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Analyzing the impact of mineral precipitation from geothermal water on the injectivity of wells

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ABSTRACT

The geothermal waters present in different geological structures may vary. They can provide freshwater and water with low dissolved mineral content (brackish water, 1–10 g/ dm^3), saline water (10–30 g/ dm^3) as well as brine with mineral contents exceeding 30 g/ dm^3. Cooling water during the operation of a geothermal system can lead to precipitation of a solid phase from the water, which subsequently enters the injection well, substantially impacting its injectivity. The paper reports the findings of a study examining the influence of varying temperatures and pressures on the precipitation of solid phases from geothermal water. The data obtained were utilized to simulate the permeability alteration in the near-well zone during injection using transient flow analytical models. The outcomes derived from the modeling will be validated by the laboratory test results of solid-phase water flow under reservoir conditions utilizing the presented laboratory system.

1. INTRODUCTION

The geothermal waters found in various geological formations may differ. In natural conditions, one can expect brackish waters (1-10 g/dm^3), salty waters (10-30 g/dm^3) and brines with significant mineralization - above 30 g/dm^3. Polish geothermal waters exhibit significant variety in this aspect. Geothermal waters accessed by boreholes in Poland include fresh, low, medium, and highly mineralized varieties, with mineralization levels ranging from below 1 g/dm^3 to over 160 g/dm^3 (Tomaszewska et al., 2018).

The primary geothermal water resources in the Polish Lowlands are linked to Mesozoic aquifers. Geothermal waters collect in sandy deposits of the Lower Cretaceous and Lower Jurassic periods (Bujakowski et al., 2024). The Stargard GT-2 well (NW part of Poland) in the Lower Jurassic reservoir produces Cl-Na, I, F, and Fe fluids with a mineralization of 114-133 g/ dm^3 and an outflow temperature of 68°C. The geothermal waters from wells Toruń TG-1 and TG-2 are classified as Cl-Na, with mineralization levels of 97–120 g/dm^3 and an outflow temperature of 60°C. The Konin GT-3 well (central Poland) produces water at an outflow temperature of 92°C, classified as Cl-Na/SO4-F-Na type, with a mineralization of 150 g/dm^3 (Bujakowski et al., 2024). In the Skierniewice GT-1 and GT-2 wells, the produced water is characterized as Cl-Na, with a mineralization of 110 g/dm^3 and an outflow temperature of 69°C (Kępińska et al., 2011). Highly mineralized brines are present in the Lower Cretaceous reservoir, shown by the Kolo GT-1 well, where the mineralization in Cl-Na water reaches 95 g/dm^3 at an outflow temperature of 85°C (Bujakowski et al., 2024). In such cases, the complexity of chemical interactions during the reinjection of cooled geothermal water and the alteration of mineral composition, which results in variations in porosity and permeability in the geothermal reservoir due to water-rock interactions, are significant contributors to injectivity issues. Injection-related issues have been extensively researched in oil and gas reservoirs (Luo et al., 2023), and subsequently in deep geothermal reservoirs and thermal aquifer storage systems (Luo et al., 2023).The interaction between water and products precipitated from it, and rock within a geothermal reservoir, is the primary driver of loss of injectivity during geothermal fluids reinjection. In addition, this effect is enhanced by changes in the physical properties of water as a function of temperature (e.g., viscosity and density) or the way the reservoir is exposed. However, the primary process for permanently reducing injectivity is clogging due to physical, chemical and biological processes. (Luo et al., 2023). The effect of these processes can be represented by a skin effect, which will be a function of temperature, pressure, amount of mineral precipitation and injection time.

The paper presents an analytical model of the water injection process into the reservoir, which includes flow in the wellbore and reservoir and a model of skin effect propagation. The model is examined on one of the Polish geothermal water injection wells and calibrated based on the injection test results.

