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Investigation of mud filtrate invasion using computational fluid dynamics

Suyoun Won
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**INVESTIGATION OF MUD FILTRATE INVASION
USING COMPUTATIONAL FLUID DYNAMICS**

Suyoun Won

**A Thesis Submitted to the College of
Engineering and Mineral Resources
at West Virginia University
in partial fulfillment of the requirements
for the degree of**

**Master of Science
in
Petroleum and Natural Gas Engineering**

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Morgantown, West Virginia
2008**

Keywords: Mud Filtrate Invasion, Formation Damage, CFD, Drilling Fluids

Despite continued research and developments in logging technology, logs processed by the prevalent standard methods continue to be influenced by formation damage and mud filtrate invasions. The mud-filtrate invasion and related formation damage due to drilling fluids can result in the misinterpreted values of rock and fluid properties in the reservoir which can affect the well plan. Well planning with accurate information of target reservoir is a very important part of any drilling procedure, as it would not only optimize drilling operation and completion but also maximizes production of oil and gas.

To produce hydrocarbons effectively, the wellbore must communicate with formations beyond the altered zone and this can be accomplished by using proper perforations, penetration or creating fractures. Thus, the prediction of invaded zone is critical and a numerical model can be employed for preplanning purposes.

In this study, the dynamic filtration process and the related penetrations into the gas and oil bearing reservoirs were studied in a vertical open hole system using a Computational Fluid Dynamics (CFD) software package. The radius of filtrate invasion was determined by the unsteady-state three-dimensional multiphase fluid flow model. The communication between fluids and formations during drilling and the effects of formation porosity and permeability, time, and overbalanced pressure were

investigated extensively. Non-Newtonians drilling fluids such as Bingham plastic, Power-law, and Herschel-Bulkley fluids were also considered for the study. The Mud filtrate invasion in a multi-layer reservoir model and effect of hydraulic fracturing operations were examined.

The results provide an insight on the formation damage around wellbore and related reduction in the hydrocarbon flow due to altered fluid saturations. The importance of accurate prediction of damaged zone around the well bore for the purpose of drilling fluid design, log interpretation, hydraulic fracturing and well completion is explicit from the results.

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NOMENCLATURE

B_w	Water FVF, RB/STB [res m ³ /stock-tank m ³]
r	Radial distance, ft [m]
k	Absolute permeability, md
k_{rw}	Relative permeability to water, dimensionless
C_w	Concentration of salt dissolved in water, lbm/ft ³ [kg/m ³]
μ_w	Water viscosity, cp [Pa s]
P_w	Pressure in water phase, psia [kPa]
t	time, days
ϕ	Porosity, dimensionless
S_w	Water saturation, dimensionless
q_w	water flow rate from source or sink, STB/D [stock-tank m ³ /d]
C_{wi}	Concentration of salt in injected water, lbm/ft ³ [kg/m ³]
r_w	Water resistivity, Ω -m
h	Net pay interval open to mud-filtrate invasion, ft [m]
T_f	Formation temperature, °F [°C]
$C_w(r)$	Formation water concentration profile in the reservoir, ppm

CHAPTER 1

INTRODUCTION

During overbalanced drilling operations, hydraulic pressure of the borehole is greater than the pressure of the porous rock. Therefore, the circulating drilling fluid forces the mud into the permeable horizons. This phenomenon creates a mud cake from slurry, as solid particles are deposited on the walls of the borehole.

In hydrocarbon bearing formations, the drilling fluids drive hydrocarbons out from the permeable formation near the borehole region thus impairing hydrocarbon productivity. In addition, the flushed zone with the filtrate from the drilling fluids causes misinterpretation of rock and fluid properties due to replacement of formation water and hydrocarbons, particularly formation porosity and permeability when measured by wireline logging methods. The mud-filtrate invasion affects the shallow investigation devices such as CNL (Compensated Neutron log), LDT (Litho Density log), MLL (Micro Laterolog) when water-base mud penetrates into oil and gas bearing reservoirs. The flushed zone inside oil or gas bearing reservoirs serves as a blockage for production of oil or gas. Prediction of horizontal extent of the invasion is important, especially for the success of perforation and hydraulic fracturing operations, because the wellbore should communicate with formation, beyond the invaded region to produce hydrocarbon effectively.

Mud Filtrate Invasion Process

An earlier study^[1] on the step model showed the idealized profile of mud filtrate invasion in a high permeability reservoir that has a sharp boundary line with no flushed zone. As shown in the left side of the figure in Figure 1.1, high permeability formation has a piston-like saturation front when viscous forces govern penetrated fluids with no influence of capillary and gravitational forces. On the other hand, right side of the figure in Figure 1.1 represents a gas-bearing low permeability reservoir that has dispersed saturation front with a flushed zone, because capillary forces only manage intruded fluids with no effect of viscous forces and gravitational forces. The three forces on the high and low permeability reservoirs are summarized in Table 1.1.

Figure 1.1: Mud invasion profile in high permeability (left) and low permeability (right) formations.^[1]

	High-permeability reservoir	Low-permeability reservoir
Viscous forces	Dominated	Negligible
Capillary forces	Not influenced	Dominated
Gravitational forces	Not influenced	Negligible

Table 1.1: Summary of forces on the high and low permeability reservoirs.

Figure 1.2 illustrates the uninvasion zone, transition zone, flushed zone, and mud cake on the left side of the wellbore, and profile change in water saturation with time is shown on the right side of the wellbore. The dynamic movements of mud filtrate in the formation are represented in the figure.

Figure 1.2: Mud filtrate with time variation.^[2]

OBJECTIVE OF THE STUDY

The purpose of this research was to investigate the effects of reservoir and operational parameters such as formation porosity, permeability, time, overbalanced pressure, naturally fractured formations, and drilling fluid type on the mud-filtrate invasion in low-permeability gas formations. To achieve this objective, the following three stages were performed:

- ✧ Development of an unsteady-state, three-dimensional multi-phase fluid flow model for mud-filtrate invasion using CFD.
- ✧ Validation of the simulation model using published data.
- ✧ Conducting parametric study.

