PROCEEDINGS, Thirtieth Workshop on Geothermal Reservoir Engineering
Stanford University, Stanford, California, January 31-February 2, 2005
SGP-TR-176

IMPROVING A NUMERICAL TOOL AND EVALUATING IMPACT OF DENSITY CHANGES OF INJECTED FLUIDS IN THE HYDRAULIC BEHAVIOUR OF HDR RESERVOIR

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ABSTRACT

During the last five years, the European Hot Dry Rock Project at Soultz-sous-Forets (France) has known major advances. Three deep wells were drilled into the crystalline basement at 5000 m depth. Stimulation of the wells by high rate fluid injections gave much information thanks to the microseismic events recorded on site. In order to better understand the development of the reservoir, a numerical model based on a Discrete Fracture Network approach was written to interpret and predict the pressure distribution in the reservoir and the hydraulic behavior of such a system. The hydraulic part of this finite volume code is strongly coupled with the mechanical behavior of the fractures.

The last years experiments showed that the density difference between autochthonous fluid (density 1060 kg/m^3) and injected fluid (heavy brine or fresh water) might play a significant role during the stimulation phases of the wells. It was then decided to enhance the numerical code, under the assumption of immiscibility of the two fluids. A new variable was introduced in the code, saturation; flow equations are now solved with an IMPES scheme.

These recent improvements allow us to evaluate the impact of fluid density on the pressure distribution in the reservoir during stimulation or circulation tests. Therefore we provide better estimates of both extension and shape of the stimulated areas and we are able to define new stimulation strategies. The new version is also proven fruitful in predicting the evolution of flow distributions in fractures intersecting the bore holes as well as in giving breakthrough estimates for tracers (chlorure contend) migration in between injection and production bore holes.

INTRODUCTION

The general background of this study is the European Hot Dry Rock Research Program located in Soultz-sous-Forets, France. The purpose of this program is to generate electrical power from a deep enhanced geothermal system. The idea consists in injecting cold water into a hole while producing hot water in adjacent ones. The first step of this geothermal exploitation of the subsurface is the development of the reservoir, released by very high pressure injections in the system. The role of these injections is to enhance the permeability of the fractures by increasing the water pressure until shear can develop along the fractures. The injected fluid is essentially cold, fresh water that will be in contact in the reservoir with hot rocks and heavy hot brines.

The model presented here has been written in order to simulate potential density driven flows during stimulation of the reservoir, occurring between brine and fresh water. It is based on the Discrete Fracture Network approach; flows in rock matrix are neglected. Fractures are considered as discs: their distribution in space, orientation and thickness respond to stochastic laws inferred from the available statistics. The continuity equation is written at the center of each fracture. Each center of a fracture is a node of the mesh, and the controlled volume of each node is the fracture volume.

This paper describes the mathematical model, the spatial discretisation used, the resolution of the nonlinear system, a validation of the model, with the Buckley-Leverett problem and applications of this code, first at the scale of one well, and then with a more complex multi-well system.

The equations are the continuity equation of each phase, commonly used (Huyakorn and Pinder 1983; Slough et Al. 1999). The spatial discretisation is done using a finite volume scheme, and the evaluation of fluxes between two connected nodes considers the geometry of intersection of the two fractures (Cacas

1989; Jeong 2000). The system is solved with an IMPES scheme for Implicit Pressure - Explicit Saturation (Coats 2000; Forsyth 1999). It consists in resolving implicitly a single pressure equation, and explicitly a saturation equation, using the computed pressure values.
The Buckley-Leverett test case, commonly used in the petroleum industry is used as a numerical benchmark. Briefly, it simulates the advancement of a saturation front in a porous media. Computed results can be compared with results of the analytical solution written by Buckley and Leverett (1946).
The first application presents works that are done in order to understand mechanisms of the stimulation of the last well (GPK4) and to determine what is the role of the density of the injected fluid. The second application presents a more global model of the Soultz-sous-Forets fracture network and the results obtained.