2. MODEL FOR INJECTIVITY ESTIMATION

The mathematical model employed to assess the quantitative impacts resulting from the injection of water into a deep geothermal system considers: water mineralization, flow resistance in the injection well, resistance related to the water injection into the reservoir, resistance in the near-bore zone due to damage, the influence of alterations in the properties of the injected water on injection pressure, and the effect of heat exchange between the water and the surrounding rock matrix. The indicator of changes in a well's injectivity is the variation in water pumping pressure, which can be expressed as follows:

$$P_{in} = P_r + \Delta P_r + \Delta P_{skin} + P_f - P_H \tag{1}$$

where:
P_{in} – wellhead injection pressure [Pa],

P_r – reservoir pressure [Pa],
ΔP_r – increment of pressure due to reservoir deliverability [Pa],
ΔP_{skin} – pressure loss due to skin effect [Pa],
P_f – pressure loss due to friction in well [Pa],
P_H - hydrostatic pressure of the injected water [Pa].

Since we inject cold water into a hot reservoir, the water and rock will exchange heat as it flows through the well. It will result in a change in the temperature of the water and thus its properties, such as density and viscosity. Therefore, parts of the injection pressure, like frictional pressure loss, the fluid's hydrostatic pressure, or the rise in pressure due to the reservoir deliverability, will depend on the input parameters of the injected water. The temperature differential between the water and the rock formation was computed iteratively in the employed mathematical model (Tomaszewska et al., 2018). The natural rock temperature is assessed based on the geothermal gradient before the well starts to be utilized. The well length is segmented into sections to estimate temperature and water parameters. The inlet temperature is identical to the injection temperature for the first element. For the subsequent elements, the entrance temperature is equivalent to the outlet temperature from the prior section. The water density (ρ) at a specific pressure (P), temperature, and salinity (S) was computed using formulae valid across the entire spectrum of mineralization, with temperatures reaching 127°C and pressures up to 34.5 MPa (McCain, 1991).

The semilogarithmic relationship between pressure and distance indicates that the state of the near-wellbore area is crucial. The pressure required to inject the fluid into a water-bearing layer takes into account the so-called skin effect, described by the skin effect factor S. The skin effect factor is a conventional metric for formation damage, representing a hydrodynamic parameter that quantifies the increased resistance to fluid flow in the near-borehole region of the reservoir, resulting in diminished production (or injection) compared to the ideal well. The well skin effect is a composite variable that can be categorized into the following types (Patel and Singh, 2016; Kjaran and Eliasson, 1983; Beggs, 1991):

1. The mechanical or formation skin factor (S_d)
2. Completion pseudo skin factor (S_p)
3. Partial penetration skin factor (S_{pp})
4. Geometrical pseudoskin factor (S_g)
5. Multiphase pseudoskin factor (S_m)
6. Non-Darcy flow or Rate-dependent high velocity or turbulent flow pseudoskin factor (S_{turb})
7. Thermal skin factor S_T.

During the injection of water under the conditions of Polish geothermal reservoirs, we deal with single-phase flow, and following Darcy's law, so the components associated with these phenomena (S_m, S_{turb}) were omitted from the model. Vertical, an open hole injection well was also assumed, so completion pseudo skin (S_p) and geometrical skin (S_g) were also omitted from the model, reducing the relationship to the form:

$$S = S_d + S_{pp} + S_T \tag{2}$$

The mechanical skin factor is described by Hawkins' formula in the form (Lu et al., 2024; Patel and Singh, 2016):

$$S_d = \left(\frac{k}{k_s} - 1\right) \cdot ln\left(\frac{r_s}{r_w}\right) \tag{3}$$

The equation assumes a reduction in reservoir permeability (k) to the value (k_s) in the damaged zone of the range (r_s). However, during the injection of cooled geothermal water, precipitated solids will be continuously deposed, resulting in a change in the permeability and extent of the damaged zone. To account for permeability variability, the model proposed by Bachman was used [Bachman et al., 2003; Orlov and Koroteev, 2019; Orlov et al., 2018):

$$\frac{k_s}{k} = \frac{R_{min} \cdot \alpha \cdot \left(\frac{Q_{in} \cdot t}{A}\right)^n + 1}{\alpha \cdot \left(\frac{Q_{in} \cdot t}{A}\right)^n + 1} \tag{4}$$

