NUMERICAL STUDIES OF THE ENERGY SWEEP IN FIVE-SPOT GEOTHERMAL PRODUCTION/INJECTION SYSTEMS

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INTRODUCTION

Most recent interest in the injection of cold water into a geothermal reservoir has been related to the disposal of geothermal brines. Injection also offers the potential benefit of prolonging the useful life of a vapor-dominated system by providing additional water to extract energy out of the rock matrix. In a liquid-dominated reservoir injection may help to maintain pressures near the production wells by pushing the hot water toward them and preventing too much local boiling. Pressure maintenance can also be achieved for superheated steam zones, because injection will cause pressures to increase towards the saturation pressure (Schroeder et al. (1980)).

The general physical principles governing these processes are understood but no quantitative information is available. The present work is aimed at helping to improve the qualitative and quantitative understanding of injection into a geothermal reservoir by considering a few idealized problems. First a vapor-dominated, single layer reservoir is considered, next a vapor-dominated, four layer reservoir, and finally a liquid-dominated, single layer reservoir. In each case varying injection rates are considered and in some cases the injection is changed at different times.

The SHAFT79 simulator (see Pruess and Schroeder (1979) for example) is used to calculate the reservoir behavior in each case. It is only with the advent of efficient geothermal reservoir simulators, such as SHAFT79 and other codes (see Coats (1977), Faust and Mercer (1979) and Brownell et al. (1975), for example), that it is possible to calculate the behavior of a two-phase reservoir during injection. The condensation of steam and the movement of thermal and hydrodynamic fronts through the reservoir as a cold zone around an injection well expands are severe tests of the capabilities of a simulator and are very difficult phenomena to model accurately. Previous work by the authors (O'Sullivan and Pruess (1980), Schroeder et al. (1980)) has demonstrated the accuracy of SHAFT79 in modeling injection problems.

Our calculations are made for a five-spot configuration of alternate, off-set rows of producers and injectors (see Figure 1). A calculation mesh with 34 nodes (see Figure 1) is used, which is barely sufficient to give accurate results. In fact, some of the results exhibit small oscillations with time due to this relatively coarse discretization.

Five-spot problems for water flooding of oil reservoirs have received considerable attention over the years, and more recently steam flooding problems are also being considered (see Taschman (1980), Greaser and Share (1980)). In oil reservoir injection/production problems the basic problem is one of mass recovery and the injected and produced fluid are not miscible. For geothermal reservoirs the problem involves both mass and energy recovery and the injected fluid may be usefully produced once it absorbs heat from the rock. The interaction of heat and mass transfer makes the geothermal five-spot problem more difficult than the corresponding oil problem. And so far little work has been done on it.

For the injection of cold water into an entirely hot water reservoir no two-phase effects are present, making the problems much more tractable, and several workers have investigated them (see Lippmann et al. (1977), for example).

VAPOR-DOMINATED RESERVOIR

The reservoir parameters are listed in Table 1. They were chosen to be similar to those for vapor-dominated fields such as that at Larderello, Italy, but are basically rather arbitrary. The production rate was selected to give a fluid supply of approximately 30 years. The reservoir was produced at a constant rate of 0.0025 kg/s.m in all cases, and different injection rates tested. The calculation was stopped when the pressure in the production node dropped below 0.7 MPa, taken to be a representative minimum value required to sustain flow in the well.

The results in Table 2 summarize the energy and fluid production data (for the calculation zone and a reservoir of 10 m thickness). With no injection the reservoir lasts 33.2 years, at which time nearly all the fluid has been extracted, but of the original 57.4×10^{13} J of energy in the reservoir only 7.3×10^{13} J have been extracted. Not all of the original energy could be easily extracted. For comparison, the rock alone at 180 °C would contain 40.8×10^{13} J, indicating that there is more high quality energy left in the rock than was produced. Towards the end of the life of the field when little mass remains, the pressure drops very fast (see Figure 2).

