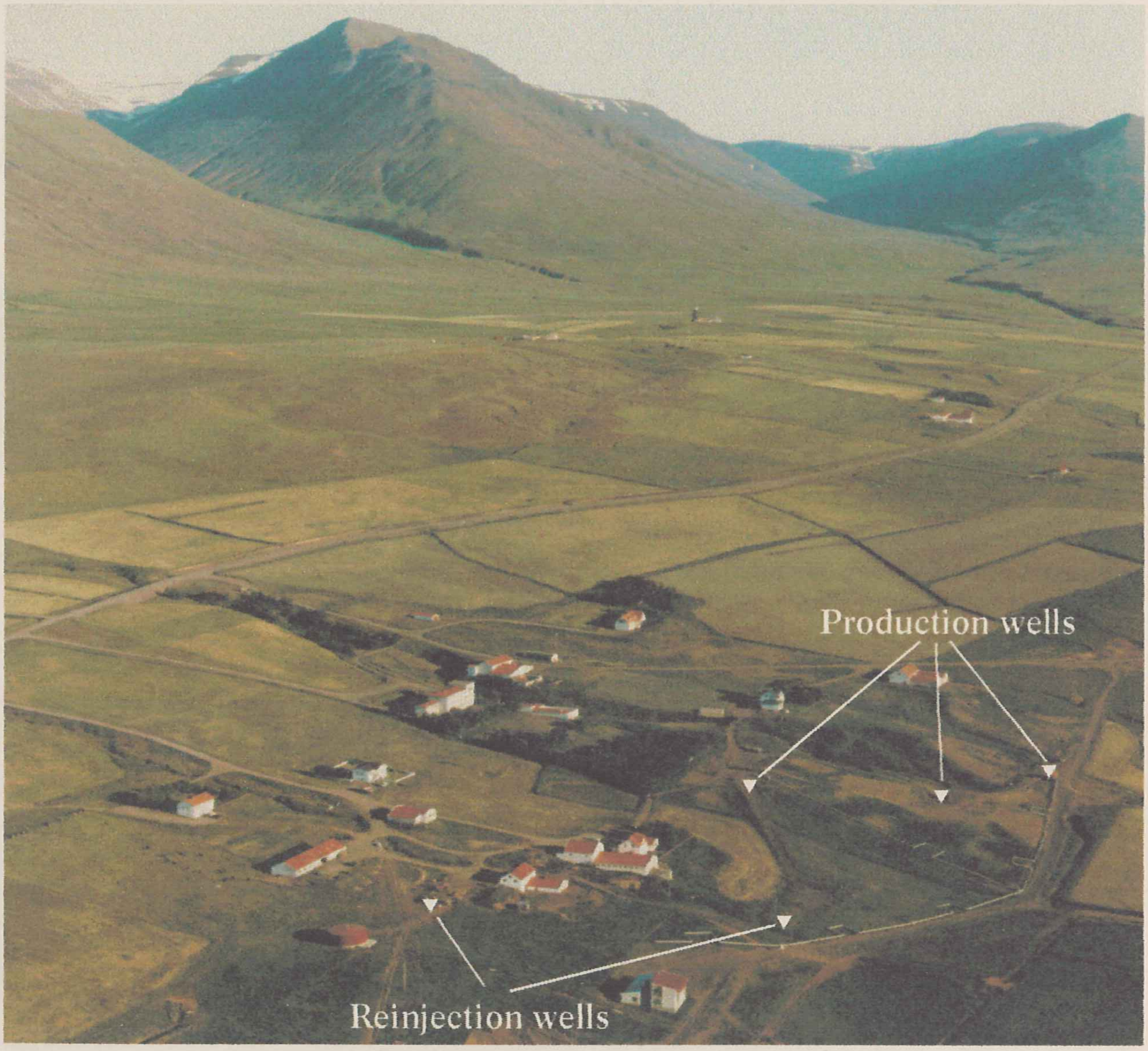
Demonstration of Improved Energy Extraction from a Fractured Geothermal Reservoir

Final Report for Thermie Project GE-0060/96



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Cover photo: The Laugaland geothermal area (Mats Wibe Lund)

SUMMARY

A demonstration project involving long-term reinjection of return water, with the aim of improved energy extraction, has been completed in the Laugaland geothermal system in N-Iceland. Energy from Laugaland is principally used for space-heating in the town of Akureyri, nearby. The project is the first such experiment undertaken in an Icelandic low-temperature area. The Laugaland system is embedded in low-permeability fractured basalt layers and its productivity is limited by insufficient recharge. More than sufficient thermal energy is, however, in-place in the 90 - 100°C hot rocks of the system. The purpose of the reinjection project was to extract some of this thermal energy and to demonstrate that energy production from fractured low-temperature geothermal systems may be increased by reinjection. The Laugaland experiment was a co-operative project involving a few companies and institutions in Iceland, Sweden and Denmark, supported by the Thermie programme of the European Commission.

The design phase of the demonstration project at Laugaland lasted from September 1996 through July 1997. It involved design of the return water pipeline, injection pumps, an automatic monitoring- and control system and a seismic monitoring network, as well as logging of the injection wells. The manufacturing phase started in November 1996 by production and construction of the return water pipeline, followed by some modification of existing seismic software and manufacture of monitoring equipment, injection pumps and seismic equipment. This phase lasted until the end of September 1997. The assembly and installation phase lasted from June through September 1997. It involved assembly and installation of the monitoring- and control system, the injection pumps and the seismic network. The commissioning phase of the project took place in August and September 1997, by start-up of the seismic network and reservoir monitoring. This was followed by the start-up of reinjection on the 8th of September. The monitoring phase of the project started on the 1st of October 1997, and ended 23 months later on the 31st of August 1999.

The progress of the project was mostly in line with the time- and cost schedule of the corresponding contract, with no major deviations occurring. At the end of August 1999 about 910,000 m^3 of geothermal return water had been reinjected, or about 14.4 L/s on the average. This may be compared to the production from the field, which during the same period amounted to 2,550,000 m^3, or about 40.4 L/s on the average. A comprehensive monitoring program was implemented as a major part of the project. This involved monitoring of production- and injection rates, water temperatures, wellhead pressures and water-levels by the automatic monitoring system. Also included were three tracer-tests, monitoring of micro-seismic activity, water chemistry, step-rate injection tests and temperature logging of the injection wells during injection.

The principal results of the Laugaland reinjection project are positive. On the one hand, the results indicate that hot water production from the field may be increased by 60-70% of the reinjection rate into well LJ-08, in the long term, without causing additional pressure draw-down. On the other hand, only a minor production temperature decline is expected in production wells. It is considered likely that an average long-term reinjection rate of about 15 L/s may be maintained at Laugaland. This would result in

an increase in energy production of about 24 GWh_t/year, which equals about 25% of the current yearly energy production at Laugaland. Thus increased energy extraction, through reinjection of return water, is technically viable at Laugaland. Economic analysis indicates that the price of the additional energy will be about 0.008 Euro/kWh, and that the payback time of the project investment will be only 2.5 years.

Detailed analysis of the comprehensive and extensive data set collected as part of the project, has been performed. In addition to the principal results outlined above the following may be mentioned: (1) The injected water exits the well through four main feed-zones, which appear to be mostly fractures. About $^2/_3$ of the water exits the well above 600 m depth, while the main feed-zones of the production wells are located below 1000 m depth. The nature of these feed-zones has been studied by a borhole televiewer. (2) A major fracture-zone appears to intersect the Laugaland area, being near vertical and striking N50°E. (3) The three production wells at Laugaland intersect the fracture-zone, which is estimated to have a permeability thickness of 15 Darcy-m. The permeability thickness of the geothermal reservoir outside the fracture-zone is estimated to be only 2 Darcy-m. (3) Repeated step-rate injection tests in well LJ-08 reveal no noticeable changes in the injectivity of the well. (4) Tracer return data (more than 1400 samples) indicate that the injected water travels through the bedrock through direct, small volume flow-paths, on the one hand, and by dispersion and mixing throughout a large part of the Laugland reservoir, on the other hand. Tracer return data also reveal a direct connection between well LJ-08 and the Ytri-Tjarnir field 1800 m north of Laugland. (5) The results of two experiments indicate that the Na-fluorescein tracer used neither decays at the temperature involved, nor interacts with alteration minerals in the reservoir rock. (6) It can be asserted that the two-year reinjection experiment did not cause a temperature decline greater than about 0.5°C. (7) No significant chemical changes were observed during the project, indicating that deposition is not expected to occur in the geothermal reservoir during future reinjection. (8) No micro-seismic events were detected during the Laugaland project, either indicating an insufficient pressure increase at great depth or an unfavourable stress-field. (9) The first phase of the development of a three-dimensional numerical model of the Laugland geothermal system and surroundings has been completed and preliminary results are in a good agreement with the results of other calculations.

Reinjection is practised in many geothermal fields in the world, in most cases to dispose of waste water due to environmental reasons. Reinjection with the purpose of extracting more of the thermal energy in the hot reservoir rocks, and thereby increase the productivity of a geothermal reservoir, has not been practised in many areas. The Laugaland project is, therefore, more in line with the Hot Dry Rock concept. Injection has, furthermore, not been part of the management of the numerous low-temperature systems utilised in Iceland. The positive results of the Laugaland reinjection experiment demonstrate that reinjection will be a highly economical mode of increasing the production potential of the Laugaland system. The reinjection system should, therefore, be an important part of the management of the geothermal reservoir for decades to come. Considerable emphasis was placed on dissemination throughout the Laugaland project. The results will hopefully encourage other operators of fractured low-temperature geothermal systems to consider injection as a management option.

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1. INTRODUCTION

Laugaland is the largest of five low-temperature geothermal fields utilized by *Hita- og Vatnsveita Akureyrar* (*HVA*) for space-heating in the town of Akureyri in Central N-Iceland (Figure 1). Akureyri has a population of about 16.000 inhabitants. Since late 1977 the annual production from the field has varied between 0.9 and 2.5 million tons of 95°C hot water (Flovenz *et al.*, 1995). Because of a low overall permeability and limited recharge this modest production has lead to a great pressure draw-down. It continues to increase with time if constant rate production is maintained. This forced the production from the field to be reduced by about 50% in the early eighties. Because of this, as well as the fact that most of the thermal energy in the geothermal system is still in-place in the 90 - 100°C hot reservoir rocks, reinjection has for long been considered a possible way to improve the productivity of the Laugaland system.

A demonstration project, involving long-term reinjection, has now been completed in the Laugaland field. The project was supported by the Thermie sub-program of the European Commissions Fourth Framework Programme for Research and Technological Development, according to contract GE-0060/96. This was a co-operative project involving companies and institutions in Iceland, Sweden and Denmark. The purpose of the reinjection project was to demonstrate that energy production from fractured low-temperature geothermal systems may be increased, in an economical way, by reinjection. Work on the project started in September 1996, following comprehensive design work carried out in the pre-proposal phase of the project. This report is a final report issued after completion of the project, according to the project contract (Annex I). It describes the progress of the project, presents data collected during the monitoring phase of the project as well as presenting results of detailed data analysis and modelling work. The progress of the project was mostly in line with the time- and cost schedule of the corresponding contract and no major deviations did occur.

According to the contract the project was divided into phases of (1) design, (2) manufacture, (3) assembly/installation, (4) commissioning, (5) monitoring and (6) dissemination. These phases involved the following:

A. Manufacture and installation of a 13 km return water pipeline from Akureyri to Laugaland (see Figure 1). A 150 mm, buried, high-density polyethylene plastic pipe, without insulation, was used to minimise the installation cost.

B. Installation of high pressure pumps at the two proposed injection wells, LJ-8 and LN-10, as well as pumps in Akureyri for pumping the water to Laugaland. Installation of a computerised control- and monitoring system.

C. Installation of a network of six ultra-sensitive, automatic, seismic monitoring stations around Laugaland (see Figure 1). This network should have located all micro-earthquakes of magnitude $M_L \geq -1$, which might have been induced by the injection, in particular during periods when the reinjection was be carried out at wellhead pressures between 20 and 30 bar. Thus some information on the locations of the fractures involved was expected (Slunga *et al.*, 1995).

D. Continuous reinjection for a period of two years, along with careful monitoring of the reservoirs response to the injection. Also monitoring of any associated seismic activity. Injection of chemical tracers to study the connections between injection- and production wells.

E. Analysis of data collected, development of a numerical model for the geothermal system and predictions of the response of the three production wells to long-term reinjection. Determine the most efficient and economical mode of utilising the Laugaland geothermal system. Estimation of the overall feasibility of reinjection in fractured low-temperature geothermal reservoirs.

F. Dissemination of the results of the project in a final report, at workshops and conferences and in articles in journals and newspapers. A workshop at the conclusion of the project was also anticipated. It was abandoned as discussed later.

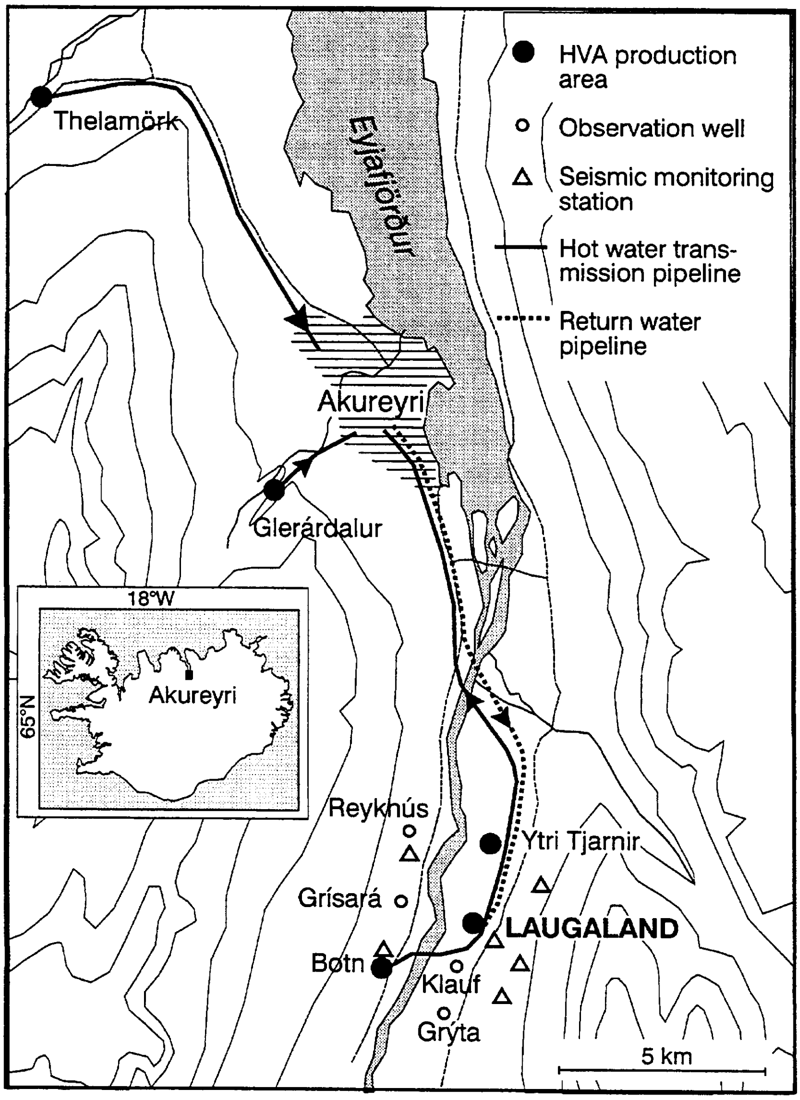


Figure 1. Location of the Laugaland low-temperature geothermal area.

A schematic drawing showing the different parts of the HVA district heating system and the geothermal areas, including the reinjection system, is presented in Figure 2.

The following were the principal participants in the project:

- *HVA*, the Akureyri District Heating Service, was the project co-ordinator. *HVA* was responsible for installation of the return water pipeline and the pumps used, controls the reinjection as well as being responsible for monitoring the geothermal systems response to the injection.
- *Orkustofnun*, the National Energy Authority of Iceland, was responsible for the scientific part of the experiment, as well as analysis of the data collected and consequent modelling. *Orkustofnun* also planned the reinjection and monitoring in co-operation with *HVA*.
- *Uppsala University* in Sweden was responsible for installing the seismic network, and was responsible for its operation (in co-operation with *Orkustofnun*, the *Icelandic Meteorological Office* and *HVA*) as well as for analysing any micro-earthquake data collected.
- *Hochest Danmark A/S* produced the return water pipeline in co-operation with an Icelandic sub-contractor, *Set hf.*
- Icelandic State Electricity, or *Rarik*, provided the pumps used for the reinjection as well as the electrical power for operating the pumps.

