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## **Optimization of Bakken Well Completions in a Multivariate World**

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### **Abstract**

The advent of mega-sized hydraulic fracturing jobs which incorporate increased proppant per foot density, enlarged fluid volumes, tighter cluster spacing, and shorter stages in the Bakken/Three Forks play, have led to significantly higher IP's on the order of 20% over the past two years. Yet despite this dramatic increase, concerns exist as to whether treatments are fully optimized with respect to costs of overall volumes, rates, and concentrations. This paper describes two case histories, one in the Middle Bakken and one in the Three Forks formations of the Williston Basin, where a multidisciplinary geoscience and engineering team was assembled to attempt to answer the optimization question within the confines of real-world operational logistics and cost constraints.

In these case histories, an optimization process is described that begins with wellbore context. The consideration of offset wells in the area, data analytics processes considering reservoir quality, and perceived successful completions for the area are incorporated as input. Detailed layered and geomechanical models are then constructed using drilling, neural network and public domain data to produce optimized perforation cluster design and grouping in precise fracturing stages. A rigorous planar 3D hydraulic fracturing model is used to simulate fracture geometry characteristics including height growth, half length, and aperture. Lastly, proppant tracing and production modeling were used to validate the approach used.

The result of the project was to develop an optimization process incorporating the multidisciplinary technical team's expertise to provide an integrated, cost-effective completion design that would lead to more rigorous support for why these engineering decisions were taken. In addition, a secondary goal was to leverage software and database capacity for completion decisions into a "best practices process" that would neither burden the existing E&P staff nor hinder the completion timing. The resultant case study captures the process, technology analysis, weighted benefits, takeaway learnings, and results from two such wells within the Williston Basin.

### **Introduction**

The Williston Basin is one of the earliest resource shale oil plays produced with regularity within the United States. Many successful completion methodologies originated & developed within the Williston Basin, and are now implemented across the country. In its early production life it represented the largest production

from unconventional resource basins in the United States, and to this day, it currently represents the second largest producing American play behind the Permian Basin.

Figure 1 demonstrates the recent shift in production leadership within North American oil resource plays, while showing the still large impact of the Williston Basin. The necessity to reach economic viability of this and all other resource plays has driven the need to reduce cost and increase production per well. The desire for maximum reservoir drainage and well density within a lease has uncovered additional challenges. Reducing typical stage lengths and thereby perforation cluster spacing can result in stress shadowing and inefficient stimulation. Well density challenges can result in parent-child well interference, asymmetrical fracture growth and negatively impact existing production. These physical completion challenges are amplified with additional hurdles placed on the operator by the commodity market.

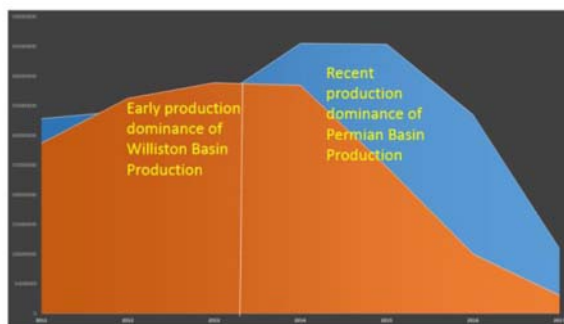
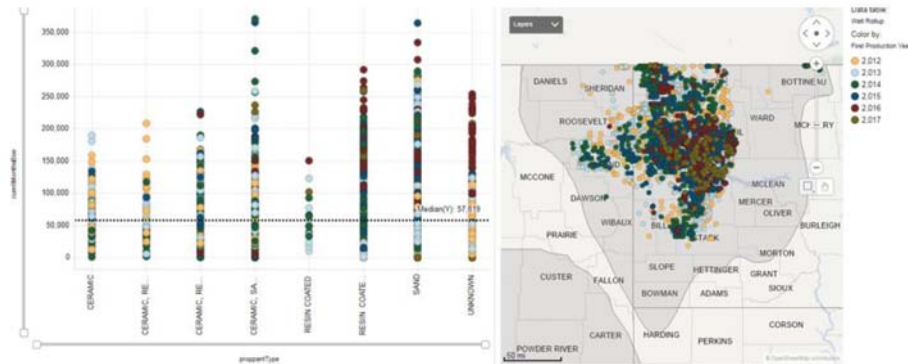


Figure 1—Basin Production Leader over Time. Williston Basin is Orange, Permian Basin is Blue.

Depressed trends in oil pricing and the subsequent business cycle, have historically fostered evolution within the oil & gas industry. Each significant commodity price dip inevitably leads to forced reductions in costs to both E&P operators as well as service companies. The most recent and largest downturn in decades has had a compounding negative effect, being as the timing forced out a large volume of skilled senior professionals from the industry. The resulting void of expertise has revealed that many operators who previously relied on service company partnerships found a diminished support system. Larger operators who previously relied on internal technical innovation are now burdened with added work flows previously unseen.

Accepted norms within regional hydraulic fracturing practices have changed over the past several years, in part due to economic constraints. Within the Williston Basin, the pre-2015 practice of incorporating ceramic proppants has largely ceased in favor of the lower cost natural silica alternative. Figure 2 shows the trend over time toward silica proppants over the previous area design standard of ceramic proppants. Once convention shifted, experimentation on job size began based on confidence in performance of the lower cost proppant. Viscosity enhanced friction reducers gained popularity over linear guar & borate crosslink based systems for the same reasons. This progression of proppant volumes, fluids additives, and stage design has been driven by a small portion of innovative E&Ps while the majority of operators tend toward conservative observation. Validation of these trends tend to be benchmarked through empirical results of operators in their respective areas, and do not consider optimization as a holistic exercise. The declaration of success or failure focuses on new well performance compared to historic offsets. The results as seen on an individual well are often attributed to a linear extrapolation of a single parameter change; more sand equates to better production.



**Figure 2—Trend Away from the Use of Ceramic Proppant Post-2014. Production versus Proppant Type. Colored by Year of First Production**

Multidisciplinary reviews and analysis of these trends (historically performed within E&Ps or large service companies) have waned as experience has departed the industry. A proper analysis is complex and must take into account multiple variables related to the area:

- How does the reservoir of this well compare to those nearby?
- Is there significant geologic or lithologic heterogeneity along the wellbore path?
- What is the optimized perforation scenario or completion technique to maximize cluster efficiency and best drain the reservoir?
- Was the wellbore steered properly within the target reservoir?
- How variable are the geomechanical properties along the resultant path of the well?
- What are the overlying parameters of the reservoir that would affect the growth and propagation of a hydraulic fracture and therefore the resultant stimulated reservoir volume?
- Are there offset operator learnings that can improve the E&P's learning curve?

These questions can have a direct impact on a well's production and economic viability. As such, they will impact the best method to optimize its completion. Understanding these parameters can enhance the decision hierarchy of completion design and eliminate some of the statistical variation realized in resource play completions.

A multi-disciplinary team from several technology companies was constructed to bring each organization's expertise into a group that worked in concert with an operator to maximize well performance and optimization techniques. Specialist team members and operator enlistment drove data collection, evaluation & development of an optimized completion design best suited for the area of interest (AOI). Results and findings of the completion are included within this case study.

## Challenge

The operator anticipated a series of well completions within an area that had been densely drilled by surrounding offset operator within Mountrail County, North Dakota. The expectation formulated during drilling was that the area could be under-pressured due to depletion drainage of offset wells. In fact, empirical pressure measurements when opening the toe for completion indicated some existing depletion, thus confirming this fear.

A second concern with the 3-9TFH well was the fact that this well was previously classified as a drilled un-completed (DUC) and had been awaiting completion for over 23 months. The completion design was an open hole swell packer design incorporating plug and perf (P&P). The age of the packers in the well raised

concerns for packer integrity and zonal isolation. Additionally, operators in the area reported a  $\sigma_{\max}$  stress orientation within the area more closely related to N 50-60° W for the maximum horizontal stress direction. In their in depth paper on well orientation in anisotropic shales, Prioul (2011) discussed different stress regimes in 3D space that affect the growth of hydraulic fractures. The area is not known for a large amounts of anisotropy between the horizontal  $\sigma_{\min}$  and  $\sigma_{\max}$ , and theoretic design of wellbore direction in the direction of  $\sigma_{\min}$  is not always a guarantee of transverse fracture growth in this area. In addition, the initiation of a fracture tends to be parallel to the axis of the wellbore initially as it overcomes hoop stress surrounding the wellbore. As the fracture propagates away from the wellbore, rotation will take place to orient orthogonal to  $\sigma_{\min}$ . If there is minimal difference in these stresses, the rotation potentially will not occur. Figure 3 shows a map view of the local AOI wellbore layout and the assumed stress fields within the area.

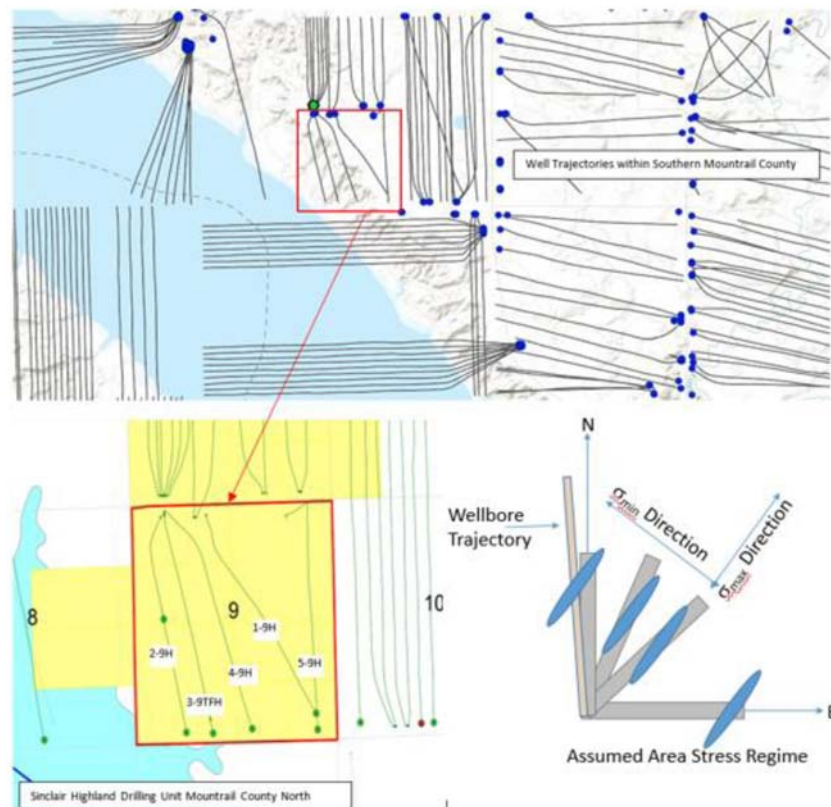


Figure 3—Well Orientations in AOI and Assumed Orientation of Stress Fields

This orientation of wellbore trajectory would, in an ideal case, have resultant fracture orientation that would be somewhat biased to sub-transverse fracture orientation. The area of interest is also surrounded by aggressive offset operators experimenting with greater proppant volume limits compared to their own historical practices. These factors led to concerns of well to well interference, screenouts, and low pressure and potentially uneconomic production. Citing these risks, the operator initially favored a conservative approach that would mitigate their perceived risk of successfully completing the well and producing it in an economic manner. The operator sought additional advice to make an informed completion decision and chose to perform this preemptive joint analysis to best optimize their completion practice.

