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Improving Post-Stimulation Coiled Tubing Drillout

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Abstract

In the last few decades, coiled tubing has been widely employed for post-stimulation drillout of composite or cast-iron bridge plugs and isolation sleeves used in multi-stage hydraulic fracture stimulation in horizontal wells. Due to its inherent capability of continual deployment, coiled tubing technology has increased in popularity for this application over conventional jointed-pipe snubbing with rig-assist snubbing units. Despite the increasing use of coiled tubing units, drillout practices have typically been based on “art” rather than science, often resulting in drilling problems such as poor fluid efficiency and hole cleaning issues, lost circulation, stuck pipe, lost-in-hole tools, and parted pipe. Unfortunately, a greater percentage of stuck pipe incidents are directly related to poor hole cleaning, and it is not surprising that the causes of these problems are often not well understood. Thus, various approaches have been utilized to prevent recurrence based on incorrect assumptions. While some of these problems have been adequately dealt with in several publications, the determination of optimum fluid properties for efficient hole cleaning as well as the effectiveness of short tripping have been given minimal attention. To a large extent, fresh water, or brine, is mixed with various additives such as friction reducer for pressure loss and pipe friction, hydrogen sulfide scavenger and inhibitor, biocide, scale inhibitor, and polymer gel while drilling plugs. A common hole cleaning practice is the use of intermittent high-viscosity gel sweeps, wiper tripping to kick-off point after drilling a predefined number of plugs, and flowing back the well in an underbalanced condition while drilling and short tripping. The effectiveness of these practices is worth questioning based on the occasional drag and stuck pipe encountered while tripping out of hole.

This paper addresses the misconceptions related to coiled tubing hydraulics and hole cleaning, as well as reviews the common drillout practices and their cost implications including coiled tubing rig up, coil size selection, bottomhole assembly, fluids efficiency, and short tripping. Various best practices are recommended for improving post-stimulation drillout, with specific emphasis on how to minimize drillout cost.

Introduction

Coiled tubing (CT) technology has continually evolved, and the outcome is a diverse range of well-service applications predominantly including fill cleanouts and post-stimulation plug drillouts, amongst others, such as perforating, well logging, fishing, well unloading etc. Even though many of these applications are not new to the oil and gas industry, the learning curves are still steep for the use of coiled tubing technology to accomplish specific objectives relating to each application. In order to achieve those objectives, it is imperative to have adequate knowledge of each discipline, the limitations of coiled tubing, and the challenges envisaged during a planned well-service operation. Obviously, the restricted pulling capacity, weight limitation, and inability to rotate the string or place drilling jars within the continuous string can often limit coiled tubing drilling and fishing capabilities in horizontal wells. However, several documented case studies (Solanet et al., 1999; Byrom, 1999; McCarty et al., 2002; Engel and Rae, 2002; Johnson, 2007; Telesford et al., 2008; Li et al., 2010) have shown that tremendous cost savings can be achieved by using coiled tubing for many drilling and completion applications.

As the oil and gas industry continues to push for slimmer holes and longer laterals, greater drilling and completion challenges are often encountered in horizontal wells. Lateral lengths ranging from 5,000 ft to 7,000 ft are not uncommon in many shale plays in the United States and the average drilling time has progressively reduced with improving directional drilling technology. Owing to the fast drilling pace and current geo-steering practices, a significant number of wells are left with tortuous trajectories and various sites of high dogleg severity. This often imposes considerable obstacles to completion and production activities, particularly reentry operations with wireline, coiled tubing, and workover rigs.

One of the major limitations of coiled tubing drillouts in horizontal wells is the high potential for helical buckling and subsequent lockup which is characterized by extremely high metal-on-metal friction and often results in several unplanned trips or the inability to reach the desired depth. Lockup potential during post-stimulation coiled tubing drillout is greatly influenced by geo-steering practices, well placement (toe-up or toe-down), dogleg severity, tortuosity of the well path, and drilling fluid properties. In some cases decisions are made to utilize the natural energy of the well for hole cleaning (typically flowing the well in an underbalanced condition to increase turbulence or annular velocity), however this effectively reduces the drilling fluid lubricity and increases friction lockup tendencies.

Larger and stiffer coiled tubing sizes, such as 2-3/8, 2-5/8, and 2-7/8 in., are more resistant to fiction lockup at deeper depths than the commonly used 2 in and 1-3/4 in coiled tubing. Nevertheless, regulatory weight restrictions for road transportation often limit the length of larger size tubing, and the cost implication of running these larger sizes can be prohibitive. Various chemical additives and downhole tools have also been developed to increase coiled tubing reach in highly deviated laterals, but their effectiveness primarily depends on the quality of each additive or tool and how they are applied. Currently, an industry-wide practice is to perform torque and drag analysis using one of the commercially available modeling software, wherein the optimum pipe size and grade are primarily selected based on the planned depth (measured depth) and the predicted friction lockup potential. However, due to the vast uncertainty involved in selecting many of the modeling input parameters, friction lockup is still frequently encountered in many deep horizontal wells. Consequently, the selection of the optimum coiled tubing size remains a major challenge in the coil tubing industry.

In conventional drilling with jointed pipe, the importance of drilling fluids (or drilling mud) is well understood and the types of drilling fluids, hydraulics, and fluid rheology have been adequately delineated. However, there are only a handful of publications specifically addressing the issues related to coiled tubing fluids, hydraulics, and hole cleaning. Even though the fundamental principles of solids transport in both conventional and coiled tubing drilling are fairly similar, the conditions under which those principles are applied are undoubtedly different. The ability to rotate the pipe combined with the use of consistently high-viscosity fluids and higher circulating rates through larger pipe sizes are factors that facilitate cuttings removal in conventional drilling. Fluids used in jointed pipe drilling generally exhibit thixotropic characteristics due to the need to suspend drill-cuttings while the pumps are shut down to make connections. However, since coiled tubing can be continually deployed, the need for such frequent pump shutdowns is eliminated, and several low viscous or Newtonian fluids can be effectively used for drillouts. Inevitably, the fluid selection often determines the cost and success of a coiled tubing drillout.

The small size of coiled tubing often presents a restricted flow area which limits the flow rate and hydraulic velocity available in the annulus to clean the hole. In highly deviated or horizontal wells with eccentric annular geometries, insuffcient flow rates can lead to the formation of solid beds in the flow stagnation region on the low-side of the wellbore and the subsequent drag or stuck pipe that are often encountered. The flow stagnation problem is directly associated with high eccentricity in highly deviated wells and typically occurs in the small gap width between the coiled tubing and the casing (Figures 1 and 2). This phenomenon has been thoroughly explained by several researchers, including Haciislamoglu and Langlinais (1990), Chin (1992), Azouz et al. (1993), Hussain and Sharif (1998), Escudier et al. (2002), Ogugbue and Shah (2011), and Asafa and Shah (2012). Without agitation induced by pipe rotation, pipe reciprocation, and turbulent flow, solid beds continually build up along the wellbore. Therefore, much emphasis has been placed on frequent and expensive wiper trips, or short trips, (pipe reciprocation) to prevent solid beds formation since coiled tubing cannot be rotated. Even though it is clear that eliminating or reducing the number of short trips can significantly lower the drillout cost, the alternative means of cleaning the hole are often not known or fully understood.

Similar to conventional drilling, annular velocity (AV) has been widely used as a measure of hole cleaning during post-stimulation plug drillout with coiled tubing. Various AV rules-of-thumb have been adopted that evince inadequate knowledge of solids transport or lack of consideration for solid properties and fluid rheology. A common rule-of-thumb for hole cleaning assumes that the annular velocity must be at least twice the solids terminal settling velocity in vertical wells and ten times that for horizontal wells in order to inhibit bed formation. Other rules-of-thumb assume a minimum value of annular velocity needed for efficient hole clean. One such assumption is that the minimum annular velocity required to sufficiently clean the hole in vertical and horizontal holes are 50 ft/min and 100 ft/min, respectively. Another general misconception is that the use of intermittent highly-viscous sweeps or pills provides good hole cleaning which certainly confuses good suspension characteristics of such sweeps with hole cleaning capability. In most cases, the effects of temperature and shear on gel polymers are disregarded, and the various attempts to apply annular velocity rules-of-thumb or replicate conventional drilling concepts in coiled tubing drillouts has led to severe hole cleaning problems.

Additional factors including downhole tool selection and drilling practices have been known to influence the success of coiled tubing drillouts. The choice of bit or mill used for drilling or milling bridge plugs dictates the size of plug debris generated and how efficiently the debris can be removed. In many cases, superior sealed-bearing roller-cone bits (rock bits) generate smaller plug parts than equivalent mills and have been successfully used to drill up to 30 or more bridge plugs in a single run. While the life of a rock bit is mostly dependent on the bearing type, the size of plug parts generated ultimately depends on the gauge and cutting structure of the bit, the material composition of the plug, weight on bit (WOB) and downhole motor revolution (RPM). The jetting action at the bit also contributes to the hydraulic horsepower and impact force that are needed for hole cleaning. Thus, optimizing bit hydraulics and using a moderately aggressive cutting structure, low WOB, and high RPM are generally desirable. A huge knowledge gap still exists, however, in the area of designing and optimizing bottomhole assembly for coiled tubing drillouts.

This paper discusses the critical aspects of post-stimulation coiled tubing drillouts and focuses on the fundamental theories and applications of coiled tubing hydraulics and hole cleaning. Based on laboratory test results of many chemical additives, the effectiveness of many field practices have been found questionable and various ways of improving the overall drillout efficiency have been recommended.

Coiled Tubing Unit and Pipe Selection

Many parameters must to be taken into account when selecting a coiled tubing unit, pipe size, and grade. The tubing diameter must be large enough to provide the necessary flow required to efficiently run the downhole motor and clean the hole while minimizing the internal tubing pressure. The fatigue life of the pipe reduces with every cycle on the service reel and gooseneck, and the presence of internal pressure results in an exponential growth in fatigue and associated cost. Selecting larger diameter tubing can significantly increase the flow rate and reduce internal pressure, but the logistics and economic concerns often limit the use of certain pipe sizes. Moreover, selecting a large coil tubing size may lead to a considerable reduction in the annular clearance between the tubing and wellbore which can change the annular flow regime. This creates additional annular velocity and turbulence in the flow stream that is desirable for hole cleaning with non-weighted Newtonian fluids. The downside to this phenomenon is the increased annular friction pressure loss and its associated increase in pump horsepower requirements.

Larger coiled tubing sizes require larger service reels (based on fatigue life considerations) and are usually transported on separate trailers. Due to weight limitations on many roads, the length of pipe that can be fit onto a reel depends on its nominal outside diameter and weight per foot. In deep horizontal and highly deviated wells, the longer length of coiled tubing required to reach the well total depth (TD) imposes a restriction on the coiled tubing size that can be utilized. Obviously, the additional benefit of using a large tubing size in such deep well applications is the greater tubing stiffness and resistance to friction lockup. This is particularly true of 2-3/8 in. or larger coiled tubing sizes that are being used today. Nonetheless, the fatigue life of larger diameter tubing is generally lower compared to smaller diameter tubing of the same grade, regardless of the presence of internal pressures.

Unlike conventional jointed pipe, coiled tubing typically undergoes plastic deformation during normal operations. This deformation results in tubing wall thickness reduction, circumferential growth and potential necking, or development of microscopic cracks due to low-cycle fatigue. Catastrophic failures of coiled tubing may occur at high fatigue points and can be avoided by accurately monitoring the fatigue life of the pipe. Methods of tracking coiled tubing fatigue have been established and refined over the last decade with the primary factors influencing the induced pipe fatigue being the bend radius, internal pressure, pipe metallurgy, loading history, and well geometry. Even though service companies often retire coiled tubing after a predetermined maximum fatigue limit (commonly 80% of theoretical maximum fatigue life), a considerable number of pipe failures have been reported below those limits. Many operators have further reduced the fatigue limits on pipe used in their operations but still have not completely eliminated pipe failure from their coiled tubing operations. Field studies have shown that pipe failures with larger coiled tubing sizes occur at much lower fatigue life compared with smaller sizes of the same grade, especially when exposed to high pressures on conventional types of service reels. There are speculations that these occurrences may be associated with a rapid increase in pipe fatigue or crack propagations around mechanical damage zones in larger pipes. However, further research and experiments would be required to support this claim. It is also important to know that pipe cycles under low pressures between 500 and 1,500 psi can cause significantly higher fatigue damage than moderately higher pressures (Tipton, 2003). Hypothetically, the moderate pressure somehow provides more internal structural support for the tubing than a low-pressure condition, thus creating a more uniform distribution of bending strains and negligible circumferential growth. These factors must be carefully considered when planning a coiled tubing drillout.

The root cause of many coiled tubing failures has been traced to pipe fatigue, pipe defects or manufacturing imperfections, abusive usage, mechanical damages from the gripper block, gouges, injector ring, and change in pipe metallurgy or corrosion due to exposure to harsh environments. However, the accuracy of the method or software used for tracking the fatigue life is not questioned in most failure analysis. Long after recognizing the limitations of the running footage and empirical methods of tracking pipe fatigue, the theoretical or mechanistic method was developed by Dr. Steve Tipton at the University of Tulsa. Now there are many coiled tubing fatigue models being used in the oil and gas industry based on mathematical computation of tubing stresses and corresponding strains along with the incremental estimation of fatigue damage resulting from working conditions. To a reasonable extent, the mathematical model algorithms have been verified experimentally. However, the uncertainties related to the statistical computation of certain input parameters, the inability to account for mechanical damages, and the inaccuracy associated with capturing the operating conditions and bending event parameters can lead to incorrect fatigue damage predictions. Thus, research is ongoing for possible methods of improving the accuracy of current mathematical models.

