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REINJECTION STRATEGY FOR GEOTHERMAL SYSTEMS

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ABSTRACT

In this study, hypothetical geothermal systems were constructed and used in numerical simulations to examine the effects of various reinjection strategies on the energy extraction and longevity of the resources. After testing the system with infinite, open and closed boundaries, a closed system was chosen to make the effects of the reinjection more distinct. Several well patterns were compared for both shallow and deep reinjection into the reservoirs. In the first stage of the study, presented here, the main emphasis was put on two phase geothermal systems. For completeness, some results are presented for liquid dominated systems as well as vapor dominated systems. The results favor reinjection strategy in which the emphasis is on thermal sweep. Peripheral and dipole configurations for the reinjection wells appear to conform to the strategy goal for liquid and two phase systems.

Key words: *reinjection strategy, reinjection modeling, configuring reinjection, two phase systems, thermal sweep.*

INTRODUCTION

Several studies on reinjection into geothermal fields have been conducted. These studies involve theoretical considerations, laboratory experiments, field experiments and operations. In recent years the focus for theoretical studies has been mainly on the transport of thermal and chemical fronts in porous and fractured media, while the laboratory work has mainly focused on tracer flow in fractured reservoirs (Bodvarsson and Stefansson, 1989). Reinjection experiments have been reported for up to 40 geothermal fields, and reinjection is an integrated part of field operations in about 20 fields, worldwide. A collective review of the geothermal reinjection field experience has been summarized by Stefansson (1992). The review reveals that reinjection into geothermal fields is not a widespread method for reservoir management. In many fields, reinjection is required for geothermal waste water disposal, and fields under development usually have plans for reinjection.

In the oil industry, reinjection has been recognized and widely used for decades to increase the sweeping effect in the reservoir and hence improve the recovery of hydrocarbons. That view is gradually gaining recognition in the geothermal industry as a great number of studies conducted on reinjection have concluded that reinjection should be beneficial for the management of geothermal reservoirs.

High enthalpy geothermal systems are frequently found to be limited by fluid reserves rather than heat reserves. Therefore, reinjection can be expected to be beneficial in optimizing the recovery from those systems. In this study the emphasis was on finding general guidelines for reinjection strategies to increase the energy extraction and longevity of the geothermal resources. In the course, several hypothetical cases were studied using numerical simulations. The geothermal systems studied involved single and two phase reservoirs with different boundary conditions. The work is still in progress, but the preliminary results, currently available, are presented in this paper.

THE SYSTEMS STUDIED

The system constructed, consists of four layers where the top two layers are 300 m thick each and correspond to the ground water system and cap rock of the reservoir. The lower two layers are 400 m thick each and represent the reservoir rock. The areal extension of the layers is 1.6x2.0 km^2 and each layer is divided into 66 elements, most of size 200x200 m^2 (Figure 1). A further refinement of the grid was used around the production wells. Values for fixed thermal and mechanical parameters are given in Table 1. The reservoir was assumed to consist of a porous medium and the simulator TOUGH, which is the geothermal mode of the general purpose simulator MULKOM (Pruess, 1983), used for the numerical calculations (Pruess, 1986).

Table 1. Thermal and mechanical parameters of the numerical model.

Matrix	
Matrix density, kg/m^3	2650
Specific heat, J/(kg °C)	1000
Thermal conductivity, W/(m °C)	1.7
Porosity %	5-10
Permeability, m^2	(3.5-17.5) 10^{-15}
Relative Permeability Linear curves	
S_{lr}	0.30
S_{vr}	0.05
S_{pv}	0.70
Well Parameters	
Productivity index, m^3	1.6 10^{-12}
Pressure at upper layer, bar-a	30.0
Reinjection enthalpy, kJ/kg	721.0
(temperature, °C)	(170.4)
Separator Conditions	
Pressure, bar-a	8.0
Temperature, °C	170.4

The geothermal systems studied, include both single and two phase reservoirs, initially with different boundary conditions. The location of the reinjection was varied. Figure 1 shows the grid and geometric locations of the production and reinjection wells for the three main configurations: A) Reinjection distributed in between the production wells, *the intermixed configuration* (mode A). A similar configuration was also used when reinjection wells were alternatively used as producers and injectors (huff and puff), but with the addition of one reinjection well. B) Reinjection near the boundaries of the reservoir, *the peripheral configuration* (mode B). C) Reinjection in a certain area of the reservoir and production from another distinct area, *the dipole configuration* (mode C). The dipole configuration was also used for reinjection with pressure potential applied across the system.

