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Tank Development in the Midland Basin, Texas: a case study of super-charging a reservoir to optimize production and increase horizontal well densities

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Abstract

Simultaneous petroleum extraction operations, including drilling, completion, and production of tightly spaced horizontal wells are the inevitable reality in unconventional development. This next wave of development has just begun in the Midland Basin of West Texas, where operators are shifting from parent well tests to increased well density development. However, the development of increased well densities in a sequential, parent/child methodology commonly results in less effective stimulated rock volumes of child wells, increased production downtime, and drilling hazards. The key to maximizing corporate value will be in adopting development strategies that realize higher well densities while avoiding these pitfalls.

Here we present a case study of a novel multi-disciplinary approach aimed at the optimization of both surface and subsurface development operations for tightly-spaced and stacked stratigraphic intervals. Our methodology, here termed “Tank Development”, aims to exploit a volume of rock at one time to maximize reservoir potential. The fundamental principle of Tank Development is maximizing well productivity by “super-charging” the reservoir prior to simultaneous initiation of production. Super-charging the reservoir is accomplished by sequencing hydraulic fracture operations and bringing all wells online simultaneously to pressurize the reservoir in an effort to create a demonstrably more complex fracture network. A surface microseismic array was used to monitor the completions of four horizontal wells in the Spraberry Formation. The results indicate evidence of breaking more rock when Tank Development is employed. Microseismic data also show an increase in near-wellbore fracture complexity for wells that were stimulated later in the Tank Development sequence.

The principle result from our tests is that productivity indexes for wells in our Tank Development program clearly exceed the productivity indexes for wells from the industry standard parent/child well development methodology. Thus, the new development approach has proven essential for maximizing asset value during simultaneous development of multiple horizons with horizontal wells in close proximity to one another. This multi-disciplinary development approach is key to optimizing near-wellbore fracture complexity and the conservation of completion energy required for increased well densities. In addition, Tank Development effectively eliminates the detrimental effects of parent and child well interactions. The surface and subsurface efficiencies maximize oil recovery and corporate value.

Introduction

The billion dollar question in developing unconventional plays is the optimal well spacing and development plan of horizontal wells. The density goal is to develop the optimum well count yielding the highest rate of net present value (NPV). Drilling too few wells initially can strand reserves, reduce NPV, and create poor pressure conditions, all of which lead to increased costs and reduced estimated ultimate recovery (EURs) for infill wells. Drilling too many wells results in over-capitalization, wherein incremental wells reduce the present value of a drilling unit. In the Midland Basin, where there are more than 2,000 feet of high quality reservoirs, each with several target benches, the 3D optimization of inter- and intra-stratigraphic well densities is paramount and a very challenging problem with enormous economic impact (Figure 1). This paper will explore how development techniques allow for realized surface and subsurface efficiencies that maximize corporate value, particularly with respect to increased well densities.

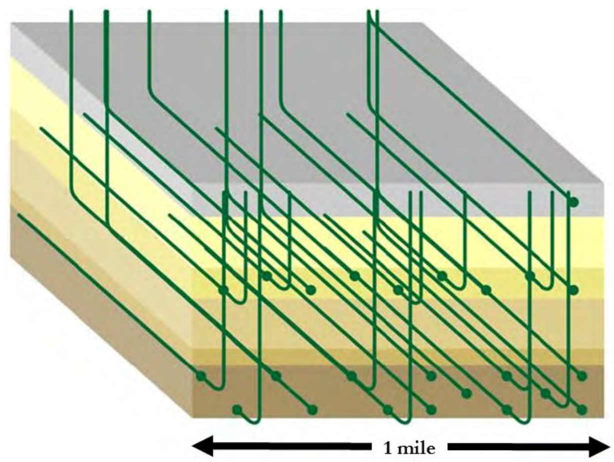


Figure 1: Example of challenging 3D horizontal development in multiple stacked pay horizons in a one mile drilling unit. Green lines are wellbores drilled from North and South in multiple formations.

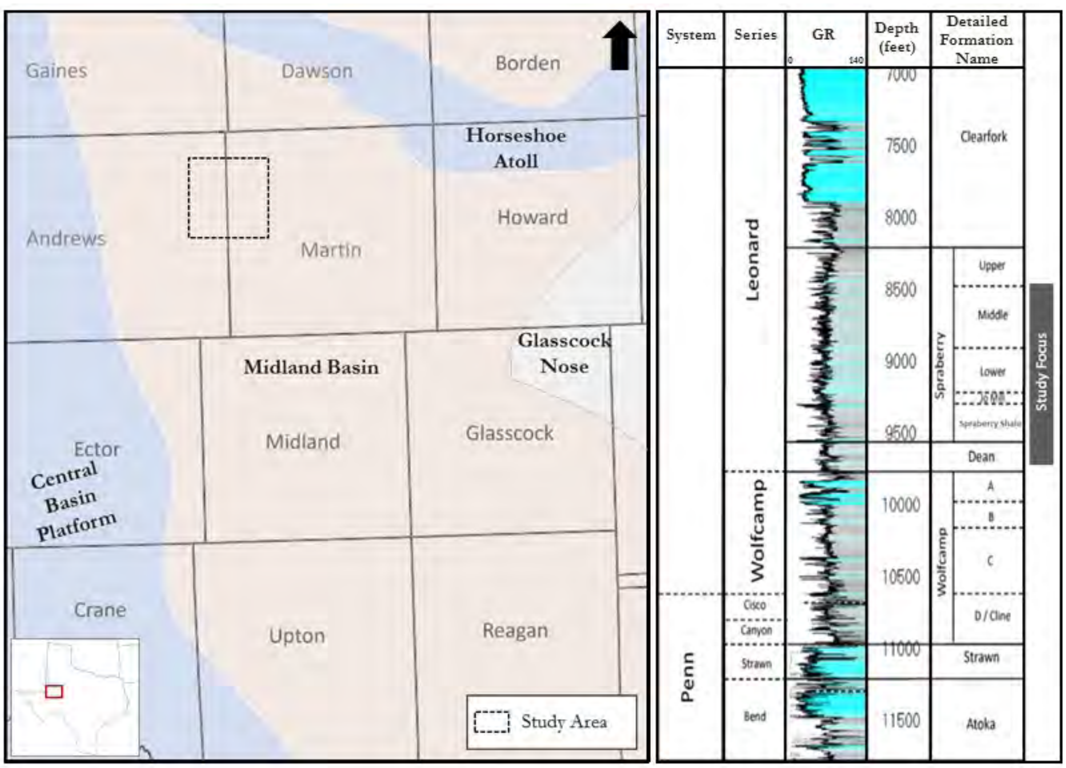
Operators in the Midland Basin advertise a wide range of potential formation well spacing in their investor relation reports. Publicized spacing for the Spraberry Formation can range from 4 to 22+ wells per mile. This variation can be explained through many factors: location and associated reservoir quality, acreage footprint, company-specific economic and production goals, long-term strategies, completion designs, pace of field-testing spacing, risk tolerance, costs, assumed oil and gas price, and advancement and adoption of various technologic analyses. However, compelling subsurface data to support the success of the well spacing decision are commonly not provided. In this paper, we present evidence that our Tank Development methodology can be implemented to optimize operational and reservoir performance in high-density production areas. In accordance with industry terminology, we will be using “well spacing” and “well density” (number of wells per mile) interchangeably throughout this paper. Table 1 illustrates the relationship between density and spacing within a one mile drilling spacing unit (DSU).

