Proceedings World Geothermal Congress 2015
Melbourne, Australia, 19-25 April 2015

# Pressure and Temperature Behaviors of Single-Phase Liquid Water Geothermal Reservoirs under Various Production/Injection Schemes

Yildiray Palabiyik, O. Inanc Tureyen and Mustafa Onur

Department of Petroleum and Natural Gas Engineering, Istanbul Tech. U., Maslak, 34469, Istanbul, Turkey

palabiyiky@itu.edu.tr, inanct@itu.edu.tr, onur@itu.edu.tr

**Keywords:** Liquid-water geothermal reservoirs, 2D (*r-z*) non-isothermal model, temperature behaviors, sensitivity, reservoir parameters.

## ABSTRACT

In this work, we investigate the transient pressure and temperature behaviors of liquid-dominated geothermal reservoirs containing single-phase liquid water. Investigation is conducted by using a 2D (*r-z*) non-isothermal model that couples both the mass and thermal energy balance equations rigorously and considers various modes of production/injection well conditions and outer reservoir boundary conditions of no-flow/constant-pressure with or without constant-temperature in the vertical and lateral directions. Using this model, a sensitivity study with respect to various reservoir properties (such as porosity, permeability, skin, thermal conductivity, rock density and rock heat capacity) is conducted for investigating the information content of the sandface pressures and temperatures at source/sink locations as well as some selected observation points along the wellbore. In the sensitivity study, the effects of the reservoir parameters on temperature and pressure responses were quantified through the use of sensitivity coefficients, which are defined as the derivatives of temperature or pressure data with respect to the natural logarithm of the parameter of interest. The results of the sensitivity study reveal which reservoir parameters can be reliably estimated from temperature and pressure measurements in cases where non-linear parameter estimation methods are employed for history matching. Based on the results of these synthetic cases assuming homogeneous single-layer systems, it is shown that, depending on the mode of production or injection (constant-rate production, or shut-in following production or fall-off following injection, etc.), the sandface pressures and temperatures show sensitivities to parameters like porosity, permeability, rock thermal conductivity, rock density and rock heat capacity. For instance, we show that the reservoir permeability has no considerable effect on the sandface temperature for the constant-rate injection case, whereas it has a relatively significant effect on the temperature for the constant-rate production case at especially low permeability. It has also been found that skin (due to damage or stimulation around the well) and permeability have significant effects on sandface temperatures when injection is performed at a constant-pressure. However, it is observed that sandface temperature changes do not exceed 2 to 3 K for most of the constant-rate production cases studied. Such small changes may be difficult to measure in practical field applications.

## 1. INTRODUCTION

Use of temperature data has often been neglected for the purpose of reservoir characterization until recent times although temperatures are usually recorded in well test applications. Nevertheless, various researchers have lately shown that temperature data when used together with pressure data are useful and help in reservoir characterization (Onur et al. 2008, Sui et al. 2008a, b, Ramazanov et al. 2010, Duru and Horne 2010a, b).

A forward model enabling the simulation of the temperature response of a geothermal system is necessary for integrating temperature data to characterize a geothermal reservoir. Three approaches, lumped parameter (tank) models, analytical/semi-analytical models and numerical models are generally used to model pressure and/or temperature responses of geothermal reservoirs. To the best of the authors' knowledge, Whiting and Ramey (1969) were the first to provide the lumped-parameter models based on the material and energy balances for predicting the pressure and temperature behaviors of geothermal reservoirs producing both liquid and/or steam. Their formulations are based on pressure and temperature differences and are difficult to use for variable-rate injection/production schemes from a geothermal system. Later, Onur et al. (2008) developed a non-isothermal lumped-parameter model capable of estimating both pressure and temperature responses of single-phase liquid water geothermal reservoirs as idealized as a single-closed or recharged tank. The unique features of Onur et al. (2008)'s model are that it solves two non-linear ordinary differential equations resulting from mass and thermal energy balances, handles easily the variable-rate injection and production schemes, and can easily be incorporated into the automated history-matching algorithms for the purpose of parameter estimation. Onur et al. (2008) have shown that one could estimate reservoir parameters (e.g. bulk volume and porosity of reservoir) if the information content of average reservoir temperature data along with average pressure data is used in history-matching. Later, Tureyen et al. (2009) have extended Onur et al. (2008)'s study to multiple tanks. Nonetheless, spatial changes in pressure and temperature cannot be modeled using such lumped-parameter models.

In the mass and thermal energy balance equations of most of the models based on analytical and semi-analytical solutions, it is assumed that fluid and rock properties are independent of pressure and temperature. Some of the earlier important analytical solutions are suggested by Lauwerier (1955) and Atkinson and Ramey (1972) who presented the analytical solutions for 1D linear and radial flow systems to predict temperature behavior in the reservoir under various simplifying assumptions (e.g. rock/fluid properties independent of pressure and temperature, uniform fluid velocity inside the reservoir, etc.). Current studies using the semi-analytical solutions related to this topic have been given by Ramazanov et al. (2010), Duru and Horne (2010a), and Duru and Horne (2011). The method of characteristics has been used by Ramazanov et al. (2010) to model temperature response while the method of operator-splitting and time stepping has been presented by Duru and Horne (2010a, 2011) to calculate pressure and temperature responses. Ramazanov et al. (2010) have taken only the convective heat transfer into account in the reservoir while Duru and Horne (2010a, 2011) have taken both effects of the conductive and convective heat transfers into consideration in the reservoir. The results of these studies have shown that information about reservoir permeability and porosity along with skin zone around the well can be determined from temperature measurements. Moreover, it is shown by Duru and Horne (2010a) that production rate data from temperature data could be predictable. Nevertheless, the outcomes above are only valid for the cases where the rates are very high and the wellbore storage effects could be negligible as indicated by Ramazanov et al. (2010). Consequently, it has also been recommended by Ramazanov et al. (2010) that the general numerical models are necessary to obtain more accurate temperature solutions.

There are numerous numerical studies published about this topic in the literature. The earlier numerical models regarding this topic are presented by Lippmann et al. (1977), Coats (1977), Toronyi and Farouq (1977), Crookston (1979) and Miller (1980). On the other hand, Sui et al. (2008a, b) and App (2010)'s studies can be regarded as some of the most current studies in the literature related to the topic. A 2D (*r-z*) radial simulator modeling temperature response for the case of single-phase liquid flow in 2D stratified systems has been presented by Sui et al. (2008a). Sui et al. (2008a) have indicated that the wellbore temperature is sensitive to the radius and permeability of damage zone around the wellbore in stratified systems. In this work, the developed energy balance equation contains the effects of Joule-Thomson and thermal expansion whereas pressures used in energy balance equation have been obtained from the mass balance equation that makes the assumptions of isothermal flow and slightly compressible fluid. This is the same assumption assumed in Ramazanov et al. (2010) and Duru and Horne (2010a). Therefore, the pressure and temperature responses under non-isothermal conditions cannot be rigorously modeled by using such solutions. An algorithm for an inverse solution formulated as a non-linear least-squares regression problem to estimate permeability (region outside damage zone), porosity, radius and permeability of damage zone by history matching observed temperature and pressure data has been given by Sui et al. (2008b) as another study. The claim that the mentioned parameters could reliably be estimated by history matching temperature data if noise in temperature measurements is not very high is the important result of this study. A transient, 1D radial model coupling the mass and energy balance equations to estimate the pressure and temperature responses of a system with the components oil, connate water and rock has been given by App (2010). App (2010) has shown the change of pressure and temperature responses in the reservoir because of Joule-Thomson expansion of fluids under non-isothermal conditions.