In addition several companies and institutions were involved in the project as subcontractors or suppliers. The most important were Raftákn ehf, Raftó ehf, Verkfræðistofa Norðurlands and Vélaleiga Halldórs Baldurssonar ehf.

This report is organised as follows: A review of previous work and knowledge on the geothermal system at Laugaland (chapter 2) is followed by a description of the progress of the demonstration project (chapter 3). A presentation of the production- and reinjection history of the project as well as presentation of data on the response of the Laugaland reservoir, collected during the project, follows (chapter 4). The next six chapters (5, 6, 7, 8, 9 and 10) are devoted to the results of analysis of all the data collected, while chapter 11 is devoted the results of micro-seismic monitoring. Following this a revised conceptual model of the Laugaland geothermal system is presented (chapter 12) as well as the preliminary results of the first phase of numerical modelling for the Laugaland system, which was carried out as part of the project (chapter 12). The report is concluded by an analysis of the main benefits of future reinjection (chapter 13), a discussion of the economics of including reinjection in the management of the Laugaland reservoir (chapter 14) and a review of the dissemination activity associated with the project (chapter 15).

Some of the data and results discussed in the following have already been presented in the mid-term report for the reinjection project (HVA *et al.*, 1998), by Axelsson *et al.* (1998a, c & d), by Hjartarson (1999) and by Hauksdottir *et al.* (1999) as well as in several progress reports for the project in Icelandic.

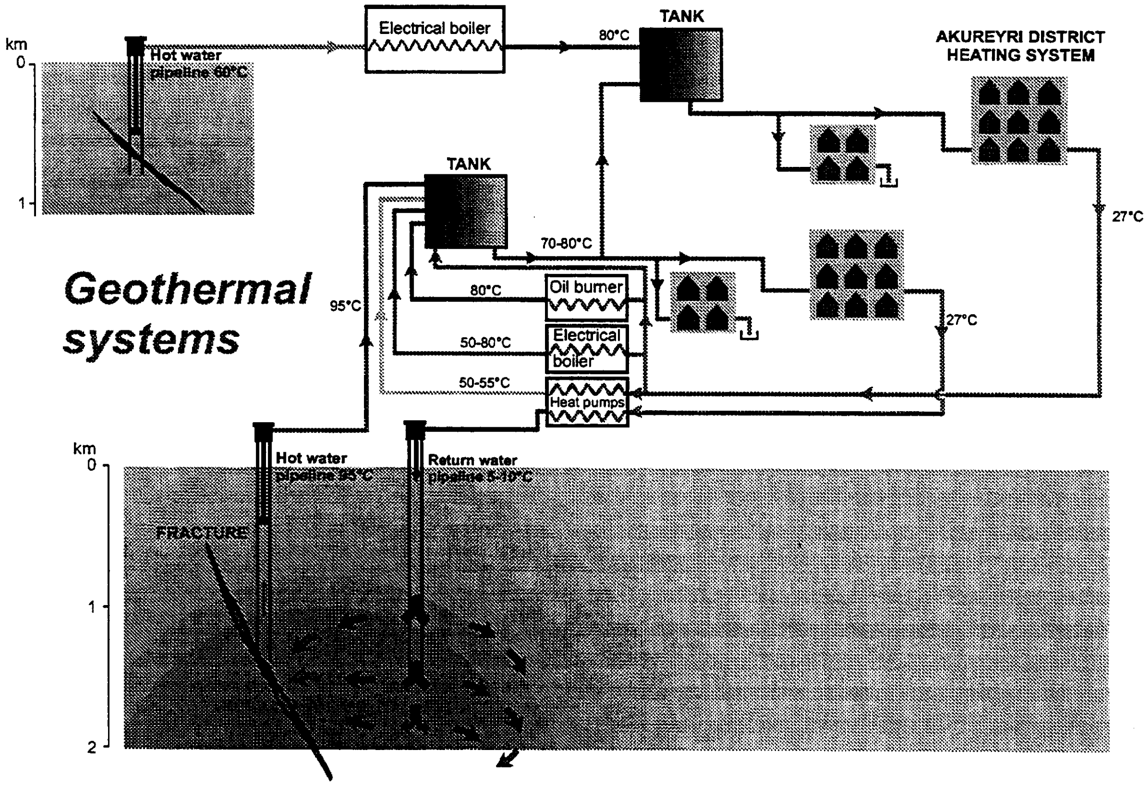


Figure 2. A schematic figure showing the different parts of the HVA district heating system, along with the geothermal areas and reinjection system.

2. PREVIOUS WORK

2.1. Utilisation of the Laugaland system

The Laugaland geothermal system is a typical fracture controlled system, embedded in 6-10 My. old flood basalts, wherein the hot water flows along open fractures in otherwise low-permeability rocks. Eight deep wells have been drilled in the area, only three of which are sufficiently productive to be used as production wells. Information on the wells currently in use in the field, as production-, observation- or injection wells, is presented in Table 1, and their location is shown in Figure 3.

Table 1. *Wells in use in the Laugaland geothermal field.*

Well	Drilled	Depth (m)	Casing (m)	Use
LJ-05	1975	1305	96	Production well
LJ-07	1976	1945	930	Production well
LJ-08	1976	2820	196	Obs./injection well
LG-09	1977	1963	37	Observation well
LN-10	1977	1606	9	Obs./injection well
LN-12	1978	1612	294	Production well

The production- and water-level history of the Laugaland system, up to the beginning of the reinjection, is presented in Figure 4. The monthly average hot water production has varied between 0 and almost 120 L/s, and seasonal variations in energy demand can clearly be seen in the figure. Figure 4 also shows the rapidly increasing draw-down the first few years, which reached about 400 m at the beginning of 1982. The drastic reduction in production, in the early eighties, reversed this trend, however. During the period from 1984 through 1997 the average yearly production has been about 40 L/s, which the geothermal reservoir will apparently be able to sustain for the next one or two decades, at least (Flovenz *et al.*, 1995).

While hot water production from the Laugaland geothermal system is limited by a low permeability, and limited recharge, most of the thermal energy in the system is still in-place in the 90 – 100°C hot reservoir rocks. To recover more of that energy and increase production from the field, increased water recharge into the geothermal system is in fact needed. Therefore, *HVA* has been planning long-term reinjection during the last several years, based on advise from Orkustofnun. The current project is the first long-term reinjection project to be started in an Icelandic low-temperature area (Stefansson *et al.*, 1995).

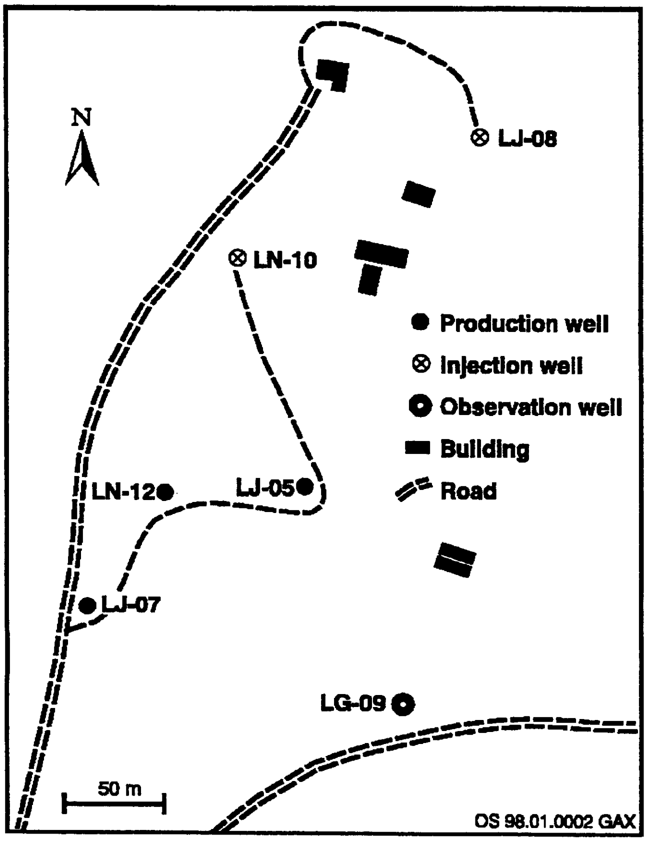


Figure 3. Wells in the Laugaland geothermal field.

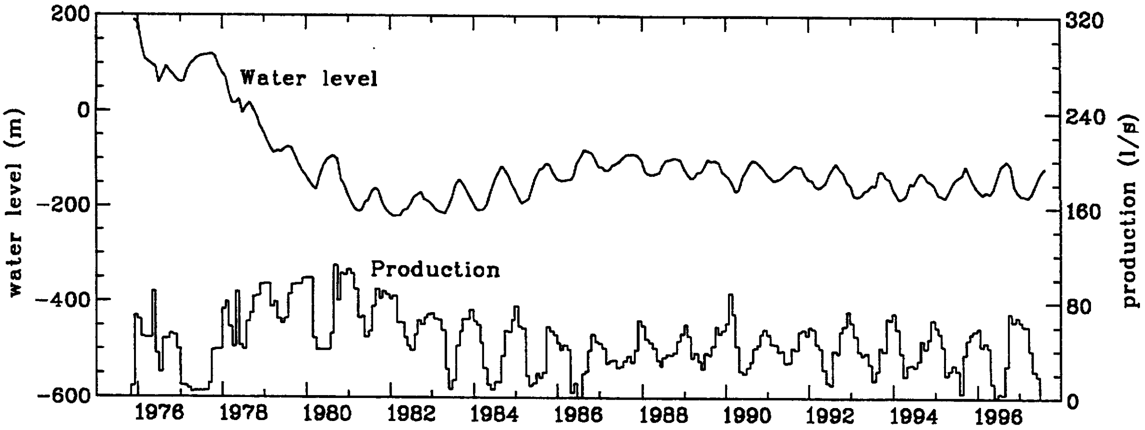


Figure 4. Production history of the Laugaland field.

2.2. The Laugaland conceptual model

Exploration of the Laugaland field started in the early 1970s and extensive sets of geological, geophysical, chemical and reservoir engineering data are available for the field. In addition to these data, production response monitoring has provided a continuous 20 year record of weekly production, pressure draw-down and water temperature, in addition to some chemical monitoring data (Axelsson *et al.*, 1998b).

These data are the basis of the current conceptual model of the system, which involves a near vertical SW-NE trending fracture-zone, with a moderate permeability, maintained by recent tectonic activity. The permeability of the lava-pile outside the fracture-zone has been reduced drastically by low-grade alteration. Successful wells in this area are either located very close to or they intersect this fracture-zone. Other wells are virtually non-productive. In the natural state, prior to production, convection in these recent fractures transferred heat from a depth of a few km to shallower levels. The heat was consequently transported into the low-permeability rocks, outside the fracture-zone, mostly by heat conduction. This convective/conductive heat transfer is believed to have been ongoing for the last 10,000 years, at least.

The reservoir engineering data have been analyzed to derive the reservoir characteristics of the Laugaland geothermal system. This includes lumped parameter modelling which has been used to simulate the pressure draw-down history of the geothermal system (Axelsson *et al.*, 1988; Axelsson, 1989). The average permeability of the system is only of the order of a few mDarcy and the reservoir volume is of the order of a few km^3. A distributed parameter model has, so far, not been developed for the Laugaland geothermal system. It should be mentioned that this conceptual model has been revised on basis of the results of the reinjection project, as will be discussed later in this report.

2.3. The 1991 injection test

A small scale injection experiment was carried out at Laugaland in the spring of 1991 (Axelsson *et al.*, 1993; Axelsson *et al.*, 1995). During the experiment, 80°C water from a near-by geothermal field was injected into well LJ-8. At first 8 kg/s were injected with only a minor wellhead pressure, later the injection rate was reduced to 4 kg/s. This experiment lasted for 5½ weeks. During the experiment 38 kg/s of 95°C water were produced from well LJ-5, which is 250 m away from well LJ-8. Concurrently the water-level in nearby wells was monitored carefully. The water-level rose almost instantaneously in response to the injection and it appeared that the reduced draw-down would allow an increase in production, approximately equalling the injection. No change in production temperature of well LJ-5 was observed during the experiment.

The connection between the injection- and production wells was investigated by adding chemical tracers to the injected fluid. Two different tracers were employed. Firstly, 1 kg of sodium-fluorescein was injected instantaneously into well LJ-8 at the beginning of the experiment. Secondly, sodium-bromide was released continuously into the injection water. During the experiment water samples where taken frequently from the production well and the tracer concentrations measured. In this experiment 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 was believed to indicate that the injected water diffused into a very large volume and that wells LJ-5 and LJ-8 are not directly connected. This is in contrast to most other tracer tests conducted in Iceland, where the tracer return has been fast and tracer breakthrough times have been of the order of one to three days (Axelsson *et al.*, 1995).

Icelandic tracer test data have been analysed by an one-dimensional fracture-zone model, where the tracer return is controlled by the distance between injection and production wells, a small fracture-zone volume and dispersion. The Laugaland data, on the other hand, were analysed by a very simple lumped model, where the tracer return is controlled by mixing in a relatively large reservoir volume (2,300,000 m^3) and geometry and dispersion neglected (Axelsson *et al.*, 1993). This model consists of two interconnected tanks. The first tank simulates the geothermal system next to the injection well and the second tank simulates the part of the geothermal system around the production well. In addition hot recharge is assumed into the second tank. 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 conventional models.

This simple model was later used to predict the effects of long-term (20 years) injection. It should be kept in mind, however, that these predictions are inaccurate due to the short duration of the 1991 experiment and the simplicity of the model. The principal results, for a case of 10 kg/s injection into well LJ-8 and 48 kg/s production from two of the production wells, are presented in Figure 5. Firstly, the injection of approximately 15°C return- or ground-water is expected to cause a decline in the temperature of water produced from 95°C to about 90°C in 20 years. Secondly, the figure shows the predicted integrated energy production for this 20 year period, resulting from the injection, which may be expected to reach about 400 GWh_t. This can be compared to the annual energy production of *HVA*, which during the last few years has been on the order of 240 GWh_t.

The results of the test in 1991 indicated that injection should be viable as the means to increase the production potential of the Laugaland geothermal system. At first injection of local surface- or ground-water was considered. That idea was abandoned, however, since serious problems may be associated with the injection of such water. The most serious of these is the possibility of deposition of magnesium-silicates in the feed-zones of an injection well, which may cause the well to clog up in a relatively short time, rendering further injection impossible. Using return water from the Akureyri district heating system is ideal, because its chemical composition is almost identical with that of the reservoir fluid. This, however, was more costly, since it required the construction of a return water pipeline from Akureyri to Laugaland.

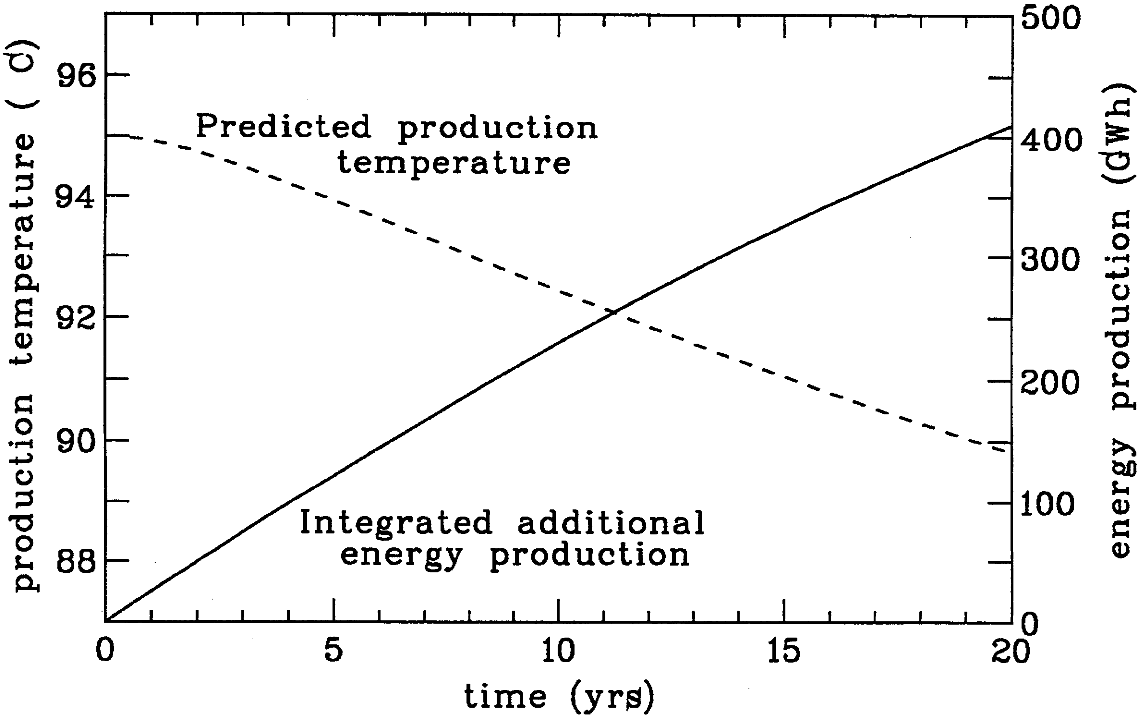


Figure 5. Estimated temperature decline and additional energy production during 10 kg/s long-term injection at Laugaland, based on the 1991 model.

