

Modern Shale Gas Horizontal Drilling: Review of Best Practices for Exploration Phase Planning and Execution

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Abstract

The challenging characteristics of shale formations often require horizontal drilling to economically develop their potential. While every shale gas play is unique, there are several best practices for the proper planning and execution of a horizontal well. In planning a horizontal well, the optimal method and technology for building inclination and extending the lateral section must be determined. Properly specified logging-while-drilling tools are essential to keep the wellbore within the target formation. Planning must also focus on casing design. Doing so will help ensure stability and enable reliable and productive completions. Shales pose a challenge for these elements of well planning due to their thin strata and potentially low mechanical competence when foreign fluids are introduced. Once a plan is developed, executing it is even more important to prove a viable exploration program. Fast, efficient drilling with wellbore control and minimal torque and drag should be the priority. This may be achieved by focusing on fluid hydraulics and rheology and bottom hole assembly. Managed pressure drilling (MPD) will help fast drilling, well control and stability. If MPD can be combined with new generation rotary steerable systems that allow the drill string to maintain rotation, impressive efficiencies are possible. Modern drilling parameter analysis represents the newest opportunity for executing shale gas horizontal wells. A method for ROP analysis to improve operational parameters and equipment selection is also proposed.

Introduction

Horizontal drilling has received much attention in the past few years, and rightfully so. In the emerging shale gas plays of North America, such drilling is central to the preferred exploitation method. Horizontal wells offer greater contact area with the productive strata than vertical wells. While the cost factor may be as much as two to three times that of a vertical well, the production factor can be enhanced as much as 15 to 20 times. Every shale gas asset is unique; finding the "ideal" drilling and completion method is just as unique. Optimization of such key attributes as kick off method, lateral length and number of completion stages is found through experimentation and experience. Capturing successful industry experience and modern technology into best practices may accelerate this learning curve. The exploration phase of any shale gas asset development program is critical. Spending too much time and money to prove the economic viability of an asset can kill a program. This paper reviews many of the best practices for the proper planning and execution of drilling horizontal shale gas wells during the exploration phase.

Rig Requirements

Modern rigs designed for horizontal drilling should be specialized, or “built for purpose BFP).” To aid in the economy of scale required for shale play development success, skidding rigs are a wise investment. Skidding rigs can move the substructure and derrick with ease, without moving anything else. One such example is provided in Appendix 1. There are a few rig requirements that are specific to horizontal drilling, and should not be overlooked. The first is the Top Drive Drilling System (TDDS). TDDS consists of a traveling block, power swivel, power unit, guide dolly, hydraulic station, pipe making up/breaking out set and control panel. The drill string is rotated directly by a power swivel. The pipe making up/breaking out set includes rotating head, power tongs, dual direction elevator link tilt mechanism, remote control internal blowout preventer valve and elevator. The breaking out is made by the power tong; the power swivel rotates counterclockwise and hoists upward the protective connector. When making up, either the power tong or the power swivel is used. The rotating head and elevator link tilt mechanism are used for grabbing and handling stands of three joints. Field experience shows that TDDS can reduce drilling time by 15%~25% because of simplified makeup and breakout. The major feature of TDDS is that it can rotate the drill string clockwise or counterclockwise and circulate the mud at the same time, which enables thorough backreaming important to horizontal drilling. The mechanized breakout/makeup operation can reduce stuck accidents, improve drilling efficiency, lower the labor intensity and make the operation safe and reliable.

In order to drill directionally, some kind of downhole motor is needed. The mud motor has long been the type of motor used for this application. This device is powered by the force of drilling fluid or “mud” that is pumped down the drill pipe. A mud motor contains a rotor, which is a spiraled shaft that turns the bit. It is surrounded by a fixed chamber called a stator. See Figure 1 below.

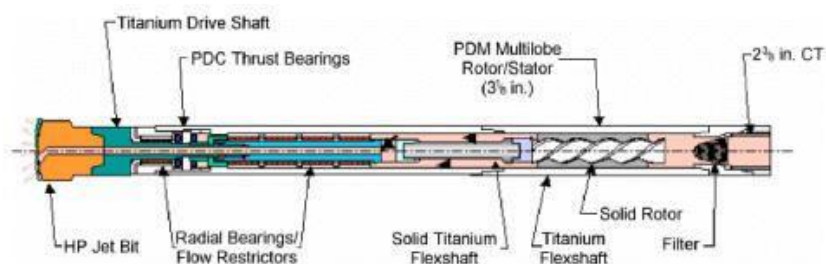


Figure 1: Mud motor used for directional drilling.

The mud motor above appears straight but actually has a slight bend of two degrees to facilitate directional drilling. Often mud motors are adjustable so that directional drillers can make adjustments in the field according to how much angle they need to build. There are other new technologies in directional drilling such as rotary steerable that are revolutionizing the industry. Utilizing a system of sensors and kick pads, the drill string can be rotated from the surface and the kick pads bump the drilling assembly and bit in the desired direction. This allows a well to be drilled horizontally much faster since more weight and torque can be applied to the drill bit. Such systems will be discussed in a later section.

Mud systems should be treated differently for horizontal operations. Engineering design can be improved through a more realistic consideration of drilling fluid drag effects and skin friction coefficients. The conventional practice of calculating annular frictional pressure loss caused by drilling fluid drag based on the assumption of concentric annular flow of a Bingham plastic fluid is overly conservative. Consequently, critical design parameters, such as depth of cover, which affects crossing length, and drilling equipment size, which is selected based on anticipated pulling load, cannot be optimized. This can result in overly conservative design and unnecessary construction costs. Baumert et al found the viscous shear of drilling fluid is significantly less than typically quoted for horizontal drilling, and that the friction coefficients often employed are not representative of all skin friction effects, affecting parameter values used in pulling load predictions (2005).

Well Planning

Well planning can be critical for shale gas horizontal drilling. Hole sloughing, torque and drag, and completion method planning are among particular challenges. Casing and cement design are critical for wellbore stability. Due to the unique nature of shale gas completions and production, the production string has special considerations. Reservoir drainage mechanisms are another challenge that must be addressed with careful completion stage and delivery method planning. Kick off, build angle and lateral placement are important to minimize torque and drag, work around stability issues, and maximize drainage and production performance. This section will discuss modern best practices relating to shale gas horizontal well planning.

