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# Thermo-Hydrological Modeling of Thermal Energy Storage in a Depleted Oil Reservoir

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## ABSTRACT

Thermal energy storage in oil and gas reservoirs leverages the existing surface and subsurface infrastructure, which can pave the way for economic production of geothermal energy. Existing studies on geothermal energy storage are focused mostly on the use of aquifers with more homogeneous rock and fluid properties. Coupling of heat and fluid flow in a multiphase-multicomponent system, such as an oil reservoir, is imperative especially if existing oil field assets need to be repurposed as required for a sustainable energy transition. The objective is to model the subsurface thermo-hydrological processes associated with reservoir performance and operational sustainability. The model evaluates formation pressure and temperature within the reservoir and at the injection/production wells during multiple charge and discharge cycles.

Hot water (~200°C) heated by Concentrating Solar Power (CSP) at high pressure is injected into the existing oil reservoir for storage and produced as thermal energy for power generation, which will be accompanied by enhanced oil recovery. To demonstrate the coupled fluid and heat flow during the injection/production cycle in the subsurface reservoir, TOUGH3 (developed by Berkeley Lab) is used to simulate the thermo-hydrological (TH) processes in a multiphase, multicomponent system. Two well geometries are considered within the reservoir grid: 1) a single-well huff-n-puff system (same well is used for injection and production), and 2) an isolated injection-production well doublet. Seasonal charge and discharge cycling are implemented based on the scheduling specified in the model input file.

The model reports pressure, temperature, enthalpy, liquid fluxes, heat fluxes, pore velocities, and changes in porosity & permeability due to temperature and pressure variations during the cyclic Reservoir Thermal Energy Storage (RTES) operations. The results from the simulations can be used to optimize the operational parameters (such as well spacing and injection/production rates) and round-trip efficiency for surface power-plants coupled with thermal energy storage over time. They can also serve as important inputs for levelized cost of storage estimations. The research will help to design and integrate surface renewable energy sources, such as concentrating solar power (CSP), with RTES to help balance out power supply and demand on the grid.

## 1. Introduction

Energy storage is increasingly necessary as Variable Renewable Energy (VRE) technologies replace fossil fuels for electricity generation and heating. Many energy storage solutions are being developed to address short discharge durations, but there are significant seasonal variations in VRE generation and electricity consumption. Seasonal energy storage is a promising technology that can shift energy generation from the summer to the winter, but these technologies must have extremely large energy capacities and very low costs. High temperature reservoir thermal energy storage (HT-RTES) is proposed as a solution for long-term energy storage. Benefits of HT-RTES includes long-term storage and productivity as it is charged externally unlike traditional geothermal resources. Excess thermal energy can be stored in permeable reservoirs such as aquifers and depleted hydrocarbon reservoirs for several months. Sharan et al. (2021) recently determined that storing solar thermal energy in RTES provides a constant and lower levelized cost of storage (LCOS) over both short and long durations compared to the commonly used molten salt thermal energy storage (TES).