In order to achieve practical fatigue predictions, the engineer must have adequate knowledge of the coil tubing properties including the pipe outside diameter, wall thickness, pipe grade, reel and guide arch radius, and the position of the reel with respect to the well. While setting up equipment for coiled tubing operations, space constraints at the wellsite sometimes prevent an optimum rig up. However, the reel would be ideally positioned at an optimum fleet angle with respect to the guide arch to prevent excessive pipe strain when spooling. The fleet angle is sometimes unknown, and there is no concensus amongst coiled tubing vendors on the recommended optimum value of the fleet angle. Often the model does not account for the actual distance between the reel and the well or any offset from the initial model setup which leads to a false fatigue estimate on the pipe at the end of each job. Fundamentally, a simple trigonometry calculation using the actual coiled tubing stack height and desired fleet angle can be used to estimate the optimum reel position and minimize additional fatigue introduced to the pipe due to an improper rig up.

Other modes of pipe failure such as tubing collapse, ovality, kinking and corkscrew buckling are not uncommon in coiled tubing operations. Selecting a unit with an automatic override on a number of operating parameters can partially eliminate human interface and help reduce operator errors that often lead to these failures. Van Adrichem and Adnan (2001) published a survey of coiled tubing failures and attributed a significant percentage of reported failures to human error. As such, the use of an electrical override has been recommended for setting limits on injector head parameters including running speed, weight, and pressures. In addition, incorporating an Automated Coiled Tubing Integrity Monitoring (ACIM) system on the coiled tubing unit can provide superior real-time monitoring of corrosion, pitting, and tubing geometry, thereby reducing coiled tubing failures (Trinidad and Ahmad Zaki, 2010).

In harsh environments containing hydrogen sulfide (H_2S) or carbon dioxide (CO_2), specific attention must be paid to the concentration and partial pressure of these gases to minimize tubing corrosion and susceptibility to failure. Depending on temperature and pH, sulfide stress cracking or hydrogen embrittlement can potentially occur in deep sour wells when using high-strength steel tubing. Much research has been done to identify the working pH range and H_2S partial pressures for popular pipe grades used in the coiled tubing industry as well as equipment suitable for sour gas applications (McCoy, 2005; McCoy and Thomas, 2006; Hampson et al., 2009). Lower pipe grades with a minimum yield strength of 90,000 psi or less are often more suitable for H_2S environments, but the lower strength and weight accompanying these pipe grades may present depth limitations and buckling problems. Inhibitor or scavenger type chemicals have been successfully used to eliminate or reduce the H_2S gas concentration. In some cases, the wellbore fluid containing H_2S or CO_2 is bullheaded into the formation or circulated out of hole, after which an overbalanced condition must be maintained to prevent further influx. When planning for a sour gas well where a significant amount of H_2S is expected, it is also important to verify that surface equipment such as valves and blow-out-preventers (BOPs) are H_2S-certified.

Torque and drag modeling, including well geometry, coiled tubing depth capability, and tubing buckling tendency, remains the primary pipe selection criteria for coiled tubing operations. It is evident, however, that pipe fatigue, working fluid type and additives, annular clearance and hole cleaning, well effluent, constituents and influx potential, internal and external coiled tubing flow dynamics, and downhole tool configuration must also be carefully considered.

Hole Cleaning and Drillout Practices

One of the greatest challenges often encountered when planning a coiled tubing drillout is the selection of drilling fluids with desirable properties and good hole cleaning capability. In horizontal well applications, the factors influencing hole cleaning include the wellbore geometry, hole deviation, pipe eccentricity, solids properties (size, specific gravity and concentration), fluid rheology, annular velocity, and wiper trip or short trip frequency. Unfortunately, wellbore geometry, hole deviation, and pipe eccentricity are always fixed, and operators are left only with control over the remaining factors. Solids properties can be predicted and controlled to some degree and are generally based on the proppant size used for stimulation, type of plugs drilled, bit type, and drilling parameters (WOB and Motor RPM). On the other hand, annular velocity, fluid properties, and short trips are variable parameters that are primarily available to achieve effective hole cleaning during coiled tubing drillouts. It is, therefore, necessary to understand the fundamental theories of fluid flow and fluid rheology, as well as their applications for effective solids removal from coiled tubing annulus. This knowledge will ultimately prevent the formation of cutting beds in the lateral and build section of the wellbore which have been the known cause of many stuck pipe incidents during coiled tubing drillouts.

Although increased annular velocity and short trips are common concepts used in coiled tubing drillouts, fluid properties and their effect on efficient hole cleaning have been historically overlooked. The effects of temperature and shear on the gel polymer used for the sweeps are usually ignored, and the marsh funnel viscosity of the gel sweeps is the only criteria for conditioning them in many instances. In highly deviated and horizontal wellbores, this misunderstanding and failure to account for the effect of wellbore conditions on the fluid properties has led to unnecessarily high chemical usage, stuck pipe, and the need for frequent and costly short trips during drillouts.

Most coiled tubing drillouts are conducted using 2-3/8 in. or smaller tubing sizes in casing sizes ranging from 4.5 in. to 7 in. Hole cleaning problems are usually more severe in larger casing sizes, especially in tapered casing strings. The restricted inside diameter of the coiled tubing compared to the larger equivalent diameter of the annulus often results in high frictional pressure losses in the tubing and an inability to provide the adequate flow rate, annular velocity, and turbulence needed for solids transport. Unlike conventional drilling with jointed pipe where the pipe can be rotated, the primary means of cleaning debris from the coiled tubing annulus includes stationary circulation while drilling plugs, mechanical agitation with jetting tools and short trips, and the use of high viscosity sweeps. All of these factors can promote efficient hole cleaning during coiled tubing drillouts, but an effective management of the fluids system can provide significant cost savings by minimizing chemical usage and reducing the frequency of short trips.

Many operators have a predefined maximum number of plugs drilled before short tripping which can vary from two to six or possibly more. The key to an effective short trip is a pulling speed that prevents bypassing accumulated debris on the low side of the annulus. Debris bypass has been verified with post-drillout venturi junk basket runs in which significant additional quantities of plug debris have been recovered from the wellbore. A low pulling speed of 35 fpm or less has been found to promote debris removal and minimize opportunities for bypass. Although rare, some operators will drill all the plugs in a well, up to 20 or more plugs, without short tripping and will typically flow the well in an under-balanced condition to enhance annular velocity. Whether few plugs are drilled before short tripping or all plugs are drilled without any short trips, numerous incidents of stuck pipe and friction lockup associated with poor hole cleaning have been reported with both practices. Knowing the early signs of hole cleaning problems, the necessary action to mitigate the problems, and how to condition the drilling fluids in order to optimize solids removal and militate the problems can be more important than frequent short trips. In most cases, the up and down string weight and system pressures, including circulating pressure, wellhead pressure, and choke pressure, are the variable parameters available to monitor drag and solids build up in the tubing annulus. However, it is often difficult to differentiate between any gain in pressure due to partial solids build up in the annulus and the pressure increase caused by shear or temperature degradation of the friction reducers. A simple way to differentiate these pressures is to install a differential pressure transducer on the surface flow line to evaluate the change in drag reduction characteristics of the friction reducing polymer being used.

The size of the plug parts or debris drilled and their specific gravity determines the ease of their removal. Typically, limited attention has been given to bit and mill selection and drilling parameter optimization, and the outcome is usually the generation of large plug debris that are difficult to transport. Using moderately aggressive milled tooth tri-cone rock bits, with just enough weight on bit (500 to 3,000 lbs) to prevent motor stalls, can reduce plug debris size and promote good hole cleaning. Bit and mill selection criteria that promote hole cleaning are discussed further in the bottomhole assembly and drilling practices section of this paper.

Stationary circulation periods can account for approximately half of the total drillout time. Paying considerable attention to solids removal during this period is critical to the success of a coiled tubing drillout. During stationary circulation, solids transport is influenced by fluid density and rheology, the type of slurry flow, flow regimes, and solids properties. Various unsuccessful attempts have been made to use consistent high viscous fluids for CT drillouts, but the high circulating pressure and associated pipe charge has made it uneconomical. Low viscosity Newtonian fluids, either weighted or un-weighted, are generally better suited for solids transport in the horizontal or inclined sections of the coiled tubing annulus (Leising and Walton, 2002). Without misconstruing fluids suspension capability and hydraulic solids transport, experience has shown that the use of shear-thinning high viscous sweeps with good suspension characteristics can be effective for solids removal in the inclined sections of the annulus. However, in the vertical section, high viscous fluid in the laminar flow regime is best suited for solids transport. Thus, the dynamics of fluid flow and solids transport in an eccentric annulus must be fully understood in order to optimize gel sweep usage.

Solids, or particle, transport in the horizontal and inclined fluid streams are clearly different than that of vertical fluid streams. The transport efficiency in vertical wellbores is often evaluated by determining the relative velocity between the solids and fluid stream, known as the settling velocity. In highly deviated and horizontal wellbores, solids removal is often quantified by the critical flow rate or velocity needed to prevent solid bed formation or re-entrain solids into the fluid stream.

The determination of the critical flow rate at various well inclinations has been the focus of much previous research (Wilson, 1986; Hsu et al., 1989; Ford et al., 1990; Shah and Lord, 1991; Martins and Santana, 1992; Luo and Chambers, 1992; 1993; Clark and Bickham, 1994; Walton, 1995; Zou et al, 2000; Ramadan et al., 2003). However, estimating critical rate or velocity in a dynamic heterogeneous horizontal slurry flow can be very difficult due to the simultaneous effects of pipe geometry, eccentricity, hole inclination, flow regime, fluid properties, and rheology.

Similar to a vertical wellbore, the direction of particle settling in a deviated wellbore is vertical, but the fluid velocity has a reduced vertical component which decreases its ability to suspend solids. In near-vertical wellbores, larger particles have been found to have lower transport efficiency, while medium sized particles have the lowest transport efficiency in horizontal wellbores (Li and Wilde, 2005). Critical velocity is also known to increase with particle size for fine particles less than 0.5 mm, however, it decreases with particle size for larger particles greater than 0.5 mm. This phenomenon was reported to be due to the increased shear stress at the fluid-solid bed interface as particle size increases (Wilson, 1986). The greatest challenge in applying such theories is how to predict the size of the plug debris when planning a coiled tubing drillout.

The slurry flow in inclined and horizontal wellbores is normally characterized by a combination of homogeneity and heterogeneity. In the absence of pipe rotation, previous studies have shown that the flow regime and fluid viscosity dictates the effectiveness of solids transport in a highly deviated wellbore annulus (Walton, 1995; Leising and Walton, 2002; Cho et al., 2002). Flow regimes are quantified with Reynolds number which is a function of annular diameter, annular velocity (AV), fluid viscosity, and density (Equation 1 and 2). The onset of turbulence can be drastically delayed by increasing fluid viscosity or reducing flow rate. This explains why shear-thinning highly viscous gel sweeps can provide good solids suspension but need some degree of turbulence to re-entrain solids that have settled to the lowside of the wellbore. Viscous sweeps flowing in the laminar regime simply glide over the solid beds with little or no potential of re-entrainment. Moreover, when pumping highly viscous gel sweeps during drillout operations, it has been commonly observed that the solids do not return with the sweeps but, instead, are carried within the Newtonian fluids pumped behind the sweeps. This observation is consistent with that of Leising and Walton (2002).

With low viscous or Newtonian fluids such as fresh water, more turbulence can be achieved at much lower flow rates than with high viscous gel sweeps. It must be noted, however, that very thin Newtonian fluids with very low viscosity provide limited solids transport due to their inherent poor suspension capability. Theoretically, chaotic flow with turbulent eddy drag forces creates the necessary energy to lift and keep solids moving in the flow stream through a process known as saltation. The analytical study conducted by Leising and Walton (2002) demonstrated that the solids are transported a certain length, described as the transport length, after which they settle to the low-side of the wellbore during the saltation process. Thus, the key to achieving good hole cleaning is to maximize the solids transport length. This is accomplished by finding the optimum shear-thinning viscosity that achieves turbulent flow with available flow rate while retaining as much suspension capability as possible.

For Newtonian fluids:
$$N_{res} = 378.79 \frac{\rho q}{(d_2 + d_1)\mu} \tag{1}$$

For non-Newtonian fluids:
$$N_{res} = \left(\frac{1}{12}\right)^n \frac{7.48052}{32.17 \times 8^{n-1}} \frac{d_e{}^n v^{2-n} \rho}{K_a} \tag{2}$$

Smaller and lighter solids normally have longer transport lengths than larger and heavier ones, and, depending on fluid viscosity, the transport lengths in the laminar flow regime are usually shorter than in the turbulent flow regime. Increasing the fluid viscosity promotes longer transport lengths for entrained solids, but invariably deters the required turbulent flow. Laminar slurry flow of both Newtonian and non-Newtonian fluids is more prone to the formation of solid beds, and the solids at the topmost layer of the bed essentially roll along the horizontal section of the wellbore. In the entire wellbore, the curved section with inclination between 30 and 65 deg is the most difficult to clean (Leising and Walton, 2002). The continual build up of solids in this section can eventually lead to sliding of the solid bed layers back towards the heel of the horizontal in a situation known as an avalanche. Pulling the bottomhole assembly through an avalanche will lead to excessive drag and subsequent stuck pipe if necessary redemptive actions are not taken. Additionally, high eccentricity and the consequent occurrence of the flow-stagnation region (Figures 1 and 2) in the horizontal and curved sections make it very critical to maintain turbulent flow with sufficient viscosity or apply mechanical agitation to re-entrain solids. However, the flow rate needed to achieve turbulence in the annulus can be restricted by the downhole mud motor capacity and the tubing burst pressure. The annular flow rate has typically been supplemented by producing the well between 0.25 and 1 bpm above the circulating flow rate when feasible. This practice of underbalanced drilling has been found helpful when applied correctly but has led to serious drilling problems in many cases.

