ABSTRACT

Microseismic events along pre-existing zones of weakness occur in a reservoir due to pore pressure build up and fracturing during fluid injection. We use a multiphase fluid-flow numerical simulator to model water injection in a gas reservoir. Previous studies generally consider a single fluid, where the relative permeabilities and capillary pressure play no role. Here, we analyze the effects of partial saturation on the injection process. On the basis of a spatial distribution of weak stress zones and a threshold pore pressure, the simulator models fluid transport in the formation and allows us to obtain the spatio-temporal distribution of the microseismic events. The study considers uniform and fractal distributions of the pore pressure at which micro-earthquakes are triggered. The influence of the initial water saturation and the presence of pre-existing natural fractures is analyzed, as well as the effect of updating the rock properties after the microseismic events occur. Moreover, we perform simulations in a low permeability reservoir in which the borehole pressure increment generates a system of fractures that propagate into the reservoir. The importance of considering two-phase fluid flow resides in the fact that partial saturation greatly affects the trigger time evolution. This is mainly due to the difference in compressibility of the two phases.

INTRODUCTION

Fluid injection has been widely used by the petroleum industry for secondary or enhanced oil recovery as well as for hydraulic fracturing treatments. The process of hydraulic fracturing allows to generate fractures or to connect already existing natural fractures thus creating a pathway by which the hydrocarbons can flow to the wellbore (Riahi and Damjanac, 2013). When it comes to unconventional reservoirs (tight or shale), this technique turns out to be necessary for the well to become productive (Nagel et al., 2013).

As a result of the injection process, the pore pressure build up within the formation leads to a decrease of the effective stress, causing the zones of weakness to break down and consequently P and S waves are emitted. This passive seismic emission can be used to monitor the overall process. Longer-term microseismic monitoring has been used to estimate fracture geometry and reservoir properties as permeability (Shapiro et al., 2005, 1997; Carcione et al., 2015). This analysis is usually performed by adjusting the trigger envelope curve and obtaining the associated hydraulic diffusivity parameter (Rothert and Shapiro, 2003). Other authors have presented rigorous models of hydraulic fracturing (Wangen, 2011) based on Biot's equation and a finite element representation of the fracture pressure.

The purpose of this work is to apply a two-phase fluid flow simulator to describe water injection in a gas reservoir. We first consider a relatively high permeability and porosity. In this case, the injected fluid can be leaked into the formation due to the injection pressure. We also assume a fractal distribution for the stiffness properties of the medium. As the fluid is being injected, the pressure builds up and breaks down the weaker zones becoming micro-earthquakes sources. Here we only consider tensile failure as a consequence of the injection. Using this approach, we evaluate the influence of different variables, such as the breakdown pressure and initial water saturation, the existence of natural high-permeability paths and the effect of porosity and permeability variation in the fractured zones.

TWO-PHASE SIMULATOR

This section describes the two-phase fluid-flow model used to simulate water injection into a gas reservoir, and the trigger criterion to obtain the distribution of the micro-earthquake sources. A list of symbols is listed in Appendix .

WATER INJECTION MODEL

Our first aim is to model the simultaneous flow of gas and water in a reservoir. This is achieved by solving the differential equations that describe the two-phase fluid flow in porous media (Aziz and Settari, 1985). These equations, obtained by combining the mass conservation equations with Darcy's empirical law, are

$$\nabla \cdot \left(\underline{\kappa} \frac{k_{rg}}{B_g \eta_g} \nabla p_g \right) + \tilde{q}_g = \frac{\partial \left[\phi \left(\frac{S_g}{B_g} \right) \right]}{\partial t}, \tag{1}$$

$$\nabla \cdot \left(\underline{\kappa} \frac{k_{rw}}{B_w \eta_w} \nabla p_w \right) + \tilde{q}_w = \frac{\partial \left[\phi \left(\frac{S_w}{B_w} \right) \right]}{\partial t}. \tag{2}$$

