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A Comprehensive Fluids Engineering Approach to Deep Devonian SWDs Reduces Cost

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Abstract

From January 2010 to 2020, oil production in the Permian Basin (Figure 1) has risen from 880,000 to an estimated 4.7 million barrels of oil per day (EIA, 2020). For each barrel of oil, it is estimated that an additional 2-4 barrels of water/saltwater as associated water or flowback from stimulation operations (Kronkosky and Ettehadtavakkol 2016, Hunter and Lowry 2018) is produced.

The increased disposal demand and new permitting regulations require the delivery of deeper, larger diameter well designs without compromising public safety, mechanical integrity, and injectivity.

Drilling challenges—such as salt zones, lost circulation, hydrogen sulfide, over-pressured formations and poor rate of penetration—require a comprehensive approach. A typical solution to one issue complicates another when drilling below the current producing intervals. Casing design, rig selection, drill string optimization, fluid selection and application of managed pressure drilling are major factors in mitigating the regional risks.

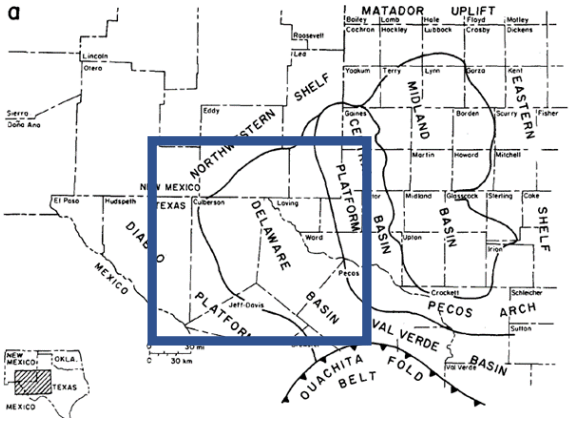

Figure 1: Map of the Permian Basin

Saltwater Disposal (SWD) Permitting Considerations

SWD wells are regulated by the Safe Water Drinking Act. Individual states can request primary enforcement if they meet the minimum EPA requirements. Texas and New Mexico, along with many other oil-producing states, perform primary enforcement, permitting SWD wells which meet EPA and additional state requirements.

The EPA underground injection control (UIC) program breaks wells into six categories, with SWD wells falling under Class II (McCurdy 2011).

An additional regulation enforced by the State of New Mexico requires that disposed water cannot be introduced into producing or potentially commercial oil and gas zones. Previous disposal into the Delaware Mountain Group (DMG) has been discontinued and deeper wells are now required to dispose of the New Mexico produced water volumes. In Texas, disposal is permitted into the DMG, but these formations have become over-pressured along Highway 285 resulting in significant risk accessing oil bearing formation in the area. This likely means Texas regulation will require deeper injection horizons – presumably into the Devonian/Silurian.

Devonian Geology

At vertical depths of over 18,000 feet, the Devonian and adjacent formations present challenges which are compounded by the complications encountered in the upper hole sections. Figures 2 and 3 show the Siluro-Devonian structure map highlighted in core regions of the Permian Basin (Galley, 1958).