The goal of any horizontal well is to enhance efficiencies regarding drainage and economy of capital. Inflow performance of horizontal wells is given by,

$$q_{sc} = \frac{703 \times 10^{-6} kh [m(p_r) - m(p_{wf})]}{T \left(\ln \frac{2r_e}{L_h} + 1 + S + F - \frac{3}{4} \right)} \quad \text{Equation 1}$$

where,

$$F = -\frac{h}{L_h} \sqrt{\frac{k_x}{k_z}} \ln \left[4 \sin \left[\frac{p}{2h} \left(2z_w + r_w \sqrt{\frac{k_z}{k_y}} \right) \right] \sin \left(\frac{p}{2h} r_w \sqrt{\frac{k_z}{k_y}} \right) \right] \quad \text{Equation 2}$$

Horizontal performance of a given completion stage will only be as good as that of vertical performance if F is zero (Ozkan, 1988). F may reach a limit of zero either by significant vertical permeability compared to horizontal permeability, or by a very long lateral section compared to formation height. Therefore the necessity to drill horizontal is dictated by geology, lithology and lateral length optimization. Given that shales have exceedingly low permeability and are often thin beds, accurate and extended lateral placement is of critical significance. That is, assuming the shale formation requires a horizontal

approach, the onus is upon the drilling engineer to realize the potential that nature has provided.

Wellbore Geometry and Stability

Shale formations are notorious for sloughing problems, which can be made worse depending on the clay content. In exploration, cuttings analysis is necessary to determine clay geochemistry and respond with appropriate drilling mud design. X-ray diffraction at a lab will identify clay minerals like water-sensitive smectite. On location, the mud logger should run a simple test of placing cuttings in water to investigate swelling. Particularly clay rich shales would benefit from oil-based drilling mud, to prevent swelling of these water sensitive clays. To save money, oil-based mud as drill-in fluid may be selected, while using water-based for the surface and intermediate portions of the wellbore. This sloughing problem may also be mitigated by smaller radius build angles, so that time spent sliding and at low ROP will be minimal in the shale formation. Sliding is the conventional method to create inclination, as the drill string does not rotate ("slides") and the bent mud motor creates inclination. To reduce torque and drag and key seating, a soft landing should be used (Joshi, 1991), like the one illustrated in Figure 2. The soft landing should begin near the top of the shale and should be near 90 degrees lateral by the target.

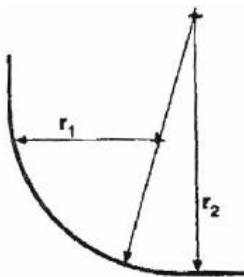


Figure 2: Soft landing into the shale formation is preferred. This reduces time spent sliding and key seating into the shale. Longer radius (r_2) starts near shale top.

Timing the dual builds of both radii in a soft landing requires accurate geosteering. Modern near-bit logging while drilling (LWD) is a worthwhile investment. The best practice for exploratory shale horizontal drilling is to combine an azimuthal density neutron tool with a laterolog-based resistivity-at-bit (RAB) tool. This is due to the potentially low contrast in lithological differentiation (anything below 15 API gamma ray measurement is too low) from clay content of the shale and any overlying sands. The azimuthal density neutron aids dip interpretation by investigating sinusoidal signatures (Figure 3).

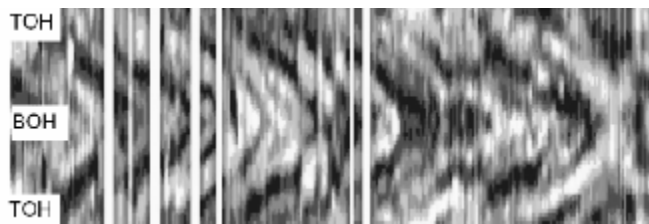


Figure 3: RAB tool used in geosteering to determine if drilling upsection or downsection. Blanks are sliding (Rohler, 2004).

RAB aids finer lithological differentiation than gamma ray, and can help see ahead of the bit with deeper resistivity tools. Shale beds are often characteristically thin, making accurate LWD/MWD all the more important to stay within the target zone without creating severe doglegs. The geosteering team should use software that enables dynamic depth corrections to measurement while drilling (MWD), such as VISION by Schlumberger. As seen in Figure 5, wellbore profiles, temperature profiles and drilling modes can result in depth fluctuation as much as 0.39 ft / 1,000 ft as calculated by Dashevskiy (2006). Such an error can result in missed targets, doglegs from overcorrection, and misplaced stages.

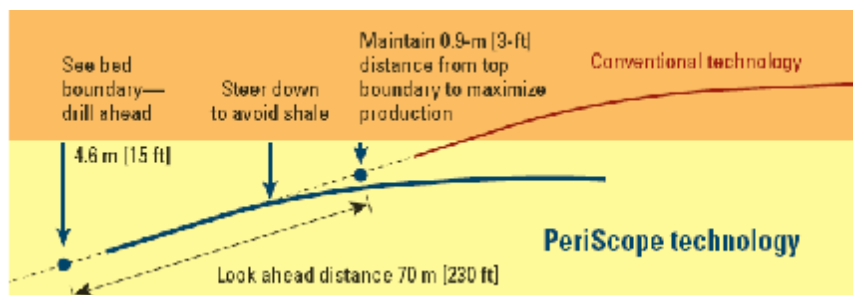


Figure 4: Schlumberger's PeriScope technology is one example of near-bit LWD technology. Seeing ahead of the bit enables preemptive action, saving time, exposing more productive reservoir, and avoiding "porpoising".