3. PROGRESS OF THE REINJECTION PROJECT

The structure of this chapter is based on the items described in the detailed breakdown of the project in Table 21 of Annex I of the project contract, with some minor deviations. Work on the project started in September 1996 and the progress until January 2000 is described. A progress diagram for the project is shown in Figure 6. Several photographs taken during the project are presented at the end of the chapter (Figure 7 through Figure 14). These are mostly associated with the construction of the reinjection pipeline and aspects of the assembly and installation phase of the project.

3.1. Design

3.1.1. Overall design of the project

This part of the project was mostly finished during the pre-proposal phase. The overall design was reviewed in connection with the more detailed design of individual parts of the project, resulting in only minor changes from the original design. The overall design of the project was, however, under constant re-evaluation during the progress of the project.

3.1.2. Logging

The first logging phase was completed during the autumn of 1996 under the supervision of Orkustofnun. Geoforschung Zentrum in Potzdam, Germany undertook part of the logging. This included sonic-, resistivity- and borehole televiewer logging of the two reinjection wells as well as several other conventional logs. Analysis of the logging data relevant for the project is presented in chapter 5.

3.1.3. Pipeline design

The general specifications for the return-water pipeline were available in October 1996 and its detailed design in November 1996. The technical department at HVA carried out the design work, with the assistance of consulting engineers.

3.1.4. Design of pumps

The design of pumps for the reinjection system was completed at the end of February 1997. This was carried out by the technical department of HVA in co-operation with Orkustofnun, Rarik and consulting engineers.

3.1.5. Design of seismic monitoring system

The design of the seismic monitoring system started in December 1996 and was finished by the end of June 1997. The design was the responsibility of the University of Uppsala in co-operation with Orkustofnun and HVA.

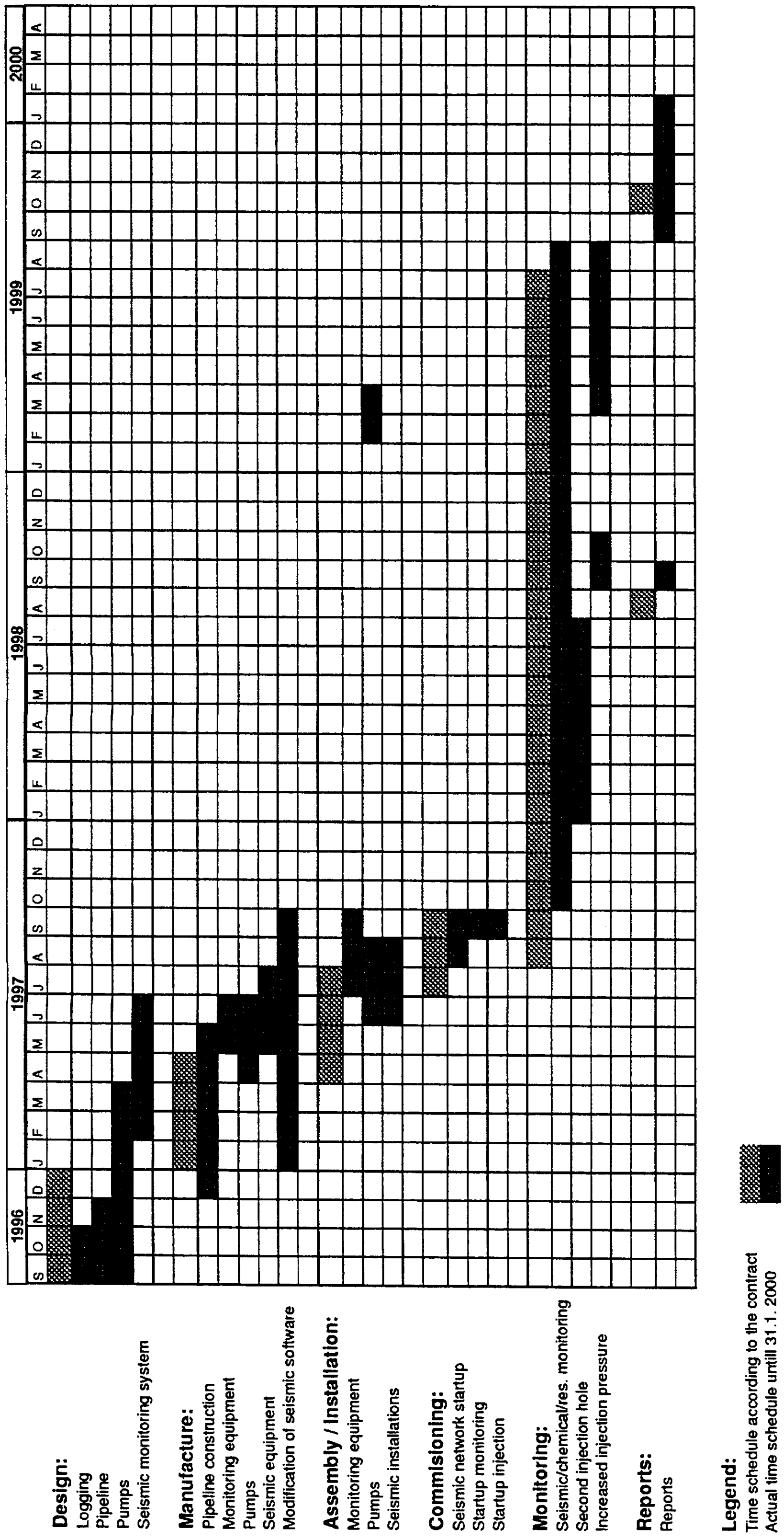


Figure 6. Final progress diagram for project GE-0060/96 showing the initial time schedule and the actual progress until the end of the project on January 31st 2000.

Field investigation of the Laugaland area, regarding selection of sites for the six seismic stations, was performed in January 1997. Good bedrock was found on hill-sides west and east of the river Eyjafjardara, but the flat valley floor is covered by thick sediments, which cause unfavourable conditions for precise detection of high frequency seismic signals. The valley bottom was therefore avoided in site selections.

Genetic Algorithms were used to invert for the best location of the stations. The criteria used in the inversion was maximizing the variance of the a) distances up to 3500 m, b) angles from the source to the stations, and c) the angles within quadrant modules. The results showed a very strong dependency on the exact location of the closest station. To find a suitable site for the closest station, noise tests were carried out in April 1997 to record the ground motion from pumps in the hot water production wells, which can produce large signals especially close to the resonance frequency of the pumps.

Contact was established with the National Telephone Company (Postur & Simi) to get information about the availability of telephone lines in the area. The type of connection we were seeking ranged from a) simple modem connection, b) X.25 connection, c) Internet subscription or d) ISDN connection. We selected the simple modem connection that was the alternative with the best price-performance ratio for our purpose.

Several alternatives were considered regarding the three component seismometers. Two main types of seismometers are available, active elements with feedback electronics and passive elements, which do not include any electronic circuitry (pure mechanical). Considering the frequency range, the background ground motion and the size of the expected seismic signals we excluded the active seismometers due to the noise characteristics of these devices. The final decision made was to purchase separate passive 4.5 Hz elements for each component (vertical, North-South and East-West) and assemble them in a robust housing. Orkustofnun carried out the assemblage work.

There are not many digitizers on the market meeting the requirements of up to 1000 samples per second, high dynamic range and very low electronic noise. The units with the best price-performance ratio were found in the HRD-24 24 bit digitizer from Nanometrics in Canada.

3.2. Manufacture

3.2.1. Pipeline construction

Manufacture of plastic pipes for the 12 km long return-water pipeline from Akureyri to Laugaland was completed in early December 1996. Hochest Danmark was responsible for this part of the project with aid of a subcontractor, Set hf. The pipeline has an inner diameter of 150 mm.

An open tender for the construction of 8 km of the pipeline was launched in December 1996. The remaining 4 km were constructed by the staff of HVA as well as all welding and transport of the pipeline. A total of 5 contractors made bids. The lowest bid was accepted and a subcontract signed in December 1996. The lowest bid amounted to 38%, while the highest one was 83%, of the expected cost. These unusually low prices resulted from limited activities among contractors during the main winter season. The pipeline construction started in late December 1996 and 8 of the 12 km had been finished by the end of February 1997, in spite of difficult weather conditions. The remainder of the pipeline had been completed by the end of May 1997. The pipeline is buried at a depth of 1.2 m to avoid freezing in wintertime. Figure 1 shows the location of the pipeline.

3.2.2. Monitoring equipment

Automatic, computer-controlled equipment for monitoring various parameters describing the injection, and the response of the Laugaland reservoir to the injection, were manufactured in May and June 1997. These parameters include the flow-rate and temperature of the return-water leaving the pumping station in Akureyri, rate of injection, water temperature and wellhead pressure for both injection wells, as well as flow-rate and water temperature for the three production wells at Laugaland. In addition the system monitors the frequency of the pump-motors involved.

3.2.3. Pumps

Pumps for injecting the return-water into the two injection wells were manufactured during April through June 1997. These have capacities of 20 L/s at 30 bar-g pressure and 10 L/s at 10 bar-g pressure, respectively. A pump intended for pumping the return water from the pumping station in Akureyri towards Laugaland was manufactured during the same period.

3.2.4. Seismic equipment

Digitizers of the type HRD-24 were ordered from a Canadian company, Nanometrics. Six vertical and twelve horizontal 4.5 Hz geophones were ordered from the company SENSOR in the Netherlands. An individual calibration test was ordered for each geophone element. Seven Pentium PC's with internal modems and one Sun SPARC Station was ordered from a local dealer. Optic cables for the data communication between digitizer in the seismic station vaults and the on-site computers were ordered from the National Telephone Company P & S. Power backup units are installed for all digitizers and all computers, both at the seismic stations and at HVA headquarters.

3.2.5. Modification of seismic software

During December 1996 and January 1997 work focused on software development related to the interfacing of the Nanometrics HRD digitizer to the SIL Utility Software. Tests were performed for 500 samples per second on three channels using Pentium computer. The results showed a good performance. Configurable logging facilities was implemented for logging various "State Of Health" parameters available from the digitizer.

During the period from Mars through May 1997 work concentrated on adaptation of the phase-detection procedure to the 500 cps configuration and the higher frequency content of the data. Adaptation of the rest of the seismological software was carried out during May through July. This involved among other things the change from using single float representation of co-ordinate and time information into double precision. This was necessary due to the small size of the network area. To make the interactive view of the seismic activity more sensible, information regarding source location is displayed relative to the injection borehole, both in distance and angle.

Work during May and June 1997 involved software development and configuration of the standard Unix-to-Unix communication package (UUCP). Some modifications of the acquisition software related to the communication between the stations and the centre was done. This mainly involved modifications or rewriting of Unix shell scripts.

3.3. Assembly/Installation

3.3.1. Monitoring equipment

The automatic injection- and reservoir monitoring system was installed and tested during the period from July through September 1997. This work was carried out by the technical department of HVA, Raftákn Consulting Engineers and Raftó Electrical Contractors. Data collected by this system, as well as instantaneous information on the status of the injection and production wells, can be accessed through computers in the pumping station of HVA in Akureyri, as well as in its headquarters. Consequently these data are transmitted by e-mail to Orkustofnun for evaluation and analysis. The data collected by the system is reviewed in chapter 4.

3.3.2. Pumps

The pumps for pumping the return water from Akureyri to Laugaland, and hence into the injection wells, were assembled and installed during the period from June through August 1997. This was done by the staff of HVA and Rarik with the aid of Raftó Electrical Contractors.

3.3.3. Seismic installations

The vaults housing the seismic stations, and the associated infrastructure, were constructed during the period from late May through the middle of July 1997. Figure 1 shows the locations of seismic stations. Some less sophisticated vaults were constructed for additional mobile seismic stations to be operated in case of observed seismic activity located in the reservoir.

The seismic network was installed during the period of July 15th through July 30th. Technically the network was in operation on July 30th and remotely available for parameter tuning and adjustments from Uppsala through the Internet. During August and September the main work concentrated on tuning the network parameters for the highest possible micro-earthquake detection ability, within the reservoir. The large amount of earthquakes north and north-east of the area (50 to 100 km distance) were avoided by using different detection parameters for different regions. The day by day control of the network operation was done in Uppsala through the Internet. All saved earthquake data was also transferred to Uppsala through the Internet at night.

3.3.4. Installation of an additional pump

Because of the small diameter of the return-water pipeline, as well as the long distance between Akureyri and Laugland, its transport capacity is rather limited. As originally designed, the pipes maximum capacity is of the order of 15 L/s. Therefore, a new pump was installed in March 1999, about halfway between Akureyri and Laugaland, to boost the capacity of the return-water pipeline. This boosted the transport capacity of the return-water pipeline to 21 L/s, or by about 40%.

3.4. Commissioning

3.4.1. Seismic network start-up

The start-up of the seismic network took place in late August 1997.

3.4.2. Start-up monitoring

The start-up of the monitoring took place during September 1997. This involved water-level measurements in a number of observation wells inside, as well as outside, the Laugaland area. It also involved the collection of water samples from hot water production wells, and a return water sample, for chemical analyses, which will be used as references during later phases of the project. Furthermore, the start-up of monitoring involved additional logging of the two injection wells, as well as start-up of the automatic monitoring system. Some fine-tuning of the automatic monitoring system was also performed in September. In addition, the start-up included a step-rate injection test of the main injection well.

3.4.3. Start-up injection

The start-up of the actual injection took place on the 8th of September 1997. A nearly constant injection rate of 8 L/s was maintained through the remainder of September. The temperature of the return-water, as it was injected, was around 21°C. The wellhead pressure increased slowly to about 6 bar-g during this period. At the end of the start-up period a chemical tracer was injected into the injection well. The recovery of this tracer in the production wells in the Laugaland area has been monitored carefully.

3.5. Monitoring

The monitoring phase of the reinjection project at Laugaland started on October 1st 1997. The monitoring did progress mostly according to schedule and great amounts of data have been collected. The reinjection has been mostly continuous. Until the end of January 1998 about 8 L/s were injected continuously into well LJ-8. From that time an additional 6 L/s were injected into well LN-10. Reinjection into LN-10 was discontinued in late August 1998. In early September 1998 injection into well LJ-8 was increased to 20 L/s, which raised the wellhead pressure of the well to 2.5-3.0 MPa. Since early October 1998 the injection rate into well LJ-8 has varied between 15 and 21 L/s, and the wellhead pressure between 1.4 and 2.7 MPa.

Before the installation of the booster pump discussed in section 3.3.4 injection rates above 15 L/s were enabled by injecting a mixture of return water and 80°C geothermal water available at Laugaland. Since the installation of the booster pump in March 1999, this has not been necessary.

In addition to production- and injection rates, water temperatures, wellhead pressures and water levels were observed by the automatic monitoring system mentioned above. These values were collected every ten minutes. Water levels were also monitored manually in a number of wells inside, as well as outside, the Laugaland area. The monitoring data are presented and discussed in the following chapter (chapter 4) while the results of analysis of parts of the water level records are presented in chapter 6. The water temperature measurements are, of course, of a paramount importance in any reinjection project. These are discussed separately in chapter 9.

During the monitoring phase variations in the chemical content of the water produced at Laugaland were also monitored carefully through frequent sampling and analysis. The results are presented in chapter 10.

Two tracer-tests were successfully completed during the winter of 1997/98, each lasting a little over two months. The first one began at the end of the start-up period of the project, while the second one was started during the middle of March. Tracer samples are still being collected, since the tracers are still being recovered in the production wells in the field. It may also be mentioned that the tracer from the first tracer injection is being recovered at an increasing concentration in a different geothermal field, Ytri-Tjarnir, located about 1.8 km north of Laugaland. The third and final tracer test was successfully conducted during the spring of 1999. A total of more than 1400 tracer-samples, from a number of production wells, both inside and outside the Laugaland area, have been collected and analysed up to the end of August 1999. The results of the tracer tests are presented in chapter 7.

A small-scale experiment was set up as part of the monitoring phase of the Laugaland reinjection experiment to study the stability of one of the tracers used (fluorescein) at the reservoir temperature. The results of the experiment are presented in chapter 8.

Three step-rate injection tests were conducted for the injection wells, during the first year of the monitoring phase. The first test for well LJ-8 was repeated 8 months later, such that changes in well injectivity, due to scaling etc., could be detected. The results of the tests are discussed in chapter 5. The temperature profiles of both were also measured during active reinjection. This was done on four occasions for the main injection well, LJ-8, which has enabled fairly accurate estimates of the relative importance of the different feed-zones of the well (see also chapter 5). The latest temperature log was measured at the end of March 1999.

