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Modeling Study of Single-Well EGS Configurations

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ABSTRACT

From the perspective of reducing EGS cost, a single wellbore configuration could be cost-efficient compared to a traditional doublet system because fewer wells would be required. The applicability of a single wellbore configuration depends on its thermal output capacity. In this work, a numerical model was built to investigate the thermal output capacity of several single-well EGS configurations. The parameters that affect the output were also studied.

A single-well downhole heat exchanger (DHE) with connection to artificial fracture intervals was investigated. In this configuration, the working fluid is circulated directly through the wellbore, taking advantage of the resulting thermosiphon effect. CO2 as a working fluid was compared with other common binary working fluids, e.g. isopentane.

However, the simulation results show limited thermal production capacity of the downhole heat exchanger configuration. Hence, several other alternative single wellbore configurations were studied, in an attempt to improve the thermal production capacity. The numerical study showed that a key factor determining the thermal production is the flowrate in the fractures.

1. INTRODUCTION

The conventional concept of an enhanced geothermal system (EGS) includes a region of fractured rock, through which fluid is circulated from one well to another well, as in Figure 1. However, making EGS projects competitive with other energy sources has to be achieved through technological advances to make them cost-efficient. From the perspective of reducing EGS cost, a single-wellbore configuration may be a useful candidate, because it reduces the number of wells that need to be drilled.

In this study, we built numerical models to investigate the thermal energy output of two categories of single-wellbore configurations. In the first case, fluid is only circulated within the wellbore, as sketched later in Figures 6 and 11. More detail will be offered in Section 3. The results showed that this kind of configuration had limited thermal production capacity, so another category was studied. As shown later in Figure 9, in the second configuration the working fluid is circulated directly through the fracture, which will bring more thermal energy to the surface; more detail will be discussed in Section 4.

In the first category of devices, secondary working fluid circulates directly through the wellbore. This idea has been suggested in a number of contexts including Horne (1980) and Morita and Tago (2000). The design envisaged in this paper differs from previous proposals because it involves circulation of water outside the casing between a second annulus and the reservoir. In the second category, water is circulated directly through the formation. This has proposed by Outman (1980) and Matthews (1984) among others. The GENESYS project in Germany recently implemented this design in an EGS project, proving its technical feasibility (Jung et al. 2005).. The benefits of the first approach can be summarized as follows:

1. Achieving a thermosiphon: The thermosiphon is a device that circulates fluid spontaneously by taking advantage of the gravity head difference at different temperatures. The thermosiphon effect can be achieved by injecting secondary fluid downhole, because most of the common secondary working fluids, e.g. isopentane, have a lower boiling temperature than water at the same pressure. The thermosiphon mechanism removes the necessity of a downhole pump, which is usually not usable for temperature greater than 180^{o}C. Also, placing the pump at the surface, or avoiding it altogether, increases the system reliability and reduces the cost.

2. There is no need for a surface heat exchanger, as circulating secondary working fluid downhole basically makes the wellbore itself a heat exchanger downhole.

3. Mitigating the scaling problem: in EGS, the formation water, which dissolves several kinds of minerals, may cause scaling or fouling problem in pipelines and surface devices. By contrast, circulating secondary working fluid, such as a hydrocarbon, may mitigate the scaling problem.

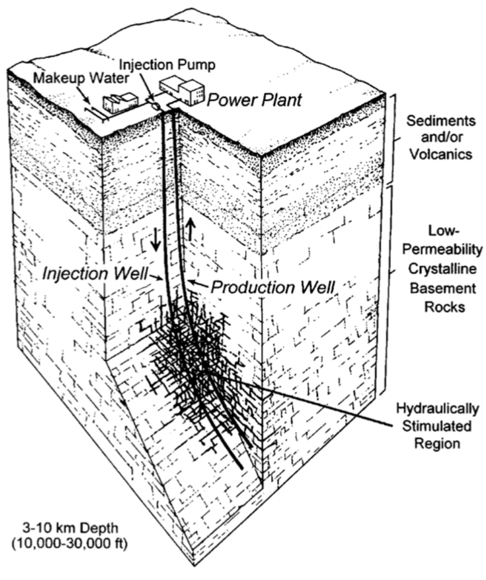

Figure 1: Conventional two-well EGS configuration, from Tester et al. (2006).

Both approaches share the advantage that they require only a single well to extract heat through the reservoir.

Two kinds of working fluid were compared, isopentane and CO2. From the comparison, CO2 has several advantages. Supercritical CO2 shows favorable flow and heat transfer properties, and it also has higher thermal efficiency in the turbine. Also concerning the issue of greenhouse gas emission, another benefit of circulating CO2 underground is that CO2 sequestration is achieved if it gets lost in the reservoir.

2. METHODOLOGY

The basis of this study was the construction of a model to simulate a single-well EGS configuration. Modeling of these configurations was achieved by coupling a wellbore model and a fracture model.

2.1 Coaxial Wellbore Model

The wellbore model took into consideration fluid mechanics, fluid phase behavior and heat transfer. This is a nonlinear, nonisothermal problem; iteration is required for the solution. A numerical method was implemented, with finite differences used to solve the governing partial differential equations. The temperature field at each new time step was calculated by solving the governing equations (mass, momentum and energy conservation equations), and fluid properties at each cell were interpolated from thermodynamic properties tables.

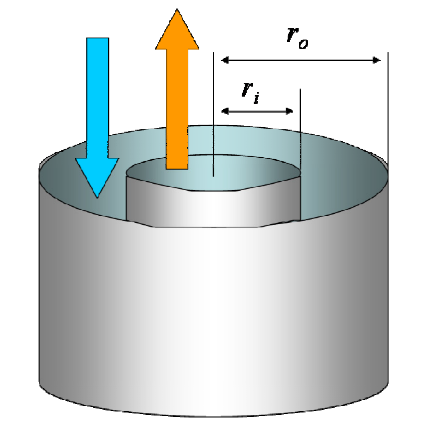

Figure 2: Sketch of coaxial well configuration, from Horne (1980).

A sketch of the coaxial single wellbore configuration is shown in Figure 2. The temperature profile in the wellbore can be obtained by solving the energy balance equation, which can be written as in Eq. 1:

$$\pi r_w^2 \frac{\partial \rho u}{\partial t} = \frac{\partial \rho h}{\partial z} - 2\pi r_w U (T_i - T_o) \tag{1}$$

where u is specific internal energy and h is the specific enthalpy. T_i and T_o are temperature in the inner tubing and outer casing respectively. U is the overall heat transfer coefficient, which can be calculated by Eq. 2 (from Horne, 1980):

$$\frac{1}{U} = \frac{r_o^2}{r_i^2}\frac{1}{H_i} + \frac{r_o}{k_s}\ln\frac{r_o}{r_i} + \frac{1}{H_o} \tag{2}$$

in which r_i and r_o refer to radii of the inner and outer tubing respectively. k_s is the thermal conductivity of the pipe and H is the convective heat transfer coefficient given by (Holman, 1968):

$$H = \frac{k}{r} 0.0395 \,\mathrm{Re}^{0.75} \tag{3}$$

The last term in Eq. 1 corresponds to heat transfer between the tubulars. The heat transfer between the inner tubing and outer casing is determined by the overall heat transfer coefficient U as stated in Eq. 1, however, the heat transfer between the outer casing and the formation is calculated by Fourier's law:

$$Q = kA\nabla T \tag{4}$$

After solving the energy balance equation (Eq. 1), temperature can be calculated from Eq. 5:

$$u = c_v (T - T_{ref}) \qquad h = c_p (T - T_{ref}) \tag{5}$$

Where c_v and c_p are heat capacity at constant volume and pressure respectively, T_{ref} is a reference temperature.

