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Investigating The Impact Of Offset Fracture Hits Using Rate Transient Analysis In The Bakken And Three Forks Formation, Divide County, North Dakota

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INVESTIGATING THE IMPACT OF OFFSET FRACTURE HITS USING RATE TRANSIENT ANALYSIS IN THE BAKKEN AND THREE FORKS FORMATION, DIVIDE COUNTY, NORTH DAKOTA

by

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This thesis, submitted by Cody L. Brown in partial fulfillment of the requirements for the Degree of Master of Science in Petroleum Engineering from the University of North Dakota, has been by the Faculty Advisory Committee under whom the work has been done and is hereby approved.

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Department	Petroleum Engineering
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Cody L. Brown
April 27, 2018

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ABSTRACT

The common development plan for operators in the Williston Basin has been to initially drill and complete one well in order to hold a 1280 acre spacing unit. Once acreage is secure across the asset, operators return to each spacing unit and drill infill wells. By the time infill wells are drilled, reservoir depletion from the original (parent) well can be observed within the spacing unit. Reservoir depletion increases the likelihood of existing wells experiencing inter-communication when infill wells are hydraulically fractured. Such inter-well communication, or frac-hits, often have detrimental effects on existing wells. As such, understanding the effect of well timing and spacing on overall spacing unit performance is of critical importance when determining an appropriate development plan.

Rate transient analysis (RTA) is an effective way to quantify the impact of offset frac hits, providing changes in reservoir properties such as stimulated rock volume (SRV) and well productivity. This study used pseudo normalized pressure versus material balance square root of time plots in order to determine the impact of offset frac hits on existing wells. The slope of the superposition time plot is inversely proportional to $A_c\sqrt{k}$, which offers a good metric for early time well productivity and completion effectiveness. Superposition time plots were created, and a production lookback was performed on 71 operated wells in northern Divide County, North Dakota. Changes observed in reservoir properties and production performance were used to determine appropriate well spacing and infill timing.

In addition, this study conducted a look back economic evaluation for 71 wells and 15 spacing units, using current commodity pricing, to assess the investment efficiencies of each project. Results from rate transient analysis, production analysis, and the economic evolution indicate that 5 – 6 wells is the optimal wells spacing per 1280 acre spacing unit within the study area.

CHAPTER I

INTRODUCTION

Background

Over the last decade, oil and gas operators have moved in earnest to establish lease positions in unconventional plays such as the Bakken. This typically involves drilling and completing the minimum number of wells in a spacing unit required to secure leases. During the initial development phase, operators may also wish to delineate their acreage in order to assess reservoir characteristics and geologic variability. Once leases are secure, additional wells are drilled and completed, in order to fully develop spacing units. Depending on acreage size and available capital, the initial development phase may span 1 – 3 years. Infill wells generally consist of multi-well pads with high well density. Tighter well spacing results in inter-well interference due to fracture hits ("frac-hits"). Frac-hits occur when a hydraulic connection is established between stimulated rock volumes (SRV) of an existing well and a newly completed well. This event can often be observed on existing wells by: sudden pressure spikes, increase in water cut, and loss in production (oil and gas). Additionally, an increase in pump failure rate due to sand has been observed in the study area post offset frac. Three different mechanisms are thought to cause frac-hits: depleted zones, changing stress fields, and high permeability lithofacies (Lawal, 2013). While frac-hits have occasionally been observed to have a positive impact (i.e., increase in SRV), the impact is usually negative, as is the case for all examples in this study. In low permeability plays, a high density of development wells is required to effectively drain the resource – which make frac hits an inevitability. As a generality, the industry has identified that tighter spaced wells fractured using more water and sand are producing more gross oil, but field data indicates that incremental production per frac is decreasing (Rassenfoss, 2017). Understanding the characteristics and mechanistic behavior of offset fracs is vital when optimizing well spacing, development timing, and completion design.

Mukherjee et al. (1995) explained that pore pressure depletion causes changes to stress gradients in the drainage area of old producers with higher stresses near the drainage boundary and lower stresses around the fracture surface. This causes fractures from infill wells to preferentially extend towards the depleted zone due to reduced closure stress in that direction (Mata et al., 2014). Roussel et al. (2013) discussed the importance of infill timing as it relates to stress reversal. He determined a window of 1.1 years exists, after the initial well is completed, before the direction of maximum horizontal stress in the infill region begins to shift from the transverse direction. Beyond this time frame, fractures gradually turn to orient parallel to the infill well, which increases the likelihood of longitudinal fractures and lower SRVs.

Kurtoglu et al. (2015) demonstrated that decline curve analysis can be used to determine the impact of frac hits on pre and post frac hit estimated ultimate recovery (EUR). Rate Transient Analysis (RTA) is more robust than decline curve analysis as it provides an understanding of the flow regimes and incorporates flowing pressure data, in addition to assistance in determining key parameters such as fracture area, fracture half-length, and matrix permeability. Lawal et al. (2014) explained that the main driving force in producing tight unconventional formations is the combined parameter of fracture area and square root of reservoir permeability ($A_c\sqrt{K}$). Any apparent increase or decrease in this metric can be used to quantify the impact of a frac hit.

Purpose and Objectives

The purpose of this study is to determine the impact of infill wells on current producing wells as a function of distance, completion design, and timing in the Bakken and Three Forks Formations, in northwestern Divide County, North Dakota. The ultimate goal of this study is to provide guidance for optimal spacing unit development, as it applies to SM Energy's undeveloped acreage in Divide County. The objectives of the study are to: (1) conduct a production look back on operated wells in order to quantify changes in pre/post frac EUR, water cut, and GOR, (2) model well bottom-hole pressure to develop accurate depletion trends and reservoir flow regimes based on well vintage, (3) construct and analyze superposition – time plots (rate-transient analysis) in order to determine the impact of offset frac hits, and (4) analyze SM Energy spacing unit tests and development timing to determine their economic efficiency.

Area of Study

SM Energy's current asset holdings in the Williston Basin are comprised of 120,830 net acres across Divide County, in northwestern North Dakota. The study area spans the northern portion of this acreage, internally referred to as "Gooseneck". This area covers 21 1280 acre spacing units and includes 81 producing wells in northern Divide County, abutting the Canadian border. In 2009, SM Energy acquired acreage in McKenzie County, which included the Gooseneck acreage in Divide County. Historically, hydrocarbon production in this region was attributed to conventional wells targeting the Duperow Formation.

Around this time, some operators were beginning to test unconventional, short lateral (640 acre) Three Forks wells. The only potential associated with the newly acquired acreage was assumed to be in the Three Forks Formation. In 2007 operators in the Williston Basin began testing multi-stage fracs, which were initially thought to be uneconomic due to longer expected hydraulic frac pump times and operating costs. In response to this issue, service companies provided lower cost alternatives for completions, such as sliding sleeves, which eventually became the new industry standard. From 2010 – 2013, SM Energy developed the Three Forks Formation by drilling one well per 1280 acre spacing unit (~10,000' laterals) and applying an open-hole, sliding sleeve completion design. These 10,000' laterals were double that of other companies in the area during this time period (640 acres, ~5,000' laterals). In 2013, operators in the area tested the Middle Bakken. Test results showed produced water cuts were much lower than SM Energy's original saturation model predicted at the time.

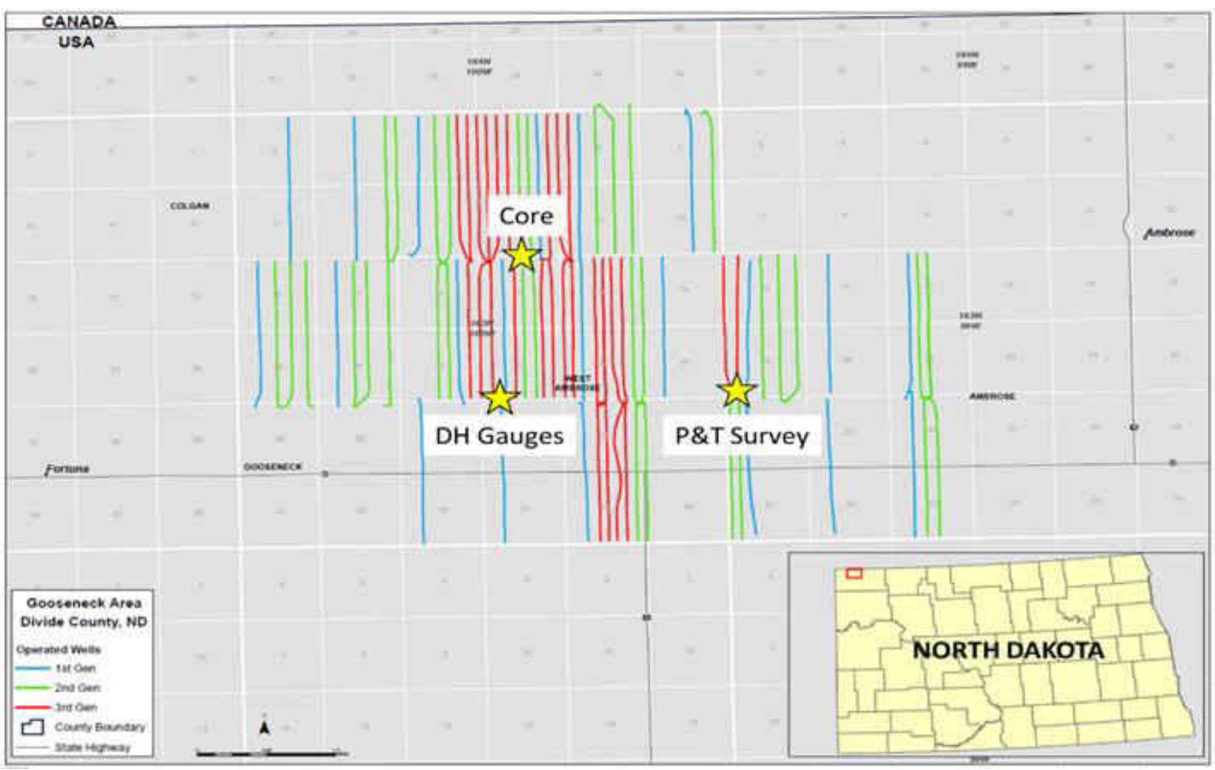

Figure 1. Gooseneck Study Area.

Based on these observations, in 2014 SM Energy commenced drilling wells targeting the Middle Bakken in Divide County. In addition, Bakken and Three Forks cores were pulled on two wells (one in Gooseneck) in order to create new petrophysical and facies models. Between 2014 and 2015, the industry shifted away from the Open Hole Sleeve Multi-Stage System (OHMS) to a cemented liner Plug-and-Perf (P-n-P) design, which many operators consider the completion standard in the Williston Basin.

Regional Geologic Overview

The Williston Basin is a structural and sedimentary basin extending over 51,600 square miles over North Dakota, South Dakota, Montana, Saskatchewan, and Manitoba. Sedimentary rock thickness is greater than 15,000 feet at basin center and represents every geologic period of Phanerozoic time (Dumonceaux, 1982). Basin development may have been influenced by the north-south-trending Precambrian Superior and Churchill geologic province boundary that extends through central North Dakota into Manitoba. This boundary delineated the hinge line for the eastern part of the Williston Basin.

Basin sedimentation is characterized by cyclical transgressions and regressions with the repeated deposition of carbonates and clastics. Paleozoic strata are dominated by carbonates, whereas Mesozoic and Cenozoic strata consists mainly of clastic rocks (LeFever et al., 1991). During the Early Ordovician, the basin began to subside, causing a major transgressive event which was eventually broken during the Devonian by uplift. This uplift, due to movement along the transcontinental Arch, caused the Williston Basin to tilt northward, connecting it to the Elk point basin (Gerhard et al., 1982). During this time, depositional environments were predominately shallow marine. Subtitdal and intertidal environments developed in the basin center, with sabkha deposits present along the basin margin (Gerhard et al., 1982). A reorientation of the seaways occurred again during the Mississippian when the basin opened to the west through the central Montana Trough. Terrestrial, marginal marine, and evaporate sediments are represented by Pennsylvanian through Triassic strata during the Jurassic and Cretaceous periods (LeFever et al., 1991).

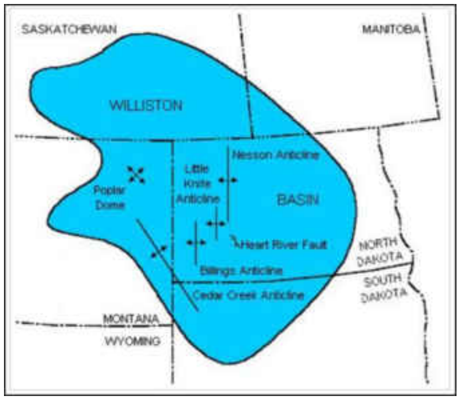

Figure 2. Arial extent of the Williston Basin (from Pitman et al., 2001).

A major angular unconformity separates the Paleozoic from the Mesozoic, representing one or more periods of erosion that occurred from Late Mississippian to Early Jurassic time (LeFever et al., 1991). During this interval, Paleozoic strata in the northeastern part of the basin were uplifted and differentially eroded, while strata in the southern portion of the basin were relatively unaffected. Successively older Paleozoic strata were progressively truncated toward the basin margin (Dumonceaux, 1982). Deposition resumed during Mesozoic time, when a thick sequence of Jurassic and Cretaceous strata were deposited on the eroded Paleozoic surface (LeFever et al., 1991). Within the Paleozoic itself, an unconformity separates Devonian and Mississippian strata and represents uplift and erosion, which occurred from Late Devonian to Early Mississippian time (Gerhard et al., 1982). During that interval, Devonian strata were uplifted and exposed along the basin margins, while deposition continued in the deeper portions of the basin. Mississippian sediments were later deposited on the eroded Devonian surface (LeFever et al., 1991).

Major hydrocarbon reserves exist within the Williston Basin, most notably the Late Devonian – Early Mississippian age Bakken Petroleum System. The Bakken Petroleum System is defined as the oil saturated interval stratigraphically inclusive of and adjacent to the Upper and Lower Bakken Shales. It includes the Lower Lodgepole, Upper Bakken, Middle Bakken, Lower Bakken, Pronghorn and Upper Three Forks (LeFever et al., 2011). The North Dakota Industrial Commission (NDIC) defines the Bakken Pool producing interval as any strata 50 feet above the top of the Upper Bakken Shale and 50 feet below the base of the Lower Bakken Shale.

The Bakken Formation unconformably overlies the Upper Devonian Three Forks Formation. The Devonian – Mississippian boundary is generally placed within the Bakken Formation (Peterson and MacCary, 1987). The Bakken Formation is interpreted as deposits representing transgression as the Late Devonian and Early Mississippian seaway advanced (Gerhard et al., 1987). The Bakken Formation is described as an organic rich, mudstone and sandstone unit that is continuous through the Williston Basin, with depths from 130 feet at basin margin to 12,000 feet at basin center near McKenzie County. The Bakken Formation is comprised of three members: 1) a finely laminated, organic rich, black mudstone Lower Member; 2) a gray mudstone/sandstone Middle; 3) a black mudstone Upper Member with similar composition to the Lower Member (Smith and Bustin, 1996). The Upper Bakken is overlain conformably by the argillaceous carbonate bed of the basal Lodgepole Limestone (Peterson and MacCay, 1987).

The Three Forks Formation is a late Devonian shale dominated rock package above the Birdbear Formation of the Jefferson Group and unconformably below the Lower Bakken Shale. The Three Forks is the thickest in the center of the Williston Basin, where it reaches a maximum thickness of 270 feet in western Dunn and northeastern Billings Counties, and thins to an erosional zero-edge to the east and the southwest (LeFever et al., 2008). The Three Forks

Formation consists of interbedded greenish-grey and reddish-brown micrite and dolomicrite with anhydrite nodules scattered throughout and subordinate amounts of biomicrite. Sedimentary structures such as ripple cross laminations, soft sediment deformation and mudcracks suggest deposition occurred in a shallowing-upward, sub-tidal, nearshore, subtidal to supra-tidal environment (Bottjer et al., 2011). Dumonceaux (1984) observed five lithofacies in cores from the Three Forks Formation in northern North Dakota. He then subdivided these lithofacies into three informal members: Lower Three Forks, Middle Three Forks, and Upper Three Forks. The highest oil saturations are found in the upper dolomitic layer, also known as the "first bench".

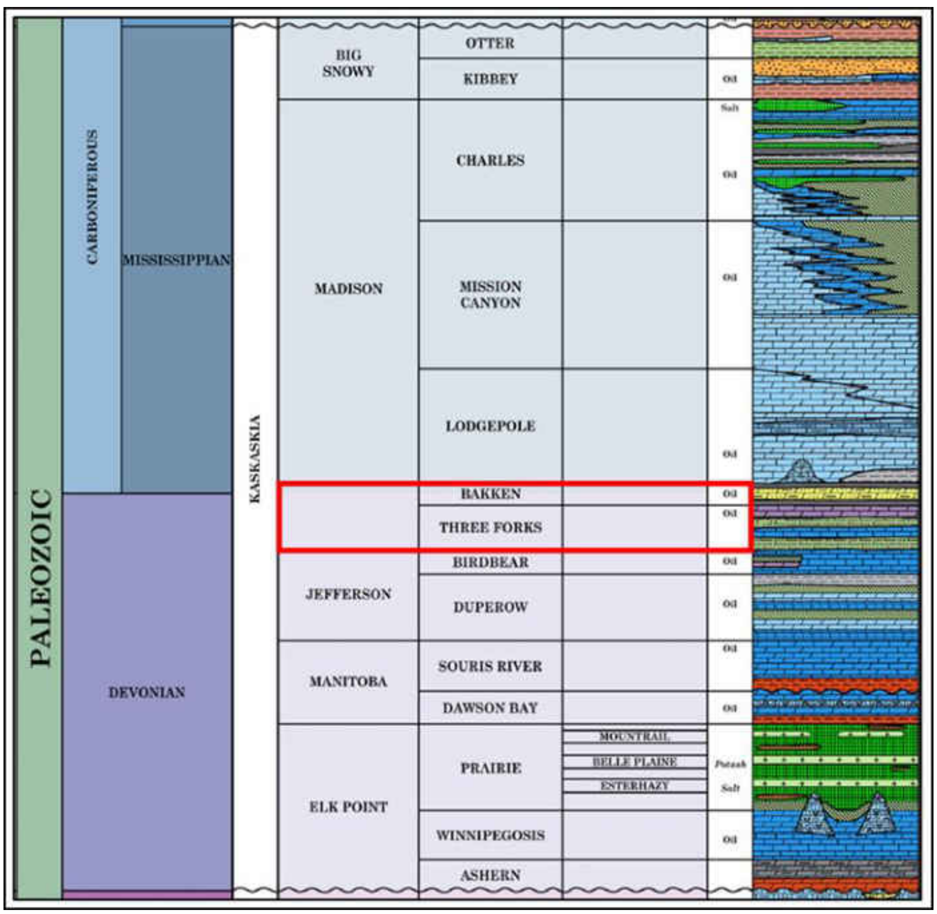

Figure 3. Stratigraphic column of the Bakken and Three Forks Formation in North Dakota. (modified from Murphy et al., 2009).

The Gooseneck study area lies on the northern margin of the Williston Basin, outside the overpressure zone (Figure 4). A general pinching out of facies occurs in northern Divide

County. Middle Bakken thickness averages 59 feet, while the first bench of the Three Forks averages 9 feet. Structurally, the top of the Middle Bakken is ~2,500' TVD closer to ground elevation relative to its depth in McKenzie County. Less overburden and resulting compaction can be attributed to better Bakken and Three Forks rock quality in Divide County (i.e., higher permeability/porosity facies, lower water saturations from core). Gooseneck average reservoir temperature and pressure are lower relative to basin center due to its shallower depth. (Figure 4) illustrates the change in reservoir parameters between the Gooseneck area and McKenzie County.

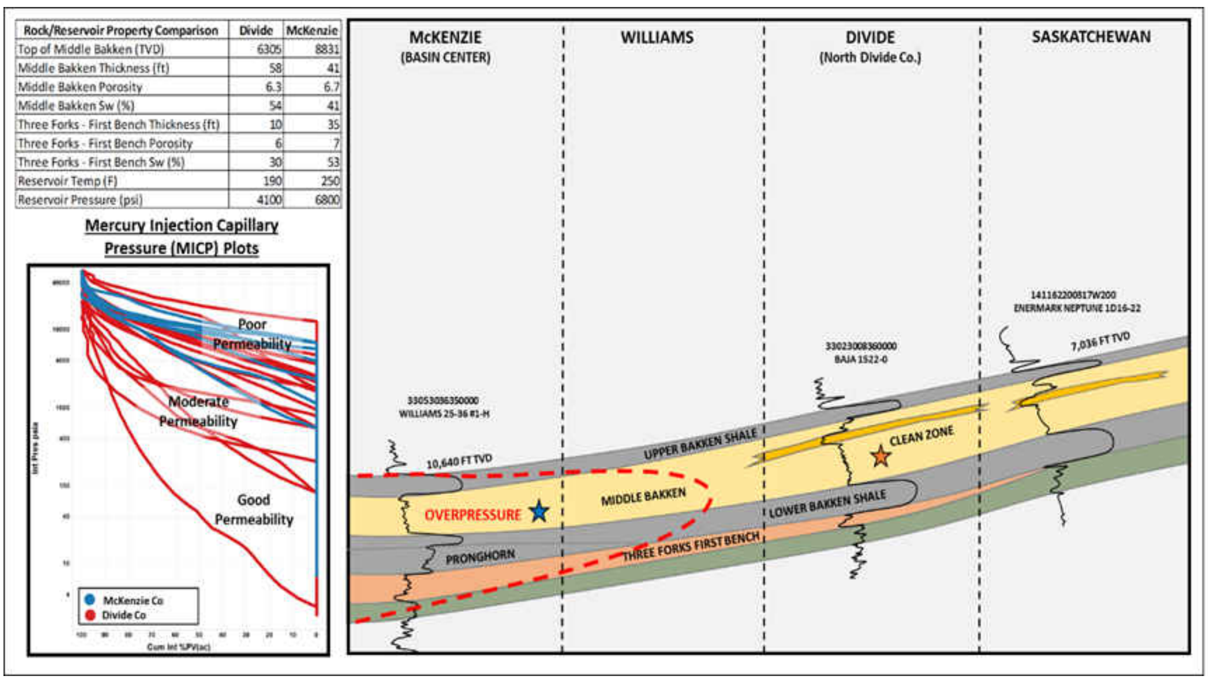

Figure 4. Reservoir properties from basin center to northern Divide County. (modified from SM Energy).

T_{max} values, a key indicator of hydrocarbon generation, for the Bakken Shale obtained from Rock-Eval pyrolysis support decreasing maturity towards the basin margin (Figure 5). T_{max} values for the Bakken Shale are generally highest near basin center where overburden thickness is greatest. LeFever et al. (1991) discussed the implication of heat flow anomalies which strongly affect the depth at which source rock generation may occur, allowing for kerogen to convert to hydrocarbon at relatively shallower conditions.

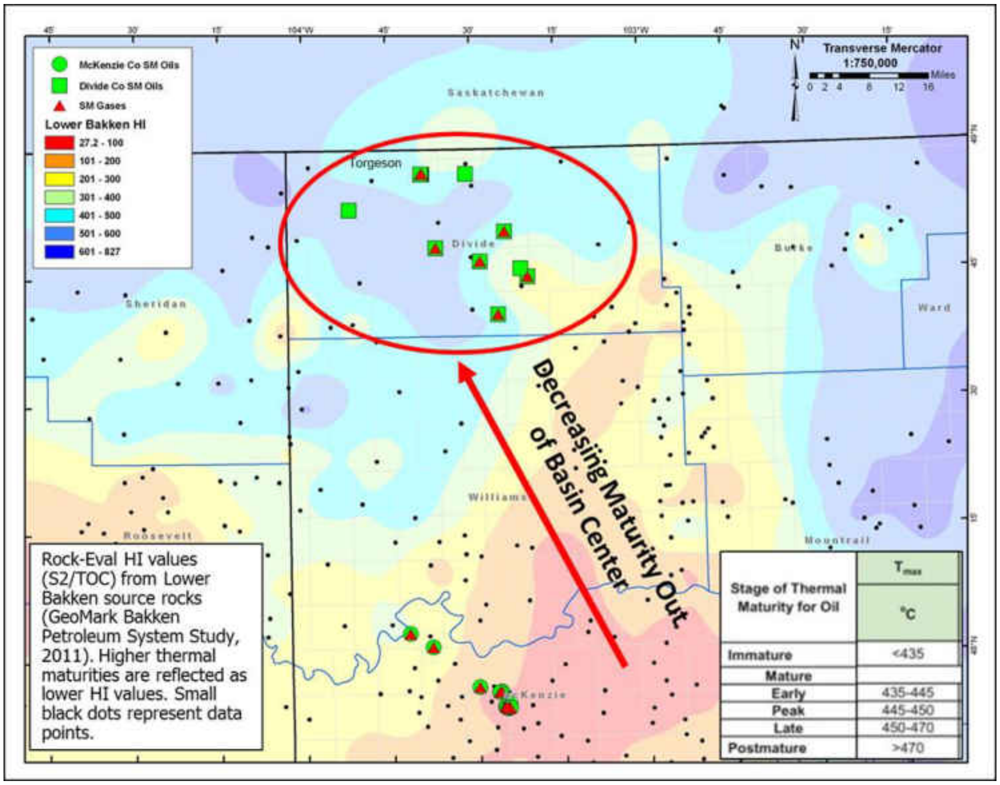

Figure 5. Pyrolysis data supports migration theory, as produced oils in Divide County have higher maturities than in-situ Lower Bakken Shale (modified from SM Energy).

Completion Design

The application of horizontal drilling and hydraulic fracturing in unconventional reservoirs over the past decade has unlocked vast hydrocarbon resources; spurring rapid development in plays such as the Williston Basin. The extremely low permeability (< 0.1 md) of tight reservoirs requires hydraulic fracture treatments to create a conductive pathway from the reservoir to the wellbore.

The first horizontal well targeting the Middle Bakken, rather than the source shale (Upper Bakken) was drilled in the Elm Coulee Field of Montana in 2000, applying an open-hole single stage completion. The Elm Coulee development established that large volumes of oil had been generated in the Upper and Lower Bakken Shales and expulsed into the Middle Bakken and Three Forks Formations, and that the geomechanical properties of the Middle Bakken are more favorable for hydraulic fracture treatment. The Elm Coulee learnings were applied to the Bakken in North Dakota in 2005. Completion design in these early wells typically involved single-staged fracs with 2 million pounds of proppant and 1 million gallons of cross-linked gel. (Nordeng et al., 2011). According to Pearson et al. (2013), the first multi-stage frac was completed in the Parshall Field in 2007. Due to positive well performance, this technology was applied by other operators across the basin. A year later, the average stage count per well had reached ~10 stages. The average fluid treatment volumes were typically 20,000 bbls with 100 lbs/ft of proppant (Pearson et al., 2013).

Operated wells in Divide County are positioned in a north-south orientation to take advantage of induced fracture propagation in the direction of maximum stress, which has a NE to SW orientation across much of the basin (Sonnenberg et al., 2013) (Figure 6). Micro-seismic and chemical tracer data collected in 18-19 T163N R99W display a similar trend.

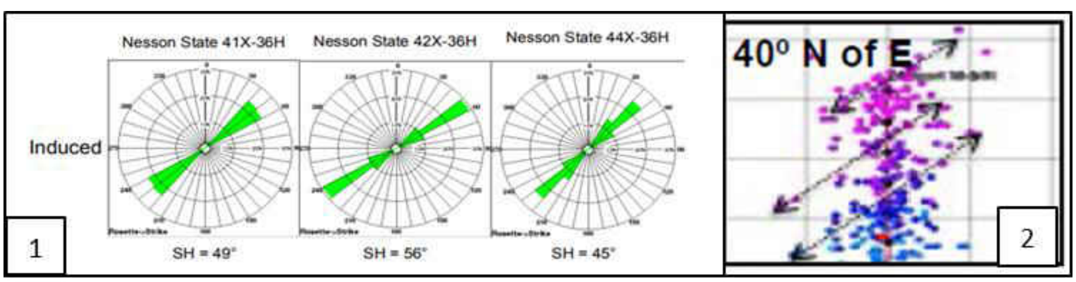

Figure 6. Micro-seismic and chemical tracer data (2) agrees with published data of maximum horizontal stress (1) (modified from Sonnenberg et al., 2013).

At the inception of Gooseneck development from 2010 - 2012, SM Energy employed an open hole, swell packer and sliding sleeve completion design targeting the first bench of the Three Forks. The sliding sleeve design is run with external packers meant to isolate different intervals of the wellbore. Frac port subs with sliding sleeve tools are run between the swell packers. The sliding sleeves open by dropping specifically sized actuation balls into the system, which then push the injection ports open, subsequently creating a single-entry point (Figure 7).

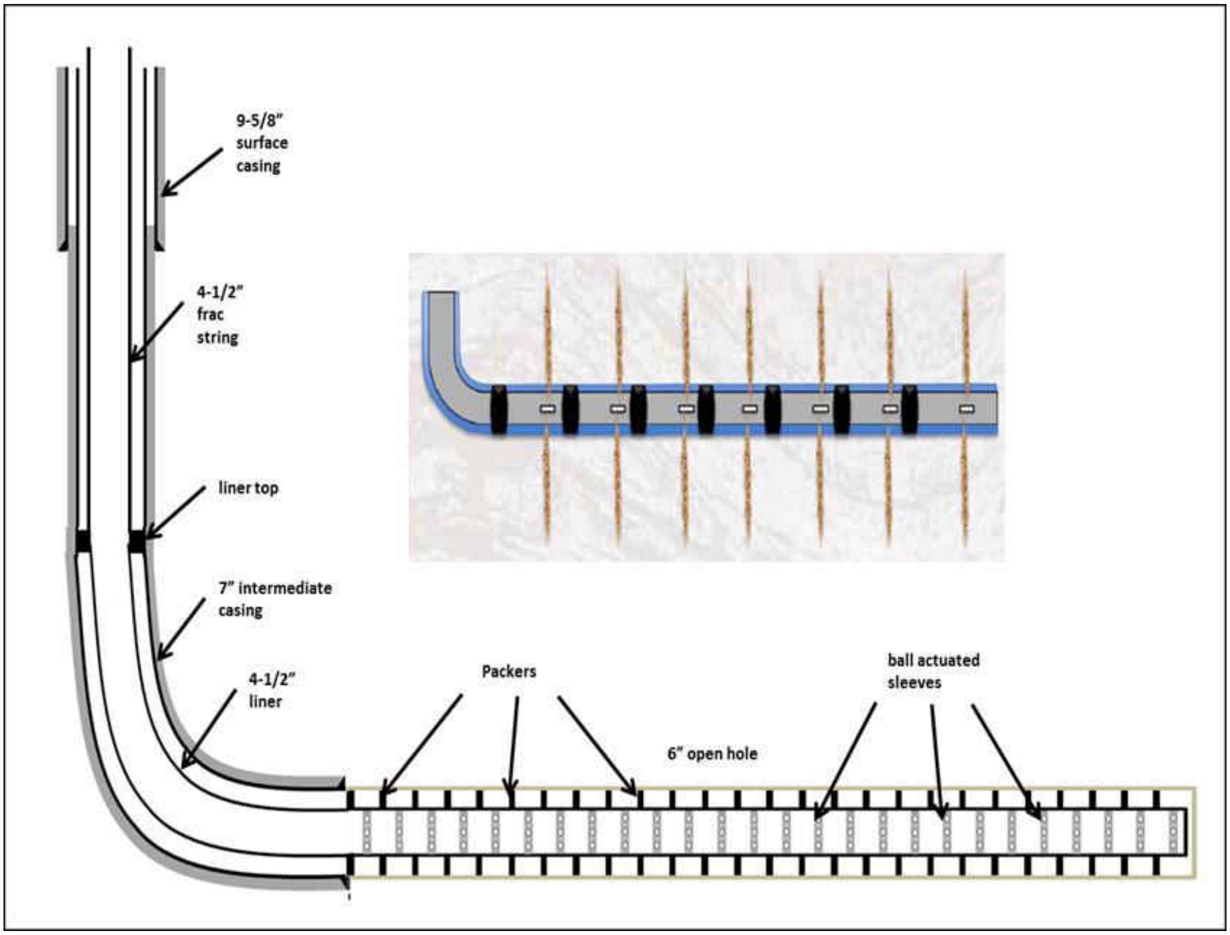

Figure 7. Wellbore schematic of open hole sliding sleeve completion design, with one entry point per stage.

From 2012 – 2015, SM Energy progressively optimized its completion design by increasing the number of stages, while pumping more proppant and fluid per foot (Figure 8) – similar to other operators during this time (Wright et al., 2014). The first Middle Bakken wells were drilled in 2014, utilizing the same completion design applied to Three Forks wells. From 2015 – 2016, completion design transitioned from an open hole sliding sleeve assembly to a cemented liner, plug and perf system. In this design the 4-1/2" liner is cemented in the wellbore (Figure 9). A perforating gun and pump-down plug are ran on wireline inside the liner. This allows for perforations to be shot immediately after the plug is set. After all stages are complete, coiled tubing is used to drill out the plugs. The cemented liner, plug and perf design creates multiple perforation clusters per stage, resulting in a larger near-wellbore stimulated rock volume (SRV). Several papers discuss the benefit and drawback of sliding sleeve versus plug and perf (Pearson et al., 2013; Wright et al., 2014; Rahim et al., 2015; Algadi et al., 2015).

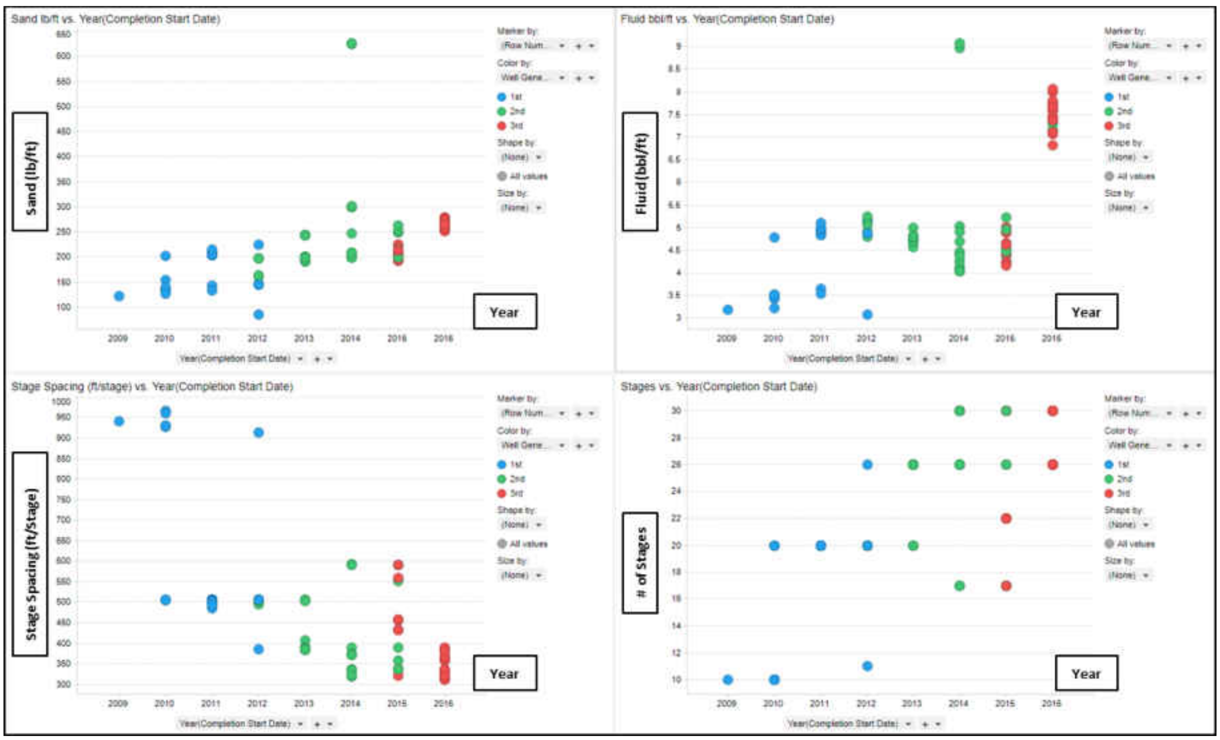

Figure 8. Evolution of study well completion design over time.

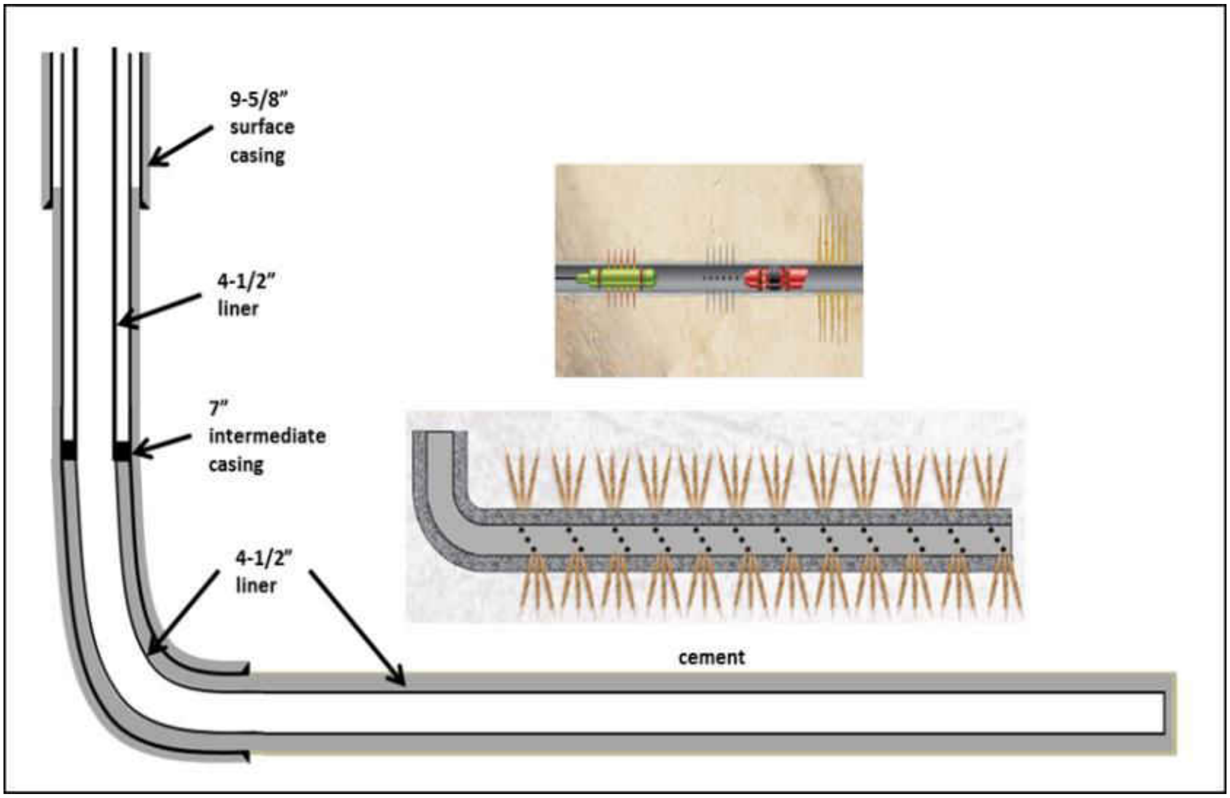

Figure 9. Wellbore schematic of typical cemented liner, plug & perf completion design, with 5 clusters per stage.

While open hole sliding sleeve and cemented liner plug and perf are the two main completion designs SM Energy used, it should be noted that one other design, multi-sleeve single ball (MSSB) system, was trialed on 6 wells from 2014 – 2015. The MSSB system was tested in order to achieve the multiple entry point benefit of the plug and perf method, while maintaining the efficiency of a ball actuated sleeve conveyance system. The open-hole design contained 17 swell packers ran on 4-1/2" liner with 51 frac port subs (3 frac ports per stage). Similar to the plug and perf system, the MSSB was thought to shorten fracture half-length while increasing the stimulated area near the wellbore. Trial candidate wells were selected primarily on proximity to existing offset wells. Performance for wells completed with the MSSB design significantly underperformed relative to wells completed with a standard sliding sleeve or plug and perf design (Figure 10). Excluding the MSSB system, this study was unable to associate well performance with a specific completion design since first generation (parent) wells tend to perform better than subsequent infill wells.

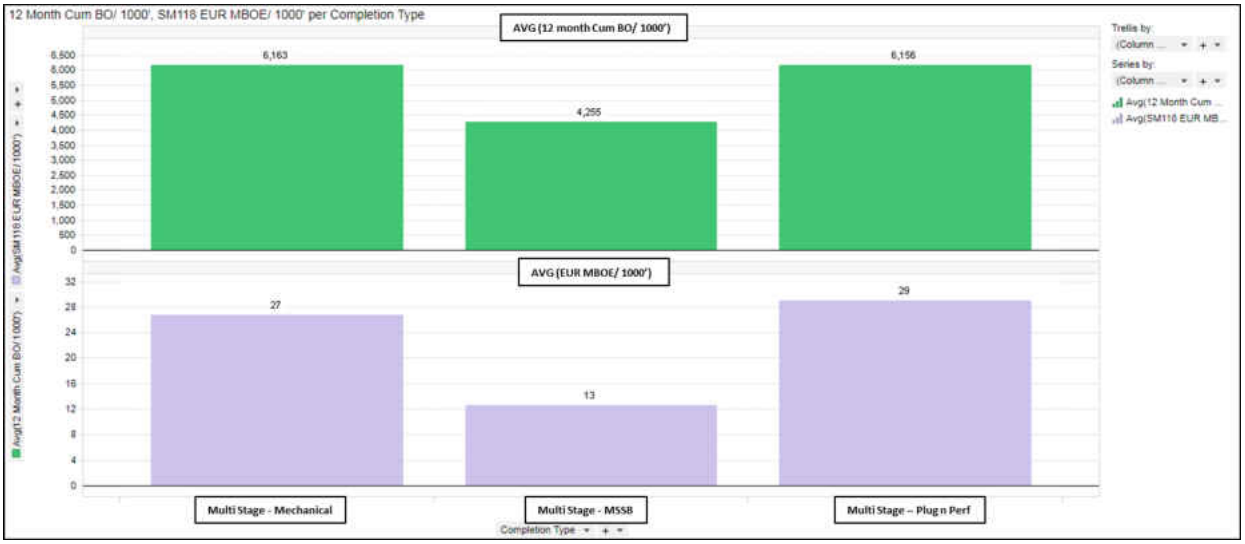

Figure 10. Comparison of well performance by completion design, normalized to lateral foot.

Table 1. Completion design parameters by generation.

Metric	1st Gen (Parent)	2nd Gen (Infill)	3rd Gen (Infill)
Completion Date	2009 - 2012	2012 - 2015	2015 - 2016
Formation	Three Forks	70% Three Forks, 30% Bakken	45 % Three Forks, 55% Bakken
Completion Type	Open Hole Sliding Sleeve	OH Sliding Sleeve, P&P	Plug & Perf
Number of Stages	10 - 26	17 - 30	26 - 30
Cluster Spacing	1 perf cluster per stage	1 - 5 perf clusters/stage	5 perf clusters/stage
Stage Spacing (ft)	390 - 970	319 - 593	310- 460
Sand Concentration (lbs/ft)	85 - 225	160 - 625	195 - 280
Sand Type	20/40 & 20/70	20/40 & 20/70	30/50 & 40/70
Fluid Volume (bbl/ft)	3 - 5	4 -9	4 - 8
Fluid Type	Slickwater/ XL tail-in	Slickwater/ XL tail-in	Slickwater/ XL tail-in
Pump Rate (BPM)	46	46	46

Development History

SM Energy acquired the Gooseneck acreage in northern Divide County in 2009 and began drilling the minimum number of wells (one per spacing unit) required to hold acreage. Each well targeted the first bench of the Three Forks and held a 1280 acre spacing unit, which allowed for ~10,000 foot laterals. A total of 21 parent or "first generation" wells were drilled and completed from late 2009 through 2012, with an average TVD of 8,071 feet. After fracture treatment, the wells were immediately turned over to flowback up the 4-1/2" frac string. Parent wells typically flowed freely for 1 – 2 months, before being converted to rod lift. Typical downhole production design was 2-7/8” tubing with a 2-1/4” tubing barrel pump. In accordance with the North Dakota Industrial Commission (NDIC) set back requirements of 1220 feet from the east/west section line and 200 feet from the north/south section line, most parent wells were drilled 1320 feet east of the western section line.

Starting in 2012, SM Energy began developing its first infill wells, which are referred to as “second generation” in this study. The initial infill development plan called for 3 additional Three Forks wells, which totaled 4 Three Forks wells per spacing unit, with an average distance of 1,320 feet between each wellbore. From 2012 to 2013, five units were developed with the spacing described above. For each spacing unit, all 3 infill wells were completed at approximately the same time, utilizing an open hole sliding sleeve design. The number of completion stages ranged from 20 – 26 per well, treated with 161 – 244 pounds per foot of proppant and 4.7 – 5.25 barrels of fluid per foot. These wells typically flowed up the 4-1/2” casing for ~ 1 month before being cleaned out and converted to rod lift, with initial downhole production configurations similar to parent well configuration.

As discussed in the opening remarks of this study, offset operators began testing the Middle Bakken directly adjacent to SME’s acreage. Production results from the Bonneville 36-25-163-100H (API: 33-023-00666-0000; Sec 36 T163N R100W) indicated Middle Bakken water cut was significantly lower (~31%) than SME’s original saturation model would have predicted. Based on these observations and with the support of high commodity prices, SM Energy began targeting Middle Bakken wells in 2014. In addition, two cores were sampled in Sec 19 T163N R100W (Gooseneck) and Sec 1 T161N R100W in order to improve the understanding of rock and reservoir properties across Divide County. Down spacing was applied in order to accommodate and maximize the additional Middle Bakken reserves. This development plan included one Three Forks parent well, 6 infill wells, and two section line wells (half in each spacing unit). Each infill well alternates between Bakken and Three Forks, with 1320 feet between wells in the same formation, and 660 feet between adjacent wells, totaling 4 Three Forks and 4 Bakken wells (Figure 11).

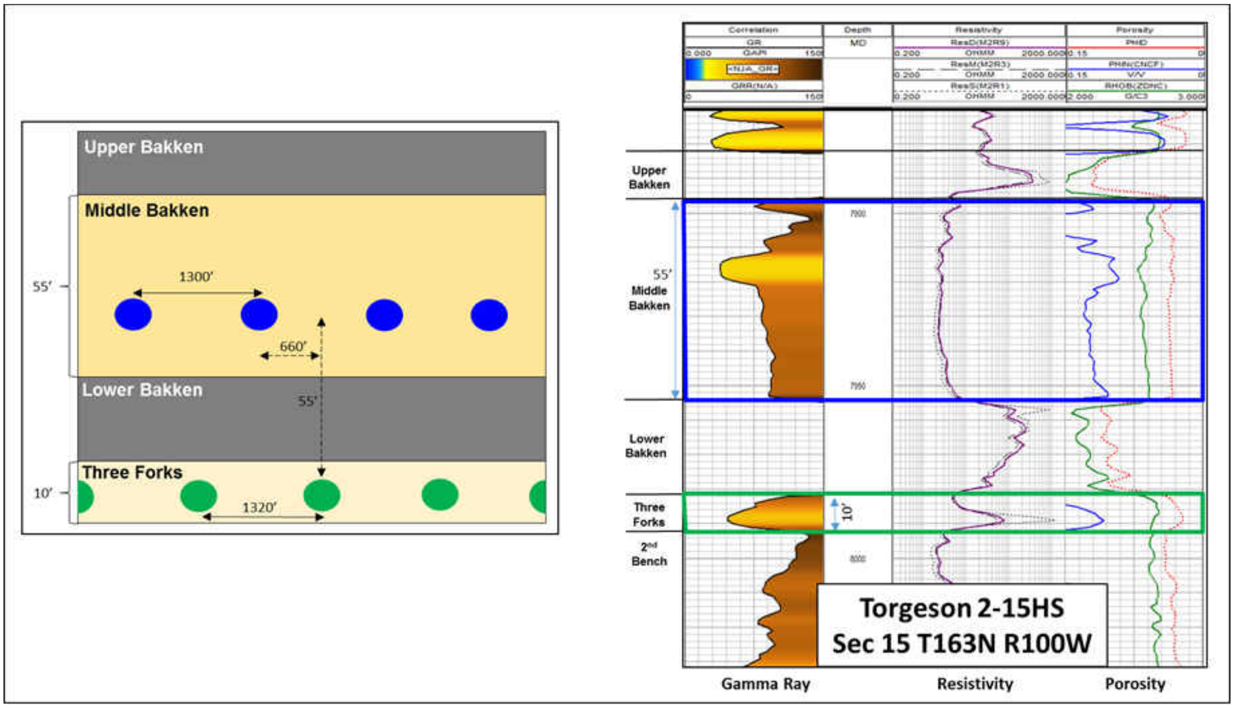

Figure 11. Schematic of 8 well development plan with staggered Middle Bakken and upper Three Forks wells, and correlative type log.

Three Forks spacing was largely based on production history and from micro-seismic and chemical tracer study results indicating an average fracture half-length of 550 feet. Appropriate Middle Bakken well spacing was assumed to be similar to that of the Three Forks, due to a lack of Bakken production data. Multi-well pads were utilized to reduce costs and add efficiency. Second generation well pads were designed to accommodate 4 wells – two laterals in the northern spacing unit and two wells in the southern spacing unit.

Initial Bakken completions were paired with a Three Forks well separated by ~ 600 feet.

Hydraulic fracturing was conducted one immediately after the other, and turned over to production at approximately the same time. Early Middle Bakken results were positive, as illustrated in Figure 12. Average 6 month cumulative oil production normalized by lateral length was on par with Three Forks wells with similar completion design. There was little variation with respect to target zone, drilling, or completion design over this time.