Flowing back the well in an underbalanced condition to increase annular velocity usually creates a mixture of drilling fluids and hydrocarbon that is not desirable. Since drillouts are often conducted with re-circulated fresh water or brine, the effectiveness of friction reducing chemicals often declines in such contaminated or gas-cut fluids. Likewise, the gel sweeps, which are needed to increase solids suspension, are diluted down considerably, thereby losing their efficiency. Another negative outcome of underbalanced drillouts includes the rapid loss of fluid lubricity and consequent friction lockup encountered in deep wells. These lockup situations are further escalated by the presence of debris between the coiled tubing and the low-side of the wellbore which prevents lubricating fluid from contacting the necessary surface area. Operators may consider a rig-up similar to that in Figure 3 for recycled fluid systems and must use filter pods with the proper screen sizes to prevent re-introduction of solids into the well. Also, the clarity and density of the fluid must be frequently checked to determine when to change out the entire fluid system. Failure to change out the fluids when necessary can lead to a loss of fluid lubricity with higher potential for downhole motor failure and premature friction lockup.

Conversely, when conducting a drillout without recycling the fluids (single pass flow system shown in Figure 4), underbalanced drilling can be more consistently utilized to promote hole cleaning, and it is possible to drill more plugs before short tripping. Nevertheless, the well must be choked back to maintain a positive pressure differential above the formation pressure when a gel sweep is passing through the lateral. This time required for sweeps to pass through the lateral must be carefully monitored in order to prevent dilution and maintain effectiveness. Field experience, however, has shown that drilling out plugs while underbalanced can create more problems than when drilling balanced. Likewise, inappropriate use of the surface flow control equipment is an issue encountered on many coiled tubing drillouts. Well control skills and effective pressure management must be given specific attention, as many on-site supervisors lack an adequate knowledge of the well control methods needed to maintain the well at balance and would rather conduct the drillout in an underbalanced condition. It is commonly assumed that the annular velocity needed for hole cleaning cannot be achieved with the returning flow rate lower than the circulating flow rate. However, this assumption may be true only for certain annular geometries or when the annular flow rate is aggressively reduced below the circulating flow rate. Provided the fluid system has been optimized, drilling and hole cleaning problems can be minimized by maintaining balanced or overbalanced conditions. Furthermore, the cost of additional fresh water and chemicals when using non-recycled fluids and the cost of frequently changing out recycled fluids can also make underbalanced drillouts unattractive.

The use of circulating or jetting subs, sometimes referred to as AV subs, in the bottomhole assembly is becoming increasingly popular. These subs are either ball activated or flow activated and help to divert flow, either partially or wholly, away from the mud motor, thereby increasing the flow rate beyond the maximum capacity of the mud motor. A jetting sub could provide additional improvements in hole cleaning during short trips, however, the nozzles must be properly sized and angled backwards at 45 degrees to provide the necessary hydraulic jetting force to lift and re-entrain solids. The downside for many jetting subs is the inability to activate them more than once, difficulty determining or controlling flow rate due to washed out or incorrectly sized nozzles, and the subsequent damage to the mud motor when run beyond its maximum RPM. A number of measurement while drilling (MWD) tools and other downhole flow rate and pressure monitoring devices can be used to optimize the flow rate, pressure, and drilling parameters and eliminate the possibility of damaging the mud motor. The ideal jetting sub for coiled tubing drillouts must be capable of multiple activation and highly resistant to wear.

In deep high pressure, high temperature (HPHT) wells, the apparent viscosity of shear-thinning gel sweep polymers decreases with increasing bottomhole temperature. While there are many commercial gel polymers available for coiled tubing drillouts, some polymers demonstrate high resistance to temperature and shear along with good viscoelastic characteristics, and others may break down completely with slight exposure to similar conditions. The most commonly used polymers for coiled tubing drillouts include natural polymers such as xanthan, HEC, and polyacrylamide, as well as various proprietary synthetic polymers and polymer blends. The concentration of the polymer mixed into the base fluid determines the apparent viscosity and temperature stability to a large extent, and some studies have reported the incompatibility of certain polymers with various brines (Kelco Bulletin). Most polymers require some level of agitation or shear in order to hydrate and achieve optimum viscosity, however, the continual shearing of some polymers results in shear degradation and permanent loss of viscosity. Additionally, most polymers used for gel sweeps also exhibit friction reduction characteristics in the turbulent flow regime, and a few of them can potentially be used as friction reducers. A temperature degradation study of friction reducing polymers in brines conducted by Ke et al. (2006) demonstrated that certain polymers are not suited for HPHT environments. There are certainly many types of polymers available depending on the downhole conditions. Consequently, adequate care must be exercised when selecting a polymer to be used for gel sweeps, especially in HPHT wells.

When flowing down the coil tubing string, gel sweeps are continuously and thoroughly sheared due to the restricted inside diameter of the pipe, and the apparent viscosity of the sweep is usually at a maximum. The polymer then undergoes the greatest shear when going through the bit nozzles or water courses on the mill. Due to their shear-thinning characteristics, such polymers become very thin and flow through the nozzles without causing excessive friction pressure loss. Once in the annulus, a viscosity recovery occurs due to the significant reduction in hydraulic velocity and shear rate resulting from the larger annular clearance. This viscosity increase is required for solids suspension in the annulus but will prevent the desired turbulence if excessive. An optimum viscosity range of 5-15 centipoise (cP) at a nominal shear rate of 170 sec^{-1}, proposed by Leising and Walton (2002), is expected to provide adequate turbulence in the lateral or inclined sections of the wellbore depending on the annular clearance. Even though this recommended viscosity range has been found helpful, HPHT tests must be conducted to determine the polymer loading needed to achieve the desired viscosity at bottomhole temperature within the prevailing pipe geometry. In the vertical section of the annulus, the continued decrease in temperature as the polymer fluid travels uphole leads to further increased viscosity and the corresponding reduction in turbulent flow needed for solids transport in the vertical flow stream. During the entire drillout, it is important to continually monitor the viscosity of the gel sweeps going in the hole and returning to surface to enable the field engineer to make necessary adjustments. Although the optimum range of Reynolds number for effective solids removal is currently the subject of ongoing research, optimal sweep viscosity can be matched with available flow rate and corresponding shear rate in various annular geometries to facilitate efficient hole cleaning and minimize polymer cost.

Bottomhole Assembly (BHA)

An important aspect of coiled tubing drillouts is the selection of downhole tools, bearing in mind the importance of each component required for drilling and solids transport optimization. The most common BHA includes a full or near drift bit or mill, mud motor, agitator or oscillator, and motor head assembly consisting of a hydraulic disconnect, back pressure valve, and coil connector. Additional tools, such as MWD tools and hydraulic jars, are also considered by some operators. The benefit of running MWD tools cannot be overemphasized owing to their immense drilling optimization and hole cleaning functions. The data obtained may include, but is not limited to, downhole weight on bit, torque, temperature, vibration, and internal and external bottomhole pressures. The weight on bit and motor RPM control the pace of drilling and the size of plug debris generated, the importance of which has been discussed in the hole cleaning and drilling practices section of this paper. Although the inclusion of hydraulic jars in the BHA is often considered worthless for the purpose of jarring stuck pipe in the lateral, the jars can be considerably more helpful if stuck uphole in the curve. With no need for jars on most wells, operators must weigh the additional cost against the risk of getting stuck in the curve without any means of jarring free. Moreover, a properly designed bottomhole assembly can prevent many drilling related problems including stuck pipe, helical buckling and friction lockup.

Similar to conventional drilling techniques, bit or mill selection for coiled tubing is usually done by trial and error. However, improper bit selection can have a negative impact on solids removal and result in numerous unplanned trips. Depending on the cutting structure of the bit or mill, various sizes and shapes of plug debris are generated. In order to transport these solids to the surface, fluid properties and annular geometry must be matched with the bit or mill selected. In well geometries with large annular clearance, for instance, the expected plug debris must be significantly smaller due to the lower annular velocity and the reduced turbulent flow typically obtained in such geometries. Using a less aggressive bit or mill with short, closely spaced cutters can be of great benefit for this type of application.

Milled tooth tri-cone rock bits and five-bladed mills, such as reverse clutch and junk mills, are predominately used for coiled tubing drillouts depending on the type and number of plugs to be drilled. Unfortunately, bit and mill records are rarely kept in completion operations. The onsite supervisor and tool representative are often forced to choose the bit or mill based on only their experience. An appropriate procedure for selecting the optimum bit type for coiled tubing drillouts is to gather all available offset well data. This data includes basic well information, IADC dull bit grading, the plug type and number of plugs drilled, fluid properties, weight on bit and RPM, and circulating flow rate and pressure. The offset well data is then compared with the description of the planned well and used to select the bit or mill that will generate the desired size of plug debris. The compatibility of the selected bit with other BHA components must also be verified prior to the job, and post-job bit economics should be evaluated using a cost per plug approach.

For optimal bit or mill selection, it is also beneficial to review the suitability of the available bit and mill types for each type of plug in the well. Moderately aggressive roller cone bits with IADC No. 225 to 315 are recommended for most plugs made out of hard cast iron, composites, and elastomer materials. Roller cone bits are relatively lower cost and are capable of drilling up to 20 plugs or more in a single run when used correctly. However, the risk of losing a cone can be a deterring factor for their use in long laterals. Thus, fixed cutter PDC bits are recommended for long laterals with more than 20 plugs, although the high cost of PDC bits may justify the alternative consideration of reverse clutch or junk mills. When selecting a roller cone bit, close attention should be given to the type of bearing, cone offset, nozzle size and position, type of agitator being considered, abrasive wear rates, and required gauge protection. Sealed journal bearings are recommended to prevent damage due to contaminated fluids, while cone offset ranging from zero to two can increase bit durability and reduce gauge scraping. Bit nozzles must be appropriately sized to provide the necessary jetting force for hole cleaning without creating excessive friction pressure loss. Furthermore, the position and size of each nozzle on the bit often dictates the solids removal efficiency from the bit face.

In addition, matching the selected bit with the mud motor size will prevent motor failures. As the casing size reduces, the bit choice is primarily driven by the coiled tubing size or motor consideration (Portman and Short, 2000). Since the coiled tubing maximum torque rating cannot be exceeded, the motor size should be carefully selected to avoid twisting off the tubing. Table 1 shows the available mud motors with corresponding bit sizes. The maximum torque output from each motor increases with the motor and casing size, and the larger motors are generally used to turn larger bit sizes due to greater torque requirements. Thus, motor torque performance comparisons must be performed using the torque per square inch (MTSI) criteria (Figure 5). The optimum MTSI can be obtained through larger motor sizes with greater torque capability, but the corresponding power output is compromised. It must be noted, however, that the data provided in Table 1 represents motor versus bit specifications from when Portman and Short's (2000) work was published. Much more powerful, high torque mud motors are currently available for the sizes shown in the table.

Helical buckling and subsequent lockup of the coiled tubing string can be severe limitations in horizontal well applications. Lockup occurs when the wall contact forces due to helical buckling become excessive, and the coiled tubing string cannot make further depth progress regardless of the magnitude of surface force applied. The coiled tubing string can also be badly deformed or fail due to combined axial and bending stresses. The critical buckling load at which the coiled tubing buckles can be predicted using various equations in numerous published works (Lubinski et al., 1962; Mitchell, 1982; Dawson and Paslay, 1984; Cheatham and Pattillo, 1984; Newman et al., 1989; Chen and Cheatham, 1990; He and Kyllingstad, 1993; Wu et al., 1993; Miska and Cunha, 1995; Qiu, 1998; Kuru et al., 1999; Mitchell, 2002 and Weltzin et al., 2009). The maximum achievable depth and the applied compression load at which lockup will occur can be estimated using these equations. Since helical buckling and lockup are directly related to bending stiffness and hole clearance, larger coiled tubing diameters should be considered to prevent lockup.

In horizontal well applications, vibratory tools, such as agitators or oscillators, can help prevent lockup and increase coiled tubing reach while maintaining adequate and uniform weight on bit. Non-uniform weight on bit affects the reactive torque of the mud motor and significantly impacts the number of stalls and corresponding pipe cycles recorded while drilling each plug. However, excessive vibration can result in rapid bit or mill wear, loose cones, and other severe damage to bit or mill. For wells with very long laterals, the agitators or oscillators may also provide some help with depth advancement, while good hole cleaning and drillout practices are generally necessary for drilling progress.