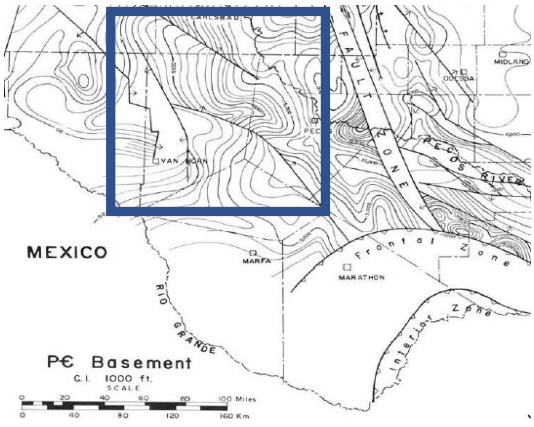

Figure 2: Devonian structure map in Texas and New Mexico

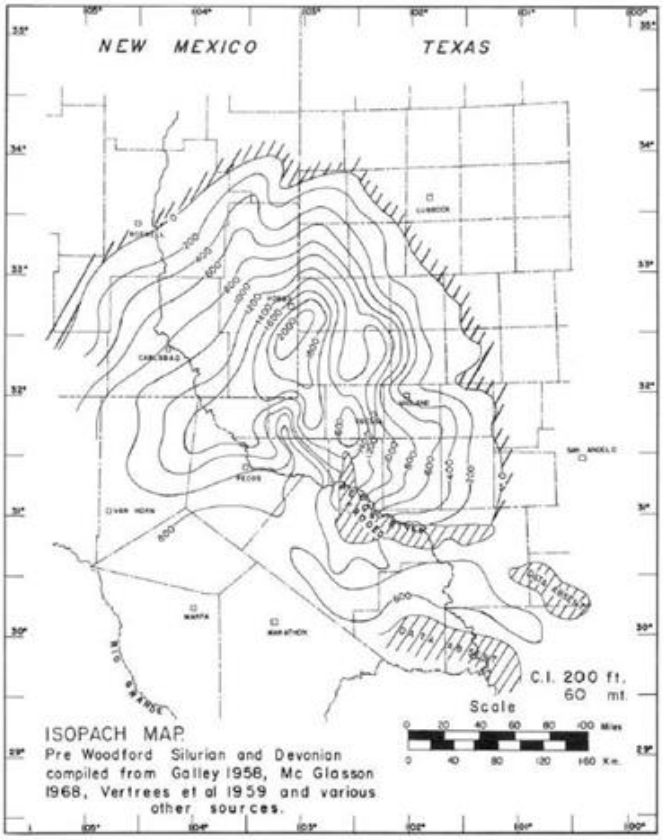

Figure 3: Thickness of pre-Woodford Silurian and Devonian strata

The Devonian time was that of a warm climate and great tectonic activity. The Tobosa Basin, which covered much of modern west Texas and southeast New Mexico was exceptionally deep, resulting in limited limestone accumulation in the late Devonian. The clastic supplies were also limited compared to subsidence rates, leading to a mostly starved basin for some time.

Depositional environments from the inland basin ranged from shallow carbonate shelf deposits which would later become injection reservoirs, to deeper water siliciclastics and cherts. Later, continental collision of the South American continent with the North American continent resulted in uplift, folding, and subaerial exposure of Devonian units. These geologic processes lead to the dolomitization and exposure of the carbonates which would later undergo diagenetic processes and become suitable for wastewater injection.

Dolomitization, when magnesium ions replace calcium ions, causes an increase in porosity and permeability of carbonates. The upper reservoir zone of the Devonian dolomite includes 1 to 3 different intervals of porous dolomite that have a total net pay thickness of up to 90 ft. Porosity in dolomite commonly ranges between 1% and 20%, and permeability between 0.1 and 100 millidarcies. Porosity and permeability are very heterogeneous in the upper dolomite, with local high permeability streaks. Pore types are dominated by molds of grains and intercrystalline pores between dolomite rhombs (Saller et al., 2010).

Wastewater injection wells drilled in the Delaware Basin below the Devonian have revealed several hundred feet of lithology available for injection. Their lithologies are primary dolomite and dolomitic limestone ranging from very fine crystalline to coarse crystalline. Interestingly, in the Midland Basin, the Devonian is not present, as beds were truncated and eroded. Some geologists believe these rocks are actually Silurian in age. In the Delaware Basin, the Devonian carbonates are often referred to as the “Thirty-one Formation”. The major lithology which lies on top of the Devonian and a significant lithologic marker for drilling these wells is the shale rich Woodford Formation, a primary source rock in the Permian Basin.

Many of the risks associated with planning and drilling wells in this pay interval pertain to the unknown properties and location of the Devonian relative to overlying and underlying formations (Figure 4). Some of the more undeveloped areas have poor geologic control and poorly developed pay which comes with its own challenges when choosing casing depths and injection intervals. It can be noted that some operators drill into the Ellenburger to target extra capacity, but this must be balanced with its proximity to the Precambrian and potential for the injection fluids to lubricate existing faults, inducing seismicity.

