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Investigation on the Effects of Thermophysical Properties of Drilling Fluids on the Simulation of Thermally Driven APB

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Abstract. *Drilling wellbores requires different fluids to balance the geostatic pressures from the pressurized hydrocarbons filling the rock formation and the weight of the rock itself. However, once drilling is finished and the well starts producing, the drilling muds and completion fluids are remain trapped in the concentric annular spaces. As the hot reservoir fluids rise inside the production tubing, they heat the entire wellbore structure, including the static fluids trapped inside the annuli, raising their pressures. If not correctly dealt with (i.e., prevented or remediated), the annular pressure buildup (APB) may result in collapse or burst of the casings or the production tube, leading to a premature end of the wellbore's life cycle. Being a thermally driven phenomenon, APB is heavily influenced by the thermophysical properties of wellbore fluids. Despite the relatively large number of studies on the behavior of their volumetric and rheological properties as a function of pressure and temperature, there is much less literature on thermal properties (thermal conductivity and specific heat capacity) of drilling and completion fluids, specially for fluids with synthetic or oil bases. In this paper, a short overview of the literature on the thermophysical properties of the different wellbore fluids (brines and water, oil and synthetic-based muds) revealed a significant scatter of the specific heat capacity (over 50%) and thermal conductivity (30%) predictions according to the most popular correlations. Furthermore, when incorporated into a mathematical model to compute the annular pressure behavior, such variations lead to changes in APB greater than 2.5* MPa *at the start of production. Finally, the paper presents new experimental data on the thermal conductivity and specific heat capacity of completion and drilling fluids as a function of temperature and pressure, enabling the formulation of improved correlation methods for actual oil producing wellbores application.*

Keywords: *Drilling Fluids, Oil Wells, Thermal Conductivity, Specific Heat, Sensitivity Analysis and Annular Pressure Buildup*

1. Introduction

In the context of hydrocarbon producing wellbores, the heat transfer simulation is of upmost importance as it is directly related to many phenomena Impacting the cost of the operation. One such phenomenon is the annular pressure buildup (APB), which is a pressure increase due to the heating of any trapped fluid in the annuli of the well. This phenomenon is natural to any well and is impossible to be completely eliminated, therefore its correct prediction is important as the design of the well should be able to withstand the extra loads (Moe, George Robert; Erpelding, 2000).

Many papers aim to properly estimate the heat transfer in wellbores and its influences on APB (Ramey, 1962; Hasan *et al.*, 1991; Hasan and Kabir, 1994; Halal and Mitchell, 1994; Hagoort *et al.*, 2004; da Veiga *et al.*, 2022). However, almost none actually focus on the thermophysical properties of the fluids trapped in the annuli. Even fewer papers analyze the impact of the uncertainty of those variables on the APB.

Therefore, this paper proposes a sensitivity analysis of the properties of the fluids trapped in the annuli of an actual wellbore and their impact on the final APB. Also a brief review of the correlations and methods to calculate those properties is presented. In this context, using the results from the sensitivity analysis with typical deviations between the models available in the literature, this paper assesses the need to further investigate thermal properties of packer fluid, their reliability and potential risks to wellbore thermal design.

2. Methodology

To better understand the risks associated with the lack of adequately modeling the thermophysical properties of drilling fluids, in the context of APB simulation, this section will present the basic methods used in this work.

2.1 Hydrodynamic model

To predict the APB and thus study the effects of fluid properties on the wellbore heat transfer, the state-of-the-art formulation of da Veiga *et al.* (2022) was used. In their model the wellbore temperature profile is obtained by integrating the conservation equations inside the production tube of the wellbore. At each integration node, the heat equation is solved radially by applying the equivalent thermal network analogy and considering pseudo steady-state.

For the thermal resistances, inside the production tube forced convection is considered for multiphase flow, this is calculated with the correlation of Chen (1966). For the annuli filled with fluid, two parallel resistances are used, as proposed in Hasan and Kabir (1994), one for the radiation heat transfer and the other for natural convection, the latter is calculated with the correlation from Zhou (2013). For any cemented layer and for the metallic tubing (production tube and casings), the conduction resistance is used.

The heat transfer with the rock formation surrounding the wellbore is modeled with the use of a time function, as defined in Eq. 1 (Ramey, 1962). In this paper the time function proposed by Hasan and Kabir (1994) was used.

$$f(t) = -\frac{2\pi k_{fm}}{Q'}(T_{pf} - T_{fm,i}) \tag{1}$$

here, k_{fm} is the formation thermal conductivity, Q' is the heat flux per unit length, T_{pf} is the temperature of the production fluid and $T_{fm,i}$ is the wellbore-formation interface temperature.

As the heating of the annulus leads to the expansion of the trapped annular fluid, the formulation proposed by da Veiga *et al.* (2022) is used to calculate the thermal APB coupled with the heat transfer. In this model the APB is computed based on the variation of density of the trapped fluids and the casings deformation, determined using the method of Halal and Mitchell (1994) which connects multiple casing strings and cemented layers.

The properties of the wellbore fluids are computed from interpolation tables generated from PVT package (Multiflash, 2014) based in its composition. For the production fluid the carbon groups are known from PVT data, for the packer fluid and drilling fluid the composition is not known, thus for theses the adopted practice uses brines with appropriate salt content to match the fluids density in the standard condition.

2.2 Drilling fluids Specific Heat and Thermal Conductivity

In the modeling of the thermophysical properties of drilling fluids, it is common to find formulations based on simple curve fits. These are used to simulate the heat transfer during wellbore drilling and other phenomena.

