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# Design Optimization of Geothermal Wells Using an Improved Overall Heat Transfer Coefficient

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## ABSTRACT

Geothermal wells have evolved in the past decade, moving from concepts inherited from oil and gas well construction to modern and unconventional solutions tailored to local conditions. Typically, geothermal wells are optimized based on their design flow rate output, e.g. modern geothermal wells may have large casing sizes and no production tubing down to the reservoir. When doublets are required, drilling them from the same location can reduce costs. However, this approach poses the question as to whether the injector and the production wells should have the same design. In previous papers, the authors have discussed how drilling and cementing affect heat transfer along the wellbore. By using appropriate cement composition and controlling filter cake thickness and mud filtrate invasion, the heat transfer can be reduced or enhanced. These findings constitute the premises of this paper, which proposes a theoretical discussion on overall wellbore heat transfer coefficient, focusing on improving well design to maximize heat recovery from geothermal wells.

## 1. INTRODUCTION

Drilling doublets for heat mining applications is common practice. The concept of injecting and producing has been lately refined by increasing the number of injectors or producers to better serve the flow in the underground. Ungemach (2001) showed an evolution of the geothermal well doublets construction (Figure 1). He started with the original doublet concept (first generation), using vertical wells drilled at a given distance (d) and introduced deviated wells, minimizing the surface location distance between wells while keeping the same departure at the reservoir level. Third and fourth generation wells have reduced the surface distance between wells by using two directional wells opposing each other in order to maintain the reservoir distance (D).

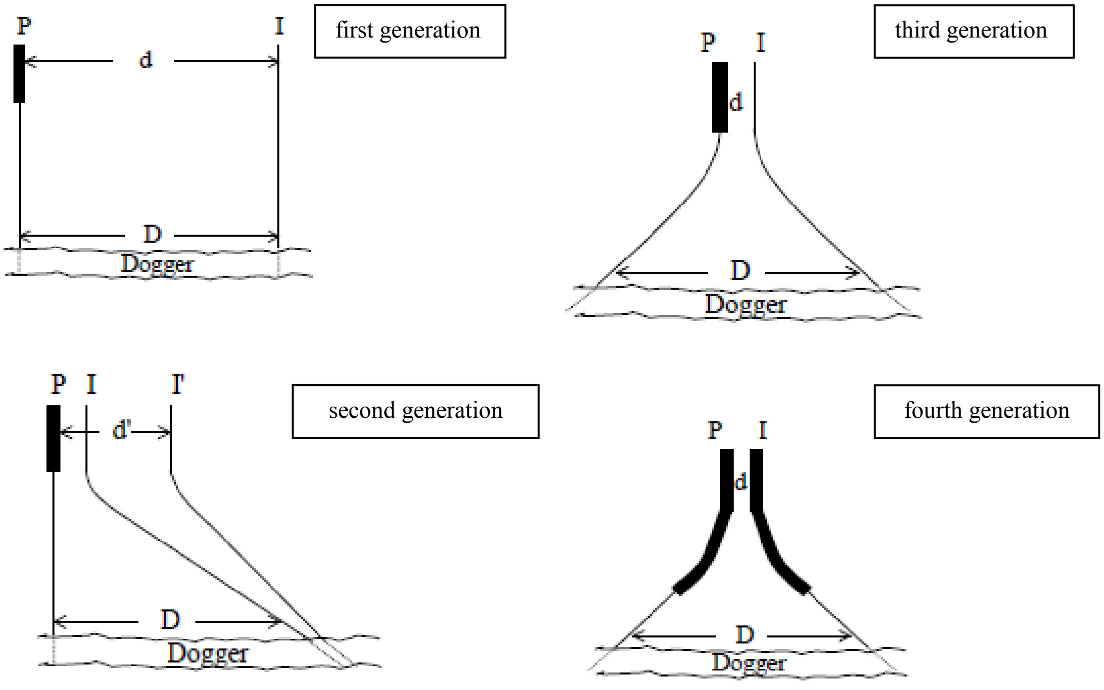

**Figure 1: Geothermal Doublets Topology, after Ungemach (2001).**

Gedzius and Teodoriu (2011) presented alternative construction solutions for well doublets, as well as single well concepts, as shown in Figure 2. The authors presented differences between one well concepts and doublets. Single wells consider the fluid injection and production through the same well, targeting natural or induced fractures.