Our study area is the Andrews-Martin county border in the Midland Basin (Figure 2a). The Midland Basin is an asymmetrical, westward-thickening basin to the east of Central Basin Platform within the Permian Basin (Ye et al., 1996). Multiple stratigraphic zones and benches within the Spraberry Formation are the focus of our study (Figure 2b). The 350 feet thick oil-rich Spraberry Shale which consists of mixed silicate and calcareous mudstones, siltstones, and fine sandstones deposited as turbidites in deep-water submarine fans with associated channels is our primary interval of interest (Ball, 1995).

We set up an experiment to test Non-Tank Development compared to Tank Development. This paper will first describe Non-Tank Development concepts, current standard of the industry, and our associated case studies. Then we will introduce our Tank Development strategy and case studies followed by strong microseismic, pressure, and production evidence which supports that this methodology increases near well-bore hydraulic fracture complexity required for increased well densities.

Density Wells/mile	**Spacing** Interwell (feet)
4	1320
6	880
8	660
10	528
16	330

Table 1: Density (wells per mile) to inter-well spacing relationship



2a 2b

Figure 2: a) Map of study area along the Andrews-Martin County Line b) Midland Basin type log

Industry Standard: Non-Tank Development

Frac-Hits and Non-Tank Development Concepts

Frac-hits are a common occurrence in unconventional horizontal development and can be described as the invasion of fluids and pressure into a parent well (existing producer) from the hydraulic stimulation of a child well (well offsetting a parent producer) (Hao et. al., 2017). Parent wells can be producing days, months, or even years prior to child well development. Production from the parent well creates a zone of lower pore pressures, due to the withdrawal of fluids, known as a pressure sink. Depending on rock properties, complexity of stimulated hydraulic fractures, and production time, a pressure sink can extend into the hydraulic fractures, natural fractures, or the rock matrix. The hydraulic fracture energy of the child well stimulation will preferentially grow towards lower pressure zones. Preferential growth can create a compromised stimulated rock volume (SRV) of the child well (Figure 3) and affect the production of the parent well.

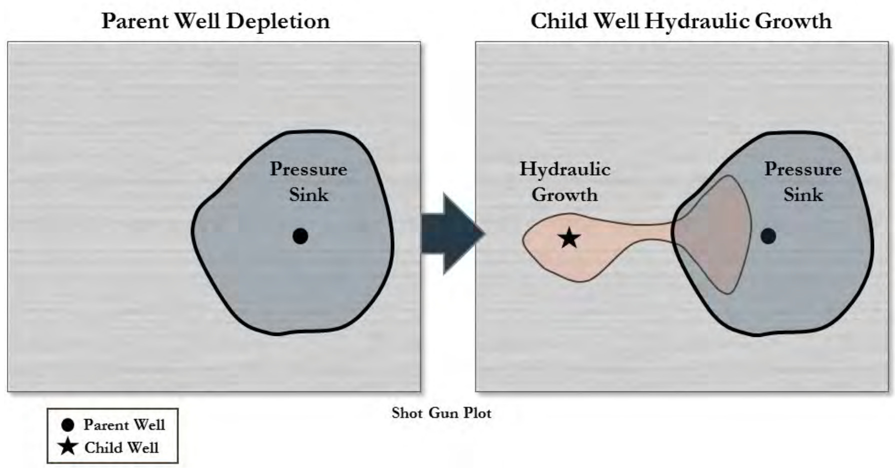


Figure 3: Cartoon illustration of parent well pressure sink resulting in a compromised SRV from a child well

Many authors have described and companies have experienced a wide range of frac-hits across the majority of unconventional plays and basins (Yadav and Motealleh, 2017; Ajisafe et. al., 2017; Hao et. al., 2017). In our study area, we have experienced two types of frac-hits: communication and interference. Communication frac-hits occur when pressure and/or water increases on the parent well and may be a singular event. A communication frac-hit does not necessarily result in production interference between wells. Interference frac-hits are the result of inter-well overlapping drainage areas and are typically more than a singular event, occasionally lasting for the productive life of the well. Even if there is initially some degree of production interference, it may not be maintained throughout the well's producing life (Cao et. al., 2017).

We have observed communication frac-hits at great vertical and lateral distances. We do not believe these distances represent optimal well densities or are indicative of a high degree of connectivity between parent and child wells. Rather, we suggest that the complex interplay of stacked pay, natural fractures, deformation zones, interlaminate bedding planes, and reservoir pore pressure differences are controlling the severity of communication and interference frac-hits.