To account for the phase change that would occur in a two-phase thermosiphon, an iterative method was implemented. A flow chart of the iterative method is shown in Figure 3. The methodology is:

(1) Starting from the initial condition, temperature, pressure and enthalpy at a new time step can be calculated by solving the energy balance equation. With this information, a judgment is made to tell whether the fluid is boiling or not, by looking up in the steam table, or thermodynamic table of the relevant fluid.

(2) If not boiling, the fluid properties (density and heat capacity, etc.) are based on the result of the next time step calculation. If boiling, temperature is set to the boiling point, and vapor fraction is interpolated by specifying the calculated enthalpy from the steam table or relevant fluid thermodynamic properties table. Fluid properties can then be read from the thermodynamic properties table, and used for the next time step calculation.

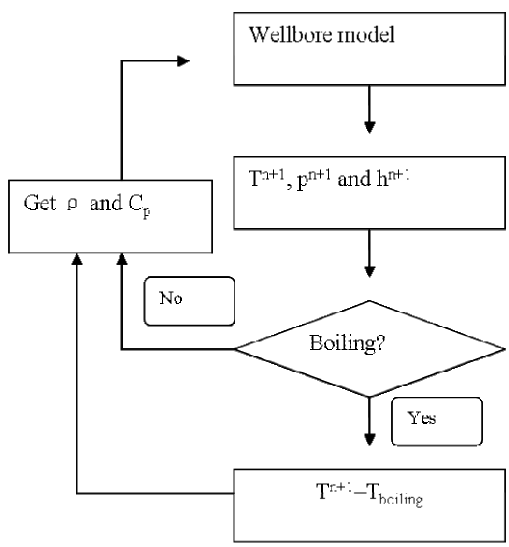

Figure 3: Flowchart for iterative process of temperature calculation.

This wellbore model was verified by comparing to the results of a paper published by Nalla et al. (2006). In this particular case, the well outlet temperature history for 3 years was calculated from a coaxial wellbore heat exchanger which circulates water. The comparison is shown in Figure 4. The results show good agreement with Nalla et al. (2006). The model was also verified by comparing to an analytical solution by Ramey (1962).

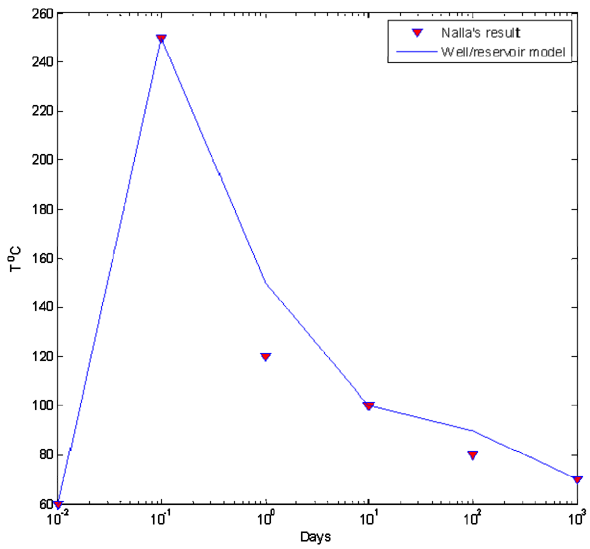

Figure 4: Verification of the wellbore model.

2.2 Reservoir Fracture Model

The reservoir model was constructed to represent a typical EGS reservoir. In order to make the model realistic, we used information about the characteristics of the European EGS site at Soultz-sous-Forêts in France. We called our model 'Soultz-like', not intended to be a true representation of Soultz. Soultz is a good site to use an example because it has been the subject of extensive research and characterization.

The reservoir model was constructed using the simulator AUTOUGH2. AUTOUGH2 was written at the University of Auckland, and is a version of TOUGH2, an integrated finite difference numerical reservoir simulator developed at Lawrence Berkeley National Laboratory (Pruess, 1999). TOUGH2 can simulate nonisothermal, multicomponent, multiphase flow and diffusion.

The 'Soultz-like' reservoir model consists of two parallel fracture planes. The two fractures represent two idealized paths through the reservoir. One zone, with higher permeability and smaller volume, is the primary (short-circuit) zone. The secondary zone which has lower permeability but greater volume represents a larger overall flow path throughout the fractured volume. The two-path concept matches a conceptual model of the Soultz reservoir that was based on a two-well tracer test analyzed in Sanjuan et al. (2006). The two fractures are assumed far enough away from each other that they are effectively independent.

The fractures are planar and vertical with the wellbore in the center, as shown in Figure 5. Each is 1000 m. tall and 1000 m. wide. The thickness of the fracture zone is one meter. The short circuit path through the reservoir has a porosity of 1.3% and a permeability of 534 md. The secondary path has a porosity of 2.17% and a permeability of 228 md. The fractures are surrounded by granite basement rock that conducts heat but is not permeable to flow. Because of symmetry, only one quarter of the total system needs to be gridded.

The total flow rate through the system is four times the flow rate through the quarter-system. The grid of each quarter-system fracture is 20 by 20, with blocks 50 m high and 25 m wide. The fracture zone of the quarter system is one half the actual thicknesses, 0.5 m. Perpendicular to the plane of the fracture, the matrix rock is gridded with 11 blocks in logarithmic spacing from 0.05 m to 50 m. To test the accuracy of the discretization for heat conduction in the rock mass, a one-dimensional heat conduction calculation was performed and compared to the analytical solution. The discrepancy was found to be about 5%. In the model, the fracture is filled with liquid water. The initial pressure at the top of the reservoir (depth 4 km) is set at 400 bars. The geothermal gradient is 40°C/km with a surface temperature of 20°C. Each quarter-system is connected to the well on one side at the top and bottom. More detail of this fracture model can be found in Wang et al., (2009).

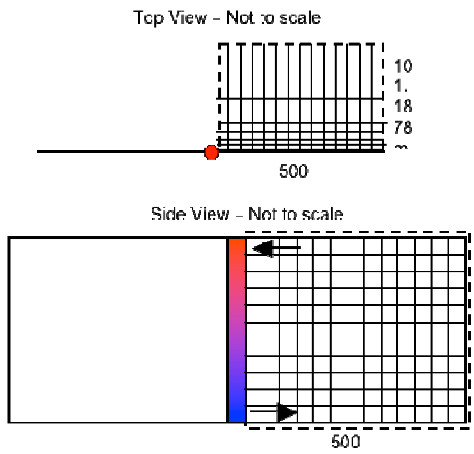

Figure 5: Planar and vertical view of fracture model.

2.3 Coupling Wellbore/Fracture Models

The wellbore configurations studied in this work can be categorized into two cases, and the coupling method is different for these two cases:

2.3.1 Case 1 - Downhole Heat Exchanger

For the first category, sketched in Figure 6, the wellbore model and fracture model provide boundary conditions for each other, so we used an iterative procedure to equalize the calculated values of flow rate in the second annulus computed from both models.

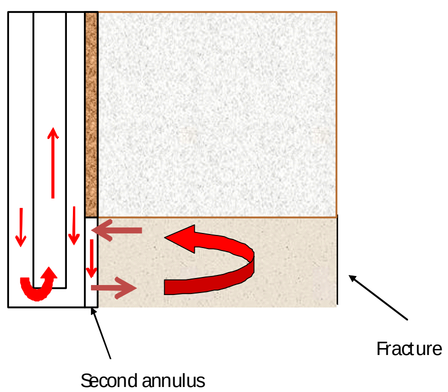

Figure 6: Sketch of Case 1.

A flow chart is shown in Figure 7. The pressure at the top of the second annulus was set constant at 400 bars, (as the depth is 4000 m, where the static hydraulic pressure is around 400 bar), and then starting with an initial guess of the flow rate, the well model provided temperature and pressure values at the bottom of the second annulus. These values were used as input to the fracture model, and then the TOUGH2 model would calculate the fracture outlet temperature and a new flow rate. The process iterated until the flow rate in the annulus and the reservoir converged. The values of flow rate during the iterative process are shown in Figure 8. The process converged after five or six steps if we set the convergence criterion to be within 10^{-3} kg/sec.