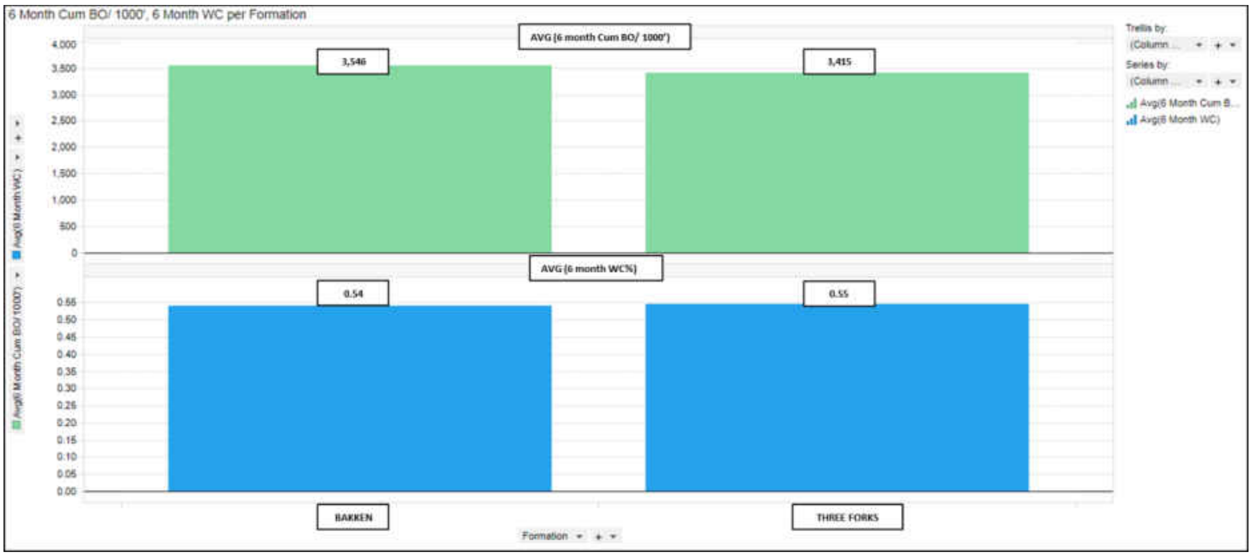

Figure 12. Initial Middle Bakken well performance compared to Three Forks wells with similar completion design.

However, the placement of second generation wells relative to the parent well varied widely. In some spacing units, second generation wells were placed directly offset to the parent, while others were placed on the opposite side of the spacing unit. Minimum distance from parent well to infill well ranges from 540 – 2,646 feet and the time between parent well completions and second generation completions is 2 – 4 years. The implication of timing and distance will be discussed in detail in subsequent sections of this study.

In 2015, based on positive results in SME's McKenzie County acreage, and congruent with overall industry trends, a cemented liner, plug and perf completion design was implemented in Gooseneck. The design was trialed on 6 second generation wells, then applied to 25 of 27 third generation wells from late 2015 through 2016. In this study, "third generation" refers to wells completed after second generation wells. These wells are defined as the second set of infill wells and represent full spacing unit development. The placement of these wells within its respective spacing unit was dependent on the location of second generation wells relative to the parent. As such, a wide variety of scenarios occurred. In general, third generation wells were either hydraulically fractured one immediately after the other, or simultaneously (zipper frac). Of the 27 third generation wells, 12 were completed at the same time as the adjacent well. In some spacing units, a single third generation well was completed in between the parent and second generation well, while in others, 4 wells were placed between the parent and second generation well. Minimum distance from a second generation well to third generation well varies from 460 – 3,440 feet and the time between second generation well completion and third generation completion is 1 – 4 years. The time between end of completion job and when third generation wells were brought online varied from 1 – 10 weeks based on operational logistics. Third generation wells began producing with rod lift already installed. Initial production flowed up 3-1/2" tubing and up the 7" casing - 3-1/2" tubing annulus. Simultaneous pumping and flowing (known as "flumping") continued until the 2-3/4" tubing barrel pump capacity was greater than inflow from the reservoir.

During infill development, existing wells were protected from potential pressure communication by "soft-setting" the rods on the seating nipple and installing a 5,000 psi rod BOP at surface. The installation of rod BOPs was a proactive measure meant to prevent blowouts at surface, rather than provide any downhole wellbore protection. As development progressed, it became apparent that the Bakken and Three Forks were communicating, essentially acting as one reservoir. Evidence of communication was be observed in production trends on existing wells pre and post offset frac, demonstrating a decrease in EUR and an increase in water cut. Brinkerhoff et al. (2015) provided evidence of significant Lower Bakken Shale contribution to Three Forks wells in Divide County. They proposed, based on a calculated Fracability Index, that the Lower Bakken Shale has a higher propensity to generate fracture surface area than many of the primary target intervals in the underlying Three Forks Formation within the Gooseneck area. In addition, GeoMark conducted an isotopic "time evolution" study. Results demonstrate that Three Forks oils from two wells in the Gooseneck area appear to have picked up oil from the Middle Bakken, especially after 1 month of production. Small variation in completion design for like-generation wells allows for a well performance analysis based on infill timing and distance. Understanding the impact and interaction between infill wells and existing wells has significant implications for field development strategies.

Methods

For this study, a production look-back was performed on 81 operated wells in the Gooseneck area of northern Divide County. All well data used in this study was internally sourced by SM Energy. Daily production values were analyzed and quality controlled in order to provide a representative performance trend for each individual well. Operational history was considered, which required cataloging various tubing and pump sizes ran, reviewing dynamometer reports, completion parameters, and workover job descriptions. Reservoir data was compiled for 21 spacing units based on core data, petrophysical logs, and facies models generated by members of SME's geoscience team. Two pressure-temperature surveys were used to calculate pressure and temperature gradients. Gas and fluid properties were compiled from well specific analyses. All data was used to create bottom-hole pressure models and superposition time plots per well using Fekete Harmony™ software. Decline curves were applied to historical production trends using Aries™ software. Economic scenarios were run on

71 individual wells and 13 spacing units in order to assess the impact of well spacing and timing. Superposition time plots were used to determine initial productivity, effect of offset fracs, flow regimes, and completion parameters. Spotfire® was used to identify correlations and trends.

CHAPTER II

RATE TRANSIENT ANALYSIS

Applications to Unconventional Reservoirs

The use of rate transient analysis (RTA) to evaluate well performance, including type curve analyses, has been discussed by Fetkovich (1980) and more recently by Blasingame et al. (1991) and Agarwal et al. (1999). In contrast to conventional wells with high permeability, unconventional shale reservoirs typically exhibit transient flow for long periods of time. The average time to end of linear flow (t_{elf}) for the 21 parent wells in this study is 1 year. As a result, early assessment of reservoir properties can be challenging when using only conventional decline curve analysis (DCA). During early time transient flow, RTA provides insight to well characteristics that otherwise might go undetected using DCA. Transient linear flow occurs during the early life of a well, when the reservoir boundaries have not been felt, and the reservoir is said to be infinite-acting (Fekete). The concept of linear transient flow in shale oil wells was introduced by Wattenbarger et al. (1998). Of most importance for this study is the parameter $A_c\sqrt{K}$, which is defined as the contacted surface area multiplied by the square root of the effective permeability of the contacted rock. It can be used to determine early well performance and completion design effectiveness, assuming similar landing zones and geology. Below is the equation proposed by Wattenbarger to determine $A_c\sqrt{K}$ under constant flowing bottom-hole pressure:

Eq. 1 $$A_c\sqrt{K} = \frac{19.927\ \mathrm{B}}{\mathrm{m}}\sqrt{\frac{\mu}{\phi c_t}}$$

As discussed by Belyadi et al. (2015), a plot of normalized pressure, with $\frac{(p_i)-(p_{wf})}{q}$ on the y-axis – where q is oil rate, p_{pi} and p_{pwf} are initial pressure and flowing pressure, versus square root of time on the x-axis is shown in Figure 13.

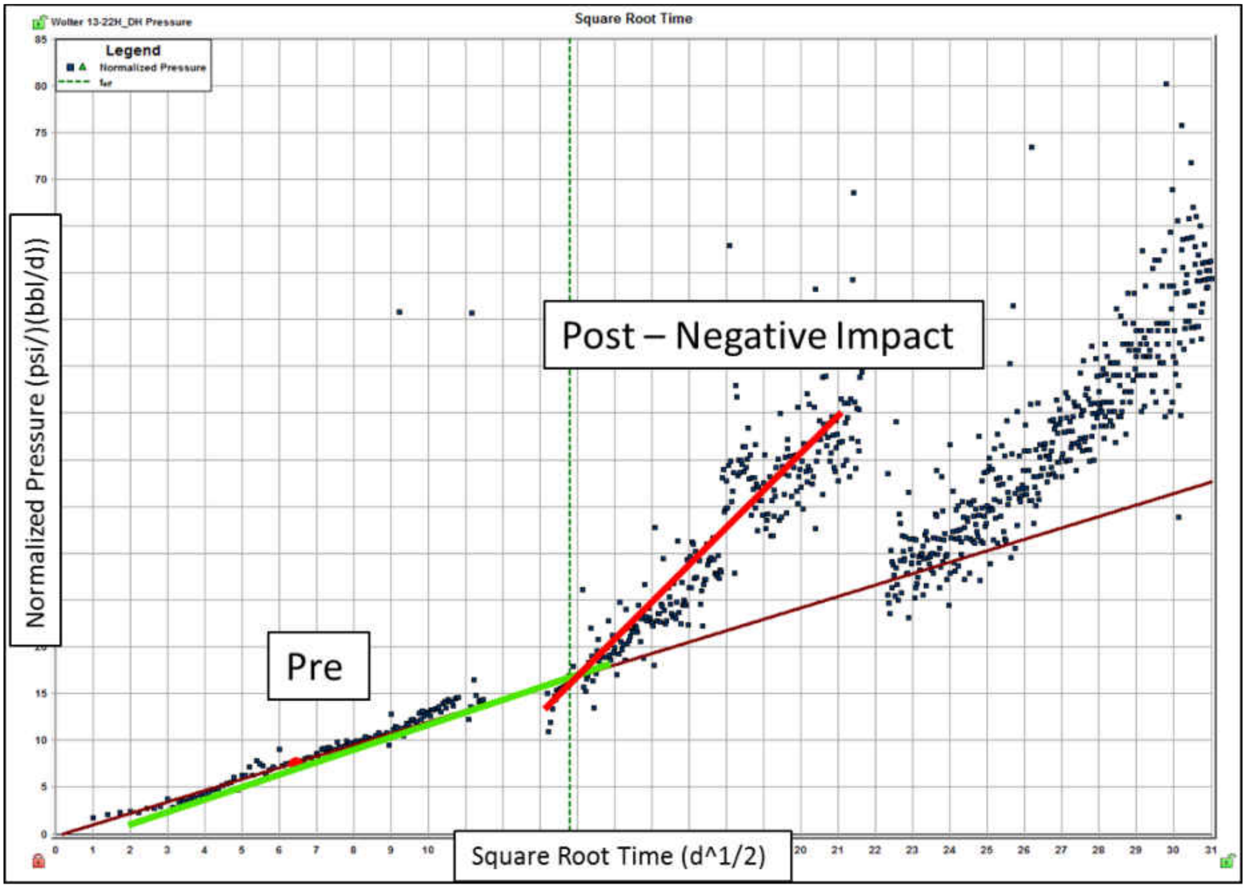

Figure 13. Normalized Pressure versus Square Root of Time

Transient flow is characterized by a half-slope on a log-log plot of oil rate versus time and as a straight line on the square root-time plot. The plot can be used to determine *m*. In Equation 1, Ø is the porosity, μ is oil viscosity, c_t is total compressibility, *B* is formation volume factor. The slope of the line is inversely proportional to $A_c\sqrt{K}$. As such, as the slope of the line increases, $A_c\sqrt{K}$ decreases.

It should be noted that the linear flow study outlined above assumes constant rate and/or constant pressure. In practice, variable production rate and pressure occur. Specialized plots are used to analyze linear flow when both rate and pressure vary. The classic way to deal with variable rate is to use superposition time. As described by Fekete, superposition is a mathematical tool that allows use of simple solutions (such as constant rates) to produce complex ones (such as variable rates). So, a rate that changes from q_1 at time t to a new rate q_2 is equivalent to q_1 continuing forever, superposed, or added on $(q_1 – q_2)$ starting at time t and continuing forever. To help illustrate this concept, Liang et al. (2013) provided the following example: A well is flowing in a multi-rate situation in Figure 14a. The total pressure drop (ΔP) at time t_3 can be expressed as follows:

ΔP = pressure drop from the well due to q1 throughout the entire flow period (flow time = t3)

+ pressure drop from the well producing at (q2 – q1), beginning at time t1 (flow time = t3 – t1)

+ pressure drop from the well producing at (q3 – q2), starting at the time t2 (flow time = t3 – t2)

Figure 14b illustrates that the total pressure drop is given by:

Eq.2 $$\Delta P = \Delta P_1 + \Delta P_2 + \Delta P_3$$

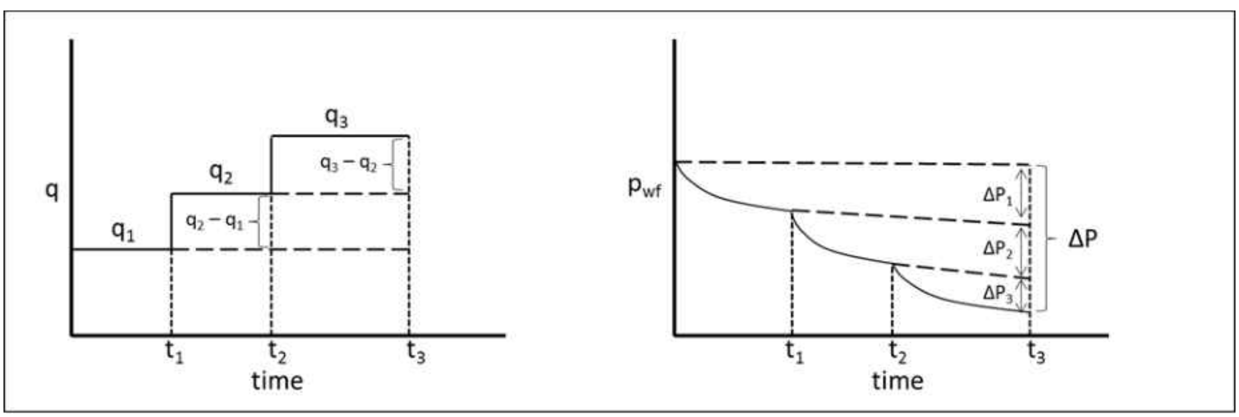

Figure 14. a) multi-rate flow; b) pressure response due to different rates (from Liang et al., 2013).

In unconventional reservoirs, two superposition time functions are commonly used in production analysis: linear superposition time (used for transient linear flow) and material balance time (used after pressure transient has reached all reservoir boundaries). Both superposition time functions can effectively convert variable rates to their equivalent constant rate solutions. Therefore, the plot of $\frac{p_i - p_{wf}}{q}$ versus linear superposition time or square root of material balance time results in a straight line, the slope of which (m) can be used to calculate $x_f\sqrt{K}$ (Fekete), where:

Eq. 3 $$4 * h * x_f\sqrt{k} = \frac{19.927\,B}{m}\sqrt{\frac{u}{\emptyset\, c_t}}$$

In the equation above, x_f is fracture half-length and *k* is the effective permeability. In practice only one supposition time plot is used to analyze variable rate data, despite the likelihood that more than one flow regime is present during analysis.

Fekete provides a basic theory behind material balance time. Type curves published by Fetkovich (1980) are applicable to wells that produce at a constant bottom-hole pressure. However, nearly all wells experience a decline in bottom-hole pressure during their life. In order to account for this reality, Blasingame et al. (1991) developed a time-function that allows for the matching of production rate data on Fetkovich type curves, even when flowing pressure is varying. After developing different time functions, they came up with a simple function called material time balance. This function can be applied to wells that experience a smooth change in bottom-hole pressure, which is often the case. Blasingame et al. (1991) and Agarwal et al. (1999) also demonstrated that using material balance time converts the constant pressure solution into the constant rate solution, which is widely used in the field. Material balance time is defined as the ratio of cumulative production to instantaneous rate:

Eq. 2 $$t_c = \frac{Q}{q}$$

t_c represents a corrected time based on cumulative production. It is the value of time that a well would have to flow at the current rate in order to produce the same amount of fluid, conserving the material balance principle.

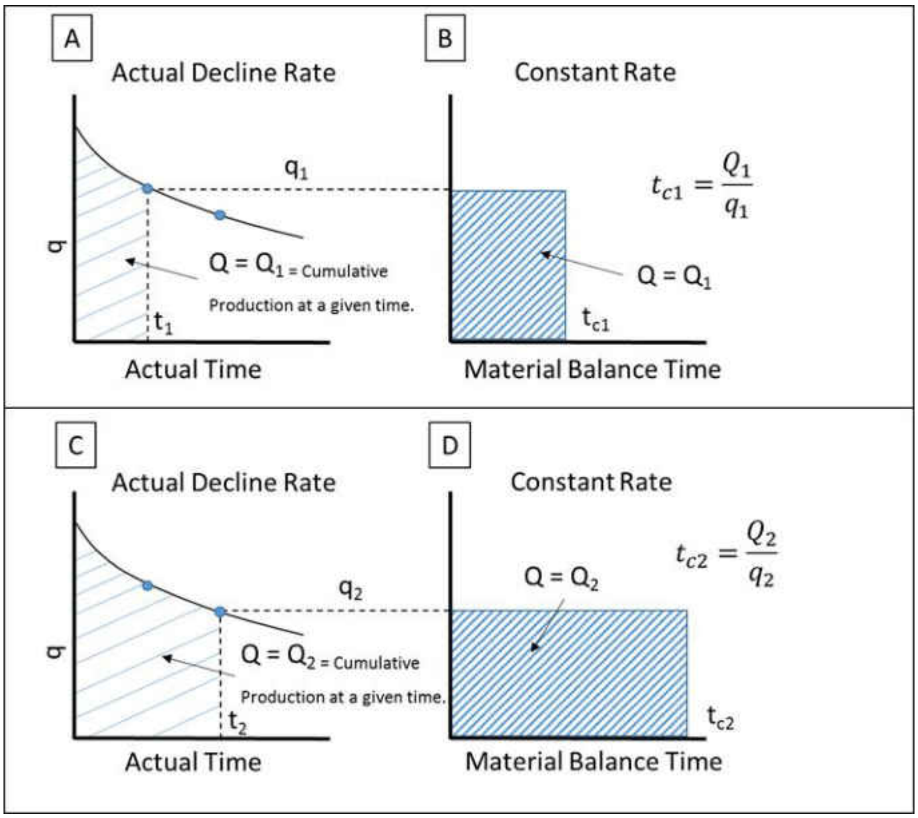

Figure 15. On graph A, at time (t_1) the cumulative production is (Q_1). The rate, (q) at that time is used in Graph B and is assumed to be constant. The time taken in Graph B for the well to flow at the constant rate to get the same cumulative production as in Graph A, is (t_{c1}) or material balance time. Graphs C and D demonstrate the same principle, using a different time (t_2) and the corresponding material balance time (t_{c2}). (from Fekete).

Liang et al. (2011) discussed the drawbacks of each function and concluded that of the two, material balance time provides the better interpretation when analyzing multiple flow regimes. They reasoned that material balance time gives a half-slope straight line during transient flow, as well as a unit-slope straight line during boundary dominated flow (BDF). In other words, material balance time keeps the characteristic shapes of both flow regimes. Using normalized pressure versus material balance square root of time plot, $A_c\sqrt{k}$ is related to $x_f\sqrt{k}$ as follows:

Eq. 4 $$4 * h * x_f\sqrt{k} \approx A_c\sqrt{k}$$

Since reservoir properties such as drainage area, fracture half-length, and fracture conductivity are challenging to estimate before a well reaches BDF, $A_c\sqrt{k}$ offers a good metric for early time well productivity and completion effectiveness. In addition, this metric aides in quantifying the change in SRV before and after a frac hit occurs (Liang, 2017).

Multi-Stage Horizontal Frac Flow Regimes

Luo et al. (2010) identified five unique flow regimes for multi-stage fractured horizontal wells (MFHW). However, the most commonly observed flow regimes include: early transient (unsteady), late transient, and boundary dominated (pseudo steady). Typically, MFHW experience transient linear flow for long periods of time (Al-Ahmadi, 2010). During periods of transient flow, reservoir boundaries have not yet been felt. The size of the reservoir has no effect on well performance, and is essentially infinite-acting (Fekete). During periods of transient flow, $A_c\sqrt{k}$, which is inversely proportional to the slope of the straight line, can be obtained from the superposition time plot. Transient flow demonstrates a unit ½ slope on a normalized rate versus material balance time log-log plot. Late liner flow is the period of time that separates the transient state from the steady or pseudo-steady state. This can be interpreted as the time when parts of the well drainage radius has reached some parts of the reservoir boundaries (Belyadi, 2015). Boundary dominated flow (BDF), is diagnosed when pressure transient has reached all of the boundaries and the static pressure is declining at the boundary, although not evenly across the reservoir (Fekete). BDF is typical of late time flow behavior when the reservoir is in a state of pseudo equilibrium. It is represented by an upwards departure from linear trend, in a curved fashion, on the superposition time plot and can be characterized on the log-log plot as a unit slope. Figure 16 illustrates characteristics of the aforementioned flow regimes on the superposition time and log-log plots.

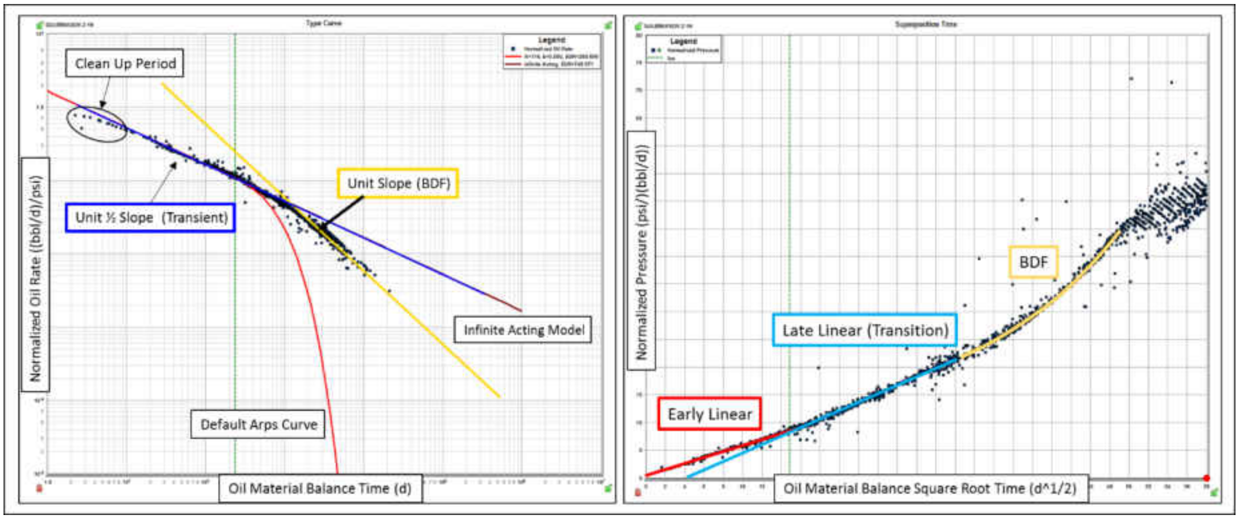

Figure 16. Flow regime identification using the log-log and superposition plots.

Analytical Model

Stalgorova and Mattar (2012) presented an analytical model to simulate the flow rate and pressures of horizontal wells with branch fractures, rather than simplistic bi-wing fractures. This model takes into account three linear flow regimes: flow within the fracture itself towards the well (early), flow within the stimulated region towards the fracture, and flow within the un-stimulated region towards the stimulated region (Figure 17). The enhanced frac region model (EFRM) is a rectangular reservoir model consisting of a non-contributing horizontal well and transverse fractures. The model assumes that all the fractures have the same length and conductivity, and are spaced uniformly along the horizontal wellbore (Fekete). It also assumes the reservoir is a single layer system that is homogeneous and isotropic with single porosity and uniform thickness, and fluid flow in the formation and fracture in laminar. Each fracture is surrounded by a high permeability region (K_1), representing the area of stimulated reservoir volume (A_{SRV}) while the remaining reservoir has a lower permeability (K_2), representing matrix permeability. The authors state that contribution from the region beyond the fractures is negligible.

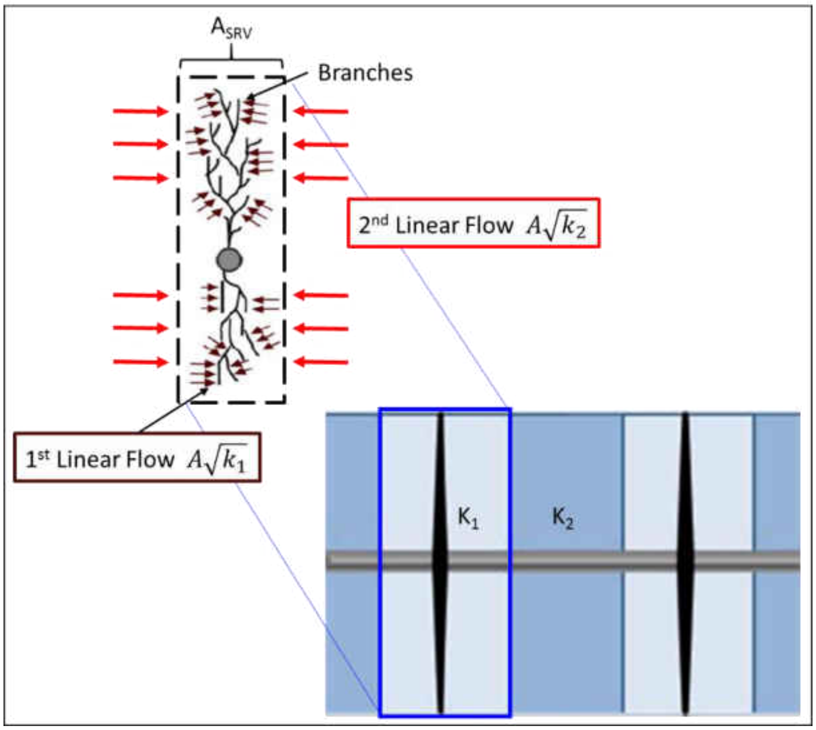

Figure 17. EFR model with enhanced areas of permeability. (modified from Stalgorova and Mattar, 2012).

Reservoir properties were entered into the model, along with parameters determined from the superposition time plot. Only points of calculated pressure were selected, as the software runs linear iterations between points. Iterations were run on K_1, K_2, X_I (distance from fracture to permeability boundary). Reservoir width (Y_e) was adjusted until original oil in place (OOIP) matched the value determined from the flowing material balance plot, and until a representative trend was created. Due to the variability in production rate history across the study area, it was not feasible (Figure 18) to apply the analytical EFR model to every well. When applicable, the model was used to history match bottom-hole pressure and rates.

Resulting model reservoir parameters such as x_f, A_{SRV} , and K_m were compared to values obtained from the superposition time plot, in order to ensure accuracy.

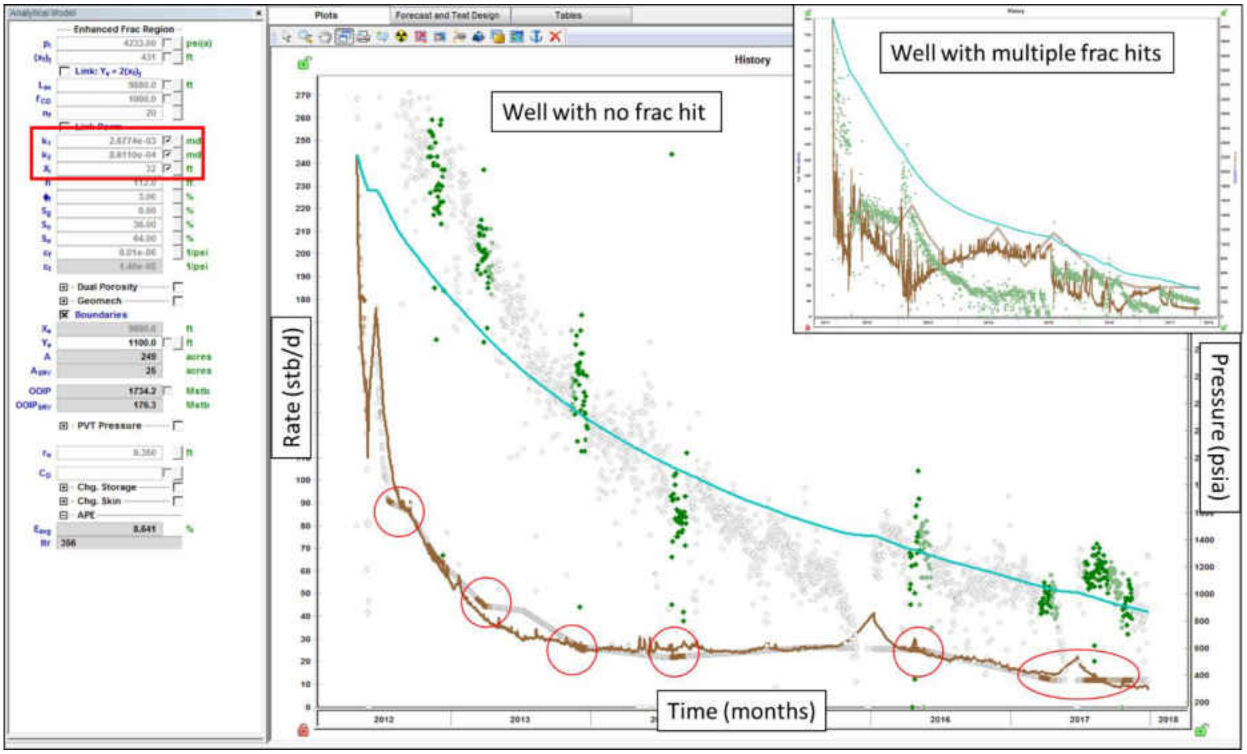

Figure 18. Analytical EFR Model history match. Circles denote pressure derived from well fluid levels while producing. Red box demonstrates parameters model iterations are run on. Inset figure demonstrates the difficulty in history matching wells that have experienced frac hits.

Methods for Rate Transient Analysis

Historical daily production data (oil, water, gas, casing and tubing pressure) was gathered for the 81 Gooseneck wells in this study. For each well, daily history was analyzed and any erroneous data such as negative or zero values was removed, in order to provide an accurate depiction of well performance over time. Wellbore profiles were built in Harmony using deviation surveys, casing data, tubing data, and perforation interval. Various tubing sizes, tubing depths, and lift methods have implications when attempting to calculate flowing bottom-hole pressure (FBHP) within the software. Pressure and temperature gradients were calculated from two pressure/ temperature surveys performed in the Gooseneck area and used to determine reservoir conditions unique to each well's mid-perf total vertical depth (TVD). Fluid and gas properties were gathered from analyses across the field. Geologic parameters, based on log, core, and petrophysical models created in-house, were obtained for each spacing unit. Matrix permeability values were taken from a Gooseneck core sample. Based on the evidence of inter-formational communication previously discussed in this study, the sum thickness of Upper Bakken, Middle Bakken, Lower Bakken, and the first bench of the Three Forks was used as reservoir height. Saturation and effective porosity values were averaged for the Middle Bakken and first bench of the Three Forks.

Table 2. Harmony input parameters.

Parameter	Value
Wellbore Radius (ft)	0.35
Casing ID (in)	6.184
Casing Depth (MD)	7,657
Liner ID (in)	3.92
Liner (MD)	18,116
Tubing ID (in)	2.992
Tubing Depth (MD)	7612
Perf Interval (MD)	8,462 - 18,116
Reservoir Pressure (psi)	4,263
Reservoir Temp (F)	197
Bubble Point (psi)	2,247
Oil API	42
Water SG	1.19
Gas SG	0.913
% N2	4.5
% CO2	0.72
% H2S	1.40E-03
Formation Thickness (ft)	113
Effective Porosity (%)	4
Water Saturation (%)	54
Oil Saturation (%)	46
Solution GOR (scf/bbl)	700
Number of Stages	26

Bottom Hole Pressure Analysis

Access to accurate bottom-hole pressure data is arguably the most crucial part of performing rate transient analysis. However, while real-time BHP gauges are common in high-rate conventional reservoirs, they are much less common in onshore unconventional plays. Scott et al. (2015) discussed the benefits of using real-time BHP for well interference evaluation, artificial lift optimization, and fracture network characterization. In the absence of real-time BHP gauges, one must rely on surface pressures and multiphase pressure drop correlations when attempting to infer downhole conditions. Numerous multiphase pressure loss models have been published, both empirical and mechanistic (Beggs & Brill, 1973; Duns & Ross,1963; Aziz & Govier, 1972; Hagedorn & Brown, 1965), and can provide reasonable approximations under naturally flowing well conditions. This study used the Hagedorn and Brown correlation, modified for the bubble flow regime (Economides et al., 1994), for wells with flowing conditions. Ruiz et al. (2014) evaluated the accuracy of 7 multi-phase pressure drop correlations by comparing predicted pressure drop to lab measured pressure drop. Their statistical analysis determined that the modified Hagedorn and Brown correlation had the best performance in predicting pressure drop. Generally speaking, this only applies to first generation (parent) wells. The period of free flow for these wells ranges from 1 – 2 months. Although this empirical correlation was derived from vertical well tests, Harmony software calculates pressure drops for horizontal and inclined flow. The software uses only the vertical depth to calculate pressure loss due to hydrostatic head, and the entire pipe length to calculate friction. If bubble flow exists, the Griffith correlation is used to calculate the in-situ volume fraction (Fekete).

Once artificial lift is installed, the variability of rate, pressure, and fluid column height in the annulus make the use of multiphase pressure drop correlations unreliable (Scott et al, 2015). Of the 81 wells included in this study, only 8 had downhole gauges at some point in their life. Of these 8 well, only one had pressure gauges ran to mid-perf TVD (actual reservoir conditions). These gauges did not transmit live data, rather the recorded pressure and temperature information was only accessible after the tubing was pulled. However, in a look back scenario such as this, these recordings provide invaluable insight into dynamic reservoir conditions. Figure 19 compares actual BHP gauge data from a Gooseneck well to three multi-phase pressure drop correlations over the same time period and clearly demonstrates the need for an alternative approximation for BHP when utilizing artificial lift.

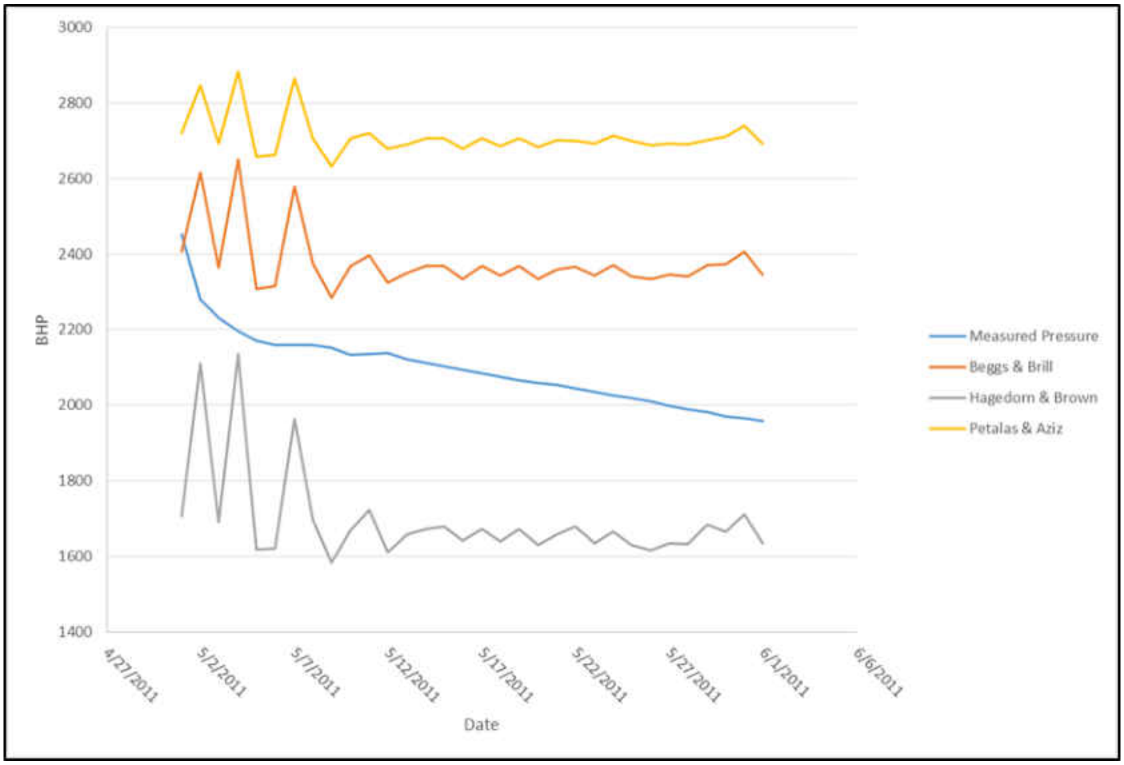

Figure 19. Comparison of multi-phase pressure drop correlations with recorded BHP for a well on artificial lift.

In Gooseneck, acoustic fluid-level measurements are periodically conducted on wells utilizing rod lift. In conjunction with dynamometers, these measurements provide insight to downhole pump conditions and performance. Fluid level tests compute downhole pressures in wellbores that contain mixtures of gas and liquids. These calculations are based on measurement of surface pressure, determination of the depth to fluid level, and estimation of the gradients of the fluid in the wellbore. From Rowlan et al. (2011), pump intake pressure (PIP) can be defined as:

Eq. 6 *Pump intake pressure = casing head pressure + annular gas gradient × gas column height + gaseous liquid gradient × height of fluid column above pump*

Figure 20 provides a simplistic depiction of various factors incorporated in a typical PIP calculation. In normal conditions, the pump intake depth is below liquid level, allowing for gas to break out of solution and flow to surface via the tubing/casing annulus while oil/water is lifted up the tubing. This helps prevent pump issues such as gas lock from occurring.

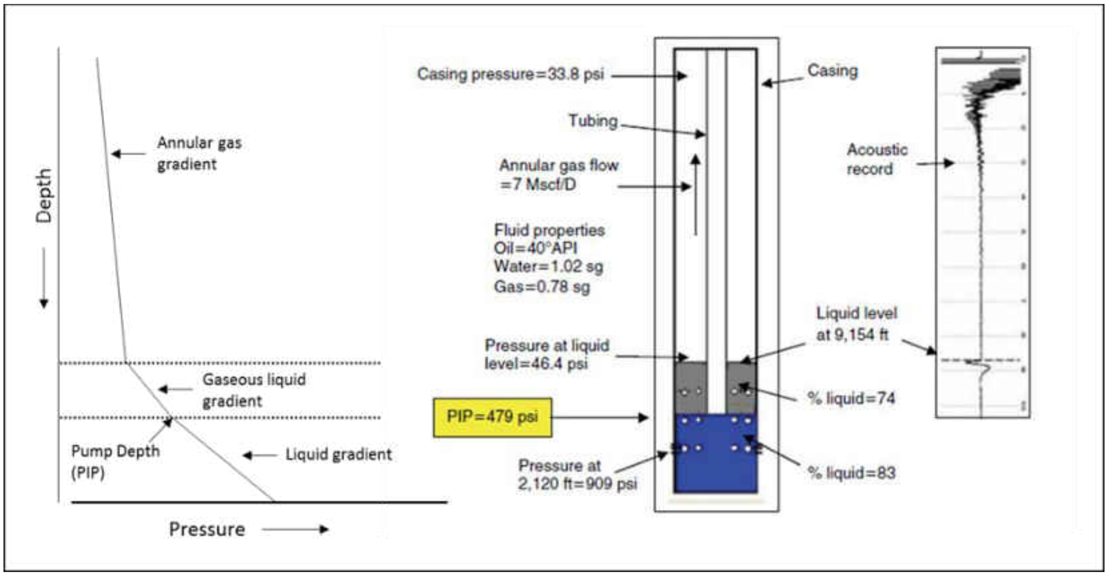

Figure 20. Example of PIP determined from acoustic fluid level measurement. (modified from Rowlan et al., 2011).

Based on field observations, it is reasonable to assume that a mixture of oil and water occupy the wellbore volume below the pump, with minimal free gas below the pump. Therefore, the following equation was used to calculate BHP from PIP data:

Eq. 7

$$BHP = \left(\left(\frac{\left((q_{fluid} - q_{water}) * SG_{oil} + q_{water} * SG_{water} \right)}{q_{fluid}} \right) * 0.433 \right) * (mid\ perf\ depth\ - pump\ depth) + PIP$$

The calculation above was applied to each fluid level measurement for each well. A thorough investigation of workover history was required, as pump depths varied each time a tubing pull occurred. All depths and pump intake pressures were verified. These calculated pressures act as reference points over time, by which the software linearly interpolates between. It should be stated that the method outlined above is used as a best approximation due to insufficient pressure data. Calculated BHP was plotted against actual gauge data for the one instance (well) where both data points were available. On average, the three calculated BHP points underestimate pressure by ~ 17%, but match the overall drawdown trend well (Figure 21). This method proves much better than the three phase pressure drop correlations, as demonstrated in Figure 19.

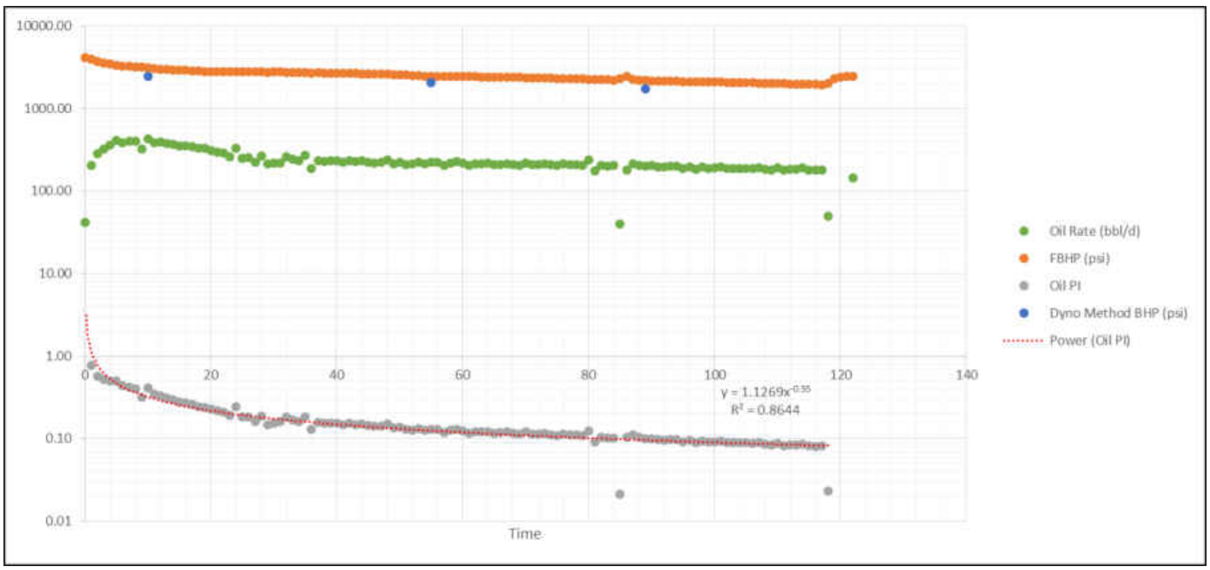

Figure 21. BHP calculated from PIP and Oil PI model applied to wells with no free flowing period.

For some second generation wells and all third generation wells, there was no initial free flowing period. These wells were generally hydraulically fractured and brought on production at the same time. After laterals were cleaned out, production tubing and rods were run. When initially turned on, wells pumped and flowed (“flump”) simultaneously. In other words, fluid rates were greater than pump capacity, resulting in flow up both the tubing and the annulus. During such dynamic conditions, it is not possible to accurately measure a sonic fluid level.

For this reasoning, a data gap exists from the time of first production to the time the first fluid level was shot, which is typically 2 – 4 months. This applies to most second generation and all third generation wells. Applying pressure drop correlations under such conditions creates unrealistic results. In Figure 22, the pressure profile generated using a pressure drop correlation shows low initial pressure and a large shift in pressure when transitioning to the BHP derived from fluid level. This presented an issue, as accurate initial pressure and periods of early flow are crucial when attempting to determine early time well productivity and completion efficiency. In order to develop a model to predict flowing pressures during this early "flumping" period, a study area well with downhole pressure gauges installed was evaluated. This well was used to develop a proxy for well productivity, initial pressure and rate of decline during the early flow time period, in the form of a pseudo well productivity index (Figure 21). Productivity index (PI) is given by:

Eq. 4 $$PI = \frac{q}{(P_i - P_{wf})}$$

For this application, q is oil rate (bbl/d), P_i is the initial pressure recording (≈ reservoir pressure) and P_{wf} is flowing bottom-hole pressure. Oil PI was plotted and fit with a (power) curve. This curve expression was then applied to wells with no free flowing period, in order to approximate the initial flowing pressure behavior of the wells where no data existed. For each instance, q is known and the ending value of P_{wf} must equal the BHP calculated from the fluid level. So, the value for P_i can be adjusted until the ending value for P_{wf} is equal to the first BHP data point. Ideally, Oil PI models should be based on and applied to wells with similar properties (completion design, rate, formation, vintage, etc.). However, this study was limited to one available model. Despite its general nature, the model provided significant improvement over pressure drop calculations and demonstrated realistic initial pressures and early flow trends as shown below.

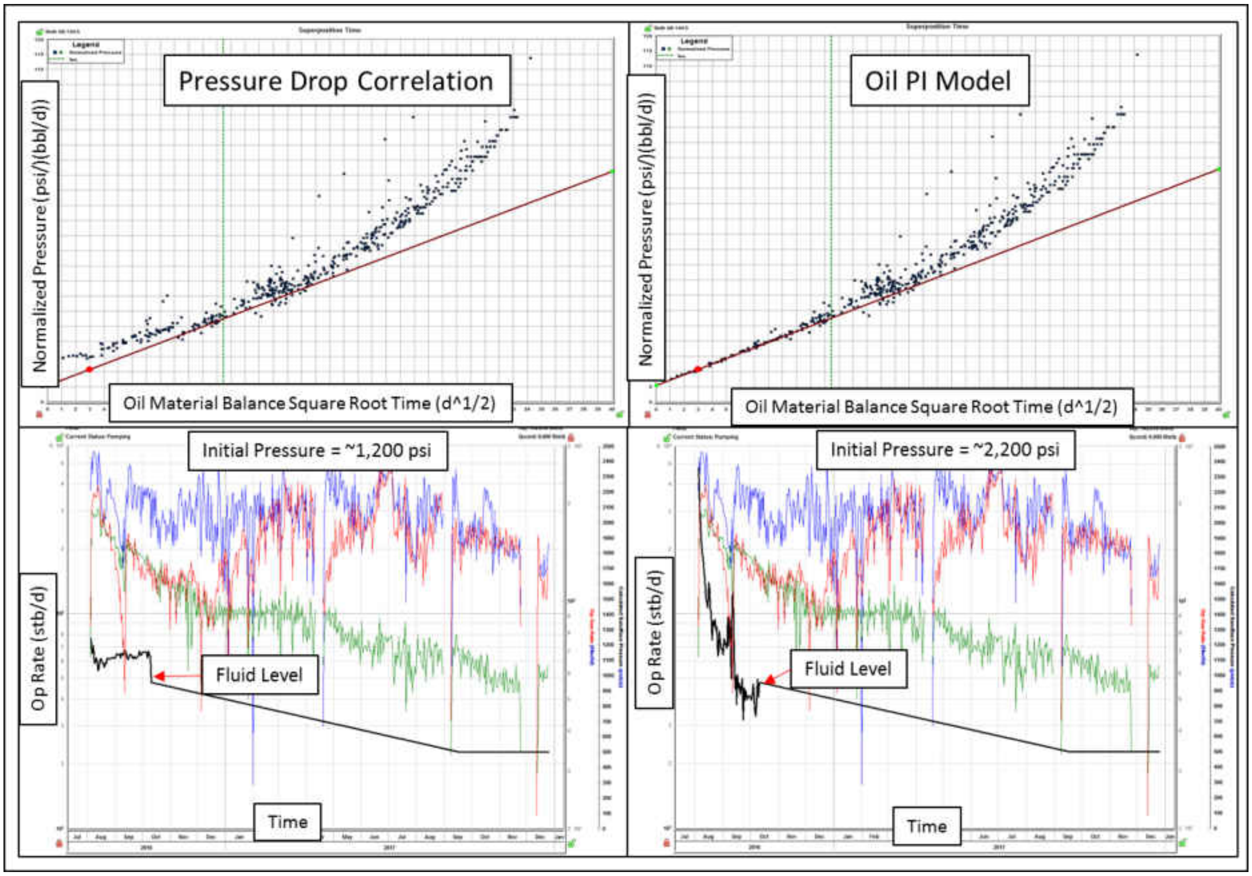

Figure 22. Superposition plot and pressure profile before and after applying oil PI model.

CHAPTER III

DECLINE CURVE AND ECONOMIC ANALYSIS

Effective development strategies require accurate predictions of production rates and ultimate recoverable oil. During initial lease development, predictions for future well performance are based on very limited data. Such assumptions can have significant implications when attempting to determine appropriate well spacing and overall project profitability. Often, infill well type curves are based on parent well performance. In addition, overall spacing unit economics generally don't factor in offset frac hit detriment to current producing wells. This can result in over-optimistic spacing unit performance.

Three different methods of determining economics were applied in this study in order to account for the impact of frac hits. All economic analyses were performed using Aries software. In all instances, a look-back approach was taken in order to depict actual well performance and to assess the economic viability under current market conditions. First, production history for 71 individual wells was fitted with a decline curve. This required matching multiple curves over different decline rates, water cuts, and gas cuts over the life of each well. The individual curves were then combined into one representative curve on a well-by-well basis. This allowed for pre and post frac hit analysis by providing changes in water cut, GOR, and EUR. Results were incorporated with changes in $A_c\sqrt{k}$ to provide a better understanding of offset frac interference. EURs were forecasted based on the curves and used to identify performance trends across the study area.

