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A time-convolution approach for modeling heat exchange between a wellbore and surrounding formation

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ABSTRACT

In oil, gas, and geothermal energy production, as well as geological CO_2 storage, the target formation is typically deeper than 1000 meters. As a result, associated wellbores have a large heat exchange area with the surrounding formation. Large gradients and temporal variations in temperature induced by the injection and production of fluids require accurate and efficient ways to calculate the heat exchange between fluids in the wellbore and the formation. One way to calculate this heat exchange is to fully discretize and numerically model the formation that surrounds the wellbore. However, because only the energy equation needs to be solved (i.e., there is no fluid exchange between the cased wellbore and the formation), this approach is computationally inefficient. In this work, we propose a time-convolution method, where only the wellbore is fully discretized, and heat exchange between fluids in the wellbore and the formation is calculated using semi-analytical solutions of radial conductive heat flow. The time-dependent temperature evolution in the wellbore is calculated numerically using a wellbore simulator for non-isothermal, multiphase fluid mixtures. At each time step, radial heat transfer with the formation is calculated by superposition of analytical solutions of heat flow that are dependent on the temperature differences between subsequent time steps. This coupling scheme is implemented in the TOUGH2 suite of reservoir simulators. To verify the proposed semi-analytical method and demonstrate its applicability, we present examples and compare them to full numerical solutions.

1. Introduction

In applications of oil, gas, and geothermal energy production, as well as geological CO_2 storage, injection and production wells serve as a conduit between the ground surface and the subsurface reservoir. The great length of these wellbores results in a very large heat exchange area between the well and the formation. For example, for a 12-cm-radius well with a length of 1500 m, the total heat exchange area is more than 1100 m^2. If such a well is used to inject CO_2 for geological carbon sequestration, the heat transfer will have a significant effect on the properties of the CO_2 as it flows down the well, and thus, on the downhole conditions, potentially affecting injectivity and thereby overall storage efficiency. Similarly, the performance of an injection–production cycle in an engineered geothermal system depends on the temperature and thus, phase state, density, and viscosity of the working fluid in the cool injection and hot production wells. An accurate simulation of heat transfer processes between the formation and fluids in these wells is thus essential for performance evaluation and design of fluid injection and production systems.

During fluid injection or production, the processes to be considered above the target reservoir (which often consist of low-permeability caprocks) mainly include non-isothermal, multiphase fluid flow within the wellbore and conductive heat exchange between the wellbore and the geologic formation. Fluid flow in the caprock is considered small, and associated convective heat transport is thus neglected. Moreover, the thermal properties of the caprock may vary with depth, but are assumed to be homogeneous in radial direction.

The processes within the well are usually modeled using a numerical wellbore simulator. However, numerical modeling of the conductive heat exchange between the cased well and the formation would be computationally inefficient if the region around the well affected by this heat transfer were fully discretized, especially when the target formation is on the order of 1000 m deep, which is typical in geothermal fields and anticipated in large geologic CO_2 sequestration projects. Because the only process involved in this transfer is heat conduction (e.g., no fluid exchange), the alterna-

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tive is to solve the heat conduction problem between the wellbore and formation analytically. Avoiding numerical discretization of the formation above the reservoir of interest significantly reduces computational cost. In this paper, we review prior approaches to modeling borehole heat transfer, present a new time-convolution approach, and finally demonstrate its applications to geothermal and geologic CO_2 storage problems.

2. Prior work

For a layered formation, Lauwerier (1955) developed an analytical solution to solve the linear conductive heat transfer problem between the layer and its adjacent confining units using the Laplace transformation. Vinsome and Westerveld (1980) developed a semi-analytical solution for the heat conduction problem between an oil reservoir undergoing thermal recovery and its base and caprocks. They proposed a second-order polynomial with an exponential tail for the temperature profile in the confining units, which are considered to be infinite half-spaces. This approach gives accurate solutions to linear heat conduction in a system with layered geometries, where the cross-sectional area for heat transfer is constant. By contrast, a wellbore and its surrounding formation form a cylindrical system, in which the cross-sectional heat conduction area increases proportionally to the radial distance from the center of the well. As a result, these solutions are not valid for a radial system.