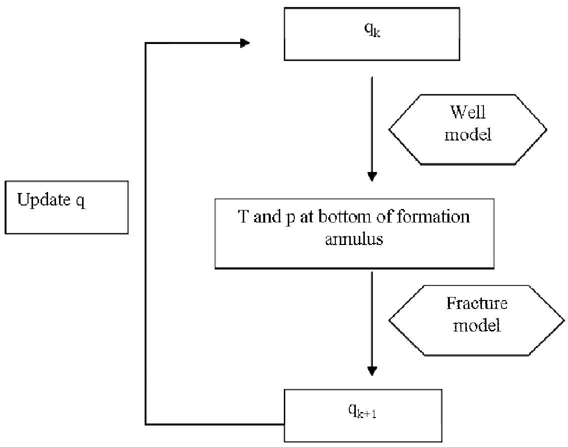

Figure 7: Iterative approach to couple the well model and reservoir model.

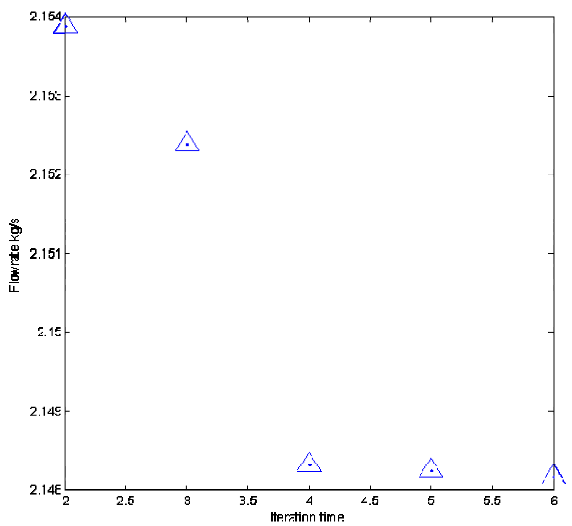

Figure 8: Convergence of the calculated flow rate in the second annulus.

2.3.2 Case 2 - Circulating Fluid through Fracture

When circulating fluid directly through the fracture, as shown in Figure 9, the coupling method needed to be modified. In this case, fluid does not circulate in the second annulus (which may not even be present), but enters the reservoir fracture directly from the wellbore and reenters the wellbore from the fracture at a different depth. The pressure at the inlet point to the fracture can be calculated from the wellbore model, and also the flow rate in the fracture should be consistent with that in the wellbore, so we can iterate the fracture outlet pressure to match the flowrate in the fracture to that in the wellbore. A flowchart of this iterative method can be seen in Figure 10.

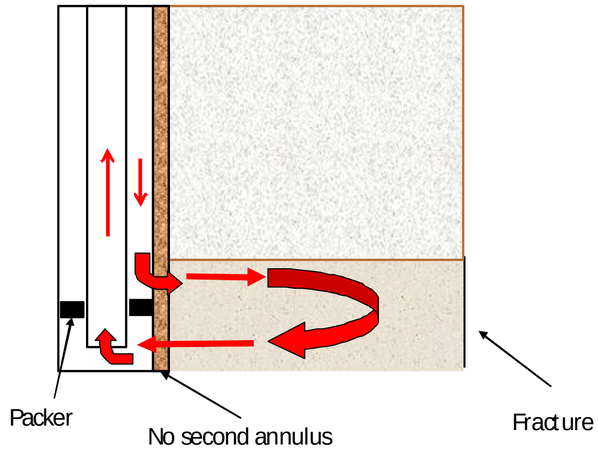

Figure 9: Sketch of Case 2.

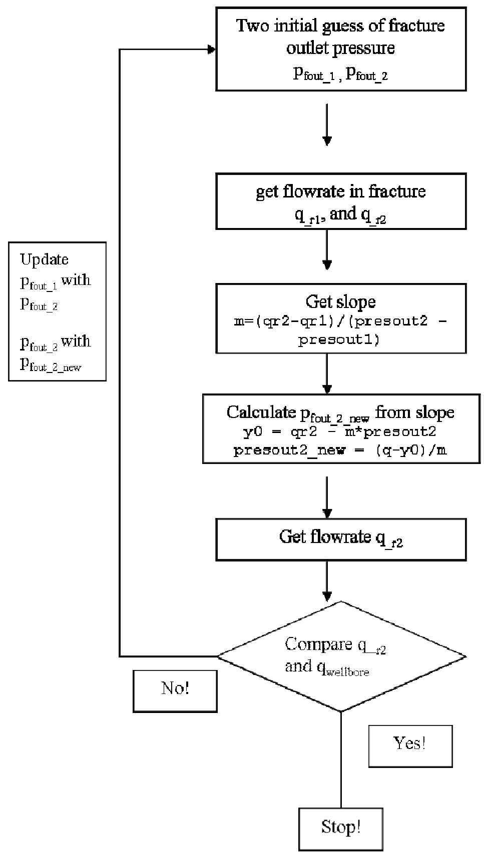

Figure 10: Flow chart of second iterative method.

3. SINGLE WELLBORE DOWNHOLE HEAT EXCHANGER

3.1 Description of Wellbore Configuration

The first configuration investigated is an uncommon design for an EGS system, namely a hybrid of a downhole heat exchanger and an EGS fracture network. The design includes a number of novel ideas, including:

1. Use of a single well with level-to-level fracturing, in place of multiwell systems.

2. Use of a downhole heat exchanger in place of surface heat exchangers.

3. Use of a gravity head thermosiphon in place of well pumps.

4. Use of downhole circulation of a secondary working fluid in place of water

Traditional coaxial downhole heat exchangers have been used in direct use applications. The problem with using a device that extracts heat only by conduction is that conduction is unable to bring heat to the wellbore very quickly or for very long, and thus cannot be used for large scale heat extraction (Nalla et al., 2006). So in the configuration proposed here, the downhole heat exchanger is connected to the fracture system. As shown in Figure 11, our idea of enhancing heat flow to the device is to fracture the formation from two intervals 1000m apart. In such a configuration, geothermal water would move convectively through the annular space surrounding the heat exchanger (referred to here as the second annulus), and circulate 500 to 1000 m through the fracture network in the formation. Hence the heat transfer to the heat exchanger would be enhanced over simple conduction.

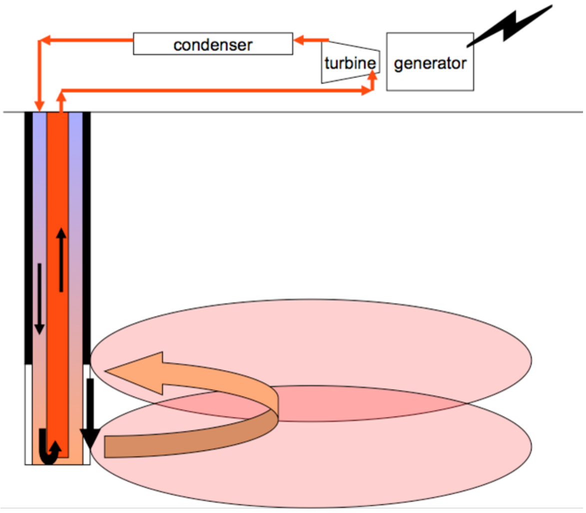

Figure 11: Sketch of single-well, coaxial downhole heat exchanger with fractures.