The observed torque and drag are usually more severe in smaller casing sizes. This is due to the increased wall friction between the coiled tubing and the casing. Drag forces on the walls of the wellbore can also be increased by residual bends in the coiled tubing, since the coiled tubing is usually not completely straightened out by the injector head before running into the well. The magnitude of drag encountered can be determined from the amount of weight available at the bit, while the observed torque dictates the maximum mud motor RPM. The coefficient of friction used for drag modeling can be fine tuned from one well to the other by continually monitoring up, down, and neutral weights. Proper selection of drilling fluids and drilling practices can help minimize torque and drag as discussed in the earlier sections. Mixing drag reducing additives, popularly referred to as pipe-on-pipe, with the drillout fluid also improves lubricity and reduces wall friction when used appropriately. Such drag reducing additives should be evaluated for adequate lubricity at downhole conditions.

Eliminating Frequent Short Trips

Despite the obvious advantages of coiled tubing for drilling out bridge plugs in horizontal wells, an inherent shortcoming is the inability to rotate the pipe and the resulting hole cleaning problems. Operators often turn to an alternative method of short tripping to the kick-off point after drilling a predefined number of plugs. These frequent short trips are commonly regarded as the only effective way of removing sand and plug debris from the lateral and inclined sections of the wellbore. While this method has proven effective, it is also very time consuming and costly. Depending on the cost of other third party equipment on location, the lateral length of the well, and the number of plugs drilled prior to short tripping, incremental costs due to frequent short trips can be tens of thousands of dollars. Moreover, each additional short trip becomes more costly than the one preceding it, and the time spent short tripping can account for a significant portion of the total drillout. Fortunately, short trips can be minimized through a combination of monitoring drilling parameters, fluid properties optimization, and BHA advancements.

The drilling parameters that should be monitored for coiled tubing drillouts include circulating pressure and flowing wellhead pressure as well as weight on bit and torque and drag. Circulating pressure and flowing wellhead pressure are good indicators of whether or not sand and plug debris are building up in the annulus. Although it is easy to assume that an increased circulating pressure is due to an increase in friction pressure, there is also a high probability that it is due to partial occlusion of the bit nozzles or debris accumulation in the coiled tubing annulus. In many cases, increased circulating pressure that is accompanied by a corresponding decrease in flowing wellhead pressure can be a good early indicator of debris build up in the annulus. Poor hole cleaning can more easily be differentiated from the degradation of friction reducers through the installation of a differential pressure transducer on the surface flow line that is capable of evaluating any change in drag reduction. This evaluation of debris build up in the coiled tubing annulus can be used to reduce short trip frequency to when necessary instead of after a predefined number of plugs.

Additionally, weight on bit and drag should be monitored during coiled tubing drillouts. Along with bit selection and motor torque, these drilling parameters can significantly impact the size of plug debris and their transport efficiency. To this end, minimizing weight on bit and using high torque motors are usually favorable. The additional time required to drillout plugs with minimal weight on bit can be a deterring factor for some, however, spending more time on each plug to generate finer debris can greatly impact solids removal and reduce stuck pipe incidents. The drag encountered when tripping out of hole can also be a good indicator of imminent stuck pipe. It is beneficial to record pickup weights every three to four plugs or every 1,000 ft and compare them with pickup weights at the same depth while tripping out of hole. When excessive drag is observed, supervisors should consider tripping back in the hole, increasing annular flow rate if feasible, and pumping additional sweeps. Torque and drag data acquired from the drillout can be compared with predicted values, and modifications can be made to the predicted coefficient of friction for upcoming wells.

Returning solid sizes and quantity, returning fluid viscosity, and annular flow rate must be constantly monitored during a drillout. A manual plug catcher with a screen that can be periodically pulled or a hydraulic plug catcher with a screen at the end of the dump line can be used to help visualize and evaluate the returning solids. When large plug debris is being recovered on surface, the weight on bit should be reduced and motor RPM increased if feasible. If little or no plug and sand debris are being recovered, increasing the gel loading of the sweeps or a short trip may be required. Additionally, excessive break down of the returning sweep viscosity may also necessitate increase in gel loading if the proper chemicals are being used. As earlier discussed, an optimum downhole viscosity range of 5 to 15 centipoise (cP) at a nominal shear rate of 170 sec^{-1} can greatly facilitate solids transport. Using a consistently high viscous fluid with this range of downhole viscosity may be more effective than the use intermittent sweeps, but the high cost and circulating pressure associated often make this prohibitive. Furthermore, greater operational success and cost savings have been reported with of freshwater or brine as the primary drillout fluid along with intermittent high viscous gel sweeps. Since the wall shear rates in existing annular geometries may be higher or lower than 170 sec^{-1}, as shown in Table 2, a reasonable method of conditioning polymer fluids is to estimate the desired viscosity based on the actual shear rate and downhole temperature. However, it can be difficult to get a good estimate of downhole temperature unless a temperature measuring tool is included in the bottomhole assembly. Likewise, the shear rate is directly impacted by the annular flow rate which should be determined based on the appropriate balanced or underbalanced drilling practices. In addition to reducing short trips through efficient hole cleaning, optimally conditioned gel sweeps can also lead to lower chemical usage and associated cost. It should be noted, however, that advanced methods of conditioning drillout fluids and monitoring solids removal efficiency are not generally available, and are being developed for future coiled tubing drillout applications.

Other beneficial hole cleaning methods that are currently being developed for possible future use with coiled tubing drillouts include the incorporation of a jetting tool and possible use of heavy-weighted brine with weighted sweeps. Short trips with a conventional motor and mill or bit assembly use mechanical agitation as a means for re-entraining debris from solid beds, but the hydraulic force transmitted through forward facing bit nozzles has limited effectiveness. A jetting tool with optimally sized backward facing nozzles that can be shifted open prior to short tripping can increase annular flow rate and maximize the use of hydraulic force for solids re-entrainment. However, such a tool must be capable of being reliably shifted multiple times and must permit partial diversion of flow, so that the mud motor action is uninterrupted while using the jetting sub. Obviously, improving the efficiency of a short trip could also limit its frequency.

Heavy-weighted brine commonly used in jointed pipe workover operations as a method of pressure control can also be utilized for coiled tubing drillouts. It has been observed that heavy-weighted brine creates additional mass transfer for better solids re-entrainment, while heavy-weighted sweeps have superior high temperature stability, rheology, and solids suspension capability necessary to remove wellbore solids and minimize or eliminate short trips. The downside to this is the high cost of such weighted brines, which may be more than the cost savings obtained from any further reduction in the number of short trips.

Drilling Fluids and Additives

In an effort to improve hole cleaning, reduce short trips, and minimize costs, a series of rheology experiments were designed to test and evaluate the gel sweep and friction reducing polymers being used in the operator's Eagle Ford coiled tubing drillout operations. Common gel sweep polymers were tested using a HPHT rheometer in order to simulate the downhole conditions typically encountered in the Eagle Ford area. In addition, commonly used friction reducers were evaluated in a high temperature flow loop.

Gel Sweep Analysis

Various chemicals were recommended by the vendors being utilized in the field and samples were sent to a third party laboratory. For consistency, the same lab, personnel, and equipment were used throughout the process. The experiment was designed with an assumed maximum downhole circulating temperature of 250 °F and was carried out as follows:

- Frac pond water from the area of operation was obtained and utilized as the base fluid system
- Each gel sweep polymer being considered was mixed at 3, 5, and 7 gal/10 bbl to cover the range of recommended concentrations and minimize the number of changing variables for evaluation
- Each polymer was mixed at 1500 RPM for 20 minutes to ensure adequate hydration
- Marsh funnel viscosity was obtained for reference to field measurements
- Each sample was tested using a Fann 77 rheometer with a full shear suite (600, 300, 200, 100, 60, 30, 10, 6, 3, 1 RPM) for each of the following temperatures and pressures
    - 75°F and 15 psia (ambient conditions)
    - 150 °F, 200 °F, 250 °F and approx. 2,500 psia

The polymers were then evaluated by plotting the measured apparent viscosity against shear rate. As discussed from previous literature, a viscosity of roughly 5 to 15 cP was assumed as the target viscosity window. The annular shear rate was calculated for both 2 and 2-3/8 in. CT inside 5-1/2 in. OD casing using Equation 3. At a typical flow rate of 2.5 to 3.5 bpm the annular shear rate is 87 to 121 sec^{-1} for 2 in. and 111 to 155 sec^{-1} for 2-3/8 in. coiled tubing. The maximum viscosity of 15 cP was confirmed by calculating the Reynolds number (Equation 2) of each polymer within this annular shear window. This verified, that for the wellbore geometry, flow rates, and gel sweeps used, a viscosity of 15 cP or less should maintain turbulent flow. The yield point (YP), another measure of carrying capacity, was also calculated for each polymer (Equation 4), but it was found to directly correlate to the viscosity of the fluid at high temperature and pressure. Thus, the yield point was disregarded from the evaluation process. The viscosity and shear windows referenced were plotted overlapping the data on Figures 6 - 11.

$$\gamma = 96 \frac{v}{(d_2 - d_1)} \tag{3}$$

$$YP = \theta_{300} - (\theta_{600} - \theta_{300}) \tag{4}$$

In general the results showed that there was a definite breaking point between 200 °F and 250 °F where certain polymers, regardless of concentration, did not hold up to the combination of high shear and temperature. Figure 6 showed that at 200 °F and a polymer loading of 3 gal/10 bbl, all of the polymers tested maintained viscosity between 5 and 15 cP with shear rates from 87 to 155 sec^{-1}. As seen in Figure 7, when the temperature was increased to 250 °F, the polymers started to breakdown and only a few adequately performed at the lower end of the shear window. Looking at Figures 8 and 9, another trend started to emerge. When gel loading was increased to 5 gal/10 bbl at 200 °F, a few of the gel sweep polymers actually measured greater than 15 cP throughout the shear window, while the others essentially retained the desired viscosity. Again, when the temperature was increased to 250 °F, the viscosity reduced drastically, but the majority of the polymers managed to stay in the viscosity window. Furthermore, it was revealed that polymers E, G, and J sustained too high a viscosity at 200 °F and too low a viscosity at 250 °F. The 7 gal/ 10 bbl tests, presented in Figures 10 and 11, showed the majority of the polymers performing well above the viscosity window at 200 °F. When increased to 250 °F, there were still many of the polymers that recorded viscosity above 15 cP, while some were broken down enough by the temperature and shear that it put them within the viscosity window. For the 7 gal/10 bbl test, polymers E, G, and J were again verified as the most impacted by temperature. This was a critical finding in that these gel sweep polymers can more easily end up in the laminar flow regime if the downhole circulating temperature is not precisely known and the gel sweep concentration appropriately determined. Additionally, the 7 gal/10 bbl concentration required to get these polymers into the viscosity window at 250 °F yielded a marsh funnel viscosity that was unreasonably high and impractical for field use. All other marsh funnel viscosities measured were in line with expectations and typical field measurements (Table 3).

After reviewing the test results and graphical data, Table 4 was developed and distributed as a reference for the field supervisors to show the recommended marsh funnel viscosity of each polymer based on the annular flow rate. These recommendations were the result of tying together the measured apparent viscosity, shear rate, annular velocity, and marsh funnel viscosity of each polymer.

In terms of pure performance the following recommendations were made. Those polymers requiring substantially higher marsh funnel viscosities were not recommended due to the impracticality of achieving and pumping such high viscosities, as well as the higher cost associated with the increased chemical usage. Polymers A, C, D, F, H, and I all performed consistently within the viscosity and shear windows at both 200 °F and 250 °F. It is important to note that the magnitude of the marsh funnel viscosity, typically the only tool used to evaluate gel sweeps in coiled tubing field operations, did not correlate with the sweeps that performed well in the experiment. Instead, the polymer type was evaluated to be far more critical. The polymers that measured higher marsh funnel viscosities (polymers E, G, and J from Table 3) were also the most affected by temperature, measuring apparent viscosities that were too low at 200 ^oF and too low at 250 ^oF. Likewise, none of the gel sweep polymers showed significant improvement in apparent viscosity at the 7 gal/10 bbl concentration. Overall, the tests confirmed that marsh funnel viscosity is not an effective means of comparing gel sweeps, dramatic increases in marsh funnel viscosity do not improve hole cleaning, and polymer type is a critical factor in optimized fluid rheology.

Based on the test results, polymers A, C, D, F, H, and I were recommended for further use. To maintain full turbulence and maximize solids suspension, it was recommended to pump the sweeps at a 3 gal/10 bbl marsh funnel equivalent for annular rates of 2.5 bpm and at a 5 gal/10 bbl marsh funnel equivalent for annular rates of 3 bpm or greater (Table 4). A 2.5 bpm annular rate is typical for balanced drilling, and a 3 bpm or greater rate is typical for underbalanced drilling and short trips. Interestingly, polymer E maintained 4 cP at 5 gal/10 bbl and 250 ^oF even at the highest shear rates in the test. Although it performed just below the 5 cP cutoff, this suggests it may be a suitable candidate if higher annular flow rates and shear rates are expected. Polymers B, G, and J either required excessively high marsh funnel viscosity or lacked the necessary downhole viscosity at all tested concentrations and, thus, were not recommended for further use.

This experiment showed that careful consideration of the gel sweep polymer type and viscosity is required to achieve effective hole cleaning, reduce stuck pipe, and reduce costs. After evaluating the performance of each gel sweep polymer the cost implication on the field operations was evaluated. A simple daily cost comparison was carried out using the recommended concentrations from the test results. The most cost effective gel sweep polymers were identified and recommended for inclusion in a total vendor cost analysis.

