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Simulation Study on Heat Extraction Efficiency and CO_2 Recovery Rate for CO_2-EGS in Hydrothermal Reservoirs

Kentaro Masuoka, Hajime Yamamoto and Sou Kumamoto

344-1 Nase-cho Totsuka-ku Yokohama 245-0051, Japan

msoknt00@pub.taisei.co.jp

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ABSTRACT

As a new geothermal power generation, a novel enhanced geothermal system (EGS) concept that uses CO_2 instead of water as heat transfer fluid has been proposed. Its advantages may include more heat extraction efficiency than water and storage of unrecovered CO_2 in underground geological formations. In Japan it is likely that most geothermal reservoirs are filled with water because of high precipitation weather conditions and derived water from ocean plate. Therefore, when CO_2 geothermal power generation is implemented, it is expected in many cases that CO_2 is injected into geothermal reservoirs where water (hot water) exists (i.e. hydrothermal reservoir). So, it is important to design with consideration of water-CO_2 two phase flow condition in a hydrothermal reservoir. One of the problems to be solved for EGS is to produce as much injected fluid as possible from geothermal reservoirs. In a field test of a water-based EGS targeted on a granitic rock mass in Ogachi, Japan, it was reported that the water recovery rate at the production well was as low as about 20 to 25%. With implementation of CO_2 geothermal power generation in Japan in mind, this study focused on the heat extract efficiency and recovery rate of injected fluid when using CO_2 as heat transfer fluid for a hydrothermal reservoir through numerical simulations. As a result, it was found that compared with the case when using water as heat transfer fluid, it is important to make CO_2 breakthrough as early as possible to ensure a higher heat production from an early stage of production. The higher the reservoir temperature, the earlier breakthrough occurs due to the larger volume expansion of CO_2 in the reservoir. In addition, it was indicated that the recovery rate of CO_2 at a production well increases to around 50% after CO_2 breakthrough, due to the relative permeability effects in the two-phase flow of CO_2 and water in hydrothermal reservoirs.

1. INTRODUCTION

As a new geothermal power generation, a novel geothermal energy concept that uses CO_2 instead of water as heat transfer fluid has been proposed [Brown, 2000], here we call it "CO_2-EGS". Many researchers have studied this so far [*e.g.*, Pruess, 2006, 2008; Song et.al 2020; and Zhong et.al, 2022], but its implementation has not been achieved yet. For the implementation of CO_2-EGS in Japan, we have conducted research and development since 2021 through the project "Carbon recycle CO_2 geothermal power generation technology" supported by the Japan Organization for Metals and Energy Security (former Japan Oil, Gas and Metals National Corporation, JOGMEC). The targeted depth of a geothermal reservoir is assumed to be 1000 ~ 2000 m in this project. Unlike hot dry rock (HDR) overseas, it is likely that most geothermal reservoirs are filled with water because of high precipitation weather conditions and derived water from ocean plate in Japan. Therefore, when CO_2 geothermal power generation is implemented in Japan, it is expected in many cases that CO_2 is injected into geothermal reservoirs where water (hot water) exists (i.e. hydrothermal reservoir). So, it is important to design the technology with consideration of water-CO_2 two phase flow condition in a geothermal reservoir.

Regarding geothermal power generation using CO_2 as heat transfer fluid in water-CO_2 two phase flow condition, CO_2-plume geothermal (CPG) has been studied by Randolph and Saar (2011). CPG targets on the sedimentary layer saturated with water and does not need hydraulic fracturing by the injected fluid. In their study, advantages of using CO_2 as heat transfer fluid in water-CO_2 two phase flow condition is shown, but their interest is at a low temperature range (~120 °C). Others also studied CPG but temperature of interest is not so high [*e.g.*, Borgia et al., 2012; Cui et.al, 2017; Pan et al., 2018]. It is considered in general that the behavior of the water-CO_2 two-phase flow would vary greatly depending on the reservoir temperature and pressure, and that it could affect greatly the heat production, since the physical properties of CO_2, esp. viscosity and density, vary greatly depending on the temperature and pressure. When investigating a suitable geothermal reservoir for CO_2 geothermal power generation, it is therefore very important to understand the temperature and pressure effects in the geothermal reservoir. In addition, how the temperature and pressure conditions of the geothermal reservoir affect the heat extraction efficiency of CO_2 geothermal power generation in high temperature and pressure has not systematically been studied.

The recovery rate of injected fluid can also be an issue for the EGS implementation. For example, in Ogachi, Japan, a water-based EGS field test was conducted, then it was reported that the recovery rate relative to the amount of injected water at the production well was about only 25% [Kaieda, 2005]. On the other hand, in a two-phase flow of water-CO_2, it could be expected that once a channel is formed between the injection and production wells by CO_2, it could provide higher recovery rate than that in a single-phase condition. It is because selective flow may occur due to relative permeability. However, few studies have focused on the recovery rate of CO_2 when CO_2 is circulated as heat transfer fluid in a geothermal reservoir filled with hot water.

In this study, numerical simulations were conducted in a case where CO_2 is injected as heat transfer fluid into a geothermal reservoir filled with water. The impact of the temperature and pressure conditions of the geothermal reservoir for CO_2 geothermal power generation was then examined from the viewpoints of heat extraction efficiency and CO_2 recovery rate of injected fluid.