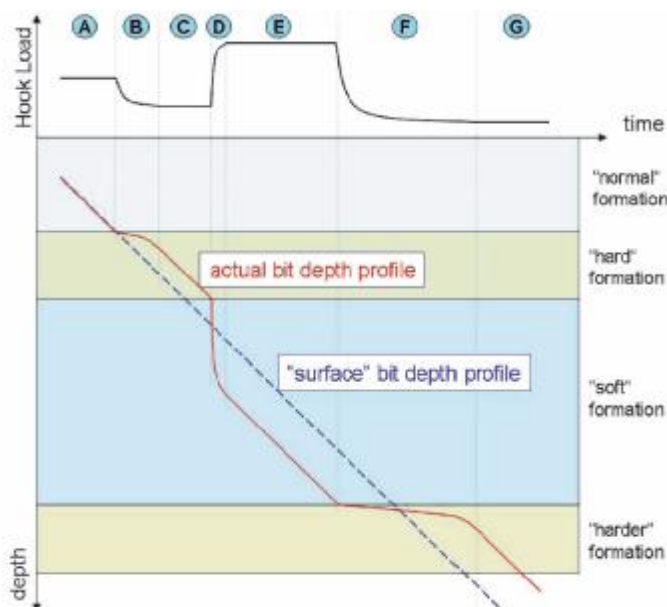


Figure 5: Effect of changing pipe loading on the time-depth profile (Dashevskiy, 2006).

Completions Planning with Casing Design

Once a plan is established for build angle and lateral landing, casing design may begin. Basic principles such as selecting the right grade and internal diameter will not be revisited here. A best practice for exploration horizontal

drilling in shale gas is to drill and set intermediate casing for a pilot hole. This will stabilize the formation overlying the shale and provide pressure stability as the drill string builds angle and soft lands into the shale. A vertical pilot hole can also give the operator a preview into the zone intended for completion. Looking ahead to the emerging popularity of multi-lateral drilling, pilot hole designs allow re-entry for infill multi-laterals.

The production string design must account for the completion method. For shale gas reservoirs, uncemented casing or liner completions with sequential stage systems are becoming common as reliability improves. These systems use sleeves that are mechanically or hydraulically actuated. In the most common example illustrated in Figure 6, sequentially sized balls are dropped after each frac stage is pumped, closing off the pumped stage and opening the sleeve for the next.

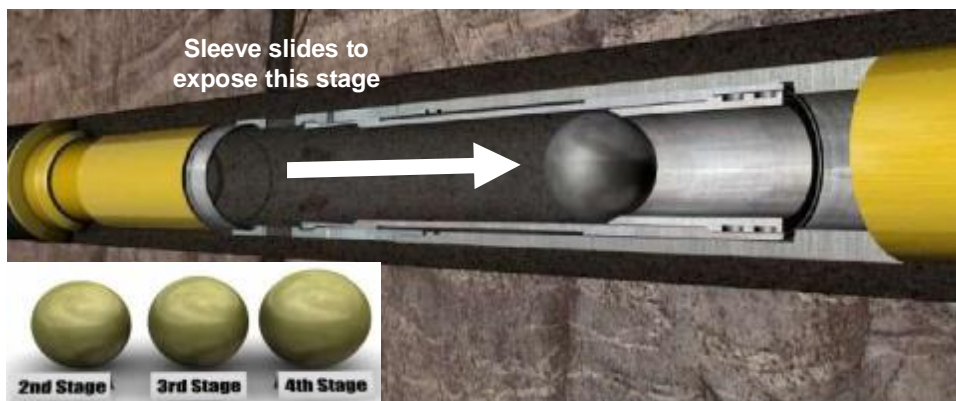


Figure 6: Sequentially larger balls are dropped while pumping fracture treatments. The ball seals the completed stage, and slides a sleeve down to expose the next stage.

As operators extend laterals and add stages, better and better technology becomes available. The benefit of these systems is clear in time saved by not running multiple plugs. Depending on shale competence, a cemented completion may be required. A larger diameter production string is required to allow for the packer assembly.

Cement poses a particular challenge for shale gas wells. Because of sloughing and swelling, boreholes often need to be well over-gauged to the casing. This opens the door to channeling, as the casing and cement settle to the low side of the hole, creating a channel where fracture fluid can flow into another zone. The best practice is to use foamed cement. In a case study of the Woodford shale formation in Oklahoma, foamed cement enabled zonal isolation while withstanding high fracturing pressures. Foamed cement expands and fills in the high side of the hole shown in Figure 7. This expansion also helps prevent sloughing during setting. Finally, the ductility of foamed cement has been found to compensate for its low compressive strength.

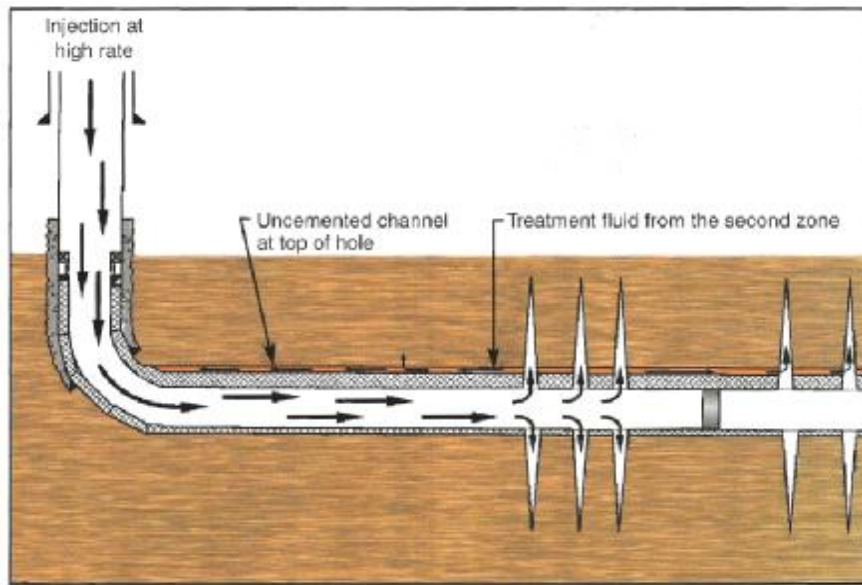


Figure 7: Casing and cement settles to low side, leaving a channel for cross flow (Ringhisen, 2008).