The seismic network is believed to have operated as expected throughout the project and the results of micro-seismic monitoring of the effects of the two years of reinjection are presented and discussed in chapter 11. Detailed analysis and interpretation of the great amounts of data collected has been going on continuously since the beginning of the monitoring phase until the end of 1999, while emphasis on numerical model development has been concentrated during the last half year of that phase (see chapter 12).

Figure 7. The view from Laugaland towards Akureyri in the north, degassing and storage tank in the foreground.

Figure 8. Plastic pipes for the return water pipeline waiting to be assembled.

Figure 9. The return water pipeline being buried beside the hot water transmission pipeline.

Figure 10. The return water pipeline being laid across river Eyjafjardara.

Figure 11. The return water pipeline being buried below river Eyjafjardara.

Figure 12. The final touch being applied to the degassing tank for the return water at Laugaland.

Figure 13. Did we forget anything?

Figure 14. Reinjection being formally started from the offices of HVA, on Septemberth 1977, by Mr. Svavar Ottesen, then chairman of the board of directors.

4. MONITORING DATA

4.1. Reinjection/production

Reinjection started on the 8th of September 1997. Since then injection into well LJ-08 has been mostly continuous, varying between 6 and 21 kg/s. From the end of January 1998 about 6 kg/s were also injected into well LN-10, raising the combined injection rate to 14 kg/s as shown in Figure 15. During the second half of the project injection rates were as high as 20-21 kg/s for a few periods, the longest such period lasting from the middle of March to the middle of May 1999. This was after the booster pump discussed earlier (section 3.3.4) had been installed. Stable injection rates have been maintained for most of the project, except for brief periods when the reinjection has been varied or discontinued. A total of 910,000 tons had been injected at the end of August 1999, or about 14.4 kg/s on the average.

The temperature of the injected water was normally in the range of 6 - 22°C, as shown in Figure 16. Lower values occur when the return water has passed through the heat pumps of the HVA district heating system (Figure 2). The temperature drop in the 13 km non-insulated return water pipeline has been of the order of 5°C. During the fall of 1998 injection rates up to 20 kg/s were enabled by injecting a mixture of return water and 80°C geothermal water available at Laugaland. This caused the temperature of the injected water to rise to 28 - 33°C for shorter periods.

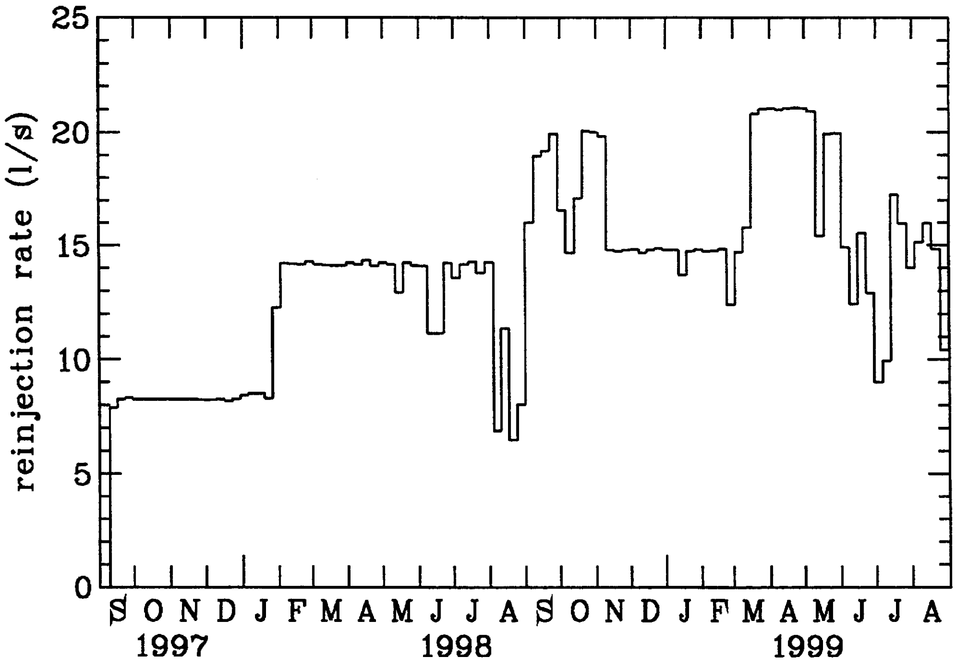


Figure 15. Weekly average reinjection into wells LJ-8 and LN-10 during the two-year reinjection project at Laugaland.

Figure 17 shows daily average hot water production from the Laugaland field during the project. About two weeks prior to the start-up of the reinjection, production from one of the production wells, LN-12, was initiated after a summer break. This was done to create semi-stable pressure conditions in the reservoir when reinjection would start. During the period from the end of August until the end of November 1997, LN-12 was the only production well in use in the area. Therefore, this period provides a good opportunity for studying the effects of reinjection into well LJ-8. During a few other shorter periods constant production was maintained to create semi-stable reservoir conditions. This was done to facilitate various tests and consequent data interpretation.

During January through March 1998, as well as during the winter of 1998/1999, production was more variable, because of greater hot water demand (Figure 17). From December 1997 through March 1998 two wells were continuously on-line, either wells LN-12 and LJ-5 or wells LJ-5 and LJ-7. Intermittent production from well LJ-5 was also required during the following summer (1998), because of unusually cold weather. Interpretation of data collected during the summer is, therefore, more difficult. Two wells were also on-line most of the winter of 1998/1999 and some intermittent production was required during the following summer.

The total production at Laugaland varied between 0 and 130 L/s and a total of 2,550,000 tons were produced from the field from late August 1997 until the end of August 1999. This corresponds to an average production of 40.4 L/s, which is about 6% more than the average hot water production from Laugaland during the period 1995 - 1997. The reinjection equals about 36% of the total production during the reinjection experiment.

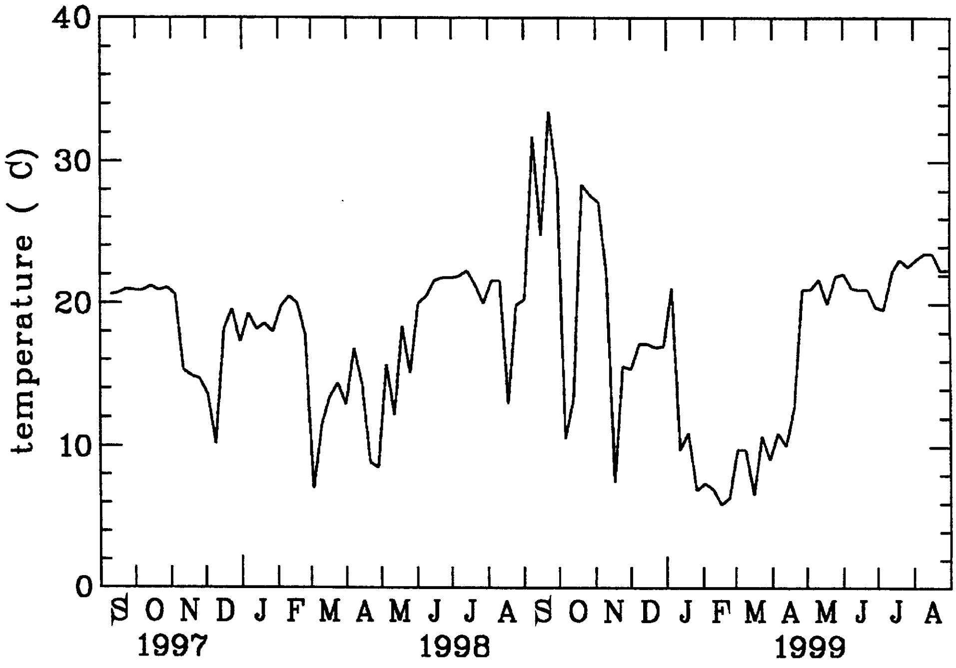


Figure 16. Temperature of return water reinjected during the project.

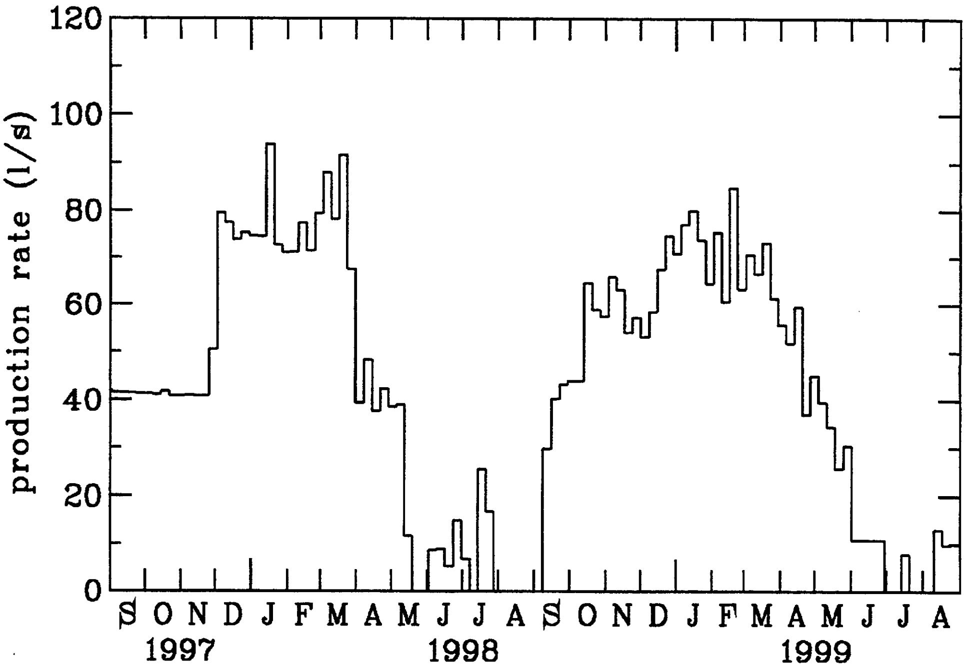


Figure 17. Weekly average production from wells LJ-5, LJ-7 and LN-12 at Laugaland during the reinjection project.

Figure 18 shows the wellhead pressure of injection well LJ-8 during the reinjection project. It slowly increased to about 8 bar-g in November 1997, after about two months of injection. Before injection started the water-level in the well was at a depth of 126 m. Therefore, the pressure in the well had at that time increased by about 20 bar. Until the end of March 1998 the wellhead pressure did not increase, because of increased production from the field. During the spring and summer of 1998 the pressure continued rising, in phase with rising reservoir pressure (water level), having reached slightly more than 11 bar-g at the beginning of August 1998. During the second year of the project injection rates were higher, causing well-head pressures as high as 28 bar-g.

The well head pressure of well LJ-8 has been somewhat greater than anticipated on the basis of the 1991 test. This is the result of much colder water being injected presently than in 1991, i.e. at 6 - 21°C instead of 80°C, resulting in a viscosity contrast of about 3.5. The first few months the wellhead pressure also increased steadily, even though the reservoir pressure was relatively stable (see following section). The cause for this has not been resolved, but it may also be the viscosity contrast between injection- and reservoir fluid, as well as thermal effects in the reservoir around well LJ-8. It should be noted that some of the variations in the wellhead pressure of well LJ-8 are simply caused by variations in the temperature of the injected water.

In addition to some well-head pressure transients being caused by viscosity- and thermal effects, most of the well-head pressure variations observed in the case of well LJ-08 may be attributed to variations in injection rate as well as variations in production and the consequent variations in reservoir pressure. Results of further analysis of the well-head pressure transients for well LJ-08 is presented in chapter 6.

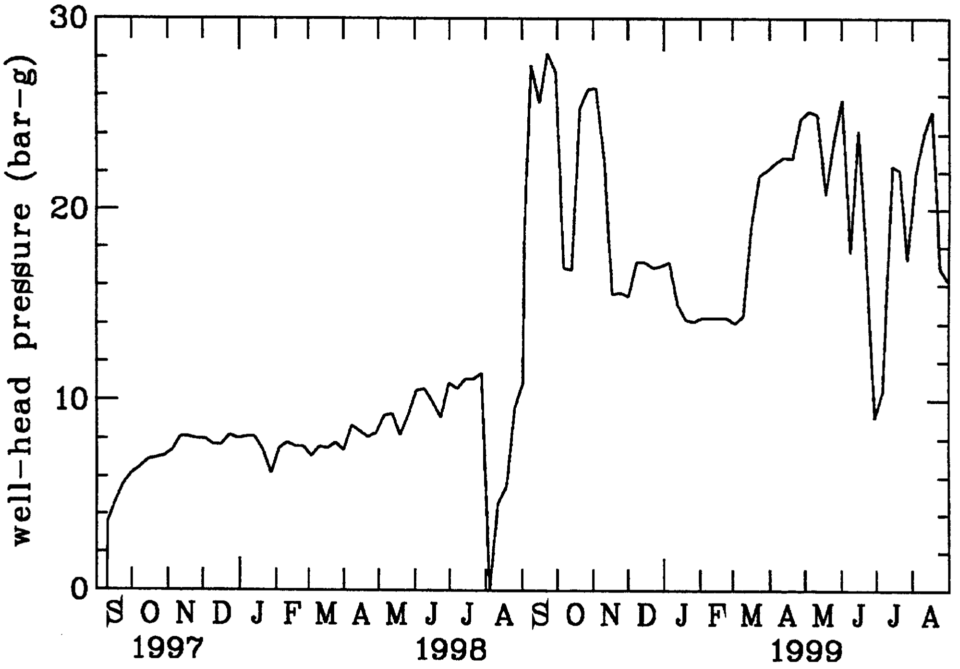


Figure 18. Well-head pressure of well LJ-8 during the reinjection project.

Well LN-10 responds quite differently to injection, if compared to well LJ-8, as shown in Figure 19. During a couple of days, after injection into the well started, the water level in the well rose by about 100 m. Since then the water level in the well has changed very slowly, from a depth of about 10 m in the beginning of February 1998 to a wellhead pressure of about 2 bar-g at the beginning of August the same year. The long-term injectivity of well LN-10, therefore, appears to be about 30% greater than the injectivity of well LJ-8. A steady increase in water level/pressure for the first months after injection is started, such as observed for well LJ-8, is not seen in well LN-10. Results of analysis of these water level transients are also discussed in chapter 6.

4.2. Water level changes

The data presented in Figure 15 through Figure 19 were all collected by the automatic monitoring system. In addition to these data, water level measurements were taken on a regular basis in a number of wells inside, and outside, the Laugaland field. Some of the water level measurements are presented in Figure 20 through Figure 22. Figure 20 shows the water-level changes observed in two wells inside the Laugaland field during the first six months of the injection project. These are well LN-10, which is situated about halfway between the production wells and well LJ-8 (Figure 3), and production well LJ-5. Figure 21 presents the water level changes in production wells LJ-05 and LN-12, on one hand, as well as observation well LG-09 inside the Laugaland field, on the other hand. Figure 22 finally shows water level changes observed in two observation wells outside the Laugaland field.

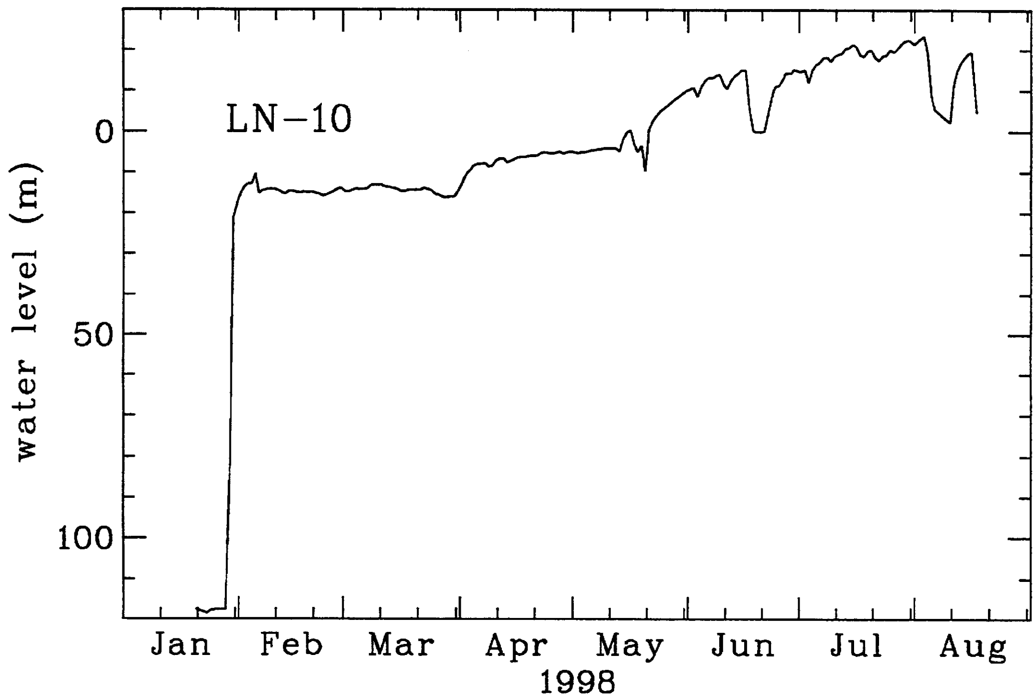


Figure 19. Water level in well LN-10 during injection into the well itself from the end of January through August 1998.

