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Drilling Unconventional Shales with Upward or Downward Laterals: What are the Hydraulics and Well Control Consequences?

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Abstract

A recent study on 300+ shale wells in Oklahoma showed that inclined upward (toe-up) laterals produce more hydrocarbons. Greater the elevation difference between heel and toe, greater the impact on production. However, the influence of drilling upward/downward (UP/DO) laterals on drilling fluid hydraulics and well control practices necessitate more investigation. Objectives of this study are to investigate the consequences of drilling upward/downward on mud hydraulics and kick behavior. This includes comparing kicks experienced at shallow, middle and deep zones in the lateral section. A multiphase simulator is used to evaluate unexpected well control scenarios. Further, this research studied the impact of changing operational parameters and influx characteristics on wellbore integrity.

Preliminary results show that annular pressure loss (APL) and associated equivalent circulating density (ECD) depend on lateral configuration. In inclined upward laterals, gas bubbles migrate towards the toe and accumulates in high side pockets. Moreover, surface pit gain is not representing the actual kick size due to dispersed gas bubbles trapped by yield stress which increases mud compressibility. Likewise, choke experiences less pressure, volume, and gas discharge rate for extended periods of time in toe-up laterals. Therefore, higher circulation rates and longer circulation times are essential to flush out the dispersed and trapped gas bubbles. In contrast to kicks experienced at the lateral toe, kicks at the heel require shorter circulation time; however, pit gain, gas discharger rate, and associated pressures are higher. Well integrity was verified by monitoring surface choke, casing shoe and constant bottomhole pressures throughout the entire well control operations.

Introduction

Unconventional shale resources utilize horizontal drilling technology coupled with multi-stage hydraulic fracturing to expose trapped hydrocarbons (Kaufman et al. 2013). However, during the drilling of lateral sections, wellbore intersection with induced fractures results in kicks and blowout incidents (Ridley et al. 2013). In fact, lateral section orientation (toe-up or toe-down-TU/TD) follows the geologic bed dip to maximize reservoir contact and production. Browning and Jayakumar (2016) studied the impact of toe-up and toe-down orientation and lateral TVD change on 300+ wells in Oklahoma. They concluded that liquid loading in liquids rich unconventional shale results in productivity loss over the time. Therefore, toe-up lateral yields the highest production rates followed by flat horizontal, then toe-down laterals. Thus, production loss is 30% of the estimated ultimate recovery at the economic limit (Browning and Jayakumar 2016). In an experimental study, results showed that under stable production conditions, toe-up is the best configuration for liquid production (Brito et al. 2016a). At slow gas rates, liquid slug accumulates at the heel and gas accumulates at the toe. Gas pressure builds up until it overcomes the liquid hydrostatic, then gas blow-outs and causes production surges. These instability cycles cause significant fluctuations in pressure, liquid hold-up, and gas and liquid flow rates which reduces recoverable reserves (Brito et al. 2016b). Meanwhile, toe-down laterals present the lowest efficiency in production from toe to heel (Brito et al. 2016a).

This study investigates hydraulics and well control consequences in toe-up and toe-down laterals. This includes developing and verifying a hydraulics model with actual data from a Marcellus shale horizontal well drilled in Monongalia county, WV in 2015. Then, examining the impact of toe-up/toe-down on hydraulics parameters such as pump pressure, annular pressure loss, cutting transport ratio, and equivalent circulating density. Furthermore, this paper studies gas kick behavior and well control practices in (TU/TD) laterals. This contains the impact of influx size, kick circulation rate, and influx location in the lateral section on surface and downhole pressure/volume measurements.

Kicks and Blowout Control Studies

1-Unconventional Shale Blowout Statistics

Statistics show that blowout incidents in unconventional oil and shale gas wells from 2009 to 2013 were higher than conventional wells in Texas. For instance, shale gas wells blowouts were 200% more than conventional gas wells. Also in oil wells, the rate of blowouts was three times higher (Bidiwala and Orr 2014). In fact, drilling though natural or induced fractures causes kick and blowout incidents in horizontal shale wells. Recently, in Haynesville shale, a study of 54 kicks showed formation pressure increased to a surprisingly high geopressure (18 ppg) over short intervals, which can lead to dangerous kicks and potential blowouts (Zhang and Wieseneck 2011).

Offset shut-in wells undergoing hydraulic fracturing causes induced fractures in Eagle Ford since hydrocarbons prefer to flow towards the least resistance path. In addition to kicks through induced micro-fractures in Austin Chalk, loss circulation presents a further challenge for Eagle Ford. Even with drilling underbalanced in a formation pressure of 14 ppg using 11 ppg OBM, well control incidents resulted in a 20% non-productive time of the total well cost. (Guo et al. 2012).

2-Well Control in Horizontal Wells

In well control, the main objective is to keep a constant bottomhole pressure while circulating the kick out and displacing the old mud with a new heavier mud. This can be accomplished by means of one circulation (Wait-and-Weight) method or two circulations (Driller's) method. In Driller's method, gas removal circulation starts immediately upon receiving the kick and closing the BOP. Then, with simple circulating pressure calculations, the heavy mud displaces the old inappropriate mud weight. However, in the Wait-and-Weight method, the prepared heavy mud displaces the kick and old mud using a pre-estimated pressure step-down chart. This reduces bottomhole and surface pressures if the heavy mud reaches the bit before the kick passes the casing shoe. The step-down calculation in deviated wells is complex since it depends on wellbore/string configurations (Grace 2003).

Hence, a vertical well step-down chart is inapplicable for horizontal wells (Santos 1991) and multilateral trajectories (Choe et al. 2005). Moreover, step-down charts require additional adjustments for different string configurations (Elshehabi and Bilgesu 2016b). In fact, gas migration is insignificant in horizontal wells (Guner et al. 2016). Therefore, in the lateral section gas kick behaves like liquid kicks and the assumption of liquid kick should not be made. Also, wellbore geometry, influx size and flow rate impact horizontal well control procedures (Santos 1991). Thus, in unconventional shale, early kick detection is a key factor in properly containing wellbore pressures without violating safety and environment regulations and reducing the blowout associated risks (Elshehabi and Bilgesu 2016a).

