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Investigating the Effect of Synthetic Fluid PVT Properties on APB-Induced Collapse Loading

Ryan Simpson and Samuel Ighalo, Halliburton

Abstract

Temperature modeling in complex wells requires a good understanding of wellbore events that may occur in the well. Accurate determination of these events also requires approximate modeling inputs. One such modeling input includes synthetic-fluid pressure-volume-temperature (PVT) properties for different temperature and pressure ranges. Fluid properties can have a strong effect on annular pressure buildup, a common phenomenon in deepwater, subsea HPHT wells.

This paper studies these effects on the prediction of annular pressure buildup (APB) in a deepwater well in the Gulf of Mexico. The study reviews the different modeling approaches for the synthetic-based mud (SBM) based on laboratory-measured PVT values for six different synthetic-based fluids. The modeled wellbore event was a worst-case discharge (WCD) event for different times until the maximum temperature was reached. The generated APB values obtained from thermal/stress modeling software were used to calculate the collapse load on a 14-in. tieback. The effect of selecting the wrong base fluid and using limited data points was also analyzed in this study.

The results show that the inaccurate selection of base fluid, the use of limited input data points, or choosing an inefficient SBM model can result in an overly conservative prediction of APB. This can lead to an expensive casing program or the inability to pass design criteria. The results also indicate that the pressure/temperature correlation affects the fluid behavior during the convective transport of the fluids for a WCD event.

The study, in general, illustrates the importance of using the appropriate synthetic-based fluid model in association with the full laboratory PVT fluid properties to model fairly accurate pressure buildup in the annuli.

Introduction

The use of synthetic-based fluids has gained increased importance in the drilling of deepwater wells owing to its ability to provide shale inhibition and excellent lubricity while maintaining compatibility with the environment. The change of operational strategies by major companies in highly volatile regions of the world to operate in deeper waters has also led to the increased use of synthetic-based fluids in the drilling phase. However, fluid properties, such as density, can change significantly as temperature and pressure increase with increased drilling depths (Demirdal and Cunha 2009) owing to the compressibility and thermal expansion of the fluids. This can lead to inaccuracies when calculating downhole pressures.

Modeling a wellbore event during a worst-case discharge (WCD) requires that the densities of the synthetic-based fluids be used as modeling parameters. It is easy to see where errors can be introduced into the calculation of induced loadings on the wellbore casing during a potential blow-out event. Because subsea wells experience a wide range of temperatures and pressures, it is important to use accurate PVT properties for the planned SBM. SBM formulated with linear alpha olefins (LAO) and isomerized olefins (IO) exhibit lower kinematic viscosities and are, thus, now required in deepwater drilling (Mitchell 2006).

In their experimental study, Demirdal and Cunha (2009) showed that LAO-based oil density is the most sensitive to temperature after a comparative analysis with other fluids. Several industry-published PVT correlations exist for estimating the density of the SBM at static and dynamic conditions. Zamora et al. (2013) provided a summary of industry publications on drilling-fluid-related PVT studies.

In this study, the Zamora model was used for the PVT analyses of the mud to estimate downhole densities. For synthetic-based drilling fluids, the pressure change owing to annular fluid expansion is directly related to the PVT behavior of the base fluid of the mud. Accurate modeling of expected annular fluid–expansion (AFE) pressures is essential in designing for well integrity for the following reasons:

1. Increased annular pressure can lead to failure in collapse.
2. Annular pressure can increase lift-off forces on hangers.
3. Over-designing leads to needless expense or the inability to meet design criteria.

The consequences of APB can be severe to the overall integrity of the well if not properly mitigated. The subject of APB mitigation is well documented, of which several methods are available depending on well conditions, reliability, ease of implementation, and cost. The study of APB mitigation is beyond the scope of this paper. However, understanding the behavior of SBM during a well blow-out situation can be useful in the prevention and/or minimization of APB from a design standpoint.

This paper describes the wellbore configuration, reservoir information, and fluids composition used to model a well blow-out scenario and reviews the different compositions of synthetic-based fluids using the Zamora model. The results of the temperature distribution and the subsequent APB for these different annular fluids will be provided, along with a comparative analysis. The study will also illustrate the impact of base oil on predicted APB and collapse loading of a 14-in. production tieback.

