Journal of Natural Gas Science and Engineering 34 (2016) 1096–1105

Contents lists available at ScienceDirect

Journal of Natural Gas Science and Engineering

journal homepage: www.elsevier.com/locate/jngse

Determination of equivalent circulating density of drilling fluids in deepwater drilling

Vahid Dokhani [a, *], Yue Ma [b], Mengjiao Yu [c]

[a] Yu Technologies, Inc., Tulsa, OK, USA
[b] Oilfield Chemicals R&D Institute, China Oilfield Services Limited, Sanhe City, Hebei, China
[c] McDougall School of Petroleum Engineering, The University of Tulsa, Tulsa, OK, USA

ARTICLE INFO

Article history:
Received 17 March 2016
Received in revised form
25 May 2016
Accepted 1 August 2016
Available online 3 August 2016

Keywords:
Equivalent static density
Equivalent circulating density
Deepwater
Temperature profile
Heat transfer

ABSTRACT

Evaluation of bottom-hole pressure is a critical concern for high-pressure/high temperature (HP/HT) and deepwater drilling operations. Accurate determination of drilling fluid temperature and pressure is a key step for the prediction of fluid density. A simulator was developed to calculate the wellbore temperature and pressure during circulation and static conditions. The simulation includes effects of various operational parameters, such as rate of penetration, fluid loss as well as pump rate schedules. The mathematical model of heat transfer was developed for a deviated offshore well profile to make the algorithm flexible for different applications. The upwind numerical discretization scheme is used for determination of temperature profile. The temperature prediction of the model was verified with available analytical models for a vertical onshore well. The hydraulic model employs the yield power-law rheology model. The local density of drilling fluid as a function of temperature and pressure is evaluated using the available PVT correlations. It is shown that when mud circulation stops, the equivalent static density slightly increases with time. The results of simulation also indicate that during circulation, a higher equivalent circulating density is expected as compared to the case of constant fluid density. The results of the developed method are compared with downhole temperature and pressure data in an offshore well. The comparison indicates that the developed model has a good accuracy to track the bottom-hole circulating temperature and pressure. The proposed method can be integrated into various parts of a drilling simulator such as hydraulic design, wellbore stability and well control.

1. Introduction

Determination of hydrostatic pressures in high-pressure/high-temperature (HP/HT) and deepwater wells is the most important factor to well control. In addition, deepwater drilling poses new challenges related to downhole pressure control due to narrow margin between pore pressure and fracture pressure. In many phases of drilling operation, the wellbore pressure should remain within the specified pressure window to minimize the drilling cost. Various problems such as loss circulation and wellbore instability can arise in case of operating outside of the safe pressure window. As a result, wellbore hydraulics has received special attention in the past to improve the downhole pressure predictions. In the past, several hydraulic models have been presented to estimate the frictional pressure losses during drilling fluid circulation (Reed and Pilehvari, 1993; Merlo et al., 1995). One of the major players in the hydraulic models is the drilling fluid density, which is usually considered to be a constant parameter. However, the drilling fluid density is a pressure-temperature dependent parameter. In particular, PVT studies of various drilling fluids showed a considerable difference between the ambient and downhole measured values of fluid density (McMordie et al., 1982; Politte, 1985; Zamora et al., 2013). In addition, synthetic-based and oil-based fluids are highly sensitive to temperature and pressure (Sorelle et al., 1982; Politte, 1985). McMordie et al. (1982) presented laboratory data on the changes of density of three oil and water based drilling fluids in the range of 70°–400 °F and 0–14,000 psig. It is reported that change of fluid density for some of the drilling fluids is a non-linear 4function of temperature and pressure and can be independent of ambient fluid density. Sorelle et al. (1982) proposed a general correlation applicable for oil and water base drilling fluid, which uses a linear relationship between the density of base component

* Corresponding author.
E-mail address: vahid-dokhani@yutechnologies.com (V. Dokhani).

http://dx.doi.org/10.1016/j.jngse.2016.08.009

(i.e., water or oil) and pressure and temperature. Karstad and Aadnoy (1998) proposed a model for evaluation of drilling fluid density as a function of temperature and pressure. The proposed model contains five different coefficients, which should be determined for different muds from density measurement at high temperature and pressure. Zamora et al. (2012, 2013) investigated the PVT characteristics of a broad range of oils, brines, and synthetic fluids. The study reported the measured volumetric behavior of various base fluids at temperatures from 36° to 600 °F and pressures from atmospheric pressure to 30,000 psi. The authors suggested a correlation applicable for several base components, which is followed in the current study. Altogether, the constant fluid density assumption can compromise the well integrity especially for the case of HPHT wells or deepwater drilling.