3-Gas Kick Behavior in Water and Oil Based Muds

Gas migration in water based mud and solubility in oil based mud represent a significant challenge. In water based mud, gas bubbles percolate in a static mud column and the assumption of gas kick remains as a continuous slug at the bottom is inacceptable (Matthews and Bourgoyne 1983). The critical factors affecting bubble rise velocity are wellbore/string configuration, hole deviation angle, gas and liquid viscosities and densities (Rader et al. 1975). Oilfield reported bubble migration velocity of 900 ft./hr or slower. Additionally, the trail of entrapped and suspended stationary gas bubbles increases mud compressibility (Johnson et al. 1995). In contrast, gas dissolves in oil based mud and causes massive volumes release when pressure drops below the bubble point in the upper 2,000 ft. Higher the wellbore pressure and gas specific gravity, higher the gas solubility, but increase in temperature, solid content and water/oil ratio decreases solubility (O'Bryan et al. 1988).

Methane is fully miscible in diesel, mineral, synthetic, and ester oils when pressure is above the miscibility pressure and paraffin shows higher solubility than ester oil (Monteiro et al. 2010). Therefore, higher degrees of gas solubility in horizontal shale gas wells result in higher surface volumes and pressures. In addition, frequent choke adjustments are required to shield the casing shoe from intense changes in pressure when gas is liberated at the bubble point pressure (Elshehabi and Bilgesu 2015).

Wellbore Configurations and Approach

Figure 1 shows the Marcellus X1 horizontal well drilled in Monongalia county, WV in 2015 with a TVD of 7,500 ft, total depth of 14,500 ft, and lateral dimeter of 8.5". The kick-off point was 6,500 ft and the landing point was 8,700 ft measured depth (TVD=7,530 ft). The TVD at the total depth was 7,458 ft with 92^{o} inclination angle. The drilling fluid was a synthetic oil based mud with 70% oil. In the lateral section, the mud density was 12.5 ppg, plastic viscosity was 24 cp, and yield point was 10 lb/100ft^{2}. The average drilling rate was 150 ft/hr and mud flow rate was in the range of 350-460 gpm with a corresponding pump pressure range of 1900-3600 psi.

In addition, three lateral configurations were used for mud hydraulics and well control investigation. This includes inclined downward (toe-down), flat horizontal, and inclined upward (toe-up) laterals. For toe-down lateral, the inclination angle is 86^{o}. The TVD at the heel is 7,500 ft; however, the TVD at the toe is 7,980 ft and the total depth is 15,000 ft. For the flat horizontal well, the inclination angle is 90^{o}, TVD is 7,500 ft, and the total depth is 15,000 ft. In inclined upward, the inclination angle is 94^{o}. The TVD at the heel is 7,500 ft; however, at the toe the TVD is 7,022 ft only. In all lateral configurations, the kick-off point depth is 6,900 ft, build-up rate is 8 ^{o}/100 ft, and the landing point measured depth is 7,900 ft.

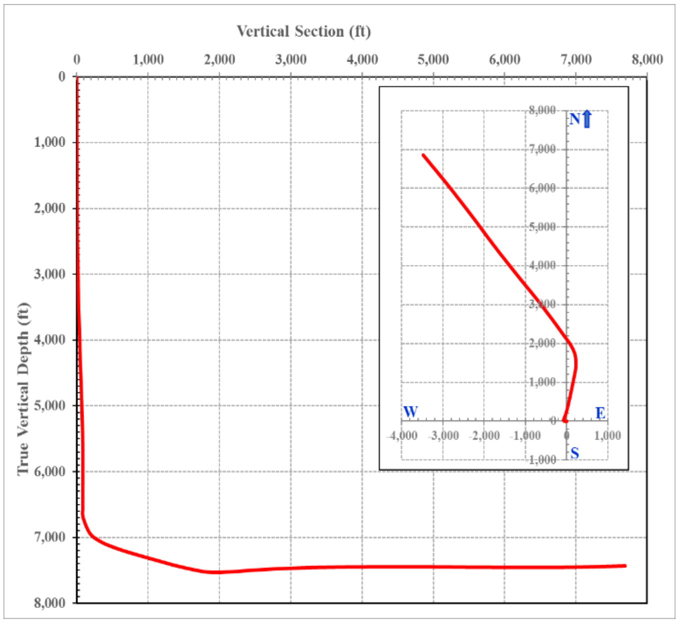

Figure 1: Marcellus X1 horizontal well drilled in Monongalia county, WV in 2015.

This study implemented the steady-state hydraulics and dynamic well control Drillbench software. This multiphase simulator is capable of modeling gas migration in water based mud as well as gas solubility in oil based mud with a compositional PVT model. Multiphase flow correlations and Equation-of-State are used to evaluate dynamic fluid properties, gas bubble migration in WBM and solubility in OBM. During influx circulation, bottomhole pressure is kept constant and choke opening is adjusted accordingly.

Upon developing the hydraulics model that represents the wellbore configuration shown in Figure 1, the model was tested and verified with the recorded data from Marcellus X1 lateral. Estimated pump pressure is compared to the measured values taking into account mud properties, flow rate, and drilling rate of penetration. Once the model was verified, it is used to investigate hydraulics in inclined upward/downward laterals. This includes, developing static and dynamic pressure profiles at drilling rates, slow pump rate, and shut-in conditions. Further, annular pressure losses, equivalent circulating density, and cutting transport ratio at flow rates up to 600 gpm in TU/TD laterals were investigated.

In addition, this work investigates well control consequence in inclined upward/downward laterals. This includes, comparison of kick behavior in a horizontal well and a vertical well drilled with the same TVD to another vertical well with the same measured depth. Also, the impact of kick location is taken into account by comparing kicks experienced at the heel, midway or toe. Finally, the impact of influx size and kick circulation rate on surface and bottomhole pressure/volume measurements were examined.

Results and Discussion

1- Hydraulics Results

Figure 2 illustrates the verification of the developed hydraulics model for Marcellus X1 wellbore. As shown, the average pump flow rate was 450 gpm and pump pressure was linearly increasing with the drilled depth. Figure 2 compares the estimated pump pressure with the field recorded values, taking into account drilling rate of penetration, mud properties and flow rate. The results show a direct impact of drilling rate and cuttings loading on pump pressure.

The model successfully estimated the standpipe pressure (SPP) with a regression coefficient R^2 of 0.974. For instance, at 9,000 ft, the drilling rate of penetration decreased to 73 ft/hr, therefore the model accurately predicted the pump pressure of 2752 psi. This is consistent with the actual pump where the pressure decreased to 2728 psi. In addition, at the total depth, the model estimated the pump pressure to be 3760 psi compared to 3855 psi with an accuracy of -2.5%. This can be contributed to the uncertainty about the cuttings shape, size and concentration, the corresponding density, and plastic viscosity. The verified model was implemented for further study of hydraulics complications in toe-up/toe-down laterals. The three lateral configurations are inclined downward (86^o), flat horizontal (90^o) and inclined upward (94^o).