While companies with leasehold obligations will continue drilling parent wells for extended periods, companies with held acreage are pressured by economics to quickly understand and execute higher density development plans over multiple stratigraphic horizons. From 2014-2016, our horizontal development transitioned from parent well development to sequential development of increased densities. Although this transition is a natural progression, it can often result in production loss due to frac-hits, potential long-term production impact on parent wells, and less effective SRVs of child wells. The key to maximizing corporate value through this progression is managing densities and production optimization.

Non-Tank Development Case Studies

During sequential development, wells are typically brought online immediately after completion in order to maximize corporate value using internal metrics of the wells, while continuous operations occur only a short distance away. An example of this situation is DSU-A in Figure 4. DSU-A consists of an average well density test of 10 wells/mile in the Spraberry Shale with 2 parent wells in the Middle Spraberry and Spraberry Shale (stars on left side of the DSU). Wells 1 and 2 (red wells on right side) produced 34 days prior to the completion of Wells 3, 4, and 5. During the production time, the hydraulic fractures and possibly the natural fractures experienced a decrease in pressure, resulting in a pressure sink. Wells 1 and 2 were not shut-in and were producing during offset stimulation. When Wells 3, 4, and 5 were completed, the hydraulic energy and fluids preferentially grew towards the pressure sink. This was expected and matched our previous frac modeling efforts. Wells 1 and 2 experienced 36 days of lower production due to the interference frac-hits. This is not an isolated event in our experience; loss in production occurred every time sequential development of completions and production was deployed. Some wells returned to forecast while other wells failed to reach pre frac-hit production levels. Using all of our observed frac-hit data, we were able to quantify production loss as a function of distance (Figure 5). This relationship is used to understand and incorporate the economic effects of frac-hits in development planning when using a sequential development technique. We also see indications of compromised SRVs of child wells, which is consistent with microseismic data, frac modeling results, and production analysis.

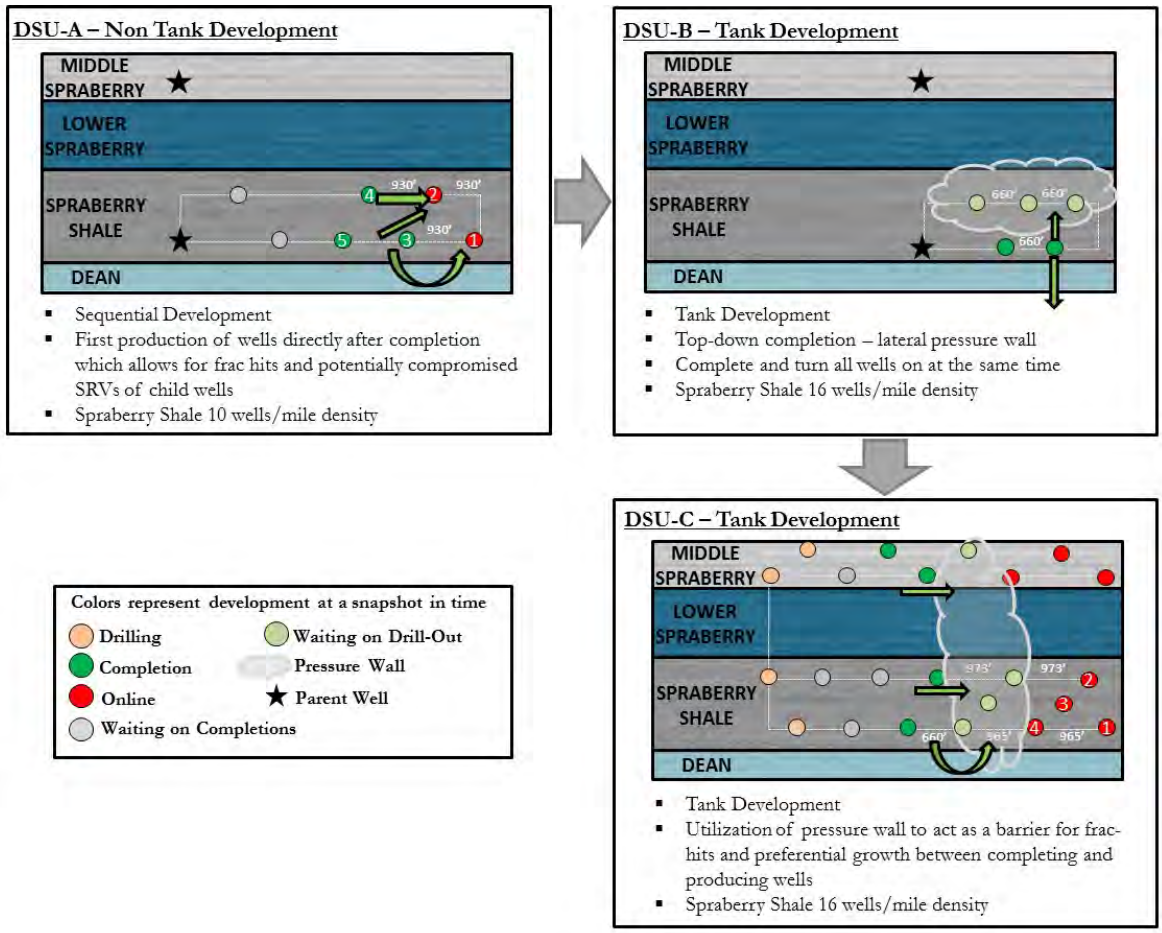


Figure 4: Block diagrams illustrating development strategy evolution over three DSUs

