INJECTION EXPERIMENTS IN LOW-TEMPERATURE GEOTHERMAL AREAS IN ICELAND

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ABSTRACT

It is anticipated that injection will soon become an integral part of the management of low-temperature (< 150 °C) geothermal systems in Iceland. These systems are embedded in fractured basaltic rocks and most of the thermal energy in the systems is stored in the rock matrix. Cold water injection will counteract the pressure draw-down due to production as well as extract some of this thermal energy. Injection experiments have been carried out in several low-temperature areas. During the experiments, connections between possible injection wells and production wells were investigated by tracers-tests. The data from the experiments were analyzed by simple models, which in turn were used to predict the effects of long-term injection. The results indicate that in some cases substantial cold water injection will be advantageous, whereas in other cases only limited injection of warm rather than cold water will be feasible.

***Keywords:** injection experiments, low-temperature systems, fractured rocks, tracer flow models, water temperature predictions*

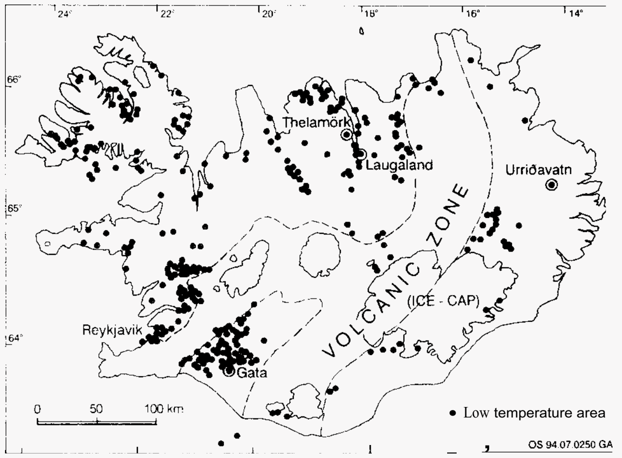

Figure 1. ***Location of low-temperature areas in Iceland, in particular the areas discussed in this paper.***

INTRODUCTION

Almost half of the primary energy supply in Iceland is geothermal. This energy is mostly used for space heating and about 85 % of all residential buildings are heated by geothermal energy (Pálmason, 1992). Most of the hot water comes from the numerous low-temperature (< 150 °C) geothermal systems, which are found outside the volcanic zone, passing through the country (Figure 1). These low-temperature systems are all embedded in fractured basaltic rocks and most of the thermal energy in the systems is stored in the reservoir rocks. In some cases cold natural recharge may, during production, extract some of this thermal energy and stabilize the production induced pressure draw-down. In most cases, however, recharge is limited and pressures continue to drop as hot water production continues. In such cases it may be possible to inject cold water to counteract the pressure draw-down due to production as well as to extract some of the thermal energy from the rocks.

Fluid reinjection is currently used at many geothermal fields in the world (Bodvarsson and Stefhsson, 1989). The primary purpose has been the disposal of waste water due to environmental reasons, but in a few areas injection has been carried out to maintain reservoir pressures. Injection has, to date, only been carried out in one high-temperature (> 200 °C) geothermal field in Iceland (Bjornsson and Steingrimsson, 1992), whereas injection into the low-temperature systems has not been practiced. Injection experiments have, however, been carried out in several areas. During the experiments, connections between possible injection wells and production wells were investigated by adding chemical tracers to the injected fluid. The data from the experiments were analyzed by simple models and these models used, in turn, to predict the effects of long-term injection on the reservoirs and production wells in question.

This paper gives a brief description of injection experiments carried out in four low-temperature areas in Iceland during 1991-1993. The methods used to analyze the associated tracer test data are presented along with the methods of predicting the effects of long-term injection on near-by production wells. A few selected examples of the data, their analysis and predictions will be given in the paper, along with a summary of the results of the experiments.