Mechanics of APB

The concept of expanding annuli owing to thermal expansion is not new and is especially common in subsea wells, where the casings are cemented above the previous shoe. This creates a situation where the annular fluids are sealed in and generates high pressure during a drillstem test (DST) or production (Adams and MacEachran 1994). APB can also result from fluid circulation while drilling (Patillo et al. 2006).

The determination of APB in a closed elastic container is based on the unconstrained volume expansion of the fluid owing to a temperature change and expansion of the annular volume (Aadnoy et al. 2009). This can be expressed mathematically as:

$$\Delta p_{APB} = B_f \frac{\Delta V_f - \Delta V_a}{V_f} \quad (1)$$

Where, B_f is the isothermal bulk modulus (fluid compressibility), ΔV_f is the volumetric expansion of the fluids, ΔV_a is the volumetric expansion of the elastic container, and V_f is original volume of the fluid.

This approach works when the temperature change, as well as the initial temperature and pressure distributions, are small. However, in deepwater wells, the behavior of fluids in relation to pressure and temperature is non-linear, and the magnitude of APB can be significantly underestimated (Ellis et al. 2002).

Halal and Mitchell (1994) identified and analyzed the coupling of multiple annuli and their contributions to APB, as well as the effect of fluid PVT behavior on annular pressures. Their work enabled the study of the mechanisms of APB as it relates to well integrity. These mechanisms can be subdivided into the following three categories:

1. Annular fluid expansion (AFE), which increases or decreases in volume as a result of temperature change
2. Change in annular volume due to thermal expansion, ballooning, or compression of the casings
3. Formation leakoff, which is the ability of the formation to absorb increased pressure by breaking down or through an influx of fluid into the formation

Oudeman and Kerem (2006) and Hasan et al. (2010) described these three components using the equation:

$$\Delta p = \frac{\alpha_l}{\kappa_T}\Delta T - \frac{1}{\kappa_T V_a}\Delta V_a + \frac{1}{\kappa_T V_l}\Delta V_l \quad (2)$$

The most dominant effect is the expansion of the annular fluid in the sealed annulus (Hasan et al. 2010). The second term can become dominant in situations where the temperature does not rise rapidly enough to counter the changes in internal pressure or compression of the casing string. The second term is also a downward correction on the order of 10 to 20% (Oudeman and Kerem 2006). The third term can become dominant when fluid is allowed to leak off to the formation, especially when cement is placed lower than the previous casing shoe. The third term does not have any effect on a fully sealed annulus.

The Sathuvalli et al. (2005) method calculates APB using the magnitude of the annular volume, the mechanical response of the annulus/annuli pressure, and temperature changes. Their work focused on calculating the fluid volume change. One of the methods was an adaptation of the works of Hasan et al. (2010) and Oudeman and Kerem (2006), while the other method calculated the fluid volume change by integrating volume changes across the annulus. This method incorporates the temperature/pressure-dependent density, but does require the bulk compressibility or the coefficient of thermal expansion.

PVT Fluids Modeling

The density of fluids varies with temperature and pressure. It is important to understand the PVT behavior of these fluids for accurate modeling. Different models have been used for modeling the PVT behavior of water and oil-based drilling fluids. The two most common PVT fluid models are the Sorelle and Zamora models.

Sorelle Model

The curve-fit equation proposed by Sorelle et al. (1982) is given as follows:

$$\rho_o = A_0 + A_1 (T) + A_2(P_t) \quad (3)$$

$$\rho_w = B_0 + B_1 (T) + B_2(P_t) \quad (4)$$

Where, A_0, A_1, and A_2 represent the model constants, which are obtained empirically. In this study, Sorelle et al. (1982) showed that the diesel-oil curve fit and the water curve fit correlate to 99.6% and 97.8%, respectively.

Zamora Model

Zamora et al. (2000) proposed that fluid PVT behavior can be described by curve fitting the data to a polynomial that is linear in temperature and parabolic in pressure. The equation has the form:

$$p_o = (a_2 T + b_2)P^2 + (a_1 T + b_1)P + (a_0 T + b_0) \quad (5)$$

Where, p_o is the specific gravity of the fluids at a given temperature, T (°F), and pressure, P (psi); and a_0 a_1, a_2, b_0 b_1, and b_2 are the empirical constants of the model equation.

