Review of the 1st unconventional testing of the prospective Tyler Formation, southwestern North Dakota

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Introduction

Beginning in late 2010, on the heels of the emerging Bakken play, the North Dakota Geological Survey published a series of maps and reports on the resource potential of the Tyler Formation. Mineral rights leasing in prospective Tyler acreage began to take off accompanied by a significant amount of media attention. The Tyler was speculated during that time to eventually emerge as another Bakken-like unconventional resource play. During September 2013 to August 2014, two horizontal test wells, the Rundle Trust 21-29TH and the Powell 31-27TH (figs. 1 & 2), were drilled in the Tyler Formation and stimulated using multi-stage hydraulic fracture completions. Although both wells went on to produce oil with some associated gas, the production rates were relatively low. Oil prices proceeded to collapse in late 2014, shortly after these test wells were completed. Following approximately a year of production both wells were plugged and abandoned, returning the unconventional Tyler play into dormancy for the time being. Revisiting the Rundle Trust and Powell completions, and examining what was achieved and learned, may assist the Tyler Formation in re-emerging one day into the unconventional oil and gas landscape.

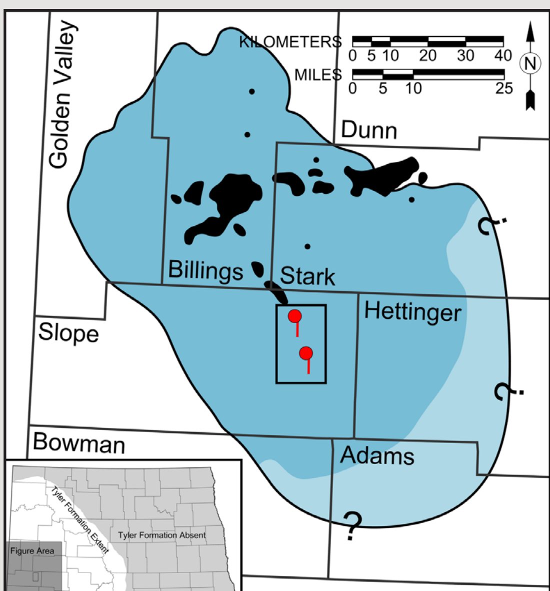


Figure 1. Map of southwestern North Dakota displaying the extent of organic-rich upper Tyler petroleum source beds (blue) and Tyler oil production (black). The red symbols represent the recent Rundle Trust and Powell horizontal test wells. A North Dakota index map with county outlines, Tyler Fm. extent, and the figure 1 area is shown in the bottom left corner. The figure 2 area is shown by the black outline around the two red test wells.