The method outlined above, while providing important insight at the well level, does not illustrate the overall performance of the spacing unit. To evaluate the economic performance for the full spacing unit development project, production from all wells within the unit were combined. As an example, a spacing unit has 8 wells and three generations of development. First a decline curve was applied to the 1st generation well (parent). Two years later, production from 2 – 2nd generation wells was added. Lastly, 5 – 3rd generation wells were brought online two years after the 2nd generation wells. A curve was assigned to each of the three generations and then combined into one overall curve (Figure 23). A $4MM per well capital investment was applied, along with well costs such as LOE/WOE/overhead, at the appropriate start date. This method captures the net gain in production by factoring in not only the additional barrels from new wells, but also barrels lost due to frac hits on current producing wells. Finally, in order to determine if the net gain in production was worth the capital investment, incremental economics were applied (Figure 24).

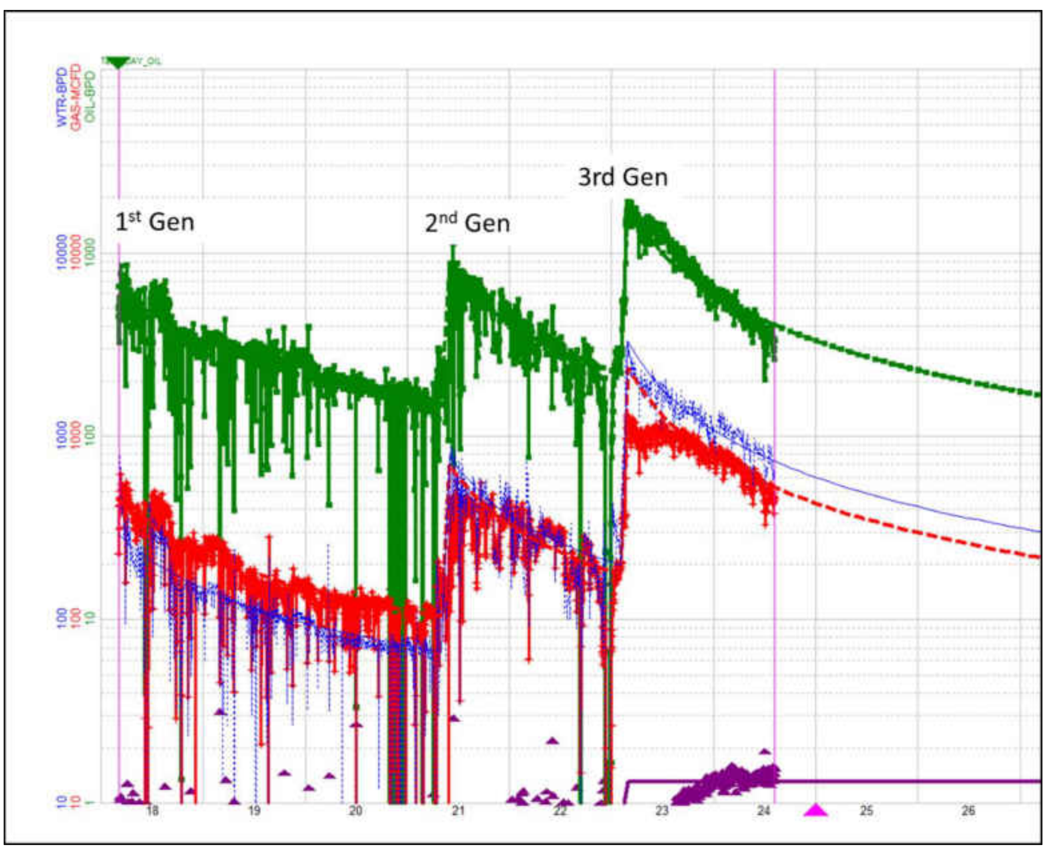

Figure 23. Combined production profile curve for entire spacing unit

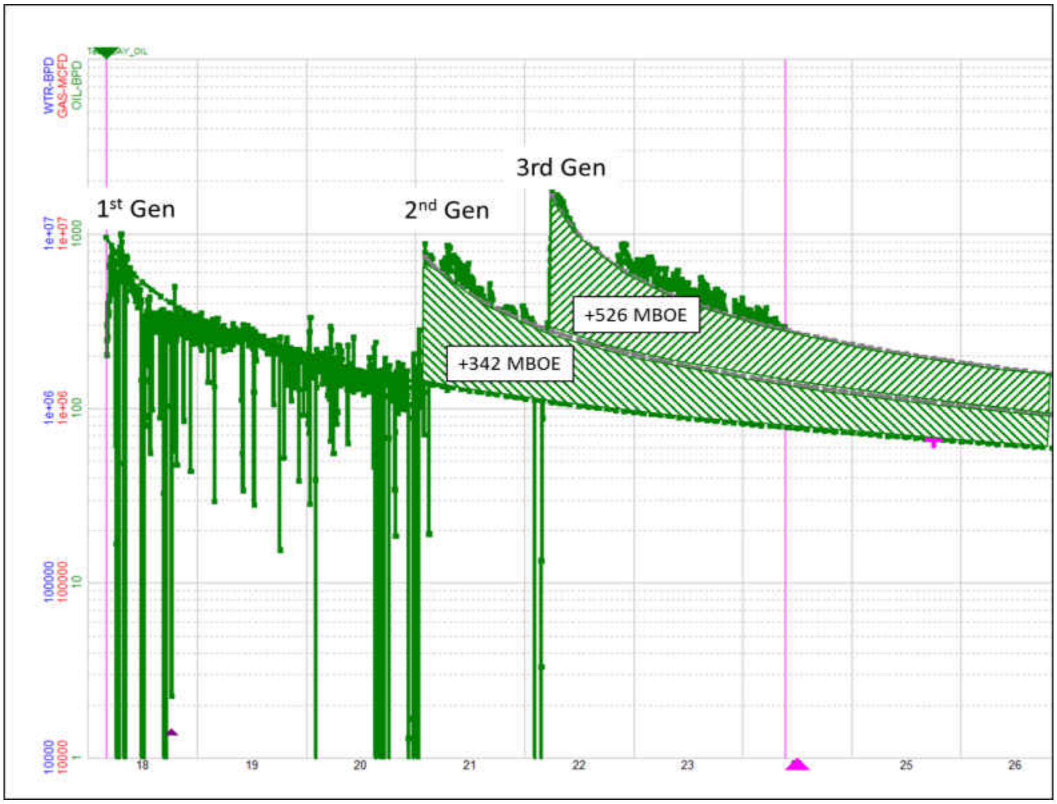

Figure 24. Incremental production gained as infill wells are added to the spacing unit.

Three primary metrics were used in determining economic performance: net present value, rate of return, and profit to investment ratio. The net present value (NPV) is the difference between the present value of cash inflows and the present value of cash outflow. The net present value of an investment is calculated by discounting the future net cash flows to time zero and summing them (Oil Property Evaluation – Thompson and Wright). Discount rates help to determine the present value of future cash flows. Discount rates vary by company. The risk of a project and the risk profile of a company impact which discount factor is most appropriate for determining the present value of future cash flows. For this study, a discount rate of 15% was applied to all economic cases.

Rate of return (ROR) can be defined as gain or loss on an investment over a specific period, expressed as percentage increase over the initial investment cost. Gains on investment are considered to be any income received from the security plus real capital gains. ROR is a ratio of yearly income from the investment to the original investment (Oil Property Evaluation – Thompson and Wright).

Discounted profit to investment ratio (DPI) is an economic metric used to determine which projects are worthy of capital allocation (i.e., projects that cause the treasury to grow at the fastest rate). DPI is calculated by dividing the sum of the net cash flow from a project and the associated investment by the sum of the investment. A value of 1.0 is a breakeven value where the investment is just recovered.

Eq. 5 $$Undiscounted\ Profit\ to\ Investment\ Ratio = \frac{(Net\ Cash\ Flow + Net\ Investment)}{Net\ Investment}$$

In order to determine the economic performance under current market conditions, all cases used a fixed oil price of \$60/Bbl and a fixed gas price of \$3/Mscf.

Table 3. Economic input parameters.

Parameter	Value
Oil Price ($/bbl)	60
Gas Price ($/Mscf)	3
Fixed LOE ($/Month)	5,000
Fixed WOE ($/Month)	5,500
Overhead ($/Month)	300
S&A ($)	95,000
WI (%)	100
NRI (%)	82.5
Capital Investment ($ / Well)	4,000,000
Life (Years)	52
Discount Rate (%)	15

The original oil in place (OOIP) was calculated for 13 spacing units, with well count per spacing unit ranging from 1 to 8. This provides an overall representation of estimated reserves and recovery factors across the field. Net recovery factors only include pay facies, as determined by SME's geology/geophysics team. This excludes both the Upper and Lower Bakken shales from pay thickness. Table 4 includes recovered reserves to-date (cumulative), and recovery factors based on EURs calculated from decline curves.

Eq. 6
$$OOIP = \frac{7758 \frac{bbl}{acre \cdot ft} \times (1 - S_w) \times \varphi \times H \times Area}{B_o}$$

Table 4. OOIP and Recovery Factors

							Cumulative				EUR			
1280 Spacing Unit	1280 Spacing Unit #	TFS Pay Net/Gross	BKN Pay Net/Gross	Total Pay Net/Gross	Total Net Resource MMBO	PDP Wells per SU	TFS Recovery MMBO	BKN Recovery MMBO	Total Recovery MMBO	Net SU RF %	TFS Recovery MMBO	BKN Recovery MMBO	Total Recovery MMBO	Net SU RF %
6-7-163N-100W	1	9.15%	55.81%	38.57%	13.19	1	0.27	0.00	0.266	2.02%	0.41	0.00	0.41	3.11%
5-8-163N-100W	2	10.12%	54.17%	37.93%	12.72	3	0.39	0.12	0.513	4.03%	0.49	0.36	0.84	6.62%
4-9-163N-100W	3	13.62%	55.91%	40.27%	12.45	6	0.60	0.26	0.86	6.91%	0.99	0.43	1.42	11.42%
3-10-163N-100W	4	14.90%	54.62%	39.48%	12.48	8	0.66	0.34	1	8.01%	0.94	0.73	1.67	13.37%
2-11-163N-100W	5	16.26%	54.52%	39.77%	12.72	5	0.94	0.07	1.01	7.94%	1.49	0.16	1.65	12.98%
1-2-163N-100W	6	16.26%	54.52%	39.77%	12.82	2	0.49	0.00	0.492	3.84%	0.82	0.00	0.82	6.38%
17-20-163N-100W	8	8.11%	51.44%	35.89%	11.04	4	0.59	0	0.59	5.35%	0.76	0.00	0.76	6.90%
16-21-163N-100W	9	10.26%	51.16%	36.55%	11.05	5	0.47	0.13	0.6	5.43%	0.79	0.25	1.03	9.33%
15-22-163N-100W	10	14.76%	51.72%	38.34%	11.67	8	0.59	0.29	0.88	7.54%	1.04	0.62	1.66	14.22%
14-23-163N-100W	11	17.28%	52.53%	39.48%	12.33	8	0.55	0.31	0.86	6.98%	0.87	0.56	1.43	11.59%
18-19-163N-99W	13	18.07%	56.23%	41.61%	13.55	5	0.89	0.07	0.96	7.08%	1.30	0.19	1.49	10.97%
26-35-163N-100W	18	17.97%	46.71%	36.21%	11.93	7	0.52	0.26	0.78	6.54%	0.93	0.37	1.30	10.87%
30-31-163N-99W	19	18.28%	53.07%	40.06%	13.09	3	0.32	0.07	0.3816	2.92%	0.54	0.16	0.70	5.33%
													Average	9.47%

CHAPTER IV

RESULTS AND ANALYSIS

Multiple metrics illustrate the importance of spacing and timing when developing acreage. (Figure 25) shows significant loss in production performance from 1st generation (parent) through 3rd generation infill wells. The average EUR decreases by 38% from 1st generation to 2nd generation wells, and by 30% from 2nd generation to 3rd generation wells. On average, 1st generation wells produced ~2.4 years before 2nd generation wells were brought online, while 2nd generation wells produced ~2 years before production from 3rd generation wells commenced.

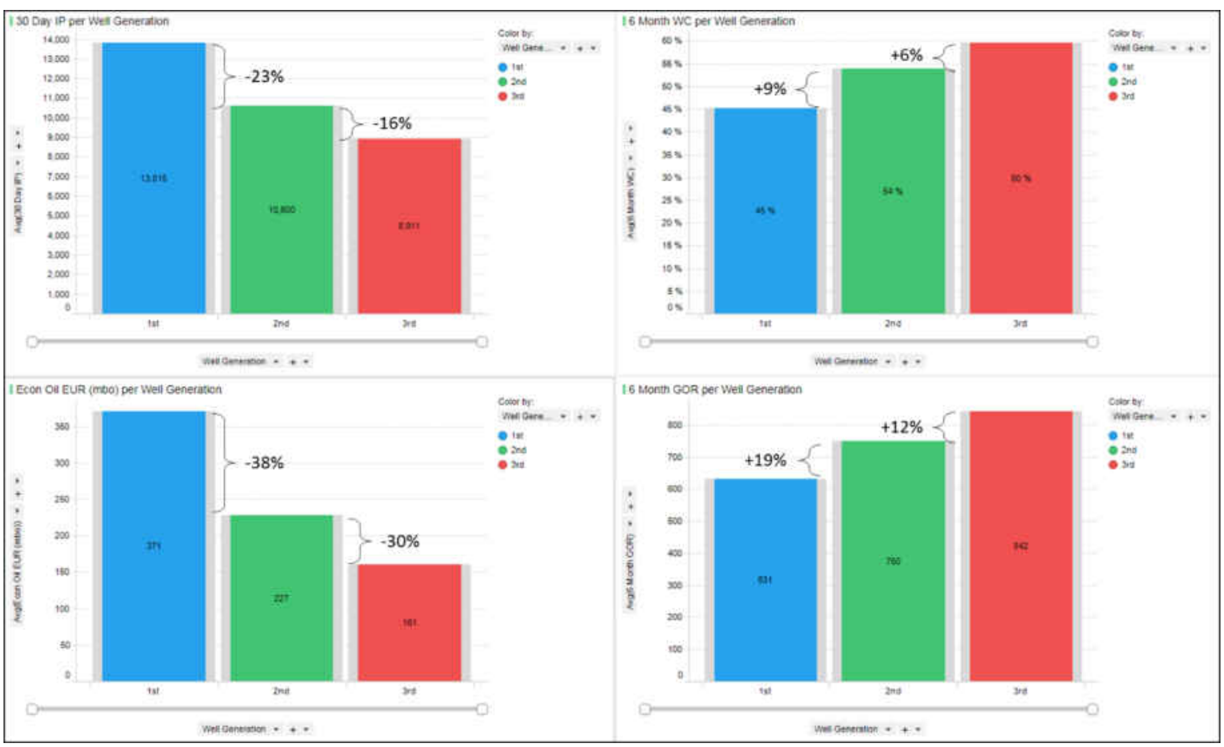

Figure 25. Well performance by well generation for all wells.

Within the study area, the occurrence of reservoir depletion is demonstrated by a decrease in 30 day initial production rate, an increase in water cut, and an increase in GOR. The time until a well reaches the end of linear flow (EOLF) decreases significantly between well generations, indicting smaller stimulated rock volumes, consistent with the tighter well spacing in the infill programs, and the interactions with the pre-existing parent wells. The coinciding drop in $A_c\sqrt{k}$ values support this assumption (Figure 26). As mentioned in Chapter 1, literature has shown preferential fracture growth towards areas of depletion and re-orientation of stress fields, resulting in higher probability of longitudinal fractures and less contacted area open to flow from the reservoir, which may explain the decrease in fracture half-length. The overwhelming evidence of offset frac hits in Gooseneck, from Bakken and Three Forks wells, indicate overlapping SRVs and competition for the same barrels in most spacing units.

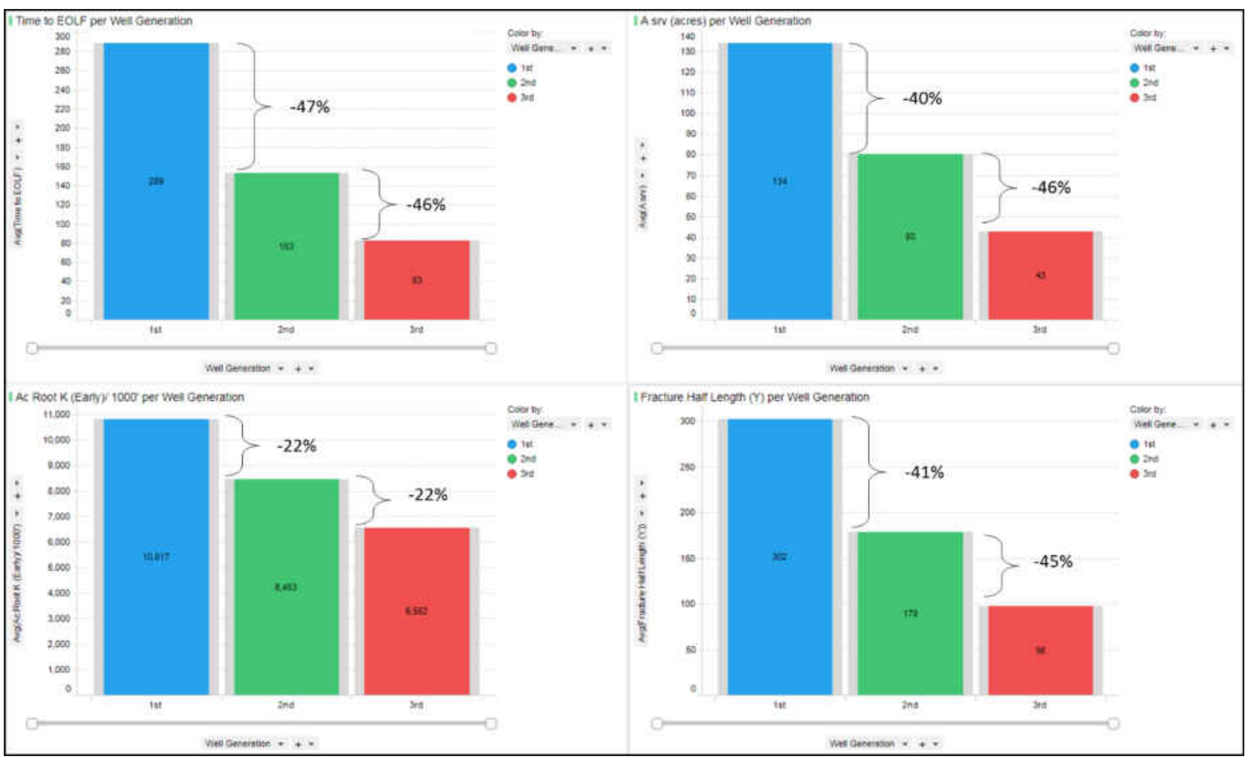

Figure 26. Completion parameters determined from superposition time plots for all wells.

Another way to illustrate the effects of reservoir depletion on infill wells is to compare infill well performance with distance from the parent well. Figure 27 shows that, in general, the performance of both 2nd and 3rd generation wells is strongly tied to their distance from the 1st generation well.

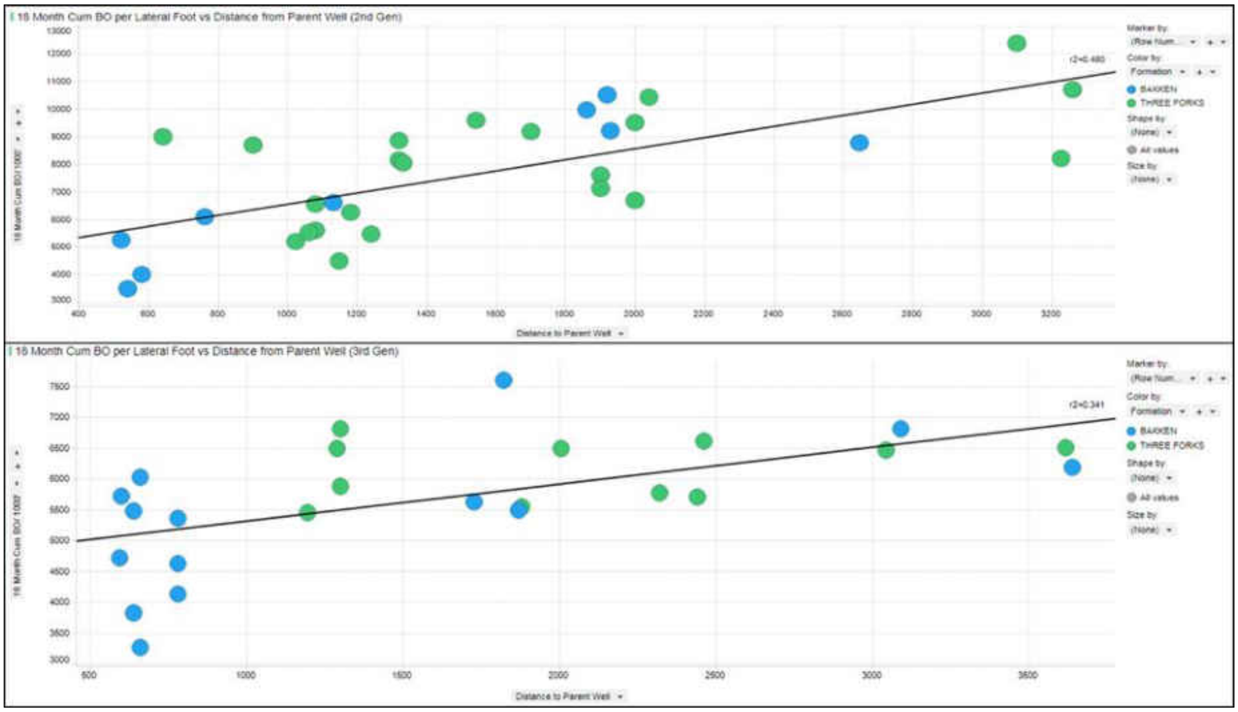

Figure 27. Crossplot of 18 month cumulative production per lateral foot versus distance from parent well. Top plot is 2nd generation. Bottom plot is 3rd generation. Colored by formation.

A good correlation exists between $A_c\sqrt{k}$ normalized per lateral foot and 12 month cumulative BOE per lateral foot. Cumulative production was used rather than EUR due to the impact of offset frac hits. In general, 1st generation wells exhibit the highest $A_c\sqrt{k}$ values and EURs, followed by 2nd generation, with 3rd generation representing the lowest values (Figure 28.) As expected, when the timing between completions is similar, the impact of an offset frac is a function of distance from existing wells. Figure 29 demonstrates changes in EUR and water cut for 1st generation wells relative to distance from offset frac. Parent wells experience a greater loss in EUR and a larger increase in water cut the closer an offset frac occurs.

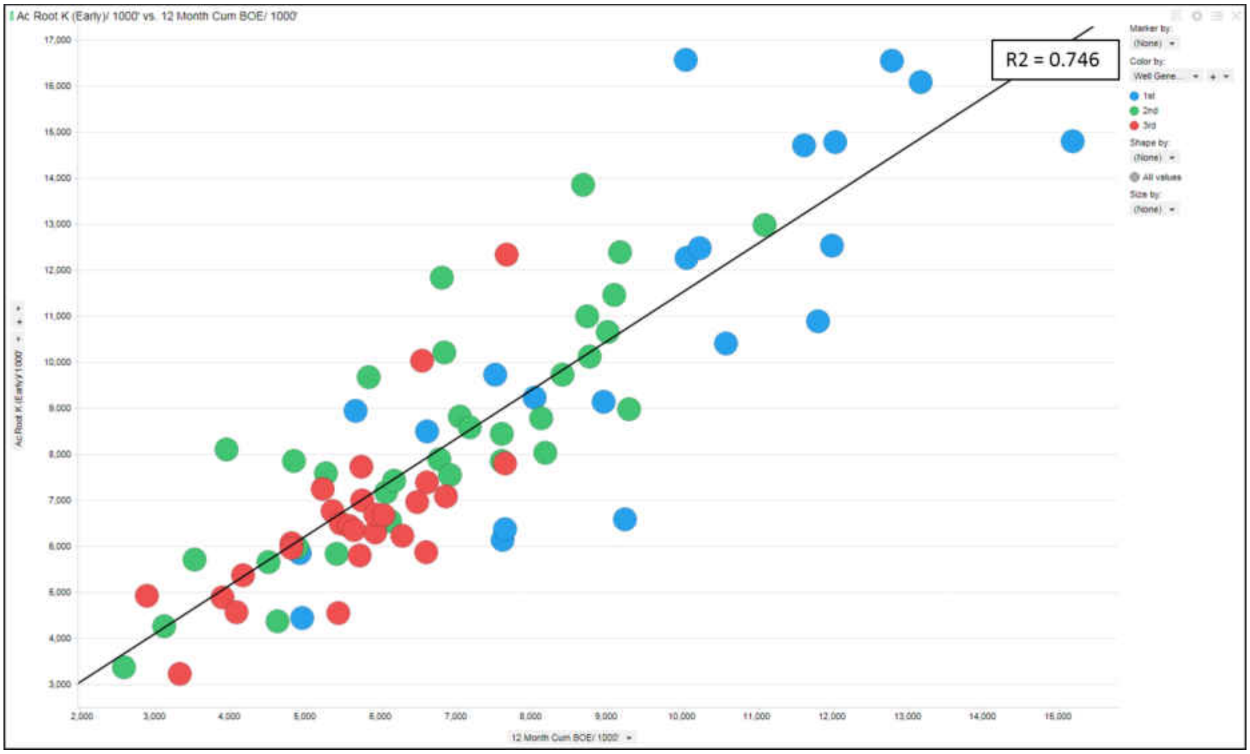

Figure 28. Crossplot of Ac Root K per lateral foot versus 12 month cumulative BOE per lateral foot for all wells.

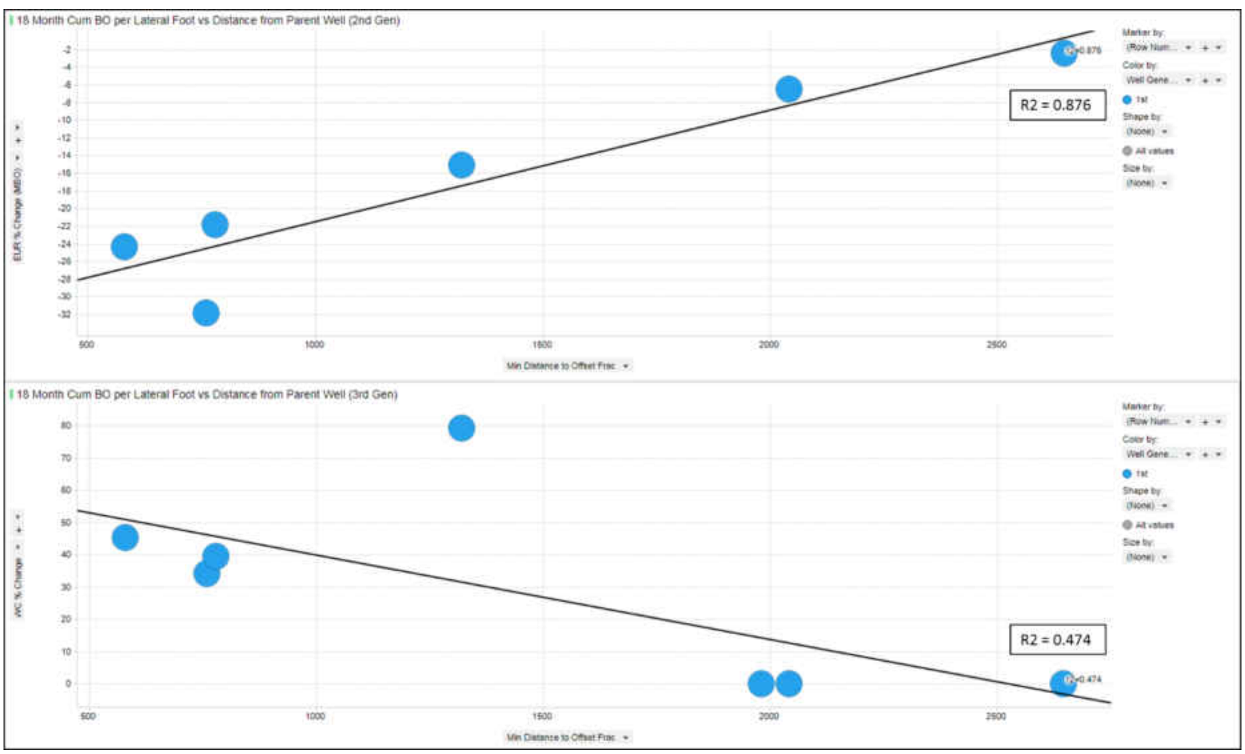

Figure 29. Impact of offset frac hits on parent wells. Data excludes wells with laterals cleaned out post offset frac.

Development History and Impact of Frac Hits

The previous section demonstrated the impact of timing and distance on infill well performance as it relates to reservoir depletion. The impact of frac hits as a function of distance was also noted. As discussed in Chapter 1, unique spacing unit development histories exist across the study area. One of the main objectives for this study was to determine appropriate well spacing in the Gooseneck area. With a variety of wells per spacing unit completed in different sequential order, quantification of offset frac hits and overall development efficiency required analysis of each spacing unit and its associated wells. The following sections describe development timing, well spacing and offset frac hits per spacing unit. Each spacing unit was assigned a number – from west to east and north to south (#1-21). Each well within a spacing unit is numbered based on the order it was completed. While these numbers provide some insight into timing, it should be noted that well generation is of more importance, as wells of like generation were completed at approximately the same time. Each well generation was color coded with blue representing 1st generation, green being 2nd generation, and red for 3rd generation wells as shown in the maps below. Each map also denotes distance between wells. Spacing units with 4 wells (early development plan) have a standard 1,320 foot spacing, while spacing units with 8 wells (full development plan) have a standard 660 foot spacing. The distances listed on the maps are the minimum distance between wellbores. These values were calculated in ArcGIS using a gridding process. Only the actual laterals were considered when calculating minimum distances. The section of wellbore from surface to kick off point was excluded. For consistency, section line wells were assigned to one specific spacing unit.

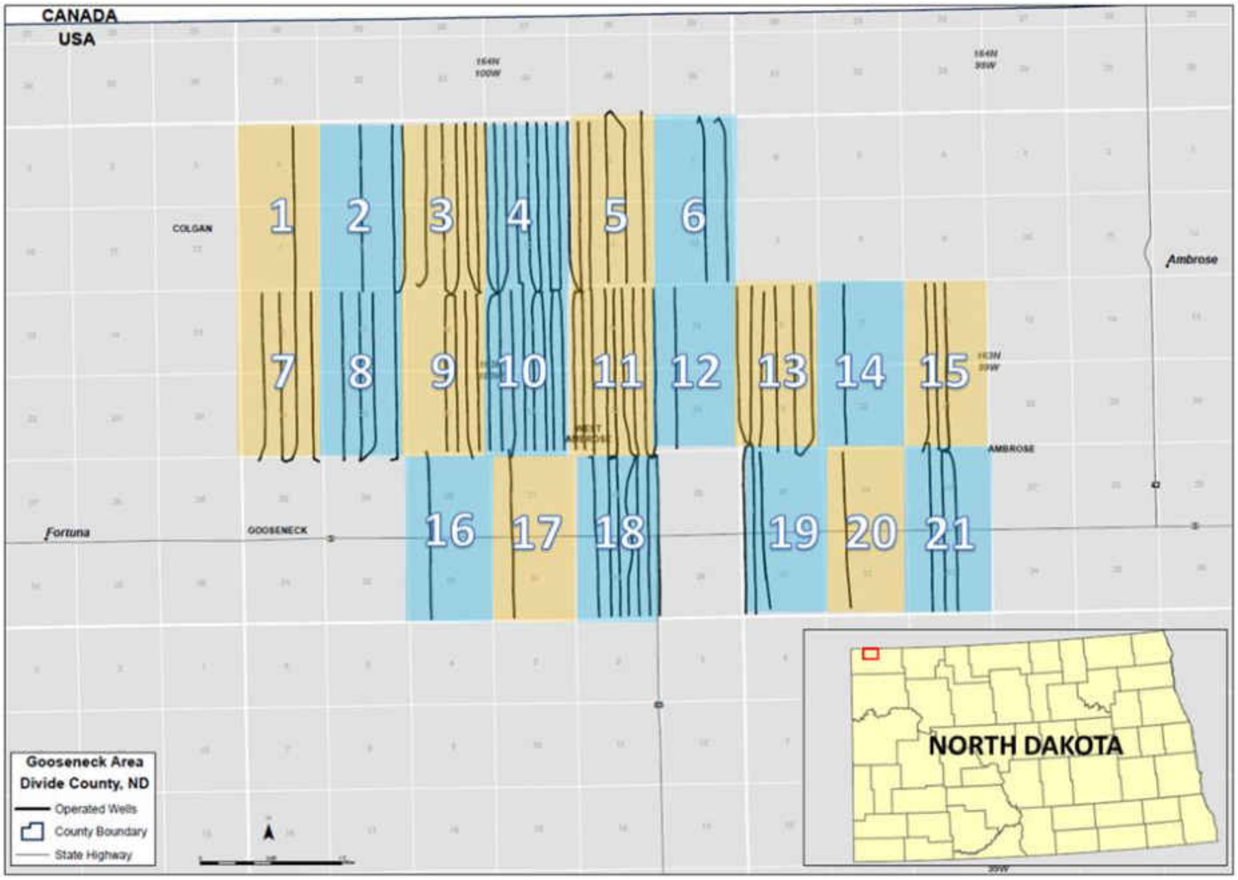

Figure 30. Overview of spacing units studied and associated numbering.

Figure 31. Spacing units 1 – 4.

Spacing Unit #1 (6-7-163N-100W)

Well 1.1 is the only well producing in spacing unit 1. A distance of 4,300 feet separates it from well 2.1 to the east. Production decline has remained constant over the life of this well, with transient flow lasting over 1 year, and an expected EUR of 410 MBO. No offset interference was noted.

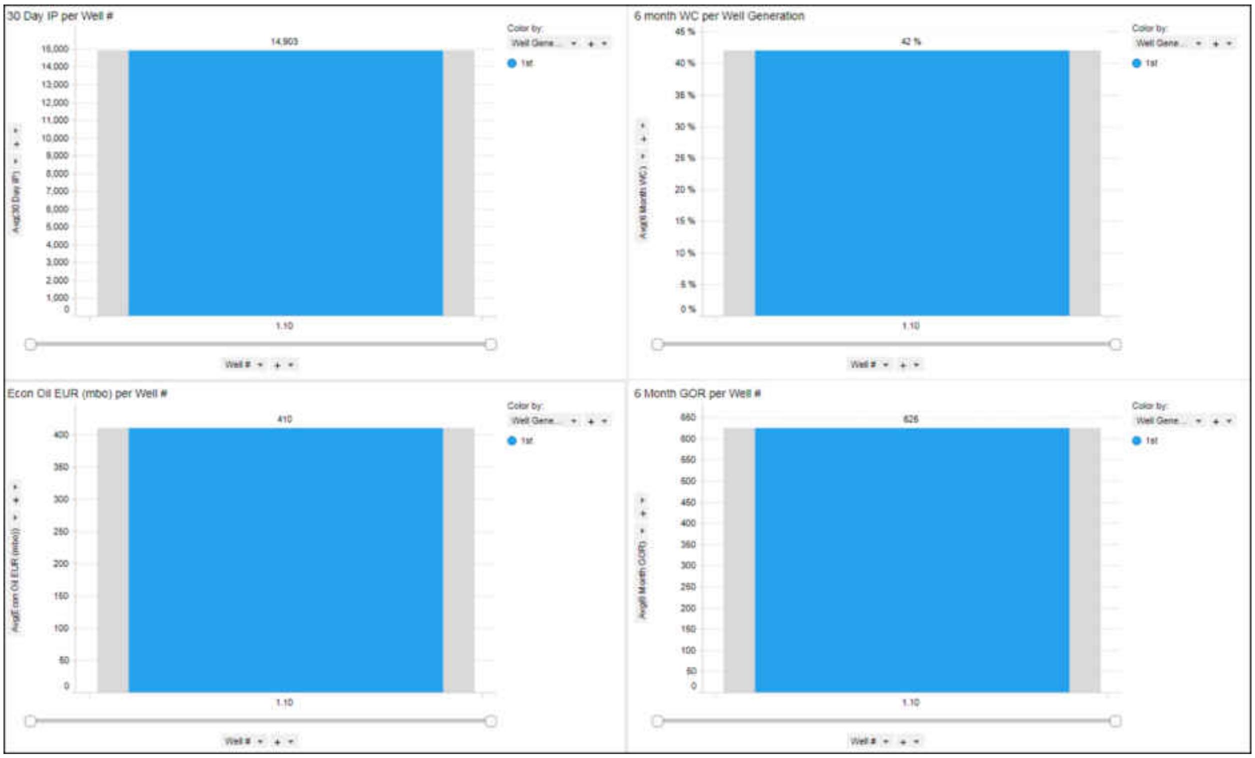

Figure 32. Well 1.1 production performance.

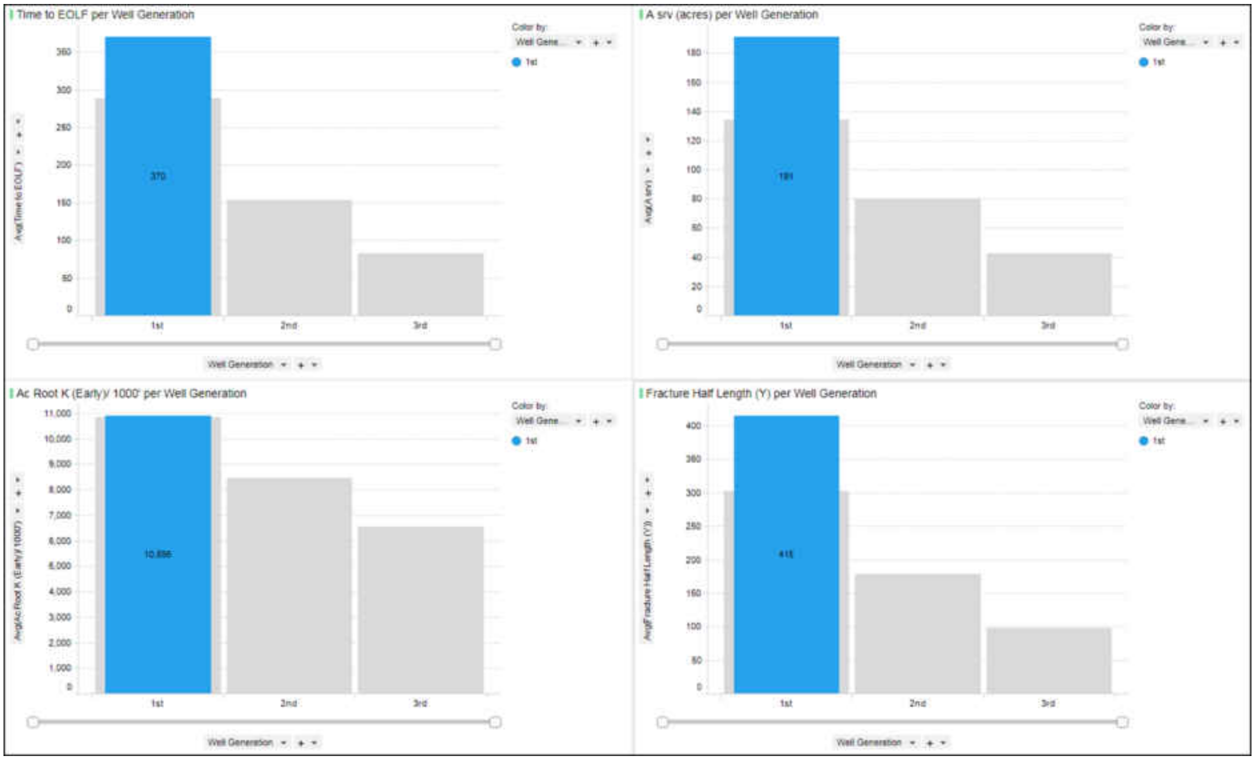

Figure 33. Well 1.1 reservoir and completion metrics.

Spacing Unit #2 (5-8-163N-100W)

Spacing unit 2 has 3 wells, 2 Three Forks and 1 Bakken. A distance of 1,980 feet separates 2.1 from 2.2, and 600 feet from 2.2 to 2.3. Wells 2.2 and 2.3 were completed at the same time, ~ 3 years after 2.1. Despite being a respectable distance apart, offset frac communication was observed in spacing unit 2. Well 2.1 experienced a 20 bbl/d bump in oil after the 2nd generation wells were completed. The production bump lasted ~ 1 year before returning to its original trend. This can be observed in the superposition time plot as the post-frac slope initially dropping in position (positive pressure re-set), then gradually steepening (Figure 37). Interestingly, well 2.2 (Bakken) has a larger 30 day IP and EUR than well 2.1.

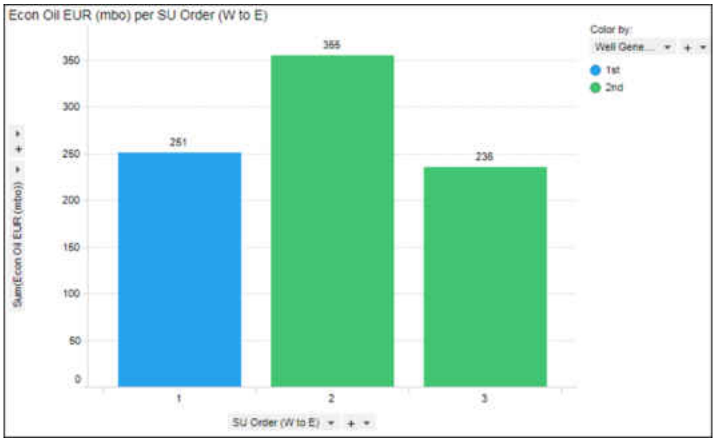

Figure 34. Spacing unit 2 well order from west (left) to east (right) and EURs.

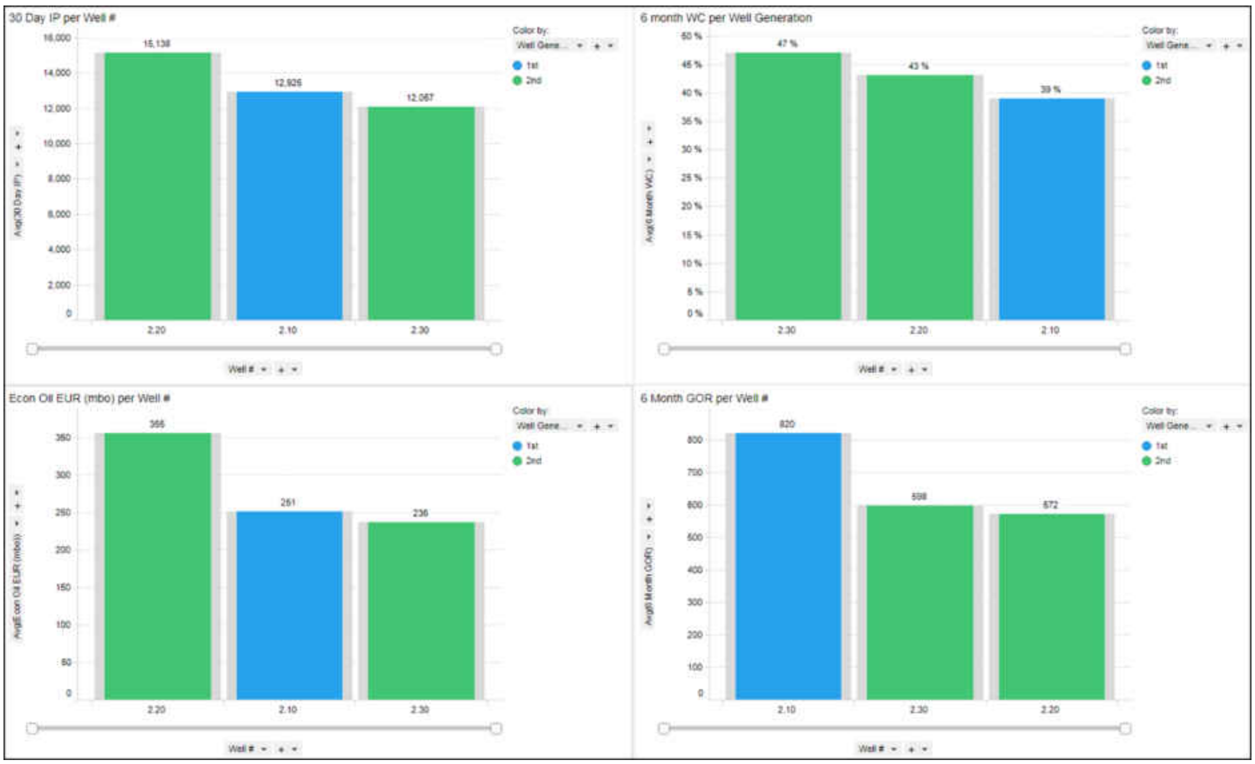

Figure 35. Spacing unit 2 production performance by well.

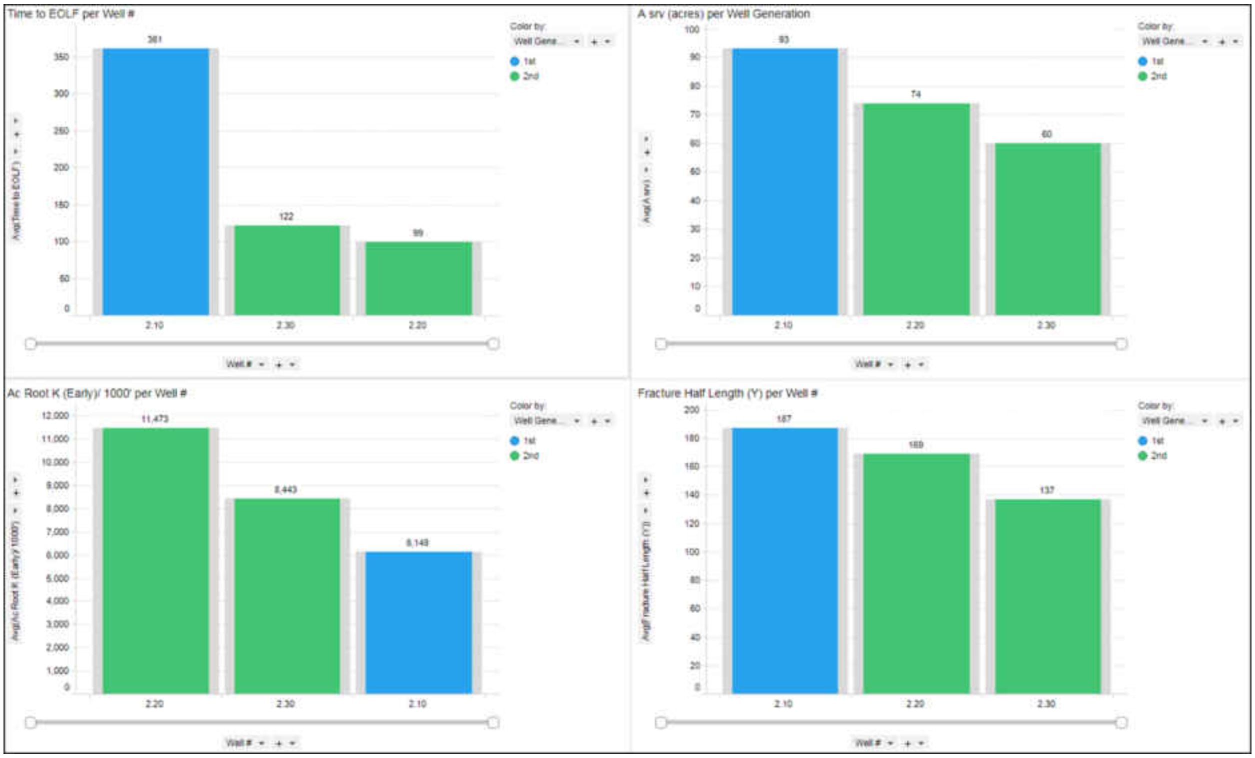

Figure 36. Spacing unit 2 reservoir and completion metrics.

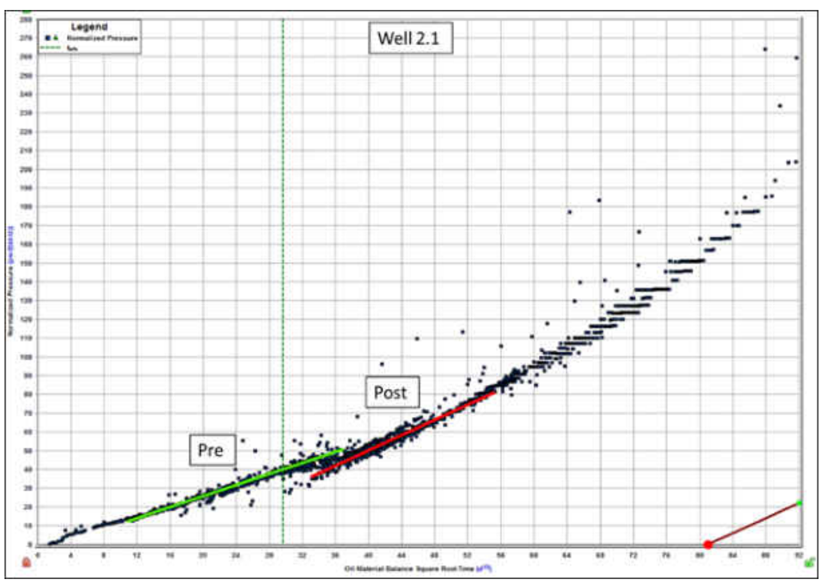

Figure 37. Well 2.1 superposition time plot.

Spacing Unit #3 (4-9-163N-100W)

Spacing unit 3 has 6 producing wells and two DUCS, spaced at 660 feet. The 2nd generation wells (3.3 and 3.2) were completed ~3.5 years after well 3.1, and were completed directly offset of the parent well. Wells 2.2 and 2.3 were completed at the same time as 3.2 and 3.3. Well 3.1 experienced a 15% loss in EUR, a 14% loss in $A_c\sqrt{k}$, and a 79% increase in water cut. Wells 3.4, 3.5, and 3.6 were completed ~1.3 years after the 2nd generation wells ~600 feet to the east of well 3.2. Well communication was detected in both 3.2 and 3.3.

Table 5. Spacing unit 3 frac hit metrics.