From relation (4), the permeability changes as a function of the time of pumping geothermal water into the reservoir can be determined as:

$$k_s(t) = \frac{k \cdot \left[R_{min} \cdot \alpha \cdot \left(\frac{Q_{in} \cdot t}{A} \right)^n + 1 \right]}{\alpha \cdot \left(\frac{Q_{in} \cdot t}{A} \right)^n + 1} \quad (5)$$

where:
α, n, and R_{min} - the parameters of the model,
Q_{in} – injection rate [m^3/s],
A – flow area [m^2],
t – time of injection [s].

Parameter α represents the intensity of the damage, n changes the shape of the damage curve. R_{min} sets an asymptotic limit for permeability reduction ($k_{min} = k \cdot R_{min}$) (Orlov et al., 2018). The volume of the damaged zone around the well will depend on the injection rate and the intensity of sediment precipitation from the water:

$$V_d(I_p, t) = \frac{I_p \cdot Q_{in} \cdot t}{\rho_d} \quad (6)$$

The damaged zone radius is then:

$$r_s(I_p, t) = \sqrt{\frac{\pi \cdot r_w^2 \cdot h + V_d(I_p, t)}{\phi \cdot \pi \cdot h}} \quad (7)$$

where:
I_p - intensity of sediment precipitation [kg/m^3],
ρ_d – solid sediments density [kg/m^3],
h – reservoir thickness [m],
ϕ – rock porosity [-]

The value of the intensity of the sediment precipitation factor depends on water mineralization and pressure-temperature changes. It can be determined by a laboratory experiment or calculated with geochemical software (Tomaszewska et al., 2018).

The partial penetration skin factor (S_{pp}) is represented in the model by a formula (Beggs, 1991):

$$S_{pp} = \left(\frac{h}{h_p} - 1 \right) \cdot \left(ln\left(\frac{h}{r_w} \cdot \sqrt{\frac{k_h}{k_v}} \right) - 2 \right) \quad (8)$$

where:
k_h – horizontal permeability [m^2],
k_v – vertical permeability [m^2],
h_p – open reservoir thickness [m],
r_w – well radius [m].

The formula proposed by (Kjaran and Eliasson, 1983) was used to determine the thermal skin factor (S_T) in the form:

$$S_T = \frac{\mu_{Tin}}{\mu_{Tr}} \cdot \frac{\rho_{Tr}}{\rho_{Tin}} \cdot ln\left(\frac{r_T}{r_w} \right) \quad (9)$$

where:
μ_{Tin}, μ_{Tr} – respectively water viscosity at injection (downhole) and reservoir conditions [Pas],
ρ_{Tin}, ρ_{Tr} - respectively water density at injection (downhole) and reservoir conditions [g/m^3],
r_T – radius of the cooled zone [m].

The radius of the cooled zone represents the cold water front range assuming piston displacement (Kjaran and Eliasson, 1983), and is determined from the relationship:

$$r_T = \sqrt{\frac{\beta \cdot Q_{in} \cdot t}{\pi \cdot h}} \quad (10)$$

where:

$$\beta = \frac{\rho_w \cdot C_w}{(1-\phi)\cdot(\rho_r \cdot C_r) + \phi\cdot(\rho_w \cdot C_w)} \tag{11}$$

ρ_w, ρ_r - respectively water and rock density at reservoir conditions [kg/m^3],
C_w, C_r - respectively water and rock heat capacity at reservoir conditions [J/kg·K].

