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The Development of a Fully Coupled Wellbore-Reservoir Simulator for Geothermal Application

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ABSTRACT

Boreholes under dynamic conditions are a highly non-linear and complexly coupled thermo-hydraulic system. Multiple parameters, for instance, temperature, pressure, specific heat, enthalpy, viscosity, flow regime, heat transfer, degassing, steam quality and salinity are inter connected. Production and injection often entail several engineering challenges and operational problems, within the boreholes but also up and down stream (reservoir - power plant - reservoir), which can be very diverse in their character. Finding solutions or working on process optimization prerequisite a profound understanding and a reliable numerical tool to quantify the processes. In this context, we developed a wellbore simulator implicitly solving transient fully-coupled non-isothermal two-phase pipe flow. Since the hydraulic and thermal connection to the reservoir is a crucial and critical point at the same time, we overcome the "reservoir-mimicking" boundaries (e.g. inflow performance relationships, productivity index, etc.) by integrating a real reservoir. Since the development of the tool is an ongoing process in this work we present the current state of the tool and it's most important capabilities, such as non-isothermal compressible two-phase pipe flow and the integration into a real reservoir. Future development efforts will concentrate mainly on the coupling to an appropriate module for the quantification of the aqueous chemistry and reactive multicomponent transport.

1. Introduction

The access to a geothermal reservoir and the exploitation of its energy is accomplished by wellbores. Therefore, wells are an integral and very important part of a geothermal system. The physical processes, such as pressure drop, heat transfer, phase composition, densities, viscosities, etc., inside a well during production or injection are characterized by large pressure and temperature differences between wellhead and bottomhole. From an engineers and operators perspective, the quantification of these processes and the governing parameters are of high interest but contemporaneously hard to achieve. Geothermal operations are wellhead controlled only. Therefore, the assessment of the system parameters in depth has to be deduced from wellhead measurements. For steady state applications, a long history of empirical and analytical solutions exist for heat (e.g. Kabir and Ameen, 1996; Ramey, 1962) and for the hydraulics (e.g. Beggs and Brill, 1973; Hagedorn and Brown, 1965; Orkiszewski, 1967). For nearly 30 years, since (Aunzo, 1990) released GWELL, numerous numerical tools has been developed to model coupled thermo-hydraulic well flow to overcome the typical limitations of analytical solutions (e.g. in complex scenarios, geometries, transients). Nowadays, several well-developed commercial oil-and-gas codes, like OLGA (Bendiksen et al., 2007), LEDAFLOW (Goldszal et al., 2007), WELLFlo (Weatherford, 2008) among others exist. However, they are designed specifically for the necessities of hydrocarbon production, e.g. solving two-fluid (liquid) flow, slow mass transients, hydrate and wax formation. On the other hand, also a number of codes were developed to meet the requirements of geothermal. The majority are steady state simulators. HEX-B2 (Mégel et al., 2007) solves single-phase 1D-Navier-Stokes flow of pure water in the borehole. FloWell (Gudmundsdottir et al., 2013) additionally accounts for two-phase water (including supercritical). To quantify the behavior of systems rich in non-condensable gases (NCG), Swelflo (Mcguinness, 2015) and GWELL (Aunzo, 1990) calculate based on a H_2O-CO_2 specific equations-of-state (EOS) a two component system. Other codes, such as WellSim (Gunn and Freestone, 1991), GWNACL (Aunzo et al., 1991), SIMU2000 (Sánchez-Upton, 2000) and Profili (Battistelli, 2010) additionally include the effects of dissolved solids (usually as NaCl-equivalent) on fluid properties. The aforementioned codes account for the reservoir only by setting productivity index-type boundary at a feed zone or by applying more specific inflow performance relationship models (IPR). In order to simulate the integrated system of a reservoir and the wellbores (Marcolini and Battistelli, 2012) 2012 coupled the wellbore simulator PROFILI with the reservoir simulator TOUGH2 (Pruess, 2003) to model pure H_2O. For transient geothermal operation scenarios and the considered highly non-linear physics in the well, the steady state assumption is often a too strong simplification. With T2Well/ECO2N, an integration of a wellbore simulator into TOUGH2 as well, Pan et al. (2011) developed a transient tool for H_2O-CO_2 mixtures in wells and reservoir.