Well #	Min Distance to Offset Frac	Delta T - First Prod to Offset Frac	WC % Change	EUR % Change (MBO)	Ac Root K Reduction %
3.10	1321	1252	79.31	-15.08	14.48
3.20	600	464	14.00	-24.43	34.08
3.30	1420	430	9.09	-16.41	32.73

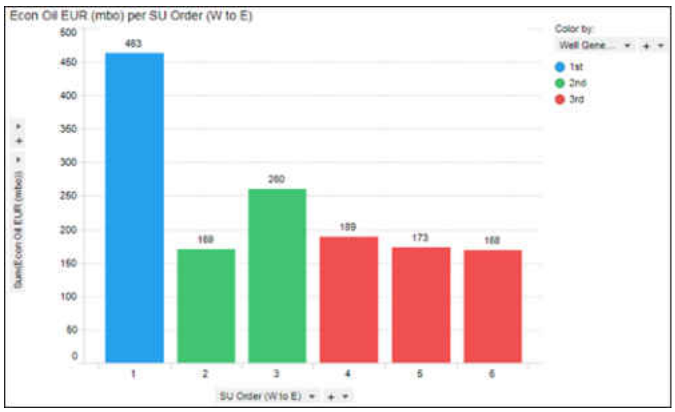

Figure 38. Spacing unit 3 well order from west (left) to east (right) and EURs.

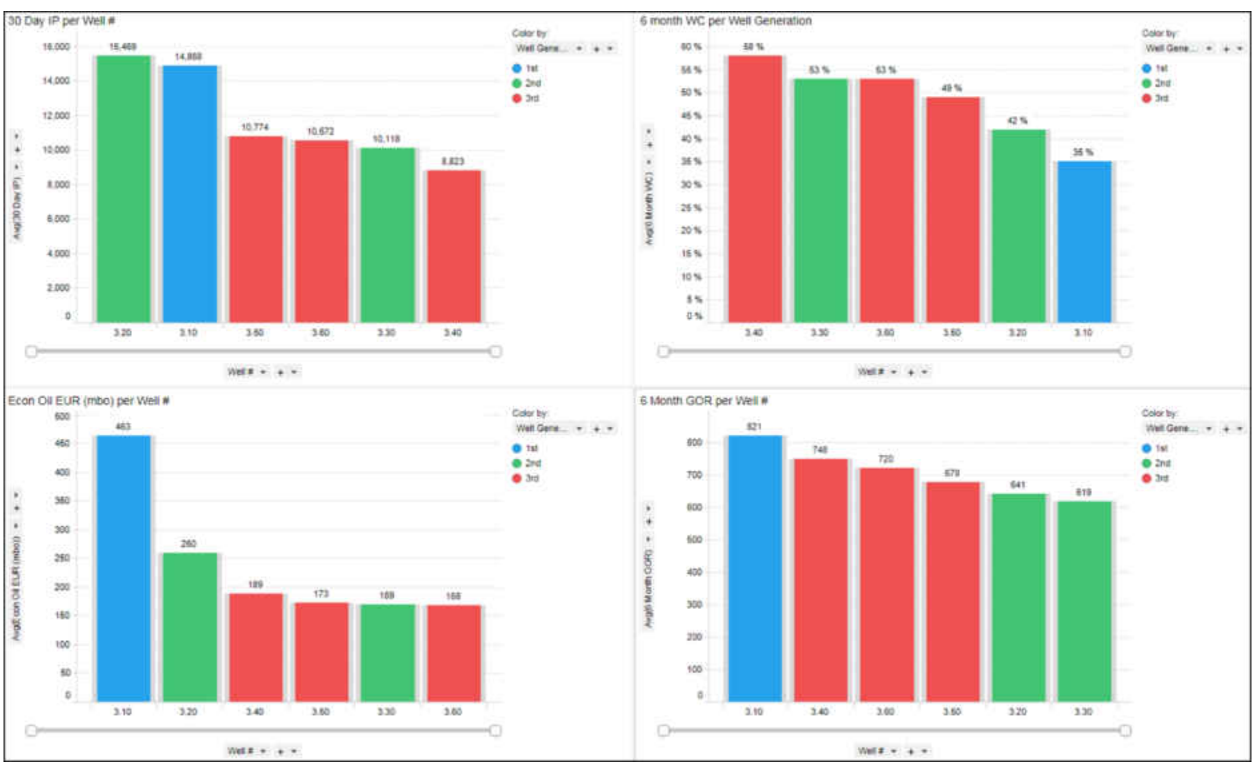

Figure 39. Spacing unit 3 production performance by well.

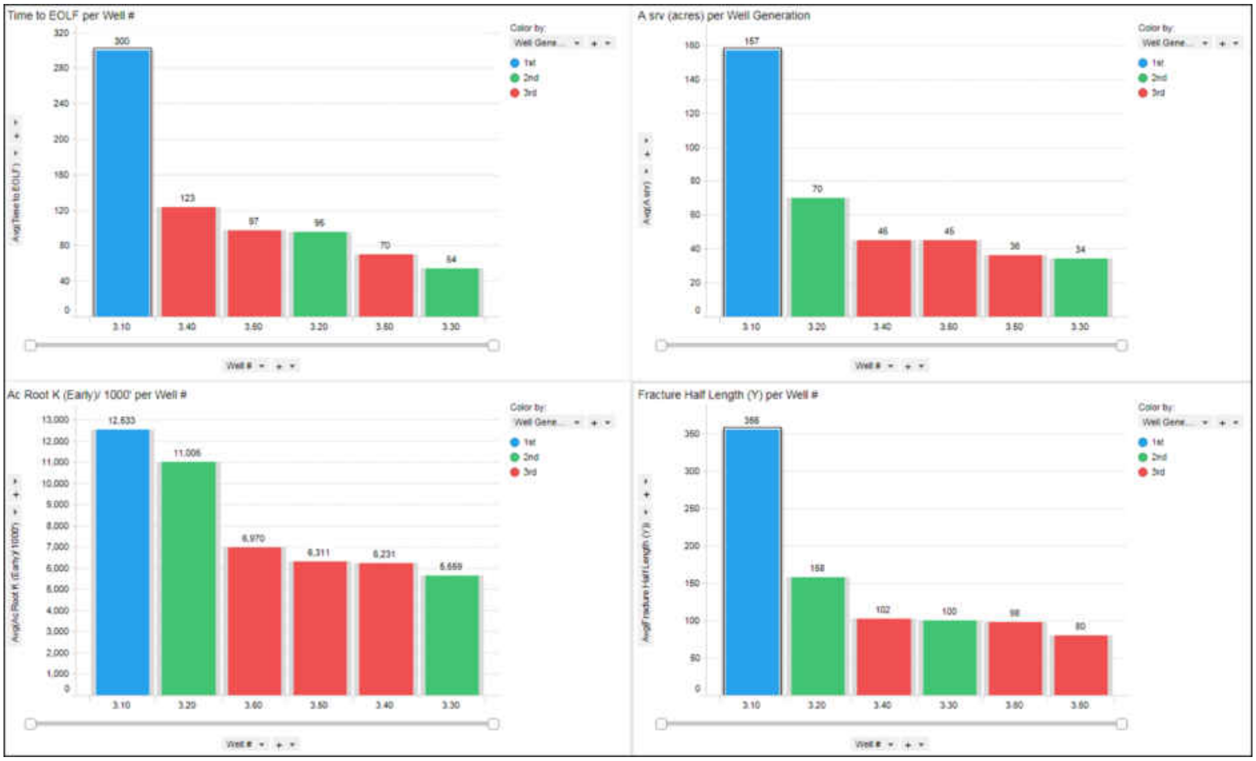

Figure 40. Spacing unit 3 reservoir and completion metrics.

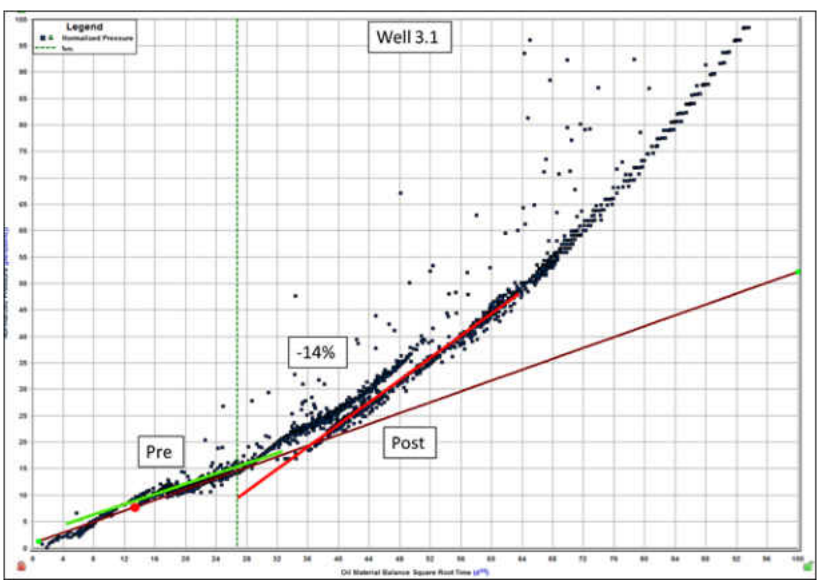

Figure 41. Well 3.1 superposition time plot.

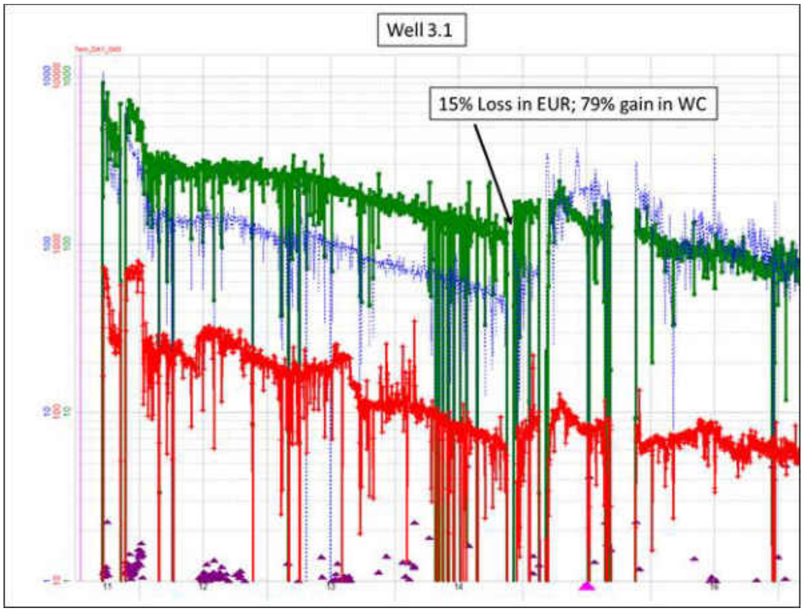

Figure 42. Well 3.1 production chart.

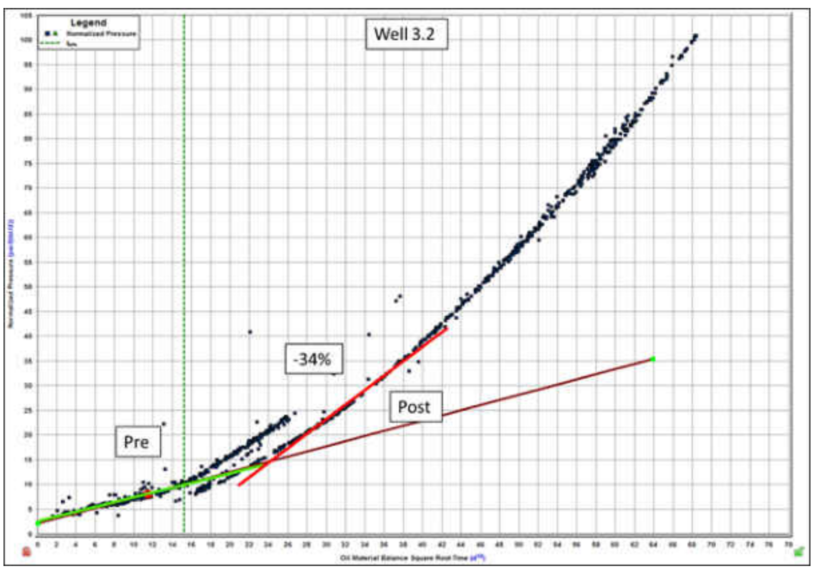

Figure 43. Well 3.2 superposition time plot.

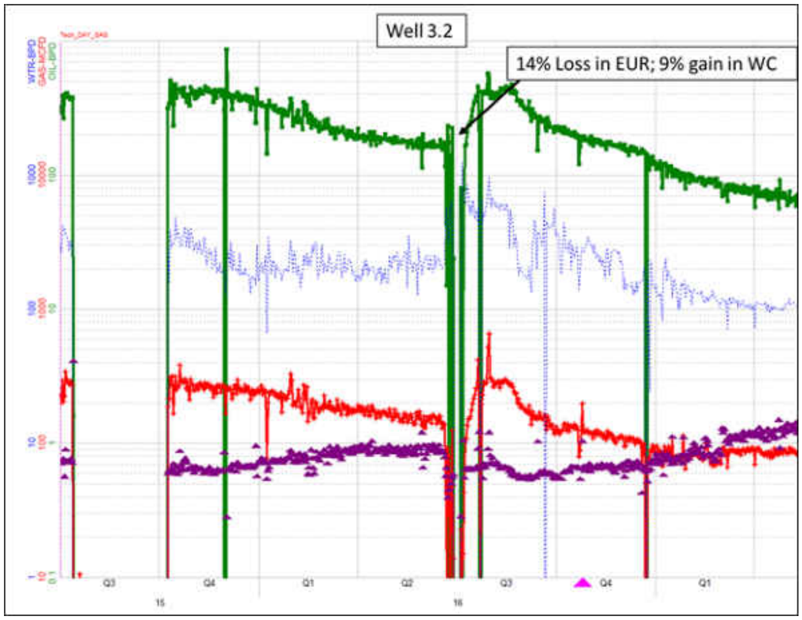

Figure 44. Well 3.2 production chart.

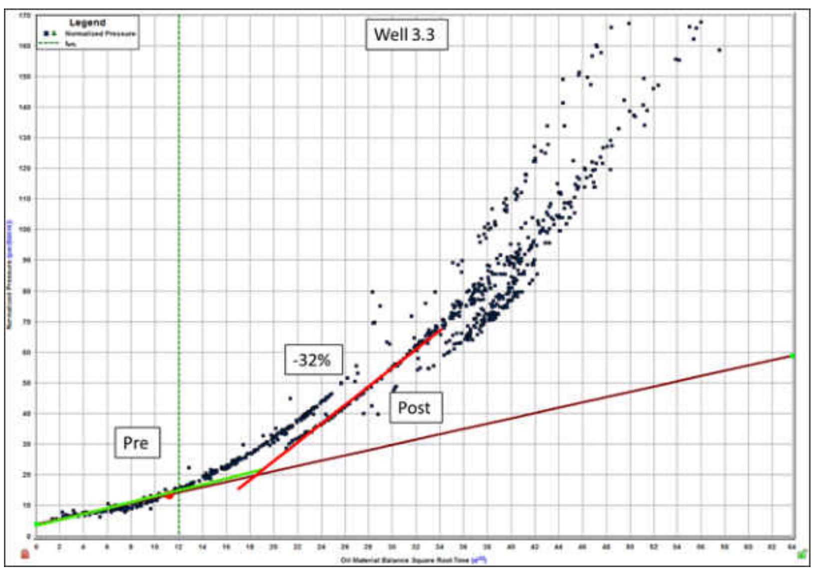

Figure 45. Well 3.3 superposition time plot.

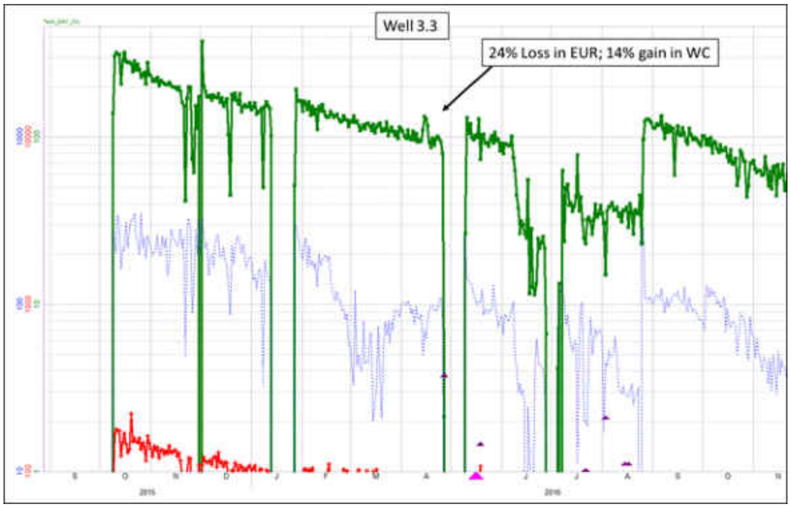

Figure 46. Well 3.3 production chart.

Spacing Unit #4 (3-10-163N-100W)

Spacing unit 4 contains 8 total wells, with 2 – 2nd generation and 5 – 3rd generation wells. The 2nd generation wells were completed ~3 years after the parent and are direct offsets 590 feet to the west. 5 – 3rd generation wells were completed 1.5 years after the 2nd generation wells – two were direct eastern offsets to the parent well while the other three were placed west of the 2nd generation wells. The impact of offset frac 4.5 on well 4.1 is artificial low, as the lateral was bailed on 4.1 after the offset frac. In this instance, change in $A_c\sqrt{k}$ provides a better metric than change in EUR. The lateral was also bailed on well 4.2 post offset frac. However, this job was not as effective relative to the bail job performed on 4.1.

Table 6. Spacing unit 4 frac hit metrics.

Well #	Min Distance to Offset Frac	Delta T - First Prod to Offset Frac	WC % Change	EUR % Change (MBO)	Ac Root K Reduction %	Min Distance to Offset Frac_2	WC % Change_2	EUR % Change_2 (MBO)	Ac Root K Reduction %_2
4.10	590	1134	25.81	-31.01	37.44	595	52.27	-9.51	49.08
4.20	1185	586	24.56	-37.25	40.56	(Empty)	(Empty)	(Empty)	(Empty)
4.30	690	590	7.50	-48.20	31.47	(Empty)	(Empty)	(Empty)	(Empty)

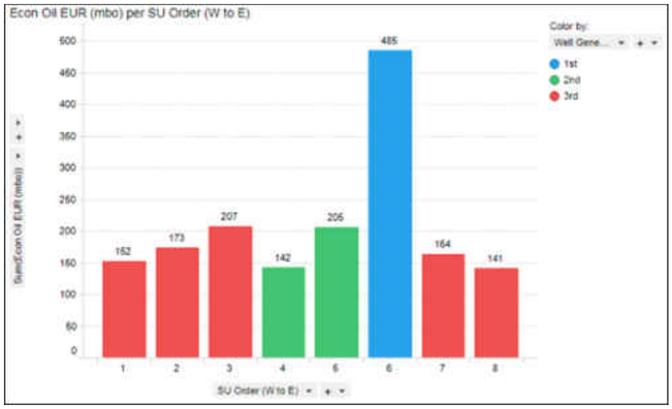

Figure 47. Spacing unit 4 well order from west (left) to east (right) and EURs.

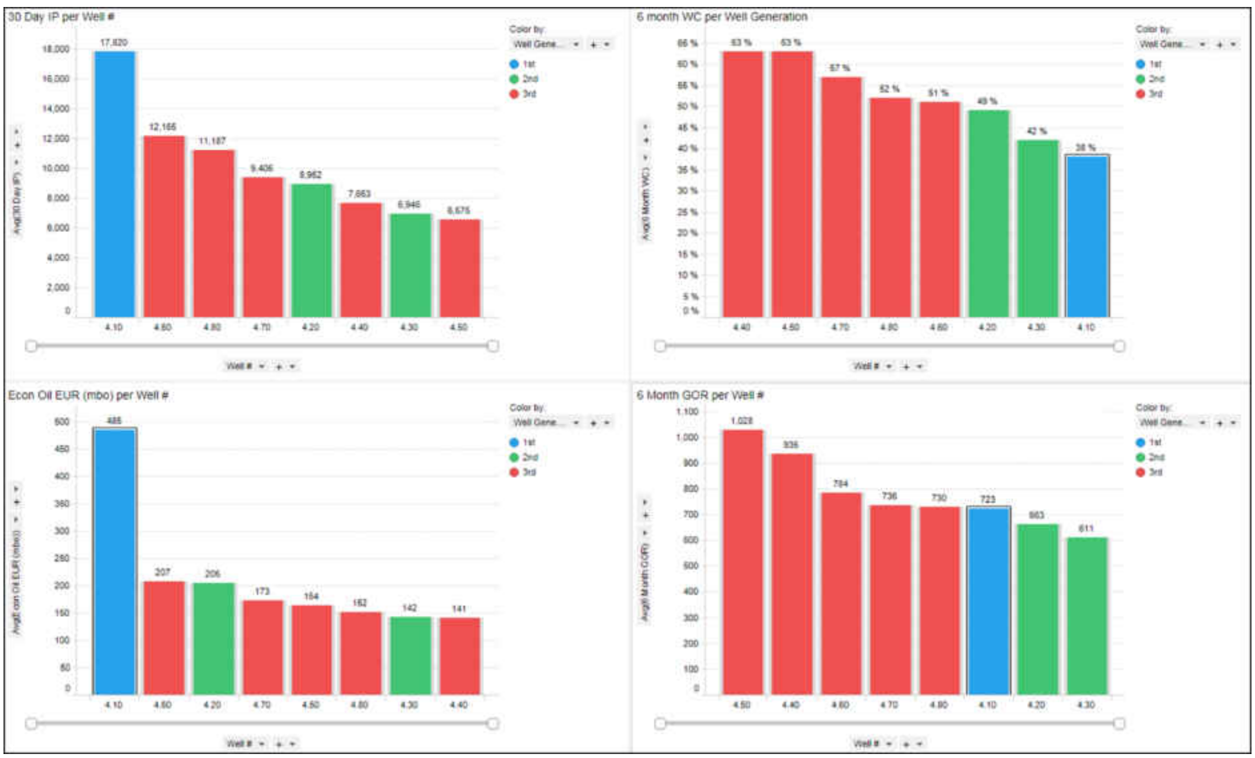

Figure 48. Spacing unit 4 production performance by well.

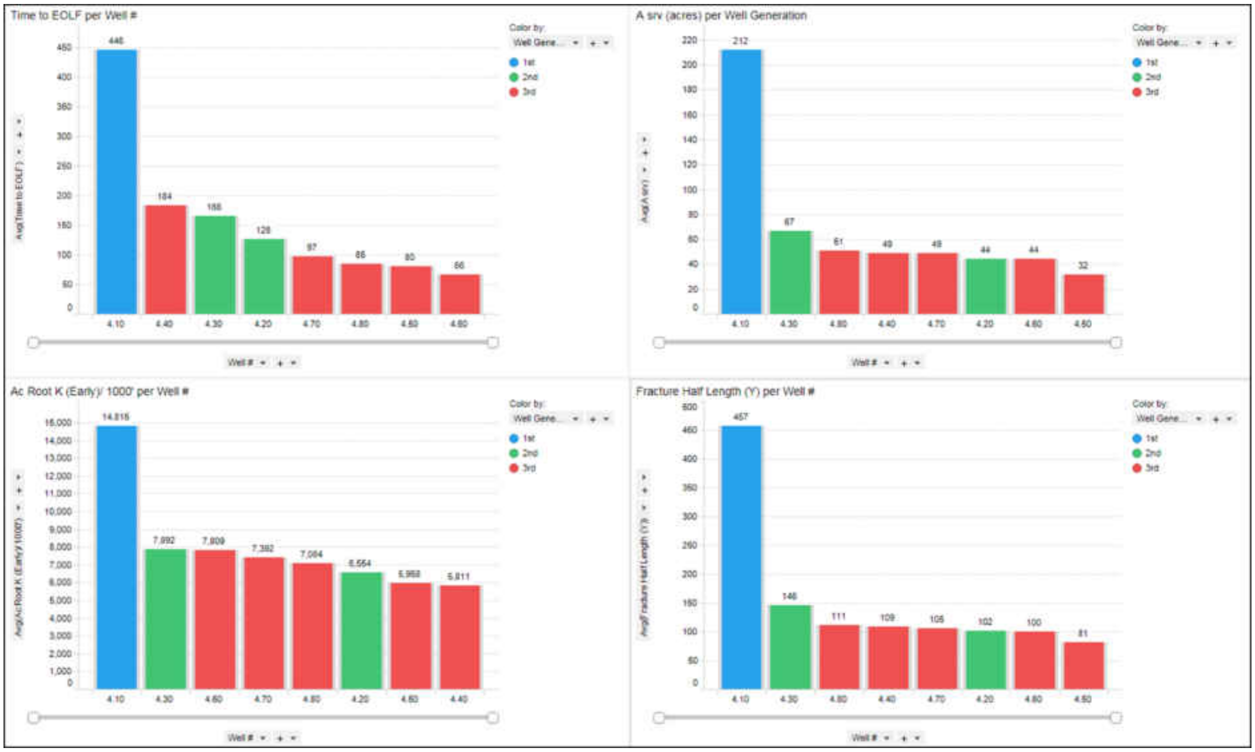

Figure 49. Spacing unit 4 reservoir and completion metrics.

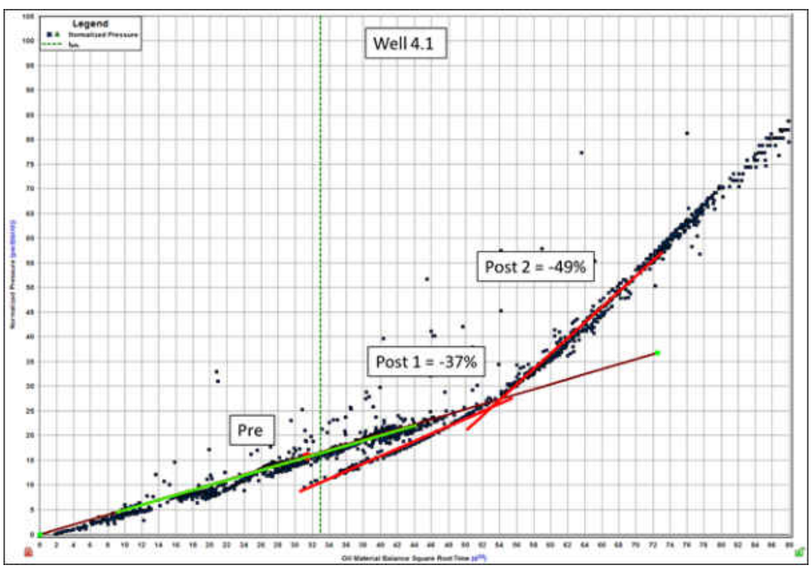

Figure 50. Well 4.1 superposition time plot.

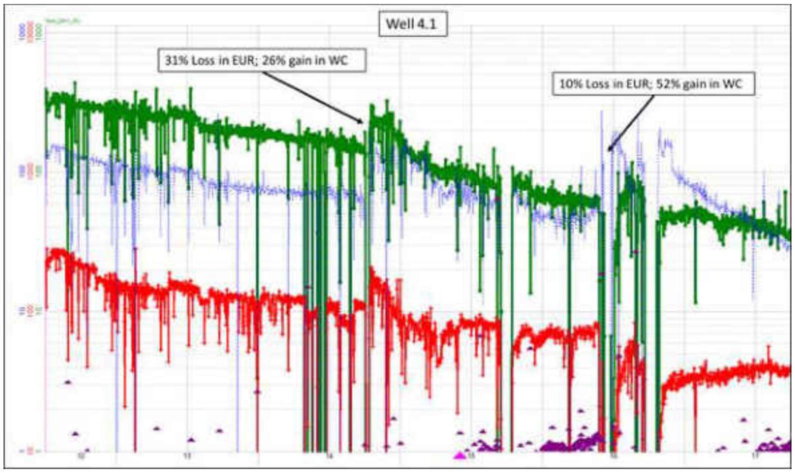

Figure 51. Well 4.1 production chart.

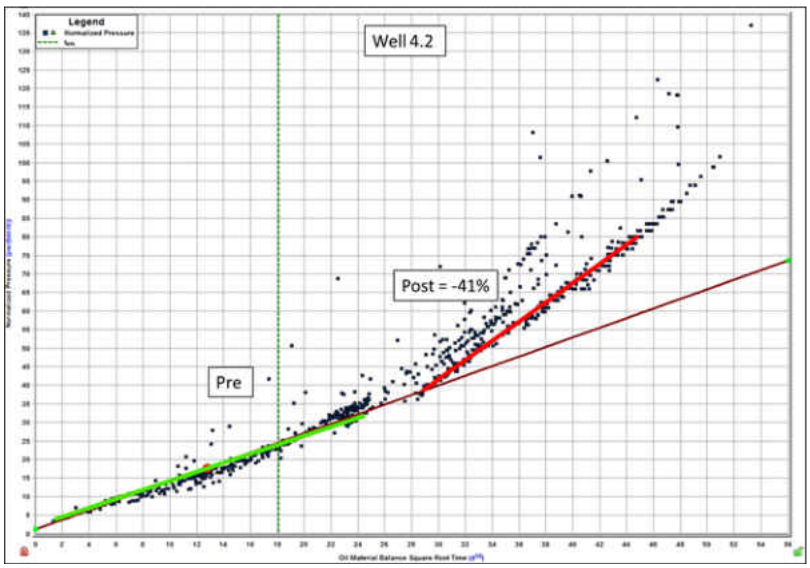

Figure 52. Well 4.2 superposition time plot.

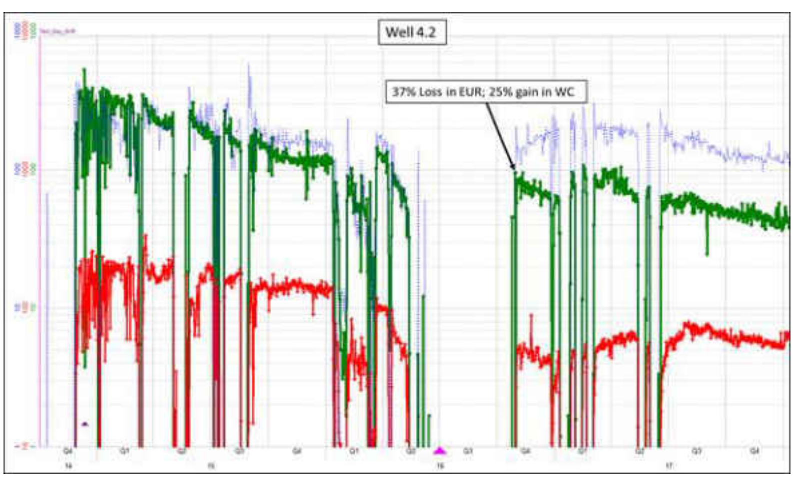

Figure 53. Well 4.2 production chart.

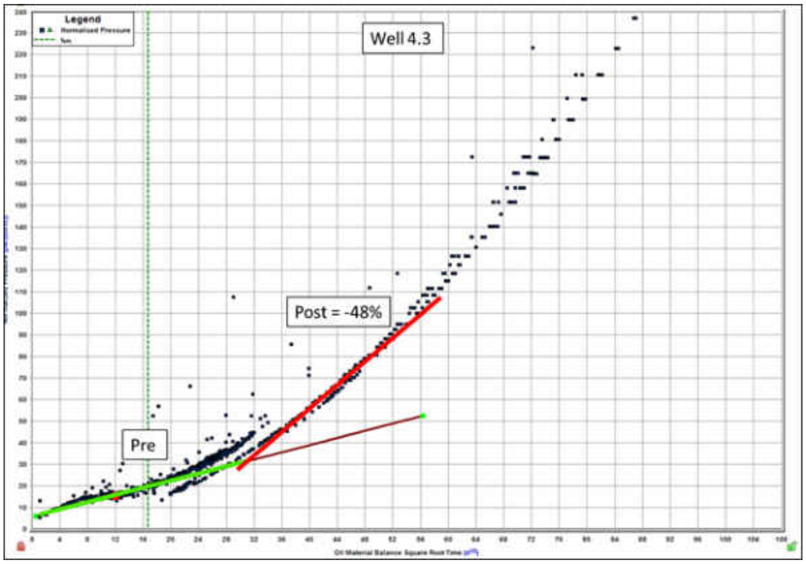

Figure 54. Well 4.3 superposition time plot.

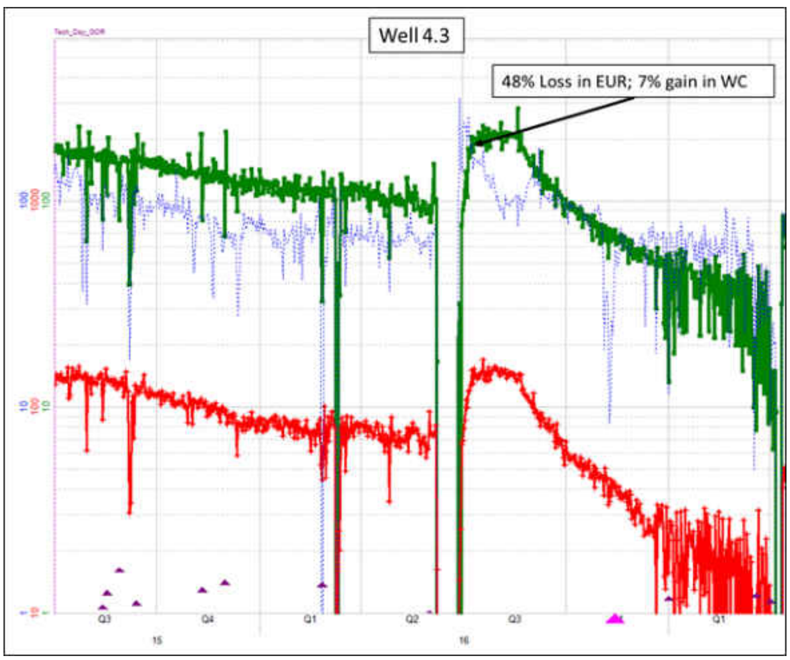

Figure 55. Well 4.3 production chart.

Spacing Unit #5 (2-11-163N-100W)

Spacing unit 5 has a total of 5 wells. The first four wells were spaced at 1,320 feet, while the last well (5.5) was spaced at 660 feet. The 1st and 2nd generation wells are Three Forks and 5.5 is a Bakken well. All 2nd generation wells were completed 1.4 years after the 1st generation well was brought online. The 3rd generation well was completed 3.3 years later. The impact of 2nd generation fracs on 1st generation wells is likely artificially high. Dynamometer results show a severely worn pump over this time period. In addition, no increase in water cut was observed on the parent well.

Figure 56. Spacing units 5 & 6.

Table 7 Spacing unit 5 frac hit metrics.

Well #	Min Distance to Offset Frac	Delta T - First Prod to Offset Frac	WC % Change	EUR % Change (MBO)	Ac Root K Reduction %	Min Distance to Offset Frac_2	WC % Change_2	EUR % Change_2 (MBO)	Ac Root K Reduction %_2
5.10	900	498	0.00	-37.19	66.66	640	41.67	-4.88	46.17
5.20	1540	1195	3.70	-8.77	30.90	(Empty)	(Empty)	(Empty)	(Empty)
5.30	2640	1204	0.00	(Empty)	0.00	(Empty)	0.00	(Empty)	(Empty)

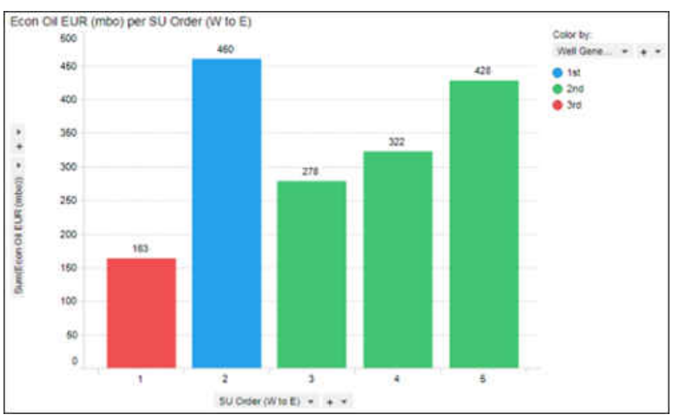

Figure 57. Spacing unit 5 well order from west (left) to east (right) and EURs.

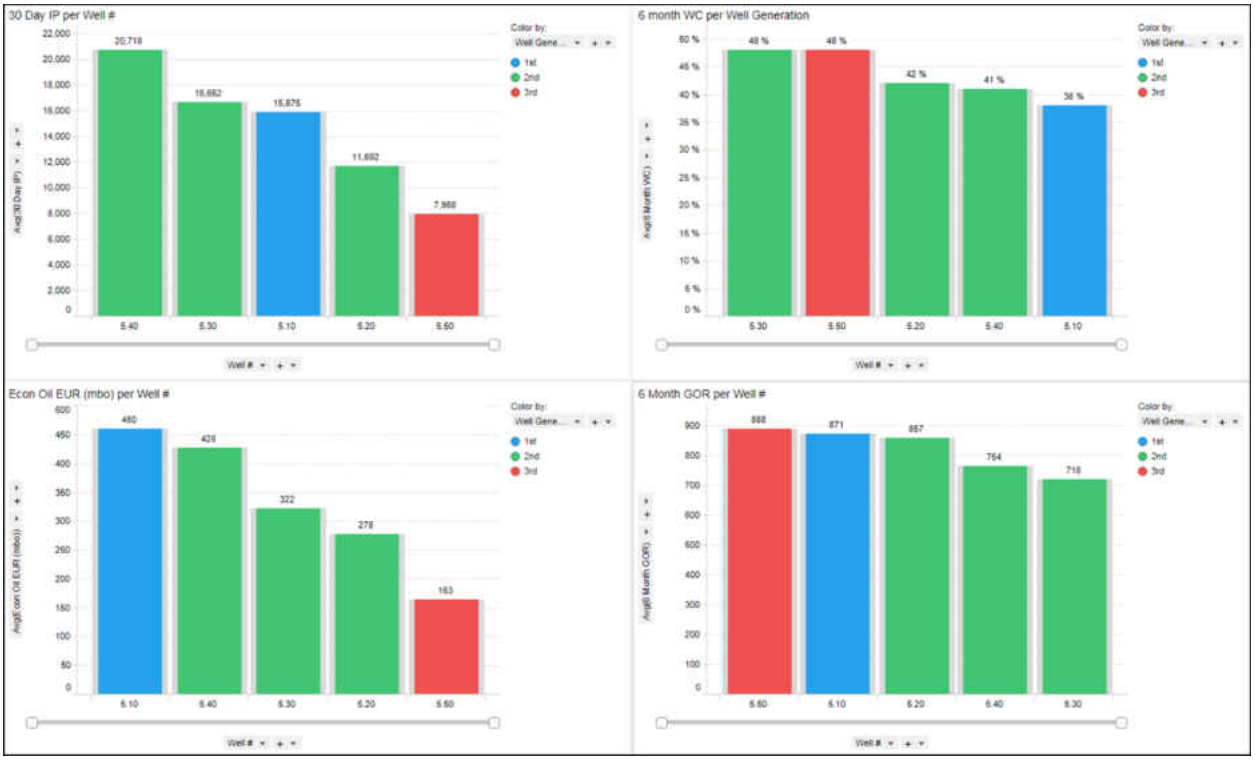

Figure 58. Spacing unit 5 production performance by well.

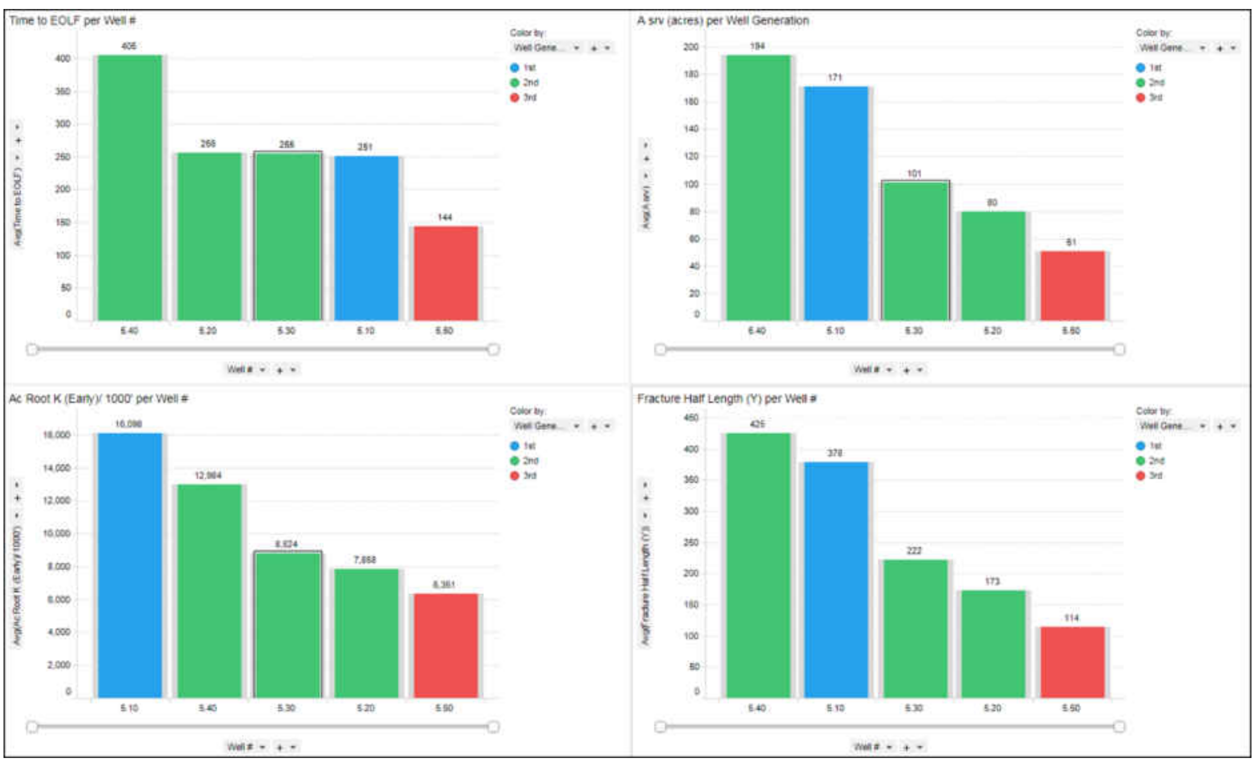

Figure 59. Spacing unit 5 reservoir and completion metrics.

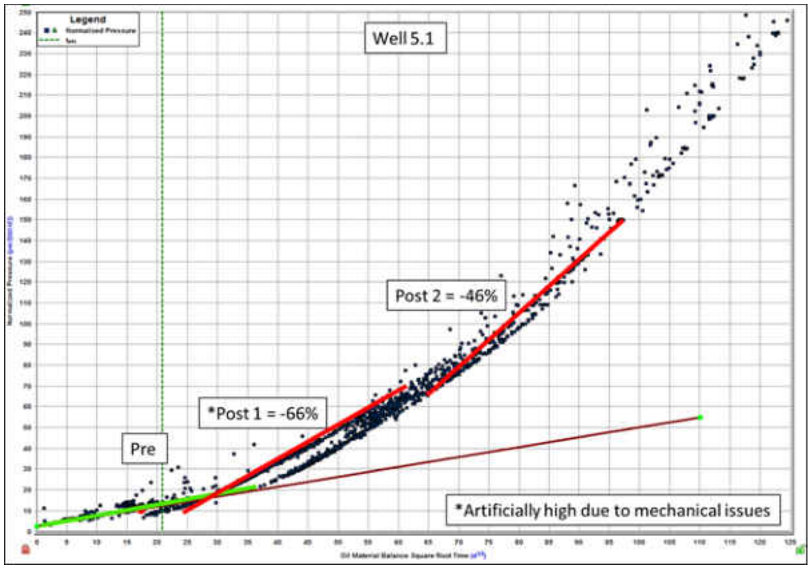

Figure 60. Well 5.1 superposition time plot.

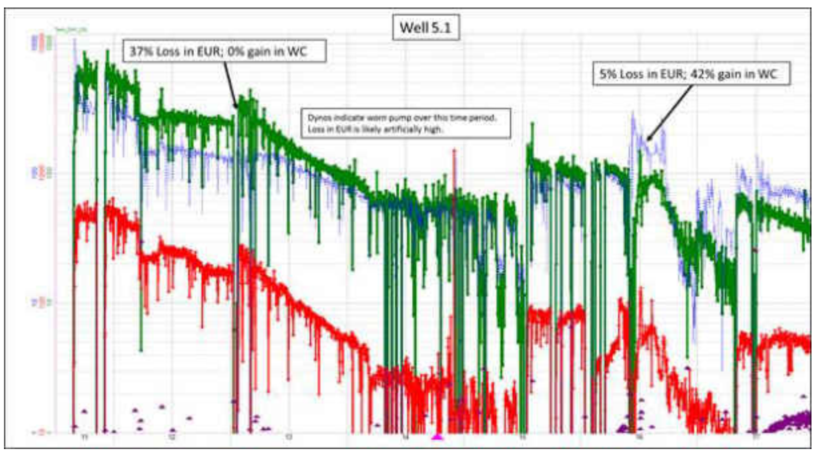

Figure 61. Well 5.1 production chart.

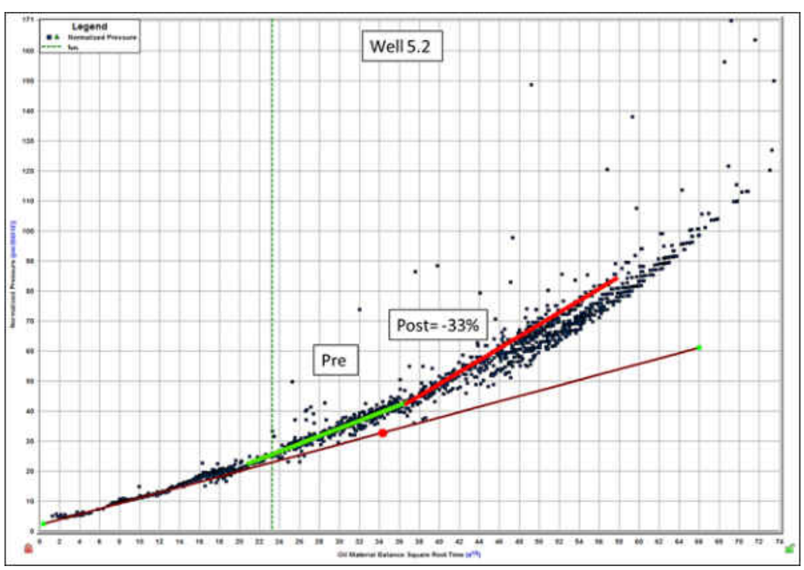

Figure 62. Well 5.2 superposition time plot.

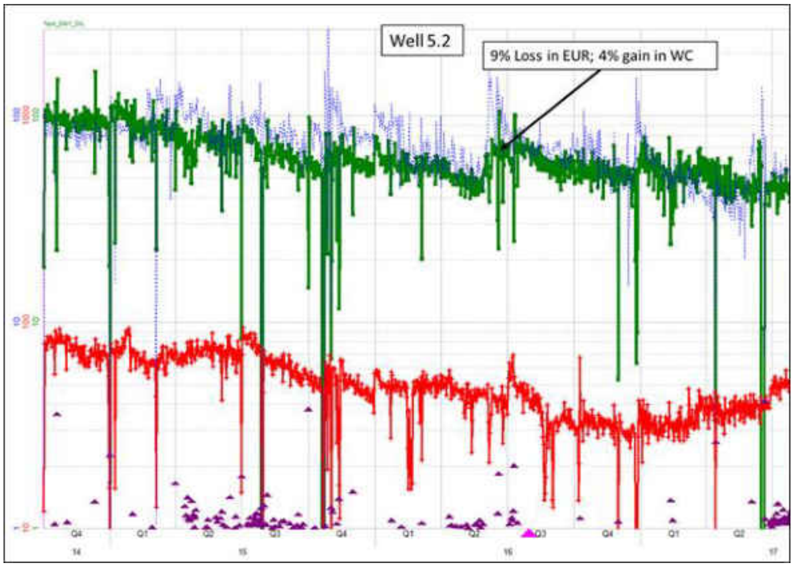

Figure 63. Well 5.2 production chart.

Spacing Unit #6 (1-2-163N-100W)

Spacing unit 6 contains two Three Forks wells completed 4 months apart with a minimum distance of 1,320 feet between. A non-operated well was completed at the same time as well 6.2, 1,220 feet to the east. No change was observed in production trends or in the superposition time plot for either offset frac. Spacing unit 6 illustrates the benefit of completing wells at or near the same time, when reservoir pressure still near virgin pressure. The comparatively better well performance of 2.1 may be tied to completion design, which had 6 additional stages, tighter stage spacing, and 12% more proppant per foot.

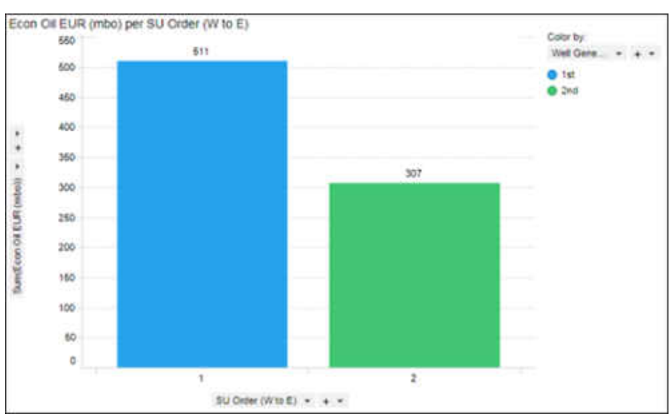

Figure 64. Spacing unit 6 well order from west (left) to east (right) and EURs.