FORMULATION

Governing equations

The equations describing a two-phase flow are obtained by combining Darcy's law with the individual phase conservation. They may be written in the following form (Huyakorn et Al.1994):

$$\nabla.(k\tau_l\nabla(P_l+\rho_l gz))=\frac{\partial}{\partial t}(\rho_l\Phi S_l)-M_l$$

where subscript l denotes the phase; k is the intrinsic permeability; τ_l is the mobility of the phase l ($\tau_l=k_r^l\rho_l/\mu_l$, in which k_r^l is the relative permeability, ρ_l is the fluid density and μ_l is the fluid dynamic viscosity); t is time; P_l is the pressure of the phase l ; g is the gravitational acceleration; z is the elevation above the datum plane; Φ is the porosity; S_l is the saturation of the phase l; M_l is the rate of mass injection or withdrawal of fluid phase l per unit volume of the medium.
In addition to these flow equations, the following constitutive relations have to be considered, with P the average pressure of the two fluids:

$$S_{l1}+S_{l2}=1$$

$$k_r^l=k_r^l(S_l)$$

$$k=k(P)$$

Major assumptions

The Boussinesq assumption

This is quite a common assumption in reservoir modeling; it consists in neglecting variations of the fluid densities in the conservation equation, except in the buoyancy term ($P_l+\rho_l gz$). This equation now becomes:

$$\nabla.(k\frac{k_r^l}{\mu_l}\nabla(P_l+\rho_l gz))=\frac{\partial}{\partial t}(\Phi S_l)-Q_l$$

where Q_l is the volumic rate of injection of fluid phase l per unit volume of the medium.

The zero capillary pressure assumption

The capillary pressure is often neglected in reservoir modelling because it is usually very small compared to pressure variations in subsurface flows (Helmig 1997).
Practically, this leads to:

$$P_{l1}=P_{l2}=P$$

NUMERICAL TREATMENT

The numerical method used is very classical; it consists in a finite volume discretisation, associated with an IMPES resolution scheme.

Finite volume spatial discretisation

The finite volume method is a well-established method that is used in porous media. Our purpose is to adapt this method to a discrete network of fractures. This can be done thanks to the physical aspect of the finite volume formulation.
This formulation is obtained by integrating the conservation equation over the volume V_{frac} of one fracture:

$$\int_{Vfrac}\nabla.(k\frac{k_r^l}{\mu_l}\nabla(P+\rho_l gz))dV=\int_{Vfrac}(\frac{\partial}{\partial t}(\Phi S_l)-Q_l)dV$$

At that point it should be underlined that Φ no longer is the porosity of an equivalent porous media but it is the porosity of the considered fracture.
Applying the divergence theorem to the last equation, and making the assumption that saturation and porosity are constant in a single fracture, one obtains:

$$\int_{Sint}\nabla.(k\frac{k_r^l}{\mu_l}\nabla(P+\rho_l gz))\cdot\underline{n}dS=V_{frac}\frac{\partial}{\partial t}(\Phi S_l)-q_l$$

where q_l is the is the rate of injection of fluid phase l , *Sint* is the surface of the intersection between two fractures and $\underline{n}$ is a unit vector , normal to the surface of intersection of the two fractures and pointing outside of the considered fracture.
Physically, the left term of the last equation is the flow going out of the considered fracture through an adjacent one. In our code this term is computed using an "integrated intrinsic permeability», k_{ij}^{int}, for the link between fractures i and j, calculated as follows:

$$k_{ij}^{\text{int}}=\frac{k_i.k_j}{k_i+k_j}.S_{\text{int}}(fracture\_i, fracture\_j)$$

Then, making the assumption that pressure is constant over one fracture and developing the gradient term to the first order, the conservation equation, written for the fracture i becomes:

$$\sum_j k_{ij}^{int} \frac{k_r^l(S_{ij}^l)}{\mu_l}\left(\frac{(P_i+\rho_l g z_i)-(P_j+\rho_l g z_j)}{\Delta x_{ij}}\right)=V_i \frac{\partial}{\partial t}(\Phi_i S_i^l)-q_l$$

using an upstream weighting scheme for the calculation of relative permeabilities:

$$S_{ij}^l=\alpha S_i+(1-\alpha)S_j$$

with α=1 if $P_i+\rho^l g z_i > P_j+\rho^l g z_j$ and α=0 if not.

The IMPES scheme

Only the main ideas of this method are exposed here as many authors describe it in details.

Solving such a system of equations is not easy; as underlined by Peaceman (1977) the problem is parabolic in pressure and hyperbolic in saturation. An important point is that using a finite volume formulation provides numerical stability to the computation method. The IMPES method consists in solving implicitly the pressure equation and in solving explicitly the saturation equation, with the computed pressure values. The basic idea is to obtain a single pressure equation by summing the flow equations for each fluid phase (Settari and Aziz 1990).