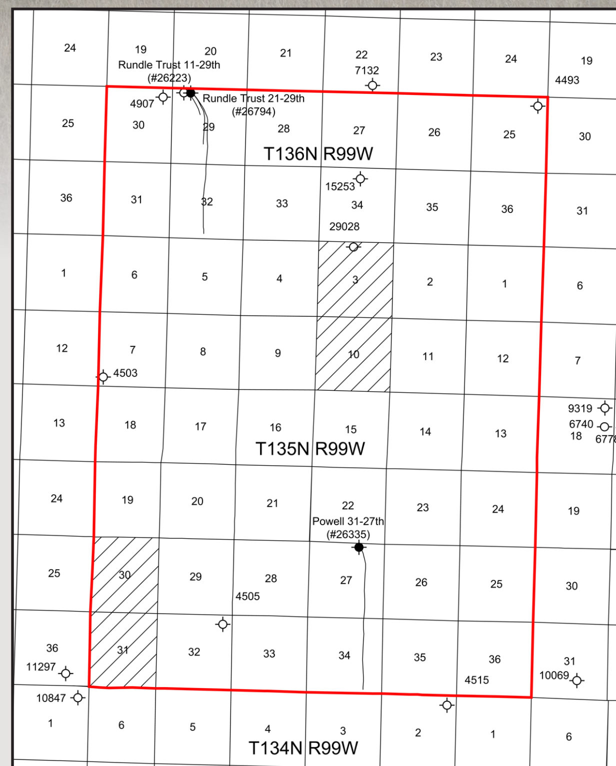


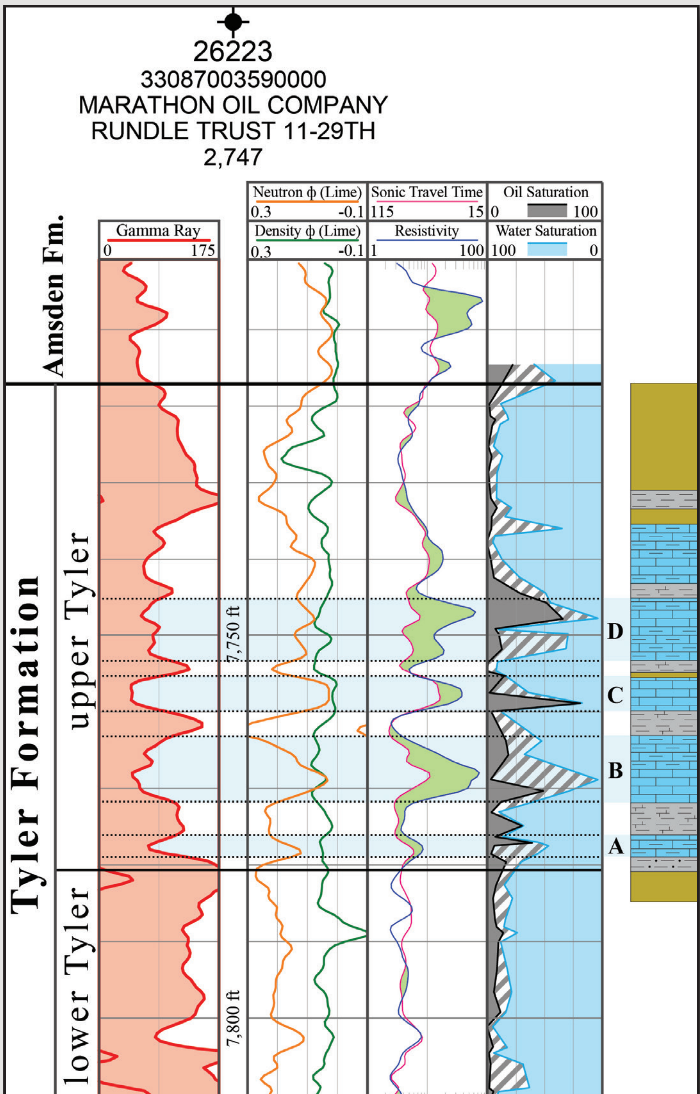
Figure 2. Map of the Moord Field showing the location of legacy vertical oil wells and the recent horizontal Rundle Trust and Powell test wells. NDIC well numbers are listed next to each well. The diagonal line-filled sections depict the locations where two additional Tyler test wells were requested but have since been cancelled.

Upper Tyler Stratigraphy

The upper Tyler Formation, the target of the unconventional test wells, is composed primarily of interbedded shale and limestone with thin, discontinuous paleosols (buried soil horizons) and a locally present sandstone near the base of the section (figs. 3 & 4). The locally present sandstone occurs along a roughly east-west trend, extending from Dickinson to Medora, and has served as an oil-productive reservoir for roughly 270 vertical wells that have produced approximately 80 million barrels of oil. The primary petroleum source rock of the upper Tyler petroleum systems are the carbonate mudstone beds (argillaceous limestone), informally referred to as carbonate beds A-D in ascending order (figs. 3 & 4). The upper Tyler section is thought to have formed within a variable, but predominantly brackish water lagoonal setting (Nesheim and Nordeng, 2016).