Ramey (1962) developed an approximate solution for radial heat transfer with the assumption of steady-state flow in the wellbore, in which an overall heat transfer coefficient for wellbore heat loss as a function of dimensionless time is estimated. While his solution works well in many situations, it has some limitations because of the assumption that heat transfer within the wellbore is at steady state. In other words, his solution may not give reliable results if the rate or temperature of the injected or produced fluid changes. Hagoort (2004) summarized situations where Ramey's solution is a good approximation. Based on Ramey's solution, Horne and Shinohara (1979) provided a formulation of the total heat loss between wellhead and reservoir.

Wu and Pruess (1990) developed an analytical solution for wellbore heat exchange assuming constant mass flow rate in the well and steady-state radial heat flow between the wellbore and the formation. They also obtained a more accurate heat transfer coefficient (compared with Ramey's coefficient), which is a function of both dimensionless time and dimensionless depth.

Kanev et al. (1997) performed a parametric study to identify the parameters that have a major impact on the heat loss to the surrounding formation in geothermal wells. They derived a proportional relationship between a non-dimensional function and the heat transfer coefficient in Ramey's solution. This non-dimensional function includes the Peclet number, well length, and average temperature difference between the wellbore fluid and the surrounding formation, as well as a time-decaying function.

While the approaches reviewed above have been useful for many applications, they all have limitations, either in accuracy or computational demand, which motivate new approaches applicable to highly unsteady and strongly non-isothermal geothermal and geologic CO_2 storage applications. Here, we propose a new superposition approach to consider the effect of temperature history on heat loss from a cased well to the surrounding formation. Unlike previously mentioned studies, no assumptions of steady-state heat flow or constant mass flow rate in the well need to be made. The solution is able to handle applications where the flow rate and temperature of the well fluid varies significantly with time. The resulting heat-loss term has been added in the TOUGH2 reservoir simulator (Pruess et al., 1999), a finite-volume numerical simulator capable of modeling non-isothermal multiphase flows in fractured and porous media. The main assumption of the approach is that vertical conductive heat flow within the formation is negligible. This is a reasonable assumption because of the much faster convective heat transfer in the wellbore than the radial conductive heat transfer in the formation. The solution also assumes that there is no thermal resistance between the cased well and the formation; however, such a resistance can easily be accounted for by inserting a cylindrical element between the wellbore simulator and the radial domain in which the semi-analytical solution is applied. These cylindrical elements would represent, for example, the metal casing, cement and grouting materials, other wellbore installations, and the skin zone; radial and axial heat transfer through these materials and zones will be calculated using the simulator's numerical solution approach, providing the temperature condition at the interface to the formation. The proposed approach thus offers great flexibility in solving practical heat exchange problems in deep wells with strongly changing flow rates and temperatures, as well as with depth-dependent variations in well casing diameter, thermal formation properties, and initial temperature distributions.

3. Approach

Carslaw and Jaeger (1959) provided an approximate solution for heat conduction between a cylinder and surrounding media where the temperature of the cylinder is maintained constant. If the initial temperature difference between the two domains is $\Delta T = T_w - T_f$ (where T_w and T_f are the temperatures in the well and the formation, respectively), the heat flux q from the wellbore to the formation can be calculated as the product of a heat transfer function and the temperature, using Eq. (1) for small values of the dimensionless time $t_d = \alpha t/r_0^2$, where α is the thermal diffusivity, and Eq. (2) for large values of t_d:

$$q = f_1(t_d)\Delta T = \frac{k\Delta T}{r_0}\left\{(\pi t_d)^{-0.5} + \frac{1}{2} - \frac{1}{4}\left(\frac{t_d}{\pi}\right)^{0.5} + \frac{1}{8}t_d - \cdots\right\} \quad (1)$$

$$q = f_2(t_d)\Delta T = \frac{2k\Delta T}{r_0}\left\{\frac{1}{\ln(4t_d) - 2\gamma} - \frac{\gamma}{[\ln(4t_d) - 2\gamma]^2} - \cdots\right\} \quad (2)$$

Here, k is thermal conductivity ($W\,m^{-1}\,K^{-1}$), r_0 is the wellbore radius (m), and γ is the Euler's constant (0.57722).