THE INJECTION EXPERIMENTS

Table 1 provides basic information on the four injection experiments discussed in this paper. These experiments were conducted in the following areas (Figure 1):

1. ***Laugaland*** in N-Iceland. This is one of four small geothermal fields utilized for space heating in the town of Akureyri (pop. 16,000). This field has been utilized since 1978 and the annual production has varied from 1.0 to 2.6 Gl of 95 °C water.
2. ***Gata*** (also Laugaland) in S-Iceland. This field has been utilized for space heating in the near-by towns of Hella and Hvolsvollur (pop. 1300) since 1983. The annual production has varied from 0.54 to 0.69 Gl of 100 °C water.
3. ***Urridavatn*** in E-Iceland. This field has been utilized for space heating in the near-by town of Egilsstaðir (pop. 1800) since 1980. The average annual production has varied from 0.63 to 0.92 Gl of 76 °C water.
4. ***Thelamörk*** in N-Iceland. This is a prospective production area for district heating in the town of Akureyri, mentioned above. It is expected to yield 0.5 - 0.6 Gl of 91 °C water annually.

The experiment at Laugaland was carried out in the spring of 1991 (Axelsson et al., 1993). During the experiment, 80°C water from a near-by geothermal field was injected into well **8**, which is 2800 m deep. At first **8 l/s** were injected with only a minor well-head pressure, later the injection rate was reduced to **4** l/s (*see* Table 1). During the experiment **40** l/s of 95°C water were produced from well **5**, which is 1300 m deep and **250** m

Table 1. ***Injection experiments carried out in low-temperature areas in Iceland during 1991-1993.***

LT-system	distance between wells (m)	injection rate (l/s)	duration of experiment (weeks)
Laugaland	250	4 - 8	5.5 [1)]
	110	1 - 2	14
Umhavatn			10
Thelamork			
inj. well 6			11
inj. well 8			12

[1)] Tracer recovery monitored for 15 months, however.

away from well 8. Concurrently the water-level in nearby wells was monitored carefully. Two chemical tracers were employed during the injection experiment. Firstly, 1 kg of sodium-fluorescein was injected instantaneously into well 8 at the beginning of the experiment. Secondly, sodium-bromide was released continuously into the injection water. The Laugaland experiment had to be discontinued sooner than anticipated because of a pump failure.

The experiment at Gata was carried out in the fall of 1992 (Bjornsson et al., 1993). During this experiment natural down-flow in well G-1 was utilized instead of actual injection. At a depth of 540 m 75 °C geothermal water enters the well, flowing down to a depth of 900 m, where it reenters the geothermal system. At the Same time an average of 17 l/s were produced from the 1000 m deep production well L-4, located about 110 m from well G-1. Here, 1 kg of sodium-fluorescein was injected instantaneously into well G-1 at the beginning of the experiment.

The experiment at Umhavatn was also conducted in the fall of 1992 (Axelsson and Sverrisd6ttir, 1993). This was not an actual injection experiment since the primary purpose was to study whether internal flow in well5 may cause cooling of a nearby production well, well 8, which is 900 m deep. At a depth of 220 m 45 °C water enters well 5, flowing down to a depth of 590 m, where it reenters the geothermal system. The distance between the wells is only 40 m. During the experiment the average production from well 8 was 23 l/s.

Following the successful drilling of a production well (LP-11) at Thelamork, in the summer of 1992, a feasibility study was performed (Bjornsson et al., 1994; Fl6venz et al., 1994). This study consisted of a nine month full scale production test, with careful monitoring of the production rate, water level and chemical changes. The production from well 11 varied from 15 to 20 l/s of 91.5 °C water. During the last 2 ½ months of the test the water produced was reinjected at rates of 4 and 1.5 l/s into wells 6 and 8, respectively. When the water level had reached a semi-steady state, a known mass of bromide was injected instantaneously into well 6 and a known mass of fluorescein into well 8.

Like most low-temperature geothermal systems in Iceland, these systems are all believed to be characterized by near vertical structures, such as fracture-zones or dykes. The upflow of hot water in these systems is believed to be along permeable parts of these structures. All successful wells in these areas are either located very close to or they intersect these structures.

