COUPLED HYDRO-MECHANICAL SIMULATION TO INVESTIGATE WATER INVASION IN A NATURALLY FRACTURED TIGHT GAS RESERVOIR

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ABSTRACT

The tight gas reservoir under consideration is a complex structure with many natural fractures and the formation properties are poor in regards of production. Most of such gas fields would experience different amounts of water invasion. The geomechanics of the field affect natural fracture development as well as fluid flow. The main purpose of this study is to investigate the geomechanics effect on water invasion and evaluate the water invasion mechanism under different geological conditions to provide a guideline for production operations. An integrated 3D hydro-mechanical (HM) two-way coupled modeling approach was developed to study the geomechanical effects of water invasion on a naturally fractured tight gas reservoir. This model enabled us to evaluate various options for controlling water invasion, allowing us to provide specific operating recommendations for the field.

INTRODUCTION

A structure map showing the bottom structure of the tight gas field is shown in Figure 1. The main reservoir is located within the overlying Paleogene sediments and contains an average thickness of 300 to 400 m. . The field spans about 45 km in the NE-SW direction and 8 km in the NW-SE direction. Reservoir pressure ranges from 105 MPa to 121 MPa and the temperature ranges from 118 ºC to 162 ºC. Therefore we are dealing with a high pressure, high temperature reservoir. Gas saturation ranges from 0 to 0.65. The gas-water transition zone is around -3760 m within Paleogene age sediments, and at a different location the transition zone is around -3740 m within Cretaceous sediments. The reservoir was split and modeling was performed in two separate simulations (blue dashed squares shown in Figure 1) due to the high resolution needed around the production wells. This paper discusses the results of the east model analysis.

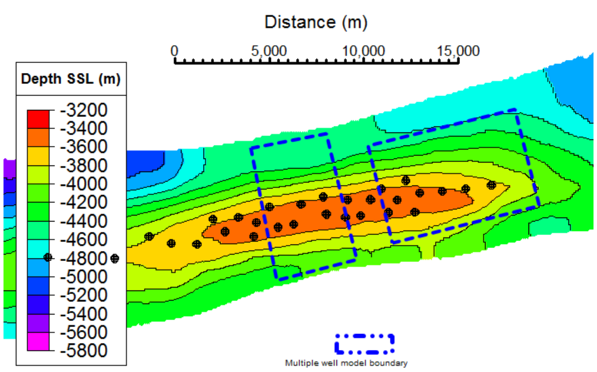

Figure 1. Tight gas reservoir structure map.

APPROACH

The general approach was to evaluate available field data, estimate rock mechanical properties and insitu stresses and pressures. Next, a fluid and geomechanical 3D numerical model were setup (using TOUGH ((Pruess et al., 1999) and FLAC3D (Itasca Consulting Group, 2012), respectively). Both meshes have identical dimensions in the horizontal direction. The geomechanical model also includes part of the overburden of the reservoir. The fluid flow model was developed using the MINC approach and the following permeability correlation was applied for the fracture permeability. The coupling procedure was set up using PYTHON language (Python Software Foundation, 2018) to control the launching of the software and the mapping of parameters between the numerical modeling meshes.

Permeability correlation

Combining previous work done by 1) (Zhang et al., 2007) on the theory for permeability in a fracture aperture for a system as shown in Figure 2, and 2) (Zangerl et al., 2008) stating a liner correlation between fracture normal stiffness and effective normal stress, we developed fracture permeability equations for an anisotropic model. They are listed here:

$$K_i = K_{io}\left\{1-\left(\frac{1}{m\sigma_i b_i}+\frac{1}{m\sigma_i S_i}+\frac{1}{E_r}\right)\left[\Delta\sigma_i - v\left(\Delta\sigma_j+\Delta\sigma_k\right)\right]-\left(\frac{1}{m\sigma_j b_j}+\frac{1}{cmS_j}+\frac{1}{E_r}\right)\left[\Delta\sigma_j - v(\Delta\sigma_i+\Delta\sigma_k)\right]\right\}^3$$

Equation 1

where:

i=x, y, z; j=y, z, x; k=z, x, y; in the coordinate system (i≠ j≠k);

K_{io} and K_i are the permeability along the i direction before and after stress changes;

E_r is the Young's modulus of the rock matrix;

υ is the Poisson's ratio.

$\Delta\sigma_i$ is the effective stress changes in i direction.

m is a linear correlation factor (to relate fracture normal stiffness to effective normal stress).

S_i is the fracture spacing along i direction.

b_i is the fracture aperture in i direction.

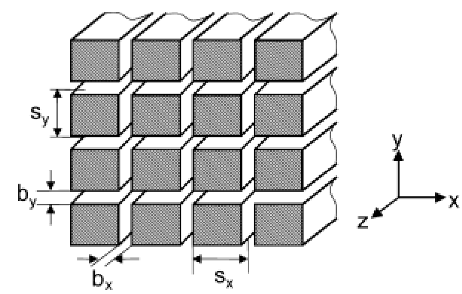

Figure 2. Fracture system.

