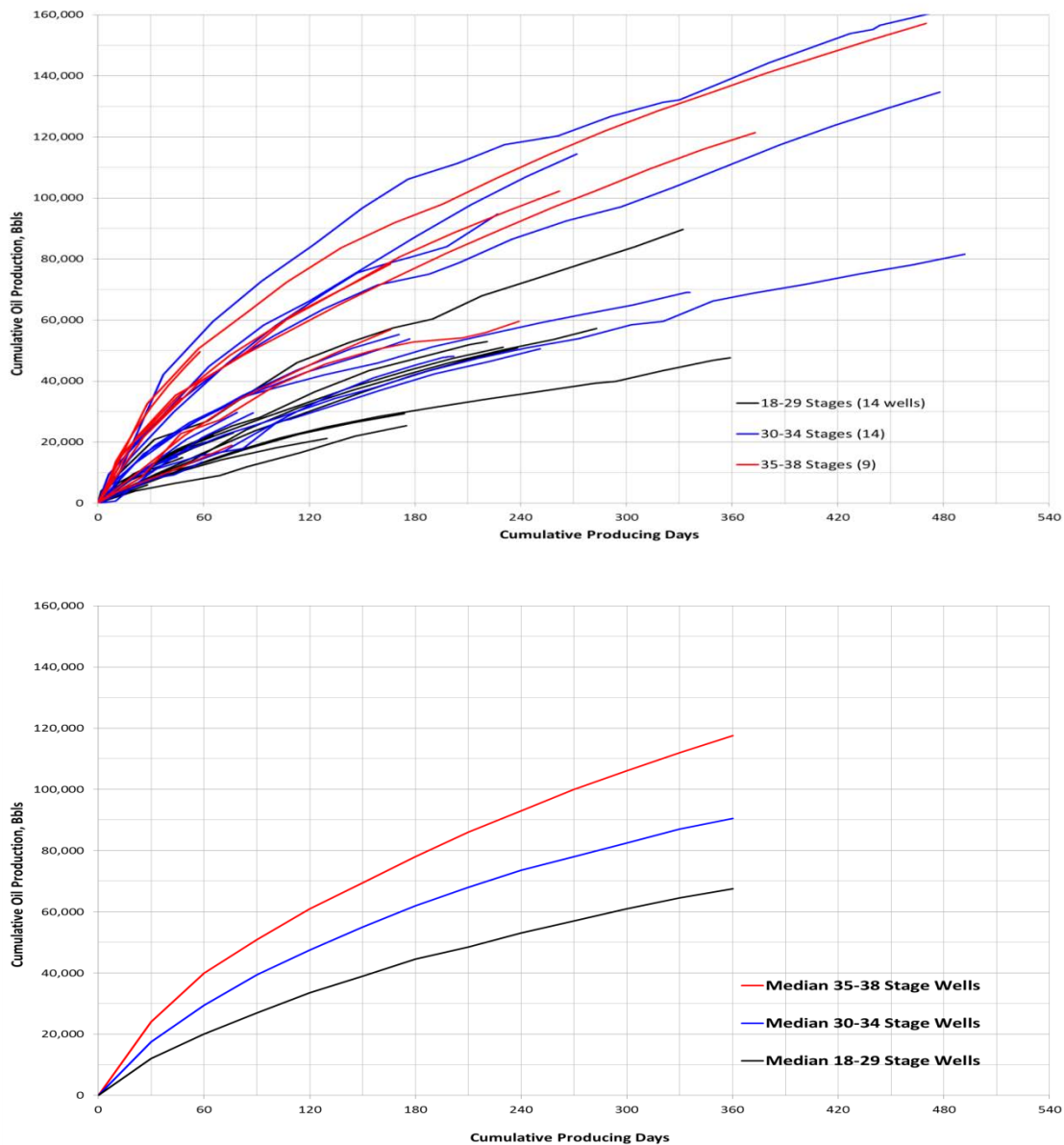


**Figure 15—30, 90 and 365 day production response (absolute production on top; production response as normalized by reservoir thickness and acreage per well on bottom), as sorted by operator, for all wells in the Central Basin. Well count for total # wells per operator shown next to operator label, well count for # wells with 365 days production given above that bar.**



The 2010 study of the Bakken formation had demonstrated an  $R^2$  correlation of 0.96 between 90-day production responses to forecast EUR's predicted from later historical production.<sup>10</sup> Intuitively this also seemed an appropriate time period for defining a quantitative production metric since it is beyond the period of initial high-drawdown in which different operating practices will be a significant driver of results.