## Procedure

The team of analysts was assembled to define best practices in the area, identify optimization opportunities, model the proposed completion, establish post completion monitoring techniques for evaluation, and perform the stimulation. All associated design work operated within the constraints of the existing wells to

optimize the completion results without negatively impacting operations/completions timing or costs. The team divided the project into several subsections:

#### Historic Completion Analysis

1. Type & Creaming curve analysis of operator completion trends
2. Identification of production performance versus offset peers
3. Customization of completion design to fit engineering challenges of the wells

#### Specific Reservoir Analysis

4. Analysis of regional petrophysical data within a geologic reservoir model
5. Confirmation of target accuracy of wellbore path within geo-model
6. Identification of potential heterogeneity issues along wellbore path
7. Analysis of near wellbore stress along well path to optimize perforation cluster placement

#### Operational Design and Analysis

8. Modeling of fracture growth to maximizing the stimulated reservoir volume (SRV)
9. Perforation design comparison using alternating charges on opposite stages
10. Deploy tracer on strategic stages for post-completion monitoring of cluster efficiency
11. Complete & monitor well using learnings from study

Each of these process stages are interdependent, such that final performance is based on obtaining an adequate understanding of the wellbore placement, formation quality & heterogeneity, potential operational hurdles, with adequate cross checks and corroboration between operator and the assembled team.

## Historic Completion Analysis

Public domain data sets in conjunction with proprietary scrubbing processes were used to provide an overview of evolutionary changes in completion techniques and results within the AOI. Trends over time were analyzed and multiple variables were monitored to locate parameters of large consequence versus reservoir quality. Operator production was analyzed against its offsets, taking into account various parameters of completion: vintage, fluid, proppant per lateral ft. volume, perforating technique, and other quantifiable variables. Through the incorporation of production data, multiple variables were analyzed to derive ones that had the most impact on production, to be able to gauge completion success.

Reservoir quality was factored into the analysis in order to normalize completion comparison in "like" reservoir quality. Multiple 'graded acreage' and proprietary 3D geologic reservoir models ensured that when comparing completion designs versus production, bias due to differing rock quality was minimized. Analysis of completion techniques compared to production within the AOI gave insight as to which parameters had meaningful impact on EUR. It was paramount to understand that trends transformed over time in order to influence overall performance by enhancing EUR, decreasing completion costs, enabling longer lateral completions, and utilizing products available during time of completion, amongst other operator facing variables. While there was no one change that was linearly impactful, changes often led to unintended consequences related to specific wells, offset wells, or Drill Spacing Units (DSUs) where changes occurred. The exercise reinforced understanding that a detailed analysis of the multiple variables was important to comprehending the way these interact. [Table 1](#) reflects some of the parameters monitored and compared to draw recommendations for the wells within the AOI.

Table 1—Historic Completion Comparators by Operator

Comparators	Operator A	Operator B	Operator C	Operator D	Operator E
Peak BOE					
Peak Rate by Completion Date					
Well Spacing					
Avg. Perforated Interval					
Normalized Rate/1000 ft Perforated Interval					
Production Curves Over Time					
<b>Engineering Insights and Trends</b>					
Creaming Curves of Historic Completions					
Basin Target Depth Variation					
Normalized 3-6 mo. Cum. BOE/1000 ft Perf. Interval vs Total Proppant/1000 ft					
Operator Benchmark vs Competitor by Acreage Grade					
<b>Proppant Trends vs Production Trends</b>					
Proppant Concentration and Type Trends					
Treatment Type vs 6 Month BOE					
Stage Count vs 6 Month Normalized BOE/1000 ft Perf.					
Proppant Mesh Size vs Normalized Production					
Historic Proppant Trend by Operator					
Proppant Type vs Normalized 3 mo. BOE					
Production Comparisons Over Time (6 mo. vs 12 mo.)					
Completion Type vs Normalized 3 mo. BOE					
Completion Type Production Over Time (6 mo. vs 12 mo.)					

This style of analysis, when compiled with a large population of wells, gave modal distributions that were useful in attempting to isolate the resulting effects of each parameter change. In some cases, thresholds of specific parameters can be illustrated to show diminishing returns on production: from increasing proppant and fluid volumes, concentrations, rates, etc. This matrix approach was used to identify a "base" completion

design that would be better suited to the AOI for the target formations. The extenuating issues of offset operator well density, localized pressure depletion, orientation of wellbore related to minimum horizontal stress, and concerns of fracture hits on offset wells made design additionally challenging. A compromise between the mitigation of the concerns previously mentioned and the calculated yet decisively more aggressive completion, produced the operator elected stimulation.

## Customization of Completion Design

A completion design comparison was conducted on five major offset operators to gauge how learnings were being adapted and implemented within the AOI. Lateral length and spacing within the AOI demonstrated that the partner operator (Operator A) was conservative with an average perforated lateral length of 5,705 ft. nearly a 175-acre average spacing. The remaining operators tended to capitalize on leasing positions and drilled two section laterals of approximately 10,000 feet in length. Most offset operators were within a 138 to 176-acre spacing with the exception of Operator C who trended toward a tighter 86 acre spacing with some minimal diminished production. On first viewing, Operator A's well production lagged versus the other operators in the study. Once the analysis was normalized for production per perforated interval, Operator A actually performed as well or better than near offset competitors.

Cross plots and creaming curves were used to analyze the results of modifications to the drilling and completion practices of wells within the AOI. [Figure 4](#) represents an analysis of proppant concentration per perforated foot versus 12 month cumulative production of different operators within the area. Although there is statistical distribution, the trend shows that with increasing proppant volumes, operators are experiencing larger 12 month production rates. Some of the higher proppant outliers that show diminished production rate were isolated to areas of higher reservoir quality. This behavior seems to represent a diminishing returns on proppant volume when placed in higher quality reservoir. Creaming curves illustrate changes in an operator's production performance over time and can be related to production variables such as production per lateral foot. They also identify how an operator is performing versus its peers. Positive inflections in the curve can be indicative of process changes that improved production rate per well. Often these slope changes can be related to specific design changes or well-suited completions in better acreage. Similarly, negative inflection can indicate unsuccessful design modifications or possibly recognize when an operator has moved to poorer quality reservoir, as production will start to plateau. Several of the offset operators exhibit strong creaming curve performance compared to peer Williston Basin operators. [Figure 5](#) shows a creaming curve type log of several Williston Basin operators. Within this figure one can note slope changes that can be tied to a timeline equivalent to completion design changes within the basin. Operator E displays a sharp inflection both early in their program, and again at about well 320. After robust investigation, it was determined these changes were related to increased proppant volumes per foot of lateral completed. Tying this data to completions in varying reservoir quality, the team finds that increased proppant volume has a strong positive impact on the creaming curve when the wells in question are in poorer reservoir quality. Conversely it is noted that that an increasing volume of proppant presents a case of diminishing returns when landed in higher quality reservoir.

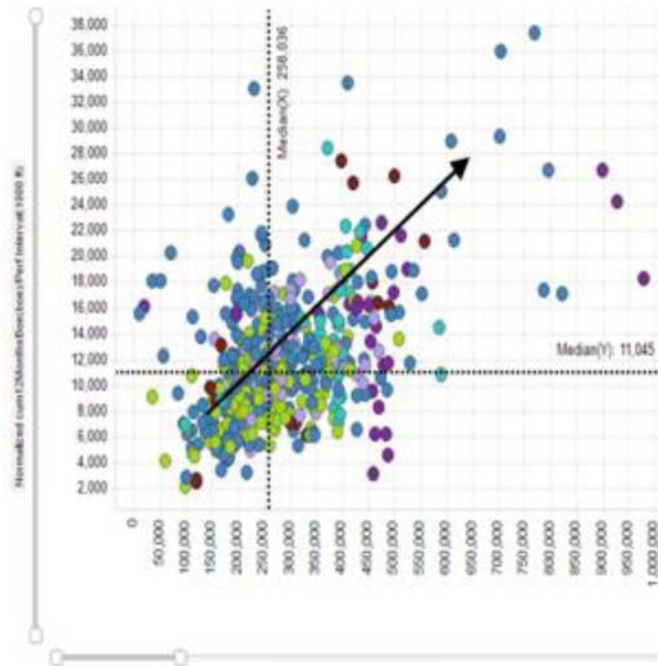


Figure 4—Normalized 12 mo. Cumulative BOE Production per 1000 ft. of Lateral vs Proppant Density per 1000 ft. of Lateral

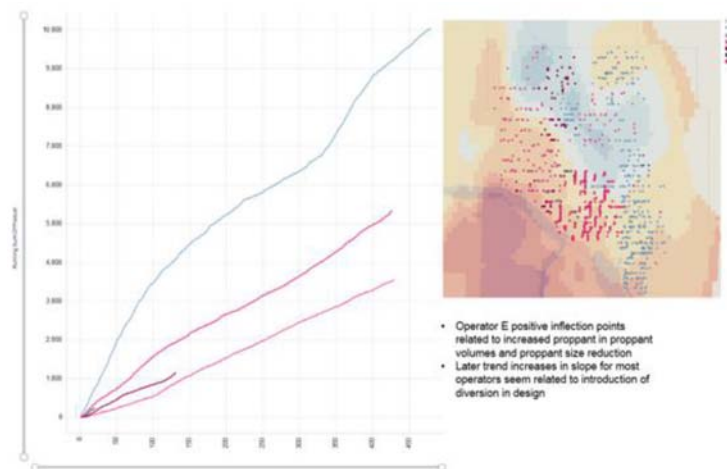


Figure 5—Creaming Curve of Operators within the AOI's Graded Acreage, The Creaming Curve Represents Cumulative Production versus Well Count by Operator

Some operators exhibit positive inflections on their creaming curves that could be related back to introducing other new technologies, in particular, diverting agents to increase cluster efficiency. Although potentially not a standalone cause and effect of improved well performances, the introduction of intra-stage diversion tie to the well count at the point of the positive inflection.

