Proceedings World Geothermal Congress 2020+1
Reykjavik, Iceland, April - October 2021

Application of Wellbore Flow Modelling in Geothermal Systems - Lessons Learned from Oil and Gas Production Systems

Aris Twerda, Pejman Shoeibi Omrani, Andreas Mack, Jos van 't Westende

P.O. Box 6012, 2600 JA, Delft, The Netherlands

pejman.shoeibiomrani@tno.nl

Keywords: Geothermal doublet, multiphase flow, wellbore flow, operation, scaling, corrosion, erosion

ABSTRACT

Proper operation of geothermal wells is important for ensuring reliable heat production over their lifecycle period. The geothermal production could suffer from several production issues such as corrosion, scaling, erosion and hydrocarbon production. These issues can limit the performance of these systems. They can also lead to unstable production, a decline in the flow rates or endangering the integrity of the geothermal doublets. Similar problems are also occurring in upstream oil and gas and there are numerous studies and experimental data available to help understand, monitor and mitigate these issues.

For better identification of operational issues in geothermal wells, combining the relevant reaction and thermodynamics models with flow solvers could be of added value. The prediction of production issues such as scaling and corrosion is currently being studied globally without considering the local changes in flowing conditions in the wellbore and top-side facilities (e.g. in pumps, filters, separators). These issues could be enhanced or suppressed by changing the local pressure, temperature and flow properties of the produced geothermal fluid. Thus, detailed information on the local flow properties of the geothermal fluid in the wellbore and top-side facilities is crucial for preventing the aforementioned production issues.

In this study, simulators were employed for the multiphase flow in the wellbores which are used for assessing production issues in oil and gas wells. Several models are applied on a well which is exemplary for Dutch geothermal wells and conditions (doublet brine systems, with a temperature range of 75 to 105 ˚C). The dynamic multiphase flow solver provides useful information for the local operating conditions in the well (flow velocities, pressures and temperatures). This information was fed to the relevant models for scaling, erosion and corrosion.

The simulations showed that trends/sensitivity of scaling, erosion and corrosion to several operating parameters were captured accurately. The predicted trends by the simulator were validated with the observations from the field. The results showed the applicability and potential of wellbore flow models initially developed for oil and gas for maximizing the geothermal production while minimizing the operational and integrity risks.

1. INTRODUCTION

Within the energy transition, it is foreseen that a part of the future energy mix will be delivered by geothermal energy (in the form electricity and heat). As this is a growing sector in several countries (e.g. the Netherlands), the geothermal operators are constantly optimizing their production, (i.e. improving the gain and reliability of the geothermal doublets). However, the production from geothermal wells is often associated with operational challenges such as scaling, corrosion, reinjection, erosion and hydrocarbon production. An overview of some production issues is presented in the OpERA report (Schreiber et al., 2016). These observations are in line with other sources in literature (Wood Group, 2017; M. Antics and N. Hartog, 2015).

There are similarities in the operational issues occurring in upstream hydrocarbon production and geothermal production; furthermore, there are also some experiences available on detecting, monitoring, controlling and mitigating these issues for both oil and gas and geothermal wells. However, the applicability of tools, models and knowledge of the oil and gas domain for the geothermal domain is not straightforward. For instance, the fluid compositions are quite different, as are the temperatures.

In Figure 1 a schematic diagram of a geothermal doublet for heat production is shown. The geothermal fluid flows into the production well and arrives at the top side where it is flowing through a separator and a heat exchanger before it returns into the reservoir via the injection well. During this journey through the wells and topside equipment, the geothermal fluid will encounter different process conditions. This will have an effect on the fluids (e.g. gas exsolution at the separator or even before that, high shear conditions around the pumps, temperature drop in the heat exchanger, etc). Several parameters could affect the fluid flow behaviour and phase fractions such as:

- well trajectory, casing diameter and depth,
- fluid composition,
- depth and power of pumps (both downhole and surface injector pumps),
- separator/tank pressure

Operational challenges such as scaling, corrosion and erosion could be controlled or potentially mitigated by adjusting the operating conditions of the systems. For instance, for the calculation of scaling potential, corrosion and erosion, flow properties are needed. These are: shear rate, pressure, temperature, CO_2 concentration and flow velocity. These values will vary along the well due to diameter changes, cooling or the presence of an electrical submersible pump (ESP). Also, the scaling, erosion and corrosion will depend on the location in the well. Furthermore, operational settings such as tank pressure, ESP boosting pressure and flow rate will also determine the flow profile. By adjusting these parameters, the operator could be able to mitigate the production issues. Therefore, the description of the multiphase flow inside the wells and topside piping from the producer to the injector well is an important part in describing the whole system and coming up with an optimized decision for design or operation of the system.