Mishra and Guyonnet (1992) provided a solution for fluid flow during a constant-head pumping test for relatively large t_d (which is defined using transmissivity and storativity). The solution can be adapted to the heat exchange problem:

$$q = f_3(t_d)\Delta T = \frac{k\Delta T}{r_0}\left\{-\frac{2\exp(-1/(4t_d))}{Ei(-1/(4t_d))}\right\} \quad (3)$$

The three heat transfer functions f_1, f_2, and f_3 express the amount of heat flux with time due to a unit temperature difference (i.e., $\Delta T = 1\,^\circ C$). Fig. 1 shows the heat transfer functions f_1, f_2, and f_3 as a function of the dimensionless time t_d. The figure shows that for $t_d \approx 2.8$, the three functions are approximately the same and that for $t_d > 2.8$, $f_2(t_d) \approx f_3(t_d)$. Therefore, $t_d = 2.8$ is considered the critical dimensionless time to switch from f_1 to f_2 or f_3. In our model, we used Eq. (2) as the late-time solution, as it is easier to implement than Eq. (3). The combined heat transfer function, consisting of f_1 at early times and f_2 at late times, will serve as the basis for the superposition method proposed below.

The basic principle of superposition is that the response of a system to a number of perturbations is equal to the sum of the responses to each of the perturbations as if they were present by themselves if the responses are linearly related to the perturbations. During fluid injection and production, and as a result of the heat exchange processes, temperature changes continuously

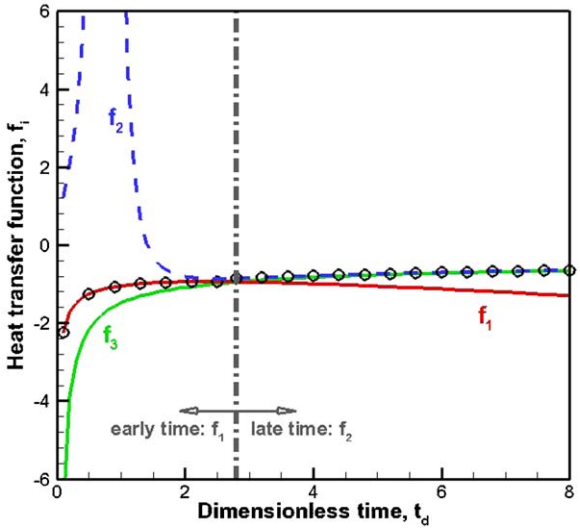

Fig. 1. Heat transfer functions f_1, f_2, and f_3. The function implemented in the proposed approach is indicated by circles; it uses f_1 at early times (i.e., $t_d < 2.8$) and f_2 at late times.

over time at any point within the wellbore and at the wellbore-formation interface. Based on superposition, the radial heat flux across each wellbore element to the surrounding formation is a time-convolution result of varying temperature at the wellbore wall. The discretized form at each time step can be expressed by the following:

$$q_{\text{total}} = \sum_{i=1}^{d-1} f(t_d - t_i)\Delta T(t_i) \tag{4}$$

Here, t_d represents the current time after d time steps, and t_i represents the time after i time steps; the function f is f_1 if $t_d - t_i \le 2.8$ and f_2 if $t_d - t_i > 2.8$. The temperature difference $\Delta T(t_i)$ is the temperature in the well at time step i minus the formation temperature at the interface at the previous time step, i.e., $\Delta T(t_i) = T_w(t_i) - T_f(t_{i-1})$. Recall that we assume that the thermal resistance at the boundary between the domain handled by the numerical wellbore simulator and the domain handled by the semi-analytical solution is negligible. Therefore, the formation temperature at the interface of the wellbore and formation is equal to the well temperature, i.e., $T_f(t_{i-1}) = T_w(t_{i-1})$.

A similar superposition technique has been used in the design of borehole heat exchangers, in which solutions for constant heat flux are superimposed to obtain the temperature changes due to heat input (Cullin and Spitler, 2011; Eskilson, 1987; Huber and Wetter, 1997).