Duru and Horne (2010b) have presented another study about the information content of transient temperature data. An inverse solution of permeability and porosity distributions in reservoir has been presented by history matching to temperature data with the method of Ensemble Kalman Filter (EnKF) using a forward model based on a coupled numerical solution of mass and energy balance equations for a 3D (*x-y-z*) system. Duru and Horne (2010b) have indicated with this study that temperature data contain more information about porosity distribution than that of permeability distribution.

This work has two main objectives: The first one is to study the temperature and pressure responses of single-phase liquid-water geothermal systems under non-isothermal flow conditions with different production and injection schemes (constant-rate/variable rate or constant-pressure). Secondly, it is to quantify the information content of temperature data in terms of reservoir parameters by computing the sensitivities of the temperature data recorded at the production/injection locations plus observation points along the wellbore to reservoir rock parameters (such as porosity, permeability, skin, thermal conductivity, rock density and rock heat capacity). These objectives were achieved by making use of a 2D (*r-z*) non-isothermal single-phase simulator developed by Palabiyik et al. (2013). The simulator used is a 2D (*r-z*) fully-implicit and removes the limitations of the analytical, semi-analytical models and some of the numerical models (e.g., those of Sui et al. 2008a, b) stated above.

In the organization of the paper, first, a brief description of the 2D (*r-z*) model used in this study is given in the next section. Then, synthetic applications that present the effects of various reservoir and well properties on the pressure and temperature responses along with the sensitivities of pressure and temperature to various reservoir parameters are demonstrated.

## 2. NUMERICAL MODEL

A numerical simulator that rigorously considers mass and energy conservation equations (that take heat transfer into account by way of both convection and conduction) has been used in this work. Flow in porous media is modeled by using Darcy's law. In the developed model, a finite difference approach has been used to solve the non-linear equations. Temperature gradients to overburden and underburden in the *z*-direction have been assigned to model heat transfer to adjacent strata. Both no-flow and constant-pressure reservoir boundaries in the lateral directions with or without constant-temperature are considered. Gravity effects in the *z*-direction on the pressure and temperature behaviors can also be included if desired. Pressure and temperature responses arising from production of hot geothermal water and/or injection of low temperature water into the reservoir can be modeled using the developed simulator. Furthermore, the model is capable of handling variable production or injection rate histories. The well-known method of Newton-Raphson has been used to solve the non-linear mass and energy conservation equations in a fully-implicit manner. The specific heat capacity of the rock, density of the rock, thermal conductivity, thermal expansion coefficient, rock compressibility and the bulk volume are all assumed to be constant. Validation of the model through comparisons with a well-known commercial thermal reservoir simulator and existing analytical models in the literature can be found in the studies of Palabiyik et al. (2013) and Palabiyik (2013).

## 3. INVESTIGATIONS OF PRESSURE AND TEMPERATURE BEHAVIORS

In this section, different synthetic example applications designed with the developed model in the 2D (*r-z*) reservoir system for simulating both pressure and temperature responses of liquid-dominated geothermal reservoirs are shown. Constant-rate production/injection and injection-falloff cases are simulated for a 2D (*r-z*) closed reservoir system with no-flow and constant-temperature at the outer boundary (at $r = r_e$) of the reservoir. A constant-pressure injection case is also studied to investigate the effects of permeability and skin on the sandface temperature behavior. Heat transfer from reservoir to adjacent strata (at $z = 0$ and $z = h$) and gravity effects in the *z*-direction are ignored in the cases. Palabiyik (2013) has also shown that heat transfer from reservoir to adjacent strata does not have a significant effect on the sandface pressure and temperature for the case studies considered here. Anisotropy is not taken into consideration unless otherwise stated. In the model, to eliminate the wellbore storage effects, the wellbore volume is taken very small ($V^w = 3.14\times10^{-4}$ m$^3$). It is assumed that geothermal water is pure liquid water, that is, no dissolved solids exists in the water. In all cases, the sandface pressure and temperature considered is computed in the middle of the open interval to flow for both fully-penetrating and limited-entry wells unless otherwise stated. In some cases, the sensitivities of the sandface pressure and temperature behaviors to various rock parameters (porosity, permeability, skin, rock thermal conductivity, rock density and rock heat capacity) are also investigated to be able to understand the information content of the reservoir to be obtained from especially temperature data. Well completion effects (full penetration or limited-entry) on pressure and temperature behaviors are also evaluated in the cases. The other pertinent reservoir parameters used in the cases along with their definitions and values are given in Table 1. Input model parameters given in Table 1 are valid for all the application cases unless otherwise stated.

**Table 1: Input model data for the application cases.**

| Parameter | Definition of Parameter | Value |
|---|---|---|
| $N_r$ | Number of grid blocks in the $r$-direction | 21 |
| $N_z$ | Number of grid blocks in the $z$-direction | 9 |
| $p^0$, kPa | Initial reservoir pressure | 10000 |
| $T^0$, K | Initial reservoir temperature | 413.15 |
| $r_w$, m | Well radius | 0.1 |
| $r_e$, m | Reservoir radius | 1000 |
| $h$, m | Reservoir thickness | 100 |
| $V^w$, m$^3$ | Wellbore volume | $3.14\times10^{-4}$ |
| $\phi$ | Reservoir porosity | 0.2 |
| $k$, m$^2$ | Absolute reservoir permeability | $1\times10^{-13}$ |
| $c_s$, 1/kPa | Isothermal compressibility of rock | $2.9\times10^{-7}$ |
| $\beta_s$, 1/K | Isobaric thermal expansion coefficient of rock | 0 |
| $c_{p,s}$, J/kgK | Specific heat capacity of rock | 1000 |
| $\rho_s$, kg/m$^3$ | Density of solid rock phase | 2650 |
| $\lambda_t$, J/msK | Total thermal conductivity | 2.92 |

### 3.1 Effects of Porosity and Flow Rate on the Sandface Temperature for Constant-Rate Production Case

In this case, the sandface temperature responses during production of 200 days from a fully penetrating well at constant-rates of 1 kg/s and 5 kg/s for the reservoirs with different porosity values ($\phi$ = 0.20 and $\phi$ = 0.04) are investigated. Hence, both rate and porosity effects on the sandface temperature are studied in this case, separately.

Figure 1 illustrates the sandface temperature responses for the reservoirs with different porosity values for a fully penetrating well. As can be seen from Figure 1, the temperature takes higher values as porosity decreases. This is caused by the fact that the reservoir with a lower porosity ($\phi$ = 0.04) has a higher heat content (higher rock volume) than that of reservoir with a higher porosity ($\phi$ = 0.20). The sandface temperature decreases at very early and late times of production because of the expansion of the fluid volume nearby the well region at very early times and the expansion of the entire fluid volume of the reservoir at late times. After the very early times, Joule-Thomson effect surpasses the expansion of the fluid volume around the well and a period of temperature increase is observed. At late times, the Joule-Thomson effect is surpassed by excessive pressure drops linked to the expansion of the entire fluid volume (although not shown, this is the region where pseudo-steady state behavior is observed) of the reservoir and so, the geothermal fluid cools again.