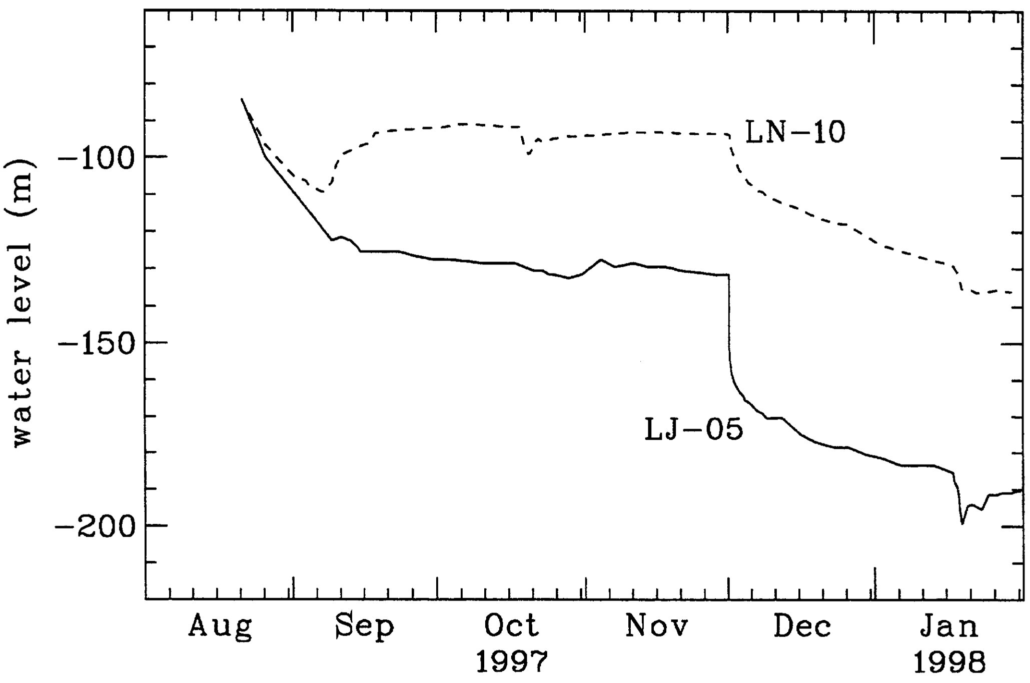


Figure 20. Water level changes in production well LJ-5 and observation well LN-10 during the first half year of the project. Reinjection started on September 8th 1997.

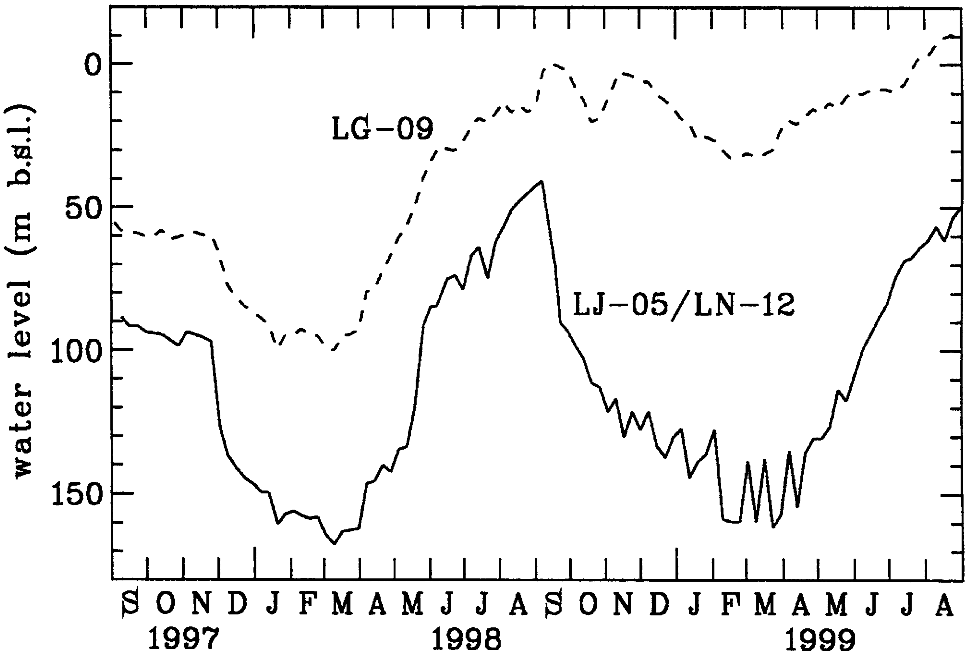


Figure 21. Water-level changes in three wells (production wells LJ-05 and LN-12; observation well LG-09) at Laugaland during the whole reinjection project.

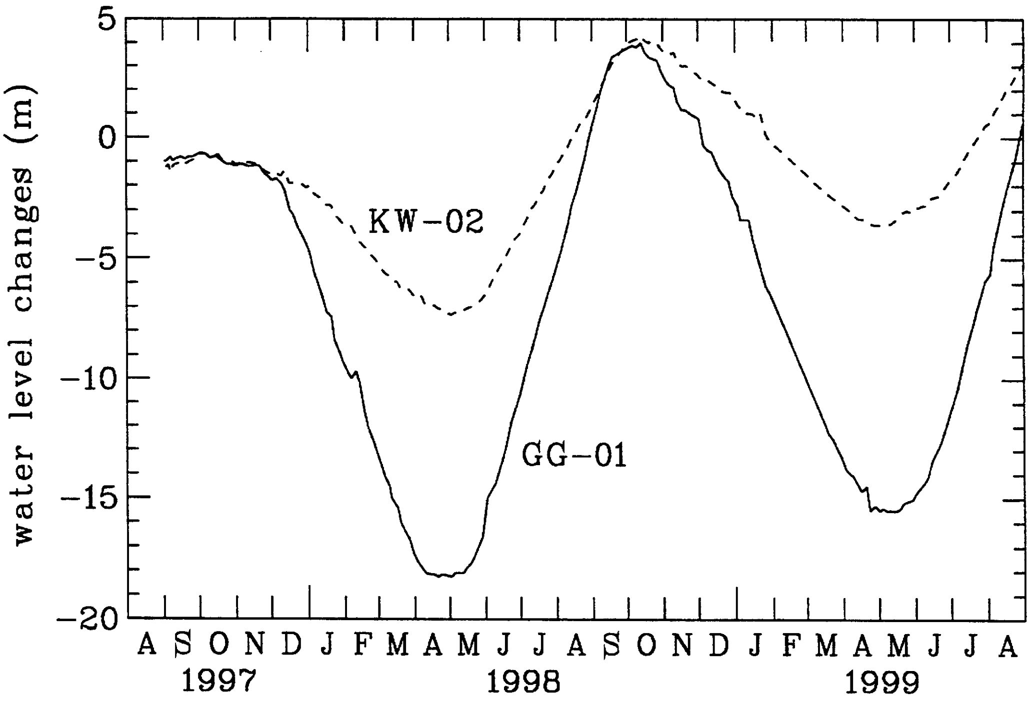


Figure 22. Water-level changes in two observation wells outside Laugaland. Well KW-2 is situated 1 km S of Laugaland and well GG-1 1.6 km WNW of Laugaland.

The effects of the start-up of the reinjection in early September 1997 can clearly be seen in Figure 20. The water-level in LN-10 rises by about 15 m, but stabilises in LJ-5 after being declining rapidly due to production from well LN-12. It should be noted that wells LJ-5 and LN-12 are directly connected, through the same fracture zone, while well LN-10 does not intersect that zone. Other changes in water level are the results of changes in production, such as the rapid decline in early December 1997, which is the result of well LJ-5 being added on-line.

Figure 21 shows the water level changes inside the Laugaland field throughout the whole project, both in the production wells and in one observation well (LG-09). The water-level measuring device in well LJ-5 broke down at the end of May 1998. At about the same time water level monitoring became possible in well LN-12, when the pump in the well was removed for maintenance. During early 1999 water level measurements were again transferred from LN-12 to LJ-05. The annual water level variation is, of course, the result of the seasonally varying hot water demand (Figure 17). The rapid water level rise in May 1998 is, for example, the result of production from the Laugaland wells being discontinued for the summer. When viewing Figure 21 one must keep in mind that the annual hot water production increased significantly in 1998 (and 1999). Therefore, a generally declining water-level would have been expected. The opposite is, however, the case. The water level in the system appears to be rising. This is most apparent in well LG-09 where the water level did rise by almost 70 m between the winters of 1997/1998 and 1998/1999. This is clearly the effect of reinjection.

Water level changes are also monitored in several observation- and production wells as far as 2 km away from Laugaland. Figure 22 shows the most interesting of these data-sets. Wells GG-01 at Grisara and KW-02 at Klauf are located 1.6 and 1.0 km from Laugaland, respectively (Figure 1). The water level in well GG-01, in particular, has been monitored carefully during the last two decades. The water level variations in these wells are clearly influenced by the production at Laugaland, which is evident in a 10 – 20 m annual variation. More importantly, there is a clear long-term water level rising in both wells, superimposed on the seasonal variations. This is most likely because of the reinjection. It may be pointed out that modelling of the water level variations in well GG-01 has resulted in an estimate of the average permeability of the bedrock in the Eyjafjordur region, which is of the order of 2 Darcy-m (Axelsson *et al.*, 1999).

The details of the water level records will not be discussed further in the present chapter. It actually constitutes a series of pressure transient tests, however, several of which have been analysed as such (Hjartarson, 1999). The results of this analysis are presented in chapter 6, later in this report. The main results are, however, that the production wells intersect the NE-SW fracture zone mentioned previously, which has an estimated permeability thickness of about 15 Darcy-m. The injection wells are clearly outside this zone. The permeability thickness of the low-permeability rocks outside the fracture-zone is estimated to be about 2 Darcy-m

5. BOREHOLE ANALYSIS

In this chapter information on the nature of the Laugaland geothermal system, as well as properties of the geothermal wells in the field, is derived from available borehole logs. The injection wells were temperature logged before and during injection and by simulating the measured profiles, the feed-zone properties (i.e. injectivity) of the wells can be studied. A borehole televiewer log measured by Geoforschung Zentrum in Potsdam, Germany, is available for sections of the main injection well, LJ-08. This log will be analysed to provide valuable information on dip and direction of fractures intersecting the well. This is the first time such an analysis is carried out for a geothermal well in Iceland. Finally, the location of feed-zones in the three production wells will be used to estimate the direction of the principal fracture zone, which intersects and controls the Laugaland geothermal system. The principles of geothermal logging applied to this analysis are presented in Appendix A of this report.

At least sixty temperature logs have been measured in the wells at Laugaland since production started from the field in 1976, mostly by Orkustofnun. A few select examples are presented in Figure 23, while some more are presented by Hjartarson (1999). Basic information on the wells in the Laugaland field is found in Table 1 above and Table 2 below. Figure 23 clearly demonstrate the variety of profiles that can be confronted in a geothermal well.

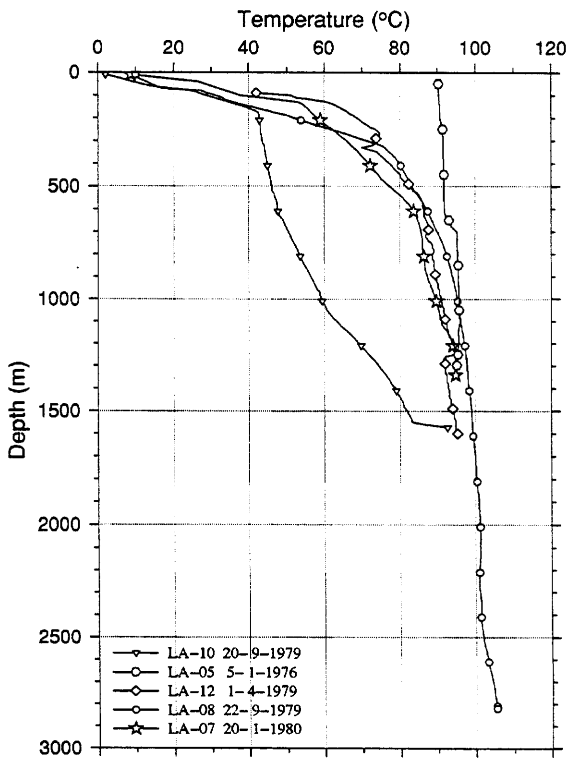


Figure 23. A few selected temperature logs from the wells in use in the Laugaland geothermal field.

Table 2. *Main feed-zones of the wells in the Laugaland field.*

Well	Depth (m)	Main feed-zones (m)	Minor feed-zones (m)
LJ-05	1305	620, 1262	584, 712
LJ-07	1945	1124, 1490	700, 820
LJ-08	2820		320, 600, 1335, 1875, 2400
LN-10	1606		150, 590, 1040, 1080
LN-12	1612	1141, 1571	310, 670, 950

5.1. Temperature log simulation results

A multi feed-zone borehole simulator, named HOLA (Bjornsson, 1987 and Bjornsson *et al.*, 1993), solves numerically the differential equations that describe energy, momentum and mass flow in a vertical well. The HOLA program, therefore, can by conveniently used to simulate temperature profiles measured during injection. The HOLA program was used to simulate temperature profiles measured during injection into wells LJ-08 and LN-10 at Laugaland, and consequently estimate the flow rate into each feed-zone. The simulation results are presented below.

Figure 24 shows five temperature profiles measured in well LJ-08. One of the profiles was measured prior to reinjection and is assumed to represent the undisturbed rock temperature. Four other profiles where measured during injection, at different injection rates, and have been simulated by HOLA. The simulation profiles are shown in Figure 24 and Table 3 below presents the simulation results, i.e. the estimated flow rate into each feed-zone.

According to the temperature logs, and injection simulations, there are four main feed-zones in the well, where most of the injected water leaves the well. They are at depths of approximately 325 m, 600 m, 1350 m and 1875 m, respectively. An attentive reader might notice that the feed-zone depths do not correspond exactly with depths presented in Table 1. This is because of restrictions imposed by HOLA (the feed-zones have to be at knot-points in the finite difference grid employed). According to the simulation results, 49 % of the injected water exits the well through the feed-zone at 325 m depth, on the average, 20 % at 600 m, 20 % at 1350 m and 10 % through the zone at 1875 m depth. The remainder, which is only about 1 %, leaves the well below 2000 m, most likely around 2400 m, but the well is obstructed at 2000 m depth. The bulk of the injection fluid, therefore, leaves the well above 600 m depth. This is about 500 – 700 m above the main feed-zones of the production wells.

By comparing the simulation results for different logging dates, some variations in the relative flow into each feed-zone are apparent. It seems, for example, that as the injection rate is increased, relatively more water leaves the wellbore at shallow depths, and if the flow rate is reduced relatively more exits the well at greater depths. This can be studied in further detail by estimating the injectivity of each feed-zone, a parameter that reflects the ability of a feed-zone to accept fluid.

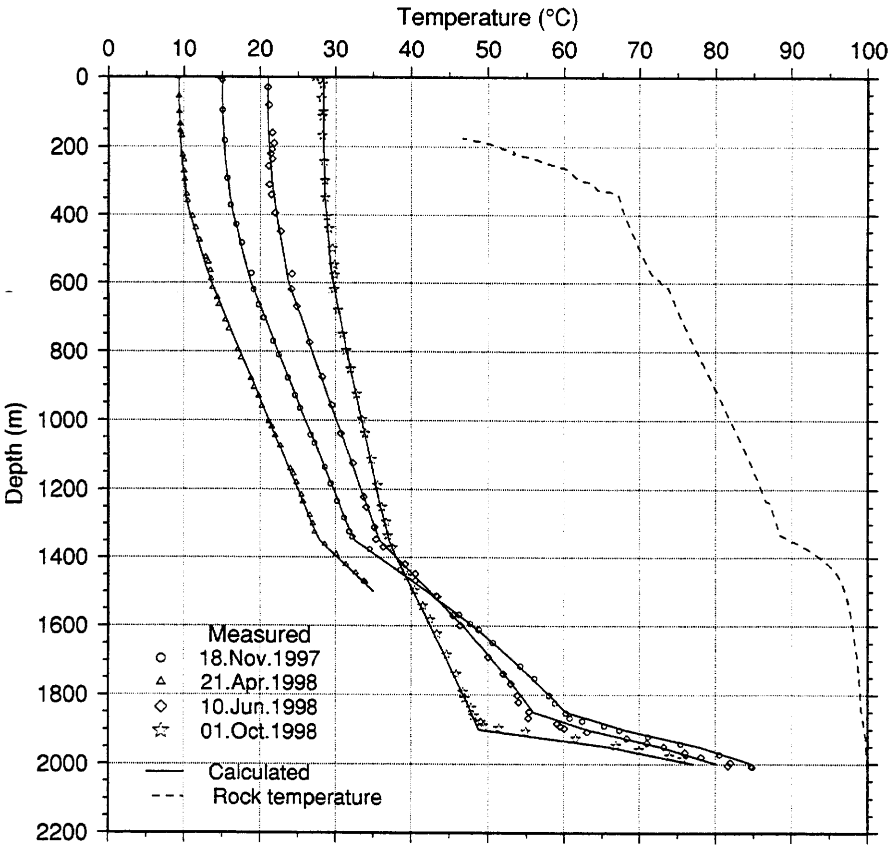


Figure 24. Measured and calculated temperature profiles during injection into well LJ-08.

