International Conference on Applied Energy 2019
Aug 12-15, 2019, Västerås, Sweden
Paper ID:0332

NUMERICAL SIMULATION OF CO_2 ENHANCED GAS RECOVERY (CO_2-EGR) FOR THE OPTIMAL PERFORATION POSITION OF INJECTION WELL AND INJECTION RATE

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ABSTRACT

CO_2 enhanced gas recovery (CO_2-EGR) technology can exploit more natural gas fuels from the depleted gas reservoir and simultaneously sequestrate CO_2 into the underground formation. The perforation position of CO_2 injection well and injection parameters play key roles to the natural gas recovery of CO_2-EGR applications. In this work, CO_2-EGR simulations in a quarter of square ‘five-spot’ well arrangement of a depleted natural gas reservoir were carried out with perforation positions of CO_2 injection well at the bottom, middle and top layers of the reservoir model. The optimal perforation position is determined as the top layer of the reservoir, and the reason should be attributed to the accelerated vertical displacement due to the gravity effect. Moreover, an optimization method was built by integrating genetic algorithm (GA) and TOUGH2 for the determination of the optimal injection rate. The optimal injection rate of CO_2 is obtained as 0.0824 kg/s while the perforation is set at the top layer of the reservoir, and the final natural gas recovery achieves up to 65.37%. This work provides some insight for the CO_2-EGR employment in the depleted natural gas reservoirs.

Keywords: CO_2 enhanced gas recovery, perforation position, genetic algorithm, optimization

1. INTRODUCTION

CO_2 mitigation is urgently needed due to a large amount of CO_2 emissions released by consumed massive fossil fuels, causing the global warming and other extreme weathers. Carbon capture, utilization and storage (CCUS) provides one of promising potential alternatives by sequestrating CO_2 into the underground formation for enhanced coal bed methane, oil and natural gas recovery [1, 2]. In applications of enhanced gas recovery (CO_2-EGR), the undeveloped natural gas by the conventional technologies, will be extracted through injecting millions of tons of CO_2 into the depleted gas reservoirs. CO_2-EGR makes it possible to produce more clean fuels and simultaneously reduce anthropogenic CO_2 emission, attracting worldwide attentions.

The scale of natural gas reservoirs are generally in hundreds or thousands of meters. Computational fluid dynamics simulation provides a promising technique to describe the flow characteristics of CO_2 and underground fluids. Technical feasibility of CO_2-EGR was proved by predecessors through simulations [3-6]. Researchers also have done some simulation to study various influence factors on CO_2-EGR, such as geological heterogeneity, injection parameters, water injection, etc [7-9]. The perforation position of CO_2 injection well and corresponding injection parameters play key roles to CO_2-EGR. However, study on appropriate perforation position and injection parameter is still scarce and need to be further analyzed in depth.

In this work, CO_2-EGR in a depleted homogeneous reservoir with various perforation position of CO_2 injection well are modelled. An optimization method is built through integrating genetic algorithm and TOUGH2, and employed for obtaining the optimal injection strategy to exploit the maximum amount of natural gas.

2. METHODOLOGY OF SIMULATION

2.1. Reservoir model and parameters

In this work, the benchmark problem of CO_2-EGR in Holger et al.[10] is simulated in this work. CH_4 is considered as the initial fluid in the gas reservoir without any brine and irreducible water.

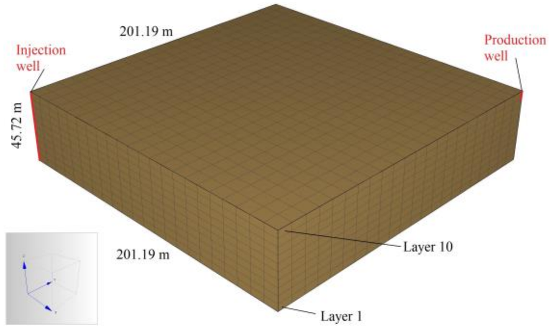

Fig. 1. 3D view of the modelled domain.

