Realistic Simulation of Multiphase Kick Tolerance Model Promotes Safer Well Control Operations: Case Study

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Abstract
Nowadays, deep-water drilling is of great importance for the development of oil and gas production. It is necessary to determine the maximum pressure that the formation can withstand during well control operation. This value can be calculated using several variables, including kick tolerance. The purpose of this study is to analyze a real well control event using dynamic well control modeling software that calculates the kick tolerance based on the single-phase and multiphase dispersed kick (gas) model. The initial results show that the type of drilling fluid plays an important role in the calculation of the kick tolerance. The calculated kick tolerance using a single-phase model indicates an allowable kick volume of 56 barrels (bbls), but in reality, we had a dispersed gas kick in a synthetic oil-based mud (SOBM) drilling fluid, which requires special kick tolerance calculations based on a multiphase dynamic model. After reviewing the results of the multiphase kick tolerance simulation, it was found that the maximum gas kick volume is more than twice that of using a single-phase model in an oil-based mud drilling fluid, allowing safe well control operations and reducing the possibility of accidents.

Keywords Deepwater drilling · Well design · Kick tolerance analysis · Multiphase modeling · Well control simulation · Casing shoe pressure

Abbreviations

| Abbreviation | Definition                      |
|--------------|--------------------------------|
| BBLS         | Barrels                        |
| DPP          | Drill Pipe Pressure            |
| ESD          | Equivalent Static Density      |
| GPM          | Gallon per Minute              |
| HPHT         | High pressure/High temperature |
| KI           | Kick Intensity                 |
| KT           | Kick Tolerance                 |
| MWD          | Measurement While Drilling     |
| MD           | Measured Depth                 |
| NAF          | Non-Aqueous Fluid              |
| OBM          | Oil-based Mud                  |
| PPG          | Pound per Gallon               |
| SIDPP        | Shut-in Drill Pipe Pressure    |
| SICP         | Shut-in Casing Pressure        |
| SOBM         | Synthetic Oil-Based Mud        |
| TVD          | True Vertical Depth            |

1 Introduction

Drilling is an integral part of the oil and gas industry as it is essential for hydrocarbon exploration and development. Increasing energy demand is driving wells into deeper and harsher environments, making well control increasingly challenging.

Successful drilling of any well section depends largely on onboard personnel noticing the problem with equipment or well conditions before it becomes a serious problem and taking appropriate action, such as increasing levels of connection over pulls, slow deterioration of mud properties, increasing levels of background gas content.

A deepwater well drilling program has recently been designed and implemented using the most advanced and
modern technical tools for well planning. Because the overburden pressure is low and the drilling fluid density window is narrow in deepwater drilling, higher demands for kick tolerance prediction precision are placed on the prediction precision. Multiple elements, such as kick intensity, fracture pressure at casing shoe seating point, and drilling fluid property, impact kick tolerance calculation, which must fulfill the condition of safe well killing operation under the most hazardous working situations.

Since kick tolerance (KT) was considered a crucial feature, its effects on well planning, drilling, and well control were measured [1]. It has been reported that a practical method for measuring KT in good planning has been applied to wells in the Canadian Beaufort Sea, which has high abnormal pressure and unconsolidated formation, as well as permafrost, gas hydrates, and plastic shale [2]. Due to the problems associated with this location, it was important to set the casing string optimally [3].

Therefore, several technical works were carried out to obtain a more realistic picture of the well design in preparation for the KT simulations. A better and more complete picture of the boundaries required for well planning was achieved by using advanced multiphase KT models [4].

The main objective of this work is to investigate the application of the multiphase KT model to predict the maximum allowable kick volume using advanced KT simulator software to explore the possibility of handling larger influx capacities.

2 Principle Calculation of Kick Tolerance

When planning the length of the next open hole section, it is important to determine what type of wellbore pressure will occur in the open hole section when an unexpected gas kick needs to be controlled to avoid underground blowouts if the fracture pressure is exceeded [1]. Typically, the weakest point in the open hole section is the last casing shoe in the wellbore. This dimension is often referred to as KT.