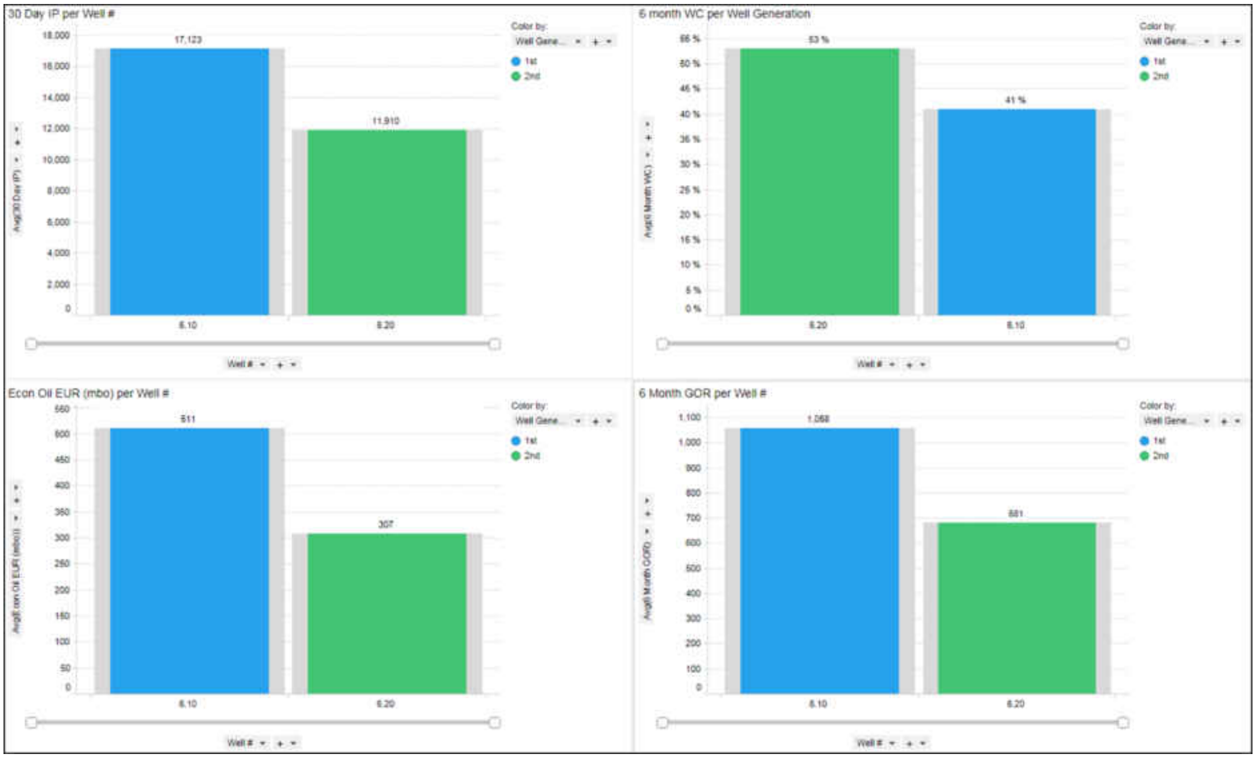

Figure 65. Spacing unit 6 production performance by well.

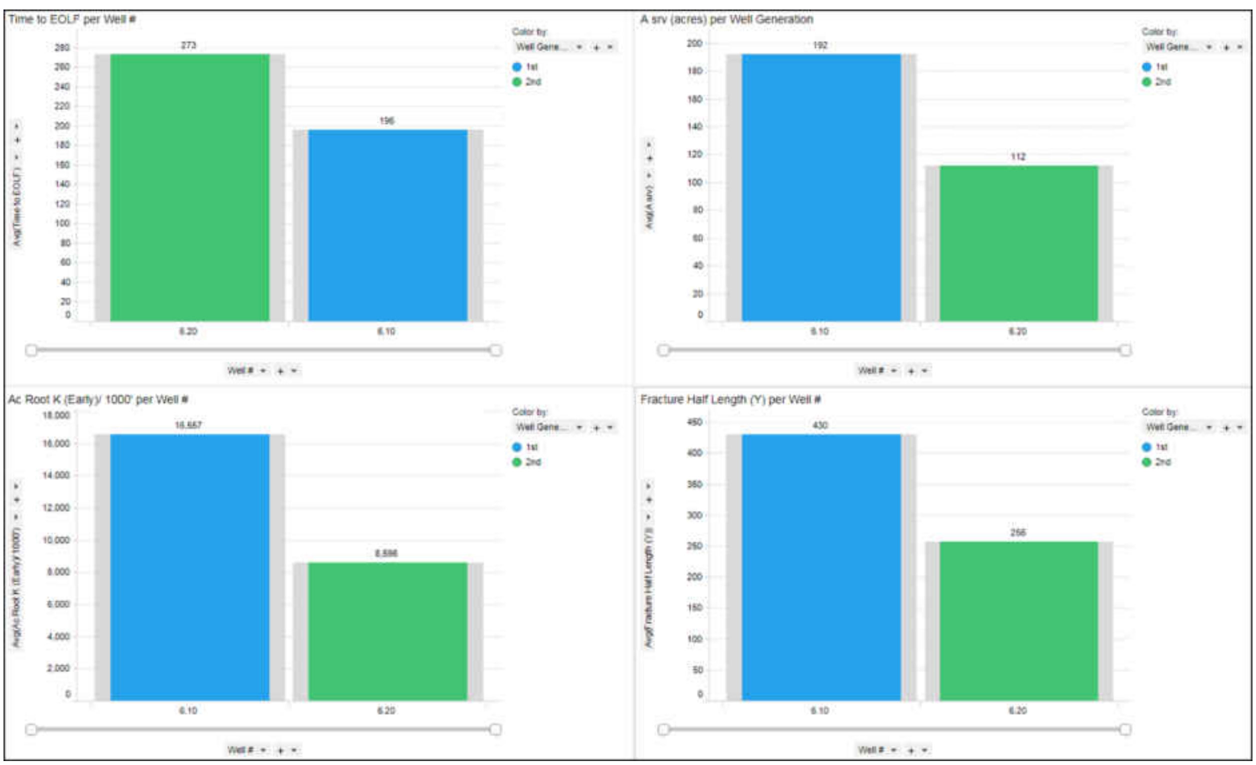

Figure 66. Spacing unit 6 reservoir and completion metrics.

Spacing Unit #7 (18-19-163N-100W)

Spacing unit 7 has 4 Three Forks wells spaced at 1,320 feet. Three 2nd generation wells were completed ~2 years after the 1st generation well was brought online. A minimum distance of 1,060 feet separate 7.1 from the closest infill well (7.3). Infill wells were completed at the same time. 30 day IPs increase as distance from the parent well increases. However, EURs are very similar for all infill wells. Overall, wells in spacing units 7 and 8 perform poorly relative to other spacing units with similar spacing, target, and completion design. Comparing 1st generation wells from spacing unit 5 to spacing unit 7, the 30 day IP for well 7.1 was 30% lower than 5.1 and the 6 month water cut was 4% higher than 5.1. Based on these comparisons, geology seems to be the main negative production variation driver in spacing unit 7. When 2nd generation wells were completed, well 7.1 experienced a 29% loss in EUR, no change in water cut, and a 26% reduction in $A_c\sqrt{k}$.

Figure 67. Spacing units 7, 8 & 9.

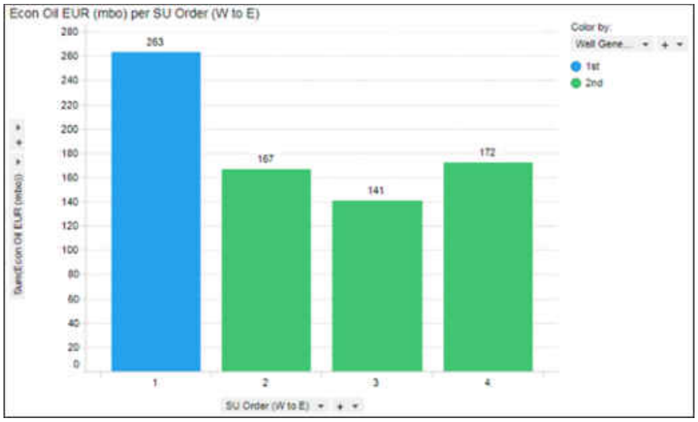

Figure 68. Spacing unit 7 well order from west (left) to east (right) and EURs.

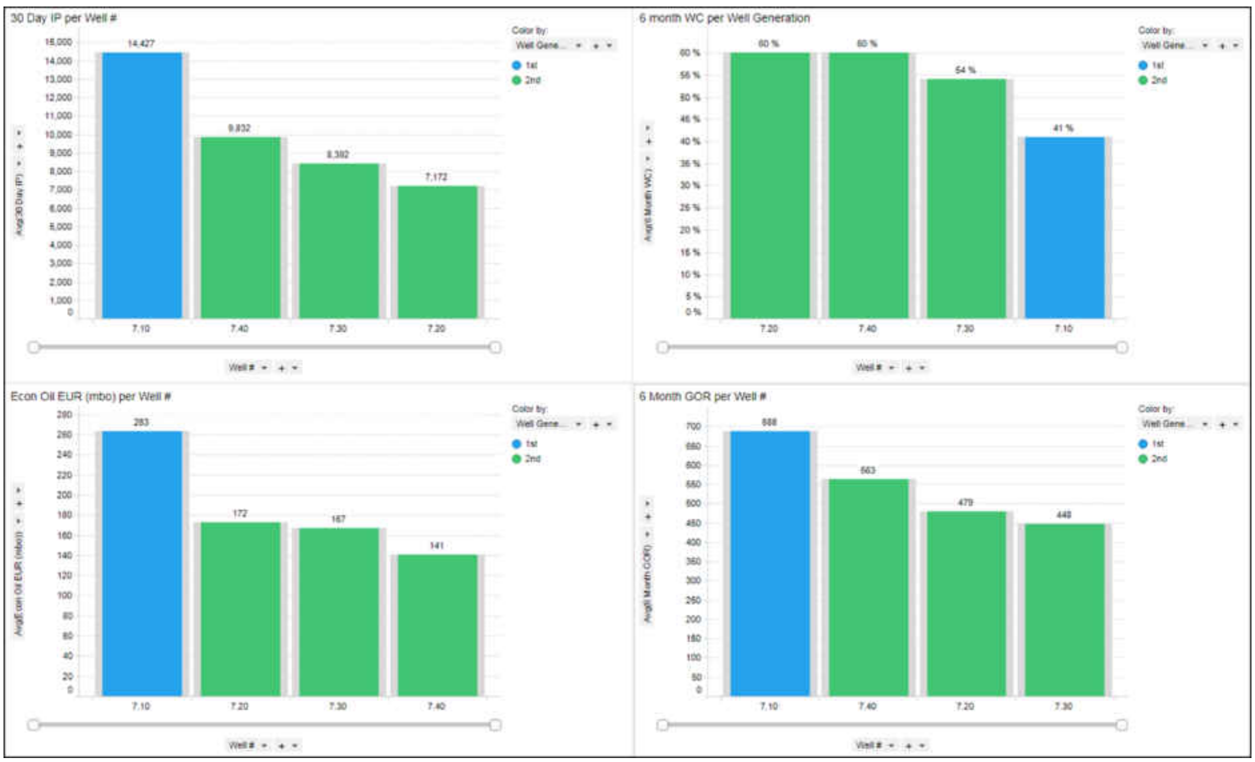

Figure 69. Spacing unit 7 production performance by well.

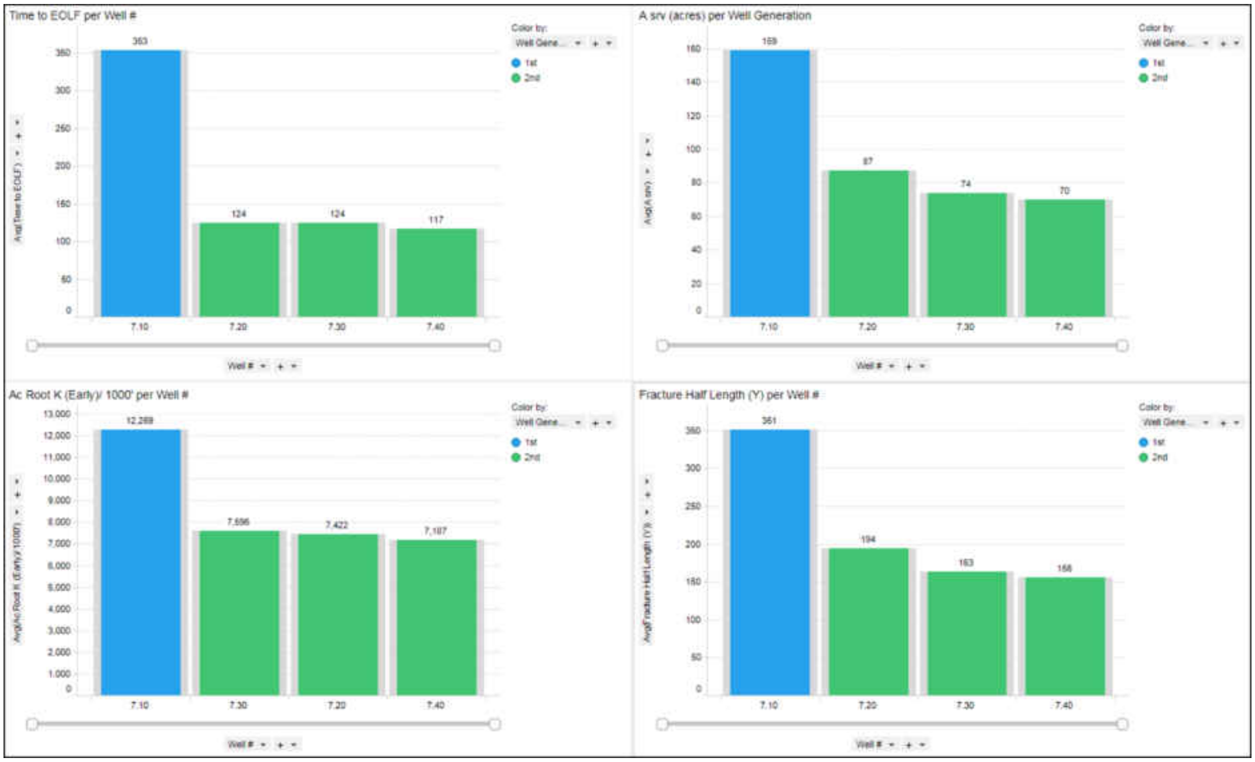

Figure 70. Spacing unit 7 reservoir and completion metrics.

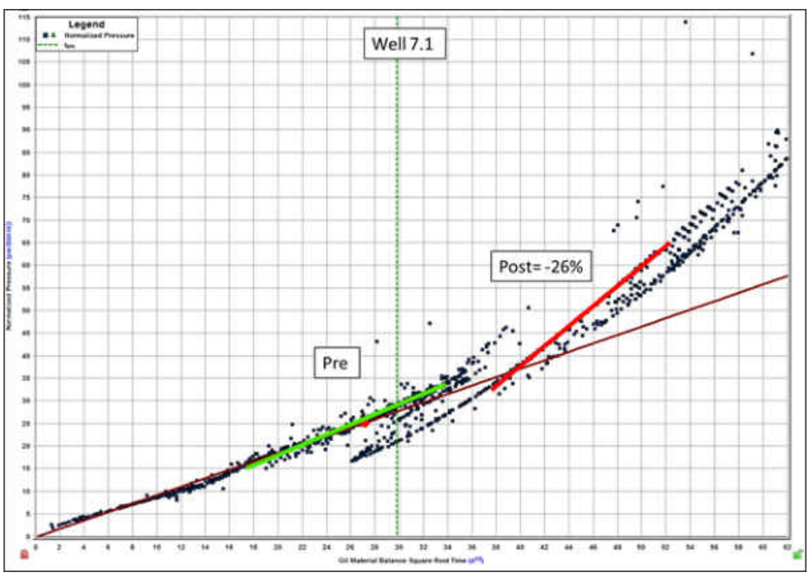

Figure 71. Well 7.1 superposition time plot.

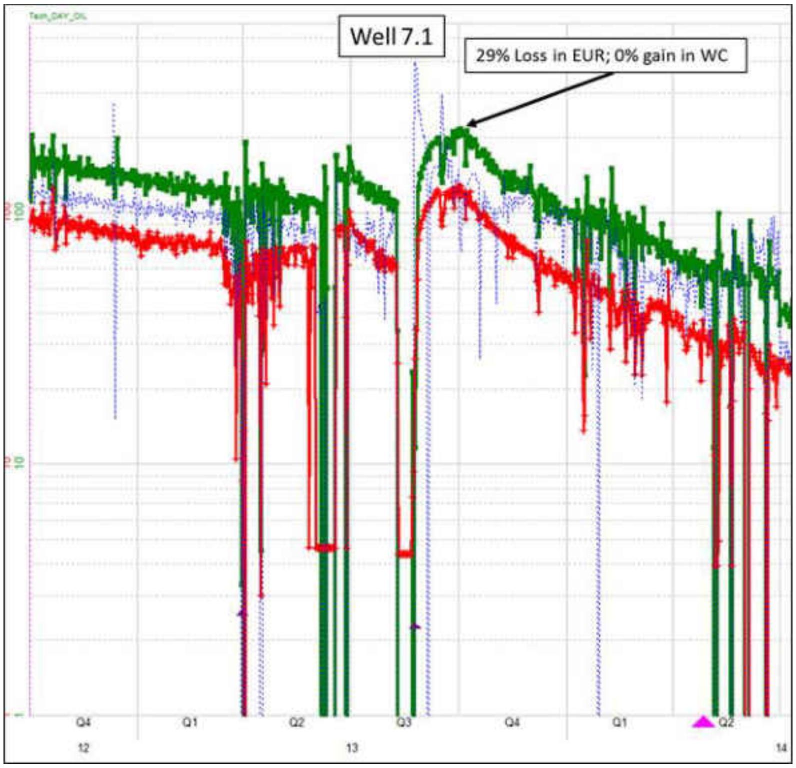

Figure 72. Well 7.1 production chart.

Spacing Unit #8 (17-20-163N-100W)

Spacing unit 8 development is similar to spacing unit 7. The unit contains 4 Three Forks wells spaced at 1,320 feet. The 1st generation well (8.1) started producing ~2 years before 2nd generation wells were added. Wells 8.2, 8.3, and 8.4 were completed at the same time as wells 7.2, 7.3, and 7.4. The minimum distance from the parent to the western 2nd generation wells is 1,900 feet and 1,080 feet to the eastern wells. As mentioned above, this area has poor geology relative to the rest of the Gooseneck area, as demonstrated by higher initial water cut and lower 30 day IP. Three Forks net pay is ~8% lower than in spacing unit 5. Well performance for 2nd generation wells increases away from the parent well, again demonstrating the impacts of reservoir depletion. Well 8.1 experienced an initial bump in production after the infill wells were completed. The lateral was bailed, and minimal sand was encountered. However, the decline rate increased ~6 months after the offset fracs. The well experienced a 28% decrease in

EUR, a 15% increase in water cut, and a 14% decrease in $A_c\sqrt{k}$. Production performance is best in the far eastern well (8.4). The outperformance of well 8.4 relative to 8.1 demonstrates effective enhancement in completion design (assuming geology is the same). Well 8.4 has 6 additional stages and tighter stage spacing. Well 9.2 was completed 2 years after well 8.4, 2,877 feet to the east. However, no communication was observed.

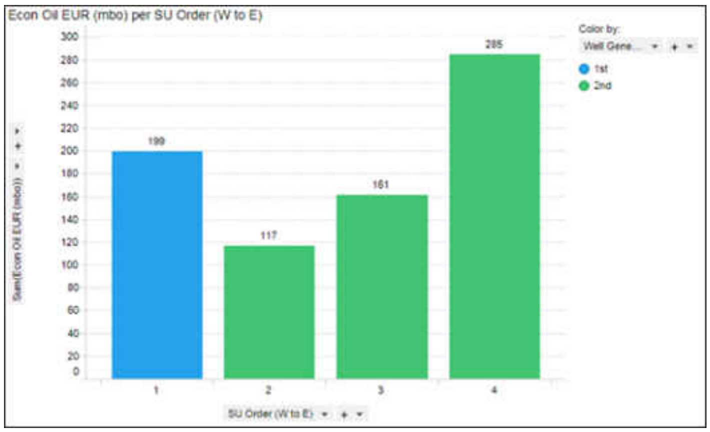

Figure 73. Spacing unit 8 well order from west (left) to east (right) and EURs.

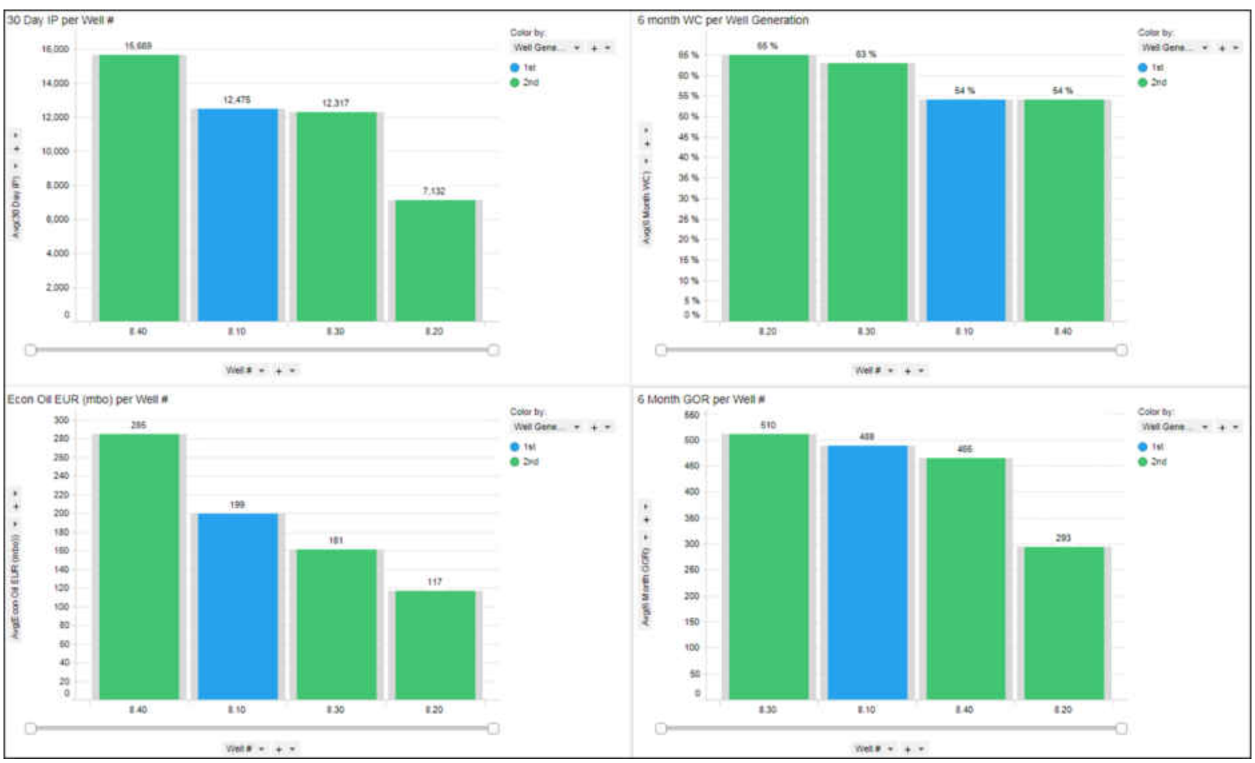

Figure 74. Spacing unit 8 production performance by well.

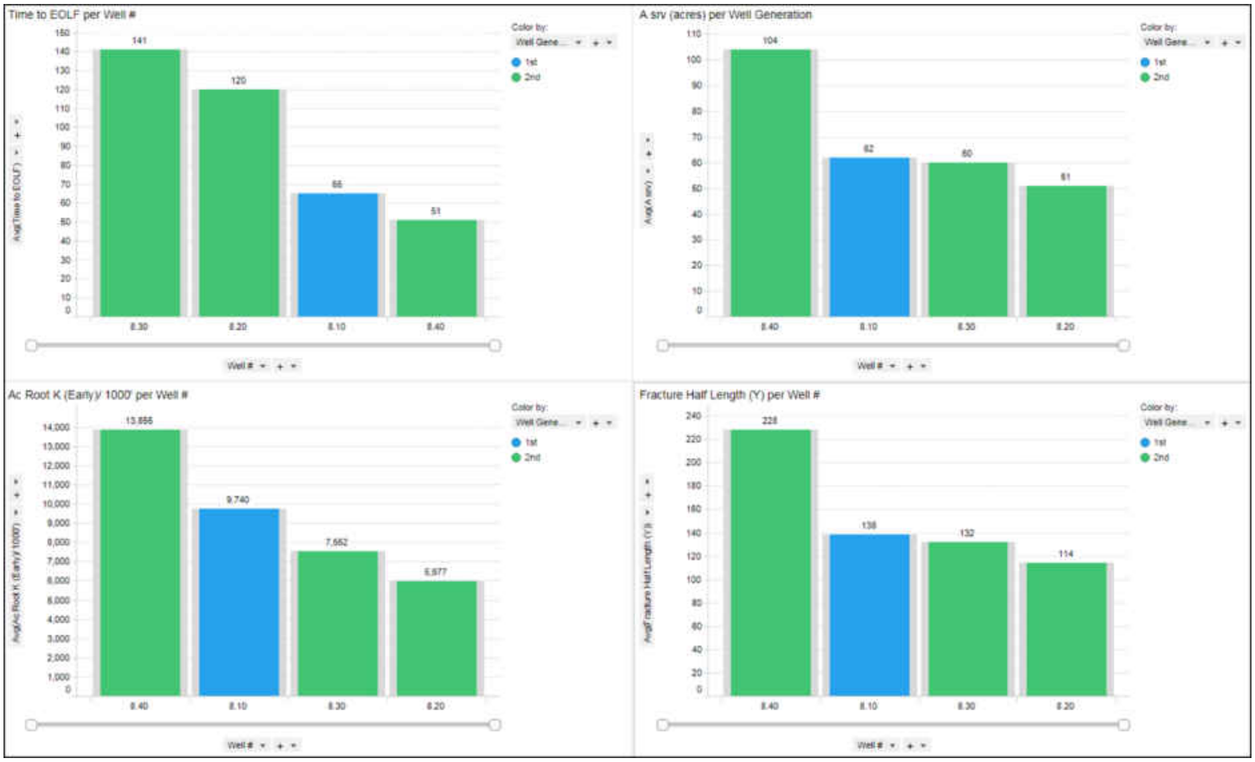

Figure 75. Spacing unit 8 reservoir and completion metrics.

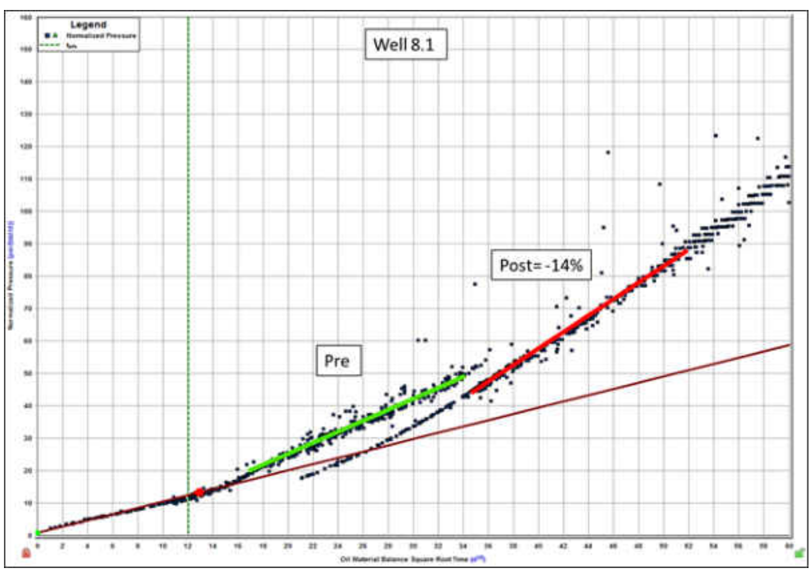

Figure 76. Well 8.1 superposition time plot.

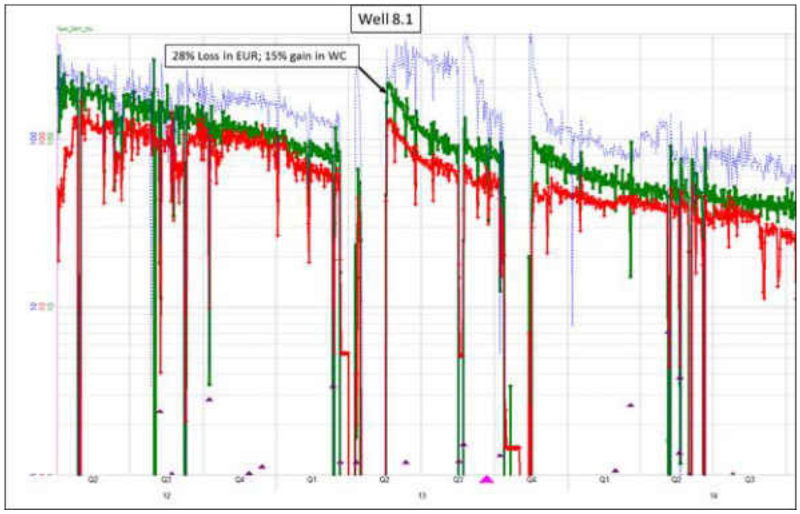

Figure 77. Well 8.1 production chart.

Spacing Unit #9 (16-21-163N-100W)

Spacing unit 9 is comprised of 5 producing wells and 3 drilled but not completed (DUC) wells. Wells are spaced at 660 feet. Two 2nd generation wells were placed directly offset of the parent well. These wells were completed ~4 years after the parent, with a minimum distance of 580 feet between the parent and closest 2nd generation well. Two 3rd generation wells were completed directly offset to the east of the parent well two years after the 2nd generation wells were complete. When wells 9.2 and 9.3 were completed, the parent well experienced a 24% loss in EUR, a 45% increase in water cut, and a 40% decrease in $A_c\sqrt{k}$. When the 2nd generation wells were completed, the parent well lost 9% EUR, gained 24% in water cut, and lost 33% in EUR. The impact of 3rd generation offset fracs on well 9.2 and 9.3 could not be accurately determined. This well was completed using an MSSB design. As noted earlier, these wells perform poorly compared to plug and perf or sliding sleeve designs. Both 9.2 and 9.3 were shut in and drill protected 3 months after initial production. Infill wells were drilled ~800 feet to the west of well 9.2. When returned to production, both wells experienced a sharp decrease in oil production. These wells have experienced major solids issues and erratic production. Also, initial fluid levels measurements were not recorded for one year, making superposition time plots unreliable. Of interest is that offset drilling had such a significant impact on 2nd generation wells. This indicates that significant depletion occurred between well 9.1 and 8.4 (2,800 feet).

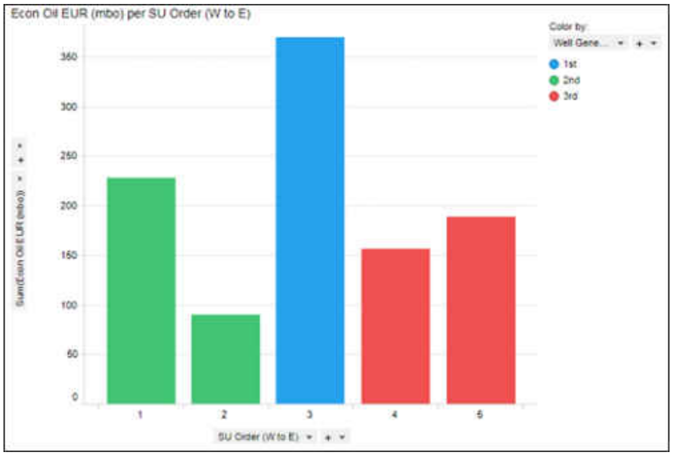

Figure 78. Spacing unit 9 well order from west (left) to east (right) and EURs.

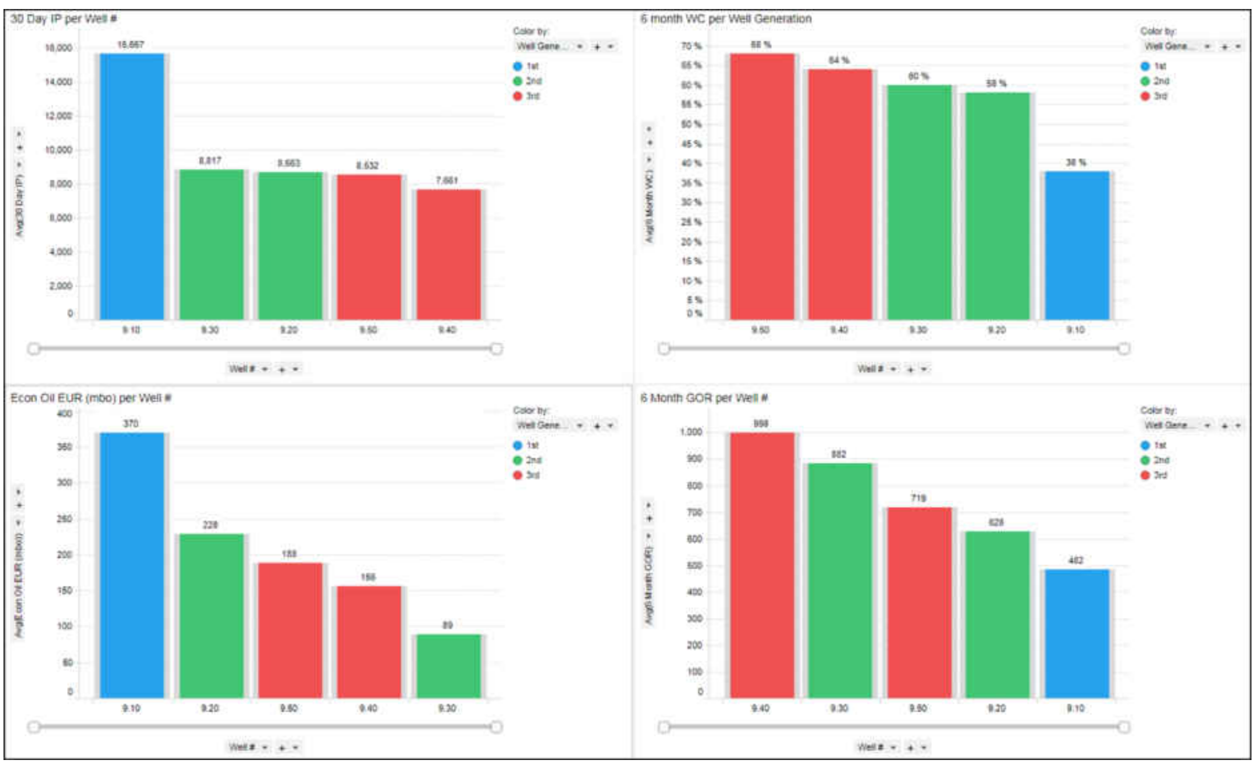

Figure 79. Spacing unit 9 production performance by well.

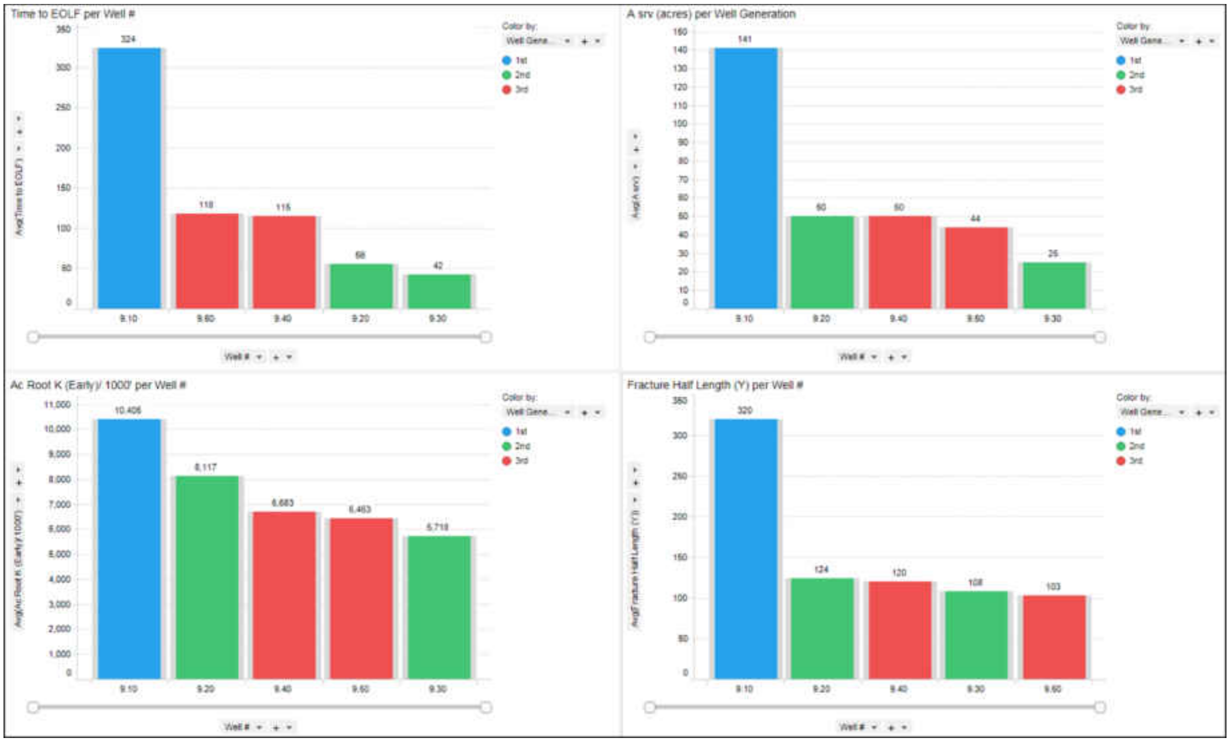

Figure 80. Spacing unit 9 reservoir and completion metrics.

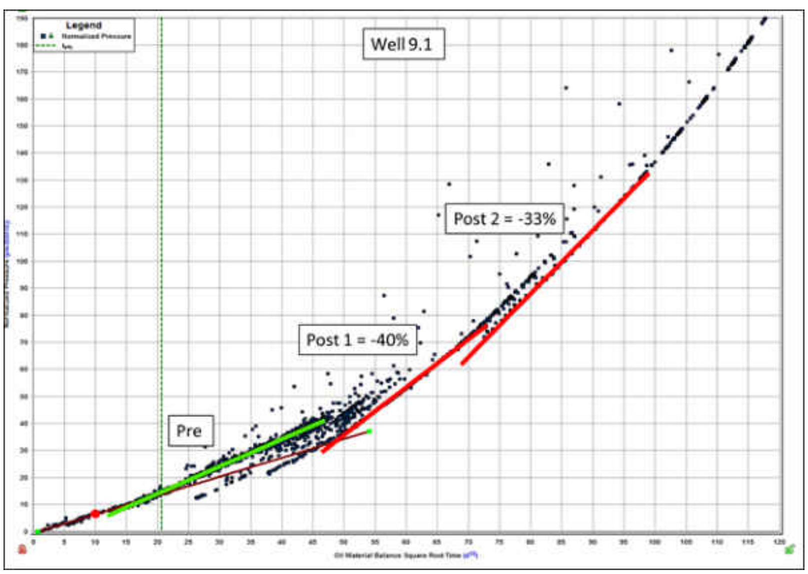

Figure 81. Well 9.1 superposition time plot.

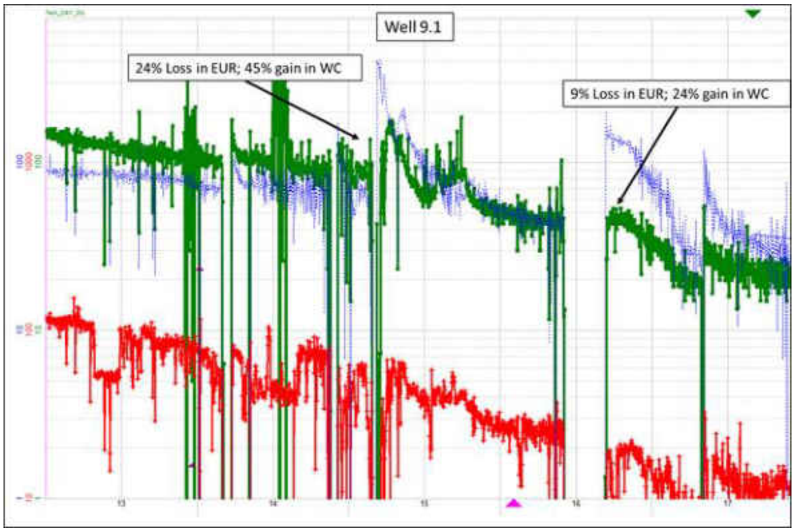

Figure 82. Well 9.1 production chart.

Spacing Unit #10 (15-22-163N-100W)

Spacing unit 10 has 8 wells, 4 Bakken and 4 Three Forks, spaced at 660 feet. Two 2nd generation wells were placed in the middle of the spacing unit, ~ 1,180 feet east of the parent well. Approximately two years later, 5 – 3rd generation wells were completed, with 3 wells 460 feet (closest) east of well 10.2, 1 well 780 feet west of the parent, and 1 well in between the parent and 2nd generation well. As expected, the 3rd generation well completed between the parent and 2nd generation well is the poorest performer, with the highest water cut and GOR, and lowest EUR. An enhanced completion design was tested on well 10.3 (Three Forks). A total of 20% more fluid per foot and 130% more proppant per foot were applied, relative to typical 2nd generation completion designs. Interestingly, well 10.3 significantly underperformed its offset Bakken counterpart (10.2). The 30 day IP for well 10.3 was 60% lower than 10.2, its 12 month cumulative per lateral foot was 44% lower, and water cut 16% higher. Although well 10.2 is closer to the parent well, these metrics demonstrate that larger fracs don't always yield more reserves. The higher water cut on 10.3 is likely a combination of fractures extending down into the second bench of the Three Forks, and SRV overlap with the parent well.

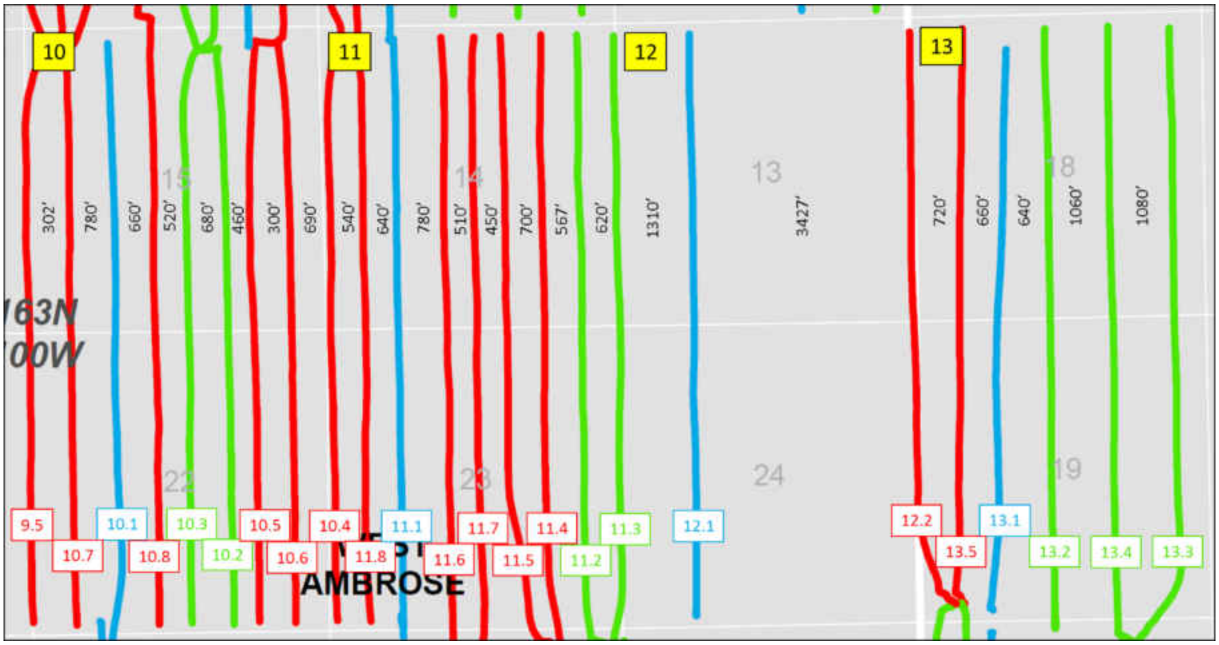

Figure 83. Spacing units 10 – 13.

Table 8. Spacing unit 10 frac hit metrics.

Well #	Min Distance to Offset Frac	Delta T - First Prod to Offset Frac	WC % Change	EUR % Change (MBO)	Ac Root K Reduction %	Min Distance to Offset Frac_2	WC % Change_2	EUR % Change_2 (MBO)	Ac Root K Reduction %_2
10.10	1180	1084	28.57	-29.94	18.77	660	31.67	-18.38	39.08
10.20	460	591	25.00	-52.26	37.62	(Empty)	(Empty)	(Empty)	(Empty)
10.30	520	581	11.59	-18.65	38.34	(Empty)	(Empty)	(Empty)	(Empty)

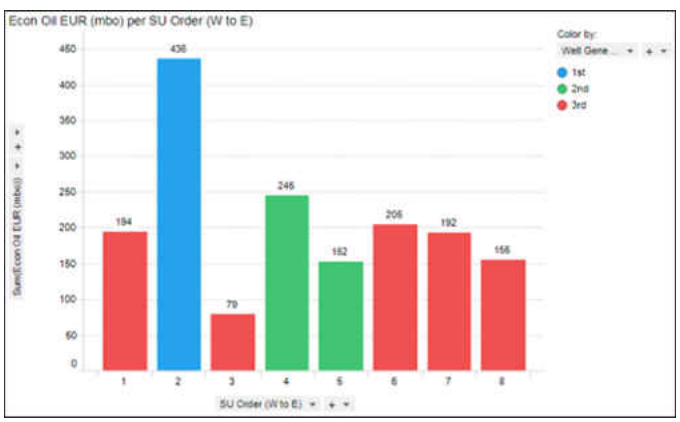

Figure 84. Spacing unit 10 well order from west (left) to east (right) and EURs.

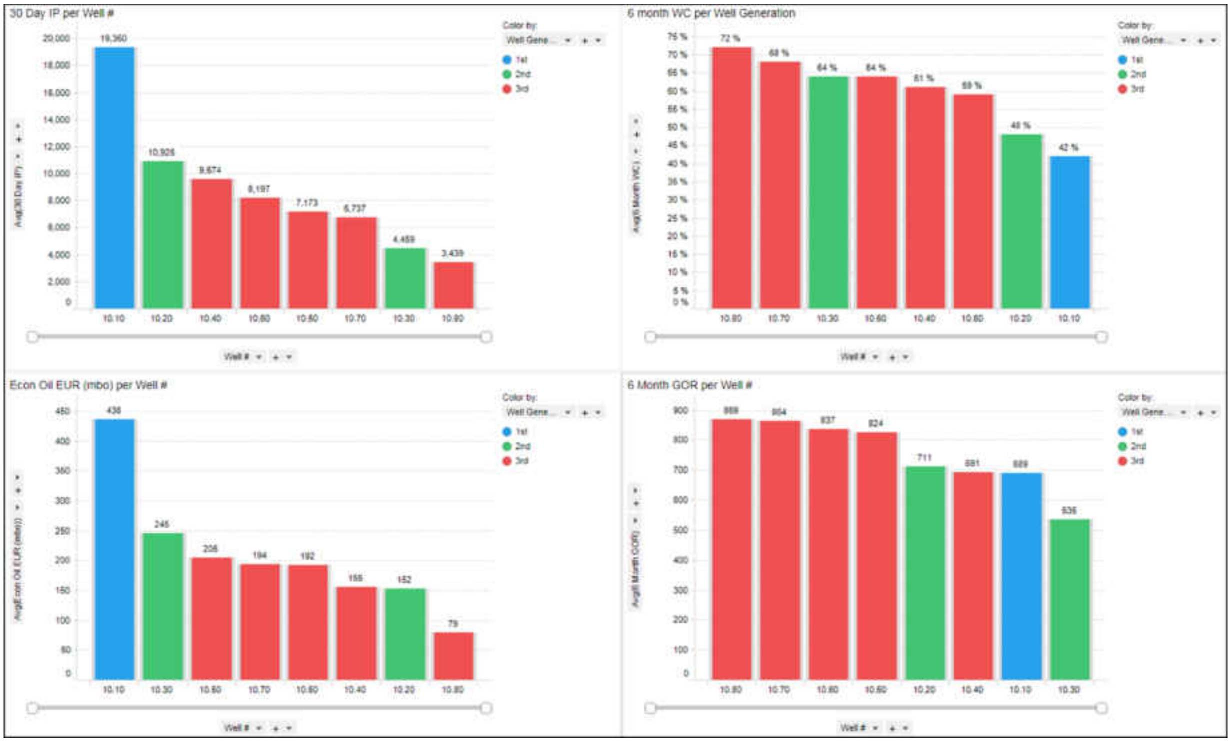

Figure 85. Spacing unit 10 production performance by well.