The modelled domain (201.19 m × 201.19 m × 45.72 m) is a quarter of square 'five-spot' well arrangement of a homogeneous reservoir segment [10]. As CO_2 is denser than CH_4 at all kinds of reservoir conditions, CO_2 will sink as a cushion gas [3] after injected into the gas reservoirs. Thus the CH_4 production well is placed at the top layer. The CO_2 injection well and CH_4 production well are diagonally arranged in the modelled domain, shown in Fig. 1. In CO_2-EGR simulations, the CO_2 injection rate keeps constant and the production pressure is invariable. The horizontal permeability is 10 times of the vertical permeability with the value taken from an carbonate reservoir in North Texas [11]. The modelled domain are meshed into 10 layers of identical thickness of 4.572 m. The details of the reservoir properties and simulation parameters are listed in Table 1.

Table 1. Parameters of the simulated model.

Parameters	Value
Porosity	0.23
Reservoir pressure	3.55 MPa
Reservoir temperature	66.7 ℃
Diffusion coefficient	6.0×10^{-7} m^2/s
Horizontal permeability	50×10^{-15} m^2
Vertical permeability	5×10^{-15} m^2

2.2. GA-TOUGH2/EOS7C optimization method

TOUGH2 is a typical simulator designed by Lawrence Berkeley National Laboratory (LBNL) for simulating the multi-phase and multi-component flow in the underground formation. EOS7C a is technically developed sub-module for simulating flow in the natural gas reservoirs within TOUGH2 framework[3] and is employed for CO_2-EGR simulation in this work. The TOUGH2/EOS7C simulator, can only run a single simulation from an input file and generates one output result at a time. Genetic algorithm (GA), a heuristic computational optimization method simulating the process of biologic evolution, is used as the optimization technique. The conjunction of GA and TOUGH2/EOS7C makes it possible to obtain the optimal injection parameters of CO_2-EGR. A flowchart of the integrated GA-TOUGH2/EOS7C is shown in Fig. 2.

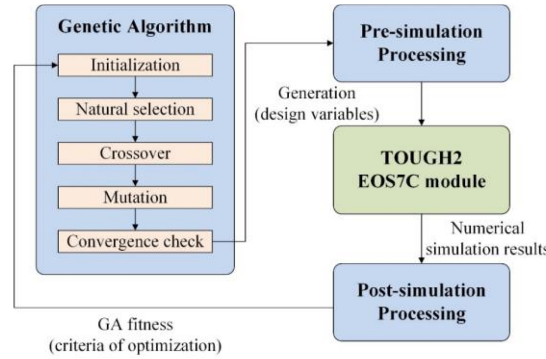

Fig. 2. Flowchart of GA-TOUGH2/EOS7C program

3. RESULTS AND DISCUSSION

3.1 Simulations with various perforation positions

Three simulation cases (No.1, No.2 and No.3) were carried out in this work, with the perforations opened at the bottom (Layer 1), middle (Layer 5) and top (Layer 10) layer, respectively. The CO_2 injection rate is the same with the benchmark problem as 0.1 kg/s in the modelled domain. In this CO_2-EGR simulations, the produced gas is considered as "pure" natural gas before CO_2 concentration (by mass) reach 1 %, and this moment is recorded as CO_2 breakthrough time (CBT). Because the cost of natural gas processing will be very high when CO_2 concentration is larger than 20 %, the CO_2-EGR simulation will end once as CO_2 concentration reach 20% in the produce gas [9, 12] in this work. That moment is recorded as well shut-in time (WST). Moreover, the recovery factor (RF) at CBT or WST is evaluated as

$$\text{RF}=\frac{\text{Mass of the produced CH}_4}{\text{CH}_4\ \text{mass in the reservoir}} \qquad (1)$$