Fluid Composition

The base fluids studied include HAL01, HAL02 (proprietary), internal olefin (IO) C16C18, internal olefin (IO) C11C18, linear alpha olefin (LAO) C12C14, linear alpha olefin (LAO) C16C18, and diesel/water compositional mud (CM). Single-phase fluids (diesel- and water-based) were also considered.

The NAF/water ratio of the liquid components was assumed to be 80/20, and a 5% low-density solids (LDS) concentration was assumed for all fluids. Because the base fluids differed in density at standard surface conditions (**Table 1**), the concentration of high-density solids (HDS) differed in fluids of the same overall density (**Error! Reference source not found.**).

Base Fluid Component	Density (ppg)
HAL01	6.74
HAL02	6.68
IO C16C18	6.59
IO C11C18	6.64
LAO C16C18	6.61
LAO C12C14	6.34
Brine (in synthetic fluid)	11.10
Diesel	7.00
Water	8.33

Table 1—Liquid densities at standard surface conditions.

Name	Density (ppg)	Normalized Volume %				Ratio HDS/LDS
		Brine	NAF	HDS	LDS	
HAL01	12.6	15.69	62.76	17.63	3.92	4.49
HAL02	12.6	15.63	62.50	17.97	3.91	4.60
IO C16C18	12.6	15.62	62.50	17.98	3.91	4.60
IO C11C18	12.6	15.64	62.57	17.87	3.91	4.57
LAO C16C18	12.6	15.63	62.52	17.94	3.91	4.59
LAO C12C14	12.6	15.51	62.06	18.55	3.88	4.78
CM	12.6	15.80	63.22	17.03	3.95	4.31
HAL01	14.5	14.36	57.43	24.62	3.59	6.86
HAL02	14.5	14.30	57.20	24.93	3.57	6.97
IO C16C18	14.5	14.30	57.19	24.94	3.57	6.98
IO C11C18	14.5	14.31	57.25	24.87	3.58	6.95
LAO C16C18	14.5	14.30	57.20	24.92	3.58	6.97
LAO C12C14	14.5	14.20	56.79	25.46	3.55	7.17
CM	14.5	14.46	57.85	24.08	3.62	6.66
HAL01	15.4	13.73	54.91	27.93	3.43	8.14
HAL02	15.4	13.67	54.68	28.23	3.42	8.26
IO C16C18	15.4	13.67	54.68	28.23	3.42	8.26
IO C11C18	15.4	13.68	54.74	28.16	3.42	8.23
LAO C16C18	15.4	13.68	54.70	28.21	3.42	8.25
LAO C12C14	15.4	13.57	54.30	28.74	3.39	8.47
CM	15.4	13.83	55.31	27.41	3.46	7.93
HAL01	15.6	13.59	54.35	28.67	3.40	8.44
HAL02	15.6	13.53	54.13	28.96	3.38	8.56
IO C16C18	15.6	13.00	52.01	31.74	3.25	9.76
IO C11C18	15.6	13.55	54.18	28.89	3.39	8.53
LAO C16C18	15.6	13.53	54.13	28.96	3.38	8.56
LAO C12C14	15.6	13.44	53.74	29.46	3.36	8.77
CM	15.6	13.68	54.74	28.16	3.42	8.23
HAL01	15.8	13.45	53.79	29.40	3.36	8.75
HAL02	15.8	13.39	53.57	29.69	3.35	8.87
IO C16C18	15.8	13.39	53.56	29.70	3.35	8.87
IO C11C18	15.8	13.40	53.62	29.62	3.35	8.84
LAO C16C18	15.8	13.40	53.58	29.67	3.35	8.86
LAO C12C14	15.8	13.30	53.19	30.19	3.32	9.08
CM	15.8	13.54	54.16	28.91	3.39	8.54

Table 2—Normalized volumetric compositions.

The diesel-based and water-based fluids either contained all water or all diesel and only high-density solids (**Table 3**).

Fluid	Density (ppg)	Water	Diesel	HDS
Diesel	12.6	0.00	80.00	20.00
Diesel	14.5	0.00	73.21	26.79
Diesel	15.4	0.00	70.00	30.00
Diesel	15.6	0.00	69.29	30.71
Diesel	15.8	0.00	68.57	31.43
Water	12.6	83.99	0.00	16.01
Water	14.5	76.87	0.00	23.13
Water	15.4	73.49	0.00	26.51
Water	15.6	72.74	0.00	27.26
Water	15.8	71.99	0.00	28.01

Table 3—Single-phase fluid compositions.

