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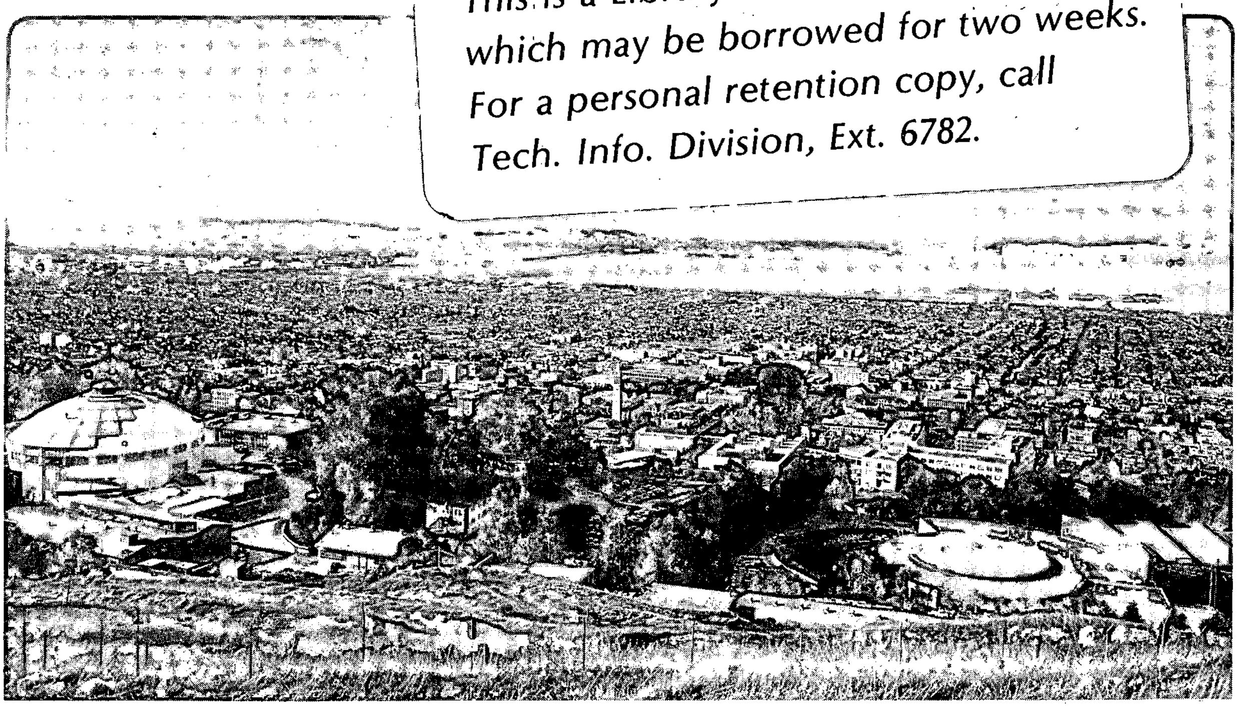

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DISCLAIMER

A STUDY OF NONISOTHERMAL CHEMICAL TRANSPORT IN GEOTHERMAL SYSTEMS BY A THREE-DIMENSIONAL COUPLED THERMAL AND HYDROLOGIC PARCEL MODEL

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ABSTRACT

This paper describes a new three-dimensional numerical simulator, CPT, developed at Lawrence Berkeley Laboratory to understand the implications of chemical-hydro-thermal coupled physical processes for geothermal reservoir engineering. CPT is an improved version of the well-validated code PT used in several geothermal reservoir engineering studies. The use of model CPT is illustrated for three different examples. In the first case, a dense fluid is injected into a partially penetrating well in the upper portion of a reservoir. In the second case, a geothermal reservoir containing carbonates is produced where the colder recharge water partly dissolves the carbonates as it flows toward the well. In the third case, the effects of using either nonreacting or reacting tracers for locating an injected cold front are examined for the case of injection and production wells connected by a fracture zone.

INTRODUCTION

Reservoir engineering in nonisothermal systems such as geothermal reservoirs presents a challenge to conventional well testing, production, and injection techniques. This is particularly true because there are many phenomena which need to be understood as coupled physical processes (e.g., buoyancy flow, tracers which react with minerals in the reservoir matrix, temperature-dependent chemical reactions in the reservoir, etc.). To analyze these complex coupled processes in the field is very difficult and very often numerical modeling offers a useful means to investigate their implications. The objective of this study is to indicate how numerical simulation can give valuable insights into the coupled thermal, hydrologic, and chemical processes in geothermal reservoirs.

