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Simulating Reinjection of Produced Fluids into the Reservoir

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ABSTRACT

In order to maintain reservoir pressure and stability and to reduce reservoir subsidence, reinjection of produced fluids into the reservoir is common practice. Furthermore, studies by Karvounis and Jenny (2012; 2014), Buscheck et al. (2015), and Saar et al. (2015) found that preheating the working fluid in shallow reservoirs and then injecting the fluid into a deep reservoir can increase the reservoir life span, the heat extraction efficiency, and the economic gains of a geothermal power plant. We have modified the TOUGH2 simulator to enable the reinjection of produced fluids with the same chemical composition as the produced fluid and with either a prescribed or the production temperature. The latter capability is useful, for example, for simulating injection of produced fluid into another (e.g., deeper) reservoir without energy extraction. Each component of the fluid mixture, produced from the production well, is reinjected into the reservoir as an individual source term. In the current study, we investigate a CO_2-based geothermal system and focus on the effects of reinjecting small amounts of brine that are produced along with the CO_2. Brine has a significantly smaller mobility (inverse kinematic viscosity) than supercritical CO_2 at a given temperature and thus accumulates near the injection well. Such brine accumulation reduces the relative permeability for the CO_2 phase, which in turn increases the pore-fluid pressure around the injection well and reduces the well injectivity index. For this reason, and as injection of two fluid phases is problematic, we recommend removal of any brine from the produced fluid before the cooled CO_2 is reinjected into the reservoir. We also study the performance of a multi-level geothermal system (Karvounis and Jenny, 2012; 2014; Saar et al., 2015) by injection of preheated brine from a shallow reservoir (1.5-3 km) into a deep reservoir (5 km). We find that preheating brine at the shallow reservoir extends the lifespan of the deep, hot reservoir, thereby increasing the total power production.

1. INTRODUCTION

Reinjection of produced fluids into geothermal wells started purely as an attractive method for disposal of these fluids. However, both theoretical studies and field experiences have shown that properly designed reinjection wells can serve many additional purposes such as maintenance of reservoir pressure, reduction of subsidence, and improvements in reservoir management (Pruess and Bodvarsson, 1984; Stefansson, 1997). Reinjection also serves as a tool to gain information about flow paths in geothermal reservoirs by inducing chemical changes in the reservoir fluid (Stefansson, 1997). However, reinjection of produced fluids can also cause problems, e.g., maintaining consistent and reliable injectivity and production losses due to premature thermal breakthrough (Horne, 1985). Therefore, when developing a reinjection strategy, apart from the problems and benefits associated with production, distances of reinjection wells from production wells and the amount and quality of the reinejcted fluid also have to be taken into consideration (Diaz et al., 2016).

CO_2 Plume Geothermal (CPG) systems (Randolph and Saar, 2011; Saar et al., 2012; Garapati et al., 2015), involve injecting supercritical CO_2 into natural, highly permeable geologic reservoirs that are overlain by one or more low-permeability caprocks. Some of the injected and geothermally heated CO_2 is brought back to the surface for power generation and is then reinjected into the reservoir along with the main CO_2 sequestration stream that comes from a CO_2 emitter in a carbon capture and storage (CCS) system. This added utilization (U) of CO_2 renders the overall approach a CCUS system. The fluid produced from the reservoir often contains small amounts of brine along with CO_2. Therefore, it is important to understand the effects of reinjecting produced multi-component fluids on the injectivity and reservoir pressure near injection wells.

Karvounis and Jenny (2012; 2014), Buscheck et al. (2015), and Saar et al. (2015) found that injecting preheated working fluids could increase the reservoir life span, heat extraction efficiency, and economics of deep geothermal systems. The subsurface temperatures in relatively shallow reservoirs (1.5 km - 3 km) are not suitable for electricity production. However, when such shallow reservoirs are located above and near deeper and thus hotter reservoirs, the shallow reservoirs may be used as a preheater for the deeper reservoirs. During this approach, the working fluid is first circulated through the shallow porous reservoir and then injected into the deep reservoir, thereby producing higher-temperature fluids over longer periods of time, increasing the life span of the deep reservoir (Karvounis and Jenny, 2012; 2014; Buscheck et al., 2015; Saar et al., 2015). In order to evaluate the complete performance of multi-level geothermal systems, it is important to model all reservoirs together, i.e., where the produced fluid from one reservoir serves as injection fluid to another reservoir, with or without energy removal.