The first work which contains equations for both specific heat and thermal conductivity is the one by Corre *et al.* (1984), who proposed an entire formulation for modeling the heat transfer during the perforation of the well. Therefore, the authors needed a way to estimate both thermal conductivity and specific heat and created basic relations for calculating these terms. Based on previous works and experimental data, the following expressions were presented:

$$C_p = \begin{cases} 3440 + 2.72T & \text{for water-based muds} \quad (2) \\ 2200 & \text{for oil-based muds} \quad (3) \end{cases}$$

$$k = \begin{cases} 0.0585 + 2.3 \times 10^{-3}T & \text{for water-based muds} \quad (4) \\ 0.342 - 1.8 \times 10^{-4}T & \text{for oil-based muds} \quad (5) \end{cases}$$

here, C_p is the specific heat calculated in $\mathrm{J\,kg^{-1}\,K^{-1}}$, k is the thermal conductivity in $\mathrm{W\,m^{-1}\,K^{-1}}$ and T is the temperature in K.

For both properties, expressions are presented for a water-based mud and an oil based mud. The water-based fluid consists of a KCl solution with addition of polymers and a standard density of 1100 $\mathrm{kg\,m^{-3}}$. The detailed composition of both fluids were not disclosed in the paper, therefore these equations should be limited to applications similar to the base fluid.

Sasaki *et al.* (2000) developed an expression for the thermophysical properties of water-based drilling fluids at low temperatures. Their expressions consider contributions of several factors known to affect the properties. Therefore, the following equation was proposed for the specific heat of drilling fluids:

$$C_p = 4.0\left(\rho \times 10^{-3}\right)^{-1.25} + 1.3 \times 10^{-2}G - 3.7 \times 10^{-2}D \tag{6}$$

where ρ is the density of the drilling fluid at the standard condition, G is the mass fraction of glycol and D is the percentage (mass fraction) of drilled material carried with the fluid. Although the specific heat does not depend on the temperature, the thermal conductivity was correlated with a correction based on a reference state at $T = 273.15\mathrm{K}$. Thus:

$$k = \begin{cases} 0.562 + 0.115(\rho - 1000) \times 10^{-3} - 6 \times 10^{-5} S - 2.4 \times 10^{-3} G + 3.7 \times 10^{-2} S & \text{if } T = 273.15\mathrm{K} \quad (7) \\ k_0 + \beta(T - 273.15) & \text{if } T \neq 273.15\mathrm{K} \quad (8) \end{cases}$$

where S mass fraction of salt. k_0 is the thermal conductivity calculated at $T = 273.15\mathrm{K}$ and β is a linear coefficient which can be adjusted to better fit the experimental data for different fluids. In this paper, the value of β was set at 5×10^{-4}.

Zhong *et al.* (2018) focused on the heat transfer during drilling of wellbores, more specifically on the two phase heat transfer due of the flow of gas from the formation. In the study the authors present values of specific heat for two drilling fluids with different bases. These values are presented for both a synthetic fluid with base of polymeric slurry and polysulfonated. Presented for a range of 20 to 85 °C, and for both 10, 15 and 20 MPa.

Suleman (2019) studied the effects of the variation of the thermophysical properties of drilling fluids in the final simulation of the thermal profile during production. Using an experimental setup the author proposed polynomial expressions for both the specific heat and thermal conductivity for a water-based mud and an oil-based mud. The expressions are:

$$C_p = \begin{cases} 7.56534(T - 273.15) + 3320.7 & \text{water-based mud} \quad (9) \\ -0.0426(T - 273.15)^2 + 4.5735(T - 273.15) + 2055 & \text{oil-based mud} \quad (10) \end{cases}$$

$$k = \begin{cases} 0.0023(T - 273.15) + 0.4221 & \text{water-based muds} \quad (11) \\ -6 \times 10^{-7}(T - 273.15)^2 + 2 \times 10^{-5}(T - 273.15) + 0.1908 & \text{oil-based muds} \quad (12) \end{cases}$$

Zhang *et al.* (2021) used general polynomial expressions for specific heat and thermal conductivity of pure water and used it to model heat transfer phenomena during drilling. The general property expression were:

$$C_p = c_1 + c_2 T + c_3 T^{1.5} + c_4 T^2 + c_5 T^{2.5} \quad (13)$$

$$k = c_6 + c_7 T + c_8 T^{1.5} + c_9 T^2 + c_{10} \sqrt{T} \quad (14)$$

where the parameters for the equations are presented in Table 1.

Table 1. Set of parameters for Eqs. 13 and 14.Values are for pure water as informed in Zhang *et al.* (2021).

Parameter	Value
c_1	4.2174356
c_2	-0.0056181625
c_3	0.0012992528
c_4	-0.00011535353
c_5	4.14964×10^{-6}
c_6	0.5650285
c_7	0.0026363895
c_8	-0.00012516934
c_9	-1.5154918
c_{10}	-0.0009412945

2.3 Experimental Apparatus

As the literature on the estimation of the thermophysical properties of drilling and completion fluids is scarce, an commercial measurement equipment was used to measure thermal conductivity of these types of fluids.

The apparatus consists of the equipment FOX50, manufactured by the company *Lasercomp*. Fig. 1 presents the entire experimental setup with a thermal bath used to cycle water for temperature control, and the computer used to acquire the results. The FOX50 equipment operates by applying a temperature differential on a thin layer of the tested material. By measuring the heat flow necessary to sustain such temperature differential, the equipment relates the result directly to the thermal conductivity of the sample.

The experimental procedure consisted of filling the test cell (cleaned with the solvent R-141b), shown in Fig. 2, with the desired fluid and placing the cell in the test section. Once placed in the equipment the cell is closed with pressurized air and the tests start.

