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Reduce Risk and Save Cost by Better Understanding of the Physics of Well Control

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Abstract

In drilling-related well-control workflows, general assumptions are usually made based on years of training, basic theory of well control, and experience. However, the standard spreadsheet and hand calculations used for evaluating well control situations do not necessarily represent a true understanding of what is happening downhole. Well control therefore depends heavily on the experience of the personnel and their ability to read the well and react accordingly. This works in most well control situations, but often responses to well conditions are not fully understood and no sound logic or reason for a particular event is given.

This paper investigates why certain well-control phenomena occur in some wells and why certain events cannot be explained by conventional assumptions. Simulations based on actual well events are presented to explain why well-to-well variances occurred and how multiphase flow simulation solutions explained the unconventional behavior seen. The simulation scenarios include shut-in pressure and flowback analysis, mud weight response to a kick, and interpretation errors in kick responses. After an understanding of what was occurring downhole is achieved, the information can be used to develop operational procedures and guidelines that make well-control incidents much more manageable and less costly, reducing unplanned project costs and making the ongoing projects more feasible.

The use of a multiphase flow simulator to model well-control events proved invaluable in determining what actually was occurring down hole as a part of preplanning, real-time, and post mortem studies for future wells. This paper shows how the understanding the physics of what is happening in a multiphase environment is paramount in making the right well-control decisions and preventing health, safety, and environment (HSE) issues and costly authorization for expenditure (AFE) overruns.

Introduction

Our objective is establish a reliable means for considering advanced well control in preplanning and post planning and demonstrate the diverse capabilities of current transient simulation. The drilling industry has been using the same simple calculations, commonly referred to as the single-bubble method, throughout the well plan process, from preplanning to operations to post-drilling analysis. In drilling, the well-control assumptions are made based on general theory, years of standardized training, and experience. Although the basic theory is valid, the need to simplify and reduce a complex event to formulas that are easy to calculate and understand has taken precedence. These calculatios may not prove adequate in an increasing amount of wells because drilling conditions have become more demanding. This situation is not just relegated to offshore wells. Many land wells now need more advanced understanding of well control.

Common spreadsheet and hand calculations used for evaluating well-control situations do not necessarily represent a true understanding of what is happening downhole The single-bubble method assumes an influx gradient of typically 0.10 to 0.15 psi/ft. The influx is treated more as a density change in the mud column than as a multiphase migrating bubble. This aids in the simplification of the well-control calculations [1] but provides little information as to the complexity of what is happening downole. Some operators and service providers have incorporated more-sophisticated calculations to provide a more realistic simulation., Corrections for wellbore profile, temperature, pressure, and Z-factor for the expansion and contraction of gas [2] have been added. These more intensive calculations represent progress, however, they still do not correctly model the influx bubble as it enters the well or as it moves up the wellbore, changing shape and associated pressures as the wellbore profile changes. The single-bubble method does not consider important attributes such as gas solubility in oil-based mud (OBM) and associated "breakout". Breakout is typically another calculation based on a very simple black oil production model that sacrifices important information for the sake of simplicity to calculate when gas will actually start to come out of solution. Some of the assumptions, simplifications, and rules of thumb the industry has been trained to use are not sufficient to meet today's drilling requirements.

In areas prone to well control problems, experienced rig personnel become critical. The ability of the driller to read the well becomes a requirement to successfully navigate a well-control event. This seems to have worked in the past, given the large safety margins afforded, but, often, responses to well conditions are not fully understood and no sound logic or reason for a particular event is given. Many of today and future wells will not have forgiving safety margins for well control events and without understanding downhole events even experienced drillers can make a poor choice with serious consequences. This understanding could avert major, lengthy and costly well control incidents by modifying simple operational procedures at the appropriate time. We hope to show the benefits of multiphase simulations and how these simulations can have been used to understand well control issues.

Multiphase models have long been available to provide reasonably accurate simulations that would give office and rig personnel a better understanding of what is happening downhole. Understanding the physics in this environment is paramount in making correct decisions that prevents health, safety, and environment (HSE) issues and costly authorization for expenditure (AFE) overruns. These simulations when used as a part of preplanning, real-time, and post mortem studies provide insight into what may appear to be anomalies such as unusual surface pressure changes as the influx moves up the wellbore, timing of when pressures and volumes are expected to change, breakout events time and depth, etc. In a nutshell, better tools, better answers with better results.

This paper covers several instances in which various levels of well-control issues were encountered. With the assistance of a multiphase flow simulation, explanations and solutions were found for well-control events that were considered unconventional behavior for the well. After a proper understanding of events was achieved, operational procedures were put in place to minimize or eliminate well-control events that were plaguing the project. The disparity of the instances demonstrates how widespread the need is for understanding the fundamental physics occurring in well-control events.

Verify Downhole Pressures in Operating Conditions

Typically, the use of a transient simulator should be considered to determine if any operational parameters were causing issues. Primary issues such as exceeding fracture gradients, or dropping below pore pressure during connections can be quickly spotted and operational procedure corrected to prevent any potential problems.

The example in Figure 1 shows where losses were experienced at approximately 1120 minutes of drilling, first due to an instantaneous ROP of 180 ft/min and then a major increase in mud flow / pump pressure to assist in sliding a mud motor. Equivalent circulating density (ECD) increased significantly due to a larger cuttings load traveling up the wellbore, adding additional downhole pressure until the cuttings reached surface. The decision was then made to increase flow to clean the hole and assist the mud motor in sliding which continued the increase of ECD that exceeded the fracture gradient. This was supposed to be a casing point but due to the losses the casing was set above the projected casing shoe depth. The result was drilling out of the shoe and encountering more losses and a subsequent cement squeeze job to drill to the next casing shoe.. Had the need for control of the rate of penetration (ROP) been known then the original casing point would have been reached and no unnecessary lost time. This error in not recognizing the effects of a drilling break was repeated on several wells. It never showed up on steady state analysis because no one thought to evaluate the effects of instantaneous ROP.