In order to numerically model the reinjection of produced fluids, we have modified the TOUGH2 simulator by adding a new subroutine called CIRCULATE which calculates the flow rate and enthalpy of the reinjected fluid based on the produced fluid. The modified TOUGH2 code is used for investigating the effects of reinjecting brine that is produced along with CO_2 in a CPG system and also to study the performance of multi-level geothermal systems, where brine is preheated in shallow reservoirs before injecting it into a deep reservoir.

2. MODIFICATION OF TOUGH2-ECO2N FOR CIRCULATION OF PRODUCED FLUID

TOUGH2 (Pruess et al., 1999; Pruess, 2004) is a numerical simulator for modeling non-isothermal multiphase flow in fractured porous media, and ECO2N (Pan et al., 2015) is an equation of state (EOS) fluid property module for TOUGH2 that enables modeling of CO_2 sequestration in saline aquifers. In order to calculate the flow rate and enthalpy of the circulation fluid, a new subroutine called CIRCULATE is added to calculate the generation terms for the circulation wells based on the produced fluid properties. The user can activate this option by specifying a sink (i.e., production well) in the GENER block of the input file and later include NK sources (i.e., one source for each component). A special injection well with source name CIR, followed by the number of the production well to be linked to the injection well, needs to be specified as shown in Figure 1.

```
GENER----1----*----2----*----3----*----4----*----5
ELE50PRO50                   0     MASS       -2.0
ELE51PRO51                   0     MASS       -2.0
ELE66CIR 2                   0     WATE        1.0
ELE66CIR 2                   0     COM2        1.0
ELE66CIR 2                   0     COM3        1.0
```

Figure 1: Example of the new GENER block in an input file, demonstrating usage of the new source (injection well) term, CIR. Entries are defined and explained in the main text.

The three sources in Figure 1 (lines 3-5 after GENER) represent the injection well (all inject into the same element); they are linked to the second producer (PRO51). The first source refers to water, which is calculated as the amount of water produced in PRO51; the second source is NaCl, and the third source is CO_2. The fraction of the produced fluid component to be circulated is specified as the injection rate, GX, for the CIR source. If all the produced fluid has to be reinjected, GX is 1.0 as shown in Figure 1 or, if for example only half of the produced fluid is reinjected, then GX is 0.5. If the fluid is reinjected without any enthalpy extraction, then the enthalpy is zero. Hence, the enthalpy of the injected fluid is set to be same as that of the produced fluid. Conversely, if the produced fluid is reinjected with an enthalpy that is different from the production enthalpy, fixed specific enthalpy of the injected fluid has to be specified, similar to the regular TOUGH2 source term.

3. EFFECTS OF REINJECTING BRINE ALONG WITH CO_2

3.1 Model Description

The geothermal reservoir considered has a porosity of 10%, is 50 m thick, is located at an average depth from the land surface of 2.5 km, is bound by impermeable bedrock and caprock formations, and is heated from below by a typical continental geothermal gradient of 35°C/km (Pollack et al., 1993; Davies and Davies, 2010). We employ a numerical, three-dimensional (2D), axisymmetric model with the cold injection fluid entering the shallow reservoir through a vertical injection well (Figure 2). After moving through the geothermal reservoir, the heated fluid is produced from a horizontal, circular production well placed at a distance of 707 m from the injection well as described in detail in Garapati et al. (2015). Initially, the pore space in the reservoir is filled completely with 20 wt% NaCl brine. In order to produce fluid with a concentration of approximately 94% CO_2, which is based on suggestions by Welch and Boyle (2009) for direct CO_2-based power generation equipment, the CO_2 plume is built-up initially over 2.5 years as described in Garapati et al. (2015). Once a sufficiently large CO_2 plume is established, further CO_2 injection is stopped and fluid production and circulation commences. The circulation rate is increased linearly over 2 years, and then maintained at a constant rate. In all figures, time is set to zero at the beginning of CO_2 production and circulation. All the produced fluid, along with the small amount of brine that is co-produced with the CO_2, is circulated back into the reservoir at a temperature of 46 °C. The reservoir constants and fluid parameters are taken from Garapati et al. (2015).