where g and w denote gas and water phases respectively, and the unknowns are the fluid pressures p_β and saturations S_β ($\beta = w, g$). Moreover, $\tilde{q}_\beta$ is the injection flow rate per unit volume, $k_{r\beta}$ is the relative permeability, η_β is the viscosity, ϕ is the porosity and $\underline{\kappa}$ is the absolute permeability tensor. Finally, B_g and B_w are the PVT parameters, which are the gas formation volume factor and water formation factor, respectively. These equations are obtained by assuming that there is no mass transfer between gas and water phases. Two algebraic equations relating the saturations and pressures complete the system:

$$S_w + S_g = 1, \qquad p_g - p_w = P_C(S_w), \tag{3}$$

where $P_C(S_w)$ is the capillary pressure function. Appendix describes how the nonlinear differential equations (1)-(2) are obtained and solved.

TRIGGERING CRITERION

In order to determine the microseismic emission zones, we apply a criterion based on a "breakdown pressure" (P_{bd}), defined as follows: When the pore pressure p is greater than the breakdown pressure on a certain cell, it becomes a "microseismic source". P_{bd} can be computed from the in-situ stress field. An accurate estimation of this stress is essential and can be obtained from seismic data. Here, we will only consider the tensile events and the P_{bd} is obtained from the horizontal stress σ_H and the tensile stress of the rock T_0 (Economides and Hill, 1994) as

$$P_{bd} = 3\sigma_{Hmin} - \sigma_{Hmax} + T_0 - p_H, \tag{4}$$

where

$$\sigma_{Hmax} = \sigma_{Hmin} + \sigma_{Tect}, \tag{5}$$

being σ_{Tect} the tectonic stress contribution and σ_{Hmax} and σ_{Hmax} the maximum and minimum horizontal stresses, respectively, obtained from the vertical stress (σ_V) as

$$\sigma_{Hmin} = \frac{\nu}{1-\nu}\sigma_V, \tag{6}$$

where ν is the Poisson ratio and σ_V is calculated from formation density (ρ_f) as

$$\sigma_V = g \int_0^H \rho_f \, dH, \tag{7}$$

with H indicating the formation depth and g the gravity constant.

NUMERICAL EXAMPLES

We consider a 2D horizontal section of a gas reservoir with an extent of 180 m on the x-direction and 180 m on the y-direction. The reservoir is located at a depth of 3 km b.s.l. The simulation is performed by using a mesh with equally spaced blocks in each direction, distributed in 300 cells on the x-direction and 300 cells on the y-direction.

We designed a reservoir with a permeability of 0.1 mD and 8 % of porosity. In our first analysis, we maintain these reservoir properties constant, i.e., we assume that when the breakdown pressure is reached, the properties are not modified. We also assume a fractal distribution for P_{bd} based on the Von-Kármán correlation function (Carcione and Gei, 2009) as shown in Figure 1. Water-injection simulation is performed at a constant flow rate of 0.15 m^3/s at the injection point located in the center of reservoir with the BOAST Simulator. Figure 2 shows the spatial distribution of triggers after 10 h of the fracking process.

We can see that the pore pressure increase due to water injection generates fractures in the reservoir in weak zones around the well. The spatial distribution of fractured cells observed in Figure 2 corresponds to the end of the fracking process, where each particular trigger occurred at a different time. This trigger time evolution can be observed in Figure 3 as a cloud of crosses (Fractal P_{bd}), where the maximum distance to the well reached after 10 h of injection can clearly be seen.

If instead of assuming a fractal distribution for the breakdown pressure we use a homogeneous distribution taking the minimum value of the fractal one (4000 psi / 27.6 MPa), we obtain the trigger time evolution result depicted in Figure 3 as a dotted curve of points (homogeneous P_{bd}). This curve is the envelope of all trigger events generated in the previous case.