Since fracture aperture (b), spacing (S) and the linear coefficient of normal stiffness to effective stress (c) are variables in the equations, we concluded that too many variables will make it difficult to perform a reasonable history match. Additionally a reasonable estimation of these parameters is complex. Therefore we decided to further simplify the equation according to the following assumptions:

I. the fracture spacing in each direction is the same, meaning $S_i = S_j = S_k = S$

II. the fracture aperture in each direction is the same, meaning $b_i = b_j = b_k = b$

III. the three effective principle stresses are very close to each other, due to the high temperature and high pressure conditions, we introduce one single correlation constant C:

$$\frac{1}{mb_x}+\frac{1}{mS_x}+\frac{\sigma_x}{E_r}=\frac{1}{mb_y}+\frac{1}{mS_y}+\frac{\sigma_y}{E_r}=\frac{1}{mb_z}+\frac{1}{mS_z}+\frac{\sigma_z}{E_r}=C$$

Equation 2

Therefore, the stress dependent permeability in each direction can be reduced to:

$$K_i = K_{io}\left\{1-C\sigma_i\left[\Delta\sigma_i - v\left(\Delta\sigma_j+\Delta\sigma_k\right)\right]-C\sigma_j\left[\Delta\sigma_j - v(\Delta\sigma_i+\Delta\sigma_k)\right]\right\}^3$$

Equation 3

Further simplification leads to (introducing average effective stress change of the three principle stresses $\Delta\sigma_{jj}$):

$$K_i = K_{io}\left\{1-C\times\Delta\sigma_{jj}\right\}^3$$

Equation 4

Constant C is the parameter that needs to be calibrated when performing the history match against the field data.

Coupling procedure

Figure 3illustrates the coupling process between the geomechanical and the fluid flow model. From the fluid flow simulation, the pressure distribution can be obtained and then transferred to the geomechanical model. The effective stress change due to pore pressure change was estimated in the geomechanical model simulation. Based on a stress dependent permeability correlation, the permeability modifier for fractures was calculated and fed back to the fluid flow simulation to complete one coupling process. The coupling frequency was driven mainly by the computational effort it takes and the accuracy required.

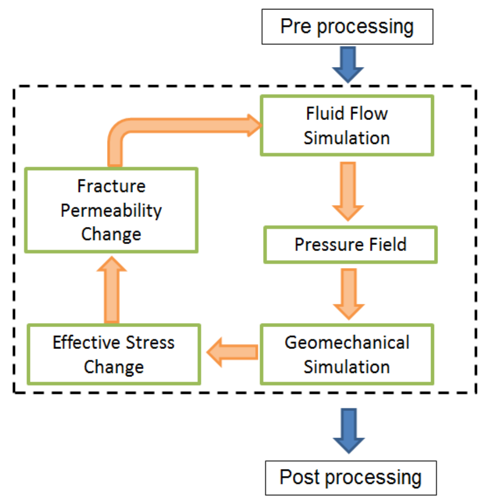

Figure 3. Coupling process.

This coupling scheme is a two-way coupling, not fully coupled. This means the simulation for the fluid flow model and the geomechanical model are independent. Pressure and permeability data are transferred between these two models each time when coupled. The real time is driven by the fluid flow simulation. The time interval period for coupling has been defined by looking at the non-coupling simulation, when the pressure results start to deviate from the calculated pressure. An optimized coupling frequency was found during the history match period, which was then also applied for future prediction scenarios. The coupling process was performed on high end workstations for the geomechanical modeling and the python scripts and cloud computation (with 40 cores) was used for the nearly 2 million cell TOUGH-MINC model.

RESULTS & DISCUSSION

During history matching of the multi well models over a period of 6 years of production, we see that the pressure decline trend is better reflected when using the coupling approach and adjusting the permeability reduction due to stress changes. A comparison of field measurements versus modeled pressure is shown in Figure 4. Though there is not a large difference in the first couple of years, the change in permeability due to stress is significant after about 2 years. When considering long term field development, this effect cannot be neglected. There is still a difference in pressure match after 6 years of production. Since the C constant in the permeability correlation equations is applied for the entire field, the best match was chosen, when comparing pressure match trends in all 9 wells in that model.