Figure 2 demonstrates the sandface temperature responses for the same case from the point of view of rate effect. Figure 2 indicates that more temperature variations are observed in a higher rate (5 kg/s) since more pressure drop occurs in the production in a higher rate. It is also observed that the magnitudes of these temperature changes increase with increasing production rate.

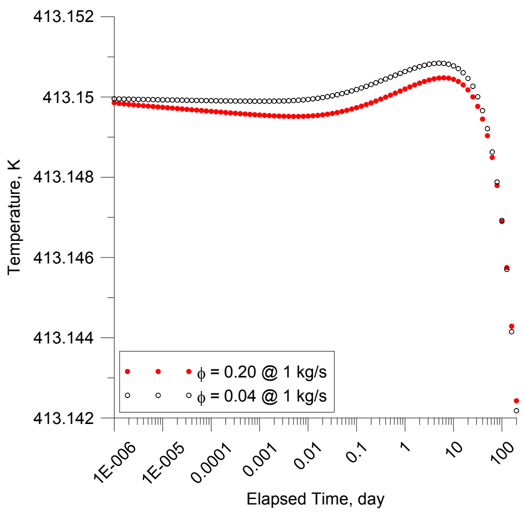


**Figure 1: Effects of porosity on the sandface temperature of a fully penetrating well producing at a constant-rate.**

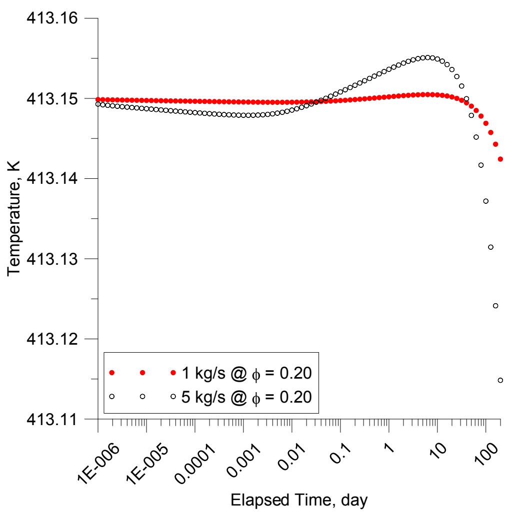


**Figure 2: Effects of flow rate on the sandface temperature of a fully penetrating well producing at a constant-rate.**

### 3.2 Effects of Permeability on the Sandface Pressure and Temperature for Constant-Rate Production Case

In this case, the sandface temperature responses in the reservoirs with different permeability values are investigated at a constant-rate of 1 kg/s during production of 1000 days from a fully penetrating well. Figure 3 shows the log-log diagnostic plots of pressure differences at the sandface ($\Delta p = p^0 - p_{sf}$) and their Bourdet derivatives defined as the derivative of the pressure change with respect to the natural logarithm of time, that is, $\Delta p' = d\Delta p/d\ln t$ (Bourdet et al., 1989) as a function of time for this case. Figure 4 shows the sandface temperature responses. Temperature changes increase as permeability decreases. The biggest changes in temperature are observed in the reservoir with the lowest permeability ($k = 1\times10^{-15}$ m$^2$). This is because the greatest pressure drop occurs when permeability is the lowest in the reservoir. The processes that cause the changes in temperature is actually similar to the previous case. Temperature drop is observed at early time as the water expands around the well. This fluid expansion surpasses heating effect owing to Joule-Thomson expansion since the pressure drop is low at early time. After this period, heating in fluid is observed because of Joule-Thomson effect which starts dominating over the temperature behavior. At the end of the production, the greatest pressure drop created by the contribution of the expansion of the entire reservoir volume results in temperature drop observed to meet the production rate in the well at late time because reservoir is closed and mass withdrawal reduces temperature at the sandface.

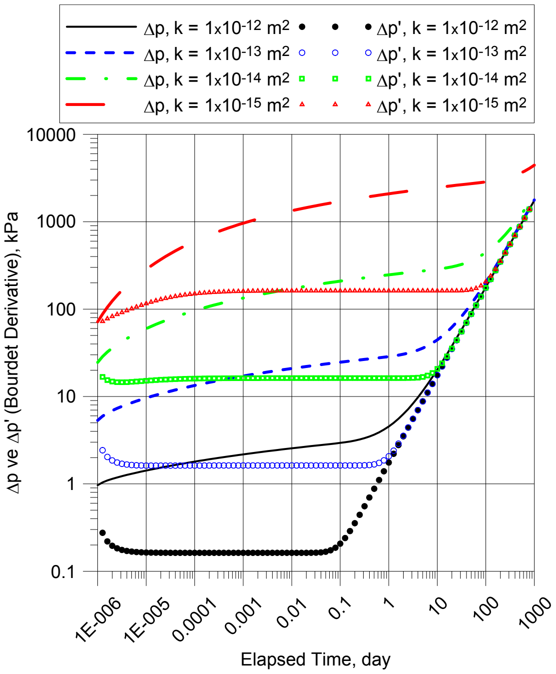


**Figure 3: Effects of permeability on the sandface delta pressure and Bourdet derivatives of a fully penetrating well producing at a constant-rate.**

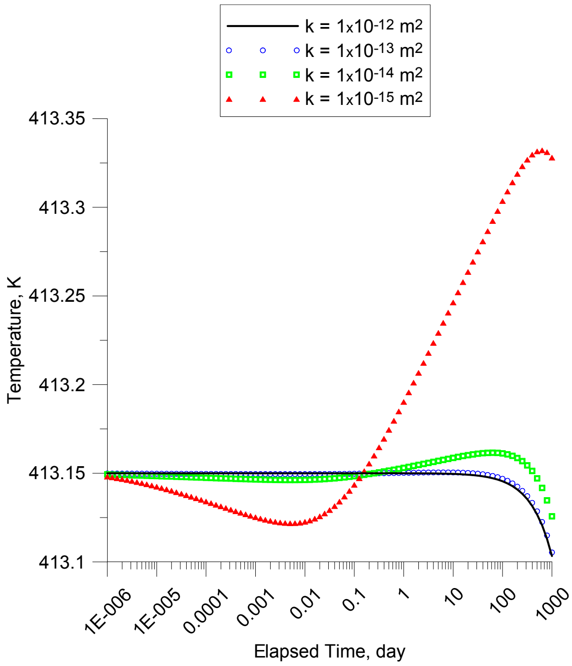


**Figure 4: Effects of permeability on the sandface temperature of a fully penetrating well producing at a constant-rate.**

### 3.3 Effects of Production at a High Rate on the Sandface Pressure and Temperature Behaviors for a Limited-Entry Well

In this case, the sandface pressure and temperature behaviors in a production period of 150 days at a constant flow rate of 60 kg/s, a realistic production rate for the wells of the single-phase water geothermal fields in Turkey, from a limited-entry well ($h_w$ = 1 m, interval length open to flow) are investigated. Intervals open to flow are considered to be in the middle of the reservoir in the $z$-direction. Differently from the other cases throughout this paper, initial reservoir pressure is 30000 kPa; initial reservoir temperature is 453.15 K (180°C) and permeability is $3.16\times10^{-13}$ m$^2$. The permeability value has been chosen as the geometric mean of an anisotropic reservoir with horizontal permeability, $k_r = 1\times10^{-13}$ m$^2$ and vertical permeability, $k_z = 1\times10^{-12}$ m$^2$ (or $k_r = 1\times10^{-12}$ m$^2$ and $k_z = 1\times10^{-13}$ m$^2$). Other input parameters are as given in Table 1. Moreover, the sensitivities of the sandface pressure and temperature to various reservoir parameters are also investigated by using the sensitivity coefficients as a function of time.