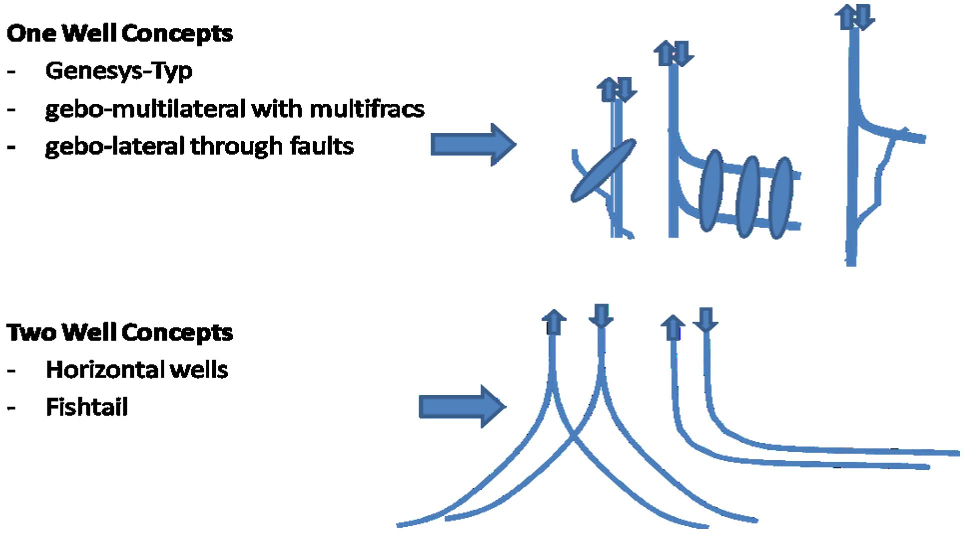

**Figure 2: Geothermal Well Topology, after Gedzius and Teodoriu (2011).**

Heidinger (2014) proposed the concept of a geothermal well farm which uses several doublets drilled into the same geothermal reservoir, but alternated for injection and production of the doublets, see Figure 3. This led to a reduction of the reservoir cooling effect during the injection process, increasing the efficiency of the overall heat mining in the reservoir.

