THE INJECTIVITY OF COALBED CO$_2$ INJECTION WELLS

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ABSTRACT

Though it may be possible to enhance methane production from coal by injecting CO$_2$, because coal is poorly permeable it is usually necessary to inject under fracturing conditions to achieve acceptable injectivity. Concomitantly, the process of replacing the methane by the injected the CO$_2$ causes the matrix to swell. These two processes – the fracturing of the coal and the swelling – have opposite effect on the injectivity.

TNO-NITG have pressure data from a CO$_2$ injection test in a coalbed methane field. We used the SIMED II coalbed methane simulator to history match the test behaviour and to find the most sensitive parameters affecting the injectivity of the CO$_2$ injection well. An analysis of the pressure records revealed both the occurrence of fracturing and the reduction in permeability that swelling induced. When applied to an extended injection simulation, the simulator showed that the most sensitive parameters influencing the injectivity were the permeability, the fracture conductivity, and the cleat system porosity. Unfortunately, due to the adsorption of the CO$_2$ and the fluctuations in pressure during injection tests, all these vary over time.

INTRODUCTION

Injecting CO$_2$ into coal seams might be an attractive option for the underground sequestration of CO$_2$: the CO$_2$ would be stored and, simultaneously, the production of coalbed methane enhanced (ECBM). The revenue from methane production could offset the expenditure on the storage operation. There is a problem, however: coal is poorly permeable to fluids. Furthermore, replacing the methane by the injected CO$_2$ will cause the matrix to swell. This swelling will partially block the cleat system and negatively affect the main flow parameters. To achieve an acceptable CO$_2$ injection rate it might therefore be necessary to allow the near-well gas pressure in the cleat system to exceed the hydraulic fracturing pressure.

In this paper we present the analysis of a CO$_2$ injection test in a coalbed methane field and demonstrate the processes of fracturing of the reservoir during injection and a gradual decrease in reservoir permeability during continued injection. We used the resulting knowledge to simulate extended injection tests, with larger injection rates and greater volumes.

FIELD EXAMPLE

TNO-NITG have reliable and comprehensive pressure data from an intermittent injection test of CO$_2$ into an existing coalbed methane well, followed by an extended shut-in period. The scaled raw data are depicted in Fig. 1. We made history matches using SIMED II [1,2], a reservoir simulator designed for modelling coalbed methane reservoirs, taking account of combined flow of water and multi-phase gas flow and adsorption to the coal. For the given problem we decided to use a two-layered radial grid with radial symmetry. Where appropriate, the fracture is located in layer 1 and partially penetrates layer 2. We also performed runs in which a quarter of the reservoir was divided into 4 or 6 radial segments, one of them containing the fracture. This had some effect on the outcome of the adjustable parameters but it did not influence the major outcomes of the study. The starting point was to try to history match the data conventionally, without using hydraulically induced fractures.
Figure 2, however, shows that it was impossible to obtain a reasonable history match with a single permeability for the CO₂ injection and pressure fall-off stages. When the permeability was adjusted so that the simulated pressure fall-off during well shut-in matched the data, the resulting pressures during injection were much greater than those recorded.

SIMED II can take account of hydraulically induced fractures [3]. Introducing a reasonably long but relatively poorly conducting fracture at the wellbore did indeed yield a better overall match for the pressure at the end of an injection period and for the subsequent pressure decline during shut-in. However, the pressure built up far too slowly: whereas the scaled pressure in the field test quickly rose to about 0.61 and then more or less stabilized, the simulation showed a continued pressure increase, with the rate of increase dependent on the fracture conductivity. The field behaviour can be explained by the fact that CO₂ injection is often performed above fracturing pressure, but after shut-in the pressure inside a fracture has fallen below the fracture closure pressure and hardly any conductivity remains. To overcome this, we introduced into the program the concept of a fracture whose opening depends on the actual pressure. For each grid block that was crossed by the predefined fracture, the conductivity of the fracture was set at zero if the actual pressure was smaller than the fracture closure pressure, and at a finite value otherwise. When the fracture closed, only the reservoir permeability would dictate the flow in that block. Figure 3 shows a simulation of the 2nd, 3rd and 4th injection cycles with the scaled fracture opening pressure set at 0.61. This procedure resulted in pressure increasing rapidly after injection started, until the threshold value of fracture opening had been reached. Thereafter, gradually more grid blocks in the reservoir allowed the predefined fracture in them to open and the pressure in the wellbore no longer rose sharply. We feel that this process closely resembled reality: although it did not simulate actual fracture propagation by taking into account the associated rock mechanics, it did allow for an increase in the effective fracture length. At the same time, the frictional pressure drop in the fracture brought about by the input fracture conductivity was taken into account.

It proved impossible to history match all the injection cycles with one formation permeability. Separate matches of the 12 cycles showed that in subsequent cycles of CO₂ injection the permeability decreased. This effect is already apparent in Figure 3. The trend of decreasing permeability can be explained in relation to the adsorption process of CO₂ in coal: the methane was driven out of the coal by the injected CO₂, effectively causing the matrix to swell. In turn, the swelling brought about partial closure of the cleat system and a decrease of the permeability. Conventional fall-off test interpretation shows this decrease very clearly. Figure 4 is a graphical representation of this process. The effect of increasing normal stress on permeability as a possible result of swelling has also been demonstrated by de Haan [4].