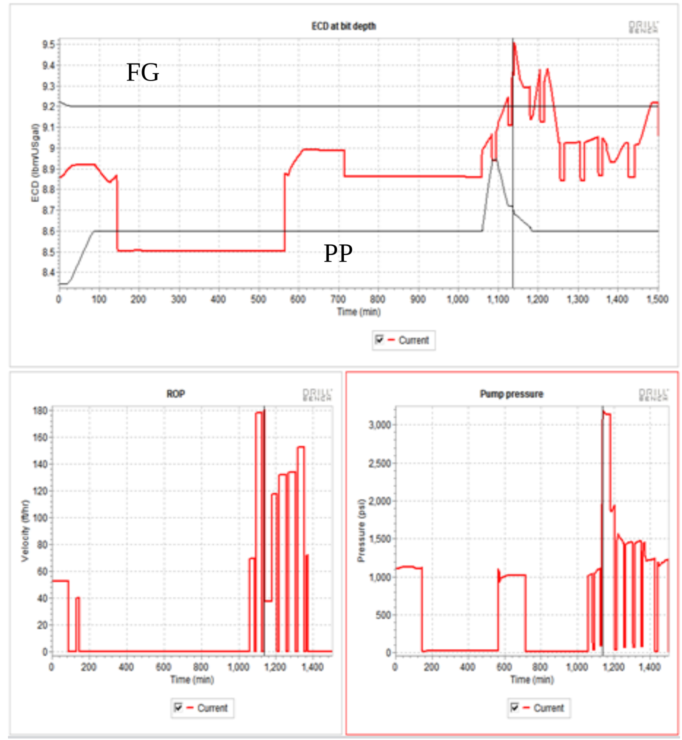

Figure 1-Losses due to high instantaneous ROP and pump pressure.

Understanding Surface Conditions

Commonly, well control issues are evaluated when they happen. Kick studies will be done mostly in terms of casing design and not for understanding operational issues, unless there are suspected or known issues. If a serious event occurs, lessons learned will be done, evaluated, and applied to the next well. Here is where multiphase simulation can be of particular use as well control is a complex multiphase environment. Nuisances of pressure buildup, choke response, timing, etc. can easily simulated and provide a better understanding of what to expect in an event. Standard single-bubble methodology simplifies it to essentially an easy to calculate dual density solution without much understanding of actual conditions The differences can be significant and costly. Figure 2 demonstrates how a poor circulation procedure using single bubble methods resulted in the fracturing of the casing shoe. This could have been prevented had preplanning simulations with a transient multiphase simulator been run. By evaluating and choosing the proper slow pump speed serious loss circulation and lost time could have been prevented.

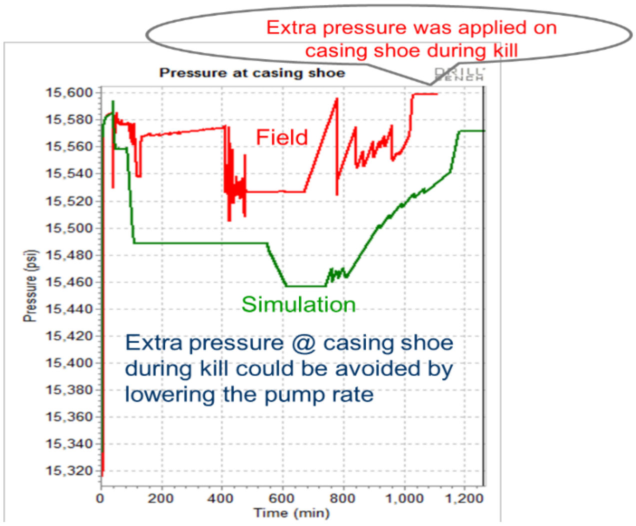

Figure 2- Prevention of shoe fracture during kick circulation

Typically, mud weight is adjusted based on gas counts. Most gas counts represent a quantitative analysis and not a qualitative one. The general assumption is that more gas counts may be an indication of an influx (always assumed to be gas). This may not be a bad assumption with water-based muds (WBM) because the influx fluid typically does not readily mix with water-based fluids. However, with oil-based drilling fluids, hydrocarbon influxes mix with oil phase of the drilling mud, changing the properties of both fluids in the area where they interact. The pressure/volume/temperature (PVT) properties being of most concern as this reflects relevant issues such as breakout and dissolution. The decision to weight-up based just on gas count may be unjustified and potentially damaging if there is a modest drilling margin pressure window. On the other hand, the dissolution of the hydrocarbon influx and base oil of the mud has different properties that are not accounted for in conventional well control [3]. This changed mud may not show a significant density change at surface with conventional monitoring tools and procedures.

The assumption is that the influx is always gas because it is considered conservative. Most rigs are set up to deal with that assumption, but that is not always the case. Therefore, it must be decided if surface equipment to clean and condition the mud properly is available or if the mud should be ejected. This could result in costly solutions.

An example illustrates how the assumption of a gas influx created operational problems because surface and downhole behavior were not as expected in a horizontal well. The misunderstanding caused considerable nonproductive time (NPT) and HSE issues. The expectation was that a gas influx, should result in a breakout near surface. However, the breakout was never seen. There were high gas counts reported, and there was some flaring, sometimes significant, but no breakout. The procedure due to high gas counts and flares was to increase mud weight but this caused the breakdown of a weak zone creating a serious loss circulation issue.

To assess the issue, various influx fluids were simulated, matching recorded surface pressures and flow rates. It appeared that the influx composition was somewhere between a black oil and a volatile oil, not the assumed gas. This was verified when influx composition and PVT data were given. It also meant that the calculated mud weight to stop an influx was excessive. The influx fluid was heavier than gas. It was the forcing them in to a loss circulation scenario that was not necessary. A reason was now provided for why no breakout was ever seen and why there were flares from the mud gas separator. The simulations showed that the influx contamination was very small at surface because it was being strung out along the wellbore so the mud density was not adversely affected. However, the influx was building up in the horizontal section of the hole, which was drilled underbalanced in a tight formation (Figure 3).