CHAPTER 2

LITERATURE REVIEW

2.1 Mud Filtrate Invasion

Jiao and Sharma^[3] conducted experiments to measure permeability during mud circulation across the face of the sandstone cores employing a specially designed core holder. Several characteristics which affect the formation damage were considered such as mud type, salinity, filtration rates, cuttings concentration and size, and concentration of polymer additive. Throughout the experiments they found that water-based mud induces more migration and releases more clay particles than oil-based mud. In addition, low salinity, small particle size and low particle concentration induced deep mud-filtrate invasion. Lastly, the backflow experiments were conducted using the same apparatus, it was concluded that once the particles are inserted into the pore space, it is very hard to extract them and this results in permanent formation damage.

Wu et. al.^[4] replicated the phenomena of mud-filtrate invasion in an overbalanced vertical, inclined, and horizontal wells using a commercially available numerical model and an in-house developed software package. Though their algorithms remark the form of water saturation extent in the formation, the effects of mud-cake buildup with time-lapse on the dynamic process of mud filtration were more emphasized in the study. In addition, a function of wellbore angle, formation layers, and horizontal and vertical permeability values in the reservoir are considered in their algorithm. Wu et. al.'s model^[4] consisted of formation porosity equal to 20 volume percent, formation permeability in the range of

100 to 800 md and an irreducible water saturation equal to 37 volume percent. Only water-based mud as the injection fluid and oil-based reservoir as the formation type are considered. The results of their study indicate that the depth and extent of mud-filtrate invasion are extremely affected by capillary pressure, and deviation of borehole.

Semmelbeck and Holditch^[1] developed a finite-difference numerical model that focused on investigating the effects of several fluid-flow properties on the mud filtrate invasion, and determining a method for resistivity values. The simulator consists of the convective-transport and Archie's water-saturation equations.

Formation salinities are calculated by the convective-transport equation given by

$$\frac{1}{r} \frac{\partial}{\partial r} \frac{C_r k k_{rw} C_w}{B_w \mu_w} \frac{\partial p_w}{\partial r} = \frac{\partial}{\partial t} \frac{\phi S_w C_w}{B_w} + \frac{q_w C_{wi}}{r_w^2 h} \dots\dots\dots(1)$$

A sequential solution technique is utilized where the salinities (C_r and C_w) on the left side of the equation are upstream values.

Water resistivity is calculated by

$$R_w = \left[\exp(3.562 - 0.955 \log C_w) \right] \left[\frac{82}{(T_f + 7)} \right] \dots\dots\dots(2)$$

Where C_w is expressed in PPM (Part Per Million).

The formation resistivity is solved by the Archie's equation.

The form of the equation is

$$R_f = \frac{R_w}{(\phi^2 S_w^2)} \dots \dots \dots (3)$$

Where

S_w = water saturation, fraction

R_f = formation resistivity, $\Omega - m^2 / m$

ϕ = porosity, fraction

Yao and Holditch^[2] developed a numerical method to estimate the values of formation and mud cake permeability derived from time-lapse log data in gas-bearing reservoirs throughout history match analysis. These are the intimate relations between time and volume of the invasion during drilling and they used this score for estimating not only the permeability values but also medium and deep resistivity values using simulation technique. Since reservoir and mudcake permeability values change with a time-lapse, these resistivity values can be derived from the permeabilites. Yao and Holditch^[2] also used the convective-transport equation to obtain water concentration in the same way as Semmelbeck and Holditch's^[1] method. However, a different equation was applied to acquire water resistivity value as shown in Equation 3.

$$R_w(r) = 0.0123 + \frac{3647.5}{C_w(r)^{0.995}} \dots \dots \dots (3)$$

Shihong et. al.^[5] investigated the effect of mud-filtrate invasion on acoustic measurements and correct radial length of invasion using a numerical model called Biot-Gassmann fluid-substitution algorithm. They also studied change in amplitude and arrival time of seismic waves such as P- and S-waves due to invasion. In their research, injection fluid and formation fluid types were used as variables for the vertical open hole system. It was assumed that injection fluids only soak through horizontal direction in the permeable formation. Permeability values of 30 and 300 md, and porosities of 15 and 30 percent in the numerical simulator were considered as petrophysical properties. After comparing with field data, they concluded that the invasion radius increased more with the oil-based mud than with water-based mud in the gas-bearing porous formation as a function of time.

Chowdhury and Torres-Verdin^[6] conducted a numerical study to determine the influence of mud-filtrate invasion in laminated sand-shale and sand-sand sequences on formation tester and acquired nuclear and resistivity measurements. They used a synthetic two-dimensional (2D) numerical model to simulate mud-filtrate invasion process for drilling with water-based mud in an oil-bearing reservoir. Certain petrophysical parameters such as water saturation, capillary pressure, and relative permeability are acquired by the 2D model. Results of the study indicated that not only mud-filtrate invasion but also rock type are directly affected by those logging measurement. The mud-filtrate invasion causes significant errors on relative permeability values which were obtained from the measurement of the dual-packer formation tester.

To reconstruct capillary pressure and relative permeability curves acquired by measurements of wireline log, dual-packer formation tester, and electromagnetic-induction, Alpak and Torres-Verdin^[7] introduced a new equation called novel inversion algorithm for the two-phase fluid flow. In addition, salt concentration, saturation of aqueous phase, and pressure distribution are determined for the vertical and highly inclined wellbore. The mud cake buildup is numerically simulated as a function of time and space. In the study, the presence of diffusion and chemical reaction, and mass transfer between rock and fluid were ignored. They found that thickness and the permeability of mud cake determined the depth of mud-filtrate invasion as decisive factors. On the other hand, formation permeability does not affect the ratio of the invasion much.