The applications of borehole simulators in order to analyze and solve problems during operation, to design, monitor and optimize new power plants or to explore new geothermal sites are numerous and equally diverse. Typical applications are, determination of static formation temperature from dynamic log data, optimization of production- and injections scenarios, handling of NCGs (two-phase flows), designing the geothermal reuse of abandoned oil wells, design and dimensioning of the future power plant in an early project stage and handling of scaling and corrosion processes. Furthermore, the simulations are not limited to systems of vertical flow but can be used in horizontal pipe flow with countless applications. This diversity of involved processes shows the necessity for the development of an encompassing transient integrated wellbore-reservoir THC-simulator. Herein, we present the underlying physics and the governing equation of a fully-coupled implicit in-house wellbore-reservoir simulator for multicomponent non-isothermal two-phase flow. The simulator is able to handle a wide range of pressure-enthalpy conditions (up to supercritical water), multiple feed zones, transient production and injection histories, numerical and semi-analytical solutions for lateral heat exchange with the reservoir as well as complex well completions. Since the development of the tool is an ongoing process, here some of the most important ready-to-use features, such as fluid compressibility, well inclination, wellbore-reservoir integration and two-phase flow are demonstrated in a number of application cases. Future work will mainly focus on the hydraulic and thermal coupling to a 3D-reservoir and on including aqueous chemistry and reactive multicomponent transport.

2. Methods

The 1D-wellbore simulator is based on the drift-flux model (Hasan and Kabir, 2010; Shi et al., 2005). Non-isothermal fluid flow is calculated for a fully-coupled, implicit, transient, two-phase, single component system using generalized conservation equations:

Mass conservation equation:

$$\frac{\partial}{\partial t}(\rho_m) = -\frac{\partial}{\partial z}(\rho_m u_m) + Q \tag{1}$$

where ρ_m = mixture density, u_m = mixture velocity and Q are sink/source terms.

Momentum conservation:

$$\frac{\partial}{\partial t}(\rho_m u_m) = -\frac{\partial P}{\partial z} - \frac{f\,\rho_m u_m |u_m|}{2\,A} - \rho_m\,\mathrm{g}\cos\theta - \frac{1}{A}\frac{\partial}{\partial z}[A(\rho_m u_m^2 + \gamma)] \tag{2}$$

where A is the cross-sectional area of the well/pipe, P is the pressure, g the gravitational acceleration, θ the inclination of the well, f is the friction coefficient and λ is a term depending on the slip velocity between the liquid and vapor phase (Pan et al., 2011).

Energy conservation:

$$\frac{\partial}{\partial t}\left[\rho_m\left(u + \frac{1}{2}\,u_m^2\right)\right] = -\frac{\partial}{\partial z}\left[u_m\rho_m\left(h + \frac{1}{2}\,u_m^2\right)\right] + \rho_m u_m\,g\ \cos\theta - \frac{q}{A} + Q \tag{3}$$

where h is the enthalpy and q the lateral heat exchange through the casing or pipe wall.

The main variables, solved in the three conservation equations are pressure, enthalpy and volumetric flow rate. The following auxiliary variables are derived from the main variables using the equation of state (EOS): temperature, fluid and vapor density, quality of vapor fraction and saturation of vapor fraction. The IAPWS formulation are used as an EOS (IAPWS, 2007). The formulation is able to cover the pure liquid, pure vapor, two-phase and supercritical conditions. valid for all Drift flux model, based on transient pressure gradient, is used according to the formalism of Hasan and Kabir (2010 a,b) determining fluid flow for five flow patterns in the two-phase region (bubbly-, dispersed bubbly-, slug-, churn- and annular-flow). Well completion and deviated wells as well as multiple feed zones are possible to simulate.

3. Application

A wellbore simulator has to cover a wide range of physical processes. In the following we are demonstrating the major features and capabilities of the tool in the current state of development. Using validation data from Al-Safran and Brill (2017) the pressure drop of compressible single-phase pipe-flow is validated. In a second application, a production case for two-phase flow in an inclined well is modelled to demonstrate drift flux of the liquid and the vapor phase of pure water and the effect of changing flow patterns on the pressure traverse. Finally, an integrated model of two wells (production and injection well) and a reservoir is calculated, displaying the hydraulic interaction of Darcy-type flow in a porous reservoir and pipe flows along the wells.