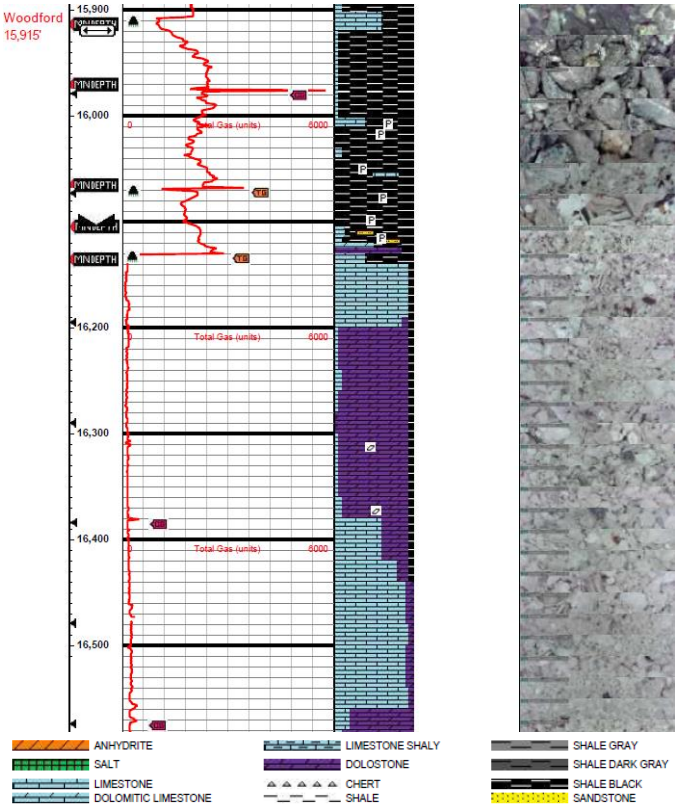

Figure 4: Devonian Lithology – note transition from Woodford Shale (black) to acid soluble Limestone/Dolomite

Regional Risks

Aside from the geological risk of targeting the Devonian structure itself, there are a myriad of risks that show up in select regions where SWD wells have been drilled. Of note;

- Uphole salt sections with high levels of washout
- Highly pressurized DMG formations in some regions with loss circulation zones away from commercial disposal areas along Highway 285. Some areas of the DMG could also contain H_2S
- Wellbore instability
- Natural fracture networks contributing to losses
- Severe losses and depleted zones in the Bone Spring
- Overpressured areas of the lower Wolfcamp and Atoka
- Small ECD windows and very hard drilling in the Mississippian
- Severe losses likely in Devonian

Figure 5 shows a map of abnormally the pressured Atoka formation (reddish) within the Delaware Basin. The Capitan Reef (yellow) is considered a freshwater aquifer and requires a separate casing string to isolate it from the salts (above) and the DMG (below). It is also a notorious loss circulation zone.

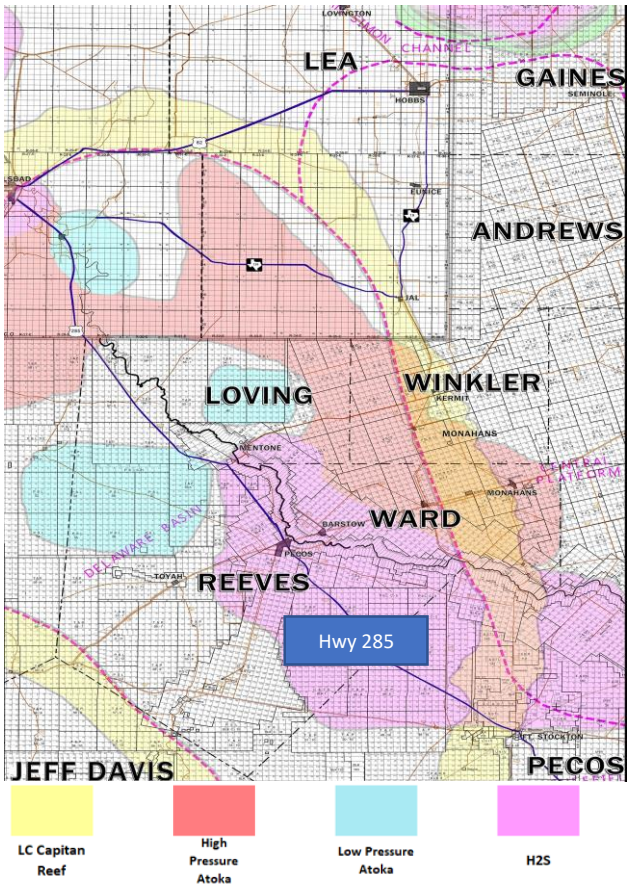

Figure 5: Atoka formation regions of abnormal pressure regimes (general trends)

