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Multiphase Flow Modeling of Gas Influx in High-Pressure High Temperature (HPHT) Well Control

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Abstract. The study uses a transient multiphase flow simulator in order to evaluate the influence of operational parameters on the response of gas kicks with oil- and water-based drilling fluids (OBM and WBM) in high-pressure high-temperature (HPHT) wells. The approach is to use a dynamic multiphase flow simulation of gas kicks in drilling fluids. It uses fictitious well data with key variables, such as mud type, flow rate, liquid holdup, free gas volume fraction, flow pattern, fluid velocity, and mixture density. The analyses are performed at high (150 gpm) and low (75 gpm) flow rates in order to document the changes in fluid behavior. Moreover, close attention is given to the effect of increasing bottomhole temperatures (BHT) on kick circulation times.

Even at higher circulation rates, the WBM presents slug flow with significant gas slippage, delaying dispersed bubble flow. Slug flow causes more gas bubbles to coalesce as the gas gets closer to the surface. On the other hand, the OBM exhibits a lower tendency for slug formation by maintaining a dispersed bubble flow pattern with little slippage between the gas and oil. Both types of mud restrict the flow of gas. In OBM, the gas gets trapped inside the oil under bottomhole conditions. Similar issues arise close to the surface in WBM. A higher BHT has an impact on this phenomenon. The study highlights multiphase transient simulators' potential for well control and planning. It aims to help well planners and wellsite engineers understand gas kick incidents in HPHT wells.

Keywords: well control, multiphase fluid dynamics, high-pressure high-temperature, gas influx.

1. Introduction

Managing gas influxes in HPHT wells is a challenging operation at the rig site. If gas kicks are not properly controlled, they may develop into severe blowouts. These

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can have catastrophic consequences (i.e., damaging equipment, polluting the environment, and killing people). Extreme pressure and temperature gradients in HPHT environments make fluid dynamics complex, requiring a clear understanding of multiphase flow behaviors.

Traditional models used to estimate kick tolerance and manage gas flow are generally based on simplified single-bubble two-phase flow dynamics. The main problem with these approaches is that they do not accurately capture the transient and multiphase characteristics of fluid behavior, especially under HPHT conditions. Therefore, it is necessary to use advanced simulation techniques during the well planning phase to obtain a more realistic understanding of gas kicks.

A blowout can be defined as an uncontrolled influx of formation fluid with sufficient pressure, causing damage to rig equipment and injuries to the personnel. Unlike sudden events, blowouts develop gradually when the hydrostatic pressure of the drilling mud falls below the level required to contain formation fluids. At this point, formation fluids enter the wellbore, resulting in a kick. If undetected and uncontrolled, the kick escalates to a blowout [1].

In normal drilling operations, drilling mud is continuously circulated down the hole such that the volume pumped in equals the volume of returns at the surface, ignoring the minor losses due to filtration. Two situations can arise to disturb this balance. First, the volume of returns is less than the volume pumped in, indicating a lost circulation situation. Second, the return volume exceeds the pumped volume, suggesting formation fluids have invaded the well. When lighter fluids enter the wellbore, the circulation pressure is further reduced because of the U-tubing effect resulting from the density difference between the heavy mud inside the drill pipe and lighter fluids in the annulus. The decrease in pump pressure is also accompanied by an increase in pump speed, as the same input power is now available to circulate the same volume of fluid against the reduced pressure losses [1]. Other parametrical indicators of a kick taking place may be the increase in the hook load due to reduced buoyancy force and increased rotary torque. Once a kick occurrence is confirmed through the pit gain, the well is shut in at the preventers and the drill pipe. The lighter fluid invades the annular space between the casing and the drill string, and this results in the shut-in casing pressure (SICP) being higher than the shut-in drill pipe pressure (SIDPP). The reason why SICP would be higher than the SIDPP is that the casing side has a reduced mud column along with a lower density influx, while the drillpipe has a full column of mud. Thus, less hydrostatic pressure on the casing side, but the same bottomhole pressure results in the drillpipe pressure "U-tubing" more pressure on the casing side at the surface. The SICP plays a key role in the process of well-killing, which is measured at the surface using the casing pressure gauge. It is used as a monitor to prevent bursting of the casing and fracturing of the formation below the casing shoe. The maximum allowable SICP is taken equal to 70% (i.e., worst-case) of the burst resistance of the casing [1]. Also, for a given casing setting depth, the formation just below the casing shoe has an initial strength that must not be exceeded. Thus, the maximum allowable SICP is also dictated by the formation strength. For anisotropic fields, [2] showed how to calculate accurate fracture pressures by integrating leak-off test data with in-situ stress modeling. The

maximum allowable surface pressure (MASP) must be calculated based on the pressure ratings of mud pumps, input pipes, choke manifolds, and casing burst ratings. The lowest of the values, namely MASP and maximum allowable annular surface pressure (MAASP), is used during well-killing operations. Although in this study, a vertical deviation profile was used, casing wear from drilling strings can significantly reduce the burst and collapse ratings [3]. This suggests that standard MAASP calculations in HPHT models should also incorporate a casing wear factor. Another essential consideration in well-killing is the speed at which the heavy mud is circulated [1].

The driller's method is one of several methods to regain control of the well during a well control scenario. It is one of the most widely used worldwide. The main concept is to kill the well while maintaining the constant bottomhole pressure (BHP). To achieve this, two steps are required. First is circulation, which removes the influx. The second step is circulation, used to regain control of the well with heavier mud. During the first circulation, the BHP is kept constant by maintaining drill pipe pressure constant while circulating until the influx is entirely displaced from the annulus. The flow rate is ramped up while maintaining the choke pressure constant until initial circulation pressure (ICP) is established, which is the minimum pressure needed to maintain a constant BHP [4]. After the kick is removed from the well, drill pipe and casing pressures are similar when the well is shut. To keep the BHP constant during the second circulation, the casing pressure is kept constant while circulating kill mud is being circulated. Once the kill mud passes the bit, the drill pipe pressure is maintained at a constant level until the kill weight mud has reached the surface and the annulus shows no sign of influx. Then, the pumping operation is shut down to observe the behavior of the drill pipe and casing pressures with a flow check [5]. Two types of kicks are common in well operations: liquid and gas influxes. Gas kicks lead to worst-case incidents in HPHT wells. The high compressibility of gas kicks makes them particularly dangerous compared to liquid kicks. Gas kicks ascend more rapidly within the wellbore since they are less dense than the drilling mud, and as a result, they reduce the hydrostatic pressure exerted above the kick and gas expansion. Typically, the industry models a gas kick as a single bubble, which works well for designing kick tolerance and choosing casing shoe depths where maximum worst-case pressure scenarios are evaluated. However, this approach does not capture complex interactions between the operational variables and two-phase flow dynamics. The gas kick behavior is more complicated than the assumed single-bubble methodology. The influx interacts with the mud during a kick and is totally dissolved in the oil phase of OBM until it reaches the bubble point. At that point, the influx gas quickly boils out of the oil and begins to expand. WBM causes the influx to expand as soon as it enters the well rather than dissolving. This dynamic process cannot be represented by single-bubble models, which often produce unrealistic results, especially in tight-margin wells. It is indeed feasible to reduce BHP and annular casing pressures during the circulation of a gas kick by considering two-phase flow dynamics [6].