Friction Reducer Analysis

In addition to gel sweeps, friction reducer (FR) is another chemical additive heavily relied on during coiled tubing drillouts. Pump rate is limited by the small ID of the coiled tubing due to high friction pressure losses and is usually dictated by the operating parameters of the downhole motor assembly. Additional coiled tubing charges may also be applied to account for added pipe fatigue if working pressures are above a certain threshold. Even in lower pressure wellbores, some amount of friction reducer is usually recommended to keep the downhole motor assembly lubricated and to reduce operating temperature. Thus, friction reducer is required in most CT drillout operations. Unlike the gel sweeps discussed, friction reducer is generally added to the fluid system continuously throughout the job and can be a substantial portion of the chemical cost. This is especially true if the fluid system is not recycled, however, the shear resistance of some friction reducers allow them to remain effective for multiple cycles when the fluid system is continuously re-circulated.

In order to reduce costs and increase coiled tubing drillout efficiency an additional experiment was designed to test the friction reducers currently being used in the operator’s Eagle Ford coiled tubing operations. The same vendors were utilized from the gel sweep tests. A flowloop experiment was planned to test various chemicals recommended by the mixing plant vendors and samples were sent to a third party lab. The same lab, personnel, and equipment were utilized for all tests. The experiment was designed and carried out as follows:

- Utilized 9 gallon flowloop with maximum operating temperature of 130 ^oF and maximum rate of 20 gpm (pressure limited).
- City water was used due to the volume required for each test.
- Each vendor recommended the chemicals and concentrations to be tested which are displayed in Table 5.
- A baseline pressure drop was established with fresh water only at 130 ^oF.
- With an operating temperature of 130 ^oF, each chemical was tested at 5, 10, and 15 gpm for 1.5 minutes each and at 20 gpm for 20 minutes, or until max pressure was reached on the flowloop. Rate was then dropped back to 5 gpm for 1.5 minutes to compare to the friction reduction achieved when the test started.

Since the flowloop was not a closed system, downhole temperature and pressure could not be achieved. As such, the purpose of the tests was not necessarily to gain a direct measurement of what could be expected from each friction reducer downhole. Instead, the experiment gave relative indications of friction reduction performance, shear resistance, and optimum concentration.

The results from the experiment were evaluated by converting the pressure drop to percent friction reduction and plotted graphically, along with rate, against time (Figure 12). A large spread in the data was immediately noticed depending on chemical and concentration tested. The first observation noted can be seen in Figure 13 where the lower concentrations generally had higher percent friction reduction at 5 gpm due to the lower viscosity of the fluid system at the lower rate. Then as the rate increases, the higher concentrations start to benefit from the increased shear and the percent friction reduction starts to converge. At the peak flow rate of 20 gpm and corresponding shear rate, another pattern emerged as shown in Figure

14. Three distinct performance areas became evident, wherein the relative optimum concentration area yielded high initial percent friction reduction and moderate shear resistance. Polymers A1, B1, D2, F5, and G1 fell into this category. A second performance area was determined to be the relative maximum concentration, wherein the initial percent friction reduction at 20 gpm was slightly lower than the optimum but much greater shear resistance was achieved after 20 minutes. Polymers C1 and G2 fell into this category exhibiting very little shear degradation. Finally, a third performance area was deemed to be the low concentration, wherein the initial percent friction reduction was approaching or equal to the highest in the test but shear degradation started immediately at 20 gpm. The optimum performance group was recommended as the concentration to use when not re-circulating water, while the maximum performance group was recommended only if the fluid system was being re-circulated and FR concentration decreased or cutoff throughout the job due to the increased shear resistance demonstrated (Table 6).

The economics of each friction reducer were evaluated based on the recommended optimum concentration. The concentrations were converted to a daily cost based on normal operating conditions, and the most cost effective friction reducers were identified. While all the friction reducers tested were recommended for further use in terms of performance alone, the daily cost evaluation was a key factor in the total cost evaluation for each vendor. The difference in initial percent friction reduction at 20 gpm for each polymer was determined to be negligible (Figure 14). As such, the cost benefit of re-circulating the fluid system and reducing overall FR use can be significant without sacrificing performance. Some friction reducing polymers can also be used for gel sweeps and once initially saturated the recycled fluid continues to be re-saturated as the gel sweeps are pumped. This dual capability can also contribute to the reduced cost of the fluid system. However, a recycled fluid system can also reduce the effectiveness of certain chemicals and their ability to mix properly, leading to increased chemical usage if not properly monitored and blended with clean water when necessary. Likewise, if the fluid rheology becomes affected this can lead to poor hole cleaning and stuck pipe.

Lastly, a full economic evaluation was performed on the recommended gel sweeps, friction reducers, and other mixing plant operating costs. The daily cost analysis of the gel sweeps and friction reducers were added to the daily operating charges for each vendor along with some assumptions about pipe-on-pipe lubricant usage and other miscellaneous chemicals often used in CT drillouts. The analysis revealed that the key drivers for mixing plant costs were friction reducer, gel sweeps, and personnel charges. Of course, changes in the scope of an operation can lead to high pipe-on-pipe or H_2S scavenger charges as well, but these key drivers are consistent throughout all coiled tubing drillout operations. Efficient use and monitoring of these chemicals can significantly improve drillout costs, but the chemicals used should be chosen with great care. A sound understanding of the science behind the chemicals and the necessary rheology can result in immediate, measurable cost savings from efficient chemical usage. More importantly, significant cost savings can be realized through more effective hole cleaning, fewer short trips, and reduced stuck pipe.

Conclusion and Further Studies

Coiled tubing has many advantages over conventional jointed pipe that have led to its tremendous popularity for post-stimulation drillouts, especially in horizontal wells. However, a general lack of understanding of the limitations of coiled tubing has led to many operational issues throughout the industry such as friction lockup, pipe fatigue, poor hole cleaning, stuck pipe, and frequent short trips. Various solutions have been detailed and recommended in this paper to mitigate these issues including consideration for wellbore geometry, proper pipe selection and rig up, hole cleaning and fluid optimization, downhole tools selection, and proper drilling practices. Careful management of these considerations can reduce the costs and many of risks associated with coiled tubing drillouts.

Regarding hole cleaning and fluid optimization, much progress and insight was gained through extensive rheological experiments. However, additional research is recommended to validate the findings and drive further advances in coiled tubing operations. A major assumption in the evaluation of the rheology experiment was that a viscosity of 5 to 15 cP was necessary for hole cleaning in the lateral. The upper bounds of the viscosity window were verified using Reynolds number for each gel sweep tested. however, additional modeling is required to confirm the necessary fluid rheology. Based on the lack of existing research on the subject matter, future studies are being undertaken to develop analytical and numerical models capable of handling the conditions encountered in coiled tubing drillouts. Such a model or simulator would allow for additional fine tuning of the viscosity, flow rates, and turbulence that must be achieved downhole and could greatly increase industry insight within the growing necessity of coiled tubing operations for horizontal wells.

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Nomenclature

A_s Cross-sectional area of tubing wall ($in.^2$)
bpm barrels per minute
d_1 Diameter of inner boundary of the annulus (*in.*)
d_2 Diameter of outer boundary of the annulus (*in.*)
d_e Effective diameter of annulus (*in.*)
f Fanning friction factor, *dimensionless*
gpm Gallons per minute
g Gravity force (lb_f)
K_a Annular flow Consistency index for Power-law model ($lb_f s^n/ft^2$)

n	Flow behavior index for Power-law model, *dimensionless*
N_{res}	Solvent Reynolds number, *dimensionless*
ppg	Pounds per gallon
q	Flow rate, gal/min
RPM	Revolutions per minute
v	Flow velocity (*ft/sec*)
YP	Yield Point ($lb/100ft^2$)

Greek Symbols

θ	Wellbore inclination (*degree*)
θ_{300}	Dial reading at 300 RPM
θ_{600}	Dial reading at 600 RPM
μ	Fluid viscosity (*cP*)
μ_a	Non-Newtonian apparent viscosity (*cP*)
ρ	Fluid density (lb_m/gal)
γ	Shear rate (sec^{-1})

Appendix

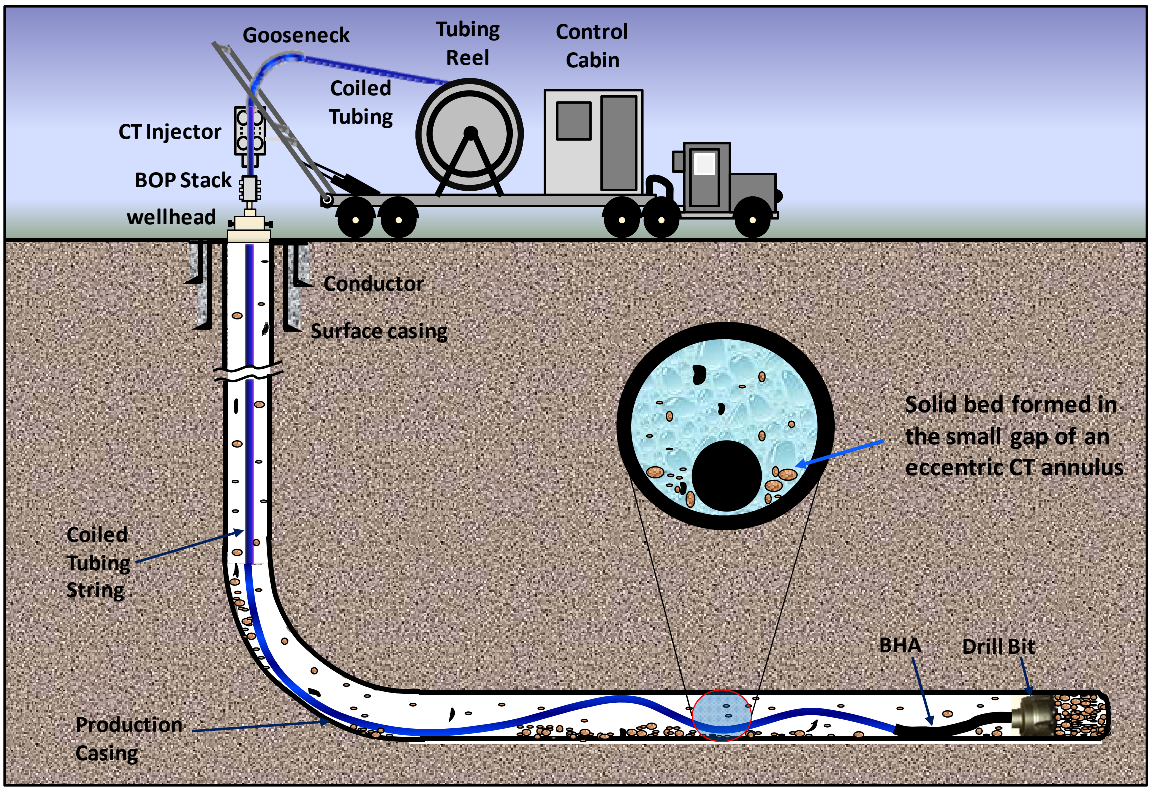

Figure 1 Slurry Flow in Coiled tubing Annulus

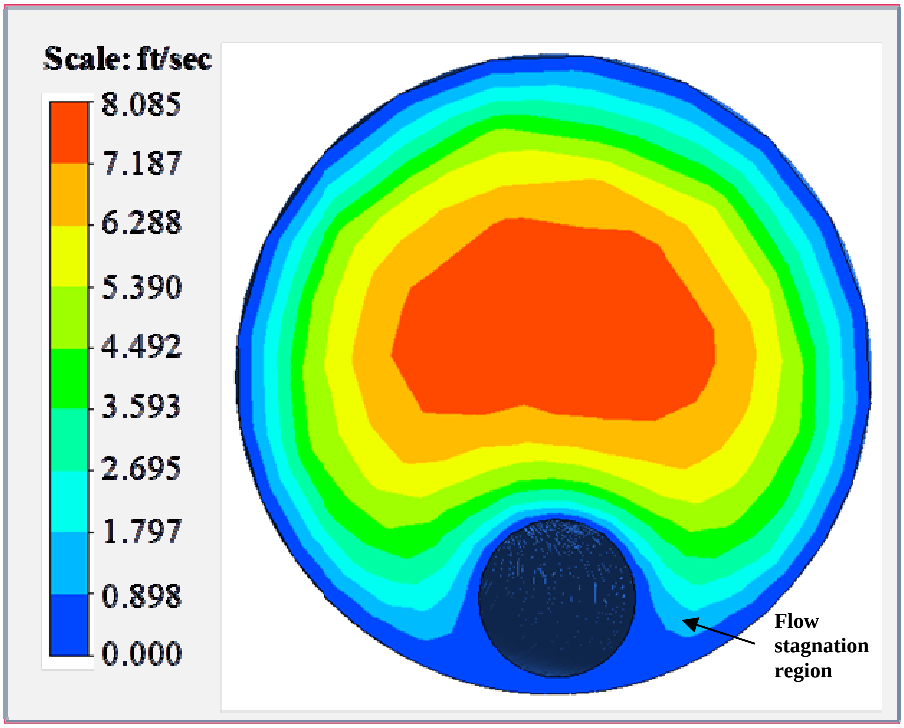

Figure 2 Typical Axial Flow Velocity Profile in Eccentric Annulus (*Asafa and Shah, 2012*)