Stage placement is critical to capitalize on efficiencies offered by extended laterals. The drilling engineer must interface with completions and reservoir engineers to determine optimal spacing. Shale formations are unique in that drainage is limited to near the fracs, due to extremely low permeability. Stages may be more tightly spaced because of this. However, staging too close could cause frac communication. It is very important in exploration to run sonic logs which are used to calculate Young's Modulus and Poisson's Ratio. Young's Modulus and Poisson's Ratio can then be used to model and predict fracture stages to mitigate these risks. Radioactive tracers and microseismic should also be strongly considered during the exploration phase. Tracers are radioactive chemicals combined with proppant, that when logged, identify proppant placement (and therefore frac fluid). Microseismic identifies slippage in rocks as the formation is fractured, giving a strong indication of where the fracture went.

True optimization of stage number and lateral length is obtained by drilling several dozen or even hundreds of wells in a given area, experimenting with various combinations and analyzing the data for statistical correlations. However, a best practice is to use six to 10 stages in a lateral of 2,000 to 5,000 feet of effective length (1,500 to 6,000 feet total length). Effective length is measured from the heel completion zone to the toe completion zone. In exploration, the operator should start conservative (2,000 foot lateral with six stages) and work up, developing a rigorous data set.

This iterative process may be enhanced and accelerated through geostatistical reservoir modeling. A full discussion of reservoir modeling is beyond the scope of this paper. It is important to gather log and core data in the exploration and delineation phase to begin developing a reservoir model. Modern kriging, gridding and history matching techniques create a robust model that may be used to test various lateral length and stage number scenarios. The perpendicular-bisector (pebi) grid method is recommended and illustrated in Figure 9 (Vestergaard, 2007). The model can optimize the number and spacing

of stages to drain all recoverable hydrocarbons while avoiding redundant stages or competing drawdown. Application and case studies are discussed in a later paper regarding completions.

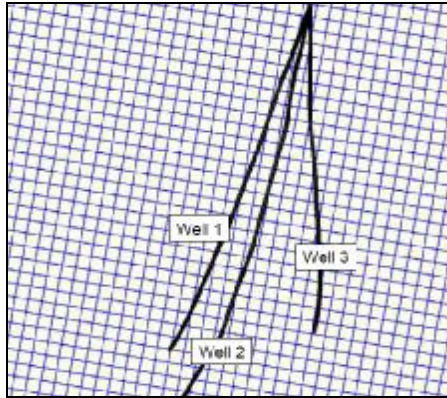


Figure 8: Cartesian grid.

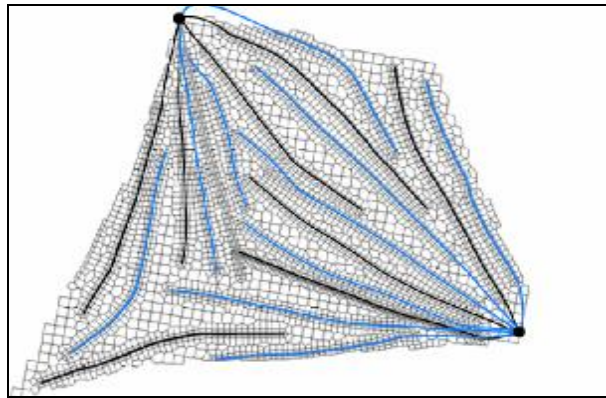


Figure 9: Pebi grid showing near-wellbore resolution

Drilling Performance

Horizontal drilling in gas shale is expensive. Clearly, drilling faster is the key to controlling cost. Doing so without spending too much is the challenge. Enhancing ROP may be achieved through bit selection, hydraulic improvements, superior mud properties, and bottom-hole assembly (BHA) selection. This section will review some of these elements as they relate to specific shale gas horizontal drilling.

Hydraulic Performance and Hole Cleaning

Rate of penetration is broadly influenced by hydraulic performance. Equivalent circulating density (ECD), friction losses, nozzle performance, fluid rheology and hole geometry all play a role in hydraulic performance. In horizontal drilling, hole cleaning is critical to reduce torque and drag, enhance ROP, maintain wellbore integrity and mitigate stuck pipe risk. Hole cleaning can be particularly challenging in drilling shale formations. Given the high Young's Modulus of shale, polycrystalline diamond compact (PDC) bits are required. PDC bits chip away rock, leaving large cuttings to clean (Spaar, 1995).

Improper hole cleaning can be devastating to ROP, affecting pressure losses and even weight on bit as torque and drag builds with high angles. Ozbayoglu et al proved that pipe rotation is the most important factor influencing hole cleaning in highly deviated wells (2008). It was empirically determined that hole cleaning efficiency (measured by bed-/wellbore-area ratio) can double just by increasing pipe rotation to 40 RPM compared to no rotation. These findings are presented graphically in Figure 10.

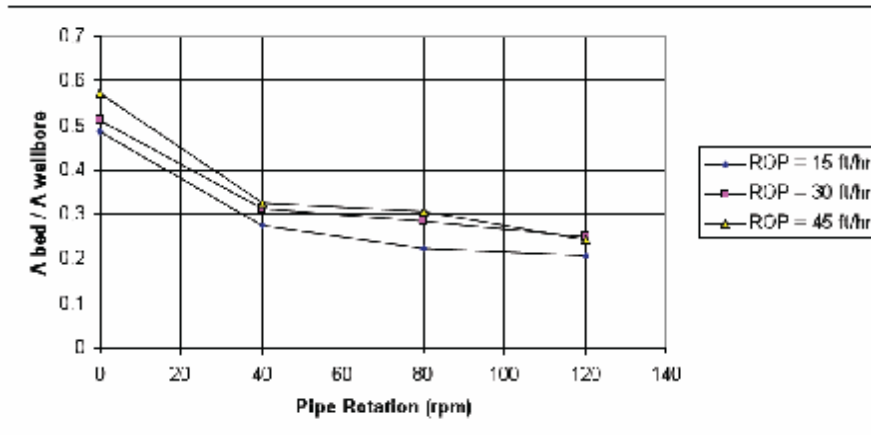


Figure 10: Effect of pipe rotation speed on stationary bed thickness (Ozbayoglu, 2008).