Transient multiphase simulations have proven themselves to be accurate and reliable tools for well control planning [4]. They help navigate the challenges of tight PPFG

margin HPHT wells by reducing the uncertainties regarding kick tolerance, and thus enhancing safety [7]. These simulation engine models lower the well control risks by accurately estimating the downhole pressure changes as a function of operational mode, fluids, influx type, geometry, water depth, pressure, and temperature conditions [4]. A particular benefit of transient multiphase technology for well control usage is the accurate modeling of gas kicks being dissolved in the undersaturated oil phase of the mud. Free gas then reappears in the upper section of the wellbore, where the pressure is reduced or if the gas concentration becomes high to oversaturate the oil phase [8].

Usually, the single-bubble kick tolerance methodology may fail to accurately capture the transient and multiphase characteristics of the influxes in HPHT wells. Occurrence of kicks and blowouts represents one of the highest severity categories in drilling risk assessments, according to [9]. Hence, advanced simulation models are necessary to obtain more accurate information about the gas kick behavior as well as their interactions with the drilling fluids. This study uses a transient multiphase flow simulator to model gas influx in a fictitious HPHT well. It specifically examines the impact of mud type and flow dynamics on the gas influx behavior during drilling operations. These case studies are provided to enhance the predictive skills of well planning personnel and wellsite drilling crews and to validate the benefits of multiphase technology over single-bubble methodology.

2. Methodology

A commercially available multiphase flow simulator has been used for this case study. The theory behind this multiphase flow simulator [10] relies on three separate momentum equations for the continuous liquid phase, gas, and liquid droplets. A slip relation is considered between the three phases, considering the velocity of liquid droplets in the gas. A mixture energy balance is used to model the temperature, assuming all phases have the same temperature. A second-order mass transfer scheme is applied with a relatively fine grid to prevent numerical diffusion. There is a total of seven conservation equations: three for mass, three for momentum, and one for energy. It is worth noting that this model also includes the acceleration term [8]. The study simulates a well with a total measured depth (MD) of 17,223 ft, where a 14" casing shoe is set at 14,763 ft (Fig. 1). The mud density used in the simulations is 15.45 ppg (Table 1). The model considers both OBM and WBM scenarios to compare their effects on the dynamics of gas kicks. The mud density is intentionally assumed to be low to simulate a well control incident. Different kick scenarios are introduced into the simulation in order to evaluate the multiphase system's response to changing gas volumes and pump rates. Accurate estimates of pit gain and maximum flow rate are essential to design the mud gas separator and ensure a sufficient gas handling capacity for the maximum kick sizes [5]. For the fluid dynamics simulations, the kick volume is set at 25 stb in both drilling fluid scenarios. Moreover, the simulation detects and closes the BOP just after the set amount of pit gain is observed.

Finally, various BHTs are simulated at the last casing shoe, namely 250, 300, 350, 400, and 450°F. The BHT is intentionally increased to understand the fluid behavior under higher temperatures and observe the trend in kick circulation times for high-temperature drilling conditions.

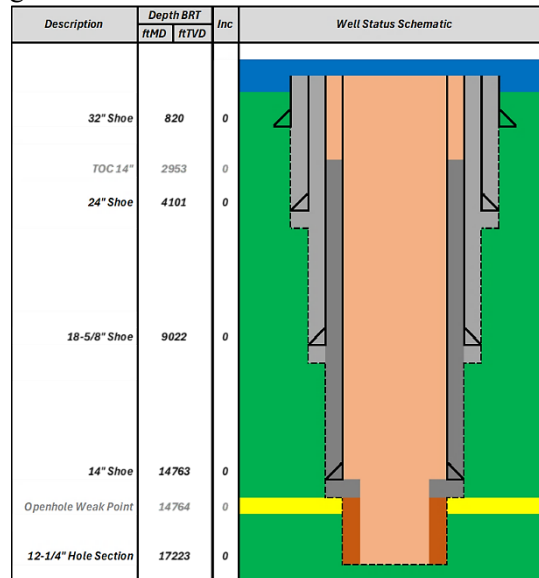


Fig. 1. Fictitious well schematic showing the wellbore profile, casing strings, and the open hole weak point at 14,764 ft.

Table 1. Fictitious well data used in simulations.

Parameter	Data
<i>Well Profile</i>	<i>Vertical</i>
Min. Pore Pressure Gradient, ppg	17.00
Max. Pore Pressure Gradient, ppg	17.29
Min. Fracture Pressure Gradient, ppg	17.36
Max. Fracture Pressure Gradient, ppg	18.36
Casing Burst Pressure, psi	10,160 (70% of casing burst rating)
MASP, psi	7,112
Openhole Weak Point MD, ft	14,763
Openhole Weak Point TVD, ft	14,763
Openhole Weak Point Temperature, °F	250
Surface Temperature, °F	65
Pit Gain, stb	25
Choke Line Length, ft	65.62
Choke Line ID, in	4.063
Kill Line Length, ft	65.62
Kill Line ID, in	4.063
Mud Weight, ppg	15.45
PV, cP	35
YP, lbf/100 sq. ft	20
Mud Pump Liner Size, in	7.5
Mud Pump Max. Discharge Pressure, psi	5,000
Mud Pump Efficiency, %	97

This section covers simulation case studies, and it discusses the effects of different mud types, temperatures, and circulation rates on the flow dynamics.

3. Results and discussions

3.1. OBM and WBM – fluid dynamics

The main analysis is conducted to compare the gas influx in OBM and WBM. Fig. 2 shows the changes in the BOP opening during the gas kick process for both muds. Detecting a gas kick in OBM is more difficult than in WBM. For the simulations of this figure, the kick volume is set at 25 stb, and both the OBM and WBM had a mud weight of 15.45 ppg. The gas kick is detected a few minutes later in OBM (orange line in Fig. 2). It can be understood that it requires a faster reaction time to shut in the BOP. The gas does not dissolve in WBM due to its lower solubility in water and remains in its gaseous form, which can be detected in Fig. 2. Moreover, changes in the mud volume and flow rate are more apparent with WBM. OBM, on the other hand, has a higher capacity to dissolve gases and makes the detection more challenging, thus delaying the appearance of kick indicators.

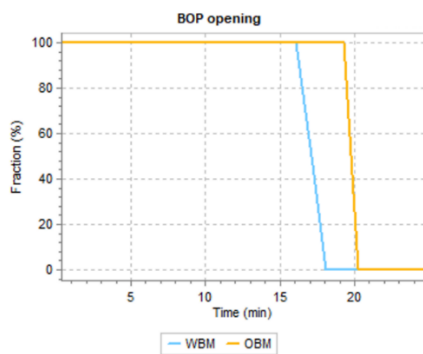


Fig. 2. BOP opening in OBM and WBM.