The transient term of the conservation equation is written using Euler's implicit temporal discretisation scheme, and the final equation is solved using Newton-Raphson's algorithm because of the strong non linearity of $k_{ij}^{int}(P_i,P_j)$. The saturation is obtained explicitly by replacing the newly computed pressure value in one of the flow equation, assuming that porosity is constant during one time step.

TEST CASE: THE BUCKELEY-LEVERETT PROBLEM

This test problem is a very classical numerical benchmark for simulation codes in reservoir modeling. More precisely, it is a one dimensional flow problem, that was first solved by Buckley and Leverett (1946), since then it has been used by many scientists in order to evaluate the behavior of their codes (Settari and Aziz 1990; Huyakorn and Pinder 1978).

Physical parameters

The Buckley-Leverett problem consists in injecting a fluid at one side of a one-dimensional porous media while extracting the initial fluid at the other side of it (Figure 1). The geologic media and both fluids are assumed to be incompressible, and capillary pressure is neglected. A moving saturation front between the two fluids is observed; its shape and its migration rate are a severe test for numerical models. As pointed out by Buckley and Leverett (1946), the shape of the front strongly depends on the relative permeabilities. The analytical solution, obtained by the characteristics method, won't be given here. Please refer to Dahle et al. (1990) for further information.

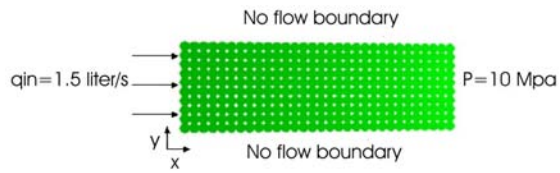

Figure 1. Geometry for the Buckeley-Leverett Problem.

The difficulty is to adapt this example from a porous media to a discrete fracture network. Two ways to proceed are possible: build a stochastic network and deduce its equivalent permeabilities and porosity, or work on a deterministic network, like a plane, built by juxtaposition of fractures. This method appeared to be easier to perform. Nodes of the mesh are at the center of the fractures, every 10 meters. In order to fit to a finite difference scheme, the radius of the fractures is set to 5.64m. Using this value, the area of one fracture is equal to the area of one cell, which means that the porosity of the network is equal to the porosity of a single fracture. This fracture network is equivalent to a porous media of a cross section of 10^{-1} m^2.

The table presented in figure 2 shows the physical parameters used to compute the Buckley-Leverett solution. As it can be seen on this table, the equivalent area of cross section of our model is 10^{-1}m ; implying a Darcy velocity of $1{,}5.10^{-2}$m/s. It means that the simulation duration of 1296s is equivalent to an elapsed time of 1500 days following the values used by Thorenz (2001).

Parameter	Used value	Thorenz Value
Length	300m	302m
Width	100m	1m
Height	-	10m
Frac. thickness	10^{-3}m	-
Sim. Time	1296s	1500d
Porosity	0.2	0.2
Permeability	1. 10^{-8}m/s	No influence
Viscosity	1000Pa.s	1000Pa.s
Inject. Rate	1. $10^{-3}$$m^3$/s	1.5 $10^{-6}$$m^3$/s
Init. Sat.	0.2	0.2
Sat. injected	0.8	0.8

Figure 2. Parameters used by Thorenz in the Buckley-Leverett example.

In both examples the relative permeability is computed by:

$$k_r^l=\left(\frac{S_l-0.2}{0.6}\right)^2$$

Results

The figure 3 is a cross section of the model along the x axis and shows the advancement and the shape of

the saturation front at a time of 1296s. The time step of this simulation is set to 20s, and the mesh size is set to 5m. The theoretical front was established with the characteristic method. The mass balance is good, as the areas delimited by the two curves are equal.
The shape of the computed front is acceptable as the shock wave is not damaged too much by numerical diffusion. One can observe (fig. 3) a small difference between the two profiles. It is due to the inability of the finite volume method to capture sharp fronts. As underlined by Faust (1985), this kind of difficulties is very usual in reservoir simulation. Thorenz (2001) proposed numerical methods in order to skip this problem (*mass lumping* and *Gaussian point upwinding*), but none of them could be applied to a finite-volume numerical scheme.