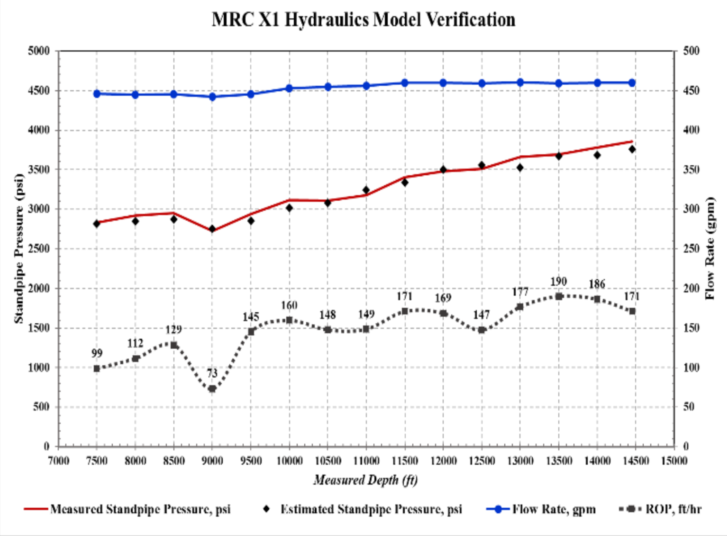

Figure 2: Hydraulics model verification in Marcellus X1 lateral drilled in Monongalia county, WV in 2015.

(a) Impact of Inclined Upward/Downward Lateral Configuration on Pressure Profile

While drilling, the surface pump pressure represents system friction losses and any hydrostatic imbalance arising from annulus cuttings loading. Figure 3 compares static and dynamic pressure profiles for inclined downward, flat horizontal, and inclined upward laterals. Wellbore static and circulating pressure increase until it reaches the maximum at the lateral section, then it varies according to lateral configuration. For instance, Figure 3 shows that in a flat horizontal well, the hydrostatic pressure is constant at the value of 4845 psi in the lateral section, while the pump pressure is 3,811 psi at 460 gpm.

Even though inclined upward lateral and flat horizontal show the same value of SPP and APL, the value of ECD is higher in inclined upward since TVD at the toe is less than at the heel. For instance, APL is 520 psi in inclined upward and flat horizontal, but ECD values are 13.84 ppg and 13.73 ppg, respectively. In inclined downward, TVD is higher at the toe therefore, circulating pressure decreases at lower rate than inclined upward inside the lateral section as shown in Figure 3.

In comparison to flat horizontal, inclined downward hydrostatic pressure increases by 6.5%, standpipe pressure slightly increases by 3.2%, and thus APL is 21.9% higher. In contrast, in inclined upward where TVD is less than flat horizontal, hydrostatic pressure decreases by 6.5%. Also, APL slightly increases by 0.4% and ECD increases by 0.7%. This is can be contributed to cutting transport ratio (CTR) of 73.8 % in inclined downward in comparison to 83.9% in inclined upward at the drilling flow rate of 460 gpm.

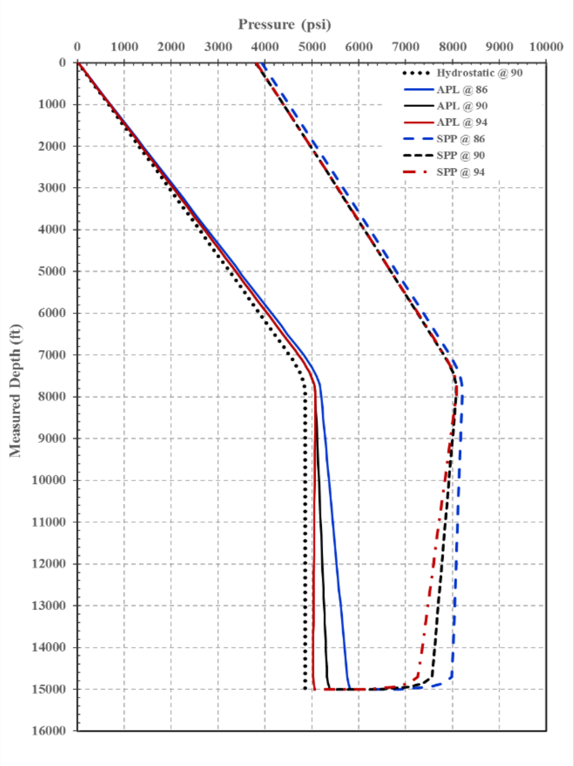

Figure 3: Hydrostatic and circulating pressure profile in inclined downward, flat horizontal and inclined upward laterals.

(b) Impact of Flow Rate on Equivalent Circulating Density and Cutting Transport Ratio

Figure 4 compares Equivalent Circulating Density (ECD) and Cutting Transport Ratio (CTR) in inclined upward with inclined downward laterals at flow rates up to 600 gpm. APL and associated ECD are higher in inclined downward lateral as a result of lower CTR compared to inclined upward laterals. This is mainly because of gravity associated cuttings accumulation on the bottomhole side at the toe. As shown in Figure 4, higher the flow rate, higher the cutting transport ratio and lower the ECD in inclined downward. However, upon achieving the optimum hole cleaning, higher flow rates create excessive friction losses, and increase ECD. For instance, at no circulation and due to cuttings loading, the ECD at the bottomhole can reach a dangerous value of 21.3 ppg in inclined downward lateral since cutting settling velocity is 33.5 ft/min.

In contrast, ECD is 12.5 ppg only in inclined upward lateral where cuttings settling velocity is 16 ft/min and cuttings accumulate at the heel. Further, in inclined upward lateral at flow rate of 200 gpm, CTR is 67% and ECD is 13.22 ppg. In inclined downward lateral, CTR drops to 46.3% therefore, ECD increases to 14.08 ppg. At high flow rate of 500 gpm, CTR is more than 50% (85% in inclined upward and 75% in inclined downward), and ECD is around 13.9 ppg for both cases. Therefore, APL, associated ECD, and critical flow rate for proper hole cleaning are higher in inclined downward laterals compared to inclined upward laterals.