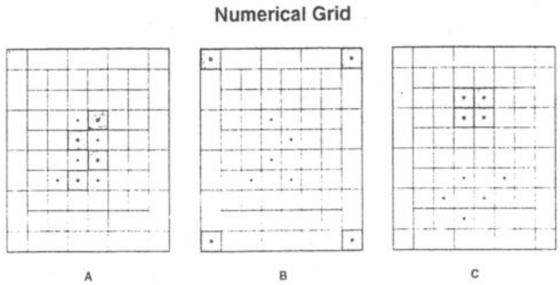

Figure 1. *The numerical grids used in the simulations. Location of production wells (dots) and reinjection sites (shaded) are shown for intermixed (mode A), peripheral (mode B) and dipole (mode C) configurations.*

The distance between the producers/injectors was 200-280 m for the intermixed configuration and for the alternating production reinjection scheme. For the dipole configuration the minimum distance was 600 m, and for reinjection at the corner boundaries the distance was 720-850 m.

The initial reference simulations were without reinjection. The permeability, porosity and well productivity index were adjusted so that the minimum production from the system during an exploitation period of 30 years corresponded to about 20 MW_e. Separator pressure was set at 8 bar-a (170.4 °C) and the conversion factor for steam rate at separator to electrical power was taken as 2.2 kg/s per MW_e. The production wells were modeled using a deliverability model that allows declining flow rates with time as the reservoir is depleted. Equations for produced flow rate, flowing enthalpy and usable steam rate at separator are given by Bodvarsson *et al.* (1985a). Reinjection rates were fixed as the 30 year average of the total flow rate and of the separated brine rate as obtained in the reference cases. That gave reinjection rates varying from 40 kg/s to 230 kg/s that were divided mainly between four injectors. Linear relative permeability curves, which have been found to give reasonable results in modeling real geothermal fields, were used (Bodvarsson *et al.* 1984b, 1985b, 1990).

For the early simulation runs, cases with closed and open boundaries set in a 43% reduced permeability zone 1.2 km outside the aforementioned 3.2 km^2 area were tested as well as infinite boundaries (6 km outside the area). It was found that the results for the reference and reinjection cases did not depend on the boundaries chosen during a 30 year production time. However, it became evident later, especially for the higher permeability cases, that a considerable portion of the recharge to the main reservoir came from the outer zone (in some cases almost equalling the reinjection rate). Therefore, the moderate production conforming to 20 MW_e from a relatively large reservoir (17.6 km^2) was nearly independent of the boundary conditions. In later runs the boundaries were closed around the 3.2 km^2 area to make the effects of the reinjection more pronounced. The same reinjection rates were used for later runs as for the earlier runs, despite changes in production rates caused by the change in boundary conditions.

For the parameters selected, five production wells, that are open to both reservoir layers were needed to maintain the 20 MW_e production for about 30 years in the case of low permeability and moderate porosity (case I in Table 2). These permeability and porosity values are similar to those obtained in the simulation of the Krafla field, Iceland (Bodvarsson *et al.* 1984a) and the Olkaria field, Kenya (Bodvarsson *et al.* 1985b). To investigate the sensitivity of the system to permeability and porosity, permeability was increased by factor five and porosity by factor two (see Table 2). The higher values are comparable to those used in the simulation of the Nesjavellir field, Iceland (Bodvarsson *et al.* 1990). The average flow rate per well can, however, differ from those at Krafla, Olkaria and Nesjavellir because different productivity indices and different production levels in wells are applied in the present study. Including the two reinjection rates up to 8 runs were needed for each producer/injector configuration for given initial reservoir conditions.

Table 2. Permeability and porosity for the different cases

	Case I	Case II	Case III	Case IV
Permeability, md	3.5	17.5	3.5	17.5
Porosity, %	5.0	5.0	10.0	10.0

RESULTS FOR TWO PHASE SYSTEMS

Most Icelandic high enthalpy geothermal systems, that are considered suitable for electrical production are expected to be two phase systems. Therefore, the main emphasis during the first stage of this study was on two phase systems.