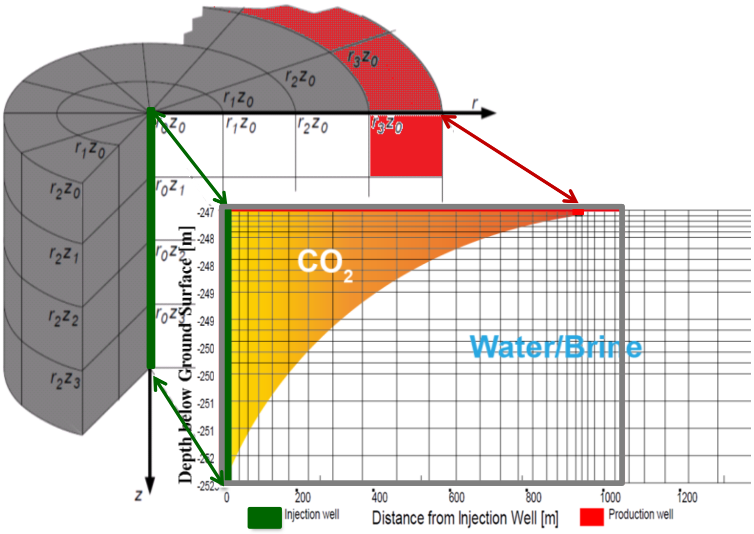

Figure 2: Two-dimensional axisymmetric numerical model with cross section showing the grid discretization and placement of wells. The injection well is vertical and fully penetrating the reservoir and acting as the axis of symmetry. The production well is horizontal, circular located just below the caprock at a distance of 707m from the injection well (modified from Garapati et al., 2015).

3.2 Results and Discussion

Aqueous saturation fractions in the reservoir pore fluid at various times during the simulation are shown in Figure 3. Brine starts accumulating at the bottom of the reservoir near the injection well as it has a lower mobility (i.e., a larger kinematic viscosity) than supercritical CO_2 at a given temperature. Such brine accumulation reduces the relative permeability for the CO_2 phase at the well, which in turn increases the pore-fluid pressure in the reservoir around the injection well as shown in Figure 4. This pressure variation depends upon the amount of the liquid (brine) in the produced fluid, as the liquid saturation in the produced fluid increases the pressure at the injection well increases.