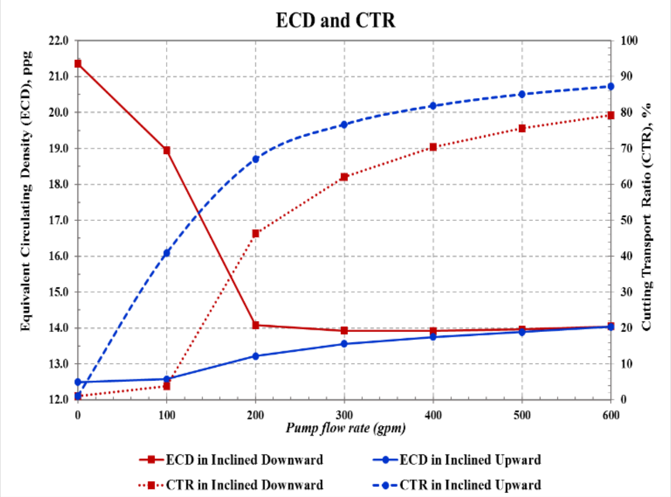

Figure 4: Impact of flow rate on ECD and cutting transport ratio in inclined upward and downward laterals.

(c) Pressure Profiles in Marcellus X1 Lateral at Slow Pump Rate and Shut-in Conditions

In fact, it is a common practice to circulate kicks at a slow pump rate (SPR), between one-third and one-half of the normal drilling rate. Slow pump rate decreases annular friction loss and surface/downhole pressure fluctuations in response to choke adjustments. Also, it reduces the risk of pump mechanical problems and enables better control over the instantaneous gas expansion at the choke manifold and mud/gas separator. This offers enough time to analyze surface pressure/volume measurements which leads to better judgment and wiser decisions (Watson et al. 2003).

As shown in Figure 5 for slow pump rate of 150 gpm, pump pressure ws 657 psi in comparison to 3,373 psi at the normal drilling rate of 460 gpm. This means the system friction losses at SPR decreases by 81%, however, APL reduces to 64% of the drilling rate value. It is common to neglect the APL at slow pump rates in vertical wells. However, in horizontal wells, APL represents a large portion of the system losses and can be considered as a safety factor over the bottomhole (Watson et al. 2003). Unless neglection of APL jeopardizes wellbore integrity, the pump pressure should be reduced to account for APL (Elshehabi and Bilgesu 2016b). For instance, at 100 gpm, pump pressure is 692 psi and APL is 315 which represents 45% of the pump pressure. If neglected, this introduces an extra 315 psi to wellbore pressures.

Unlike the vertical well shut-in conditions, Figure 6 shows no difference between SICP and SIDPP (650 psi) because the gas influx has an insignificant vertical depth in the lateral section. This observation is consistent with the results of Santos (1991) and Choe et al. (2005). There is no impact of influx size on SICP, it is only the degree of underbalance between reservoir and hydrostatic pressures. Initially the dynamic bottomhole pressure overbalances the reservoir pressure until the kick is started. After the well is shut-in, the ICP and FCP values are estimated to keep the dynamic BHP balancing the reservoir pressure at 5,500 psi. The estimated values of ICP and FCP are 1,330 and 720 psi, respectively.

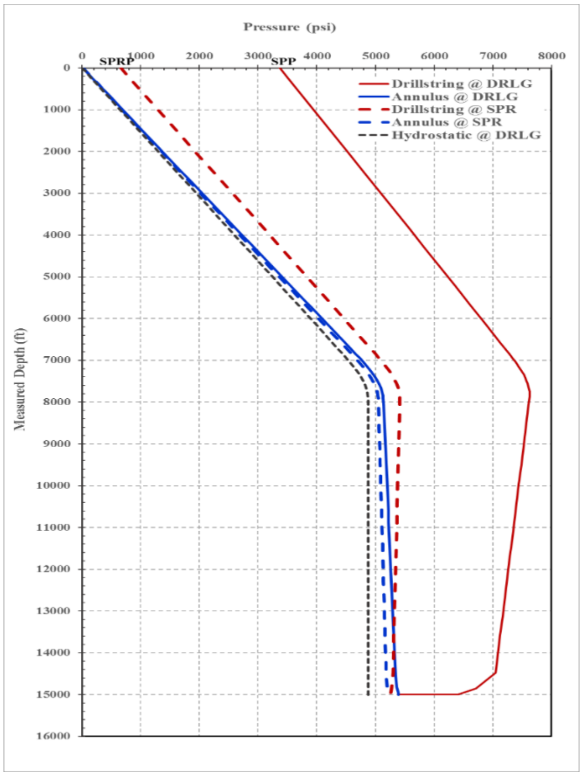

Figure 5: Pressure profile at normal drilling rate of 460 gpm and at slow pump rate of 150 gpm in Marcellus X1 horizontal well with a 20 bbls gas kick.

2- Well Control Results

a) Impact of Vertical and Horizontal Wells on Kick Circulation

Figure 7 shows the choke pressure for a horizontal well, a vertical well with the same TVD, and a vertical well with the same TD, all with a kick size of 20 bbls circulated at a rate of 150 gpm. Clearly, gas expands continuously in vertical wells after it breaks out of solution at the bubble point. The maximum choke pressure increase is 166% in long vertical well when compared to the horizontal well. Typically, deeper the vertical well, higher the difference between bottomhole and surface conditions. For that reason, the influx expansion rate is 169% in the vertical well compared to 137% in the horizontal well. Gas discharge flow rate is 2.5 MMSCFD in the short vertical well compared to 1.4 MMSCFD in the horizontal well. Choke and casing shoe pressure significantly change upon the expansion of gas bubbles at the curve section. The surface pressure, gas expansion, and flow rate are significantly reduced in horizontal wells compared to vertical wells with the same TVD or TD. This is due to gas dispersion and entrapment in lateral section compared to single slug expansion in vertical wells. The short vertical well ICP and FCP values were 836 and 397 psi, respectively. However, for the horizontal well with higher friction losses, ICP is 1,114 psi and FCP is 525 psi. In addition, the kick imposes twice the circulation time (8.2 hours) in the horizontal well, compared to 4.1 hours in the vertical.