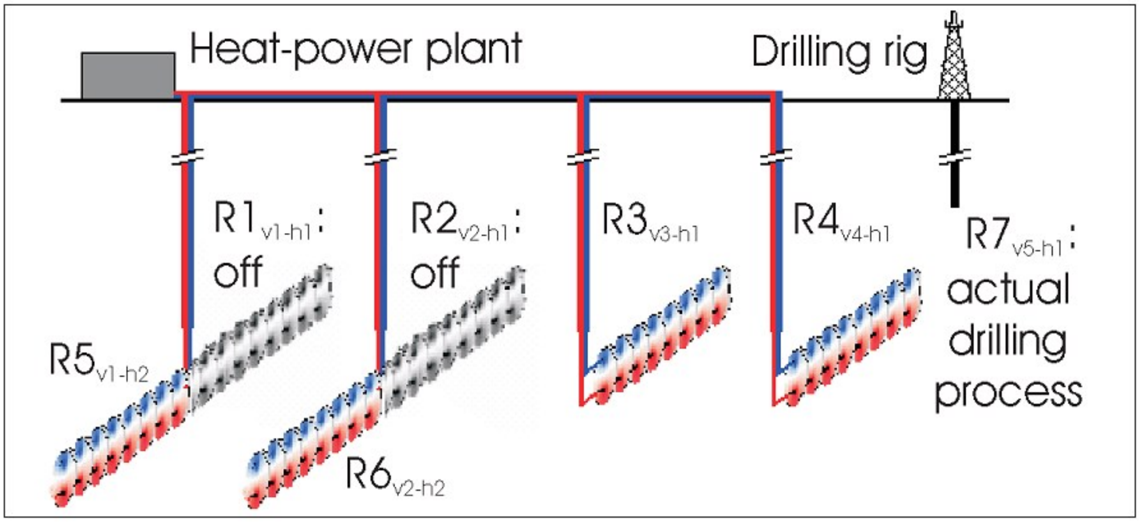

**Figure 3: The Geothermal Farm Concept (Heidinger, 2014)**

A study of fracture efficiency for horizontal well doublets, performed by Teodoriu and Birger (2015), showed that the use of three wells (triplet) could increase the heat mining efficiency to up to 96%. The use of triplets has also been reported by other researchers: Kipsang (2015), Nami et al. (2008).

Moreover, it is known that high flow rate decreases specific heat losses, leading to a raise of the wellhead temperature. Figure 4 shows the calculation performed by Rosca (2000) for a low enthalpy geothermal well. Here, an increase of approximately 30% is observed when increasing flowrate. Figure 5 shows a similar calculation for a high enthalpy geothermal well. Heat flux is enhanced by roughly 60% while specific heat losses are reduced by 90% after the flowrate increase.