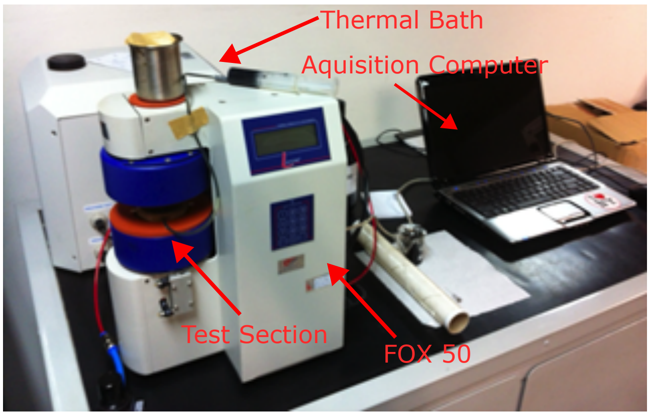

Figure 1. Commercial thermal conductivity analyzer used to determine the properties of drilling fluids.

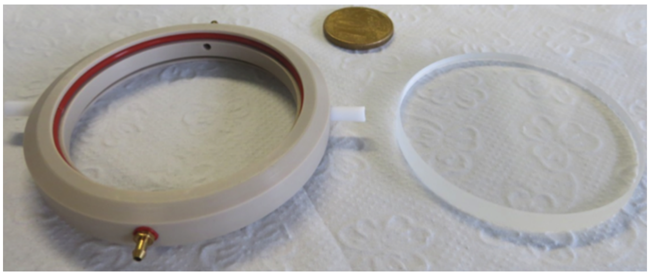

Figure 2. Test cell formed by polymer casing and two transparent glass lids. The fluid is then pressed between the lids and pressed in the test section.

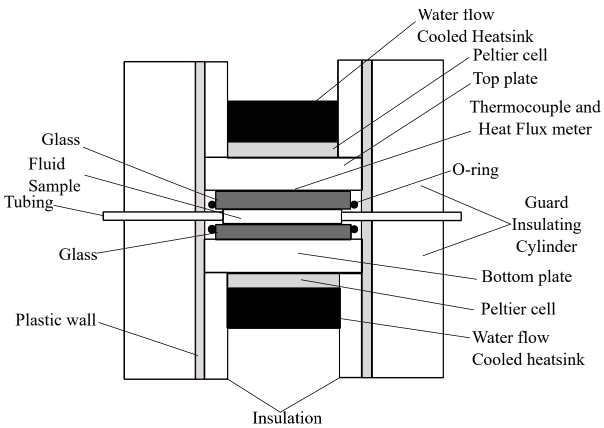

Figure 3. Schematic drawing of the test section use din the FOX50 equipment. The test cell is inserted in the section and pressed between two heat flux meters. The heat flow meters are in contact with peltier cells which are used to set the temperature differential in the cell and measure the dissipated heat.

This test cell is inserted in the test section of the equipment and pressed with pressure, set as recommended in the manual to 60 psi. Fig. 3 presents a schematic drawing of the enclosed cell and the measurement equipment.

Every test is controlled by the equipment software *WinTherm50* in which temperature sets are inputs. For every fluid the measurements were performed for the temperatures 10, 20, 30, 40 and 50°C both in the ascent followed by a descent stage. The data are taken automatically by the software and once the test is complete the cell was cleaned and prepared for the next fluid.

The calibration procedure followed the orientations of the equipment manual. Initially it is expected for the precision to stay within 3% of the measured thermal conductivity. In order to ensure the precision, the equipment was calibrated with standard pyrex plates and latter tested with a standard fluid.

The calibration procedure was performed and a comparison with a standard pyrex plate was performed. Table 2 shows the result of the validation procedure. The maximum deviation from the values form the literature occurs at 20°C with the value of 2.12%. The last column shows the stability of the signal, this variable indicates if any fluctuation in temperature is reducing the precision of the result. For fluids higher values indicate high convection.

A second validation was performed with n-Dodecane. Table 3 presents the comparison from experimental data and

Table 2. Validation of calibration procedure for commercial equipment. Validation with Pyrex plates.

Solid Pyrex				Signal Stability
Temperature [ºC]	Experimental [W/mK]	Reference [W/mK]	100((kexp - kref) / kref)	
10.01	1.049	1.058	-0.85%	1.32%
15.01	1.056			1.05%
20.02	1.064	1.087	-2.12%	0.81%
25.02	1.072			0,50%
40.02	1.095	1.116	-1.88%	0.25%
45.02	1.102			0,37%
50.02	1.110	1.131	-1.90%	0.80%

the reference data from literature (Bell *et al.*, 2014). The measurements has good agreement with the reference values, thus indicating that the calibration of the equipment is good for measuring the thermal conductivity of drilling fluid.

Table 3. Validation of calibration procedure for commercial equipment. Validation with n-Dodecane.

n-Dodecane				Signal Stability
Temperature [ºC]	Experimental [W/mK]	Reference [W/mK]	100((kexp - kref) / kref)	
10.01	0.14105	0.13893	1.53%	0.67%
20.02	0.1408	0.13647	3.17%	1.84%
30.02	0.1402	0.13407	4.57%	4.27%
40.02	0.1391	0.13171	5.61%	7.64%
50.03	0.1375	0.12941	6.25%	11.54%

3. Results and Discussion

3.1 Sensitivity Analysis

Using the formulation of da Veiga *et al.* (2022), presented previously (Section 2.1), a real wellbore geometry was simulated in order to predict both the temperature at wellhead and the resulting APB in the annuli of the well.