Drilling the Rundle Trust 11-29TH

The Rundle Trust 11-29TH was spudded by Marathon Oil Company on September 12th, 2013 in northeastern Slope County (figs. 1 & 2). This initial well cut cores of the Tyler and underlying Three Forks Formations before attempting to drill horizontally into the upper Tyler Formation. The upper Tyler core section was noted by the wellsite geologist to contain discontinuous hydrocarbon fluorescence and oil seepages as well as periodic medium to dark brown oil staining. The horizontal leg of the well was drilled targeting a ~4ft-thick limestone bed within the lower portions of the upper Tyler, an interval that displayed strong oil shows in the core sample (fig. 3).



This initial lateral was drilled using a saltwater-based drilling fluid and only went 126 ft. before the tool assembly became stuck and part of the tool assembly was left in the hole. A sidetrack lateral was then drilled off the initial lateral, using diesel invert drilling fluid instead of saltwater drilling fluid. The sidetrack went approximately another 1,000 ft. before a failed casing shoe halted the drilling operations again. The sidetrack had difficulties staying within the target zone and had penetrated an underlying shale bed at the time the sidetrack was abandoned. A decision was made to temporarily abandon the Rundle Trust 11-29TH in favor of moving the drill rig over and drilling a new well on the existing pad.

Drilling and Completion of the Rundle Trust 21-29TH

The Rundle Trust 21-29TH was spudded on October 28th, 2013 right adjacent to the abandoned Rundle Trust 11-29TH (fig. 2). The Rundle Trust 21-29TH was drilled vertically to a depth of 7,202 ft. and then began curving into the upper Tyler Formation and reached its horizontal kick-off point target on November 2nd, less than 6 days after being spudded.

This second Rundle Trust horizontal test well was drilled using entirely oil-based mud in the upper Tyler Formation to help maintain well-bore integrity. As the Rundle Trust 21-29TH drilled into the formation, the background gas increased from around 20 units to upwards of 145. The initial lateral was drilled targeting the same 4 ft. zone as the first Rundle Trust well, which again was unsuccessful and took approximately 12 days of drilling time. The second lateral attempt (sidetrack) was positioned just a few feet higher, within a ~2-ft-thick shaly limestone bed that was bounded above and below by dense, non-shaly limestone (figs. 3 & 4). The sidetrack stayed in-zone for the entire ~2 mile lateral and reached TD on December 2nd after approximately 21 days of drilling. Background gas varied during the lateral's construction between a minimal 10-20 units to around 50-70 units. Oil fluorescence was not noted during drilling, possibly owing to the oil-based drilling mud, but the oil to water ratio in the drilling mud increased steadily as construction of the lateral progressed.

The Rundle Trust 21-29TH lateral was completed with 24 stimulation stages (sliding sleeve) that injected 35,388 barrels of fluid along with 1.67 million lbs. of frac sand. Initial 24-hour production was 88 barrels of oil and 153 barrels of water. During the first month of production, daily yields averaged 23 barrels of oil, 81 barrels of water, and 19 MCF (thousand cubic feet) gas. The produced oil was reportedly light crude oil (41° API oil gravity) and the gas consisted of 37% nitrogen, 36% methane, with lesser amounts of several other hydrocarbon gases and some carbon dioxide. Daily oil production steadily declined during the first several months before stabilizing at around 6-7 barrels of oil per day during the final 4 months, and actually appeared to have been slightly increasing during the last two months of that time frame (fig. 5).

Figure 3. Wireline logs with core oil-water saturations and generalized lithologies of the upper Tyler Formation from Marathon's Rundle Trust 11-29TH. The A-D labels for the upper Tyler carbonate beds are after Nesheim and Nordeng (2016).