2. HEAT EXCTRACTION EFFICIENCY STUDY

2.1 Model

To investigate the heat extraction efficiency of CO_2 geothermal power generation in a geothermal reservoir with hot water, numerical simulations using a 5-spot model were conducted. When injection and production wells are arranged in such a way as they are staggered, it is possible to model just a part of the target area due to symmetry. This 5-spot modelling has been used in a lot of previous studies. Here, referring to a planar two-dimensional 5-spot model by Pruess (2006) in which the distance between injection and production wells used is 707.1 m, a numerical simulation model was created (Figure 1). Matrix-fracture heat exchange was modeled using the method of multiple interacting continua (MINC) with subgridding of the matrix blocks into five continua. Injection and production wells were given as fixed temperature and pressure grids. The other conditions of the model are shown in Table 1.

Table 2 shows simulation cases of this heat extraction efficiency study. It can be broadly classified into (1) “CO2-EGS” case where injection fluid is CO_2 (40 °C) and (2) “H2O” case where injection fluid is water (40 °C). In each case, calculations were performed in 25 different temperature-pressure combinations: 5 patterns of initial reservoir temperatures (120, 160, 200, 240 and 280 °C) multiplied by 5 patterns of initial reservoir pressures (10, 12.5, 15, 17.5 and 20 MPa). A numerical code, TOUGH3, was used, which is a numerical simulator of non-isothermal flows of multi-component, multi-phase fluids in three-dimensional porous and fractured media. The ECO2N V2.0 EOS module was used, which enables thermal-hydraulic calculation of supercritical CO_2 in a temperature range of 10 to 300 °C and a pressure up to 60 MPa. Capillary pressure and relative permeability curves used in this research are shown in Figure 2.

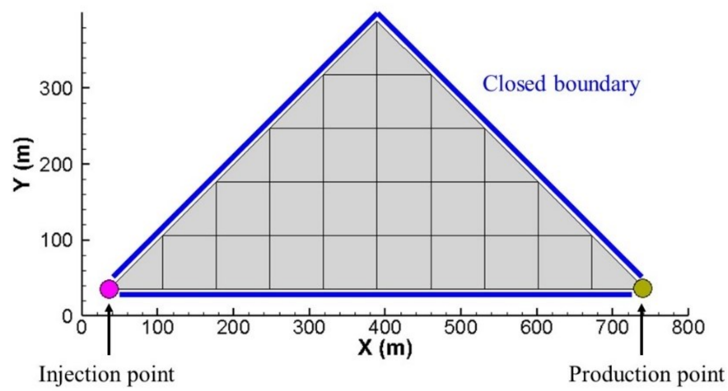

Figure 1: Schematic diagram of 5-spot model in the heat extraction efficiency study.

Table 1: Model parameters used in the heat extraction efficiency study.

Reservoir		
thickness	305	m
fracture spacing	50	m
fracture volume fraction	2	%
permeability	5.0×10^{-14}	m^2
porosity in fracture domain	50	%
rock grain density	2650	kg/m^3
rock specific heat	1000	J/kg/°C
rock thermal conductivity	2.1	W/m/°C
Production/Injection		
pattern area	1	km^2
injector-producer distance	707.1	m
injection temperature	40	°C
injection pressure	Initial reservoir pressure plus 1MPa	
production pressure	Initial reservoir pressure minus 1MPa	

Table 2: List of numerical simulation cases for this heat extraction efficiency study.

Case name	Initial pore saturation fluid	Injection fluid	Initial temperature of reservoir (°C)	Initial pressure of reservoir (MPa)
CO2-EGS	Water	CO_2	120、160、200、240、280	10.0、12.5、15.0、17.5、20.0
H2O	Water	Water		

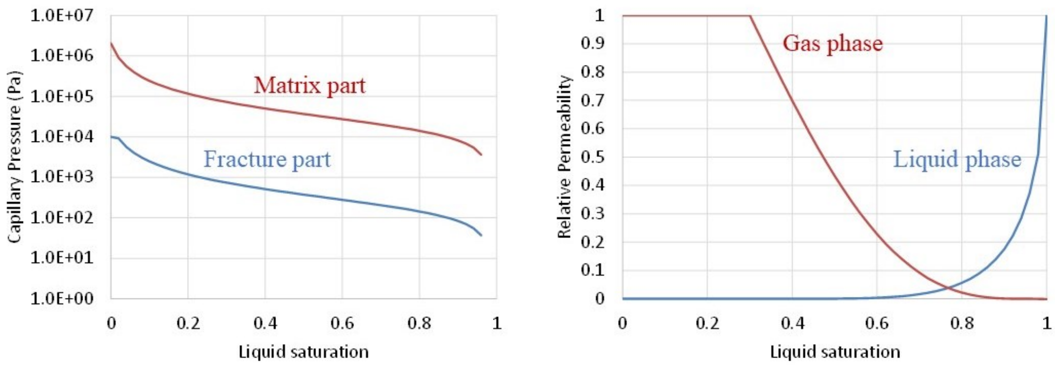

Figure 2: Capillary pressure and relative permeability curves used in the research.

