Coupling of the Reservoir Simulator TOUGH and the Wellbore Simulator WFSA

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ABSTRACT: The reservoir simulator TOUGH and the wellbore simulator WFSA have been coupled, so as to allow simultaneous modeling of the flow of geothermal brine in the reservoir as well as in the wellbore. A new module, COUPLE, allows WFSA to be called as a subroutine by TOUGH. The mass flowrate computed by WFSA now serves as a source/sink term for the TOUGH wellblocks. Sample problems are given to illustrate the use of the coupled codes. One of these problems compares the results of the new simulation method to those obtained using the deliverability option in TOUGH. The coupled computing procedure is shown to simulate more accurately the behavior of a geothermal reservoir under exploitation.

INTRODUCTION

Several reservoir simulators currently exist that model flow processes occurring in the subsurface (e.g., PT, Bodvarsson, 1982; TOUGH, Pruess, 1987; TETRAD, Vinsome, 1991; STAR, Pritchett, 1994). These models typically ignore the details of flow in the wellbore, and treat the well in a very simplified manner. Likewise, several wellbore flow simulators exist which model the internal flow in the wellbore, with varying degrees of accuracy and sophistication (e.g., WF2, Ortíz-Ramírez, 1983; GEOTEMP2, Mondy and Duda; 1984; WELF, Miller, 1984; HOLA, Bjornsson and Bodvarsson, 1987; WFSA and WFSB, Hadgu and Freeston, 1990). These codes usually take as their input some parameters, such as flowrates and enthalpies, that would be found as output of a reservoir simulator. Several previous attempts have been made at coupling wellbore and reservoir simulators. For example, Miller (1980) developed a simplified transient-wellbore code to model wellbore storage effects. Recently, Murray and Gunn (1993) used lookup tables generated by the wellbore simulator WELLSIM to be used as input to the reservoir simulator TETRAD. We have written a computational module called COUPLE that allows the wellbore simulator WFSA to serve as a subroutine for TOUGH. The resulting coupled reservoir-wellbore simulation capability allows more accurate and integrated modeling of the exploitation of geothermal systems.

TOUGH RESERVOIR SIMULATOR

TOUGH (Pruess, 1987) is a numerical code designed to simulate the coupled transport of fluid, heat and chemical species for multi-phase flow in porous as well as fractured media. TOUGH is a three-dimensional code which solves the equations of mass and energy conservation by discretizing them in space using the "integral finite difference" method. Time is discretized in a fully implicit manner, as a first-order finite difference. Darcy's law is used to describe single-phase and two-phase flow with interference between phases represented by relative permeability functions. Thermodynamic and transport properties of water are obtained from steam table equations. Heat flow is represented by conduction, convection and gaseous phase diffusion.

At each time step, TOUGH solves mass balance and an energy balance equations for each computational gridblock. TOUGH equates the net flux into each gridblock, including source/sink terms, with the change in the stored amount of that component in the block. The difference between the change in storage and the net influx, which is called the residual, is set to zero. These balance equations are nonlinear, due to the dependence of the thermodynamic and transport properties on the independent variables pressure, temperature and saturation. An iterative Newton-Raphson method is used to solve these equations, which results in a set of linear algebraic equations at each iteration step, which are then solved using sparse matrix solvers.

TOUGH has options for describing fluid/heat injection or withdrawal from the reservoir, treated as source/sink terms. One particular type of source/sink is the "deliverability" option, in which well output is calculated based on a specified bottomhole pressure and productivity index through the equation

$$W = \nu PI(Pr - Pwb), \qquad (1)$$

$$\nu = \frac{krl\rho l}{\mu l} + \frac{krg\rho g}{\mu g}, \qquad (2)$$

where the subscript l denotes liquid, the subscript g denotes vapor, Pwb is the wellbottom pressure, Pr is the reservoir pressure in the gridblock containing the well, and ν is the effective kinematic viscosity of the flowing two-phase mixture. When using the deliverability option, Pwb must be specified in advance at some constant value. In most production scenarios, however, Pwb will vary with time. This variation can only be found by simultaneously solving for the flowfields in the reservoir and the wellbore.

PRODUCTIVITY INDEX

In order to use the deliverability option, a productivity index (PI) must be specified, in order for TOUGH to calculate the flowrate from the wellblock into the wellbore. In many instances, PI would be found by performing a history match. In principle, however, the productivity index can be found through the following analysis.