To implement the solution into the TOUGH2 simulator, we need to calculate q_{total} and its derivative at each time step and incorporate these two terms into the heat balance equation and the corresponding linearized form, which is needed for the implicit solution of the fully coupled system of mass and heat flow equations in the well. This requires the algorithm to store the temperature history for each wellbore element. This may be problematic if the time history becomes very long, which increases the computational demand of the time-convolution approach and potentially reaches the limit of the computer's memory. To mitigate this problem, a maximum number of time steps can be defined in our algorithm, beyond which the contributions from earlier temperature changes are lumped into a single term, which is calculated based on the time-weighted average of the individual temperature changes $\Delta T(t_i)$ and associated times t_i. The maximum number is internally calculated based on available computer memory; in all examples discussed below, this number was larger than the actual number of time steps needed to solve the respective fluid and heat flow problem.

Table 1
Input parameters used in numerical analyses of radial heat exchange.

Parameter	Example		
	1	2	3
Well radius (m)	0.05	0.10	0.09
Well length (m)	1	4000	3000
Fluid[a]	H_2O	H_2O	CO_2
Thermal conductivity (W/m °C)	2.1	2.1	2.5
Heat capacity (J/kg °C)	1000	1000	920
Rock grain density (kg/m^3)	2650	2650	2600
Heat injection (W)	20–80	Variable	Variable
Fluid injection (kg/s)	n/a	2	Variable
Fluid production (kg/s)	n/a	2	n/a
Initial wellhead temperature (°C)	20	20 (const.)	35
Initial bottomhole temperature (°C)	n/a	180 (const.)	90
Geothermal gradient (°C/m)	n/a	0.04	0.018

[a] Thermophysical properties for H_2O from IFC (1967); for CO_2 from Altunin (1975).

To make the algorithm flexible for handling various wellbore configurations and thermal conditions in the rock formation, the code gives the user an option to choose between uniform or depth-dependent formation properties, wellbore radii, and geothermal gradients (uniform properties were used in the examples discussed below). The solution is also linked to the wellbore simulator of TOUGH2, where the transient multiphase non-isothermal wellbore flow is modeled using the drift-flux model (Pan et al., 2011).

We will present three examples in the next section to verify the proposed approach and algorithm, as well as to demonstrate the importance of considering heat transfer between wellbore and formation.

4. Examples

The input parameters for the three examples are listed in Table 1.

4.1. Example 1: heat injection into a single grid block

The first example investigates heat transfer effects without fluid flow. Consider heat injection into a wellbore represented by a single grid block, i.e., the heat is instantaneously distributed and averaged within the well, which is filled with water. The well element has a cylindrical shape, with length $l = 1$ m and radius $r = 0.05$ m (Fig. 2). The element is radially attached to an infinite formation. The heat injection rate alternates between 80 J/s and 20 J/s every 10^7 s, starting with 80 J/s. Fig. 3 shows the temperature in the well calculated in three ways: (1) using the proposed semi-analytical solution for radial heat conduction, (2) using a fully discretized numerical solution for radial heat conduction, and (3) without considering radial heat conduction. This result shows that, first, heat exchange between the well and the formation is obviously important, as the well temperature would continuously increase to very high values if the radial heat loss to the formation were ignored. Second, the numerical solution and proposed semi-analytical solution are in very good agreement. The maximum difference between the two solutions is less than half a degree, which is on the order of 2% of the induced temperature change. Third, the semi-analytical

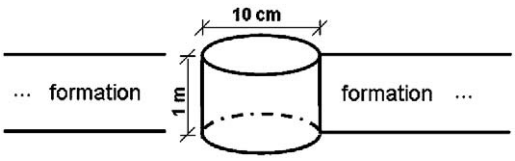

Fig. 2. Schematic of Example 1 set up (not to scale).