2.1 Result

Time evolution of heat production for CO2-EGS cases are shown in Figure 3 and for H2O cases in Figure 4, respectively. For CO2-EGS cases, in order to study changes in the very early stage, just after injection, time axis is set in log scale. As seen in Figure 4, the heat production for all of the H2O cases decreases linearly over time. Moreover, in spite of different initial reservoir pressures there is little difference in the behavior of the heat production. Note that only the results of 10 and 20 MPa are shown here, but that the results of the other cases are very similar. On the other hand, in the case of CO2-EGS, the heat production for the period just after injection (until about 0.1 years) is in about the same level as that in the case of H2O. After that, however, it drops sharply and then re-rises. The time the heat production re-rises varies with the initial reservoir temperature. The higher the initial reservoir temperature, the earlier.

Figure 5 shows the normalized heat productions at the production well in each CO2-EGS case, setting the heat production for the H2O to be unity. They are plotted against the initial temperature of the reservoir for 2, 10, 30 and 50 years after the initial CO_2 injection. It may be observed that 2 years after the injection, the normalized heat production was less than 1.0 except at 280 °C. This means less heat production than using water as heat transfer fluid in these cases. However, over time, the normalized heat production exceeded 1.0. Especially, it increased to nearly 5.0 at 120 °C in 30 or 50 years. As reported in previous studies, it was confirmed that geothermal power generation using CO_2 as a heat transfer fluid was superior to that using water in the low temperature range of around 120 °C. It is also important to mention here that the time for the heat production to re-rise becomes shorter when the initial reservoir temperature is higher.

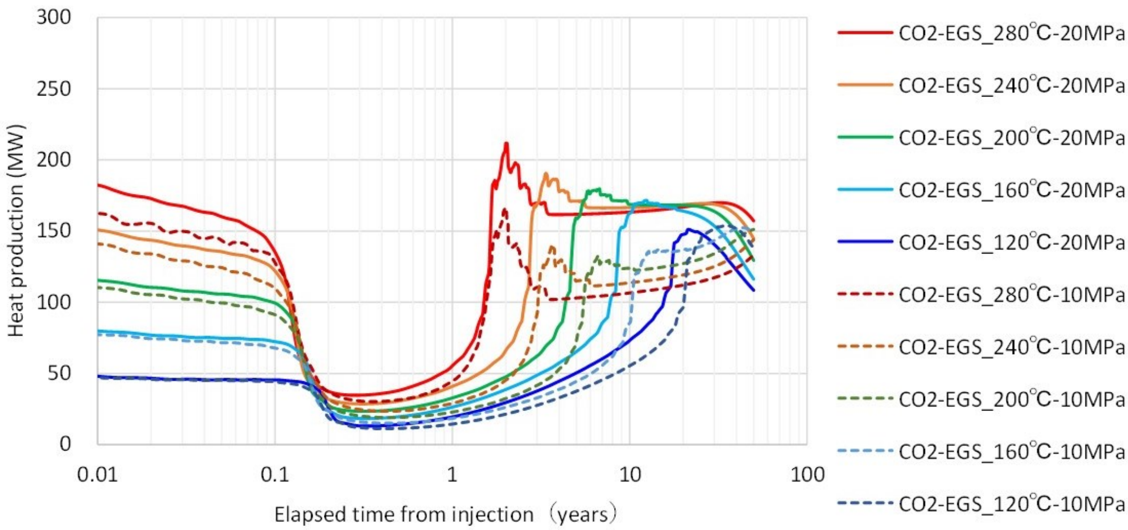

Figure 3: Time evolution of heat production for CO2-EGS cases in heat extraction efficiency study. Results for the initial reservoir pressure of 10 and 20 MPa only are shown here as examples.

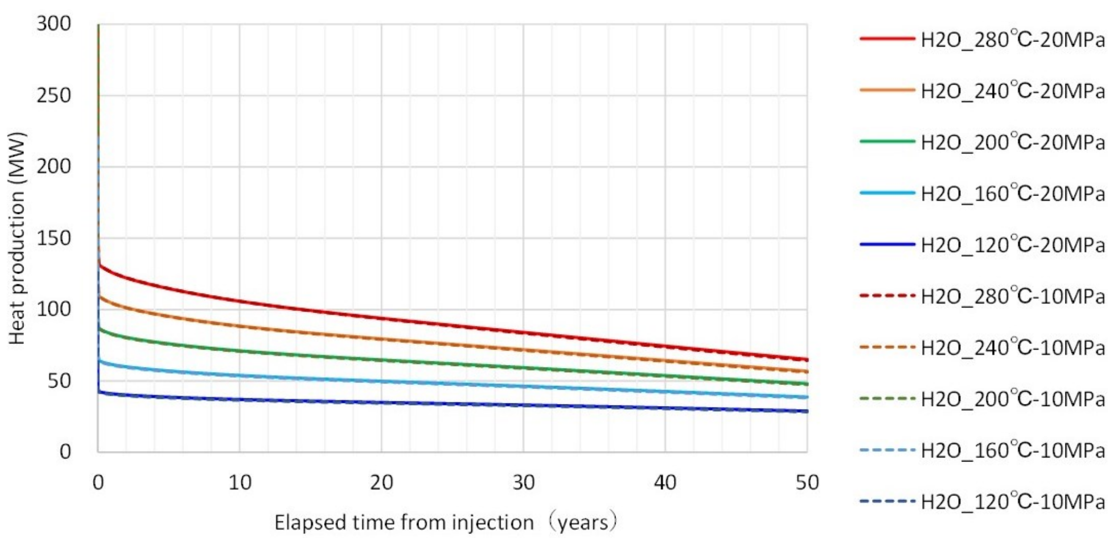

Figure 4: Time evolution of heat production for H2O cases in heat extraction efficiency study. Results for the initial reservoir pressure of 10 and 20 MPa only are shown as examples.