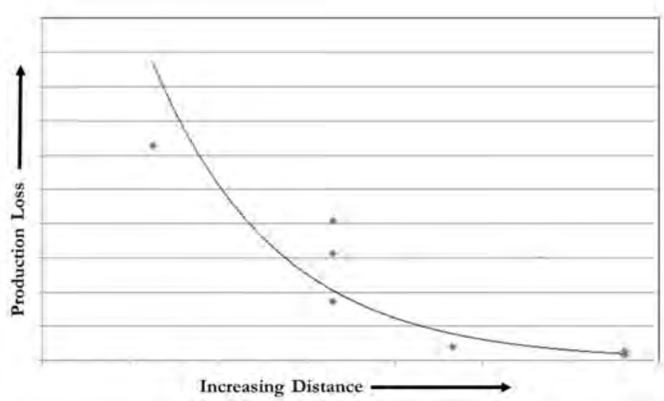


Figure 5: Observed parent well production loss versus distance from completing child well

In addition to the sequential development test (DSU-A), we have executed one horizontal infill program to better understand the economics of infilling for stranded reserves within the Spraberry Formation (Figure 6). An infill well is a well drilled in between two or more existing producers. In our one-mile DSU study, two Spraberry Shale infill wells were drilled and completed 150 feet above 7 producing Spraberry Shale wells and approximately 650 feet below 4 producing Middle Spraberry wells. At the time of completion of the two infill wells, the 11 existing wells produced a combined ~3,000,000 barrels of fluid over 1-2 years. During completion of the infill wells, 7 of the 11 existing wells, positioned both above and below the infill wells, experienced interference frac-hits. The wells with frac-hits decreased in production by 30-100% and took several months, if ever, for oil production to return to pre frac-hit trends. In addition to decreased production in the existing wells from frac-hits, the infill wells had lower performance compared to all other wells producing in the Spraberry Shale (50% reduction in EUR). We believe the lower production is due to a compromised SRV caused by the pressure sinks above and below the wells. Our hypothesis is supported by frac modeling results that predicted immediate growth into pressure sinks, proppant settling away from the wellbore, and smaller SRV. Considering current operational costs, oil prices, and our development experience described above, it is not economic to drill additional infill wells at this time. This perspective emphasizes the need to understand optimal multiple stratigraphic horizon spacings in an effort to balance stranding economic oil and maximizing value.

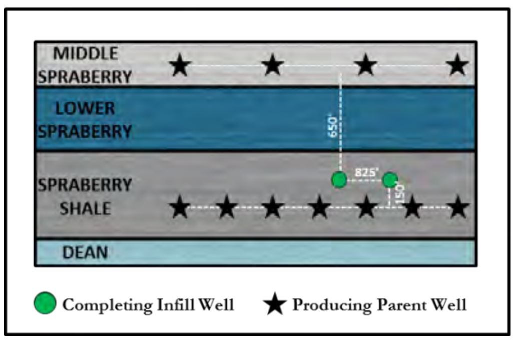


Figure 6: Infill Spraberry Shale trial

Novel Development Strategy: Tank Development

To overcome the pitfalls at DSU-A, our goal in DSU-B and DSU-C was to optimize the development strategy rather than use a mitigation technique leading to the creation of our multi-disciplinary Tank Development approach aimed at optimizing both the surface and subsurface operations for tightly-spaced and stacked horizons. The principle element of Tank Development is the exploitation of a volume of rock at one time in order to maximize reservoir potential. This is accomplished through detailed planning of well placement and the integration of drilling, completions, drill-out timing, and putting wells on production.

Ideally, all wells in a given area are drilled, completed, and then brought online at the same time to minimize the effects of frac-hits resulting from pressure sinks. However, understanding that there is a practical balance between optimal development and production goals, a "pressure wall" concept was developed and implemented to minimize well interference while optimizing production and stimulation. A pressure wall in our context is a lateral and/or vertical volume of reservoir that has been completed (and thus is "pressured up") but not turned online for flowback (Figure 4 DSU-B and C; Figure 7). The reservoir within the pressure wall is above pore pressure due to completion energy and acts as a barrier to frac-hits and preferential energy growth between completing and producing wells. A volume of unstimulated rock is present and acts as a buffer between drilling and completion operations (Figure 7). We have experienced multiple frac-hits resulting in drilling operation downtime and associated increased costs prior to the implementation of this buffer.

Tank Development must therefore be accomplished by continual timely development of a DSU such that the drilling rig(s) are followed by completion crew(s) that create a pressure wall and are in turn followed by simultaneous flowback and production of all the wells (Figure 7). The three critical steps to deploying Tank Development are:

1. Complete wells in a top-down manner whenever possible in order to minimize stimulation fluid and pressure leakoff into shallower, lower pressure zones and open natural fractured rock generating more near-wellbore complexity.
2. Bring wells online only when there is a pressure wall separating producing wells from completing wells.
3. If a pressure sink exists, start completion operations at the pressure sink and drill laterally away from sink.

Prior to our two tank case studies discussed in detail below, we recognized Tank Development maximized surface efficiencies through higher utilization (i.e. less downtime) of drilling, completions, facilities equipment, crews, and infrastructure. In addition, we hypothesized it would maximize subsurface reservoir energy and well productivity through "super-charging" the reservoir. In this context, super-charging is the conservation of pressure and additive energy within a volume of reservoir from multiple horizontal hydraulic stimulations and is discussed in more detail below.