3.1 Compressible One-Phase Pipe Flow

In order to validate compressible single-phase flow a test case is calculated and compared to analytical results (Al-Safran and Brill, 2017). The flowing pressure of a vertical gas well with a length L = 3048 m, a uniform diameter d = 0.06 m and a pipe wall roughness ε = 0.0213 mm for a production case is modelled. The produced fluid is single-phase natural gas. The temperature gradient is linear, with T_{bh} = 118.3 °C at bottomhole depth and T_{wh} = 43.3 °C at wellhead. Depicting the wellhead-control of the modelled scenario, the hydraulic boundaries are set at the wellhead. The wellhead pressure (P_{wh}) is 138.3 bar and the flow rate (q) is 9.3 l/s.

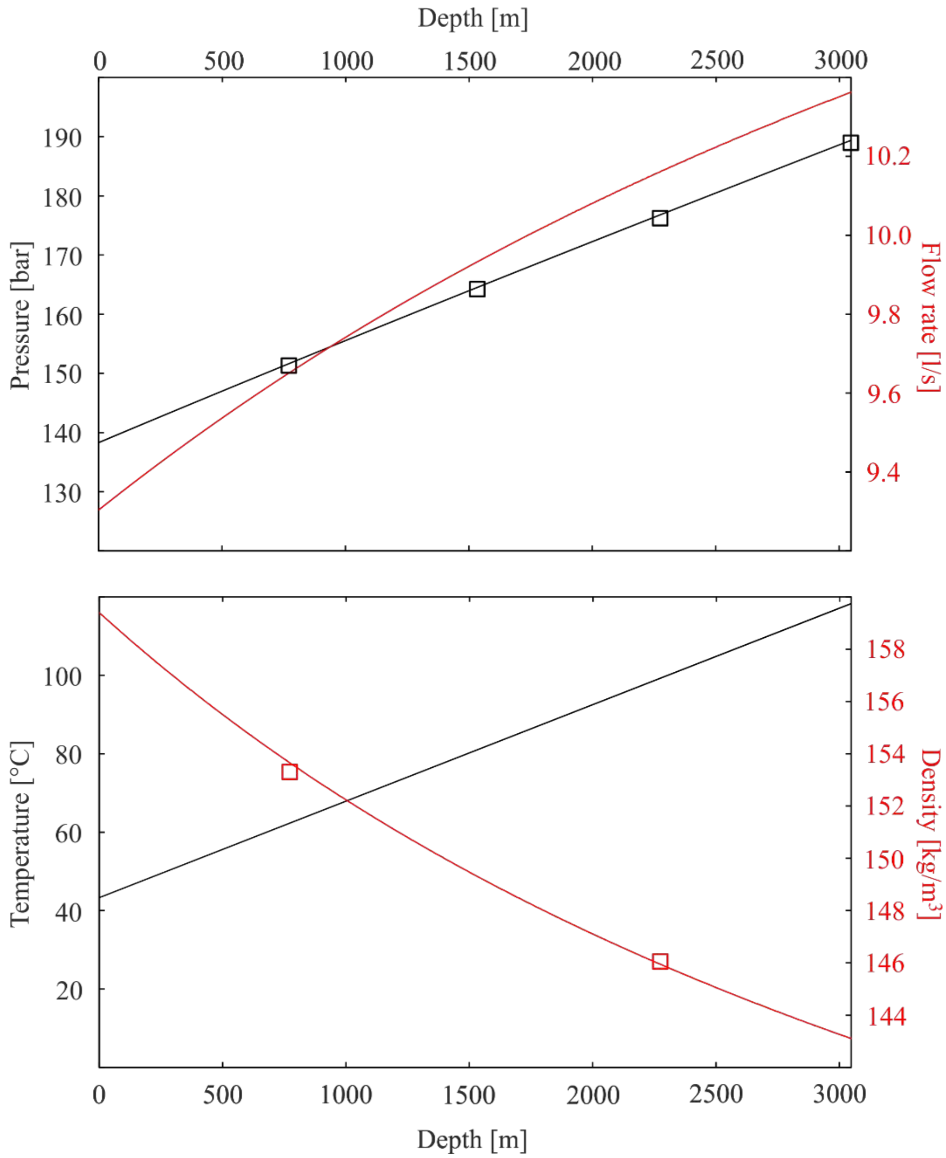

Figure 1: a) The modelled pressure (black line) is matching the analytical values (black squares) from Al-Safran and Brill (2017) in good agreement. Due to the compressibility of the fluid the volumetric flow rate (red line) is a non-linear function with depth. b) The linear temperature gradient (black line) from T_{wh} = 43.3 °C to T_{bh} = 118.3 °C together with fluid compressibility results in a non-linear fluid density function (red line), matching the decreasing analytical values (red squares) with depth.

