THE REPLACEMENT OF GEOTHERMAL RESERVOIR BRINE AS A MEANS OF REDUCING SOLIDS PRECIPITATION AND SCALE FORMATION

by
John C. Martin
Chevron Oil Field Research Company
P. O. Box 466, La Habra, CA 90631

INTRODUCTION

A number of technical difficulties are encountered in producing geothermal energy from reservoirs containing brines with high concentrations of dissolved solids. The reduction in temperature and pressure associated with brine production results in the precipitation of solids which can form heavy scale in producing and injection wells and in surface equipment. Evidently under many conditions precipitates form in the reservoir surrounding producing wells, thereby reducing their productivity. In some cases the precipitation of solids is so severe that it can prevent economic production.

This paper presents results of an investigation of the possibility of injecting a different water in a geothermal reservoir as a means of reducing problems caused by solids precipitation and scale formation. Corrosion problems may also be reduced depending upon the water-rock-metal behavior. The results are confined chiefly to reservoir mechanics, a logical first step in evaluating the process for a given reservoir. Water-rock chemistry, water treating, water supply, brine disposal and overall economics are discussed only briefly or are beyond the scope of this paper.

In general the composition of water injected into geothermal reservoirs does not remain the same. In addition to mixing with the original water the injected water tends to equilibrate with the reservoir rock. If fresh water is injected it may pick up such minerals as silica, carbonate, iron, sulphur, etc. These minerals may precipitate and cause problems in producing the reservoir. Nevertheless, under suitable conditions, a change in the reservoir water may be an attractive alternative to cycling the original reservoir brine.

DISCUSSION

Figures 1 and 2 illustrate one method of replacing the original reservoir brine with injected water. Figure 1 illustrates a single well injecting water. Region 1 contains injection water that has cooled the reservoir rock. Region 2 contains injection water that has been heated by the rock and adjacent formations. Region 3 contains the original brine at high temperatures. Figure 2 illustrates cycling operations. The original injection well continues as an injection well and two producing wells produce hot injection water from Region 2.

An alternate method to that illustrated is to produce the reservoir heat by continuous water cycling. The original reservoir brine is produced but a different water is injected. This method may be particularly attractive for very low porosity reservoirs in which many pore volumes of water are required to produce the heat by water cycling,

The ratio of the volume of Region 1 to the volume of Regions 1 and 2 of Figures 1 and 2 is the ratio of the cold water volume to the injection water volume. This ratio is determined by the ratio of the velocity of the cold bank separating Regions 1 and 2 and the velocity of the injection water bank separating Regions 2 and 3.

The velocity of the injection water bank, u_f, is:

$$u_f = \frac{u_{w2}}{\phi} \tag{1}$$

Where ϕ is the porosity and u_{w2} is the volumetric flow rate of the hot injection water per unit cross section area. The relation for the velocity of the cold bank, u_c, can be obtained by applying mass and heat balances across the cold bank

$$\frac{u_c}{u_{w2}} = \frac{1}{\phi\left[1+\left(\frac{1-\phi}{\phi}\right)\frac{\rho_r}{\rho_{w2}}\frac{\left(h_{r1}-h_{r2}\right)}{\left(h_{w1}-h_{w2}\right)}\right]} \tag{2}$$

Where the subscripts 1 and 2 refer to Regions 1 and 2 respectively, and

- h_r is the enthalpy of the solid portion of the rock
- h_w is the enthalpy of the water
- ρ_r is the density of the solid portion of the rock
- ρ_w is the density of the water

The desired ratio, u_c/u_f is (from equations 1 and 2)

$$\frac{u}{u_f} \quad \frac{1}{1+\left(\frac{1-\phi}{\phi}\right)N} \tag{3}$$

where

$$N \equiv \frac{\rho_r\left(h_{r1}-h_{r2}\right)}{\rho_{w2}\left(h_{w1}-h_{w2}\right)} \tag{4}$$

In most potential applications N lies between .5 and 1.0. Using the porosities found in oil and gas reservoirs as a guide, one would expect the porosities of geothermal reservoirs to vary from about .01 for some fractured reservoirs with no matrix porosity to about .35 for highly porous sandstone reservoirs. These ranges of N and ϕ result in a range of u_c/u_f from about .01 to about .50. Thus, the volume of injection water may vary from about twice that of the cold water to perhaps as much as 100 times larger.