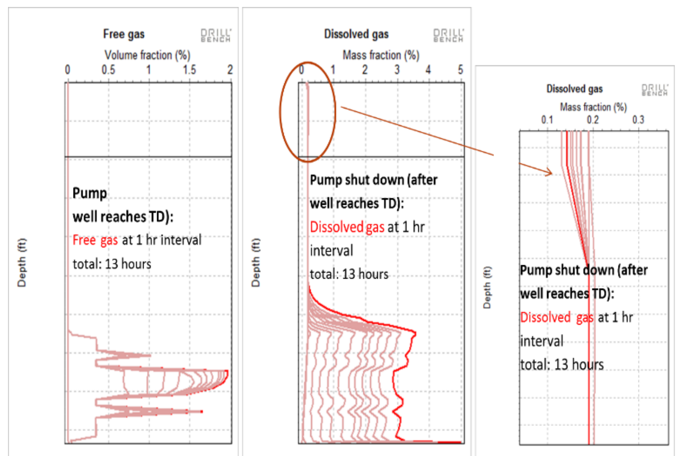

Figure 3-Influx stringing out along wellbore of horizontal well.

This buildup in the lateral part of the well explained the large flares that were occurring when circulating bottoms up from the bottom of the hole when tripping for a cleanup run for casing. However, there were instances at low flow rates when flares were not seen, but, with an increase in flow rate, flares became significant. It was obvious from the simulations that the reservoir was producing from the underbalanced drilling conditions. Simulations showed a correlation with the drawdown pressures and surface flow rates during connections. No excessive flow was seen while drilling as the ECD exceeded the pore pressure. The simulations included the effects of producing reservoir lengths for a given drawdown, but no data were available for correlation. The most interesting thing that was visible was that at low flow rates (laminar flow), the influx fluid would get trapped in the peaks of the lateral section oscillations. (Figure 5) This would result in little to no flaring at times. This condition, stratified flow, (Figure 4) allowed the drilling fluid to slip by the influx, trapping it in the peaks of the lateral oscillations during laminar flow. However, at turbulent flow rates, significant flaring would be seen as the stratified flow conditions did not exist and all the influx fluids were being picked up and circulated

The next concern to be resolved was that the flow rates and pressures seen at surface did not coincide with the formation pressures given. The simulations were adjusted for reservoir pressures that made the models work. Later, when better information was available as to exact formation pressure, the multiphase simulator's adjusted inputs for formation pressure proved correct.

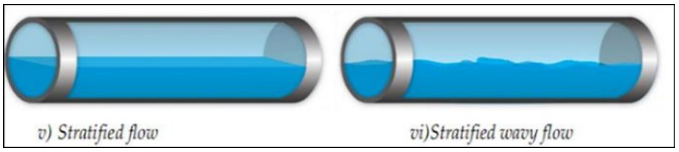

Figure 4-Stratified flow.

The conclusions were

1. The flow regime in the horizontal section of the well is stratified .
2. Although some reservoir fluid is mixing with the OBM, some is not mixing, but is instead maintaining a separate flow.
3. The reservoir is continually producing, so even though reservoir fluid is mixing with the OBM, fresh reservoir fluid is replacing that which is dissolved. This increased volume would be seen as flow at surface.
4. Per simulations, flow at surface should be about the same as what the reservoir is producing until dissolved gas gets into the vertical part of the well. At this time, the flow at surface will be very slowly increasing as the dissolved gas moves up the well, hydrostatic pressure is reduced, and the entrained gas bubbles start expanding.
5. Fortunately, what has been observed on location and in the simulations show is that there is not sufficient expansion and volume of entrained gas to break out, at least not for a long time (>40 hours).

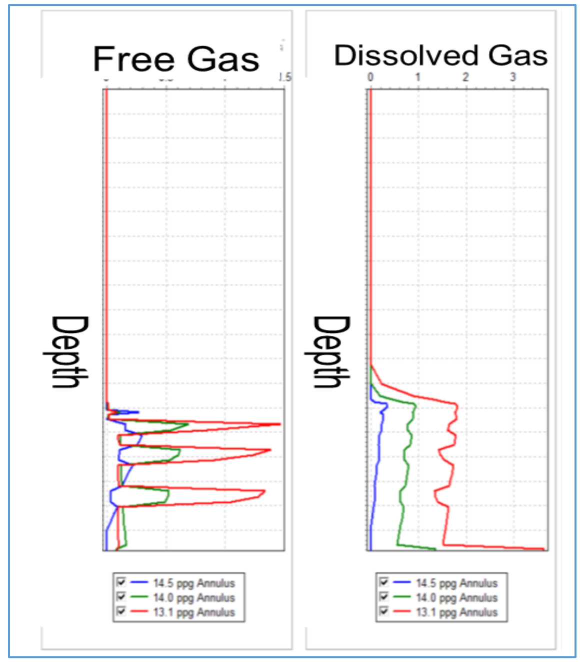

Figure 5- Gas position.

Effects of the Well Profile

It is well known that the shape of the wellbore and changes of diameters in the wellbore have an impact on how an influx is circulated out and the changes can have on the bottomhole pressures. Single-phase simulations cannot accurately represent the conditions seen in Figure 5, where an influx can be trapped in the oscillations of well, or those in Figure 3, where an influx tends to string out along the wellbore in a small tube with the flow as it enters the wellbore.

Some simulations have been done to understand the effects of the orientation of the lateral in terms of toe-up (>90°) and toe-down (<90°). As expected, influx fluids tended to collect more in the toe with toe-up and in the heel with toe-down (Figure 6). What was surprising was the amount of delay time it took for the influx to move out of the curve during circulation and into the vertical part of the well. It was not a continuous movement. There appeared to be some delay at the heel in the simulations. Possible causes could be slippage between the influx fluid and mud or there could be some issue with the influx fluid transitioning into dissolution. The most likely explanation is that the wellbore formed a P-trap or water trap at the heel (Figure 7) causing heavier fluid to remain in the trap.

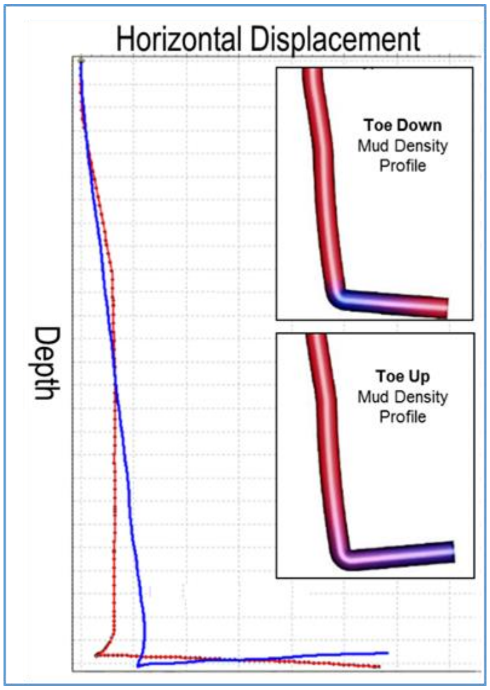

Figure 3-Toe up vs toe down.