Table 3. *Results of water loss tests in well LJ-08, simulated by the HOLA well-bore simulator.*

Feed-zone Depth (m)	97.11.18 inj. 8.2 L/s		98.04.21 inj. 8.0 L/s		98.06.10 inj. 6.2 L/s		98.10.01 inj. 20 L/s	
	flow (L/s)	flow (%)	flow (L/s)	Flow (%)	flow (L/s)	flow (%)	flow (L/s)	flow (%)
325	4.0	49 %	4.8	60 %	1.8	29 %	11.5	58 %
600	1.4	17 %	0.7	9 %	2.0	32 %	4.0	20 %
1350	2.0	24 %	1.5	19 %	1.5	24 %	2.7	13 %
1875	0.7	9 %	1.0	12 %	0.8	13 %	1.7	8 %
below 2000	0.1	1 %			0.1	2 %	0.1	< 1%

The injectivity (I) is defined by the equation:

$$q_i = I (P_{w,i} - P_{r,i}) \qquad (1)$$

where q_i is the water flow through the corresponding feed-zone, $P_{r,i}$ is the reservoir pressure outside the injection well at the depth of the feed-zone and $P_{w,i}$ is the pressure in the well. In principle these parameters, including the injectivity, are varying functions with time. The injectivity can be assumed to be approximately constant, however, unless the feed-zone properties change with time.

The injectivity for each feed-zone, during the differrent temperature logs, has been estimated as follows. The estimated flow rate into the feed-zones is known from the simulations. The pressure difference between each feed-zone and the reservoir has been estimated from the wellhead pressure in LJ-08 (see Figure 18) and by assuming that the water level in well LG-09 (see Figure 21) represents the reservoir pressure. This, of course, adds some uncertainty to the estimates because of the distance between LJ-08 and LG-09. By plotting the flow through each feed-zone against the pressure difference, the data points should fall on a straight line passing through the origin. The injectivity is then easily found on the basis of equation (1) and the gradient of the line. The method of least squares was used to obtain an average injectivity for each feed-zone by assuming a straight line. The result is shown in Figure 25, and the estimated average injectivity for each feed-zone is presented in Table 4. It is evident, however, from the Figure that the assumption of constant injectivity is not fully valid for the uppermost feed-zones. Thus there are considerable uncertainties in the injectivity estimates.

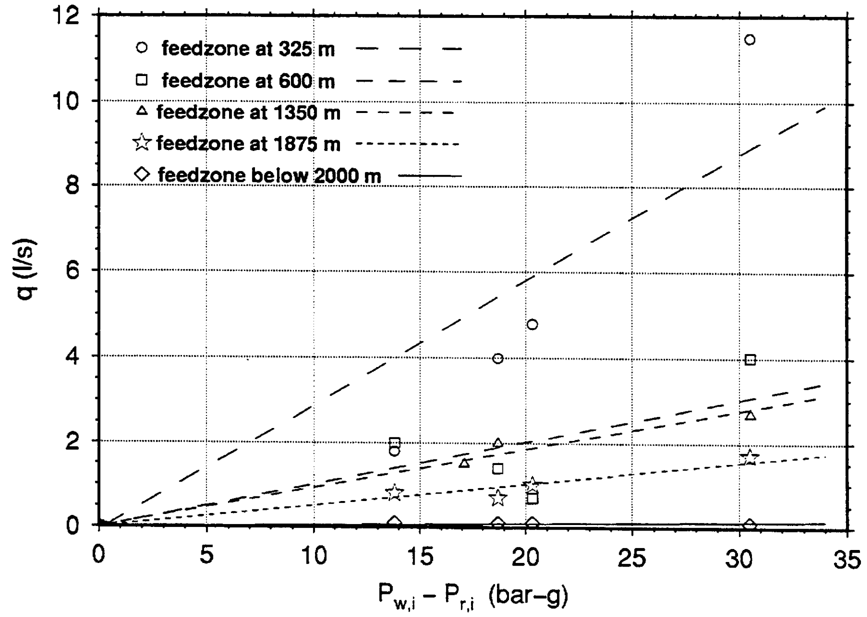


Figure 25. The flow through each feed-zone of well LJ-08, as a function of the difference between well- and reservoir pressure. The slopes of corresponding lines yield the average injectivity of each feed-zone.

Table 4. *Estimated average feed-zone injectivities for well LJ-08.*

Feed-zone depth (m)	injectivity (L/(s.bar))
325	0.30
600	0.10
1350	0.09
1805	0.05
below 2000	0.004

It is evident from Figure 25 that the injectivity is highest for the top feed-zone and decreases with depth down the well, in accordance with the result that more fluid exits the well at shallow levels than at deeper levels. A fixed injection rate creates a relatively greater pressure increase, at shallow depths in the system, than at greater depths, where the overburden pressure is much higher. This probably explains decreasing injectivity with depth.

Figure 25 also indicates that there is not a linear relationship between the flow and the pressure change, in particular in the feed-zone at 325 m depth. It seems that the injectivity increases with higher injection rate. Possibly the increased pressure associated with higher injection rate causes the feed-zone to open up. It is also possible that the flow-path has opened up due to thermal contraction of the rock as the reinjection project has proceeded.

The theory behind the temperature profile simulation assumes that the injection rate and the temperature of the injection water remains constant, and that all the injected water exits the borehole through well defined feed-zones but not through the rock matrix. As seen in Figure 15 and Figure 16, the injection rate and the injection water temperature do not remain constant with time. The simulations, therefore, become less accurate as the reinjection experiment progresses. The resulting errors are not considered to be very large, keeping in mind other uncertainties in this analysis. Therefore, the general result is considered reliable (i.e. Table 4).

Figure 26 shows one temperature profile measured in well LN-10 on the 18th of November 1998, during injection of 6 L/s into the well. Unfortunately there is an obstacle in the well around 500 m depth and the well cannot be logged to greater depth. According to the simulation only 5 % of the injected water exits the well through the feed-zone at 150 m. The rest leaves the well somewhere below 450 m, possibly through feed-zones at 590 m, 1040 m and 1080 m depth, identified by older temperature logs (Hjartarson, 1999).

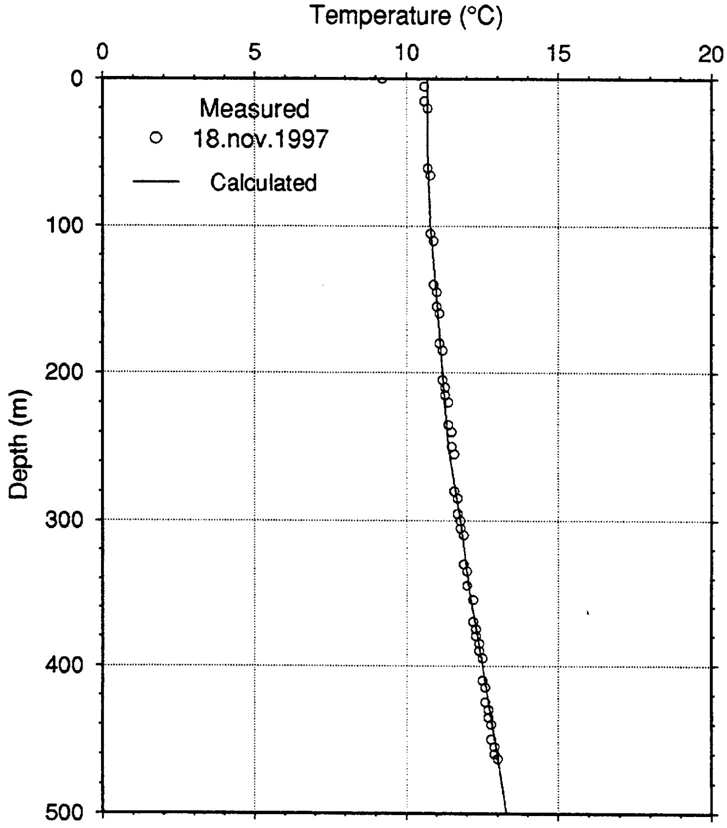


Figure 26. Measured and calculated temperature profile during injection into well LN-10. Well not accessible below 500 m depth.

A spinner tool is commonly used to measure flow-rates in boreholes. Spinner logs have been attempted in a few Icelandic geothermal wells. Flow-rate estimates from such measurements have often been considered highly inaccurate, especially at low flow-rates. The method discussed above is believed to possibly give more reliable results, in particular at conditions not deviating seriously from the assumptions made.

5.2. Televiewer logging in well LJ-08

In the summer of 1996, sections of well LJ-08 were logged with a borehole televiewer tool by the Geoforschung Zentrum logging group, as mentioned earlier. This kind of logging tool can be very useful in determining locations and orientations of fractures, interbeds and dikes. Data from such a tool are quite valuable, because they can provide detailed information about the nature of feed-zones in geothermal wells, including determining whether they are fractures or interbeds. The usefulness of such information for the geothermal reservoir physicist doesn't have to be emphasised. However, such a tool has not been available for geothermal research in Iceland, so far. Large-scale printouts of the uncorrected data from the 1996 televiewer survey are available at Orkustofnun and results of their analysis will be discussed below. The functioning of the televiewer tool will first be reviewed.

5.2.1. The borehole televiewer tool

The borehole televiewer is an acoustic tool, which operates on the following principle. While the tool moves up the borehole, a rotating transducer scans the borehole wall by emitting a pulsed ultrasonic beam and measuring the amplitude of the reflected pulse as well as the transit time between the borehole wall, and the tool. As the tool moves up it scans a spiral path (helix) along the borehole wall. The data are represented as an image of the borehole wall, as if the well was cut open vertically and laid flat. The horizontal axis is given as degrees and the vertical axis as depth (see Figure 27). A dipping fracture intersecting the well appears, therefore, as a sinusoidal trace while vertical fractures appear as vertical lines. From the sinusoidal trace the dip and strike of the fracture is easily calculated. Operation fundamentals of the borehole televiewer tool are described by Zemanek *et al.* (1970).

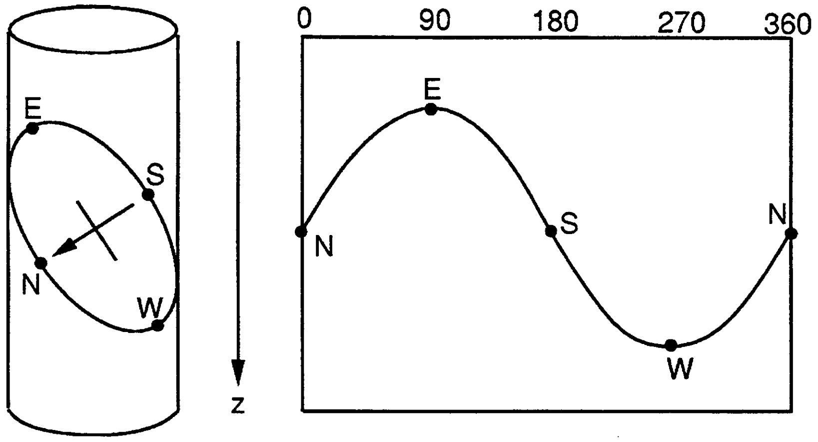


Figure 27. Schematic representation of a fracture intersecting a borehole as detected by a borehole televiewer log.

5.2.2. Televiewer data

During the televiewer survey at Laugaland in 1996, two sections of well LJ-08 were logged, from 500 m down to 1050 m depth and from 1220 m down to 1350 m depth. The data quality is generally not very good. The data printout is on a large scale (1:400), so the vertical resolution is poor and the dipping angles of features dipping less than 30° from the horizontal are, therefore, not measurable. In some depth intervals, only an image of half the borehole wall has been recorded. This may be caused by scattering of the reflected beam, the fact that the tool was not centred in the hole or that the hole is elliptic in shape rather than circular. Features that are supposed to appear vertical are twisted back and forth, over relatively short depth intervals, which makes the features intersecting the well harder to interpret. This indicates that the data have not been calibrated, processed or edited for systematic noise or tool related problems.

Detailed knowledge is not available at Orkustofnun about the borhole televiewer tool in question. Its limitations, accuracy and possible problems with interpretation are unknown. Common sense was, therefore, mainly used for the data analysis and interpretation. Table 5 shows results of the televiewer data analysis for well LJ-08. The human eye was used for feature detection and a ruler for measurements. No digital processing or statistical methods were applied. The accuracy of the measured relative fracture direction is about ±10°. The accuracy of the measured dip increases with increasing dip and the accuracy is about ±1° for fractures dipping more than 80° from the horizontal. Eleven fractures were found that were distinct enough for calculating dip and direction. Indications of sixteen other fractures were found, but due to the poor data quality, dip and direction could not be estimated. Five features, which are most likely interbeds, were also observed. This analysis of the borehole televiewer data for well LJ-08 in the Laugaland field, is the first such analysis ever made for an Icelandic geothermal system. Now an attempt will be made at interpreting the findings.

Table 5. *Observed fracture directions in well LJ-08, relative to the instrument 0°, based on the borehole televiewer log measured by Geoforschung Zentrum in 1996. Dip is measured from the horizontal.*

Fracture depth (m)	Fracture strike	Fracture dip	Direction of dip
529	114°	76°	260°
552	123°	84°	298°
591	170°	84°	100°
617	208°	74°	24°
635	10°	76°	24°
699	114°	82°	33°
705	123°	82°	33°
786	133°	83°	43°
985	152°	83°	62°
1327	0°	76°	270°
1329	0°	82°	270°

Possible fractures also at 549, 588, 609, 652, 738, 829, 831, 834, 913, 917, 921, 1004, 1017, 1034, 1227 and 1236 m depth. Possible interbeds at 521, 583, 666 and 1046 m depth.

5.2.3. Televiewer data interpretation

Instrumental problems during the logging operation interfered with the orientation of the data, unfortunately, and correction efforts by Geoforschung Zentrum have not been successful (Gudlaugsson, 1999). Orientation of fractures observed in the well can, therefore, not be determined with complete certainty. Relative directions of the fractures detected, their dip and relative dipping direction, however, are not questioned. In addition, fracture directions can be roughly estimated, based on an assumption discussed below. This assumption is somewhat uncertain, however.

When drilling into a stratified lava pile the drill-bit tends to intersect the pile at a right angle (Stefansson and Steingrimsson, 1990) and if the pile is dipping so will the hole. Geological mapping shows that the lava pile in the Laugaland field dips around 5° to the SE and that dikes are directed N-S (Bjornsson *et al.*, 1979, Flovenz *et al.*, 2000). The borehole is therefore most likely deviated in a direction somewhere between NW and N.

The televiewer data show a prominent vertical feature extending down the well, which most likely is a keyhole. This is an oval side-hole that forms when the drill-string scratches the deviated borehole wall. The keyhole can, therefore, be used as a reference line by assuming that the well is deviated to the NW. The keyhole is usually directed around 270° according to the televiewer data. Based on this assumption, 45° have to be added to the relative directions, to obtain the geographical orientation of the observed fractures. After that correction, the fractures were grouped, according to their direction, into the four main direction sectors N-S, NE-SW, E-W and SE-NW, each spanning 45°. The results are presented in Table 6 below.

Table 6. *Estimated orientation sectors for fractures in well LJ-08. Corrected values from Table 5.*

Fracture depth (m)	Fracture strike	Fracture dip	Direction of dip
529	NE-SW	76°	SE
552	E-W	84°	S
591*	NE-SW	84°	NW
617	N-S	74°	E
635	N-S	76°	E
699	N-S	82°	E
705	N-S	82°	E
786	N-S	83°	E
985	N-S	83°	E
1327*	NE-SW	76°	NW
1329*	NE-SW	82°	NW

* Feed-zone according to temperature logs.