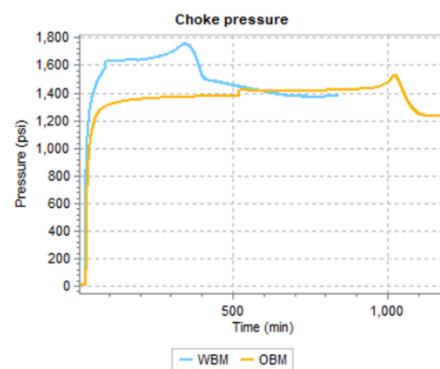


Fig. 3. Choke pressure in OBM and WBM.

Fig. 3 shows the changes in the choke pressure during the gas kick process. The gas influx requires more backpressure in WBM (blue line in Fig. 3) to maintain a constant BHP compared to OBM. When gas enters WBM, it tends to expand significantly as it moves up. This expansion adds the required backpressure to counteract the pressure above the gas column.

Fig. 4 shows the changes in the surface liquid holdup during the gas kick process. As the gas enters the well, it behaves like an undisturbed single gas phase in WBM. The holdup decreases from 93% to 78% until the gas nears the last casing shoe (Fig. 20, Appendix). After that, the liquid holdup begins to increase to 87% as the gas expands, reaching 5,000 ft. At that depth, the holdup again decreases until the gas is circulated out of the well, with the holdup around 74% at the surface (blue line in Fig. 4).

As the gas enters the casing, it begins to accelerate and expand. Its velocity is around 0.7 ft/sec, increasing to 3 ft/sec inside the open hole near the casing shoe, then

reducing again to 0.45 ft/sec. The gas velocity increases to 0.85 ft/sec throughout the casing string. After approximately 5,000 ft, the gas velocity fluctuates slightly and remains between 0.6-0.8 ft/sec until it reaches the surface. Overall, the influx mostly stays in the gas phase for WBM and expands as it circulates up the wellbore (or expands with a decrease in pressure). Regarding flow dynamics, the mud velocity is around 0.45 ft/sec up to approximately 5,000 ft, while the gas velocity is around 0.85 ft/sec. This suggests a flow similar to slug flow. There is some slippage between the gas and mud throughout the well. This makes the dispersed bubble flow unlikely. As the influx nears the surface, the flow pattern likely shifts to slug flow due to some holdup reduction near the surface. This allows the bubbles to coalesce and increase in size. After the gas comes out of the well, further study is needed to understand the flow pattern since the flow path changes from vertical to horizontal with several bends.

In comparison, it is observed that when gas enters a well filled with OBM, there is initially only a minor reduction in the liquid holdup. The gas stays dispersed in the oil phase and flows as a single phase with the mud, unlike the two-phase flow observed in WBM. If the well were shut in, the gas would remain dissolved and not migrate toward the surface with OBM. Gas only comes out of solution at around 3,250 ft and instantly reduces the liquid holdup to about 80% as it moves up (red line in Fig. 4). The holdup then increases again as the gas flows out of the well.

For the OBM, gas and liquid velocities remain the same at around 0.45 ft/sec until approximately 3,000 ft, after which the gas velocity increases to 0.6-0.8 ft/sec until reaching the surface. Overall, the influx mostly dissolves in the mud at the bottom of the well under high pressure during circulation. As the influx moves up the well in OBM, more gas comes out of the solution, and the size of the gas bubbles increases. Regarding flow dynamics, the gas is dispersed into the mud up to around 3,000-3,250 ft, which indicates no slippage between the gas and mud. After 3,000 ft depth, the gas evolves, and a slug flow is observed with some slippage. Considering this fluid dynamics, it is assumed that OBM flow has a lower capability to create slugs than WBM. This is because the liquid holdup in OBM only reduces to about 80% near the surface. However, more slugging is possible after passing the choke manifold (i.e., the main flow path changes from vertical to horizontal). It needs further analysis to discuss the flow behavior in the horizontal line.

Fig. 5 shows the free gas concentration throughout the well and demonstrates gas expansion with WBM. This plot is recorded right before the front of the gas reaches the surface. It seems from Fig. 5 that gas suspension happens near the surface in WBM, and this is where the tail of the expanded gas becomes challenging to move out of the well. The term "gas suspension" here is referred to as the velocity of the gas being very low to make it look like stopped. This (i.e., gas suspension) is observed with both mud types. In OBM, this also occurs but under the bottomhole conditions, where the dissolved gas is suspended in the oil phase. Because of this, it is harder for gas to move up the casing string in OBM.

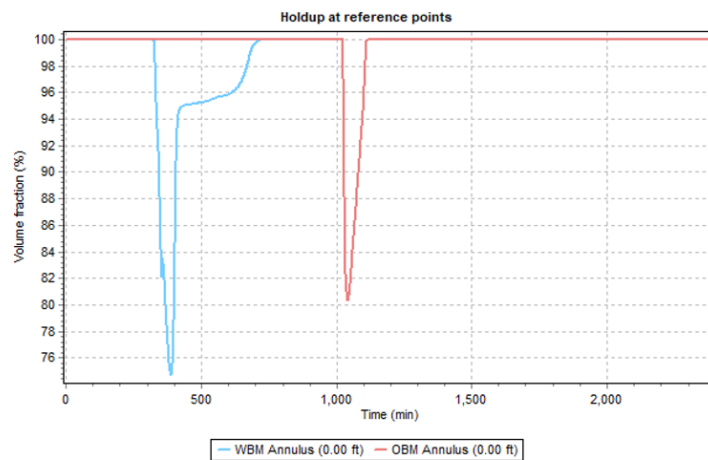


Fig. 4. Surface liquid holdup in OBM and WBM.

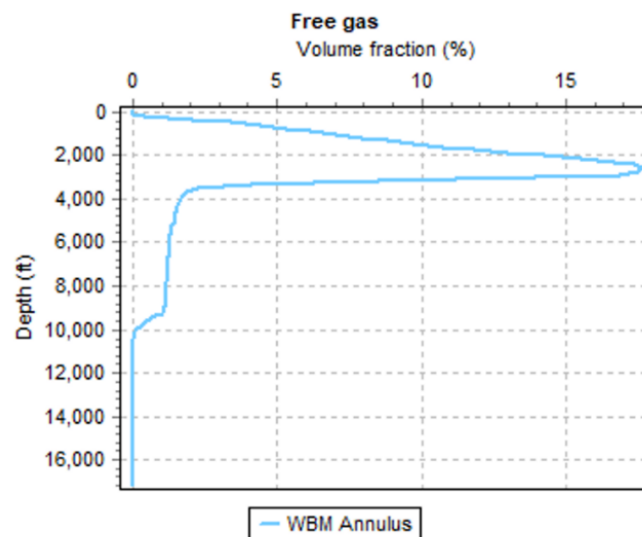


Fig. 5. Free gas concentration in WBM.