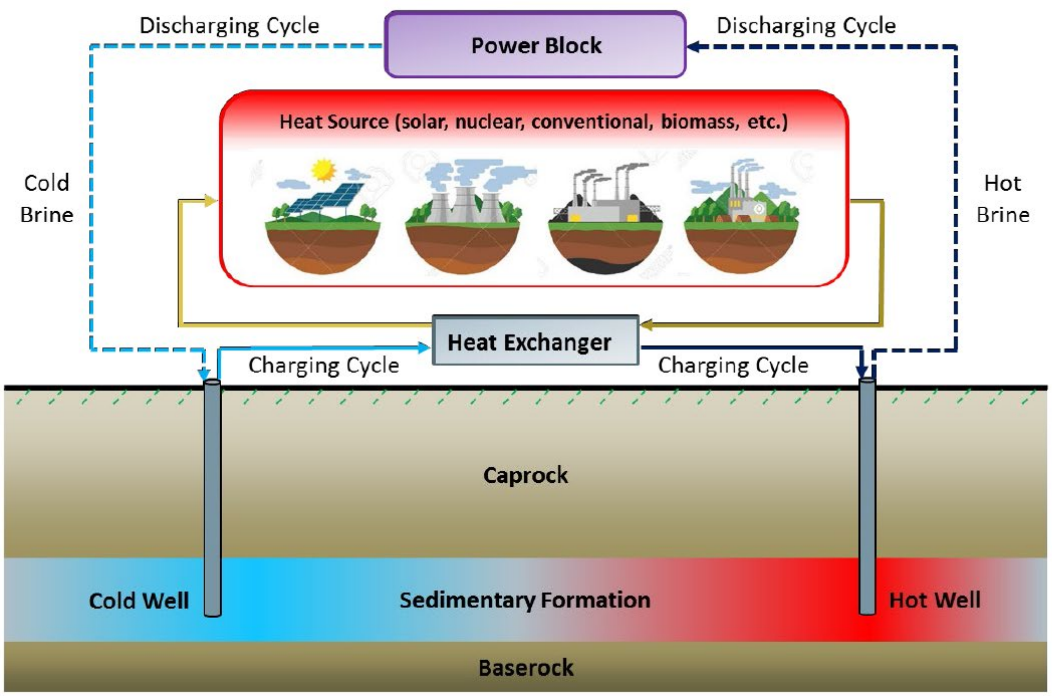


**Figure 1: A conceptual model of a reservoir thermal energy storage (RTES) system (US DOE, 2020).**

Thermal storage in shallow aquifers has been implemented in the United States and western Europe for decades for low-temperature (< 50°C) building and district heating applications (Fleuchaus et al., 2018; Kumar et al., 2021). There are currently no commercial thermal storage projects in depleted oil reservoirs, although demonstration projects are ongoing in Germany. Nevertheless, the oil and gas industry has successfully injected hot water and steam for enhanced oil recovery applications in reservoirs containing heavy (high viscosity) oil. In this paper, we will advance the state-of the art by developing subsurface models for higher temperature RTES (e.g., >150°C) in porous and permeable sedimentary formations. The idea is to heat the water from the subsurface (produced from a cold well) and inject it in hot wells (Figure 1). The stored hot water will be used for electricity generation during peak hours or direct use during seasonal heating and cooling. The goal is to evaluate heat and mass flow during charging and production cycles using a thermo-hydrological (TH) model. Modeling results such as heat flux, mass flux, density, temperature, and enthalpy of the produced fluid will be helpful to optimize the energy generation and related surface power cycle operations during variable seasonal demands and integrate the geothermal energy into the grid. The TH modeling results from this study will also help in addressing some of the challenges such as thermal short-circuiting during HT-RTES operations.

## 2. Geologic and Hydraulic Setting

For this study, oil and gas fields in Central California are analyzed as potential candidate formations for high temperature geothermal energy storage (Figure 2). Reservoir data such as porosity, permeability, thermal conductivity, temperature, pressure, mineralogy, depth and size of the formation, brine chemistry, and well data is collected from the Geologic Energy Management Division (CalGEM) database, the United States Geological Survey (USGS), the California Department of Conservation, and Premier Resource Management (PRM), LLC. Based on the collected data from more than 50 oil and gas fields in central California, an interactive database has been prepared in a spreadsheet. Initial reservoir pressure in the collected database ranges from 200 - 5,100 psi whereas temperature lies between 32°C and 138°C. The average thickness of the production unit varies between 4 m and 150 m. The depth of these units ranges from 122 m to 3353 m. The porosity of the formations ranges from 0.12 to 0.5 with an average 0f 0.28. Permeability varies from 1.5 to 3070 millidarcies. Salinity (as NaCl, ppm) of the formation waters varies from 800 to 40,000 ppm.

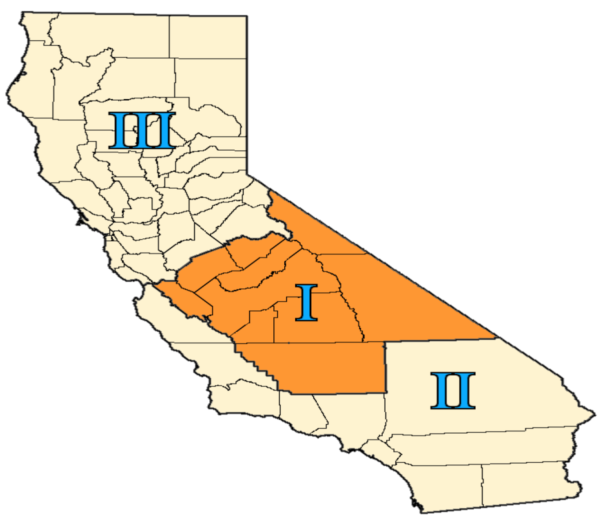


**Figure 2: California oil and gas fields. Source: California. Division of Oil, and Gas. *California Oil and Gas Fields: Central California*. No. 11. California Department of Conservation, Division of Oil, Gas, and Geothermal Resources, 1998.**