In the two experiments where actual injection took place, at Laugaland and Thelamork, the desired reduction in pressure draw-down was observed. In both geothermal systems water levels rose almost instantaneously in response to the injection and it is clear that the reduced draw-down will allow an increase in production in both areas approximately equaling the injection. No change in production temperature of well 5 at Laugaland or well 11 at Thelamork was observed during the experiments. An example of a water level recovery is presented in Figure 2 below.

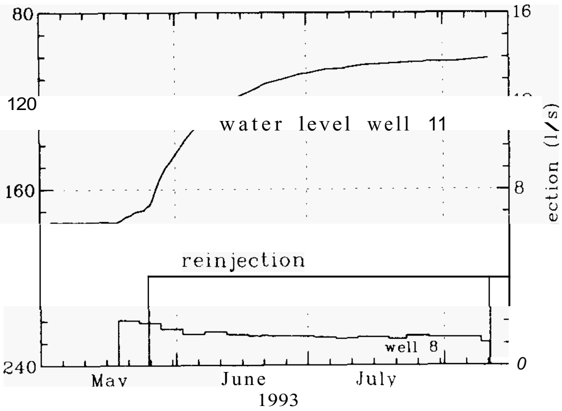

Figure 2. ***Waterlevel changes in well 11 at Thelamörk during an injection experiment.***

During the experiments water samples where taken frequently from the production wells and the tracer concentrations measured. An example of tracer recovery results is presented in Figure 3.

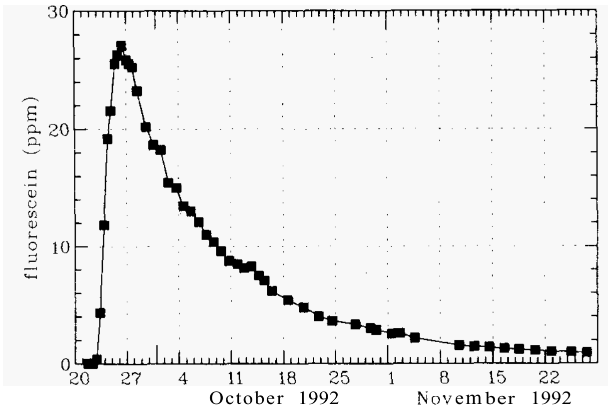

Figure 3. ***Observed fluorescein recovery in well 8 at Urriðavatn during a tracer test.***

ANALYSIS OF TRACER TEST DATA

In the Gata, Urriðavatn and Thelamork experiments the tracer return was fast and typical tracer return curves were obtained (Figure 3). The tracer breakthrough times were of the order of one to three days. This indicates that the injection and production wells, involved in these cases, are all directly connected, most likely along permeable fracture zones or interbeds. In the Laugaland experiment, on the other hand, the return of tracers was very slow, and in fact only about 1.7 g of 1 kg of sodium-fluorescein were recovered during the 40 day experiment. The tracer breakthrough occurred after about 10 days. This is believed to indicate that the injected water diffused into a very large volume and that wells 5 and 8 are not directly connected.

Numerous papers dealing with solute transport in fractured rocks and the analysis of tracer test data in fractured geothermal reservoirs have been published (e.g. Robinson and Tester, 1984; Home, 1985; Ramirez et al., 1988; Bödvarsson and Stefhsson, 1989). Two very simple models, which will be discussed briefly below, were used in this paper to analyze the tracer return curves from the four experiments. These models simulated the tracer test data very accurately. Nevertheless, they do not take into account the possible retention of the tracers by adsorption, matrix diffusion and other mechanisms (Home, et al., 1982; Maloszewski and Zuber, 1993)

The Gata, Urribavatn and Thelamork data were analyzed by an one-dimensional fracture-zone model, where the return is controlled by the distance between injection and production wells, a small fracture-zone volume and dispersion (Axelsson and Sverrisdóttir, 1993; Bjornsson et al., 1994). The Laugaland data, on the other hand, were analyzed by a very simple lumped model, where the tracer return is controlled by mixing in a large reservoir volume and geometry and dispersion neglected (Axelsson et al., 1993).