Figure 4 shows the geometry of the simulated well. In this geometry, there are three annuli which will be heated by the production fluid. Since there is no information about the type of fluid filling each space apart from their density, it is assumed a composition similar to the one of pure brines (based on NaCl) with different concentrations. The amount of salt added to each composition is such to match the density of the fluid in standard condition, the concentrations was calculated based on the salt concentration table from Bourgoyne *et al.* (1986).

For the thermal model inputs, the temperature, pressure at the Pressure Downhole-Gauge (PDG) are provided by the operator of the well, in addition the flow rate as a function of time. As this study does not focus on the exact result, but in the variation in results, the final predicted values are not relevant for this study.

In order to verify the impact of the variation of properties on both studied variables, a simple sensitivity analysis is performed by means of varying the properties of the drilling and completion fluids used.

The basis formulation uses thermodynamic tables and interpolation for temperature and pressure, the sensitivity analysis consisted on multiplying the entire thermodynamic table by the variation analyzed. For example, for a variation of +10% on the specific heat, the original table would be multiplied by 1.1. This was performed for both the thermophysical properties and both target results (wellhead temperature, measured at the TPT, and APB in the first annulus from the center line of the well) were compared for several different times.

Figure 5 presents the effect of variations in the wellhead temperature due to variations in the modeled specific heat of the drilling fluids and completion fluid. An inversely proportional dependence between the heat capacity and the heating of the well becomes clear: for higher values of specific heat, colder temperatures are expected in the wellhead. In addition, it is noticeable that for long times the effect of this variable is reduced. In any case, the variation of C_p leads to small heating effects of the well, up to the point that a decrease of 60% in the value of this variable would have effects within a margin of 1K in the wellhead temperature when the pseudo steady-state assumption is valid.

Since this variation in temperature is small, it is not clear how it can affect the APB in the final result. For that, Fig. 6 presents the variations in APB due to variations of specific heat of the fluids. In the first two hours of production, the effects of the specific heat appears to be inversely proportional to the predicted APB, with higher values of C_p leading to smaller values of pressures increase. However, after the first day this behavior inverts and increases in the specific heat leads to higher APB.

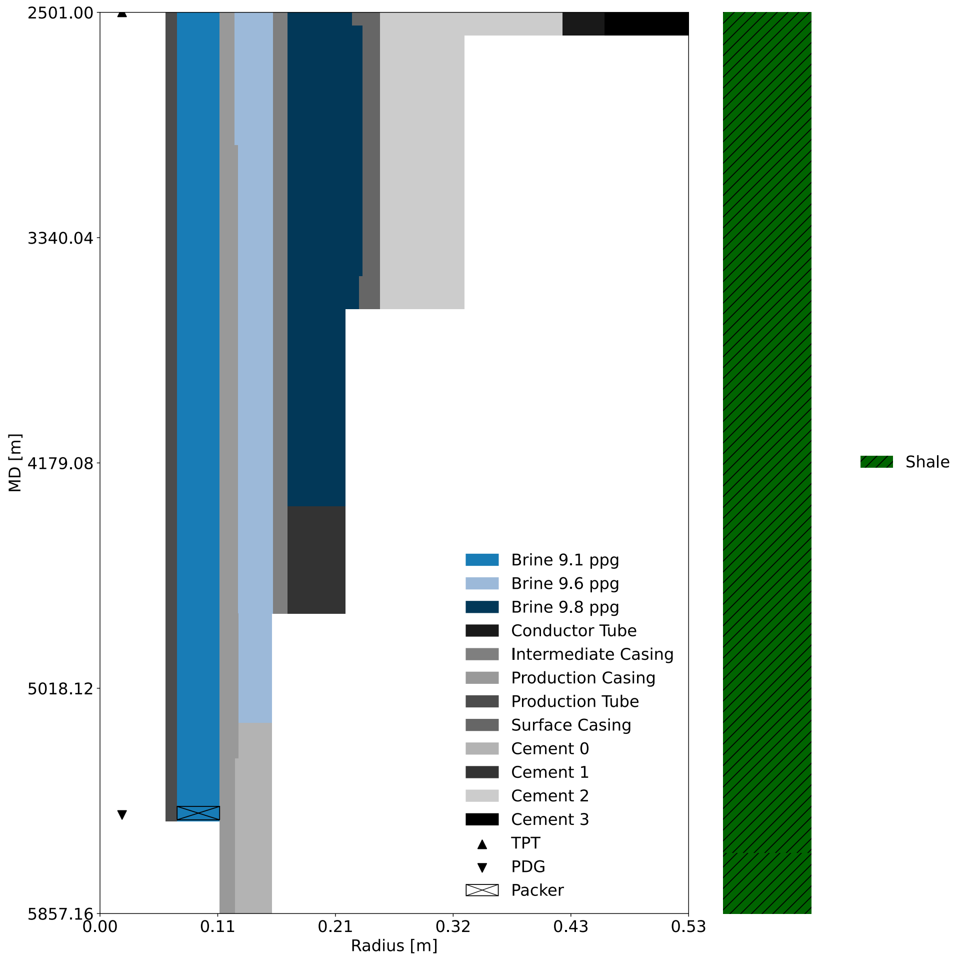

Figure 4. Schematic geometry of the studied well. Gray scale colors indicate solid materials as described in the legend. Blue tones indicates the presence of trapped fluid in each annulus. The rightmost green bar is the formation lithology, in this case pure Shale. TPT and PDG are locations where probes measure pressure and temperature of the produced fluid.