The CO_2 breakthrough time, well shut-in time and the corresponding recovery factors are plotted in Fig. 3 for three cases No.1, 2 and 3 with the perforation at the bottom, middle and top layer of the reservoir, respectively. The CBT of the case No.1, 2 and 3 are 1369, 1460 and 1330 days, and the corresponding recovery factors at CBT are 41.86%, 44.82% and 40.61%, respectively. It's clearly illustrated that CO_2 breaks through into the production well faster in the case No.3 with the perforation at the top layer than the others. To avoid the premature CO_2 breakthrough and produce more pure natural gas, the perforation position should selected at the middle layer of the reservoir because the CBT and recovery factor at CBT of case No.2 are the maximum of three cases, respectively. In addition, the WST of case No.1, 2 and 3 are 1902, 2024 and 2098 days, and the corresponding recovery factor at WST are 58.52%, 62.43% and 64.66%, respectively. It's presented that the production time increases with the perforation position going up and the simulation case No. 3 with the perforation position at the top layer has the longest production time. The variation trend of the recovery factor at WST is similar as WST. It's demonstrated that the maximum recovery factor will be achieved as the perforation set at the top layer. The distribution of CO_2 in the reservoir may give a reasonable explanation.

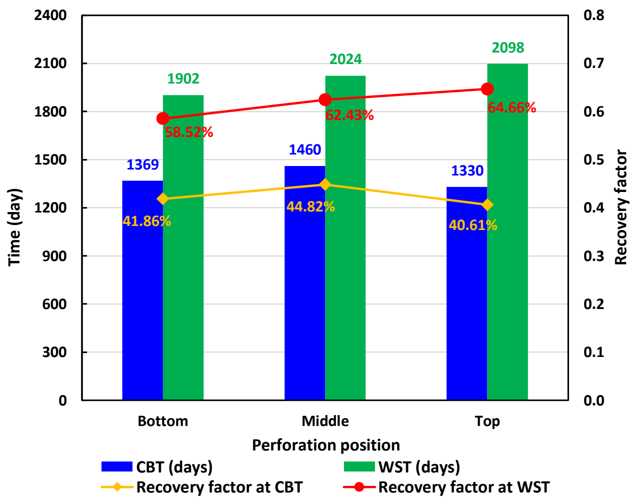

Fig. 3. Recovery factors at CBT and WST of three cases with the perforation postion of bottom, middle and top layer.

Fig. 4 shows the CO_2 distribution in the reservoir at WST for three cases. It's presented that the performance of CO_2 distribution in the bottom area of the reservoir, where almost all of CH_4 are displaced by CO_2, are very similar for three cases. The CO_2 distribution difference mainly manifests in the top area of the reservoir. As the perforation position being moved up, the amount of CH_4 in the top layers displaced by CO_2 increases. For the simulation case No.3, CH_4 in approximate a quarter of the top area is thoroughly displaced by CO_2 and its amount is the largest one of the three cases. The phenomenon should be attributed to the gravity effect. Due to the density variation between CO_2 and CH_4, CO_2 tend to sink down to the reservoir bottom after injection. When injection from the top layer, the gravity effect can exert the biggest influence on accelerating the vertical transport of CO_2. Moreover, the CH_4 in the top layer of the reservoir can also be displaced by top injected CO_2 in a greater degree than other cases. As a result, the optimal perforation position to realize the better recovery of natural gas exploitation is the top layer of the reservoir, although CO_2 will breakthrough earlier in this situation than the others.

3.2 Optimization of the injection rate

To find out the optimal CO_2 injection strategy to enhance the maximum recovery is the key issue for CO_2-EGR. After the top layer of the reservoir is determined as the optimal perforation position, the optimization of injection rate was conducted by employing the GA-TOUGH2/EOS7C method. According to the literature [12], the optimization simulation was executed by setting the initial injection rate in the range of 0 - 0.5kg/s with the perforation at the top layer of gas reservoir. The other parameters used in the GA are listed in Table 2.

Table 2. Parameters of the GA.

