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A simple dilation-recompaction model for hydraulic fracturing

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ABSTRACT

Production of unconventional oil and gas resources has played a significant role on the global energy supply, of which tight oil and gas reservoirs are drawing greater focus. The key enabler behind tight oil and gas production has been multi-stage hydraulic fracturing along extended reach horizontal wells. Despite many advances in multistage fracturing, it still remains unclear how to model the hydraulic fracturing process to provide the basis to optimize and predict the properties of fracture networks and associated enhancement of fluid production. In typical reservoir simulation practice, the conventional way to represent the hydraulic fracture is to place high permeability planes around the horizontal well – this means that the user has prescribed the orientation and length scale of the fracture before the simulation has started. In the research documented here, we explore a dynamic fracturing approach that uses a dilation-recompaction model in a reservoir simulator to model hydraulic fracturing. The key strength of the approach is that the geometry and length scale of the fracture is not prescribed a priori. The results of the simulation show that dilation-recompaction model is capable of modeling the hydraulic fracturing process prior to the flow-back and production. The oil, gas, and water rates of the model are well matched to the field data and the extent of the fractured zone predicted by the model is reasonable.

1. Introduction

In the 1970s, the technology of hydraulic fracturing was invented to crack tight formations and extract greater volumes of oil and gas. In the early days, before the advent of horizontal well and directional drilling, the industry typically used vertical wells to transport the fracturing fluid, often brine, to the formation (Cooke Jr, 1975). With further investment in the tight oil and gas business, the technology of hydraulic fracturing has been improved significantly especially after the 1990s with the use of horizontal wells and directional drilling (Cattaneo, 2012).

Hydraulic fracturing dramatically increases reservoir permeability in the near wellbore region and enlarges the connectivity between the production wellbore and formation (Keshavarzi et al., 2012). It remains unclear how to model hydraulic fracturing so that it can be used as a predictive tool to optimize the layout and geometry of fracture networks and fluid production. This is especially difficult since it is not possible to directly image the fracture network. Although transient analysis can provide estimates of fracture width, half-length, conductivity, and closure time, it does not provide measures of the fracture network connectivity and complexity (Stevens, 2012).

Physically, hydraulic fracturing induces fractures in the rock leading to enhanced permeability channels of a fracture network with relatively high permeability (Guo et al., 2009; Zhao et al., 2013). Due to the length of the horizontal well, the wellbore can be separated into several stages so that hydraulic fracturing is implemented at various points along its trajectory (Pearson et al., 2013). In multi-stage hydraulic fracturing, at first, typically all the stages will be shut in except for the stage at the toe of the horizontal wellbore (Themig, 2011). Next, the fracturing process will be conducted for the opened stage and afterwards, the neighboring stage will be opened and fractured with all the other stages being shut in (Themig, 2011). The length of stage can be tens of meters or even greater than a hundred meters (Turri et al., 2015). The number of stages can be varied as well. Currently in industry, up to 40 stages are created in some horizontal wells (Turri et al., 2015).

There appear to be two different viewpoints to model hydraulic fracturing. One focuses on single fractures and its shape, extent (height, width, and length), and effective permeability. For example the Perkins-Kern-Nordgren (PKN) model (Nordgren, 1972) and Kristonovich-Geertsma-Daneshy (KGD) model (Geertsma and De Klerk, 1969) are the two earliest and simplest models. Basically, the PKN model considers the horizontal cross section of the fracture as an elliptical tube and the vertical cross section as an eclipse (Nordgren, 1972). In contrast with the PKN model, the KGD model provides accurate results when the fracture height is close to or

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larger than the half-length. Theoretically, the KGD model assumes the horizontal cross section of the fracture as an elliptical tube (same as the PKN model), but for the vertical cross section of the fracture, the KGD model assumes that it has a rectangular cross section (Geertsma and De Klerk, 1969). These types of models are often analytical in nature and permit calculation of aperture, pressure, and effective permeability of the fracture as the rock is hydraulically fractured. However, there are some limitations of 2D models. Both PKN and KGD models do not take fluid leak-off into consideration and the height of the fracture is assumed. The height of the fracture will vary with both time and location during injection due to reservoir heterogeneity.

Other models use finite and discrete element models to examine how rock dilates and eventually fractures as fluid is injected into it (Mayerhofer et al., 2010). In many cases, these models provide an estimate of the dimensions of the stimulated reservoir volume (SRV) that surrounds the wellbore after the hydraulic fracture operation is complete (Mayerhofer et al., 2010). Other methods that have been of interest in the literature are those that treat the fractured zone as an equivalent porous medium with an effective permeability and porosity. These methods try to provide an equivalent stress environment that has the same impact on the production. One of these methods uses local grid refinement in the near wellbore region and assigns new properties including permeability, porosity, compressibility, and capillary pressure to the fractures (Iwere et al., 2012). The limitation of this method is that the fracture orientation, shape, and extent are prescribed up front by the user. However, in reality, these data are not always available.