If cold water (40 ^{o}C) is injected at the same rate as it is produced, the reservoir lasts 39.7 years, and an extra 1.0×10^{13} J of energy are extracted. Now the pressure declines not because the reservoir is running out of mass, but because the mass is too far from the production well, and the pressure gradient required to cause it to flow across is so great that the pressure in the production block drops until the cut off of 0.7 MPa is reached.

An injection rate of double the production rate causes the field to last 49.6 years, and the final energy content is now 47.5×10^{13} J. But again the pressure drops too low, trying to induce the fluid to flow from the injection well to the producing well. An injection rate of three times the production rate produces a premature break-through of cold water. The high injection rate causes a tongue of cold water to reach the producer at around 40 years. However, energy recovery can be improved by a high initial injection rate and then cutting off all injection. The last figures in Table 2 are for 26.9 years of 300% injection followed by a period of no injection up to 57.3 years. At this stage only 45.6×10^{13} J remain in the reservoir. This strategy results in the extraction of 11.8×10^{13} J as opposed to 7.3×10^{13} J with no injection.

The pressure decline curves in Figure 2 show clearly the slightly faster rate of pressure drop resulting from the reduction of the volume available for boiling when injection takes place.

GRAVITY EFFECTS

No further attempts were made to optimize energy extraction because the reservoir considered has some limitations in its practicality. Probably the most severe limitation is that in a single layer reservoir all vertical flow is neglected. When dense cold water is being injected into a hot high vapor saturation region, gravity induced vertical flows will be large. To investigate this effect a four layer reservoir, each 25 m thick, was considered. The reservoir properties used were identical to those for the single layer case. As expected, the injected water mostly moves to the bottom of the reservoir and after 11.6 years the production from the bottom layer is a two-phase mixture rather than dry steam. The vapor saturation profile between the production and injection wells in each layer, labeled A,B,C,D, in descending order, is shown in Figure 3 with the single layer result given for comparison. Because the mesh used is three-dimensional, the calculation is expensive and no further experimentation was carried out, but obviously gravity is very important in determining the optimum energy recovery strategy for a reservoir.

LIQUID-DOMINATED RESERVOIR

A single layer reservoir with the same properties as those given in Table 1 for the vapor-dominated case was considered. The initial pressure was taken as 3.58 MPa, approximately 0.13 MPa above the boiling pressure at 240 ^{o}C. With no injection, the reservoir quickly boils and as the vapor saturation increases near the production well, and the mobility therefore declines, the pressure drops in the production block steadily with failure of the reservoir after 9.6 years. At this stage, plenty of mass and energy remain in the reservoir. The failure has occurred solely as a result of local boiling near the production well. With an injection rate equal to the production rate, boiling in the reservoir is kept at a low level, and production can be continued for 120 years with the useful heat in the reservoir mostly swept out. An injection rate half of the production rate maintains production pressures for approximately 16 years, but then local boiling again causes a sharp decline in pressure (see Figure 4). The effect of delaying injection was investigated by having no injection for six years and then injecting at the same rate as production. In this case the production block pressure first drops even more steeply. This occurs because the first effect of injection is to reduce the volume of boiling fluid available for steam production. After a short time the extra steam produced by the injected fluid near the injection well reaches the production block, increasing the pressure and temperature there. This effect is shown in the temperature profiles at 7.2 years and 8.7 years respectively (see Figure 5).

As the steam production in the middle of the reservoir proceeds, it cools (see Figure 5 at 10.7 years) and is not able to sustain such a high rate of steam production. Then boiling near the well increases and the pressure subsequently drops, reaching a failing level at about 20 years. Thus delayed injection cannot maintain pressures in this reservoir.

A further liquid-dominated reservoir was considered with a higher permeability (100 md). In this case, boiling is not so localized, and with no injection the reservoir lasts approximately 26 years (see Figure 6). In this case the failure results from localized cooling near the production well. The temperature there drops to around 180 ^{o}C, where the pressure of saturated steam is 0.8 MPa. As for the previous case injection at the same rate as production will maintain pressures in the reservoir until most of the energy is swept from it.