Next, we study the effect of modifying the local properties after the pressure reaches the P_{bd} value on a certain cell. When this happens, the cell porosity and permeability values are increased. The new porosity and permeability values are assigned by assuming an average between the existing properties of the formation and those of the fracture. The fluid-flow model does not compute these new values, but they are instead assigned as a parameter for each time step when the cell is considered fractured. Since the focus of this study is to demonstrate that any change in the local properties might alter the shape or size of the micro-earthquakes source distribution, we do not put the emphasis in determining the exact values of the new porosity or permeability of the cell. The values used to update the cell properties after fracturing were: 1 mD for permeability and 50 % for porosity.

In this case, the behavior is slightly different and it can be seen in Figure 4 that shows the triggers time evolution for both constant and variable properties assuming an uniform distribution of $P_{bd} = 4000$ psi (27.6 MPa). This difference can be explained by the fact that an increment in porosity and permeability produces a pressure drop. This decrease slows down the pressure front, which, in turn, delays the triggers.

BREAKDOWN PRESSURE AND INITIAL WATER SATURATION EFFECT

The value used as breakdown pressure depends on several factors as mentioned above, such as formation density, tensile stress of the rock and tectonic stress among others. It is our objective to determine whether an accurate value of P_{bd} is needed when simulating the fracture front, or an approximation is sufficient. Hence, it is important to consider the effect that this parameter has on the fracture evolution and to understand the sensitive of the front to changes in the breakdown pressure. To evaluate this effect, we run four simulations for different values of P_{bd}: 4000 psi (27.6 MPa), 4500 (31.0 MPa) psi 5000 (34.5 MPa) psi and 5500 (37.9 MPa) psi. These simulations are performed by assuming an uniform distribution of P_{bd}. The corresponding envelopes are shown in Figure 5.

It can be clearly observed that an increment of P_{bd} not only slows down the triggering, but also reduces the size of the fractured zone. In this case, the effect can be easily explained if we assume that within a certain region of the reservoir it is necessary to reach a higher pore pressure in order to fracture for higher P_{bd} values. An increase of about 12 % of P_{bd} produces a 50 % decrease in the distance to the well of the fracture front. On the other hand, a 37 % increment of P_{bd} leads to a 84 % decrease in the region covered by the fractured zone.

Variable water saturation is another significant property. Five different initial water saturations are considered (0.1, 0.3, 0.5, 0.8 and 1.0), while maintaining a constant P_{bd} of 4000 psi (27.6 MPa) for all five cases. Figure 6 shows the envelope behavior for the different saturations.

An increment of initial water saturation generates the opposite effect, that is to say, the fracture front evolution is accelerated and the fractured zone increases. This can be explained if we take into account that the pore pressure increases with increasing water saturation. Figure 6 shows the importance of considering two-phase fluid flow, because water injection into a gas reservoir greatly affects the trigger time evolution. This is mainly due to the difference in compressibility of the two phases.

EFFECT OF PRE-EXISTING NATURAL FRACTURES

In this section, we analyze the case when the reservoir has natural fractures before starting the fracking process, and the influence of such natural fractures on the evolution of the induced fractures. For this purpose, we incorporate zones of high permeability, as can be seen in Figure 7. These zones model the natural fractures. Since the mesh is fixed and the size of the cells is much larger than that of a natural fracture, we randomly choose a series of cells placed along parallel lines close to the injection point, and we assign them a value of permeability greater than that of the formation, weighted together with the high permeability that a natural fracture would have.

Figures 8 and 9 shows the maps of the fractured zone after 10 h of injection without and with natural fractures.

The effect of the reduction of the fractured zone, along with the decrease of the trigger events, can be seen in the trigger events time distribution (see Figure 10).

There is a decrease in the size of the fractured zone due the presence of natural fractures. The natural fractures allows water to flow more easily, thus pressure increases slowly, which in turn decreases the number of induced fractures.