Six fractures appear to be directed N-S, four NE-SW, one E-W but none NW-SE. All the fractures directed N-S dip to the E and the fracture with E-W direction dips to the S. One of the NE-SW fractures dips to the SE, while the other three dip to the NW. It has to be emphasized that the calculated directions are based on an assumption, which can be questioned, and the accuracy of the borehole televiewer tool is unknown. Yet, the results in Table 6 are considered the most reliable estimates of the directions, based on the presently available data. A total of twenty-seven fractures were observed in the two sections measured, which had a total length of 680 m. Because of the rather poor data quality, the number of fractures intersected by LJ-08 might be greater. The observed fracture dip appears to be either about 74-76° or 82-84°.

Three fractures detected by the televiewer tool correlate in depth with two of the feed-zones of the well, after the televiewer data was depth corrected, by adding 8 m to the televiewer depth values. One fracture correlates with the feed-zone at 600 m depth and two fractures, which are only 1-2 m apart, correlate with the feed-zone at 1335 m depth. The feed-zone at 1335 m depth is interpreted as one feed-zone, coinciding with the two fractures, where one or both of them can be open. Only these three fractures can be linked with feed-zones, and are therefore considered hydraulically conductive. What these three fractures have in common is that they have the same direction as well as same dip direction. This is different from the direction and dip direction of any other fracture, observed in the well. Other fractures observed through the borehole televiewer log are considered impermeable. All of the fractures observed are, however, believed to be of tectonic origin.

It is generally accepted that fractures and faults control the hydrologic properties of low porosity, crystalline rock, like basalt, and relatively few fractures can control the fluid flow. The reason why some fractures are more permeable then others has been poorly understood (Hickman and Zoback, 1997). Recent investigations on the relationship between reservoir productivity and the active in-situ stress field, which have been carried out in the geothermal reservoir at Dixie Valley, Nevada, provide some insight into this. Televiewer images from six wells penetrating the reservoir, which is associated with the Stillwater active normal fault zone, were used in conjunction with hydrologic tests and in-situ hydraulic fracturing stress measurements (see Hickman and Zoback, 1997; Barton *et al.*, 1997 and Barton *et al.*, 1998). Data from wells drilled into productive and non-productive segments of the Stillwater fault zone indicate that fractures must be both optimally oriented, and critically stressed, to have high permeability. The analysis also indicates that fracture permeability in the wells is dominated by a relatively small number of fractures with an orientation which is distinct from the overall orientation of fractures, but parallel to the local trend of the Stillwater Fault zone (Barton *et al.*, 1998).

The studies at Dixie Valley can aid the interpretation of the data from well LJ-08 in the Laugaland field. Analysis of the televiewer data indicates that the flowing fractures strike NE-SW and dip to the NW. This is parallel to the NE-SW fractures zone that intersects the Laugaland system (chapter 2). This might be similar to what is observed in Dixie Valley. The orientation of the hydraulically open fractures in well LJ-08 could, therefore, reflect the orientation of the bedrock failures in the current stress field.

Thus the producing feed-zones in the production wells at Laugaland could be critically oriented, resulting in higher permeability than in fractures with other directions. Other non-flowing fractures might not be favourably directed relative to the stress field, preventing hydraulic conduction. The low-grade alteration in the geothermal system, along with the precipitation of dissolved altered minerals is also considered to reduce the permeability of fractures, which are not optimally oriented. Six of the fractures in Table 6 are directed N-S, and most of the dikes found in the field are also directed approximately N-S. Those fractures may be relatively old tectonic features, perhaps associated with the intrusion of the numerous dikes in the area. The hydraulically conductive fractures are most likely younger, formed by recent tectonic activity.

5.3. The Laugaland fracture zone

The conceptual model of the Laugaland system accepted up to now is reviewed in section 2.2. The production wells in the Laugaland field are believed to be directly connected with each other through the fracture zone, which is oriented in a SW-NE direction (Axelsson *et al.*, 1998a). By assuming that the main feed-zones of the three production wells are connected through the fracture zone, its dip and direction can be estimated, by using the fact that three points in space define a plane. The dip and direction of the fracture zone has been calculated. The results of these calculations will be presented below and discussed in relation to the conceptual model of the Laugaland system.

5.3.1. *Dip and direction of the fracture zone*

By applying the theory of solid analytic geometry, the equation of a plane can be easily calculated from the co-ordinates of three points in space; hence the major feed-zones of each of the three production wells in the Laugaland field define the fracture zone. To calculate the dip and geographical direction of the fracture zone, the locations of the feed-zones in the reservoir space have to be known. Information on the depth to the feed-zones, geographical locations of the wells, their elevation and inclination are, therefore, essential for the calculations.

The depths to the feed-zones in the production wells in the Laugaland field are known from temperature logs, on one hand, and from the major circulation fluid losses during drilling, on the other hand (see Table 2). The deepest feed-zone in each well is also the most productive one (Bjornsson *et al.*, 1979) and they are assumed to be the main connection points to the fracture zone. The available data on the geographical location and elevation of the wells in the Laugaland field, were not considered accurate enough and, therefore, the co-ordinates of all the wells in the Laugaland field were measured by HVA in February 1999 with Differential GPS. Locations of the wells in use in the Laugaland field can be found in below.

Table 7. *Co-ordinates of the wells in use in the Laugaland field (Lambert co-ordinates).*

Well	east (m)	west (m)	elevation (m)
LJ-5	543390.6	564347.6	34.2
LJ-7	543258.1	564270.2	14.0
LJ-8	543507.6	564570.6	39.4
LG-9	543405.6	564158.2	46.8
LN-10	543374.1	564496.3	18.2
LN-12	543309.1	564329.6	18.8

According to directional surveys, conducted with a magnetic compass in wells LJ-05 and LJ-07 in the seventies, they are inclined by about 3° and 1° from the vertical to the N, respectively. These wells are therefore deviated 79 and 26 m, to the N at 1500 m depth, respectively. The inclination of well LG-09 is about 2° to the NW. Well LN-10 is also inclined about 2° most likely to the NW, but the direction is somewhat fluctuating. The inclination of LN-12 was never measured (Bjornsson *et al.*, 1979). When drilling into a stratified lava pile, the drill-bit tends to intersect the pile under a right angle as already mentioned. The lava pile at Laugaland dips to the SE (Bjornsson *et al.*, 1979), so the wells are most likely inclined to the N or the NW, as is in fact observed.

Wells LJ-08, LG-09 and LN-10, which are not productive, are not believed to intersect the fracture zone (Axelsson *et al.*, 1998a) and, therefore, provide constraints on the possible dip of the fracture zone. By connecting the three deepest feed-zones in the production wells, calculations yield that the fracture zone is directed N52°E with a dip of 87.3° to the SE. This hypothetical fracture zone plane, should intersect the surface a few meters south of well LJ-08. If, on the other hand, the upper feed-zones are selected a direction of N52°E is also obtained, but the dip is estimated 88.7° to the SE. These findings assume that well LN-12 is vertical.

If well LN-12 is assumed to be inclined 2° to the N, the fracture zone has a direction N39°E, with a dip of 83° to the NW. In this case the fracture zone would intersect well LJ-08 at around 1340 m depth, but not intersect well LN-10. This could possibly be the case, because according to the televiewer log two fractures are observed at 1335 m depth in well LJ-08 oriented NE-SW, with dips of 76° and 83° to the NW. The fracture zone needs not necessarily have high hydraulic conductivity in the whole fracture plane, which might be used to argue for the lower productivity in well LJ-08 than in the production wells. These considerations are based on two questionable assumptions, however, and could simply be a coincidence. Therefore, this is not considered to be the case.

The above discussion clearly shows how sensitive the estimate of the fracture zone dip is to the inclination of well LN-12. Because of the fact that geothermal wells are usually not strictly vertical (Stefansson and Steingrimsson, 1990) the dip of the fracture zone can therefore not be uniquely determined. Yet, the proposed fracture zone is certainly close to being vertical and its direction is most likely near N50°E. Figure 28 shows the estimated location of the fracture zone at 1500 m depth in the Laugaland geothermal reservoir.

There are other factors that can further obscure the above result. The feed-zone connections can be much more complicated than assumed, for example by fractures and possible interaction of interbeds and dikes. There are also considerable uncertainties in the directional surveys, because the readings of the magnetic compass used may be distorted by dikes or lava beds having magnetic direction different from the lava pile. This can lead to a wrong estimate of the direction of a deviated hole. Further studies, like investigations of the contemporary in situ stress field, extensive televiewer logging, temperature measurements in the production wells during production and directional survey in all the wells in the Laugaland system would provide an extensive set of data, which could give detailed information on the proposed fracture zone. However, such a program would be complicated, partly because the production wells are almost constantly in use, as well as very costly. Therefore the details of the structure of Laugaland geothermal system will be unknown, at least until such a program can be scheduled.

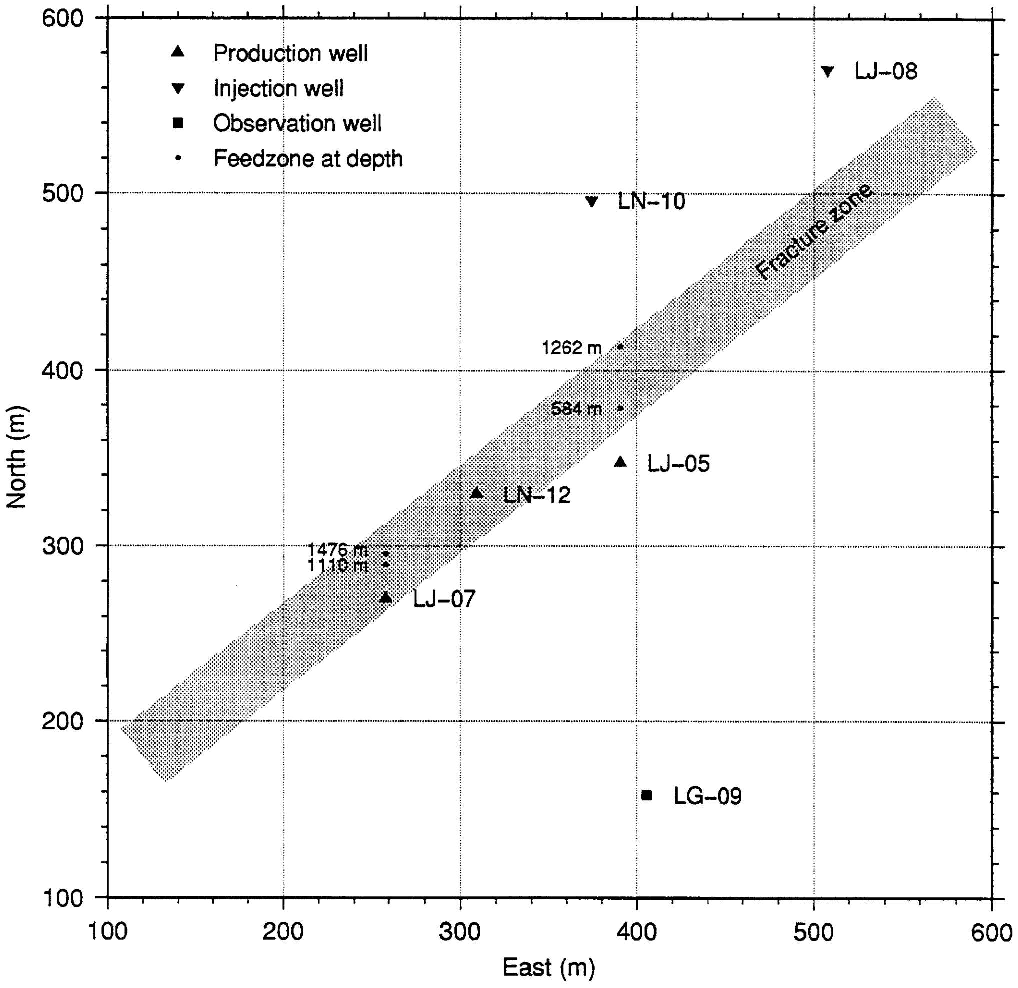


Figure 28. Estimated direction of the calculated fracture zone at about 1500 m depth, through the Laugaland geothermal system.

5.3.2. Extension of the fracture zone through the Eyjafjordur valley.

Flovenz *et al.* (1987), put forth a hypothesis about a fracture zone embedded in the Eyjafjordur valley bedrock with a SW-NE direction. The fracture zone was supposed to connect the Hólslaug geothermal spring in the NE, the production wells at Laugaland and the Botn geothermal system and two hot-springs, Botnslaug and Stokkahladalaug on the west side of the valley. The location of the hypothetical fracture zone is shown in Figure 29. This hypothesis was also based on a low-resistivity anomaly that connected the geothermal systems at Laugaland and Botn as shown in the figure. The location of the fracture zone, proposed above, is also shown for comparison. As seen, there is not a great difference between the direction of these fractures. The fracture zone proposed here is directed little more to the N. Thus, this is most likely one and the same fracture zone.

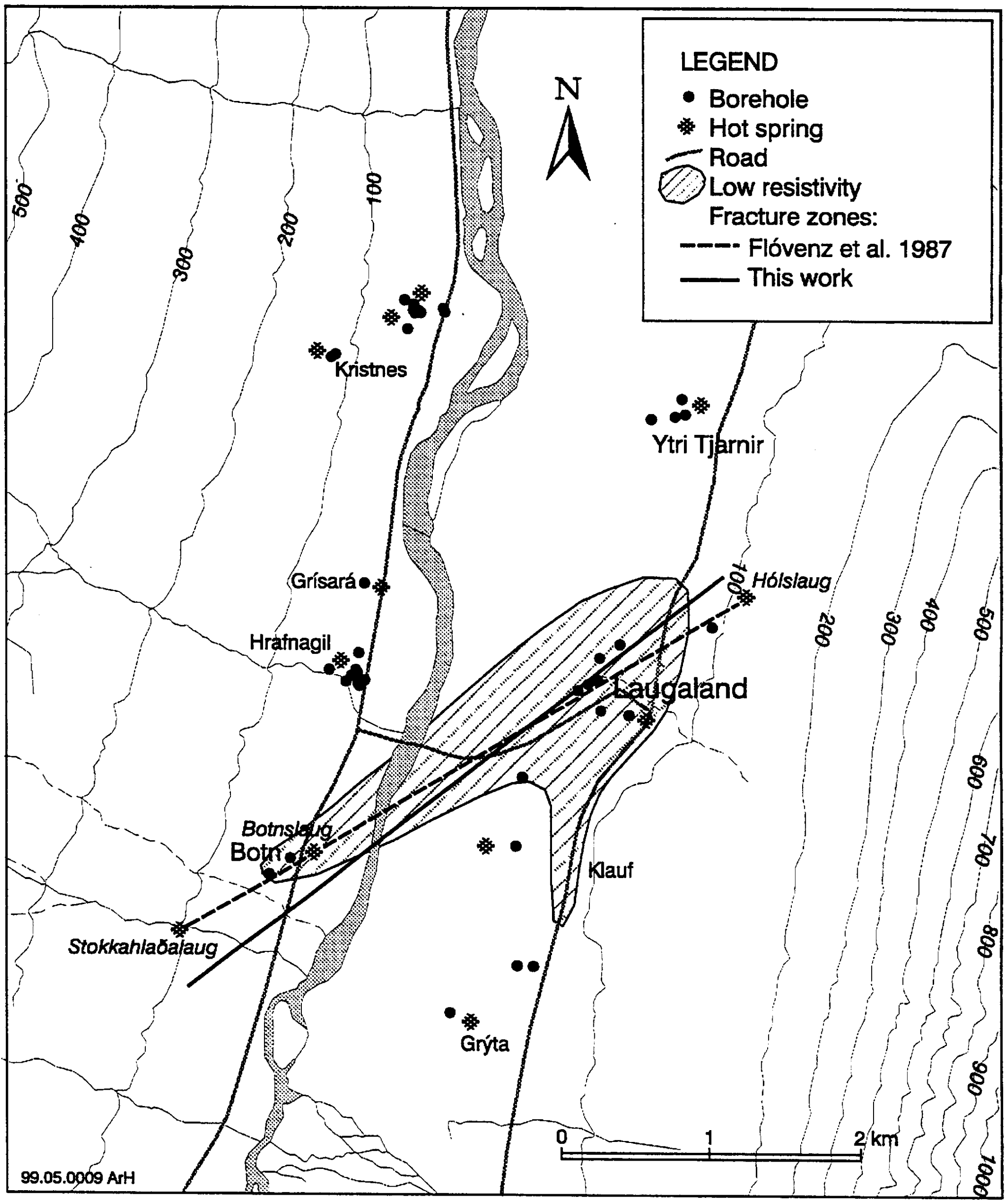


Figure 29. Proposed fracture zone through the Laugaland system.