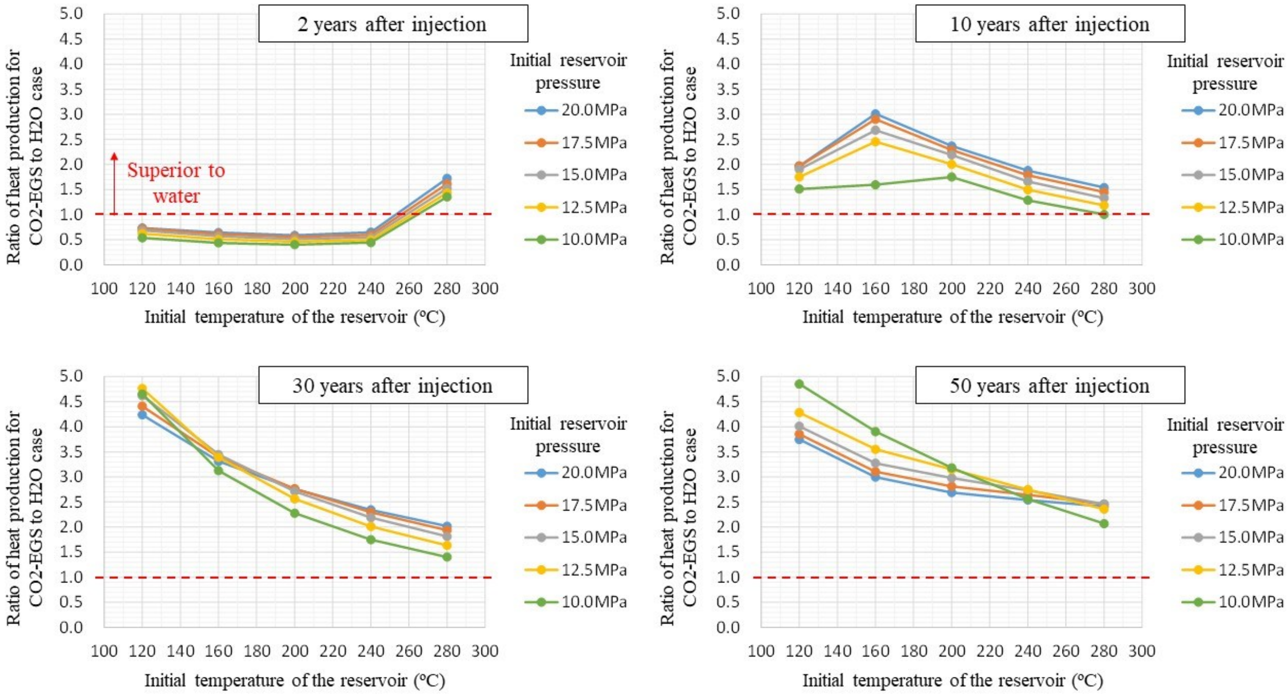

Figure 5: Heat extraction efficiency of the CO2-EGS cases. Values of the efficiency are the ratio of heat production for CO2-EGS case to that for H2O case.

3. INJECTED FLUID RECOVERY RATE STUDY

3.1 Model

To investigate the ratio of CO_2 mass flow rate from a production well to injected CO_2 mass flow rate for CO2-EGS in hydrothermal reservoir, we conducted numerical simulations. The 5-spot model used in the previous chapter is not suitable here. Because in/out flow boundaries in the 5-spot model are the production well and injection well grids only so that the fluid injected into the model from the injection well grid is recovered 100% from the production well grid. Therefore, as shown in Figure 6, we made a model where there are only a pair of wells (injection and production wells) and lateral boundaries were set as open boundaries. The model is two-dimensional in plan, and the distance between the wells is 500 m. A fixed mass flow boundary of 0.2 kg/s was given to the injection well grid. For the production well grid, a fixed temperature and pressure boundary was set with the values equal to those in the initial reservoir condition. The distance from each well to the lateral boundary is approximate 1000 m. The size of the model is 1/2 region of interest due to symmetry. The grid spacing around the well is 20 m, and the reservoir thickness is 50 m. Other parameters of the model were given referring to Pruess (2006). The other conditions of the model are shown in Table 3.

Table 4 shows simulation cases in this injected fluid recovery rate study. Similar to the heat extract efficiency study described in the previous chapter, the cases can be broadly classified into (1) CO2-EGS case where injection fluid is CO_2 (40 °C) and (2) H2O case where injection fluid is water (40 °C). For the CO2-EGS case, calculations were performed in 10 different temperature-pressure combinations: 5 patterns of initial reservoir temperatures (120, 160, 200, 240 and 280 °C) multiplied by 2 patterns of initial reservoir pressures (10 and 20 MPa). For the H2O case, calculations were performed in 4 different temperature-pressure combinations: 2 patterns of initial reservoir temperatures (120 and 280 °C) multiplied by 2 patterns of initial reservoir pressures (10 and 20 MPa). For the simulations, a numerical code TOUGH3 (ECO2N V2.0) was used here as presented in the previous chapter.