For practical purposes, the KT can be expressed as the maximum gas kick volume at a given kick intensity (KI) and a particular depth that can be shut in and circulated out of the wellbore without fracturing the formation at the weakest point at the depth of the previous casing shoe. The assumption that the depth of the casing shoe is the weakest formation segment along the entire open hole section is not necessarily true [5].

The thresholds for allowing the kick to prevent reaching the subsurface boundary are most likely determined by KI in deep wells, which are usually drilled with non-aqueous fluids (NAF), while influx volume has little to no effect on downhole pressure at the weak point. As part of the concept of KT to evaluate the setting depth of the shoe, the Influx Management Envelope analysis should show how important influx volume is.

However, for smaller hole sections, the amount of influx tends to play a greater role than for larger sections. Moreover, the solubility of hydrocarbon gas in NAF usually results in a weak-limit line that is more longitudinal, so the mechanism is more lenient toward the amount of influx [6].

Thus, stated that the KT can be calculated in two cases [7]:

A. At the time of well closure (static shut-in KT).
B. During kick circulation to the surface (dynamic circulating KT).

In condition (A), when the well is closed, the calculation technique measures the pressure within the well in the static condition. In condition (B), a kick simulator is used to calculate the pressure inside the wellbore while the kick is circulating.

If the dynamic circulating KT is exceeded during a well control procedure, a loss of circulation is expected, which could result in an underground blowout. Assuming that well control can be restored with available rig equipment, a higher risk of an underground blowout can be accepted under such circumstances. During drilling operations, formation properties are routinely measured by some operators. Therefore, the expected borehole section must be shortened if a particular borehole size cannot be safely handled, or a deeper casing depth is selected if it is known that an underground blowout is not possible or can be controlled with available rig equipment if it does occur. Without incurring an unacceptable risk of an underground blowout, significant cost savings can be achieved if the number of casing strings can be reduced.

3 The Basic Theory of Single-phase and Multi-phase Bubble Modeling

A single bubble model assumes that the kick inflow is single-phase and remains so as it circulates up the hole. This usually produces conservative results, which is usually preferable. However, for deep or high-pressure wells, the results can sometimes be overly conservative and unrealistic, making it nearly impossible to design a well. A multiphase model yields more realistic results, which is particularly significant for deep and High pressure/High temperature (HPHT) wells [8].

3.1 Classic Bubble Model Approach

The pressure at the bottom of the wellbore was assumed to be fixed and taken as a fixed value, as it is the basis for most
well control techniques. Throughout the annulus, changes in gas bubble length and gas density are assumed to be linearly proportional to changes in pressure. The gas density is therefore assumed to be constant and equal to the gas density at the center of the gas bubble at the time the gas reaches the surface.

In a single bubble model, the kick is assumed to have entered the wellbore as a single, continuous phase that displaces the drilling fluid and has a clean influx (gas), and mud interface. The single-bubble model does not account for influx distribution, gas dissolving in drilling mud, and multiphase behavior owing to pressure and temperature [9]. These simplified assumptions can lead to an incorrectly calculated KT volume, which has significant implications for safe drilling operations [10].

### 3.2 Advanced Multi-phase Model Approach

Despite the simplicity of the single-bubble model and the inherent margin of safety in such an assumption, the majority of HPHT deepwater wells cannot be practically overestimated in terms of process safety and intolerable kick sizes if the classical approach is used. However, a closer look at the gas behavior itself and the behavior of the entire mixture experimentally or empirically can also tell a different story [11].

When formation gas, which is often supercritical methane, enters the annulus during a drilling activity, it can expand and rise rapidly to the surface, creating an extremely dangerous situation that can result in a blowout and an explosion. Feng et al., (2016) showed that the occurrence of a kick is usually detected by the expansion and rise of the intruded gas (methane), which causes pit gain and other anomalies [12].