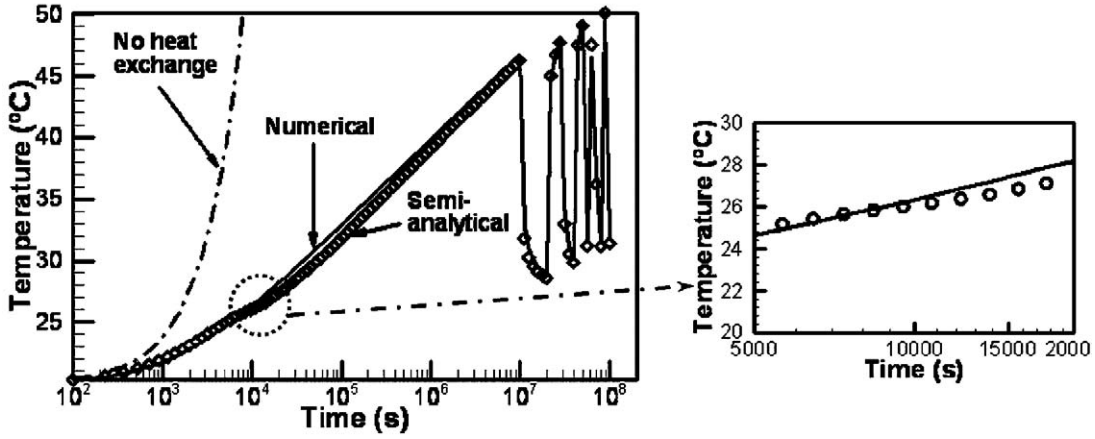

Fig. 3. Comparison of the temperature of the wellbore calculated for Example 1 using three different approaches.

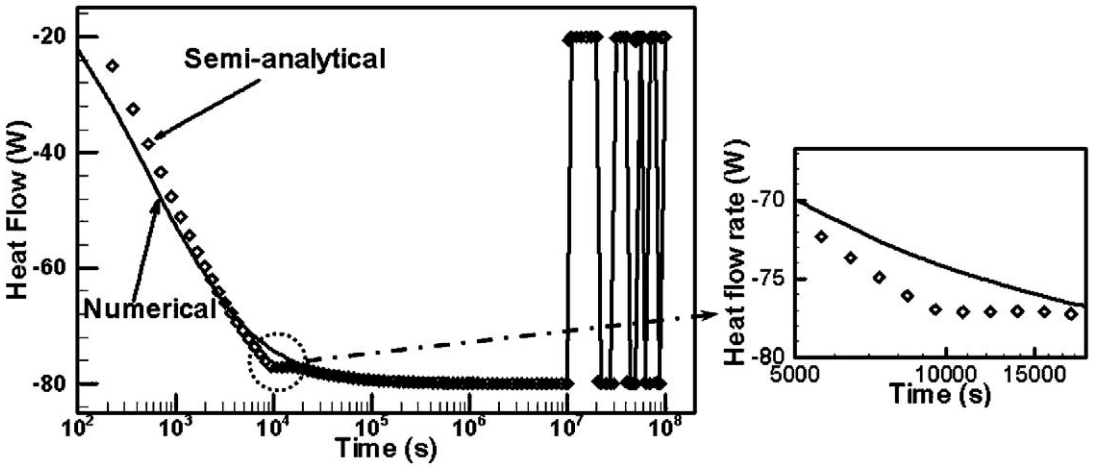

Fig. 4. Comparison of the heat flow rate between the wellbore and the formation calculated for Example 1 using three different approaches.

solution shows a slight bend (see inset of Fig. 3) at around 9000 s, when t_d is about 2.8 and the heat flux solution in the semi-analytical solution switches from the early-time solution of Eq. (1) to the late-time solution of Eq. (2).

The comparison of the heat flow between the wellbore and formation is shown in Fig. 4. The two solutions are in very good agreement over most of the simulated period despite strong fluctuations in wellbore temperature. The heat flows at very early times (less than 1000 s) deviate somewhat, with the numerical solution being less accurate because of discretization effects. An initial steady state is reached after about 10,000 s, with the transition from transient to steady-state heat flow being smooth for the numerical solution, but again showing a slight bend for the semi-analytical solution due to the switch of equations at $t_d \approx 2.8$.

