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An Alternative and Modular Approach to Enhanced Geothermal Systems

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ABSTRACT

This paper describes a low-risk, low-cost and modular alternative to the conventional Hot Dry Rock or Enhanced Geothermal Systems (EGS). In this approach, which we have named the Earth Energy Extraction System ("Triple-E" System), the injected fluid is allowed to get preheated in the injection wellbore before reaching the reservoir; this preheating is achieved through injection in ultra-slim diameter wells (2.5 to 7.5cm) and by keeping the rate of injection very low (on the order of 10 liters per second). The injected fluid then heats up further as it travels to the production well through pores and fractures in the rock. The injection wells are terminated close to and at a shallower level than the top of the productive interval in the production well. This approach avoids the two main technical limitations associated with conventional EGS: (a) creating a significant reservoir volume by artificial fracturing; and (b) fluid loss control. This approach reduces dependence on the occurrence of natural permeability that limits the scope of conventional geothermal technology. The risk of cooling of the production well by short-circuiting of injected water, a common concern in both EGS and conventional geothermal projects, is significantly reduced by preheating of the injected water.

A single Triple-E module consists of a central production well with an adequate casing diameter to accommodate a submersible pump, and surrounded by several ultra-slim injection holes of a special low-cost design; the injection holes are sited a few hundred meters from the production well and are deviated towards it. A large project would consist of multiple adjacent modules. The permeability around the bottom of the production well should improve with time due to spontaneous fracturing or fracture extension associated with thermal contraction of rock. If needed, one of several commercially available techniques can be used to stimulate the permeability of the rock in the immediate vicinity of the well bottom. Unlike a conventional EGS, the main purpose of stimulation here is to make the production well flow at a commercial rate rather than creating and sustaining an artificially fractured reservoir of substantial extent. The injection holes reach this permeable zone around the bottom of the production well and are completed a few tens of meters to a few hundred meters above the bottom of the production well to minimize any fluid loss below the production zone by gravity drainage. The pressure sink around the production well will actually create the potential for fluid gain into the system. The technical feasibility of the concept has been confirmed by analysis of heat transfer between the injection holes and the surrounding rock, and heat transfer in the reservoir between the rock and the injected fluid in pores and fractures. Optimization of the process through modeling is in progress, and will be reported in due course.

1. INTRODUCTION

Field experiments of the hot dry rock or enhanced geothermal system (EGS) concept indicate that it should be possible to create complex flow paths within the earth that can allow injected water to be heated and returned to the surface for extraction of energy from hot, low-permeability rock. EGS designs thus far have relied upon flow paths that are created by a process of hydraulic stimulation or massive hydrofracturing. Although such a process is technically feasible, it has been expensive and burdened with the difficulties of designing, creating and quantitatively defining the created fracture system, drilling wells to adequately intersect the fracture system, avoiding preferential channeling of injected water along major fractures, avoiding fluid losses out of the drainage area of the production well, and eliminating cooling of the produced fluid.

The proposed alternative EGS approach, which we have named the Earth Energy Extraction System ("Triple-E" System), is to design a system in which the injected water gets preheated in the wellbore before reaching the reservoir. This approach cannot be applied to a conventional diameter (7 to 13 inch, or 17.5 to 32.5cm) injection well, because the amount of heat gained by water flowing at a typical injection rate (on the order of 100 liters per second) would be minimal in a such a well. But if injection occurs through "ultra-slim" diameter wells (3 to 8cm) and injection rate is sufficiently low (on the order of 10 liters per second), the heat gained by the injected water per unit mass as it travels down the well can be an order of magnitude higher. The reasons for this improvement in heat transfer are (a) the higher surface area-to-volume ratio for a ultra-slim hole compared to a conventional well, and (b) a longer residence time of the fluid in the hole because of a lower injection rate. The injected fluid then heats up further as it travels to the production well through pores and fractures in the rock.

The production well is a conventional diameter well that can accommodate an electric submersible pump to allow production at commercial rates; at these rates heat loss from the production well is negligible. The production well is surrounded at a distance of tens to hundreds of meters by an array of injection wells, which are terminated close to and shallower than the top of the productive interval in the production well to minimize the loss of injected water by gravity drainage. Furthermore, in contrast to conventional EGS, the problem of fluid loss is minimized by sharply reducing the area of contact between the injected water and the reservoir rock beyond the immediate drainage volume around the production well.