Unfortunately, at the higher pressures in the deeper section of the well, all or part of the injected gas may dissolve in the mud. At lower pressures near the wellhead, dissolved gas will come out of the solution, producing a dangerous delay in detecting the kick. This greatly increases the risk of blowout tragedy [13].

Therefore, knowing the solubility of the gas in mud is very important. In addition, the pressure–volume-temperature ratio of the methane-slurry mixture in the annulus has a significant effect on the unsteady flow pattern in the annulus. As a result, the pressure variation in the wellbore is much more complicated, which further increases the difficulty of well control.

In the study of gas solubility in drilling fluid, there are two approaches: experimental work and modeling research. In recent decades, some solubility data have been obtained under different temperature and pressure conditions. Fing et al. (2016) compared the solubility of methane in three base...
Fig. 3 Satellite view of the West Delta Deep Marine concession, offshore Egypt
fluids (brine, mineral oil and, poly-alpha-olefin) and showed that the solubility of methane in mineral oil and poly-alpha-olefin is much larger than that in brine [12].

Shiniti, 1996 defined the real gas-phase diagram by three main aspects: the bubble point, the dew point, and the critical pressure. As the gas flows from the pressure and temperature at the bottom of the well to the surface, it changes its phase behavior with a possible increase in the liquid fraction as shown in Fig. 1. In other words, the bubble does not expand linearly with the pressure and temperature drop on its way up [3].

Feng et al. (2019) assumed and experimentally proven that hydrocarbon gases are easily miscible with oil-based drilling fluids [14]. The similarity in molecular composition increases the solubility, which also increases with pressure (Fig. 2). Experimental work showed that solubility increases with temperature.

### 4 Case Study

The drilling of the Well X-1, located 295 ft Northeast of Alexandria in the east-central part of the Egyptian West Delta Deep Marine (WDDM) concession as shown in Fig. 3 [15], was started in August 2018 with a water depth of 1998 ft, and a planned well depth of 15465 ft Measured depth (MD).

The drilling of the 12.25-inch hole section at 8277 ft MD resulted in an oil-based mud (OBM) spill at the surface with a planned maximum static KT of only 56 bbls as shown in Table 1 with a KI of 0.4 pounds per gallon (ppg) at depth 9330 ft True Vertical Depth (TVD).

The dramatic increasing pit level implies that gas is flowing from the bottom hole, and the gas at the bottom of the hole and the drilling fluid are currently intervening in the well. After investigating all mud tanks’ level sensors before and after the well control event and after doing a deep tracker to the volume that could be spilled to sea, the estimated volume of OBM spilled to the sea is 8 bbls, after cleaning the rig floor from mud using a super vacuum machine taking returns to mud tank. The estimated volume of mud recovered was approximately 20 bbls in addition to an increase of 102 bbls in mud tanks to result in a total pit gain of 130 bbls. Given the fact of rough weather at the same time as the incident, recognizing a small volume of spill in high seas with a fluid that rapidly vanishes in minutes is a little bit difficult especially in a well control situation having everyone focused on the live well.

As there was a risk of formation collapse during well shut-in or kick removal, well control was performed with a KT of 130 bbls. However, the unexpected results meant that the kill operation could be performed safely, which led to the very important question of how, with an allowed KT of 56 bbls with KI of 0.4 ppg at depth 9330 ft TVD, we still have a chance of controlling the well without downhole problems. Pressure at a point of interest along the wellbore may provide the answer to this question. This point was chosen as the previous casing shoe at (7185 ft TVD/7296 ft MD). To investigate this case, a comprehensive study of the main factors affecting the calculation of borehole tolerance was carried out, from formation properties and drilling fluid specifications to the calculations of KT at the design stage.