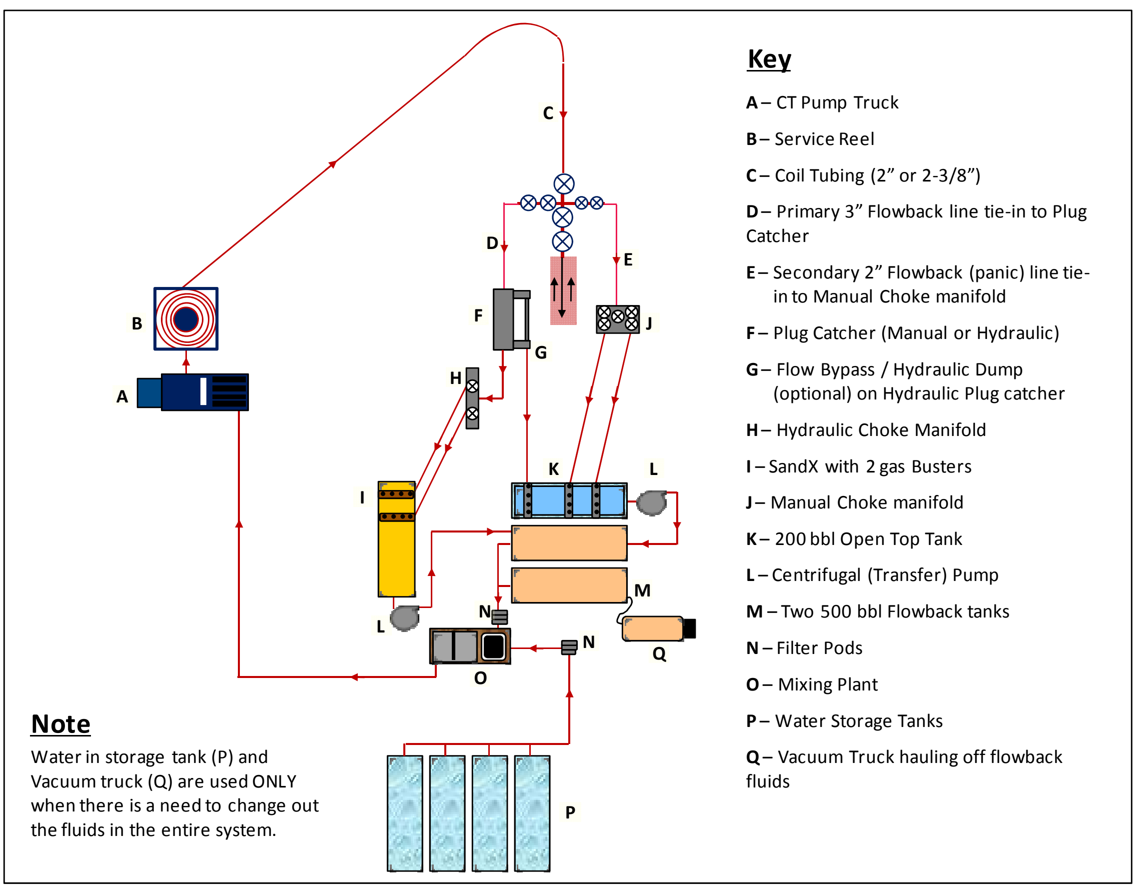

Figure 3 Re-Circulated Fluid Flow Loop

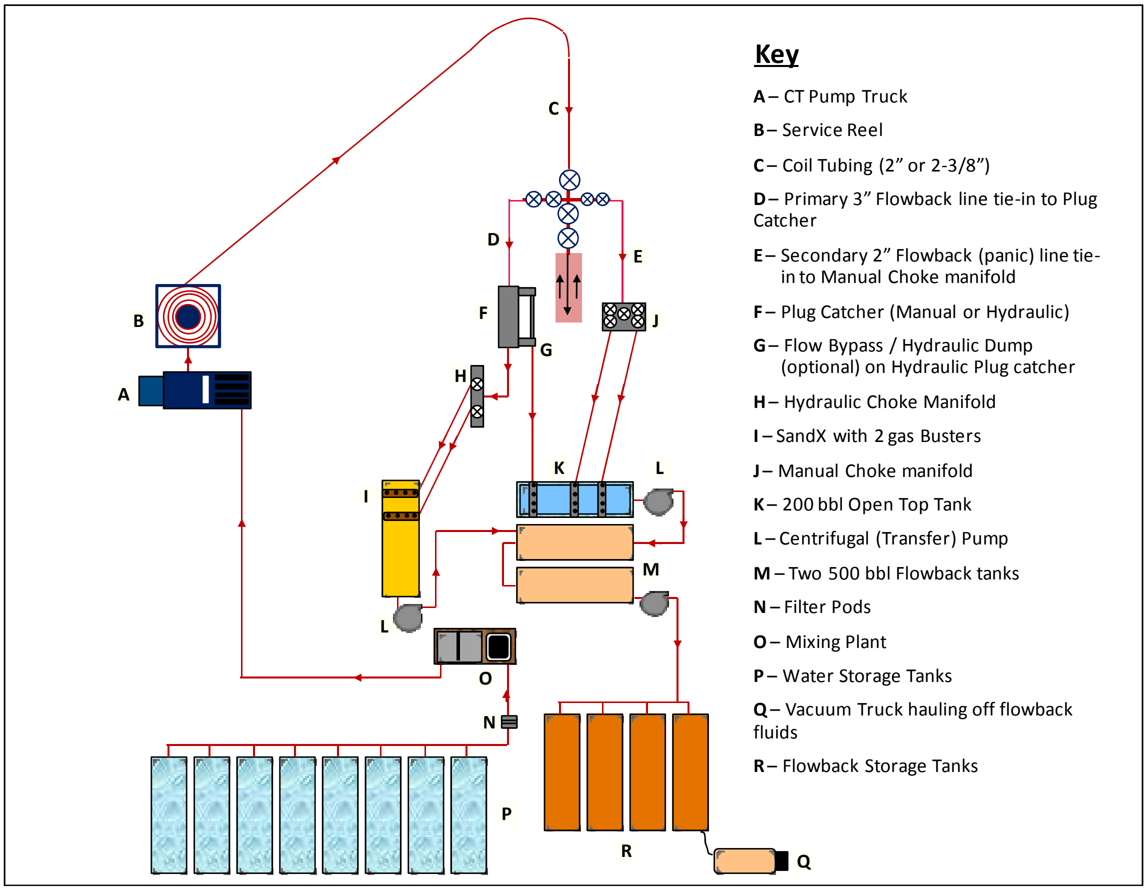

Figure 4 Single Pass Fluid Flow Loop

Table 1 Drilling Motor Sizes and Compatible Drill Bits (*Portman and Short, 2000*)

Motor size	**1 3/4"**	**2 1/8"**	**2 3/8"**	**2 7/8"**	**3 3/8"**	**3 3/4"**	**4 3/4"**
Lobe configuration	5:06	5:06	5:06	5:06	4:05	7:08	7:08
No. of stages	2.5	6	5.2	7	5	2.3	3.8
Maximum Power (HP)	2.3	17	15	34	31	12	46
Maximum rpm	205	650	370	460	360	136	250
Torque (ft.lbf)	60	170	265	466	553	965	3000
Bit size (in)	2.25	2.75	2.75	3.75	4.75	4.75	6.13
Bit Area (in^2)	4	5.9	5.9	11	17.7	17.7	29.5
Power/(Bit area)	0.6	2.9	2.5	3.1	1.8	0.7	1.6
Torque/(Bit size)	27	62	96	124	116	203	489

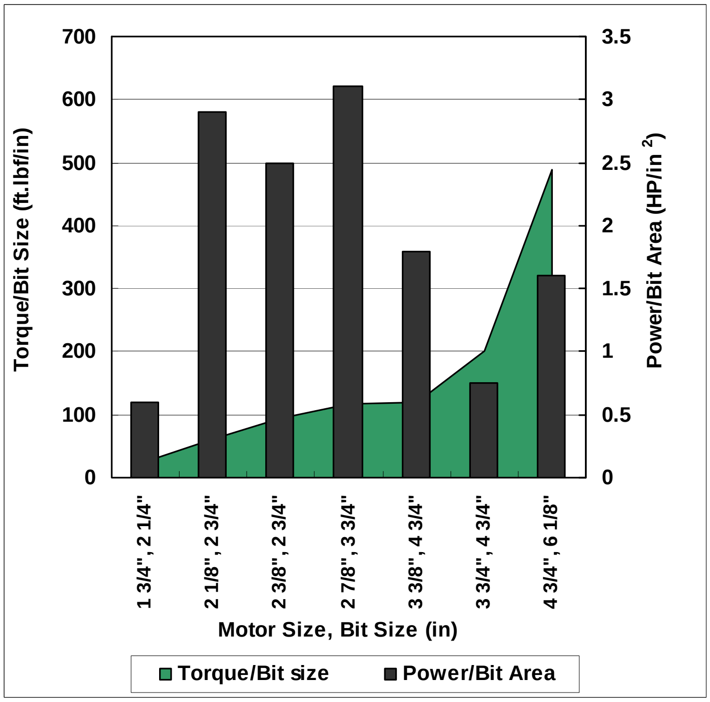

Figure 5 Drilling Motor vs. MTSI & Torque Per Bit Size (*Portman and Short, 2000*)

Table 2 Casing and Coiled Tubing Configurations with Corresponding Shear Rates

Casing Spec	Casing ID (in.)	Coil Size (in.)	Rate (bbl/min)	AV (ft/min)	Shear Rate (sec^{-1})
4.5" 15.1 ppf P-110	3.826	2.0	2.0	193	170
			2.5	242	212
			3.0	290	254
		2.375	2.0	229	252
			2.5	286	315
			3.0	343	378
5.5" 23 ppf P-110	4.67	2.0	2.0	116	69
			2.5	144	87
			3.0	173	104
		2.375	2.0	127	89
			2.5	159	111
			3.0	191	133
7" 29 ppf P-110	6.184	2.0	2.0	60	23
			2.5	75	29
			3.0	90	34
		2.375	2.0	63	27
			2.5	79	33
			3.0	95	40