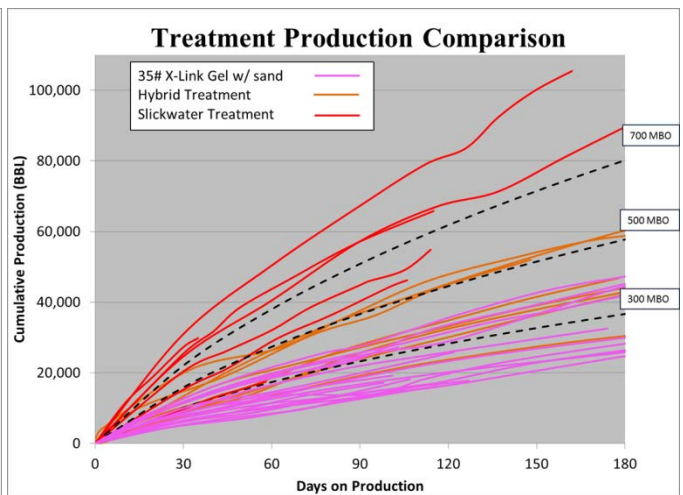
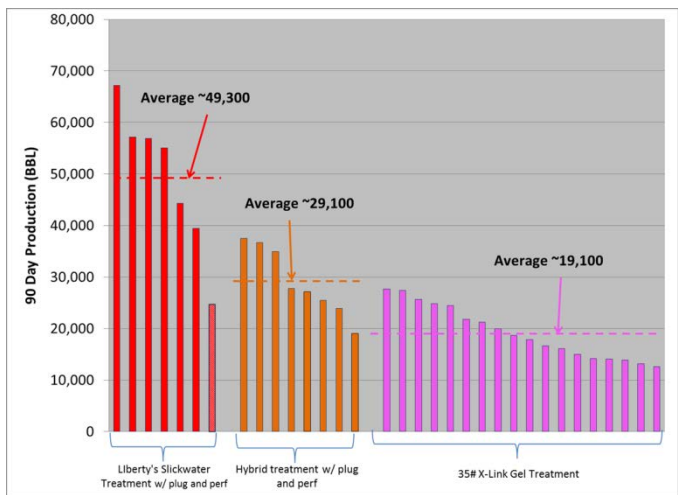
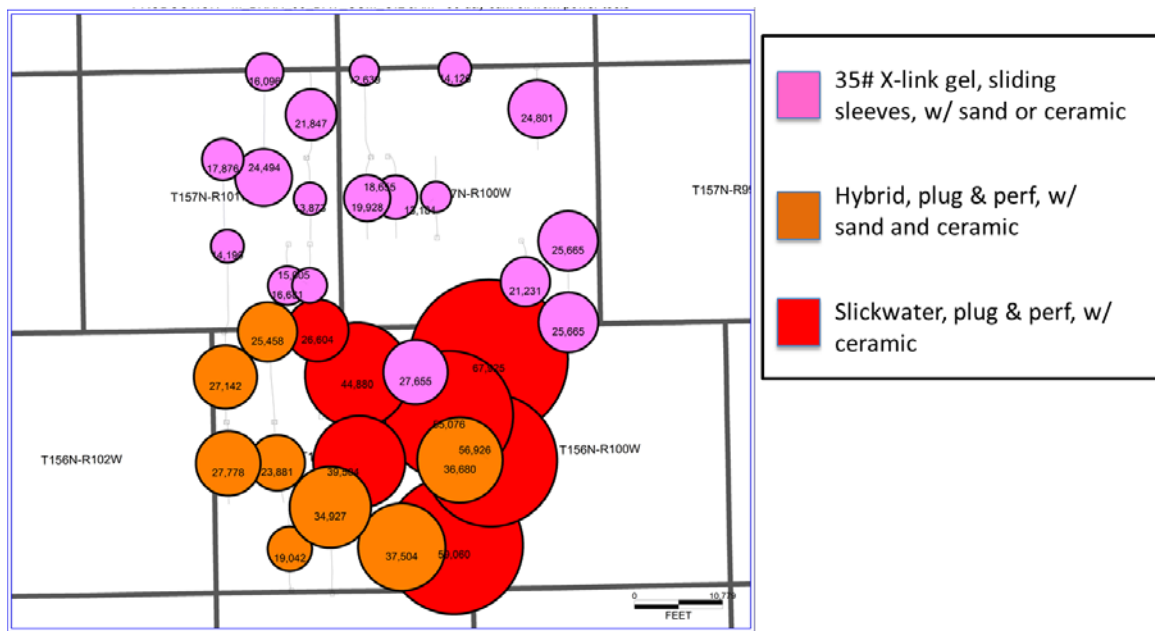
As of September 2012, there exist a total of 870 Central Basin wells in the NDIC public database which have at least one month of production data. **Figure 15** shows a bar chart of 30, 90, and 365 day data for all companies having at least five wells in the database. As seen in the data there is a wide range of performance. Normalizing the data to take into account whether the well is drilled in a 640-acre or 1280-acre DSU and for variations in the gross thickness of the Middle Bakken interval is shown in the lower plot of Figure 15. This shows that the Plug and Perf completion design with Slickwater & Ceramic Proppant fracs has over 25% better normalized cumulative production after 90-days of production when compared to any other completion and stimulation design; and over 45% better than any other design after 365-days of production.