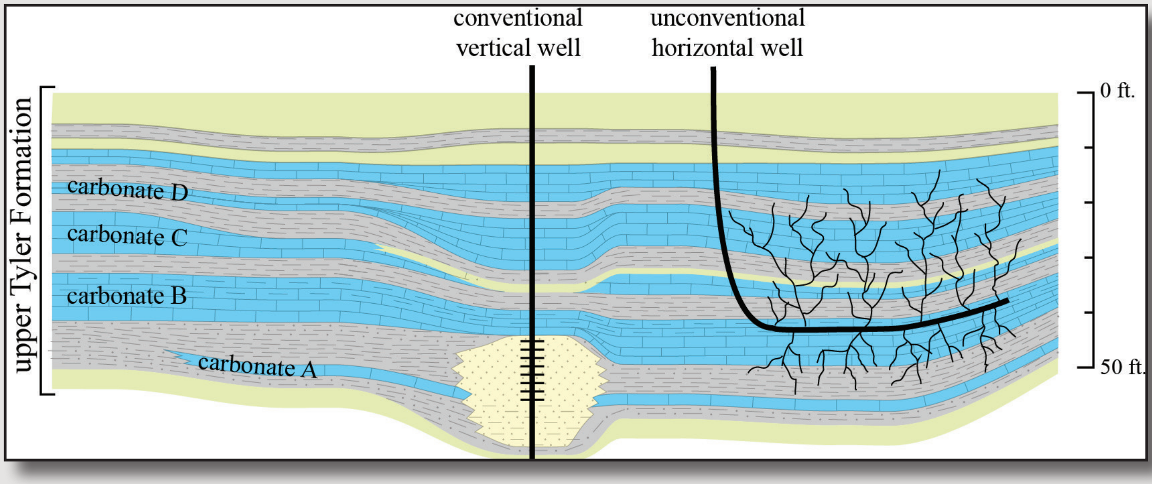


Figure 4. Schematic cross-section of the upper Tyler Formation showing an example of a conventional sandstone completion versus an unconventional completion in the upper B carbonate. Carbonate (limestone) beds are colored blue, shale beds are grey, sandstone is yellow, and paleosols are light green.

The producing water cut (water versus oil + water fluid ratio) steadily decreased from 76% during the first month of production to 58% during the final month. Marathon reported during their temporary spacing hearing that nearly all of the produced water from the Rundle Trust 21-29TH was injected hydraulic fracture fluid, and therefore minimal natural formation water was produced. After a total of 377 days of production, the Rundle Trust had only recovered a little over 10,000 of the 35,388 barrels of injected frac fluid. This means most of the injected fluid became stranded within the host rock.

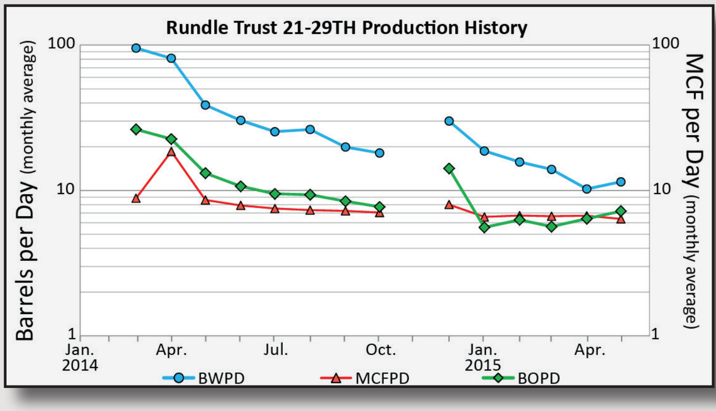


Figure 5. Average daily production by month of the Rundle Trust 21-29TH.