The modelled values for flowing pressure are matching the analytical results in very good agreement (Figure 1a). The coupled nature of the model is displayed in the non-linearity of the volumetric flow rate as a result of fluid compressibility. Reflecting thermal effects and fluid compressibility, the fluid density is a non-linear function, as well, showing decreasing values with depth. The model is also predicting the densities in good agreement with the results of the analytical reference (Figure 1b).

3.2 Two-Phase Drift Flux

A synthetic example for a two-phase problem is modelled to demonstrate the featured drift flux model (Hasan et al., 2010 a,b). Two-phase water is produced from a multiple inclined well (α_1 = 6.96°, α_2 = 18.47° and α_3 = 39.01°) and step-wise reducing pipe diameter (d_1 = 0.45 m, d_2 = 0.30 m and d_3 = 0.15 m) (Figure 2). Bottomhole depth is at 4000 m (TVD). Due to inclination measured depth is 4239 m. Hydraulic relevant fluid properties are given by a gas viscosity = 0.0001 Pa·s, liquid viscosity = 0.001 Pa·s and surface tension = 0.0288 N/m. The mixture viscosity is calculated based on Mean Maxwell Eucken (Awad and Muzychka, 2008). For simplification, heat loss during production is mimicked by applying a linear enthalpy gradient from 1.5e6 J at bottomhole to 1.4e6 J at wellhead. The hydraulic boundaries are set at the wellhead, assigning an ambient pressure of 1 bar and an extraction flow rate of 15 l/s.

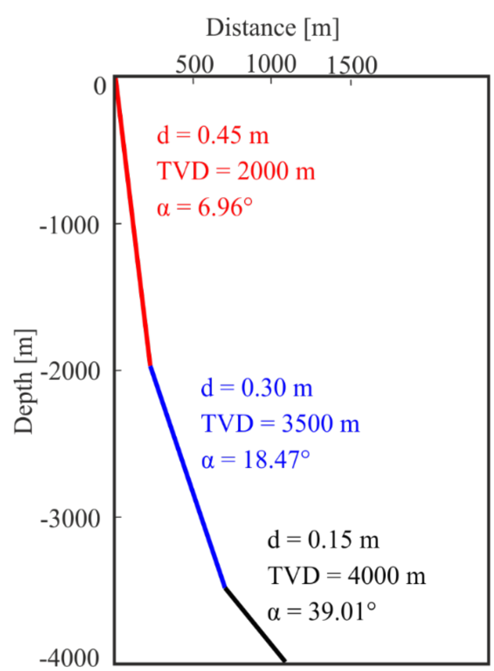

Figure 2: Layout of a 4000 m deep (TVD) multiple inclined (α_1 = 6.96°, α_2 = 18.47° and α_3 = 39.01°) production well with variant diameters (d_1 = 0.45 m, d_2 = 0.30 m and d_3 = 0.15 m).

It is shown that the flow rate profile and the pressure traverse are highly non-linear functions (Figure 3a). The stepwise decreasing pipe diameters lead to an increase of flow velocities with depth, which provoke the changes of flow patterns. For the given pressure and enthalpy conditions and mixture velocities the observed flow pattern is alternating from bubbly to slug flow (Figure 3c). The changing pressure gradient results mainly from non-constant fluid density, due to fluid compressibility and non-constant volume ratio of liquid to vapor phase (with highly different compressibilities). The density functions (Figure 3b) reflect the different behavior of a liquid phase compared to a vapor phase. Increasing vapor density with depth indicates the dominant impact of the pressure (high compressibility of gas). The decreasing liquid density is resulting from the prevailing thermal expansion.