MODEL

The numerical model CPT employed in this study was developed at Lawrence Berkeley Laboratory from an earlier code PT (Bodvarsson, 1982) which has been extensively applied in geothermal reservoir engineering research studies. PT is a three-dimensional single-phase simulator which has been validated against numerous analytical solutions for thermal and hydrologic processes, a number of geothermal reservoir development studies, and several field experiments (Tsang et al., 1981). It includes the capabilities to model complex three-dimensional geometry, heterogeneous porous and fractured media, and temperature-dependent fluid and rock properties. The energy and mass equations are solved using an efficient sparse matrix solver.

CPT has the addition of a parcel model for chemical transport and provides for changes in the permeability of the rock matrix due to either temperature changes or chemical reactions. At each time step the parcel model calculates chemical transport using the newly calculated values of temperature and pressure. In this way, the chemical transport is interlaced with the pressure and temperature calculations. Changes in permeability affect pressure and mass flow on the next time-step after they occur.

CASE I: Partial Penetration Injection Test With a Dense Fluid

The fluid injected into a geothermal reservoir usually is different from the reservoir fluid. In addition to a temperature difference, the injected fluid may have a greater density, either from utilizing spent brine after flashing with a greater concentration of chemical constituents, or because some solutes have been added to it for the purpose of the test. For a well which partially penetrates the upper portion of the reservoir this may lead to less recovery during the succeeding production period. A colder fluid tends to sink in a warm reservoir due to differences in density caused by temperature differences. However, the cooler injected water will be gradually warmed by the reservoir heat as it advances into the reservoir, which slows the downward movement. However, such a temperature-dependent process does not account for density differences due to chemical composition which may be equally great.

For this injection test the difference in water density between the reservoir temperature of 200°C (392°F) and the injected water at 100°C (212°F) is approximately 10%. In this case in our exploratory study, the concentration of the solutes in the injected water was increased enough to increase the density of the injected fluid by another

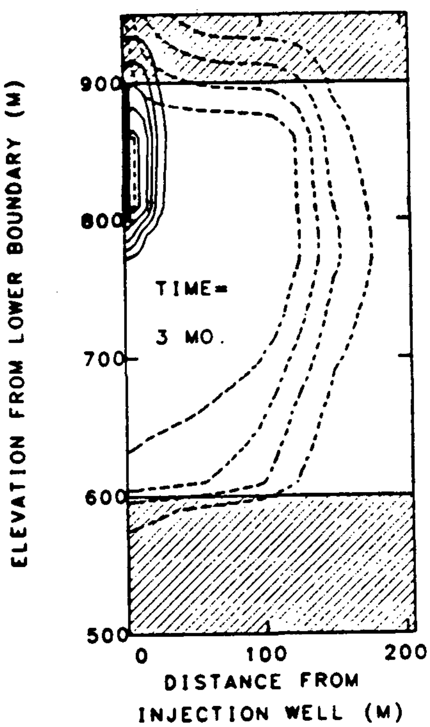
10%. The injection was performed for 3 months through a well penetrating the upper 100 m (~300 ft) of a 300 m (~900 ft)-thick geothermal reservoir. Afterwards, the well was produced for 3 months at the same rate as the injection, 20 kg/s (~300 gal/min). A list of properties used for the reservoir in this case and the following cases is given in Table 1. A homogeneous reservoir bounded vertically by less permeable confining layers is modeled with a radially symmetric mesh.

Table 1. Reservoir Properties.