For hydrostatic pressure calculation, the so-called equivalent static density (ESD) is the conventional term used for calculation of downhole pressure. However, under circulation condition, the equivalent circulating density (ECD) is the required parameter for hydraulic calculations. With increasing depth of drilling, both bottom-hole pressure and temperature increase. As the hydrostatic pressure increases, the density of drilling fluid is expected to increase due to compressibility of the drilling fluid. Nevertheless, a higher temperature causes a reduction in density due to thermal expansion of the drilling fluid. It is often assumed that the two effects will cancel each other, which is not necessarily the case for deepwater drilling or HPHT environments as will be discussed later. In addition, the variation of density along the depth can also attribute to the pit gain or loss as noted by Karstad and Aadnoy (1998). Although the hydrostatic pressure losses usually accounts for 80%–90% of total losses, the frictional pressure losses can be significant in narrow annular regions. In particular, it has been shown that the frictional pressure losses increases exponentially for radius ratios greater than 0.7, which can be found in casing drilling applications (Dokhani et al., 2013).

As drilling fluid flows in the wellbore, the fluid temperature varies along the well path. Therefore, to estimate the fluid density, it is essential to evaluate the temperature profile in the wellbore as a function of time. As of today, API has recommended a correlation for predicting bottom-hole circulating temperature. A similar correlation is also suggested by Kutasov and Eppelbaum (2015). However, these correlations are only based on statistical analysis and may not be generalized for all applications.

The literature shows that there are two major approaches for the prediction of circulating fluid temperature, namely numerical approach and analytical approach. Analytical approach can be pursued in absence of wellbore complexities. For example, Holmes and Swift (1970) obtained a steady-state heat transfer model. Arnold (1990) obtained analytic solutions for unsteady-state heat transfer in the formation but steady-state in the conduit. Kabir et al., (1996) presented analytic solutions for both fluid flow down the annulus and fluid flow down the tubing using the Holmes and Swift's approach.

On the other hand, the numerical approach can handle transient problems, complex geometries, and different boundary conditions. However, such approach requires various material properties and heat transfer coefficients. In addition, computation costs and convergence of the method can be challenging due to time-dependent nature of the problem. For example, the model suggested by Raymond (1969) is based on unsteady-state heat transfer in the formation and conduits, using explicit finite difference method. It is noted that the coupling between the formation and pipe conduit requires an iterative scheme, which ultimately increases the computation cost of the method. Keller et al. (1973) developed a transient model for simulation of temperature profile along the well path in a typical onshore well. The authors stated that the prediction of steady-state model gives good estimates of circulating mud temperature after considerable circulation time. Marshall and Bentsen (1982) followed the method proposed by Keller et al. (1973) and developed a mathematical model for circulating temperature profile in the wellbore. The solution technique is pursued using an implicit finite difference scheme. The presented parametric study indicates that including multiple casing string does not have a significant effect on temperature distribution in the wellbore. Osisanya and Harris (2005) presented a mathematical model for a typical onshore well profile. Although an implicit scheme is used to solve the governing equations, the solution procedure requires an iterative method to converge for the temperature profile in pipe, annulus and formation. In fact, using an iterative method degrades the robustness of the implicit numerical scheme. Chen et al. (2014) developed a predictive model to identify the loss circulation zones during drilling operation. The model allows specifying the loss zones directly, or calculating the possible zones iteratively.

In brief, the majority of the presented models were developed for simple wellbore geometries, i.e., a vertical onshore well profile. However, it is essential to develop the model based on a deviated offshore well profile in order to address the effect of wellbore trajectory and marine environment on temperature profile in the wellbore. In addition, the proposed models treated the drilling mud as an incompressible fluid, which is not a realistic assumption. The current study aims to develop a model for calculation of temperature profile during drilling operation using the numerical approach. The model also includes effects of operational parameters on the temperature profile. In our approach, the density of the mud is allowed to vary as a function of pressure and temperature along the well path. Then, we employ the temperature model for prediction of ESD/ECD using the published PVT models for drilling fluids. Following the model description, the procedure for calculation of circulating bottom-hole temperature is discussed.

2. Theory

The analysis of heat transfer in a wellbore can be investigated in four regions, drill string, annulus, formation, and between riser and seawater. The following assumptions are considered to simplify the problem:

a) The radial temperature gradient within the drilling fluid is neglected.
b) The vertical heat conduction along the drill string and formation are ignored.
c) Formation properties are assumed to be constant.
d) The filtration effect is neglected, although a sink term such as mud loss is assumed at the bottom hole.
e) The heat generated by the drill bit is ignored.

A schematic of the physical system is illustrated in Fig. 1. The first region includes vertical heat convection down the drill pipe and heat transfer between drill pipe and annulus. At any depth, the first and the second nodes in the numerical grid system represent the drill string and annulus. The third node indicates the wall, which couples the heat conduction within the formation and the heat convection in the annulus. Following the wall, several radial elements are required to simulate the transient heat conduction in the vicinity of the borehole.

2.1. Governing equations

As the drilling fluid flows down the drill string, it absorbs heat from the annulus, which causes the temperature of the fluid