During some injection experiments the water produced is reinjected such that the tracer is recirculated. Tracer recovery data need to be corrected for this effect before they are analyzed (Arason et al., 1993). Figure 4 shows an example from Thelamork, i.e. the observed recovery of bromide injected into well 6 corrected for the extra bromide recirculated from well 11 into wells 6 and 8.

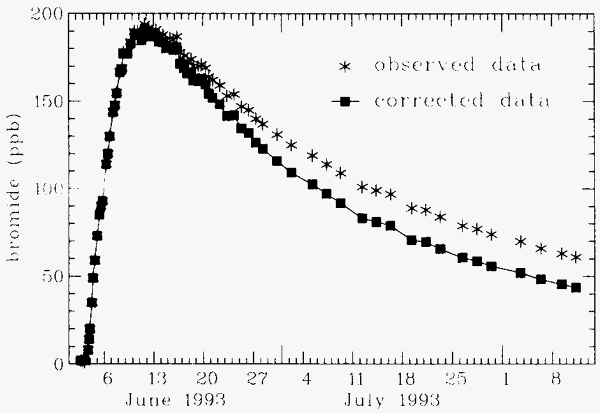

Figure 4. ***Observed and corrected bromide recovery curvesfor the well dipole 6-11 at Thelamdrk.***

The one-dimensional fracture-zone model is shown schematically in Figure 5. A constant mass flowrate, q, is assumed into an injection well and a constant mass flowrate, Q, from a production well, such that $Q > q$. A basic assumption in the formulation is that the flow channel, connecting the two wells, is along a narrow fracture zone. Furthermore, a near one-dimensional flow is assumed in the channel. The cross sectional area of the flow channel is $A = h \times b$, where h is its height and b is the width. The porosity of the flow channel is ϕ and its longitudinal dispersivity is denoted by α_L. Molecular diffusion is neglected. The differential equation describing the tracer concentration in the channel, C, is then as follows:

$$D \frac{\partial^2 C}{\partial x^2} = u \frac{\partial C}{\partial x} + \frac{\partial C}{\partial t} \qquad (1)$$

where x is the distance from the injection well, t the time, u the mean velocity of the flow ($u = q/\rho A\phi$) and D the dispersion coefficient of the flow channel ($D = \alpha_L u$).

At time $t = 0$, a mass M of tracer is injected instantaneously and consequently transported along the flow channel to the production well. The tracer concentration in the produced fluid, c, is correlated to the fracture zone concentration by using the conservation of mass, i.e. $c\,Q = C\,q$. Therefore, solving the governing equation results in (Javandel et al., 1984):

$$c(t) = \frac{uM}{Q} \frac{1}{2\sqrt{\pi D t}} e^{-(x-ut)^2/4Dt} \qquad (2)$$

An automatic, least square computer code, TRINV, was developed to simulate tracer return curves in terms of M/Q, D and u in the above equation (Arason et al., 1993). The TRINV code allows for multiple flow channels connecting the two wells.

The results of the simulation for the well pair 6-11 at Thelamork are presented here as an example of the use of the fracture-zone

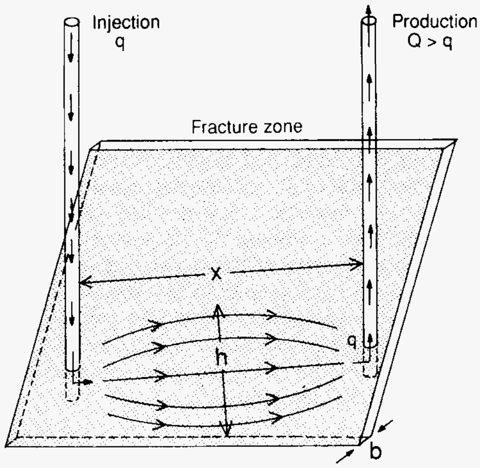

Figure 5. ***A simple model of afracture-zone connecting a reinjection-production well dipole.***