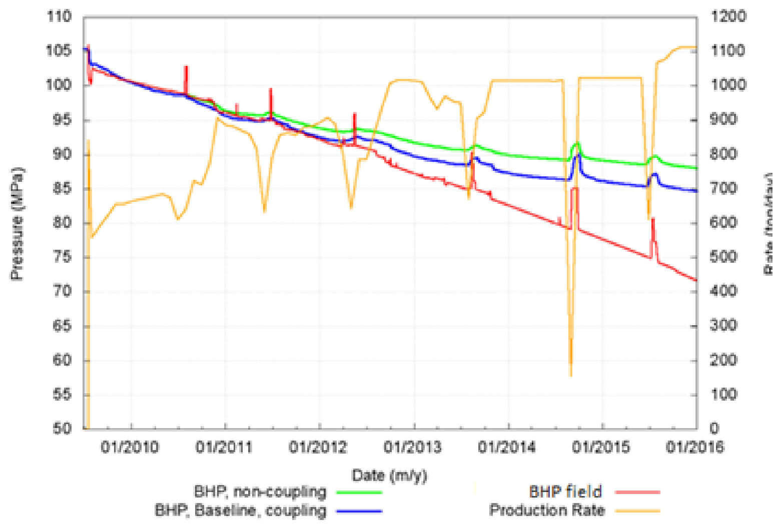

Figure 4. Pressure vs time multi-well model east, producer 1.

Using the history matched model, a 10 year forecast simulation of production was performed. Coupling was done every 2 years. Over the 10 year period forecast, we hardly see any effect of the water invasion. This suggests that coupling geomechanics effect does not seem to impact the water invasion result significantly compared to the non-coupling case when simulation was only performed for a short time period. Although, studies on a smaller single well model that was run for a forecast period of 20 years of production, showed that the water invasion starts to slow down taking into account the geomechanics effects, once the bottom of the perforations of the well are reached (Figure 5). Looking at the pressure distribution after a forecast of 10 years in the multi well model, as shown in Figure 6, we see a higher depletion on top of the reservoir when applying the coupling approach.

CONCLUSION

The simulation results from this study support the following conclusions and recommendations:

- Geomechanical effect plays an important role in production from the naturally fractured gas reservoir.
- Permeability of the natural fracture will decrease during production due to effective stress increase caused by pore pressure depletion. The decrease of natural fracture permeability will prevent or delay water coning in the naturally fractured tight gas reservoir.

- Compared to conventional reservoir simulation without taking into account the geomechanical effects, the results from coupling geomechanical effect shows a slower water coning speed for long term simulations.
- We recommend coupling geomechanical effects into reservoir simulation especially for tight gas reservoirs with natural fractures.

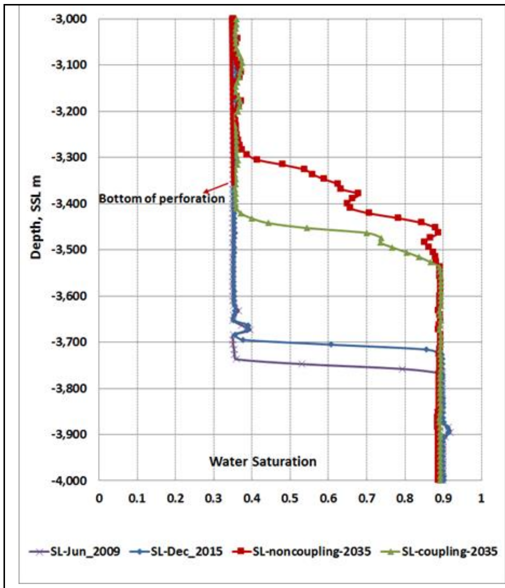

Figure 5. Water saturation below producer after 20 years of production forecast-single well model.

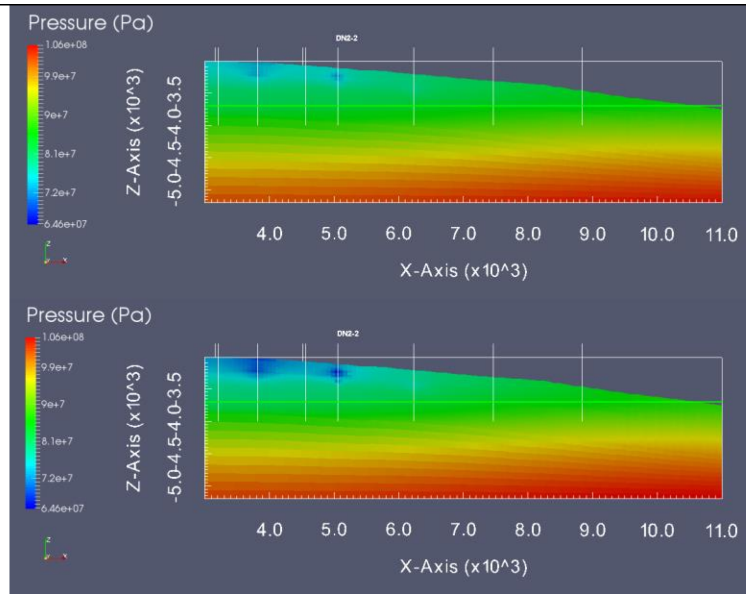

Figure 6. Pressure distribution after 10 years of production forecast, cross section along SW-NE: non-coupling (upper) and coupling (bottom), Green line marks (gas-water-contact)-multi-well model

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