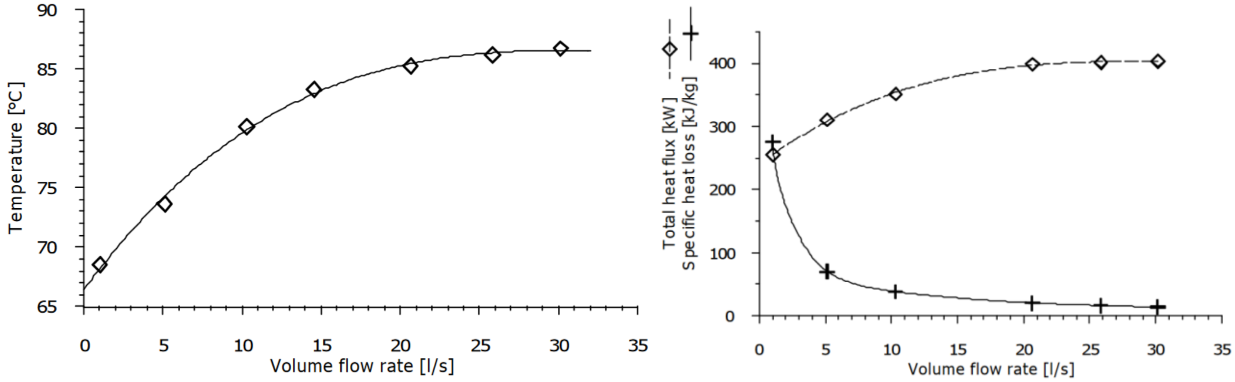

**Figure 4: Wellhead temperature, total heat loss and specific heat loss as a function of flowrate (Rosca, 2000)**

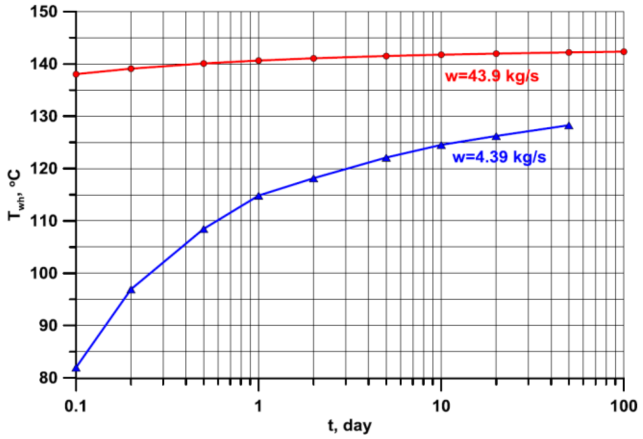

**Figure 5: Wellhead temperature, as a function of the flowrate for a high enthalpy geothermal well (Rosca, 2000)**

Kolo et al. (2014) discussed the need to heat the injection fluid prior to re-injection, using the natural geothermal gradient and wellbore diameter readjustments. They considered the concept presented by Sanyal et al. (2005) and estimated bottomhole temperature for various wellbore sizes, as shown in Figure 6. They concluded that pre-heating is possible by reducing the wellbore size or decreasing the flowrate, with the maximum temperature increase corresponding to lower flowrates and smaller diameters. However, smaller diameters of the flow path would lead to higher pressure losses, reducing the applicability of this model in high-enthalpy systems. Toth (2006) also demonstrated that an increase in flowrate would increase the wellhead temperature. Similarly, the bottomhole temperature for the injection well will decrease with the increase of the flow rate, because the heat exchange between the well and its surrounding formation is low, as this exchange also depends on the contact time between the fluid and the reservoir rock, see Figure 6.

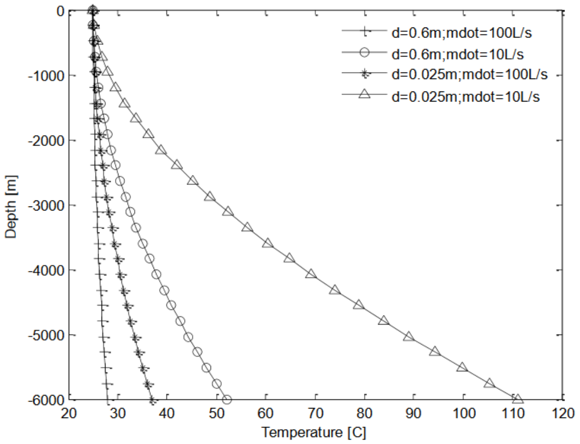

**Figure 6: Bottomhole temperature of the injection well as a function of the flowrate (Kolo, 2014)**

## 2. WELL PATH OPTIMISATION OF PRODUCER

Teodoriu et al. (2010) showed the importance of reducing pressure losses in production wells. Since the pressure losses are a function of the casing inner diameter and the wellbore length, a reduction in production well length would lead to significant pressure loss reduction. To determine the pressure drop, the following equation is used, showing that the wellbore diameter and the length of the wellbore are the critical parameters.

$$\Delta P = \frac{fLv^2\rho_{sw}}{2d} \tag{1}$$

where:
f – Darcy Weißbach friction factor
L – length of tubing or casing, m
v – fluid velocity, m/s
d – inside diameter of casing or tubing, m
$\rho_{sw}$ - fluid density (salt water), kg/m³

Considering a production well as shown in Figure 1 (third or fourth generation type) the increase in pressure drop from a vertical to a directional well (of the type “build and hold”), with a true vertical depth of 4877 m (16,000 ft) and a measured depth of 5243 m (17,200 ft), would be 7%. Although this value may seem low, it can correspond to significant capital expenditure (CAPEX) when a production pump must be selected.

Following wellbore total length as an optimization parameter, a vertical production well would be the best option within a doublet or triplet concept. This matches the second generation doublets shown by Ungemach (2001). As presented above, higher flowrates lead to a higher wellhead temperature; however, the heat losses in the surroundings of the well are not minimized, giving operators the opportunity to further enhance the efficiency of their production and injection wells. This is why additional insulation of the tubing and low conductivity cements should be used, at least for the depth of the surface casing.