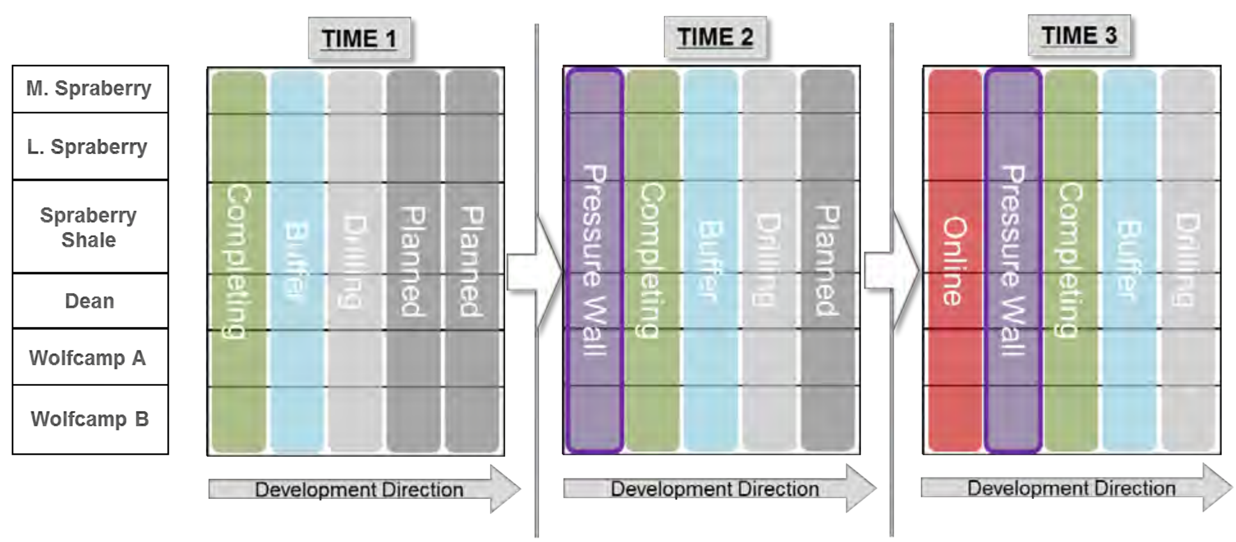


Figure 7: Continuous tank development approach

Tank Development Execution and Results

Our first implementation of Tank Development was on DSU-B in the Spraberry Shale (Figure 4). Development in this DSU consisted of 5 wells at 16 wells per mile density, offsetting existing parent wells in both the Spraberry Shale and Middle Spraberry. These 5 wells were completed in a top-down manner. The upper bench was completed first, resulting in a lateral pressure wall, followed by the two wells in the lower bench of the Spraberry Shale. The two lower bench wells had a lower GOR signature than what is usually observed in this formation. We interpret this as evidence that our lateral pressure wall increased near-wellbore complexity of the two lower wells. This lateral pressure wall may have also forced some completion energy downward into the underlying Dean Formation, which we would expect to have lower GOR than the Spraberry Shale. Early production from the DSU-B 16 well density test with Tank Development showed similar performance to the 8 wells per mile Non-Tank Development, suggesting there was an uptick in production likely due to application of the Tank Development strategy. Production and value metrics will be discussed in great detail in the following sections. Currently, RTA and reservoir simulation are ongoing in this DSU to provide more insight into the physics of Tank Development and pressure wall utilization.

Following the success at DSU-B, we planned DSU-C similarly in the Spraberry Shale at an average of 16 well density using the Tank Development strategy with comparable completion designs, but also included wells in the Middle Spraberry (Figure 4). Wells were completed in a top-down manner as best as possible, however due to the pad assignments a lateral pressure wall could not be created like in DSU-B. In addition, DSU-C was our first attempt at continual Tank Development with multiple simultaneous operations across 6 pads. We also successfully implemented our pressure wall concept based on field results. Using surface gauge data, production, and ESP pump intake pressures, we observed an effective reservoir pressure barrier was formed that minimized production losses from frac-hits and maximized effective stimulations.

In order to further evaluate the effectiveness of our development strategy, we used a surface microseismic array to monitor 4 wells (Wells 1, 2, 3, and 4) in the Spraberry Shale formation during Tank Development completions (Figure 4). A surface array was selected over a vertical array in order to detect focal mechanisms minimizing false conclusions that can result from interpreting solely raw events. Focal mechanisms describe the failure mechanisms associated with an event and are critical in modeling discrete fracture networks (DFN) and corresponding propped DFN. Moment magnitudes and failure mechanisms indicative of hydraulic fracturing are combined with rock properties to create a DFN. This DFN is calibrated using a mass-balance approach where the fluid-induced fracture volume is equal to the injected fluid and proppant volume minus the leakoff volume (as measured from a leakoff test). Proppant is injected on a stage-by-stage basis in an elliptical fashion honoring the shape of the event cloud. A full methodology of creating DFNs from microseismic events can be found in McKenna et al., 2016.

Each of the 4 Spraberry Shale wells were completed East to West with Well 1 completed first and Well 4 completed last. As Tank Development advances and wells are continually stimulated, both measured event count and magnitude of each well increases (Figure 8). This is evidence of breaking more rock due to super-charging the reservoir and is consistent with Mohr-Coulomb failure criteria. With the injection of fluids and resulting increases in pressure, the Mohr circle moves to the left into a state of shear causing optimally oriented fractures with respect to regional stresses to fail first (Figure 9) (Dohmen et. al. 2013). The additive pressures and stresses from sequential hydraulic stimulation will increase the formation stress past the critically stressed failure point allowing fractures to fail as the completions progress. In Figure 8, the propped SRV is increasingly compact from Well 1 to Well 4, with smaller height and lateral extents, suggesting increased near-wellbore complexity as Tank Development advances.