Powell 31-27TH

The Powell 31-27TH was drilled just a few miles southeast of the Rundle Trust wells (fig. 2). The Powell was drilled using a diesel invert mud system and initially went vertically through the Tyler Formation to collect wireline logs before being plugged back uphole and drilled horizontally. The Powell horizontal targeted the same thin argillaceous limestone that was successfully drilled within the sidetrack of the 2nd Rundle Trust well. Once the Powell was in-zone, the ~2 mile lateral was drilled using only two drill bits and reached a TD of 15,425 ft MD in 130 hours (5.4 days), which was only one-fourth of the drill time of the Rundle Trust 21-29TH ~2 mile lateral (21 days). Gas levels during the lateral's construction appeared to steadily increase from 30-50 units to 68-80 units, and oil shows were noted in the drill cuttings. Similar to the Rundle Trust completion, the Powell was completed with reportedly 24 stimulation stages (sliding sleeve) but used only half of the injected fluid (17,425 barrels) and proppant (0.79 million lbs.) volumes. Perhaps due in part to the smaller frac job, oil production rates from the Powell were less than that of the Rundle Trust completion, consisting of only 2-4 BOPD.

Reservoir Properties

The prospective reservoir for the upper Tyler Formation that was targeted by the Rundle Trust and Powell wells consists predominantly of organic-rich, fine-grained, argillaceous limestone beds (fig. 6). Two of these carbonate source beds combine to average 6% porosity with around 60% oil saturation (based on core plug data and log analysis) and a combined thickness of 16 ft. (B & D beds - fig. 3). Overall, the upper Tyler appears to conservatively hold around 4 million barrels of oil/section (8 million barrels of oil/1280 acres) within the area of the Rundle Trust based on available core and wireline log analysis data.

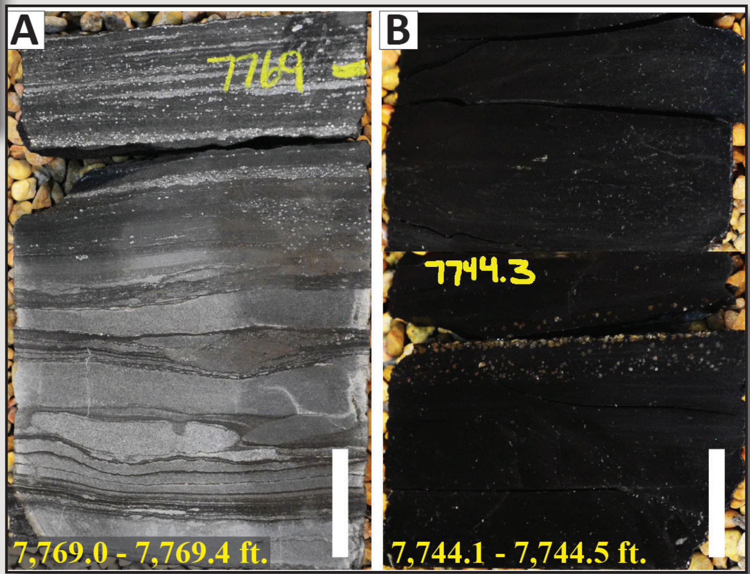


Figure 6. Core photograph examples of the B (6A) and D (6B) carbonate beds from the Rundle Trust 11-29TH Tyler core. Approximate core intervals are displayed at the bottom of each photograph. The white line in the bottom right corner represents 1 inch.

Seventeen total upper Tyler core samples were analyzed at Baker Hughes Pressure Pumping Technology Center to evaluate formation mineralogy, acid solubility, and fluid compatibility. The results indicate two potential water sensitivity issues that may have negatively affected production from the Rundle Trust and Powell completions: First, strong capillary forces may cause retention of injected fluids within micropores which would increase reservoir water saturation and decrease the relative permeability to hydrocarbons. Second, expandable clays (Smectite) that swell and weaken when in contact with fresh water (fig. 7). This can lead to proppant embedment and loss of fracture conductivity. XRD analysis of core samples indicated that the upper Tyler shale beds are composed of 10-20% smectite, which is also present to a lesser extent in the carbonate beds. Total clay content reaches upwards of 80% in the shale beds and 40% in the carbonate beds (fig. 8). Injecting relatively fresh water may decrease the ability of oil to move through the natural permeability (water retention) and the induced fractures (clay expansion) within the upper Tyler, thereby inhibiting oil production.