## 3. WELL PATH OPTIMISATION OF INJECTOR

Because of its importance, the increase of bottomhole temperatures of the injecting fluid in geothermal exploitation should be analyzed in more detail. It is known that low injection temperature will affect the mechanical properties, the integrity of the reservoir rock, and the overall system efficiency through fluid short-cutting and uncontrolled fractures. Although the effectiveness of heat transfer in an injection well is associated with a wide set of inter-connected parameters (rock properties, geothermal gradient, well construction and properties of used materials, operational parameters, budgeting etc.), a discussion focusing on the effect of wellbore heat transfer on the injector well construction is presented in order to address the well path optimization based on a working parameter.

Most authors have used Ramey’s equation (Kolo et al, 2014, Horne and Shinohara, 1979), reporting satisfactory results which match field measurements. Ramey’s equation for the estimation of the injection bottomhole temperature is shown in Equation 2.

$$T_{f,inj} = Az + B - \frac{A}{L_R} + \left(T_o(t) + \frac{A}{L_R} - B\right)e^{zL_R} \tag{2}$$

Here, B is the surface temperature (°C), Az+B represents the linear geothermal gradient (z – true vertical depth, m), and $T_o(t)$ is the time-dependent injection temperature at surface (°C). The relaxation coefficient, $L_R$,is:

$$L_R = \frac{2\pi}{c_p\dot{\mathrm{m}}}\left(\frac{r_{to}Uk}{k + r_{to}UT_D}\right), \tag{3}$$

and is primarily a function of the overall heat transfer coefficient and mass flow rate. In this equation, $c_p$ is the specific heat of the injected fluid (J/K), ṁ is the mass flowrate (kg/s), and k is the thermal conductivity of the formation (W/m-K). $T_D$ is the dimensionless temperature function, a logarithmic expression based on the injection time (Kolo et al., 2014).

Because the other influencing parameters in equations 2 and 3 are fixed in most of the cases (e.g. rock thermal conductivity, required flowrate and injection time, tubulars’ diameter), the only improvable parameter allowing better heat transfer management is the overall heat transfer coefficient. The overall heat transfer coefficient (commonly expressed in W/m$^2$-K or BTU/ft$^2$-h-°F) proposed by Ichim and Teodoriu (2016) extends conventional applications and aims at taking into account cement, filter cake thickness, together with mud invasion in the porous formation (the last three terms of equation 4):

$$U = \left[\frac{r_{to}}{r_{ti}h_L} + \frac{r_{to}\ln(\frac{r_{to}}{r_{ti}})}{k_{steel}} + \frac{r_{to}\ln(\frac{r_{ins}}{r_{to}})}{k_{ins}} + \frac{1}{(h_c + h_r)} + \frac{r_{to}\ln(\frac{r_{co}}{r_{ci}})}{k_{steel}} + \frac{r_{to}\cdot\ln(\frac{r_{wb}}{r_{co}})}{k_{cement}} + \frac{r_{to}\cdot\ln(\frac{r_{fc}}{r_{wb}})}{k_{filtercake}} + \frac{r_{to}\cdot\ln(\frac{r_e(t)}{r_{fc}})}{k_{invaded}}\right]^{-1}, \tag{4}$$

where $r_{to}, r_{ti}, r_{ins}, r_{ci}, r_{co}, r_{wb}$ are the tubing outer radius, tubing inner radius, insulation radius, casing inner radius, casing outer radius and the wellbore radius, respectively; and $h_L, h_c, h_r, k_{steel}, k_{ins}, k_{cement}$ are the liquid convective heat transfer coefficient, convective heat transfer coefficient, radiation heat transfer coefficient, conductivity of tubing and casing steel, conductivity of the insulation material, and the conductivity of the cement, respectively. The existence of insulated tubulars in the well is taken into account through the third term of equation 4. The newly introduced terms are $r_{fc}$, which, depending on the type of filter cake (internal or external) represents the radius from the well center to the filter cake, and $r_e(t)$, representing the radial invasion depth of the mud filtrate in the formation with time (Ichim and Teodoriu, 2016). The thermal conductivities of the newly introduced terms are $k_{filtercake}$ and $k_{invaded}$ (W/m-K). Although the thermal conductivity of the external filter cake can be experimentally determined, the thermal conductivity of the invaded zone must be estimated based on the fluid invasion and original formation thermal conductivity. The expression of the overall heat transfer at certain depths is independent of well length and depends only on the radius of the wellbore elements. From a conceptual point of view, this form of the overall heat transfer coefficient may allow the fine-tuning of $U$ through a change in the thermal conductivity of the wellbore cements and a drilling fluid program also designed to meet heat transfer demands.

