Abstract

Numerical modelling has been conducted to determine in which situations it is better to include the multi-phase flow properties of fault rocks in production simulation models and when it is better to accurately include fault rock thickness. The answer to this problem depends on drive mechanism, well position, and the capillary pressure distribution along the fault, as well as on which parameters need to be modelled (e.g. bottom-hole pressures, hydrocarbon production rates, water cuts, etc.). In the situation where a producer is separated from an injector by a fault with a high capillary pressure, it appears that fault rock thickness has a large influence on predicting the pressure distribution within the field, but has only a slight effect on the oil and water production rates. In other circumstances (e.g. producing from one side of a fault where pressure support comes from an aquifer), it is essential to incorporate multi-phase flow properties into the simulation. In other situations (e.g. predicting field pressure where injector and producer are in different compartments), it is critical to incorporate both fault thickness and two-phase flow properties into the simulation model.

KEYWORDS: faults, production simulation, multi-phase flow, up-scaling, relative permeability

1. Introduction

It has been proposed that a possible way of incorporating the multi-phase flow properties of faults into simulation models is to use pseudo-functions (Fisher and Knipe, 2001; Manzocchi et al., 2002). Essentially, dynamic pseudo-functions are generated by conducting high-resolution fluid flow models at the scale of the reservoir simulation grid block, using flow rates that are similar to those that are likely to be encountered within the reservoir. In these high-resolution models, both the fault and reservoir rock are given their own capillary pressure and relative permeability curves. The results of the simulations are then used to create a relative permeability and capillary pressure curve that is then incorporated into the up-scaled production simulation model to account for the presence of both the fault and undeformed reservoir. There are many ways to calculate such pseudo-functions; the reader is referred to Barker and Thibeau (1996) or Barker and Dupouy (1999) for comprehensive reviews of the subject.

One of the problems with the use of pseudo-functions is that fault rock thickness is likely to vary significantly as a function of fault throw (e.g. Hull, 1988). A large number of pseudo-functions may therefore need to be created to account for the range of fault rock thicknesses.
present within a typical reservoir. A simplification would be to assume that only a small number (or even one) of fault rock thicknesses existed within the reservoir, thus limiting the number of pseudo-functions necessary to model the reservoir.

A key question raised by such arguments is “under what circumstances is it better to incorporate the multi-phase flow properties of faults into production simulation models than to accurately account for fault rock thickness?” In this paper we present some initial results from some simple, yet informative, numerical modelling that has been conducted to answer this question. The paper begins by describing the various models used in this study. The results are then presented and their implications discussed.

2. Model Description

A simple simulation model was constructed and bi-compartmentalised by a single fault in the middle. Flow across the fault was simulated for three models with similar geometries but varying wells locations (Fig. 1). The models each have $50 \times 5 \times 8$ cells and a dimension of $40 \text{ ft} \times 200 \text{ ft} \times 25 \text{ ft}$. For each model, two fault rock thicknesses of 0.3 ft and 3 ft were used. The sealing capacity for each fault was represented in the simulation using the following three representations:

- Transmissibility multiplier (derived using the methodology of Manzocchi et al., 1999).
- Multi-phase (capillary pressure and relative permeability curves) properties incorporated discretely with a low capillary entry pressure (curves derivation is analogous to that proposed by Manzocchi et al., 2002).
- Multi-phase (capillary pressure and relative permeability curves) properties incorporated discretely with a high capillary entry pressure.

3. Fluid Flow Modelling Results

3.1 Model 1 (Fig. 1a)

Model 1 has an injector and producer at opposite sides of the fault. The injector is perforated in the lower two layers and the producer is perforated in the upper two layers. All simulations predict that most of the oil from the opposite side of the fault (Compartment 1) would be produced (Fig. 2a).
transmissibility multipliers and the models in which the fault is included discretely with a low capillary entry pressure all predict similar cumulative oil production profiles, irrespective of whether the fault is 3 ft or 0.3 ft thick. The model in which the fault is given a high capillary pressure predicts that less oil is produced from Compartment 1 than the other models. A rather counter-intuitive result is that the simulations indicate less oil being produced from Compartment 1 when the fault is 0.3 ft thick than when it is 3 ft thick. The physical reason behind this result is that a far higher drawdown occurs in the case of the 3 ft fault (Fig. 2c) because less water flow occurs across the fault in the aquifer. The larger drawdown allows higher oil saturations to develop within the fault rock and hence increases its relative permeability.

Large differences exist between the simulation models in terms of their predictions of the field average (Fig. 2b) and bottom hole pressure within the producer (Fig. 2c). It appears that the prediction of average field pressures requires an accurate incorporation of both fault rock thickness and two-phase flow properties (Fig. 2b). The models containing a 3 ft-thick fault all predict similar bottom hole pressures, which are around 1000 Psi lower than the models containing a 0.3 ft-thick fault. These results suggest that accurately incorporating fault rock thickness into these models is far more important when predicting bottom hole pressures than accurately incorporating the capillary properties of the faults (Fig. 2b). The reason for this is that the pressure in the producing block is rapidly drawn down until the capillary entry pressure of the fault rock has been overcome, after which the rate of movement across the fault is almost independent of its capillary pressure characteristics.