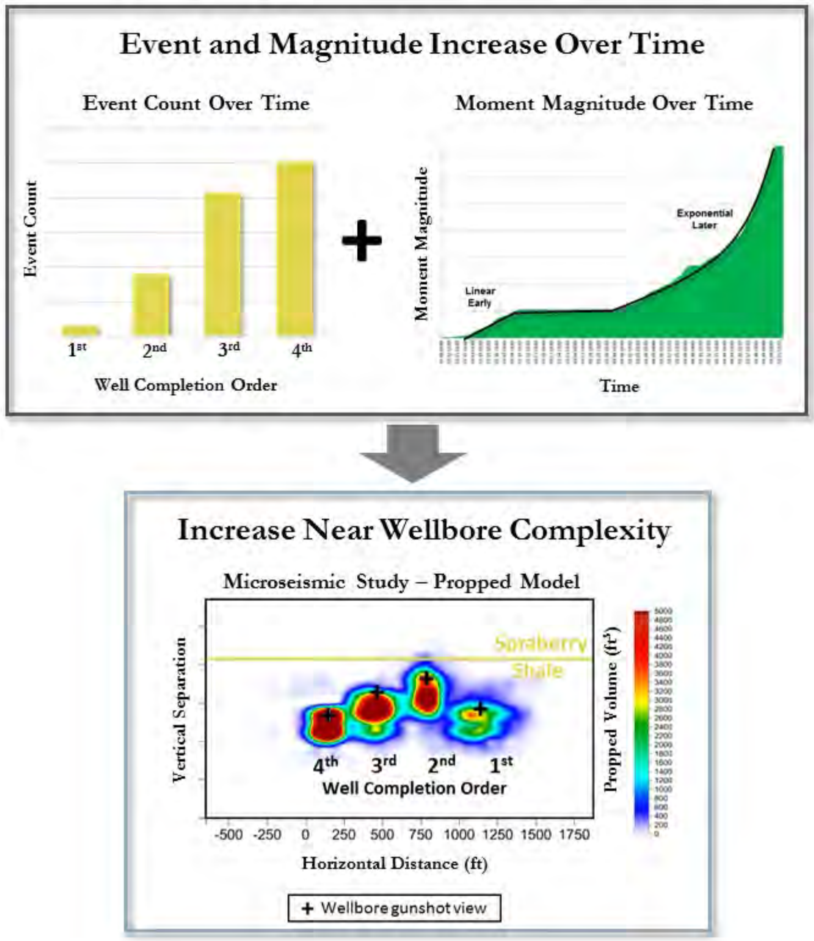


Figure 8: Event Count and Moment Magnitudes increase with Tank Development

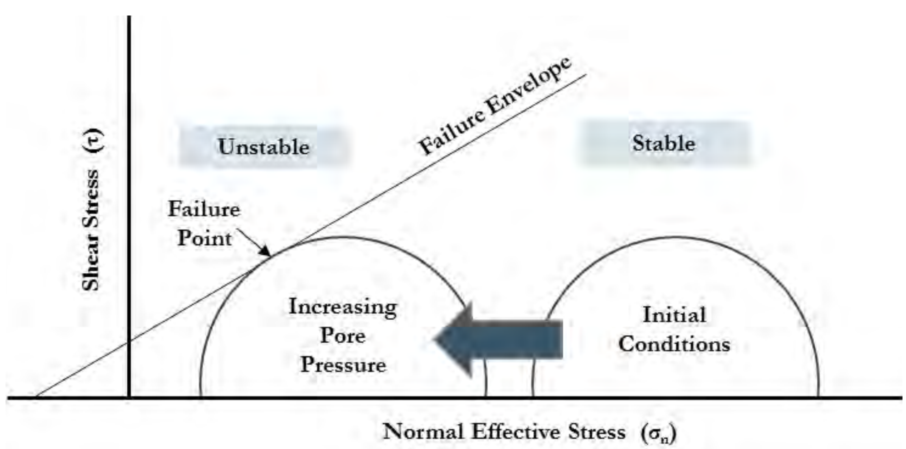


Figure 9: Mohr circle: increasing pore pressure diminishes normal effective stress, moving system towards shear failure envelope.

The increase of propped volume and near-wellbore complexity seen in microseismic data is corroborated by production diagnostics. Figure 10 shows a diagnostic plot illustrating reciprocal productivity index (Δp/q) against the square root of time. This plot is instructive because, during linear flow, the slope is equal to the reciprocal of the product of surface area of reservoir contacted and the square root of permeability (Equation 1). A shallower slope then equates to greater surface area, and is indicative of greater complexity in the fracture network. The shallower slope of the DSU-B average indicates that Tank Development created greater complexity and greater fracture network surface area than that of the Non-Tank Developed DSU-A.

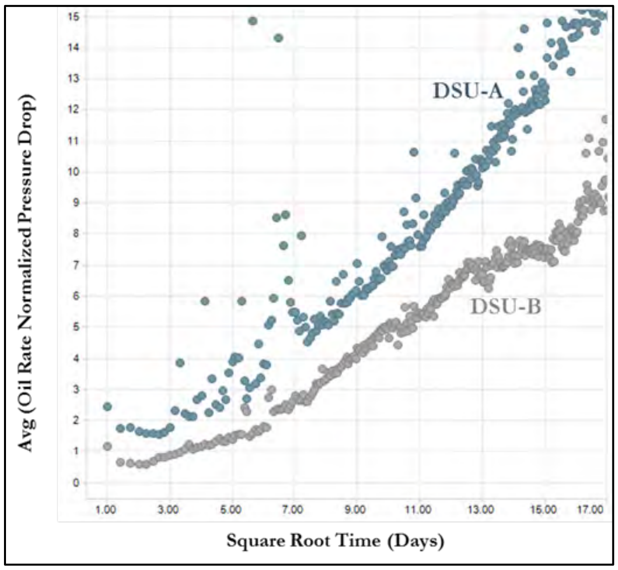


Figure 10: Reciprocal Productivity Index plot of average of Tank Developed wells (DSU-B completed at 16 wells/mile) compared to Non-Tank Developed wells (DSU-A completed at 10 wells/mile).

$$\text{RPI Slope} = \frac{1}{h_f n_f x_f \sqrt{k}} \qquad (1)$$

Completion datasets contain trends that imply the process by which this complexity is created. Pressure data from DSU-C exhibit a rising trend in pre-frac pressures when wells are completed in close proximity to one another (Figure 11). The pressures for the first two pairs of wells did not increase dramatically, perhaps due to greater spatial extent of their position, having been spread over two formations, but well pairs three and four in the sequence exhibit increasing initial pressure profiles. This suggests that the latter wells were influenced by the energy from the preceding completions. The fluid placed by the first two pairs elevated pressures in the reservoir, increased local pore pressures, which in turn diminished the system's normal effective stress, moving the system towards its shear failure envelope (Figure 9). Completion pairs three and four (Figure 11) were then completed in the same reservoir, and at tighter spacing than the first two pairs, into a system whose energy had been elevated by the first two completions. This region of heightened pressure and stress above well pairs three and four appear to have acted as a partial hydraulic seal for the last two pairs, resulting in greater localization of completion energy for the last two completion pairs, and thus greater elevation in their initial pressures.