Casing and Fluids Design

While many of the drilling challenges in the Delaware Basin are well known, deep SWD wells introduce greater complexity. Nearby producer wells targeting Wolfcamp formations feature a three-string casing design with the horizontal interval around 9,500' TVD. Deep SWD wells must pass through the same formations plus several more enroute to a depth of more than 18,000' TVD.

Drilling Strategies

The drilling strategies are discussed by their respective casing interval, highlighting the associated risks and methods to mitigate them.

Surface Interval

The surface interval is roughly 800' of 24" hole passing through the notoriously unstable red beds, reactive clays and the Rustler anhydrite. A gel spud mud is the fluid of choice, maintaining a mud weight below 9.0 lbm/gal to minimize the risk of losses. The reactive clays present in the surface formations can quickly become troublesome, causing bit balling and leading to premature trips to clean the bit. A steady regiment of SAPP and soap sticks can help minimize bit balling by dispersing the clay leading to easier transport to the surface. In some cases, high concentrations of PHPA is used to effectively encapsulate reactive clays.

Larger casing and surface procedures mean the surface section is generally drilled without any form of pressure control, which limits the depth at which surface casing is set. Circulating good cement to surface is required by regulators to protect existing groundwater aquifers. Lead and tail cement slurries are pumped behind 20" casing with 75% excess to ensure returns at surface.

First Intermediate Interval

The first intermediate interval enters a series of salt formations prone to excess washout. 10-10.5 lbm/gal brine is used for the section in an effort to mitigate dissolution. The brine requires minimal treatment as fluid loss control is not required. Hole cleaning is addressed with elevated flow rates to clear the large volume of cuttings generated. Treatment additives are generally limited to corrosion inhibitors and H_2S scavenger.

These poorly consolidated salts are also prone to caving and mobilization. Caliper sweeps/logs usually indicate washout requiring 50%-75% excess cement, pumped as a single stage. In some cases, the featured 13 ⅜" casing string can be cemented in two stages with a DV tool to ensure proper cement lift, though tools of this size are more difficult to source.

Second Intermediate Interval

The 12 ¼" second intermediate interval spans from 2200' to total depth at approximately 9800'. This interval passes through extremely challenging formations, including the Delaware Mountain Group, Bone Spring, and the top of the Wolfcamp. The unpredictable nature of severe losses and flows, along with potential production in the Bone Spring and Wolfcamp

formations has resulted in the decision to employ managed pressure drilling. Losses in the Cherry and Brushy Canyon regularly result in ballooning. Identifying this phenomenon is particularly challenging during flows from other exposed formations.

Fluid selection in this interval encompasses a wide spectrum of WBM varieties, direct emulsions, or invert. The best performing fluid system is chosen based on area specific hazards, limitations of each system, specific offset research and data analytics. The major factors for fluid selection include the relative sensitivity of the DMG and nearby shallow disposal wells in the area of concern. These two factors can have negative consequences for the operation leading to elevated cost for all aspects.

Drilling fluid ranges from freshwater to cut-brine with mud weights ranging from 8.6 to 9.2 lbm/gal. The use of clear fluid is preferred in this interval since the mud weight is more easily managed with solids control equipment and ECD's can be kept to a minimum. High viscosity sweeps are used to aid in hole cleaning. In areas where seepage losses are encountered, the system may be converted to a viscous fluid system with a filtration control additive to reduce fluid loss.