As shown in Figure 11, the wellbore casing is cemented only to the top of the fracture interval (not to the very bottom), and then a tubing is installed inside it. The cold secondary working fluid is injected downward through the annulus between the tubing and casing. To enhance heat transfer, two intersecting fractures are generated. Formation fluid flows downward in the annulus below the cement (the second annulus), and would be heated up in the fracture. The fluid would flow upward in the fracture because of buoyancy. This is a thermosiphon, which has spontaneous flow caused by the density variation at different temperature. Circulation through the second annulus and through the reservoir fractures is driven by free convection. The convection brings additional heat to the heat exchanger, and will extend the duration of time that heat can be extracted. There is also a second thermosiphon effect inside the wellbore. The wellbore flow is spontaneous due to the thermosiphon effect, although for high flowrate an on-surface pump might be needed to overcome friction. A pump operating on the surface is much more reliable than one working downhole. Removing the downhole pump is a benefit of the thermosiphon. Downhole pumps have drawbacks in two ways: firstly, in the harsh downhole environment pumps may have relatively short times between repairs; secondly, it is less efficient thermodynamically to use pumps to pressurize the fluid and then use it in heat exchangers on the surface (DiPippo, 2008). Another advantage of the thermosiphon is to make use of the tremendous pressure difference between the outflowing and inflowing fluid to provide a source of hydraulic energy. The thermosiphon effect can be achieved by circulating the secondary working fluid (typically isopentane, but other choices are possible) downhole, through the coaxial downhole heat exchanger. Use of a downhole choke may result in a more prominent thermosiphon effect by stimulating boiling.

3.2 Sensitivity Study

Effects of several parameters were examined in the sensitivity study. The basic configuration that all the following cases share is summarized in Table 1. All the values were chosen to make the model realistic, e.g. the geothermal gradient and thermal conductivity of the formation are set to be typical values. For electrical power generation, we assumed a constant condenser condition at 320 K, which corresponds to a saturated pressure of 1.866 bar, which is also the condition for the working fluid injected back into the wellbore. Another assumption for the turbine process is an isentropic turbine efficiency of 85%.

Table 1 Common parameters in sensitivity study

Thermal Environment	
Working Fluid	Isopentane ($i\text{-}C_5H_{12}$)
Mass Flowrate	2 kg/s
Surface Temperature	20 ^oC
Geothermal Gradient	40 $^oC/Km$
Formation Volume Heat Capacity	1800 $kJ/m^3\,^oC$
Formation Thermal Conductivity	2 W/m^oC
Formation Density	2000 kg/m^3
Formation Thermal Diffusivity	$10^{-6} m^2/s$
Well Geometry	
Casing Diameter	340 mm
Tubing Diameter	65 mm
Tubing Roughness	0.03 mm
Insulation Conductivity	0.05 W/m^oC
Insulation Thickness	5 mm
Binary Cycle Specification	
Condenser Temperature	320 K
Turbine Isentropic Efficiency	85% mm

3.2.1 Insulation of Inner Tubing

As shown in previous studies on coaxial downhole heat exchangers (DHE), e.g. Horne (1980), insulation of the tubing is a crucial factor for effective heat extraction from the formation. A comparison of the temperature profile of a traditional DHE with and without inner tubing insulation is shown in Figure 12, which shows that the well outlet temperature will approach the inlet temperature if there is no insulation of the inner tubing. By contrast, the outlet temperature is much higher with the inner tubing insulated. Hence, more energy is extracted from the formation with an insulated tubing. A comparison of thermal power output over 30 years is shown in Figure 13.

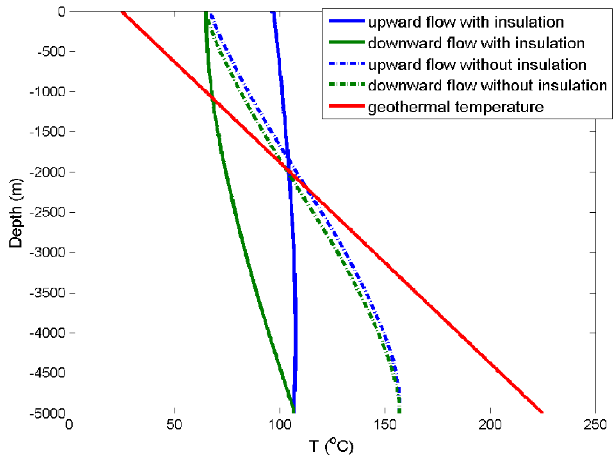

Figure 12: Wellbore temperature profiles.

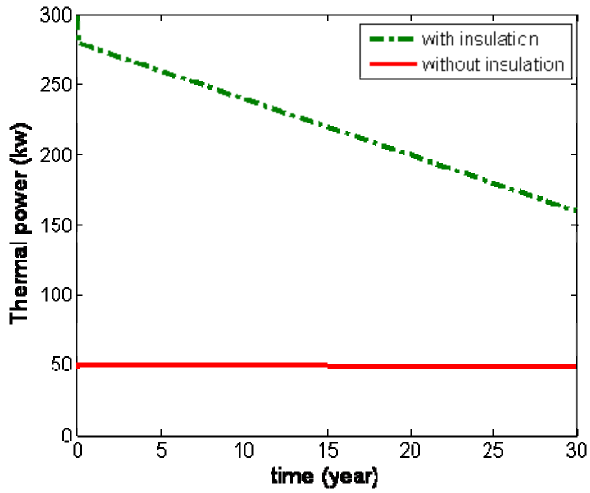

Figure 13: Thermal power output from tubing with insulation and without insulation.

Figure 14 shows the effect of insulation length on the thermal production. The insulation length indicates how deep the inner tubing is insulated. In this case, the DHE is connected to the fracture interval, as shown earlier in Figure 11. It is more advantageous not to insulate the tubing over the fracture interval (4000-5000 m deep).

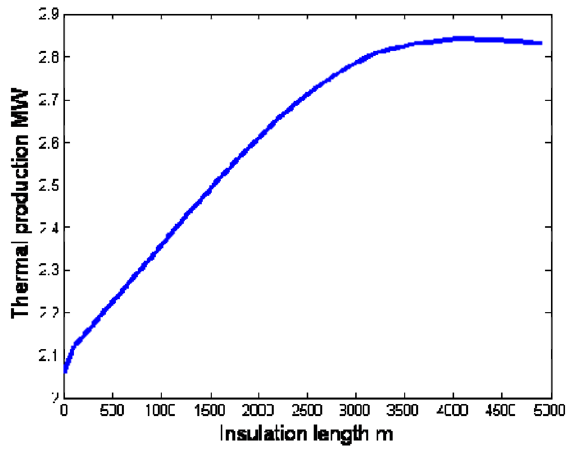

Figure 14: Heat production at different insulation length.

3.2.2 Flow Rate

The electrical power output depends both on the mass flow rate of working fluid and the specific enthalpy at the inlet of turbine, so a higher flow rate does not guarantee a greater energy output. At a slower flow, there is a longer residence time in the wellbore, thus more energy extracted from the formation. As shown in Figure 15, a higher flow rate would decrease the well outlet temperature, and the ideal work has an optimum at a specific flowrate.

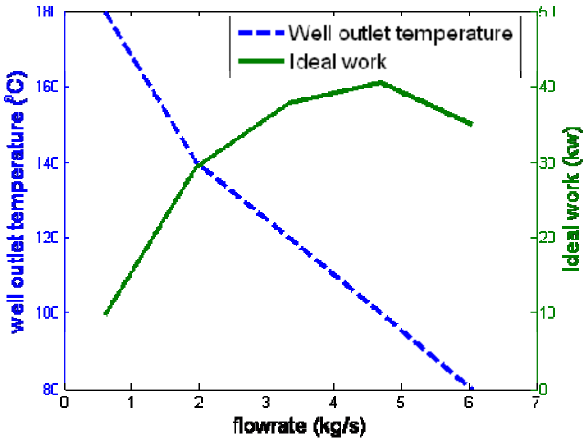

Figure 15: Well outlet temperatures and ideal work for different flow rates after 1month operation.