The PVT correlation for the synthetic fluids used in the study was based on the Zamora model. Detailed laboratory PVT data were available for the HAL01, HAL02, IO C16C18, and LAO C12C14 fluids (Demirdal and Cunha 2009). **Figures 1** through **4** illustrate the density-to-pressure relationship for several constant temperatures. The application determines the coefficients of the Zamora model based on the input of the PVT data. Laboratory data were not available for the IO C16C18 and LAO C12C14 fluids; however, the coefficients had already been determined (**Table 4**).

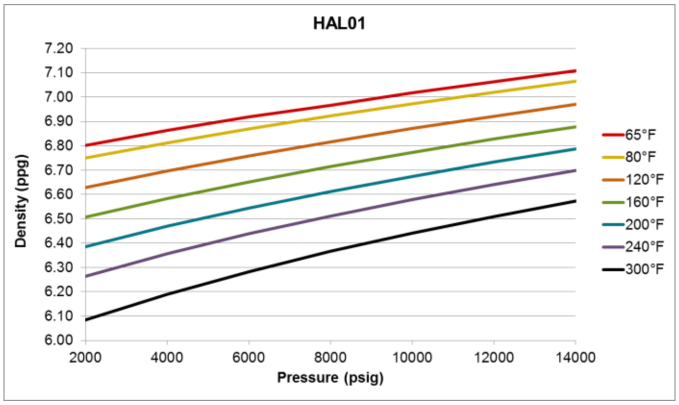

Figure 1 *Density plot for HAL 01.*

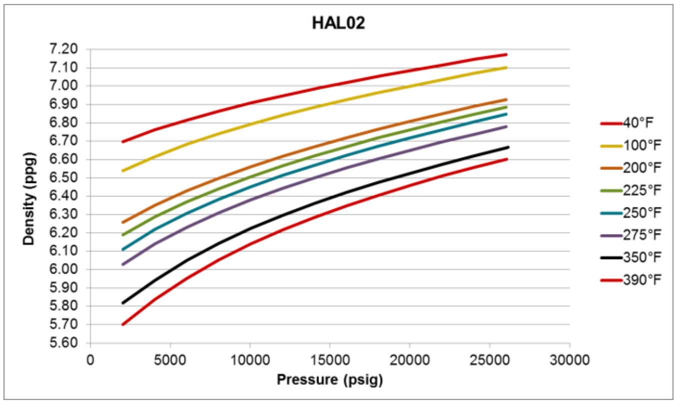

Figure 2 *Density plot of HAL 02.*

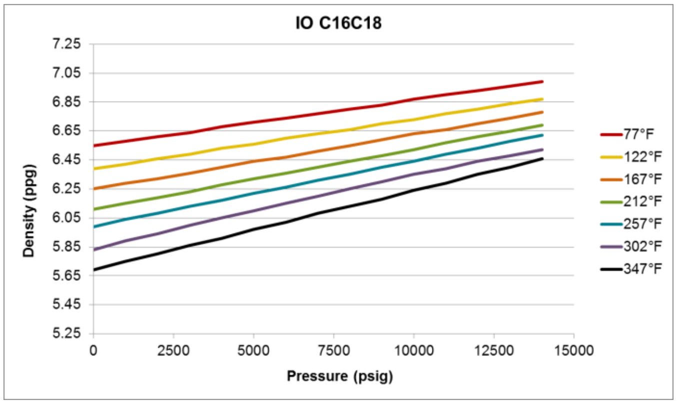

Figure 3 *Density of internal olefin C16C18.*

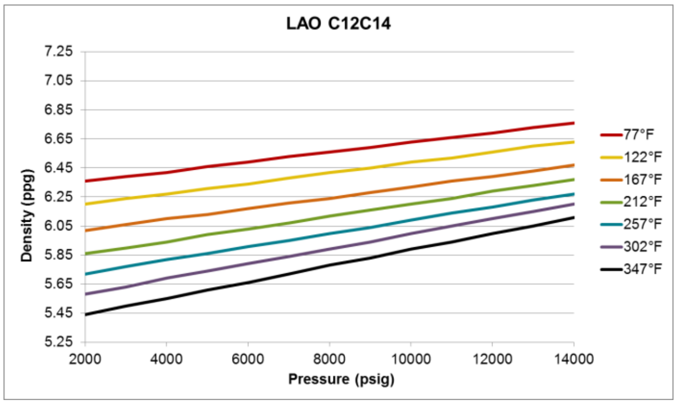

Figure 4 *Density plot of linear alpha olefin C12C14.*

Empirical Coefficients	IO C16C18	LAO C12C14
a_0	-4.0647E-04	-3.5547E-04
a_1	1.3429E-08	1.2965E-08
a_2	-2.3981E-13	-2.7166E-13
b_0	8.1964E-01	8.1304E-01
b_1	2.6739E-06	3.1226E-06
b_2	-2.3981E-11	-2.8894E-11