Figure 5 shows the log-log diagnostic plots of pressure differences at the sandface ($\Delta p = p^0 - p_{sf}$) and their Bourdet derivatives as a function of time for this case. Firstly, very sudden pressure drop is observed at early time because of the limited-entry (spherical flow). After this period, the derivative stabilizes during the radial flow. Finally, pseudo-steady state flow regime (the reservoir outer boundary effects are observed during this period) is observed up to the end of the production.

Figure 6 shows variations in temperature behavior for the same case. Since the temperature behavior observed is similar to that of the previous cases, it is not explained in detail again, here. However, it is important to note that for this case, there is a larger drawdown (see Figure 5) than that of the previous cases with $h_w$ = 1 m and this causes more temperature variations at the sandface. In this case, temperature changes due to fluid expansion from the whole reservoir at late time and especially Joule-Thomson effects at other times are much larger (1.8 K or 1.8°C) than those of fully penetrating well producing at low rate (see Figures 1, 2 and 4). This is caused by the fact that the excessive pressure drops occur with the effect of production in a high rate from a limited-entry well. Both the effects of high production rate and limited-entry length contribute these high pressure drops and temperature changes. If Figure 6 is carefully inspected, it can be seen that decrease in temperature created by fluid expansion at very early time is not observed in this case in contrast to the previous cases (see Figures 1, 2 and 4). This is because Joule-Thomson effect surpasses temperature decrease due to the fluid expansion and temperature increases from the start of production to the late time with the contribution of large pressure drop.

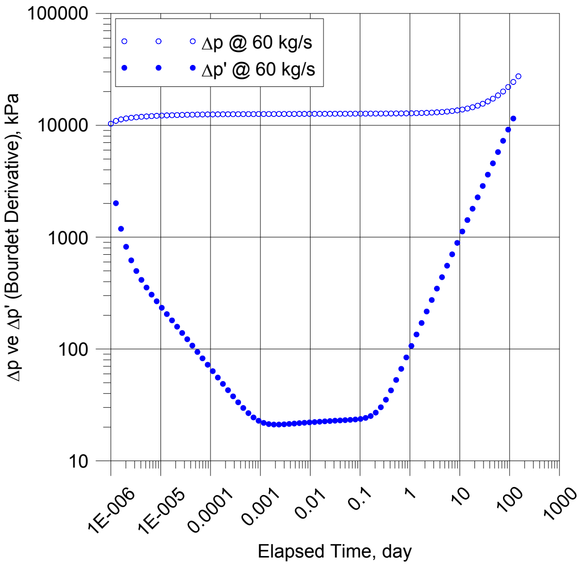


**Figure 5: Sandface delta pressure and their Bourdet derivatives of a limited-entry well producing at a high constant-rate.**

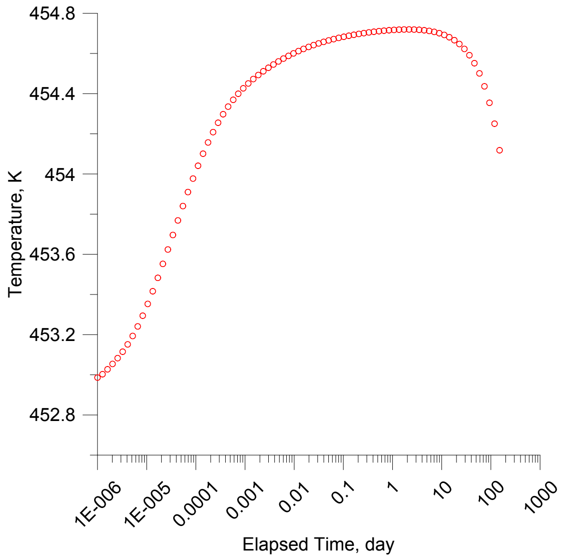


**Figure 6: Sandface temperature behavior of a limited-entry well producing at a high constant-rate.**

At this point, it is worth to investigate the sensitivities of the sandface pressure and temperature to various rock parameters using the sensitivity coefficients. Sensitivity coefficient ($\underline{S}$) of a primary variable ($\psi$) (pressure or temperature in our cases) with respect to the natural logarithm of a model parameter ($\kappa$) (e.g. porosity, permeability, etc.) can be defined as follows (the units of the sensitivity coefficients are K or kPa which enables us to compare the sensitivity coefficients for different parameters):

$$\underline{S} = \left( \frac{\partial \psi}{\partial \ln \kappa} \right) = \kappa \left( \frac{\partial \psi}{\partial \kappa} \right) \tag{1}$$

Figure 7 shows the sensitivity coefficients of the sandface pressure to various rock parameters for a limited-entry well producing at a high rate of 60 kg/s as a function of time. As can be seen from Figure 7, the sandface pressure shows the greatest sensitivity to skin. However, the sensitivity coefficient of the skin is negative in this case, that is, the sandface pressure decreases with increasing skin which is expected in a production case. This is caused by the fact that the sandface pressure drops because the positive skin factor, which indicates the damage in the vicinity of the well, creates a resistance to flow during production. After the skin, the sandface pressure shows the biggest sensitivity to horizontal permeability. After pseudo-steady state is reached, the porosity sensitivity starts increasing since during pseudo-steady state the pressure drop is controlled mostly by the pore volume of the fluid. The horizontal permeability shows more sensitivity when compared with vertical permeability which is expected because flow towards the well is perpendicular to the well surface in the horizontal direction. Therefore, the sandface pressure is more sensitive to the horizontal permeability rather than that to the vertical permeability. As can also be seen from Figure 7, the parameters that show most sensitivity to temperature are the skin and the radial permeability. From this we can conclude that, if a history matching was to be applied, we would have a better chance of determining the skin and radial permeability from temperature data when compared with the other parameters given in Figure 7.

Figure 8 shows the sensitivities of the sandface temperature to the same reservoir parameters as a function of time for the same case. As can be seen from Figure 8, the sensitivities of the temperature to the related rock parameters are less than those of the pressure. The sandface temperature shows the greatest sensitivity to the skin and horizontal permeability in view of their absolute values at late time. After those, it has some sensitivity to the porosity and vertical permeability. The sensitivity to the thermal conductivity is negligible (approximately zero) as is in the pressure. If Figure 8 is carefully inspected, the sensitivities to the permeability are negative except very early times. It means that the temperature increases with decreasing permeability and this result is in agreement with the results observed in Figure 4.