The proposed method of water injection appears favorable for low values of u_c/u_f. These low values correspond to low porosity reservoirs where flushing the brine from the reservoir and replacing it with injection water might remove only a small fraction of the useful heat initially contained in the reservoir. The prospects are much less favorable for highly porous reservoirs as illustrated by the example discussed in the following paragraphs.

Performance predictions were made for an idealized, uniform, two-dimensional, radially symmetric reservoir with the initial temperature distribution given in Figure 3-a. The calculations were made using a stream tube model in which the fluid mobility varies along the stream tubes as required by the temperature-viscosity relation. A constant pressure difference of 1000 psi was maintained between injection and production wells, and a constant pressure outer boundary was assumed at a radial distance of 20,000 feet. No heat recharge was assumed, the change in water density was neglected, and heat conduction effects were ignored. Other parameters were: porosity .25, permeability 500 md, u_c/u_f fixed at .257, and well bore radii of .46 feet;.

Figure 3 presents the temperature distribution, the stream lines, the well patterns, and the injection water and the cold banks at various times. Continuous over-injection was maintained over most of the life of the reservoir in order to maintain a sufficiently wide region of hot injection water in which to locate the production wells. In general, at cold water breakthrough producing wells were either converted to injection wells or shut in until a more appropriate time to convert them to injectors. The production wells were located and operated so that none of the original brine was produced.

The cumulative water injected and produced and the temperature of the produced water versus time are presented in Figure 4. The two sharp drops in temperature of the produced water during the first five years and the sharp drop during the twenty-fourth year are the result of cold water breakthrough into the production wells. The other three sharp temperature drops result from locating production wells in areas with lower temperatures. The gradual rises following these three drops are caused by higher temperatures being propagated outward from the center of the reservoir.

The average injection rate per well per foot of interval during the first twenty-three years of production was 676 B/D/ft, and the average production rate was 633 B/D/ft. During this time there was an average of 16 active injection wells, 8 active production wells, 3 wells shut in and 39 wells abandoned. On the average only about 57% of the wells were utilized at any time. Since well cost can be the dominant cost of geothermal reservoir development, the production of injection water heated by the geothermal reservoir as illustrated in this idealized example can add significantly to the production costs in a high porosity reservoir.

The idealized two-dimensional model illustrates some of the problems associated with high porosity reservoirs. As pointed out previously, the processes whereby injection water is heated within the reservoir and then produced should become more economical to apply for reservoirs with smaller porosities. Smaller porosities are associated with smaller values of u_c/u_f. This indicates larger regions containing hot injected water relative to the cold water regions. Results presented in Figure 3 indicate that larger regions containing hot water allow more efficient use of wells.

CONCLUSIONS

1. Problems with solids precipitation and scale formation may be reduced in some geothermal reservoirs by replacing the original reservoir brine with fresh water or a water with a different dissolved solids content.

2. Injection of a water different from the original reservoir brine is particularly attractive for very low porosity reservoirs where many pore volumes of water are needed to produce the reservoir heat by water cycling.

ACKNOWLEDGMENT

The two-dimensional reservoir performance calculations were made by R. E. Wegner assisted by F. J. Kelsey. Appreciation is extended to M. G. Reed for his valuable suggestions.