The paper deals with the potential of using multiphase wellbore models for geothermal operation and production optimization. The focus will be on three issues which are commonly seen in geothermal wells. These are: scaling, corrosion and erosion. For these subjects, tools and available knowledge of the oil and gas sector will be applied on a typical Dutch well. This paper builds up as follows: the modeling approach will be detailed in section two, section three describes the (test) case and some conclusions will be drawn in section four.

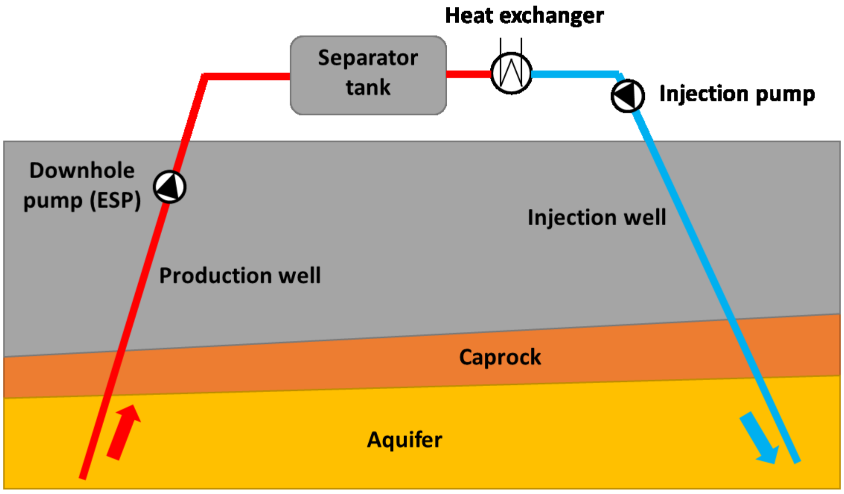

Figure 1. Schematic diagram of a doublet for hydrothermal exploitation.

2. MODELLING APPROACH

The basic model will simulate the flow properties in the well such as pressure, temperature, flowrates and composition. The model starts at the inflow from the reservoir until the separator at the top-side, which is set at constant pressure. The connection to the reservoir is modelled with a constant PI (productivity index) and constant reservoir pressure (which for further analysis could be declined). The inflow temperature is also prescribed. The local pressure, temperature, velocities and phase fractions are computed in the wellbore and top-side facilities using the multiphase mass, momentum and energy balance (further described in the next section). The result of this model is then fed into other models which can calculate the parameter of interest such are scaling, corrosion or erosion.

Multiphase flow

As a basis for our modeling approach, we start by simulating the multiphase flow inside the wellbore. This is done by solving the conservation equations for mass, momentum and energy for each field. There are several in-house and commercial multiphase flow modelling solvers available; for this task, the LedaFlow (Goldszal et al., 2007) software tool is used. This model will calculate the liquid and gas fractions in the well together with their velocities. Also, the pressure and temperature profile along the well is computed. The material properties at different pressure and temperatures are generated by the PVTsim package (PVTSim Nova™, 2018) and subsequently read in by LedaFlow.

Here a 3-phase, 9-field approach is applied. The model equations, taken from (Goldszal et al., 2007), for mass, momentum and energy (respectively) are:

$$\frac{\partial \alpha_k \rho_k}{\partial t} + \frac{\partial}{\partial x}(\alpha_k \rho_k u_k) = \sum_{i \neq k} \Gamma_{ki} + \Gamma_{kext} \tag{1}$$

$$\frac{\partial}{\partial t}(\alpha_k \rho_k u_k) + \frac{\partial}{\partial x}(\alpha_k \rho_k u_k u_k) = -\frac{\partial \alpha_k P_k}{\partial x} - \alpha_k \rho_k g \sin\theta + \frac{\partial \alpha_k \tau_k}{\partial x} + P_{\text{int}} \frac{\partial \alpha_k}{\partial x} + \sum_{i \neq k} F_{ki} - F_{kw} + \sum_{i \neq k} \Gamma_{ki} u_{ki} + \Gamma_{kext} u_{kext} \tag{2}$$