From a magnitude standpoint, the largest variation in APB during the production occurs during the earliest steps of well production, with an extra $2.5\mathrm{MPa}$ in the predicted APB for the first 15 minutes of production. This is an extra load in the casing which is not perceived in any other scenario. One reason for this phenomenon is that, with a reduction in the specific heat, the thermal resistance of the radial heat transfer system is reduced, thus leading to a faster heating of the annuli.

Figure 7 presents the effects of the thermal conductivity on the predicted wellhead temperature with a similar representation. Firstly, comparing the variation in temperature, it is clear that the variation in the thermal conductivity can lead to higher variation in the wellhead temperature than the specific heat. The behavior of this variable is also inversely proportional to the predicted wellhead, with higher values of thermal conductivity leading to smaller temperatures in the wellhead. The largest variation occurred in the first 15 minutes with an increase of $1.4\mathrm{K}$ with a reduction of 60% of the thermal conductivity of the fluids contained in the annuli.

Figure 8 shows the consequence of the variations of the thermal conductivity on the simulated APB at the first annulus. Note that, once again, the same inversion behavior occurs after the first day of production, where within this time an increase of the thermal conductivity leads to a reduction of the thermal APB. Conversely, after the first day, the reduction of thermal conductivity leads to a reduction of the predicted APB.

Like the wellhead temperature, the influence of the thermal conductivity is greater than the effects of the specific heat on the predicted APB. It is important to point out that this sensitivity study showed that variations in the thermophysical properties are more likely to impact the APB at the start of the production. For longer operations, the phenomena are mostly driven by the geothermal gradient and geometry of the problem, so the precision of the model used to represent the properties of the fluid filling the annuli is of greater importance for simulations regarding shorter operations, such as acidifications or bullheadings.

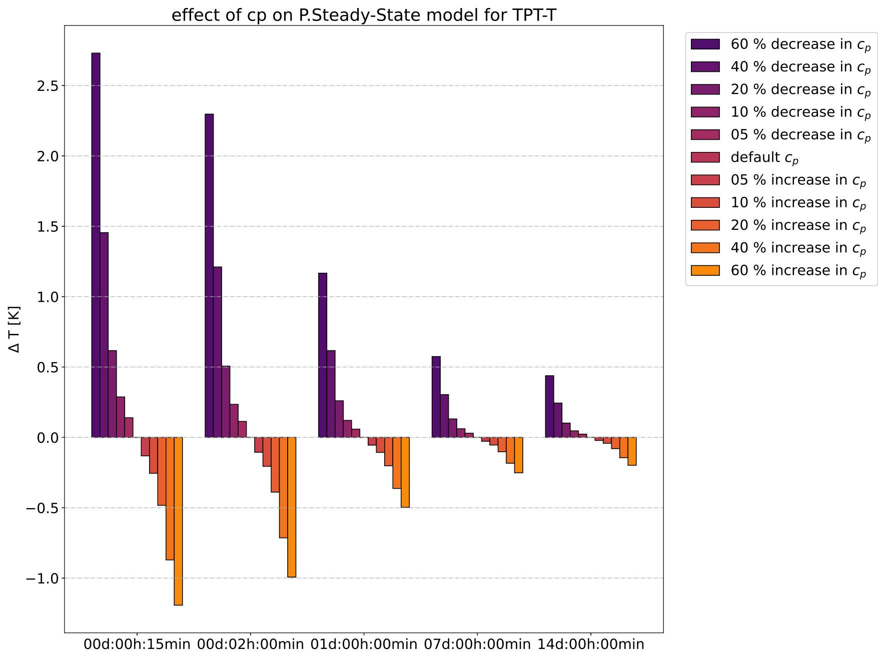

Figure 5. Variations in temperature in the TPT due to sensitivity in the C_p of the annuli fluids.

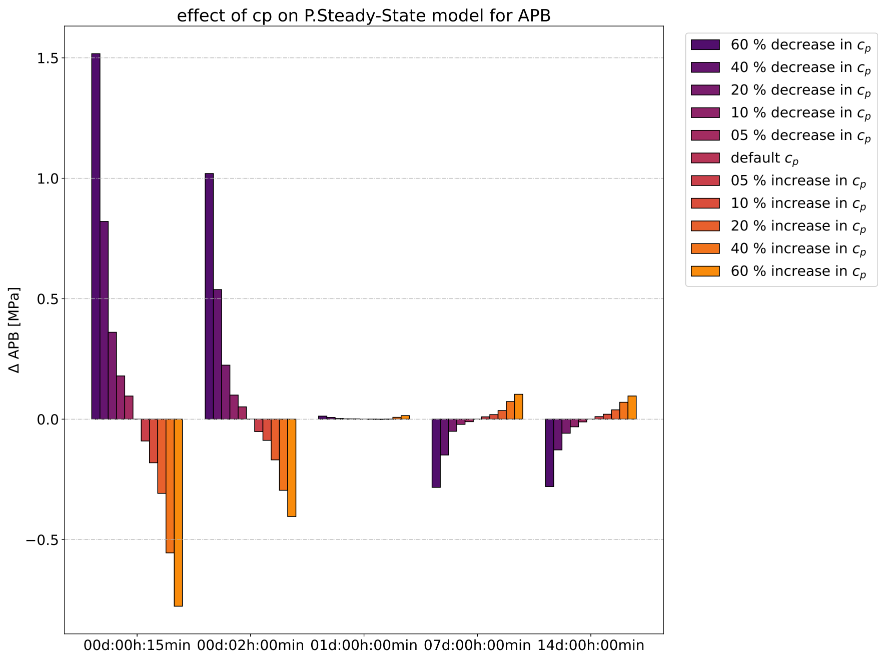

Figure 6. Variations in APB at the innermost annulus due to sensitivity in the C_p of the annuli fluids.