Both the Rundle Trust 21-29TH and the Powell 31-27TH horizontal wellbores were positioned in the upper B carbonate interval, which appears to have an intermediate clay content (~20-30%) and is probably moderately sensitive to fresh water (fig. 9). Just above this interval is a 2 to 3ft-thick shale (>40% clay) layer that is likely highly susceptible to fresh water. All of the induced fractures that spread upwards may have been completely closed off shortly after the multi-stage fracture completion owing to the injected fresh water significantly weakening the host rock. The laterally extending fractures may have also been significantly impeded.

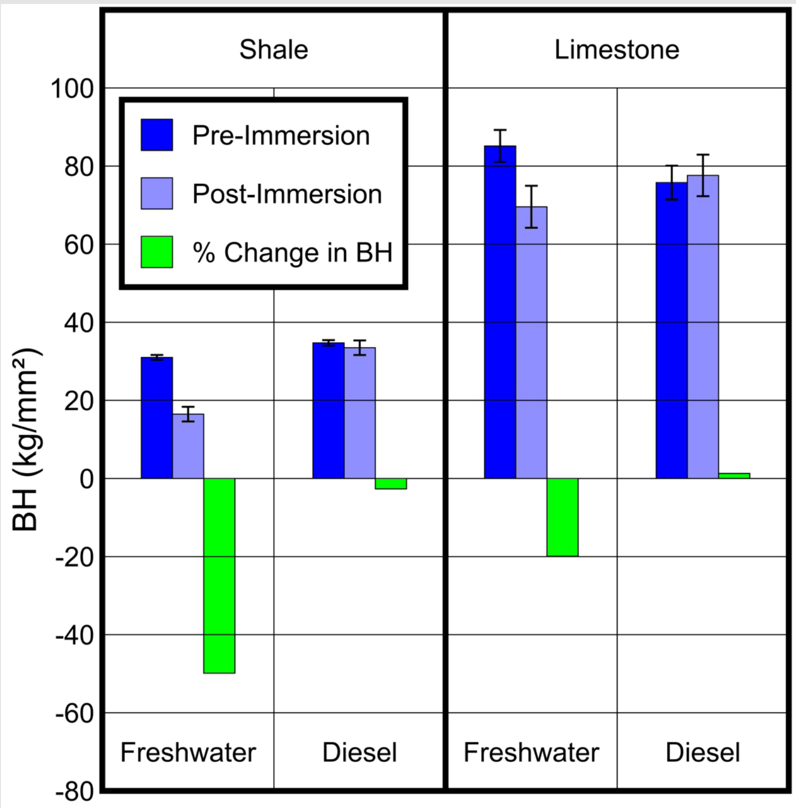


Figure 7. Diagram depicting the average formation hardness of upper Tyler shale and limestone core samples before and after immersion in fresh water and diesel. The Brinell Hardness (BH) (kg/mm2) decreased by an average of 50% within the upper Tyler shale beds after immersion in fresh water while the carbonate samples averaged a 20% hardness decrease. Several other fluids were examined, notably diesel only decreased the shale hardness by <5% on average and actually slightly increased the carbonate bed hardness. The adverse effect of fresh water on shale and carbonate bed hardness relates to the swelling, water-sensitive clay present.