In the research documented here, we explore a dynamic fracturing model that has been successfully applied to steam fracturing in cyclic steam stimulation models (Cokar et al. 2012).

2. Formation background

The Cardium Formation was selected as the research target in this study. This formation is located in the central area of the Province of Alberta and stretches from the Northwest to the Southeast of the province. Natural gas has been produced from the Pembina zone in the Cardium Formation since 1953; thereafter, light oil production started. Up to present day, about 7780 million barrels of oil has been produced from the Cardium zone (Ghaderi et al., 2011). The Cardium Formation was deposited during the late Cretaceous age in the Western Canada Sedimentary Basin and is divided into Pembina and Cardium zones. The lithology of the Cardium Formation is mainly fine-grained sandstone separated by shale layers. In the Cardium zone, the lithology consists of muddy sandstones, which leads to a low permeability in the tenths of millidarcies with porosity from 4 to 12%. The reservoir in Cardium zone consists of sand-filled intervals, thin shale barriers, and other complex facies, which leads to high heterogeneity of the reservoir. The area selected as the basis for building the geological model is the Harmattan Cardium pool with location shown in Fig. 1.

3. Dilation-recompaction model

The dilation-recompaction model used in this study, also referred to as the Beattie-Boberg model (Beattie et al., 1991), was first developed to describe steam fracturing in heavy oil and oil sands reservoirs under Cyclic Steam Stimulation (CSS). In CSS, steam fracturing occurs since steam is injected at pressure greater than the fracture pressure of the reservoir. The first utilization of the dilation-recompaction model was to model CSS in Esso's Cold Lake reservoir where the initial reservoir pressure is around 3000 kPa, the depth of oil sands is equal to 450 m and the reservoir fracture pressure is equal to about 9900 kPa (Cokar et al., 2012). During steam injection, steam is injected at pressure of 11,000–13,000 kPa leading to steam fractures within the oil sand formation (Cokar et al., 2012). There is one important difference between oil sands reservoirs and tight rock formations. Oil sands reservoirs are unconsolidated which means the fracture will close during production due to compaction from pressure depletion. As for tight rock formations, the rock is consolidated and due to the presence of the proppant that fills fractures, they are unlikely to fully heal after production starts. The dilation-recompaction model can be adjusted so that re-compaction is reduced to reflect the placement of proppant within the fractures.

When high-pressure fluid is injected into the reservoir rock, the pore pressure increases. As pore pressure rises, the mean effective stress falls and pore volume expands leading to dilation of the rock. At some point, the pore pressure is sufficient to fracture the reservoir rock and the pore volume of the reservoir rock grows at a faster pace. The propagation of the fractured zone stops shortly after injection stops. Due to the elevated pressure in the fractures, the fluids there leak into the surrounding reservoir rock leading to a decline of the pore pressure in the fracture. After production starts, the pore pressure declines more rapidly leading to a reduction of the pore volume – this part of the process is referred to as re-compaction. The key geomechanical properties that control the process are the formation compressibilities during dilation and re-compaction (Beattie et al., 1991). For linear elastic solids, the compressibility is equal to the reciprocal of the Young's modulus. The dilation-recompaction model is described in Fig. 2. The procedure is as follows: as shown in Fig. 2, when fluid is injected into the formation, the pore pressure increases from the initial reservoir pressure and porosity (labelled as Point a in Fig. 2). As a consequence the mean effective stress declines and porosity rises. If the changes of the pore pressure are small, then the system acts elastically in a reversible manner, meaning that if the pore pressure was reduced, then the porosity would traverse the same trajectory as it did when the pore pressure was increasing but now in the opposite direction. In the elastic portion of the porosity response (line bounded by Points a and b), the change of the porosity with pore pressure is relatively small and the equation governing the porosity is:

$$\varnothing = \varnothing_r e^{c(p-p_r)} \approx \varnothing_r[1 + c(p - p_r)] \quad (1)$$

where c is the compressibility (1/kPa), p_r is reference pressure (kPa), and $\varnothing_r$ is the porosity at the reference pressure. It is known that the absolute permeability of reservoir rock depends on the porosity of the rock – the higher the porosity, the greater the permeability. However, since the change of the porosity during the elastic response of the system is small, so too is the permeability. The relationship used here between porosity, $\varnothing$, and permeability, k, is:

$$\frac{k}{k_0} = e^{k_{mul}\frac{\varnothing-\varnothing_0}{1-\varnothing_0}} \quad (2)$$

where k_0 is the original permeability, k_{mul} is a multiplier that is tuned from the history match when the hydraulic fracture is matched, $\varnothing_0$ is the original porosity. This relationship is simple and has worked well for steam fracturing (Cokar et al., 2012). At some point, as the pore pressure is raised, it reaches the fracture pressure (labelled as Point b in Fig. 2). Thereafter, further increases of the pore pressure due to fluid injection leads to more rapid growth of the porosity. As shown in Fig. 2, the porosity now rises according to the line connecting Points b and c. In this part of the process, the permeability enlarges significantly as the porosity grows.

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