3.2.3 Well Geometry

The effects of the wellbore radius would be twofold: the bigger the well, the more energy it would extract from the formation; however a bigger well would deplete the formation more quickly. Figure 16 shows the thermal power output using different casing diameters, after operation for one month. We can see that the power increases as the casing becomes larger, which is consistent with our expectation. From a sustainability standpoint, as shown in Figure 17 the bigger well can still generate larger power, although it has greater rate of energy decrease. The effect of tubing size was also studied, as shown in Figure 18; a small tubing is preferable from a thermal output point of view, although it must be remembered that reducing the size would increase the pressure drop and would ultimately prevent flow.

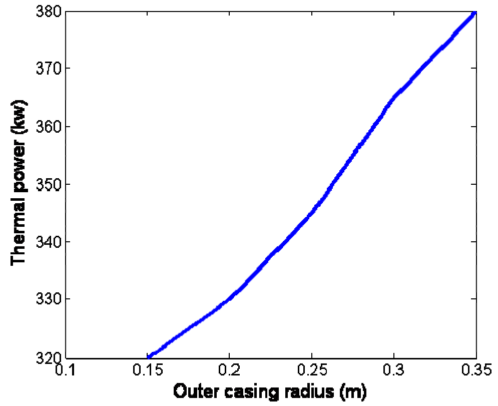

Figure 16: Thermal power output after 1 month operation, as a function of outer casing radius.

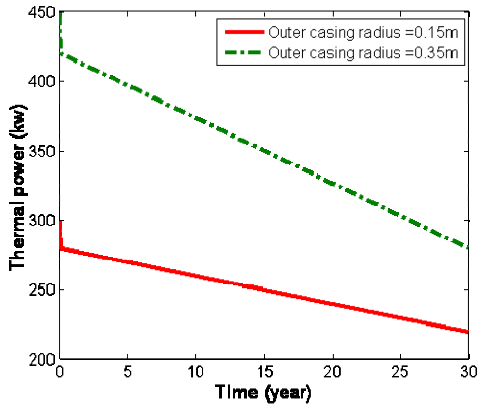

Figure 17: Thermal power generation histories for different outer casing radius.

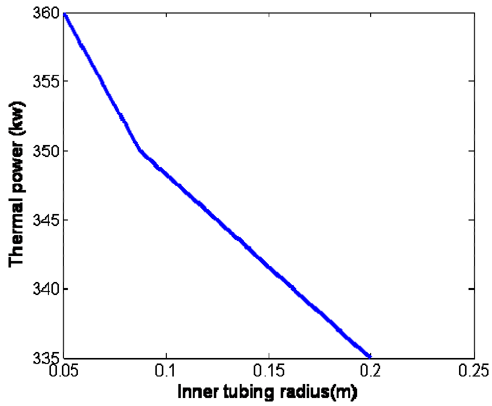

Figure 18: Thermal power generation after 1 month over different tubing radius.

<u>3.2.4 Gravity Thermosiphon</u>

One reason to circulate secondary working fluid through the wellbore is to take advantage from its greater volatility as temperature increases. By placing a choke at the bottom of the well, we may achieve a phase change as fluid rises in the inner tubing. The density difference caused by phase change becomes a force to drive the flow and the well outlet pressure is higher than the inlet pressure. This pressure difference can force the fluid to circulate spontaneously, and can provide hydraulic energy to the turbine for electrical generation. Figures19, 20 and 21 show vapor fraction, pressure and temperature distributions in the wellbore after production for 1 month, showing the phase change in the upward flow when the downhole choke is used.

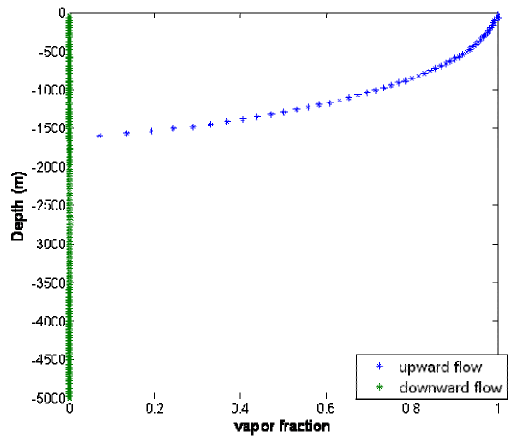

Figure 19: Vapor fraction in the wellbore, with a downhole choke.

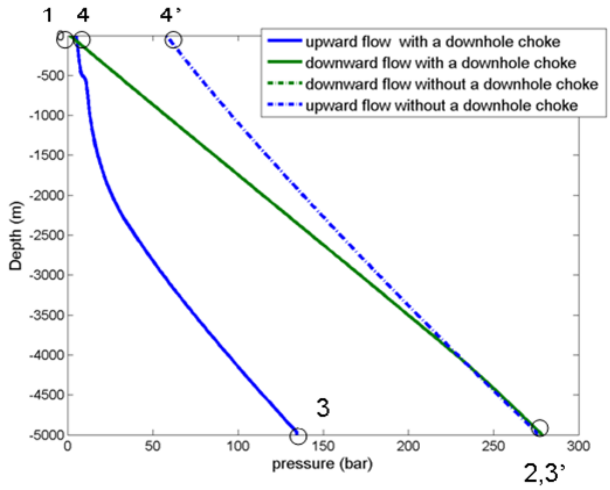

Figure 20: Pressures in the wellbore, with and without a downhole choke.

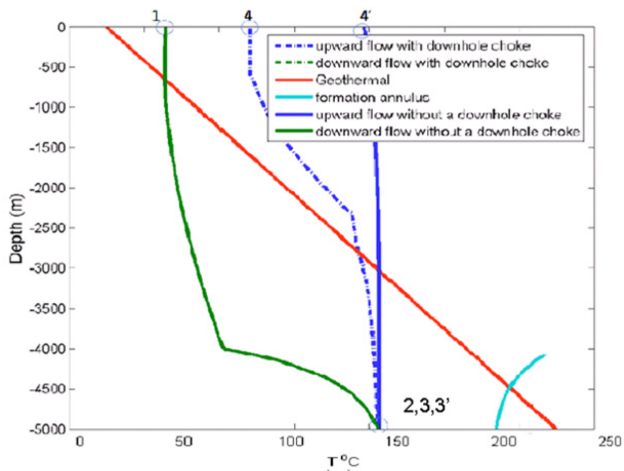

Figure 21: Temperatures in the wellbore, with and without a downhole choke.

To illustrate the thermosiphon effect, the example shown used a hotter reservoir with geothermal gradient to be 60°C/km, all other specifications are as in Table 1. Figure 22 shows the enthalpy in the two cases, showing that the choke does not change the enthalpy distribution in the wellbore. Figure 23, shows the operating cycle on a pressure-enthalpy diagram. Starting from the outlet of the condenser, State 1, fluid is injected into the outer casing and pressure and specific enthalpy increase as it flows downwards, until it reaches the bottom of casing, at State 2. At the bottom of the tubing, fluid passes through the choke and starts flowing upwards, at State 3. As the fluid loses pressure and enthalpy, it will go through a two-phase region and finally become superheated at the well outlet. The dry gas exiting the turbine is passed into the condenser, and the loop is closed. In the thermosiphon case, the cycle follows the path 1-2-3-4 in Figure 23, whereas for the case without the thermosiphon it follows the path 1'-2'-3'-4'. Without the thermosiphon, the fluid would arrive at the turbine inlet in a liquid state; with the thermosiphon it arrives in a vapor state. A calculation of the long term electricity power generation in this example is shown in Figure 24.