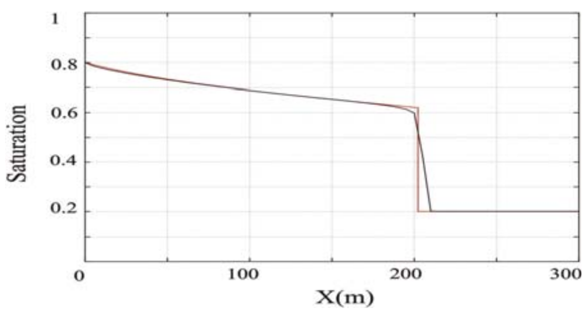

Figure 3. Results for the Buckley-Leverett problem

Various other tests have been performed with our code to characterize its accuracy. In order to see which results could be obtained with a stochastic network, we successfully simulated a salt water intrusion in a fracture network representing a coastal aquifer (Bruel and Baujard 2004).

INTEREST OF A MULTIPHASE APPROACH OF SOULTZ-SOUS-FORETS HDR SITE

One must keep in mind that during the injection tests at Soultz-sous-Forets, an important contrast exists between densities of autochthonous fluid (d=1060 kg/m^3) and injected fluid (d=1200 kg/m^3 or d=1000 kg/m^3). The question is to understand the importance of this difference on the fluid circulation and the fracture stimulation.
An other aspect of our code is its ability to take into account the fracture shear failure, thanks to a hydro mechanical coupling. The mechanical aspect appears through a Mohr Coulomb failure criterion, calculated in all the fractures at every time step; if the resulting calculated shear stress for a considered fracture is greater than the value given by the Mohr Coulomb criterion, the failure of the fracture leads to an opening of the considered fracture and to a new permeability calculation law. This change is supposed to be irreversible during a simulation.
Concerning the parameters used to allow this hydro mechanical coupling, we have to define values and orientations of principal field stress components and a friction angle and cohesion for the Mohr Coulomb criterion. Many authors have published stress evaluation of the Soultz-sous-forets rock masses (Rummel and Baumgartner 1990; Heinemann and Kappelmeyer 1994). In our recent works, we used the stress distribution proposed by Cornet et al. (2004) which allows much better results in term of stability of the fractures in field conditions before injection. The friction angle used in our simulations is 40°, and the cohesion is taken in a range from 2 to 4 Mpa (Cornet et al. 2004).

The case of GPK4

In October 2004 began the stimulation campaign of GPK4. We simulated the injections performed during that period with different densities of the injected fluid, in order to characterize the influence of this parameter on the stimulated area.

Pressure results

Density doesn't have a great influence on the downhole pressure of the well during the simulation (figure 4). With the same model, changing only the injected fluid density doesn't give drastically different pressure response at the well.

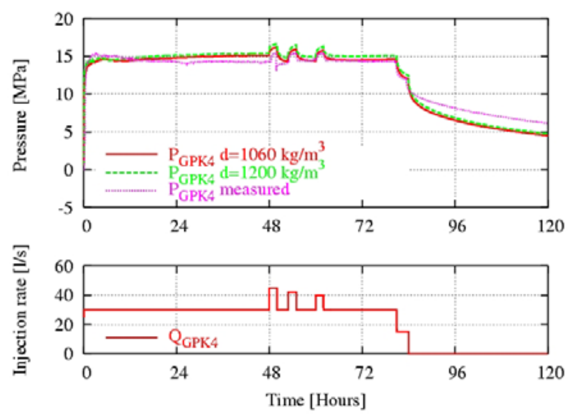

Figure 4. Results for the GPK4 stimulation campaign, modeling the influence of density of injected fluid.

It doesn't clearly appear on that particular model, but the main differences between the two simulations are observed during the shut in periods of the well; we think that this effect could be due to density driven flows that would during the shut in phase of the well take the advantage on injected flow.

Stimulation results

As we could expect, injecting heavy brine instead of water in the well implies major differences on the location of calculated shear events (see figure 5). It can clearly be observed on this image that shear events calculated while injecting a heavy fluid in the fracture network are more numerous and more at the bottom of the reservoir than those calculated while injecting fresh water. With this particular model, we obtain 919 shear events in the case of injecting fresh water and 1044 in the case of injecting heavy brine, what makes an increase of approximately 14% of the number of shear events only thanks to the influence of fluid density.