$$\frac{\partial}{\partial t}(\alpha_k \rho_k h_k) + \frac{\partial}{\partial x}(\alpha_k \rho_k u_k h_k) = \frac{\partial}{\partial x}(\alpha_k \kappa_k \frac{\partial}{\partial x} T_k) + \alpha_k \frac{DP}{Dt} + Q_{kw} + \sum_{i \neq k} Q_{ki} + \Gamma_{kext} h_{kext} \tag{3}$$

Here, k is the field index; u_k the average field velocity; t – time; x - coordinate along the pipe; α- field volume fraction; ρ- field density; Γ_{kext}- net external mass source; Γ_{ki}- net mass flow rate obtained by field k from field i.; τ_k - the shear stress of field k in the axial direction; P_k – pressure of field k; P_{int} - pressure at the large-scale interface (only for stratified flow); g- the gravity; θ - pipe inclination angle; F_{ki} - forces due to interfacial friction of field k with other fields; F_{kw} - wall friction force; u_{kext} - velocity of external mass source; h_k - enthalpy of field k; κ_k - effective thermal conductivity of field k; T_k - temperature of field k; P - system pressure (average pressure $P=\sum\alpha_k P_k$); Q_{ki} - interfacial heat transfer rate of field k with other fields; Q_{kw} - heat transfer rate of field k at pipe wall; h_{kext} - enthalpy of external mass source.

Corrosion, erosion and scaling models

For corrosion, the Norsok M 506 model ((Nyborg, 2010) was applied. The NORSOK M 506 model is an empirical model for the calculation of corrosion rates in hydrocarbon production and process systems where the corrosive agent is CO_2. The Norsok M 506 has been recently fitted to a temperature range between 5 and 150 °C and a minimum partial CO_2 pressure of 0.1bar which is in a suitable range for the conventional geothermal doublets in the Netherlands.

There are several models to assess erosion rate (Parsi et al., 2014), and three different models (The Oka model, the Tulsa and DNV model) were used to estimate the erosion rate along the production tubing with the following assumptions:

- Steel pipes
- 10% mass fraction for the solid in the water.

OLI Analyzer (Dyer, 2003) software was used to model the scaling potentials based on the ion composition of the water. Initially, ion compositions of the water (based on ICP measurements) were the input for the OLI Analyzer model. Subsequently, a reconciliation was performed making the composition electrically neutral while having the measured pH.

Figure 2 shows a typical result of the model. Here the precipitated solids of two minerals are plotted as function of temperature. We can see that the two minerals behave differently. $BaSO_4$ precipitates at low temperature while $CaCO_3$ comes out of solution at high temperature.

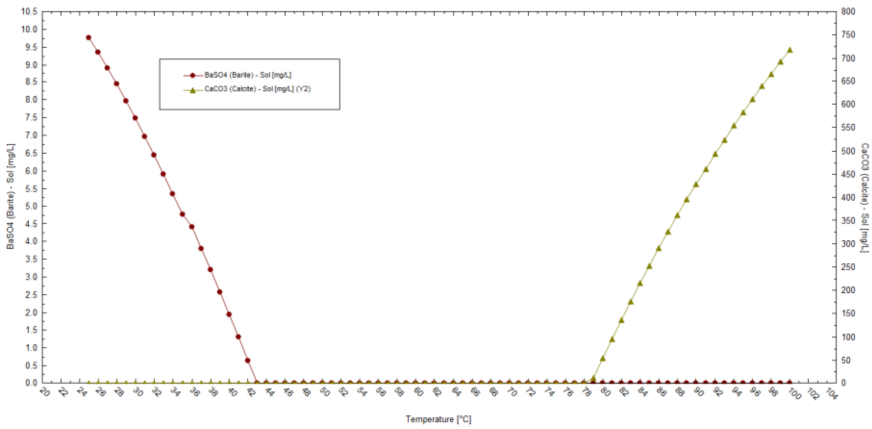

Figure 2. Precipitated solids (two minerals) as function of temperature calculated by OLI Analyzer

3. EXAMPLES/CASES

A test case was setup to assess the operational issues in geothermal wells by coupling the scaling, corrosion and erosion models. An example well completion for a typical geothermal well was used as shown in Figure 3. The well was producing in two zones (of which only one is shown in the figure) each around 100 meters in length, and an ESP was currently installed at the depth of around 500 m (MD). The depth of the well was around 2200 m and it was a deviated well.