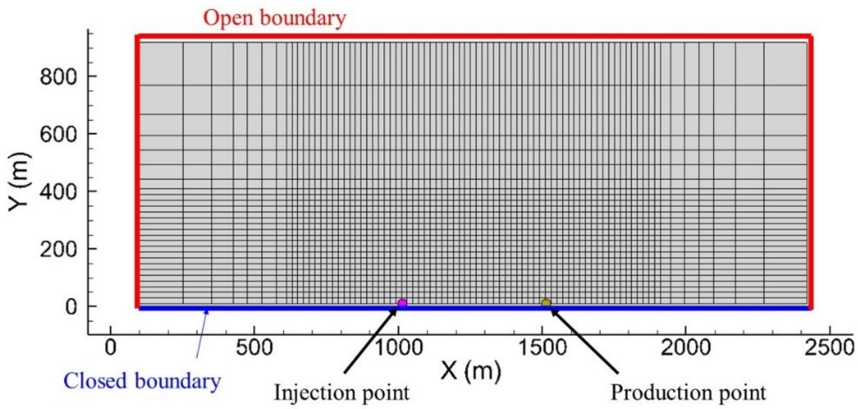

Figure 6: Schematic diagram of the open-boundary model for heat extraction efficiency study.

Table 3: Model parameters used in the recovery rate study.

Reservoir		
thickness	50	m
fracture spacing	50	m
fracture volume fraction	2	%
permeability	1.0×10^{-14}	m^2
porosity in fracture domain	50	%
rock grain density	2650	kg/m^3
rock specific heat	1000	J/kg/°C
rock thermal conductivity	2.1	W/m/°C
Production/Injection		
pattern area	1	km^2
injector-producer distance	500	m
injection temperature	40	°C
injection mass flow	0.2	kg/s
production pressure	Same to initial reservoir pressure	

Table 4: List of numerical simulation cases for recovery rate study.

Case name	Initial pore saturation fluid	Injection fluid	Initial temperature of reservoir (°C)	Initial pressure of reservoir (MPa)
CO2-EGS	Water	CO_2	120、160、200、240、280	10.0、20.0
H2O	Water	Water	120、280	10.0、20.0

3.2 Result

Time evolution of heat production for CO2-EGS cases in this injected fluid recovery rate study are shown in Figure 7, and for H2O cases in Figure 8, respectively. In the H2O case, the heat production was almost constant over time, but the initial reservoir temperature made a difference in the heat production. In the CO2-EGS case, as in the case of 5-spot, heat production is a large at the beginning of the injection (approximately up to 1 year after the initial injection), but after that, it drops sharply and then re-rises in the case of a high temperature at 240~280 °C.

Time evolution of the recovery rate of the injected fluid, produced mass flow rate divided by injected mass flow rate, for the initial reservoir pressures of 20 and 10 MPa are shown in Figure 9 and in Figure 10, respectively. As shown in the figures, in the H2O case where injected fluid flows in the reservoir in a single-phase, the recovery rate of the injected fluid is almost constant at about 0.15. On the other hand, in the CO2-EGS case where injected fluid flows in two-phases, the recovery rate is higher than that in the single-phase flow except at the stage just after the initial injection when hot water is produced. In particular, for cases above 200 °C, the recovery rate increases significantly. An interesting finding here is that in the temperature and pressure range of this study, the time for the heat production to re-rise became shorter when the initial reservoir temperature is higher and/or initial reservoir pressure is lower.

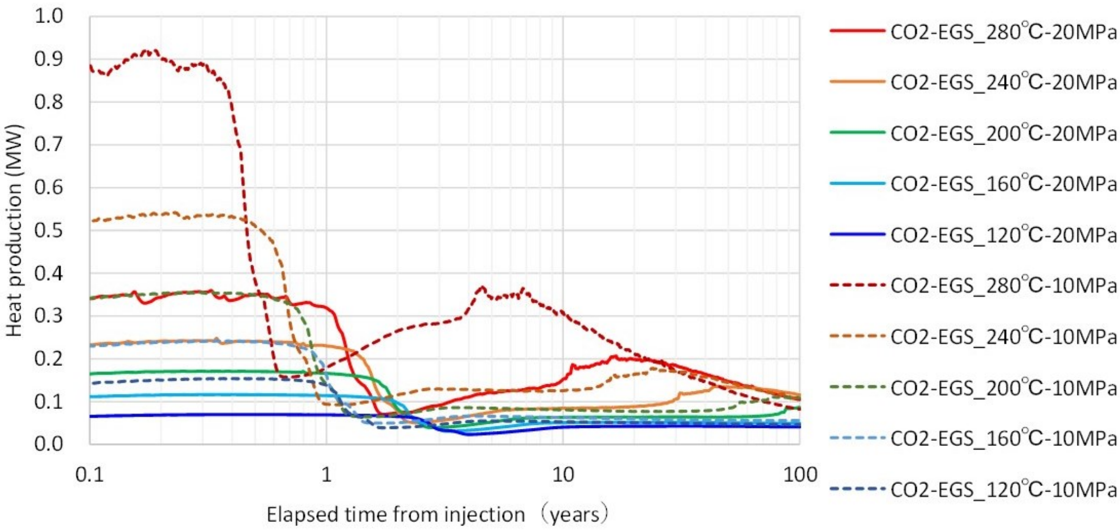

Figure 7: Time evolution of heat production for CO2-EGS cases in the recovery rate study. Results for the initial reservoir pressure of 10 and 20 MPa only are shown as examples.