If we ignore the possibility of turbulent flow occurring near the borehole (see Kjaran and Eliasson, 1983, for a discussion of turbulent flow to geothermal boreholes), the mass flowrate would be described by the two-phase version of Darcy's law:

$$\frac{dP}{dR} = \frac{W\nu}{2\pi kHR}. \qquad (3)$$

Coats (1977) showed that this equation could be numerically integrated from R = R* to R = Rw, where R* is the effective radius of the gridblock containing the wellbore, and Rw is the radius of the wellbore. However, if the pressure drop in the wellblock is small enough that flashing does not occur, we can evaluate all properties appearing in eq. (3) at reservoir conditions, and solve directly for the flowrate. Including a skin factor to account for the added pressure drop due to an altered zone around the wellbore, we find

$$W = \frac{2\pi kH}{\nu[\ln(R^*/Rw) + s]}(Pr - Pwb). \qquad (4)$$

To find a numerical value for PI, we need to know the effective wellblock radius, R*. If a single well test is being modeled, a fine-meshed radial grid would typically be used around the wellbore. One common type of radial grid is one in which the outer radius of the ith gridblock, Ri, is defined by

$$R_{i+1} = cR_i, \qquad (5)$$

where c > 1 is a constant. For this type of grid, the effective wellblock radius will be (Aziz and Settari, 1979, p. 88)

$$R^* = \frac{\ln(c)}{(c-1)} R_1. \qquad (6)$$

The productivity index can then be found by equating (1) and (4):

$$PI = \frac{2\pi kH}{\ln(R^*/R_1) + s}, \qquad (7)$$

where R* defined by eq. (6). A similar analysis for a rectangular grid is presented in Hadgu et al. (1995).

The deliverability equation (1) was derived for steady-state cases. To test the validity of this assumption, Hadgu et al. (1995) compared the deliverability method with the analytical solution for flow from a constant-pressure wellbore, and the output from a TOUGH simulation in which the wellblock is discretized into a fine mesh. They found that the deliverability method agreed with the analytical and fine-mesh numerical solutions for sufficiently large times. The time needed for the quasi-steady-state approximation to become accurate agreed reasonably well with the value estimated by Pritchett and Garg (1980), which was $4\phi c\mu R_1^2/k$, where R_1 is the radius of the gridblock.

WELLBORE SIMULATOR WFSA

The presence of liquid water, steam, dissolved solids and non-condensable gases in the geothermal fluid renders wellbore flow a complex multi-phase flow problem. Because of these complexities, many researchers have used empirical methods to simulate the fluid flow. Unfortunately, most existing empirical correlations were derived under conditions very different from those found in geothermal wellbores, i.e., air and water as the two phases, instead of air and steam, diameters of only a few inches, etc.

The wellbore simulators WFSA and WFSB attempt to model the two-phase flow in the wellbore by actually solving a one-dimensional version of the Navier-Stokes equations. These simulators were developed at Auckland University, New Zealand (see Hadgu and Freeston, 1990). These codes include features such as presence of dissolved solids, presence of non-condensible gases, multiple feed zones, and fluid-rock heat exchange. A related code, STFLOW, was developed to handle wells in vapor-dominated fields, and can treat superheated steam. These three codes (WFSA, WFSB and STFLOW) were later combined into a single simulator with all the features, WELLSIM Version 1.0 (Gunn and Freeston, 1991). We have used WFSA in our work.

WFSA assumes that the flow is steady and one-dimensional, the phases are in thermodynamic equilibrium, and dissolved solids can be represented by NaCl. In the case of wells with multiple feedzones, the mass flowrate and enthalpy (or reservoir pressure, drawdown factor and enthalpy) are needed as input for each feed point. WFSA uses finite differences to solve the equations of mass, momentum and energy conservation along the length of the wellbore. There is no restriction on the geometry or variation of well diameter with depth, and any number of feed points can be included, provided that the mass flowrate, pressure and enthalpy of the fluid are prescribed.

COUPLING OF TOUGH AND WFSA

For a well with multiple-layer completion (i.e., multiple feedzones), TOUGH's deliverabiliy option requires a productivity index for each of the layers and a constant wellbore pressure for the uppermost one. The code then calculates wellbore pressures for the other layers based on that specified wellbore pressure. The assumption is made that wellbore pressures in other layers can be obtained approximately by accounting for gravity effects.