### 4.1 Borehole Data

#### 4.1.1 Temperature Prediction

The field of operations has more than 110 subsea wells drilled. Static Temperature was directly measured using wireline tools as part of the formation evaluation program. The majority of these wells are producers with two downhole gauges deployed per well in addition to temperature sensors at the horizontal section an annual temperature survey for seabed is being conducted through a third party throughout the field. Circulating temperatures are being modeled in the pre-drill phase using commercial software while Measurement While Drilling (MWD) is being used while drilling to validate.

Based on the temperature trend recorded in the nearest offset wells, the expected maximum formation temperature at the well depth of 12883 ft TVD will be approximately 213°F with a gradient of 0.0165334°F/ft, an ambient temperature of 80°F, and a mudline temperature of 57°F.
### Prognoses vs Actual

| System | Formation | Prognosed Lithology | Actual Lithology | DEPTH (m) MD | Actual DEPTH (m) MD | Marker | Casing Shoe |
|--------|-----------|---------------------|------------------|-------------|----------------------|--------|-------------|
| Recent - U Pliocene | | | | -500 | 624 | Sealed | 621.5 | Sealed |
| | | | | -1000 | 993 | Anomaly 1 | 1118 | Anomaly 2 |
| | | | | -1500 | 1387 | Anomaly 4 | 1170 | Anomaly 3 |
| | | | | -2000 | 1730 | Anomaly 7 | | |
| | | | | -2500 | | Anomaly 6/F-1 | | |
| | | | | -3000 | 2195 | Top Anomaly 9 | 2190 | Top Anomaly 9 |
| | | | | -3500 | 2750 | Top Anomaly 10 | 2639 | Top Anomaly 10 |
| | | | | -4000 | 4697 | Top Seagull L2 Td | 4699 | Top Messenian (Be) |

**Lithology Description**
- Claystone: Gv, mod frm - frm, sb bkly - bkly, sl calc, Sticky.
- Siltstone: Pale yel, amorph - sb bkly, mod frm - frm, sl calc.
- Siltstone: Pale yel, amorph - sb bkly, mod frm - frm, sl calc, grdg v. f. SST.
- L.S: wh, occ milky, sft-mod hd, crypt xdn, occ.
- Claystone: Dk. gy, frm - mod frm, sfl sft i/p, bkly - sb bkly, sl calc i/p.
- Sd. Sd: Loe Qz, clss, transp-transl, md - fn grn, mod srtmd, red - sub rad.
- Claystone: Gy, dk, gy, occ brnsh, frm - mod frm, sfl sft i/p, bkly - sb bkly, w/ free Sd grn.

**Fig. 4** Well X-1 Geo pressure prognosis (Old Egyptian datum/Helmert 1907 spheroid Egypt Red Belt TM)
4.1.2 Schematic Diagram of the Borehole

Well X-1 planned trajectory has avoided any major faults and it is assumed that significant drilling problems are unlikely. A series of amplitude maps show the anomalies in the area of the well are included. All anomalies have been identified based on the seismic data. The proposed well location is expected to path through 9 anomalies as shown in Fig. 4.

Two faults intersected the well path. The faults are within shale-dominated intervals and do not identify as hazards but anomaly-10 which was located from (8441 ft to 8477 ft) MD is classified as a moderately low hazard potential as shown in Fig. 5, described as a soft kick (gas signature) silty facies regional.

4.1.3 Casing Seat Criteria

The 14-inch casing string was set at 7201 ft MD and has sufficient formation fracture strength to drill a 12.25-inch hole to (9507 ft MD/2769 ft TVD), with maximum allowable tolerances of 56 bbls with a planned mud density of 11.7 ppg.