**3.4 Effects of Permeability on the Sandface Pressure and Temperature for Constant-Rate Injection Case**

In this case, colder water with $T_{inj}$ = 333.15 K (60°C) is injected from a fully penetrating well into the reservoir with $T^0$ = 413.15 K (140°C) at a constant-rate of 1 kg/s during 1000 days and the sandface pressure and temperature responses in the reservoirs with different permeability values are investigated. The other reservoir and well properties are as given in Table 1.

Figure 9 shows the log-log diagnostic plots of pressure differences at the sandface ($\Delta p = p_{sf} - p^0$) and their Bourdet derivatives as a function of time. As expected, the pressure differences decrease with increasing permeability because resistance to flow is reduced with increasing permeability, that is, the same amount of mass rate is injected (or injectivity is enhanced) into the reservoir with the less pressure difference occurred. Pressure differences and derivatives observed in Figure 9 exhibit different behaviors than those observed in the production case. Before the pseudo-steady state flow period, two radial flow periods are observed (radial flow is identified with the zero slope line in the Bourdet derivative plot). The earlier radial flow is caused by the mobility of the hotter reservoir fluid whereas the second radial flow is caused by the mobility of the colder injected fluid. However, if Figure 9 is carefully evaluated, the two radial flow periods are not observed in cases where the permeability is very high. The main reason for this issue is that the outer reservoir boundary effects (or pseudo-steady state flow) are felt at the sandface before occurrence of the second radial flow because pressure signal moves very fast further into the reservoir with very high permeability. Since pseudo-steady state flow is felt earlier with increasing permeability, the effect of this flow period is observed in the reservoirs with very high permeability without existing of the second radial flow.

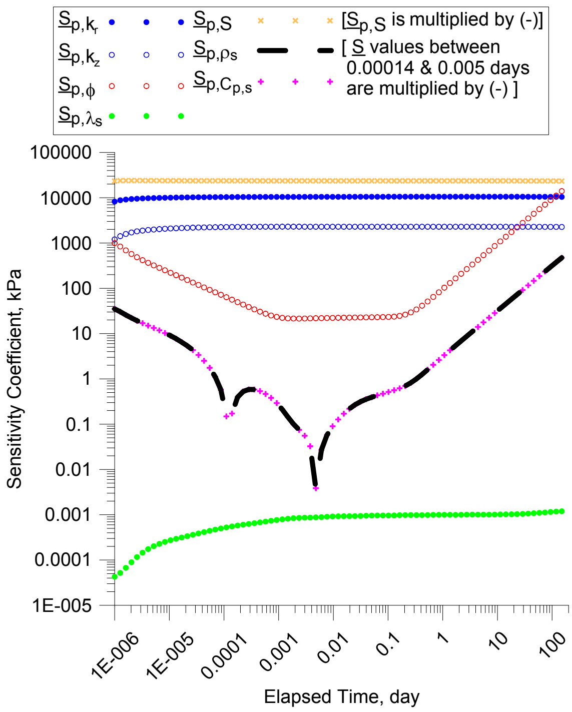


**Figure 7: Sensitivities of the sandface pressure to various rock parameters for a limited-entry well producing at a high constant-rate.**

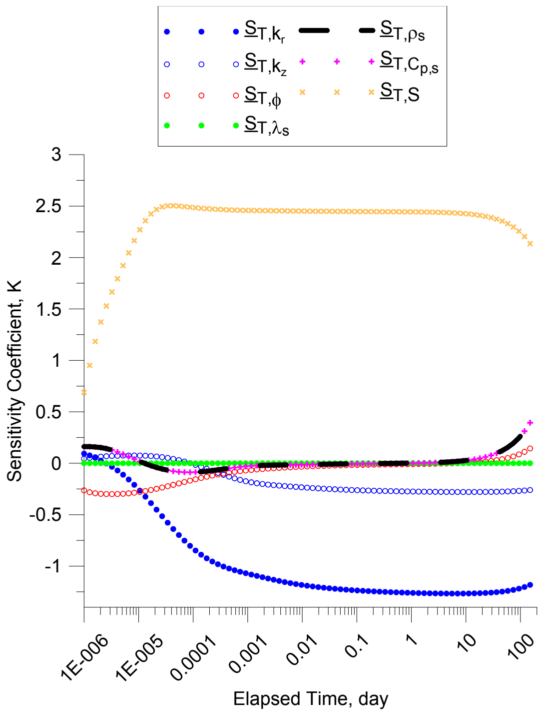


**Figure 8: Sensitivities of the sandface temperature to various rock parameters for a limited-entry well producing at a high constant-rate.**

Figure 10 shows the sandface temperature responses as a function of time for the same case. As can be seen from Figure 10, permeability does not have any considerable effect on the sandface temperature at constant-rate injection. The similar behavior of the sandface temperature is also observed for the changing skin even though it is not shown here. The main reason for this is the fact that since the injection is performed at a constant-rate, no matter what the permeability or the skin is, the same amount of heat is injected into the reservoir. The differences in permeability or skin are reflected on the pressure behaviors. In the previous subsections, we have mentioned that pressure affects the temperature behavior as well. However, the magnitude is rather small when compared with the temperature change magnitudes given in Figure 12. Hence, even though there are very small changes in temperatures due to the changes in pressure, they are not observable for this case. However, the same results are not valid for the injection case at constant-pressure to be discussed later.

Figures 11 and 12 show the pressure and temperature distributions along radial distance at certain time snapshots in the reservoir for the same case. As can be seen from these figures, permeability has a significant effect on pressure distributions as expected whereas it has not any effect on temperature distributions. The temperature case is really the same as the water saturation profile that would be obtained from a water injection problem into an oil reservoir (single-layer) at a constant-rate injection. In such a case, it can be shown that saturation profile is independent of permeability. This is caused by the fact that convection is more dominant than conduction and the problem becomes hyperbolic (wave equation) like the Buckley-Leverett problem whereas it should be noted that the problem is parabolic in the production case.

Figure 13 shows the sensitivities of the sandface pressure to various reservoir parameters for the same case. Input data given in Table 1 are also valid for this case. As can be seen from Figure 13, the sandface pressure shows the greatest sensitivity to permeability at early time; to porosity during pseudo-steady state flow and after those, it shows the greatest sensitivity to skin. On the other hand, the sandface pressure shows very small sensitivity to rock thermal conductivity as expected.

Figure 14 shows the sensitivities of the sandface temperature to the same parameters for the same case. It can be seen from Figure 14 that the sandface temperature shows the biggest sensitivity to rock thermal conductivity. On the other hand, the sandface temperature is not sensitive to permeability and skin that these results are also verified with the ones observed in Figures 10 and 12. If the sensitivity behaviors of the sandface temperature to the parameters are cautiously observed, it can be seen that these responses are directly linked to the sandface temperature behaviors. As noted before from Figure 10, the sandface temperature does not change so much (almost unchanged) at early time. Therefore, we cannot observe a sensitivity to any parameter at early time and then, it is seen that the sandface temperature shows sensitivities to the parameters except permeability and skin. The sensitivities increase up to a peak point as temperature decreases until the sandface temperature approximately reaches the injection temperature. After that, the second temperature stabilization period continues up to the end of the injection period and the sensitivities approximate to zero again.