For the reservoir-wellbore coupling (see Fig. 1), the above procedure has been changed. The wellbore pressure of the uppermost layer is no longer required, but wellhead pressure needs to be specified instead. The deliverability option in TOUGH is used, but the calculations are performed in the separate subroutine COUPLE that couples TOUGH and WFSA. The deliverability equation (1), which connects the reservoir and the wellbore is applied at each feedzone.

An iterative procedure is utilized between COUPLE and WFSA to evaluate mass flowrates and wellbore pressures at each feedzone. The iterative methods are encoded in subroutine COUPLE, using a 4th-order Runge-Kutta method. To initiate the iteration, the first guess for Pwb in the bottom-most feedzone is taken to be slightly less than the pressure in the reservoir. Based on this initial Pwb, the mass flowrate is calculated using eq. (1). WFSA then computes fluid parameters up the wellbore until the next feedzone is encountered. Applying mass and heat balance at this feedzone yields new parameters required to continue computation up the wellbore. The procedure is repeated at each feedzone until the wellhead is reached. If the computed wellhead pressure differs from the specified wellhead pressure by more than some specified tolerance, the computation is repeated, starting from bottomhole.

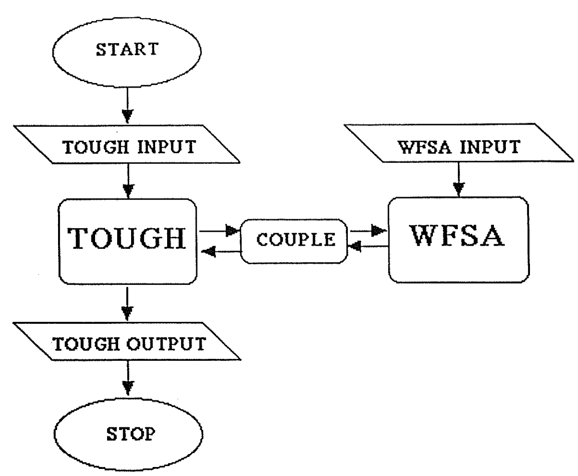

Fig. 1. Schematic diagram of the coupling procedure.

SAMPLE SIMULATIONS

Following are some sample calculations to demonstrate the use of the coupled simulation procedure; further examples can be found in Hadgu et al. (1995). We consider a single well having an inside diameter of 0.2 m, and a depth of 1000 m, located in an infinite, radially-symmetric reservoir. The reservoir has a thickness of 500 m and is overlain by a 750 m-thick caprock. The reservoir is taken to have a permeability of 0.1 D, a porosity of 0.1, a rock density of 2600 kg/m^3, and a rock specific heat of 1 kJ/kg°C. The initial conditions in the reservoir are taken to be a pressure of 60 bars, a temperature of 275.6°C, and a gas saturation of 0.1. A radial mesh was used according to eq. (5), with a wellblock radius of 100 m, and a mesh-amplification factor of c = 1.29. Using eqs. (6) and (7), and assuming no skin effect, the nodal distance for the wellblock and the productivity index were calculated to be 87.8 m and 4.64 x 10^{-11} m^3, respectively.

First, we compare the output of the coupled codes with that obtained by running TOUGH using the deliverability option. The above set of data is common for the two simulation approaches. The difference is that the coupled codes use a constant wellhead pressure, while TOUGH's deliverability option uses a constant bottomhole pressure. In order to find the best estimate for Pwb, the coupled codes were run first. The selected wellhead pressure was 7 bars. The initial calculated bottomhole pressure from the coupled codes, which was Pwb = 57.4 bars, was then used as the input to TOUGH.

The wellbore pressure is predicted to remain constant when using TOUGH's deliverability method, whereas the coupled codes predicted a drawdown (Fig. 2). The decrease in wellbore pressure is accompanied by a drop in reservoir pressure which is larger than that predicted using TOUGH's deliverability option. The larger drawdown given by the coupled codes results in a higher rise in vapor saturation, and a higher discharge rate (Fig. 3). Consequently, the initial rise in flowing enthalpy predicted by the coupled codes is also greater (Fig. 4).