4.1.4 Drilling Fluid Design

The planned SOBM density shall have suitable properties (Table 2) with a static overbalance of 150 psi above the expected pore pressure and be capable of circulating 163

Table 2 Drilling fluid properties

| Fluid properties           | Unit | Value   |
|---------------------------|------|---------|
| Mud density               | ppg  | 11.7    |
| Viscosity                 | sec/qt | 55–65  |
| Yield point (YP)          | lb/100ft² | 20–30 |
| Gels                      | lb/100ft² | 10–15 |
| Water phase salinity (WPS)| Mg/l  | 180–200 K |
Table 3 Drilling parameters of the 12.25-inch hole section

| Pumping rate (GPM) | Pumping pressure (psi) | Revolutions per minute (RPM) | Drilling Torque (Klbs-ft) | WOB (Klbs) | Rate of Penetration (ft/hr) |
|-------------------|------------------------|-----------------------------|--------------------------|------------|-----------------------------|
| 900               | 3120                   | 140                         | 7–8                      | 15         | 65                          |

bbls of swabbed kick (KI = 0 ppg) and securing the wellbore without fracturing the weakest point in the open hole section considering compressibility.

5 Summary of drilling 12.25-inch Hole Section

The drilling of the 12.25-inch hole section proceeded well essentially from (8070 ft to 8257 ft) MD with the following drilling parameters as shown in Table 3.

At a depth of 8257 ft MD, the driller recorded high drilling torque peaks of up to 16 Klbs as a formation change with a small gas pocket from (8300 ft to 8339 ft) MD was expected around the hole trace and the planned trajectory to intersect it. It was anticipated that the new formation could be located 10 ft earlier.

The mudlogger confirmed that the gas appeared to peak at approximately 94% and then dropped and remained stubbornly at 60%. The well was shut-in at this point, the MWD engineer monitored the equivalent static density (ESD) with the pressure while drilling tool (PWD) and confirmed that ESD had dropped to 11.68 ppg (average) and 11.58 ppg (minimum) with a sudden drop in annular pressure loss (APL) (Fig. 6).

After the flow check was performed with a negative result, drilling of a 12.25-inch hole from (8257 ft to 8277 ft) MD was resumed, but again a sharp increase in gas content at depth of 8277 ft MD was observed to 94% (expected drilled gas). After following the standard well control procedure and conducting a second flow check, it was found that the well was static and ESD had dropped to 11.66 ppg (average) and 11.54 ppg (minimum), which was due to the gas cut mud.

At this point, it was decided to circulate the well at 900 GPM. The monitored gas content decreased from 94 to 60% and remained constant, but the initial pit gain of 4 bbls was recorded by the spillage of drilling mud on the rotary table due to gas expansion near the surface. The well was shut-in at the top annular ram and the flow in the riser was checked statically. Monitored and recorded shut-in drill pipe pressure (SIDPP) = 0 psi and shut-in casing pressure (SICP) = 20 psi with a non-ported float in the BHA.

After performing 2.3 × bottoms-up circulation with the existing mud density of 11.7 ppg, gas content of 8% was determined. After stopping the pumps, close the manifold valves and record the SIDPP = 50 psi and SICP = 90 psi.

It is always difficult to determine if this is a trapped pressure or if it is caused by an influx in the hole. The kill operation was started with the first circulation of the driller’s
method. The driller started the pumps and increased the flow rate to 40 Stroke per minute (SPM) while opening the choke and allowing the pressure in the kill line to increase around 150 psi choke margin. The slow circulation rate was recorded during drilling as follows (Table 4):

By maintaining the Standpipe drill pipe pressure (DPP) during the first circulation of the driller method at 550 psi (Fig. 7a), the measured gas content in the mud in the flow-line increased rapidly to 40–48% and then remained constant (Fig. 7b).

The unexpected maximum casing shoe pressure was recorded as 3700 psi, which is less than the calculated formation fracture pressure (Fig. 8).

After completing the first circulation of the driller method, the well was shut in and the pressure was recorded as shown in Table 5 without fracturing the formation.