Taking into account the relationships (3) - (11) in equation (2), the final skin effect can be presented as a function of three primary parameters: time, the temperature of the injected water, and the intensity of sediment precipitation. It was used to determine the changes in injection pressure in the form:

$$S(t, I_p, T_{in}) = S_d(t, I_p) + S_{pp} + S_T(t, T_{in}) \tag{12}$$

Inserting equation (12) into the classical relationship for pressure losses associated with skin effect (Horne, 1995; Kutasov and Eppelbaum, 2016), one gets:

$$\Delta P_{skin}(t, I_p, T_{in}) = S(t, I_p, T_{in}) \cdot \frac{Q_{in} \cdot B_w \cdot \mu_w}{2 \cdot \pi \cdot k \cdot h} \tag{13}$$

where:
B_w, μ_w – respectively water volume factor [-] and water viscosity [Pa·s] at injection (downhole) conditions.

The hydrostatic pressure (P_H) of the water is calculated considering changes in water density due to temperature changes along the length of the well caused by heat exchange with the surrounding rocks. The calculation of frictional pressure loss in the well (P_f) considers both the nature of the flow and changes in viscosity and density due to temperature changes (Tomaszewska et al., 2018).

Reservoir deliverability is defined as the rate of water production or injection achievable from or into a reservoir at a specified bottom-hole pressure. It significantly influences the deliverability of a well. Reservoir deliverability is contingent upon several factors, including reservoir pressure, pay zone thickness, permeability, and the characteristics of both the reservoir and injection fluids. Reservoir deliverability can be quantitatively estimated based on flow regimes. The increment of pressure due to reservoir deliverability (ΔP_r) for steady-state flow can be expressed as (Ahmed, 2000):

$$\Delta P_r = \frac{Q_{in} \cdot B_w \cdot \mu_w}{2 \cdot \pi \cdot k \cdot h} \cdot ln\left(\frac{r_e}{r_w}\right) \tag{14}$$

For transient flow, is described by the general equation in the form of (Ahmed, 2000; Kutasov and Eppelbaum, 2016):

$$\Delta P_r = \frac{Q_{in} \cdot B_w \cdot \mu_w}{4 \cdot \pi \cdot k \cdot h} \cdot \int_x^\infty \frac{e^{-u}}{u} du \tag{15}$$

where:

$$x = \frac{\phi \cdot \mu_w \cdot c_t \cdot r_w{}^2}{4 \cdot k \cdot t}$$

c_t – formation compressibility factor [1/Pa],

Considering the influence of temperature and precipitated sediment on a several parameters affecting flow in the reservoir, it is reasonable to assume transient flow when analyzing injection pressure in a geothermal well. In this case, the parameters such as water viscosity, water volume factor, and formation compressibility factor in equation (15) will depend on the temperature and pressure at the bottom of the well, thus from the injection temperature, as well as time:

$$\Delta P_r(t, T_{in}) = \frac{Q_{in} \cdot B_w(T_{in}) \cdot \mu_w(T_{in})}{4 \cdot \pi \cdot k \cdot h} \cdot \int_{x(t, T_{in})}^\infty \frac{e^{-u}}{u} du \tag{16}$$

Finally, equation (1) takes the form:

$$P_{in}(t, T_{in}, I_p) = P_r + \Delta P_r(t, T_{in}) + \Delta P_{skin}(t, I_p, T_{in}) + P_f(T_{in}) - P_H(T_{in}) \tag{17}$$

The model is solved iteratively for the flow in the discretized well and then in a time loop for the flow in the reservoir. Heat exchange calculations in the well are coupled with flow calculations.

3. ANALYSIS OF INJECTION PRESSURE VARIATIONS FOR A SELECTED GEOTHERMAL WELL IN POLAND

One of the prospective geothermal areas in Poland is the Skierniewice city region. There are two geothermal wells in the area: Skierniewice GT-1 and Skierniewice GT-2. These wells are located in the southwestern part of the Warsaw Basin and provide access to the Lower Jurassic geothermal reservoir. The Skierniewice GT-2 well is to function as an injection well. The geothermal water reservoir there is located at a depth of 2771-2886 m below ground level; the water temperature is 68.2°C with mineralization at 110 g/dm³ (Kępińska et al., 2011). Several tests were carried out in the well, including an injection test, the results of which proved unsatisfactory (a significant increase in pumping pressure) (Kępińska et al., 2011). The model presented above was used to analyze changes in pumping pressure. In the calculations, the data from the test was used; the model calibration was carried out to the pumping pressure measurements (Kępińska et al., 2011). Table (1) shows the key data used in the **calculations**.