CONCLUSIONS

The calculations presented here are limited in their scope. Virtually only one set of reservoir parameters was considered.

However, some tentative conclusions can be reached. In a two-phase vapor-dominated reservoir, injection cannot maintain pressures, but it can increase the energy recovered. In liquid-dominated systems, injection can be used to maintain production pressures and increase longevity, but it should be started early and at a high rate.

Much work remains to be done, particularly with regard to gravity effects, the combined effects of injection and natural recharge, and the effect of fractures.

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Table 1. Reservoir Parameters

$\phi = 0.1$

K = 40 mD

Production Rate 0.0025 kg/s.m

Well Spacing 1000 m

Initial Temperature 240 °C

Initial Liquid Saturation 0.75

Table 2. COMPARISON OF EXPLOITATION STRATEGIES

DESCRIPTION	TOTAL ENERGY (10^{13} J)	FLUID ENERGY (10^{13} J)	FLUID MASS (10^{6} kg)
INITIAL STATE (240°C)	57.4	2.6	27.0
ROCK AT 180°C	40.8	0.0	0.0
33.2yrs production no injection	50.1	0.2	0.8
39.7yrs production 100% injection	49.1	2.2	27.0
49.6yrs production 200% injection	47.5	4.9	66.1
57.3yrs production 300% injection for 26.9yrs	45.6	3.3	45.3

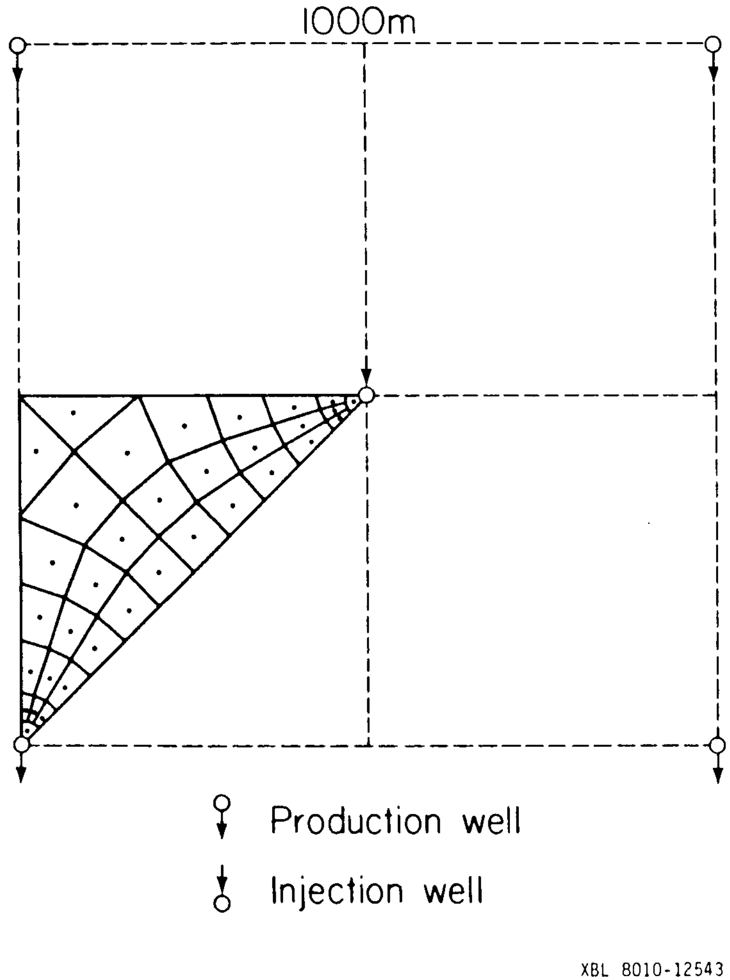

Figure 1. Five Spot Geometry. The spacing between production (or injection) wells is 1000 m, corresponding to $\simeq$ 700 m distance between producers and injectors. The mesh design covering 1/8 of the five-spot is also shown.