In the second circulation of the driller method, the driller increased the pumps to a kill rate of 40 SPM while opening the choke and keeping the bottom hole pressure constant. The wellbore was recirculated from 11.7 ppg to 12.1 ppg mud density, restoring the primary well control barrier with final 0 psi surface pressure.
Table 5 Pressure in the borehole after the kick was removed

| SIDPP, psi | SICP, psi | Kill line pressure, psi |
|-----------|-----------|------------------------|
| 120       | 180       | 130                    |

6 Problem Statement

The reported case showed an intact open hole, although a high volume of formation kick was seen at the surface 130 bbls. An extensive investigation was conducted to discuss the findings and the gaps that led to the late response to such an influx. It could be considered pure luck that the casing was intact even though such a large volume had flowed to the surface, but the engineers wanted to know why twice the allowable kick volume had been exceeded and they were still able to pump it conventionally.

7 Research Methodology

It is important to note that the single-bubble theory was used before the introduction of software with pressure, volume, and temperature correction functions (PVT). For this reason, the gas gradient is considered to be constant at 0.086 psi/ft, independent of gas/well pressure.

The dynamic drilling simulation software Drillbench™ with its unique transient and dynamic capabilities is used to evaluate the well control case study. The use of the dynamic well control module allows the simulation of complex transient conditions, including the dissolution of gas in oil-based mud. The transient analysis tracks all the interactions of the inflowing fluids and their properties and displays the casing shoe pressure as the inflowing fluids circulate in the well during the well control process. This leaves little uncertainty about what will happen and when it will happen and confirms that an operation is feasible.

It was interesting to provide accurate simulations to examine how the well was controlled with twice the allowable kick tolerance without downhole problems. In this work, with some preliminary calculations, an empirical evaluation was carried out in a perfectly logged well control circulation with a backward simulation of this case for both bubble and multiphase techniques using WellPlan™ and Drillbench™ dynamic drilling simulation software to find out how realistic the assumption of extended multiphase limits and associated capabilities is. It also shows how conservative or, in other words, how expensive it is to use the bubble formula in deep HPHT wells.

8 Kick Tolerance Simulation Results and Discussion

In the studied well, an uncontrolled release of hydrocarbons can have serious consequences on human lives, assets, and the environment. In this well, the wellbore conditions also posed a great challenge due to the multiphase fluids (gas kick and oil-based fluid) and different densities in the wellbore. The main concept of this simulation is to determine casing shoe pressure at a kick volume of 130 bbls.

KT simulations were performed for the depth of interest at a 14-inch casing shoe at 7296 ft MD, 7185 ft TVD. The first circulation of Driller’s Method was used to circulate the kicks at a mud density of 11.7 ppg to obtain conservative results.
The bubble and multiphase model results were plotted so that they could be compared to actual well pressures.

8.1 The Simulation of Kick Tolerance Based on the Classical Single Bubble Model.

Table 6 summarizes the actual kick and killing data. The initial mud in hole gradient before kick occurrence was calculated 0.608 psi/ft (11.7 ppg equivalent mud density). The kick gradient was directly calculated from shut-in pressure data 0.630 psi/ft (12.1 ppg equivalent mud density). Kill mud gradient, kill rate, and kick size were pulled from the actual kick circulation data. It was intended to use all possible actual data, simulate the case in reverse engineering, to anticipate wellbore pressures when circulating similar kick size and intensity being modeled as a single bubble.

Same data were used as input on the other software that considers the gas miscibility and phase behavioral change.

Using the Wellplan™ software, the single bubble approach, which neglects the miscibility of the kick with the drilling fluid and any phase change during circulation in the annulus with instantaneous pressure and temperature changes, resulted in a maximum kick size of 56 bbls with a

| Table 6 Input data             | Kick class | Kick while drilling |
|--------------------------------|------------|---------------------|
| Initial mud gradient           | 0.608 psi/ft|                      |
| Kill mud gradient              | 0.650 psi/ft| Gas                |
| Circulation flow rate          | 200.0 GPM   | Influx gradient     |
| Kick interval gradient         | 0.630 psi/ft| 0.086 psi/ft        |
| Kick interval pressure         | 5153.83 psi | Total influx volume |
| Depth of interest              | 7296 ft     | Circulation bottom hole pressure (BHP) |
| Circulation bottom hole pressure (BHP) | 5036.14 psi | 4972.67 psi |
KI of 0.4 ppg at 8277 ft MD to safely shut-in and circulate the well (Fig. 9), which is too far from the real case.