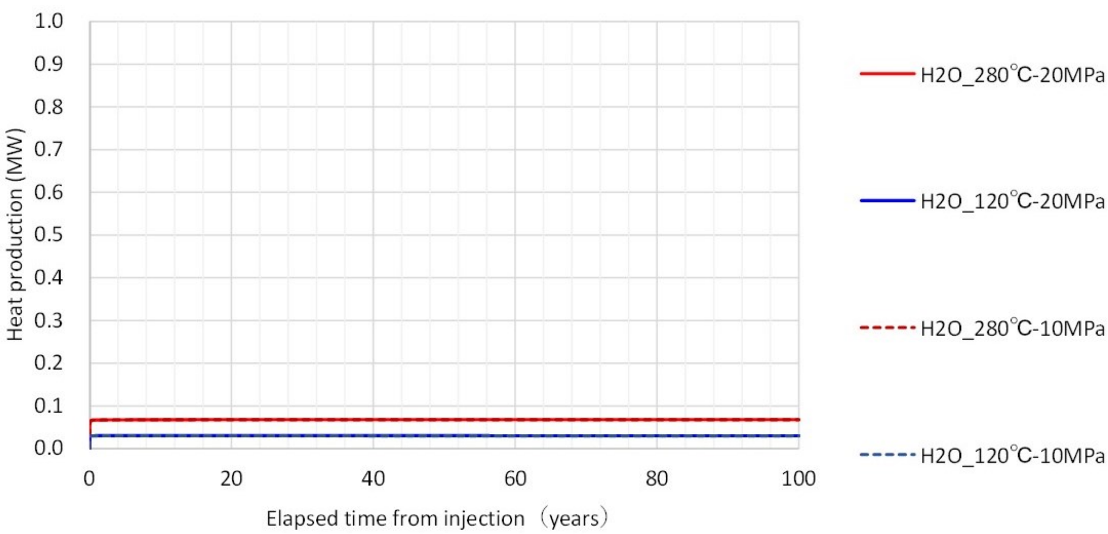

Figure 8: Time evolution of heat production for H2O cases in recovery rate study. Results for the initial reservoir pressure of 10 and 20 MPa only are shown as examples.

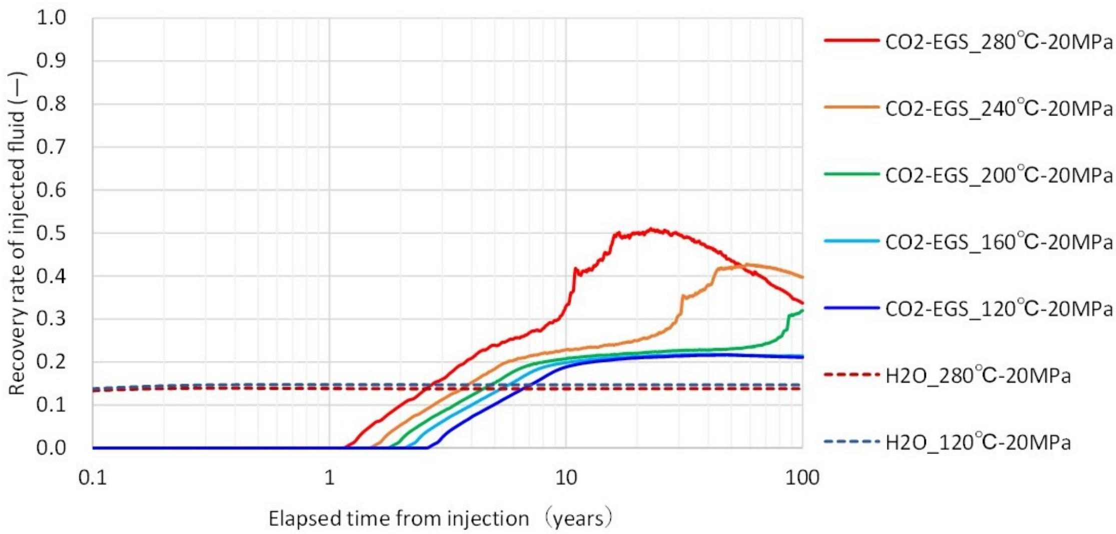

Figure 9: Time evolution of recovery rate of injected fluid at 20 MPa. For CO2-EGS the ratio of produced to injected CO_2 mass flow, for H2O the ratio of produced to injected water mass flow.