Table 1: The main data used in the calculations.

Item	Value
Injection rate [m^3/hr]	30
Injection temperature [°C]	50
Reservoir temperature [°C]	68.2
Rock permeability [mD]	210
Intensity of sediment precipitation [kg/m^3]	0.063
Water mineralization [g/dm^3]	110

Water parameters such as density, viscosity, compressibility, and volume factor were calculated as a function of temperature and pressure for saline water. Figure 1 shows the changes in density and viscosity of water in the well as a function of depth after 2400 hours of injection.

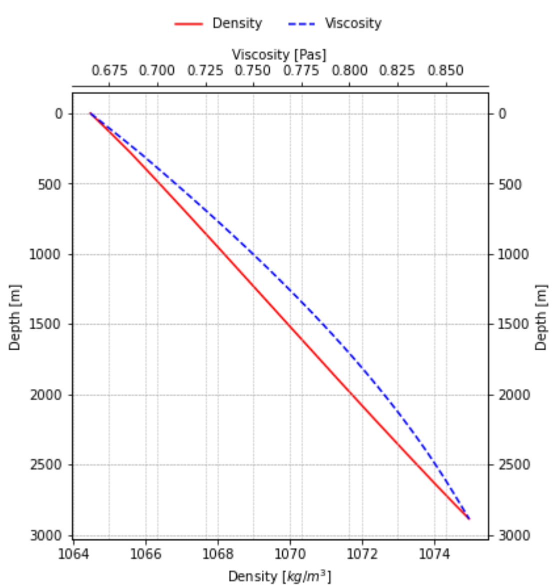


Figure 1: Density and viscosity of water distribution in the well after 2400 hours of injection.

Initial pressure and temperature distribution in the well are presented in figure 2. The temperature distribution shows the temperature in the surrounding rocks; the pressure distribution shows the water level in the well, located at a depth of 125 meters.

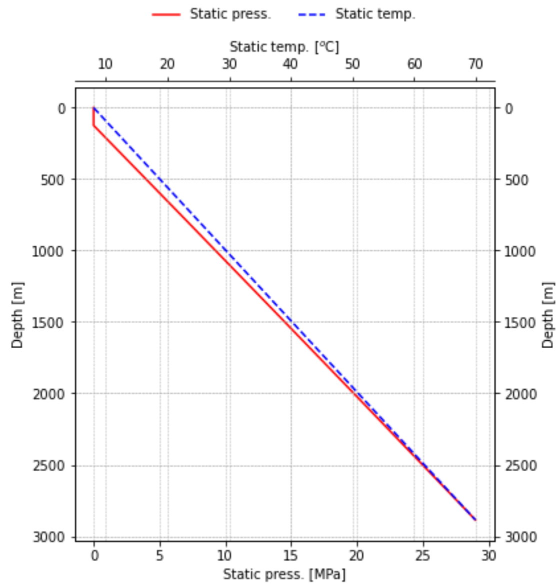


Figure 2: Initial pressure and temperature distribution in the well.

The flow of injected water causes heat exchange between the fluid and surrounding rocks and a change in temperature with depth, as shown in Figure 3. At the upper part of the well, the injected water cools, and at a depth of about 1700 meters, the temperature begins to rise, reaching 47.3°C after 2400 hours of pumping, which is still lower than the temperature of the water at the wellhead. The figure also shows a significant increase in pressure compared to static conditions.