On the other hand, when simulating the real case with a gas kick volume of 130 bbls, it was found that the maximum casing shoe pressure was 5225 psi (Fig. 10), which exceeds the formation fracture pressure of 4967 psi.

8.2 The Simulation of Kick Tolerance Based on A Multi-phase Model

The multiphase simulation shows good closeness by showing the pressures at the previous shoes and promises very good opportunities to have larger windows to either tolerate higher influx capacities or extend the limits of the confidence in kick detection at smaller sizes provides generously longer hole sections, fewer casing points, and less expensive drilling.

The results of the multiphase KT simulation, which terminates the kick at the actual kick size and determines the transient pressure at the previous shoe with a good margin to the fracture pressure, are very interesting.

The multiphase run suggests a safe kick size of 130 bbls before the well is shut-in. While circulating 130 bbls of gas during the first circulation of the driller method, the maximum casing shoe pressure was 4646 psi, which is less than the estimated formation fracture pressure of 4967 psi (Fig. 11).

A standard cubic foot of the gas in the reservoir (kick zone) is different from the volume of gas under standard conditions. The relationship between the two is defined as the volume friction factor. Some of this gas goes into solution under downhole conditions at a given downhole pressure and temperature. If the influx is circulating out with the well closed, keeping the downhole pressure constant, the gas composition will change with the change in pressure and temperature as it moves up the annulus. The dissolved fraction begins to leak out of the solution under bubble point pressure conditions. As a result, droplets of liquid fractions are formed. In the case of dispersed gas in the oil-based liquid, free gas was simulated with a volume fraction of 51% (Fig. 12).

9 Conclusion

During drilling operations, a dynamic kick tolerance model can better analyze the risks of being able to circulate an...
amount of kick volume at a particular depth and specific kick intensity. If casing shoe fracture or weak formation along the wellbore is the limiting factor for KT, which leads to several additional casing points from a planning safety point of view, it is worthwhile to consider the possibility that the pressures are much lower than what we would expect with the proven KT method. The multiphase technique is applied with a thorough understanding of the factors that affect the results. As with any simulation, the availability of accurate data will produce reasonable results.

The initial results show that the input parameters, especially the type of drilling fluid, play an important role in the calculation of the KT, as the simulated KT using a single-bubble model indicates an allowable kick volume of 56 bbls. To fully comply with the 56 bbls KT, it was planned to set 11–3/4-inch-long casing strings with multiple liners for 9491 ft, further increasing the complexity, cost, and risk of the well, and operations. After reviewing the results of the multiphase KT simulation, it was determined that the maximum gas kick volume was nearly double that of a single-phase model with an oil-based drilling fluid.

The advantage of accepting the KT of more than 56 bbls would be that the studied well could be drilled with the planned six casing strings, which was already more robust than most offset wells using five casing strings. With the six-casing string approach, there is little room for a contingency casing without compromising the objective of the well.

Finally, this work has focused on certain points to improve well control in deepwater drilling, the following conclusions can be drawn in the scope of this study, based on results obtained from software simulation:

1. The input parameters, especially the type of drilling fluid, play an important role in the calculation of the kick tolerance.
2. Accurate input data with a multiphase kick tolerance model results in more realistic results.
3. Kick is identified when a pit gain is noted on surface mud pits. This volume could be a misleading indicator to determine the actual kick size downhole.
4. The maximum influx allowed with the available equipment and the effect of the multiphase model on the pressure circulation process was necessary before proceeding with the planned well control.
5. It also shows how expensive it is to use the bubble formula in deep HPHT wells because the multiphase kick

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**Fig. 11** Pressure at the casing shoe
tolerance model can reduce the number of casing strings, allowing safe well control operations and reducing the possibility of accidents.

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