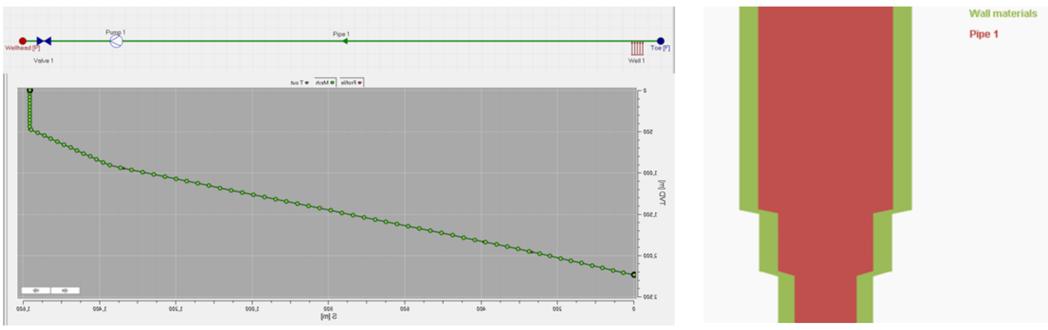

Figure 3. (left) well trajectory and (right) schematic of the well completion

The downhole temperature was assumed to be 100°C, and the top-side temperature is 15°C. The external heat-exchange coefficient (from formation to the casing) was calibrated to match the production data. CO_2 was assumed to be the only gas present, and its fraction in the brine was estimated based on an indication from the operator (1.05 m^3 gas in 1.00 m^3 of produced water, at tank pressure). The reservoir pressure, productivity index (PI) and pump boosting pressure were tuned to match the field data. In the case of more information being acquired from well tests and pump curves, more accurate calibration can be performed. The mineral content based on ICP measurements was used and a reconciliation was performed using a pH of 5.5. In order to evaluate scaling, corrosion and erosion in the system, several variations in the operating conditions were performed such as changes in separator tank pressure and pump boosting pressure. For these cases, the results are shown along the well tubing (0 indicates the bottom of the well).

Scaling

The result of the scaling model shows the precipitation of several minerals at certain pressure and temperatures. The total solid precipitations at different pressure and temperatures are shown in Figure 4. The results of the analysis from OLI Analyzer model show that, for this specific case, the precipitation was dominated by mainly three minerals:

- $CaMg(CO_3)_2$ (Dolomite)
- $CaCO_3$ (Calcite)
- $BaSO_4$ (Barite)

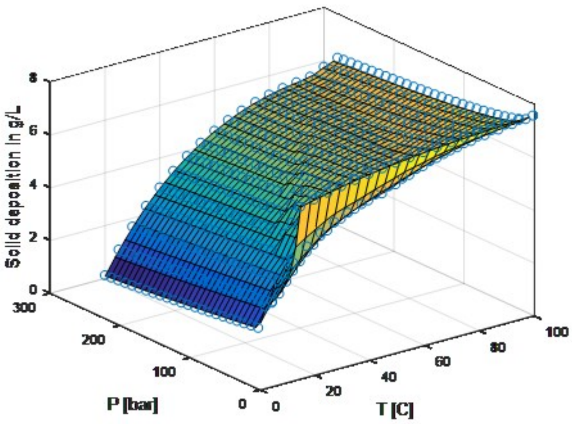

Figure 4. Solid deposition of a geothermal water composition at different pressures and temperatures

For several of the minerals, precipitation is strongly linked with the pressure which is influenced by the separator tank pressure. Thus, three cases were computed with different tank pressures. A base case and two cases with a lower / higher pressure. The results are shown in Figure 5. The bottom plot shows the temperature and pressure along the well where slight changes are visible as a result of changes in the separator tank pressure. In the top plot, the total precipitated minerals are plotted along the tubing length; it can be seen that the higher tank pressure is beneficial in terms of lowering the scaling amount. This increase in scaling behavior (for the example case in this paper) is because $CaCO_3$ precipitates more at lower pressure because CO_2 is coming out of solution.