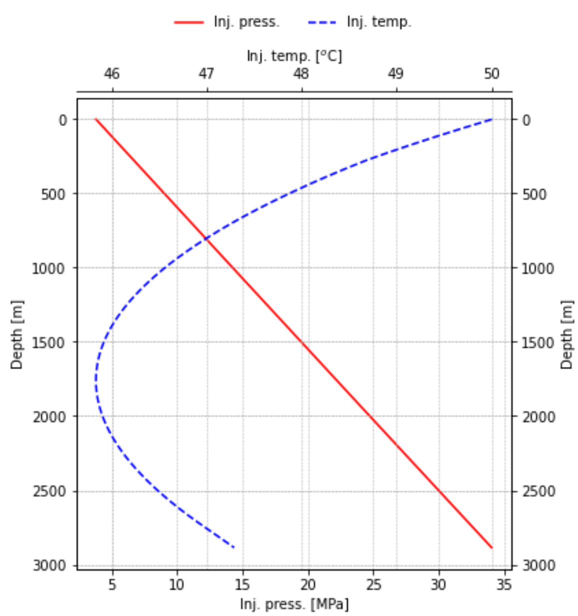


Figure 3: Pressure and temperature distribution in the well after 2400 hours of injection.

The parameters that determine the change in permeability of the near-wellbore zone are the coefficients in the equation (5). The variation of these parameters and the effect on permeability were analyzed in (Bachman et al., 2003). Their value can be determined from laboratory tests. In the analysis presented here, these parameters were adjusted to the measured injection pressure in the calibration process. Table (2) shows the obtained values of the model's coefficients.

Table 2: Permeability reduction model parameters after fitting.

Parameter	Value
α	0.8
n	0.9
R_{min}	0.05

The used model assumes a continuous increase in damage of the near-well zone manifested as a reduction in permeability and an increase in the damaged zone range. As a result, the resistance to flow and, consequently, the water injection pressure will increase. Figure 4 shows the increase in injection pressure over time obtained after fitting the model to measured data from the injection test. The test results have been plotted on a graph.

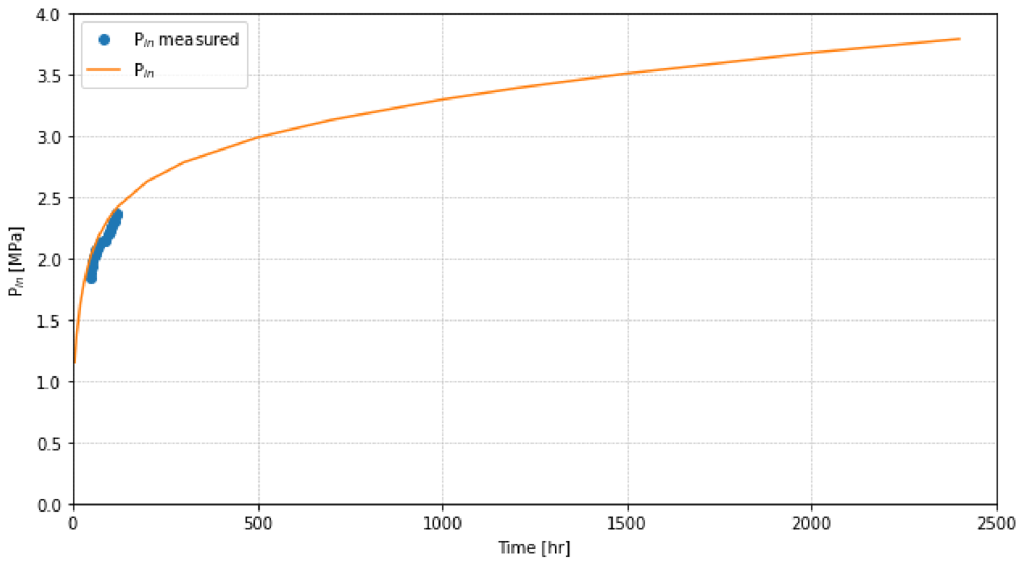


Figure 4:Calculated and measured injection pressure in well Skierniewice GT-2.

The graph demonstrates a sharp increase in injection pressure during the 72-hour recorded test period. The figure also matches the model and the measured values satisfactorily. In the further period of injection, according to the used model, the course of pressure increase has a smoother form; however, the pressure increase over the entire modeled period is significant. From an initial injection pressure of 1 MPa, it increases to a value close to 4 MPa after 2400 hours of injection. It is due to the increasing skin effect over time, the changes of which are divided into individual components and shown in Figure 5.