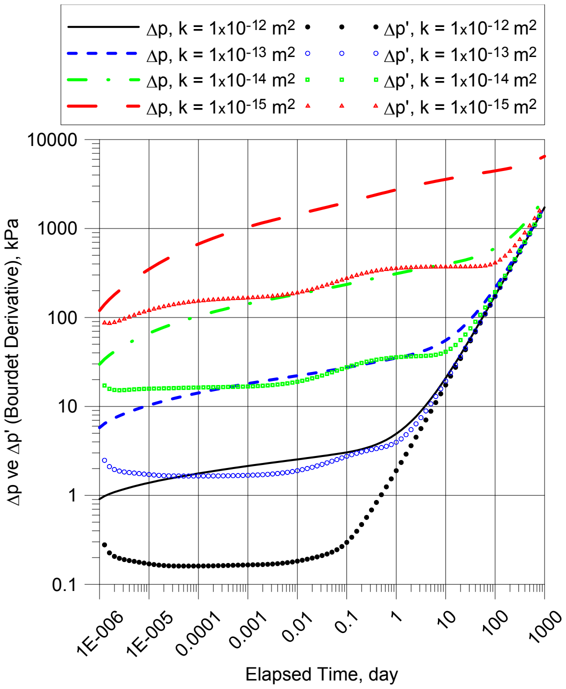


**Figure 9: Effects of permeability on the sandface delta pressure and Bourdet derivatives of a fully penetrating well injecting at a constant-rate.**

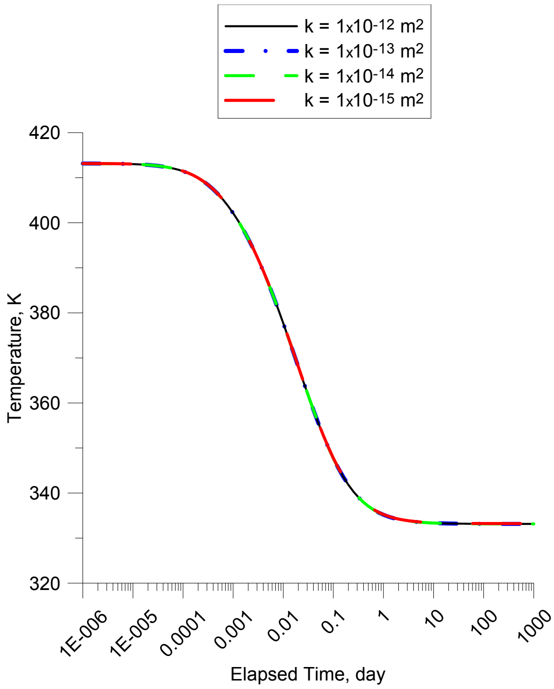


**Figure 10: Effects of permeability on the sandface temperature of a fully penetrating well injecting at a constant-rate.**

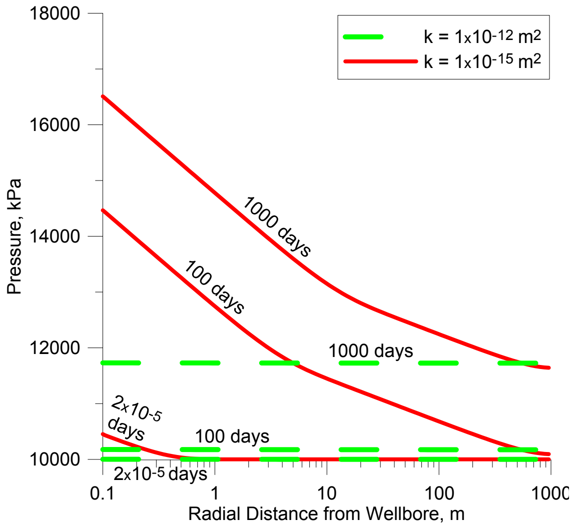


**Figure 11: Effects of permeability on the pressure along radial distance from wellbore at certain times during injection at a constant-rate from fully penetrating well.**

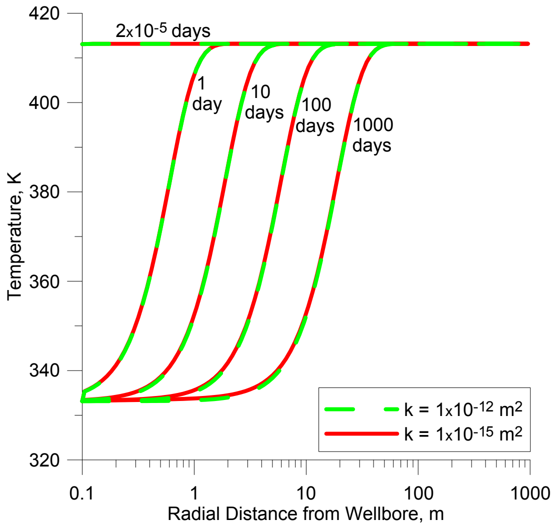


**Figure 12: Effects of permeability on the temperature along radial distance from wellbore at certain times during injection at a constant-rate from fully penetrating well.**

**3.5 Effects of Permeability and Skin on the Sandface Temperature for Constant-Pressure Injection Case**

In this case, colder water with $T_{inj}$ = 333.15 K (60°C) is injected from fully penetrating well into the reservoir with $p^0$ = 5000 kPa and $T^0$ = 413.15 K (140°C) at a constant-sandface pressure of 10000 kPa during 1000 days and the sandface temperature responses in the reservoirs with changing permeability and skin are investigated. The other reservoir and well properties are as given in Table 1. In these cases, it should be noted that flow rate into the reservoir at constant-pressure injection is to change (to decrease even though it is not shown here) with time and so, the behaviors of injection rate vary depending on the permeability and skin.

As can be seen from Figures 15 and 16, the sandface temperature changes depending on both permeability and skin values. This is caused by the fact that different amounts of fluid enter the reservoir depending on permeability and skin values. As for the permeability case observed in Figure 15, cold water front moves slower through the reservoir because flow rate to be injected into the reservoir decreases. Hence, the sandface temperature drop gets slower in a reservoir system with lower permeability. The similar results are also valid for the skin case observed in Figure 16.

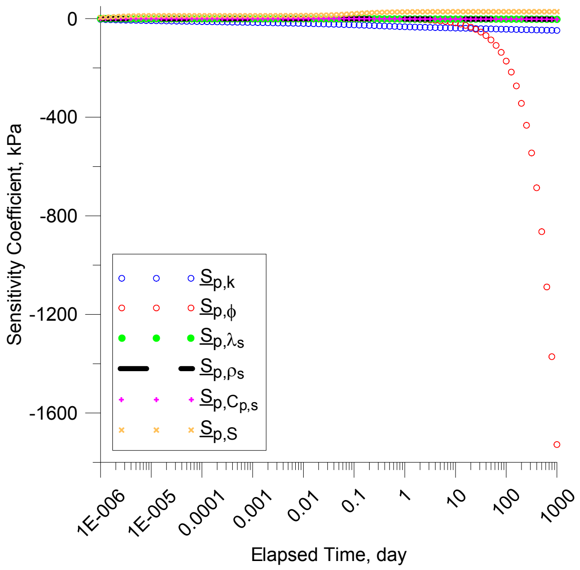


**Figure 13: Sensitivities of the sandface pressure to various rock parameters for an injection case at a constant-rate from a fully penetrating well.**