For the TH modeling case study, location-specific data for the North Antelope Field (Tulare Formation) in the San Joaquin Valley is shared by Premier Resource Management, LLC (Berger et al., 2023). The Tulare Formation, for the purposes of this study, is broken into two separate units (Tulare Oil Sand, and Tulare Clay) based on the depositional environment. In general, the Tulare Formation consists of yellowish tan to greenish-grey/bluish-grey clays with intervening grey sand bodies. CalGEM well records were examined for all wells in the study area in a search for core data (sidewall or continuous conventional cores) where cores were taken from the Tulare Formation interval. Porosity (Φ) and Permeability (κ) results from cores with available laboratory analysis are summarized in Table 1 as follows:

**Table 1: Hydraulic properties of sand and clay units in the Tulare Formation**

| Interval | Porosity range | Average porosity | Permeability range(md) | Average Permeability(md) | #samples |
|---|---|---|---|---|---|
| Tulare clay | 23-44% | 28.0% | 0.4-7.0 | 2.73 | 5 |
| Tulare clay (Sand lenses) | 20-44% | 33.3% | 10-1200 | 215.9 | 44 |
| Tulare Oil Sand | 18-50% | 32.9% | 1-2500 | 570.3 | 93 |

### *2.1. Modeling approach*

Based on the acquired data, a thermo hydrological model for subsurface energy storage has been developed using the TOUGH suites of codes, developed by Berkeley Lab (Pruess et al., 1999; Jung et al., 2018). Initially, a push-pull injection/production model has been set up to show the temperature variations and energy loss during the seasonal operation cycle. A 3-D mesh with dimension of 400 m × 300 m × 460 m is created for the TH modeling (Figure 3). The model includes the hydraulic and thermal properties in each layer from the field data but doesn't consider heterogeneity in horizontal direction. Also, the model doesn't consider a separate oil phase and approximates a majority of aqueous phase for flow modeling in porous media.

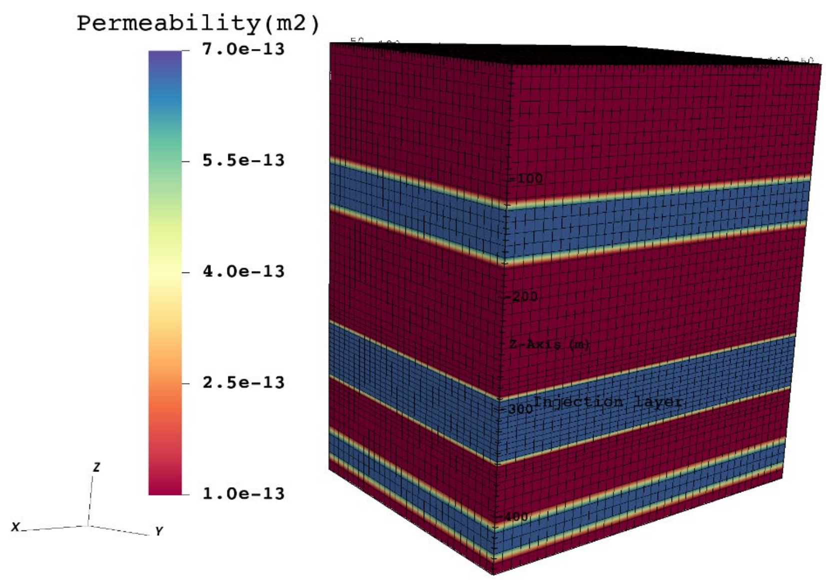


**Figure 3: Schematic of the modeled domain setup using TOUGH2-EOS7**

Initial temperature, pressure, TDS, and injection parameters are summarized in Table 2 as follows:

**Table 2: Initial reservoir conditions and injection rate**

| | |
|---|---|
| Reservoir Temperature (°C) | 50 |
| Reservoir Pressure (Pa) | 4.089e6 (593 psi) |
| Injection rate | 1200 bpd @200°C<br>2.2 kg/s, 12000 kWh/d |
| TDS | 16000 mg/L |

Initially, the reservoir was charged for 9 months followed by 3 months of production cycle for both scenarios 1) a single well huff-n-puff system, and 2) an injection-production well doublet. The heated fluid was injected at a depth of 335 m in a sand layer that has a thickness of 60 m for both the scenarios. The injection rate corresponds to a targeted power output of 12,000 kWh per day after fully charging of the reservoir. During the 3 months production cycle from the hot well, the cold well is charged with water at 60 ºC, which is discharged from the power block (Figure 1).

## 3. Results & discussion

### *3.1. Temperature Dissemination in huff-n-puff*

Temperature is plotted (Figure 4) during 9 months of charging and 3 months of discharging cycle in the injection-production well as well as at the grid block located 10 meters away from the well in the lateral direction. The temperature profiles suggest that there is a scope for more charging to obtain an optimum storage efficiency.