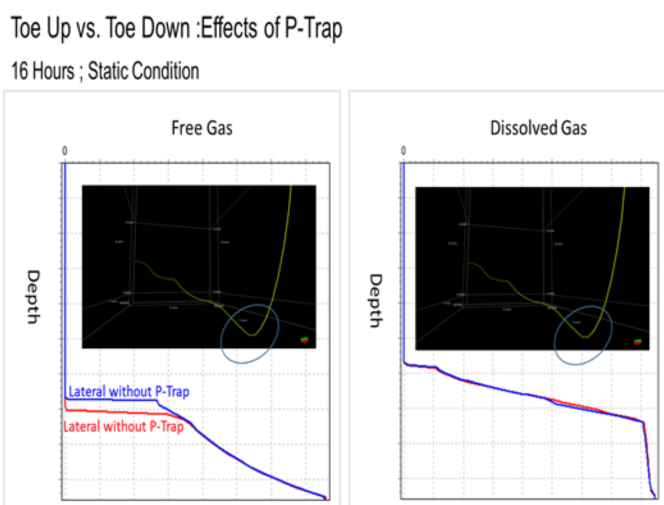

Figure 4-Effects of P-trap on influx migration in heel of horizontal well

Effects of U-Tubing

U-tube effect is part of basic in well-control theory. [5, 6, 7]. An example is a scenario in which the production casing was not able to fill with mud as expected when running in the hole., At times there were some well-control issues with some serious flaring when circulation was involved. Because of the flaring, it was assumed there was some influx coming in, but where or how could not be determined. Stripping operations needed to be implemented to ensure well control, but were made difficult because the casing had not reached a depth where the casing centralizers were below the blowout preventer (BOP). Assuming the reservoir was producing equivalent to the flow seen at surface, simulations were done to look at where the top of the influx was over time at various flow rates (0.5 to 5.0 bbl/hr) during tripping out and setting up for the production casing. Charts indicating influx positon (measured depth) in time using multiphase simulation were made based on the wellbore configuration, hole size, mud weight, producing reservoir length, drawdown pressure and MPD back pressure. After looking at the simulation data and reviewing operational needs, it was determined that a flow below 2 bbl/hr would be safe to allow tripping out of the hole and get the casing to stripping depth in a 24-hr period (Figure 8).

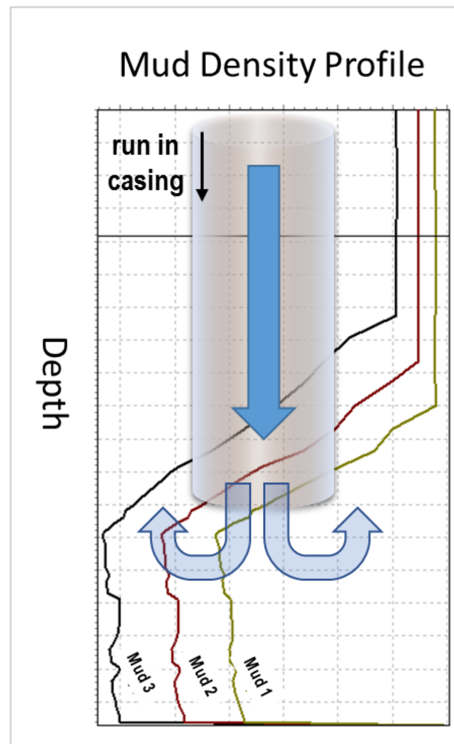

Figure 5-U tubing of mud in casing due to influx levels.

This theory was confirmed in actual conditions.. During the casing run, the casing was filling up per expectations going into the hole until it reached the point where per the simulation charts and time indicated that the casing would encounter the influx cut mud (lower density). At this point, the casing started failing to fill with expected volumes. Annular flow slightly increased and flares started occurring creating lengthy well control procedures. The u-tubing made filling the casing very difficult and time consuming until the mud density outside the casing shoe had reached a similar equivalent density through extensive circulation. Understanding what was occurring downhole allowed for small procedural changes that minimized time to regain well control quickly and continue tripping the casing or start stripping operations.

In another example, the effects of U-tubing in a riserless environment wellbore breathing or possibly a kick was studied [5]. It shows the contribution of flow of each event using pressure-while-drilling (PWD) data to correlate how and when each event enters the flow regime and how it becomes part of the total. Figure 9 shows the matching of the PWD pressure, and Figure 10 shows the composition and timing of flow needed to produce the pressure recorded by PWD. The study helped show the complexity of u-tubing environment and the contributions of different flows. More importantly a workflow was developed that could accurately model non measured visual events with minimal data. In this case standpipe pressure and pressure while drilling (PWD) data.

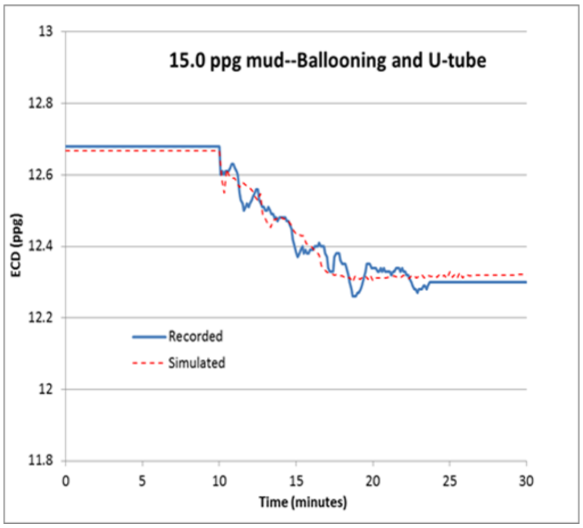

Figure 6- Recorded vs simulated pressure in a riserless hole.