Liu and Civan^[8] developed a mathematical model for the analysis of formation damage using laboratory core tests. The model considered filter cake buildup on sand face, invasion of external particles, release of formation fines, migration and retention of external particles and formation fines, interphase transfer of particles, and alteration of porosity and permeability. The model has also been extended to simulate and predict formation damage and skin factor in field operations. The mathematical model developed in this study was based on several assumptions and later validated by laboratory core analysis. Different experimental analysis were conducted with various samples containing Residual Oil Saturation (ROS), some without ROS and then compared with the simulator results. Every important parameter like permeability alteration factor in single phase flow, permeability alteration factor in two phase flow, pressure drop (atm)

due to damaged core, pressure drop (atm) due to undamaged core were considered individually. These parameters were analyzed for the different samples and were plotted against the pore volume of the injected fluid to get better understanding of the model. Formation damage due to dynamic mud filtration in two-phase flow was also predicted to demonstrate the capacity of the model and compare with the single phase flow. It was concluded that formation damage due to formation fines migration is less pronounced in the presence of oil in water sensitive sand stones. Moreover, formation damage due to mud filtration is less severe in two phase flows.

Civan^[9] developed a mathematical model for predicting the distribution and mixing of mud filtrates in the reservoir formation. The model could simulate the single and two-phase flow situations in the formation with water or oil based drilling mud cases. In the study, an improved formulation of the multi species and two-phase fluid transport in deforming porous media and derivation of compressible and incompressible cake models with and without particle invasion, and an application involving radial flow filter cake and mud filtrate invasion were presented.

Proett et. al. ^[10] studied all the options that can potentially improve sample quality and reduce pump out time. To study the effects, a sensitivity analysis was conducted using the simulator to determine the impact sampling methods have on sample quality. Pumpout Wireline Formation Tester (PWFT) log examples were used to compare with the simulator output. This study also presents the analysis for a well bore invasion simulator that models Water Base Mud (WBM) and Oil Based Mud (OBM) invasions. The

invasion modeling included a coupled mudcake growth mode where the mud cake thickness was governed by the properties of mud cake and the filtrate invasion, whereas the previous models used constant mud cake thickness or invasion rate. The new model developed in this study was used to precisely predict the complete set of transient data recorded by a PWFT during the sampling process.

2.2 Naturally Fractured Formation

Fracture propagation by drilling usually happens when the target formation is depleted and/or located close to salt. A recent paper by Smith and Growcock^[11] discussed the role of mechanical technique in strengthening the formation and also in preventing drilling fluid loss. The technique was accomplished using Hoop-stress enhancement, also known as Circumferential Stress Enhancement (CSE), a manner of sealing the openings with large sized particles and propping them up using high borehole pressure. The upper part of Figure 2.1 illustrates that fracturing of permeable formation increases the circumferential (hoop) stress, and as a fracture is induced, particles are wedged into its mouth before the fracture propagates significantly. The lower part of Figure 2.1 illustrates the smaller particles which seal the bridge at the fracture mouth, and leak-off through walls of fractured permeable formation allowing the fracture to close on the bridging particles. The particles maintain the enhanced hoop stress along the process. The solids which are added to the drilling fluid, namely graphite and calcium carbonate aid in resisting closure stresses. In addition, Wet-Sieve Analysis (WSA) is conducted to determine optimum particles size and injection rate of drilling fluid. A field application demonstrated the operations at a rig site in the deepwater of Gulf of Mexico for a directional well. According to the field experience, around 1 micro meter size of clay with 15 to 30 lb/bbl of bridging mix are injected into the fracture with a width of 1 mm and length of 1 m. The overbalanced pressure was 4,000 psi and a minimal drilling fluid loss was observed.

Figure 2.1: Process of Circumferential Stress Enhancement (CSE).^[11]

Al-Adani and Al-Khatib^[12] researched the probability of natural fractures in inclined formations with an emphasis on the differences between natural and drilling-induced fractures. Initially, experiments of high-resolution borehole images were performed to identify textural and structural features. Then, analyses of shear wave splitting and shear dispersion was implemented to analyze degree of anisotropy. Finally, Stoneley wave was used to detect the presence of microfractures. The presence of microfractures cannot be identified using high-resolution images. The above integrated processes enable not only in identifying the features of natural fracture but also in distinguishing between the natural fractures and drilling-induced fractures. Figure 2.2 shows an example of a borehole image with natural fractures^[12].

Figure 2.2: An example of borehole image which has natural fractures.^[12]

Teufel^[13] studied about natural fractures and its effects on formation permeability and permeability anisotropy in tight-gas sandstones to determine the optimum number and position of new wells. The principle which he employed in his study was that permeability anisotropy induces the drainage area around the wellbores to be elliptical. First, the permeability and permeability anisotropy were determined by 3D seismic analysis, well test and production decline analysis. Then, the shape and extension of drainage area were developed using reservoir simulation models. Finally, required well spacing for optimum gas production was obtained by the above processes. Based on the

study, it was concluded that gas productivity is significantly affected by the degree of fracturing in the low-permeability gas-bearing reservoirs. Figure 2.3 shows a core sample which has a partially filled vertical fracture in the Mesaverde sandstone.

Figure 2.3: Vertical fracture in the Mesaverde sandstone core sample.^[13]

Excessive water production induces decrease in oil production and a workover rig is commonly used for a remedial treatment. However, the treatment is not only an expensive option but can also delay the production. In addition, it should be taken into consideration that figuring out water-bearing fractures and isolating the openhole section are extremely difficult with current technology. As a case study, Lightford et. al.^[14] recently presented a different technique to reduce water cut and improve oil production in a naturally fractured formation by filling up with a sealant using a coiled tubing (CT) unit in a horizontal wellbore. Figure 2.4 illustrates the horizontal wellbore used in Lightford et. al.'s^[14] research. They considered several polymer solutions to seal the water-bearing fractures such as Relative Permeability Modifier (RPMs), Crosslink Polymers and Sodium Silicate Sealants and Microfile Oil Cement (MOC). However, all these materials

were considered unsuitable for the formation because of their limitations to conform in the reservoir except the MOC granulated very fine slag. They employed the MOC with a surfactant because it causes hydration only if it is contacted by water.. Therefore, the system can be carried inside the coiled tubing (CT) without any chemical reaction and deeply penetrated into the water-bearing fractures without plugging effects in the middle of the fracture. A laboratory testing was implemented for the purpose of verification of the system. The optimum amount of the MOC and surfactant, optimized slurry density and solution ratio were determined. They found that the MOC of 1045 Kg/m^3 , surfactant of 10.5 l/m^3 and the specific gravity of 1.6 are the most suitable values for the solution. When the MOC system was applied to a wellsite where significant natural fractures existed, water cut decreased from 60% to 23% after 2 months and 40% after 14 months.