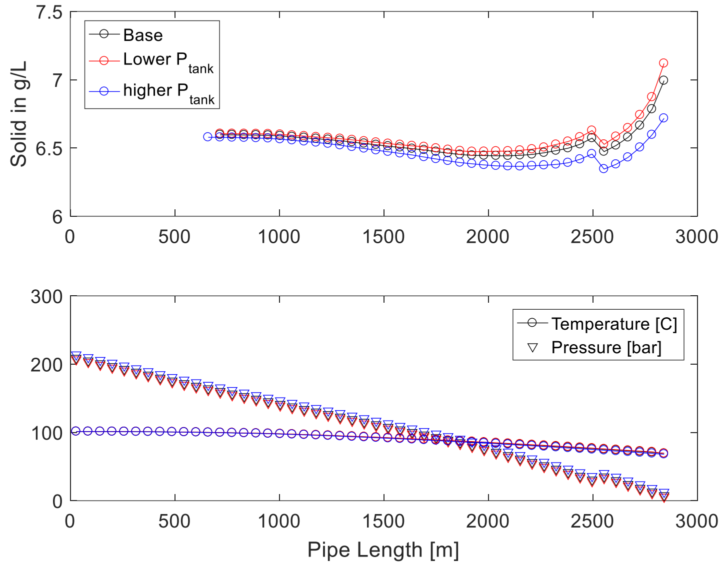

Figure 5. Pressure and Temperature along the well (bottom plot), and scaling tendency (top plot).

Corrosion

Besides its effect on $CaCO_3$ scaling, dissolved carbon dioxide also has next to scaling of CaCO3 an effect on the pH of the liquid, which could affect the corrosion. This is depicted in Figure 6, where the corrosion rate is plotted according to the Norsok model. The absolute corrosion rate values are not available due to the lack of corrosion measurement data and because the focus of the study was to observe the trends. For this reason, the normalized corrosion rate is shown and is compared to the base case corrosion rate. The lower the pH, the higher the corrosion rate which is an intuitive result. The corrosion rate that resulted from changing the separator tank pressure is shown in Figure 7. Increasing the tank pressure leads to an increase in the corrosion rate due to a higher CO_2 solubility in the brine which can reduce the pH of the brine. Also, near the ESP at the depth of 500m where higher shear rates are calculated by the model, the corrosion rate is significantly increased. A potential design optimization could be performed by adjusting the type, depth and power of the ESP in order to minimize the corrosion rate while maintaining the production flow rates. These models will enable the study and assessment of the following design and operational optimization cases.

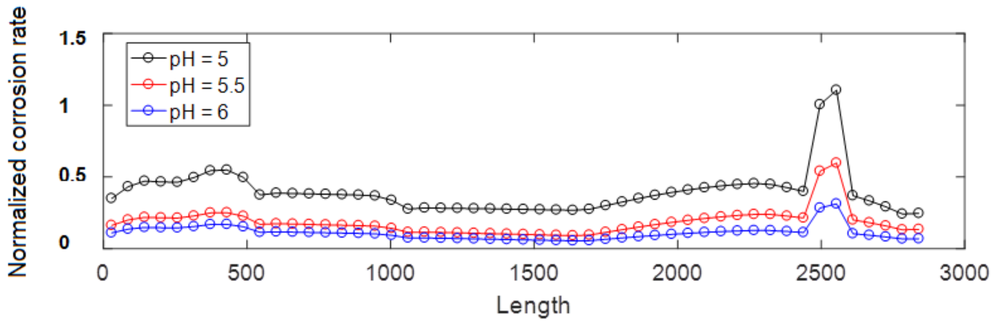

Figure 6. Corrosion rate for three different pH values along the well.