CONCLUSIONS

The model presented here allows us to generate micro-earthquake sources in a reservoir saturated with two phases during the fracking process. We analyze the influence of the rock stresses, the initial water saturation and the presence of natural fractures on the time-spatial distribution of the microseismic sources.

It can be observed that an increment of the breakdown not only slows down the triggering, but also reduces the size of the fractured zone. An increment of initial water induces the opposite effect, i.e., the fracture front evolution is accelerated and the fractured zone increases. Moreover, there is a decrease in the size of the fractured zone due the presence of pre-existing natural fractures. These fractures allows water to flow more easily, thus pressure increases slowly, which in turn decreases the number of induced fractures.

This work is a starting point that will enable us to generate seismic images produced by the fracture events that are obtained as an output of the model. Furthermore, we can obtain the fracture map from a set of real seismic images by using inversion algorithms. We point out the importance of considering two-phase flow, or in general multiphase fluid flow when studying the behavior of induced fractures, during the hydraulic fracture processes.

APPENDIX A

LIST OF SYMBOLS

B_w: Water formation volume factor

B_g: Gas formation volume factor

c_w: Water compressibility

c_f: Formation compressibility

c_g: Gas compressibility

c_t: Total compressibility

g: Gravity constant

$k_{r\beta}$: β phase relative permeability

p_β: β phase pressure

p_H: Hydrostatic pressure

P_{bd}: Breakdown pressure

$P_C(S_w)$: Capillary pressure function

$\tilde{q}_\beta$: β phase injection flow rate per unit volume

S_β: β phase saturation

S_{wi}: Initial water saturation

T_0: Tensile stress

$\underline{v}_\beta$: Darcy phase velocity

η_β: β phase viscosity

$\underline{\kappa}$: Absolute permeability tensor

ν: Poisson ratio

ρ_f: Formation density

σ_H: Horizontal stress

σ_{Hmax}: Maximum horizontal stress

σ_{Hmin}: Minimum horizontal stress

σ_V: Vertical stress

σ_{Tect}: Tectonic stress

ϕ: Porosity

APPENDIX B

BLACK-OIL FORMULATION OF TWO-PHASE FLOW IN POROUS MEDIA

The simultaneous flow of water and gas is described by the well-known Black-oil formulation (Aziz and Settari, 1985). This formulation uses, as a simplified thermodynamic model, the PVT data defined as

- B_g: Gas formation volume factor
- B_w: Water formation volume factor

The conversion of compositional data from equations of state into the Black-oil PVT data is based on an algorithm developed by Hassanzadeh (Hassanzadeh et al., 2008). The mass conservation equation for each component (gas and water) can be expressed as

$$-\nabla \cdot \left(\frac{1}{B_g}\underline{v}_g\right) + \tilde{q}_g = \frac{\partial\left[\phi\left(\frac{S_g}{B_g}\right)\right]}{\partial t}, \tag{B-1}$$

$$-\nabla \cdot \left(\frac{1}{B_w}\underline{v}_w\right) + \tilde{q}_w = \frac{\partial\left[\phi\left(\frac{S_w}{B_w}\right)\right]}{\partial t}, \tag{B-2}$$

where g and w denote gas and water phases respectively, ϕ is the porosity, $\underline{v}_\beta$ is the Darcy phase velocity, S_β is the saturation and $\tilde{q}_\beta$ is the injection flow rate per unit volume, with $\beta = w, g$.

The Darcy phase velocities in an horizontal domain can be expressed by Darcy's empirical law as

$$\underline{v}_g = -\underline{\kappa}\frac{k_{rg}}{\eta_g}\nabla p_g, \tag{B-3}$$

$$\underline{v}_w = -\underline{\kappa} \frac{k_{rw}}{\eta_w} \nabla p_w, \tag{B-4}$$

where p_β are the fluid pressures, η_β is the viscosity, $k_{r\beta}$ is the relative permeability and $\underline{\kappa}$ is the absolute permeability tensor. Combining the mass conservation equations (equations B-1 and B-2) with Darcy's law (equations B-3 and B-4) we obtain equations (1)-(2).