Table 3 gives the initial temperatures and pressures for the two phase system. In the reservoir layers these values are near saturation. As production is started the system evolves rapidly to a two phase condition. The reference case (I) gives a slowly declining steam rate that drops below the 20 MW_e after 20 years of production (Figure 2). After about 25 years the production is almost dry steam. For increased permeability (case II) the reservoir approaches mass depletion in about 22 years and becomes fully steam saturated. Increased porosity tends to smooth the response of the system, making the flow rate decline more gradually, thereby increasing the productive life of the low permeability case (case III) by 5-6 years. For the high permeability case (case IV) the effects are more pronounced as the productive life of the reservoir is increased by about 16 years and mass depletion does not occur until after 55 years of production.

Table 3. Starting conditions for two phase systems.

Layer	Pressure (bar-a)	Temperature (°C)
Ground	13.9	90.0
Cap	38.8	207.0
Upper Res.	65.5	281.0
Deeper Res.	93.8	306.2

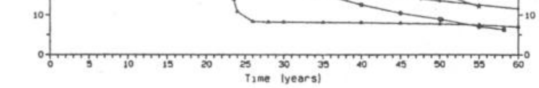

Figure 2. *Electrical power production for the reference cases (no injection) with centrally located production wells (modes A and B).*

For reinjection and intermixed configuration (mode A), an increase in total flow rate which corresponds up to 90% of the reinjection rate is obtained. The increased flow rate is accompanied by reduced enthalpy (Figure 3) so the usable steam rate at the separator is not increased and the electrical power potential remains unchanged. Therefore it is the separated brine flow that is increased. For the lower reinjection rate into the upper reservoir layer, temperature and pressure decline is similar to that in the no injection case, but steam saturation is about 30% lower. Gravity effects cause the deeper layer to be flooded near the center of the field after about 45 years. In the deeper layer, temperature and pressure remain higher at all times, but steam saturation considerably lower. The higher reinjection rate increases the total flow rate and this results in an increased separated brine flow while the usable steam rate remains nearly unchanged. However, in this case the upper layer is flooded after 8 years and the deeper layer after 30 years. No markable increase in usable steam rate is observed, though the central part of the system becomes flooded in contrast to the results of Bodvarsson *et al.* (1985a) for fractured systems.

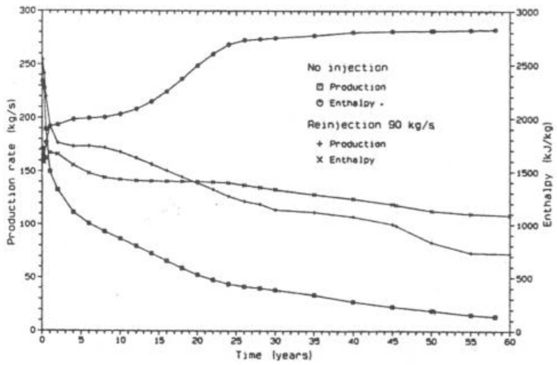

Figure 3. *Total production rate and flowing enthalpy for case I and intermixed configuration without and with 90 kg/s reinjection into the upper reservoir layer.*

Injecting into the deeper part of the reservoir does not alter the production rates or the power potential from what was observed for shallow reinjection. Better pressure maintenance is observed in both reservoir layers and stronger cooling around the injectors in the deeper layer. Therefore, a larger area in the deeper layer becomes flooded after about 40 years of production. Higher reinjection rates do not increase the total production rate as much as injection into the upper reservoir layer, and after about 45 years production the usable steam rate is increased by 3-4 kg/s, but as before, the power potential drops to 20 MW_e after 20-22 years. Pressures are higher in both reservoir layers and cooling greater in the deeper layer with thermal breakthrough after about 4 years. The upper layer remains, however, two phase with steam saturation over 60%.

The case of alternating production/reinjection scheme, which also can be referred to as an interchanged model (Stefansson, 1992), gives similar results as reinjection for intermixed configuration (mode A), but the configurations for producers/injectors are similar in both cases. The usable steam rate tends to be slightly lower for this case resulting in lower electrical power potential. The temperature decline is, however, considerably smaller while the pressure decline is similar. The longevity of the reservoir could therefore, be increased, but this case was only run for 30 years of production.