Vertical temperature dissemination is plotted in Figure 5 during the injection/production cycle. The results suggest a higher temperature drop in the bottom of the layer during the production. The preliminary results for a huff-n-puff system indicates a temperature drop during the charging and discharging cycles, which suggests further optimization of operational cycle to maximize the temperature of the production fluid or storage efficiency based on the daily energy demand. A partially charged formation doesn't yield the desired storage efficiency, which is needed to achieve the optimum power output. When comparing the temperature dissemination in both lateral and vertical directions, the flow properties of heated fluid should also be analyzed. The heated fluid moves towards the upper caprock due to buoyancy as density decreases with increasing temperature. Therefore, the plume migration increases in the lateral direction and decreases vertically. A more illustrative analysis for the heat and mass flow is represented for the second case of the hot-and-cold well doublet system.

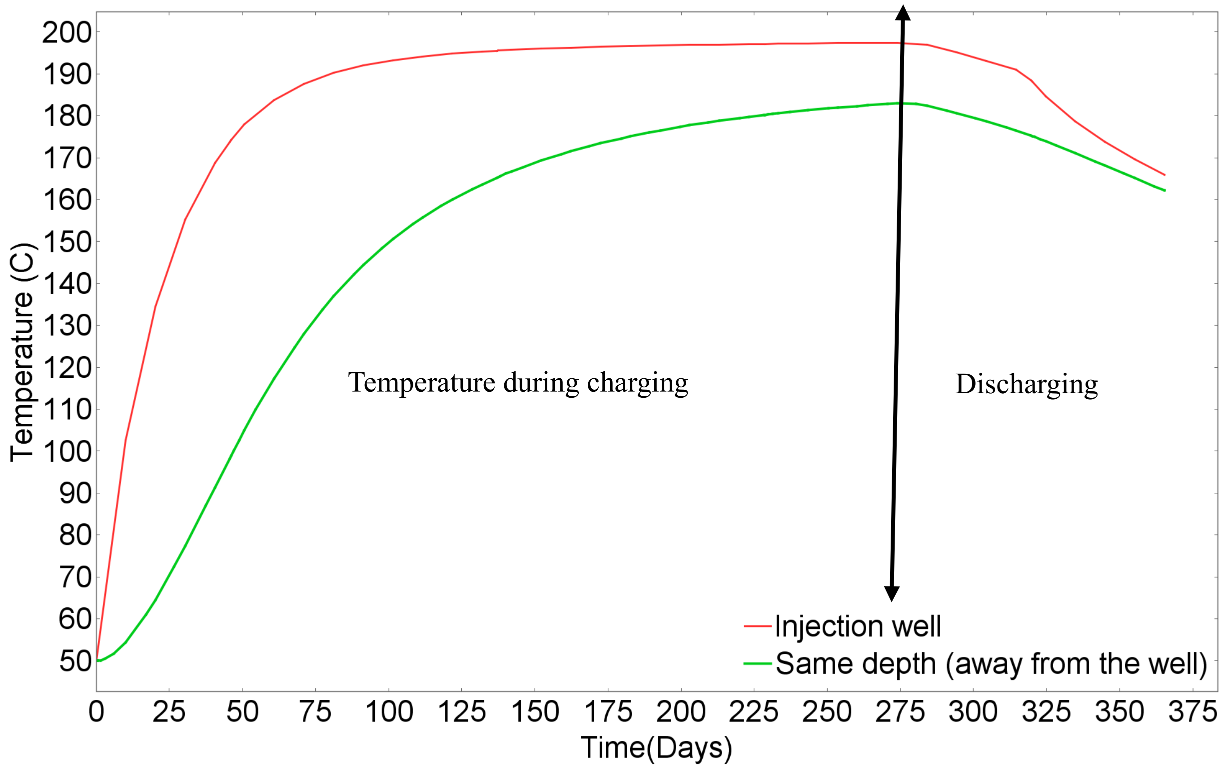


**Figure 4: Lateral dissemination of temperature during charging and discharging cycle.**

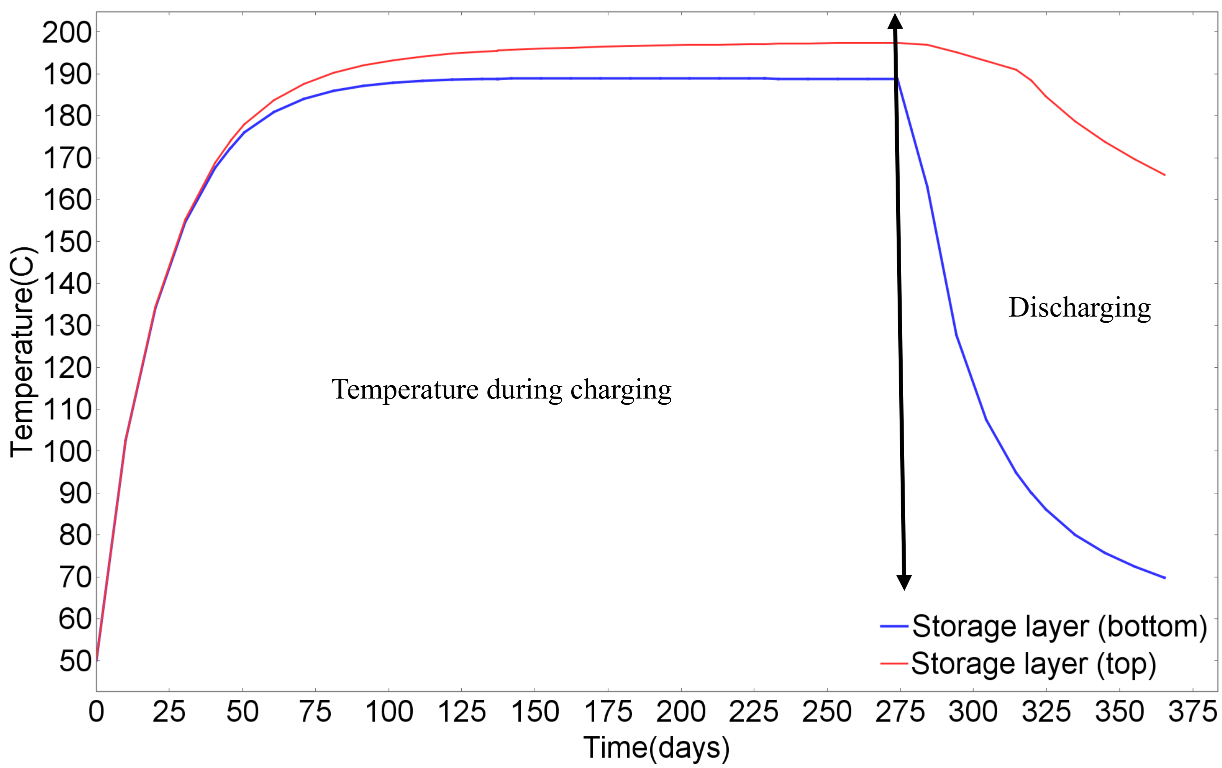


**Figure 5: Vertical temperature dissemination during charging and discharging cycle.**

### 3.2. *Flow and thermal properties in hot-n-cold well doublet*

The temperature distribution in hot and cold wells after 9 months of charging and 3 months of production is plotted in Figure 6.