model. The same methods were used and comparable results obtained for the well pair 8-11 at Thelamork as well as in the Gata and Urriðavatn experiments. Figure 6 shows the measured and simulated tracer return curves for the bromide injected into well 6 and table 2 presents the model parameters used in the simulation. Two flow channels between the injector and the producer were assumed. The model may be used to calculate, theoretically, the relative importance of the two channels by calculating the tracer recovery until infinite time. Thus it may be estimated that the first channel accounts for the return of 11 % of the tracer. It is taken to be the shortest distance between the two wells (120 m). The second channel, on the other hand, theoretically transports 66 % of the tracer mass. This flow channel is assumed to be a fracture zone connecting the major feedzones of the two wells.

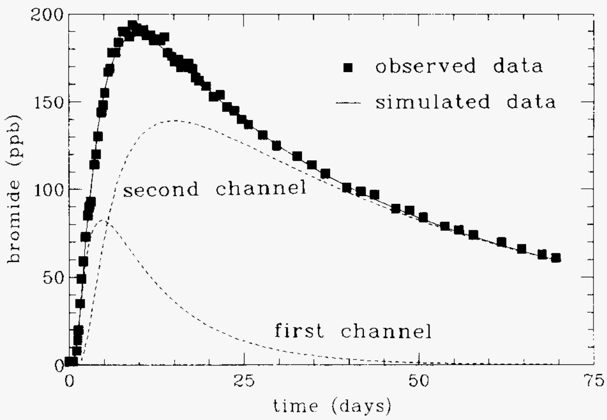

Figure 6. ***Observed and simulated bromide recovery curvesfor the well dipole 6-11 at Thelamdrk.***

Table 2: ***Modelparameters used to simulate the tracer recovery of bromidefor the wellpair 6-11 at Thelamörk.***

Channel length (m)	u (m/s)	$A\,\phi$ (m^2)	α_L (m)	M_i/M
120				
320	1.45×10^{-4}	24.0		0.66

The variable M_i in Table 2 above denotes the calculated mass recovery of tracer through the corresponding channel, until infinite time. According to this study, a maximum recovery of

77 % is predicted for the two channels. The remaining 23 % are believed to travel some unknown, much longer, flow path(s) or diffuse into the rock around the flow channels. Some retention of the bromide, perhaps by adsorption, can not be ruled out, however.

The simple lumped model used to simulate the tracer return data from Laugaland consists of two interconnected tanks (Figure **7**). The first tank (1) simulates the geothermal system next to the injection well. It has a volume V_1 and porosity ϕ_1. The second tank (2) simulates the part of the geothermal system around the production well. It has a volume V_2 and porosity ϕ_2. The injection rate is I kg/s into the first tank and the production is *Q* kg/s from the second tank in addition to a recharge of R kg/s. The differential equations describing the tracer concentrations in the two tanks, C_1 and C_2, are as follows:

$$V_1 \rho_v \phi_1 \frac{dC_1}{dt} + I C_1 = I C_i \tag{3}$$

$$V_2 \rho_v \phi_2 \frac{dC_2}{dt} + (R + q) C_2 = R C_0 + q C_1 \tag{4}$$

where ρ_v is the density of water, C_i the tracer concentration in the injection water, C_0 the natural concentration of the tracer in the geothermal system, non-zero in the case of bromide, and q the mass flow from the first tank to the second. In this model instantaneous mixing **is** assumed and the delay due to the finite travel time from injection well to production well is neglected, in contrast to the other model (Figure 5).