Figure 2.4: Graphical illustration of the horizontal borehole situation^[14].

CHAPTER 3

Computational Fluid Dynamics (CFD)

As a branch of fluid mechanics, Computational Fluid Dynamics (CFD) uses mathematical methods and algorithms to predict and analyze fluid flow, chemical reactions, heat and mass transfer and linked phenomena. Computer executes more than millions of iterations to simulate the complex interaction of fluids and gas. Basic manner to solve the CFD problems is the Navier-Stokes equation which solves for viscous flow. On the other hand, the Euler equation which is the simplified form of the Navier-Stokes equation can solve inviscid flow. The method to solve the problem in the CFD is to discretize the domain created by Gambit into diminutive cells to build up a 2D or 3D volume mesh, after then apply an appropriate algorithm to solve the problem of fluid flow.

Basic steps involved for solving the problem using Gambit and Fluent are as follows.

- Create 2D or 3D volume as a physical boundary for the problem.
- Generate meshes for the 2D or 3D volume
- Specify boundary type which characterizes physics and operation for the model.
- Process simulation by solving the equations iteratively (steady-state or unsteady-state)

CFD can simulate fluid, gas, and granular flow phenomena in complex geometries such as pipe, reactor, porous medium, rotating frame, and etc. It has the capability to deal with different flow types namely compressible or incompressible, laminar or turbulent, inviscid or viscous, etc. Boundary geometry and a two-dimensional or three-dimensional mesh are created by the preprocessor. Then the program imports the generated grid and solves the governing equations using the finite-volume method. Utilization of the CFD has been extended broadly across all industries, and it has been used increasingly in the oil and gas field. The use of CFD gives reliable results without full-scale testing and provides economical advantages in terms of cost and time.

Blanco et. al.^[15] compared Coiled Tubing (CT) friction pressures which were generated from the CFD simulation to measured friction pressures of the tubing. Different software was used to create the model and process simulation, and the non-Newtonian turbulence model using Euler equations in the solution process. The tubing consisted of a 50 ft straight section, two layer transition section, and three layers on the reel. Results indicated that the recorded pressures and simulated pressures have less than 10% differences. The conclusion drawn was that pressure drop is directly proportional to the sand concentration, and is inversely proportional to the reel diameter.

Bilgesu et. al.^[16] studied cutting transport parameters in both vertical and horizontal wellbores using CFD. The CFD model was used for cuttings and drilling fluids for an incompressible solid-liquid flow with Power Law Model. The cutting transport was strongly affected by the cutting size, density and mud circulation rate. In the study,

several CFD model runs were carried out with varying drilling fluid densities, casing-drillpipe annuli, annular velocities, and particle sizes. It was concluded that, mud weight, viscosity, and flow rate had significant effect on cutting transport.

Mishra^[17] used CFD simulations to research hole cleaning parameters such as flow rate, cutting size, rate of penetration(ROP), drill pipe rotation and inclination angle in directional and horizontal drilling. The research was carried out using water as the transportation fluid. The parameters were graphically analyzed and the calculation of intricate multiphase model was conducted using the Eulerian model. Iterations of runs were conducted at steady state using the Newtonian fluid. It was observed that the more the fluid velocity increased, the cutting concentration decreased. Drillpipe rotation affects cutting transport of all sizes but small size particles can notably be easily conveyed by the rotation. It was also reported that more cuttings were cleaned as a result of increase in the angle of direction.

In addition to above researches, CFD software were used to predict erosion pattern in frac packing tools^[18], to simulate flow profile and velocity in CT^[19], and to design a PDC bit.^[20]

3.1 Gambit

As a preprocessor, Gambit forms an interlocking network throughout the volume where the fluid flow analysis is to take place. It assists engineers to build and mesh 2D or 3D models for CFD and other engineering applications. Also, Gambit has ability to assign boundary zone types for Fluent. The following operations are basic steps for any kind of modeling using Gambit.

- (1) Creating geometry: creating volumes and merging or splitting faces or edges.
- (2) Meshing the model: Setting face vertex types and specifying boundary conditions.
- (3) Specifying zone types: Specifying continuum and boundary types.

Grids in Gambit are used to divide the solution domain into thousands or millions of elements where the problem variables can be computed and stored. In Gambit, this grid consists of elements in variety of shapes: quadrilaterals and triangles for 2D simulations, and hexahedrals, prisms, pyramids, and tetrahedral for 3D simulations.

3.2 Fluent

Fluent is a commercial software for solving fluid flow problems. It has ability to simulate applications ranging from air flow over an aircraft wing to combustion in a furnace, from bubble columns to glass production, from blood flow in an aneurysm to semiconductor manufacturing, from clean room design to wastewater treatment plants.

3.2.1 Single and Double Precision

Single-precision or double-precision solvers can be used for any kind of simulation in Fluent. Usually, the single-precision version is adequate to solve the problem. However, in some cases the double-precision solver should be used. In the following cases, the double-precision calculation should be conducted:

- Geometry has features of unequal length scales such as very long and thin pipe.
- Geometry involves multiple fluids, and flow inside small-diameter pipes. The model used in this study comes under this case. The double-precision solver need to be used for our model since drilling fluids is flowing inside 0.3 ft radius of borehole, and formation fluid is flowing inside 5 ft radius of formation.
- For problems involving high-aspect-ratio grids and/or thermal-conductivity ratios, using the single-precision solver can impair the accuracy of the results.