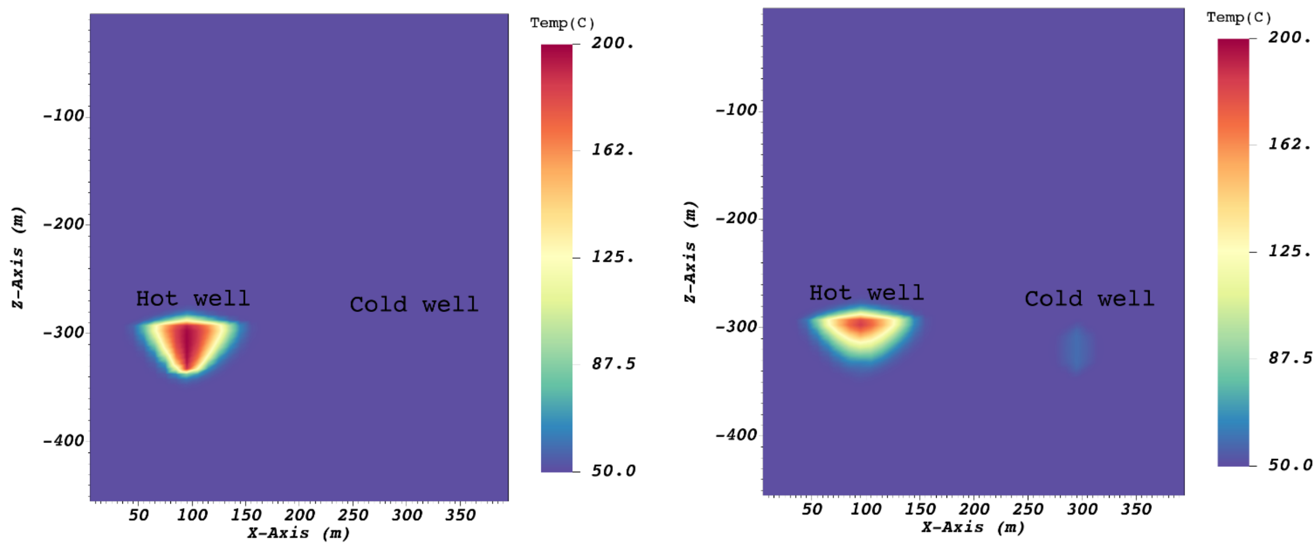


**Figure 6: Temperature (ºC) dissemination after 9 months of charging (left panel), and 3 months of production (right panel). The snapshots of x-z plane correspond to y = 145 m.**

During the 9 months of charging, the temperature near the hot well (x = 95 m) reaches ~200 ºC (Figure 6) whereas the temperature of the cold well remains constant as the native fluid is produced during this period. During the 3 months of production, the temperature of hot well decreases and hot water plume shrinks vertically as well as laterally. On the other hand, the temperature of the cold well changes slightly due to injection of slightly higher temperature (60 ºC) water from the power block. The heat flux during the charging and discharging cycle is plotted in Figure 7 which shows the energy flux at 9 months and 12 months respectively. Negative heat flux indicates (blue color in Figure 7) the removal of thermal energy whereas positive heat flux (warm colors) represents addition of thermal energy during charging. The heat flux is directly proportional to the temperature and mass flux (Figure 8) of injected/produced water. The enthalpy of the fluid is plotted in Figure 9, which varies with the temperature of injection water. The density plot in Figure 10 helps in deciding the extent of plume migration in both lateral and vertical directions. An increase in temperature decreases the density of the fluid (water in this case), which drives upward flow of lower density fluid. The extent of plume migration is a key parameter to estimate the size of reservoirs, and the distance between hot and cold wells based on the energy output. The TH modeling results such as temperature, heat flux, mass flux, and enthalpy give a detailed description of flow and thermal variations during injection and production cycle, which can be utilized for designing/sizing of the wells, evaluating the geothermal storage potential of reservoirs, and optimizing the energy production operation efficiently. Also, the modeling results don't indicate any thermal short-circuiting in this case.

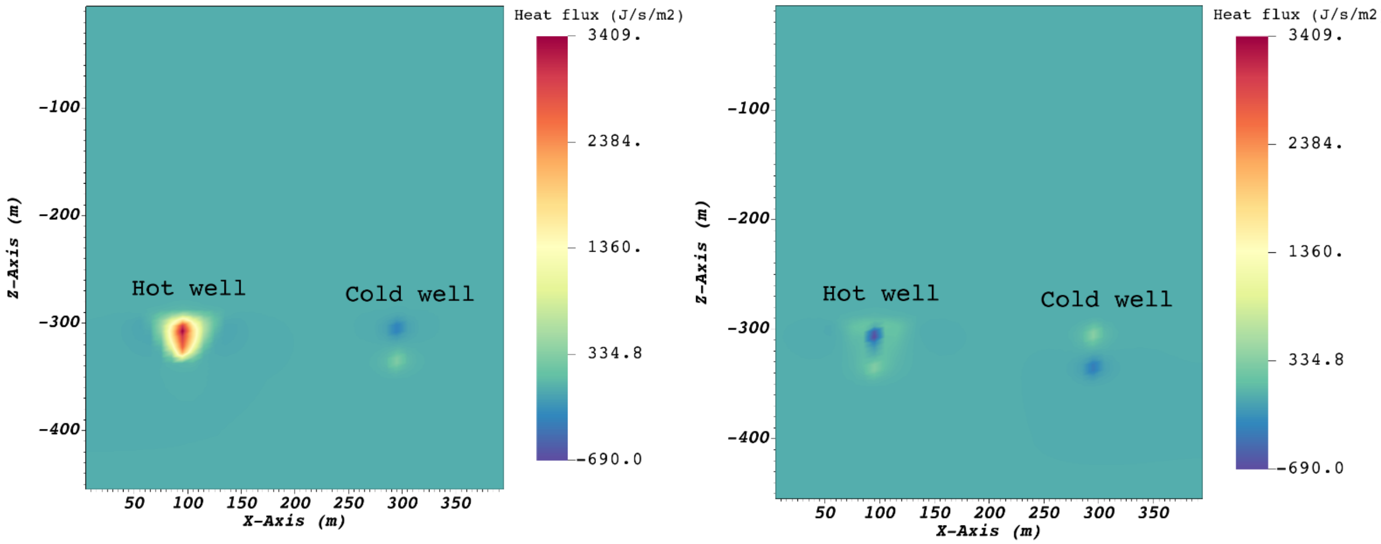


**Figure 7: Heat flux (vertical) (J/s/m$^2$) after 9 months of charging (left panel), and 3 months of production (right panel).**