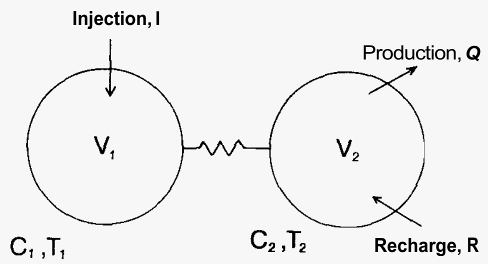

Figure *7. **A simple lumped** model **used to simulate the tracer return during the Laugaland experiment.***

The injection **starts** at time t=0 and continues until $t=t_0$. The production rate is Q_1 during the injection period and Q_2 after that. Because the pressure in the system changes much faster than the tracer concentration, **q** is assumed to be constant. Furthermore, the assumption is made that $R = Q_1 - I$ before t_0 and that $R = Q_2$ after t_0, such that $q = I$. In the case of a mass M of tracer injected instantaneously at time t=0, the solutions are given by (Axelsson et al., 1993):

$$C_2(t) = \frac{\lambda_1 \lambda_2 I M}{(\lambda_2 Q_1 - \lambda_1 I)} (e^{-\lambda_1 It} - e^{-\lambda_2 Q_1 t}) \,, \text{ for } t \le t_0 \tag{5}$$

$$C_2(t) = C_2(t_0)\, e^{-\lambda_2 Q_2 (t - t_0)} \,, \text{ for } t > t_0 \tag{6}$$

where $\lambda_i = 1/(V_i \rho_v \phi_i)$ (i=1,2). Figure **8** shows the measured return of the fluorescein injected into well 8 at Laugaland as well as the return calculated by equations ***(5)*** and (6). Comparable results were obtained based on the return of bromide, which was injected continuously during the Laugaland experiment (Axelsson et al. 1993).

The summarized results of the four tracer tests are presented in Table 3.

PREDICTIONS

The main purpose of the injection experiments discussed in this paper was to estimate the heat absorbed by injected fluid **as** it passes from injection well to production well, during long term production and injection and predict the temperature of the water

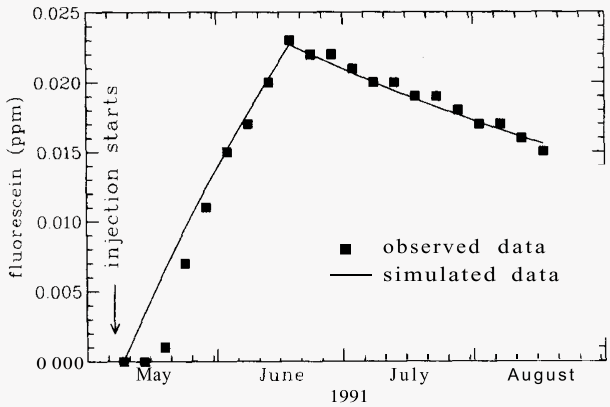

Figure **8.** ***Observed and simulated fluorescein recovery** at **Laugaland. Water** is **injected** for **the** first **40 days.***

Table *3.* ***Summarized results** of **the tracer tests.***

LT-system	recovery (%)	volume $V \times \phi$ (m^3)	dispersivity α_L (m)
	1)		-
	94		39
Urriðavatn	76	800	9-25
Thelamork			
well 6	60	10,000	51-193
well **8**	24	9,000	68-165

1) 2.5 % recovery one year after **the** experiment.

produced for various injection scenarios. The results in Table 3 above, in particular the volumes, clearly reflect the difference in the connections between injection and production wells in the different areas. The rate of cooling of water produced during long term injection may be expected to be inversely related to the volumes involved. The rate of cooling should therefore be very low at Laugaland and very high at Urriðavatn.

The models used to simulate the tracer return curves were used to *carry* out the water temperature predictions. The one-dimensional fracture-zone model in Figure ***5*** was again used in the cases of Gata, Urribavatn and Thelamork. Analysis of tracer return curves on the basis of this model provides an estimate of the cross sectional area A of the flow channel and, hence, the total contact area between the reservoir rock and the flow channel. Given the flow channel inlet temperature Ti, the channel height, length and width as well as the undisturbed rock temperature T_0, one can estimate the temperature of the injected fluid at any distance x along the flow channel. This is based **on** a formulation which considers a coupling between the heat convected along the flow channel and the heat conducted from the reservoir rock to the channel fluid. The solution to similar problems **is,** for example, presented by Carslaw and Jaeger (1959) and Bödvarsson (1972). The analytical solution for the fluid temperature $T_q(x,t)$, is:

$$T_q(x,t) = T_i + (T_0 - T_i)\, \text{erf}\left[\frac{kxh}{c_w q \sqrt{\kappa(t - x/\beta)}}\right] \tag{7}$$