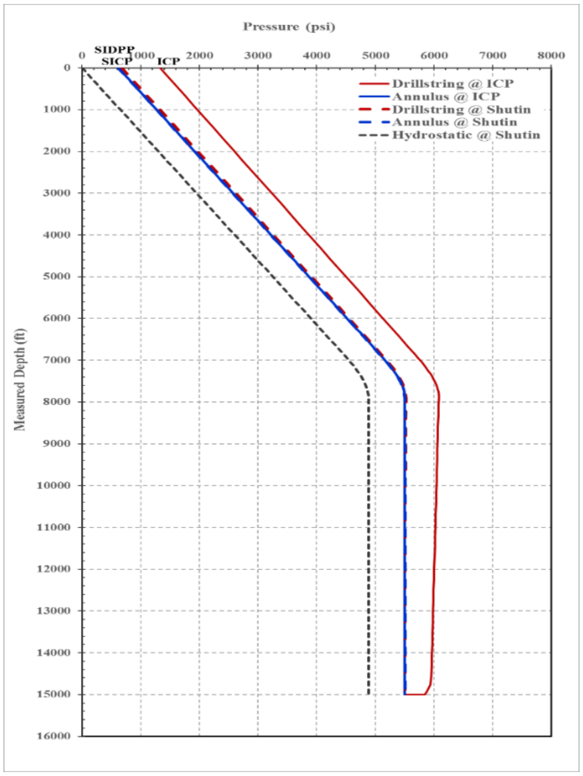

Figure 6: Pressure profile at shut-in conditions in Marcellus X1 horizontal well with a 20 bbls gas kick.

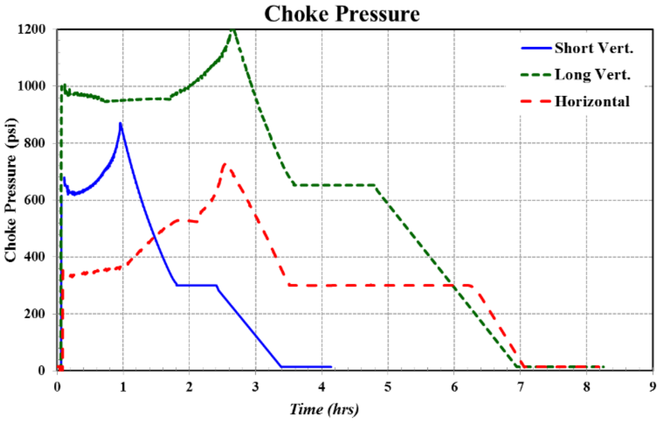

Figure 7: Choke pressure in a horizontal well, a vertical well with the same TVD, and a vertical well with the same TD.

b) Impact of Kick Location (Heel, Midway, and Toe)

Kicks experienced at three different locations as shallow, middle and deep zones in the lateral section for inclined upward/downward were evaluated. Figure 8 and Figure 9 show choke pressure and pit gain for an inclined downward lateral with the same kick size (20 bbls) encountered at the entry point of the lateral section (heel), midway to the end (midway), and at the total depth (toe). It is obvious that deeper kicks impose longer times to circulate. For instance, 8.1 hours are required to circulate the kick at the toe compared to 4.4 hours for the kick at the heel.

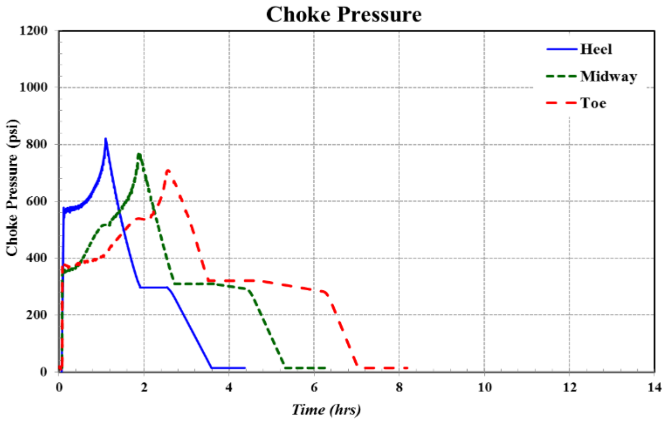

Figure 8: Choke pressure at heel, midway, and toe in inclined downward lateral.

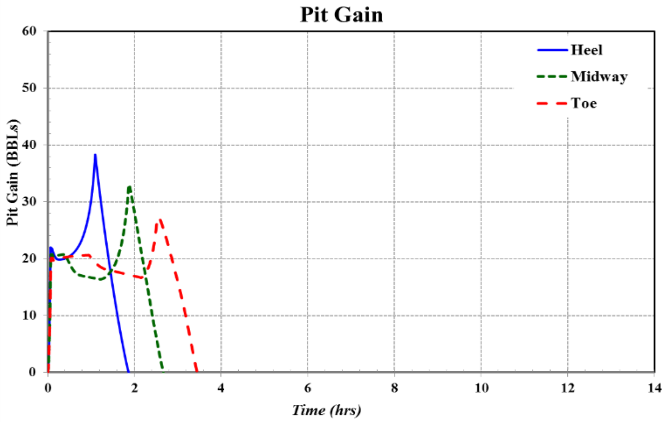

Figure 9: Pit gain at heel, midway, and toe in inclined downward lateral configuration.

In contrast, the choke pressure and consequently the casing shoe pressure are higher in heel kicks, due to continuous gas expansion after passing the BHA. The gas influx expanded by 174% in the heel kick compared to 136% only in the toe kick. Dispersed gas bubbles that are trapped by mud yield stress contributes to this behavior. In deeper kicks, when gas reaches the vertical section, wellbore pressure increases and free gas dissolves in oil based mud therefore, the surface pit gain decreases (Figure 9). At the bubble point, gas breaks out of solution near the surface and expands continuously until it reaches the choke.

Figures 10 and 11 show the results for an inclined upward lateral with the same size kick encountered at the heel, midway, and at the toe. When Figure 8 and Figure 10 are compared, it is seen that longer times are needed to circulate the same size of the kick in inclined upward laterals. For instance, a 20 barrels kick encountered at the toe requires 13 hours in upward lateral compared to 8.1 hours for toe-down lateral. Similar to Figure 8, Figure 10 shows that the choke pressure and consequently the casing shoe pressure are much higher in the heel kick, as a result of continuous gas expansion.