4.2. Example 2: alternating fluid injection into and production from a wellbore

Consider a wellbore that is 4 km long, with a radius of 10 cm. The wellbore is discretized into 100 elements. We assume that the initial formation temperature at the surface is 20 °C, and the geothermal gradient is 40 °C/km. Water of 20 °C is injected into the wellbore for 100 days, followed by 100 days of production of water, which enters the bottom of the well at a constant reservoir temperature of 180 °C. Although the formation above the reservoir is assumed impermeable, the reservoir itself is permeable and the well is perforated at the bottom so water can flow into and out of the reservoir. Both injection and production rates are 2 kg/s. Fig. 5 shows the comparison of the temperatures of three elements (top, middle, and bottom) of the wellbore, again, calculated (1) using the proposed semi-analytical solution for radial heat conduction, (2)

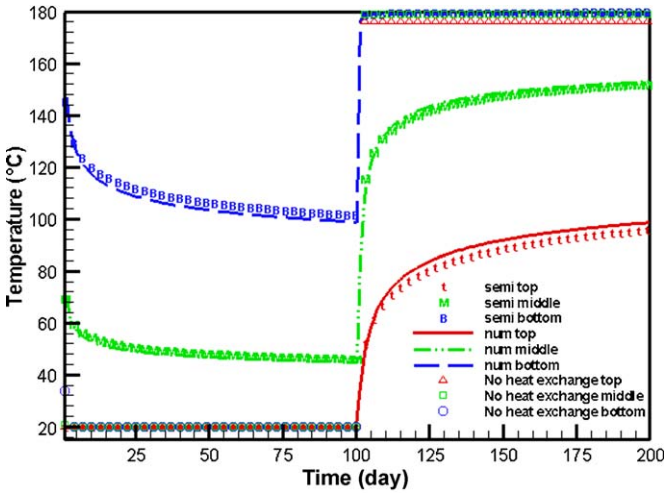

Fig. 5. Comparison of the temperature at three locations of the wellbore for Example 2. The legend identifies curves for semi-analytical (semi), numerical (num), and no heat exchange results.

using a fully discretized numerical solution for radial heat conduction, and (3) without considering radial heat exchange. When the conductive heat transfer to the formation is not accounted for, the middle and bottom of the wellbore quickly reach the same temperature as the top during the injection phase, whereas the top and middle of the wellbore reach the same temperature as the bottom during the production phase. However, the figure clearly shows that rapid attainment of an almost uniform temperature profile in the well is not realistic because of conductive heat exchange with the formation. Again, the numerical and semi-analytical solutions show good agreement, which demonstrates that our approach is able to handle alternating fluid injection and production, i.e., wellbore flow with strongly time-varying flow rates and with reversal of the temperature difference between the wellbore and the formation.

4.3. Example 3: CO_2 injection into a depleted gas reservoir

In this example, we consider CO_2 injection into a depleted gas reservoir at a depth of 3000 m, as discussed by Pan et al. (2011). The process within the well is simulated using a wellbore simulator, where conservation equations for mass, momentum, and energy under different flow regimes in the wellbore are solved numerically in an axial direction. The fluids are assumed to be well mixed in the radial direction. However, this is not a necessary assumption for our proposed heat transfer approach, which is applied at the interface between the well and the formation. Radial discretization of the wellbore (and potentially including the casing, cement, and skin zone) should be performed if the assumption of a negligible radial temperature gradient is violated. The heat transfer from the wellbore to the surrounding rock is calculated using (1) a fully discretized numerical simulation, (2) the proposed semi-analytical approach, and (3) the solution of Ramey (1962). In addition, we calculated the response of a system in which the heat transfer between the wellbore and the formation is ignored.

Again, the formation above the underground storage reservoir is considered hydraulically impermeable, i.e., heat exchange is purely conductive, allowing application of the efficient semi-analytical solution. The permeable reservoir, which is fully discretized and to which the wellbore simulator and semi-analytical heat-exchange model are attached, has a thickness of 100 m and an area of 1 km × 1 km. It is fully penetrated by a wellbore with a diameter of 0.18 m. The wellbore is discretized into 100-m-long elements (note that the focus here is to verify the heat exchange algorithm rather than the accuracy of the wellbore simulator; the discretization error will be the same for all three solutions).