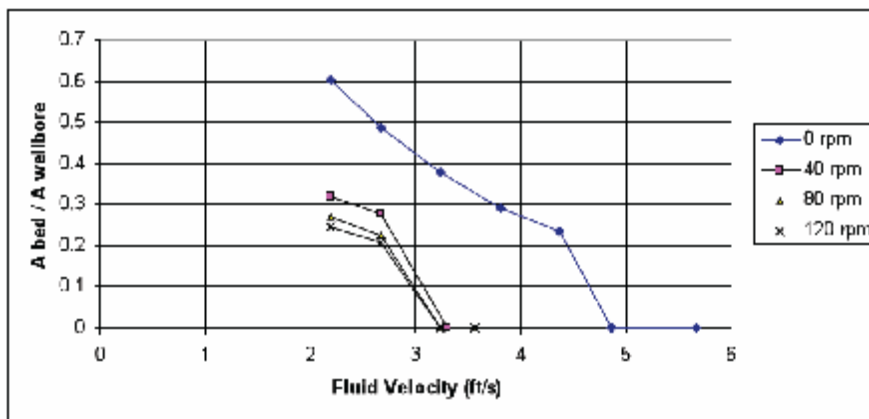


Figure 11: Effect of pipe rotation speed on critical fluid velocity.

Fluid velocity has been found to be the second most important factor for hole cleaning. The benefit of fluid velocity is shown for various rotation scenarios in Figure 11. This is especially true with large cuttings found in shale drilling. However, achieving critical velocity may be impractical when sliding, as much higher velocity is required to compensate for the lack of rotation. The best practice is to use low-viscosity sweeps. Such sweeps can reach cuttings beds in channels that the typical higher-viscosity drilling fluid would miss (illustrated below).

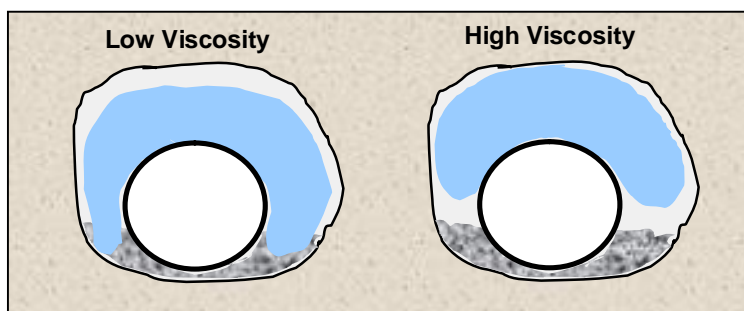


Figure 12: Cuttings settle ("dune") to low side, slowing ROP.

High viscosity fluid (high interfacial tension) does not reach the dune, whereas low viscosity does (adapted from K&M).

Ideally, the operator can maintain rotation. Doing so can mean a 33% reduction in critical velocity (Ozbayoglu). With emerging technologies – coupled with rotary steerable systems (RSS) – this is becoming more a reality even when building angle. RSS allows rotation when creating inclination, compared to conventional bent mud motors. As previously discussed, rotation is key to hole cleaning. Rotation also helps significantly to transfer weight to the bit and therefore drill efficiently and faster, with less drill string wear. The RSS concept will be revisited.

Another critical factor affecting ROP is mud weight or ECD. This has been found especially true for medium to hard shales, where it is said that mud weight should be kept as low as possible. Then again, the drilling engineer must always balance between formation pressure and fracture gradient. Exceeding the frac gradient will result in massive mud losses; whereas dipping below the formation pressure could result in catastrophic blowouts. As graphically illustrated below, this balancing act is far more challenging in horizontal wells. In horizontal drilling, ECD at the heel is very high relative to the fracture gradient, as friction losses cut down ECD at the toe. Furthermore, overburden may be lower than the fracture gradient, creating an even smaller safe operating region.

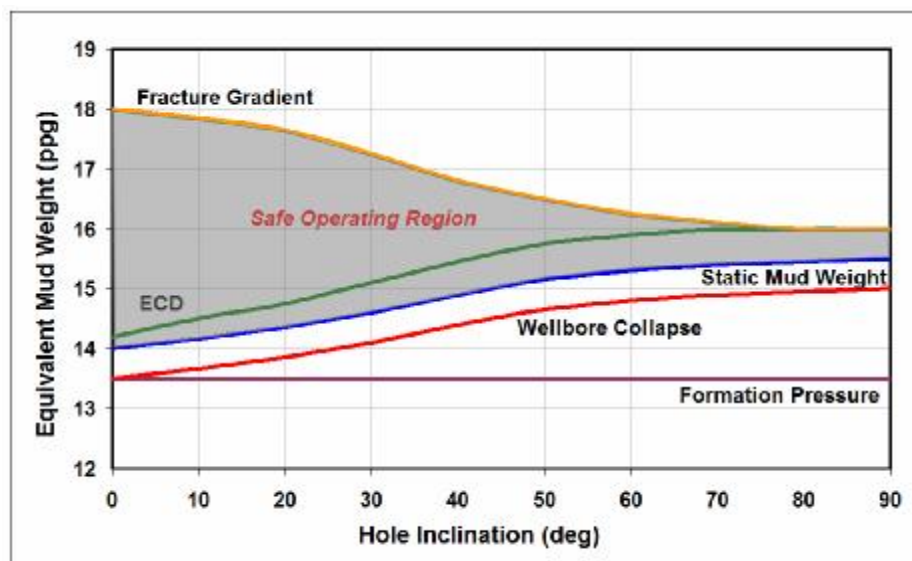


Figure 13: Effect of inclination on wellbore stability. Overburden is less than frac gradient, which becomes relevant as the well exceeds 50 degrees inclination.

This unusually small safe operating region warrants consideration of underbalanced drilling (UBD) or managed pressure drilling (MPD). Since shale has very low permeability, traditional blowouts are less likely, but uncontrolled pit gains through mud aeration can result in loss time and still pose a safety risk. Even so, in exploration phase drilling, the potential presence of natural fractures could be disastrous if drilling underbalanced. This is why MPD has received more and more attention as a best practice. MPD offers operators much tighter

control of static mud weight and ECD, making small real-time adjustments in response to influx or losses, reducing both. Activity along the Rocky Mountains of North America has shown great potential for coil tubing drilling (CTD) for MPD. With CTD, circulation never stops, meaning no static mud weight versus ECD. This advantage saves on mud losses, influx and maybe even intermediate casing due to finer control within a small operating region.