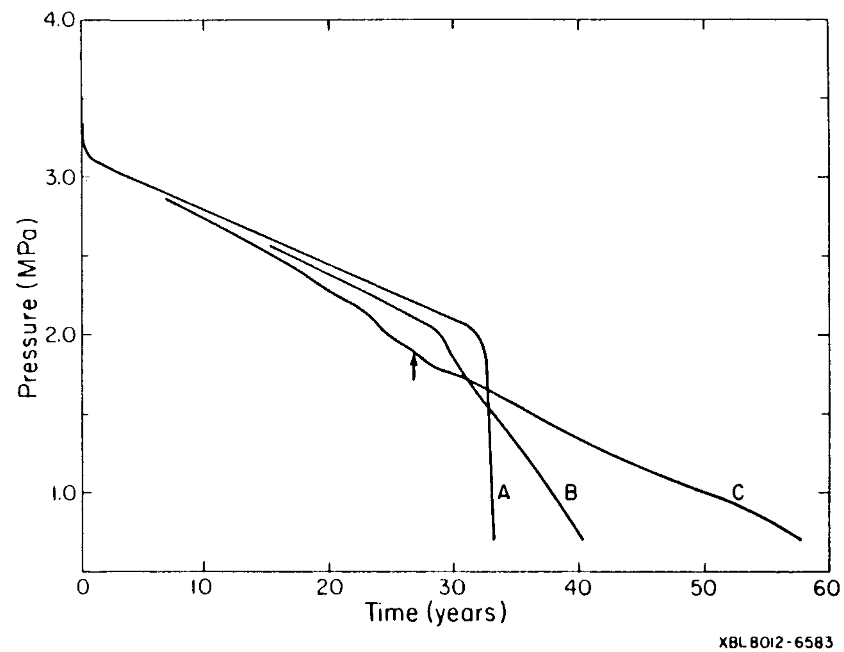

Figure 2. Pressure in the production block for the vapor-dominated reservoir. A - no injection, B - 100% injection, C - 300% injection.