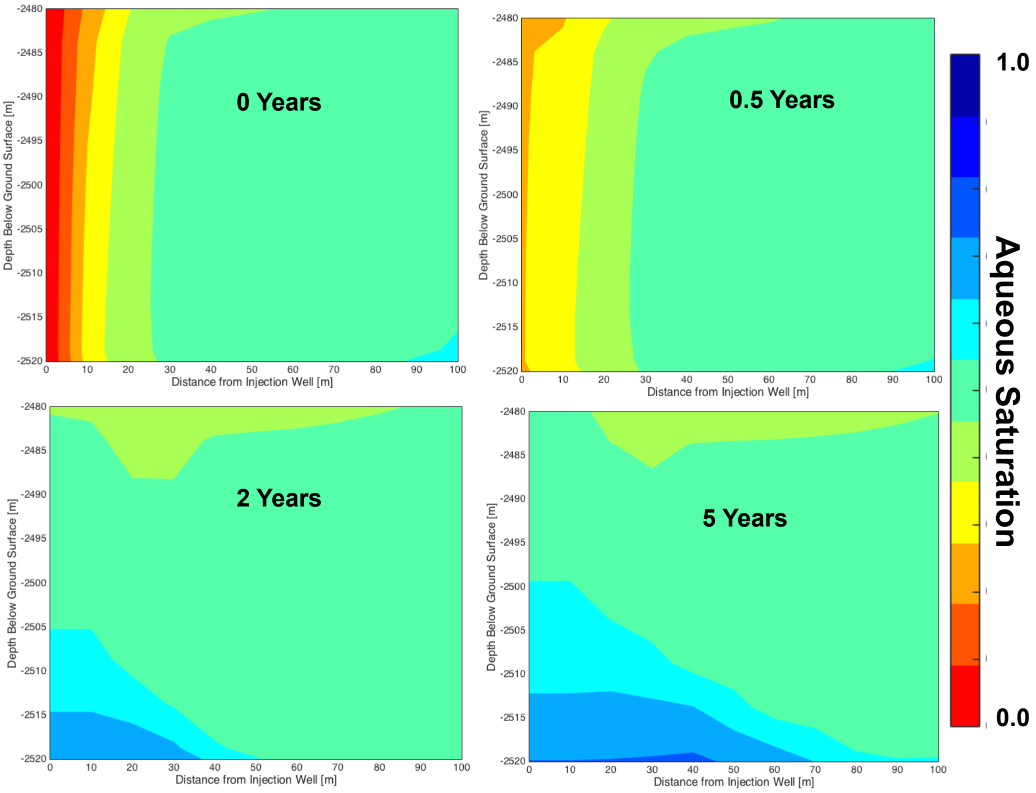

Figure 3: Radial cross-section contour plots of the aqueous saturation in the geothermal reservoir pore fluid near the injection well a) before production 0 year, and after b) 0.5 year, c) 2 year and d) 5 years. Over time,

the aqueous phase saturation increases near the bottom of the injection well with reinjection of small amounts of water that are co-produced with CO_2.

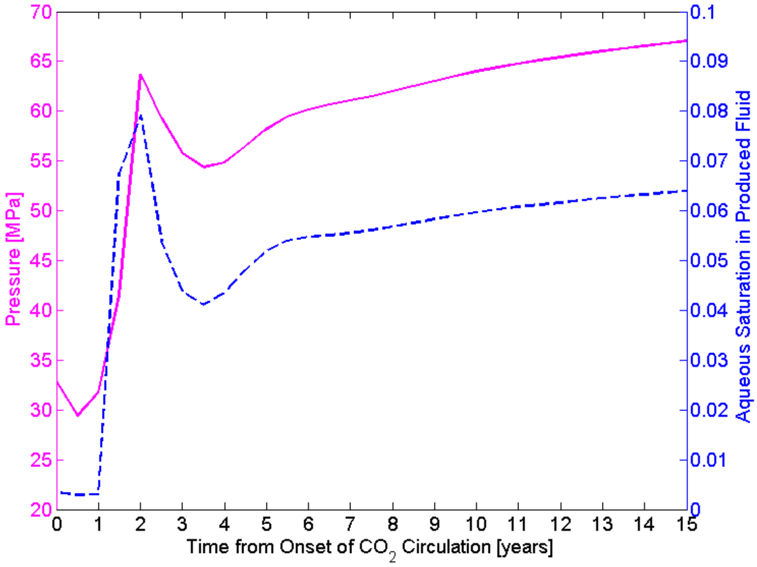

Figure 4: Reservoir pore-fluid pressure near the vertical injection well (magenta solid line) and brine fraction (blue dotted line) in the produced fluid over time. The pressure near the injection well varies in accordance with the amount of brine in the produced fluid.

For this reason, and as injection of two fluid phases is problematic, it is recommended to remove any produced brine from the produced fluid before the cooled fluid is reinjected into the reservoir. Separated brine may be re-injected into the formation away from the CO_2 plume, which can provide additional means to control and direct the CO_2 plume direction and pressure field, avoiding the need to dispose of, or treat, the brine near the land surface (Buscheck et al., 2014).

4. MULTI-LEVEL GEOTHERMAL SYSTEM

In a traditional geothermal system, hot working fluid is produced from a deep reservoir. At the surface some of the thermal energy of the fluid is extracted for electricity production, and the cold fluid is injected back into the reservoir. An alternate scenario is to first preheat the working fluid in a shallow reservoir before injecting it into the deep reservoir, which can increase the electrical power production and hence system efficiency (Karvounis and Jenny, 2012; 2014).