The dipole configuration (mode C), in which the producers and injectors are grouped in opposite halves of the system, shows some improvement in usable steam rate, especially for the higher reinjection rate. The beneficial effects are more pronounced for the higher permeability cases (cases II and IV). There the reference case approaches mass depletion after about 26 years, but with reinjection that does not occur. Furthermore, the boiling in the deeper layer is quenched after 33 years and the production approaches stabilization. For the higher reinjection rate both reservoir layers approach liquid phase conditions after 10 years, the production rates stabilize, which results in considerable increase in usable steam (Figure 4). The increase in usable steam corresponds to over 15 MW_e in the period 30-60 years compared to that in the lower reinjection rate case. Thermal breakthrough occurs after about 35 years for the higher reinjection rate.

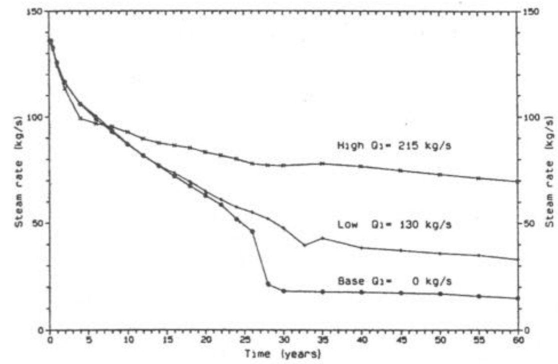

Figure 4. *Steam production rate at the separators for case II and dipole configuration. Injection is into the upper reservoir layer.*

The system with the dipole configuration was also started with a small pressure potential across it (open boundary case). Reinjection was tried both upstream and downstream in the potential field. Comparable results with those for the dipole case were obtained. The upstream reinjection gave a better sweeping effect, but pressure maintenance was slightly smaller than during the downstream reinjection. However, the initial potential difference across the system of 1 bar/km was small compared to the more than 10 bar/km difference developed by the production/injection poles. The results might therefore change if the initial potential difference was of that magnitude.

Reinjection near the corner boundaries (mode B) showed the most overall beneficial effects to the reservoir. Pressure maintenance is observed, mostly in the deeper layer, due to gravity effects. The central part of the reservoir, where the production wells are located, remains hot while the cooling occurs near the boundaries. Steam saturation is generally lower. Total flow rate is increased resulting in increased steam rate after about 35 years of production for the low permeability case (case I). The electrical power becomes 5 MW_e higher than in the reference case after 60 years production. Higher permeability reduces the steam saturation in the deeper

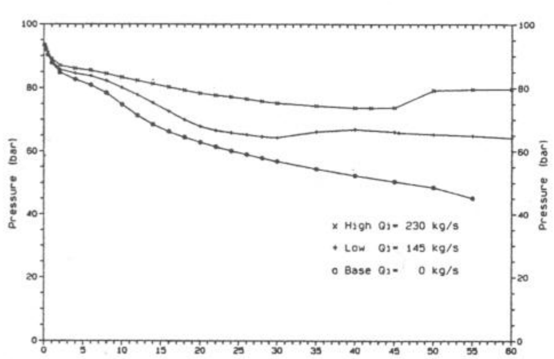

Figure 5. *Pressure in a central element in the deeper reservoir layer for case IV and peripheral configuration. Injection is into the upper reservoir layer.*

layer considerably. Total flow rate is higher, but usable steam rate is reduced slightly during the main pressure decline in the upper layer occurring in the time interval 20-40 years. As the system approaches stabilization after about 45 years the steam rate increases. Increasing the reinjection rate results in some increase in the usable steam rate after about 20 years production and a considerable increase is observed as the whole system becomes flooded (after 45 years). Figures 5 and 6 show the pressure maintenance in an infield central element in the deeper reservoir layer and steam production, respectively for case IV. Increasing the reinjection rates further, still increases the output and electrical power, until thermal breakthrough occurs after about 55-60 years and a gradual decline in steam rate is observed.