Parameters	value
Individuals per generation	6
Maximum generations	30
Natural selection removal	50 %
Mutation rate	8 %
Cross-over algorithm	Semi-random combination of parents

The convergence history of the optimization progress is illustrated in Fig.5. In the initial period, the injection rate goes up and down, and the recovery factor gradually increases along generations. After 10 generations, the optimization simulation come into convergence. The optimal injection rate stabilizes at 0.0824, and in this situation the recovery factor goes up

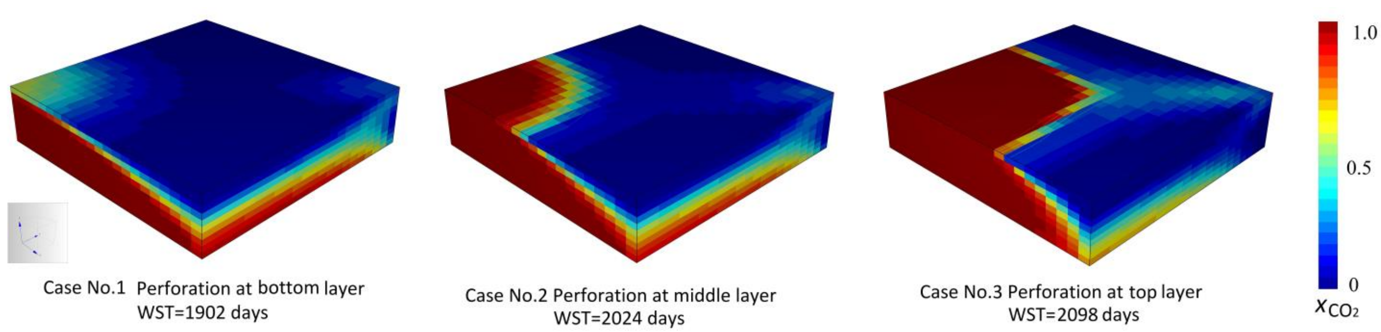

Fig. 4. Three-dimensional view of CO_2 distribution in the reservoir at well shut-in time for simulation cases No.1, No.2 and No.3 with perforation position at bottom, middle and top layer, respectively.

to the maximum of 65.37% at the WST, which is much higher than the benchmark case of 58.52% with the peroration at the bottom of the reservoir. It's manifested that appropriate injection rate with the optimal perforation position will make it possible to achieve the best natural gas recovery in CO_2-EGR applications by employing GA-TOUGH2 optimization method.

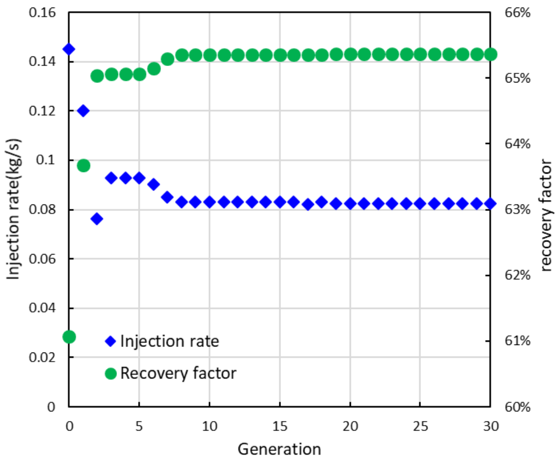

Fig. 5. Convergence history of the GA-TOUGH2/EOS7C for injection rate with perforation at the top layer.

CONCLUSIONS

CO_2-EGR simulations were carried out by employing TOUGH2 simulator in a depleted natural gas reservoir with various perforation positions of CO_2 injection well. The optimal perforation position is determined as the top layer of the reservoir model, and the reason should be attributed to the gravity effect accelerating the vertical transport of CO_2. The genetic algorithm (GA) is integrated with TOUGH2 for the optimization of CO_2 injection rate. The optimal injection rate is obtained as 0.0824 kg/s with the optimal perforation at the top layer of reservoir to enhance the natural gas recovery up to 65.37%. The results shows that appropriate perforation position and injection rate will promote the depleted gas reservoir produce more natural gas by CO_2-EGR. The further optimization of CO_2-EGR by employing horizontal well and various well arrangement will be conducted in the next study to find out the optimal injection strategy.

ACKNOWLEDGEMENT

The authors acknowledge the support from the Key Program of National Natural Science Foundation of China (No.U1762216) and the Program for Changjiang Scholars and Innovative Research Team (IRT_14R58).

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