3.2 Analysis of thermophysical properties correlations

In this section, a brief study on different formulations comparing the predicted thermal conductivity and specific heat for drilling fluids is presented. In the context of the previous sensitivity analysis, it is important to show how the correlation chosen to model the thermophysical properties of the fluids can impact the thermal simulation of the wellbore.

The comparisons of the models will be separated in the different types of base fluids to better organize the results. For the water-based results no experimental data was found in the literature at this moment. Therefore, no comparison with real data was done. For oil-based fluids, some experimental measurements were found, allowing for comparison with real data.

Starting with water-base fluids, Fig. 9 presents the predicted specific heat. It is important to explain that for the Sasaki *et al.* (2000) correlation, the fluid density is set to $1100\mathrm{kg\,m^{-3}}$ to make it a fair comparison with the model of Corre *et al.*

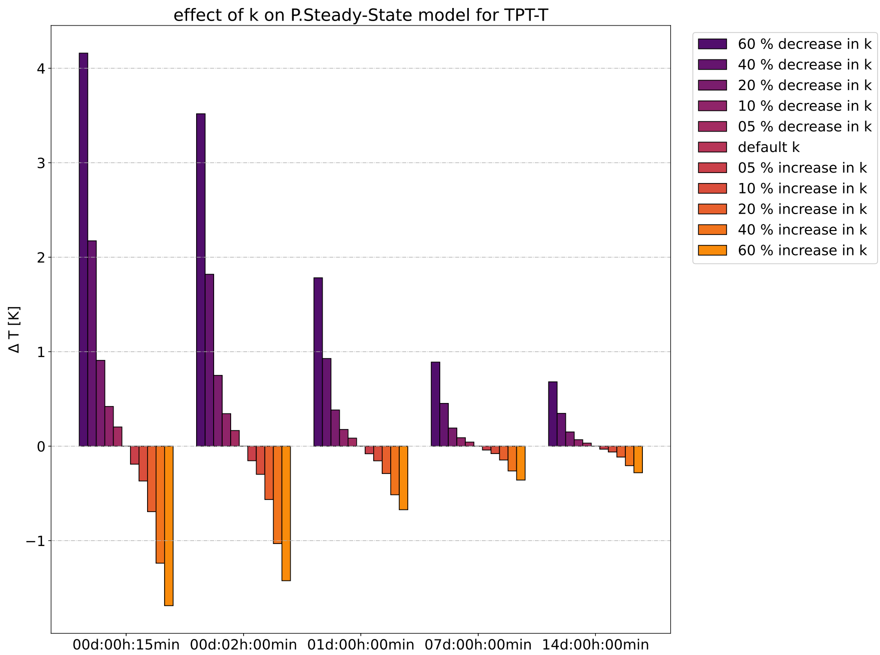

Figure 7. Variations in temperature in the TPT due to sensitivity in the k of the annuli fluids.

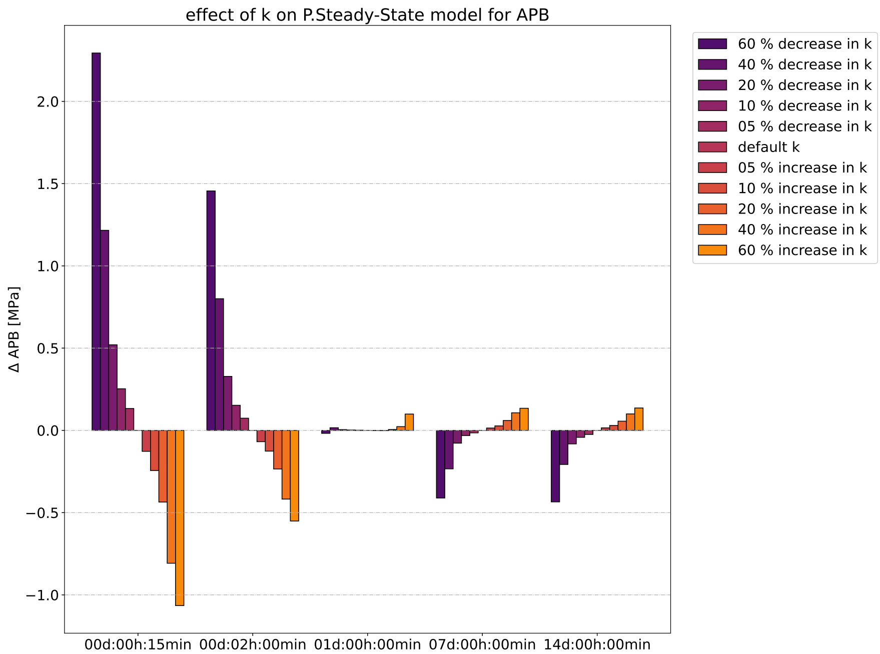

Figure 8. Variations in APB at the innermost annulus due to sensitivity in the k of the annuli fluids.

(1984).

Note that in general, all models are concentrated in a common region, except the results by Zhang *et al.* (2021), which considers the drilling fluid as pure water. However, even at the highest temperature, the equations used predicted values within 11% of variation in relation to one another, which by the sensitivity analysis is not a significant variation in terms of APB.

For the thermal conductivity, Figure 10, shows the profiles of thermal conductivity according to the equations presented previously for water-base fluids.