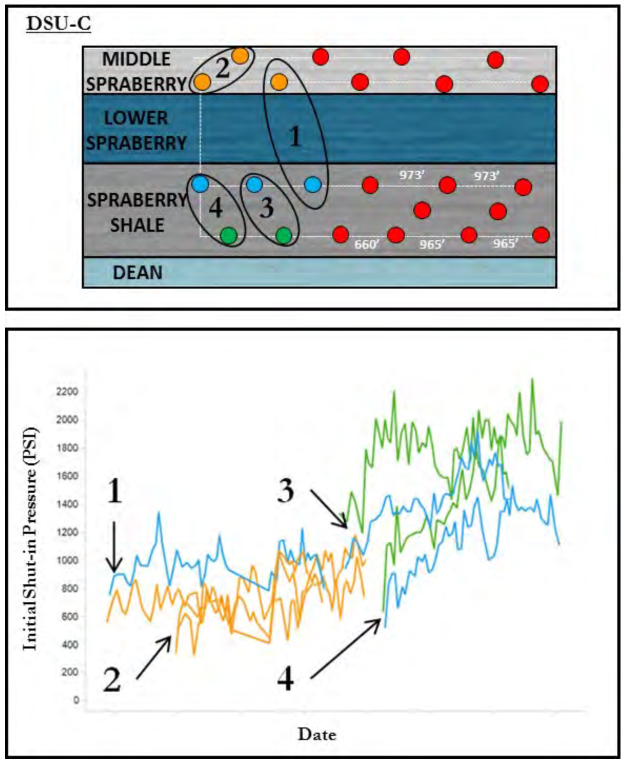


Figure 11: Initial shut-in pressures (pre-frac) rising between stages towards the end of a sequence of Tank Developed wells on the west side of DSU-C.

The relationship between rising initial pressures over the course of a Tank Developed package of wells is a significant one because it indicates that Tank Development is super-charging the reservoir, adding energy to the system faster than it can be dissipated via fracture propagation and leak-off. With data collected from microseismic mentioned above (Figure 8), it is apparent that this increasing residual energy correlates with an acceleration of fracture event generation and cumulative moment.

The connection between the rising pre-frac pressures and accelerating event generation is shown schematically in Figure 12. Because the pre-frac initial shut-in pressure is increasing for each subsequent well in a tank development sequence, the net energy needed to return the system to a critical state diminishes with each additional completion. The end result is that for each subsequent completion in a Tank Development sequence, more completion energy is spent generating fractures, and less time, energy, and capital is spent elevating the system energy to the point of formation breakdown.

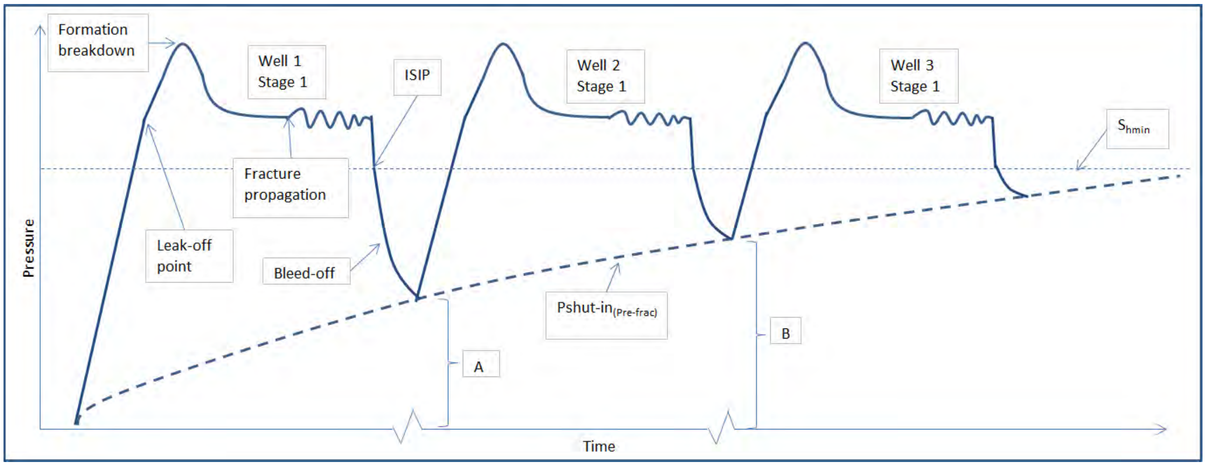
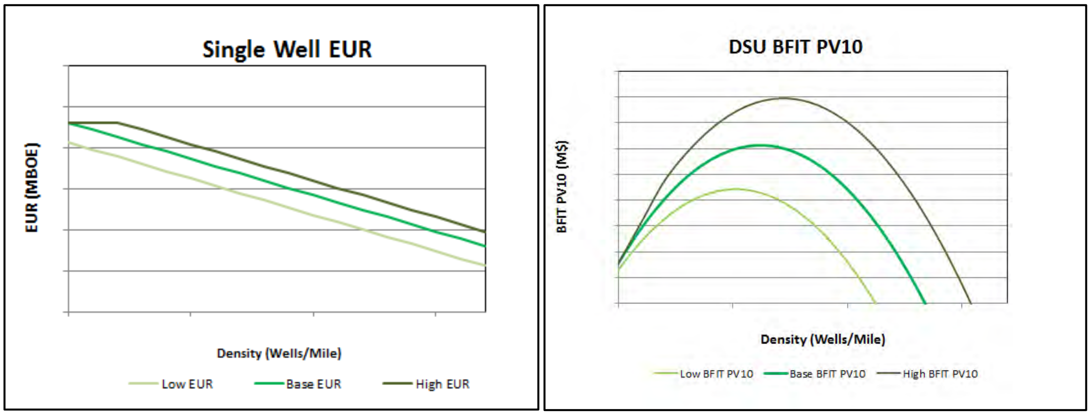


Figure 12: Schematic illustrating the following concept: Tank Development adds energy to the reservoir system faster than it can dissipate, resulting in greater number of fracture initiations in each subsequent completion, and thus greater near-wellbore complexity. Starting points A and B are higher than the first well's initial shut-in pressure (pre-frac), which translates to greater event generation and capital efficiency.