The Cherry/Brushy Canyons in the DMG, when broken down due to excessive mud weight, have a tendency to balloon. Once the annulus pressure is lowered below the pore pressure of the Brushy Canyon, the formation will give this lost volume back to the annulus, thus appearing that the well is flowing. If no pressure is visible during a shut-in procedure, all indications point to the formation "ballooning". This creates issues with increased H_2S, making the use of weighted mud caps necessary. Weighted mud caps are used in conjunction with MPD for drilling and tripping operations.

Heavy mud caps can lead to additional issues if care is not taken when calculating, spotting, and circulating out of the hole. Dynamic well conditions increase risks with uncertain hydrostatic pressures that could lead to well flows or losses.

Managed pressure drilling is proven in the region to aid in loss mitigation across these formations (Thibodeaux et al 2018). Viscosity of the drilling fluid can be increased as a whole, or high viscosity sweeps can be sent to aid in hole cleaning.

The cement job(s) in this section is particularly critical requiring three stages to ensure integrity, verified by cement bond log. Though three staged cement jobs are typically time consuming and require large, expensive, cement programs, the 9 ⅝" casing serves as the backbone to the well's integrity and requires special attention in the planning phase.

As noted in the first intermediate section, introducing multiple stages in the cementing process proves challenging. The downhole tools needed for a three-stage job need to be placed at strategic depths to reduce the risk of poor cement placement across the zones prevalent in the DMG and beyond. Stage tools, float equipment, and external packers are utilized to provide superior external mechanical integrity and full isolation of hydrocarbon bearing formations.

Cement slurries in the second intermediate section typically require additives that assist in lift, loss of circulation, transition times and compressive strength development. Excess volumes, upwards of 50% of annular capacity, are pumped at each stage and if cement is not circulated on the second and third stage, a pressure test is required.

Third Intermediate Interval

The third intermediate interval utilizes managed pressure drilling and invert emulsion drilling fluid. High formation pressure can require up to 15 lbm/gal mud weights, with typical mud weights ranging between 11-14.5 lbm/gal.

Originally, water-based drilling fluid was utilized; however, gas contamination presented numerous problems maintaining the drilling fluid properties, leading to increased cost across the operation. Therefore, invert emulsion has been successful with handling the higher temperatures and pressures as well as the water-sensitive shales and corrosive gasses encountered in this interval. Furthermore, the use of invert emulsion helps minimize stuck pipe, excessive torque and drag, and contamination associated with gas and oil influx (Caenn et al 2011). Managed pressure drilling has resulted in less downtime associated with gas contamination and the side effects associated with increased pressures.

Effective fluid properties for this interval must balance between the ability to clean the wellbore and suspend the barite while maintaining the lowest ECD's possible. Proactive wellbore strengthening sweeps seek to bridge off micro-fractures and heal any degradation to the formation caused by drilling operations. This has been beneficial in offset wells.

The narrow annulus of the 7 ⅝" liner through the 8 ½" hole presents risks in both surge and swab. Proper discipline to maintain running speeds below surge limits is essential to avoiding formation breakdown prior to the cement job. In many narrow annulus scenarios, the liner hanger assembly allows for rotation and reciprocation during cementing, substantially assisting in effective cement placement at lower pump rates (Song et al, 2016). Nitrified cement slurries are an option as a contingency.

Injection Interval

The injection interval is a relatively short interval with an estimated bottom-hole temperature of 280°F. As the injection zone, lost circulation is expected. Any lost circulation treatment must be acid soluble for removal; however, the preference is to drill with water or brine without attempting to cure losses.

H_2S (hydrogen sulfide) can be encountered. As with all hydrogen sulfide potential zones, proper fluid measures (scavengers, elevated pH), monitoring, and response procedures are required (Carter and Adams 1979).

Hard rock, including chert, can slow drilling rates considerably. All efforts are made to finalize directional work in the third intermediate to avoid sliding in hard rock. The 6 ½" hole size does not present significant hole cleaning challenges, particularly at low rates of penetration associated with hard rock.

Typically, the injection interval is competent and is completed open hole to preserve the secondary porosity of the natural fractures. Slotted liners are sometimes run, but cemented liners are not recommended.

Drilling Performance

Overall drilling performance in SWD wells of the Permian Basin is fully dependent on proper planning and assessment of the risk highlighted in the previous sections of this paper. Reducing non-drilling time associated with hole cleaning, logging, running casing, cementing, and tripping in and out of the hole can substantially decrease well costs.