Contrary to what happened with the specific heat, for the thermal conductivity, the correlation of Zhang *et al.* (2021), for pure water, is closer to the other expressions. The maximum difference between the predicted thermal conjunctivitis was detected at 80°C, between the models by Corre *et al.* (1984) and Suleman (2019), with a difference of 25.5%. As the complete formulation used to create the expression of Suleman (2019) is not known, this difference can be due to

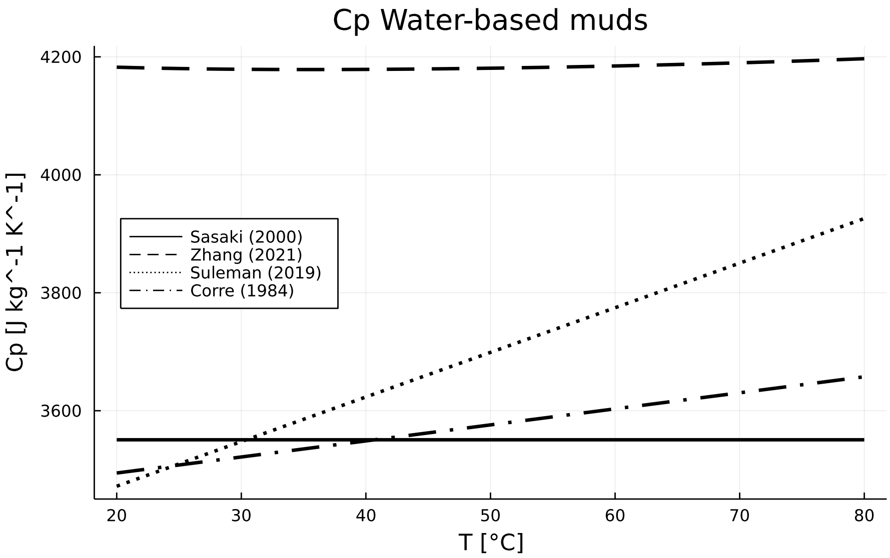

Figure 9. Specific heat predicted by different methods for water-based fluid.

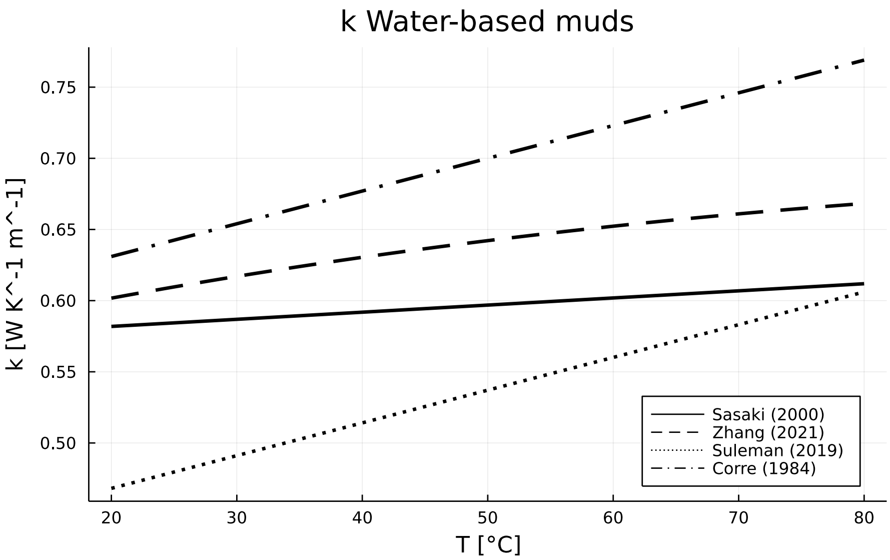

Figure 10. Thermal conductivity predicted by different methods for water-based fluid.

different components of the fluid affecting the property. However, as this paper proposes the use of generic expressions for modeling fluids, this large variations indicate that the composition of the fluid is crucial for properly modeling the heat transfer in wellbores.

This point is even more pronounced for oil based fluids. Fig. 11 presents the specific heat for this type of fluids.

For this types of fluid the deviation among the models are more pronounced with two main groups. Both Corre *et al.* (1984) and Suleman (2019) form one group with values closer around $2200\mathrm{J\,kg^{-1}\,K^{-1}}$. The second group is the one formed by the points and fits based in the data from Zhong *et al.* (2018). In fact the maximum deviation is of 41% from the model of Suleman (2019) and the data for Polysulfonated fluid. This deviation is significant and can also be attributed to the lack of knowledge of the complete composition of the fluids.

A more complete result is presented for the thermal conductivity of oil based fluids. Experimental studies were performed with three different fluids and the data points were taken in order to compare the thermal conductivity of these compositions and the literature. One fluid is formed mainly by paraffins, the second is an olefin with addition of Na-based salts and the third one is an olefin with addition of Ca-based salts. In the latter fluid, a segregation of phases occurred, so a precipitated region and a translucent region was be analyzed independently. This segregation is represented schematically in Fig. 12 where a darker, denser, phase is at the bottom of the fluid vessel. In this region a larger concentration of solids is perceived and the fluid is thicker. At the top of the vessel a section of the translucent fluid is presented with the lighter color. This section is actually transparent, less dense and with fewer solid particles in suspension.

As the experimental data was taken within a range of 10°C to 50°C the comparison will be made within this interval.