The fluid and heat flow processes in the reservoir are simulated numerically; however, the results will depend on the implementation of the heat transfer processes between the well and the rock formation above the reservoir. A hydraulically impermeable layer with a constant temperature of 90 °C is at the base of the reservoir. The reservoir permeability is 10^{-13} m^2. The initial temperature in the reservoir is 90 °C. CO_2 is injected at the variable rates shown in Fig. 6 and with a constant enthalpy of 734.8 kJ/kg, which corresponds to a temperature of 7.5 °C at a pressure of 40 bars, achieved shortly after injection is started. Given that CO_2 is injected at a constant enthalpy, Joule–Thomson effects (Katz and Lee, 1990) cause the temperature to increase because of the compression of CO_2 as it flows down the wellbore, which—in the absence of wellbore heat exchange—would yield an initial injection temperature of 36 °C at the reservoir pressure of 65 bars. Joule–Thomson effects therefore contribute substantially to the heating of the CO_2. In addition, radial heat conduction leads to heat loss (in certain sections in the upper part of the well, where formation temperatures are low and well temperatures are relatively high because of the compression of CO_2) and heat uptake (in the lower part of the well, where the formation temperature is high). This energy transfer is governed by the complex evolution of the pressure and temperature profiles in the well and the resulting perturbation of the initial geothermal temperature gradient in the formation.

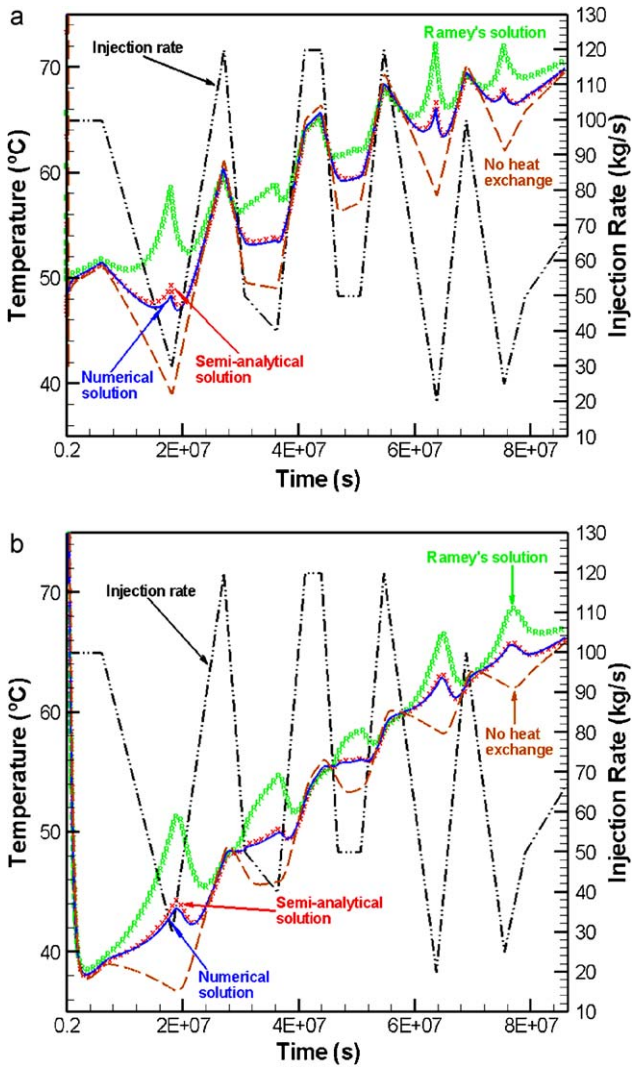

Fig. 6. Results of injection rate and temperature change for Example 3 simulated using three solutions at two different locations: (a) wellbore bottom and (b) 10 m away from the wellbore in the reservoir.