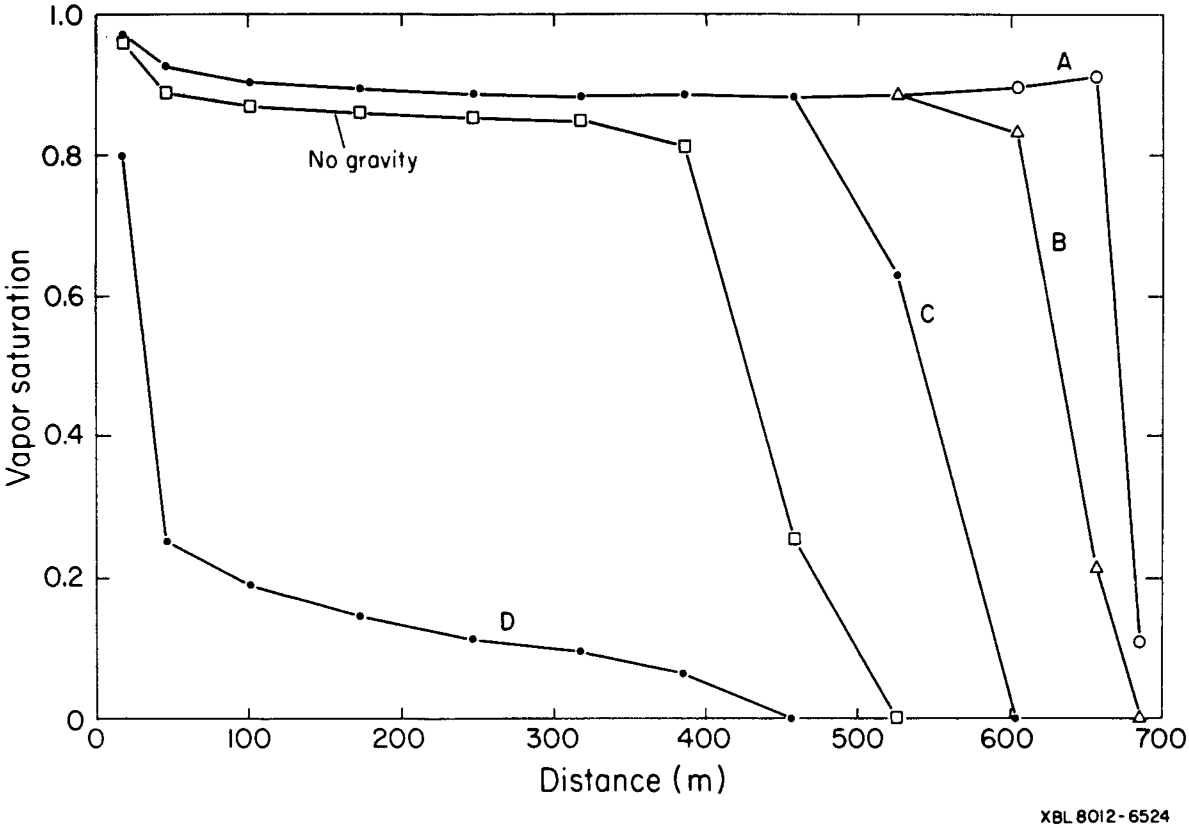

Figure 3. Vapor saturation profiles in the four-layer reservoir after 11.4 years of 200% injection compared with the no-gravity case.

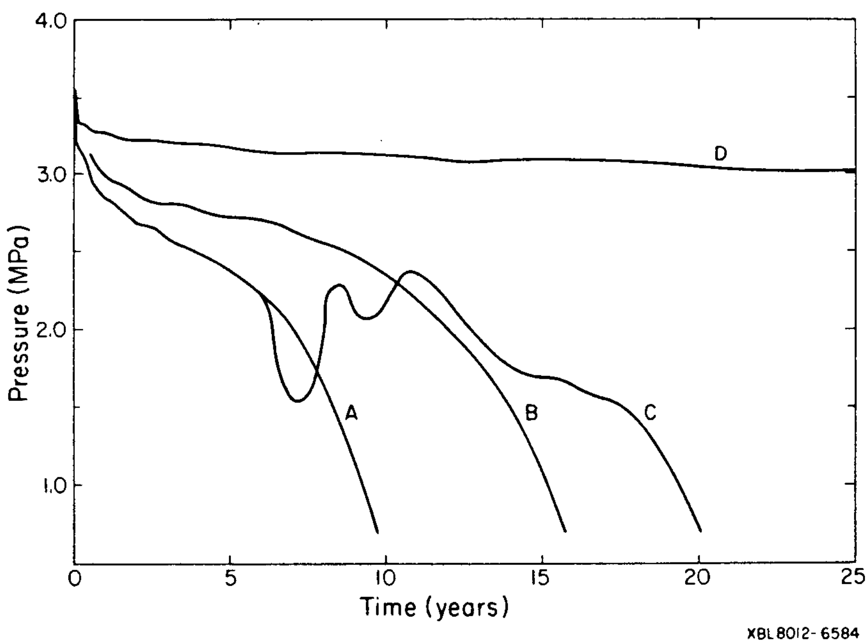

Figure 4. Pressure decline in the production block for a liquid-dominated reservoir. A - no injection, B - 50% injection, C - 100% injection after six years, D - 100% injection.