The graph reveals that the mechanical skin, which results from the deposition of solid sediments in the pore space and the subsequent decrease in permeability over a growing region, primarily influences the pressure change. Its value after 2400 hours of injection is above 26, which is exceptionally high. The skin associated with the partial completion of the reservoir also plays a significant role in influencing the process of injecting cooled water into the reservoir. Its value is constant but significant, amounting to 13.7. It is attributed to the limited completion of the reservoir during the drilling stage of the Skierniewice GT-2 well. The thermal effect expressed by thermal skin is much lower than the other components. Its increase is visible in the initial injection stage, and then some stabilization is observed. Nevertheless, the final value of 8.7 is also significant. In this case, however, we have limited possibilities for its reduction, because the primary influence on this value is the temperature of the injected water.

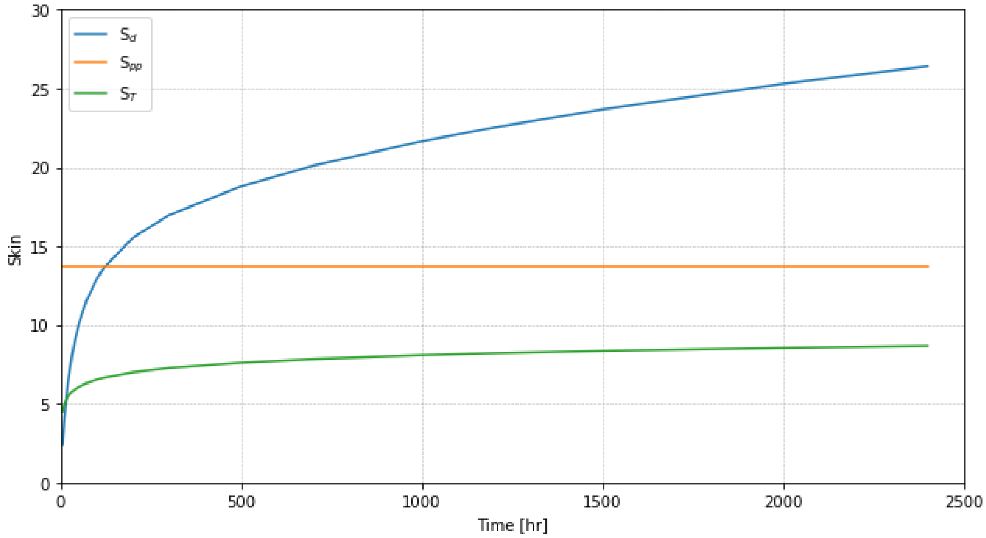


Figure 4: Changes in skin effect over time.

At such values, conducting a stable process of injecting water into the reservoir becomes challenging due to changes in the operating conditions of the surface installation, including the power of the injection pumps (Figure 5).