3.2.2 Flow Solvers

There are two numerical methods which can be used to solve the fluid flows: pressure-based solver and density based solver. In both methods, Fluent calculates integral equations for the momentum and mass conservations, and energy and scalars. In addition, the momentum equation is used to obtain the velocity field for the both solvers. Traditionally, the density-based solver is used for high-speed compressible flow, while the pressure-based solver is used for low-speed incompressible flows.

3.2.3 Boundary Types

Boundary types in Fluent can be classified as follows:

- Flow inlet and outlet boundaries: pressure inlet and outlet, velocity inlet and outlet, mass flow inlet and outlet, inlet and outlet vent, intake and exhaust fan, and pressure-far field.
- Wall, pole, and repeating boundaries: wall, axis, periodic, and symmetry.
- Internal zones: fluid and solid
- Internal face boundaries: porous jump, interior, fan, and radiator.

3.2.4 Multiphase Flow

When two or more fluids coexist, multiphase fluid model is used to describe their collective behavior, especially if the fluids are acted upon by forces that tend to separate them. The advantage of the Eulerian multiphase model is that it is available to simulate in the unstructured mesh environment. The model uses separate sets of fluid equations to describe systems of interpenetrating media (phases), which can consist of liquids, gases, and/or particles. For a phase particulates, the Eulerian granular multiphase model is available. However, it is impossible to use the Eulerian multiphase model for our research because the multiphase model cannot simulate when the model has porous medium. Instead of the model, we can use the mixture model which is normally used for simulation of interpenetrating fluid mixtures. Other multiphase models which are not considered for our research are the volume of fluid (VOF) and the discrete phase model (DPM). The VOF model has the capability to simulate and track large bubble movement

or free surface development – heat transfer with radiation, compressibility, and liquid-solid phase change. The DPM model is for simulating multiphase flows with heat transfer and phase change, even in the high mass loading regime.

CHAPTER 4

MODEL SETUP

4.1 Gambit

The radius of mud filtrate invasion during drilling in the low permeability gas and oil bearing formations was predicted in a vertical openhole system. A cylindrical permeable formation was considered with 5 ft height and 10 ft diameter. A borehole was located in the center of the formation with a radius of 0.3 feet. A drill pipe was not used, in order to reduce the computational time. Since the velocity adjacent to the surface of the wall is not different than the case with drill pipe present in the wellbore, it was assumed that there would not be any difference in the results. The grid system developed for this study is shown in Figure 4.1. In addition, boundary type setting for our model is shown in Figure 4.2.

Figure 4.1: Grid system used to represent borehole model.

Figure 4.2: Boundary type setting for the CFD model.

Faces and nodes are summarized in the Table 4.1. (All the faces used in the model are triangular in shape.)

Face type	Number of faces
Interior	22978
Wall	4294
Pressure-inlet	1608
Pressure-outlet	72
Porous Jump	2480
Interior faces	110361

Table 4.1: Face type and number of faces used in the Gambit model.

4.2 Fluent

All simulations were conducted using a three-dimensional four-phase mixture model. The basic input data for the simulation is presented in Figure 4.3. Fresh water is used as the primary phase and cuttings, gas and formation fluid of 100,000 ppm brine are selected as the secondary phases for the multiphase model. Pressure based solver which solves the Navier-Stokes algorithm and physical velocity for the porous formation are specified. The CFD software applies the Darcy's law to solve the fluid flow problem in the porous media. As a viscous model, the k-epsilon turbulence model was used. To solve fluid flow problems in the porous media, physical velocity inside the formation was activated. Since the radial distance of mud filtrate invasion from the borehole is time-dependent, unsteady state solver was selected for all cases.

Figure 4.3: Basic input data for the simulation.

CHAPTER 5

DISCUSSION OF RESULTS

In this chapter, the results of mud-filtrate invasion verifications and parametric analysis using Computational Fluid Dynamics (CFD) are presented. All the runs were performed at unsteady state and took one to two days to get one result, due to the grid size of approximately one million. After the published data and simulated results were matched in terms of formation porosity and permeability, parametric study was conducted considering various reservoir and operational parameters such as time, drilling mud density, pressure differential, drilling fluid type, formation fluid type, and fractured formation. In this study, the porous medium was represented with 7% porosity and 0.1 md permeability. In all runs, the formation was saturated with 47.5% brine of 100,000 ppm salinity. This brine saturation of 47.5% given in the published data was used in the verification runs and same value was kept the same throughout this study. An inlet pressure of 2950 psia was used for the fluid entering the model at the upstream (bottom) and a boundary pressure of 2,275 psia was used to represent formation pore pressure at initial conditions. The drilling fluid had 3% cuttings by volume in all cases.

5.1 Model Verification and Validation

Prior to conducting parametric study, model verification was performed using CFD and the simulated results were compared with published data with formation porosity and permeability.^[1]

5.1.1 Verification Runs with Formation Porosity

Runs conducted with the CFD model using three different formation porosity values namely 3.5%, 7%, and 14%. The results were compared with published data^[1]. Figure 5.1 shows the comparison of published and predicted water saturation profile at the end of 24 hours. In runs, all data other than formation porosity such as formation permeability, time, drilling fluid type, and formation type are kept constant. Figure 5.1 shows that an increase in the value of formation porosity resulted in a decrease in the extent of mud filtrate invasion for both published data and predicted results. When all other parameters were kept constant the volume of formation fluid displaced by the drilling fluids were the same. Thus, increase in void spaces in the porous medium leads to decrease in the diameter of invasion when other parameters are kept the same. This is because a high porosity formation has a greater capacity in a given volume to soak up the mud filtrate before mudcake is formed, and consequently, drilling fluids penetration is shallow. Further, Figure 5.1 shows the good agreement between reported data and results from the CFD model.

Figure 5.1: Comparison of reported and model predicted water saturation profiles for three different formation porosity values with 0.1 md permeability after 24 hours.^[1]

Figure 5.2 shows the cross sectional profile of predicted water saturation for 0.1 md permeability at the end of 24 hours. Each contour in Figure 5.2 corresponds to the calculated results in Figure 5.1.