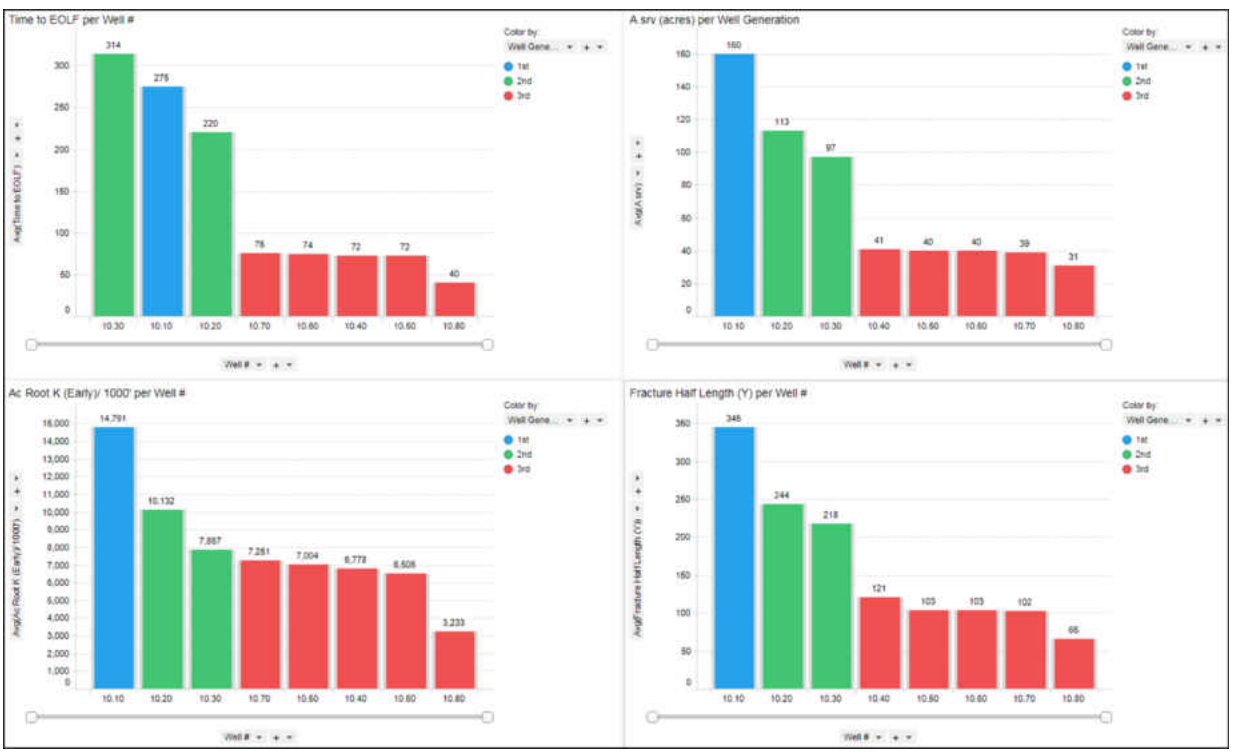

Figure 86. Spacing unit 10 reservoir and completion metrics.

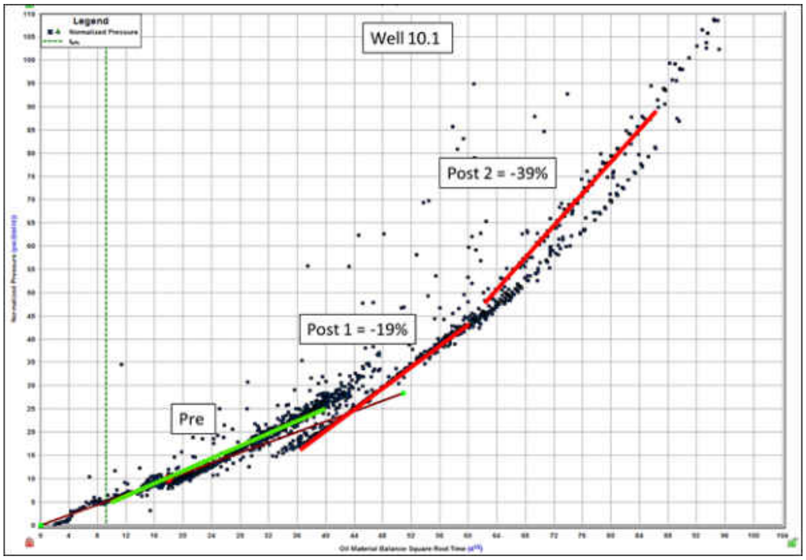

Figure 87. Well 10.1 superposition time plot.

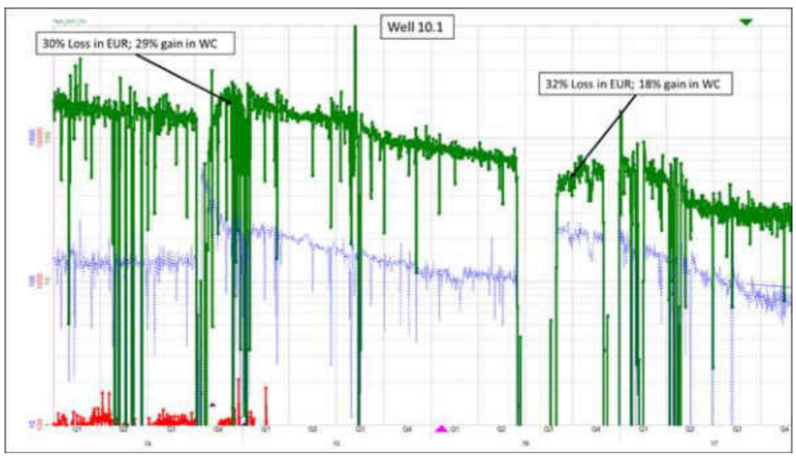

Figure 88. Well 10.1 production chart.

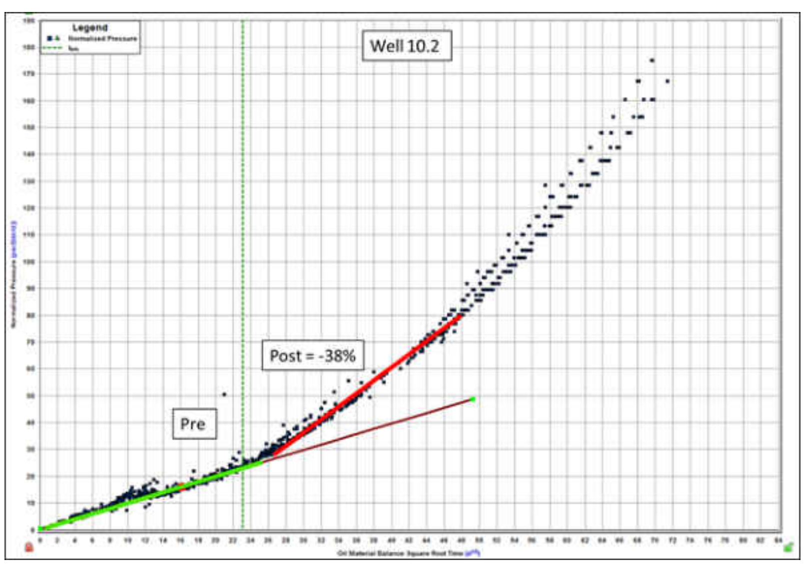

Figure 89. Well 10.2 superposition time plot.

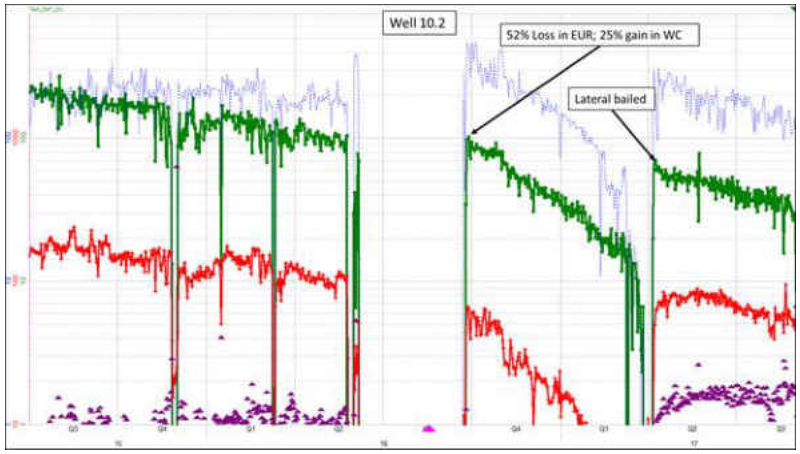

Figure 90. Well 10.2 production chart.

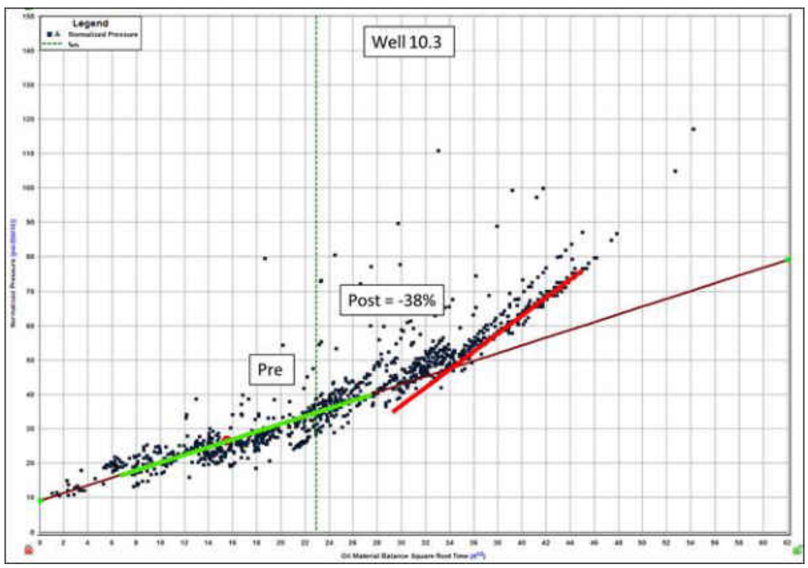

Figure 91. Well 10.3 superposition time plot.

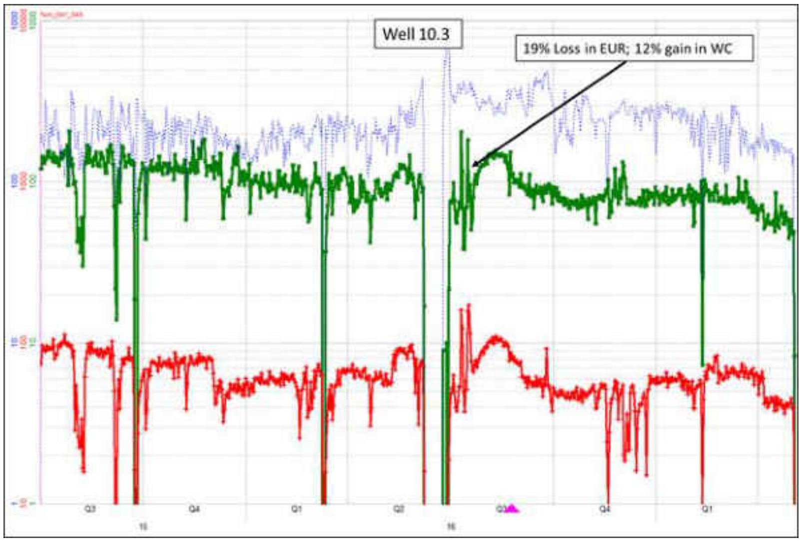

Figure 92. Well 10.3 production chart.

Spacing Unit #11 (14-23-163N-100W)

Spacing unit 11 has 8 wells, 4 Bakken and 4 Three Forks, spaced at 660 feet. Two 2nd generation wells were completed 3 years after the parent well. Wells 11.2 and 11.3 were placed on the opposite side of the spacing unit, ~3,000 feet east of the parent well. Approximately one year later, 4 – 3rd generation wells were completed in between the western most 2nd generation well (11.2) and the parent well. The last well was completed 6 months later, and placed 640 feet west of the parent well. No communication was detected between the parent and second generation wells, indicating pressure depletion had not propagated the eastern portion of the spacing unit. The 30 day IP for well 11.2 was only 12% less than well 11.1. In contrast, 2nd generation wells completed directly offset of a parent well experienced a ~ 50% reduction in 30 day IP relative to the parent. During completion operations on well 11.3, the liner parted. Complications have resulted in poor well performance. The lateral was bailed on well 11.2 after 3rd generation offset fracs. Wells 11.6 and 11.8 were completed 6 months apart. Since parent well production was still erratic from the 11.6 offset frac, the impact of the 11.8 frac hit on 11.1 was not able to be determined.

Table 9. Spacing unit 11 frac hit metrics.

Well #	Min Distance to Offset Frac	Delta T - First Prod to Offset Frac	WC % Change	EUR % Change (MBO)	Ac Root K Reduction %	Min Distance to Offset Frac_2	WC % Change_2	EUR % Change_2 (MBO)	Ac Root K Reduction %_2
11.10	780	1455	39.58	-21.86	32.00	640	15.71	(Empty)	41.97
11.20	567	373	35.85	-23.31	49.18	(Empty)	(Empty)	(Empty)	(Empty)

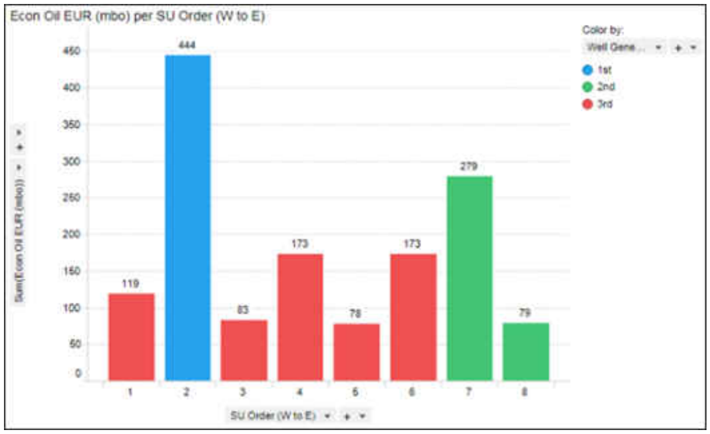

Figure 93. Spacing unit 11 well order from west (left) to east (right) and EURs.

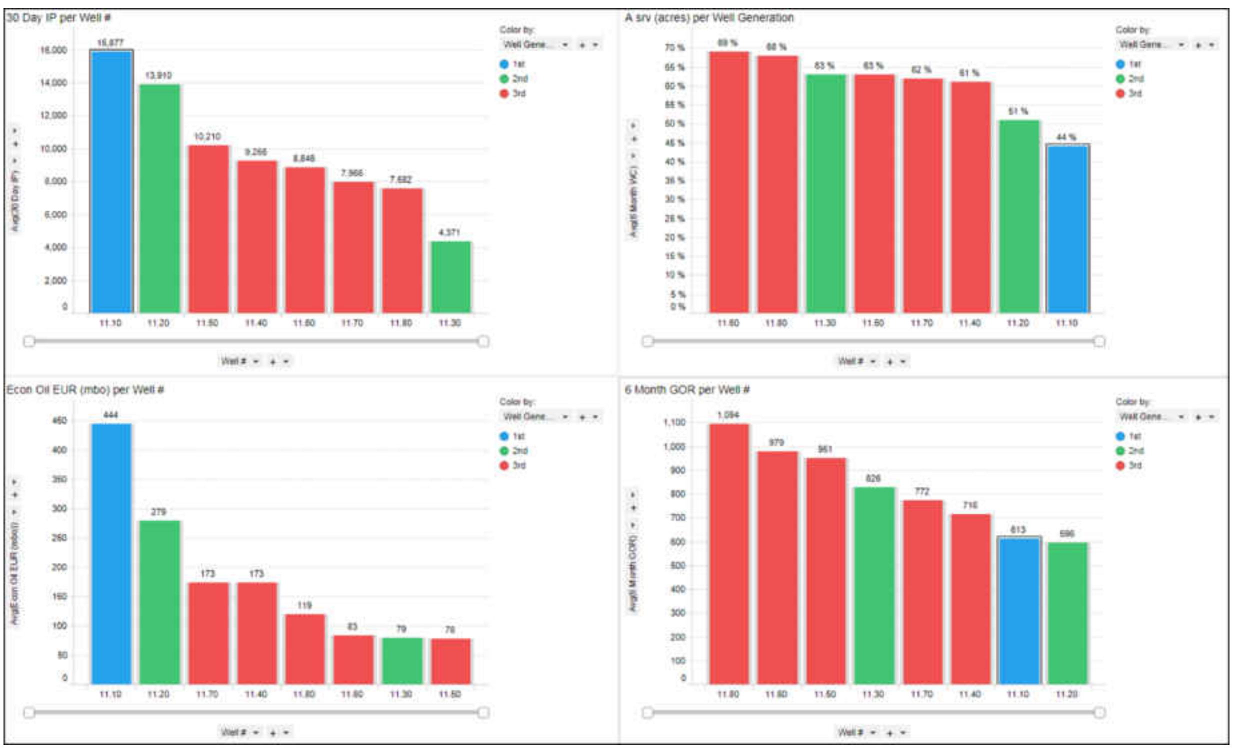

Figure 94. Spacing unit 11 production performance by well.

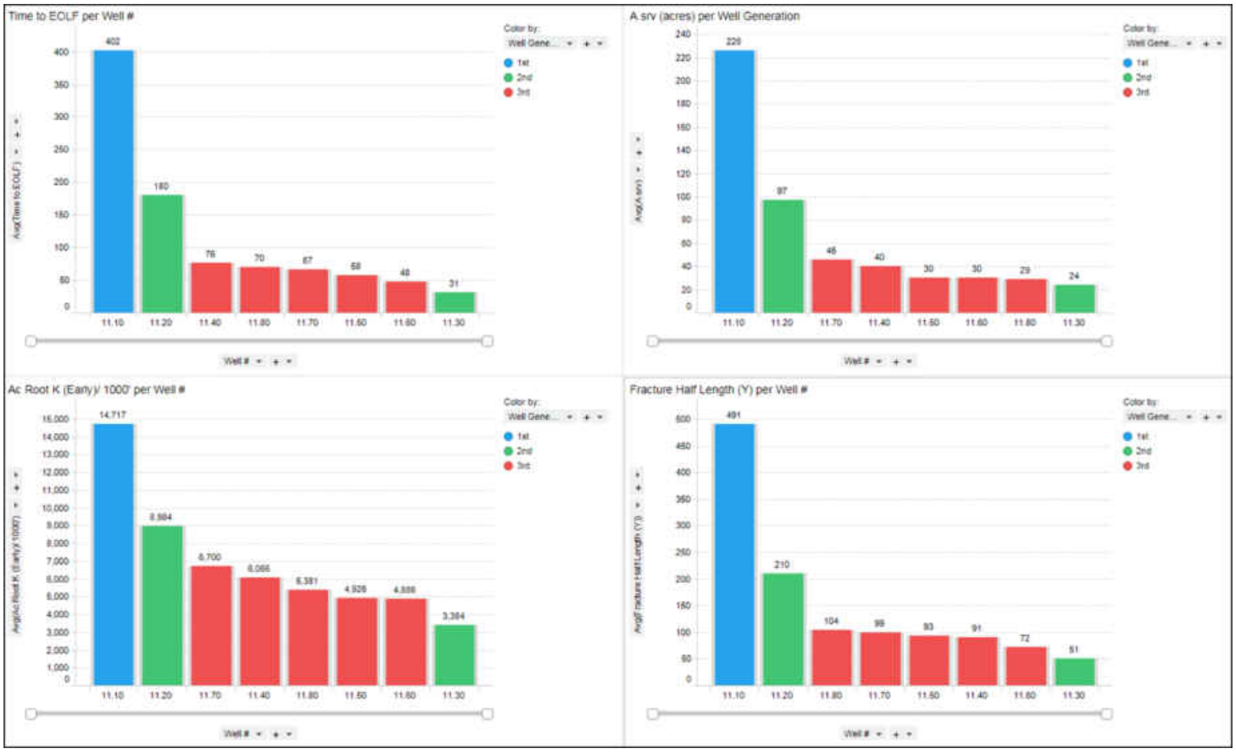

Figure 95. Spacing unit 11 reservoir and completion metrics.

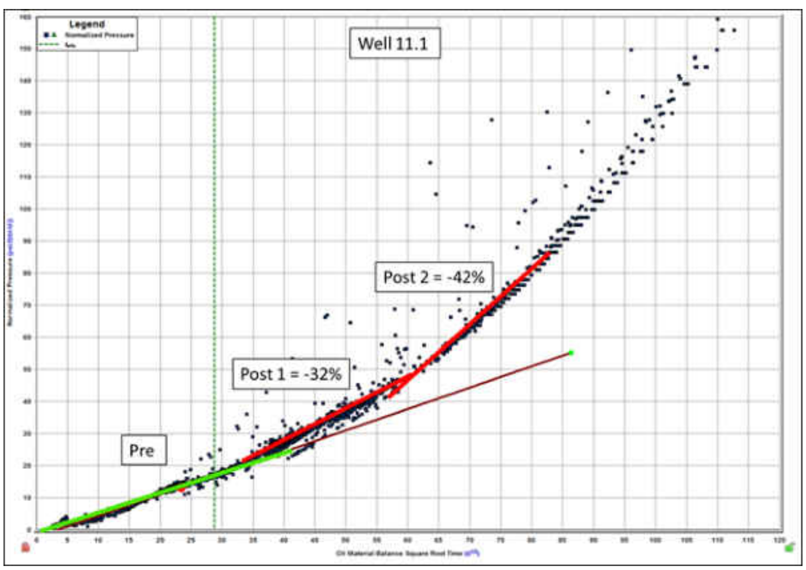

Figure 96. Well 11.1 superposition time plot.

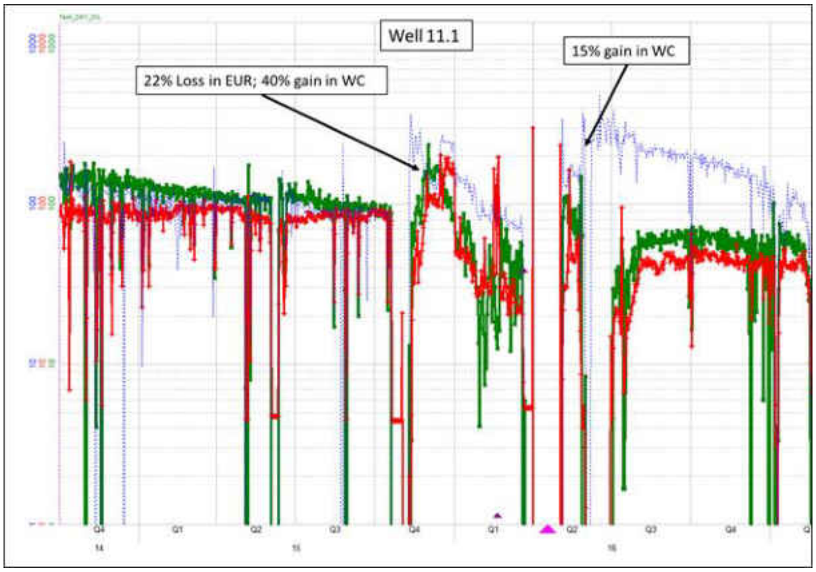

Figure 97. Well 11.1 production chart.

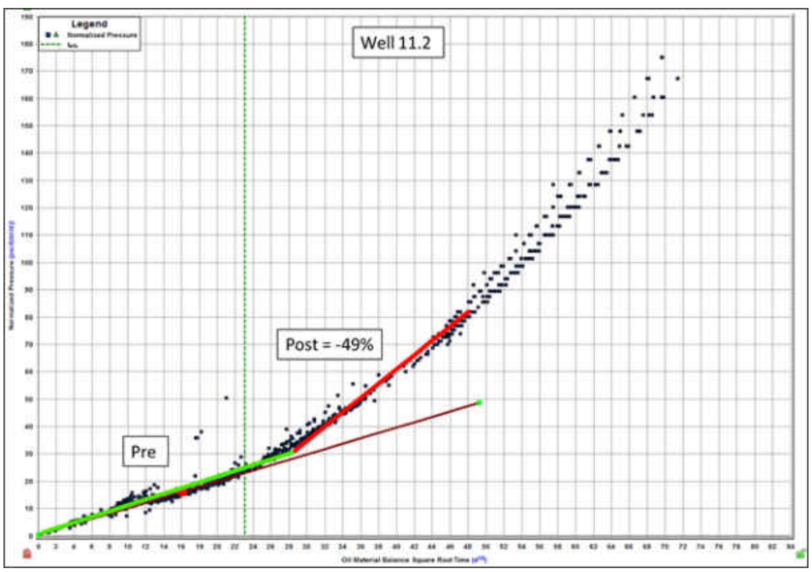

Figure 98. Well 11.2 superposition time plot.

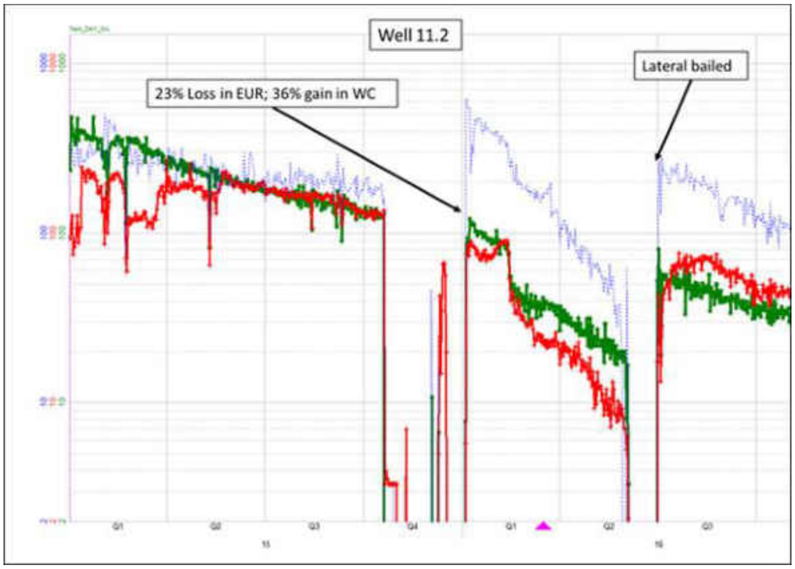

Figure 99. Well 11.2 production chart.

Spacing Unit #12 (13-24-163N-100W)

Spacing unit 12 contains 2 Three Forks wells separated by 3,400 feet. Well 12.2 lies on the eastern section line, and was completed 5.5 years after well 12.1. No communication was observed between the two wells. The western section line well (11.3) is 1,300 feet away from well 12.1, and was completed 3.5 years after the parent well. A corresponding frac hit was observed, with a 7% loss in EUR, a 19% decrease in $A_c\sqrt{k}$, and a 35% increase in water cut. The parent well received an initial bump in oil rate before eventually returning to normal trend.

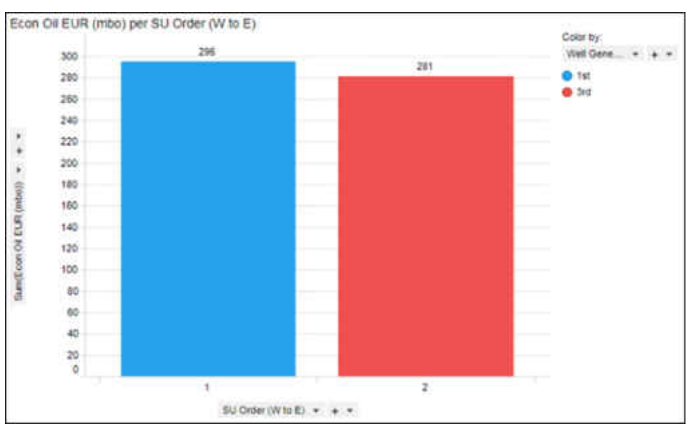

Figure 100. Spacing unit 12 well order from west (left) to east (right) and EURs.

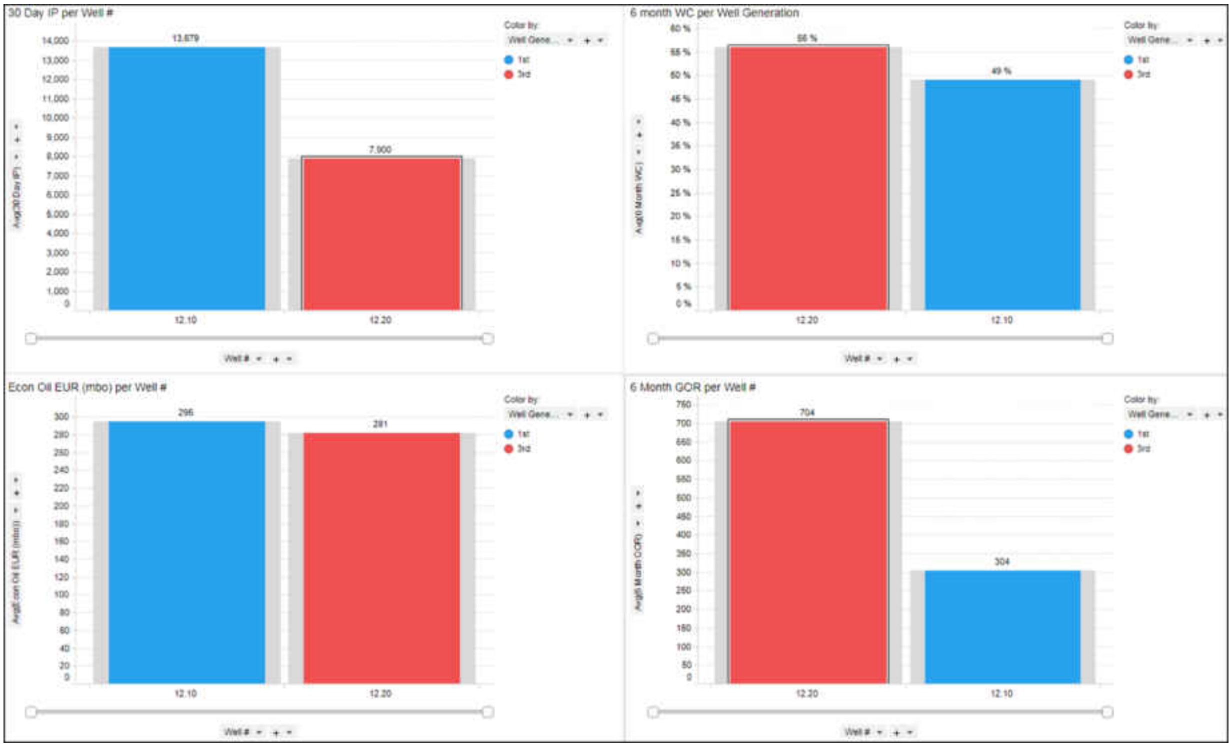

Figure 101. Spacing unit 12 production performance by well.

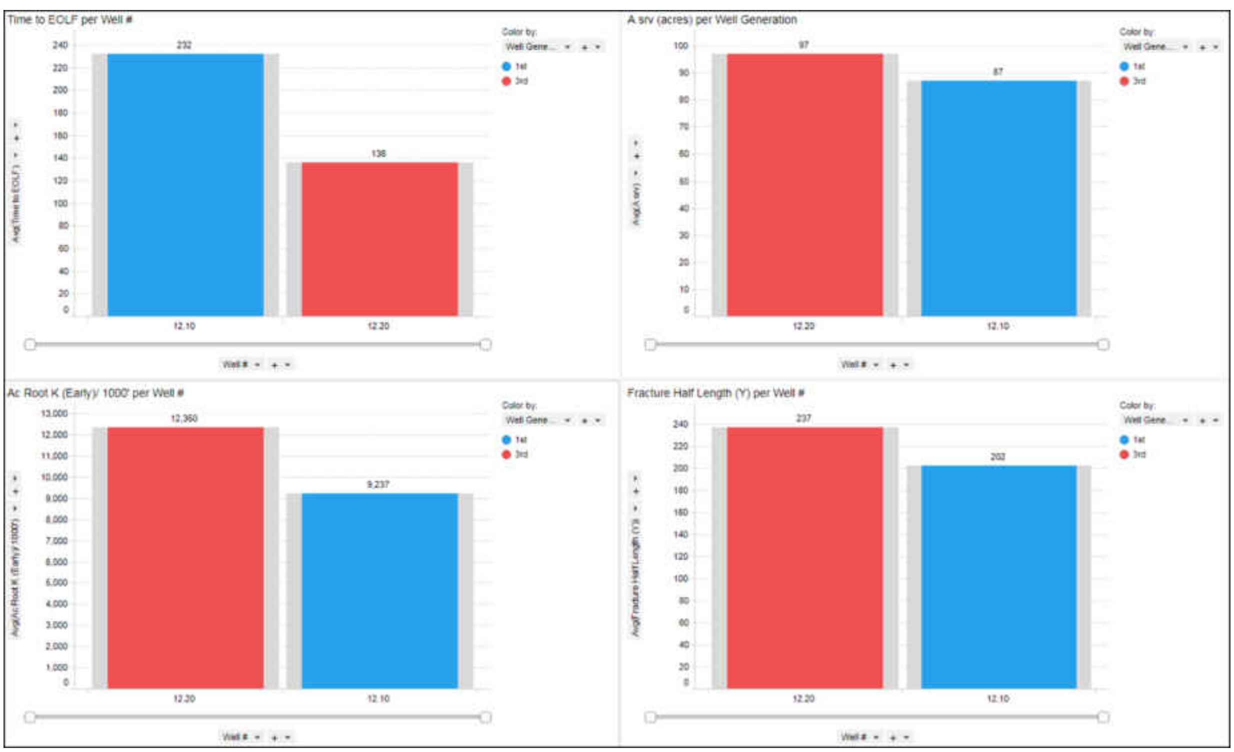

Figure 102. Spacing unit 12 reservoir and completion metrics.

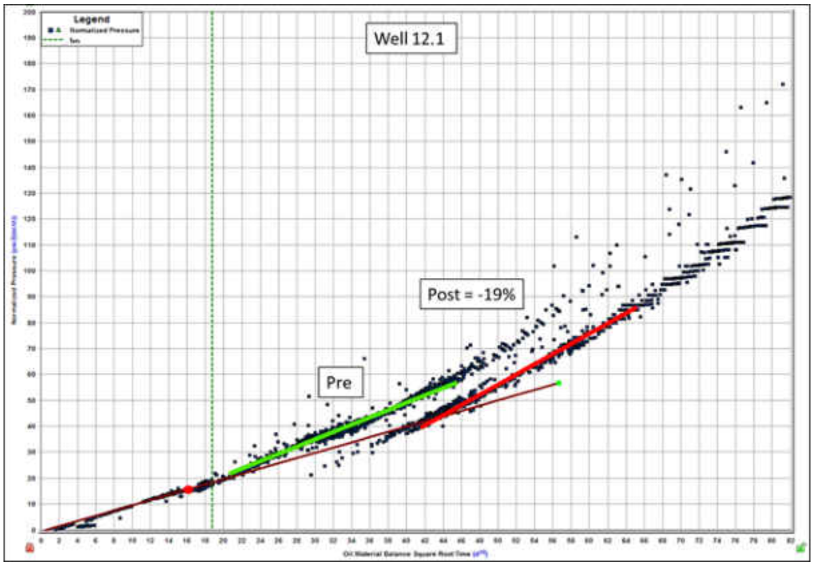

Figure 103. Well 12.1 superposition time plot.

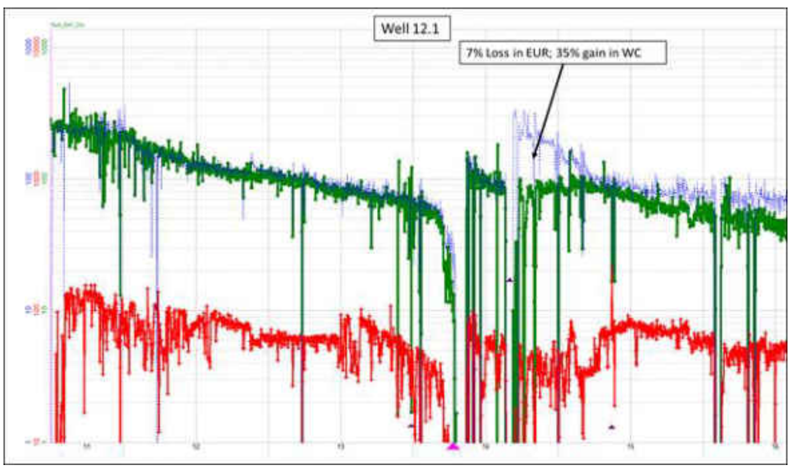

Figure 104. Well 12.1 production chart.

Spacing Unit #13 (18-19-163N-99W)

Spacing unit 13 includes 5 total wells, 4 Three Forks and 1 Bakken. Wells 13.1, 13.2 and 13.5 are spaced at 660 feet, while wells 13.4 and 13.4 are spaced at 1,320 feet. All three 2nd generation wells were completed 2 years after the parent well, with the closest offset being 640 feet east of the parent well. Well 13.5 was completed 4 years later, directly offset to the parent well. Well 13.5 was completed at the same time as the western section well (12.3). All 3rd generation wells show strong well performance. Well 13.3 had a higher 30 day IP than the parent well and a comparable EUR, once again demonstrating the benefits of a larger completion design in areas without reservoir depletion. Well 13.1 experienced less of a frac hit from well 13.5 than from 13.2, despite being completed nearly 6 years after the parent. In addition, well 13.2 experienced a positive frac hit from well 3.5.

Table 10. Spacing unit 13 frac hit metrics.

Well #	Min Distance to Offset Frac	Delta T - First Prod to Offset Frac	WC % Change	EUR % Change (MBO)	Ac Root K Reduction %	Min Distance to Offset Frac_2	WC % Change_2	EUR % Change_2 (MBO)	Ac Root K Reduction %_2	Delta T - Offset Frac_1 to...	Delta T - First Prod to Offset...
13.10	640	736	62.07	-27.51	44.75	660	57.14	-12.06	10.95	1553	2289
13.20	1300	1520	9.26	16.09	12.06	(Empty)	(Empty)	(Empty)	(Empty)	(Empty)	(Empty)

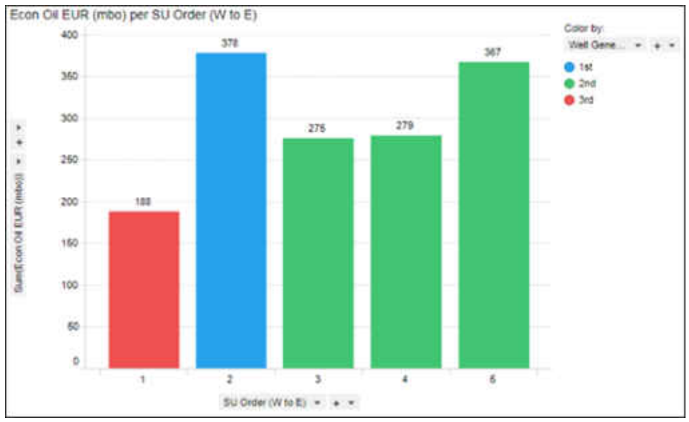

Figure 105. Spacing unit 13 well order from west (left) to east (right) and EURs.

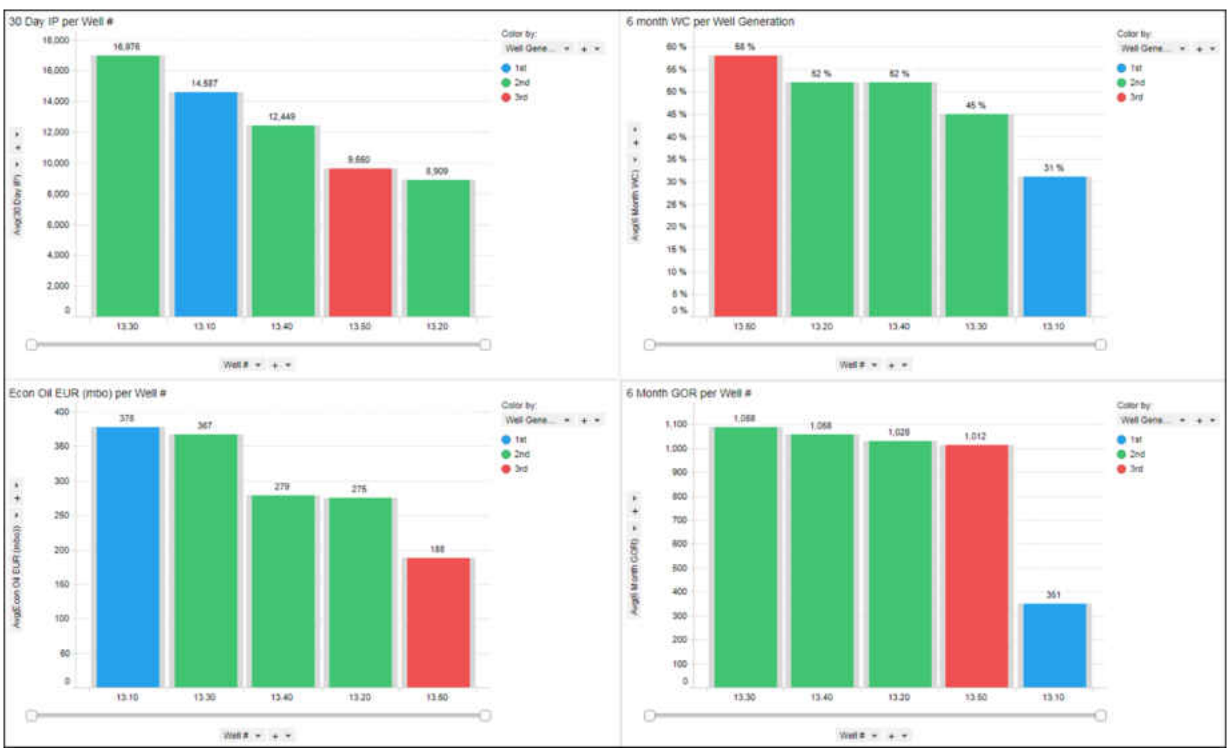

Figure 106. Spacing unit 13 production performance by well.

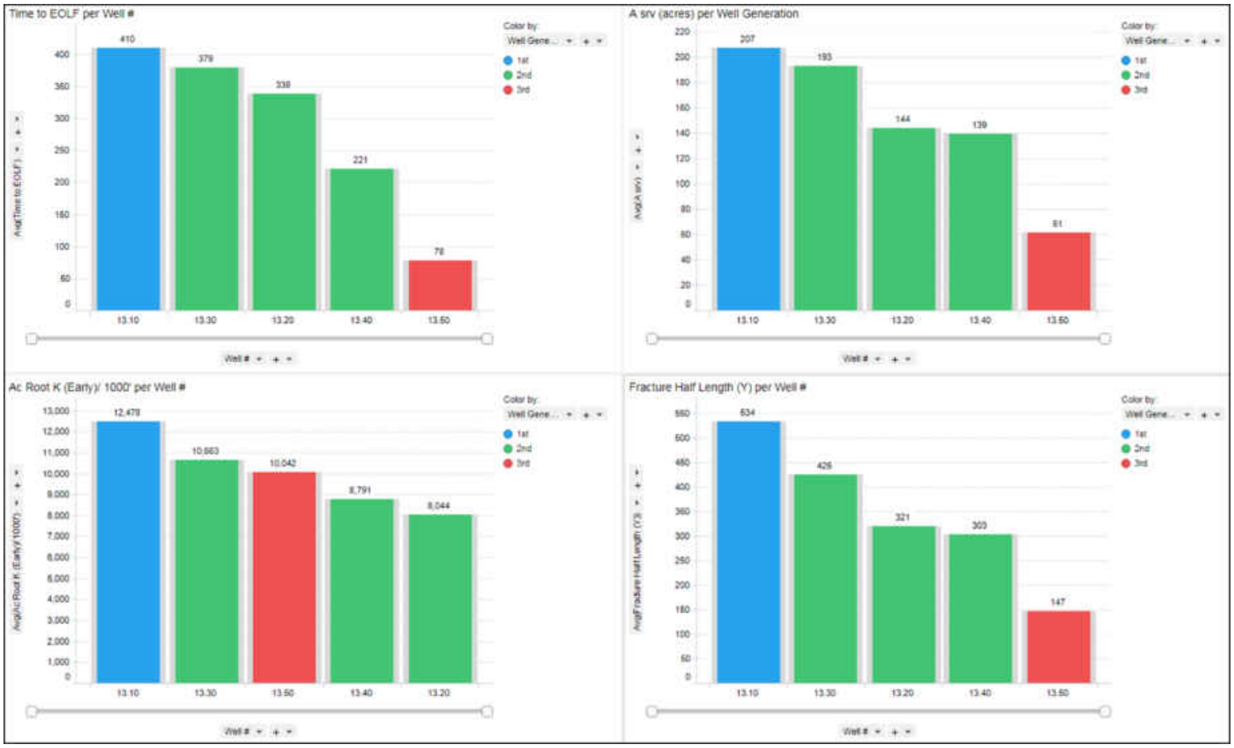

Figure 107. Spacing unit 13 reservoir and completion metrics.

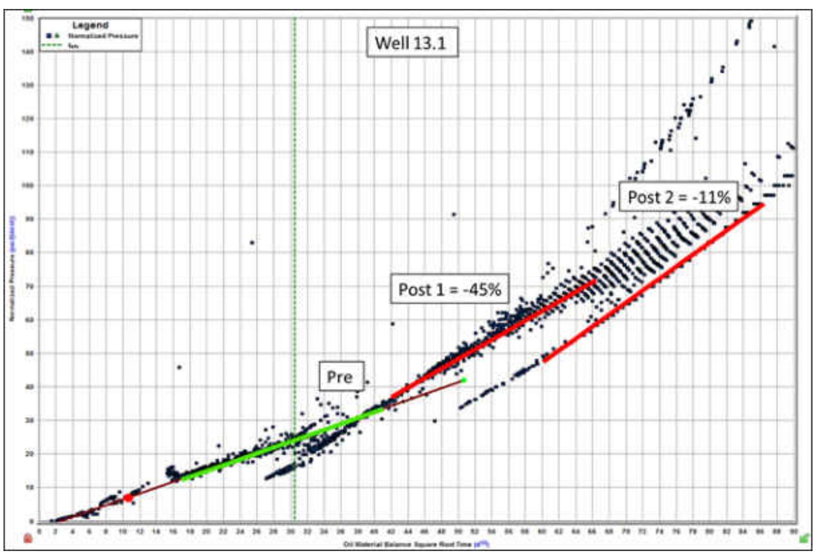

Figure 108. Well 13.1 superposition time plot.

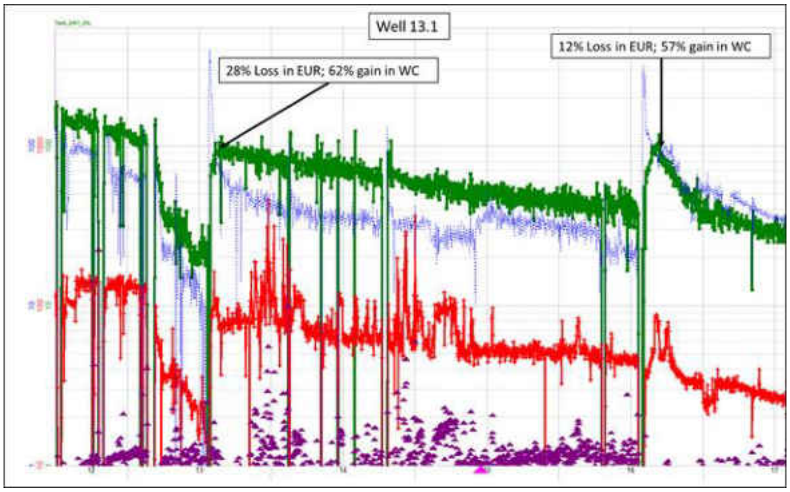

Figure 109. Well 13.1 production chart.

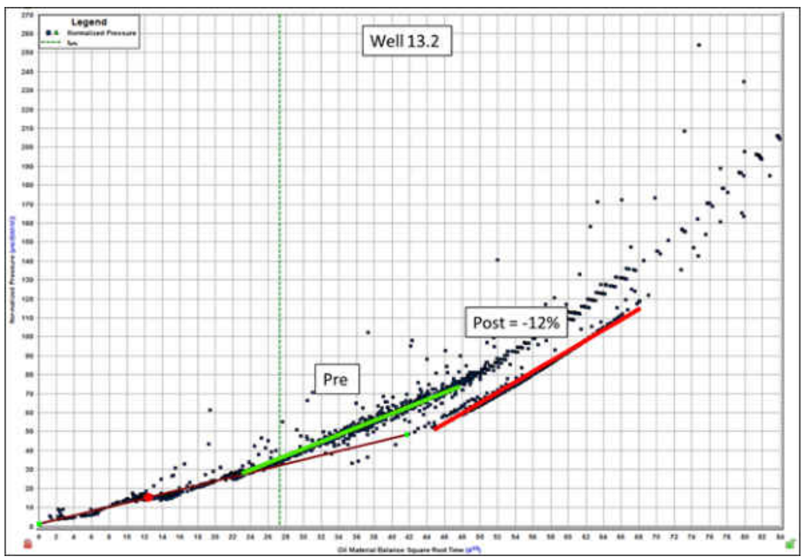

Figure 110. Well 13.2 superposition time plot.

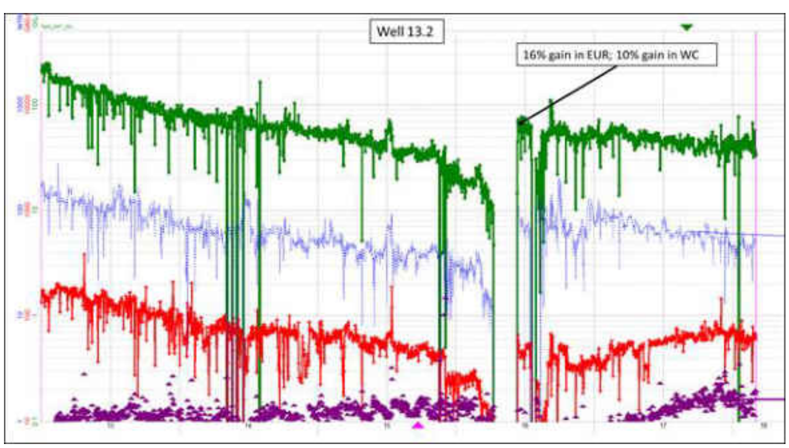

Figure 111. Well 13.2 production chart.

Spacing Unit #14 (17-20-163N-99W)

Spacing unit 14 contains just one producing well, and 4 DUCs. Well 14.1 utilized an open hole, 10 stage sleeve completion design. Production decline has remained consistent over the life of this well. The nearest offset is well 13.3, which is located 2,040 feet to the west. This well was completed 2 years after well 14.1. Despite the distance, minor communication was observed between the two wells, with a 6% loss in EUR, a 10% reduction in $A_c\sqrt{k}$, and no change in water cut.

Figure 112. Spacing units 14 & 15.