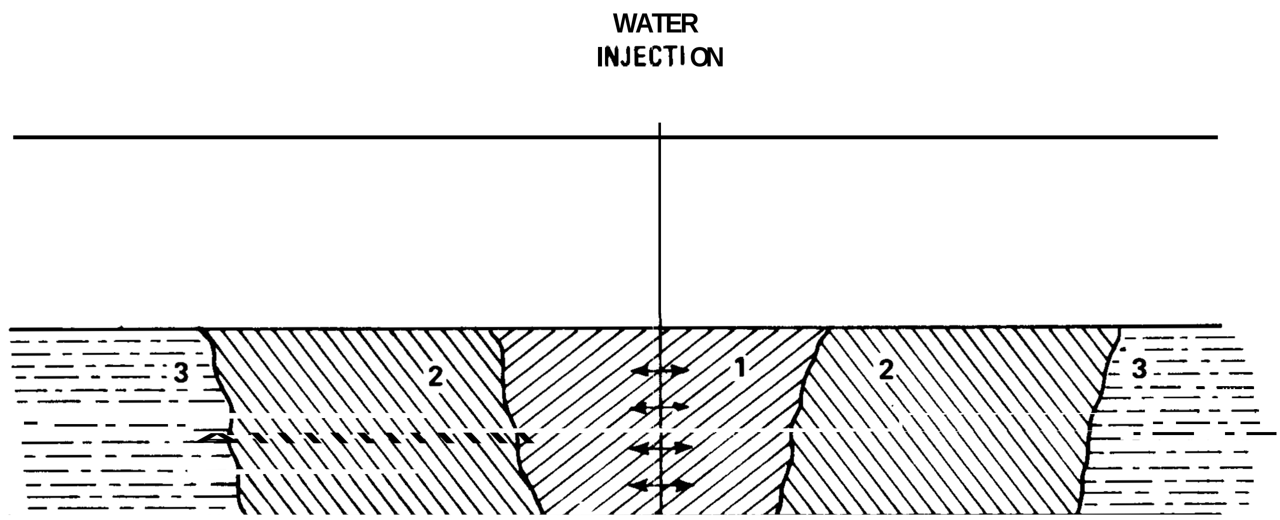


FIGURE 1

AN ILLUSTRATION OF WATER INJECTION INTO A GEOTHERMAL RESERVOIR. REGION 1 CONTAINS COOL INJECTION WATER, REGION 2 CONTAINS HOT INJECTION WATER, AND REGION 3 CONTAINS HOT BRINE.

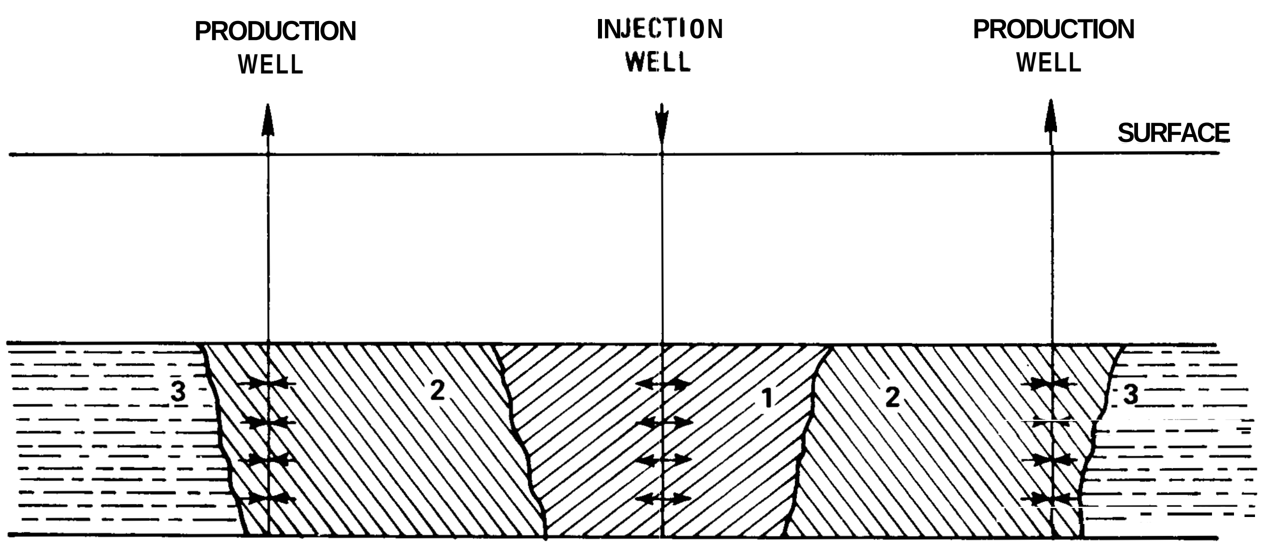


FIGURE 2

AN ILLUSTRATION OF A INJECTION WATER CYCLING OPERATION.