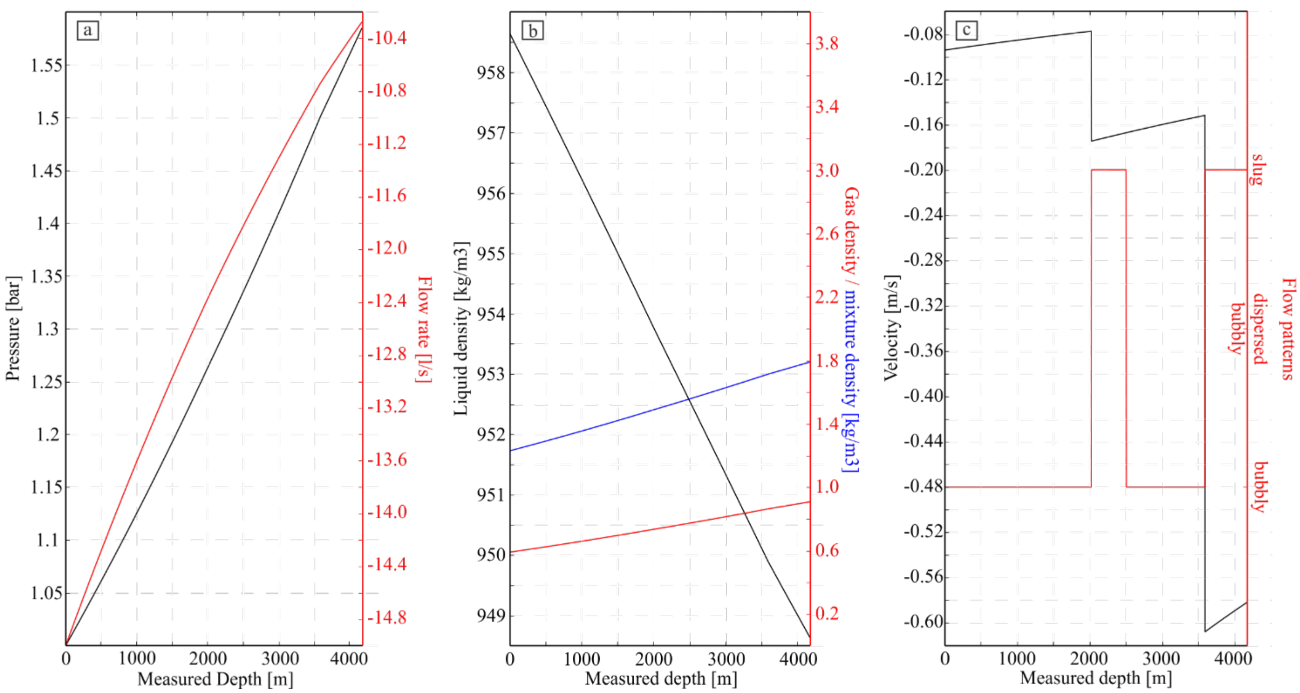

Figure 3: The pressure traverse and the flow rate are non-linear functions (Figure 3a), resulting from varying phase densities (Figure 3b) and changing volume ratios of the phases in the mixture. The decreasing pipe diameter causes increasing flow velocities which results in changing flow patterns alternating from bubbly to slug flow (Figure 3c).

3.3 Integrated Wellbore-Reservoir Simulation

In order to demonstrate the feasibility of integrating the different hydraulics of a wellbore- and a reservoir-model into one continuous simulation, an isothermal steady state test case is calculated comprising two wells which are connected via a porous reservoir. Figure 4 shows the model set-up of two vertical wells with a lateral distance of 400 m. At bottomhole depth of -1500 m they are connected to a 2D-reservoir with the dimensions of 450 m x 450 m. The pressure is constraint by a first order boundary along the reservoir margins of 147 bar. Production and injection are controlled by setting second order boundaries at the wellheads of 30 l/s and -30 l/s, respectively. The permeability in the reservoir is K = 1e-14 m^2, the well diameter is d = 0.152 m (constant along the well).