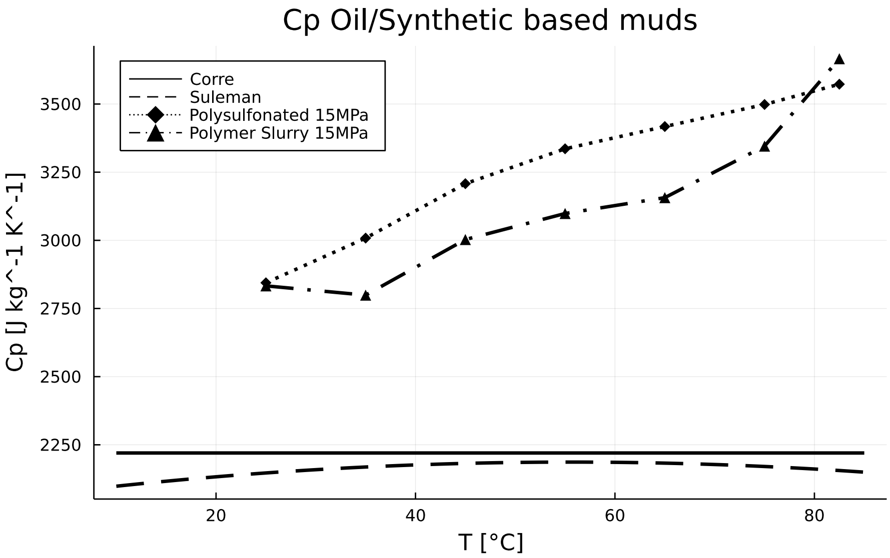

Figure 11. Specific heat by different formulations for Oil based fluids. Scatter points represents the data from Zhong *et al.* (2018) for the pressure of $15\mathrm{MPa}$

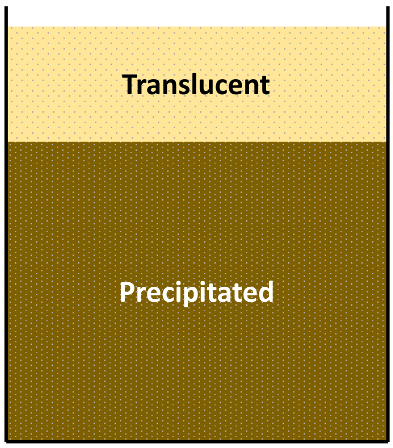

Figure 12. Schematic representation of precipitated fluid. Darker phase is the precipitate region, meanwhile lighter region is the translucent phase.

In addition, the expression for thermal conductivity based in the formulation of Sasaki *et al.* (2000) was also added for the comparison as the addition of glycol was already presented in the literature as an approximation of synthetic based fluid (Barcelos, 2017). So, a percentage of 90% of glycol is adopted.

Figure 13 presents the thermal conductivity profiles predicted by the literature equations and both the experimental data.

The experimental results point for the fact that both paraffinic fluid and olefin fluids have similar thermal conductivity, with the only significant difference for the translucent region of the olefin fluid with Ca.

As with the specific heat, for the thermal conductivity of oil-based fluids the deviations form the models and experimental data is significant. More specifically, the correlation proposed in Suleman (2019) is the one which most deviate from the data, with variations of 33%. On the other hand, for the other equations the data is better represented with the expression of Corre *et al.* (1984).

4. Conclusion

This paper proposed two complementary studies on the properties of drilling and completion fluids in order to understand the state of the literature and modeling of the heat transfer in oil producing wellbores, within the context of the thermophysical properties of fluids. Constructing on top of a state-of-the-art formulation, proposed in da Veiga *et al.* (2022), a sensitivity analysis was done on the models for thermophysical properties. It is clear that the effects of poor modeling of the thermophysical properties mainly affects the short span simulation, for longer operations the thermal APB is mainly related to the geothermal gradient and the geometry of the wellbore.

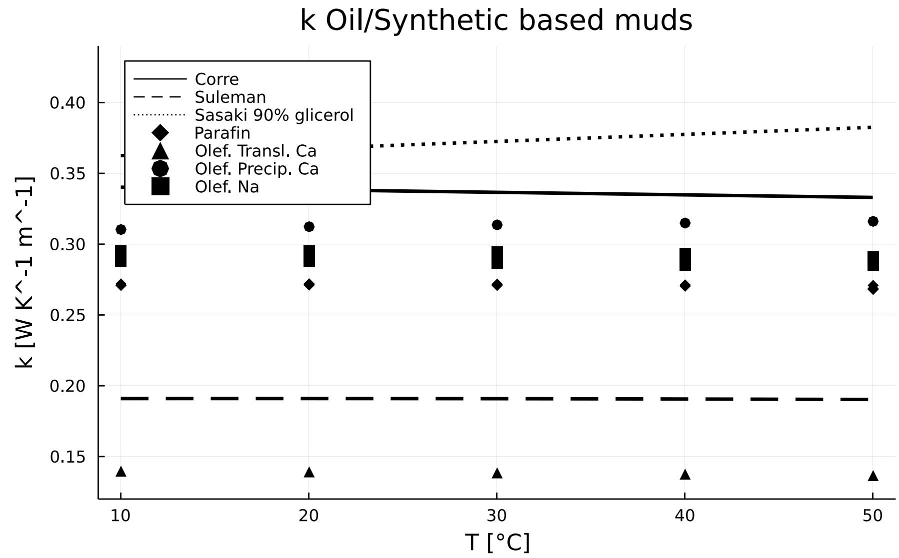

Figure 13. Thermal conductivity by different formulations for Oil based fluids. Scatter points represents experimental data for synthetic based fluids.

On the other hand, in the shorter simulations, it is clear that poorly estimating the fluids properties can lead to inaccurate results for both heat transfer and the resulting APB. This can be impactful when designing welllbores structures to deal with short term operations, such as acidifications.

From the few works in the literature with emphasis on modeling this fluids properties it is clear that there is little to no consensus on a unified formulation to model both drilling and completion fluids and their several compositions.

This indicates that more studies should be both experimentally to create a database for the properties of several compositions of fluids, but also develop mixing rules such that it is possible to calculate the properties of the fluids for any given set of compositions.

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