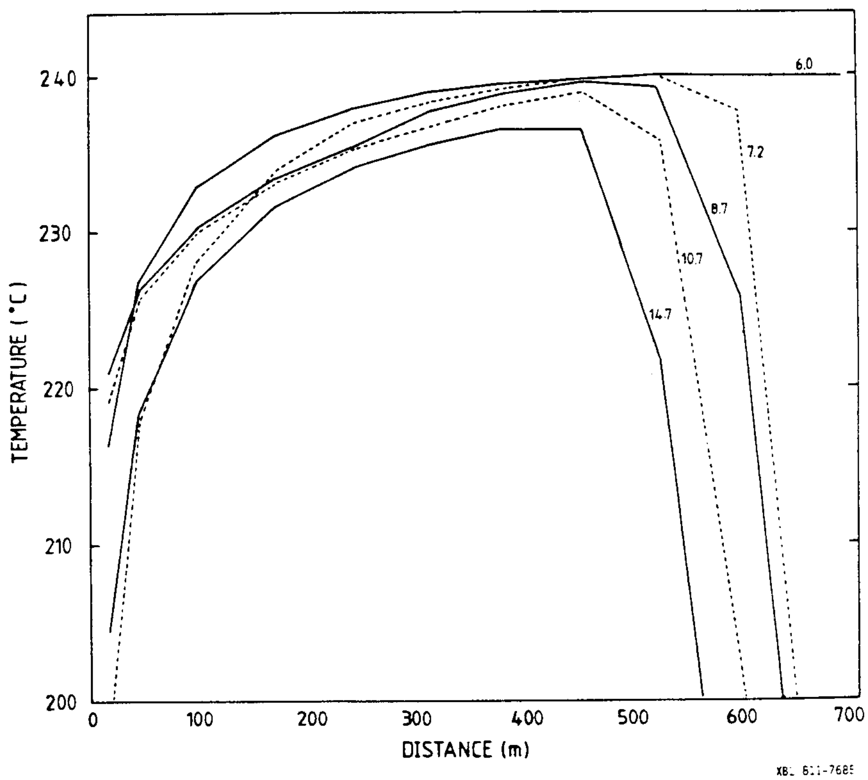

Figure 5. Temperature profiles at various times (in years).

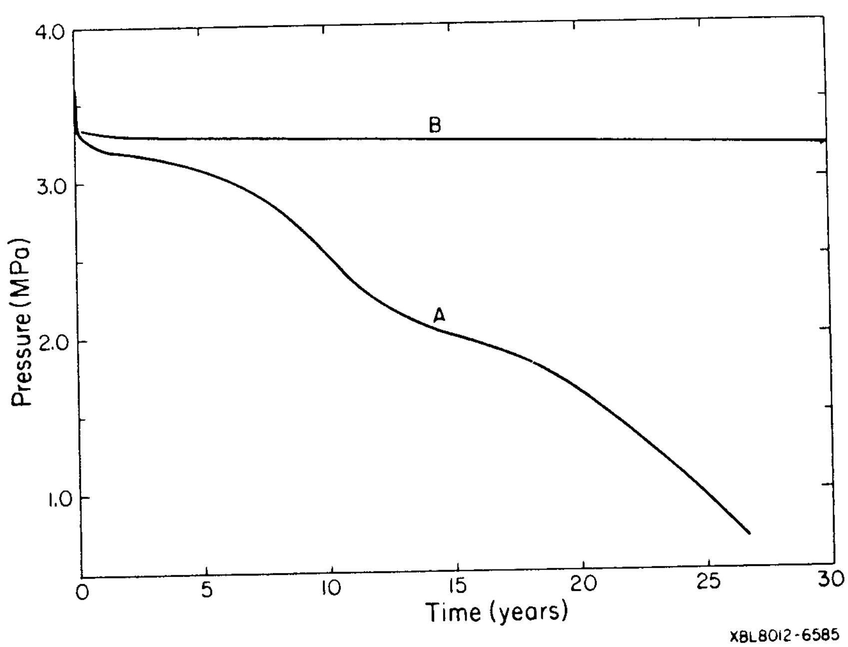

Figure 6. Pressure decline in the production block for the liquid-dominated reservoir with high permeability. A - no injection, B - 100% injection.