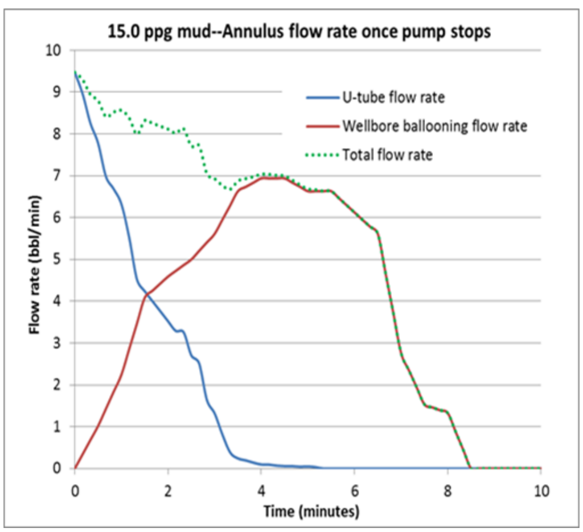

Figure 7-Composition of flow.

Effects of Flow on a Heavy Pill

There are many reasons why a heavy pill will not work in trying to contain flow in a well. Placement of the pill at too high an inclination, density differences, and insufficient viscosity are typically assumed to play a part for the pill to invert. The simulation for this scenario was based on a study[8], in which an operator had successfully used a multiphase simulator to understand expected flow rates during an influx in an unconventional well. One of the conclusions of the paper was that a high-density pill could be set above the reservoir and below a weak zone to contain pressure in the lateral to allow safe tripping. There were examples that this was not working in other operator's wells. One issue was that the density or height of the high density pills were not sufficient to stop. Height was limited due to concern of a weak zone above kick off point. The high density pills were sufficient to slow it down significantly. However, the pills were hard to find and appeared to be dissipating when reentering the well. It was thought they were inverting with the lighter fluid below the pill. However, sometimes heavy fluids would be found higher up the hole than expected, making planned cleanup more difficult. The drillstring was deeper into the high density pill than expected. Maintaining a low density for planned cleanup circulation in order not to fracture the weak zone became problematic. Simulations run on the pill indicated that the pill was dissipating, but was moving up the hole with the flow of the well and not down (Figure 11). Unfortunately, there was no conclusive evidence this was happening and if it was systematic.

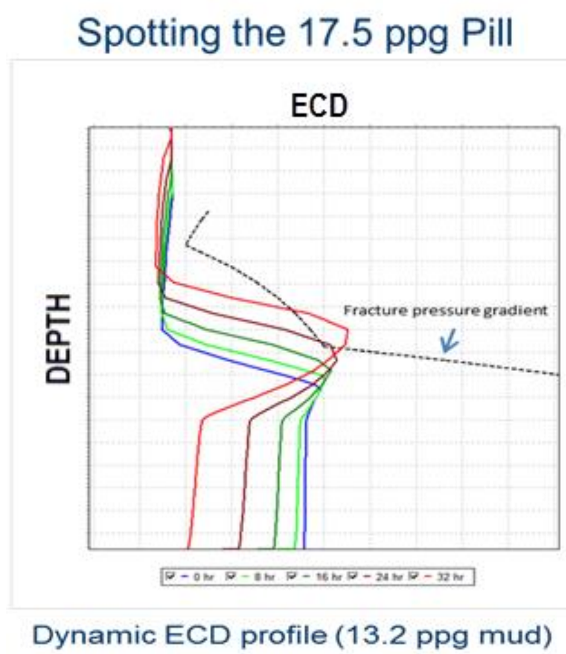

Figure 8-Heavy pill movement with flow from reservoir.

Plugged Choke

One of the scenarios typically overlooked in well-control planning is a plugged choke. The simulation for this scenario deals with modeling a typical driller's method situation to understand what should have happened. Then to determine if there were obvious reasons, such as insufficient backpressure, circulating rate, or mud weight, that could have made a difference. Nothing unusual was seen during a standard simulation. This led to review effects of a plugged choke line.

Initial simulations were carried out to review if condensate could build up in the choke line because the mud was water based. The multiphase simulators have capabilities to do this, and per the simulations, conditions were in place for condensate buildup with the WBM in the choke line.

Driller's methods with various restrictions at the wellhead were simulated. Still no pressure matches could be made. The next step was to add the losses that were recorded. A parametric study was done with various diameters of plugged choke line in conjunction with loss rates. It is important to note that placement of the loss zone in relation to the PWD sub because it had a significant effect on pressure response. After all the variables were examined, a reasonable pressure match at the choke and PWD sub was found with an approximately 90% closed choke. However, during the study, the root cause of a condensate buildup came into question. Although conditions were good for condensate buildup in the choke line, during drilling there was no indication of this buildup. Another study was done by another source that indicated that barite sag conditions were also a possibility, which gave another potential source for the plugging of the choke line. However, the simulations still were consistent that the choke line was plugged at the wellhead (Figure 12).

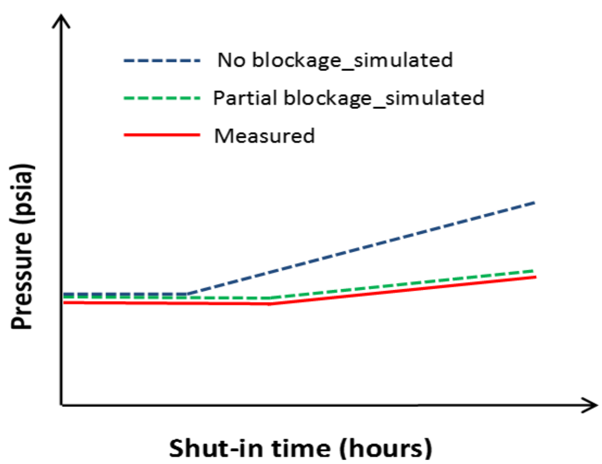

Figure 9-Comparison of various choke blockages.

Gas Migration

Bullheading is a very standard, well-understood process in well construction and production. One of the problems of bullheading, especially in a water-based environment, is the migration rate of influx up the well. There have been various studies on gas migration [9, 10], but there are no firm conclusions because there are many variables that must be considered. Variables such as pressure, temperature, mud rheology, bubble size and distribution, influx composition, and PVT properties, all need to be factored in. Even though current multiphase simulators can predict this, there is room for improvement.