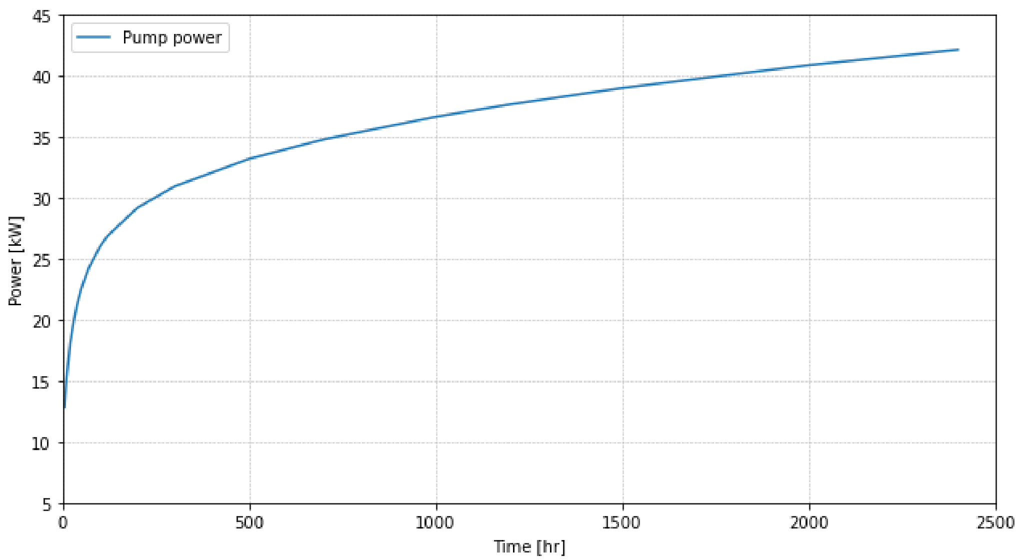
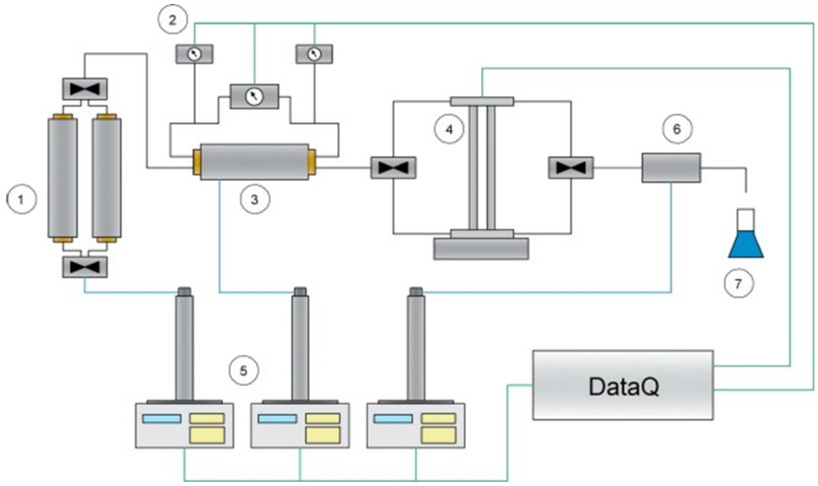


Figure 5: Changes in the power of pumps injecting cooled geothermal water over time.

The results demonstrate the relevance of solid compound precipitation to the water problem. Defining this process under specific conditions is crucial from the point of view of counteracting adverse phenomena. Therefore, a good fit for the model describing changes in the near-wellbore zone requires its calibration with both field measurements and laboratory tests on cores. An example of the laboratory setup that will be used to refine the skin effect change model is shown in Figure 6.



(1) Two movable piston type accumulators; (2) Three pressure gauges; (3) Coreholder;
(4) Acoustically monitored separator; (5) Syringe pumps; (6) Back pressure regulator;
(7) Effluents container.
Blue lines mark working fluid flow path and green lines represent signals from pressure transducers, separator and pumps.

Figure 6: The laboratory setup for refining the skin effect change model.

4. CONCLUSIONS

The results obtained as a result of modelling the process of injecting cooled geothermal waters into the Skierniewice GT-2 borehole allow the following conclusions to be formulated:

– defining the solid compounds precipitation from the water process under specific conditions is crucial from the point of view of counteracting adverse phenomena.
– due to the natural level of temperature variation in the rocks surrounding a borehole, both cooling and heating of the injected water must be taken into account. As the temperature decreases, the interval at which cooling occurs will decrease, and the interval causing water heating will increase. This information is essential from the point of view of the phenomena of secondary precipitation, corrosion, and colmatation.
– the pressure required for water injection increases over time, mainly due to the deposition of secondary precipitation and corrosion products in the near-well zone, with the fastest increase occurring at the beginning of the injection process.

The model used satisfactorily describes field observations during the injection test. However, laboratory tests based on rock cores and geothermal water samples are needed to improve validation of the model. These analyses are currently under preparation.

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