Several other parameters are identified as indices of interest. The operator historically has used a traditional viscosified fluid system (such as linear or crosslinked guar) while peers have progressed to slickwater designs. Indications of this change correlates through public domain record and timing associated with production improvement noted on the creaming curves.

In 2014, 20/40 white sand gained popularity over then common ceramics due to economic factors previously discussed. As noted, this trend intensified as the market started to tighten and the pricing downturn deepened. In late 2015 and early 2016, supply of 20/40 white sand became scarcer, and other smaller sieve sizes were experimented with due to relative availability. Several operators determined



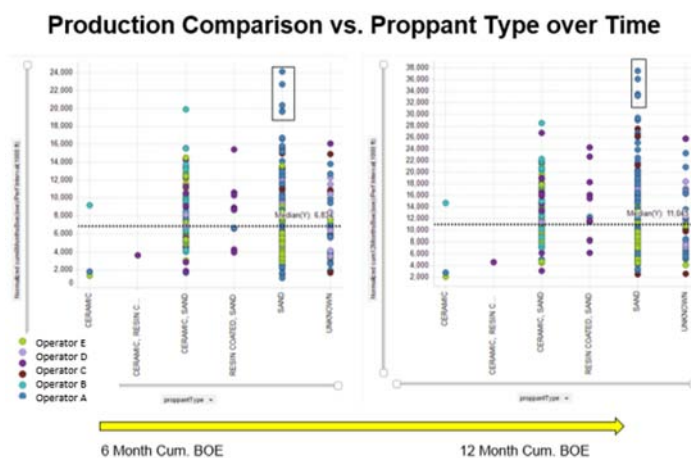
that production did not diminish with the smaller sieves. Figure 6 shows a historic breakdown of proppant sizes used through Mountrail County as it relates to completion type. It should be noted that improvements in production were observed with the inclusion of smaller sieve proppants. There was substantial experimentation in combinations of sieve sizes and their resulting production. In fact the lower relative cost allowed them to pump larger volumes at similar cost basis's compared to 2014. Review of well performance, strictly associated to sieve selection, correlates, but is not a statistical driver of production increases. This relationship may exist however in the stimulation, associated fluid selected, along with proppant sieve size leads to more direct correlations of production increases. Many completions using 20/40 proppant and linear or crosslinked fluid could place proppant at a higher concentration per unit volume, which represents a significant portion of top quartile producers. Slickwater designs have challenges with transport of larger proppants, and thus incorporate finer sieves as a practice. A 100 mesh proppant is already used while pumping a treatment in areas containing highly natural fractured formations. The small sieve material aids in blocking off the natural fractures where fluid loss and screen out of stages remains a typical concern of operators. The design practice now uses these smaller sieve proppants throughout the job rather than just in the pad. Smaller sieve proppants are preferred as they have a high suspension affinity in high rate, low viscosity fluid such as slickwater when compared to larger sieves of the same material. The industry dominance of slickwater jobs has raised the demand for finer mesh proppants. Success by several operators employing this completion design has made the method more popular and is evolving the normal completion practices within the basin. This paradigm shift effectively eliminates the perceived need for costly ceramic proppants. Furthermore, Figure 7 shows that silica completions, and silica completions with an adequate ceramic tail outperform total ceramic completions within the AOI. As seen above, proppant size does not appear to be as singularly significant to well performance as proppant type, but remains at the forefront of economic & operational decisions. General statistical indications as observed throughout the AOI indicate that smaller length stages of tighter clusters tend to be more productive. Currently, the shortening of stage lengths and increasing of perforation clusters within the stages is being explored. Further study is required to allow adequate time to isolate production trends, and limits have yet to be identified through this study. This scope of general analysis conducted within the existing public domain targeted parameters deemed of interest to operator A. Table 2. Captures many of the parameters isolated as historically viewed along with suggested modifications and discussions of each.



Figure 6—Cumulative 6 mo. Production vs. Proppant Size and Completion Type (Mountrail County 2012 - Present)

**Table 2—Modifications from Historic Design Practice Derived from Multiple Variable Analysis**

Parameter	Historic Design	Modified Design	Remarks
Well Spacing Concerns	175 acres	175 acres	Some localized offset operators use somewhat smaller spacing (86-138 acres) with limited impact on well performance
Perforated Interval	4232' median	5118' median	Generally designed on lease restrictions
Job Type	Crosslinked gel job at lower rates	Combo job of crosslinked low rate at toe and slickwater higher rate	Designed conservatively to mitigate risks of localized reservoir with modifications toward mid well
Completion Style	OH/Sleeves, Perforated OH Swell Packers	Perforated OH Swell packer and cemented liner P&P	Operator historic preference was un-cemented Sleeve or perforated swell packers. Experimented on cementing Middle Bakken well of study
Proppant Type	White Sand(WS or Silica)	WS/Ceramic	White sand prevalent and ceramic experimented with
Proppant Size	20/40, 40/70	100 mesh, 40/70	Area analysis showed trends to smaller proppant in conjunction with slickwater on higher performance wells
Proppant Volume normalized per ft. of perforated lateral	Median of 278 lb. / ft. perforated lateral	520 lb./ft. perforated lateral	Optimum ranged from 500-800 lb./ft. in this rock quality and up to 2,100lb./ft in poorer rock quality but selection was attempt at optimized conservatism in design
Barrels of Fluid	39,100	107,000	Expected as conversion to slickwater jobs increases fluid volumes
Prop Concentration	Average of 18 (lb. /bbl.) / Perf Interval (1000ft.)	< 10 (lb. /bbl.)/ Perf interval (1000 ft.)	Concentration tended downward as slickwater design was implemented
Perforation Design	1 sleeve/stage, 0.44" nominal Entrance Hole Diameter (EHD) charge 3 cluster/stage	3 cluster/stage, equal EHD design	Experimented with alternating stages to analyze differential trends in performance
Perforation Orientation	6 SPF 60 degree phase	6 SPF 60 degree phase	After review of wellbore trajectory, there was no need for special orientation of perforations on these wells
Cluster Location	Geometric design with buffer from any packer edges or collars	Clusters optimized to equivalent $Sh_{min}$ profiles	Clusters placed over stage interval with buffer near packers to minimize delta $Sh_{min}$ between clusters
Tracer Log	N/A	Run on Three Forks OH packer well	Tracer was run to see if we could correlate flow through perf clusters or elsewhere in stages



**Figure 7—Completions Incorporating Silica Alone or Silica with Ceramic Tails Outperforming 100% Ceramic Designs at 6 and 12 Months Timeframe**

## Specific Reservoir Analysis

Wellbore orientation and proximity to offset wells gives rise to concerns that a sub-transverse, or near longitudinal fracture could readily grow asymmetrically toward partially depleted producing wells placed orthogonal or adjacent to the stimulated well's toe. This depletion hazard is well established and was of concern for the well operator. Fracture growth into under-pressured areas can lead to high levels of fluid loss resulting in screen outs of the stages nearest the toe. A screen out at this point was also a concern because the operator believed the reservoir pressure could potentially be insufficient to flowback proppant within the wellbore, creating a need for costly coil-tubing intervention. During preliminary planning with the operator, the initial design favored a slickwater fluid system not historically used with relatively aggressive proppant concentrations and larger proppant sizes. Engineering trend analysis identified that area slickwater jobs with smaller proppant size, but larger stage volumes had success in the area. Designed proppant volumes were then increased, not to the maximum in the area, but to a point of approximately the second quartile.

Taking the generalized completion trend findings down to the next level of granularity requires additional insight to the reservoir and its corresponding petrophysical attributes. Localized production history, pressure mapping, cumulative production, and identifying offset fracture network communication all contribute to the understanding of the communication potential of the reservoir. Localized reservoir quality is assessed empirically from production data and water cut. In addition, technical team members produce stochastic models of petrophysical attributes and other criteria to generate reservoir quality maps over the AOI. Inferences are made from hundreds of vertical well penetrations and cuttings analysis are combined into a regional stochastic geologic model to determine attributes such as saturation, permeability, porosity, hydrocarbon pore volume, brittleness etc. These regional attributes are localized within the AOI to identify heterogeneity at any vertical depth extrapolated within the reservoir. Petrophysical and geomechanical attributes in a geologic structural model are reviewed to get a better understanding of formation quality. Figures 8-9 show examples of some of the attributes reviewed to better understand localized heterogeneity of the formations within the zones of interest. Figure 8 is a snapshot plot taken from the 3D geologic model of the water saturation ( $S_w$ ) variability along the trajectory of the wellbores. Figure 9 is an example of one of the layer porosity maps to represent in map view the variability of the various petrophysical attributes within the AOI.