In this simulation, the gas bubble size is determined by the pit gain seen during the kick, about 30 bbl. Also important are the bubble size and distribution. Determining how, where and speed the influx came into the hole can be a factors. In addition, any flow the influx was subjected to should be considered because this would cause a longer distribution along the wellbore. A gas influx was used based on fluid properties obtained. Multiphase simulators have the capability of defining the compositions and PVT properties of an influx fluid.

Simulations started with recreating operating conditions to determine what went wrong. Available data to match was standpipe pressure and casing pressure. A 4-hour shut-in period before bullheading was simulated. This allowed the gas influx to migrate up the wellbore. The rule of thumb of 1000 ft/hr for gas migration was used on the rig during actual events. The first issue that came out of this was that the bubble had migrated much faster than 1000 ft/hr. Using the 1000 ft/hr rule of thumb put the influx about midway between the bottom of hole and the wellhead in 4 hours Per the simulation, in 4 hours, the influx had reached the wellhead. The simulation indicated the bubble was migrating at a rate of 3000 ft/hr (Figure 13). .

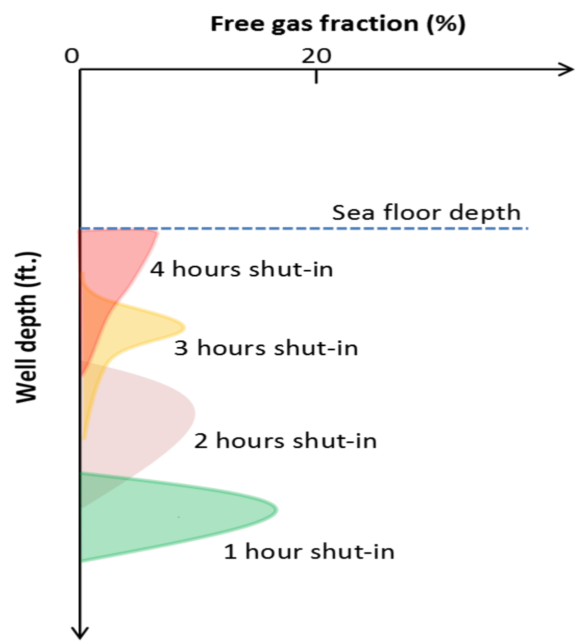

Figure 10-Comparison of gas migration over time.

The first bullhead procedure, pumping flow and time were insufficient based on the position of the influx at the initiation of the procedure. In the simulations, the influx only reached about three-quarters of the depth of where it need to be to start injecting into the formation. The effect of slippage between the mud and influx may have been a factor in the delay to reach the injection point.. It shows the need to pump longer and/or higher rates to get the influx back into formation. Injection rate into the formation were simulated with accountability for the different rheology and properties of the mud and influx by matching standpipe and casing pressures. .

The wellbore profile was not a factor as it was a vertical well and no liners to change wellbore inner diameter.

Next, was an evaluation of why the second bullheading was successful. There was some non-circulating time that would allow the influx to migrate up to the wellhead before the second bullheading attempt. A higher pump rate and a slightly longer pumping time were used on the second bullheading attempt. It was successful. Figure 14 shows the curve of minimum requirements created by the multiphase simulator for a successful bullhead in time vs. flowrate and the two bullheading attempts made.

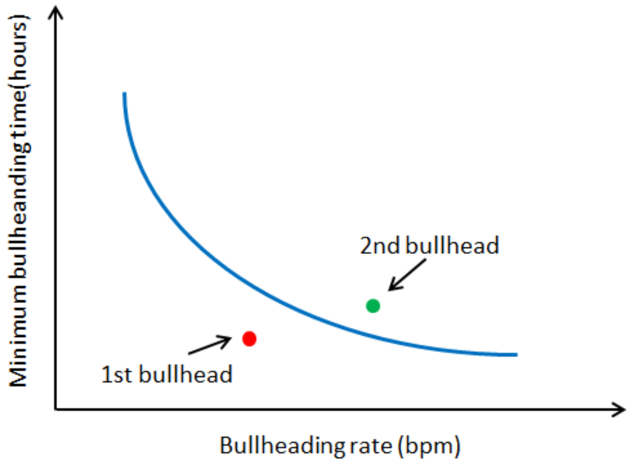

Figure 11-Minimum required time vs. rate for successful bullhead

Thermal Expansion

Thermal effects are seldom considered in trying to diagnose a reason for flow or loss, mainly because the flow tends to be slow and small. This is a function of temperature change in the wellbore. In some cases where there are significant temperature changes such as a high pressure high temperature well (HP/HT) or cold water well surface flows can be dramatically different. If the well is shut-in, the pressures can be significant given time and conditions. In a continuation of the previous bullhead scenario, after the well was bullheaded successfully and stabilized for about 5 hours, the well started have major losses. There was nothing operationally that could account for this. There were no downhole operations going on. The well was static and shut-in while the next operation was being prepared. This posed a quandary. It was known that there was not much operational margin left for the fracture gradient, but with all the operational issues, it was felt that the fracture gradient was fully understood. In addition, the hydrostatic pressure of the mud compensated for pressure and temperature and verified when the PWD was in the hole was felt to be an accurate value. Why would the well take losses after 5 hours of remaining stable? It was thought that while losses were taking in the current formation, a carbonate, it was not prone to any degradation.

One of the studies transient simulators are commonly used for is temperature effects. A study was done looking at the effects of temperature even though this was not a HP/HT well. Downhole pressure and temperature were available from the PWD sub as well as wellhead pressure. Running a simulation on the temperature and pressures in static condition provided good matches with recorded operational data (Figure 15).

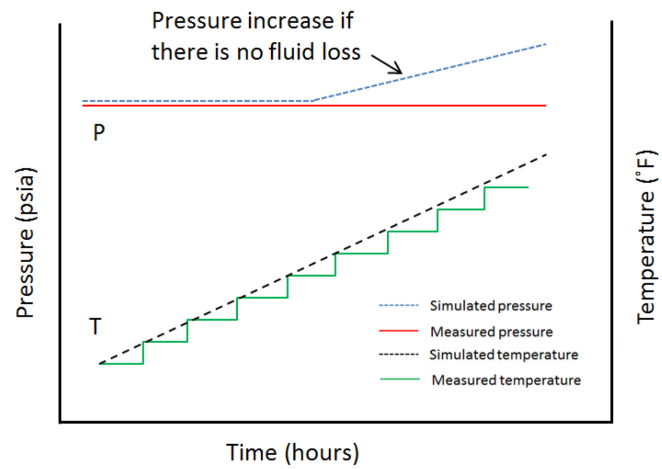

Figure 12-Losses due to thermal expansion.