The Triple-E approach avoids the two major technical limitations of conventional EGS, namely, creating a substantial reservoir volume (by artificial fracturing) and controlling water loss. Furthermore, this approach reduces dependence on natural occurrence of permeability that limits the scope of conventional geothermal technology. The risk of cooling of the production well by short-circuiting of the injected water, a common concern in both EGS and conventional geothermal reservoirs, is significantly reduced as a result of preheating of the injected water in its travel through the ultra-slim holes.

2. OTHER SIMILAR APPROACHES

The Triple-E approach is an improvement on two alternative EGS concepts that have been proposed in recent years. The first of these concepts is in U.S. Patent (2001) and is schematically represented in Figure 1. This concept calls for drilling a production and injection well pair connected in the subsurface by a parallel set of artificially created (drilled) flow channels, plus some fractures near the intersection of the injection zone with the production well. This approach faces nearly the same technological barriers as does conventional EGS, namely, the difficulty of engineering the necessary flow channel geometry, and controlling fluid loss. In addition, the cost of drilling is estimated to be very high, because the injection well is forked numerous times, and each fork is then drilled with high precision to intersect the production well.

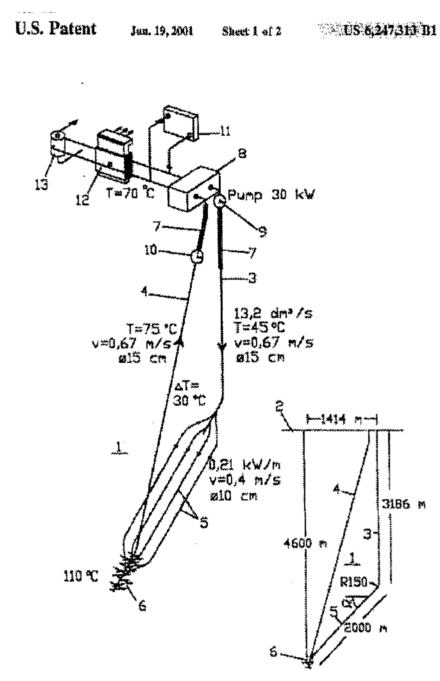

Figure 1. Process Schematic of U.S. Patent No. 6,247,313B1

The second concept has been described in Shulman and Whitelaw (1995) as well as U.S. Patent (1996); it is schematically represented in Figure 2. A central production well is surrounded by a number of conventional diameter injection wells that intersect the production well at its bottom. Neither well is pumped; the injection-production process is left to natural thermal convection. To allow closed-loop convection, the injection wells are cased to the bottom connection with the production well, so the injected water heats up in its travel to the production well without coming in contact with the subsurface rock. Although this eliminates fluid loss, this approach has three limitations, which make the process patently non-commercial: (a) drilling an injection well to several thousand meters depth targeted to intersect a production well of a few centimeters diameter is technically feasible but inordinately expensive, (b) calculations as well as experience show that heat transfer associated with a conventional diameter injection well is far too inefficient to extract much heat energy from subsurface rock; and (c) production rate dictated by natural convection would be too small to be commercial.

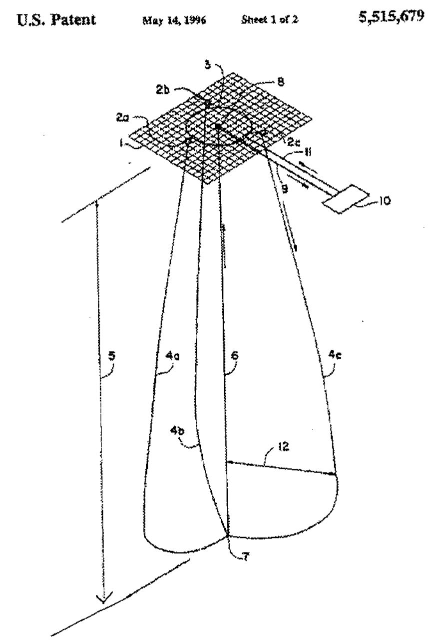

Figure 2. Process Schematic of Shulman and Whitelaw (1995)

The Triple-E design addresses both the objectives and the limitations of the designs shown in Figures 1 and 2. Preliminary calculations of heat transfer and estimation of the cost of ultra-slim hole drilling have demonstrated that this system design can be technically as well as commercially feasible.