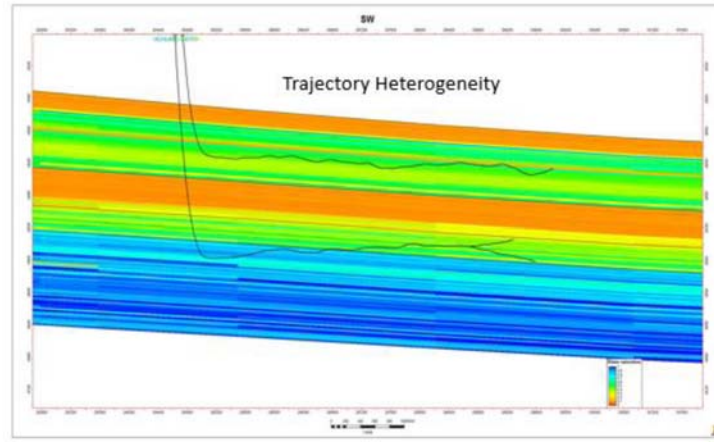


Figure 8—Variability of Water Saturation ( $S_w$ ) Along Wellbore Path

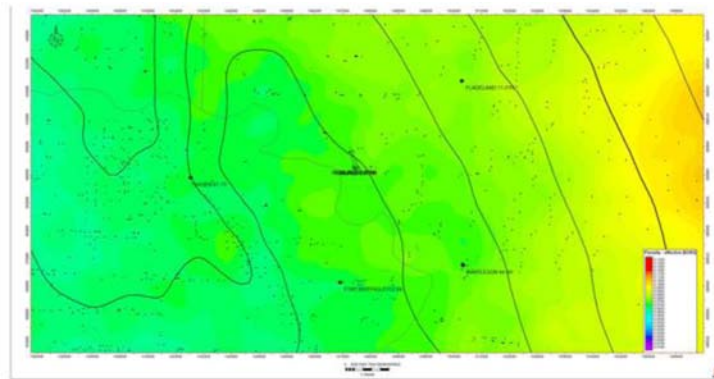


Figure 9—Effective Porosity (PHIE) Porosity Map View of Upper Three Forks

Combining this data with the calculated path of the wellbore within the model, gives a more robust understanding of variation along the wellbore path as it lands within formation. When contradictory interpretation arise, the team identifies whether the results are due to leaving the Zone of Interest (ZOI) or simply heterogeneity of the formation. Understanding the path of the lateral within the geo-model provides support for decisions on the perforating schemes. Figure 10 below shows the course of the wellbores to be within their respective ZOI over the entirety of the laterals. A 1', 6 SPF, 60 degree phased gun per cluster was designed for the case when wellbore trajectory was within the ZOI. A need for specialty oriented perforating is introduced in the case that the path is outside of designed trajectory.

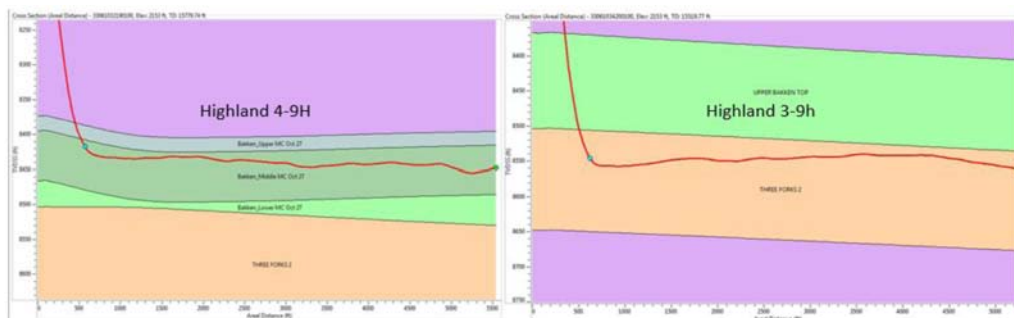


Figure 10—Wellbore Trajectory of the Two Study Wells Within a Geo-Model

Several of the parameters captured in the matrix are notably interdependent, therefore equal weighting would create a significant bias. Care is taken to minimize bias on parameters to ensure the analysis is not redundantly weighted for similar attributes. An example of this concern is noted in the predictor variables of proppant & fluid quantity and the correlation to produced barrels. By normalizing these parameters per stimulated lateral foot, a level comparison is possible.

Taking this localized reservoir information into consideration allows the team to identify an optimum proppant loading. For wells in this area the optimal range falls in the 500-850 pound/normalized foot (lb. / n ft.) of lateral. Due to some of the design risks previously outlined, the proppant design volume is limited slightly to be more conservative in design. A volume of approximately 520 lb. / n ft. is nearly twice what the operator had previously placed in their offset wells, yet is less aggressive than the high end of the optimal range. Previously stated concerns with asymmetrical fracture growth toward offset operator wells led to a more conservative approach of a moderate rate, viscosified gel stages near the toe where the risk is highest followed by slickwater placement after stage 5 on the wells.

## Design Changes to Enhance Stimulated Reservoir Volume (SRV)

Optimized completion design as seen in [Lehman, Jackson and Noblett \(2016\)](#), often referred to as an "engineered" completion, is a method utilizing data inputs such as ROP, WOB, GR from MWD, mud logs and others that are then incorporated into a machine learning network to predictively produce outputs of bulk density  $\rho_b$ , acoustic  $\Delta t_{\text{compressional}}$  (DTC), and acoustic  $\Delta t_{\text{shear}}$  (DTS) to an accuracy exceeding wireline repeatability in a horizontal wellbore. These outputs then are used to define geomechanical properties such as Poisson's Ratio, Young's Modulus, brittleness, shear modulus, and minimum horizontal stress. Using these outputs to see variability along the well path allows an operator to select perforation intervals that would place perforations in "like" stressed rock.

The theory postulates that if all perforation clusters penetrate rock with very nearly equal stress values, all perforation clusters will break down and stimulate relatively equally. It was decided that since these wells were located in different formations and were completed with differing completion strings, they would provide a good test area for optimized completion design. The intention is that by minimizing variables in the completion, such as minimum horizontal stress differential at the perf cluster locations, we can better place the stages and minimize the operational risks previously discussed. The team utilizes operator provided gamma ray log, Totco data, mud log and MWD data to profile the stress regime along the lateral. In this case, stage lengths are confined to those observed in the geometric completion, however engineering judgement, and avoidance of drill collars or packers, dictates placement of the optimized perforations to minimize stress differential while. [Figure 11](#) demonstrates a section of the optimized completion design on the middle Bakken 4-9H well. Minimizing differential stress along the wellbore initiation points leads to quicker time to maximum rate, equal growth in fracture wings and evenly distributed proppant, thus enhancing SRV.

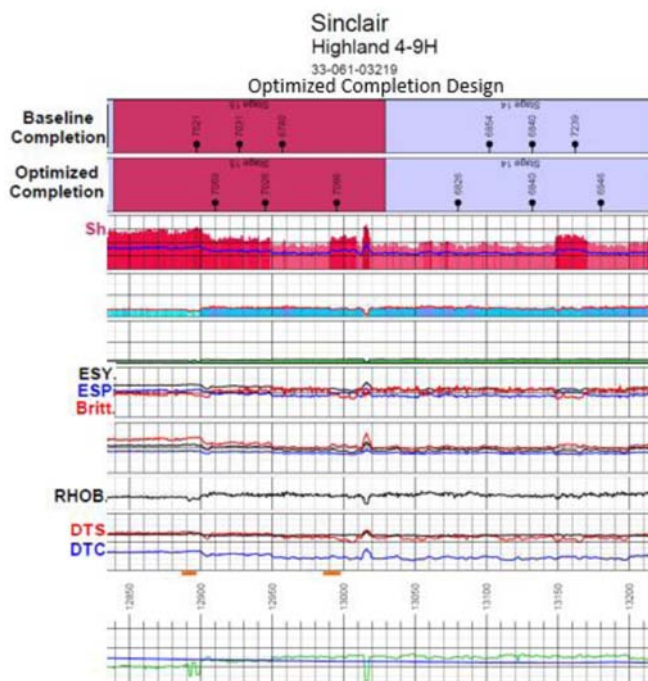


Figure 11—Near Wellbore Stress Differentials Comparing Completion Methods of the Baseline Geometric Perforation Cluster Placement to Optimized Cluster Placement.  $S_n$  represented is  $\sigma_{min}$

A supplementary method to attempt to increase SRV is to use chemical and or solid diversion materials to enhance cluster efficiency. This method, in varying form, has been used within the industry for over 80 years as discussed in a comprehensive review by Van Domelen (2017). Historically most completion designs use a fixed stage length divided by a fixed number of initiation points (clusters). These perforation clusters are typically perforated at fixed distances in a "geometric" pattern. This geometric design then assumes that the clusters will break down and take fluid in a sufficiently uniform fashion. Research from Muthukumarappan (2016) and Barraza (2017) has led to the conclusion that most completions are in the vicinity of 60-70% efficient with some percentage of the clusters never being stimulated despite use of limited entry design. Research indicates that if there is ample differentiation in near wellbore stress along a stage, the fluid will flow into the path of least resistance and continue to do so until such time that the pressure differential is minimized between the path and another cluster of perforations. This potentially explains how some clusters can go untreated within a stage completion. The theory supporting diverting practice states that when hydraulic fractures are initiated, fluid will travel in the path of least resistance, as will the diverting agent. When the diverting agent enters the fracture face of the clusters taking fluid, the diverter bridges off, and then packs off the flow to that fracture and diverts the flow to another cluster not currently taking fluid and proppant. By dividing a stage's proppant volume into multiple yet proportional pyramids, each of which is separated by a diverting agent deployment, the effective stimulation is incrementally dispersed each time the diverting agent is applied.

Within the case study, it is further hypothesized that both optimization and diversion should potentially add value to the completion. Figure 12 shows a patented hybrid particulate diverter [12] that incorporates both chemically soluble components and a rod shaped ceramic proppant. It is deployed to improve cluster efficiency. The incorporation of the highly conductive rod shaped ceramic proppant aids in replacing conductivity of the fracture that is lost when the diverting agent that is pumped into the fracture face displaces proppant near wellbore. As the chemical portion of the diverting agent hydrolyzes, the rod shaped proppant remains to aid in near wellbore conductivity. This specialized diverting agent, typically applied on geometric completions, is utilized to analyze the effectiveness of an optimized completion.