The problem with CTD is the lack of pipe rotation. As previously illustrated, pipe rotation is a must for hole cleaning in shale gas horizontal wells. Experimental rotating coil tubing drilling rigs may be the answer. If combined with rotary steerable systems (RSS), operators may drill faster, cheaper horizontal wells than ever before. Due to the marginal nature of shale gas development, fast and cheap wells may unlock entire assets even in an unstable commodity price environment. In RSS, operators may choose from “push the bit” and “point the bit” technologies, like those shown in Figure 14. A pure “push the bit” RSS steers simply by applying a side load to the bit; whereas “point the bit” steers by precisely pointing (tilting) the bit in the direction the well path needs. Some service companies now offer hybrid systems that offer the best of both worlds. While these technologies are still being developed – and come with a hefty price tag – their promise is immense.

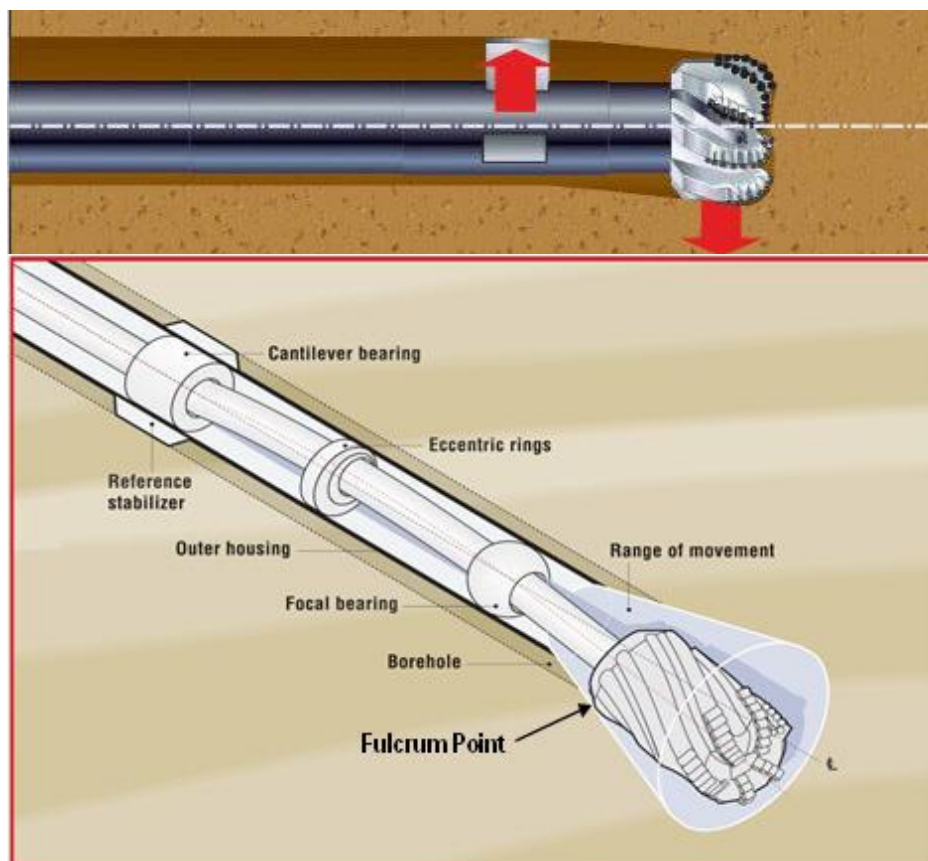


Figure 14: Push-the-bit and point-the-bit rotary steerable systems. Point-the-bit is typically preferred, since the whole bit faced is used.

Rate-of-Penetration Analysis for Selection of Operational Parameters and Equipment

As previously discussed, hydraulic performance and hole cleaning are necessary for horizontal drilling function. Assuming proper hole cleaning is achieved, the performance of ROP in any drilling operation is driven by weight on bit (WOB), differential pressure, rotations per minute (RPM), torque, strokes per minute (SPM), and pump pressure. Optimization of these parameters has been made much easier with automation interfaces such as Epoch and Pason. The driller can monitor any parameter desired on a display like the one below. Each parameter can be set within a range, and the software will run through iterations of minute adjustments to each in order to achieve the fastest ROP without exceeding a given parameter (e.g., WOB < 25,000 lbs). This automated monitoring software interface can be used to great advantage in optimizing parameters for increased ROP without spending more capital on equipment. Similarly, this software can help fine tune rig and drill string equipment to further increase ROP.