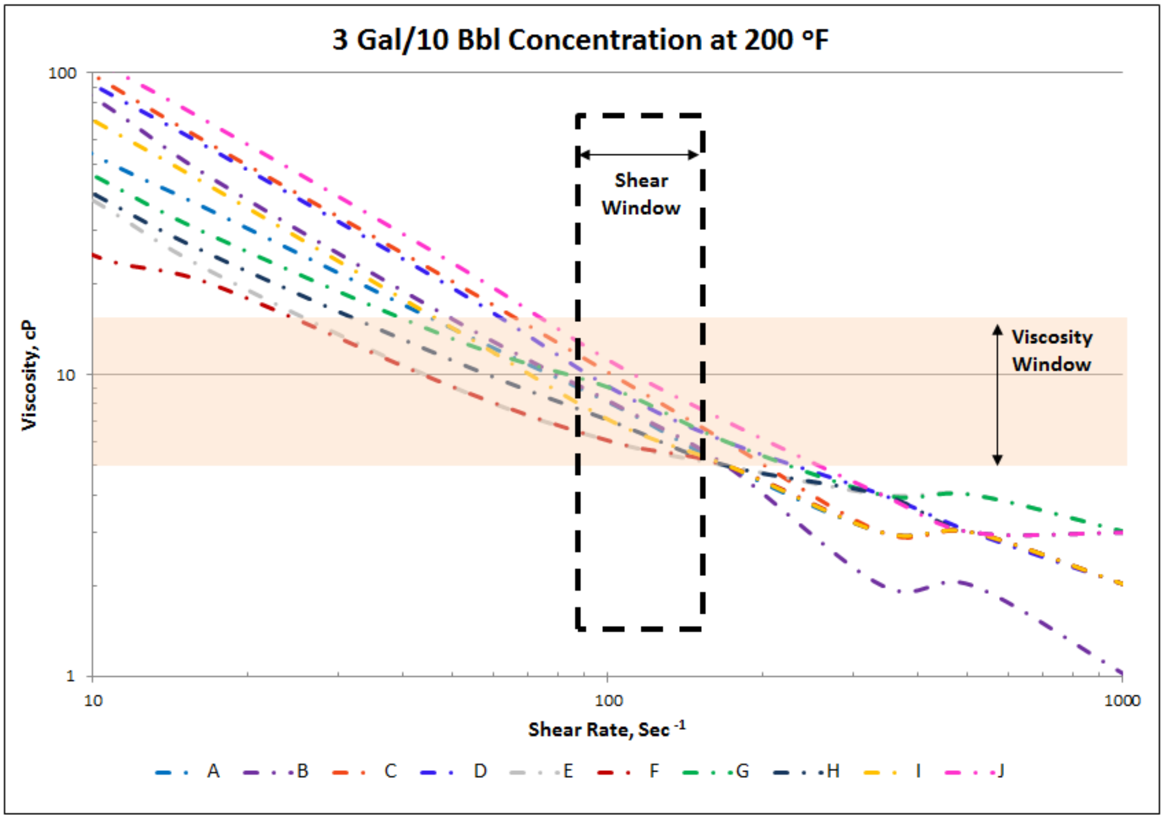

Figure 6 Gel Sweep Viscosity at 3 Gal/10 bbl and 200°F

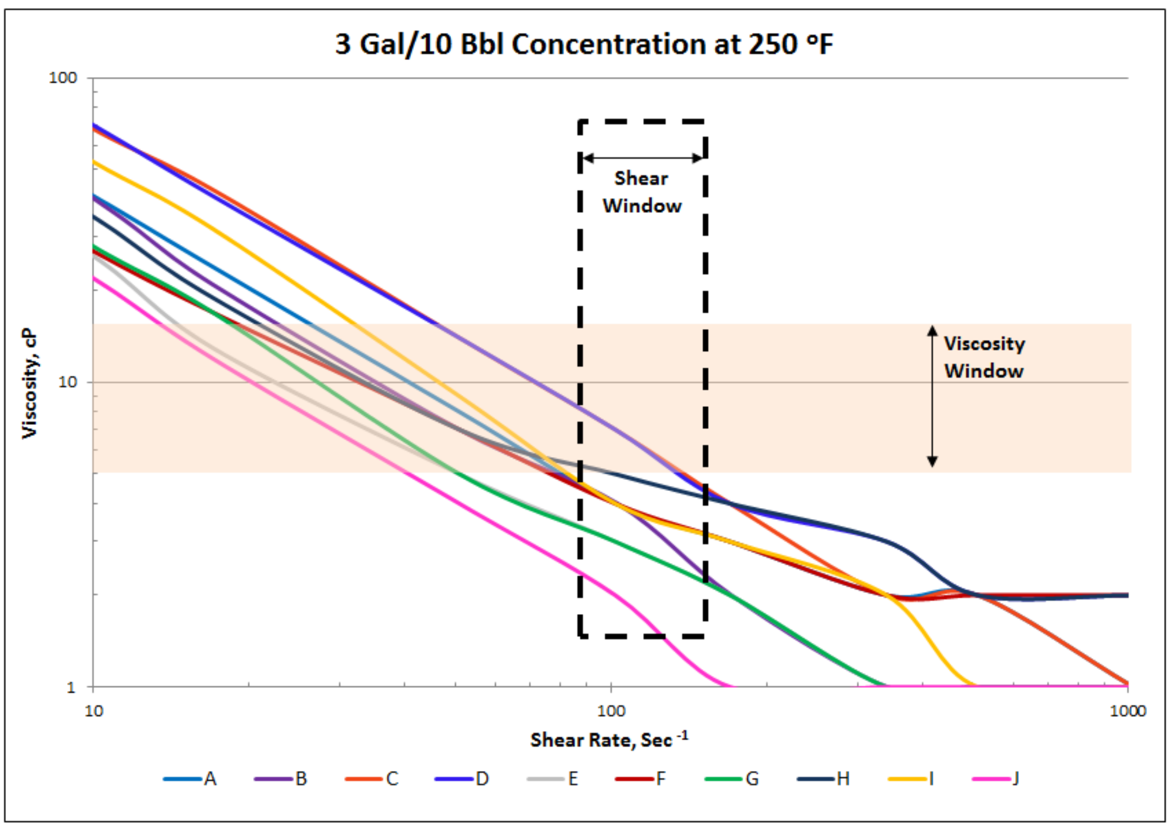

Figure 7 Gel Sweep Viscosity at 3 Gal/10 Bbl and 250°F

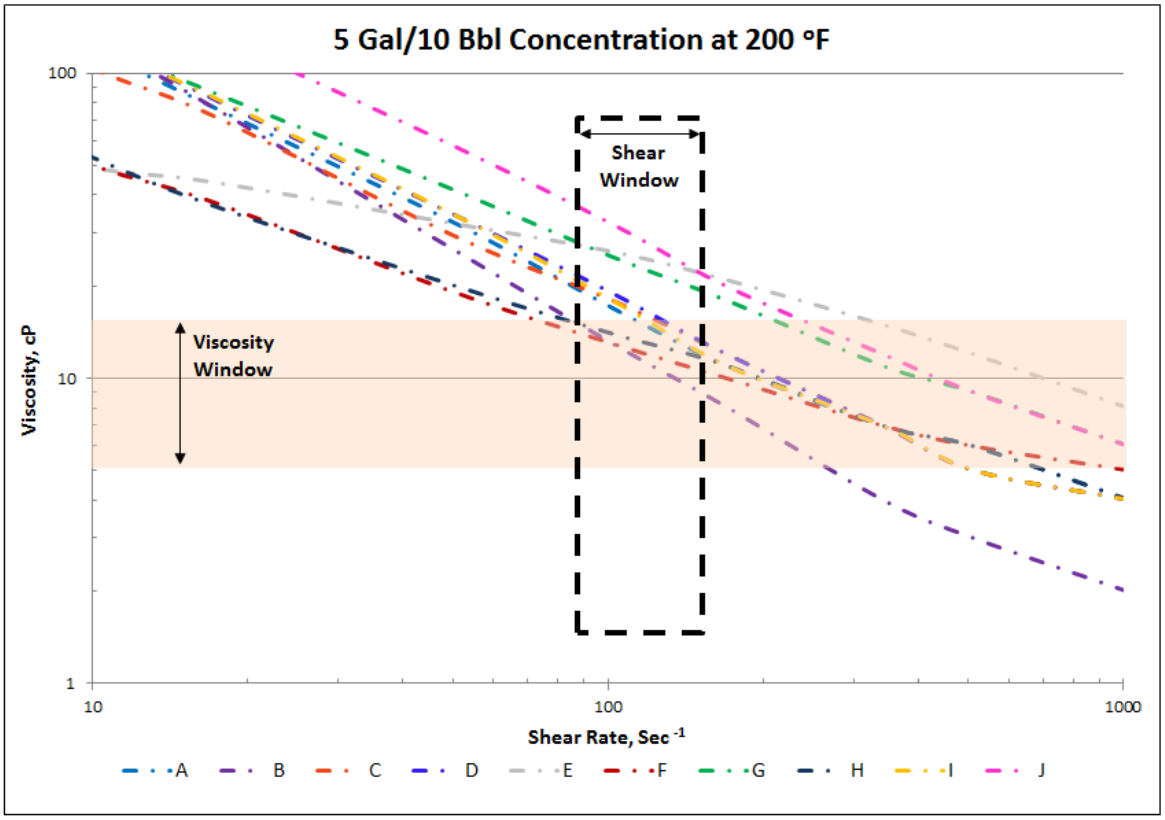

Figure 8 Gel Sweep Viscosity at 5 Gal/10 Bbl and 200°F

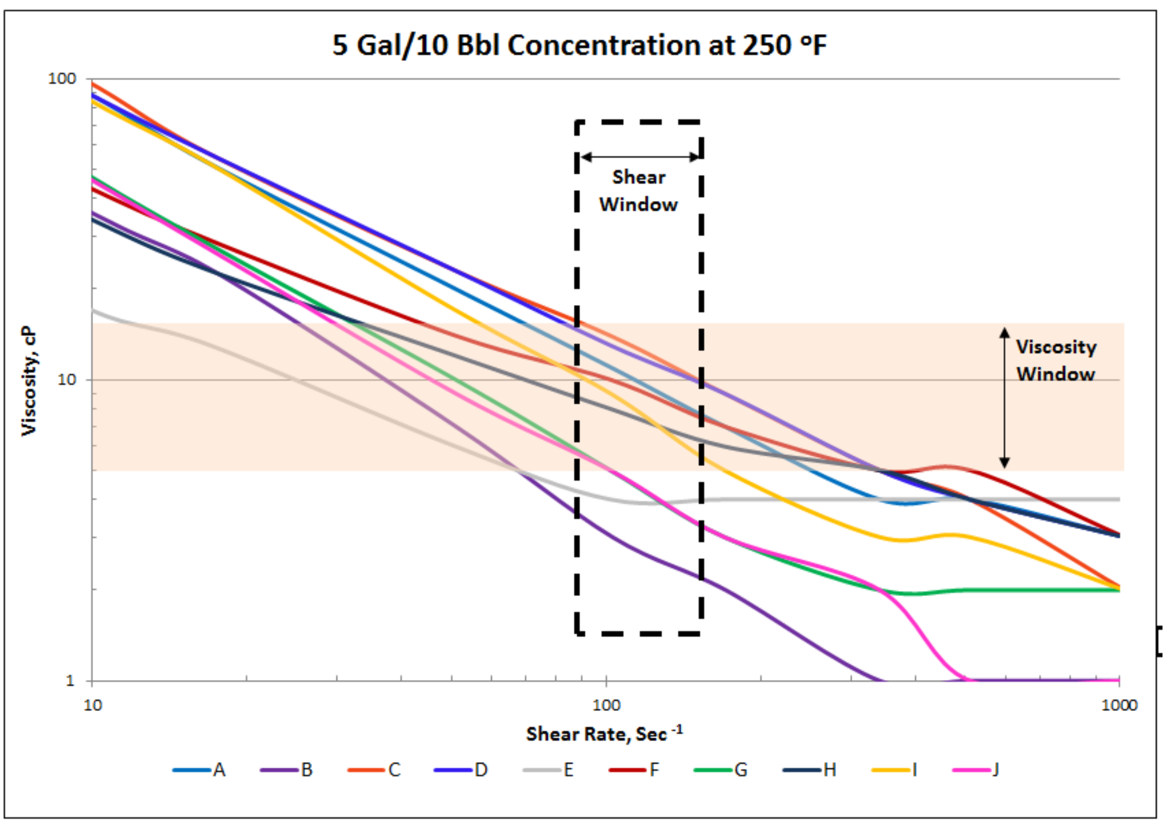

Figure 9 Gel Sweep Viscosity at 5 Gal/10 Bbl and 250°F

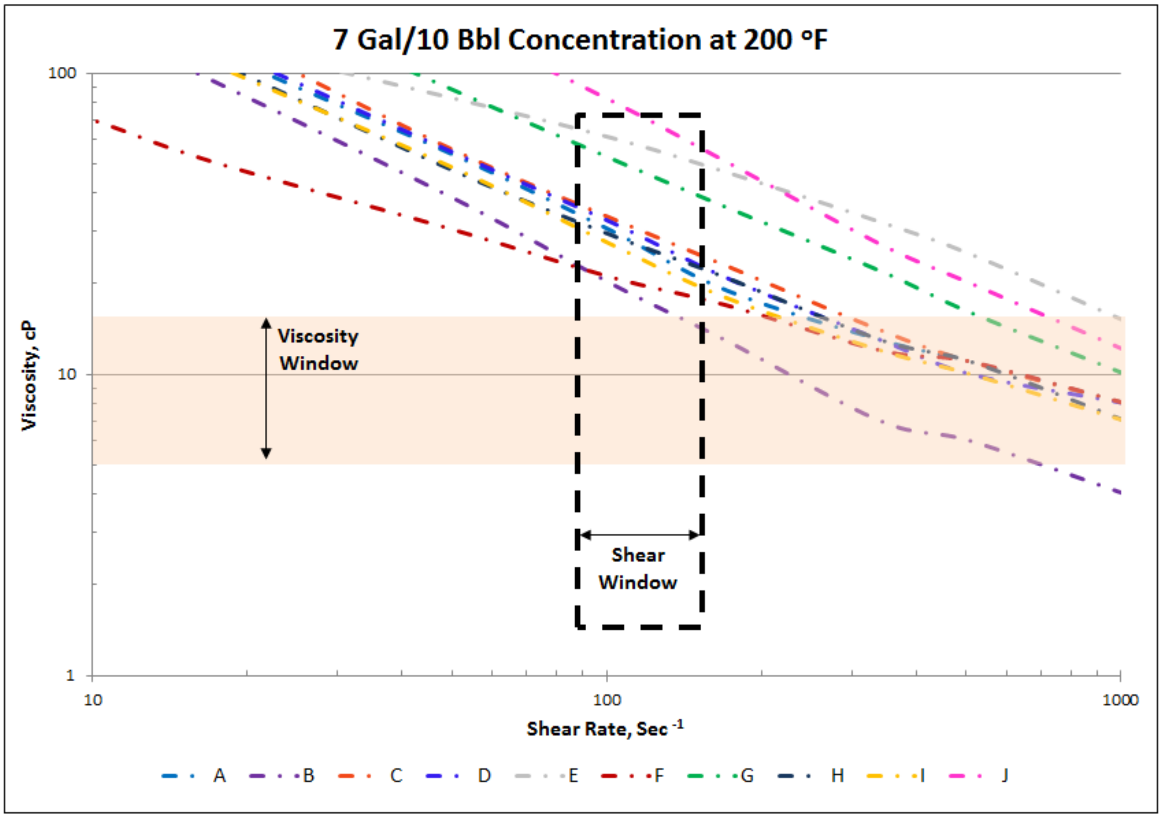

Figure 10 Gel Sweep Viscosity at 7 Gal/10 Bbl and 200°F

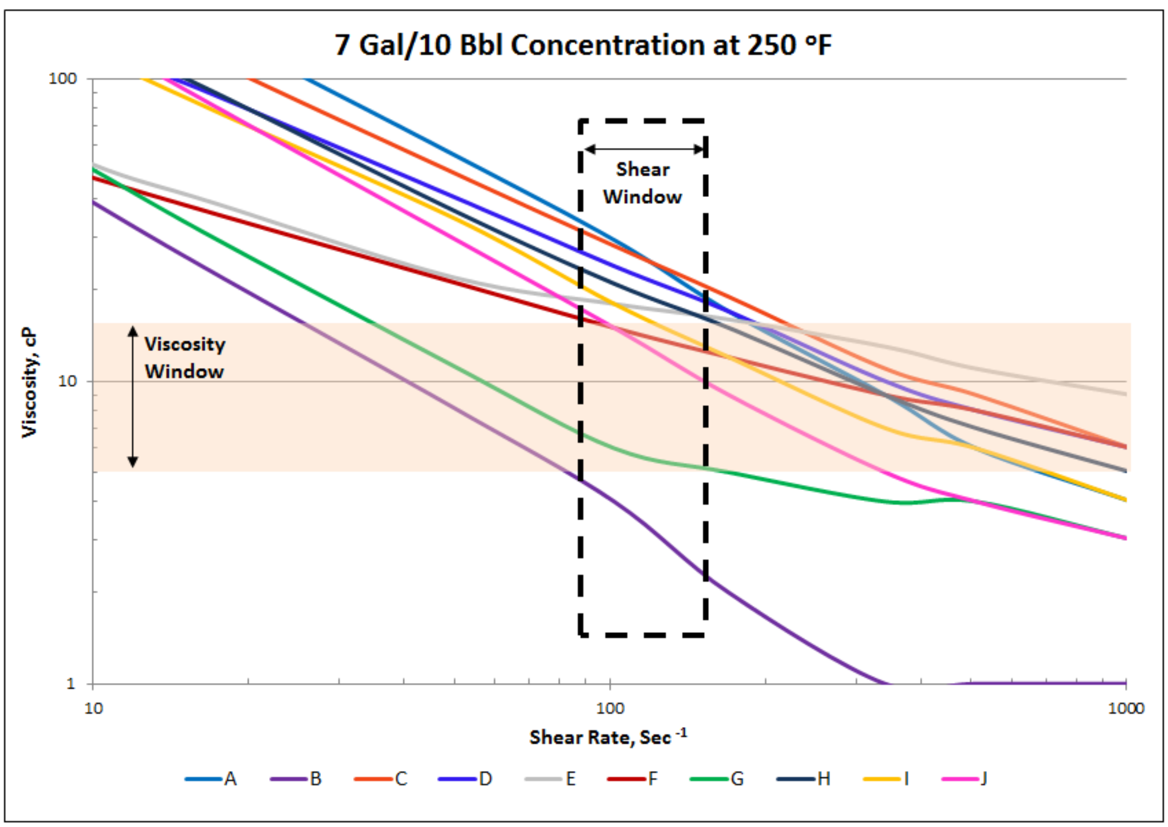

Figure 11 Gel Sweep Viscosity at 7 Gal/10 Bbl and 250°F

Table 3 Measured Marsh Funnel Viscosity in for Each Gel Sweep Sample and Concentration

Gel Sweep Polymer	Marsh Funnel Viscosity, Sec		
	3 Gal/10 Bbl	5 Gal/10 Bbl	7 Gal/10 Bbl
A	70	110	200
B	50	75	195
C	70	110	200
D	62	95	193
E	53	118	240+
F	66	80	126
G	50	95	240+
H	48	77	165
I	70	115	205
J	65	240+	480+

Table 4 Recommended Marsh Funnel Viscosity for Each Gel Sweep Sample at Varying Annular Flow Rates