3.2 Model 2 (Fig. 1b)

Model 2 has the injector and producer on the same side of the fault. The injector is perforated in the lower two layers and the producer is perforated in the upper two layers. In all simulations, most oil was produced from the compartment containing the injector and the producer; very little oil was produced from the opposite side of the fault (Fig. 3a). As with Model 1, there is very little difference between the models in terms of predicting the oil production rate (Fig. 3b). For the faults with the higher capillary entry pressures, it seems that it is more valuable to incorporate the two-phase flow properties of fault rocks than their thickness when predicting the bottom hole pressure in the producer (Fig. 3c).

3.3 Model 3 (Fig. 1c)

Model 3 does not contain an injector; instead, pressure support comes from an analytical aquifer. The producer is situated in Compartment 2 and is perforated in the upper two layers. In this model, the results when the fault rock was included discretely and when its properties were included using transmissibility multipliers differ greatly. In particular, the model predicts that only minimal oil would be produced from the opposite side of the fault when the two-phase flow properties are included (Fig. 4a). On the other hand, the model predicts that most oil would be produced from both compartments in the model when fault rock properties are included as transmissibility multipliers (Fig. 4a). These differences are reflected in both the rate of oil production (Fig. 4b) and the bottom hole pressure in the producer (Fig. 4c). Clearly, in this situation it seems that it is more valuable to accurately incorporate the two-phase flow properties of the fault rocks than the fault rock thickness when predicting the bottom hole pressure in the producer.

4. Discussion
4.1 Production mechanisms and the incorporation of fault rock properties into simulation models

The main aim of the simulation modelling conducted during the present study was to provide an answer to the question “under what circumstances is it better to incorporate the multi-phase flow properties of faults into production simulation models than to accurately account for fault rock thickness?”. The results presented in this article suggest that there are no simple answers to this question. In some circumstances (e.g. injector and producer on the opposite sides of a fault), it is clearly more important to accurately take into account fault rock thickness in the simulations. In other circumstances (e.g. producing from one side of a fault when pressure support comes from the aquifer), it is clearly more important to incorporate the multi-phase flow properties into the simulation. In other circumstances (e.g. predicting field pressure when the injector and producer are in different compartments), it is necessary to incorporate both the fault thickness and the two-phase flow properties into the production simulation model. The latter example indicates that, when considering how to incorporate the properties of faults into production simulation models, it is important to identify which are the most important parameters that must be predicted. For example, in Model 1, the fault rock thickness had a large impact on prediction of the pressures, whereas the two-phase properties had more of an impact on predicting the oil production rates.

4.2 Further work

The results from the simulations presented above indicate that for some situations it is important to incorporate both the fault rock thickness and multi-phase flow properties of faults into production simulations. The most obvious way to incorporate the multi-phase flow properties of faults into simulation models is to use pseudo-functions (Manzocchi et al., 2002). Considering the large variation in fault rock thickness within a reservoir, and the fact that pseudo-functions are flow-rate dependent, it is likely that a huge number of pseudo-functions would be generated for an individual simulation. At present we are attempting to calculate the range of pseudo-functions needed to describe reservoir behaviour and then reduce the number required to be incorporated into the final simulation model by grouping them on the basis of key physical parameters such as the cross-over and end-points of the water and oil relative permeability curves.

5. Conclusions

Two-phase fluid flow modelling has been conducted to answer the question “under what circumstances is it better to incorporate the multi-phase flow properties of faults into production simulation models than accurately account for fault rock thickness?”. The results show that in some circumstances accurately determining fault rock thickness does not have a huge impact on the modelling. In these situations, incorporation of multi-phase flow properties of fault rocks in production simulations models is far more important.

It is important to identify which are the most important parameters that need to be predicted when considering how to model faults in flow simulations. It is possible that more work in this area may provide ‘rules of thumb’ which will indicate which parameters are important to consider when modelling fluid flow in faulted reservoirs. However, each case may be so specific that it is necessary to construct simple numerical models to determine which are the most important parameters to include in full field production simulation models.

As a final conclusion, the present study has slightly reduced the uncertainty in predicting fault rock thickness for flow simulation. This article offers important constraints that should assist in providing ‘quality control’ on the parameters used to generate history matches of production data. The study also suggests that in many situations the uncertainty in predicting
fault rock thickness does not necessarily reduce our ability to model fluid flow in petroleum reservoirs.

6. References


Figure 2  Model 1 simulation results.  (a) Oil in place in compartment 1 as a function of simulation time.  (b) Field average pressure as a function of simulation time.  (c) Bottom hole pressure in the producer as a function of simulation time. High-$P_c$ and low-$P_c$ denote high and low capillary entry pressures have been used for the fault zone. TM is where fault rock properties were incorporated using transmissibility multipliers.
Figure 3  Model 2 simulation results.  (a) Oil in place in compartment 1 as a function of simulation time.  (b) Field oil production rate as a function of simulation time.  (c) Bottom hole pressure in the producer as a function of simulation time.  High- $P_c$ and low- $P_c$ denote high and low capillary entry pressures have been used for the fault zone.  TM is where fault rock properties were incorporated using transmissibility multipliers.
Figure 4  Model 3 simulation results. (a) Oil in place in Compartment 1 as a function of simulation time. (b) Field oil production rate as a function of simulation time. (c) Bottom hole pressure in the producer as a function of simulation time. High- $P_c$ and low- $P_c$ denote high and low capillary entry pressures have been used for the fault zone. TM is where fault rock properties were incorporated using transmissibility multipliers.