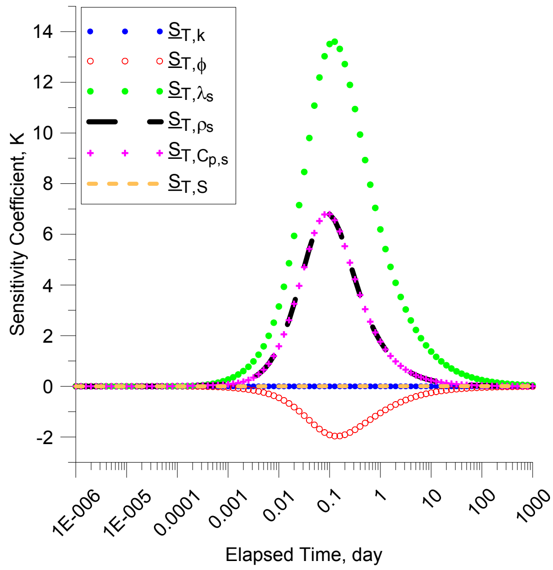


**Figure 14: Sensitivities of the sandface temperature to various rock parameters for an injection case at a constant-rate from a fully penetrating well.**

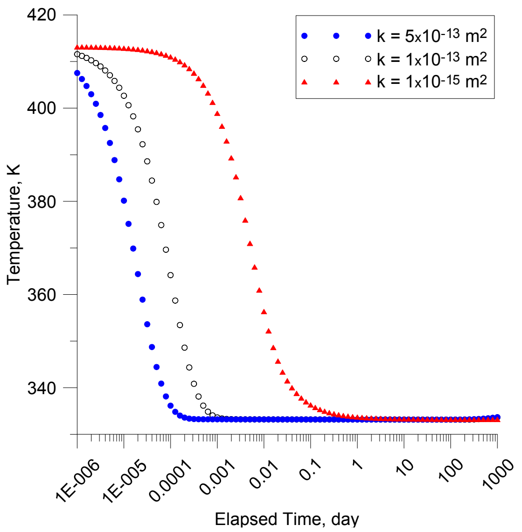


**Figure 15: Effects of permeability on the sandface temperature of a fully penetrating well injecting at constant-pressure.**

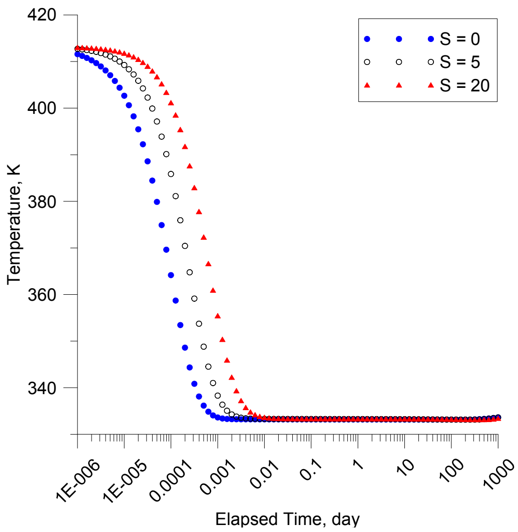


**Figure 16: Effects of skin on the sandface temperature of a fully penetrating well injecting at constant-pressure.**

### 3.6 Effects of Anisotropy on the Sandface Pressure and Temperature for an Injection-Falloff Case

Here, the effects of anisotropy (different permeability in the *r* and *z*-directions) on the sandface pressure and temperature at an observation point (probe) are investigated when cold water is injected into a limited-entry well with a packer-probe configuration shown in Figure 17. In this application, a shut-in period of 10 days following an injection period of 10 days is designed. In the injection period, cold water with $T_{inj}$ = 333.15 K (60°C) is injected into the reservoir with $T^0$ = 413.15 K (140°C) at a constant-rate of 1 kg/s during 10 days.

Shown in Figures 18 and 19 are the effects of anisotropy on the sandface pressure and temperature at an observation point (probe). As is seen from Figure 18, resistance to injection decreases with increasing permeability. Hence, the sandface pressure at the probe for the reservoir with higher horizontal permeability is lower than that for the reservoir with lower horizontal permeability. In Figure 19, a similar effect on the temperature behavior can also be observed. Colder temperature front reaches the probe faster in the reservoirs with lower horizontal permeability. This is caused by the fact that the cold water front tends to move vertically if vertical permeability is higher than the horizontal permeability. On the other hand, the reason for that the sandface temperature at the probe for the reservoir with with $k_r = 1\times10^{-14}$ m$^2$ and $k_z = 1\times10^{-13}$ m$^2$ keeps on cooling during fall-off period is due to the fact that cooling front reaches the probe lately with the effect of low permeability during injection. Therefore, the probe temperature sustains cooling during falloff period.