Permeability	5×10^{-14} m^2 (50 md)
Porosity	0.20
Compressibility	2×10^{-10} Pa^{-1} (1.4×10^{-6} psi^{-1})
Thermal Conductivity	2.0 W/m·k (1.16 Btu/h·ft^2·°F/ft)
Heat Capacity	1000 J/kg·k (240 Btu/lbm·°F)
Density	2650 kg/m^3 (166 lbm/ft^3)

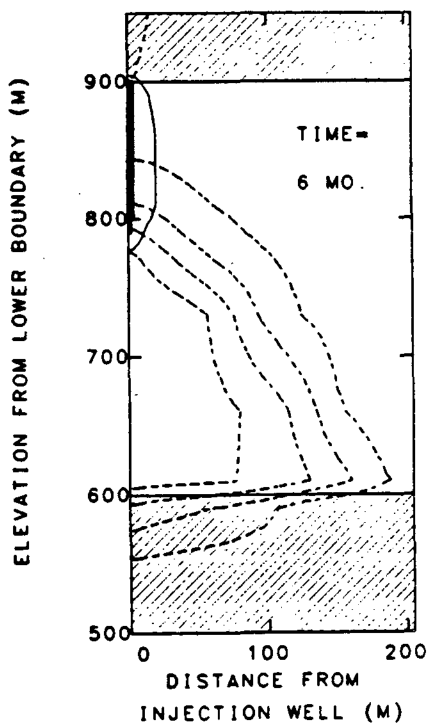
Fracture zone has 10 times reservoir permeability, with other properties the same. Caprock and bedrock have 10 times less permeability than the reservoir, with other properties the same.

The results after injection and production are shown in Figures 1 and 2. In Figure 1, the solid lines indicate the temperature contours in increments of 20°C (36°F) and the dashed lines indicate the concentration contours in increments of 20% of the initial injection concentration. It is apparent that the fluid moves downward more rapidly due to chemical concentration effects on density than due to temperature effects alone. Figure 2 illustrates the same contours after the production period: the downward movement of the denser fluid is clearly shown, despite the production of much of the cooler water injected in the first 3 months. This means that an examination of the recovery of the injected chemicals during the production period might lead to a misinterpretation of the significance of the test. The chemical substance(s) in the injected water are causing some of this water to sink deeper than predicted with temperature-induced density changes alone, and even to remain in the reservoir during the production period. This shows that low recovery of the chemical constituents of the injected fluid may be due to the effect of chemical concentration on density in conjunction with a partially penetrating well rather than to chemical reactions, adsorption, or permeability inhomogeneities such as fractures.



DENSE FLUID INJECTION

Fig. 1. Temperature (solid) and concentration (dashed) contours after 3 months of injection of 100°C (212°F) water into a 200°C (392°F) reservoir from a partially penetrating well.



PRODUCTION OF FLUID

Fig. 2. Temperature (solid) and concentration (dashed) contours after 3 months of production following 3 months of injection from a partially penetrating well.

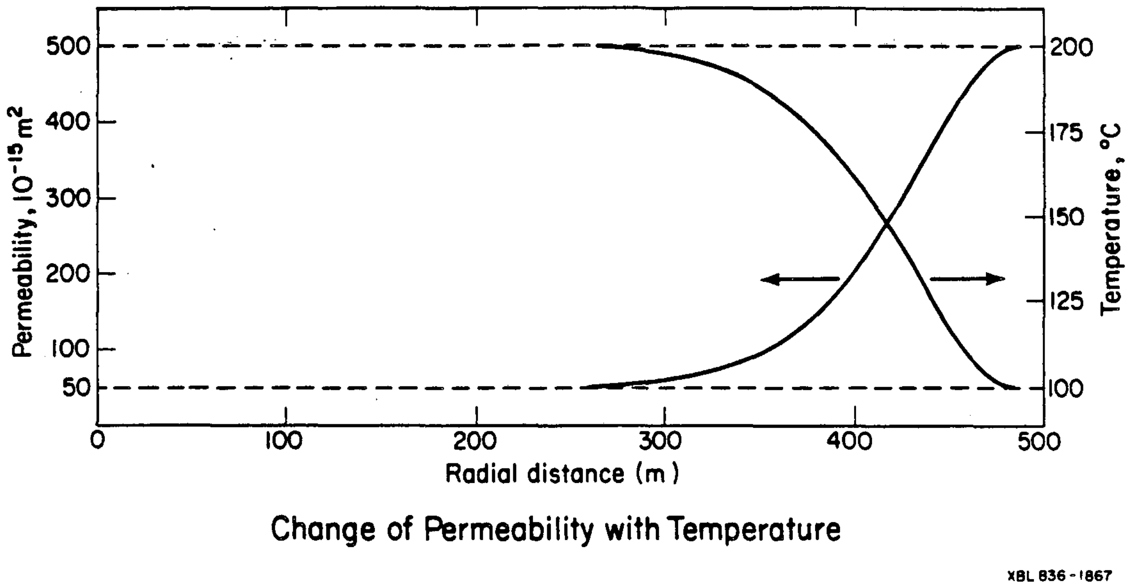


Fig. 3. Change of permeability with temperature for a 500 m (~1500 ft)-radius reservoir after 5 years of production. Permeability is indicated by the scale on the left in 10^{-15} m^2 (md), and temperature by the scale on the right in °C.