The numerical solution of the system is obtained with the algorithm BOAST (Fanchi, 1997), which solves the differential equations using IMPES (IMplicit Pressure Explicit Saturation), a finite-difference technique (Aziz and Settari, 1985). The basic idea of IMPES is to obtain a single pressure equation by a combination of the flow equations. Once pressure is implicitly computed, saturation is updated explicitly. We briefly describe IMPES for these particular system (equations 1, 2 and 3). The first step is to obtain the pressure equation, combining flow equations: Equation 1 multiplied by B_g and equation 2 multiplied by B_w are added. In this way, the right side of the resulting equation is

$$B_g \frac{\partial \left[\phi \left(\frac{S_g}{B_g} \right) \right]}{\partial t} + B_w \frac{\partial \left[\phi \left(\frac{S_w}{B_w} \right) \right]}{\partial t}.$$

Using the chain rule to expand the time derivatives and after some computations and rearrangements, we obtain

$$\phi \left[\frac{1}{\phi} \frac{d\phi}{dp_w} + S_g \left(-\frac{1}{B_g} \frac{dB_g}{dp_w} \right) + S_w \left(-\frac{1}{B_w} \frac{dB_w}{dp_w} \right) \right] \frac{\partial p_w}{\partial t},$$

where all the time derivatives with respect to the saturation disappear.

Defining

- Formation compressibility: $c_f = \frac{1}{\phi} \frac{d\phi}{dp_w}$
- Gas compressibility: $c_g = -\frac{1}{B_g} \frac{dB_g}{dp_w}$,

- Water compressibility: $c_w = -\dfrac{1}{B_w}\dfrac{dB_w}{dp_w}$,

- Total compressibility: $c_t = c_f + S_g c_g + S_b c_w$,

the right side of the pressure equation is simply expressed as,

$$\phi c_t \frac{\partial p_w}{\partial t}.$$

Finally, replacing p_g by $p_w + P_C(S_w)$ in the left side of the combined equation, the following pressure equation in p_w is obtained,

$$\begin{aligned} & B_g\Big[\nabla\cdot\Big(\underline{\kappa}\Big(\frac{k_{rg}}{B_g\eta_g}\nabla p_w + \frac{k_{rg}}{B_g\eta_g}\nabla P_C\Big)\Big)\Big] + B_w\Big[\nabla\cdot\Big(\underline{\kappa}\frac{k_{rw}}{B_w\eta_w}\nabla p_w\Big)\Big] \\ & + B_g\tilde{q}_g + B_w\tilde{q}_w = \phi c_t\frac{\partial p_w}{\partial t}. \end{aligned} \tag{B-5}$$

In the BOAST simulator, equations 2 and B-5 are discretized using a block centered grid. The system is linearized by evaluating the pressure and saturation dependent functions (PVT parameters, viscosities, relative permeabilities and capillary pressure) in the pressure and saturation values of the previous time step. The pressure equation is solved implicitly, applying a Block Successive Over Relaxation method (BSOR) to compute the linear system solution. The saturation equation is solved explicitly, therefore stability restrictions are considered to select the time step (Savioli and Bidner, 2005).

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CAPTIONS

Figure 1: Fractal breakdown pressure distribution.

Figure 2: Location of the microseismic sources obtained after 10 h of water injection.

Figure 3: Comparison between homogeneous and fractal breakdown pressure (P_{bd}) distribution.

Figure 4: Location of the events as a function of the emission time, corresponding to a homogeneous distribution of the breakdown pressure, with constant and variable properties.

Figure 5: Breakdown pressure (P_{bd}) effect on the trigger distribution.

Figure 6: Initial water saturation (S_{wi}) effect on the trigger distribution.

Figure 7: Permeability map with natural fractures.

Figure 8: Fracture map without natural fractures.

Figure 8: Fracture map with natural fractures.