The level of decrease in permeability was determined by means of a history matching exercise. We built into the program the option to change the permeability over time. The resulting permeability development is displayed in figure 5. Figure 6 shows a history match of all the cycles: the permeability declined steadily, so that by the last injection cycle it was 4.6 times smaller than the first cycle. Concomitantly, the part of the fracture open during the injection increased from some 7 m in the first cycle to about 12 m in the last one. (Note that to obtain this match, the injection rate of the 11th cycle had to be decreased by a factor of 0.7. This adjustment is permissible, given the poor data for that cycle. When this cycle was examined individually it was difficult to obtain a reasonable match of the pressure decline curve, and the clear correlation between the injection pressure and the injection rate that was found for the other cycles – see Fig. 1 – did not hold for cycle 11.) Given the uncertainties in the operating conditions during the field experiment, the overall history match is very acceptable.

**EXTRAPOLATION TO AN EXTENDED INJECTION TEST**

Using input parameters derived from the history match we performed a number of simulations to assess the behaviour of an extended injection test. These simulations were done for a higher injection rate, starting at a value about three times that of the field test. Some of the results are shown in Fig. 5. In the base case, the permeability has been kept at the value derived for the third cycle in the field
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The fracture grew to lengths of the order of 100 m while the pressure increased far above the fracturing pressure. When after 6 days the injection rate was halved, the pressure dropped considerably, but the fracture length stayed the same or increased even more. Upon shut-in, first the fracture closed and then flow was through the cleat system only. The change from the open to the closed fracture is clearly visible in the Figure after about 18.5 days, as an abrupt change in slope.

Decreasing the value of the permeability during the injection period resulted in an increased pressure during the test and a slower pressure decline upon well shut-in. Fracture closure was not even reached on the scale of the Figure. Increasing the fracture conductivity resulted in the pressure decreasing, and it increased the slope of the pressure decline curve as long as the fracture was open. Decreasing the porosity resulted in an increase in injection pressure and a slower pressure decrease upon shut-in (not shown in the Figure).

It was difficult to derive reliable values for the fracture conductivity from the field test described above, particularly as we knew that the magnitude of this conductivity would be pressure-dependent. To derive reliable values, an injection test like the one shown in Figure 7 would have been required, in which the pressure rose significantly above the hydraulic fracturing pressure and in which fracture closure could be observed. Of course, the reservoir simulator is already a very valuable tool for performing sensitivity analyses.

CONCLUSIONS AND DISCUSSION

The field example clearly allowed two conclusions to be drawn. The first is that the injection in this example took place under fracturing conditions. The opening and closing of the fracture, which was dependent on whether the pressure in the fracture was greater or less than the fracture opening pressure, had to be taken into account to obtain a realistic pressure track during injection and shut-in. We did not model the actual fracture propagation using the rock mechanics of the formation, but instead we used an existing fracture which we allowed to open and close depending on the pressure. This was found to be satisfactory for the present application.

The second conclusion is that the continued injection of CO\textsubscript{2} in coalbed methane induced a decrease in the permeability of the cleat system. This effect, which we introduced via trial and error, merits more detailed study both experimentally and using field tests. Above, we noted that the reason for the decrease in permeability upon CO\textsubscript{2} injection was the total or partial closure of the cleats brought about by the increased normal stress, which in turn originated from the swelling of the coal. A proper model of the increased stress should take account not only of the local swelling in the grid block under consideration but also of the surrounding reservoir. Indeed, a swelling of the matrix in one location would affect the stress situation at all other locations in the reservoir, with the effect diminishing over distance. The theory Biot [5] used to explain the similar effect of pore pressure on the in-situ stress field could be used here as well: instead of the increase in pore pressure we had swelling caused by CO\textsubscript{2} adsorption, which affected the stress field. The problem of permeability decrease could thus be simplified to the determination of the correlation between permeability and stress. It would not be straightforward to incorporate this in the reservoir simulator, however, since the stress in each block must be determined using the pressure in the whole reservoir.

Our simulation of an extended injection test with a higher injection rate has shown how sensitive the results are to the formation permeability, the fracture conductivity, and the porosity. It would be possible to estimate the formation permeability using field tests like those we analysed; for a reliable estimate of the fracture conductivity, however, injection tests with higher injection rates would be required, because the pressure must rise significantly above the fracturing pressure. The fracturing pressure needs to be established using the shut-in period of the well.
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REFERENCES


Figure 2: Attempt to model cycles 2 – 4 without the presence of a fracture.

Figure 3: Model of cycles 2 – 4 with an opening and closing fracture.

Figure 4: Fall-off test interpretation result.
Figure 5: Permeability development as result of swelling

Figure 6: Simulation of all cycles with an opening and closing fracture and decreasing permeability

Figure 7: Simulation of an extended injection test. The same scaling as in Fig. 1.