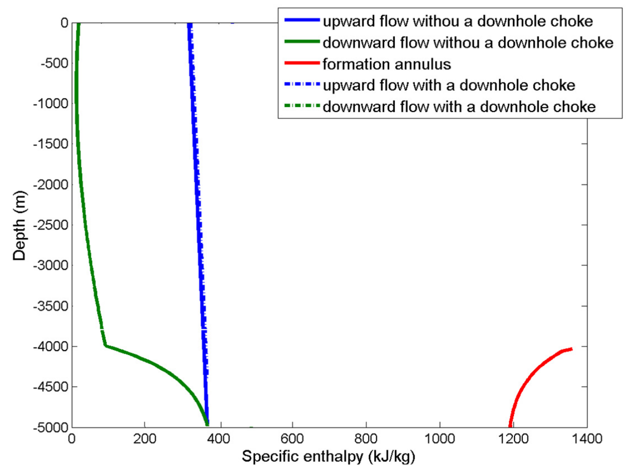

Figure 22: Enthalpy in the wellbore and formation annulus, with and without a downhole choke.

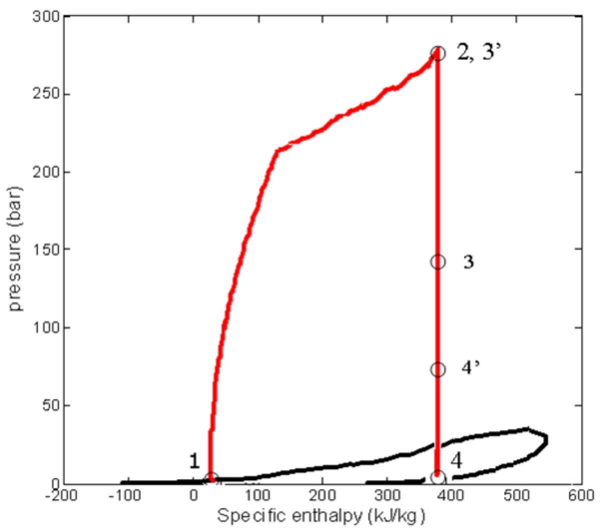

Figure 23: Pressure-enthalpy diagram of the complete cycle. 1-2-3-4 for thermosiphon case; 1'-2'-3'-4' without the thermosiphon.

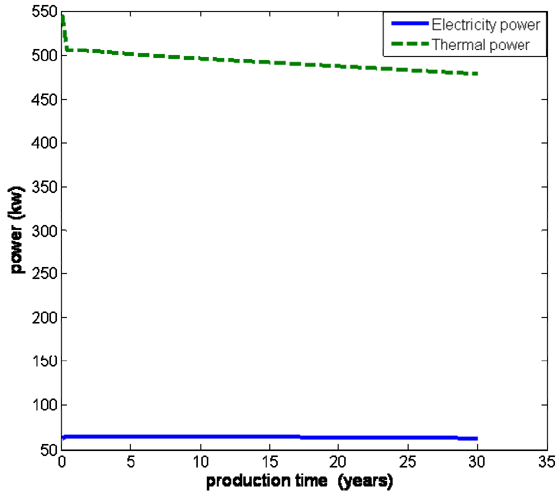

Figure 24: Thermal and electricity power generation histories for 30 years.

4. ALTERNATIVE CONFIGURATIONS

As shown in Figure 24, even with the advantage of convective heat transfer in the fracture system, the coaxial single-well downhole heat exchanger is not capable of generating much energy. Hence we chose to explore other ideas, including the second type of single-well EGS, with fluid circulating directly through the fracture system (Case 2). Several additional different types of single-well EGS were also modeled, including a cyclic injection and production scheme, "huff-puff".

4.1 Description of Different Configurations

All the configurations studied are sketched in Figure 25:

1. Two-well EGS: we set the thermal extraction capacity in a conventional two-well EGS as a benchmark for comparison. This system requires a downhole pump and surface heat exchanger (not shown in the sketch).

2. Case 1 Downhole heat exchanger: This is the system we described and studied in Section 3. It is included again here for the comparison of thermal production capacity with the other configurations.

3. Case 1b Downhole heat exchanger with crossover: a limitation of Case 1 is that there is cocurrent flow between the flows in the second annulus and in the wellbore; both of the flows are downward. A better heat transfer can be reached in countercurrent flow. A countercurrent flow can be achieved by using a crossover device, depicted in Figure 26.

4. Case 2 Single-well EGS: to circulate the fluid through fractures directly would increase the heat extraction, this idea was proposed by Outman (1980). In this configuration, a packer is installed to divert the fluid flow through the fracture.

4.2 Simulation Results and Discussion

<u>4.2.1 Case 1 – Effect of Fracture Connection</u>

The connection of the heat exchanger to a reservoir fracture brings additional heat to the wellbore and increases the energy that can be produced from the system. The connection increases the length of time the system can produce energy from a far greater volume of rock. Figure 27 shows that with the fracture the extracted thermal energy (although modest) decreases very little over 30 years. The reason is that the rate of heat extraction is small enough that thermal breakthrough does not occur in the fracture even after 30 years. Figure 28 shows the temperature distribution in one half of the primary connection fracture after 30 years. Because of symmetry, only half of the total fracture is shown. The well is located at the far left of the half-fracture. Total flow rate was approximately constant around 2.5 kg/sec. About 70% of the total flow went through the primary connection fracture. Figure 29 shows the advantage that the fracture brings in increasing the enthalpy of the produced fluid.

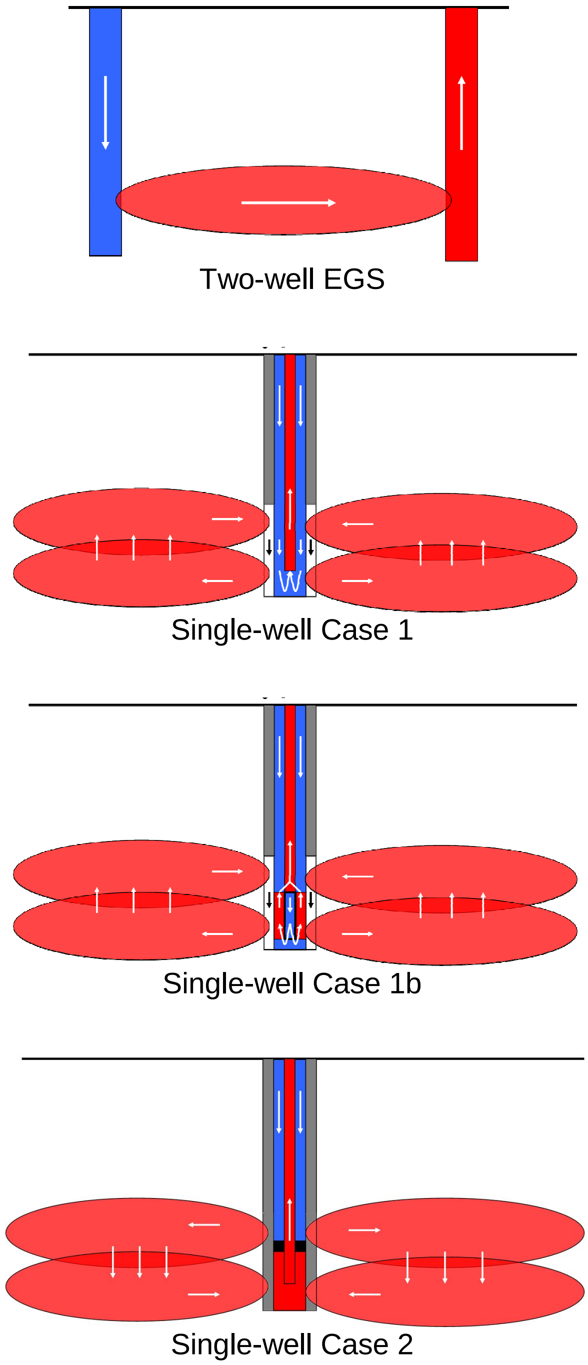

Figure 25: Sketches of different well types.