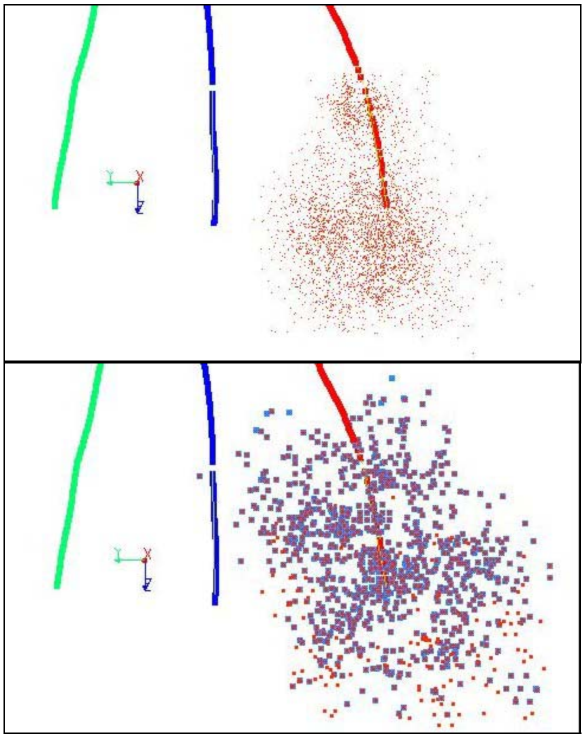

Figure 5. Location (view from west) of recorded seismic events (on top) and of calculated shear events (on bottom) for GPK4 stimulation (blue bold points: injecting at d=1000 kg/m^3; red small points: injecting at d=1200 kg/m^3).

More precisely, we tried to understand the mechanisms of this difference between the two injections with calculated flowlogs; fractures that intersect boreholes in our model are deterministic ones, which means that their orientations and thickness are the ones given by the UBI and flowlogs interpretation on site. Their extensions are assumed. The purpose of this strategy is first to reduce the variability of the hydraulic response of the fracture network due to its stochastic aspect and secondly to simulate a flowlog as close to the observations as possible. This technique has the advantage of presenting fractures that will in our model shear at the same pressure that on site fractures. Figure 6 shows the calculated flowlogs obtained with the GPK4 stimulation campaign, at a time t=48 hours. The injection rate is equal to 45 l/s. We clearly observe on that image a difference due to the density of the injected fluid. The injection rate in the deepest fracture (depth 4975 m) is 21.46 l/s for an injection of fresh water, and 21.86 l/s for an injection of heavy brine, which makes an increase of nearly 2% of injected flowrate for this fracture. It is not a huge difference, but if we consider all the stimulation campaign, it means an increase of about 170 m^3 of injected fluid going into the deepest fracture, in the case of injecting heavy brine. This difference could explain the greater deepness of calculated shear events in this scenario.

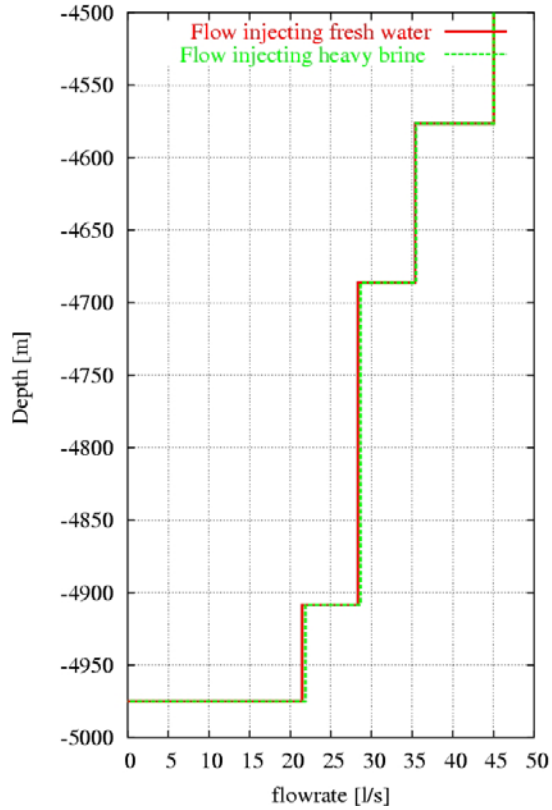

Figure 6. Calculated flowlogs during GPK4 stimulation campaign.