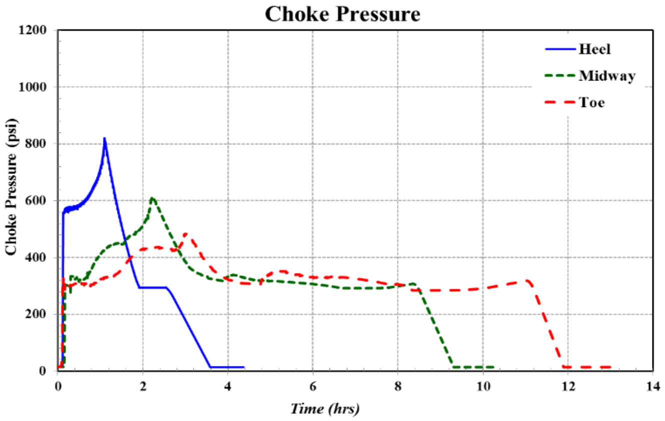

Figure 10: Choke pressure at heel, midway, and toe in inclined upward lateral.

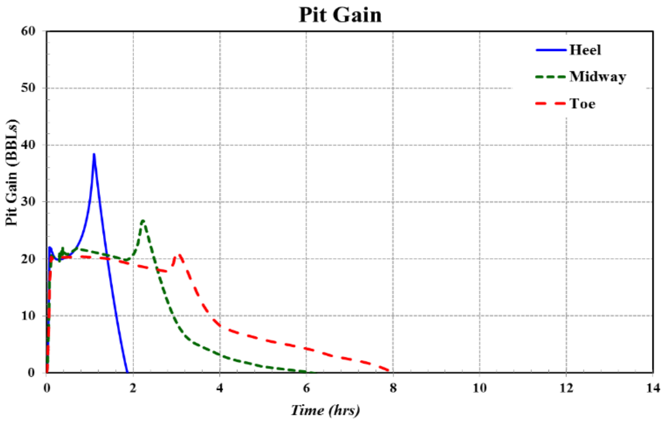

Figure 11: Pit gain at heel, midway, and toe in inclined upward lateral configuration.

The gas expanded by 174% in the heel kick compared to 104 % in the toe kick. This was contributed to the gas tendency to migrate to the toe in the opposite direction of the mud flow. Dispersed and entrapped gas bubbles by mud yield point contribute to this behavior in comparison to slug flow in inclined downward laterals. Thus, inclined upward lateral experiences less surface pressures and volumes compared to downward lateral. However, kicks in toe-up laterals require longer circulation times to flush out all the trapped gas bubbles.

Figure 12 compares surface and downhole pressures for inclined upward, inclined downward, and flat horizontal laterals. Closer the kick to the vertical section, less the circulation time, but higher the expansion rate, choke, and casing shoe pressures. Although, inclined upward experiences less wellbore and surface pressures for the same size kick, it needs extended circulation times. For example, compared to inclined downward, choke pressure is 32% less, shoe pressure is 5% less, bottomhole is 11% less, and gas expansion is 23% less, however, the circulation time is 60% higher. Therefore, higher the TVD difference, higher the deviation in behavior between heel and toe kicks in toe-up/toe-down laterals.

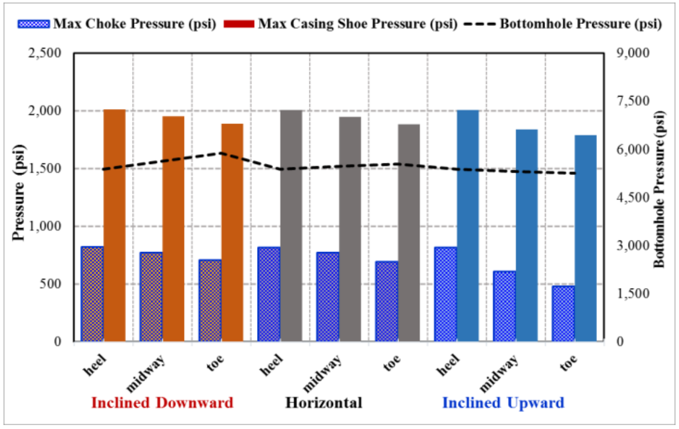

Figure 12: Choke, casing shoe, and bottomhole pressure comparison for heel, midway, and toe kicks in TU/TD laterals.

c) Impact of Influx Size on Pressure/Volume Profiles

The slower the crew in detecting a kick and closing the BOP, higher the surface pit gain. Figure 13 compares choke pressures for inclined downward/upward at 20 and 40 bbls kicks. The first circulation of Driller's method requires 3.6 hours in toe-down. Meanwhile, it needs 11.13 hours to completely discharge a 40 bbls kick in an inclined upward lateral. Obviously, larger kick sizes result in higher pit gain, gas discharge rate, choke, and casing shoe pressures in toe-down laterals. In contrast, in inclined upward, higher the kick size, longer the circulation times and associated pressures slightly change. For instance, 40 bbls kick expanded by 124% in inclined downward, but it expanded only by 104% in toe-up laterals (Figure 14).

In addition, choke pressure increases by 143% in inclined downward, however it insignificantly changes in upward lateral to 101% (Figure 13). Figure 15 illustrates that gas flushes as a single slug in inclined downward. However, in toe-up laterals, dispersed gas bubbles reach the surface in two major waves. The first wave is less in magnitude than toe-down, then a second wave of gas that flushes out all the remaining dispersed bubbles. For instance, in toe-down, when a 40 bbls gas reaches the surface, the maximum flow rate is 2.4 MMSCFD and discharge time is 1.4 hours. However, in inclined upward first gas wave reaches the surface with 0.6 MMSCFD rate. Then, after 8.4 hours of gas discharge, the second wave approaches the choke with a flow rate of 0.4 MMSCFD (Figure 15).

Figure 16 compares five kick sizes namely: 10, 20, 40, 60, and 80 bbls in inclined downward, flat horizontal, and upward laterals. To keep constant bottomhole pressure, initial and final circulating pressures were kept at the same value. However, in inclined downward and inclined upward laterals, when the influx size increases to 80 bbls, maximum choke pressure increases to 299% and 139%, respectively. At the same time, casing shoe pressure increases to 146% and 108%, respectively. Even though, all influx sizes require 8.2 hours in toe-down lateral, the circulation time for 80 bbls increases by 240% in inclined upward. Additionally, gas flow rate increases by 369% in inclined downward compared to 22% only in inclined upward.

These results are in consistent with values reported by Elshehabi and Bilgesu (2016a). This highlights the importance of crew awareness of early kick detection techniques to avoid exceeding of kick tolerance and maximum allowable annular surface pressure (MAASP) and risking well integrity. Therefore, kick size is highly influences surface pressures and volumes in inclined downward, but only impacts circulation time in inclined upward.