The blue line in Fig. 6 shows that WBM facilitates earlier gas outflow due to higher gas velocities inside the casing string. This is due to the undisturbed nature of the gas within WBM. Significantly, the surface gas flow rate in OBM (purple line in Fig. 6) surpasses that in WBM. This occurs because the gas is dispersed in OBM throughout the well instead of merely migrating. The gas then suddenly evolves from oil near the surface. As a result, OBM exhibits a higher peak gas rate and circulates the gas out of the well in a shorter time (i.e., overall, 170 minutes). Conversely, in WBM, the gas influx is migrating and expanding in the well, making the surface gas flow rate lower and the influx circulation time longer.

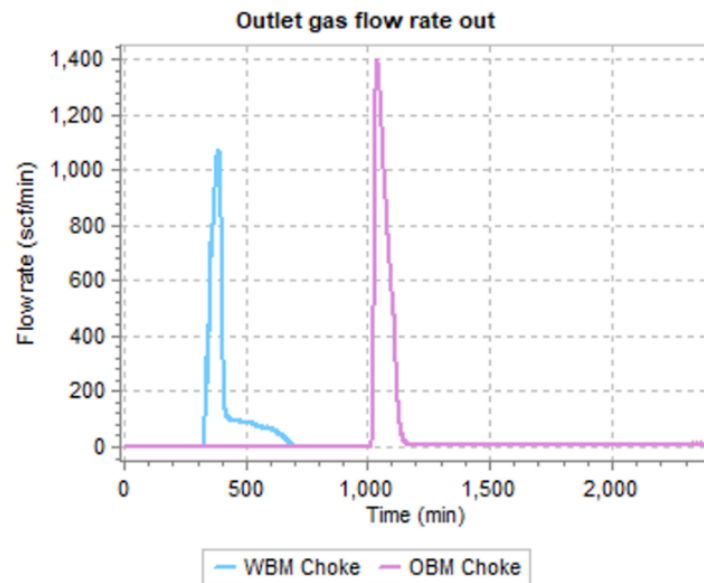


Fig. 6. Outlet gas flow rate in OBM and WBM.

3.2. Fluid dynamics in WBM – 150 and 75 gpm

This section analyzes the liquid holdup variations at 75 and 150 gpm pump rates for a 25 stb pit gain, providing comparisons. From the moment the gas influx starts, the liquid holdup decreases at an identical rate for both pump rates until reaching the last casing shoe at about 14,750 ft, where the holdup stabilizes at around 80% for both (Fig. 21, Appendix). Although the holdup increases for both rates within the casing string, the higher pump rate consistently shows slightly lower holdup values at equivalent depths, indicating a higher gas void fraction for the higher pump rate. The liquid holdup reaches a peak at 87% for the 150 gpm flow rate and 89% for 75 gpm at a depth of 5,250 ft. Then, the holdup values start to drop again after this depth, with the higher pump rate exhibiting relatively lower values. During the gas evacuation, the minimum holdup converges to approximately 75% for both rates at the surface (i.e., 0 ft).

From these observations, it can be deduced that higher pump rates correlate with increased gas velocity and a gradual decrease in liquid holdup at identical depths. It is crucial to note that for both pump rates, the predominant pattern is slug flow in WBM. While a higher pump rate increases liquid velocities (blue line in Fig. 7), it also increases gas velocities (blue line in Fig. 8).

It is understood that the influx reaches the surface faster at the higher pump rates. It takes more time to circulate the influx out with a lower pump rate fully. The influx has more contact time with the WBM, and its travel time increases while its velocity reduces due to the lower pump rate. Low velocity also results in slightly more dispersed gas throughout the well. This is shown by the red line in Fig. 9. The mixture density remains low for a more extended period at the lower circulation rate as more gas bubbles stay behind (from 200 minutes to around 800 minutes).

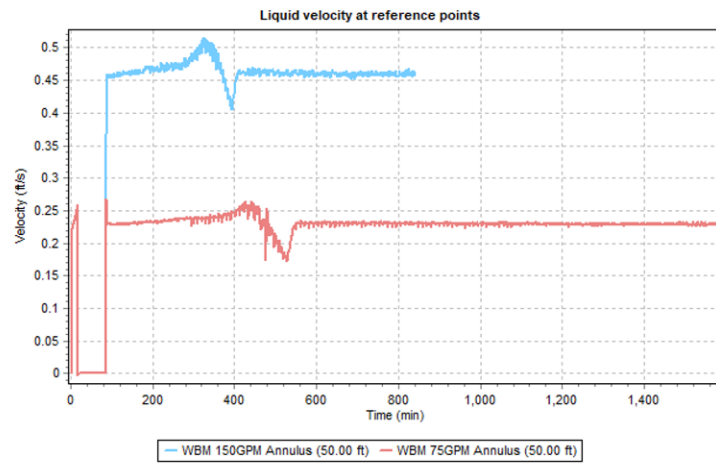


Fig. 7. Liquid velocity at 50 ft in WBM.

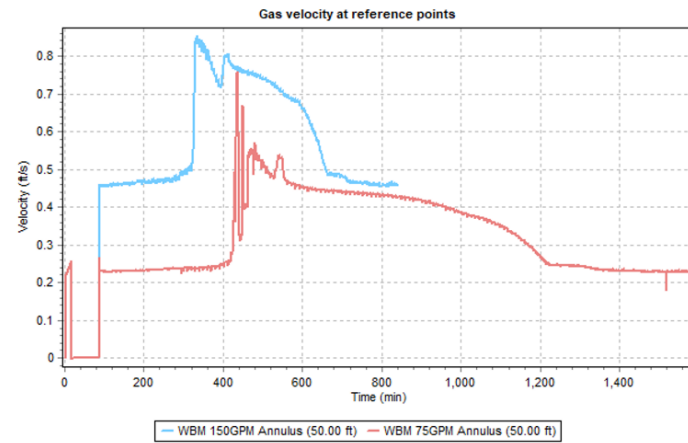


Fig. 8. Gas velocity at 50 ft in WBM.

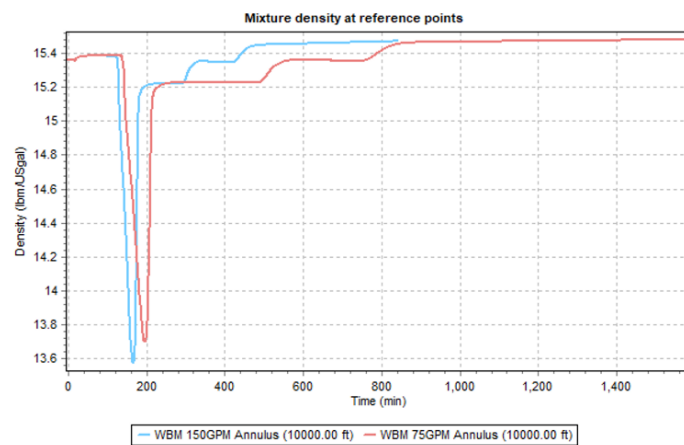


Fig. 9: Mixture density at 10,000 ft in WBM.