In the benign regions of the Delaware, deep Devonian SWD wells have been drilled in around 45 days with Drilling and Completions costs being around $10 MM. Without adequate planning and vigilance days can soar past 100.

Completion

The risks during the completion phase are listed below, along with the strategies to maximize injection performance.

Main risks

- Corrosive injection fluids, corrosion resistant coating or alloy is required for all wetted surfaces
- Load Rating of Conventional Service Rigs are insufficient to change a 7 x 5 ½" injection tubing string
- Formation Damage - Injection pressure due to solids laden injection fluids plugging

Strategies

- Wellbore design for minimum intervention
- Clean drilling fluids
- Open Hole completion to better access natural fracturing
- Larger diameter Injection tubing to reduce contribution of frictional losses on allowable surface injection pressure
- Use HCl acid to clean up formation prior to running Step Rate Test (see below)

Injection Allowables

Well regulations dictate matrix injection – that is, the formation permeability must be sufficient to receive commercial rates of disposal fluid without exceeding formation breakdown pressure (frac gradient). LSIP (Limited Surface Injection Pressure) varies by state as explained below.

In Texas, the limit is 0.5psi/ft to the depth of the injection interval. The LSIP can be contested by the TRRC (Texas Railroad Commission) if a seismic event has occurred within 9 miles of the surface hole location. New Mexico regulations tend to be more stringent since allowable LSIP is initially based on a gradient of 0.2 psi/ft.

Matrix permeability and operating surface injection pressure govern injection rate, however, the Devonian offers secondary permeability (natural fractures) that will take (in somes cases) more volumes than the matrix contribution. Consequently, the regulated surface injection pressure can be challenged with the data collected from a Step Rate Test (SRT). SRT's are required in NM and by determining the actual fracture pressure, the 0.2psi/ft LSIP can be challenged. Conducting a SRT in Texas will generally result in lowering the LSIP.

Tubing friction in deeper wells plays a significant role in limiting surface injection pressure. Obviously larger diameter injection tubing will facilitate less frictional losses and higher injection rates. The issue becomes one of optimizing the casing design to allow the utilization of larger diameter tubing.

The table below highlights the tubing friction pressure for various sizes at 50,000 bwpd injection rate into the Devonian at 17,000' TVD.

Table: Friction pressure at surface using Hazen-Williams equation for a 17,000' TVD Devonian SWD well

Tubing Size (in)	Volume (bbl/day)	Injection Rate (gal/min)	Tubing ID (in)	Friction Pressure Gradient (psi/ft)	Pressure from friction surface (psi)
3.5	50,000	1458.3	2.922	1.548834	26630
4.5	50,000	1458.3	3.958	0.353271	6006
5.5	50,000	1458.3	4.892	0.125886	2140
7	50,000	1458.3	6.279	0.037326	635

It's important to note that the initial permit application has an AOR (Area of Review) based upon the use of 5 ½" injection tubing. Moving upto 7" will require additional noticing which may delay approval.

Conclusions

A comprehensive approach to fluid design, along with other key factors, continues to improve the economics of critical deep Devonian SWDs (Figure 6). Increased well volumes will continue to increase the demand for disposal options. Key findings include:

- Larger hole size and deeper, harder formations mean that SWD wells are considerably more complex than traditional production wells in the region.
- The 2nd intermediate section can be characterized as the most important interval. It presents challenges with both severe losses and flows from the DMG and Bone Spring
- The 3rd intermediate section is challenging due to increased pressure, narrow annulus size, and geologic control into the Devonian.
- MPD is recommended for the 2nd and 3rd intermediate strings and choice of mud system is area specific.
- Fluid techniques continue refining to address to minimize the risk of losses, mitigate hydrogen sulfide, facilitate quality cement jobs, and ensure reservoir injectivity.
- Even with increasing well complexity, this program is delivering wells within time and budget expectations (Figure 7).