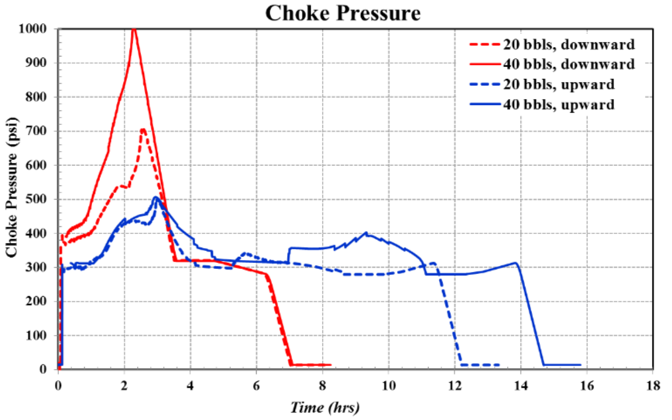

Figure 13: Choke pressure comparison for 20 and 40 bbls in inclined upward/downward laterals.

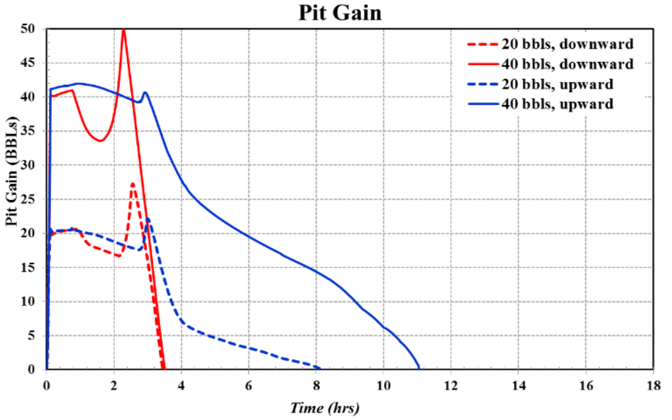

Figure 14: Pit gain comparison for 20 and 40 bbls in inclined upward/downward laterals.

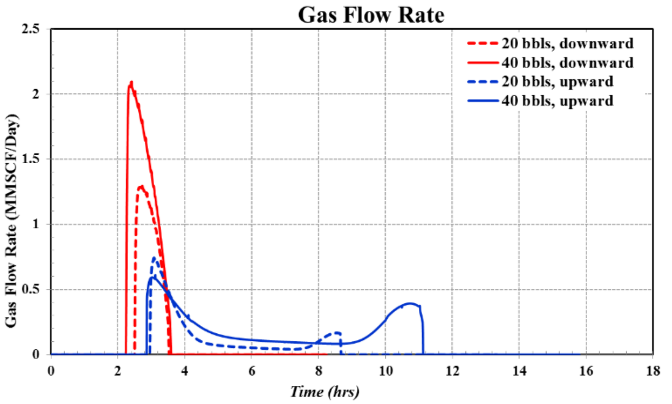

Figure 15: Surface gas flow rate comparison for 20 and 40 bbls in inclined upward/downward laterals.

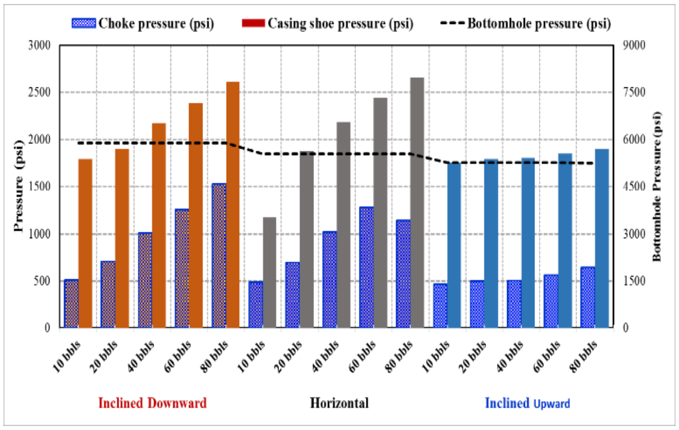

Figure 16: Choke, casing shoe, and bottomhole pressure comparison for 10, 20, 40, 60, and 80 bbls in inclined upward/downward laterals.

d) Impact of Kick Circulation Rate

Figure 17 compares initial and final circulating pressures in toe-up/toe-down laterals at 50 and 100 gpm kick circulation rates. Obviously, higher the circulation rate, higher the wellbore frictional losses and lower the circulation time. For inclined downward lateral, 100 gpm needs 50% less time (from 24.3 to 12.2 hours) in comparison to 50 gpm. Nevertheless, this results in 14% increase in ICP (from 852 to 974 psi) and 33% increase in FCP (from 290 to 385 psi) with an average BHP of 5,840 psi. However, in inclined upward lateral, 100 gpm requires 115% less time (from 32.9 to 18.9 hours). This results in 12% increase in ICP (from 821 to 936 psi), 25% increase in FCP (from 288 to 386 psi) with an average BHP of 5,216 psi. In inclined downward lateral at 100 gpm, choke pressure increases from 581 to 655 psi (Figure 18). Also, the pit gain increases with an additional 22% when the gas reaches the choke (Figure 19).

Figure 20 compares kick circulation rates for a range of 50 to 250 gpm in inclined upward/downward and flat horizontal laterals. Circulating a kick at a flow rate of 250 gpm requires 84% less time (5.5 hours compared to 32.9 hours) in inclined upward laterals. Despite keeping BHP constant, ICP and FCP progressively increase at higher rate due to larger friction losses. For example, ICP is 1,540 psi at 250 gpm compared to 852 psi at 50 gpm in inclined downward lateral. Likewise, ICP increased to 1,509 psi compared to 852 psi in inclined upward laterals. However, higher impact is noticed on FCP, it increased from 290 to 922 psi in inclined downward lateral and from 288 to 928 psi in inclined upward lateral.

At slow pump rates, the slope of choke pressure ascent is lower because of less gas liberation and expansion than the slope observed at high pump rates (Figure 18). Slug flow pattern dominates at high pump rates (250 gpm) enabling efficient gas circulation with less time. Nonetheless, gas expands at a higher rate at the surface and results in higher choke and casing shoe pressures. Earlier studies such as Santos (1991), Choe (2001), and Watson et al. (2003) claimed that circulation time is a function of pump rate only. For example, if the pump rate decreased from 100 to 50 gpm, the circulation time needed at 50 gpm should be twice the value at 100 gpm pump rate.