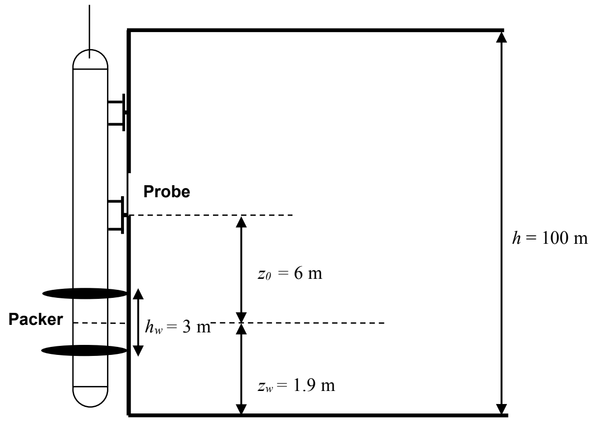


**Figure 17: Illustration of a probe configuration of a packer-probe wireline formation tester for a vertical well.**

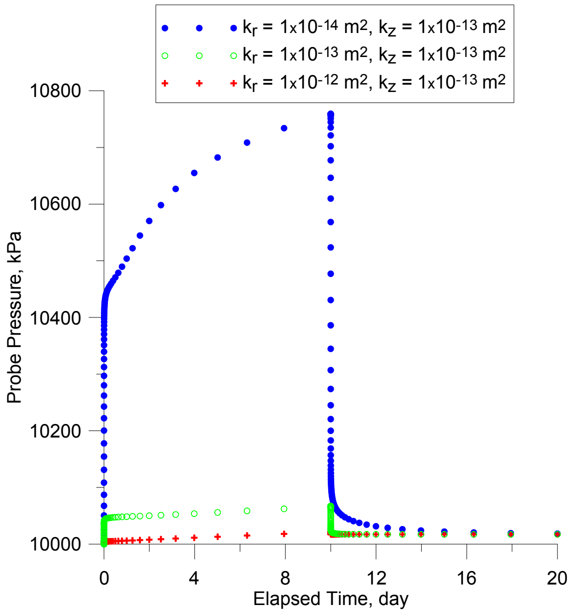


**Figure 18: Probe pressure comparisons of three different anisotropy configurations for an injection-falloff case.**

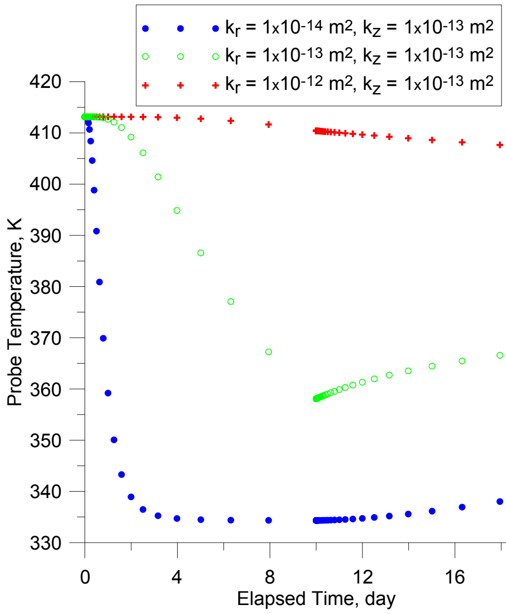


**Figure 19: Probe temperature comparisons of three different anisotropy configurations for an injection-falloff case.**

## CONCLUSIONS

It is observed that the temperature actually behaves non-isothermally during production, although not by a large amount, temperatures tend to change accordingly with the pressure behavior. During production, the temperature shows an initial decrease because of the expansion of water around the wellbore. Then, an increase is observed due to the Joule-Thomson effect which overcomes the effect of the expansion. Finally, a second decrease is observed when pseudo-steady state is observed and an overall expansion happens in the reservoir. However, it was observed that the sandface temperature changes for most of the constant-rate cases studies including fully and limited-entry wells do not exceed 2 to 3 K.

The parameters showing the highest sensitivity to the pressure behavior for the constant-rate production schemes are skin and radial permeability. The same can also be said for the temperature behavior since it is the change in pressure that causes the non-isothermal behavior of the system.

During constant-rate injection, the sandface pressure shows the greatest sensitivity to permeability at early time and to porosity during pseudo-steady state flow whereas it shows very small sensitivity to rock thermal conductivity. Conversely, the sandface temperature shows the greatest sensitivity to rock thermal conductivity whereas it is not sensitive to permeability and skin.

When a colder fluid is injected into the reservoir, the injection rate is the parameter that dominates the sandface temperature behavior since it is the rate that determines just how much heat is added into the reservoir. Hence, no matter what the permeability or skin is, since the rate is constant, the sandface temperatures are not observed to change. It is also found that the effect of Joule-Thomson on temperature is not observed for injection cases. If injection is to be performed at a constant-pressure, then the skin and permeability affect the sandface temperature behavior since in such a case, the rates actually change with different skin or permeability.

When injection is performed at a constant-rate, the temperature at an observation point can be affected by the anisotropy in permeability since depending on anisotropy, the movement of the temperature front in the reservoir may change.

**ACKNOWLEDGEMENTS**

We would like to thank the Scientific and Technological Research Council of Turkey (TUBITAK, Project No: 110M482) and the Unit of ITU (Istanbul Technical University) Scientific Research Projects for the supports that they supply to finance this work. Some parts of this work consist of the PhD thesis of the first author.

**REFERENCES**

App, J.F.: Nonisothermal and Productivity Behavior of High Pressure Reservoirs, *SPE Journal*, **15**, (2010), 50-63.

Atkinson, P.G., and Ramey, H.J.Jr.: Problems of Heat Transfer in Porous Media, the 52nd SPE Annual Fall Technical Conference and Exhibition, Denver, Colorado (1972).

Bourdet, D., Ayoub, J.A., and Pirard, Y.M.: Use of Pressure Derivative in Well-Test Interpretation, *SPE Formation Evaluation*, **4**, (1989), 293-302.

Coats, K.H: Geothermal Reservoir Modelling, the 52nd SPE Annual Fall Technical Conference and Exhibition, Denver, Colorado (1977).

Crookston, R.B., Culham, W.E., and Chen, W.H.: A Numerical Model for Thermal Recovery Processes, *SPE Journal*, **19**, (1979), 37-58.

Duru, O.O., and Horne, R.N.: Modelling Reservoir Temperature Transients and Reservoir-Parameter Estimation Constrained to the Model, *SPE Reservoir Evaluation & Engineering*, **13**, (2010a), 873-883.

Duru, O.O., and Horne, R.N.: Joint Inversion of Temperature and Pressure Measurements for Estimation of Permeability and Porosity Fields, SPE Annual Technical Conference and Exhibition, Florence (2010b).

Duru, O.O., and Horne, R.N.: Combined Temperature and Pressure Data Interpretation: Applications to Characterization of Near-Wellbore Reservoir Structures, SPE Annual Technical Conference and Exhibition, Denver, Colorado (2011).

Lauwerier, H.A.: The Transport of Heat into an Oil Layer Caused by the Injection of Hot Fluid, *Journal of Applied Science Research*, **5**, (1955), 145-150.

Lippmann M.J., Tsang, C.H., and Witherspoon, P.A.: Analysis of the Response of Geothermal Reservoirs under Injection and Production Procedures, the 47th SPE Annual California Regional Meeting, Bakersfield, CA (1977).

Miller, C.W.: Wellbore Storage Effects in Geothermal Wells, *SPE Journal*, **20**, (1980), 555-566.

Onur, M., Sarak, H., Tureyen, O.I., Cinar, M., and Satman, A.: A New Non-Isothermal Lumped Parameter Model for Low Temperature, Liquid Dominated Geothermal Reservoirs and its Applications, *Proceedings*, 33rd Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, CA (2008).

Palabiyik, Y.: Pressure and Temperature Behaviors of Single-Phase Water Geothermal Reservoirs under Various Production/Injection Schemes, ITU Graduate School of Science Engineering and Technology, PhD (2013).

Palabiyik, Y., Tureyen, O.I., Onur, M., and Deniz, M.: A Study on Pressure and Temperature Behaviors of Geothermal Wells in Single-Phase Liquid Reservoirs, *Proceedings*, 38th Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, CA (2013).

Ramazanov, A.S., Valiullin, R.A., Sadretdinov A.A., Shako, V.V., Pimenov, V.P., Fedorov, V.N., and Belov, K.V.: Thermal Modeling for Characterization of Near Wellbore Zone and Zonal Allocation, SPE Russian Oil and Gas Technical Conference and Exhibition, Moscow(2010).

Sui, W., Zhu, D., Hill, A.D., and Ehlig-Economides, C.: Model for Transient Temperature and Pressure Behavior in Commingled Vertical Wells, SPE Russian Oil and Gas Technical Conference and Exhibition, Moscow (2008a).

Sui, W., Zhu, D., Hill, A.D., and Ehlig-Economides, C.: Determining Multilayer Formation Properties from Transient Temperature and Pressure Measurements, SPE Annual Technical Conference and Exhibition, Denver, Colorado (2008b).

Tureyen, O.I., Onur, M., and Sarak, H.: A Generalized Non-Isothermal Lumped Parameter Model for Liquid Dominated Geothermal Reservoirs, *Proceedings*, 34th Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, CA (2009).

Toronyi, R.M., and Farouq, A.: Two-phase, Two-Dimensional Simulation of a Geothermal Reservoir, *SPE Journal*, **17**, (1977), 171-183.

Whiting, R.L., and Ramey, H.J.Jr.: Application of Material and Energy Balances to Geothermal Steam Production, *Journal of Petroleum Technology*, **21**, (1969), 893-900.