4.1 Model Description

Figure 5 is a schematic of the geothermal systems considered in this study with a shallow reservoir located at an average depth from the land surface of 1.5 km to 3.0 km, and a deep reservoir located at a depth of 5 km with a thickness of 125 m, a porosity of 12%, and a permeability of 10^{-13} m^2. Both reservoirs are bounded by impermeable bedrock and caprock formations and are heated from below by a typical geothermal gradient of 35°C/km (Pollack et al., 1993; Davies and Davies, 2010) with a mean annual surface temperature of 15°C. The system on the left represents a traditional geothermal system, where the two reservoirs are operated independently of each other. In contrast, the system on the right represents the multi-level geothermal system, where the shallow and the deep reservoirs are integrated. Brine that is preheated in the shallow reservoir is injected into the deep reservoir. Here we employ a 2D axisymmetric model with concentric rings of horizontal injection and production wells placed at a distance of 1000 and 1500 m from the axis of symmetry, respectively. The reservoir fluid properties are similar to our previous studies (Randolph and Saar, 2011; Garapati et al., 2015). In independent systems, the brine produced is cooled at the surface and is circulated at same flow rate back into the reservoir at a temperature of 25°C, while in integrated systems, the preheated fluid produced from the shallow reservoir is injected directly into the deep reservoir, and the brine produced from the deep reservoir is cooled at the surface and circulated back into the shallow reservoir at a temperature of 25°C. Simulations are conducted for brine production and circulation rates of 120 kg/s, 180 kg/s, and 240 kg/s.

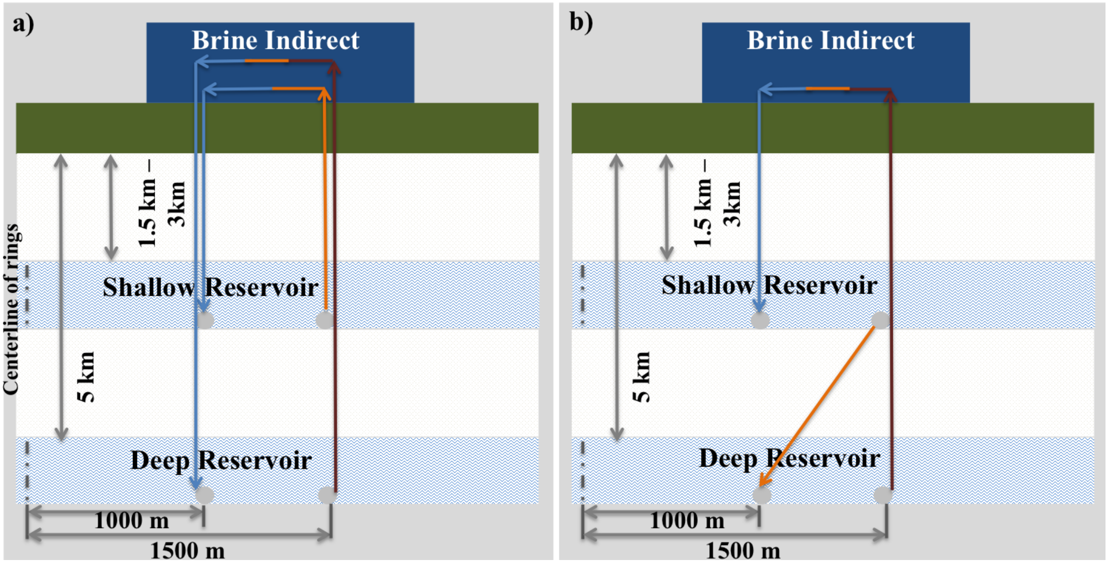

Figure 5: Schematic of a) two independent traditional geothermal reservoirs and b) an integrated multi-level geothermal system.

4.2 Results and Discussion

The produced fluid temperature time series for independent and integrated reservoirs for different flow rates are shown in Figure 6. The solid lines represent the temperature produced from the reservoirs operated separately, and the dotted lines denote the temperature of the produced fluid from the deep reservoir of a multi-level geothermal system.