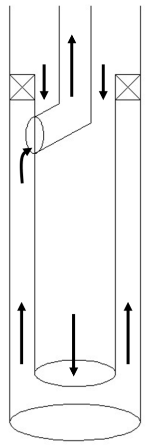

Figure 26: Sketch of crossover.

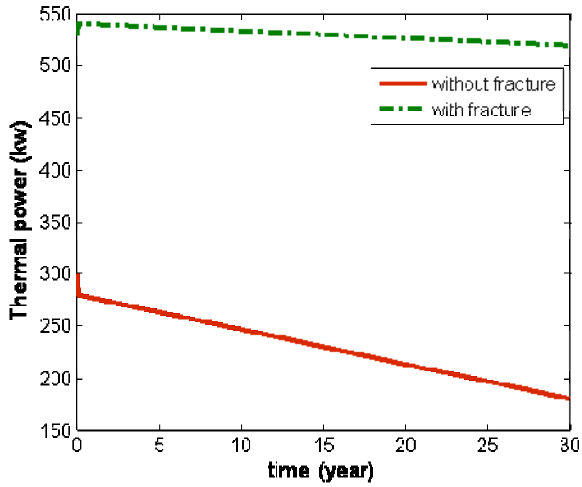

Figure 27: Thermal power output with fracture and without fracture.

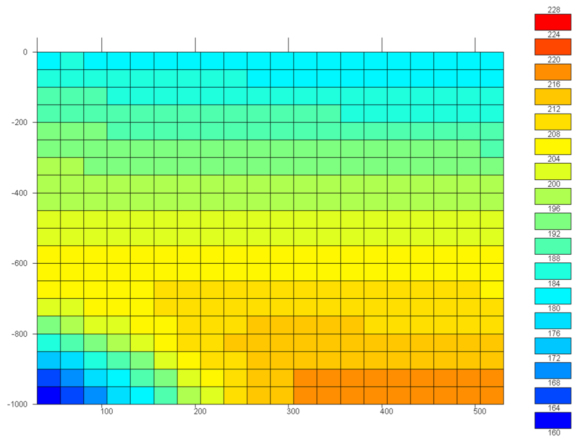

Figure 28: Temperature distribution in the primary connection fracture after 30 years.

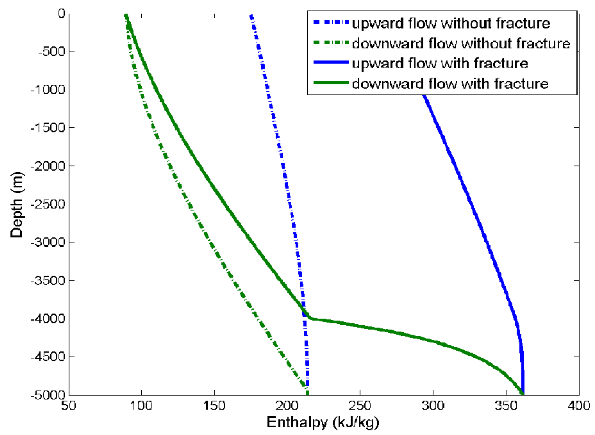

Figure 29: Specific enthalpy in wellbore after production for 1 month.

4.2.2 Case 1b-Crossover Device

The crossover device increases the thermal recovery. As we mentioned, the advantage of the crossover is gained by converting the cocurrent flow between wellbore annulus and formation annulus to countercurrent flow. As shown in Figure 30, the amount of the increase depends on flowrate. Heat transfer is more severely hampered by cocurrent flow when the flowrate is low, thus the effect of crossover device is more prominent. However we should note that the single-well geothermal system with downhole heat exchanger, even with the help of crossover, still has limited thermal production capacity.

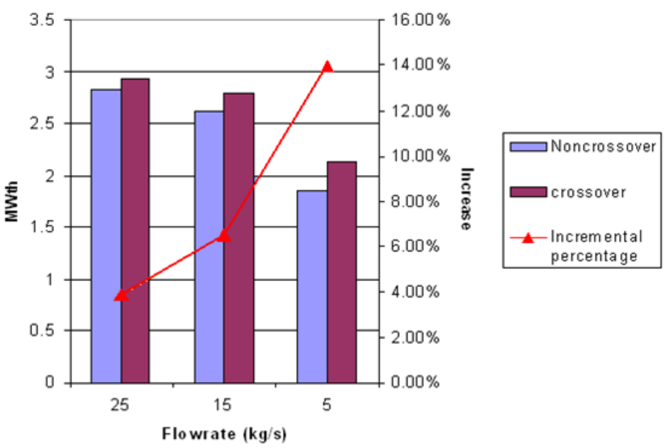

Figure 30: Crossover effect at different flow rate.

4.2.3 Case 2-Single-Well EGS and Two-Well EGS

Both in Case 2 single-well EGS and in conventional two-well EGS, fluid is circulated through the fracture, which will greatly enhance thermal energy recovery. Thermal outputs of these two configurations were compared. The comparison was made under two production scenarios: (a) with the same flow rate or (b) with the same wellhead pressure.

First, in both models, flowrate was set to be 25 kg/s. The circulating fluid was water. The thermal outputs from these two configurations are shown in Figure 31. Roughly speaking, thermal output equals the product of flowrate, heat capacity and temperature increase. Both models have almost identical thermal outputs under the same flowrate; therefore, the flowrate has dominant effect on the thermal extraction capacity. The fracture temperature distribution maps, shown in Figure 32, reveal that the temperature increase depends on the outlet location, i.e. bottom for single-well EGS, middle point for two-well EGS. Although single-well EGS has higher thermal output than two-well EGS in this case, this advantage is only because the choice of outlet location. The comparison result will be different if the outlet location changes.

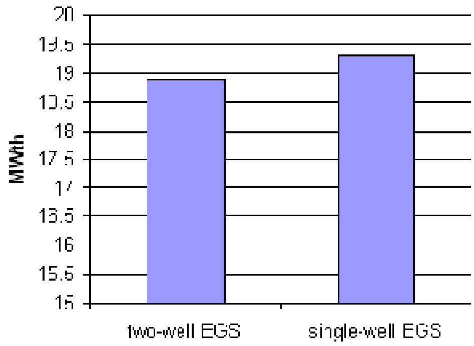

Figure 31: Comparisons of two-well EGS and single-well EGS under the same flowrate.

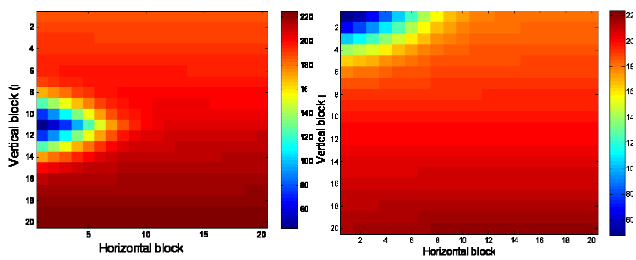

Figure 32: Temperature distributions in fracture. Left: Two-well EGS; Right: Single-well EGS, Case 2.

Second, we compared the thermal productions of single well EGS and two well EGS under specified well head pressures. To make a fair comparison, we reshaped the fracture model to be 1000 m by 1000 m, and the wellbore casing diameter was changed to 9 5/8 inch, or 24.5 cm , which is the same as casing diameter of GPK3, one of the deep wells at Soultz (Hettkamp et al., 2004). Tubing diameter was changed to 17 cm so that the cross sectional areas of the tubing and annulus would be equal, which as a rule of thumb should give optimal recovery, see Horne (1980). The single-well design will have greater frictional pressure loss because of the smaller cross-sectional area available for flow in each direction.

We modeled three cases:

Case 2: single-well EGS, one wellbore is supported by fractures on both sides of the well, as shown in Figure 33.