The simulation showed that in the 5-hour time span, the mud would expand with temperature radiation from the formation to increase pressure above the fracture gradient, thus inducing the losses. The correlation between the simulation and operational data was so good that it was apparent that this is what occurred.

Shut-in Pressure Analysis

Another issue consistently seen is difficulty in interpreting shut-in pressures once a kick is taken. Conventional well-control training assumes that shut-in pressures stabilize quickly (within 30 minutes) and that any subsequent increases in pressure are due to gas migration up the well. This behavior often does not occur in reality, for the following reasons:

1. In many wells drilled with synthetic-based mud (SBM), there will be almost no gas migration as the gas will dissolve in the base oil phase of the mud.
2. For slow influxes from low-permeability formations, it can take hours for shut-in pressures to stabilize.
3. Subsequent shut-in pressure increases may be misattributed to thermal expansion of the mud as it heats up with the well static.

Often, the resulting decision made is to take the shut-in drillpipe pressure (SIDPP) after 30 minutes as the pore pressure, with additional pressures bled off before commencing well control. This only serves to introduce more influx into the well, which could potentially exceed the kick tolerance and break down formations below the casing shoe. When well control operations commence, the pore pressure has been underestimated, and multiple circulations with increasingly higher kill mud weights are required to kill the well. This is all at substantial additional cost and risk to both the integrity of the well and personnel on the rig.

One such example of these effects occurring is outlined here. The 17.5-in. section drilled with SBM hit a low-permeability higher-pressure sand, which was flowing at 1 bbl/hr while drilling with increasing gas readings up to 32% observed. On a flow check, a 5-bbl gain on the trip tank was observed, and the well was shut-in. The shut-in pressures were observed for 1 hr and determined to be 70-psi SIDPP and 80-psi shut-in casing pressure (SICP), as seen in the model matching measured rig data (Figures 16,17).

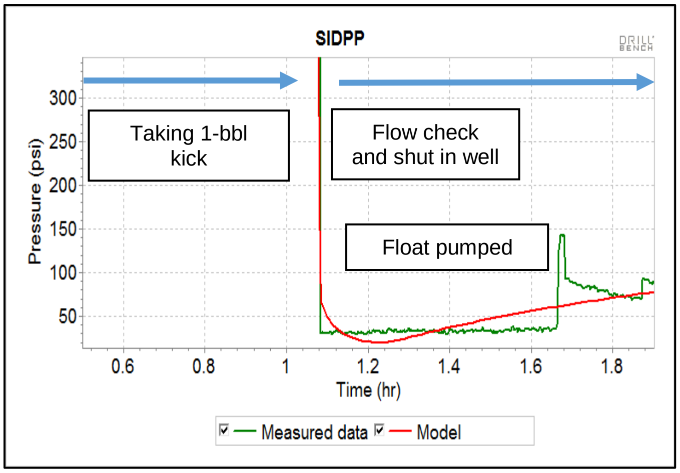

Figure 13- SIDPP during shut-in of low permeability kick.

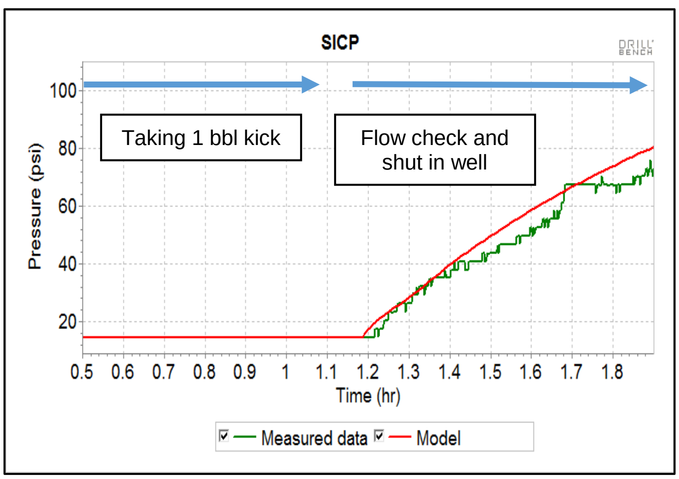

Figure 14-SICP during shut-in of low-permeability kick.

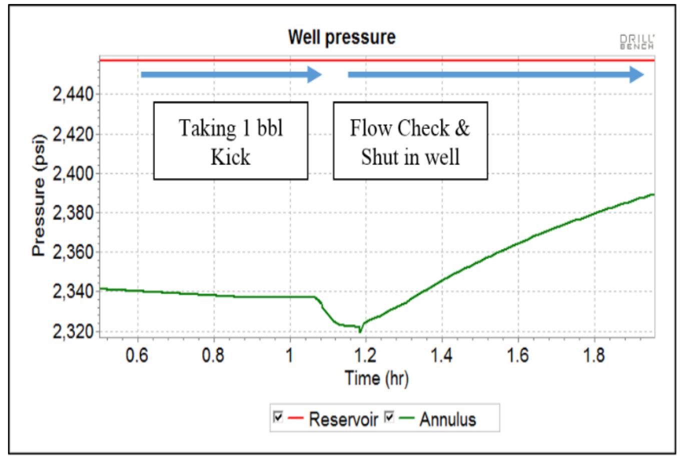

Figure 15-Modeled bottomhole and pore pressure during shut-in of low-permeability kick.