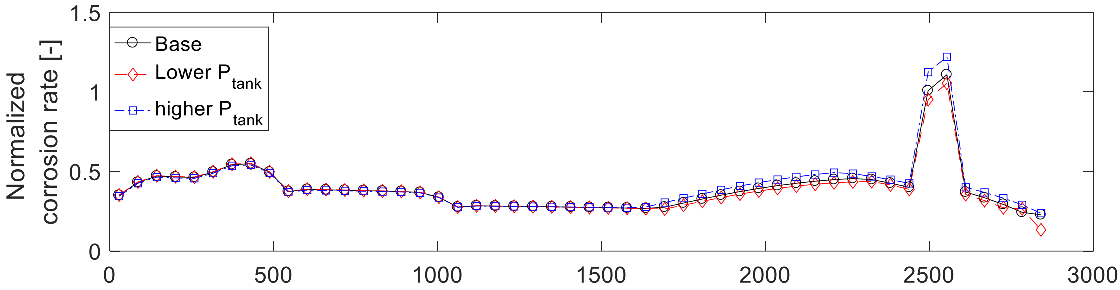

Figure 7. Normalized corrosion rate along the well length for variations in the tank pressure.

Erosion

Shear rate and flow velocity also determine the erosion rate; this is the third challenge discussed in this paper. For the three erosion models selected, the base case is evaluated. The result can be seen in Figure 8. What can be observed is that each model predicts the same trends but that the absolute values differ a lot. Higher erosion rate at the bottom of the well corresponds to a lower casing diameter at the bottom of the well. Along the tubing to the top-side, the casing inner diameter starts to increase which reduces the local fluid velocities and hence lowers the erosion rates. It can also be observed that downstream of the downhole pump (ESP) due to high shear and increase in the local velocities, the erosion rate increases again. Due to lack of erosion rate measurements, the internal parameters of different model cannot be calibrated; this leads to a discrepancy in the absolute erosion rate values. In Figure 9, the erosion rate along the well is plotted for three different cases. In this case, the pump pressure was varied. By increasing the pump boosting pressure, due to higher local shears and fluid velocities, the erosion rate increases. One important point is that the current erosion estimation is based on a fixed solid fraction dissolved in the brine (10%). An additional sensitivity analysis could be performed to assess the impact of different solid phase fractions on the erosion rate, which is an input for the particle screen size and type selection.