CASE II: Production of a Reservoir Containing Carbonate

In this case a geothermal reservoir containing carbonates is being produced, and the effect of the recharge of cooler waters is examined. A simplified mesh design was used with radial symmetry. The reservoir is at 200°C (392°F) and extends 500 m (~1500 ft) radially; beyond this point there is still carbonate but the ambient temperature is 100°C (212°F). A constant pressure at the production well and at the radial boundary 8 km away was assumed. It is well known that, unlike many other substances, the solubility of carbonate varies inversely with temperature; it changes by two orders of magnitude between 100°C and 200°C (Kharaka and Barnes, 1973). If some of the flow paths in the reservoir matrix are filled by carbonate, then the cooler water will dissolve it, increase the permeability, and allow a greater influx of the cold recharge water to penetrate the reservoir. This effect was modeled by assuming that the permeability increases tenfold when all the available carbonate is dissolved.

Figure 3 snows the change of permeability with temperature as a function of radial distance after 5 years of production. The curves indicate that the carbonate dissolution induced by the advancing cold front did increase the permeability significantly. However, in this example the greater permeability did not appear to cause more rapid advance of the thermal front.

In addition to the permeability, the calculated front movement depends also on the viscosity and density of the water.

CASE III: Locating a Thermal Front by Two Kinds of Tracers

In reinjection schemes it is desirable to know how far a thermal front has advanced toward the production wells. One means which has been suggested for doing this is to inject a tracer along with the cooler water and, based on tracer movements, to estimate the location of the thermal front. The tracer will move faster than the thermal front as long as adsorption or other chemical processes do not retard it significantly. The tracer thus provides a warning of the thermal front's approach to the production wells. However, in some cases, chemical process may occur which inhibit the tracer movement so it may be of little use in predicting front location.

These two situations were modeled generically by a planar two-dimensional one-layer reservoir with a fracture zone joining two wells 1 km (~.63 mile) apart. The fracture zone has 10 times the permeability of the surrounding porous medium. Cool water containing either a "reacting" or a "nonreacting" tracer is injected into one well at 20 kg/s (~300 gal/min) while the other well is produced at the same rate.

Figures 4 and 5 display the results for nonreacting and reacting tracers, respectively. The temperature contours (solid) are in increments of 10°C (18°F) and the concentration contours (dashed) are at levels of 1%, 5%, and 10% of the original injection concentration. In Figure 4 the tracer follows the hydrologic front and could be detected at an observation well midway between the injection