Table 4—Empirical coefficients of IO C16C18 and LAO C12C14.

Case Study of Deepwater GOM Well

This case study focuses on a subsea well located in deepwater Gulf of Mexico, with a water depth of 5,850 ft and a reservoir depth of 28,600 ft MD/TVD. The bottomhole reservoir temperature for this well was 200°F. A schematic structure of the wellbore with the casings is shown in **Figure 5**.

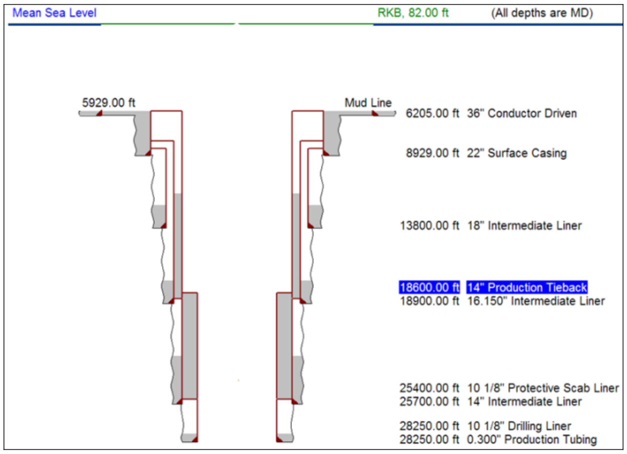

Figure 5 *Wellbore schematic for the deepwater well.*

Thermal Simulation

The flowing pressure and temperature were simulated as a blow-out scenario, with a steady-state rate of 290,000 BOPD and a gas/oil ratio (GOR) of 1,200 scf/stb from a reservoir at 28,573 ft MD/TVD. In this particular scenario, it was assumed that the annuli were trapped with no leakoff to the formations. The discharge was to the seafloor with the assumption that the riser was removed. Therefore, the discharge pressure was the hydrostatic head of seawater at the mudline.

The multiphase correlation calculated a bottomhole flowing pressure of 15,300 psi (**Figure 6**). The reservoir temperature was 200°F; however, the temperature of the flowing hydrocarbon stream increased rapidly and significantly owing to viscous effects, as shown in **Figure 7**. The fluid in the tieback annulus reached 98% of the maximum (steady-state) temperatures after flowing for 24 hours (**Figure 8**). The sudden drop in temperature observed at approximately 7900 ft. MD is due to the increased annular volume above the top of the 16" liner. The increase in temperature at approximately at 6646 ft. MD is due to the change in lithology from salt to sandstone.

A thermal simulation was performed for each base fluid, assuming that all mud weights in the well construction used the same base fluid in each separate case.