Gel Sweep Polymer	Recommended Marsh Funnel Viscosity, Sec	
	2.5 BPM	> 3 BPM
A	70	110
B	N/A	N/A
C	70	110
D	62	95
E	53	118
F	66	80
G	50	95
H	48	77
I	70	115
J	N/A	N/A

Table 5 Friction Reducer Samples and Corresponding Concentrations

Friction Reducer Samples	
Polymer	Concentration, Gal/10 Bbl
A1	0.50
B1	0.50
C1	0.50
D1	0.21
D2	0.42
E1	0.21
E2	0.42
F1	0.04
F2	0.11
F3	0.21
F4	0.32
F5	0.42
G1	0.25
G2	0.50

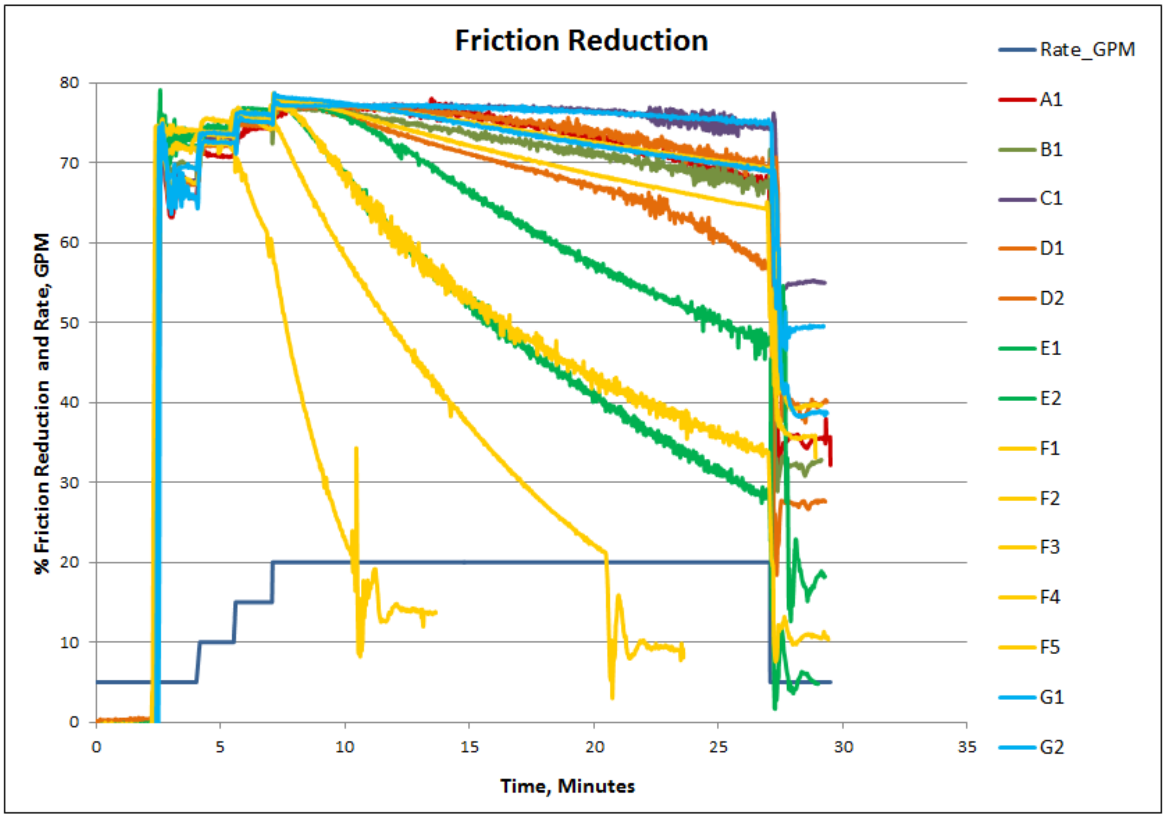

Figure 12 Percent Friction Reduction for All Samples and Concentrations

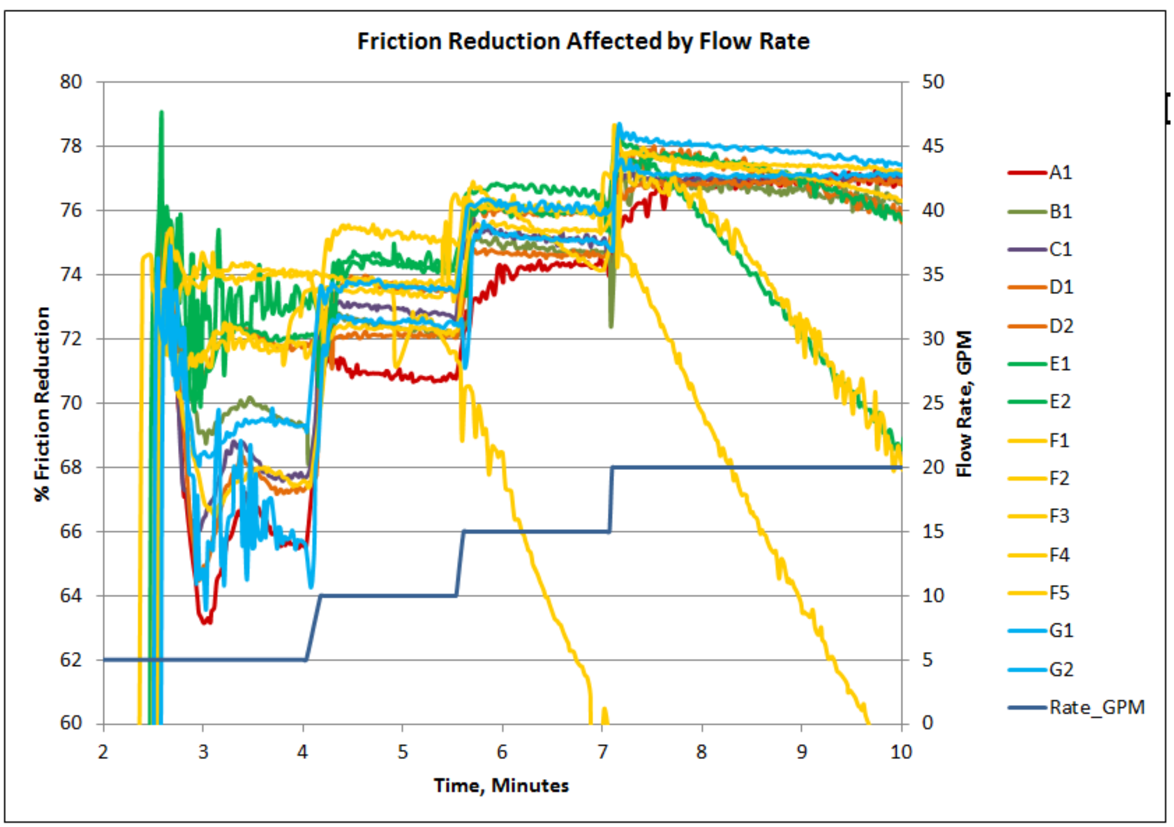

Figure 13 Friction Reduction Results with Varied Flow Rates

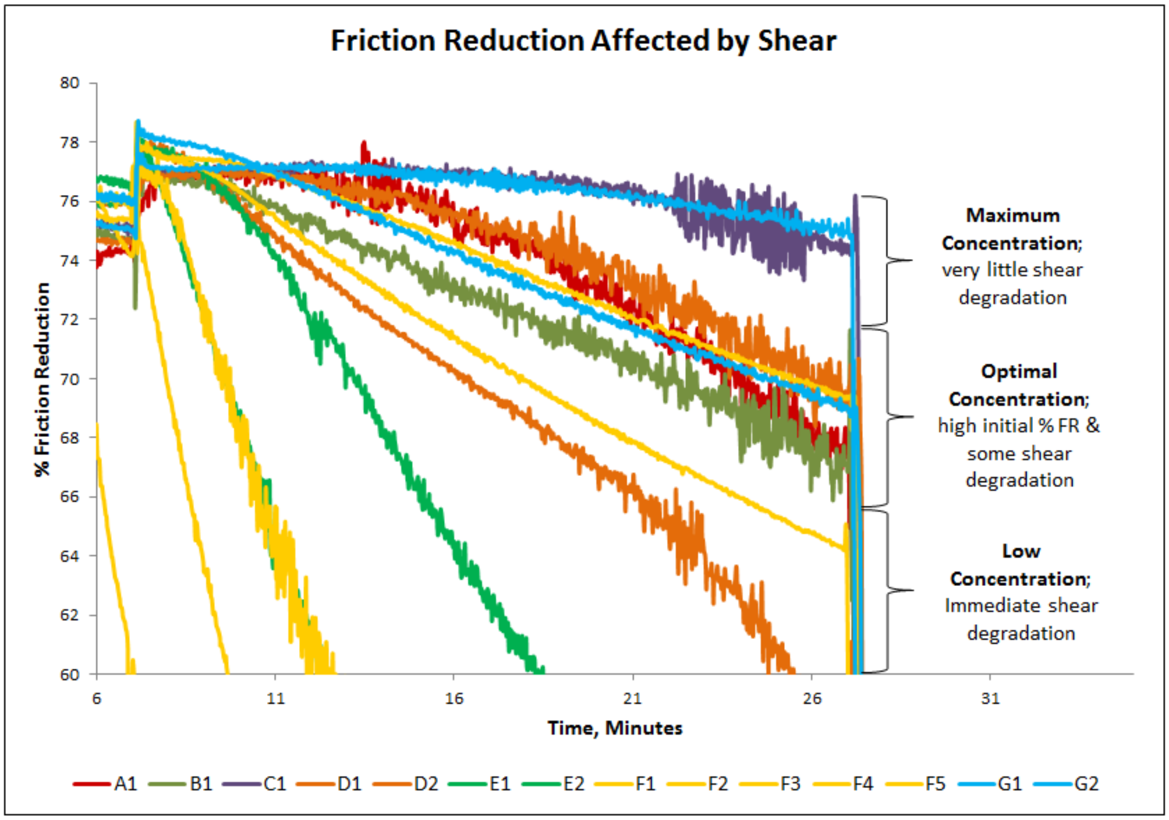

Figure 14 Friciton Reduction Results with High Rate and Shear

Table 6 Recommended Friction Reducer Concentration

Friction Reducer Recommendations		
Polymer	Concentration, Gal/10 Bbl	
	Optimum	Maximum
A	0.50	0.75
B	0.50	0.75
C	0.25	0.50
D	0.42	0.75
E	0.75	1.00
F	0.42	0.75
G	0.25	0.50