The differences in terms of the circulation rate effects on BHP and pressure are negligible at the last casing shoe. Increasing the pump rate results in around 15-25 psi lower pressure at the casing shoe and 15-25 psi higher BHP. This is expected due to the higher pump rate.

Lower pump rates cause the flow rate of the gas to decrease as it approaches the surface, as shown by the purple line in Fig. 10. Using an even lower flow rate, like 25-30 gpm, may result in a more dispersed gas influx, divided into multiple zones (i.e., suggested by the flow spikes at low pump rates). Because of the increased interfacial shear between the gas and the liquid, it is thought that the gas bubble breakage will increase with decreasing pump rate [6]. [6] can be referred to obtain more information about the pump rate and gas bubble dispersion. Thus, it is thought that there may be potential intermittent flow at very low pump rates.

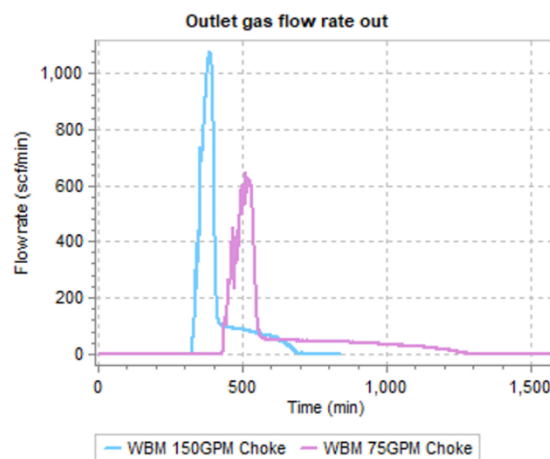


Fig. 10. Outlet gas flow rate in WBM.

3.3. Fluid dynamics in OBM – 150 and 75 gpm

This section compares the liquid holdup variations for the OBM and WBM cases with 75 gpm and 150 gpm and a 25 stb pit gain. To summarize for the OBM, when the gas influx initially kicks in, the liquid holdup is 100% until a depth of 3,500 ft for both pump rates. From about 3,500 ft to the surface, the higher pump rate leads to a comparatively lower holdup value, while the lower pump rate results in the reverse (Fig. 22, Appendix). Both scenarios exhibit a reduction in the holdup values until the kick reaches the surface. The minimum holdup for the 150-gpm pump rate is around 76% at a depth of 130 ft, while the holdup for the 75-gpm scenario reaches its minimum of around 84% at the same depth. Compared to WBM, OBM shows a reduction in liquid holdup (a higher concentration of free gas) as the pump rate increases. Another point of comparison is that the difference in pump rates leads to a larger effect on holdup values in OBM. The largest variation in holdup values is around 2% (i.e., between 87% and 89%) in WBM, while OBM shows this difference to be as much as 8% (i.e., between 76% and 84%).

Near the surface (50 ft), the plot shows that WBM leads to a lower liquid holdup (blue and red lines in Fig. 11). One likely reason is that the gas influx does not disperse as much in WBM and behaves as a less disturbed gas phase near the surface. The higher flow rates result in lower holdup (blue line in Fig. 11) for this case and coalesce all the bubbles. It is also observed that circulating out a gas influx in OBM takes much longer (dark yellow and purple lines in Fig. 11), depending on the pump rate. However, there are some similarities between OBM and WBM. Increasing the pump rate results in lower liquid holdup (blue and dark yellow lines in Fig. 11) for both cases. Since OBM has a higher capacity to dissolve gas, a portion of the gas dissolves into the oil phase, reducing the amount of free gas available for bubble breakage and forming a continuous tail. However, the degree of mixing and agitation increases with the pump rate in OBM and leads to higher shear forces and the breakup of gas bubbles. This reduces the gas expansion. Conversely, in WBM, gas bubbles expand more freely, but the expansion rate depends on the pump rate. Overall, the flow pattern in both fluids at both pump rates is mainly slug flow.

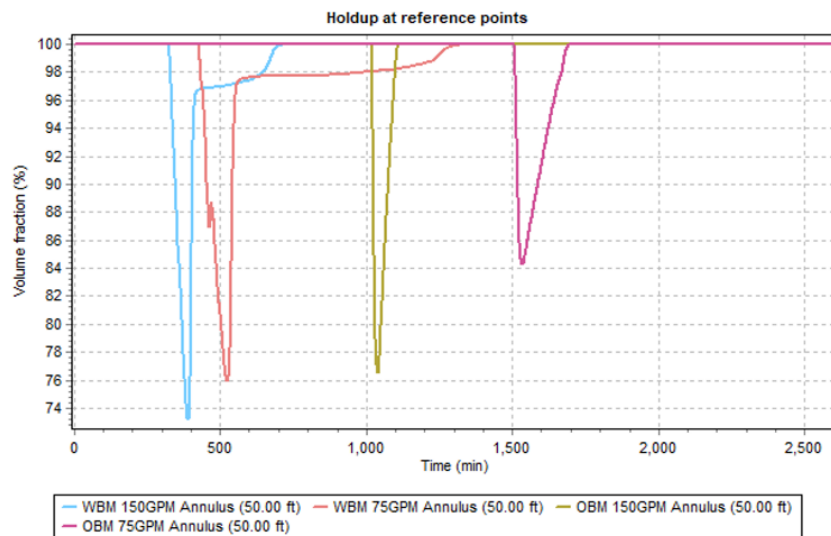


Fig. 11. Liquid holdup in WBM and OBM.

Fig. 12 and 13 compare the two-phase mixture density at 10,000 ft (Fig. 12) and 100 ft (Fig. 13). These figures show that the gas influx leads to a greater reduction in mud weight for OBM (dark yellow and black lines) compared to WBM (blue and red lines). This confirms the conclusion that the gas influx mixes and expands in WBM throughout the wellbore, while it stays dissolved and then evolves as a large single bubble in OBM. Additionally, at a depth of 100 ft, increasing the flow rate from 75 to 150 gpm results in a further reduction in mud weight. This is again due to the further mixing of gas and mud at the higher circulation rate.