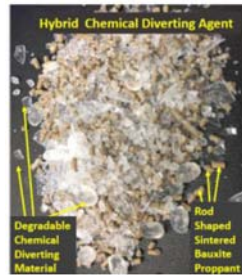


Figure 12—Hybrid Diverter Agent

Considering that the perforations are placed at optimized locations to minimize stress gradients, potential still exists for preferential flow due to variation in perforation entrance hole diameter (EHD) around the circumference of the liner, Cuthill (2017), perforation tunnel efficiency, and wellbore proximity to laminate layers or other variations surrounding the wellbore. Further discussions of this parameter are discussed later in the following section

## Operational Design and Analysis

Once the specific attributes within the region and along the wellbore path are analyzed, these factors are considered when developing the hydraulic fracturing design. Care is taken to mitigate the potential risks of offset well interference, screen outs due to fluid loss, longitudinal fracture growth and precautions are taken to positively impact the production versus historic wells in the area for the operator. A layered model is taken from the petrophysical attributes within the 3D geologic model. Near offset vertical wells incorporated within the model provide the basis for lithologic layers within the fracture model. Empirical formation pressures as well as stress field assumptions are incorporated into the model with the objective of improving SRV throughout the completion and improving production numbers. Figure 13 shows a composite fracture design taken from stage 11 in the 4-9H Middle Bakken well. The reservoir pressure toward the middle of the well is not depleted when compared to the toe of the well. Fracture modeling showed growth both out in the Middle Bakken as well as growing downward into Three Forks. A second more conservative design is deployed for the depleted interval near the toe of the well. With expectations of sub transverse fracture growth in a depleted pressure regime, a more viscous crosslinked borate gel design pumped at a lower rate was designed to attempt to control the fracture growth both to the offset wells to the east as well as those orthogonal to the well axis at the toe. A graphic of the toe stage designs is represented in Figure 14. Due to depletion and lower stress in the Middle Bakken, the model shows that the fracture growth stays contained and does not have the downward growth into the Three Forks (as in Figure 13). This also leads to fairly long fracture length as all the energy of the fracture stays contained within the Middle Bakken.

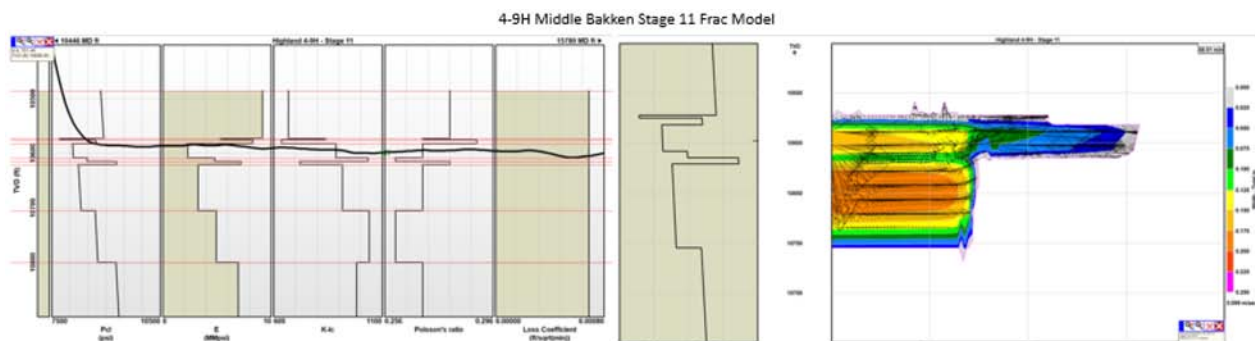


Figure 13—Representative Slickwater Design Stage Near the Middle of the Well

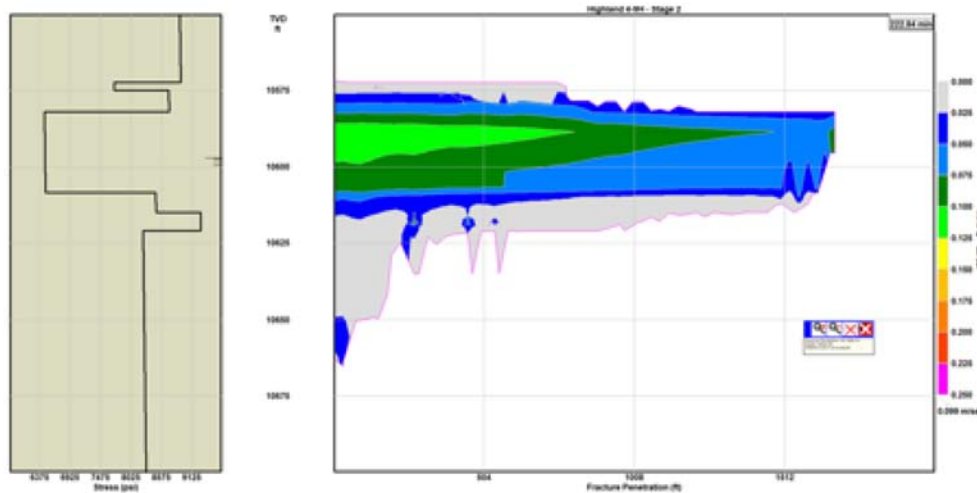


Figure 14—Fracture Model Incorporating a More Conservative Design with Viscous Fluid, Slower Rate, but Increased Proppant Loading for First Five Stages of Each Study Well Due to Area Pressure Depletion

Findings from the modeling show that the propped fracture half-length for the well is between 750'-1000'. Given the assumption that the fracture growth is biased toward the depletion, the operator is able to predict the sphere of influence along the wellbore that the stages would span. As stimulation proceeds from the toe of the well, the theory is that subsequent stages will propagate similarly with the orientation of the fracture being sub-transverse. Going forward, as this prediction is confirmed, the operator can consider lowering the well spacing as the drainage distance away from the wellbore is limited with the half length of the fracture laying closer to the axis of the wellbore. This will require further analysis and other tools for confirmation such as microseismic or tracers. Figure 15 is a graphical representation schematic describing this possible fracture growth scenario and potential down spacing opportunities.

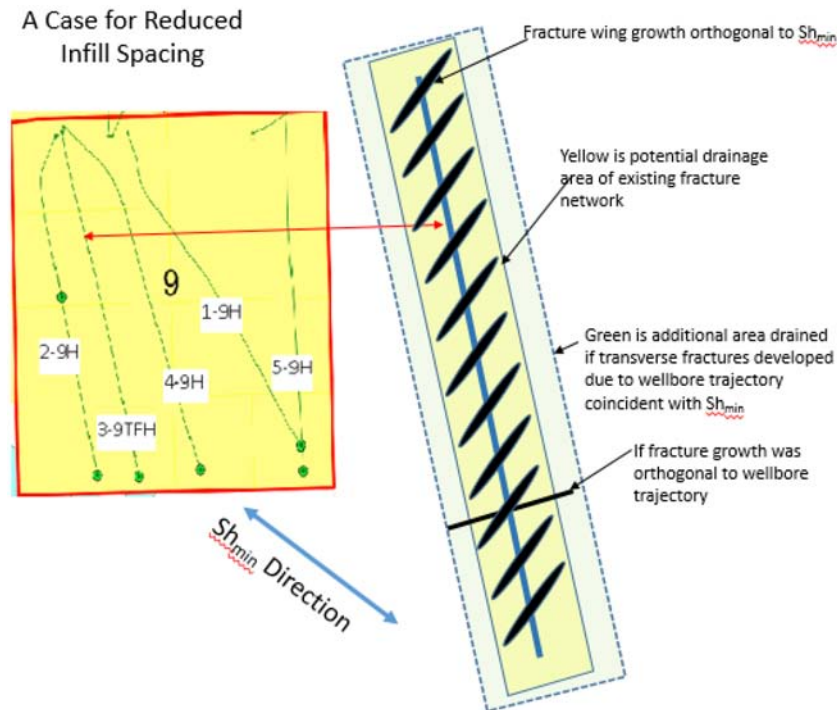


Figure 15—Minimum Horizontal Stress vs. Wellbore Orientation



Many specialty perforating charge manufacturers recognize the need to produce perforating charges that have uniform EHD, clean perforation tunnels with adequate penetration to reduce breakdown pressures, lower treating pressures, and achieve rate on horsepower in a minimal time. McNelis (2015) show the interrelation of entrance hole consistency with penetration over a range of hard rock samples and the importance of this consistent EHD to the hydraulic fracturing process. Throughout the literature, there is an emphasis on the importance of a clean perforation tunnel with minimal skin to optimally break down the formation. The surface treating pressure signature is monitored and analyzed to quantify success of the optimized completion and the efficiency at which the proppant was distributed over the zone. As noted above, the use of standard perforating charges within a gun string laying on the bottom of a horizontal wellbore can produce entrance holes of varying diameter around the casing. The lower perforations located at 180° phasing will be at design diameter or larger, while 0° phased perforations can be upwards of 60% smaller. These variations in size can give a "limited entry effect wherein the larger holes with less hole friction and more surface area will take more fluid and the fracture growth around the pipe can be asymmetrical. To minimize the possible pumping issues from differential hole size around the circumference of the production string, the team selected two manufacturers of specialty charges designed to give equal sized entrance holes around the pipe. Analysis of the two charges showed that they both worked well in minimizing breakdown pressure and time to rate. For this reason, the team deploys two different types of equal entrance hole charges to monitor any statistically significant difference in charge performance, reliability, or resulting performance during the fracturing process. At the point in the wells when the slickwater design is implemented, and diversion is pumped, the stages are alternated on each well with different charges from the two different providers. The objective of this portion of the analysis is to see if there is a discernable difference in charge performance and resulting pumping on the stages.

Radioactive tracer is a reliable method for identifying fluid and proppant transport within a near wellbore environment. A tracer job is incorporated as a means of identifying that an optimized completion design had a high percentage of perforation clusters activated throughout the well completion. This is a valuable tool in the idealized case of transverse fracture growth and no depletion concerns. A cemented liner with proper bonding is additionally an ideal completion design as you have a finite and known number of perforations. In this case, identifying clusters that take tracer is simplified. In this case study, the scope of objective is modified to determine if there are any indications or verifications of the predicted sub transverse fracture growth, and if we can discern any fracture network communication. In the case of an open hole swell packer completion with an optimized perforation cluster design, the team hopes to understand if the fractures would propagate at the perf clusters or if there are additional fractures generated in lower stress rock within the annulus that make for more complex fracture networks. Three tracer types, Iridium, Scandium, and Antimony are incorporated in the tracing of the 3-9 TFH. The methodology is to use a distinct tracer on 18 of the stages to monitor stage to stage communications, and a combination of two tracers on four of the stages with the differing tracer deployed after the diversion drop to identify diversion effectiveness. Figure 16 represents the stages where tracer are deployed, which tracer(s) are used and how the stages respond. cursory review of the tracer log show a toe directional bias for the tracer flow at early stages and subjectively better isolation closer to the heel. In every stage there are multiple tracer signatures present when only one tracer was originally pumped. This is either a result of failed packers and or fracture orientation approaching the axis of the wellbore. The team postulates that the results are a combination of the two as it is unlikely that every packer in the wellbore failed within the hole. Additionally, the strong asymmetrical signature toward the toe of the early stages indicates that we were seeing the fracture signature biased toward depletion in the toe direction as expected.