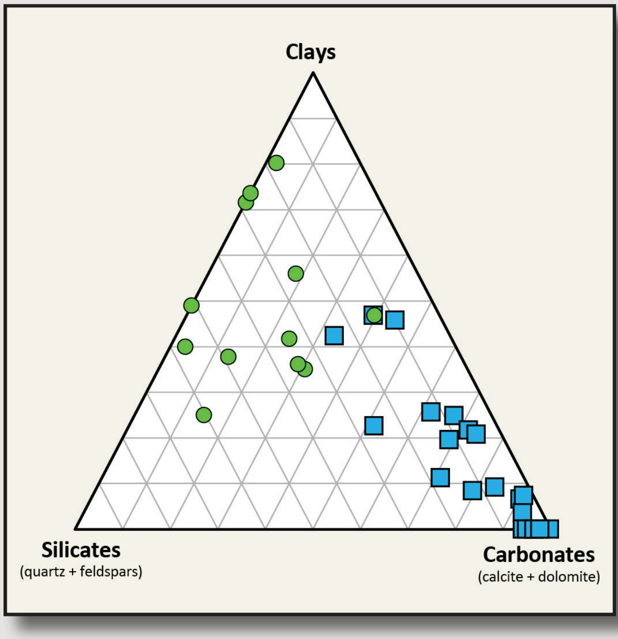


Figure 8. Ternary diagram of XRD results from upper Tyler shale (green circles) and carbonate (blue squares) beds. This data is compiled from the Rundle Trust 11-29TH discussed in this article and Duncan Energy Company's Riverbend Federal #24-23 (#13567, 33-007-01327-00-00, Sec. 23-T138N-R101W).

The only lithological interval with minimal fresh water sensitivity located near the horizontal boreholes is the original ~4-ft-thick target interval just below the final lateral target zone. The author speculates that the vast majority of the Rundle Trust and Powell horizontal production came from induced fractures that extended directly downwards into the lower B carbonate interval. The downward-extending induced fractures still may have been impeded to some degree by the fresh water due to the borehole being positioned within a moderate clay-water sensitive lithology.

Concluding Remarks

1) The core data collected form the initial Rundle Trust 11-29TH provides a better understanding of the mineralogical makeup of the upper Tyler Formation, as well as the amount of oil-filled pore space. The upper Tyler holds several million barrels of oil per section (square mile), which is comparable to some portions of the Bakken-Three Forks play.

2) Two horizontal wells with 9,000+ ft. laterals were successfully drilled in the upper Tyler and stimulated