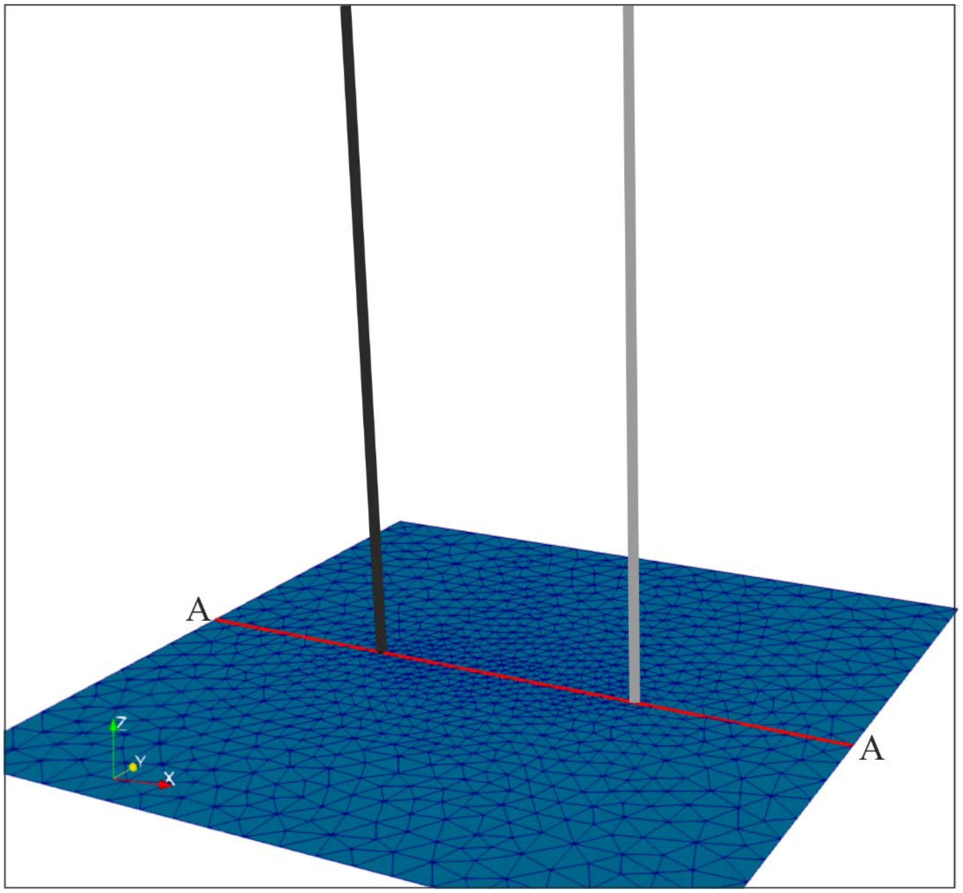

Figure 4: Model set-up and mesh of an integrated wellbore-reservoir simulation. A production well (black line) and an injection well (grey line) with a lateral distance of 400 m are connected to a porous 2D-reservoir. The line A-A is marking the section for the pressure and flow analysis (compare Fig 4c).

In Figure 5 the results of the integrated wellbore-reservoir simulation are shown. The pressures and flow rates are showing the expected values for the injection well (Figure 5a) and the production well (Figure 5b). The changing volumetric flow rates with depth are due to the compressibility of the fluid, reflecting pressure changes along the wells. The steady state results reveal that for the given flow rates of 30 l/s the lateral distance of the wells of 400 m is large enough that no hydraulic interaction of the wells occurs.