Case 3: two-well EGS, one injector and one producer connected by one fracture, as shown in Figure 33.

Case 4: infinite two-well pairs are located in a line in producer-injector pairs with fractures in between. Thus one production well is supported by two fractures, one on each side.

Figures 34 and 35 show the simulation results. The wellhead pressure was set to be 50 bar at the inlet, 5 bar at the outlet.

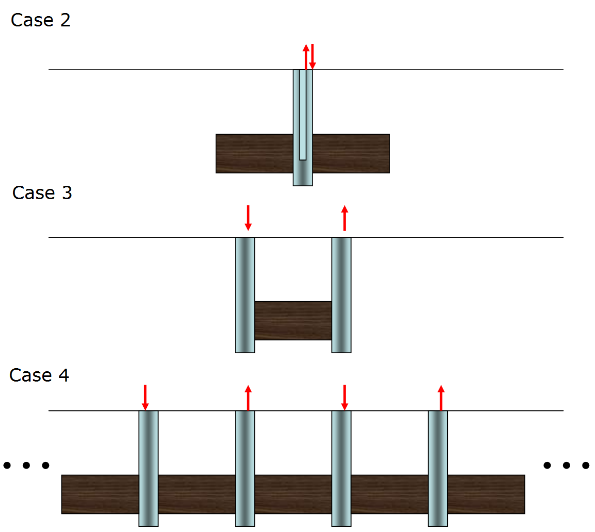

Figure 33: Sketches of different cases for the comparison under the same wellhead pressures

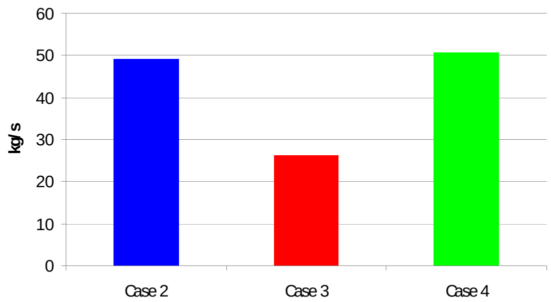

Figure 34: Production flowrates of different cases under the same well head pressures.

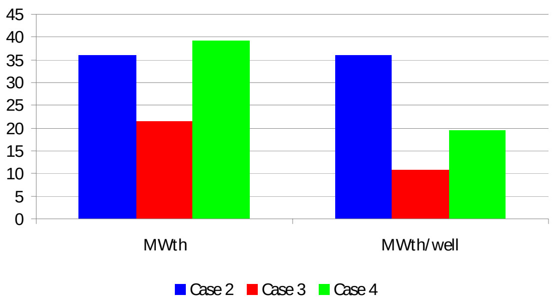

Figure 35: Thermal production and per well of different cases under the same well head pressures.

The results show that Case 2 and Case 4 had similar flowrate and thermal production, and Case 3 produced roughly half, On a per well basis, the single-well design did better than either of the two-well cases: almost two times Case 4 and four times Case 3.

4.2.4 Huff and Puff Scheme

A cyclic scheme, as suggested by Jung et al. (2005), was also investigated using our model. The production scheme is shown in Figure 36, injection for 4 hours and production for 8 hours. The corresponding thermal outputs are also shown in Figure 36.

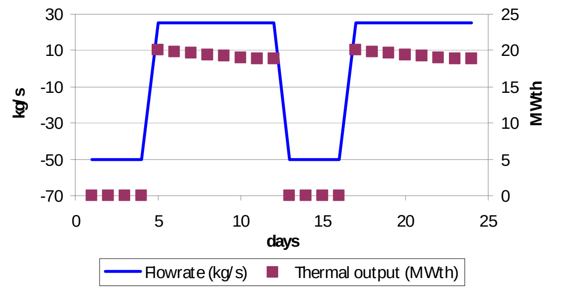

Figure 36: Huff-Puff thermal outputs.

5. CO2 AS WORKING FLUID

The fluid circulation path can be chosen to flow through fractures or not. In our Case 1 (as shown earlier in Figure 6) with the downhole heat exchanger, fluid does not circulate through the fracture, whereas in Case 2 (as shown earlier in Figure 9) it does. In Case 2, when circulating through fracture the secondary fluid, which is usually hydrocarbon, could be lost and would contaminate the formation. We compared the difference between CO2 and isopentane as a working fluid, in the Case 1b configuration. Both thermal extraction and electrical power generation were calculated, and results are shown in Figure 37. CO2 has advantages over isopentane from the aspects of both heat extraction and thermal efficiency in the turbine. Furthermore, unlike hydrocarbon, CO2 can be circulated through fractures, since there would be a benefit of sequestering greenhouse gas if it is get lost or trapped in the formation. We did not simulate this case (Case 2) with CO2 or isopentane due to limitations of our model; however, it would be worthwhile to explore this application of CO2 in geothermal systems.

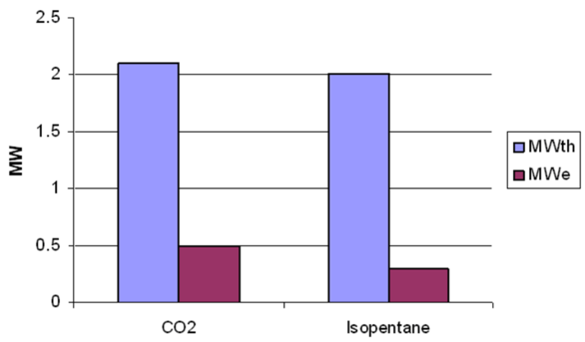

Figure 37: Comparisons between CO2 and Isopentane.

6. CONCLUSIONS

We found that the downhole heat exchanger thermosiphon version of the single-well system (Case 1) produces only modest power output. The heat production of the system is limited by the amount of heat that can be transferred from the reservoir fracture network to the wellbore through the second annulus. The heat transfer from the reservoir by convection dominates because conduction through the rock to the wellbore is small, especially in the long term. However, the rate of convection is limited by the flow rate through the reservoir which is modest because it is driven only by free convection, the density difference between the hotter water in the reservoir and the colder water in the outer annulus. A key factor to enhance the power generation is to connect the wellbore flow to the fracture (Case 2), which will increase the flowrate in the fracture.

We determined that the single most important factor governing the output of all of the configurations considered was the rate of flow through the fractures.

Neglecting the influence of wellbore pressure drop, on a per well basis a single-well EGS system would produce four times more energy than an isolated pair of wells and two times more energy than an infinite series of alternating producers and injectors. Although not shown here, a single-well design would also produce twice as much per well as a repeating five-spot pattern of injectors and producers. Pressure drop in the wellbore reduces the output of the single-well design somewhat, but it is still much better than the two-well injector/producer systems on a per well basis.

One unaddressed question is the vertical permeability of an EGS reservoir. Experimental EGS reservoir projects have flowed through the fractures horizontally. The GENESYS Project (Jung et al. 2005) is the only project known by the authors to have flowed vertically through an EGS reservoir. However it is in a sedimentary formation, and EGS projects are more likely to be in crystalline rock. It is not clear whether results can be drawn about vertical permeability of EGS reservoirs in crystalline rock based on results from a sedimentary formation. Even among crystalline EGS projects, we expect that geologic setting would have a significant effect on permeability anisotropy.

ACKNOWLEDGMENTS

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NOMENCLATURE

A	Interface area
c_v	Heat capacity at constant volume process kJ/K
c_p	Heat capacity at constant pressure process kJ/K
q	Flow rate kg/s
Re	Reynolds number
r_i	Inner tubing radius
r_o	Outer casing radius
T_r	Formation temperature ^{o}C
T_w	Wellbore temperature ^{o}C
u	Specific internal energy (kJ/kg)
h	Specific enthalpy (kJ/kg)
U	Overall heat transfer coefficient W/(m^{2}K)
k	Heat conductivity W/(m K)

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