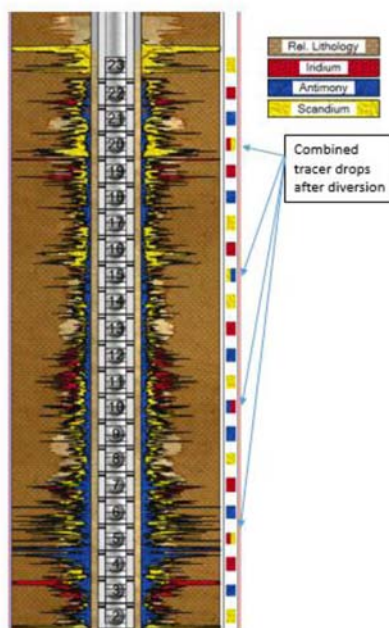


Figure 16—Tracer Log of the 3-9TFH

In preparation for completing the wells, the team combines the historic completion analysis, and specific reservoir analysis with the modeling done on the fracture stimulation design. Incorporating these lessons learned enables the team to design and perform the optimized completion design. Verification of wellbore trajectory and landing within a geologic model is used along with petrophysical and geomechanical parameters to define the formation along the well path. Similar stress regimes are selected within the design constraints of stage size and number of clusters as defined by the operator. Perforation cluster locations are selected to minimize near wellbore differential stress between clusters. Stress profiles of the original geometric completion design are compared to the selected optimized cluster locations to see stages where optimization greatly enhances the completion. The final design is agreed upon by the team and these inputs are used moving forward in execution of the hydraulic fracturing. These montage logs provided a means for consolidation of massive amounts of data into a format that is used in team discussions regarding design decisions and they represent the composite findings of the team.

Figures 17 and Figure 18 represent two examples of snapshot portions of the consolidated montage of data collected from each of the technical partner companies to best define the optimized completion design. Figure 17 is a view of the 3-9TFH well stage 9. In this case the optimized perf clusters are selected to have similar stress profile when perforated versus a set geometric perforation program. In this example the near wellbore stress is optimized from 241 psi differential down to 26 psi. Lithology tends to be slightly more dolomitic toward the heel of the stage, and there is a slight increase in oil saturation related to the increase in porosity related to the increased dolomitization. Mechanical properties of the rock are fairly consistent and brittleness is only slightly diminished in the higher porosity region. Near wellbore minimum horizontal stress varies by several hundred pounds across this stage.

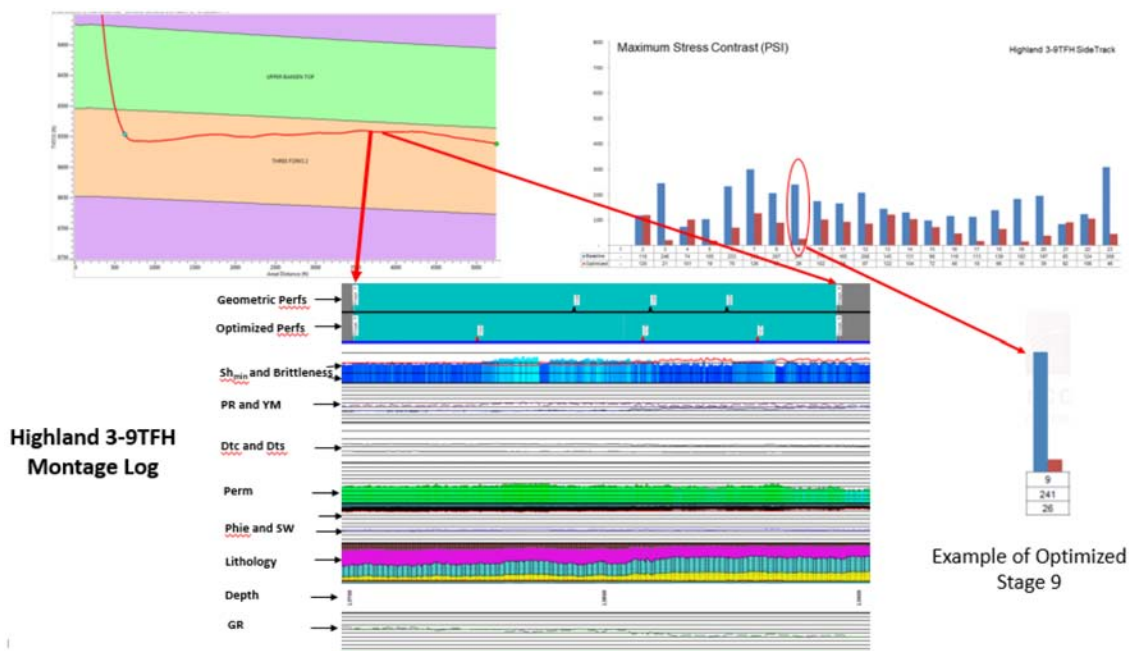


Figure 17—Optimization of Perforation Placement on the Highland 3-9TFH

Figure 18 is a graphic of stage 15 of the Highland 4-9H Middle Bakken well. In this montage the minimum horizontal stress differential is 741 psi in the geometric design and only 59 psi once optimized. The lithology varies across this stage substantially due to wellbore trajectory. With the heel section of the stage being much higher in clacite and quartz and the lower section seeing some dolomite in the mix. Stresses are higher in the limey section and the water saturation also is higher through that interval. There is a clacite bone toward the toe end of the stage that intersects the wellbore and acts as a stress barrier, so the perforations are set to perforate the better sections of this rock and minimize the effects of the hetrogeneity seen in the log response through this stage.

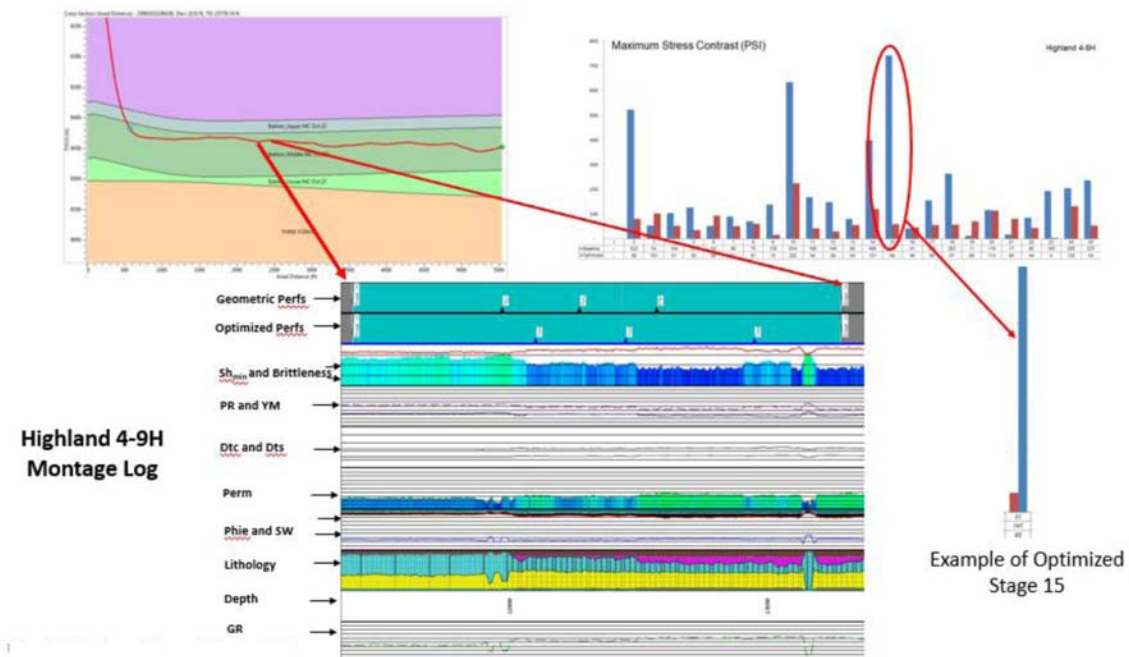


Figure 18—Optimization of Perforation Placement on the Highland 4-9H

## Findings and Results

### Diversion Efficacy

Differing theories exist regarding the pressure analysis following these completions. Historically it is recognized that one of the general trends present in a geometric completion that has had a successful diversion deployment is that the treating pressure increases with each subsequent diverter drop (Van Domelen 2017). This trend is illustrated in Figure 19 as it pertained to another Williston Basin operator.

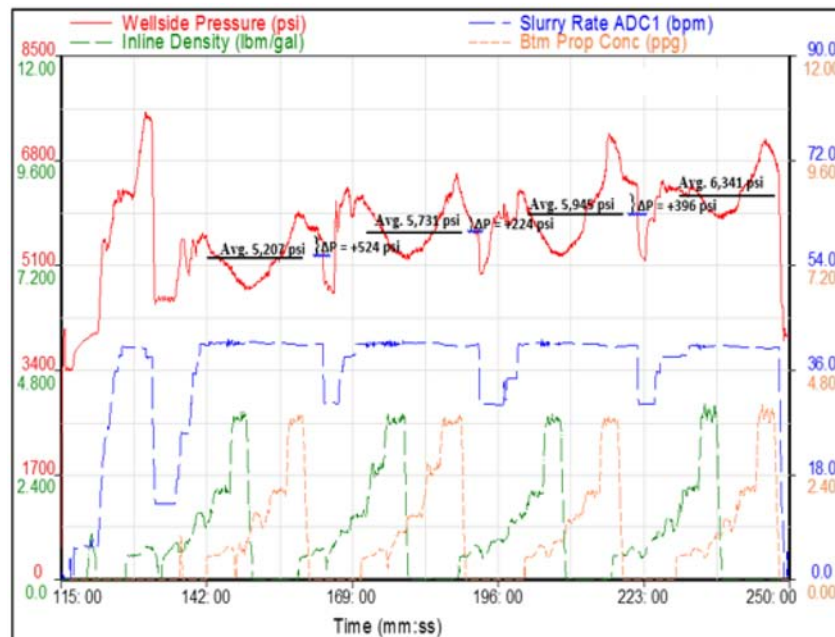


Figure 19—4 Pyramid Application of Diverting Agent in a Williston Basin Geometric Completion

Interestingly, in an optimized completion design on a cemented liner of the Middle Bakken, the signature is generally reversed. The treating pressures most often decrease with subsequent pyramids as shown in the case study excerpt depicted in Figure 20. In this particular instance, even after a reaffirming 962 psi signature of diversion seating, the second pyramid still exhibits a lower treating pressure (with slightly higher rate) than the preceding pyramid. In strategically placing perforations within a similar stress regime, the operator theoretically initially breaks down the formation adjacent to the majority of the perforations at the start of each zone. There is inevitably still a preferential flow path among the open perforations due to irregular perforation entrance hole size, perforation friction, perf location related to formation laminae, formation heterogeneity and other minimal differences in flow regime, however the "like rock" is assumed to have initiated a fracture. As a result, once the first proppant pyramid is pumped, and the first diversion slug is placed, some of the more active perforation flow paths will be diverted off. The second pyramid is then pumped, but the pressure no longer needs to exceed the fracture initiation pressure to flow, but rather just exceed the pressure threshold of fracture extension as it flows in the already existing fracture network of the remaining perforations.