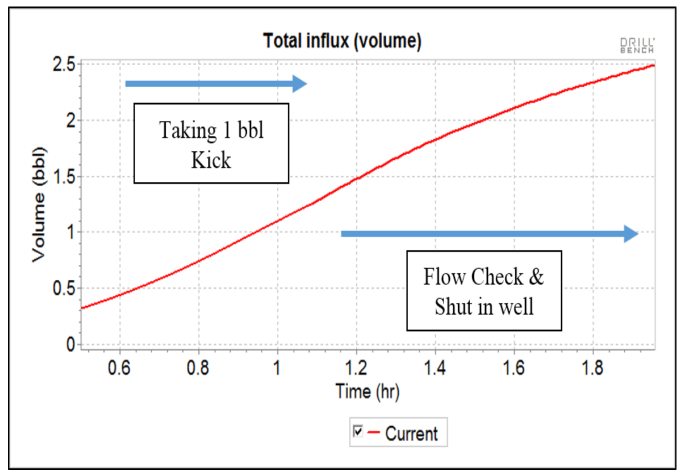

Figure 16-Modeled total influx during low-permeability kick.

Operational personnel determined the pore pressure to be 9.9 ppg using conventional calculations despite the pressures clearly slowly increasing over time (Figures 18, 19). The physics in this case were misunderstood because, in reality, there was no gas migration in the SBM that could cause further pressure increases—a further 4-hr shut-in would be required for shut-in pressures to stabilize for this tight sand (0.04-md permeability). An additional 1.5-bbl influx came into the well while the BOP was closed over this 1 hr due to the underbalance before pressure stabilization. The pore pressure was therefore initially underestimated by 0.3 ppg (10.2 ppg actual). After circulating in 9.9-ppg kill mud, a higher SIDPP of 100 psi was observed, which confused the situation; ballooning was thought to be the cause. A further week was spent alternating between inconclusive bleed-offs and kick circulations before finally the well was killed with 10.3 ppg kill mud weight in hole. This costly exercise could have been avoided with the use of multiphase models to determine the downhole conditions. The use of a multiphase model can predict the actual pore pressure and reduce the shut in time required for the readings.

Flowback Trend Analysis

Sometimes, any gains on a flow check after the well was thought to have been killed are attributed to ballooning or thermal expansion effects. This can have catastrophic consequences if circulated through the riser as the gas breaks out of solution from the SBM. All of these effects can be modeled quickly and accurately during well-control operations, and such modeling enables much better decision making and lower costs and risks to the well and rig personnel.

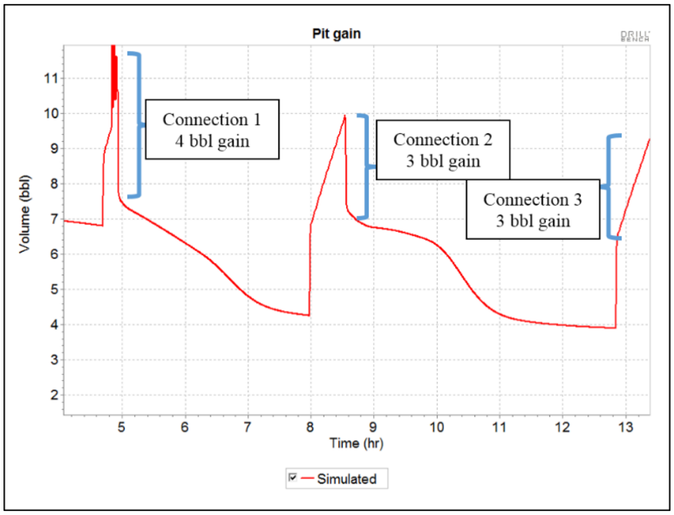

Figure 17-Modeled condensate influx pit gains during connections.

An example of this occurred on another well that experienced a low-permeability kick that was thought to have been killed with a 13.10-ppg kill mud weight. When drilling ahead, it was noticed that approximately 4-bbl pit gains were occurring on every connection (Figure 20). This was attributed to ballooning given the losses that occurred during the previous well-control event and the reducing trend of the flowback volumes. In reality, these were slow condensate influxes that, due to the nature of fluid interaction with the SBM downhole, gave the appearance of a reducing flowback trend. The well was not shut-in; these gains were circulated through the riser resulting in very high gas counts up to 100%. However, no gas breakout effects were noticed. Additional modeling determined that if the influx fluid was a dry gas, the riser would start unloading. This example demonstrates the need to consider the effects of multiphase flow and fluid properties when diagnosing and dealing with any unexplained pit volume increases.

Conclusions

There are many issues to consider to properly understand what is happening during a kick. Commonly, breathing and thermal expansion may be thought to be kicks. In such circumstances, it is always thought better to be on the side of caution and assume any flow is a kick until proven different. Unfortunately, treating such incidents as a kick can result in considerable lost time in trying to resolve the issue, and becomes very costly. Transient, multiphase simulators are very powerful tools with the capabilities to accurately model very sophisticated scenarios such as losses, phase change, dissolution, temperature effects, multiple densities, and variable wellbore configurations. There are few scenarios that current transient simulators cannot model or help understand an event with a reasonable degree of accuracy with respect to well control.

Understanding what was causing an influx, what it is composed of, the rate that it enters the well and where, its composition, and how it is interacting with other wellbore fluids and affecting conditions along the wellbore and at surface can easily be visualized and studied. Often, correcting any issues requires only small procedural changes. Of course, the simulator can be used to evaluate the effect of the changes to make sure no additional problems will occur.

There is also the issue of experience for personnel. The good is major well control events are not as prominent as they were. We have many new technologies to help us recognize more quickly and keep well control events to a minimum. The bad is that we still have a dependency on experience as factor in successful well control. With fewer and less serious well control events gaining experience is difficult for the next generation of drilling personnel. While it will never replace time on the choke, transient simulation can provide a method for better understand of the consequences of certain actions. Understanding of downhole conditions results in better decisions in a time heightened concern.

Operators who have taken the time to use transient multiphase simulation to study their problems and better understand them often find significant savings with benefits as reduced casing strings, less NPT, and fewer HSE risks. A better understanding the physics of what is happening downhole can only help drill a faster, safer well.

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Nomenclature

AFE = *Approval-for-expenditure*
BHA = *Bottomhole assembly*
BOP = *Blowout preventer*
ECD = *Equivalent circulating density*
HSE = *Health, safety, environment*
HP/HT = *High pressure high temperature*
PPG = *Pound per gallon*
PWD = *Pressure while drilling*
SBM = *Synthetic based mud*
SIDPP = *Shut-in drillpipe pressure*
SICP = *Shut-in casing pressure*

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