Lea County - Vertical Injection - Devonian, Silurian, Fusselman

Geologic Tops (MD ft)	Section	Problems	Mud	Casing	Logging	Cement	Injection String
Rustler Anhydrite - 1101 **Surface TD - 1250**	**Surface** Drill 24" 0' - 1250' Set and Cement 20" Casing	Loss Circulation Hole Cleaning Wellbore stability in the Red Beds Anhydrite in the Rustler	Spud Mud MW< 9.0	1250' of 20" 94# J55 BTC Centralizers - bottom 2 joints and every 3rd jt thereafter, Cement basket 5th jt from surface	No Logs	**Lead: 714 sx** 13.7 ppg EXTENDACEM, 1.694 ft3/sk (800') 75% excess **Tail: 622sx** 14.8 ppg HALCEM, 1.342 ft3/sk (200') 75% excess Cement to Surface	11650' of 7" P110 26# TCPC 4333' of 5-1/2" P110 17# TCPC Duoline Internally Coated Injection Tubing
Top Salt - 3404 Base Salt (Lamar top) - 4910 **1st Int TD - 5100**	**1st Intermediate** Drill 3850' of 17-1/2" Hole 1250' - 5100' Set and Cement 13-3/8" Casing	Seepage Losses Possible H2S Anhydrite Salt Sections	Brine Water <11ppg	5M A Section Casing Bowl 5100' of 13-3/8" 68# HCL80 BTC. Externally coated 1100 - 5100' Centralizers - bottom jt, every 3rd joint in open hole and 2 jt inside the surface casing	Mudlogger on site by 1250'	**4026sx** of 13.7ppg Halcem (100% XS in OH) with 5% Miccobond. Cement to surface	
9-5/8" ECP DV Tool - 5150 Bell Canyon - 4959 Cherry Canyon - 5812 Brushy Canyon - 7182 **DV Tool - 8500** Bone Spring - 8764 **3rd Int Liner Top - 11,750** Wolfcamp A - 12182 **2nd Int TD - 12,250**	**2nd Intermediate** Drill 7150' of 12-1/4" Hole 5100' - 12250' Set 9-5/8" Intermediate Casing and Cement in 3 Stages	Hard Drilling in the Brushy Canyon Seepage to Complete Loss Water Flows Some Anhydrite H2S possible Production in the Bone Spring and Wolfcamp Ballooning is possible in Cherry Canyon and Brushy if Broken Down	WBM with Produced FW until Loss of circulation	10M B Section 12250' of 9-5/8" 53.5# P110 BTC **Special Drift to 8.535"** Externally Coat Between DV Tools DV tool at at 8500' ECP DV Tool at 5150' Centralizers - bottom jt, 100' aside of DV tool, every 3rd joint in open hole and 5 within the surface casing	MWD GR Triple combo + CBL of 13-3/8" Casing	**Stage 3:** **1059 sx** 13.7 ppg HalCem™ C 10% XS 1000psi CSD after 10 hrs Cement to Surface **Stage 2:** **933 sx** of 13.7 ppg HalCem™ C 50% XS 1000psi CSD after 10 hrs Cement to Surface **Stage 1:** **1441 sx** 15.6 ppg HalCem™ 50% XS 1000psi CSD after 10 hrs Cement to Surface	
Strawn - 13687 Morrow - 14333 Miss Lst - 15543 Woodford - 15774 **Perm Packer - 15,983** **3rd Int TD - 16,083**	**3rd Intermediate** Drill 3833' of 8-1/2" Hole 12250' - 16083' Set 7-5/8" Liner and Cement in Single Stage	High Pressure (up to 15ppg) and wellbore instability (fracturing) expected in the Wolfcamp Production in the Wolfcamp Atoka and Morrow Hard Drilling in the Morrow Clastic	12.5 ppg OBM UBD/MPD using ADA (HOLD)	4333' of 7-5/8" 39# P110 USS Flush **VersaFlex Packer Hanger** Centralizers on and 1 jt above shoe jt and then every 2nd jt.	MWD GR Triple combo, CBL of 9-5/8" Casing	**202sx** of 13.2 ppg NeoCem™ PT2 8hr TT Silica Flour 50% Excess 1000psi CSD after 10hrs	7-5/8" x 5-1/2" TCPC Permanent Packer with High Temp Elastomer and full Inconel 925
Devonian - 16,033 Fusselman - 17033 Montoya - 17,601' TD - 17,901'	**Injection Interval** Drill 1818' of 6-1/2" hole 16083' - 17901'	Chert is possible Loss of Circulation is expected H2S encountered on the Striker 3 well BHT estimated at 280F	Cut brine - low grav for possible flows	Openhole completion	MWD GR Triple Combo with FMI, CBL of 7-5/8"	Displace with 3% KCl (or heavier brine if necessary)	