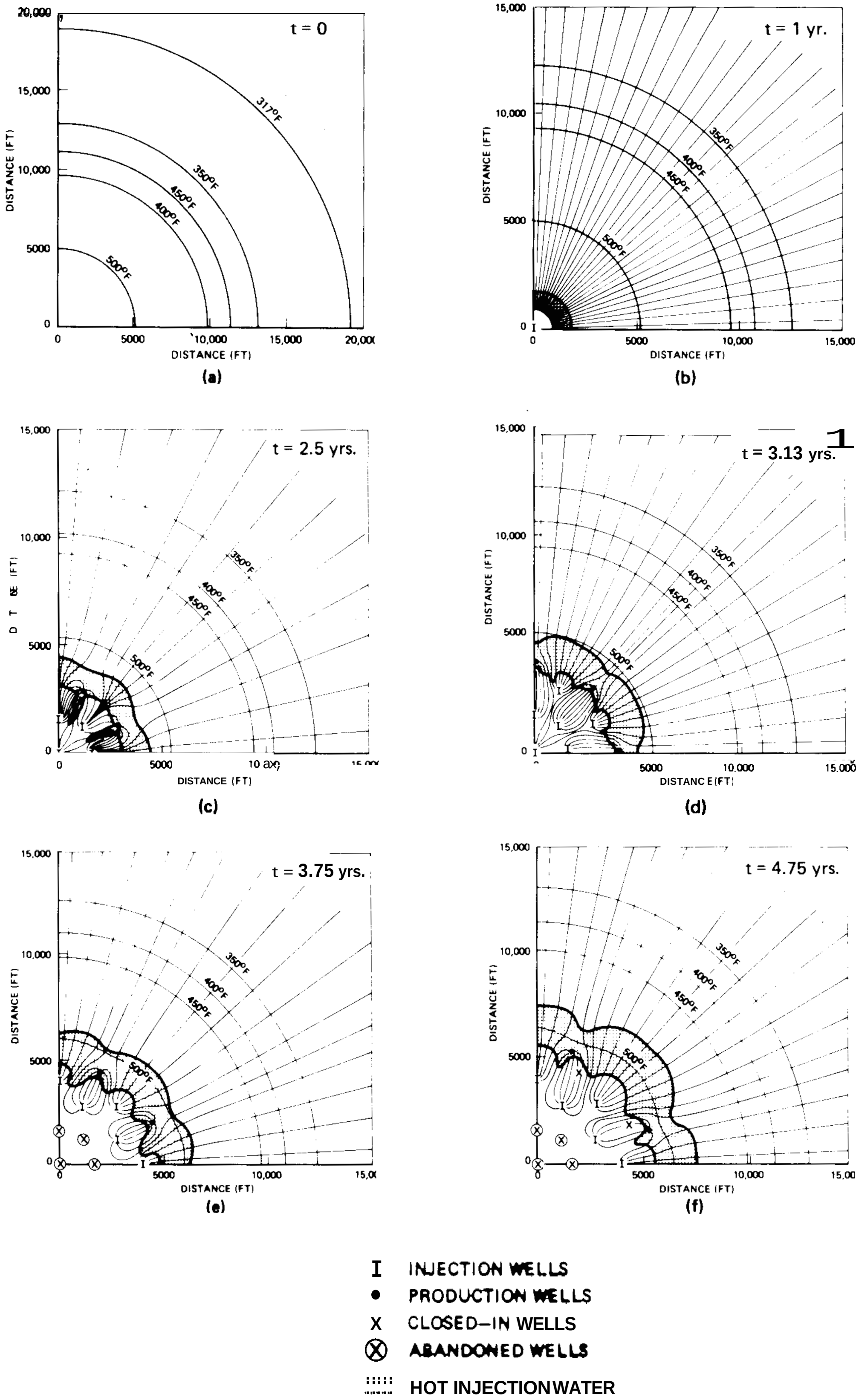