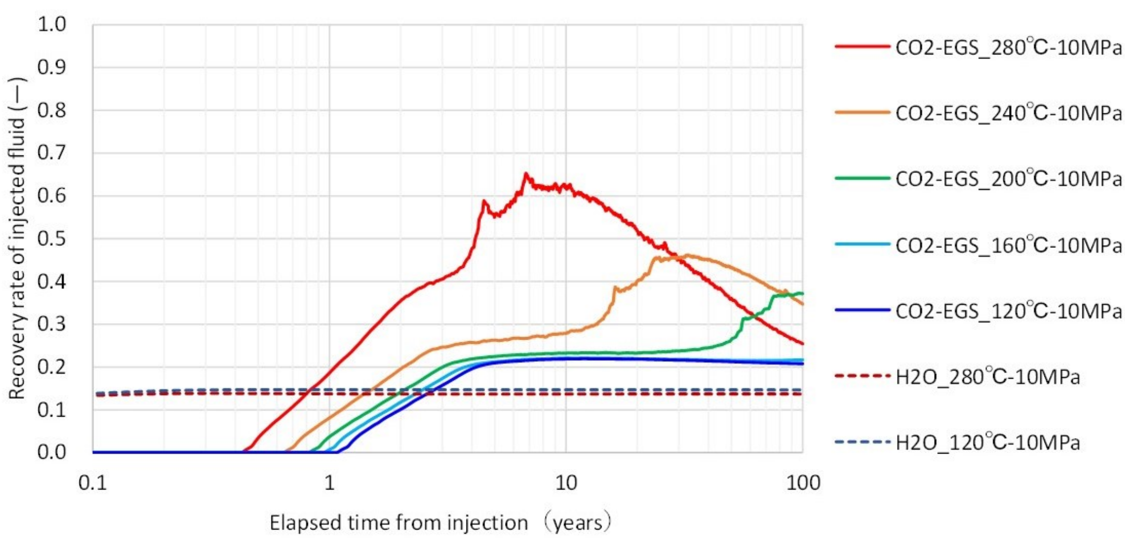

Figure 10: Time evolution of recovery rate of injected fluid at 10 MPa. For CO2-EGS the ratio of produced to injected CO_2 mass flow, for H2O the ratio of produced to injected water mass flow.

4. DISCUSSION

In both studies using the 5-spot and the open-boundary models, the heat production increased at the initial stage of injection, then dropped sharply and then re-increased with time in the CO2-EGS case. Figure 11 shows the time evolution of the heat production, the mass flow rate of liquid phase (mainly water) and the mass flow rate of gas phase (mainly CO_2) in the case where the reservoir temperature pressure are 280 °C and 20 MPa, respectively. It can be seen that hot water is produced during the period when the heat production is large at the beginning of injection. After that, when CO_2 is produced, mass flow of hot water drops sharply so that the heat production becomes small. It could be regarded as the influence of the relative permeability associated with the two-phase flow. The proportion of produced two-phase fluid then gradually shifts to the CO_2 phase only, and when the amount of mass flow of produced hot water drops to near zero (CO_2 breakthrough), the mass flow rate of the CO_2 phase thereby increases rapidly. At the same time, the heat production also increases. In other words, to obtain enough heat production in CO2-EGS, it could be considered important to cause CO_2 breakthrough as early as possible in the initial stage of injection.

From the discussion described just above, the heat production re-rises at the same time as CO_2 breakthrough occurs. So it could be said from Figures 3 and 7 that the time for CO_2 breakthrough to occur decreases as the initial reservoir temperature increases. This is due to the low density of CO_2 at high temperatures. In other words, when CO_2 at low temperature is injected into the deep reservoir, the density of the injected CO_2 is high at the well bottom, but it expands in volume in the reservoir due to high reservoir temperature. So the higher the reservoir temperature, the larger the injected volume, if the same mass of CO_2 is injected. Figure 12 shows the distribution of CO_2 phase density and CO_2 phase saturation calculated by the open-boundary model in the two cases where the reservoir temperature-pressure combinations are 280 °C, 20 MPa and 120 °C, 20 MPa. It can be seen that the higher the temperature, the larger the region of CO_2 saturation, even when the same mass of CO_2 is injected into the model. It may therefore be concluded that the higher the reservoir temperature, the more advantageous the region of CO_2 saturation is formed early. Thus, as shown in Figure 5, the heat production efficiency when the temperature is lower than 280 °C is lower than that of water after 2 years because CO_2 breakthrough has not yet occurred. In addition, the reason for the better heat extraction efficiency in the low temperature range than in the high temperature range after 10 years and over may be because mobility of CO_2 is high whereas water mobility is low at low temperatures.

Regarding the recovery rate, in the open-boundary model shown in Figures 9 and 10, it could be said that the recovery rate in the 200, 240 and 280 °C cases increases at the same time as the heat production increases, *i.e.*, at the same time as CO_2 breakthrough occurs. The figures show that even before the breakthrough of CO_2, the recovery rate is higher than that in the single-phase flow case, but the CO_2 breakthrough greatly increases the recovery rate and also increases the heat production. In the case of an open boundary, in order to secure the amount of heat production in a certain scale, it is important for CO_2 breakthrough to occur early, so that the recovery rate is improved. This study shows that high recovery rates (around 50%) can be obtained early even with just only a pair of wells, if the temperature of the geothermal reservoir is high. This clearly demonstrates superiority of using CO_2 as heating transfer fluid for hydrothermal reservoirs at high temperatures.

In the open-boundary model, the heat production by hot water at the initial stage is higher when the reservoir pressure is 10 MPa than when it is 20 MPa. This may be because the density and solubility of the CO_2 phase are lower at 10 MPa than at 20 MPa even at the same temperature. They result in greater volume expansion of CO_2 and more hot water being extruded from the production well. The reason why the same phenomenon is not observed in the 5-spot model may be due to the difference in the way the amount of CO_2 injected is given. That is, the open-boundary model gives the injected mass of CO_2 at a constant value, whereas the 5-spot model gives it using a pressure-fixed boundary grid, and the amount of CO_2 injected greatly affects the difference in reservoir pressure (the difference between the cases where the mobility and density of CO_2 are 10 and 20 MPa).