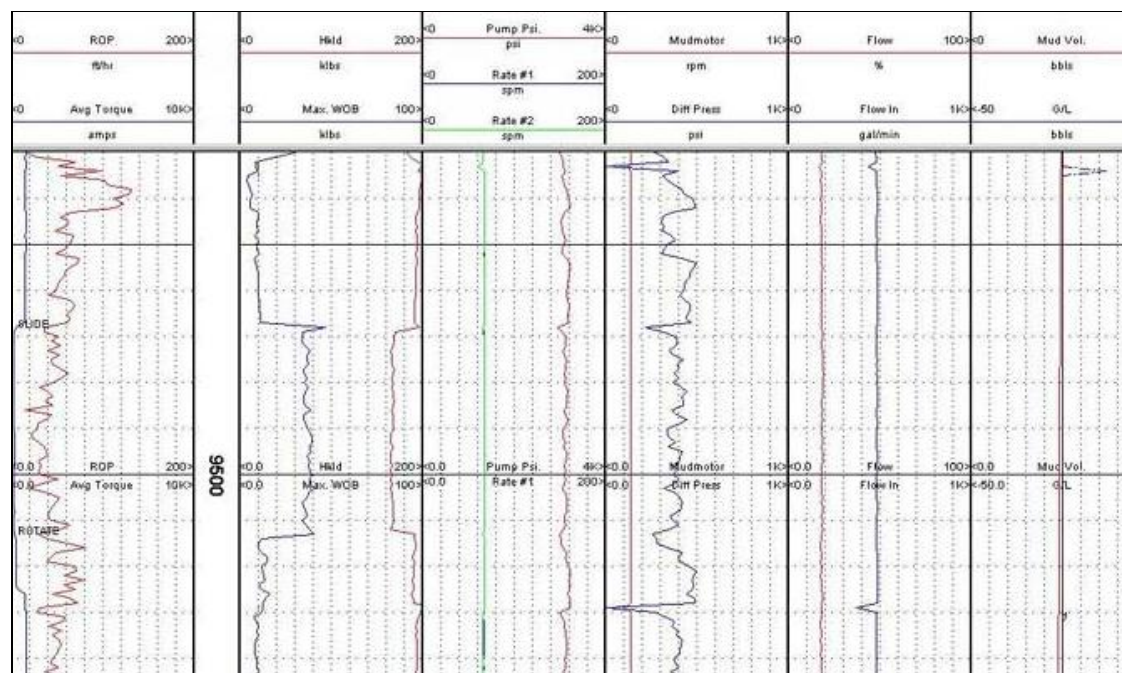


Figure 15: Epoch's Rigwatch system monitors ROP, torque, WOB, pump pressure, differential pressure and other parameters in real-time. The driller can define limits within which the software will iterate in cycles to increase ROP.

Mechanical Specific Energy (MSE) is a modern method to identify inefficiencies in drilling parameters and equipment selection. Efficient drilling refers to fast ROP without applying unnecessary energy input. While achieving equally fast ROP, inefficient drilling may abuse rig and drill string equipment, increasing repair costs and shortening equipment life. Simply stated, the concept of MSE is to balance energy input into the formation with the unconfined compressive strength (UCS) of the formation. If this is achieved, then effective, steady, accelerated penetration is possible without overexerting any

component. A helpful analogy is to imagine using a hand-held electric drill at home. If too little pressure is applied, then the drill bit will not penetrate the wood surface. If too much pressure is applied then the motor will overheat or stall out, or the bit will just “founder” (or move laterally in an uncontrolled manner) and not make much steady progress. This foundering is often associated with a jack-hammer effect, which can be devastating to the life of the bit, mud motor, and even drill pipe. The equation for MSE is represented by,

$$MSE \approx \frac{InputEnergy}{OutputROP} \approx UnconfinedCompressiveStrength$$

or

$$MSE = .3 \times \left(\frac{480 \times Tor \times RPM}{Dia^2 \times ROP} + \frac{4 \times WOB}{Dia^2 \times p} \right) \quad \text{Equation 3}$$

where Tor is torque and Dia is the diameter of the bit. This formula was empirically determined by Dupriest, et al (2005), who found that the product of drilling energy inputs would equal UCS when ROP was maximized. MSE provides immediate feedback on drilling performance and could reveal inefficiencies that would otherwise be obscured. One application is in Figure 16.

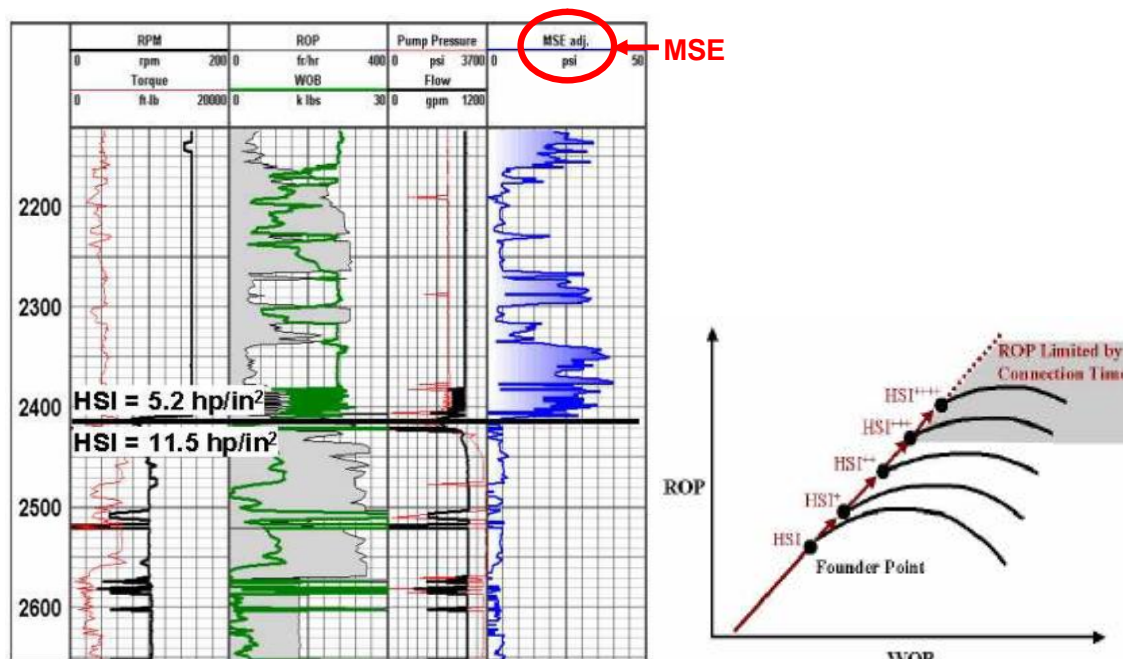


Figure 16: MSE was well above UCS of 5,000 psi. The volatile MSE signature suggests bit foundering. Bit balling was suspected, and a new bit run with increased hydraulic horsepower per square inch (HSI). With a higher founder point, ROP was consistently doubled (Dupriest, 2005).

Bit balling is a common problem in shale formations. Highly deviated and horizontal wells have the additional challenge of “stick-slip,” which happens when the drill string catches on the wellbore due to friction, then suddenly jerks free. A study by Chen et al proved that there are three stick-slip mechanisms – axial, lateral and torsional – and that their impact is immense (2006). This can

occur at any point along the drill string, BHA or bit. Identifying stick-slip early with MSE is crucial to enhance ROP and extend equipment life. Stick-slip is mitigated by reducing RPM or WOB, increasing SPM, or by adding lubrication to the drilling fluid. Generally, adjusting operational parameters to more closely match UCS will help ensure efficient drilling.

Besides aiding drilling parameter optimization, MSE can also be used to fine tune the selection of equipment for the rig and drill string. Essentially this is a troubleshooting process. If in order to optimize MSE, a parameter exceeds what is currently physically possible, then different equipment must be selected.