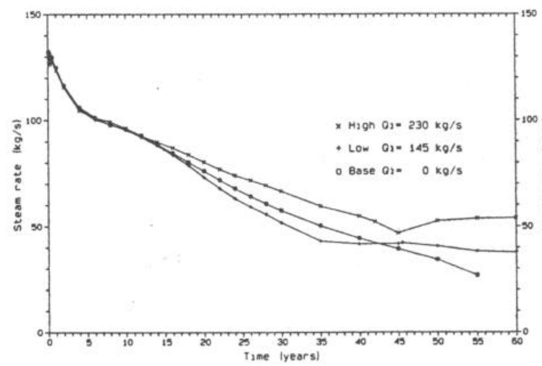

Figure 6. *Steam production rate at the separators for case IV and peripheral configuration. Injection is into the upper reservoir layer.*

RESULTS FOR SINGLE PHASE SYSTEMS

An example of a liquid dominated system with reinjection at the corners was run. The reference case indicated rapid pressure decline and therefore a rapidly declining flow rates reaching a quasi steady state in one year (Figure 7). Some boiling is initiated around the production wells in the upper reservoir layer due to the pressure decline. Reinjection quenches the boiling so the system remains single phase at all times. Low permeability reduces the effect of pressure maintenance in the production area resulting in a minor increase in usable steam rate. For higher permeability the pressure maintenance is much better resulting in increased flow rates where the total flow rate approaches the reinjection rate. Higher reinjection rates further increase the output and the usable steam rate.

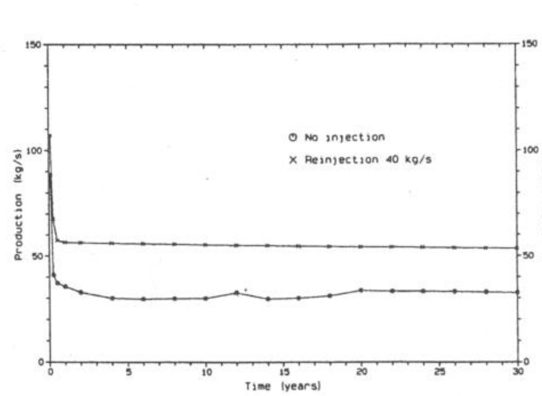

Figure 7. *Total production rate from a liquid dominated system without and with 40 kg/s reinjection to the upper reservoir layer. Case I and peripheral configuration.*

Reinjection into a vapor dominated system was also tested with reinjection at the corner boundaries and in between the production wells. The system was started with 60% steam saturation that quickly rose to 66-100% after production started. The production was almost dry steam in the beginning, but became wet later depending on configuration and permeability. The results indicate a steeper pressure decline and a slightly smaller temperature decline than those of the two phase cases (Figure 8). The pressure maintenance is therefore smaller as could be expected and it takes a longer time for the reinjection to quench the boiling in the deeper layer. The usable steam rate is also lower, but the steam rate stabilizes as the boiling is quenched while the total flow rate increases. Higher permeability greatly improves the early output because the reservoir becomes wet and the pressure maintenance is more effective.

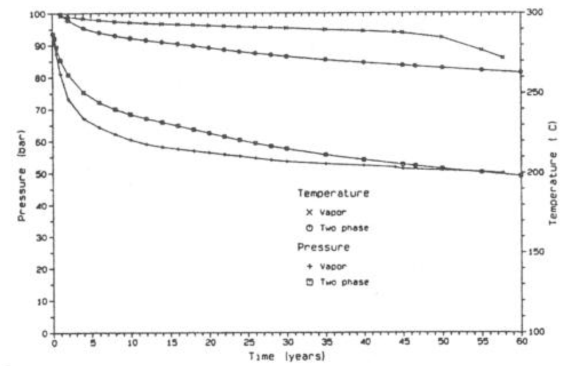

Figure 8. *Pressure and temperature in a deep infield central element for case I and peripheral reinjection. Initial conditions are vapor dominated and two phase, respectively. Both runs are with 40 kg/s reinjection.*

REINJECTION STRATEGY

Strategy for reinjection has been discussed by James (1979). His main conclusion is that production and reinjection wells are interchangeable, i.e. both well types must have good permeability and be in a good communication with the reservoir. He also points out that if one cannot grade the reinjection problem technically, then one should grade it economically. In that way the economical order of merit would be to drill first shallow reinjection wells centrally within the field and last to drill deep wells outside the field. In between, reinjection wells at the periphery of the field would be located. A review of worldwide reinjection experience by Stefansson (1992) shows that the peripheral configuration is the one most commonly used in the world today.