We have also used the coupled simulation procedure to examine the power output of a well operating under different wellhead pressures. All parameters are taken as before, except that the initial gas saturation in the reservoir is assumed to be 0.2. Fig. 5 shows the prediction of mass flowrate at different wellhead pressures. The curves indicate an increase in mass flowrate with a decrease in wellhead pressure, which agrees with typical output curves of large-diameter production wells. The mass flowrate slowly declines with time, except for the two cases with the highest wellhead pressures. For times greater than those given in the figure, all curves show a decline in flowrate, as reservoir pressure in the wellblock declines further. Predicted flowing enthalpies consistently show a rise, with enthalpy decreasing slightly as wellhead pressure increases (Fig. 6). The mass flowrates were found to change significantly with wellhead pressure, whereas the changes in enthalpy were not as substantial (not shown; see Hadgu et al., 1995).

Electrical power output and steam consumption predictions were made using the computed mass flowrates, enthalpies and wellhead pressures, assuming that the wellhead pressure represents the turbine inlet pressure. The turbine exhaust pressure was taken to be 0.8 bars. At low wellhead pressures the mass flowrates are high, but the change in enthalpy between turbine inlet and exhaust is low; at high wellhead pressures the reverse occurs (Fig. 7). As a result, the curve for electrical power output shows a peak at intermediate pressures.

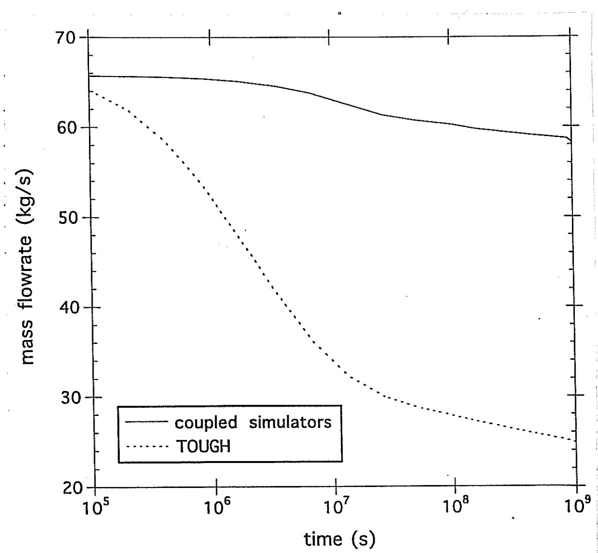

Fig. 2. Predicted reservoir pressure, Pr, and wellbottom pressure, Pwb, according to the deliverability method, and the coupled simulation procedure.

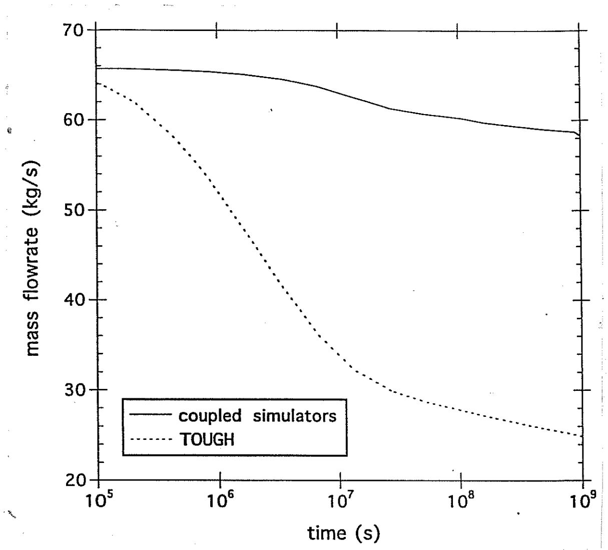

Fig. 3. Predicted discharge rates for problem discussed in text. For deliverability method, Pwb = 57.5 bars; for coupled simulation procedure, Pwh = 7 bars.

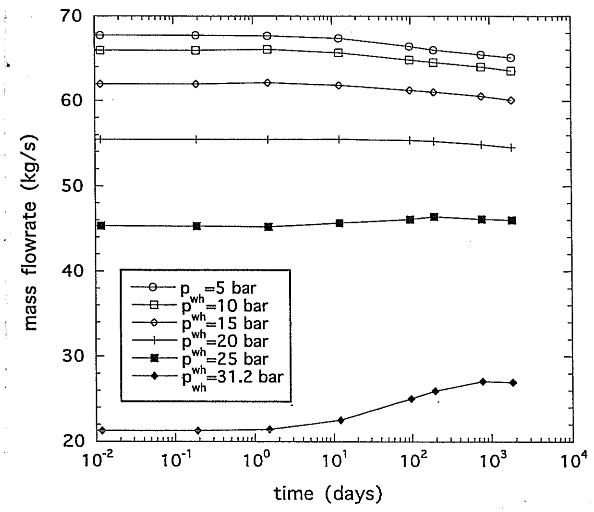

Fig. 5. Well discharge rate predicted by the coupled simulation procedure, for different wellhead pressures.