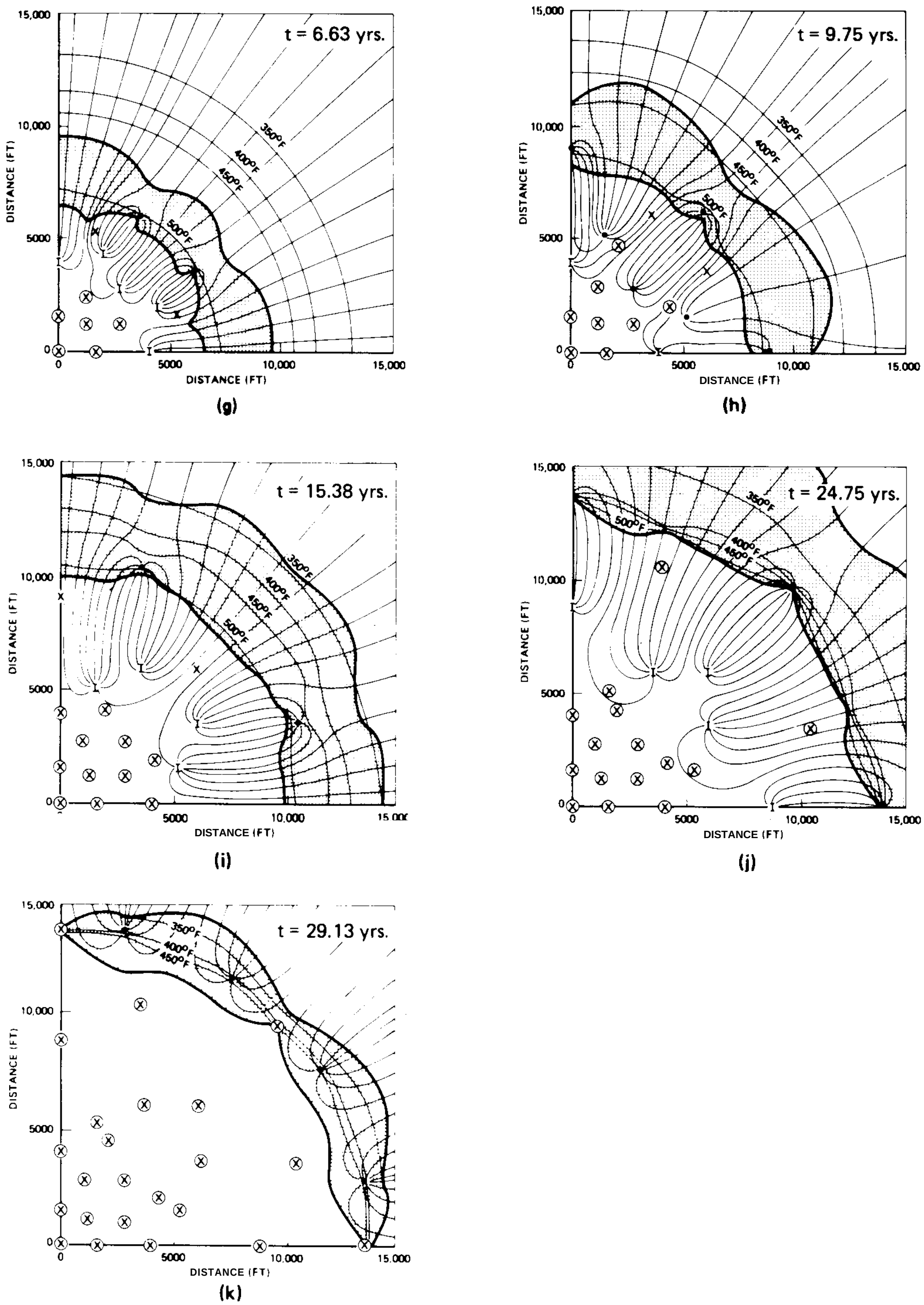