3. DETAILS OF THE TRIPLE-E APPROACH

The Triple-E concept is schematically represented in Figure 3. A single Triple-E module consists of a central production well surrounded by several highly-deviated ultra-slim injection holes; a large project would consist of multiple adjacent modules. The permeability in the drainage volume around the production wells should improve with time due to spontaneous fracturing or fracture extension associated with thermal contraction of rock. If needed, the permeability of the formation around the bottom of the production well may be further enhanced by one of several available techniques of stimulating a relatively small volume of rock in the immediate vicinity of the well; such techniques include under-reaming, hydraulic stimulation, acidizing, and explosive stimulation. Unlike a conventional EGS project, the main purpose of stimulation here is to make the production well flow at a commercial rate rather than to create and sustain an artificially fractured reservoir of substantial extent.

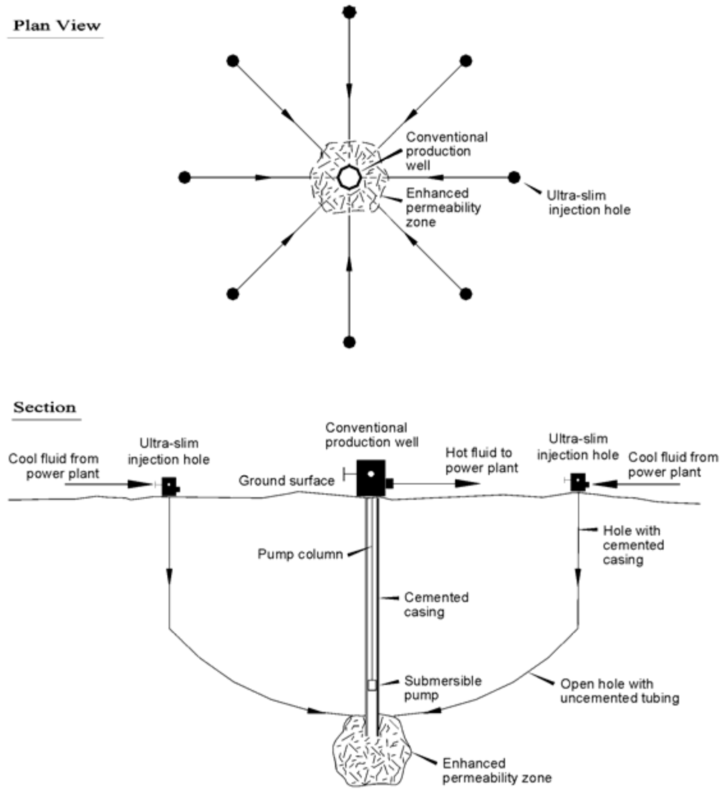

Figure 3: Proposed Energy Extraction System

The injection holes are directed to the permeable zone around the bottom of the production well but are not targeted to intersect the production wellbore itself, thus significantly reducing the cost of directional drilling. Instead, the injection holes are completed a few tens of meters to a few hundred meters above the bottom of the production well to minimize any fluid loss by gravity drainage. Because the production well would be pumped to produce hot water (to be delivered to a power plant or direct use site), the resulting pressure sink around the production well would further reduce fluid loss, and actually create the potential for fluid gain into the system.