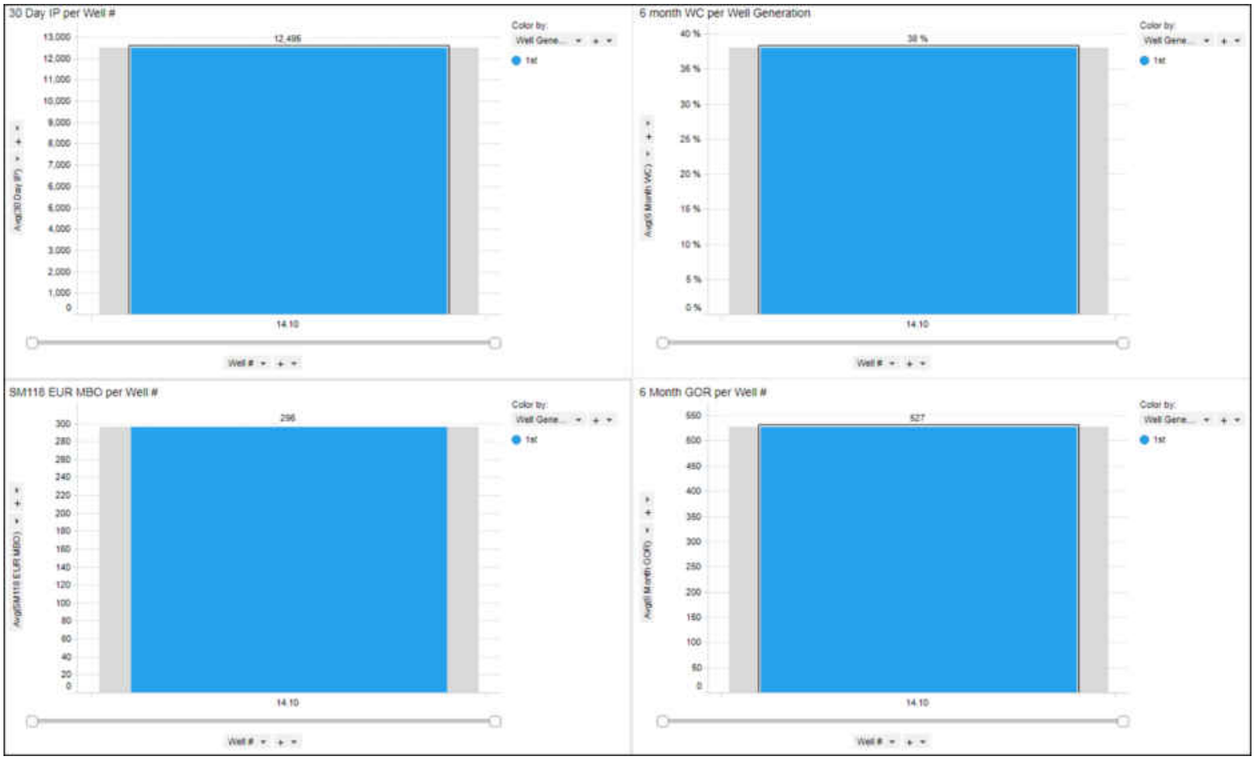

Figure 113. Spacing unit 14 production performance by well.

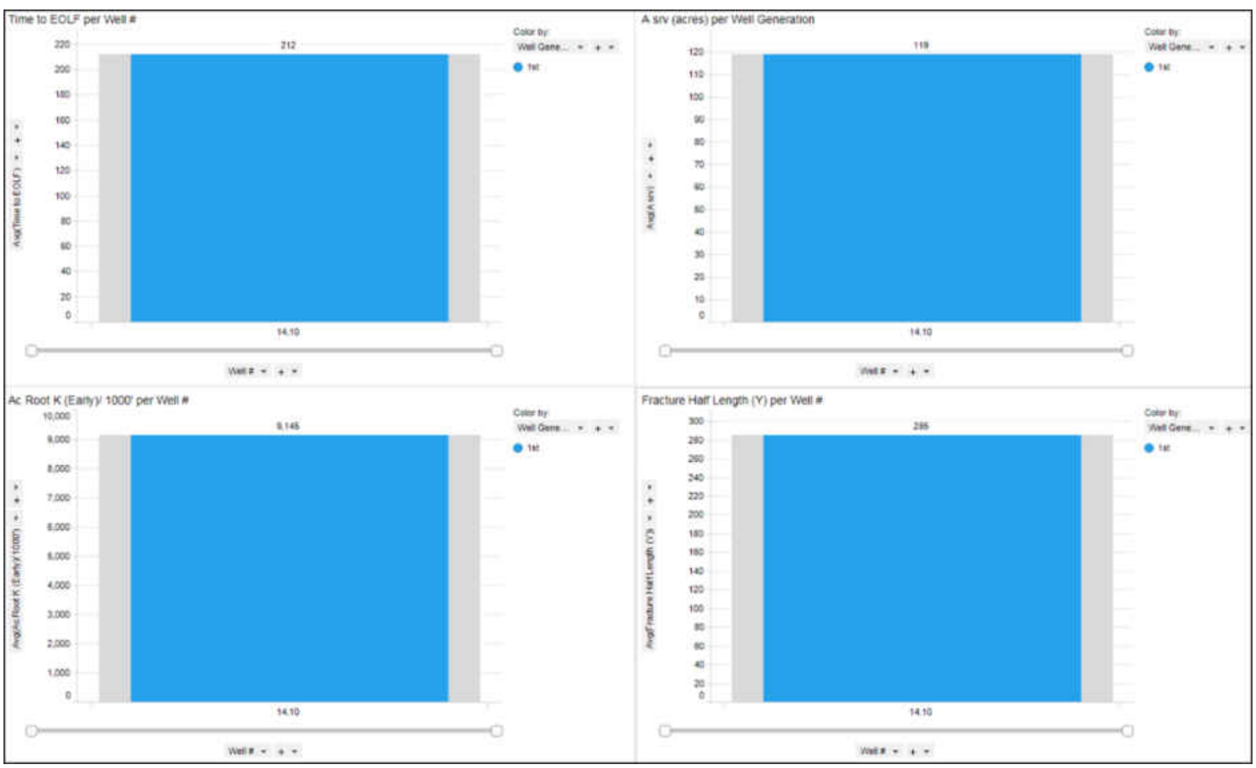

Figure 114. Spacing unit 14 reservoir and completion metrics.

Spacing Unit #15 (16-21-163N-99W)

Spacing unit 15 consists of 3 producing wells, 2 Three Forks and 1 Bakken, and 5 DUCS. The wells are spaced at 660 feet. The two 2nd generation wells directly offset the parent well to the east. Well 5.3 was completed using an MSSB design. These wells were completed 3 years after the parent well. Since the offset fracs, the parent well has experienced severe sand issues. Wells 15.3 and 15.3 have had heavy sand issues since they were brought online. Accurate assessment of the offset frac was not feasible due to extremely erratic production. The lateral was bailed on well 15.1 after the offset fracs. The lateral was also bailed on well 15.2, but neither job provided any benefit.

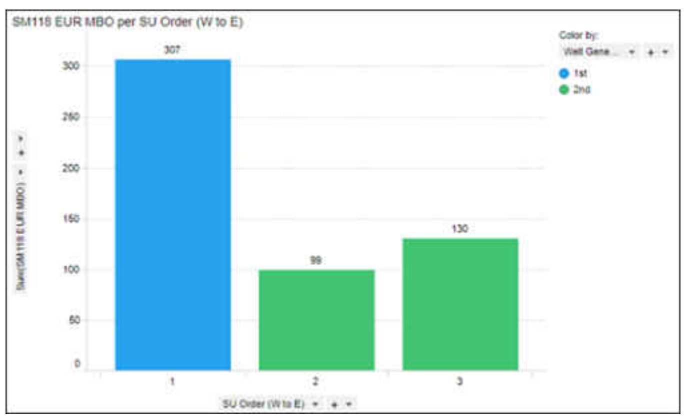

Figure 115. Spacing unit 15 well order from west (left) to east (right) and EURs.

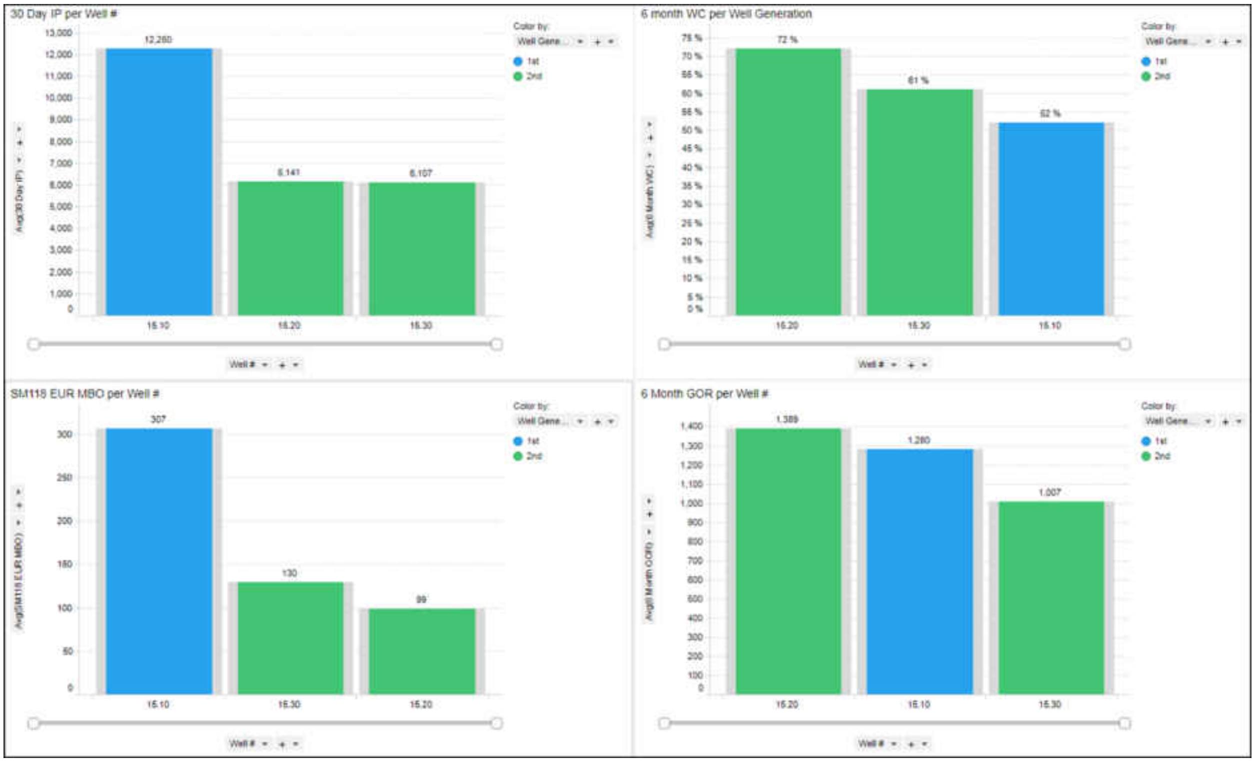

Figure 116. Spacing unit 15 production performance by well.

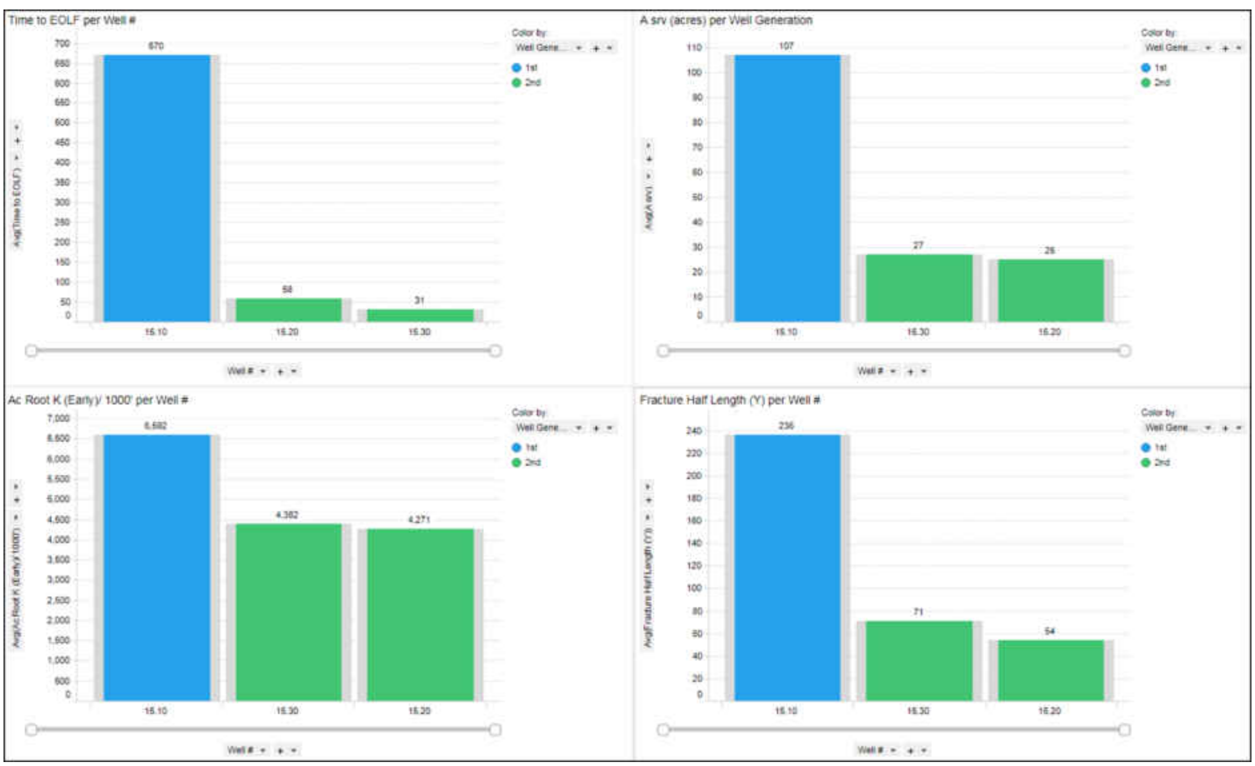

Figure 117. Spacing unit 15 reservoir and completion metrics.

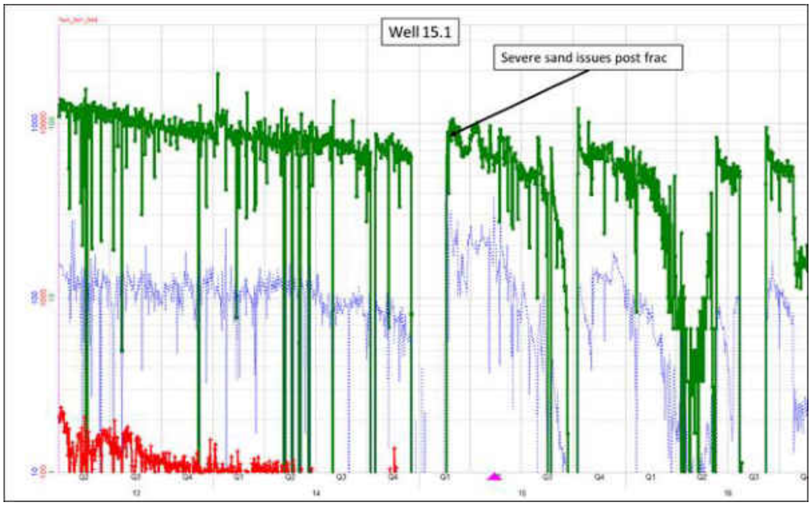

Figure 118. Well 15.1 production chart.

Spacing Unit #16 & 17 (28-33 & 27-34-163N-100W)

Spacing units 16 and 17 each have one spacing unit. As such, they have not experienced any offset well communication. Decline curves have remained steady over the duration of their production history.

Figure 119. Spacing units 16 – 18.

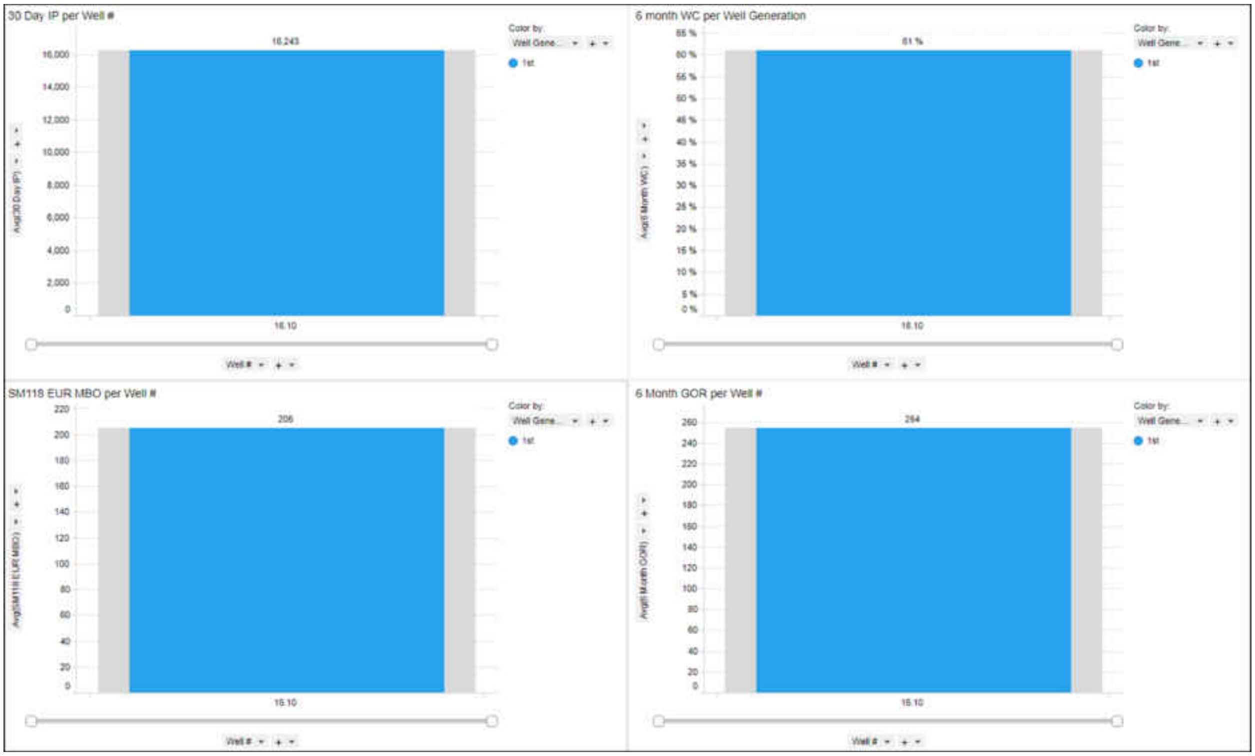

Figure 120. Well 16.1 production performance.

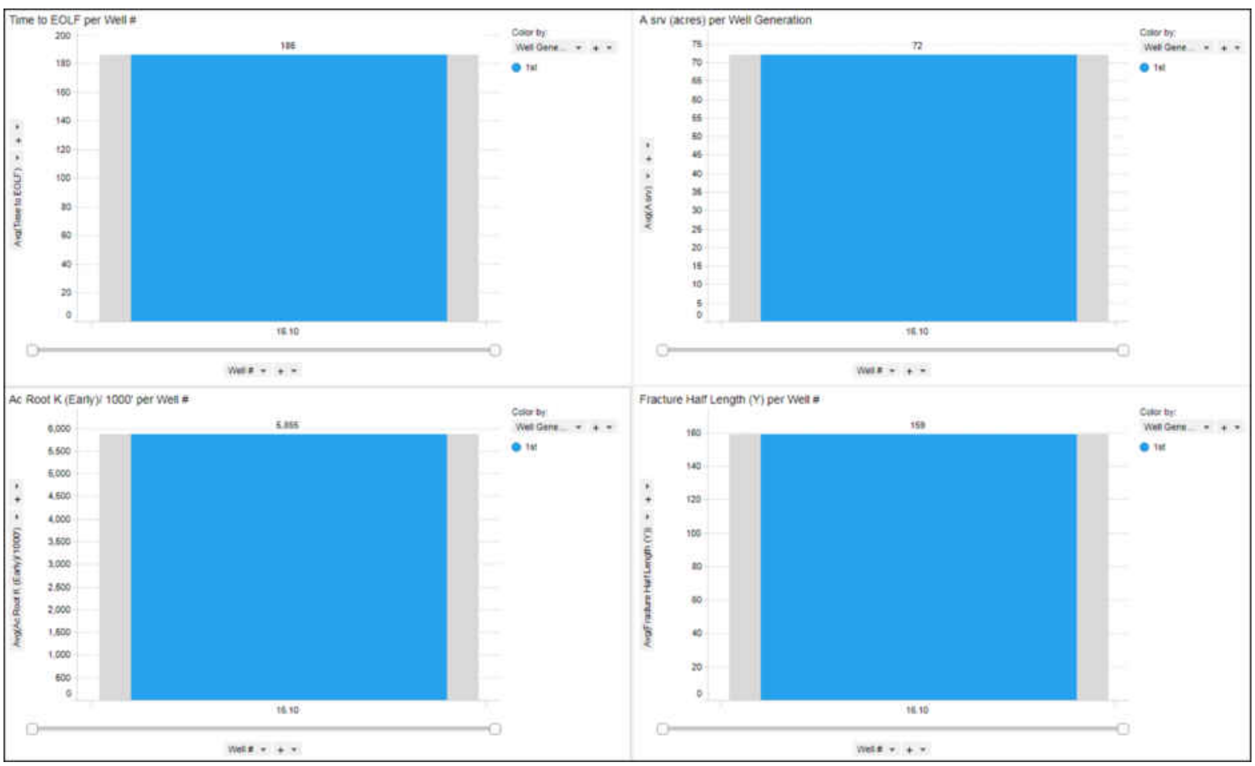

Figure 121. Well 16.1 reservoir and completion metrics.

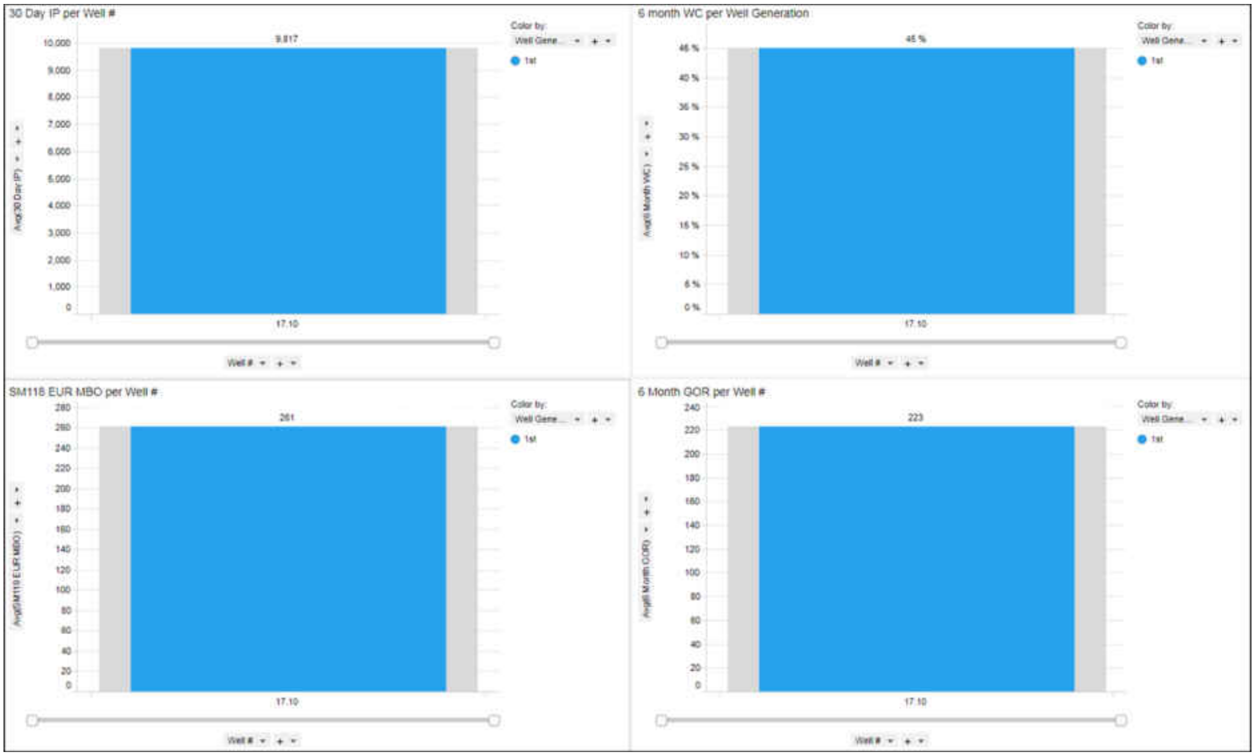

Figure 122. Well 17.1 production performance.

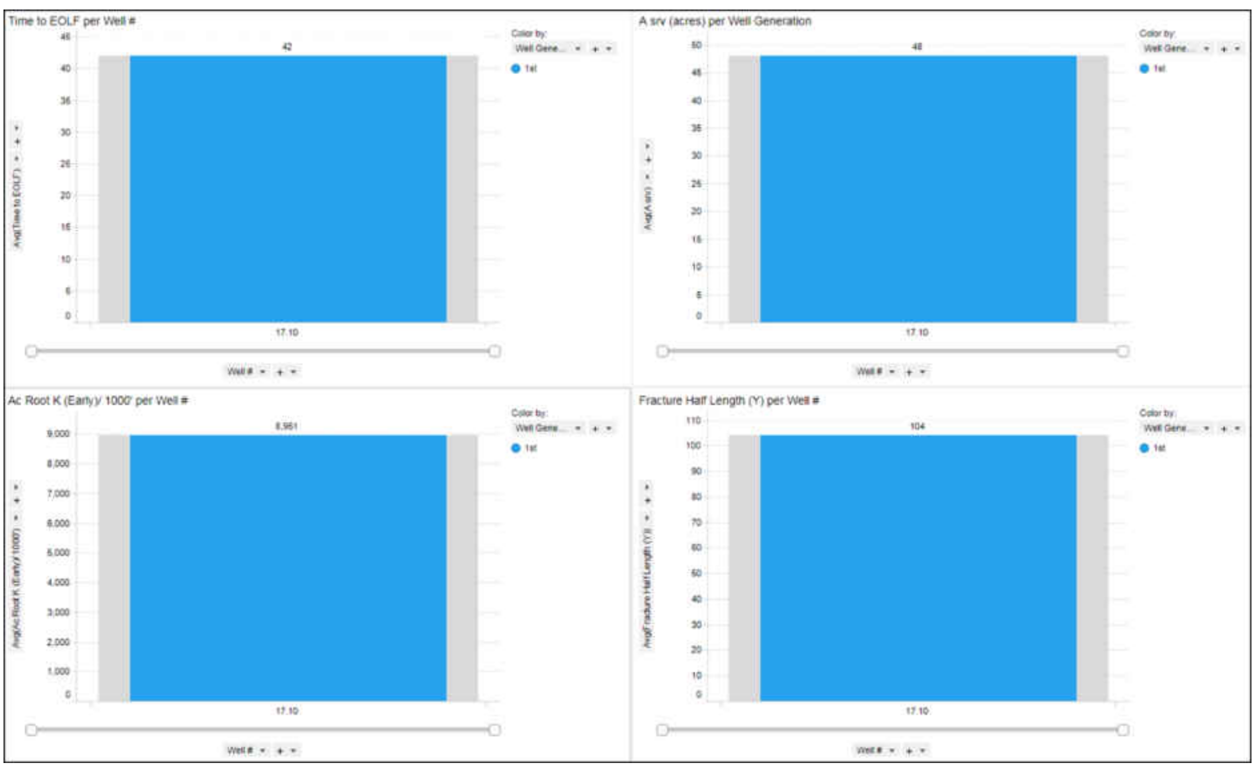

Figure 123. Well 17.1 reservoir and completion metrics.

Spacing Unit #18 (16-21-163N-100W)

Spacing unit 18 contains 7 producing wells, 4 Three Forks and 3 Bakken, spaced at 660 feet. The parent well is located on the far western side of the spacing unit, and is unbounded to the west. Two 2nd generation wells were added 4 years later, on the far eastern side of the spacing unit. Although separated by 2,650 feet, minor communication was observed on the parent well when the 2nd generation wells were completed. Four 3rd generation wells were completed one year after the 2nd generation wells. These wells were placed between the 1st and 2nd generation wells. The 30 day IP of well 18.2 nearly double that of the parent well, and also has the highest EUR in the spacing unit. The well took a big frac hit during 3rd generation completions. The lateral was bailed, but EUR remained 45% lower than its pre frac level. Similar to well 10.3 in spacing unit 10, a larger frac design was trialed on well 18.3, using 100% more fluid per foot and 170% more proppant per foot relative to normal 2nd generation completion design. Well 18.3 had a 55% lower 30 day IP and 11% higher water cut relative to its direct offset (18.2), reaffirming that larger completion designs are not appropriate in Gooseneck. The 3rd generation well directly offset to the parent (18.6) utilized a MSSB completion design. Similar to other wells in the study area, 18.6 is the lowest performing well in the spacing unit. Interestingly, despite being only 780 feet apart, very little detriment was observed on well 18.1 when 18.6 was completed. The well experienced a 53% increase in water cut, but only a 2% decrease in EUR. This may be partially attributed to the ineffectiveness of the MSSB design.

Table 11. Spacing unit 18 frac hit metrics.

Well #	Min Distance to Offset Frac	Delta T - First Prod to Offset Frac	WC % Change	EUR % Change (MBO)	Ac Root K Reduction %	Min Distance to Offset Frac_2	WC % Change_2	EUR % Change_2 (MBO)	Ac Root K Reduction %_2	Delta T - Offset Frac_1 to...	Delta T - First Prod to Offset...
18.10	2646	1499	0.00	-2.39	17.42	780	52.78	-2.28	35.80	428	1927
18.20	640	377	42.11	-45.82	65.65	(Empty)	(Empty)	(Empty)	(Empty)	(Empty)	(Empty)

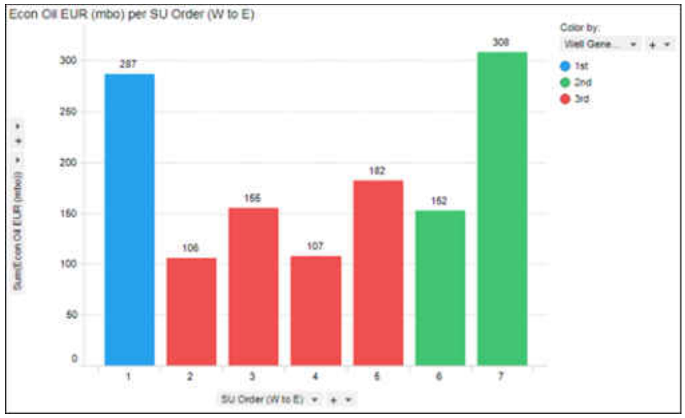

Figure 124. Spacing unit 18 well order from west (left) to east (right) and EURs.

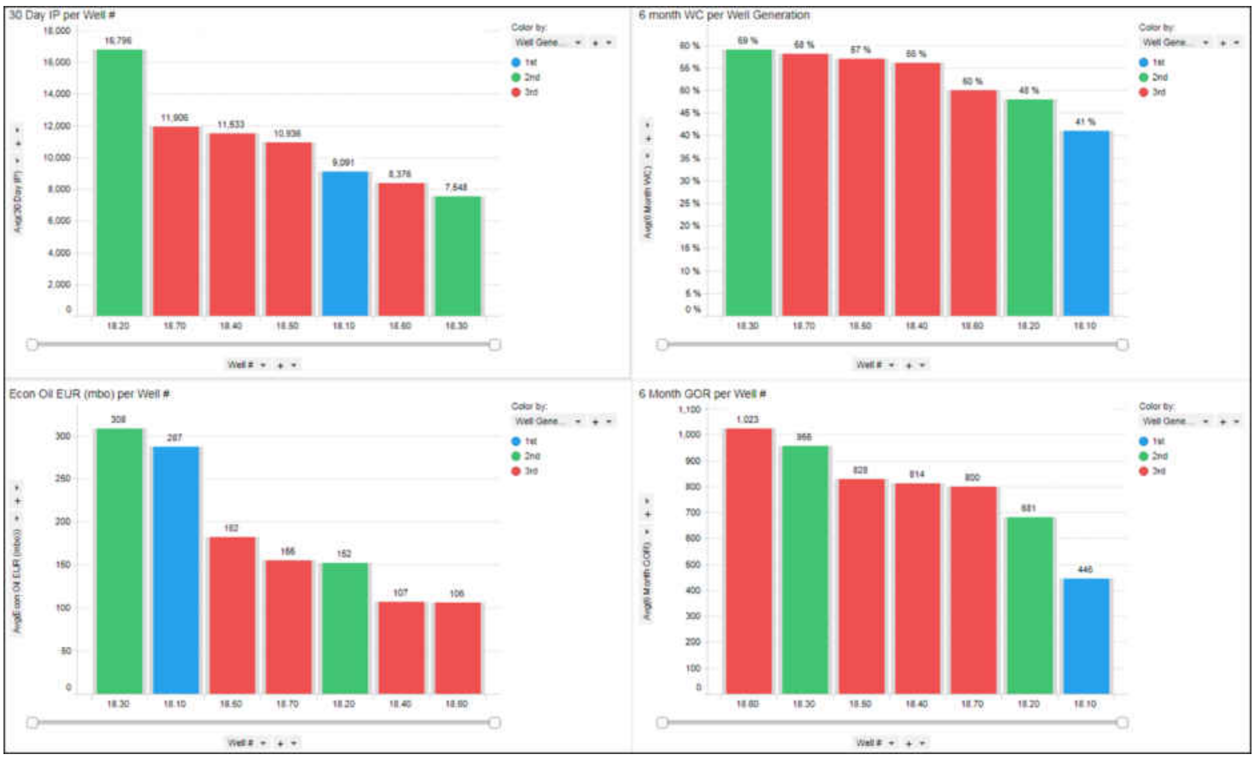

Figure 125. Spacing unit 18 production performance by well.

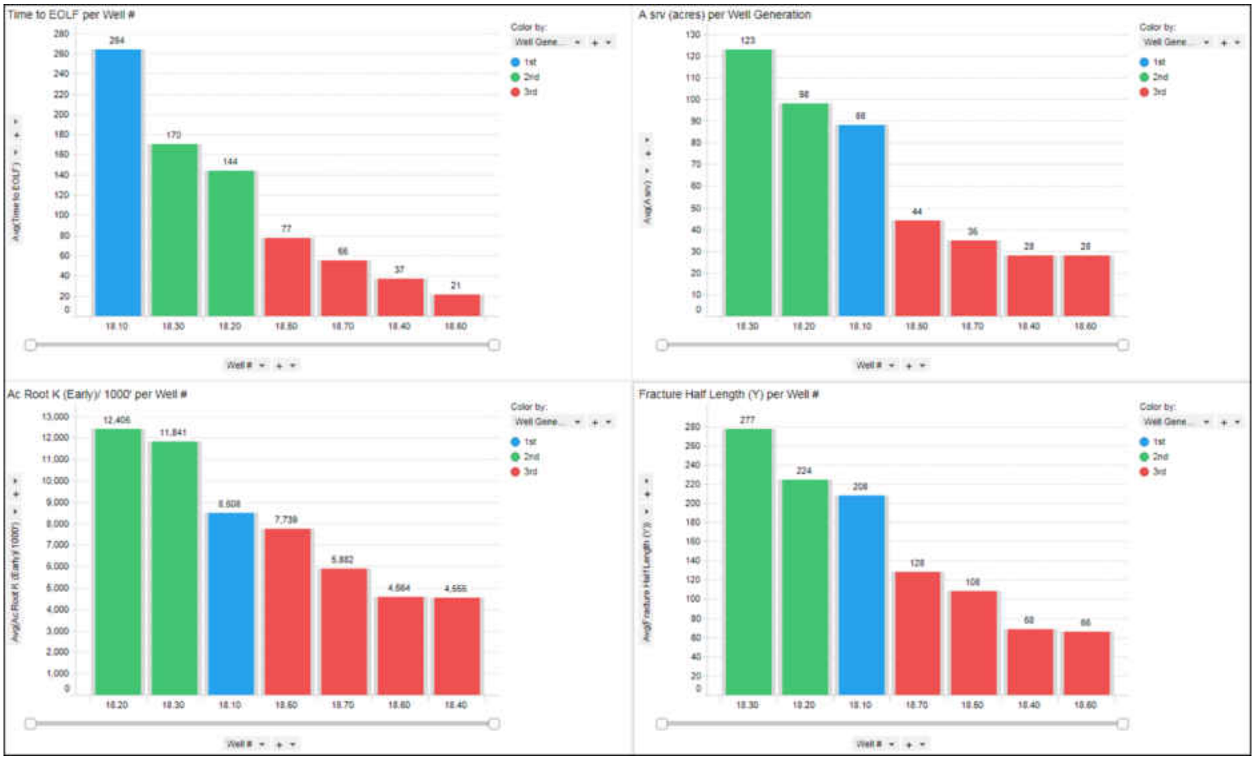

Figure 126. Spacing unit 18 reservoir and completion metrics.

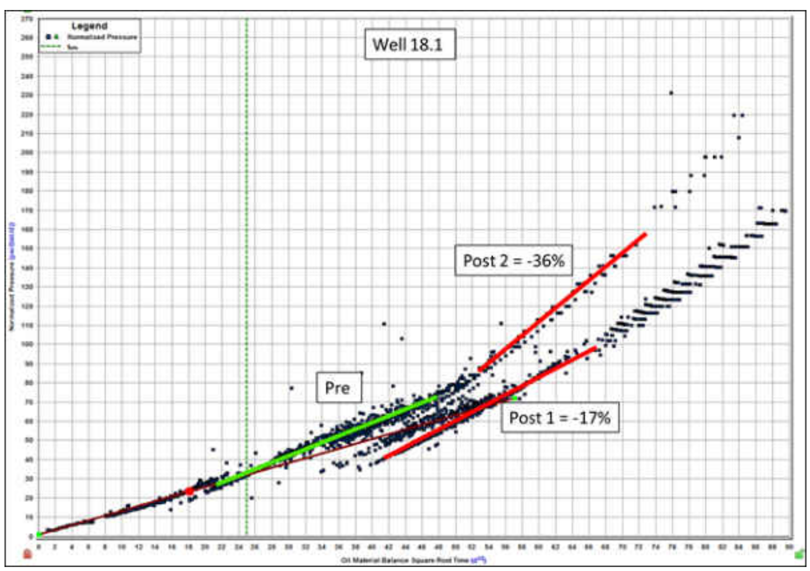

Figure 127. Well 18.1 superposition time plot.

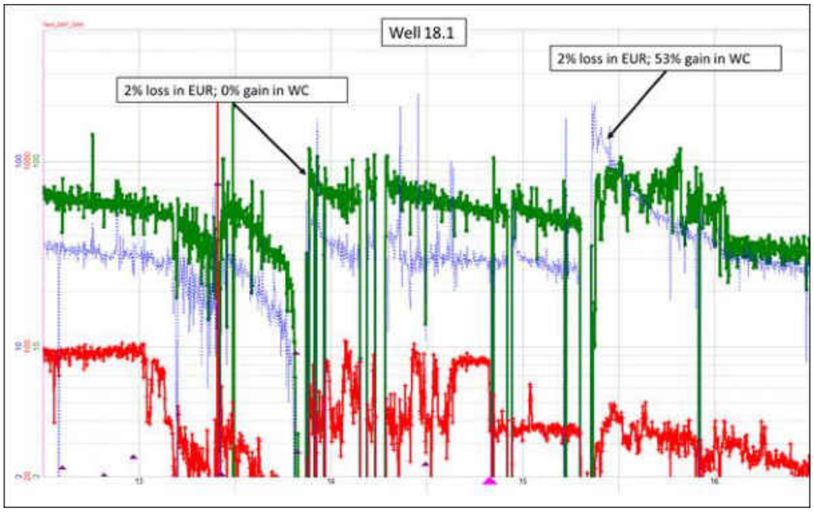

Figure 128. Well 18.1 production chart.

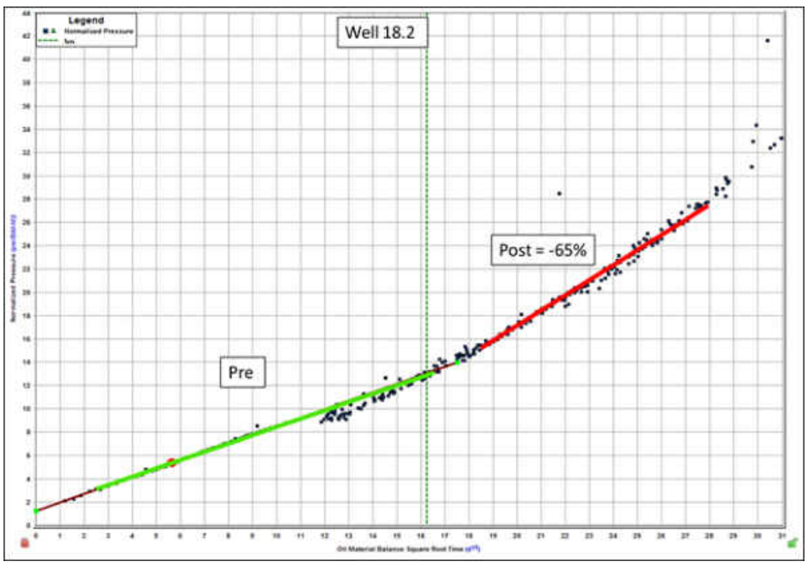

Figure 129. Well 18.2 superposition time plot.

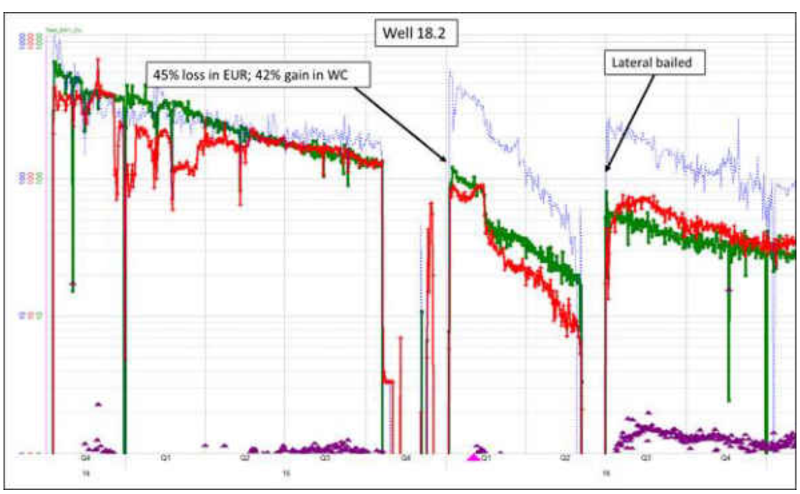

Figure 130. Well 18.2 production chart.

Spacing Unit #19 (30-31-163N-99W)

Spacing unit 19 contains 3 wells, 2 Three Forks and 1 Bakken, spaced at 660 feet. The parent well produced for 6.5 years before wells 19.2 and 19.3 were completed. The parent well is unbounded to the east and separated from well 19.3 by 520 feet to the west. Well 8.2 straddles the western section line, and is 720 feet east of a non-operated Three Forks well completed in 2014. Well 19.1 may have had communication with a non-op offset frac, 1,800 feet to the west. The well was experiencing surface and downhole issues during this time, so a clear determination was not possible. But it is likely the area between the non-op well and well 19.1 was depleted prior to wells 19.2 and 19.2 being completed. When wells 19.2 and 19.3 were completed, well 19.1 experienced a 12% loss in EUR, a 79% initial gain in water cut, and a 35% loss in $A_c\sqrt{k}$. The lateral of 19.1 was bailed immediately after the offset fracs occurred, and before being returned to production. Comparing 8.2 to the well directly north (12.2), 8.2 demonstrates a water cut that is 10% higher and a 55% lower 30 day IP. The parent well in spacing unit 19 had a 30 day IP 42% lower and a water cut 40% higher than the parent well in spacing unit 13. This indicates that the overall lower well performance in spacing unit 19 is likely a function of the geology.

Figure 131. Spacing units 19 – 21.

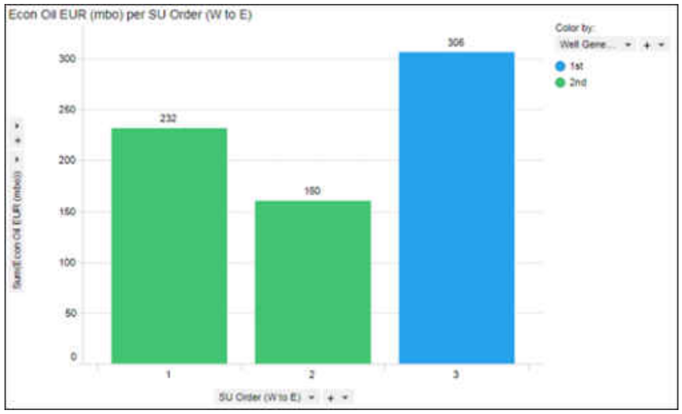

Figure 132. Spacing unit 19 well order from west (left) to east (right) and EURs.

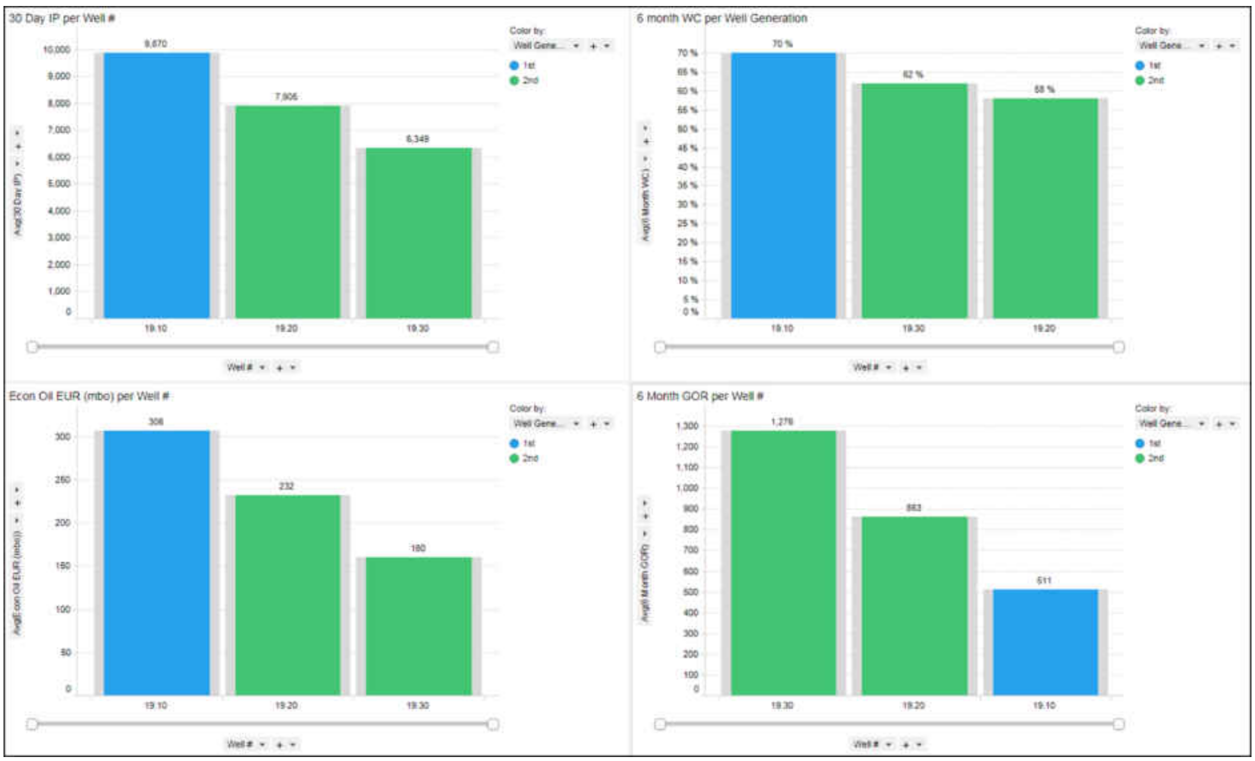

Figure 133. Spacing unit 19 production performance by well.

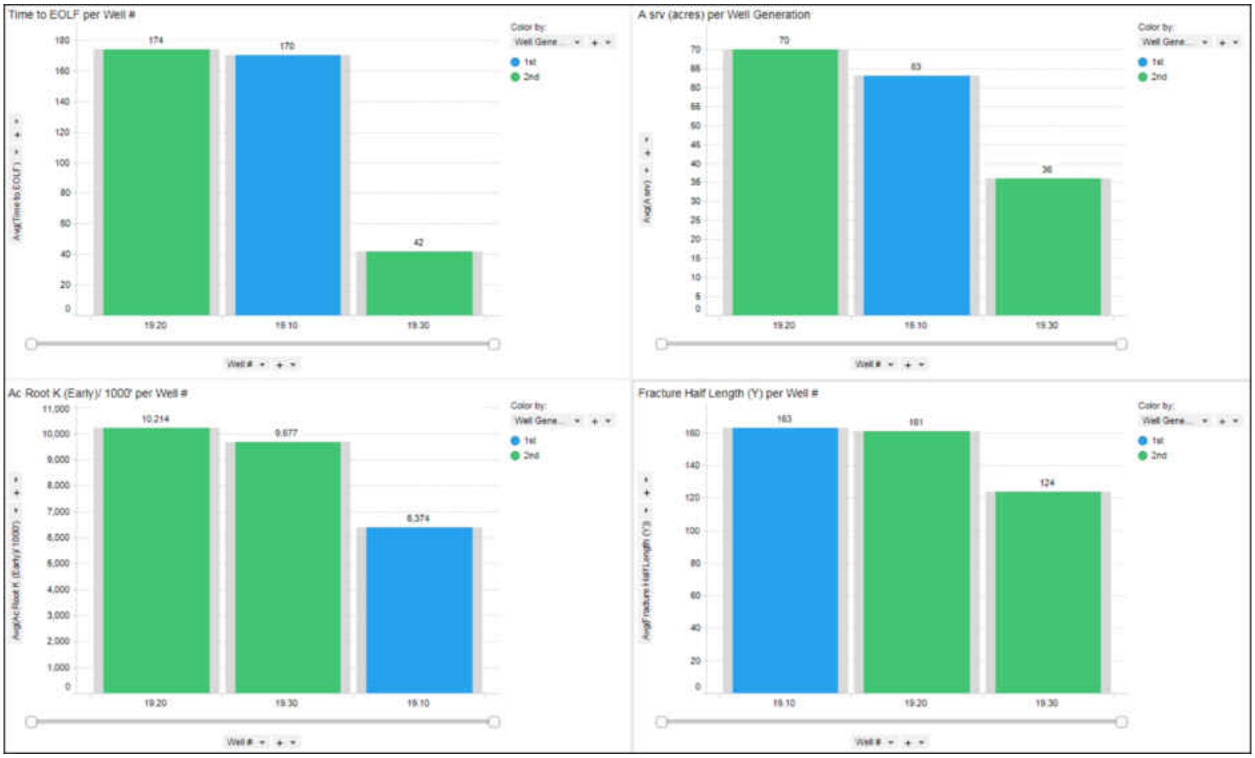

Figure 134. Spacing unit 19 reservoir and completion metrics.