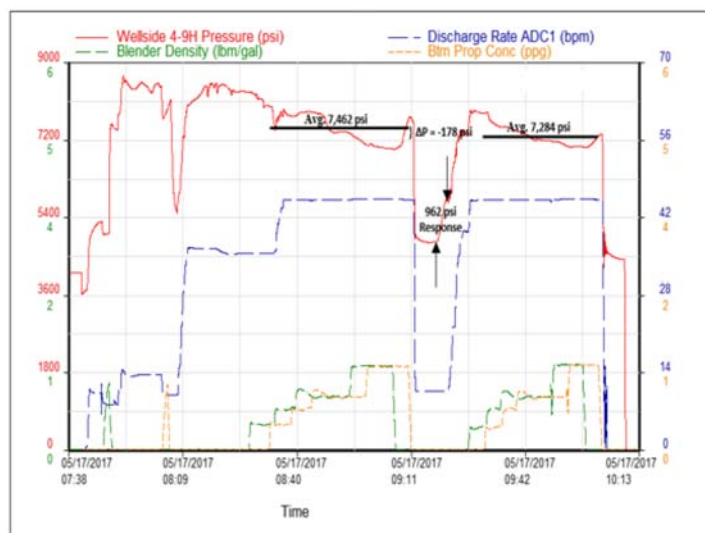


Figure 20—2 Pyramid Application of Diverting Agent in a Williston Basin Optimized Cemented Liner Completion

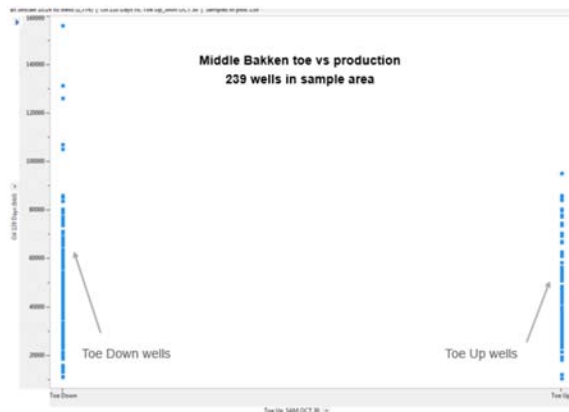
Using an open hole swell packer design across a stage adds complexity to the predictive path of fluid flow. The general assumption is that propagation will take place across from the perforated intervals that are "optimized" to be at near equivalent stress. This is not necessarily true if the stress profile along the stage has a significantly lower stress than the optimized stress locations. When the fluid enters the perforations and nearly instantaneously sees the stage annulus, the weakest rock should break as well as the initiated perforation locations. This changes the dynamics of fluid flow and adds ambiguity to our assumed model. However, when the Three Forks swell-packer completion is examined, the more commonly accepted convention is predominant of increasing treating pressure with diverter drops. Several mechanisms are hypothesized for this phenomenon. A contributing theory states that if the perf clusters are at similar stress, but not the minimum stress along the stage, flow from the initiated fracture will flow toward the lower pressure regime in a tortuous route. Once intersected, the cluster responsible can become dominant among the perf clusters receiving fluid. When diversion hits the flow path, the disproportionate share of flow is diverted and a pressure increase is seen while remaining perforations are maximized and or additional paths are introduced.

Through the multivariable analysis, there are several trends identified and presented to the operator. Some of these were not adapted due to the fact that the wells selected for completion were already drilled and completed with their production liners so some items were not able to be implemented. Some of the findings were better suited for future well design as they provided insight to best practices on wells going forward.

Reservoir models within the AOI are used to highlight variable attributes within a close proximity of the target wells. Reviewing well histories in surrounding areas and cross-referencing with reported directional data from where such wells fell within the 3D geologic model, assisted in understanding the performance of statistical outlier wells. Often wells that have been targeting a specific geologic horizon are identified as having drilled out of zone a significant percentages of the lateral. Often this lack of zonal integrity relates to poor production even though the well employ a properly-suited completion design. Identification of these issues eliminates the analogous linear regression that often accompanies a well with "good design" that underperforms greatly.

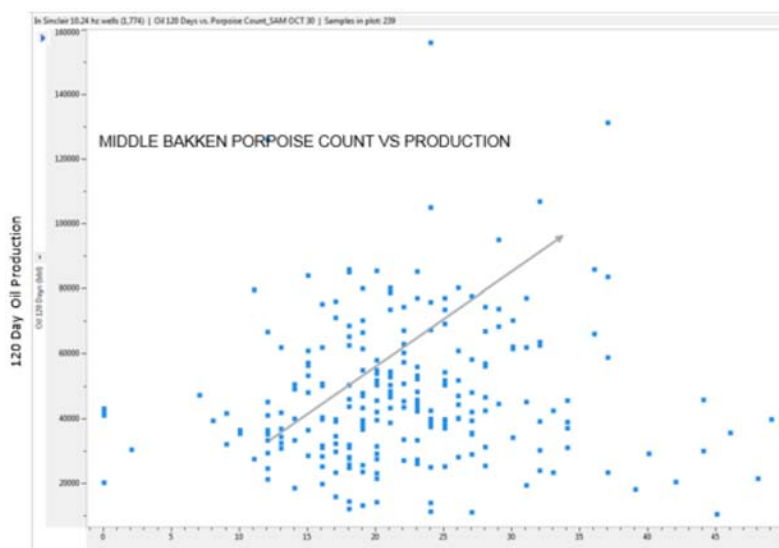
Toe up vs Toe down analysis is performed over the AOI. Findings of this analysis are interesting and the results raise further questions. In conventional oil reservoirs, it is common practice to drill horizontal wells with toe up. In doing this you have enhanced production assisted by gravity drainage. Many of the horizontal wells originally drilled in the Williston Basin followed this same practice. As time progressed however, toe down wells have become more prevalent. Often though the ending trajectory of the well is more predicated

on directional drilling targets or errors, and less on cognitive design. Analysis of these wellbore trends related to production show that in general toe down wells perform better within this part of the basin. [Figure 21](#) illustrates a sampling of 239 localized wells with a 120-day production comparison. The results show a significant increase in production related at least in part to the toe orientation. The theory developed from this analysis is that in drilling toe down, you have two distinct advantages on your production. Production in the area has a considerable amount of associated gas, as well as a significant water cut. With a toe down completion, the water tends to settle toward the toe and the hydrocarbon will rise above that. The solution gas actually provides energy for lift as it comes into the wellbore and at the time when a pump is brought on the wells, there is a better chance to control water cut (WC).



**Figure 21—Toe Direction vs. 120-Day Production**

Another analysis on drilling tortuosity in this general area proves interesting. Well porpoising is analyzed from directional surveys of wells in the area. An interesting trend is noted that wells with increased porpoising activity performed better than those with few variations. This might seem antithetical to some since each porpoising of the wellbore creates a hill and valley within the production string where you can gather water or sand or other issues that affect flow regime. The fact that these wells perform better can be due to several reasons. [Figure 22](#) represents a 239 sample of wells in the area and their 120-day production versus their toe orientation.

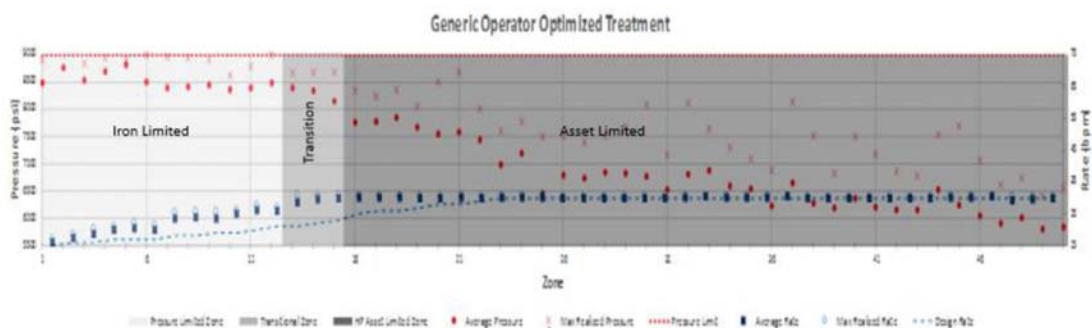


**Figure 22—120-Day Oil Production vs. Porpoising Count**

One theory is that a wellbore with many small directional corrections is associated with a diligent directional driller or geologist who is trying to target a very small target geologically. Successfully doing so insures maximum production from the operator's best rock. Through this sampling of wells, the overall average length varied no more than several hundred feet on these 10,000 ft. laterals, so well length is not statistically significant in this sampling. An alternate theory states that the lack of porpoising is related to an oversimplified view on the target and often these wells showed creeping out of the zone of interest as a result of the minimal steering events. When wells leave the target zone, they produce less thus the difference. Chances are that the real reason is a combination of both effects.

Note also that there are a small cloud of points on the chart that have very high porpoising count and yet low production to the far bottom right of the chart. A correlation was found that these wells are in areas of higher fault intensity and there is a necessity for many corrections to stay in zone. In these cases, even while in zone, reservoir quality is diminished due to the intensity of faults and related water cut.