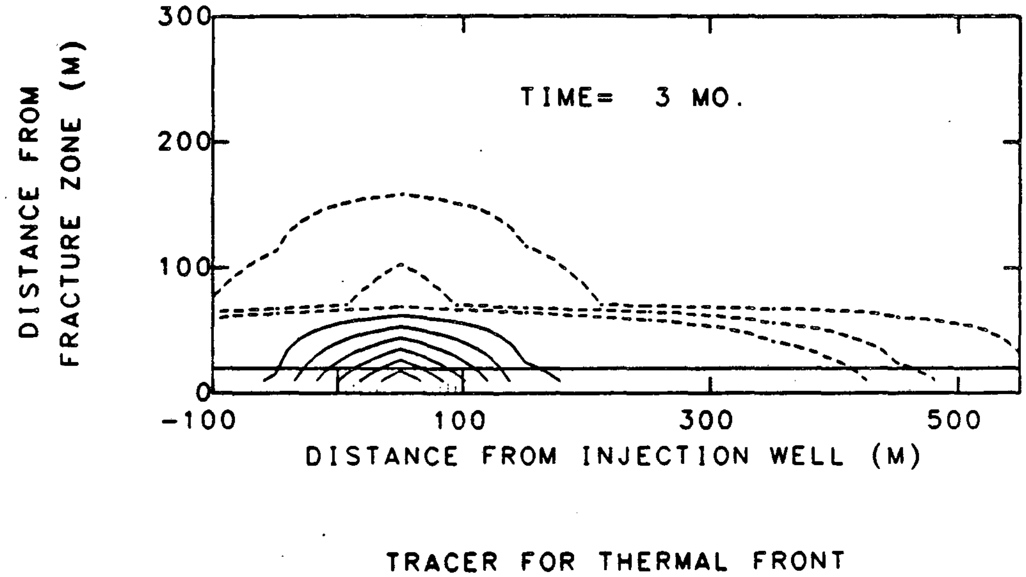


Fig. 4. Temperature (solid) and concentration (dashed) contours for injection, including a tracer, into a one-layer plane reservoir with a fracture zone extending from the injection well to the production well.

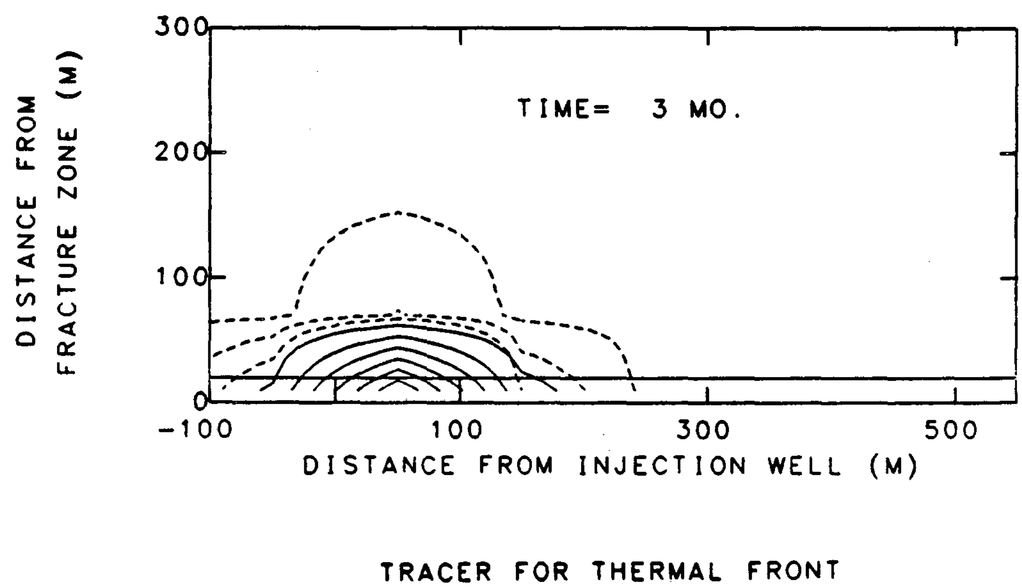


Fig. 5. Temperature (solid) and concentration (dashed) contours for injection, including a tracer, into a one-layer plane reservoir with a fracture zone extending from the production well, where the tracer is retarded by a substance in the fracture zone.

and production wells at 1% of its original injected concentration after 3 months. The temperature front has only advanced approximately 100 m (~300 ft). This gives much advance indication of the thermal front. Figure 5 shows that for a strongly reacting tracer, there is no indication of the thermal front because the tracer has been significantly retarded.

These two situations show both the benefits and the difficulties with using tracers for locating thermal fronts. The modeling of such a technique, however, may help the reservoir engineer to understand actual field results and to evaluate tracer use by predicting their effects under different conditions before employing them.

CONCLUSION

The three cases modeled illustrate the use of model CPT for understanding the complex coupled physical processes which can occur in geothermal reservoirs. The model is equipped to investigate the many coupled processes operating in geothermal reservoirs. Depending on the temperatures of the different waters and the water-rock chemical interactions, especially with their effect on fluid viscosity and rock hydrologic parameters such as permeability and porosity, a number of different outcomes for producing the reservoir could happen. For example, a discussion of viscosity effects on well test analysis was published earlier (Mangold et al., 1981). These various possible situations can be modeled by CPT over a range of different hydrologic parameter values, possible chemical reactions and exploitation strategies in order to see the significance and implications of each of the potential factors. The model can thereby give insight into the dynamics of these coupled processes, and their importance for reservoir engineering decisions.

ACKNOWLEDGMENTS

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