Our preliminary injection hole design (shown in Figure 4) calls for drilling each injection hole in two stages. First, a core hole rig is used to drill the upper portion: a vertical 3.78-inch (9.6cm) diameter hole with cemented 3.5-inch (8.9cm) internal diameter casing. The depth of this vertical section will depend on the prevailing vertical temperature gradient, and the minimum depth of cemented casing required by the regulatory agencies to protect the local ground water aquifers. To reduce cost, the lower, deviated (and major) portion of the hole will be drilled directionally using a coiled-tubing unit. The actual trajectory of the hole can be variable. A 1 to 2 inch (2.5 to 5cm) diameter injection tube will then be inserted in the hole from the wellhead to the bottom. The tubing will not be cemented in place; however, any “thief zone” too far above the intended injection zone may have to be plugged off by squeeze-cementing. The injection rate per hole will be limited to less than 20 liters per second. The cost of such a hole will be a fraction of the cost of an injection well under either of the other two schemes mentioned earlier, or in any conventional EGS project, because of the combination of the following; (a) replacing conventional diameter injection wells by ultra-slim injection holes, (b) using a combination of a low-cost core-hole drilling rig and a coiled-tubing unit rather than a conventional rotary rig, (c) eliminating the major cost of directional drilling to intersect the production well, and (d) avoiding the cost of cementing the injection tubing.

The Triple-E system is a low-risk, low-cost and modular alternative to conventional EGS, each module being capable of generating a few megawatts. This approach would allow commercial utilization of otherwise non-commercial production wells, hundreds of which lie unused or plugged and abandoned in the Western United States. An unused or abandoned conventional geothermal well can be worked over and used as the production well for a module, significantly reducing the cost of EGS development. This concept should be of strategic interest to governments and public interest groups concerned with renewable energy resources and may interest commercial power developers.

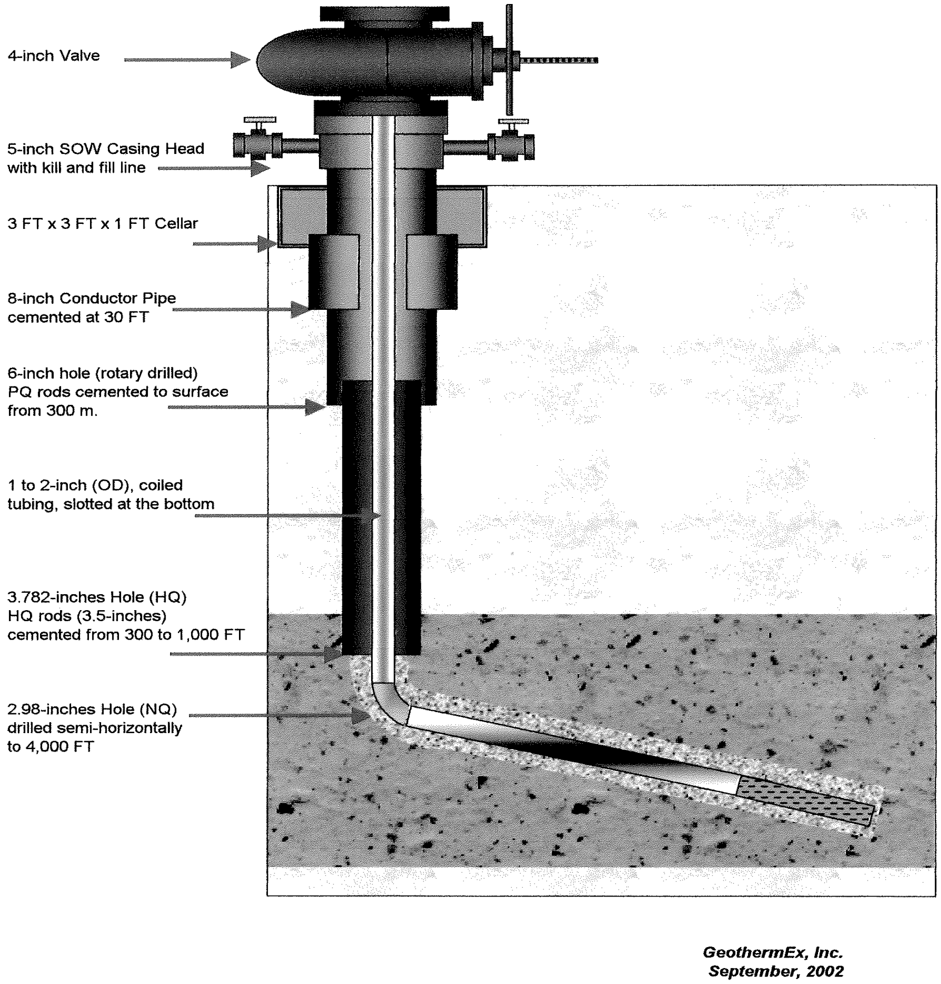

Figure 4: Preliminary Design of Ultra-slim Hole

4. TECHNICAL FEASIBILITY ANALYSIS

Before the Triple-E concept can be demonstrated in the field, its technical feasibility needs to be convincingly proven by detailed engineering analysis. This, in turn, requires the development of a quantitative heat transfer model. The heat transfer processes involved here are of two distinct types:

a) heat transfer between the injection wellbores and the surrounding rock, and

b) heat transfer in the reservoir between the rock and the injected fluid in pores and fractures.

De-coupling of the overall heat transfer process into these two categories allows major simplification in the engineering analysis as explained below.

To analyze the wellbore heat transfer process we have used the analytical modeling approach of Horne and Shinohara (1979). In formulating the heat gain as the injected water flows from the top to the bottom of the injection well, we represent the well by a series of linear segments; likewise the temperature profile in the formation is represented by a series of linear temperature gradients corresponding to the same vertical intervals as chosen for well segments. The number of linear segments chosen will depend on the extent of non-linearity in both the well trajectory and formation temperature profile. Calculations for heat gain are conducted for each well segment in sequence starting from the top of the injection well.

The water temperature (T) at the bottom of a segment as a function of elapsed time (t) can be derived from:

$$T(t) = T_f + az - aA + (T_i - T_f + aA)e^{-z/A(t)} \quad (1)$$

where T_f is formation temperature at the top of the segment (°C), T_i is water temperature at the top of the segment (°C), a is vertical temperature gradient in the formation within the segment (°C/m), and z is vertical length of the segment (m).

In equation (1), A(t) is a "diffusion depth", defined as:

$$A(t) = \frac{W c [k + r U f(t)]}{2\pi k r U}, \quad (2)$$

where W is injection rate (kg/hr), c is specific heat of water (kJ/kg/°C) k is thermal conductivity of the formatin (kJ/hr/m/°C), r is inner radius of the well (m) and U is overall heat transfer coefficient between the well and formation (kJ/hr/m/°C).

The dimensionless function f(t) in (2) is given by:

$$f(t) = \frac{-\ln r'}{2\sqrt{\alpha t}} - 0.29, \quad (3)$$

where r' is outer diameter of well casing (m), α is thermal diffusivity of the formation (m^2/hour), and t is time elapsed (hour).

Equation (2) can be approximated for all practical purposes as:

$$A(t) = \frac{W c f(t)}{2\pi k} \quad (4)$$

Figure 5 shows the temperature profiles for a typical injection rate (_____L/s) in a hypothetical, conventional-diameter (12.25 inch, or 31.12cm) injection-production well pair, intersecting at the bottom. This figure illustrates preheating of the injected water as it travels down the injection well. In the production well, water gains heat in the lower part of the well, where the rock outside the well is hotter than the wellbore fluid, and loses heat in the upper part of the well, where the rock outside is cooler than the wellbore fluid. Figure 5 illustrates, as stated before, that temperature increase with depth at typical rates of injection in a conventional diameter injection well would be very modest indeed (15° to 135°C for a depth of 7,600 m); hence our proposal to utilize ultra-slim wells and very low rates of injection.