Beyond wellbore design, there are case study findings related to the optimization of operational performance in a completion. In hydraulic stimulations, there are two key simultaneous limits that need to be monitored; pressure and rate. Pressure is limited by the iron used in the fracturing process, well heads, and horsepower components with pressure limits such as fluid ends within hydraulic pumps. Rate is limited by annular volume and pump capacity. Ideally both of these parameters are pushed to the limit to get the most efficient use of the system and optimize the output of the equipment. In Figure 23 the interval to the left is the pressure limited zone. In these stages toward the toe of the well, the formation breakdown pressures and pumping pressures can approach the safe limits of the system due to pipe friction and other flow regime issues.



**Figure 23—Diagram representing the relationship of Pressure versus Rate throughout the hydraulic fracturing process of a horizontal well**

As the well progresses, there is a darker grey (transition zone) where rate is able to increase toward pump limit and pressure decreases. This is the closest that the operator can come to optimizing the horsepower on location with the pressure threshold. Finally, the darkest grey section (asset limited zone) represents stages that are pumping at pump capacity on the well, but the pressures are far below the maximum limit. This profile is typically seen as stages approach the heel. This profile of a well has opportunities to better treat the formation. In this particular case, having more pump capacity at the well would mitigate the pump limited scenario and allow the operator to test pressure limits once more and to stimulate the maximum amount of the reservoir.

In this particular case study, there were concerns with reservoir pressure depletion, sub-traverse fractures growing toward offset operator wells, and possible frac hits on offset wells of their own. Taking this into account, the pump schedule was kept conservative to mitigate risks, but given a different risk profile the operator can readily further optimize the completions by increasing design rate on the wells and aggressively increased treating pressure to maximize SRV.

Specialty charges were incorporated through alternating stages on the two case study wells. All stages pumped without incident. There were no stages where excessive breakdown pressure was seen. No stages screened out and operationally the hydraulic fracturing was a success. Due to limited statistical feedback, there are no statistically significant findings to strongly recommend one equal entrance hole charge over the other. Additional testing and statistical data are required to define a standard.

Tracer results are very interesting and illuminating. Typically, one would expect a confined and somewhat compartmentalized distribution of the tracer material within the stages it is placed. Figure 24 is a portion of the tracer log on the 3-9TFH open hole swell packer Three Forks well.

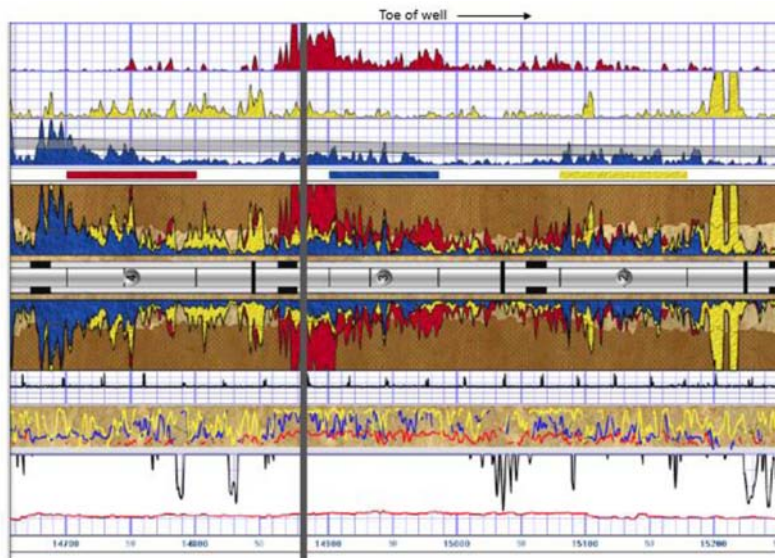


Figure 24—Tracer Log Response Showed Non-Distinct Tracer Location

This figure shows a general spreading of each tracer material well beyond the boundaries of the stages with a depletion direction bias particularly prevalent within the toe stages. Assuming a high cluster efficiency due to optimized completion design and the orientation of these fractures growing sub-transverse leaning toward the axis of the wellbore, there is adequate opportunity for the complexity of these fractures to be intense. As discussed in Prioul (2011) the initial fracture growth along the wellbore axis of the open hole environment due to hoop stress potentially explains some of this tracer signature. Transport of the tracer could readily extend long distances near the wellbore through this complex fracture network and thus the apparent wash of all the tracers throughout the wellbore. These findings support the assertions of the operator and team and validate the design decisions to be more conservative in pumping program on the deepest stages to the toe.

Early indications from production of the wells have been very positive. Despite the concerns of lower than virgin pressure, the wells have flowed and performed significantly better than other wells in the localized area drilled by the operator. Performance of the two wells represent the best Middle Bakken and Three Forks wells drilled by the operator to date.

Figure 25 shows a comparison layout of three Middle Bakken wells in the area. Well A is the Highland 4-9H well. Well B is a near offset well completed in a similar time frame by another service company and Well C is a offset well previously completed by an operator with a vintage completion style similar to that of the operator in the study.





Figure 25—Locations of Three Middle Bakken Wells

Table 3 represents a summary of the completion parameters of the three wells. The main differences in the designs of the Highland 4-9H well and Well B would be that Well B had slightly higher proppant volumes and slightly larger mesh sized proppant of 100 mesh-30/50 mesh versus 100 mesh-40/70 mesh on the Highland 4-9H. Well B was an open hole swell packer plug and perf (P&P) completion versus a cemented liner P&P completion on the Highland 4-9H. The final variables were geometric completion with chemical diverter on Well B and optimized completion with hybrid chemical/ceramic diverter on the Highland 4-9H.

Table 3—Offset Completion Parameter Comparison

	Well A	Well B	Well C
Proppant I	2,200,000 lb. 40/70 white	2,250,000 lb. 30/50 white	1,835,000 20/40 white
Proppant II	800,000 lb. 100 mesh	955,000 lb. 100 mesh	—
Lateral Length (ft)	5,792	5,320	6,993
Proppant per foot	518 ppf	602 ppf	262 ppf
Vintage	2017	2017	2014
Service Company	Design Team Member	Other	Other
Diversion	Patented Hybrid Diverter	Chemical Diverter	N/A
Zones/Spacing	25 @ 232	23 @ 231	27 @ 259
Fluid System	Slickwater	Slickwater	Borate XL
Liner	Cemented	Open Hole Swell Packer	Open Hole Swell Packer
Formation	Middle Bakken	Middle Bakken	Middle Bakken
Perforation Placement	Optimized	Geometric	Geometric

Production results as seen on Figure 26 show the differential seen on both newer wells with an upgraded design and the production improvements recognized through the proactive design process. Production from the two near offset wells is substantially higher than the historic well with Well B at nearly 59,531 bbl. at 4 months versus 32,237 bbl. for Well C at the same time frame. The Highland 4-9H outperforms both others with over 69,208 in the same period. Well B had higher concentration of proppant of nearly 100 n lb. / ft. more than Highland 4-9H, and in addition had larger proppant that would potentially provide superior conductivity on its completion. The two main variables that could be influencing the improved performance of the Highland 4-9H are the cemented liner completion and the difference in diversion design. The delta positive production of Well A versus well B is most likely related to the cemented liner completion which allows a more specific placement of proppant around the wellbore. The increasing differential in production between Well A and Well B might be related to better near wellbore conductivity supplied by the hybrid diverting agent. As the chemical diverter portion hydrolyzed, the rod shape ceramic remained in the near wellbore fracture face providing potentially a superior flow path for the Highland 4-9H well. This potentially

explains the continued improvement versus the near offset Well B. Further production analysis is needed to confirm this trend and will be discussed in future documents.

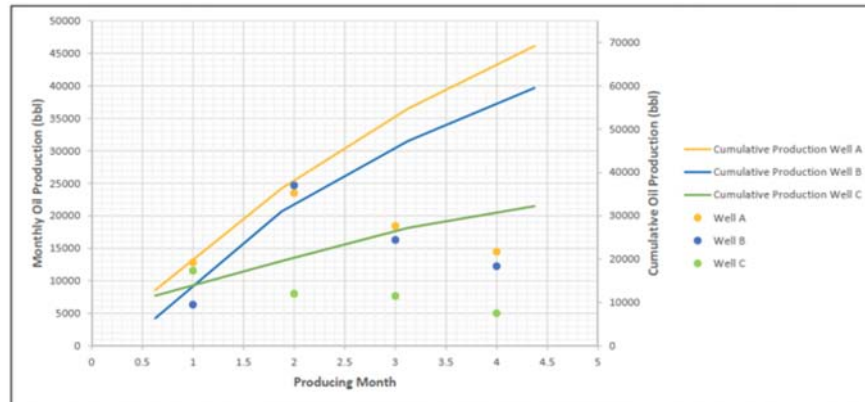


Figure 26—Comparison of 4 Month Production on Three Middle Bakken Wells of Differing Vintage and Completion Designs

## Conclusions

- A team of external service companies can develop a working process to assist an operator with technologies and skill to develop customized completion programs
- Through the use of combined technologies and analysis of multiple variables, optimized completions can be developed that take into account localized information, regional completions, and petrophysical and geomechanical parameters
- Integration of the teams findings can add value in both the completion and design phase of upcoming wells within the AOI
- Analysis of trends through the last industry downturn fostered evolution of completion designs favoring less expensive and smaller sieve proppants. Volumes, fluid designs and most general attributes were reviewed to lower the cost of completion. Results have been very positive with improved performance and no recognized long term detrimental effects have been noted thus far
- In well completion design within a pressure depleted area, it is possible to design stimulations that both mitigate risk of potential well interference and screen outs while aggressively approaching the optimization issues related to improved performance
- The optimized design, as implemented, provided 4-month production improvement of 49% on the Middle Bakken well and 101% improvement on 4 month production numbers on the Three forks wells
- Through optimized completion design in cemented liners, and deploying intra stage diversion, the observed pressure profiles were reversed from the expected increased pressure trend found in a geometric completion
- Tracer use as a diagnostic tool proved valuable in supporting the hypotheses on near longitudinal fracture stimulation growth and pressure profile especially near the toe of the well
- Cemented liners appear to provide some advantage in improved production, well modeling, diagnostics, and remediation over open hole completions
- The combination of both optimized completion design and intra-stage diversion proved to be valuable in both an operational and a diagnostic sense within the case study
- Both varieties of equal entry hole charges had similar performance and due to limited statistical data, there was no definitively superior product. Additional data is required to draw such conclusions

## Acknowledgements

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