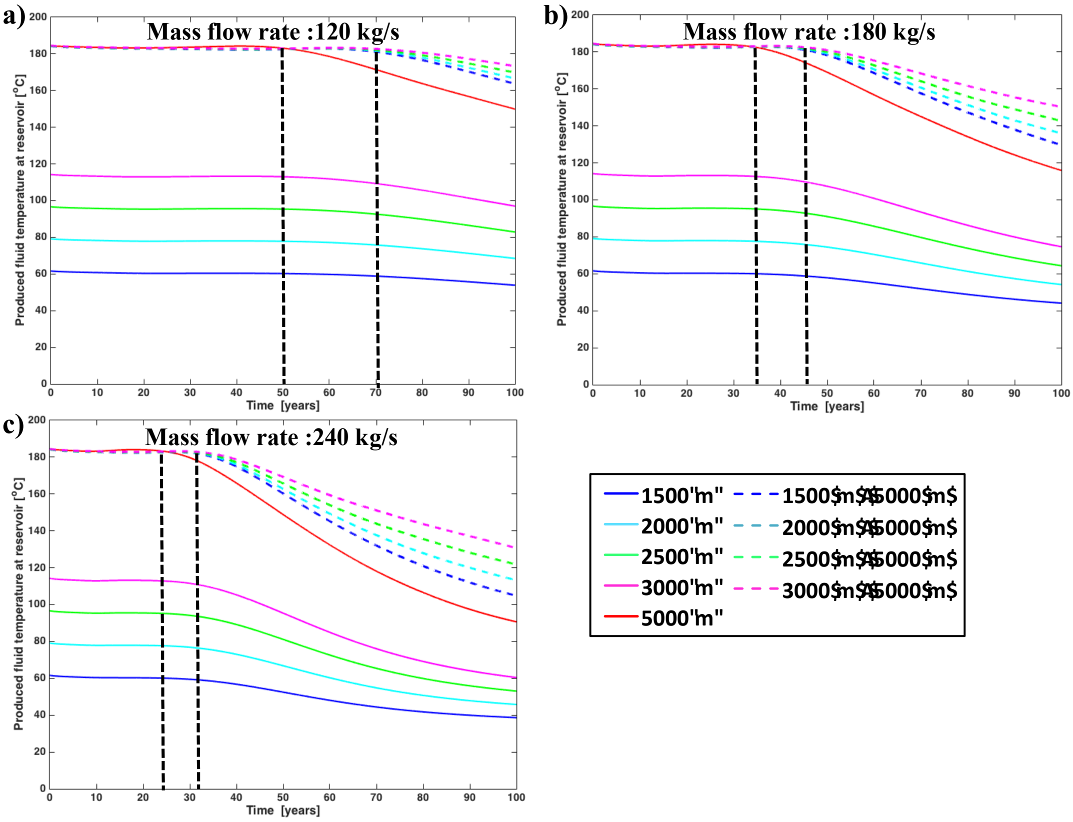

Figure 6: Temperature of the produced fluid at the reservoir with time independent geothermal systems shown in solid lines and integrated multi-level systems shown in dashed lines for different production and circulation rates of a) 120 kg/s b) 180 kg/s and c) 240 kg/s. The dotted black line represents the thermal breakthrough time of the deep reservoir.

The thermal breakthrough time of the deep reservoir (5 km) increases for an integrated system when compared to a 5 km-deep reservoir operated individually. However, with increasing flow rate the difference in the breakthrough time between the integrated system and individual systems decreased. The subsequent temperature depletion rate is also slow for integrated systems, and it further decreases with an increase in the depth of the shallow reservoir. Thus, as expected, as the brine preheating temperature increases, the deep reservoir depletes at a slower rate. The temperature profile along the radial cross section of the reservoir at the end of 100 years of production is shown in Figure 7. The thermal drawdown between the wells is quite significant for the 5 km reservoir operated independently, while for integrated system with a shallow reservoir at 1.5 km, the thermal drawn down in the reservoir has not yet reached the production well. In contrast, for the integrated system with a preheating shallow reservoir at a depth of 3 km, the thermal drawdown is seen only around the injection well. In all the cases, the reservoir temperatures beyond the production well are minimally affected by fluid production and circulation.