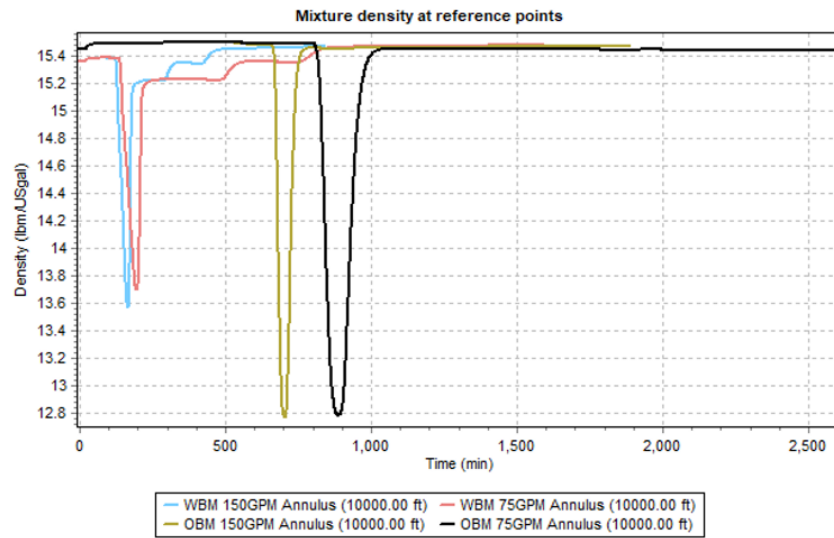


Fig. 12. Mixture density at 10,000 ft in WBM and OBM.

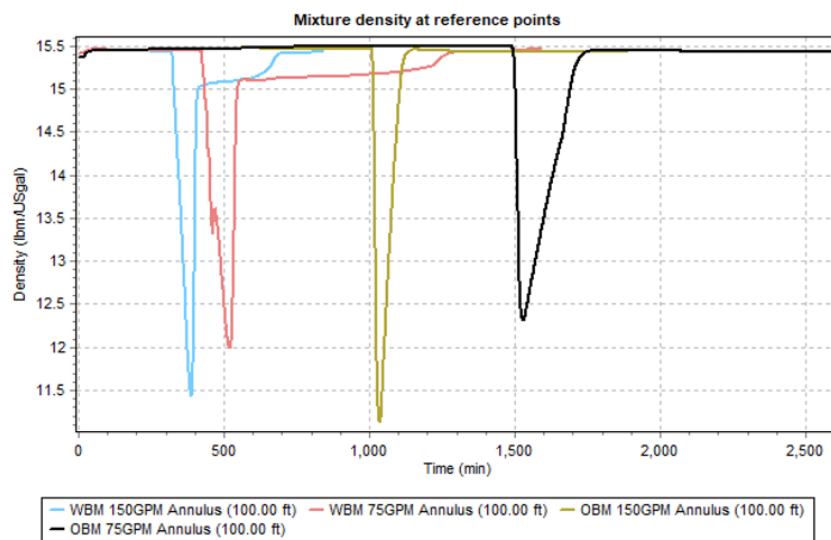


Fig. 13. Mixture density at 100 ft in WBM and OBM.

Fig. 14 and 15 show the pressure changes at the last casing shoe (Fig. 14), and BHP (Fig. 15). The two cases have approximately a 150 psi difference, with WBM resulting in higher BHP and casing pressure. The reason is understood to be the dissolution of gas into OBM, whereas the free gas occupies a greater volume and expands rapidly in WBM.

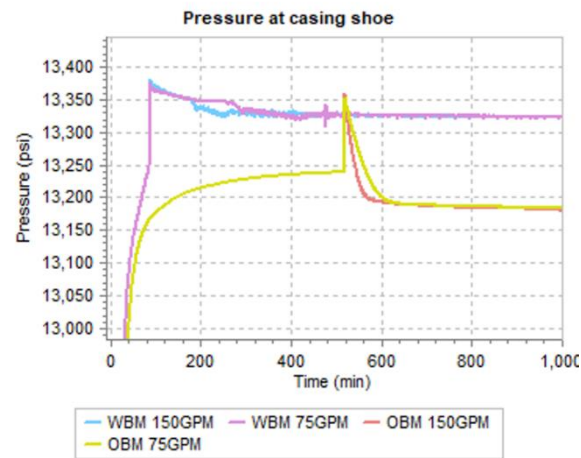


Fig. 14. Pressure at the last casing shown in WBM and OBM.

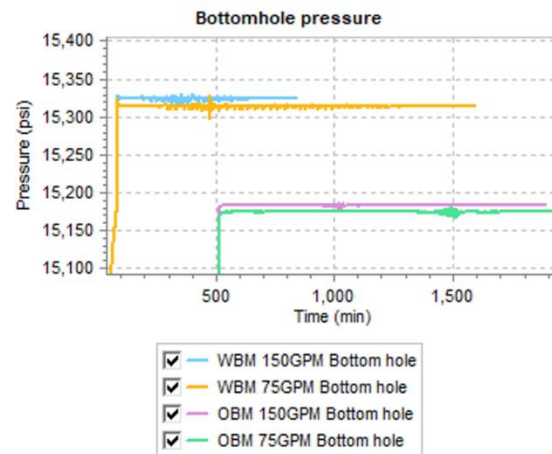


Fig. 15. BHP in WBM and OBM.

Figures 16 and 17 show the mud type and circulation rate effects on the output gas flow rate and cumulative output gas volume, respectively. The purple and yellow lines in Fig. 16 demonstrate how lower pump rates decrease the instantaneous flow rate of the gas. It is essential to consider the sizing of surface separating facilities when switching the drilling fluid from WBM to OBM, as indicated in the blue and red lines in Fig. 16. The instantaneous gas outlet flow rate is considerably larger for OBM drilling fluid. It is assumed that the reason for a higher volume in the case of OBM (purple and green lines in Fig. 17) is that the influx gas stays dissolved in the oil phase and only gets liberated near the surface, while it breaks into smaller bubbles and expands in WBM (blue and orange lines in Fig. 17). Fig. 23 in Appendix presents the outlet gas flowrate in terms of pumped volume instead of time.

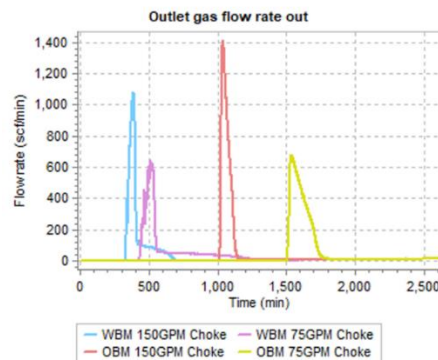


Fig. 16. Outlet gas flow rate in WBM and OBM in terms of time.

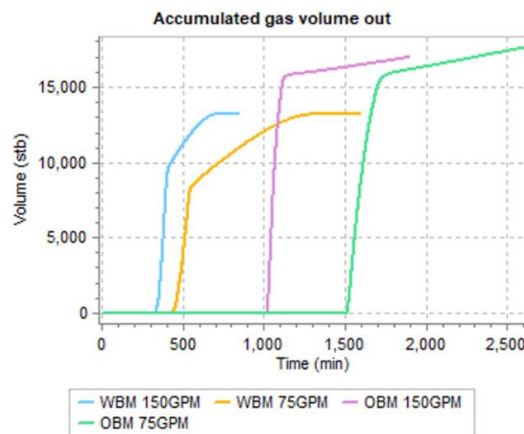


Fig. 17. Accumulated gas volume in WBM and OBM.