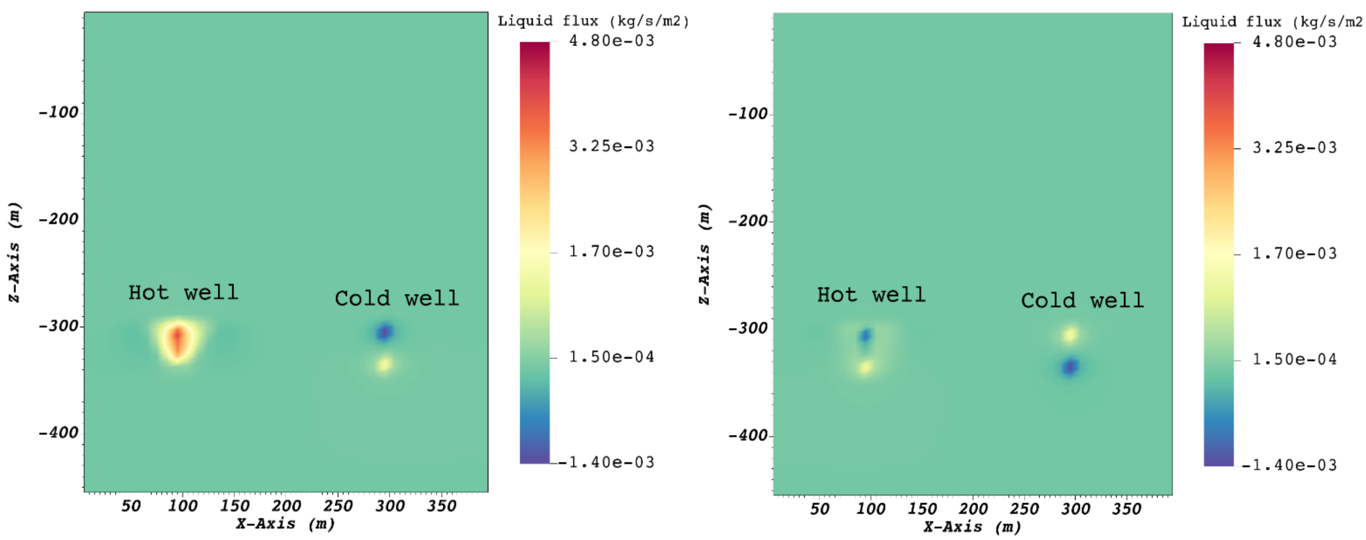


**Figure 8: Liquid flux (vertical) (kg/s/m$^2$) after 9 months of charging (left panel), and 3 months of production (right panel).**

mechanical) models should be developed to predict geochemical and geomechanical issues associated with the HT-RTES operations (Dobson et al., 2023). Also, for the future simulations, detailed operational parameters reflecting daily energy production and seasonal variations in recharging will be considered.