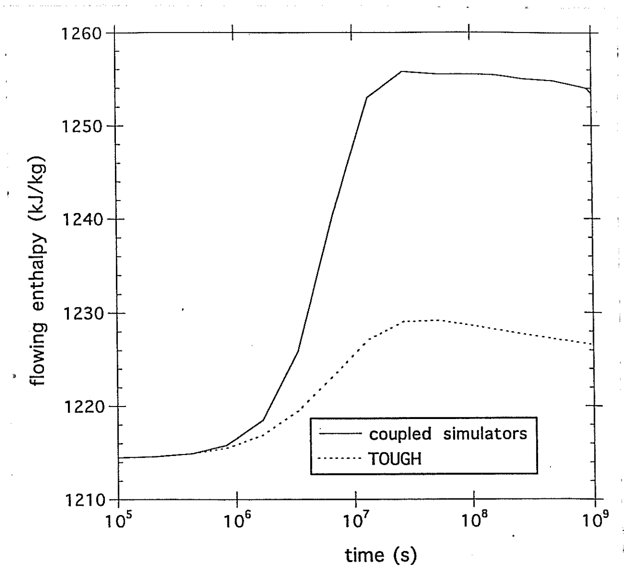

Fig. 4. Predicted flowing enthalpy; same problem as shown in Figs. 2 and 3.

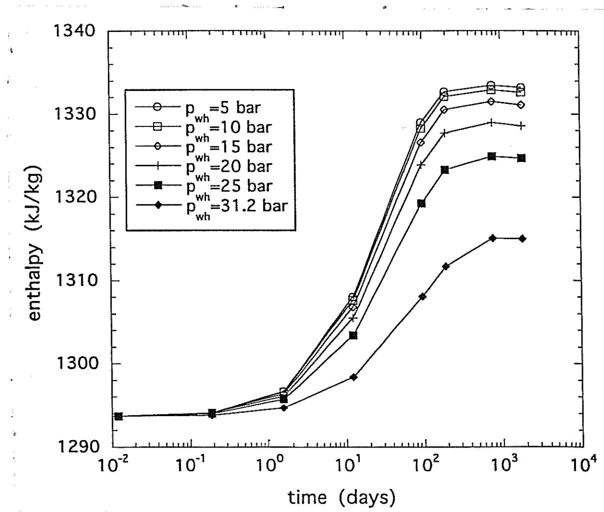

Fig. 6. Flowing enthalpies predicted by the coupled simulation procedure, for different wellhead pressures.

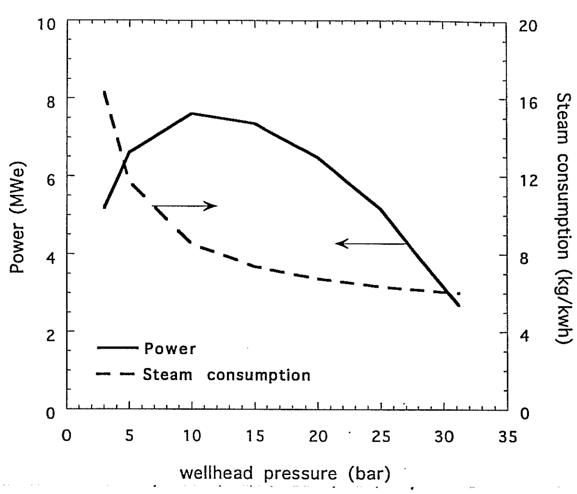

Fig. 7. Electrical power output and steam consumption, after five years of production.

SUMMARY

A module "COUPLE" has been developed to act as an interface between the reservoir simulator TOUGH and the wellbore simulator WFSA. This allows coupled, simultaneous simulation of flow in the wellbore and the reservoir. Some sample simulations were conducted to compare outputs of the coupled codes with that of TOUGH's deliverability method, and also to demonstrate possible applications of the coupled simulation procedure. The coupled simulation procedure is expected to be useful in simulating the behavior of geothermal reservoirs.

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