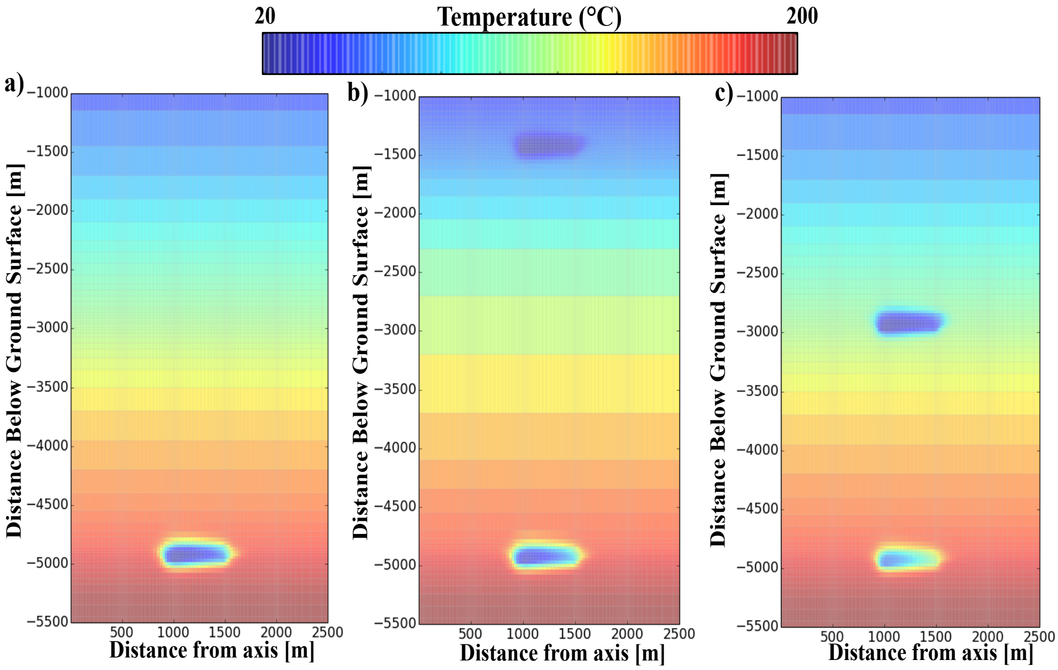

Figure 7: Radial cross section of the numerical model showing the temperature profile in the subsurface after 100 years of production at a rate of 240 kg/s in a) independent 5 km deep reservoir and integrated reservoirs with a deep reservoir at 5 km and shallow reservoir at b) 1.5 km and c) 3.0 km.

5. CONCLUSION

A new module called CIRCULATE is added to the TOUGH2 numerical simulator to model reinjection of the produced fluid either at the same produced temperature or at a prescribed temperature. Two case studies were conducted to demonstrate the use of the new module. In the first example, the effects of reinjecting co-produced fluids (CO_2 and brine) back into the reservoir were investigated. Due to its lower mobility, brine accumulates near the injection well, decreasing the relative permeability for the CO_2 phase. Therefore, we recommend separating brine from CO_2 before reinjection. The separated brine is ideally reinjected into the formation away from the CO_2 plume. In the second example, we studied the performance of separately operated and integrated multi-level geothermal systems and compared the thermal breakdown and temperature depletion rate of the deep reservoirs in both cases. We find that the thermal breakthrough and temperature depletion rates can be delayed in the deep reservoir by preheating the brine in a shallow reservoir, thereby increasing the life span and total power production of the deep reservoir. Further studies are being conducted to compare the actual power production rates at the surface of both systems.

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DISCLAIMER

Drs. Randolph and Saar have significant financial and business interests in TerraCOH Inc., a company that may commercially benefit from the results of this research. The University of Minnesota has the right to receive royalty income under the terms of a license agreement with TerraCOH Inc. These relationships have been reviewed and managed by the University of Minnesota in accordance with its conflict of interest policies.

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