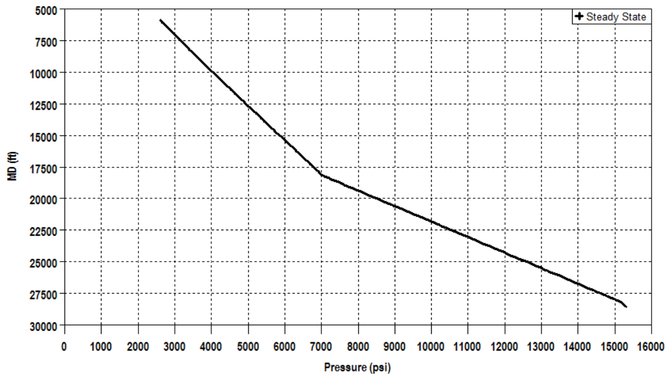

Figure 1 *Predicted bottomhole flowing pressure during a blow-out event.*

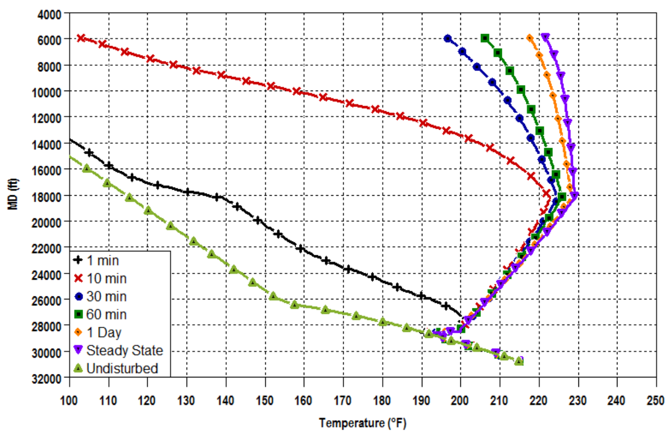

Figure 2 *Temperatures of the hydrocarbon fluid stream during a blow-out event.*

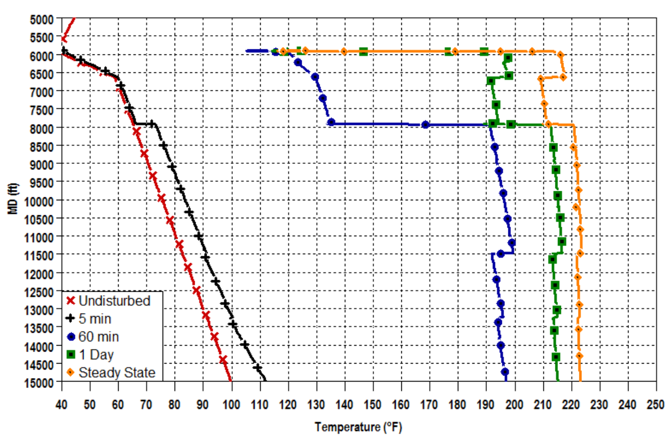

Figure 3 *Tieback annulus temperature during a blow-out event.*

AFE Expansion

The temperature and pressure profiles from the thermal simulations were used to calculate the annular fluid expansion for each base fluid model. The behavior of each fluid showed ordinal consistency throughout the model (**Figure 9**). A relatively wide distribution of values (**Figure 10**) was observed for the 14-in. tieback. The difference between the maximum and minimum values was over 2,000 psi.

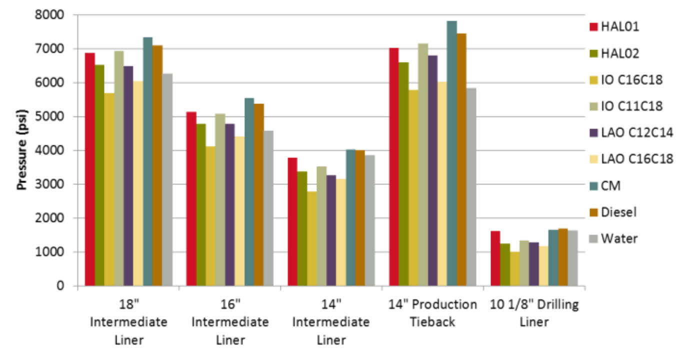

Figure 4 *Distribution of AFE pressure for all strings with each base fluid model.*

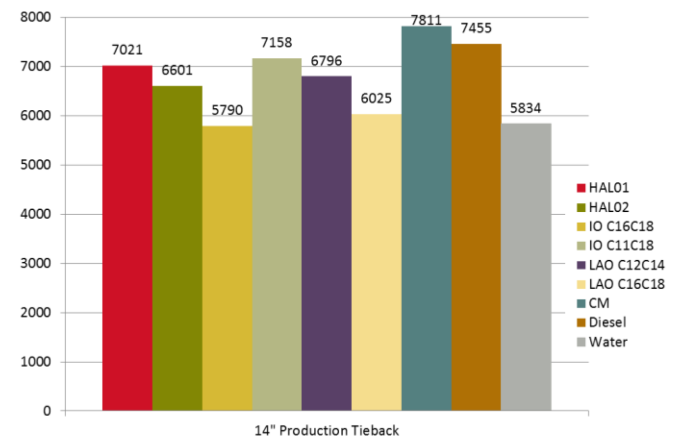

Figure 5 *Distribution of AFE pressure for 14-in. tieback.*

Casing Loads Analysis

For the collapse load, the internal pressure applied to the tieback resulted from a column of flowing hydrocarbons (Figure 6) and an external pressure profile based on a column of 15.4-ppg drilling fluid and an AFE pressure at flowing temperatures (**Figure 6**).