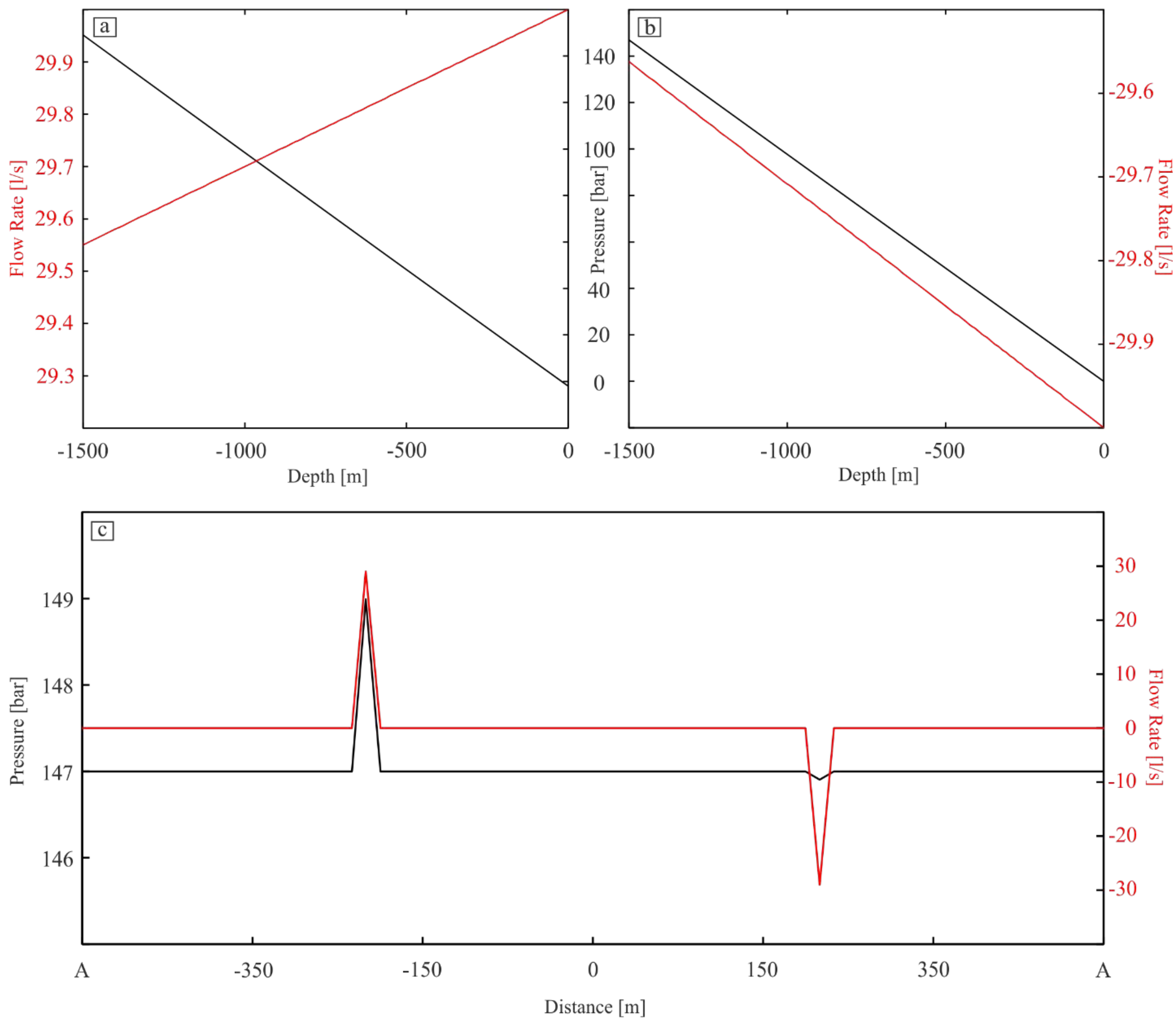

Figure 5: Hydraulics of an integrated wellbore-reservoir simulation displaying the pressures and flow rate profiles for the injection well (a) and the production well (b). In (c) the pressure and flow rates in a cross section in -1500 m (bottomhole depth) comprising the reservoir and the wells.

4. Conclusion and Perspective

The quantification of borehole process is a crucial task for many geothermal applications, varying from exploration, optimization, designing and monitoring purpose. Since a borehole under production or injection conditions is a highly dynamic system comprising many different physical, often complexly coupled processes, a fully-coupled and transient wellbore simulator is extremely advantageous.

In this work we present the most important capabilities of the code. The current state of the in-house development features a fully-coupled implicit wellbore simulator for multicomponent non-isothermal two-phase flow. The code is able to handle water up to supercritical conditions, multiple feed zones, transient production and injection schemes, numerical and semi-analytical solutions for lateral heat exchange with the reservoir as well as complex well completions. In a first step we can also demonstrate the feasibility of linking the different physics of porous media flow in the reservoir and pipe flow in the wells into one integrated wellbore-reservoir model.

We consider the current state of the tool as an intermediate step towards a fully-coupled THC-simulator. Since scaling formation and corrosion are severe problems exploiting a geothermal resource, we consider the integration of the chemical system to be highly relevant. Therefore, future development will focus on the proper quantification of the aqueous chemistry, the interaction with non-condensable gases and minerals as well as reactive multicomponent transport.

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