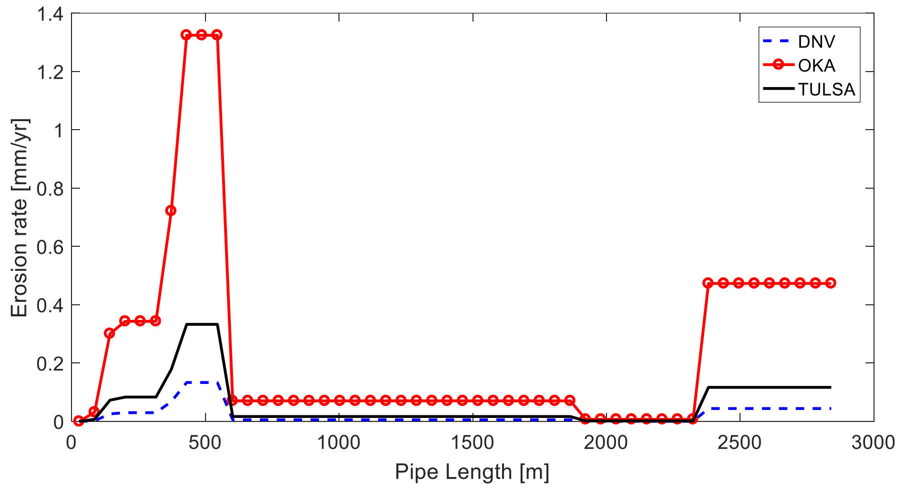

Figure 8. Erosion rate according to three different models

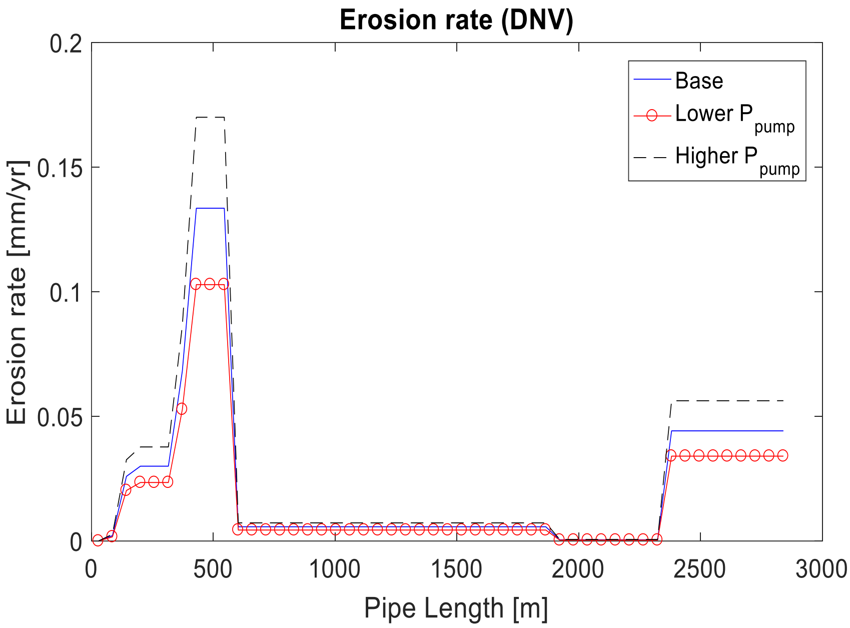

Figure 9. Erosion rate for three cases

4. CONCLUSION

The use of a multiphase wellbore flow simulator such as LedaFlow provides useful information and insights on the operating conditions which can be expected in a geothermal well during the operation. The results such as pressure, flowrates and free gas can be applied to optimize the production of geothermal doublets because evaluating different settings of operating conditions like tank pressure or ESP power can be evaluated.

Several models to estimate scaling, corrosion and erosion in the geothermal well were coupled with the multiphase flow solver. The effect of several parameters such as top-side pressure, pH and pump pressure on the operational issues were assessed. The results of the test case showed that different models give similar trends which are also observed in the field. However, the absolute values for scaling, corrosion and erosion rates require additional data/information from the field for calibrating the models. Furthermore, the models can be (highly) sensitive to their required input data, especially the geothermal fluid composition and the brine pH value.

Therefore, proper measurements and careful usage of the models are required. But, when properly applied, the models can give valuable and detailed information on where, when and how much, scale, corrosion or erosion can be expected when operating a geothermal well. Also, the models can be used to predict the effect of changes in operation of the well and can also be used as a decision-support tool.

For the near future there will be a need for model calibration for the geothermal fluid composition especially on the topics of gas liberation rate as a function of brine composition/salinity and 2-phase fluid correlation improved for low gas fractions. Next to that, the scaling model can be extended to the top-side and injection wells. Additionally, the integration with the geochemistry model in reservoir and near wellbores could be used as the next step for predicting the scaling potentials and locations. One of the topics which were not thoroughly discussed in this paper is the effect of multiphase flow resulting from co-production of hydrocarbons or gas dissolution on injectivity and performance of pumps and surface equipment.

REFERENCES

Goldszal, A., Monsen, J.I., Danielson, T.J., Bansal, K.M., Yang, Z.L, and Johansen, S.T.: LedaFlow 1D: Simulation results with multiphase gas/condensate and oil/gas field data, Proceedings, 13th International Conference on Multiphase Production Technology, 13-15 June, Edinburgh, UK, BHR Group, (2007).

Schreiber, S., Lapanje, A., Ramsak, P. and Breembroek G.(eds.), Operational issues in geothermal energy in Europe, OpERA report, October 2016

Wood Group, Corrosion review and materials selection for geothermal wells, WGI 5099A rev. 2, Wood Group Intetech Ltd., 2017

Antics, M. and Hartog, N., Report assessment of injectivity problems in geothermal greenhouse heating wells, GPC IP/KWR, 2015

Parsi, M., et al., "A comprehensive review of solid particle erosion modeling for oil and gas wells and pipelines applications", J. Natural gas science and engineering 21, 2014

Wang, C.T., and Horne, R.N.: Boiling Flow in a Horizontal Fracture, *Geothermics*, **29**, (1999), 759-772.

PVTSim Nova™ 3.1 Documentation Manual (2018)

Dyer, J.A., Trivedi P., Scrivner N.C., Sparks D.L., Lead sorption onto ferrihydrite. 2. Surface complexation modeling. Environ Sci Technol. 2003 Mar 1;37(5):915-22.

Nyborg, R., CO2 corrosion models for oil and gas production systems, NACE International Corrosion 2010 Conference and Expo, paper 10371, 2010