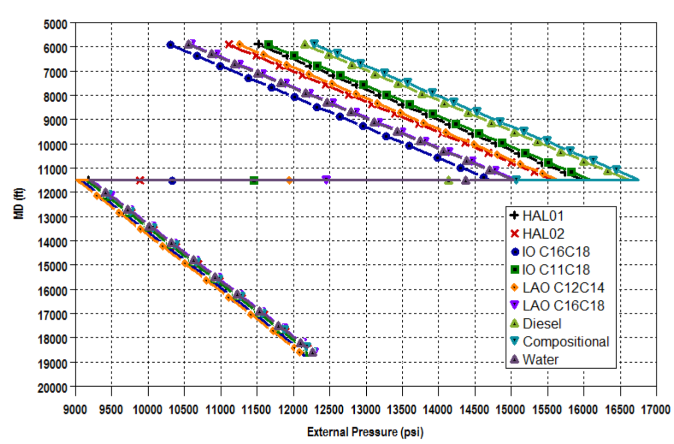

Figure 6 *External pressure profiles for the 14-in. tieback with the various base fluid models.*

In addition to the difference in AFE pressures, a difference in static pressure was also observed owing to the varying compressibility among the synthetic fluids. The diesel-, compositional-, and water-based fluids were considered incompressible in the model.

This load was applied to casing with an 11,700-psi collapse rating.

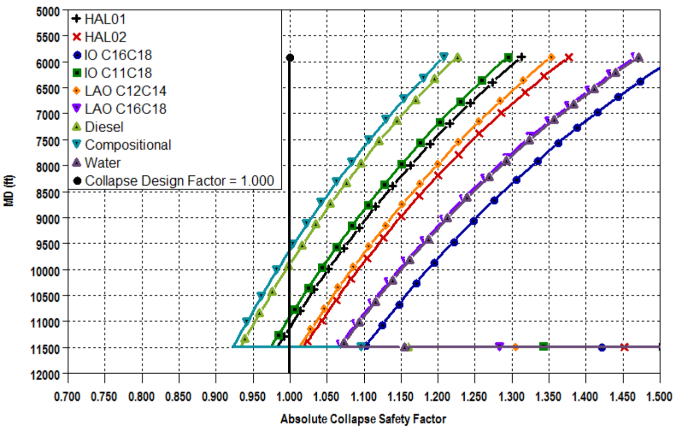

Figure 7 *Absolute collapse safety factor for the 14-in. tieback for the various base fluid models.*

Figure 7 shows the results of the collapse-load calculation for the HAL01, IO C11C18, and diesel-based fluids, as well as the compositional mud models. The resulting safety factor plot shows that the collapse design limit was exceeded when the compositional mud, diesel, IO C16C18, and HAL01 base fluids were used. As shown in the figure, the lowest collapse safety factor occurred with the models of diesel and compositional fluids resulting in a relatively high collapse load, making the design overly conservative.

It is important to note that this paper does not suggest one base fluid model over the other, especially with the IO and the LAO base fluids. This study, however, recommends that the full laboratory-based PVT data be used in defining the correlation models to accurately model APB behavior in deepwater wells.

Conclusions

The PVT behavior of synthetic-based fluids and their effects on annular pressure buildup was evaluated. As a result of this study, the following should be considered when designing deepwater wells:

- The type of base for drilling fluids can have a significant effect on the calculation of AFE pressures.
- Full laboratory-based PVT data is essential in calculating predicted APB.
- The assumption that the behavior of diesel-based and diesel/water compositional fluid is similar to synthetic fluids can be overly conservative.
- The selection and modeling of the right base fluid can determine whether or not a casing design passes.

Acknowledgments

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Nomenclature

APB = *Annular Pressure Buildup, psi*
AFE = *Annular Fluid Expansion*
DST = *Drillstem Test*
GOR = *Gas/Oil Ratio*
HPHT = *High Pressure / High Temperature*
PVT = *Pressure-Volume-Temperature*
SBM = *Synthetic-Based Mud*
WCD = *Worst-Case Discharge*

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