Figure 5.2: Model predicted water saturation contours after 24 hours.

5.1.2 Verification Runs with Formation Permeability

Runs were also conducted with two different formation permeability values of 0.1 md and 0.01 md, and the results were compared with published data^[1]. Figure 5.3 shows the comparison of reported and predicted water saturation profiles after one day of intrusion. Figure 5.3 indicates a gentle slope of invasion front for water saturation with increase in slope with decrease in permeability as a result of rapid infiltration of drilling fluids in high permeability formations. Figure 5.3 also shows the closely agreement of all predicted values with the published data. As shown in Figure 5.1 and Figure 5.3, the predicted water saturation values deviate slightly from reported values in the wellbore as a result of 3% cutting concentration used in this study compared to predicted values based on water only.

Figure 5.3: Comparison of reported and model predicted water saturation profiles for 7% porosity after 24 hours.^[1]

The cross-sectional profile of predicted static pressures for 7% porosity and 0.1 md permeability is shown in Figure 5.4 at the end of 24 hours of intrusion.

Figure 5.4: Cross-sectional view of model predicted pressure profile for 7% porosity and 0.1 md permeability after 24 hours.

5.2 Parametric Study

The results in both Figure 5.1 and 5.3 indicate that the simulated model has reliability for conducting further studies. Hence, parametric study was conducted considering the effects of time, drilling mud density, pressure differential between borehole and formation, drilling fluid types such as Newtonian and Non-Newtonians, formation fluid types, and fractured formation on the saturation profile.

5.2.1 Effect of Contact Time

The effects of contact time were analyzed by varying the porosity of the gas-bearing formation. The porosities used for this analysis are 3.5%, 7% and 14% and the permeability of 0.1 md was maintained for the three cases. The analysis was repeated by 0.01 md permeability and 7% porosity.

Figures 5.5, 5.6, and 5.7 show the variation of saturation profile with time for 3.5%, 7% and 14% porosities and 0.1 md permeability. For the three cases, other parameters are constant such as hydrostatic pressure of 2950 psi, formation pressure of 2275 psi, and 3% cuttings in drilling fluid. At the end of 24 hours, the filtration of water-base mud reached approximately 2 feet for all cases, and the invasion radius in the reservoir increased at a slower rate as time progressed. Figure 5.8 shows the water saturation profile for 7% porosity and 0.01 md permeability. After four days of invasion, the front line reaches about 4.2 ft for the case of 0.1 md formation permeability. However, as shown in Figure 5.8, invasion front line reaches approximately 3.75 ft for the case of 0.01 md permeability after 4 days of the onset of invasion.

Figure 5.5: Variation of saturation profile with time for 3.5% porosity and 0.1 md permeability.

Figure 5.6: Variation of saturation profile with time for 7% porosity and 0.1 md permeability.

Figure 5.7: Variation of saturation profile with time for 14% porosity and 0.1 md permeability.

Figure 5.8: Variation of saturation profile with time for 7% porosity and 0.01 md permeability.

5.2.2 Effect of Drilling Mud Density

The runs are conducted with four different drilling fluid density values and the results are shown in Figure 5.9 through Figure 5.12 for 3.5%, 7%, and 14% porosities and 0.1 md permeability, and 7% porosity and 0.01 md permeability values, respectively. It is known that circulating drilling fluid with appropriate density can prevent a blowout that is likely to happen when formation fluids such as oil, gas, or fresh water with high pressure and/or rate enter the borehole. In addition, drilling fluid density is crucial in retaining hydrostatic pressure to preclude extraneous gases or fluid from incoming to the borehole. However, as shown in Figure 5.9 to Figure 5.12 that the change in density did not have a significant effect on the radius of invasion for the different formation porosity and permeability values when other parameters are kept constant. There was a slight reduction in the invasion radius with the increase in mud density. As shown in Figure 5.10 and 5.12, the front line reaches about 2.2 feet and 2.0 feet, respectively, for all cases of drilling mud density. In all runs, the overburden pressure was kept constant at 2,275 psi to eliminate the effect of difference on hydrostatic pressure as it changes with fluid density. With this approach, the results reflect only the contribution of density to the invasion profile.

Figure 5.9: Variation of saturation profile with drilling mud density for 3.5% porosity and 0.1 md permeability after 24 hours of invasion.

Figure 5.10: Variation of saturation profile with drilling mud density for 7% porosity and 0.1 md permeability after 24 hours of invasion.

Figure 5.11: Variation of saturation profile with drilling mud density for 14% porosity and 0.1 md permeability after 24 hours of invasion.

Figure 5.12: Variation of saturation profile with drilling mud density for 7% porosity and 0.01 md permeability after 24 hours of invasion.

5.2.3 Effect of Overbalanced Pressure

Runs were conducted using different overbalanced pressures ranging from zero to 700 psi. The effects of overbalanced pressure are shown in Figure 5.13 through Figure 5.15 for 0.1 md formation permeability values, and 3.5%, 7%, and 14% formation porosity values, respectively. Figure 5.16 shows the results with a formation porosity of 7% and permeability of 0.01 md. The increase in overbalanced pressure resulted in increased depth of mud-filtrate invasion. When pressure in the formation and borehole are balanced, a small amount of mud-filtrate invasion was observed due to capillary pressure imbibitions. The water saturation profiles are presented in Figure 5.17 for overbalanced pressure values of 700, 500, 300, 100 and 0 psi at the end of 24 hours.

Figure 5.13: Variation of saturation profile with overbalanced pressure for 3.5% porosity and 0.1 md permeability after 24 hours of invasion.

Figure 5.14: Variation of saturation profile with overbalanced pressure for 7% porosity and 0.1 md permeability after 24 hours of invasion.

Figure 5.15: Variation of saturation profile with overbalanced pressure for 14% porosity and 0.1 md permeability after 24 hours of invasion.

Figure 5.16: Variation of saturation profile with overbalanced pressure for 7% porosity and 0.01 md permeability after 24 hours of invasion.

Figure 5.17: The effect of overbalanced pressure on water saturation contour (Top view) corresponding to the plots in Figure 5.14.