Figure 6 – Well summary by interval using an example well

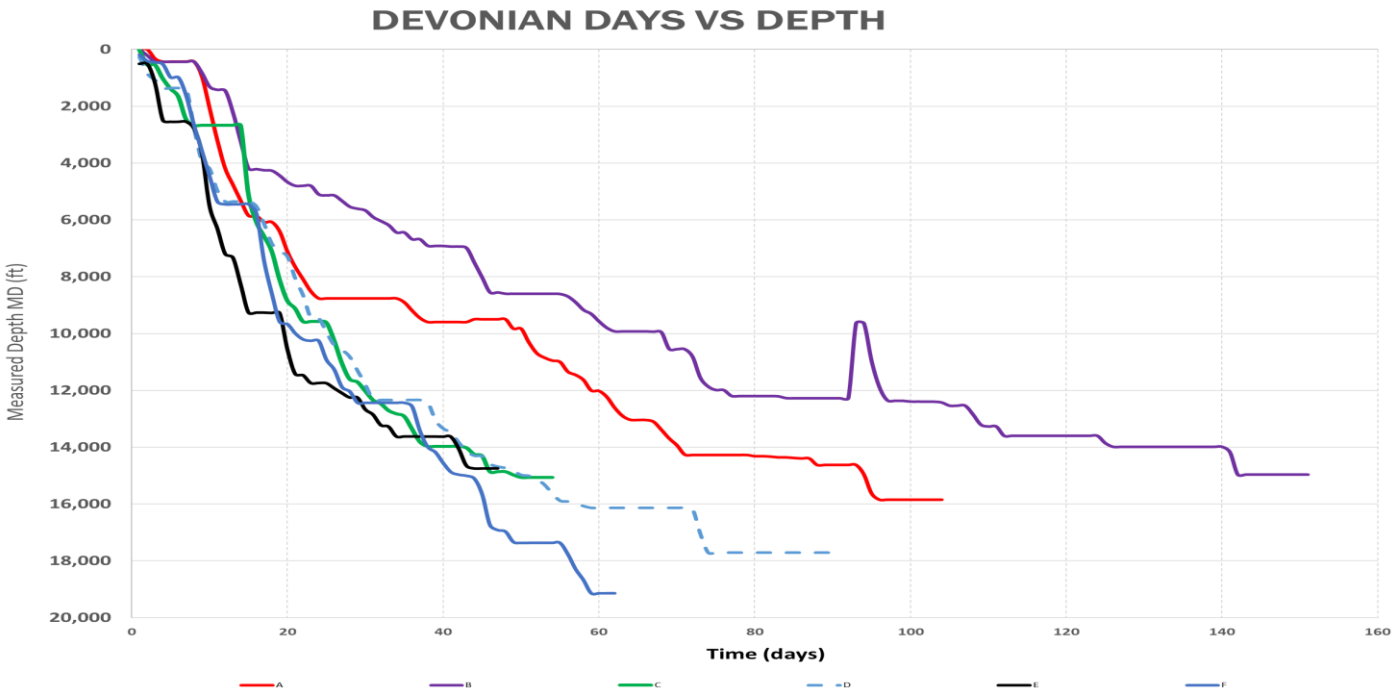

Figure 7 – Time comparison of improvements

Nomenclature

BHA = *Bottomhole assembly*
DMG = *Delaware Mountain Group*
EIA = *Energy Institute of America*
EOR = *Enhanced Oil Recovery*
H2S = *Hydrogen Sulfide*
LSIP = *Limiting Surface Injection Pressure*
SWD = *Salt Water Disposal*
UIC = *Underground Injection Control*
ECD = *Equivalent circulating density*
BWPD = *Barrels Water Per Day*

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