Since the injection temperature plays an important role in the optimization concept, the well construction optimization proposed herein will focus on the ability to increase the fluid temperature before arriving at the bottom of the well. Typical wellhead injection temperatures vary from 30 to 65°C, normally exceeding the underground temperature of a shallow formation. In order to keep the injection fluid temperature as high as possible, heat losses in the upper section of the well need to be minimized, at least until the injection fluid temperature becomes smaller than the well surrounding temperature. This could be achieved by using insulated tubing and, as shown by Ichim and Teodoriu (2016), by using low conductivity cements while taking the invaded zone into account. Once the injection fluid reaches the depth at which the surrounding temperature exceeds the injecting fluid value, the well construction should be changed in order to enhance the heat mining from the surroundings. This is shown in Figure 7 as an example of a vertical well, showing a typical geothermal gradient and the injection fluid evolution if the well is insulated in the upper part. The upper zone – named highly insulated zone - can be achieved by a combination of insulated tubing and proper selection of well cement and drilling practices. Since the depth at which the temperature of injection fluid is equal to that of the surroundings should be reached as fast as possible, a vertical well is the most appropriate solution. From this depth down below, the well should be constructed to enhance the heat flow to the injection fluid. Increasing the length of the well will also increase the exchange area and thus the heat exchange between rock and fluid, see Figure 8a. The resulting construction is similar to the second generation of the well doublets mentioned by Ungemach (2001). Since the reservoir area is the hottest, a multilateral well construction that starts just above the cap rock may further increase the heat exchange and also evenly distribute the injection fluid, reducing the chances of cold spot formation (Figure 8b).