**Figure 16—Impact on cumulative production response for subdivision of 10,000-ft lateral horizontal wells into more plug&perf stages. A total of 37 wells located in or surrounding Township 156N-R101W in Williams County (All 1280-acre wells completed after 1/1/2009).**

One of the perennial issues clung to by the nay-sayers of a high level of stimulation work is that the increased initial performance is merely rate acceleration and that after a few years of production the higher level of decline will ultimately result in equivalent cumulative production and similar EUR's. The vast majority of Central Basin wells are too early in their productive life to argue this point conclusively. However, Figure 15 shows that the differential benefit of slickwater completions is increasing with time during the first 365-days of production. Most notably, poorer performing completions after 30 and 90 days of production are still the lowest performing completions after 365 days of production. What is more, many of these poorer performing wells after the first year of production are experiencing similar decline rates to the higher performing wells.

While the above analysis was performed across the whole Central Basin it should be expected that geological variations could have a significant impact on the results. We have found that local correlations are more indicative and quantitative of the impact of completion parameters. An example is shown in **Figure 16** where 37 wells are compared, all within or surrounding Township 156N-R101W in Williams County. All of these wells are over 9,000 ft long laterals in 1280-acre DSU's with 26 to 35 stages and roughly 100,000 lbs of proppant per stage. But the similarities end there. The 37 wells provide a localized comparison of the production performance from the three main broad completion approaches currently employed in the Bakken:



**Figure 17—90-day production comparison for gel, hybrid and slickwater treatments in or surrounding Township 156N-R101W in Williams County.**

- (i) Sliding Sleeves with cross-linked gel fracture treatments placing either sand or ceramic proppant;
- (ii) Plug and Perf with hybrid slickwater and cross-linked gel placing sand and (mostly) ceramic proppant; and,
- (iii) Plug and Perf with high-rate slickwater placing ceramic proppant.

**Figure 17** shows a 90-day production bubble-plot with three different colors illustrating the dramatic difference in performance of these approaches in the same neighborhood.

**Figure 18** lists data on the specific designs. As shown in Figure 17, the three different completion and stimulation designs have a large variation in 90-day cumulative production, with averages ranging from 19,100 BO, 28,800 BO to 49,300 BO. Clearly, with wellhead commodity prices of over \$80 per barrel the increased time and costs of the Plug and Perf completion design with slickwater fracturing is highly economic.

Treatment type	Avg. Number of stages	Avg. Stage spacing	Avg. Fluid volume per lateral foot	Avg. Proppant/sand weight per lateral foot
Slickwater	35	277 ft	25.3 bbl/ft	412 lb/ft
Hybrid	26	368 ft	7.6 bbl/ft	282 lb/ft
Cross-link	29	339 ft	6.6 bbl/ft	383 lb/ft

**Figure 18—Completion differences for the production comparison in or surrounding Township 156N-R101W in Williams County.**

## Conclusions

Multi-stage hydraulic fracturing of horizontal wells has had a transformative effect on the Central Basin portion of the Williston Basin Bakken. Horizontal wells which were uneconomic with single-stage completions using diversion technology fracture treatments have become wildly economic with multi-stage mechanical isolation.

While drilling procedures and casing plans have become standardized across the industry there exists a wide variation in the type of completion and stimulation procedures being employed by different operators.

The operator has now completed over 70 wells with the Plug and Perf completion design with slickwater fracturing. Initial results presented from 58 wells contained in the NDIC public database show this is generating far superior production results that pay out additional service costs in less than 90 days compared to other completion and stimulation designs.

There is no reason why the completion and stimulation design presented here cannot be applied to the Three Forks formation – and we have recently successfully applied this although production results have not yet been publicly released.

There has been such a drive over the past two years to drill the first well in each DSU in order to HBP the acreage that industry has had little time to further optimize completion practices. More thorough evaluation of the public production data is ongoing and we anticipate that as best practices are shared the industry will move towards a consensus completion and stimulation plan when infill drilling is carried out.

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