The correlation between initial shut-in pressure and cumulative moment magnitude contains Tank Development's value creation mechanism: high density Tank Development results in more fracture network surface area per unit volume of reservoir than conventional, sequential development. As a result, the same volume of rock can support a greater number of PV-optimal wells, achieve greater cumulative asset value, and recover more resource.

Value Proposition: How to Double the Value of a Shale Asset

Operators face competing and often conflicting enterprise objectives. These include but are not limited to the need to maximize project rate of return, shareholder return, production growth, margin growth, and reserves growth. Perhaps paramount among these is the need to execute a development plan that maximizes the present value of the asset, given capital constraints. In order to do this, sufficient density tests should be conducted in order for an operator to have a reasonable confidence in how a reservoir's performance varies as a function of well density (Figure 13). These EUR trends can be used to profile the cumulative value of a DSU and/or asset in order to determine the value-optimal development density (Figure 13b).



13a 13b

Figure 13a, b: With sufficient density tests, EUR can be expressed as a function of development density. Plotting average PV10 for wells at a given density allows the operator to understand the value ramification at scale. Figure b shows the DSU level cumulative PV10 across densities. The peak of this parabola corresponds to the density that maximizes the value of a drilling unit.

A key validation of our Tank Development density trials is that the EUR trends observed from our Tank Development tests greatly exceed the results from Non-Tank Developed well packages (Figure 14). The average EURs of the density tests show distinct behavior between wells that were and were not Tank Developed. This departure from trend is a product of two factors: 1.) Tank Developed wells do not suffer frac-hits, which means SRV impairment in both child and parent wells are avoided, and 2.) Tank Developed wells exhibit greater event generation and thus greater fracture network surface area from increased fracture network complexity. This clear performance uplift has significant asset value implications.

The EUR trend of Tank Developed wells, which departs significantly from its Non-Tank Developed peers, is also seen in the present value trend. When this trend is rolled up to the DSU level, Tank Development allows an operator to increase density and increase the value of a given volume of rock (Figure 14b). The magnitude of this increase is specific to the reservoir and the DSU's location within the basin, but in the case of the Spraberry Shale example, Tank Development allows both peak value and the well count at which this is realized to more than double.

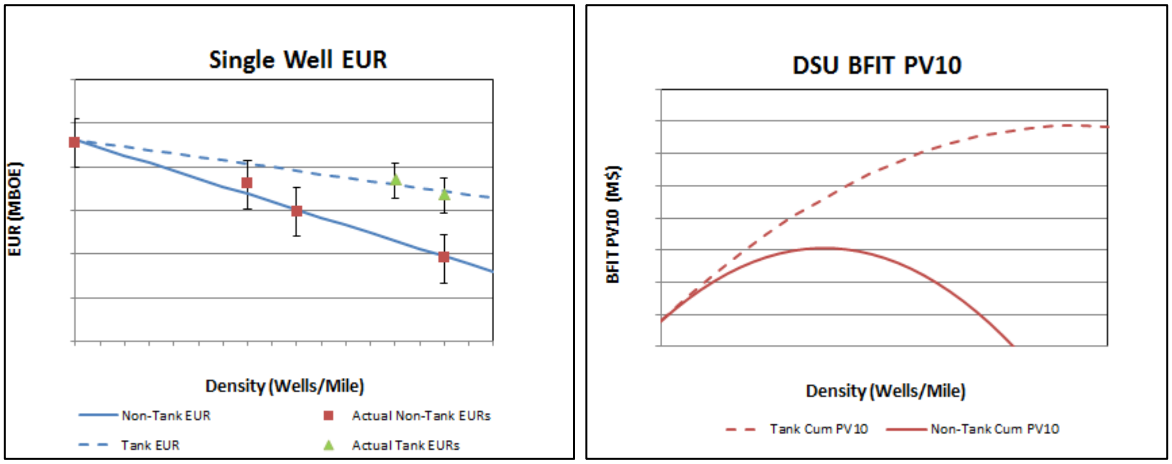


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Figure 14a, b: The average EUR trend of Tank Developed Spraberry Shale wells is elevated relative to its Non-Tank Developed peers at comparable density. The shallower degradation trend in Tank Developed wells means that the DSU can support a greater number of wells at a considerable value multiple as compared to a Non-Tank Development regime (14b).

Conclusions

- The pitfalls of parent/child sequential well development are two-fold: the stimulation of the child well results in an immediate and in some cases irreversible impact to the parent well, and the parent well acts as an energy sink, resulting in a poor stimulation of the child well. Tank Development effectively eliminates the detrimental effects of parent and child well interactions.
- Super-charging the reservoir through Tank Development results in exponential microseismic event growth profile, resulting in completions with greater near-wellbore hydraulic fracture network complexity. Increased fracture network complexity results in greater surface area per unit volume of rock, which supports higher well densities and higher oil recoveries.
- Tank Development, employing a pressure wall, minimizes well interference while optimizing stimulation, production, and operational efficiency.
- Tank Development increases both magnitude of peak asset value and the well count at which this peak occurs.
- We expect our Tank Development strategy to undergo continuous optimization as we incorporate future field tests, additional data acquisition, and reservoir modeling into our analysis.

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Nomenclature

k = permeability
x_f = fracture half length
h_f = fracture height
n_f = number of fractures

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