3.4. Thermal effects on kick circulation time

The BHT is raised from 450 to 650°F, while the temperature at the casing shoe is increased from 250 to 450°F. The purpose is to generate different scenarios for thermal well control. The pore pressure fracture gradient (PPFG) stays constant in this case study.

As the BHT increases, it takes more time to circulate the gas out of the well (blue and purple lines in Fig. 18). The outlet gas flow rate is slightly lower as the permeable zone temperature increases (Fig. 18). Free gas at the surface is higher for WBM and even higher for both mud types under lower BHT conditions. When a gas kick enters a wellbore with OBM, the gas dissolves in the oil phase, producing a new fluid mixture with its own distinct phase equilibrium diagram. In the liquid phase, this mixture may have a unique bubble point pressure, depending on the gas/liquid concentration and temperature.

Overall, circulation takes more time with higher temperatures, and this is of concern because it is not desirable to let the casing string undergo kick pressures for extended periods.

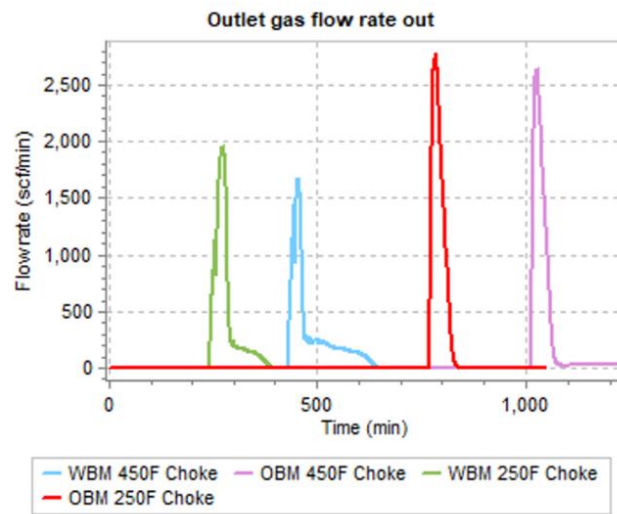


Fig. 18. Gas flow rate out in WBM and OGM with 250 and 450°F.

Increasing the BHT extends the full kick circulation time (Fig. 19). Higher temperatures cause the gas to become trapped within the oil phase under bottomhole conditions. In WBM, the same phenomenon occurred near the surface, taking a significantly longer time to circulate the expanded gas tail out of the well. This may indicate one of the reasons why gas kicks are particularly hazardous in HPHT wells, even though they are more common in HPHT than in conventional wells. As the bottomhole conditions transition from HPHT to Ultra HPHT, finalizing the circulation and zero SICP and SIDPP with the driller's method takes longer.

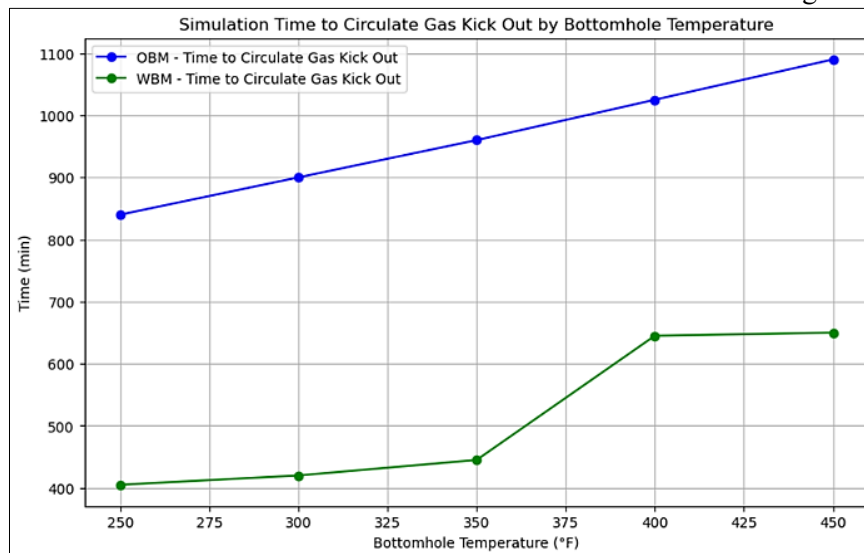


Fig. 19. Simulation time to circulate gas kick out in OBM and WBM with 250–450°F.

To better understand the nature of kick detection when gas kicks are soluble in drilling mud (such as OBM and methane), a small blowout simulator has been developed, and tests have been conducted by [11] in a scaled 20-foot model built into the OU Well Construction Technology Center (WCTC). According to [11], the testing has demonstrated that in the case of the soluble kick situation, there is a delay in detecting the pressure increments at the surface, which leads to an incorrect interpretation of the bottomhole condition. The tests have demonstrated a time increase to detect the surface kick by up to 600% from 3 minutes to 20 minutes, which has been referred to as a dormant kick [11]. The dormant kick has been defined as a kick that happens very slowly, causing the differential pressure on the bottom to change from an overbalanced to an underbalanced situation in a matter of hours. When the kick and drilling fluid are miscible, this slow tendency will have a bigger impact.

4. Conclusions

This comparative study between OBM and WBM shows that WBM tends to result in higher BHP and casing pressures, whereas OBM leads to higher peak outlet gas flow rates due to more effective gas dissolution. Experience indicates that in some cases, the capacity ratings of the surface handling equipment are not adequate to circulate the influx safely out of the well, although maximum pressures can be safely accommodated. WBM's reduced gas dissolution capacity makes earlier detection possible. Moreover, because of the gas expansion, WBM produces more choke backpressure and presents more slugging behavior than OBM. These elements help explain why WBM has more free gas near the surface than OBM, where gas is more likely to be suspended in the oil phase in bottomhole conditions.

The effect of pump rates on well control is also emphasized in this study. In addition to increasing gas velocities, higher pump rates also reduce the chance of bubble flow transition; thus, the flow typically maintains a more stable slug state.

With higher BHTs, there is a risk that the gas will become trapped inside both OBM and WBM. In thermal wells, there is a requirement for more time to circulate the gas kick out of the well. Eventually, this exerts high pressure for a longer period.