High torque capacity may be necessary in horizontal drilling of shale formations. This is because of the high angle and potential shale sloughing. Upgrading to a higher torque top drive is one important decision. Stronger drill pipe is another wise investment. Titanium drill pipe is a viable option for short-radius horizontal drilling. Titanium is more corrosion- and erosion-resistant than steel, not as stiff as steel, and has an improved strength-to-weight ratio of 1.54 times versus S-135 steel. Another viable option is double-shouldered drill pipe. Such connections distribute stress more evenly and allow for greater make-up torque, enabling greater torque capacity (Chandler, 2007).

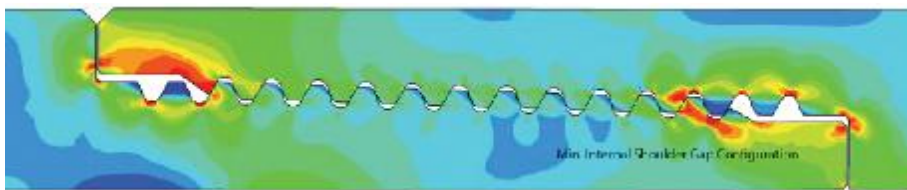


Figure 17: Finite Element Analysis shows that the internal shoulder distributes stress while allowing greater torque with a slimmer profile (Chandler, 2007).

Such a design also improves hydraulics, as the external diameter of the joints can be smaller, reducing annular friction losses so that more HSI is delivered to the bit without over-extending the rig pumps.

Drilling fluid properties optimization is also improved through ROP analysis. In addition to high torque and stick-slip problems, WOB is often lost to friction along the drill string. This will undermine any attempt to transfer energy to the formation, rendering efficient drilling impossible. If this problem is identified, the common practice is to apply lubricants to the drilling fluid. Diesel and oil are popular choices, as they provide ample lubrication and the shale does not imbibe them, preventing swelling. However, the low aniline point poses significant risk of expanding the rubber stator in downhole motors, causing it to lock up. Specialized rubber is required. There are many other synthetic lubricants, such as those derived from vegetable or mineral oils. These lubricants may offer acceptable lubrication and inhibition with a higher aniline point. Availability and cost are drivers in the experimentation process for a given area. Wax beads and similar products are fairly new to the market, and could also have benefits in acting as ball bearings to reduce torque and drag. Chemical compatibility with the existing mud system is another key concern.

Bit and BHA selection will benefit from ROP analysis. As is seen in the energy input portion of MSE, rotation is preferred; therefore rotary steerable systems will be a great advantage in horizontal drilling. More or less aggressive

cutting structures for the PDC may be selected to optimize MSE, depending on the UCS of the formation, Young's Modulus, and torque capacity of the top drive and drill string. More aggressive cutting structures would mean fewer blades on the PDC, which is designed for drilling tougher formations faster. However, excessive torque or a stick-slip signature in drilling monitoring should be a warning to use less aggressive cutters. Less aggressive cutters with shorter gauge sections help with directional control as well.



Figure 18: Shorter gauge section improves directional control, while longer improves hole concentricity.

Slimhole drilling might also be considered. Intuitively, drilling smaller holes should be faster, since less rock (less volume) is required to be drilled per lateral distance. This intuition is supported mathematically by Equation 3. The limiting factor in slimhole drilling is the motor, which is often required to be larger. An example of a modern motor designed for slimhole application is one from Scientific Drilling. The tool uses emerging navigation technology designed specifically for lateral wellbore placement. A 3-3/4" Smart Motor was tested in June 2008 which dramatically decreased drilling time. Such slimhole technology is also pivotal to any re-entry program to drill out horizontal into a shale formation from an existing vertical wellbore.

Conclusion

Planning exploratory horizontal shale gas wells must focus on wellbore geometry and stability. Best practices for setting up and landing the all-important lateral include setting a vertical pilot hole, building inclination with two radii, and steering with azimuthal resistivity LWD tools. The drilling engineer must work with completions engineers to determine the best production string design. Sequential systems in open or cemented liners save time and money when pumping the fracture treatment, but bring with them special complications. Minimizing doglegs with near-bit LWD and using foamed cement where applicable can help. Staging can be optimized with the use of sonic logs, frac modeling, tracers and reservoir modeling.

Execution of timely, cost efficient horizontal wells depends on hydraulic optimization and control; rig and drill string selection; and ROP analysis. Engineers may enhance ROP with managed pressure drilling and still maintain wellbore integrity, which is even more challenging in horizontal shale wells. Rotary steerable systems enable continuous drill string rotation even when sliding, so that hole cleaning is unabated. Poor hole cleaning creates high torque and drag and therefore lowers ROP and mechanical integrity. Lastly, modern ROP analysis and troubleshooting can mean big gains in speed by choosing the correct drilling parameters and equipment specifications to optimize.

Properly planning and executing horizontal drilling during the exploration phase is critical to proving (or disproving) the economic viability of shale gas plays. Such plays are expansive and offer predictable yet marginal results. The life of the development program requires perhaps thousands and thousands of wells to be drilled. It all hinges on getting it right in the exploration phase.

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About the Principal Author

Before Harding Shelton Group, Nathaniel worked for EnCana Oil & Gas in Denver, Colorado. Nathaniel was a field drilling engineer before working as a drilling consultant on directional wells in the Piceance Basin of northwestern Colorado. He then joined EnCana's DJ Basin team that set depth records in coil tubing directional drilling. Most recently Nathaniel worked for EnCana's West Texas asset team as an operations engineer. The West Texas team was responsible for drilling and operating exploration phase horizontal wells in the Pearsall Shale of Maverick Basin and Barnett Shale of Delaware Basin. Nathaniel's first experience in the industry was sidetrack drilling with Occidental Petroleum in California. He is a graduate of the University of Oklahoma with degrees in Mechanical Engineering and Russian Language. Nathaniel now lives in Oklahoma City, Oklahoma.

Appendix 1

Drilling Rigs



Skidding rigs can drill multiple wells at one well site, impacting relatively little of the surface, while aiding operational efficiency. The substructure and derrick move four to 40 feet, while the mud tanks, manifolds, pumps, power houses, etc, stay stationary.