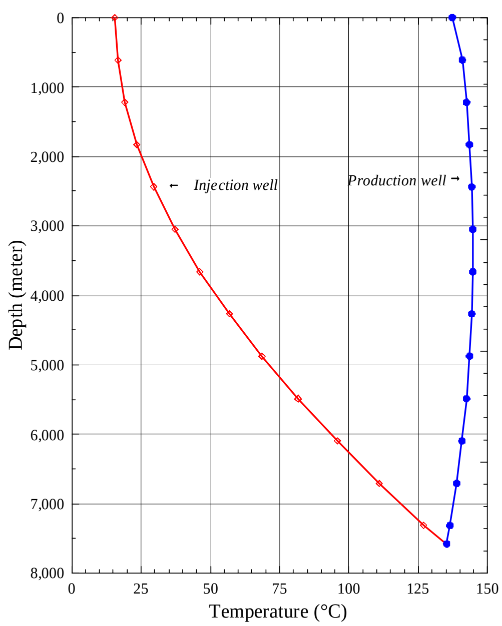

Figure 5. Typical temperature profile in injection and production wells

The injected fluid, preheated by wellbore heat transfer, reaches the reservoir and flows towards the production well through pores and fractures. This reservoir heat transfer process is readily analyzed using numerical reservoir simulation. Figure 6 presents the schematics of coupling between the analytical modeling of heat transfer in the injection wellbores and finite-difference modeling of reservoir heat transfer. The reservoir is represented by a cylindrical grid system around the production well, that is, by a vertical stack of concentric, horizontal rings of progressively increasing diameter. The central circular block represents the production block. One of the larger rings around the production block represents the injection block; this is permissible because the injection water will be distributed relatively evenly between a number of wells approximately equidistant from the production well. As many rings as needed may be inserted between the production and injection blocks to better define the heat transfer process in the reservoir. The overall size of the model can be made large enough to avoid any boundary effects.

The model simulates a "dual-porosity" reservoir, that is, one composed of fractures separating rock matrix blocks. The grid geometry and dimensions, and the rock and fluid properties, can be varied as part of the sensitivity study leading towards the optimization of the process. We have recently conducted such numerical modeling of conventional EGS systems (Butler et al., 2004, and Sanyal and Butler, 2005). However, the numerical modeling required for the Triple-E process is complicated by the fact that the temperature of the injected fluid entering the injection block (Figure 6) will decline with time. Analytical modeling shows that the rate of this variation with time is very slow beyond the first few weeks of injection (Figure 7). Therefore, the overall heat transfer processes can be reasonably modeled. This detailed modeling is in progress; the results will be published in due course.

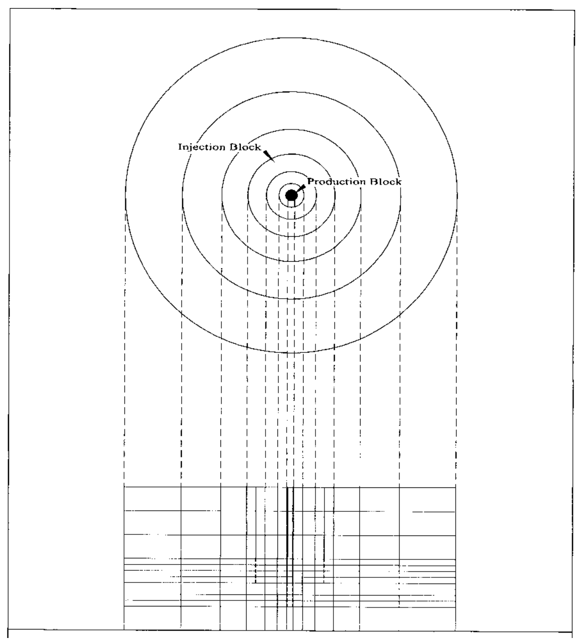

Figure 6: Schematic of Numerical Model of the Reservoir Heat Transfer Process

5. OPTIMIZING THE PROPOSED APPROACH

While the Triple-E process is technically feasible, it needs to be optimized with respect to a number of variables. The variables important to preheating of the injection fluid include:

1) vertical temperature gradient in the formation,

2) targeted depth,

3) injection hole diameter,

4) injection hole length and trajectory, and

5) injection rate per hole.

Figure 7 and 8 show computed examples of the impact of the above parameters on preheating of the injected fluid. Figure 7 shows the produced water temperature as a function of time for a conventional diameter injection-production well pair, intersecting at the bottom, for a range of injection rates. Figure 7 clearly shows that wellbore heat transfer increases as injection rate declines. Figure 8 shows the produced water temperature and energy gain with an injection-production well pair , intersecting at the bottom, as a function of vertical temperature gradient. Similar sensitivity analysis is being conducted for the other parameters listed above.

The variables pertaining to heat gain in the reservoir include:

1) horizontal and vertical spacing between production and injection wells,

2) fracture spacing in the reservoir,

3) fracture and matrix domain hydraulic properties, and

4) reservoir thickness.