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Appendix

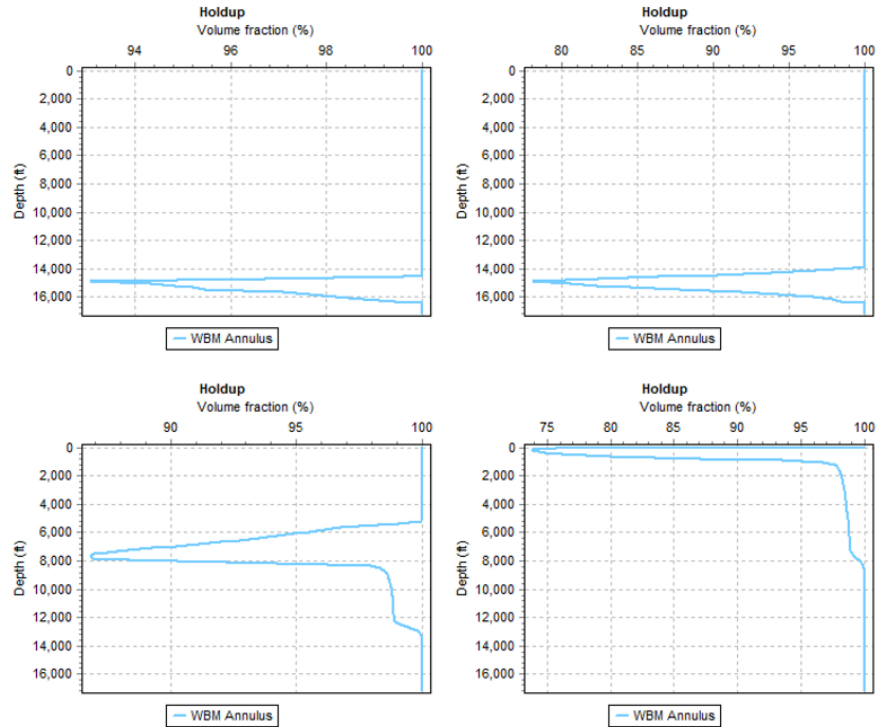


Fig. 20. Liquid holdup in WBM.

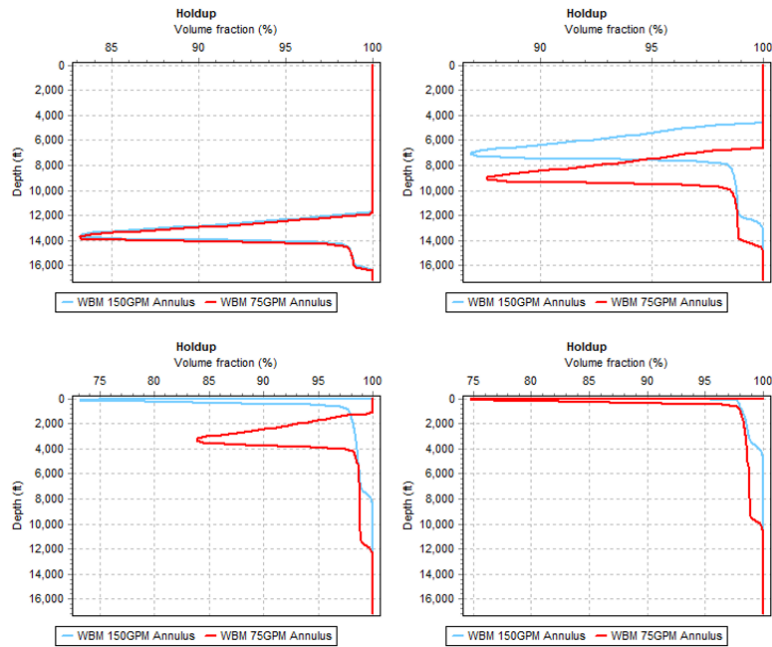


Fig. 21. Liquid holdup in WBM – 150 and 75 gpm.

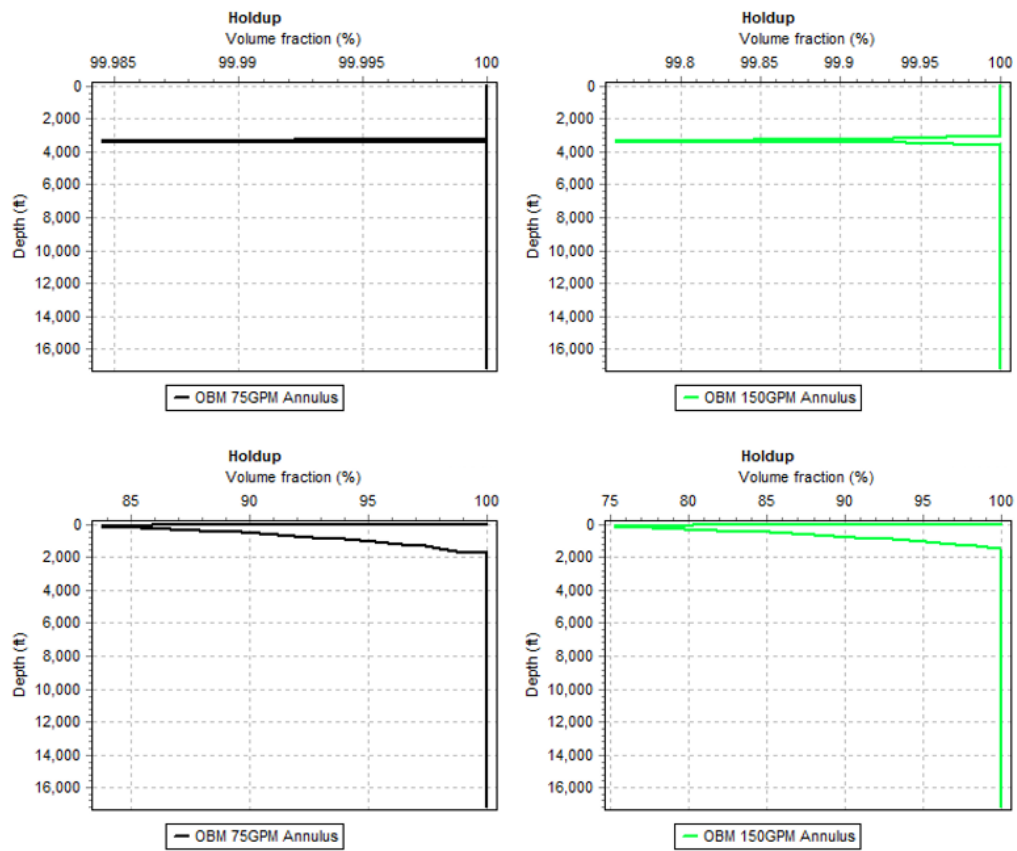


Fig. 22. Liquid holdup in OBM – 150 and 75 gpm.

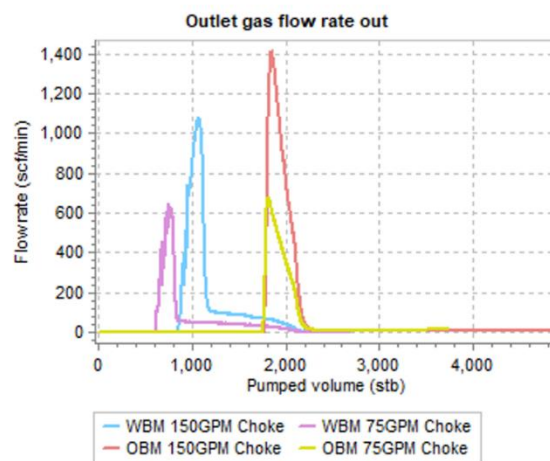


Fig. 23. Outlet gas flow rate in WBM and OBM in terms of pumped volume.

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