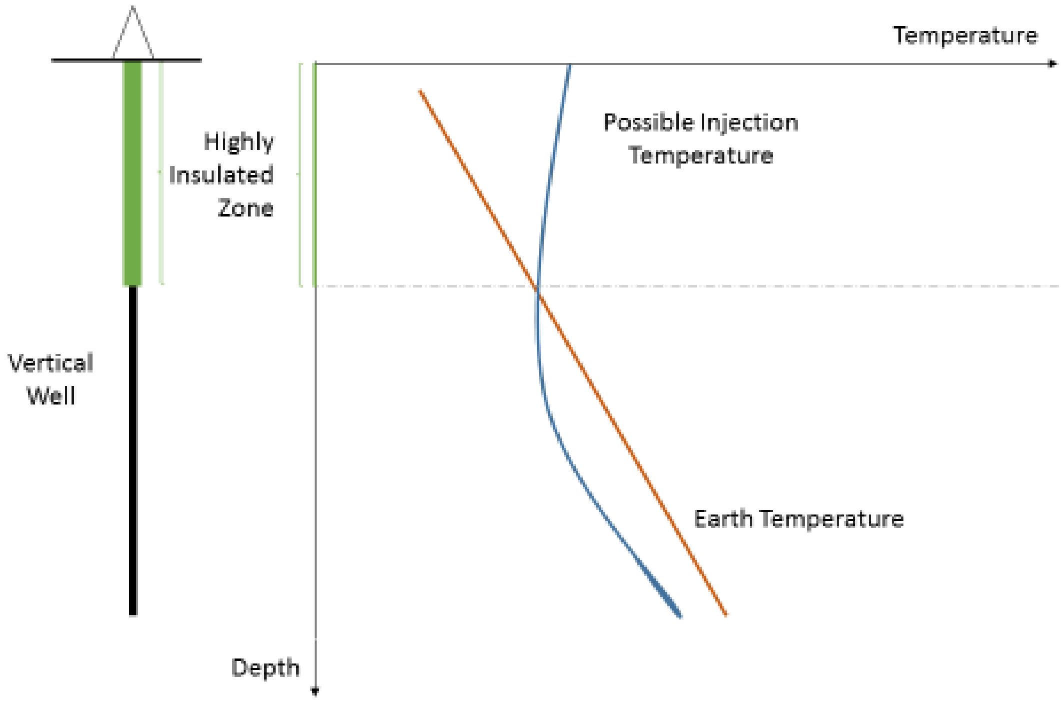

**Figure 7: Proposed well construction to enhance temperature of the injection fluid**

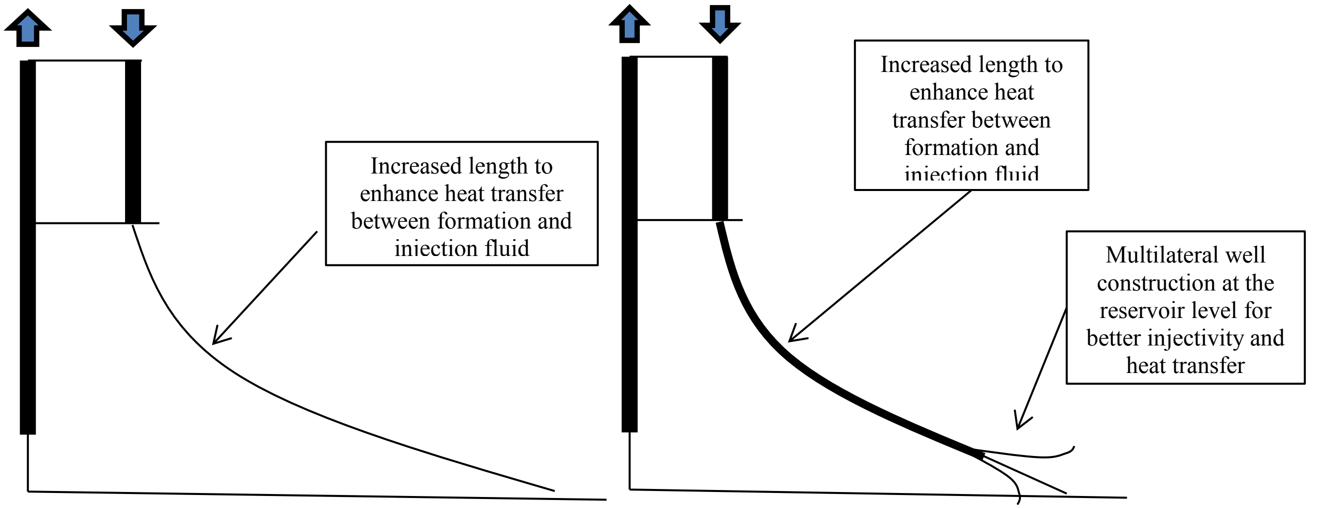

**Figure 8: proposed well construction to enhance temperature of the injection fluid using directional well (a - left) and multilateral (b - right) well**

## 4. CONCLUSIONS

This paper presents a novel well optimization idea based jointly on pressure drop and heat transfer along the wellbore.

When injection fluid temperature is the key towards an improved system performance, a long directional injection well is necessary. Using ad hoc cementing solutions in the upper part of the well would reduce further drawdown of the injection temperature, while engineered well cements in the lower part of the well would help increasing the injection fluid temperature.

To reduce the production pressure drop, a vertical well is most suitable. As a recommendation, insulated tubing in the upper part of the well, followed by low conductivity cements, help keeping the temperature lost to the surroundings as small as possible.

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