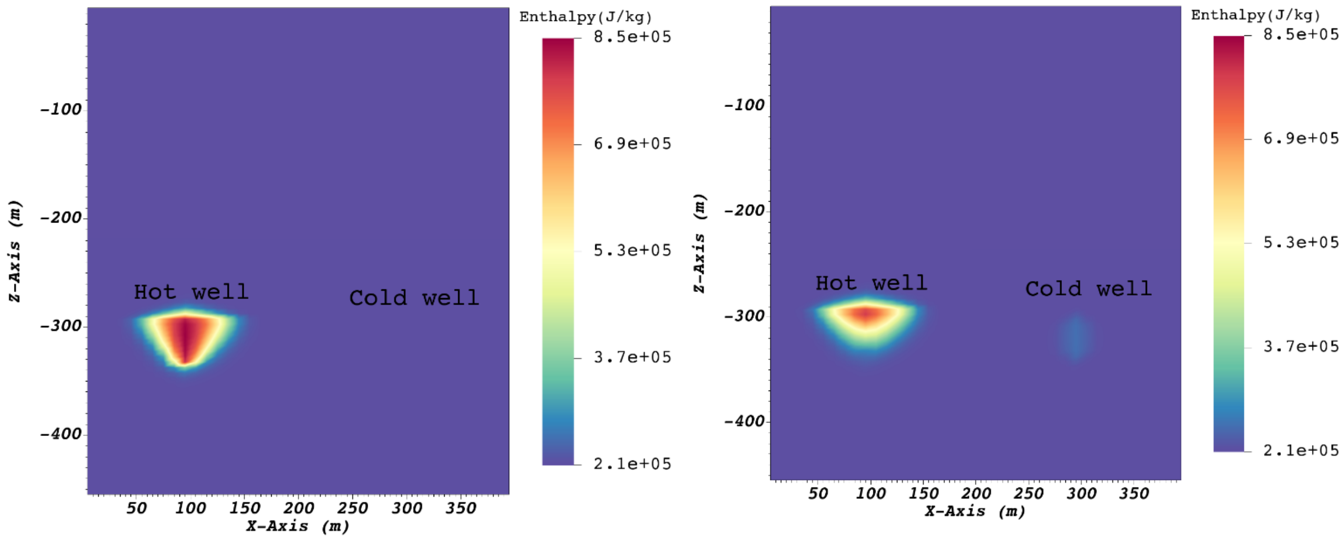


Figure 9: Enthalpy (J/kg) after 9 months of charging (left panel), and 3 months of production (right panel).

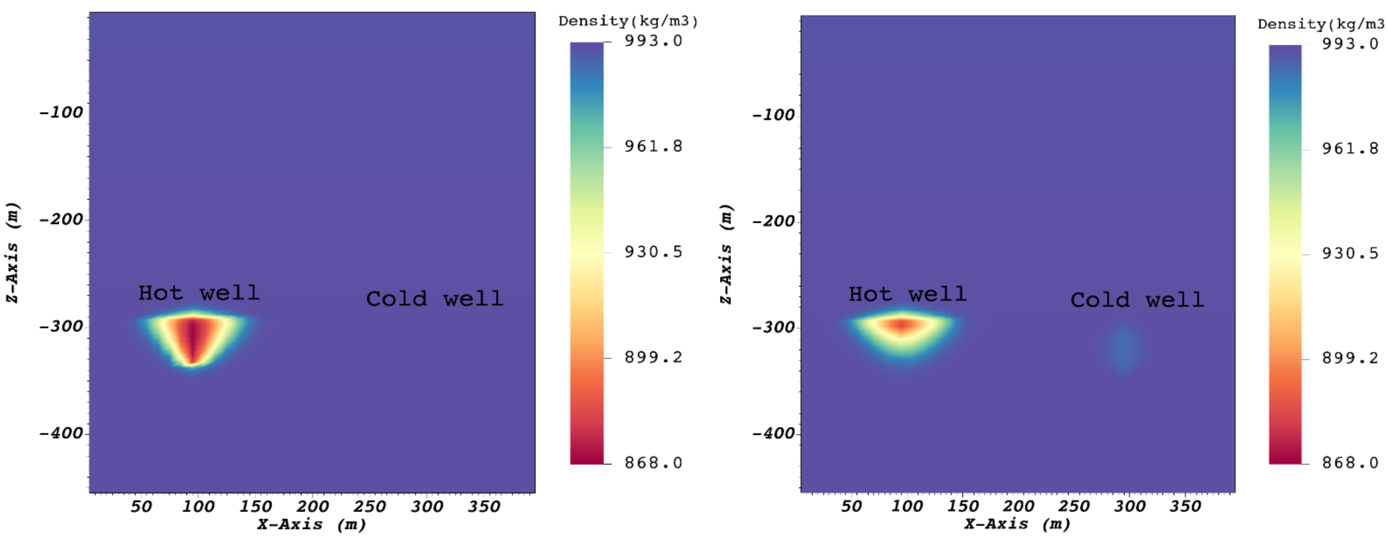


Figure 10: Density (kg/$m^3$) after 9 months of charging (left panel), and 3 months of production (right panel).

## 4. Conclusions and future work

The TH modeling results suggest HT-RTES is a promising technology for reliable and possibly long-term subsurface energy storage. The TH modeling helps optimize operational parameters such as injection/production rate, well placements, temperature of injected/produced water, storage efficiency, and to evaluate the possibility of thermal short-circuiting during the storage operations over a given time frame. The study will also help in assessing the techno-economic feasibility (Zhu et al., 2023) of solar-geothermal hybrid systems in depleted oil reservoirs. However, based on the lessons learned during the past HT-ATES (Aquifer Thermal Energy Storage) projects (Dobson et al., 2023), a detailed THC (thermo-hydrologic-chemical), and THM (thermo-hydrologic-mechanical) model should be developed to evaluate the system performance due to scaling, corrosion, surface uplift, and fracture development/propagation.

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