This equation is valid at times $t > x/\beta$, with β defined as $q\rho_w/(\rho c)_f hb$. Here k is the thermal conductivity of the reservoir rock and κ its thermal diffusivity. In addition, $(\rho c)_f$ is the volumetric heat capacity **of** the wet fracture-zone material and c_v the heat capacity of water. The temperature of the produced fluid, assuming a constant temperature, T_0, for all feedzones in a production well, except the one connected to the flow channel, is finally given by:

$$T(t) = T_0 - \frac{q}{Q}\left[T_0 - T_q\right] \tag{8}$$

Figures 9 and 10 show two examples of the results. Figure9 shows the calculated cooling of water from production well **L-4** due to the 75 °C down-flow in well G-1 at Gata. The figure shows the results for 1, 2 and 3 l/s down-flow for a ten year period, which may be considered to be the production history of the Gata field. Actual measurement of the water temperature from well **L-4** indicate a cooling of the water from the well of perhaps 2 "C, which indicates that the down-flow in well G-1 has probably been of the order of 1 - 2 l/s on the average. Calculations were also made on the cooling for various injection scenarios (Bjornsson et al., 1993).

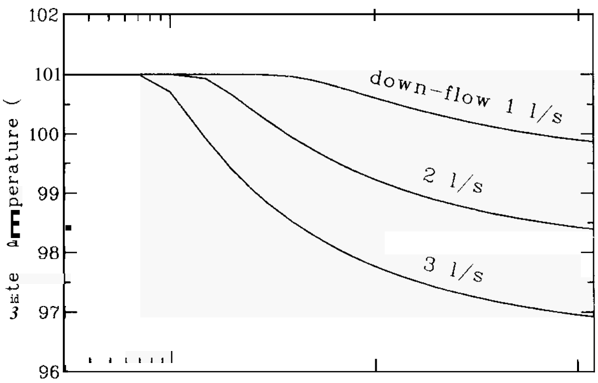

Figure **9.** ***Calculated*** cooling ***of waterfrom production well L-4 due to down-flow in well G-1 at Gata.***

Figure 10 shows the calculated cooling of water produced from well 11 at Thelamork due to injection of 30 °C water into well 6. The figure shows the results for 1, 2 and 3 l/s injection and 17, 18 and 19 l/s production, respectively, for a ten year period.

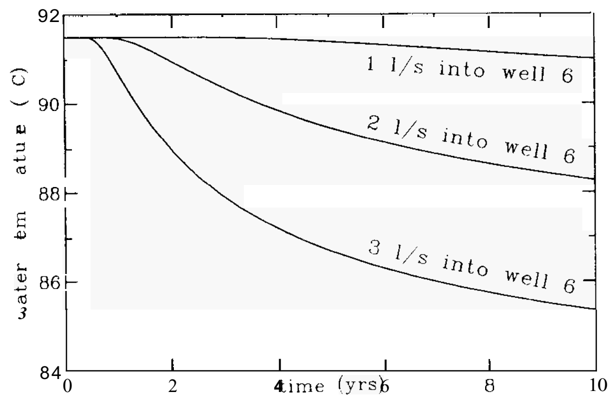

Figure **10.** ***Calculated cooling of water from well 11 at Thelamörk due to reinjection of 30 °C water into well 6.***