Iterative analysis of the fluid flow and heat transfer processes associated with the system needs to be performed over a plausible range of each of the above parameters to define the technically optimum system. This technical assessment can be accomplished using the coupled wellbore-reservoir model of the fluid flow and heat transfer associated with the process; this effort is underway.

As regards economic feasibility of Triple-E, the minimum cost of drilling must be determined, taking advantage of available and emerging technologies. As a preliminary estimate based on the design shown in Figure 4, we expect that the cost of an ultra-slim injection well to be on the order of 10% of a conventional injection well. Therefore, approximately 10 ultra-slim wells injecting at 1/10th of the rate of a conventional injector will be equivalent to the latter, both in total injection rate and drilling cost, while the extent of preheating in the former will be far higher. Optimizing the well design and drilling program will further reduce cost and/or increase heat transfer efficiency. This optimization study is in progress.

6. CONCLUSIONS

Our analysis to date indicates that the Triple-E concept should be technically feasible, and should render commercial a substantial portion of the vast strategic energy resource represented by EGS. With adequate optimization of the system and ultra-slim well design, we believe this process will become competitive with the other renewable energy technologies.

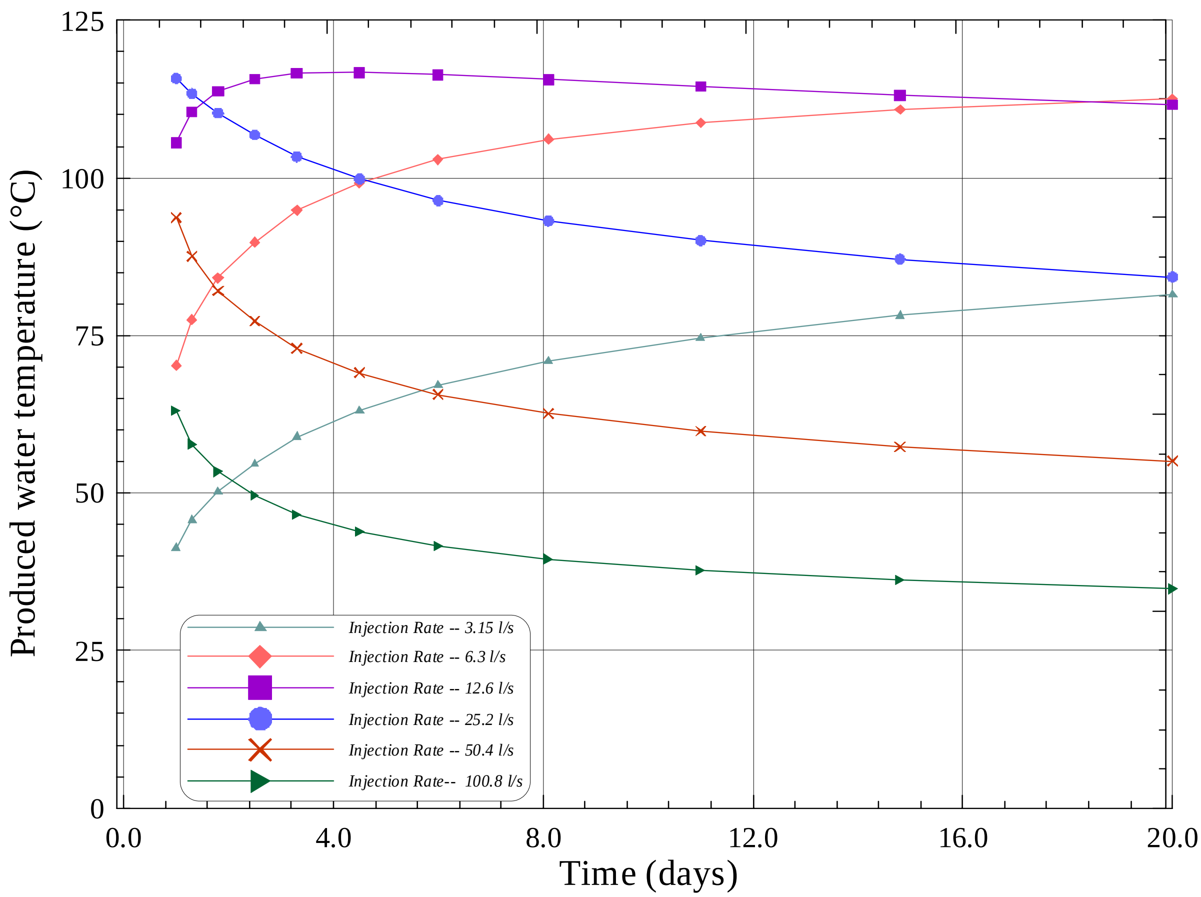

Figure 7: Effect of injection rate on produced water temperature

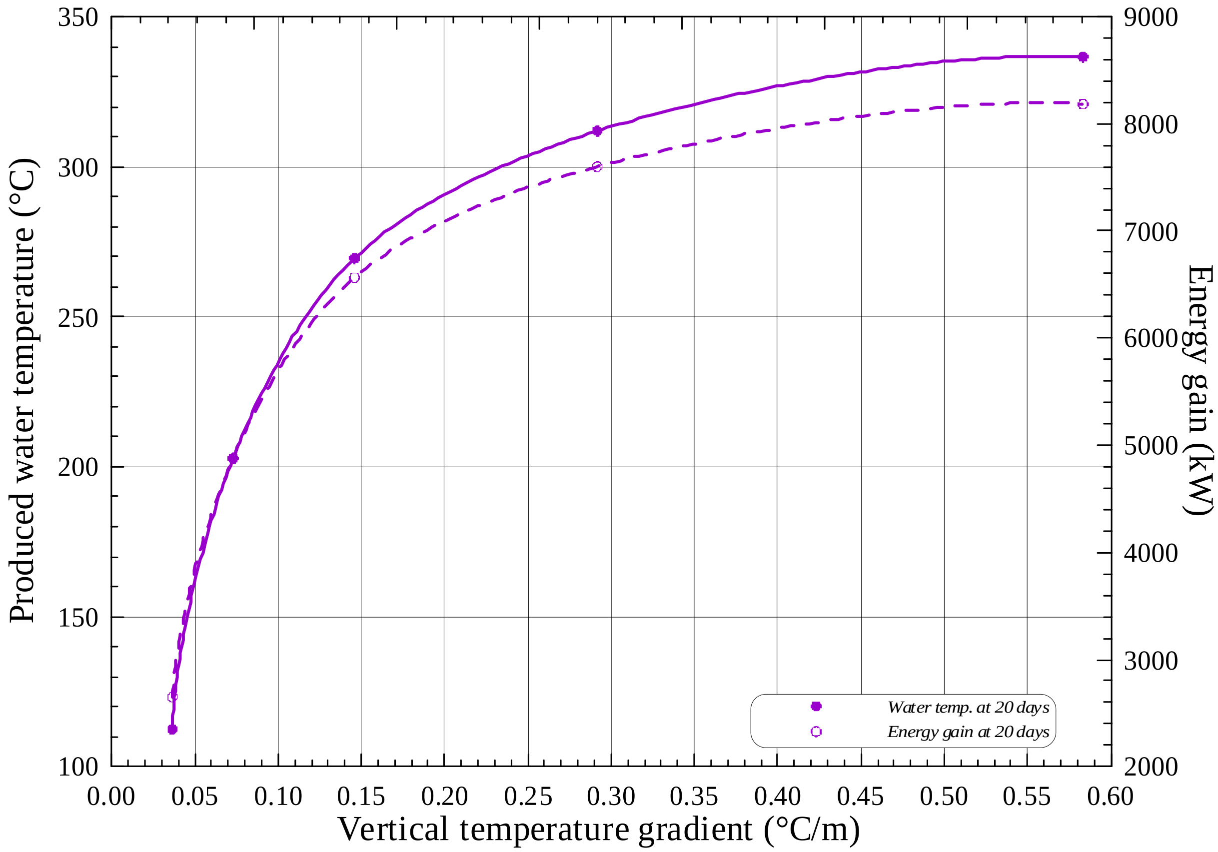

Figure 8. Produced water temperature and energy gain vs. temperature gradient

7. ACKNOWLEDGEMENT

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