Fig. 6a shows the simulated temperature evolution at the bottom of the wellbore for the four scenarios considered in this study. Upon initial injection, the bottomhole temperature decreases sharply as the cooler CO_2 arrives, as expected. However, after this initial drop, as the pressure in the well increases during this constant-rate injection period, injection temperature also increases because of Joule–Thomson effects. The large Joule–Thomson coefficient of CO_2 makes temperature changes induced by compression a dominant effect on the wellbore temperature for most of the injection rates prescribed in this example. As a result, the temperature in the well follows the injection rate change, which governs relative compression or expansion of the CO_2. During high-rate periods (i.e., periods when the injection rate is higher than 80 kg/s), conductive heat exchange with the formation is negligible compared with the convective heat transport and Joule–Thomson effects; as a result, the details of the heat exchange model are irrelevant, and all solutions coincide. However, when the injection rate is low (i.e., lower than about 40 kg/s, as is the case at around 200, 750, and

875 days), the Joule–Thomson cooling due to relative decompression of the fluid and the reduced advective downflow of relatively cool CO_2 are insufficient to counter the heating of the wellbore by conduction from the formation. During these transient periods, the choice of the heat exchange model is significant, with the numerical and proposed semi-analytical solutions yielding consistent results. Ramey's solution, which makes a steady-state heat flow assumption in the wellbore, does not properly react to these changes in wellbore conditions and overestimates the heat uptake from the formation. Conversely, neglecting any heat exchange between the well and the formation results in a drastic underestimation of injection temperatures, as no warming of the CO_2 occurs as it flows down the well at a relatively slow velocity.

Fig. 6b shows the temperature evolution in the reservoir at a radial distance of 10 m from the well. First, we note a gradual increase in temperature after the initial drop, which is again because of Joule-Thomson effects as the reservoir is pressurized from 52 bars after 2 days to 87 bars after 100 days. This pressure increase of 35 bars yields a temperature increase because of Joule-Thomson effects alone of about 15 °C. The actual temperature increase shown in Fig. 6b is higher because heat from the injected CO_2, which is at a higher temperature, is convectively transported to the location 10 m away from the well. The short-term fluctuations reflect the temperature at the bottom of the well, which in turn are affected by the accuracy with which heat exchange is simulated along the entire length of the injection well. As the assumption of steady-state heat transfer within the wellbore is violated in this example, the application of Ramey's model leads to significant deviations from the reference numerical solution, whereas the semi-analytical time-convolution approach accurately predicts the perturbation of reservoir temperatures caused by the injection of CO_2.

This example demonstrates the sensitivity of predicted wellbore and formation temperatures to the choice of the heat exchange model. Moreover, it also highlights the need to describe the thermophysical properties of the fluids using appropriate equations of state. Accounting for heat exchange and coupled thermal–hydraulic processes is especially significant for fluids whose properties vary considerably as a function of pressure and temperature, such as CO_2.

For all three example problems, comparisons between the developed solution and a fully discretized numerical solution show that the proposed semi-analytical solutions are good approximations for the given assumptions.

5. Conclusions

In this paper, we propose a time-convolution approach to calculate radial, conductive heat transfer between a wellbore and its surrounding formation. The method is based on the superposition of the basic solution where a constant temperature is maintained at the interface between the well casing and the formation. The semi-analytical solution is implemented into the TOUGH2 reservoir simulator, which is coupled to a wellbore simulator. The proposed approach is particularly useful for handling complex time-dependent flow regimes in response to varying injection schedules, but also to changes in fluid properties, which in turn respond to the heat transfer with the formation. The semi-analytical time-convolution approach implemented in TOUGH2 is able to overcome the limitations imposed by the approximations inherent in previously published solutions to the radial heat exchange problem.

The approach is based on the assumptions that vertical conductive heat transfer within the formation is small and that the formation above the reservoir has very low permeability so that convective heat transport can be ignored. These assumptions are considered reasonable and relevant for many problems involving heat transfer between deep wells and confining formations. If they are significantly violated, numerical methods need to be applied.

Three examples were presented to demonstrate that the proposed approach is accurate for both early and late times and for non-monotonic temperature and flow-rate variations. In addition, our implementation gives the user flexibility to have non-uniform formation thermal properties, wellbore diameters, and initial temperature profiles. This great flexibility and computational efficiency make the approach applicable to realistic flow scenarios, as encountered in geothermal reservoir engineering and geological CO_2 storage projects.

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