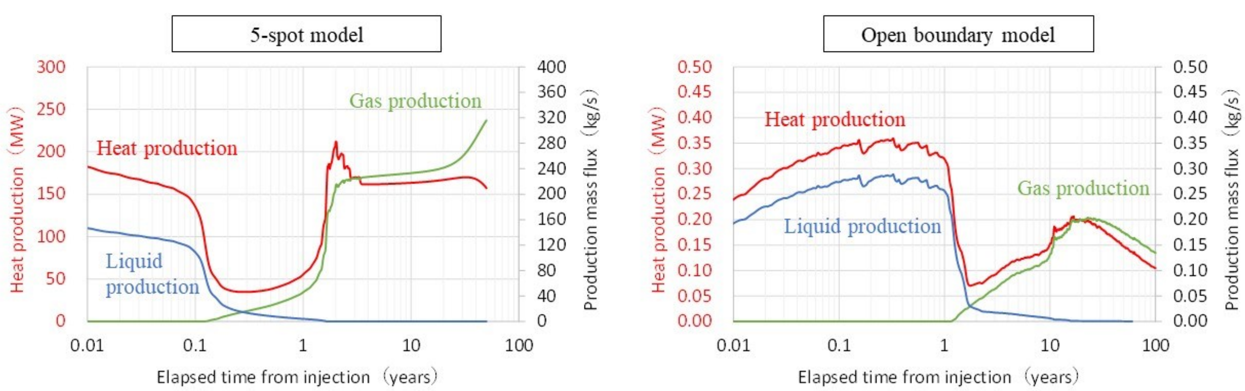

Figure 11: Time evolution of heat, gas and liquid production for CO2-EGS (temperature and pressure are 280 °C and 20 MPa at initial reservoir condition).

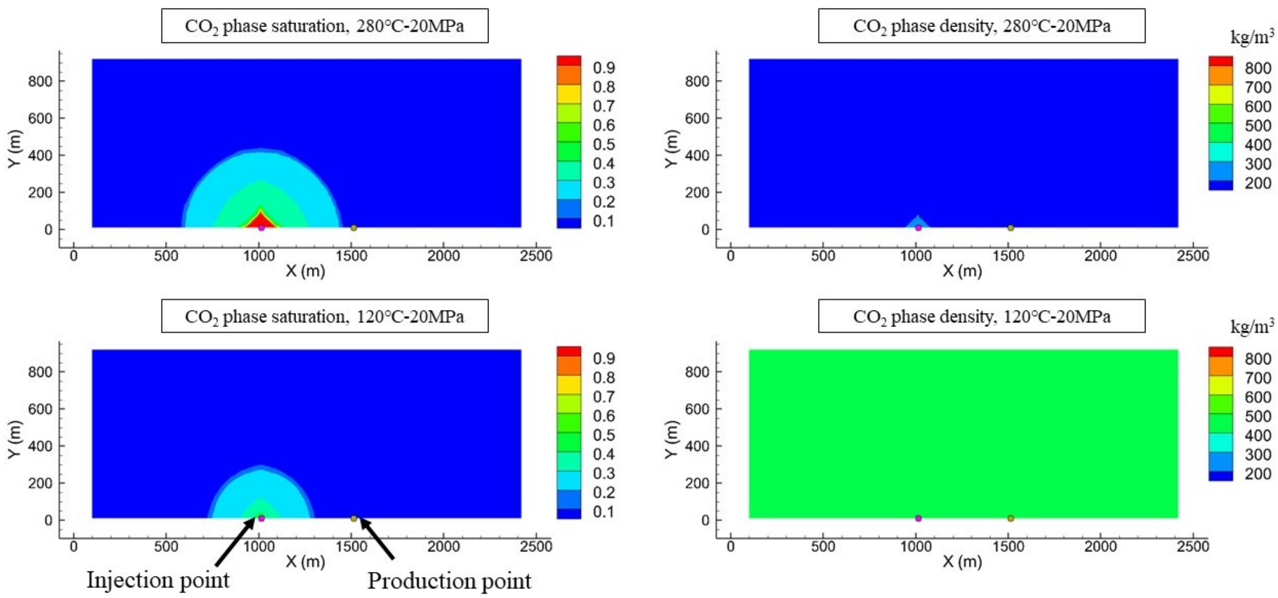

Figure 12: Distribution of saturation and density of CO_2 after 1 year from the start of the injection (temperature and pressure are 280 °C and 20 MPa at initial reservoir condition).

5. CONCLUSION

With the aim of implementation of CO_2 geothermal power generation in Japan, we conducted some numerical simulation studies focusing on the heat extraction efficiency and recovery rate of injected fluid in the case of using water and CO_2 as heat transfer fluid in hydrothermal reservoirs. As a result, it was found that it is important to make CO_2 breakthrough as early as possible to ensure a higher heat extraction from early stages of the energy production. The higher the reservoir temperature, the earlier breakthrough due to the larger volume expansion of CO_2. In addition, it was indicated that the recovery rate of CO_2 at a production well increases to around 50% after CO_2 breakthrough, due to the relative permeability effects in the two-phase flow of CO_2 and water in hydrothermal reservoirs.

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