Conclusion on the influence of the density of the injected fluid on stimulation

If the influence of the fluid density during all the stimulation can be clearly established, the problem is that injecting heavy brine during more than three days supposes to have a tank of more than 9000 m^3 of this brine. So the question is to know what could be the influence on stimulation of injecting heavy brine only during the 6 first hours of injection, as it was the case during the stimulation of GPK4 on site. This case shows an increase of more than 50 shear events during the entire stimulation. But these events are not located in the lowest part of the reservoir, as it is the case with the injection of brine during all the stimulation campaign. The distribution in space of these events is very homogeneous. So far, our simulations showed that the shear events that take place at the bottom of the reservoir with the heavy brine begin during the third day of injection, during the first pulse at 45 l/s. In order to try other scenarios of injection, we simulated the stimulation campaign with the injection of brine during this pulse. Results obtained show a less good efficiency of this case, compared to the injection of brine at the beginning of the stimulation. Finally, from all the stimulation strategies defined, the best results were definitely obtained with the injection of brine at the beginning of the stimulation.

APPLICATION TO THE DEVELOPMENT OF THE RESERVOIR

The model

Since 1989, many stimulation campaigns have been performed in Soultz-sous-forets. We will only focus here on the stimulation of the wells GPK2, GPK3 and GPK4 in the 5km depth reservoir. The idea is to try different stochastic models of fracture distribution and to see which one gives the best results in term of pressure response of the wells, saturation distribution in the reservoir and breakthrough estimates, extension and shape of the calculated shear events compared to the seismic cloud recorded on site. As we use the same model for the three wells, we can save the stimulated fractures from the first stimulation campaign (GPK2), and keep them for the GPK3 stimulation campaign, and do the same for GPK4. We can thereby simulate the development of the 5km depth reservoir since 2000, date of the stimulation of GPK2. We must specify here that the multiphase version of our code doesn't take in account the temperature variations of the fluids; their densities are thereby constant during the simulation, which doesn't allow us to predict eventual convection movements of the injected fluid in the reservoir.

The last model we built is constituted of fractures concentrated along great subvertical structures of orientation N160 and N20 (figure 7).

The extension of the model is 2km along the x-axis (eastern), 3km along the y-axis (northern) and 2km depth. The boundary of this model are closed (*q=0*) except for the subvertical structures. This means that these structures behave as conductive areas that are the only ones capable of taking water in the far field. This solution is the one that gives best results for the shut in of the wells. This model contains 45000 fractures of average radius 31m and 1mm aperture.

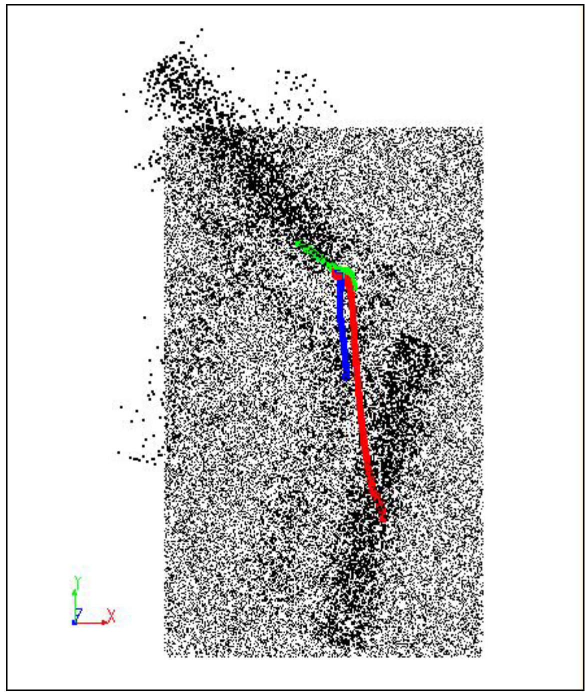

Figure 7. Location of the center of the fractures in our model (top view). Well bores are from north to south GPK2, GPK3 and GPK4.

Pressure Results

One simulation has been run for every stimulation campaign on one single well. This model gives acceptable results (in terms of pressure response) for all the wells. As an example, the figure 8 shows the pressure response of the wells during the GPK3 stimulation campaign. All the tests consist in injecting fresh water (density 1000 m^3/s) in the autochthonous brine (density 1060 m^3/s).