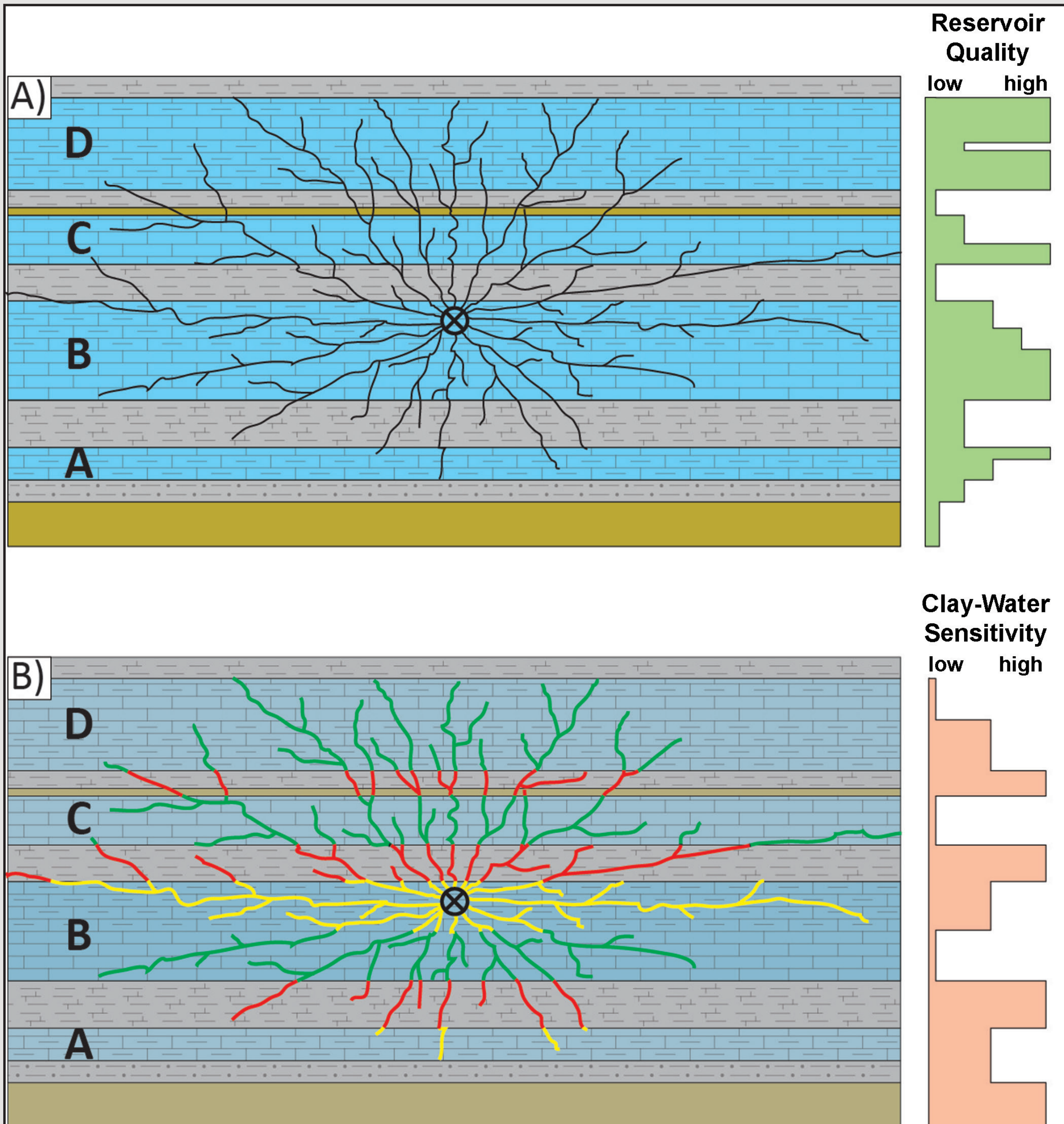


Figure 9. Schematic cross-section and induced fracture network of the upper Tyler Rundle Trust and Powell completions. 9A) Schematic cross-section and fracture network in relation to reservoir quality (right side). Reservoir quality is schematic and is based on average core plug porosity and oil saturation: high porosity and oil saturation = high quality reservoir, low porosity and/or oil saturation = low quality reservoir. 9B) Schematic cross-section and fracture network in relation to fresh water sensitivity. Schematic fractures are color-coded based on the intervals' water sensitivity: red = high water sensitivity, yellow = moderate water sensitivity, and green = low water sensitivity.

using multi-stage hydraulic fracture completions. Looking at the drill times of the vertical portion (including the curve/build) of the Rundle Trust 21-29TH and the 9,000+ ft. horizontal sidetrack of the Powell 31-27TH, a 1280-acre spacing horizontal developmental well in the upper Tyler could have been drilled within approximately 11 days in 2014. The average Bakken-Three Forks well took approximately 20 days to drill in 2014, and has significantly decreased since. The shorter total drill time for prospective horizontal Tyler wells would help make the play more economic in potential future development.

3) Even though the production rates were low, the Rundle Trust 21-29TH shows that the upper Tyler carbonate beds are capable of producing oil in an unconventional completion. The question still remains of how much they are capable of producing.

4) The usage of water-based (particularly fresh water) drilling mud and completion fluid should be avoided within the upper Tyler Formation. Diesel or oil-based drilling fluids are preferred because they help maintain wellbore integrity and also may limit damage to the formation if water sensitive clays are present. A non-water frac fluid may be more costly, but could ultimately prove to be the key to unlocking the Tyler's resource play potential.

References

Nesheim, T.O., Nordeng, S.H., 2016, Stratigraphy and Depositional Origin of Tyler Formation (Pennsylvanian) Source Beds in the Williston Basin, Western North Dakota: in Hydrocarbon Source Rocks in Unconventional Plays, Rocky Mountain Region, published by the Rocky Mountain Association of Geologists, p. 212-235.