5.2.4 Effect of Drilling Fluid Type

Three non-Newtonian fluid models were used to study the effect of drilling fluid behavior. The study was also carried out using a Newtonian fluid (water). Figure 5.18 through Figure 5.20 show the invasion profiles for Newtonian (water), Bingham plastic, Power-law, and Herschel-Bulkley fluid models with 3.5%, 7% and 14% formation porosities, and 0.1 md formation permeability. Also, runs conducted with 0.01 md permeability and 7% porosity is given in Figure 5.21. All models showed a similar trend for the invasion profile. However, invasion radius showed an increasing trend as the fluid model used in the study changed from Power-Law fluid, to Bingham plastic fluid, and then to Herschel-Bulkley fluid, and finally to fresh water.

Figure 5.18: Water-saturation profile with drilling fluid types (3.5% porosity and 0.1 md permeability after 24 hours intrusion).

Figure 5.19: Water-saturation profile with drilling fluid types
(7% porosity and 0.1 md permeability after 24 hours intrusion).

Figure 5.20: Water-saturation profile with drilling fluid types
(14% porosity and 0.1 md permeability after 24 hours intrusion).

Figure 5.21: Water-saturation profile with drilling fluid types
(7% porosity and 0.01 md permeability after 24 hours intrusion).

5.2.5 Effect of Formation Fluid Type

The run were carried out using 7% porosity and 0.1 md permeability to analyze the effect of formation fluids types on the mud filtrate invasion. Figure 5.22 shows the water saturation profile in gas and oil bearing formations at the end of 24 hours. The observed radius of invasion was much greater in oil bearing formation than a water based drilling fluid was used. The invasion front line for oil-bearing formation is inversely proportional to the radial distance from center of the wellbore. This is contradictory to normally observed field behavior and it is attributed to the program features that handles different fluid behaviors. Thus, the observation of this invasion front needs to be investigated further.

Figure 5.22: Water-saturation profile with formation fluid types (7% porosity and 0.1 md permeability after 24 hours intrusion).

5.2.6 Effect of Fractured Formation

* Grid System for the Fractured Formation

Since the fractured formation should have different geometry, a new geometry system was created with a fractured part on the borehole. The model has the same size and shape as the previous model except the fractured part. The geometry is represented as a permeable formation which is 5 ft height and 10 ft in diameter, and a borehole located in the center of the permeable cylinder which has same height of the cylinder and 0.3 ft diameter. The fractured part extends out from the borehole so that the drilling fluid can enter the opening. It has a length of 20 inches and a radius of 5 mm, and intersects the wellbore at right angles. The geometrical system used in this study is shown schematically in Figure 5.23.

Figure 5.23: Grid System with fractured formation.

Figure 5.24 shows volume fraction of formation fluid and drilling fluid with fractured formation after one day of onset of the invasion for a formation with 0.1 md permeability and 7% porosity. The circulated fluid was 100,000 ppm brine with 3% cuttings by volume, and the gas-bearing formation had 47.5% water saturation. The second part of the figure shows the volume fraction after two days of onset of the invasion. As shown in Figure 5.24, filtration process is somewhat progressed after one day of intrusion, and after two days of invasion the front line of invasion goes further from center of the wellbore. Some amount of drilling fluid flows throughout open section, and it is propagated into the formation proportional to the increase of time with 700 psi pressure differential inside the borehole and formation.

* Effects of Fractured Formation

Figure 5.24: Volume fraction of formation fluid and drilling fluid with fractured formation after 24 hours and 48 hours of invasions.

Figures 5.25 and 5.26 show the velocity magnitude with the fractured formation after 6 and 24 hours of invasion. The top view of velocity magnitude after 6 hours of invasion is given in Figure 5.27. The porosity and permeability values used for the fractured formation were 7% and 0.1 md permeability, respectively. Initial conditions of the drilling fluid velocity in the borehole is approximately 1 m/s (3.28 ft/s), and the formation fluid velocity in the formation is roughly 0.05 m/s (0.164 ft/s). After 6 hours of invasion, the velocity close to the fracture increases only partially. However, the whole section of the velocity near the opening section increases after 24 hours of invasion.

Figure 5.25: Velocity magnitude with fractured formation after 6 hours of invasion (side view) (7% porosity and 0.1 md permeability).

Figure 5.26: Velocity magnitude with fractured formation after 24 hours of invasion (side view) (7% porosity and 0.1 md permeability).

Figure 5.27: Velocity magnitude with fractured formation after 6 hours of invasion (top view) (7% porosity and 0.1 md permeability).

When the results for the fractured formation are compared with the results for the non fractured formation, the effect of fracture is observed as an increase in the penetration depth in drilling fluid. It is important for a proper mud to block fractures to prevent the invasion.

CHAPTER 6

CONCLUSIONS AND RECOMMENDATIONS

6.1 Conclusions

In this study, the influence of different formation and operational parameters on mud-filtrate invasion were studied for gas bearing formations using Computational Fluid Dynamics. Based on the results, the following conclusions are presented:

- 1) Deep mud-filtrate invasion can take place even in low-permeability formations.
- 2) The amount and depth of invasion was greatly affected by duration of contact and amount of overbalanced pressure as well as formation porosity and permeability.
- 3) The change in mud density had a minimum affect on the filtrate invasion profile.
- 4) The depth of invasion increased with increase in formation permeability, duration of contact, and pressure gradient between wellbore and formation.
- 5) Increase in formation porosity resulted in decrease in the depth of mud-filtrate penetration. It appears that the amount of fluid invading the formation in both cases of different porosities are same due to the identical initial and operating conditions.
- 6) Fluid used in the drilling process affects the penetration profile with water as the Newtonian fluid resulting in the deepest penetration.
- 7) A numerical algorithm can be used to predict the depth and extend of invasion of drilling fluids. Hence this approach can provide a useful planning tool for designing drilling fluids.