As one can observe, the pressure response calculated with this model corresponds with the pressure recorded on site, except during the shut in phase of the wells. Concerning the saturation, the calculated breakthrough is estimated to 3 days for GPK4 and a bit less for GPK3, which is also acceptable. The same kinds of results were observed with the stimulation of the other wells (The simulated GPK4 stimulation campaign results were shown above, and the GPK2 response during the 2000 stimulation campaign is also correct).

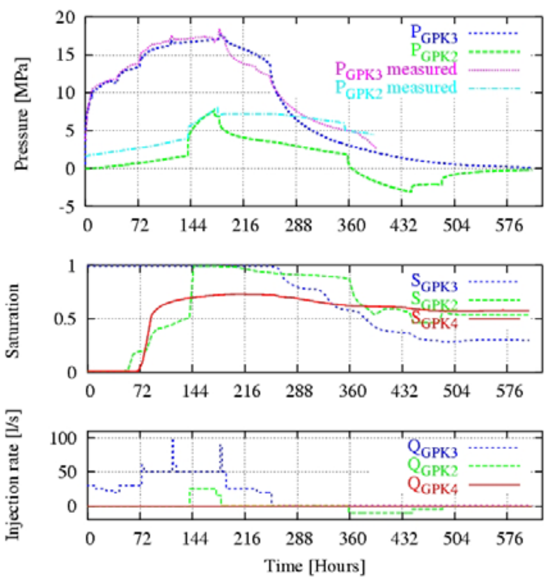

Figure 8. Hydraulic response of the model for the GPK3 stimulation.

Extension of the stimulated area

Figure 9 shows the correspondence between calculated shear events and recorded seismic events.

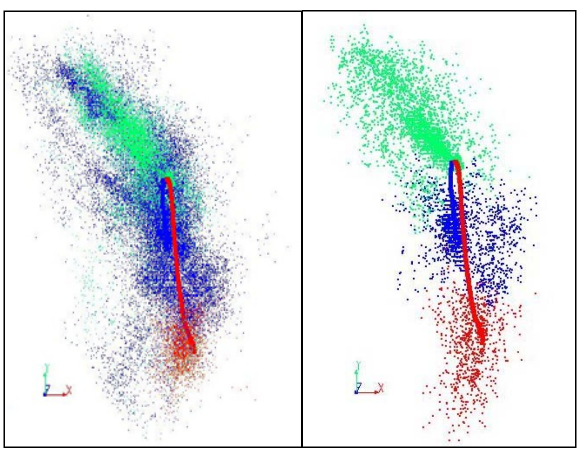

Figure 9. Recorded seismic events (on the left) and calculated shear events during the stimulation campaigns (top view). Green light points: recorded during GPK2 stimulation; blue points: recorded during GPK3 stimulation; red points: recorded during GPK4 stimulation.

We can observe on these images that the location of calculated shear events globally corresponds to the recorded seismic events, even if localized uncertainties still remain. The main problem of this model concerns the extension of the GPK3 stimulation area that is really underestimated in our model. This may come from a too active stimulation of GPK2 and of a too bad connectivity of the fractures intersecting GPK3 in our model.

CONCLUSION

The recent improvements made on the code to allow a multiphase resolution of the problem seem to give interesting results; the first application example explained in this paper clearly shows that the density of the injected fluid plays an important role in the hydraulic fracturation process. It also allows us to better fit the shut in curves, even if these results are the most difficult to reproduce with our model; its stochastic aspect leads to a great variability at that point. Acceptable results are also obtained in the estimations of shape and extension of the shear events cloud. This would let us think that the assumption of a globally closed system, with a few drainage structures connected to the far field is quite close from reality.

On the other hand, this model needs important geometrical assumptions, concerning the orientation of the fractures, their localization, thickness and extension… Nevertheless results can be obtained with this kind of modeling, like prediction of shearing events localization.

The next step of modeling may concern temperature changes in both fluids and rock matrix, in order to introduce a variable density of the fluids and to see what impact heating of the injected has on the reservoir development, or on circulation. Another direction would be to simulate a circulation test with the three wells in order to try to predict what ratio of the injected fluid could be recovered to the other wells.

ACKNOWLEDGEMENTS

We warmly thank Mr. F. Cornet for his useful advices, BRGM (France) for the data sharing of the flowlogs interpretation, EEIG Heat Mining for providing the data from the European HDR site at Soultz-sous-Forets, which is supported mainly by the European Commission, BMBF (Germany), and ADEME (France).

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