FIGURE 3

POSITIONS OF COLD AND INJECTED WATER BANKS, TEMPERATURE DISTRIBUTIONS, STREAM LINES, AND WELL PATTERNS AT VARIOUS TIMES DURING RESERVOIR PRODUCTION FOR ONE QUARTER OF THE IDEALIZED TWO DIMENSIONAL RESERVOIR.



I INJECTION WELLS
● PRODUCTION WELLS
X CLOSED-IN WELLS
⊗ ABANDONED WELLS
HOT INJECTION WATER

FIGURE 3
CONCLUDED

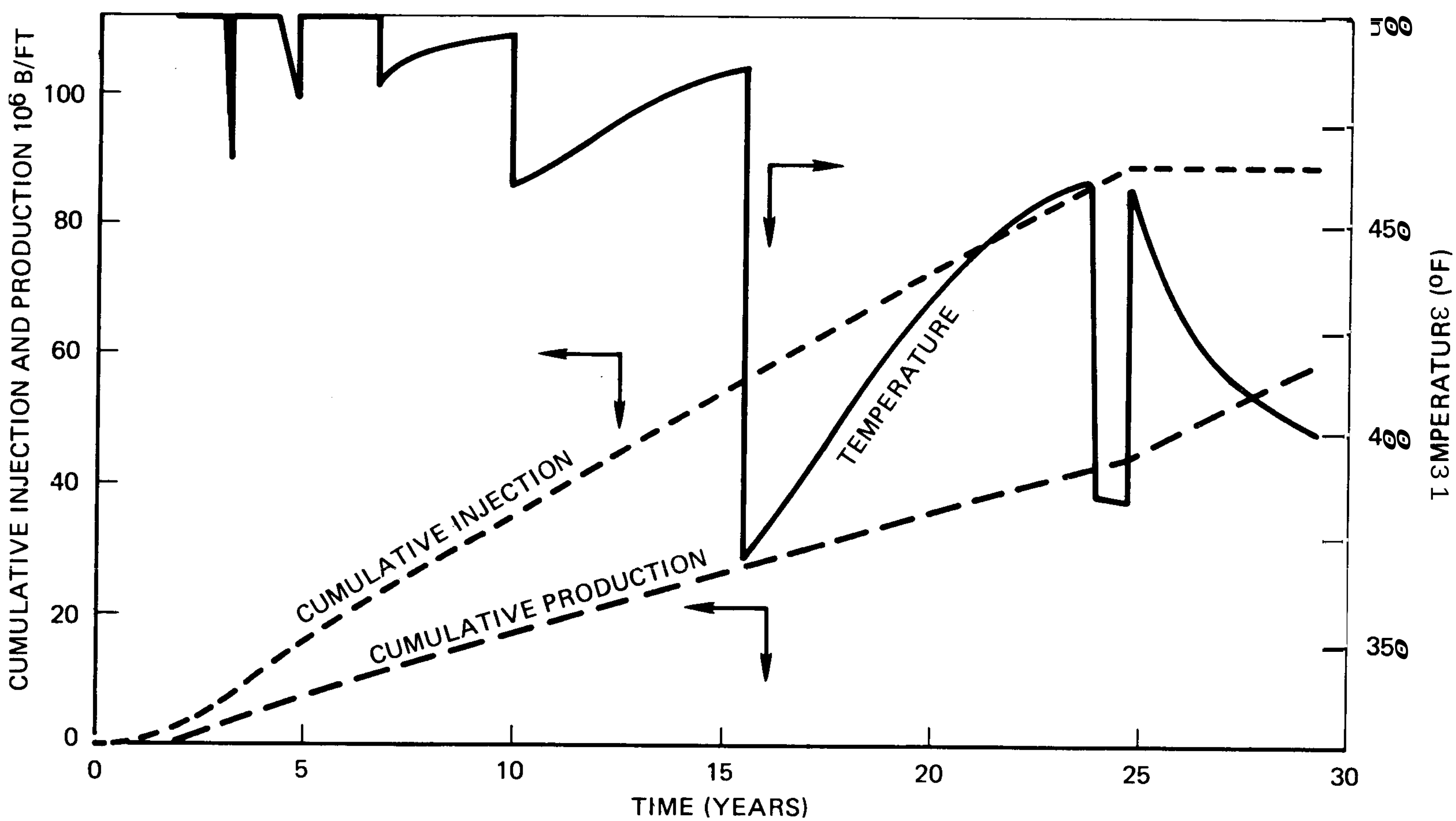


FIGURE 4

TEMPERATURE OF PRODUCED WATER AND CUMULATIVE WATER INJECTION AND PRODUCTION FOR IDEALIZED TWO DIMENSIONAL GEOTHERMAL RESERVOIR