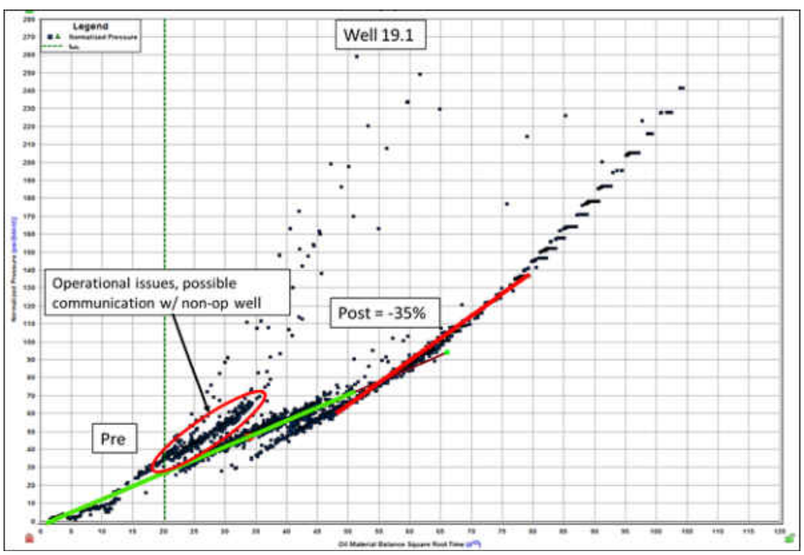

Figure 135. Well 19.1 superposition time plot.

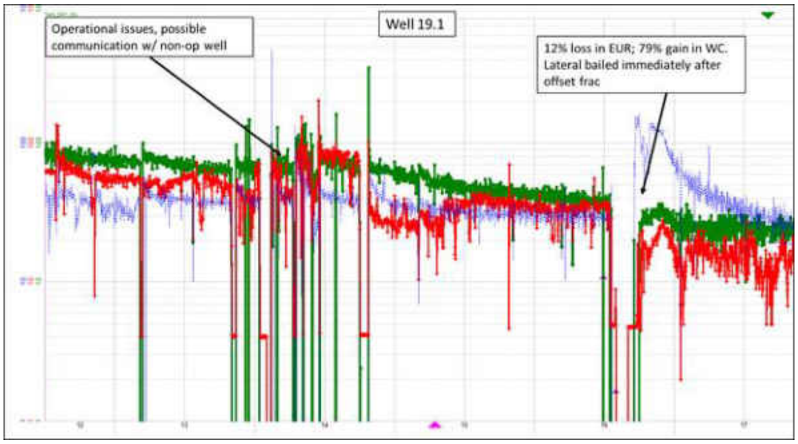

Figure 136. Well 19.1 production chart.

Spacing Unit #20 (29-32-163N-99W)

Spacing unit 20 includes one producing Three Forks well and 4 DUCs 1,800 feet to the east. No communication was observed during offset drilling. Well 20.1 has had a smooth decline trend over its life, indicating no offset communication. The 30 day IP was 55% lower and water cut 24% higher than well 14.1, which is directly north. With similar landing zones and completion designs, the difference in performance can be tied to geology.

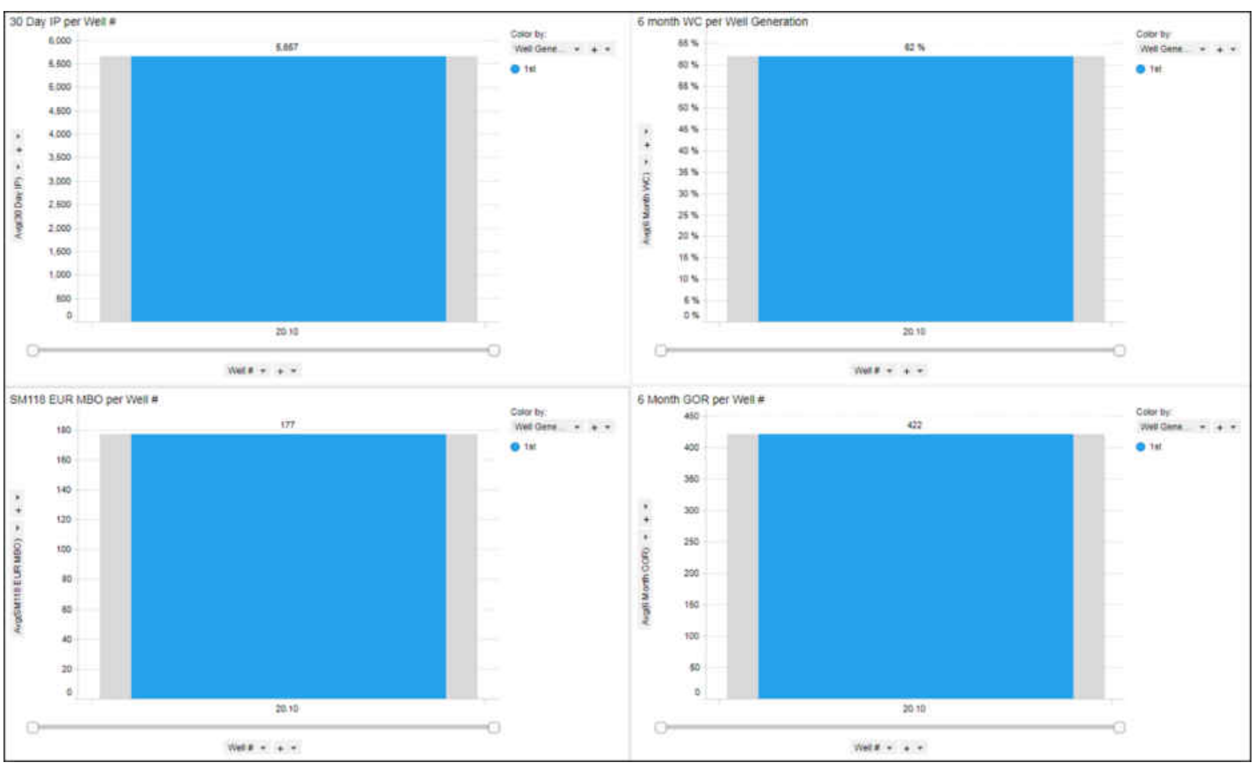

Figure 137. Well 20.1 production performance.

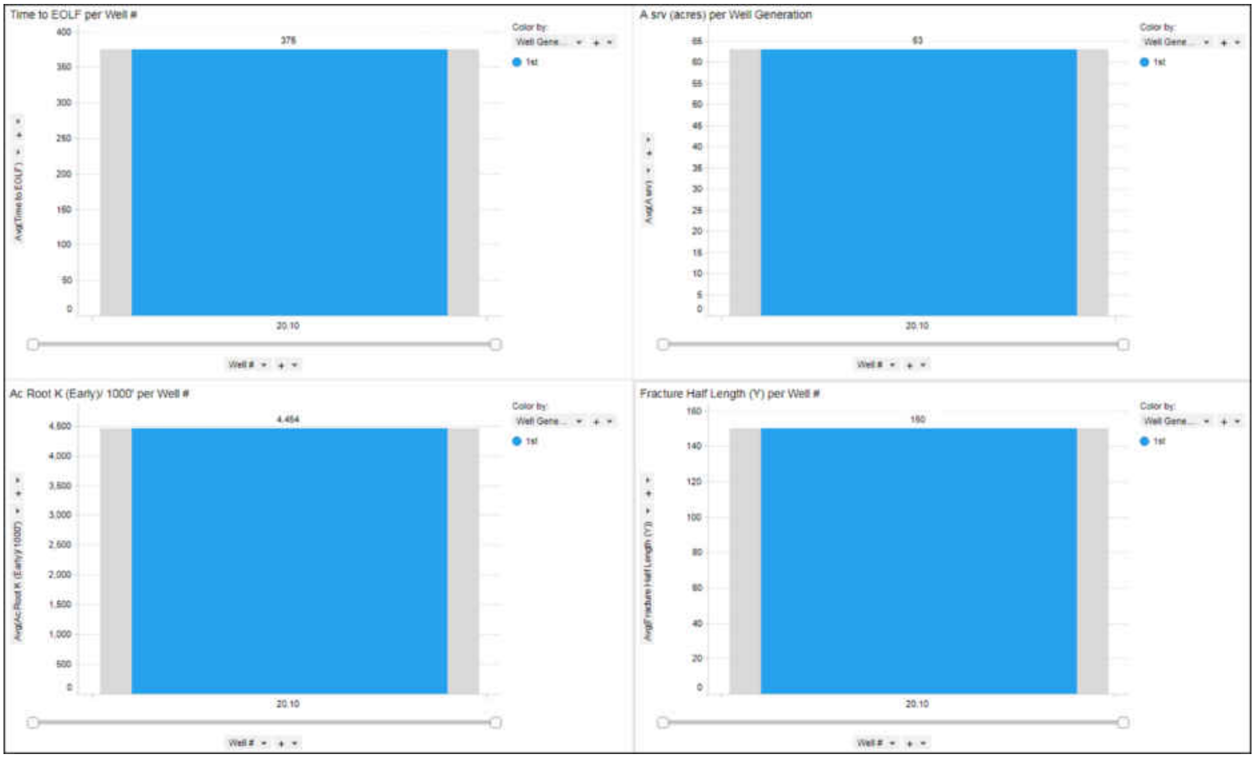

Figure 138. Well 20.1 reservoir and completion metrics.

Spacing Unit #21 (28-33-163N-99W)

Spacing unit 21 includes 3 producing wells, 2 Three Forks and 1 Bakken, and 3 DUCs. The wells are spaced at 880 feet. The 2nd generation wells were completed directly offset east of the parent well. The minimum distance between 21.1 and 21.2 is 760 feet. Well 21.1 produced for three years before the 2nd generation wells were completed. Well 12.1 experienced a 32% loss in EUR, a 34% gain in water cut, and a 43% loss in $A_c\sqrt{k}$.

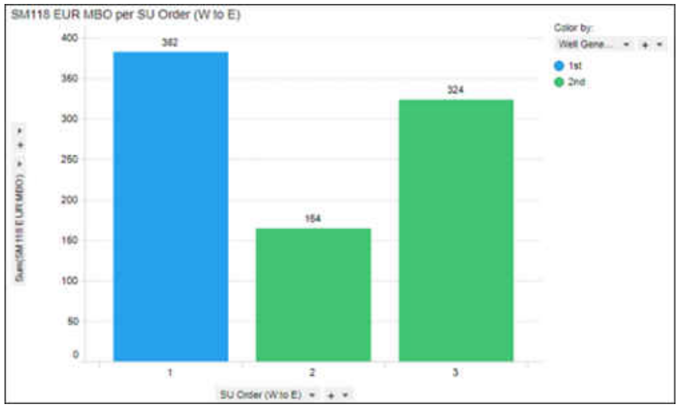

Figure 139. Spacing unit 21 well order from west (left) to east (right) and EURs.

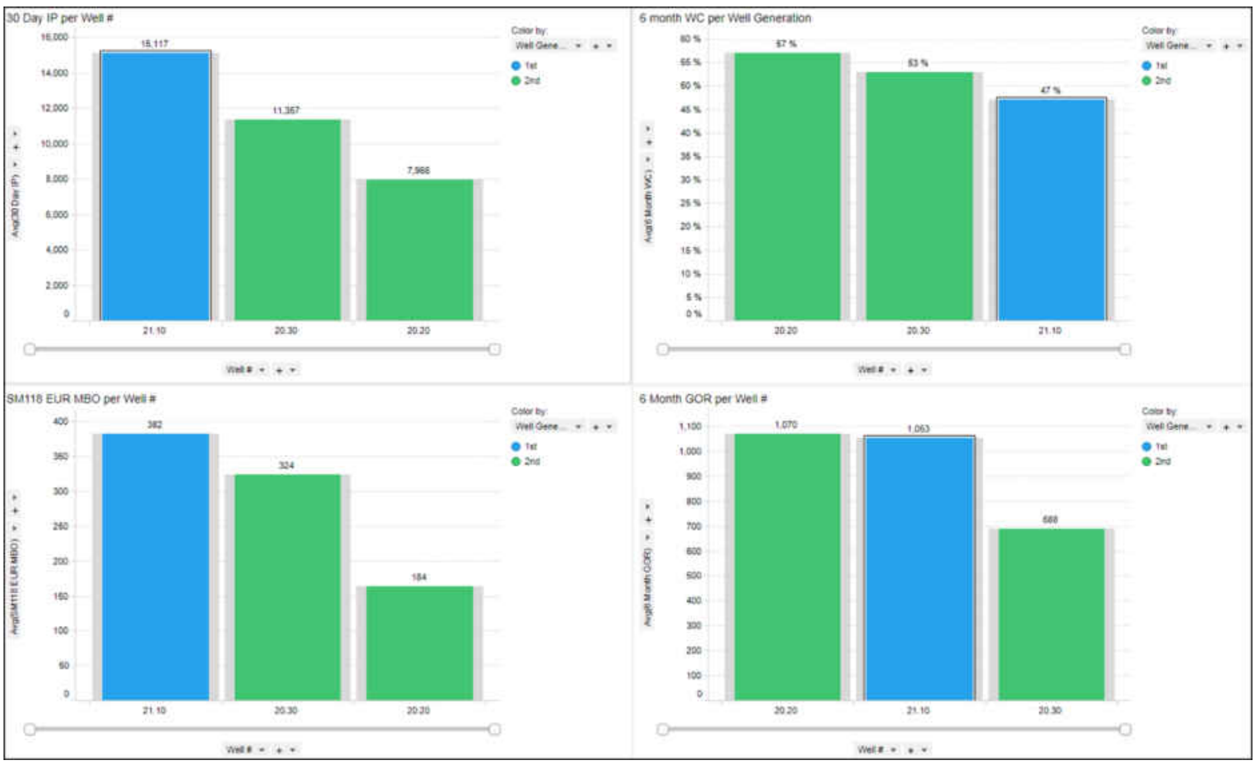

Figure 140. Spacing unit 21 production performance by well.

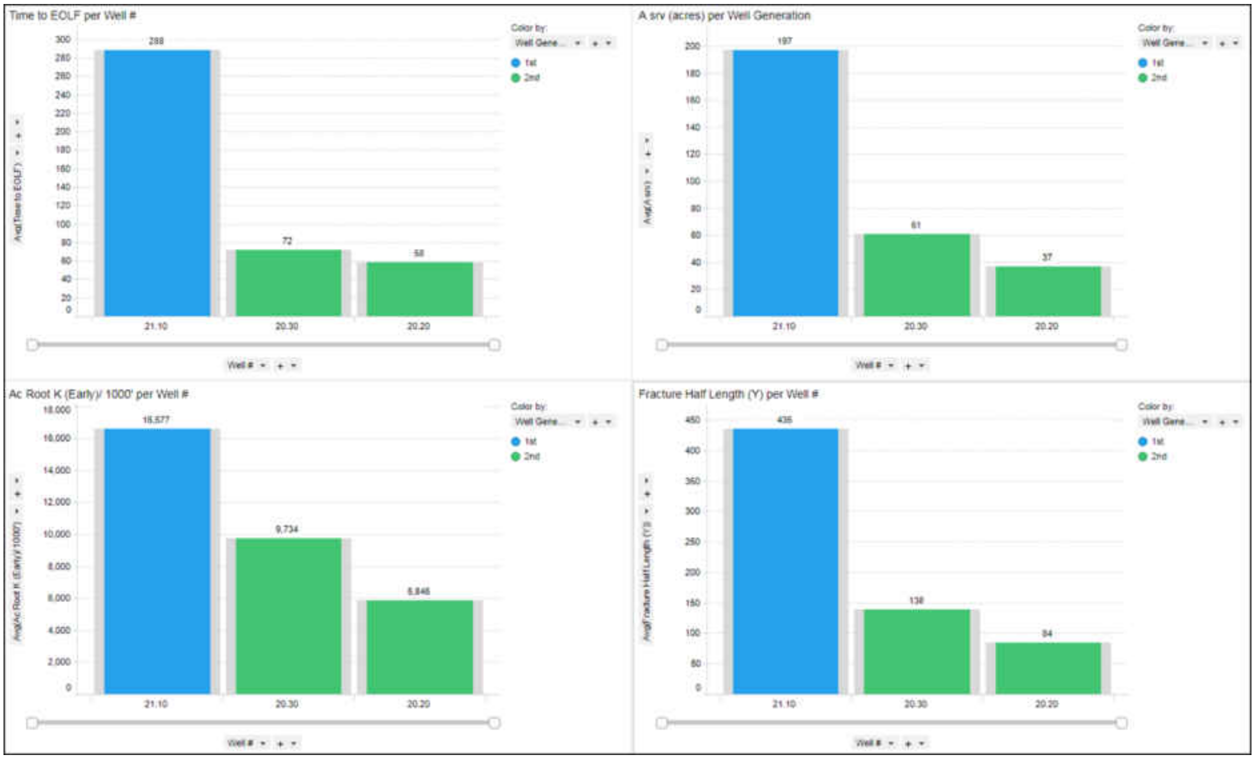

Figure 141. Spacing unit 21 reservoir and completion metrics.

Development and Frac Hit Discussion

The analyses above demonstrate that overall well performance is driven by spacing, timing, completion design, and reservoir quality. Across the study area, most spacing units were completed with a similar completion design in similar reservoir quality. As discussed in the previous session, examples of relatively poor geology and improper completion design were observed in the data set. Areas of high water cut and low well performance occur in the west-central and southeast portions of the study area. Figure 142 illustrates that parent wells utilizing similar completions designs and targeting similar intervals have higher water cuts and perform below average in these areas.

As mentioned in Chapter 1, wells with MSSB systems perform significantly lower than wells completed using standard sliding sleeves or cemented liner, plug and perf designs. Wells completed with an MSSB system have a 32% lower 12 month oil cumulative per lateral foot and a 50% lower MBOE EUR compared with the two main completion types used in the field (Figure 143).

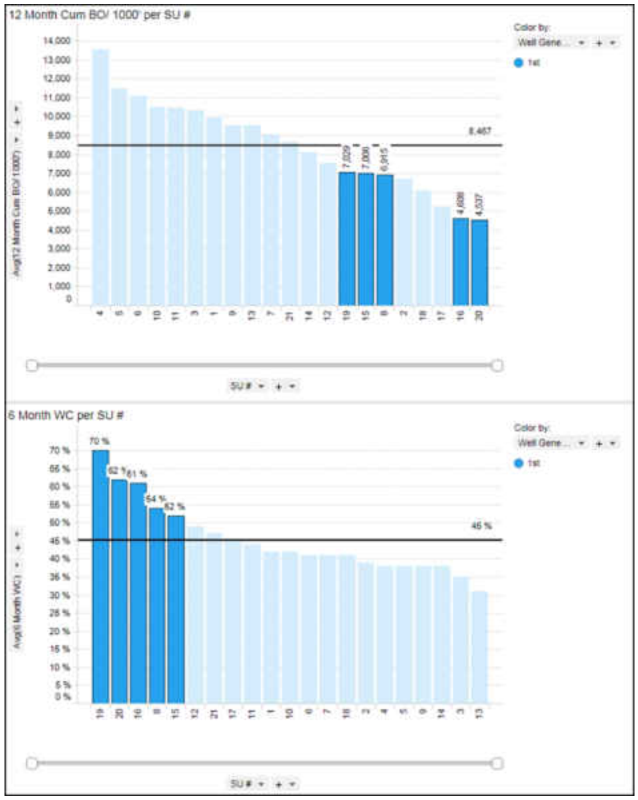

Figure 142. First generation 12 month cumulative BO per lateral foot and 6 month water cut.

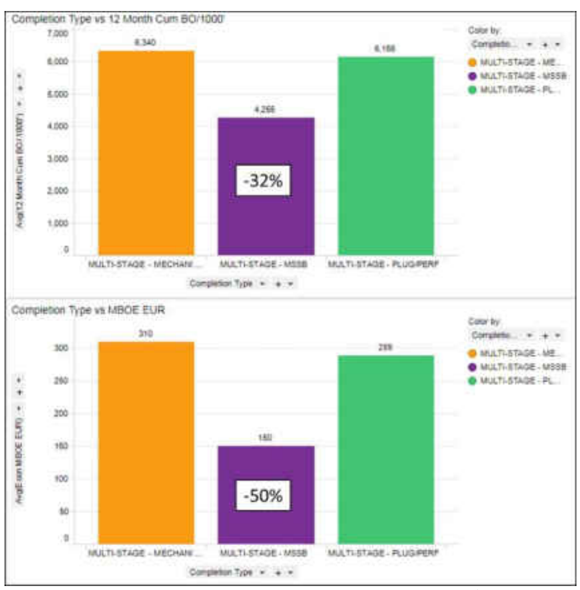

Figure 143. Completion design performance comparison for 2^{nd} generation wells.

As demonstrated in spacing unit 8, well performance enhancement can be achieved via completion design, by applying more stages and closer stage spacing. Wells 8.1 and 8.4 used similar proppant and fluid volumes per foot, and were drilled in the same target zone. Well 8.4 was completed on the far eastern side of the spacing unit, and is assumed to be outside the extent of depletion caused by well 8.1. Well 8.4 was completed with 26 stages with an average spacing of 386 feet per stage. By comparison, well 8.1 was completed with 20 stages at an average spacing of 506 feet per stage. The enhanced design of 8.4 resulted in a 40% increase in SRV, a 16% increase in 12 month cumulative oil and a 28% increase in 30 month cumulative oil (Figure 144).

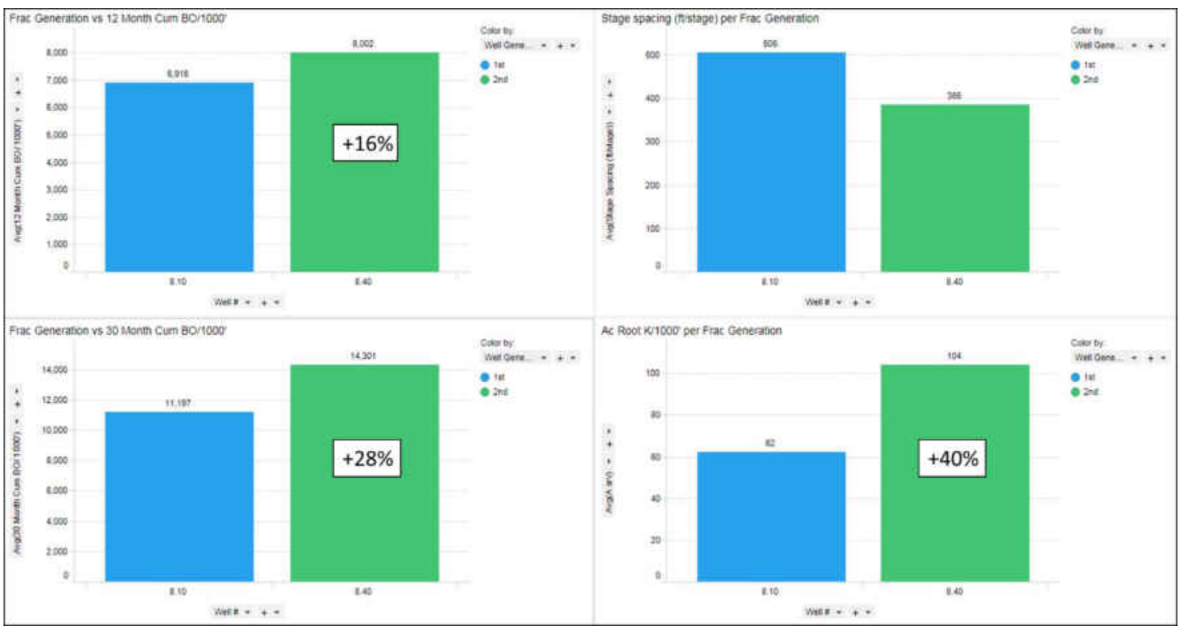

Figure 144. Completion design performance by generation.

The data indicates that more stages with tighter spacing correlates with enhanced well performance. Research has also shown that more proppant and fluid per lateral foot results in better well performance (Pearson et al., 2013). However, most research done on this subject pertains to overpressure environments towards basin center, with thicker target formations. This study demonstrates that in thinner areas of relatively low pressure (Gooseneck) or depletion, high fluid and sand volumes are actually detrimental to well performance. Figure 145 depicts wells completed with a “large frac” compared to the standard 2nd generation design. All wells in this comparison are 2nd generation Three Forks wells completed with the same number of stages. The design was trialed on wells 10.3 and 18.3, with 195% more proppant per foot and 80% more fluid per foot relative to standard completion design. On average, 12 month cumulative oil per lateral foot was 19% lower and water cut was 8% higher for wells that were treated with larger volumes. These findings demonstrate that more work is needed to optimize completion designs in areas of depletion, low pressure, and thin lateral targets.

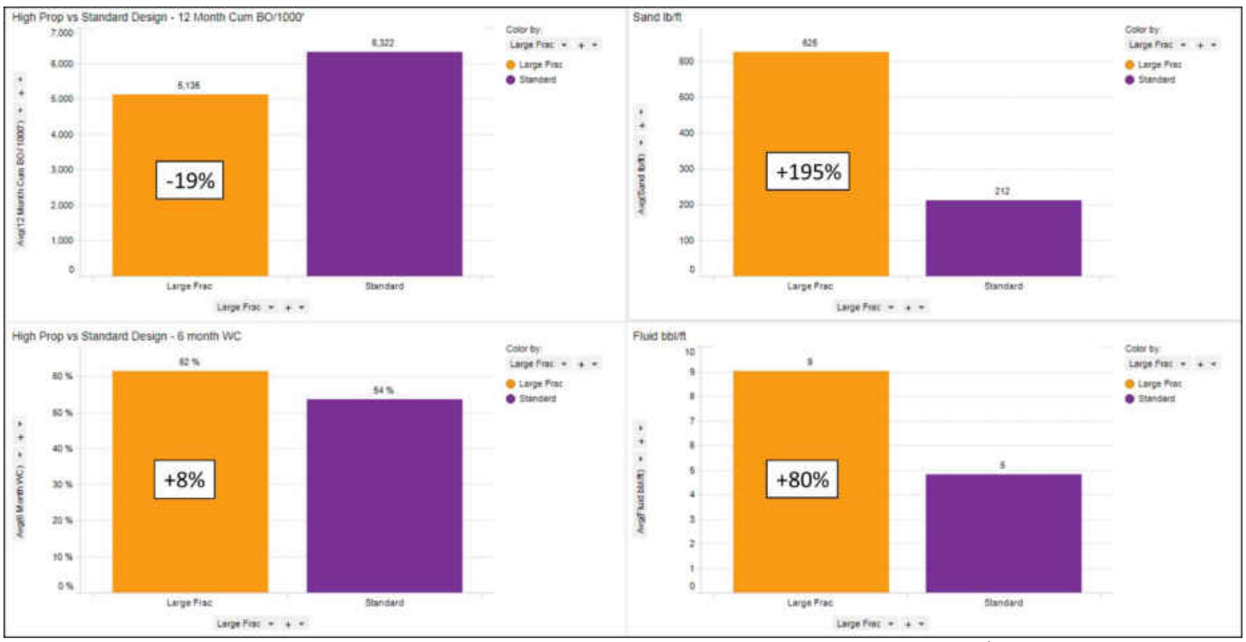

Figure 145. Proppant and fluid volume compared to well performance for 2nd generation Three Forks wells.

The magnitude of frac hits is a function of both time and distance. Ideally, all wells within a spacing unit would be completed at the same time, when reservoir pressure is at or close to virgin conditions. The importance of infill timing is exemplified by parent wells 6.1 and 14.1. Well 6.1 is seperated from well 6.2 by 1,320 feet. Well 6.2 was completed 134 days after 6.1, with no observable communication between the Three Forks wells. Well 14.1 was offset by well 13.3 ~2 years after Well 14.1 first produced. The Three Forks wells are seperated by 2,040 feet. Well 14.1 experinced a 6.5% decrease in EUR and a 10% loss in $A_c\sqrt{k}$ after 13.3 was completed, despite being further away than well 6.1 relative to its offset (Figure 146).

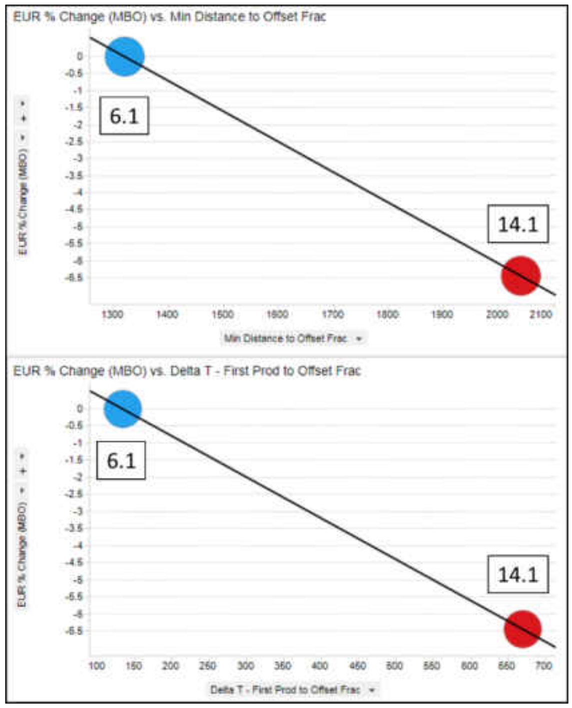

Figure 146. Comparison of offset well distance and timing.

Generally, completing all wells in a spacing unit simultaneously is not realistic. Assuming that well count and timing between infill completion is the same, what implications does completion order have on well performance? Figure 141 compares well performance by generation for two different well placement patterns. Spacing units 4 and 10 were development in an inside-out pattern, where 2nd generation wells were completed directly adjacent to the parent well, then 3rd generation wells were completed on either side of the existing wells. Spacing units 11 and 18 were developed from the outside in, with 2nd generation wells completed on the opposite side of the spacing unit relative to the parent, and 3rd generation wells filling the gap between the existing wells. Results show that, 30 day IPs for 2nd generation wells developed in an outside-in pattern are 60% higher and EURs are 108% better. This seems logical given that less depletion occurs further away from the parent well. The 3rd generation wells have varying results, with 30 day IPs being 17% higher, while EURs are 23% lower (Figure 147). By the time 3rd generation wells are added to a spacing unit applying the outside-in approach, its resonable to assume that signifiacnt depletion has occurred between the parent and 2nd generation wells. When four 3rd generation wells are completed at the same time in a low pressure environment its likely a large, interconnected SRV is created, explaining the bigger 30 day IP. However, overtime, these fractures can isolate from one another, and/or compete for the same reserves. Whereas 3rd generation wells completed in an inside-out order step out away from the area of depletion (existing wells). With reservoir pressure closer to original conditons, fracture growth will have a better chance of proppagating in a transverse manner.

Figure 147. Comparison of spacing unit development order.

Optimal Well Spacing

SM Energy initiated the 8 well per spacing unit development plan at a time when commodity prices were high and well performance data limited. As such, little was understood about the interaction between Bakken and Three Forks, the effects of reservoir depletion on infill well performance, and the impact of frac hits on existing wells. Now that sufficient production histories exists, an accurate depiction of overall spacing unit performance and economic efficiency can be determined.

Comparing SME's current development plan of 8 wells spaced at 660 feet to spacing units with 5 wells (4 wells spaced at 1,320 feet; 1 at 660 feet), it is obvious that efficiencies are lost by adding more wells. On average, EURs for 2nd generation wells are 61% higher and the area of SRV is 41% larger for spacing units with 5 wells versus spacing units with 8 wells. Despite being spaced at 660 feet, 3rd generation wells also exhibit higher EURs (14%) and larger SRVs (30%) as shown in Figure 148. It should be noted that the time between 1st generation and 2nd generation completion was much shorter for spacing units with 5 wells (~1.5 years) than for spacing units with 8 wells (~3 years). While it is true that more wells equate to higher recovery factors (Figure 149), the comparison between these two different spacing methods indicate the need for a more thorough analysis. Recovery factor outliers in Figure 149 (3 & 7) can be attributed to inefficient completion design or offset frac interference.

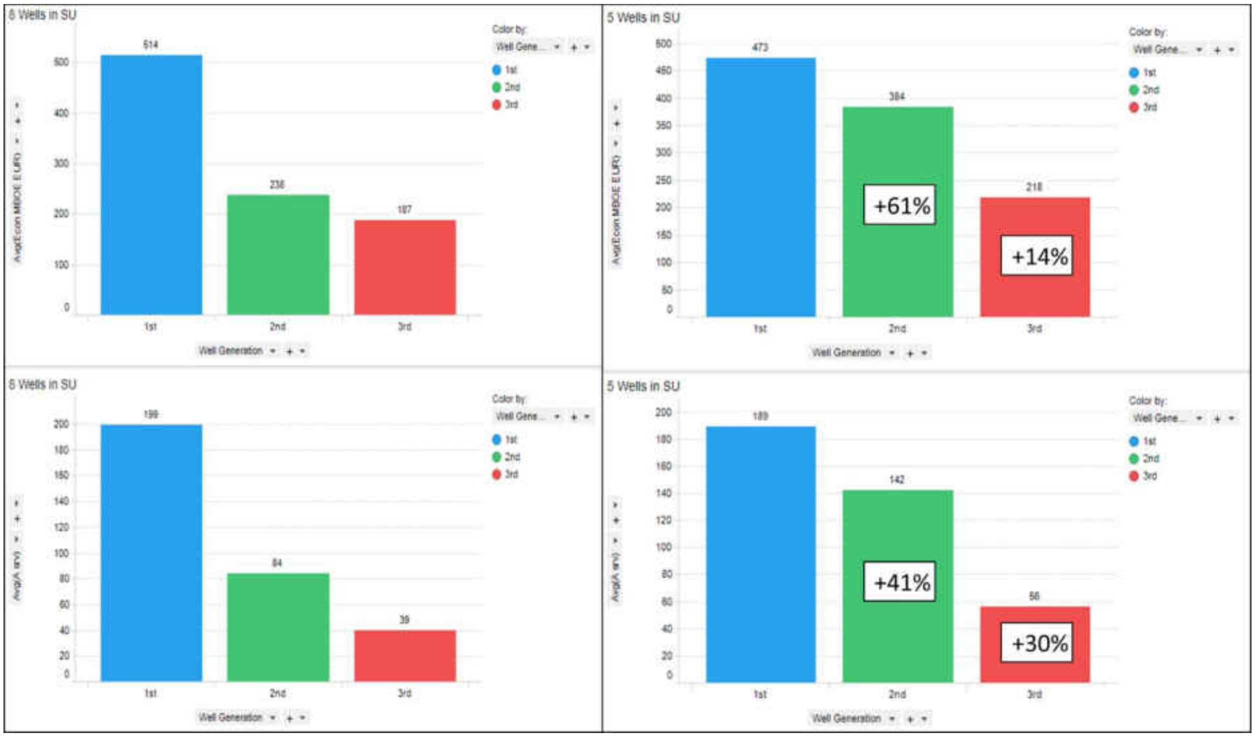

Figure 148. Comparison of spacing unit well performance by generation, EUR and SRV.

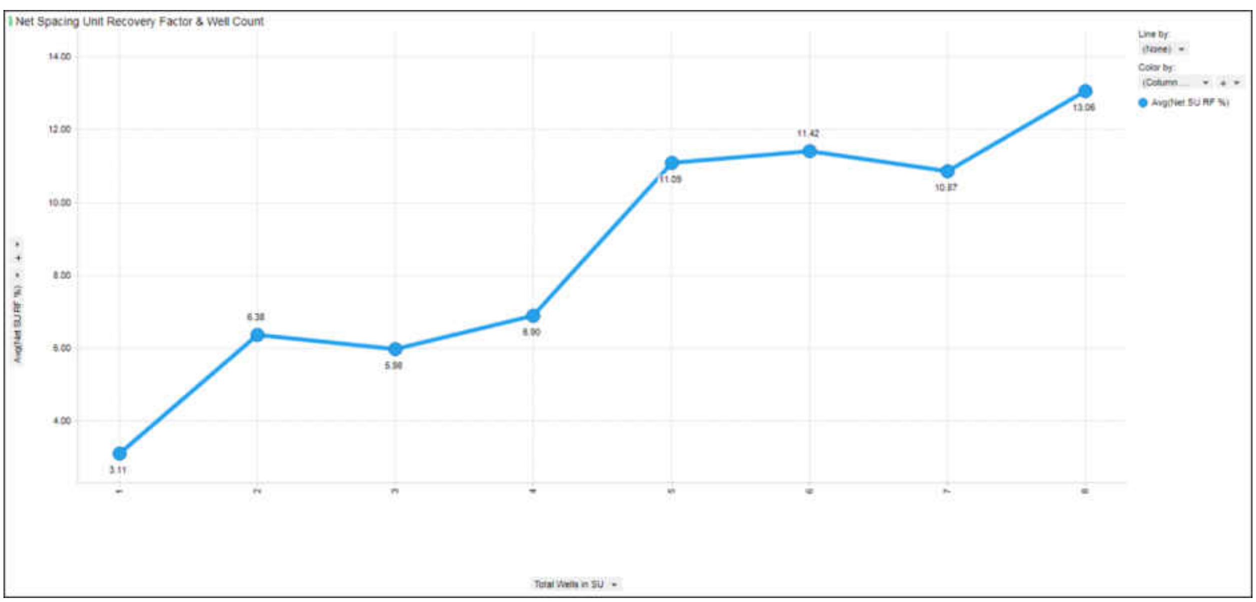

Figure 149. Recovery Factor by number of wells in spacing unit.

In low commodity price environments, understanding incremental economics is crucial when determining which projects capital should be allocated towards. For example, when evaluating economics for an additional infill well, loss of production due to the offset frac hit should be factored into the net gain. Without such insights, investment metrics may be inflated, resulting in unfavorable real returns relative to prediction. As mentioned earlier in the chapter, all economics were run assuming present day pricing. A look-back approch was used to account for actual well performance, timing, and net gains in production. Both DPI and present worth indicate that the point of diminshing returns occurs after 5 wells per spacing unit. While all spacing units shown in Figure 150 demostrate a DPI greater than 1, these metrics should be juxtaposed with well performance histories in order to make the best business and engineering decision. It should be noted that only one spacing unit with 6 wells exists in the data set. Wells within the unit are spaced at 660 feet, likely resulting in artificially low metrics.

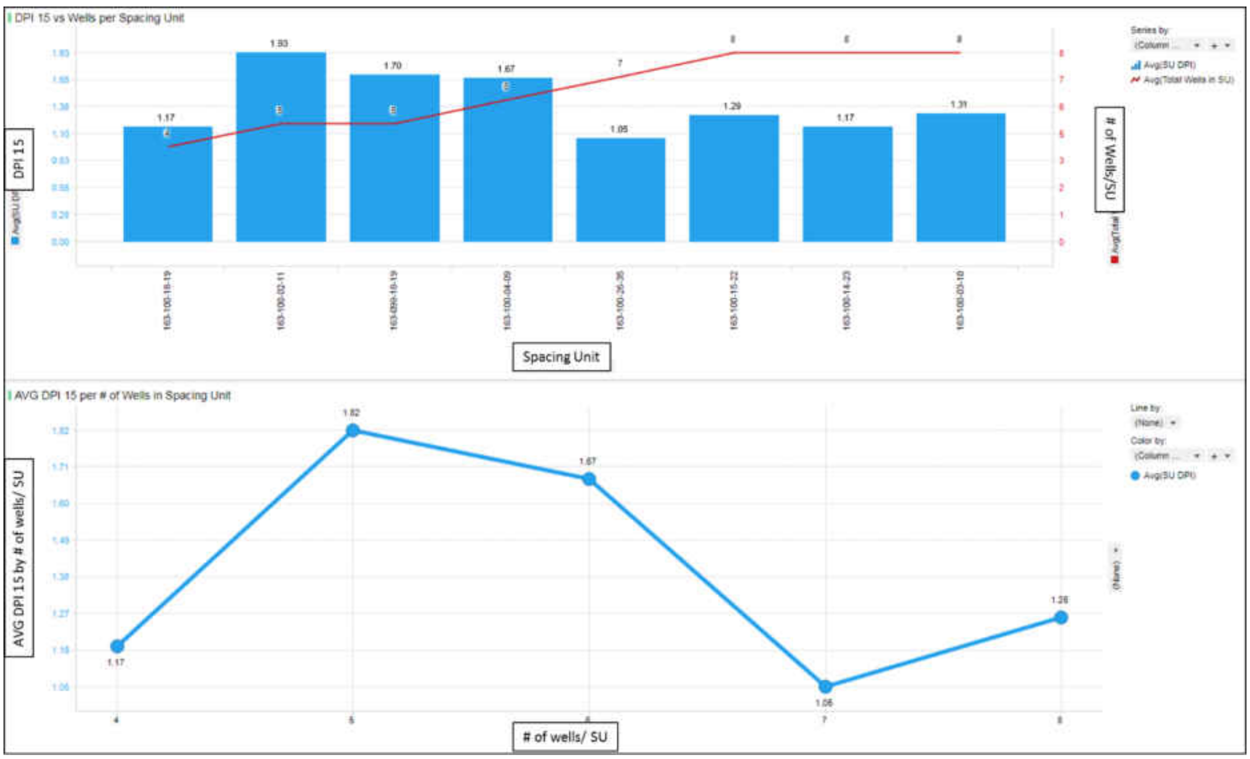

Figure 150. Top graph is DPI15 and well count by spacing unit. Bottom graph is average spacing unit DPI by number of wells in spacing unit.

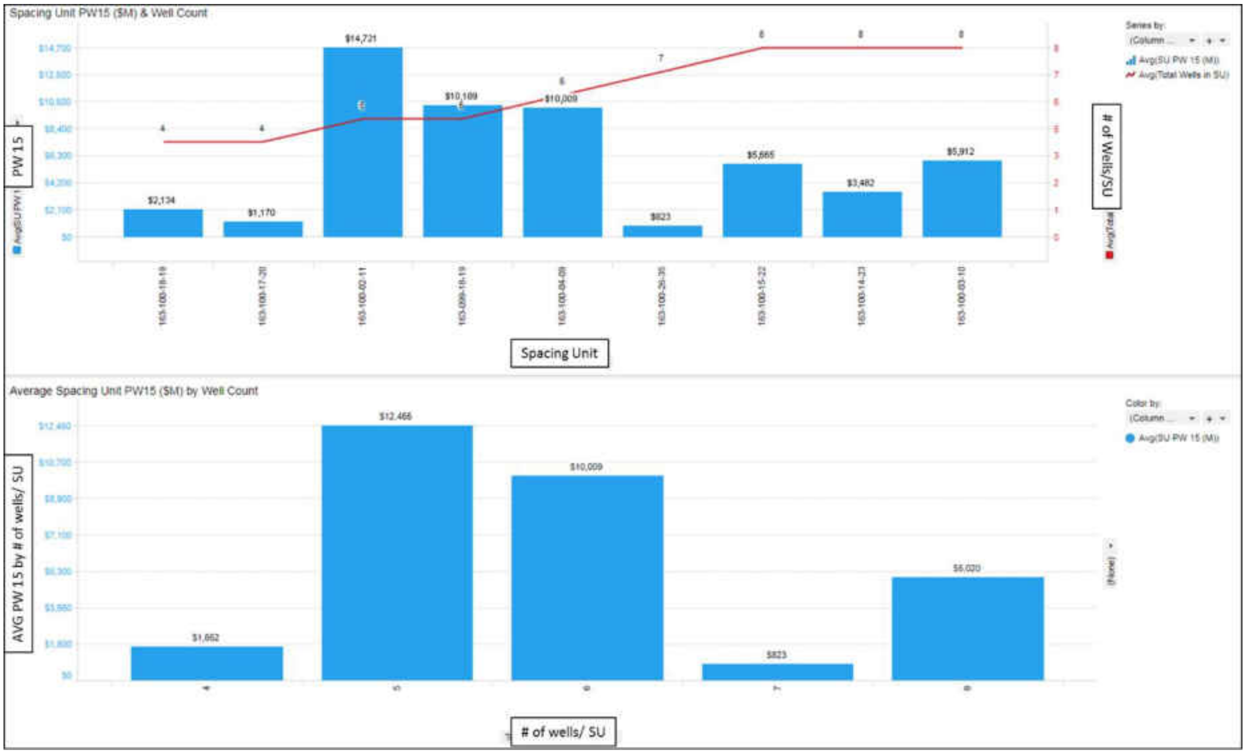

Figure 151. Top graph is Present Worth discounted at 15% and well count by spacing unit. Bottom graph is average spacing unit PW15 by number of wells in spacing unit.

Figure 152 provides further support for larger spacing and shorter time duration between parent and 2nd generation completions. The figure shows the incremental production gain when adding 2nd generation wells compared to the distance from the parent well. A general trend can be observed for wells spaced at 600 feet – the greater the distance from the parent well, the larger the net production gain. Wells added further away from the parent are not hindered by reservoir depletion. In addition, the impact of frac hits on the parent well are diminished. The two outliers on this chart represent spacing units with wells spaced at 1,320 feet, with the time between 1st and 2nd generation being much shorter.

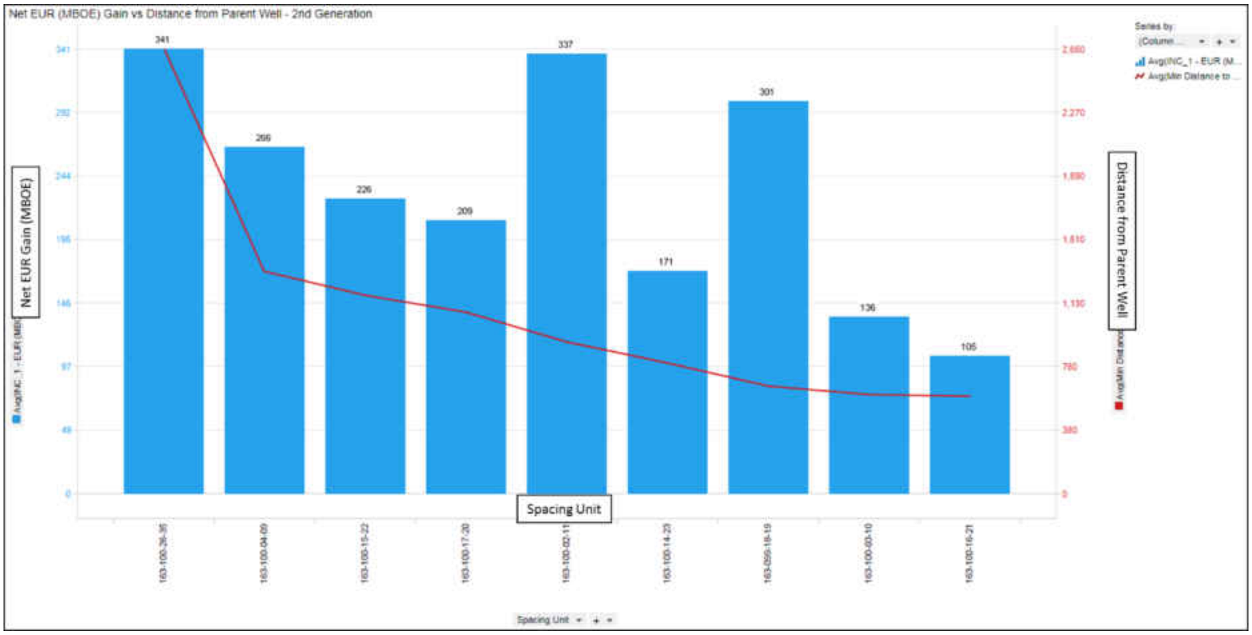

Figure 152. Incremental production gain from 2nd generation wells by spacing unit and distance from parent well.

CHAPTER V

CONCLUSIONS AND RECCOMENDATIONS

Conclusions derived from this study are as follows:

1. Frac-hit magnitude is a function of distance and time.

2. Well interference was observed between wells up to 2,600 feet apart.

3. Up to 50% loss in EUR has occurred due to frac-hits.

4. Wells with MSSB completion design have poor performance compared to standard sliding sleeve and plug and perf designs. MSSB wells have more sand issues and have higher failure rates compared to field average.

5. More stages and closer stage spacing creates larger SRV and better well performance in areas of non-depletion.

6. In the study area, a maximum proppant and fluid volume loading exists, beyond which, further increases did not result in incremental well performance gains.

7. A strong correlation exists between early time $A_c\sqrt{k}$ and well performance.

8. EURs decreased by 38% from 1st to 2nd generation wells, and by 30% from 2nd to 3rd generation wells. Reservoir depletion is the main driver for this loss in productivity.

9. The average time to end of linear flow is: 1st generation = 289 days; 2nd generation = 153 days; 3rd generation = 83 days.

10. The average area of stimulated rock volume is = 1st generation = 134 acres; 2nd generation = 80 acres; 3rd generation = 43 acres.

11. Three Forks water cut is highest in the west-central and southeast of the study area.

12. The optimal number of wells per spacing unit in Gooseneck is 5 – 6 with an inter-well spacing of 1,320 – 880 feet, assuming $60/Bbl, $3/Mscf and $4MM D&C investment per well.

The following reccomendations are based on observations from this study:

1. Perform DFIT tests on representative DUC well in area of suspected depletion to gather pertinent reservoir data.

2. Data obtained from DFIT tests should be used to optimize future infill completion designs.

3. Create look-back frac models and use in conjunction with rate-transient analysis.

4. Perform micro-seismic and tracer study on infill well in order to better understand fracture distribution and direction of propagation. This will provide insight into the effects of pressure depletion and connectivity between the Bakken and Three Forks.

5. Run live downhole pressure recording device on infill well so that data can be used for earlier determination of completion efficiency using rate-transient analysis. Findings will allow for completion optimization on future wells.

6. Collect PVT recombination sample to ensure oil and gas properties in internal models are correct.

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