6.2 Recommendations

- The model in this study can be further improved by including additional features such as incorporating the effect on foam drilling fluids.
- Based on the simulational results, experimental approach can be implemented to compare and validate more results.
- Additional simulations using different cutting size are needed to apply to the diverse situations.

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APPENDIX A

SOLUTION METHOD IN FLUENT

A.1. Mixture Model

For all simulations, the mixture model is applied for the calculation of multiphase fluid flow in Fluent because the model allows selecting granular phase option and has applicability for the solid-liquid flows. The model computes multiphase flow using Euler-Euler approach which treats the different phases as interpenetrating continua. The continuity, momentum, energy, and volume fraction equations are used to solve the mixture model.

Continuity Equation

The continuity equation for the mixture model is a kind of conservative equation. Since the mass-averaged velocity and mixture density are conserved, the multiphase fluids flow is described with the continuity equation. The continuity equation for the mixture is

$$\frac{\partial}{\partial t}(\rho_m) + \nabla \cdot (\rho_m \vec{v}_m) = 0 \quad \dots\dots\dots (1)$$

Where $\vec{v}_m$ is the mass-averaged velocity:

$$\vec{v}_m = \frac{\sum_{k=1}^n \alpha_k \rho_k \vec{v}_k}{\rho_m} \quad \dots\dots\dots (2)$$

and ρ_m is the mixture density:

$$\rho_m = \sum_{k=1}^n \alpha_k \rho_k \quad \dots\dots\dots (3)$$

α_k is the volume fraction of the phase k .

Momentum Equation

The momentum equation for the mixture can be obtained by summing the individual momentum equations for all phases. It can be expressed as

$$\frac{\partial}{\partial t}(\rho_m \vec{v}_m) + \nabla \cdot (\rho_m \vec{v}_m \vec{v}_m) = -\nabla p + \nabla \cdot [\mu_m (\nabla \vec{v}_m + \nabla \vec{v}_m^T)] + \rho_m \vec{g} + \vec{F} + \nabla \cdot \left(\sum_{k=1}^n \alpha_k \rho_k \vec{v}_{dr,k} \vec{v}_{dr,k} \right) \dots \dots \dots (4)$$

Where n is number of phases, $\vec{F}$ is a body force, and μ_m is the viscosity of the mixture:

$$\mu_m = \sum_k^n \alpha_k \mu_k \dots \dots \dots (5)$$

$\vec{v}_{dr,k}$ is the drift velocity for secondary phase k :

$$\vec{v}_{dr,k} = \vec{v}_k - \vec{v}_m \dots \dots \dots (6)$$

Energy Equation

The energy equation for the mixture model takes the following form:

$$\frac{\partial}{\partial t} \sum_{k=1}^n (\alpha_k \rho_k E_k) + \nabla \cdot \sum_{k=1}^n (\alpha_k \vec{v}_k (\rho_k E_k + p)) = \nabla \cdot (k_{eff} \nabla T) + S_E \dots \dots \dots (7)$$

Where k_{eff} is effective conductivity ($k_{eff} = \sum \alpha_k (k_k + k_t)$, where k_t is the turbulent thermal conductivity, defined according to the turbulence model being used). The first term on the right-hand side of the Equation (7) represents energy transfer due to conduction. S_E includes any other volumetric heat sources. The term E_k is defined as,

$$E_k = h_k - \frac{p}{\rho_k} + \frac{v_k^2}{2} \dots\dots\dots(8)$$

for a compressible phase, and

$$E_k = h_k \dots\dots\dots(9)$$

for an incompressible phase, where h_k is the sensible enthalpy for phase k .

A. 2. Granular Properties

Since the concentration of particles is an important factor in the calculation of the effective viscosity for the mixture, the granular viscosity is needed to define the viscosity of the suspension. The resulting volume weighted averaged viscosity contains shear viscosity arising from particle momentum exchange due to translation and collision.

The collisional and kinetic parts, and the optional frictional part, are added to give the solids shear viscosity:

$$\mu_s = \mu_{s,col} + \mu_{s,kin} + \mu_{s,fr} \dots\dots\dots (10)$$

Collisional Viscosity

The collisional part of the shear viscosity is modeled as

$$\mu_{s,col} = \frac{4}{5} \alpha_s \rho_s d_w g_{O,ss} (1 + e_{ss}) \left(\frac{\theta_s}{\pi} \right)^{1/2} \dots\dots\dots (11)$$

Kinetic Viscosity

The kinetic part of shear viscosity is

$$\mu_{s,kin} = \frac{\alpha_s d_s \rho_s \sqrt{\theta_s \pi}}{6(3-e_{ss})} \left[1 + \frac{2}{5} (1+e_{ss})(3e_{ss}-1) \alpha_s g_{O,ss} \right] \dots\dots\dots (12)$$

A.3. Granular Temperature

The viscosities need the specification of the granular temperature for the solids phase. It requires an algebraic equation derived from the transport equation by neglecting convection and diffusion and takes the form.

$$0 = \left(-p_s \bar{I} + \bar{\tau}_s \right) : \nabla \vec{v}_s - \gamma \Theta_s + \phi_{Is} \dots\dots\dots (13)$$

Where

$\left(-p_s \bar{I} + \bar{\tau}_s \right) : \nabla \vec{v}_s$ = the generation of energy by the solid stress tensor

$\gamma \Theta_s$ = the collisional dissipation of energy

ϕ_{Is} = the energy exchange between the I^{th} fluid or solid phase

and the S^{th} solid phase

The collisional dissipation of energy, $\gamma \Theta_s$, represents the rate of energy dissipation within the 8^{th} solids phase due to collisions between particles.

$$\gamma \theta_m = \frac{12(1-e_{ss}^2)g_{O,ss}}{d_s \sqrt{\pi}} \rho_s \alpha_s^2 \Theta_s^{3/2} \dots\dots\dots (14)$$

The transfer of the kinetic energy of random fluctuations in particle velocity from the g^{th} solids phase to the I^{th} fluid or solid phase is represented by ϕ_{Is} :

$$\phi_{Is} = -3K_{Is}\Theta_s \dots\dots\dots(15)$$