However, at slow pump rates, it needs extended circulation times. This is contributed to dispersed gas bubble that tends to migrate towards lateral high side in toe-up laterals. Gjorv (2003) suggested circulating the kick out at high pump rates, then displacing the heavy mud at slower pump rates in extended reach horizontal wells. Inclined upward necessities higher kick circulation rates compared to inclined downward laterals.

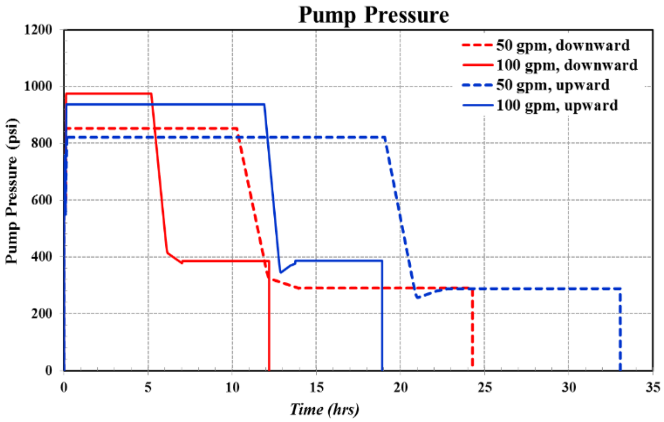

Figure 17: Pump pressure comparison for 50 and 100 gpm in inclined upward/downward laterals.

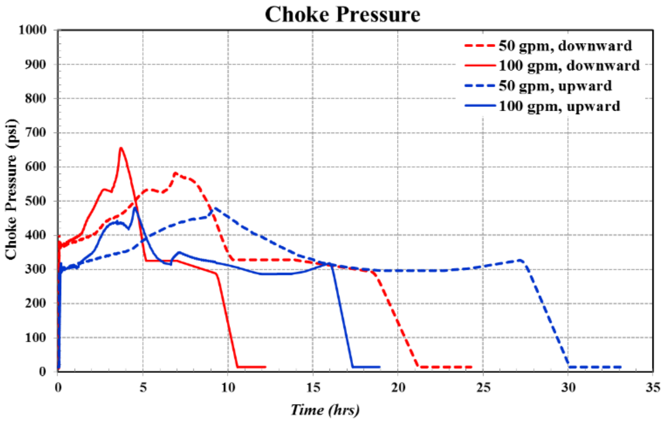

Figure 18: Choke pressure comparison for 50 and 100 gpm in inclined upward/downward laterals.

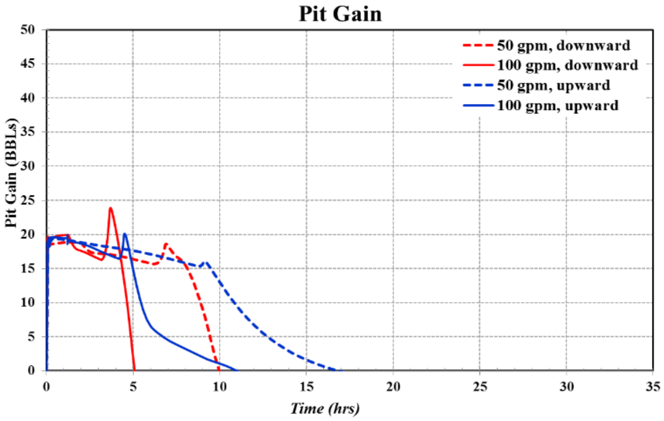

Figure 19: Pit gain comparison for 50 and 100 gpm in inclined upward/downward laterals.

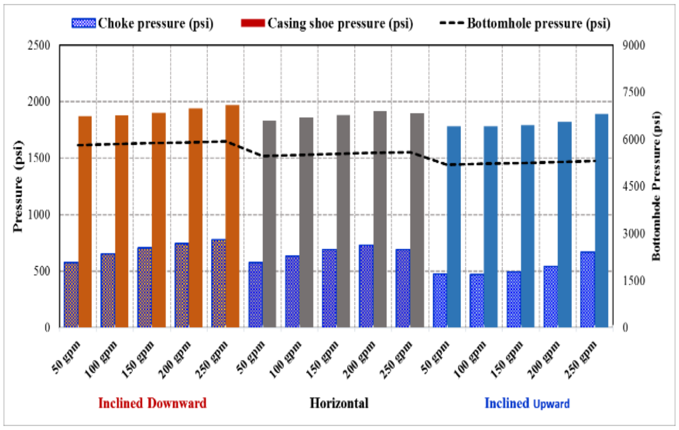

Figure 20: Choke, casing shoe, and bottomhole pressure comparison for 50, 100, 150, 200, and 250 gpm in inclined upward/downward laterals.

Conclusions

In this research, mud hydraulics and well control complications in inclined downward laterals are studied and compared to inclined upward laterals. The following conclusions are presented:

- In a Marcellus shale lateral, the developed hydraulics model successfully estimated the standpipe pressure with a regression coefficient (R^2) of 0.974. This shows the significant impact of drilling rate of penetration, mud properties and drilled cuttings characteristics on drilling fluid hydraulics.
- Annular pressure loss, associated equivalent circulating density, and critical flow rate for proper hole cleaning are higher in inclined downward wellbore trajectories as a result of lower cutting transport ratio and cutting accumulation at the toe compared to inclined upward laterals.
- In inclined upward/downward laterals, closer the kick location to the vertical section, shorter the circulation time needed. However, the pit gain, gas discharge rate, choke pressure, and consequently casing shoe pressure are higher.
- In contrast to toe-down, inclined upward lateral experiences less surface and bottomhole pressures for the same kick size. However, it requires extended circulation times to flush out the dispersed and entrapped bubbles by mud stress.
- Larger kick sizes result in higher pit gain, gas flow rate, choke and casing shoe pressures in inclined downward. Yet, in inclined upward, higher the kick size, longer the circulation times with an insignificant impact on choke and shoe pressures.

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Nomenclature

APL = *annular pressure loss, psi*
BHP = *bottomhole pressure, psi*
CTR = *cutting transport ratio*
ECD = *Equivalent circulating density, ppg*
FCP = *final circulating pressure, psi*
ICP = *initial circulating pressure, psi*
KMW = *kill mud weight, ppg*
SICP = *shut-in casing pressure, psi*
SIDPP = *shut-in drillpipe pressure, psi*
SPR = *slow pump rate*
SPRP = *slow pump rate pressure, psi*
TD = *True (total) measured depth, ft*
TU/TD = *toe-up / toe-down laterals*
TVD = *True (total) vertical depth, ft*

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