It is difficult, on the basis of Figure 10 alone, to determine how much injection will be beneficial in the Thelamork field. By calculating the additional available thermal power, resulting from the injection, this should be much easier. Figure 11 shows an example of this for the well pair 6-11 at Thelamork. The figure is based on the calculated water temperature after 10 years of injection of 10 and 30 °C water, respectively. A base production of 16 l/s is assumed with an addition equaling the injection. The results in Figure 11 show clearly that in the case of 30 °C injection the additional power increases very little for injection greater than 2 l/s. In the case of 10 °C injection the maximum additional power is obtained for an injection of 1.25 **l/s.**

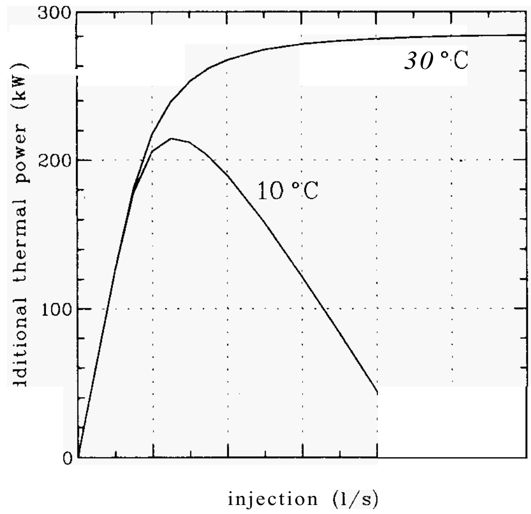

Figure **11.** ***Calculated additional thermal power resulting from injection into well 6 at Thelambrk of 10 and 30 °C water respectively.***

The results of predicting the effects of long-term injection on the reservoirs and production wells in question may be summarized as follows:

1. In the case of ***Laugaland*** predictions were made for a case were 10 l/s of 15°C water were injected into well 8 and **40** l/s produced from well 5. It is predicted that the production temperature of the well will decline very slowly, or from 95°C down to 91°C in 10 years (Axelsson et al., 1993). Water from other production wells in the Laugaland area is expected to cool down even more slowly. These results indicate that injection is viable as the means to increase the production potential of the Laugaland geothermal system.
2. At ***Gata*** injection into well G-1 does not appear to be viable, except limited injection (**< 5 l/s**) of warm (≥ 50 °C) water for a few weeks at a time (Bjornsson et al., 1993). A few **l/s** of warm water may be available in the area. The drilling of a new injection well at a greater distance from the production well **(L-4)** may, however, make injection advantageous.
3. Injection is not being considered in the ***Urriðavatn*** field, since natural recharge has stabilized the pressure draw-down in the system. The tracer test revealed, however, a very direct connection between well **5** and well 8, the main production well, such that colder water flowing down well 5 easily travels over to well 8 (Axelsson and Sverrisdóttir, 1993). This down-flow may be terminated if needed.
4. A few l/s of 30 °C return water from the heating systems of local buildings will be available in the Thelambrk field. The results for this area indicate that injection of this water should be restricted to 1-2 **l/s** per well, for an efficient heat recovery (Bjornsson et al., 1994).

CONCLUDING REMARKS

The main conclusions of the injection experiments reviewed in this paper are:

1. Injection experiments have been carried out in several low-temperature areas in Iceland in order to assess the benefits of long-term injection.
2. The desired reduction in pressure draw-down was observed during the experiments, which will allow an increase in production equaling the injection.

3. A simple fracture-zone model and a simple lumped model were successfully used to simulate observed tracer return curves and predict changes in the temperature of water produced for various injection scenarios.
4. The results indicate that in some cases substantial cold water injection will be advantageous, whereas in other cases only limited injection of warm rather than cold water will be feasible.
5. It is anticipated that injection will become an integral part of the management of low-temperature systems in Iceland in the future.

In the cases were injection appears to be advantageous injection of return water (30 °C) from the associated district heating systems will be favorable. This will minimize problems like scaling in injection wells. Yet injection of cold ground water will be more economical in some cases, such as at Laugaland (Axelsson et al., 1993). In these cases the effects of greater viscosity, cooling of the wellbore and scaling need to be tested for some time before long-term injection of cold water is initiated.

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