The following results of the simulation runs may be used in an attempt to establish some guidelines for reinjection. The results for the two phase cases indicate that minimal gain in usable steam rate can be expected for the configurations tested during the first 20-30 years or during the main economical life span of a project. Similar results have been obtained in other studies and explained with mobility effects (e.g., Bodvarsson *et al.* 1985a). Thermal breakthrough occurs relatively early when injection wells are distributed in between the production wells, the intermixed configuration (mode A). Heat sweeping from the outer parts of the field is limited and can even reduce the power production from the field.

The beneficial result of reinjection into a two phase system is that the system will not be limited by fluid reserves and therefore the productive life of the system is increased in most cases. Better pressure maintenance is generally observed in the deeper part of the reservoir due to the effects of gravity and density differences. This study does not address whether it may be advantageous to aim the injection directly at the deeper parts of the reservoir. The configurations that allow a better thermal sweep of the reservoir (i.e. peripheral (mode B) and dipole (mode C)) yield an increase in usable steam rate. The increase in capacity occurs mainly late in the production history (after 30 years) and is more pronounced when the reservoir is flooded by reinjection and single phase liquid conditions have developed everywhere, causing an increase in reservoir pressure near the producers. Higher reinjection rates give further increases in usable steam rate for those cases. After thermal breakthrough the steam rate declines.

The guidelines that can be put forward on the basis of the current results favor a reinjection strategy where the emphasis is on thermal sweep. Therefore, peripheral and dipole configurations (modes B and C) appear to be more suitable than reinjection in between the production wells (mode A) at least in terms of the long term effects for liquid and two phase systems. Reinjection outside the production area causes a heat front to form whose rate of travel is controlled by the reinjection rate. Studies have indicated that the heat front moves rapidly away from the injection wells at first, but the travel rate is considerably slowed when the fluid gains significant conductive heat from the reservoir rock (Bodvarsson and Stefansson 1989). In the cases studied here, thermal breakthrough did not occur until late, but in natural reservoirs some producer/injector pairs could respond with rapid thermal interference. The problem may be rectified by reducing the injection rate into that injector or alternatively by relocating the injector. The simulation results indicate that it is preferable to inject a substantial fraction of the produced fluid to achieve the benefits of pressure maintenance and enhance the energy extraction from the reservoir. However, in order to increase the effectiveness of heat mining it may be advisable to divide the available brine between a larger number of injection wells to keep the reinjection rate within certain limits.

In order to achieve pressure maintenance in reservoirs with low permeability, reinjection may need to be started near the production area. At later stages, preferably before thermal breakthrough, the location of reinjection is moved to greater distances from the production area.

Preliminary results for vapor dominated systems indicate that it may be better to start the reinjection near or within the production area. As the produced fluid becomes wet and some pressure maintenance has been achieved, the results indicate that it would be better to move the reinjection to the peripheries as in the two phase cases.

In the present study the temperature of the injected fluid was taken as that of the separated brine (170.4 °C), and the general rule is that the temperature should be high enough to avoid scaling and precipitation of chemicals in or around the reinjection wells. If a cold fluid reinjection is selected the geothermal fluid may need some treatment to be suitable for reinjection. The travel rate of the thermal front is the same for cold and hot fluid injection, but the front is sharper in the case of cold injection.

CONCLUSIONS

One of the objectives of the present study was to increase the usable steam rate at the separator and hence the electrical power that can be extracted from the reservoir. The following conclusions aim at that.

Reinjection projects for liquid dominated and two phase reservoirs should be designed to maximize the thermal sweep of the reservoir. The design should place greater emphasis on thermal sweep than pressure maintenance. Peripheral or dipole well configurations appear to be more suitable than reinjection in between production wells in this respect.

Very permeable reservoirs with strong natural recharge may not need reinjection, except in cases where fluid production is greater than the natural recharge and reinjection is needed to supplement the fluid for pressure maintenance.

Results for reinjection into two phase reservoirs indicate that minimal gain in usable steam can be expected. However, in the long term the reinjection can increase the productive life of the reservoir significantly, sustain steam production over longer periods of time and consequently reduce the number of make-up wells needed.

To achieve the benefits of pressure maintenance and enhancement of energy extraction from the reservoir a substantial fraction of the produced fluid is required for reinjection and preferably of similar magnitude to the production.

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