The Botn geothermal system is one of the more carefully studied low temperature geothermal system in Iceland and a detailed numerical model has been used to simulate its natural state and temperature-, pressure- and production history. The research indicates strongly that the Botn geothermal system is controlled by a fracture zone, with a direction NE-SW (Axelsson and Bjornsson, 1992; Flovenz *et al.*, 1991 and Flovenz *et al.*, 1987). This is presumably the same fracture zone as discussed above. If that fracture is extended 2 km to the NE it intersects the Laugaland geothermal system.

The proposed fracture zone at Laugaland strikes towards the Hólslaug geothermal spring, approximately 1 km NE of Laugaland, which dried up shortly after production started in the Laugaland field. A study of water samples from the spring shows that the water most likely originated in the Laugaland system, and the spring may therefore be in direct connections with the production wells in the field (Bjornsson et al., 1979). This supports the existence of the SW-NE trending fracture zone through the Laugaland system.

Extensive magnetic mapping was carried out around Laugaland during 1976 to 1979, in order to locate dikes and fractures. Many linear magnetic anomalies are observed, usually trending N7-8°E, which are believed to be dikes (Eysteinsson and Flovenz, 1993) but no anomaly is found in the SW-NE direction. An anomaly associated with the fracture zone may be masked by anomalies from other features. Also the fact that the angle from the measured magnetic lines to the fracture zone is just 30-40° may make the fracture hard to detect. Moreover, it is not certain, whether the fracture zone should yield a detectable anomaly or not.

The principal result is that a major fracture zone controls the Laugaland geothermal system. It is close to being vertical with a direction of SW-NE. This supports strongly the existence of a major SW-NE fracture zone which has been proposed to intersect the bedrock in Eyjafjordur valley.

6. WATER-LEVEL/PRESSURE TRANSIENT ANALYSIS

Fluid extraction, as well as injection, influences the pressure-state of a reservoir system, which in the case of liquid-phase hydrological systems may be observed through water level changes. These changes can provide the data for pressure transient analysis, which has the purpose to estimate important reservoir parameters. If a number of wells are available in a given reservoir, reservoir heterogeneity can be studied. During the Laugaland reinjection project, flow-rates and water level changes were carefully monitored in five wells in the field. This extensive data collection now provides a better opportunity for performing detailed pressure transient analysis, than has been possible before for an Icelandic geothermal system. Such an extensive and detailed data set has not been collected before in Iceland.

Different intervals of the production, injection and pressure monitoring data were selected for pressure transient analysis. The selection was confined by requiring semi-stable pressure conditions in the reservoir, before a change in production and injection rate caused a pressure transient or response. A few selected pressure transients were analysed as injection, pumping or interference tests. The main objective of the work described in this chapter is to estimate the permeability-thickness and storativity parameters for the Laugaland geothermal system, from the selected "tests", and to investigate its heterogeneity, i.e. locations of fractures, boundaries, etc. A review of the basics of pressure transient analysis is given by Hjartarson (1999). Earlougher (1977) and Horne (1995) present comparable reviews. The results of the analysis are presented below. Finally, results of step rate tests conducted in the injection wells will also be reviewed here (section 6.2). These can be used to estimate turbulence pressure losses in the wells, as well as detect possible changes in feed-zone properties due to scaling and cooling, resulting from the reinjection.

The twenty-three years record of weekly production and pressure draw-down monitoring data available for Laugaland can be analysed to obtain estimates on the reservoirs volume and outer boundaries (see Figure 4). This can be achieved through various simple modelling approaches or with detailed numerical modelling. The monitoring data can also be inverted with convolution integral methods (Green functions) to estimate the response of the system to constant, or impulse, production. The results from such analysis can then be compared to theoretical models. A lumped parameter model has been developed for the Laugaland geothermal reservoir, for this purpose (Axelsson *et al.*, 1988). This model has been revised on two occasions (Flovenz *et al.*, 1993; Axelsson *et al.*, 1999). It has also been employed for the purpose of this study (see chapter 13). The first steps in the development of a detailed numerical model for the Laugaland geothermal system, and surroundings, have also been taken as part of the reinjection project. The numerical modelling is discussed in chapter 12.

In the following the effects of water extraction, and reinjection, on the pressure-state of the Laugaland geothermal system, will be investigated, and the methods presented by Hjartarson (1999) applied in order to estimate the parameters that control the fluid flow in the system. The methods must be used with caution, however, because of various effects, which may complicate the pressure changes, such as non-isothermal fluid flow, wellbore effects, or complex fracture effects. We must also bear in mind that reality is usually more complicated than assumed in the models employed.

6.1. Analysis of water level measurements

Figure 15 through Figure 22 in chapter 4 show the production and reinjection history of the Laugaland geothermal field, and the resulting water level changes, during the reinjection project. The present section will focus on detailed quantitative calculations, aimed at investigating the nature of the Laugaland system and at estimating the parameters that mainly control the productivity, namely the transmissivity and storativity.

The two parameters were estimated by three methods: (1) type curve matching, (2) semi-log analysis and (3) by using the LOKUR inversion well test program (Bjornsson, 1987 and Bjornsson *et al.*, 1993). Evaluating the same parameter by three different methods should give more reliable result. Moreover, a better understanding is obtained of the data, which can sometimes be conflicting and difficult to interpret. Using only one of the methods did sometimes turn out to be more appropriate than using the others. During the analysis the transients, who could most easily be interpreted, were selected. These were transients that where not disturbed by many different effects or varying flow rates. Otherwise type curve matching method and semi-log analysis would have been difficult to apply.

The word "well test" is conventionally used when a well is tested for a relatively short period of time. Below, this term is also used when analysing water level changes, because the water level history may, in fact, be regarded as a series of a large number of "well tests".

6.1.1. Interference tests

In an interference test, the effect of production (or injection) from one well is observed in another well. The effects of wellbore storage and skin in the production well do not interfere with the observation well and, therefore, need not be considered. The transmissivity and storativity parameters obtained through analysing an interference test are not a measure of the reservoir conditions around the flowing well in question, they are rather a measure of the average properties of the media between the two wells.

Six segments of the water level monitoring sequence for the Laugaland field, which may be considered as interference tests, conducted between wells in the field, were selected for the analysis. These will be divided into interference tests of the "first kind" and "second kind", where the former are interference test with both wells either inside or outside the NE-SW fracture zone through the Laugaland system. The latter are tests where one of the wells is inside the fracture zone and the other is outside. Two of the segments selected constituted interference tests of the "first kind". A Theis model (Hjartarson, 1999) was used in analysing one of them, i.e. interference between the injection wells LJ-08 and LN-10, both of which are located outside the fracture zone. A single fracture model (Hjartarson, 1999) was used in analysing the other "test", i.e. interference between the production wells LJ-05 and LJ-07, both of which intersect the fracture zone. The results are presented in Table 8, wherein kh/μ stands for transmissivity and $c_t\ h$ for storativity; with k indicating reservoir permeability, h reservoir thickness and c_t reservoir compressibility. Furthermore, x_f stands for fracture half-length.

Appropriate simple models, which describe flow between wells, where one is located in a principal fracture and the other is located outside the fracture, are not available. The use of either the Theis model or the fracture model is, therefore, inaccurate in the case of interference tests of the "second kind". Even though not fully appropriate, the single fracture model is considered to describe better, however, the interference between production and injection wells in the Laugaland field. Therefore, four interference tests between the wells were analysed with the single fracture model, in order to obtain a rough estimate of the transmissivity between the wells. The results are presented in Table 9.

Table 8. *Results of analysis of two interference test segments of the "first kind" (both wells either inside or outside fracture zone) in the Laugaland field.*

Observ. well	Prod./inj. well	Date	kh/μ (m^3 / Pa.s)	$c_t\ h$ (m / Pa)	$c_t\ h\ x_f^2$ (m^3 / Pa)
LJ-05	LJ-07	1/4/98	4.6×10^{-8}	-	43×10^{-4}
LJ-08	LN-10	29/2/98	1.2×10^{-8}	2.4×10^{-8}	-

Table 9. *Results of analysis of interference test segments of the "second kind" (i.e. between production and injection wells) in the Laugaland field.*

Observ. well	Prod./inj. well	Date	kh/μ (m^3 / Pa.s)	$c_t\ h\ x_f^2$ (m^3 / Pa)
LJ-08	LJ-05	1/12/97	5.2×10^{-8}	69×10^{-4}
LJ-08	LN-12	1/4/98	9.3×10^{-8}	48×10^{-4}
LN-10	LJ-05	1/12/98	6.1×10^{-8}	59×10^{-4}
LN-10	LN-12	1/4/98	30×10^{-8}	88×10^{-4}

6.1.2. Pump tests

A "pump test" is defined as a well test involving a single well, i.e. where the production well is also the observation well. It can either be a production test or an injection test. Basically, there is no difference between these two kinds of tests. The pressure declines in a production test but increases in an injection test. A "production test" of well LJ-05, was selected for analysis, and "injection tests" for each of wells LJ-08 and LN-10. Three methods discussed by Hjartarson (1999) were used for estimating the transmissivity, the storativity and boundary effects for the wells. The well test data is presented in Figure 30 through Figure 32. Results of the analysis are, furthermore, presented in Table 10.

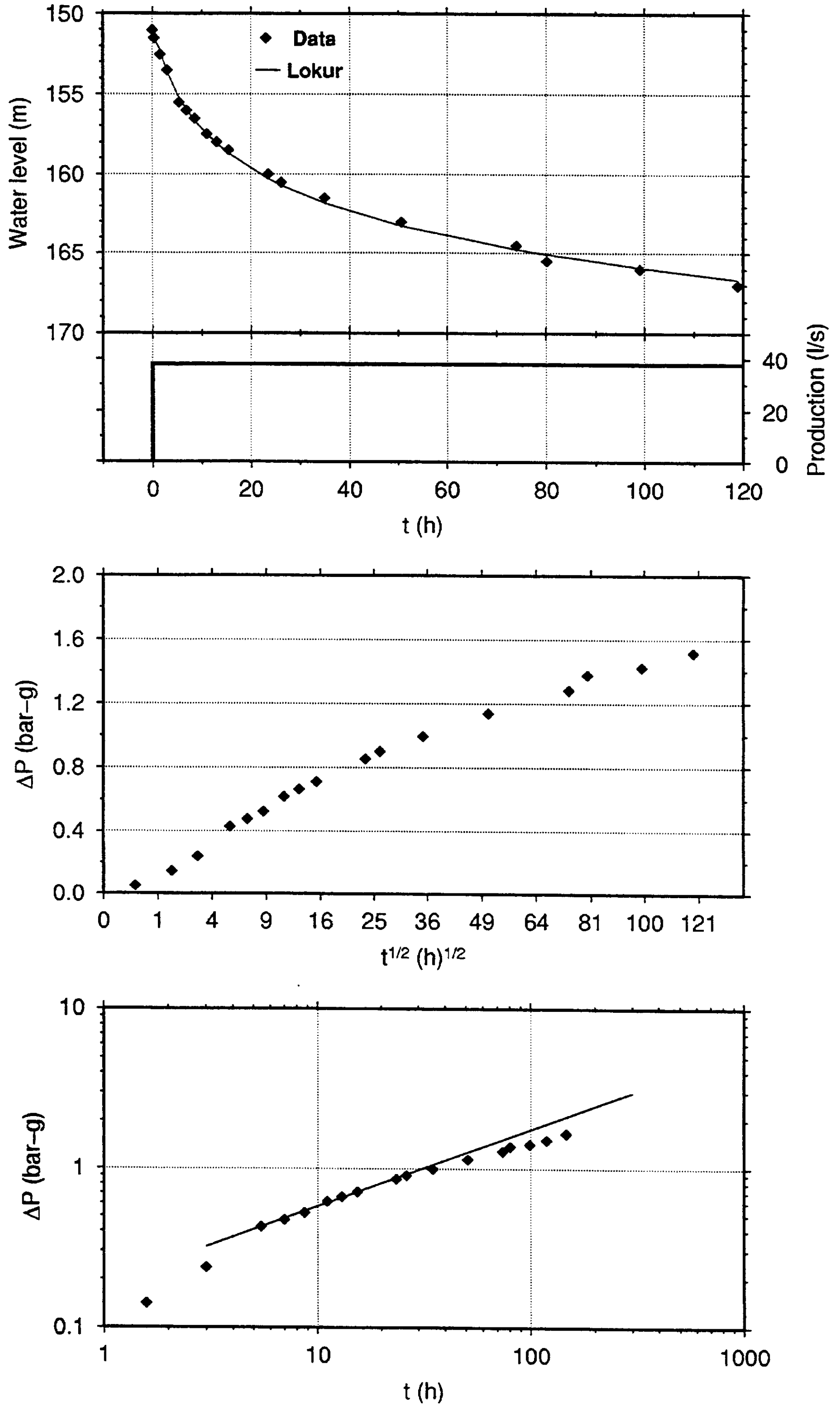


Figure 30. Data from a "production test" segment of the water level record for well LJ-05, starting on December 1st 1997. Further discussion on page 65.

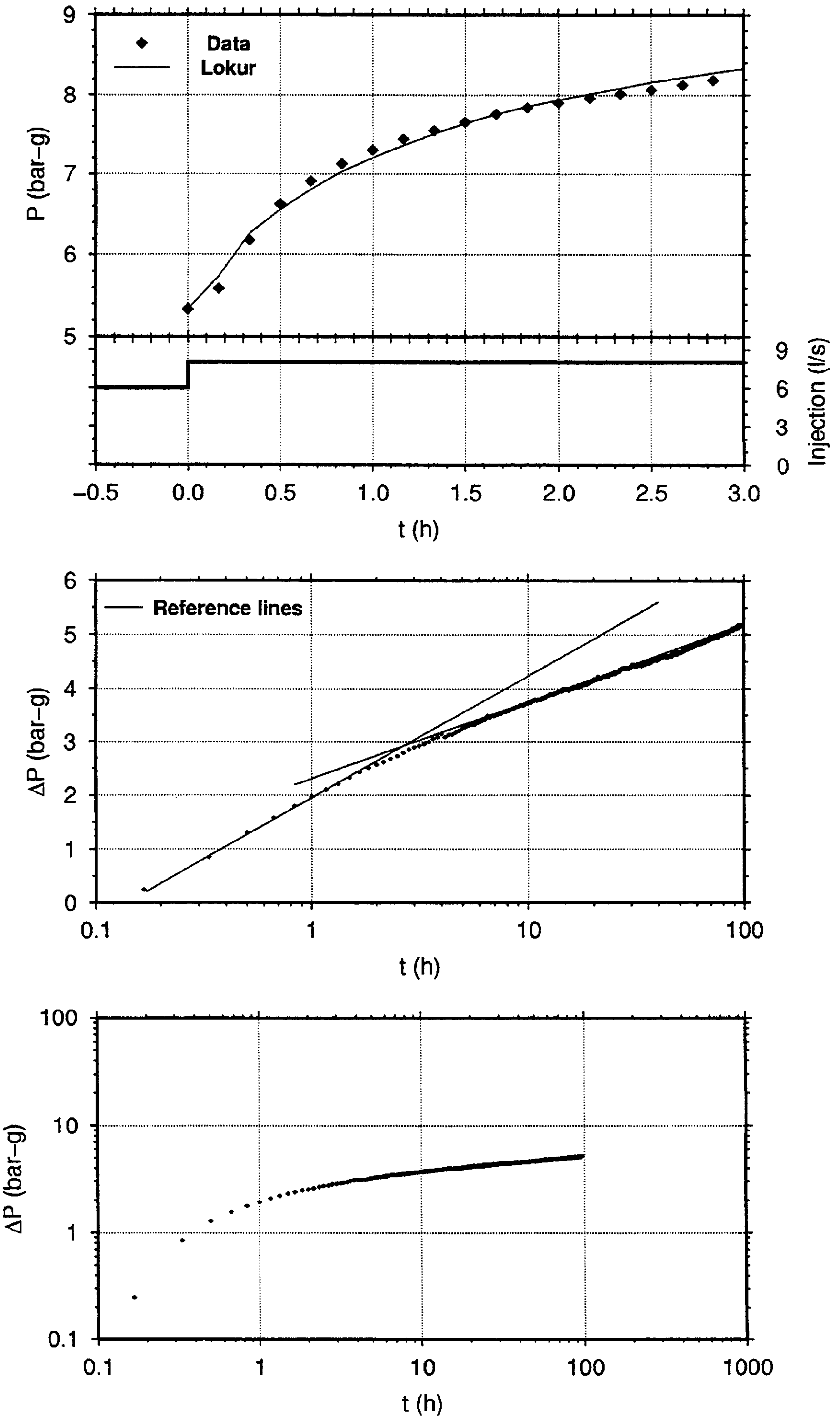


Figure 31. Data from an "injection test" segment of the well-head pressure record for well LJ-08, starting on August 24th 1998. Further discussion on page 65.

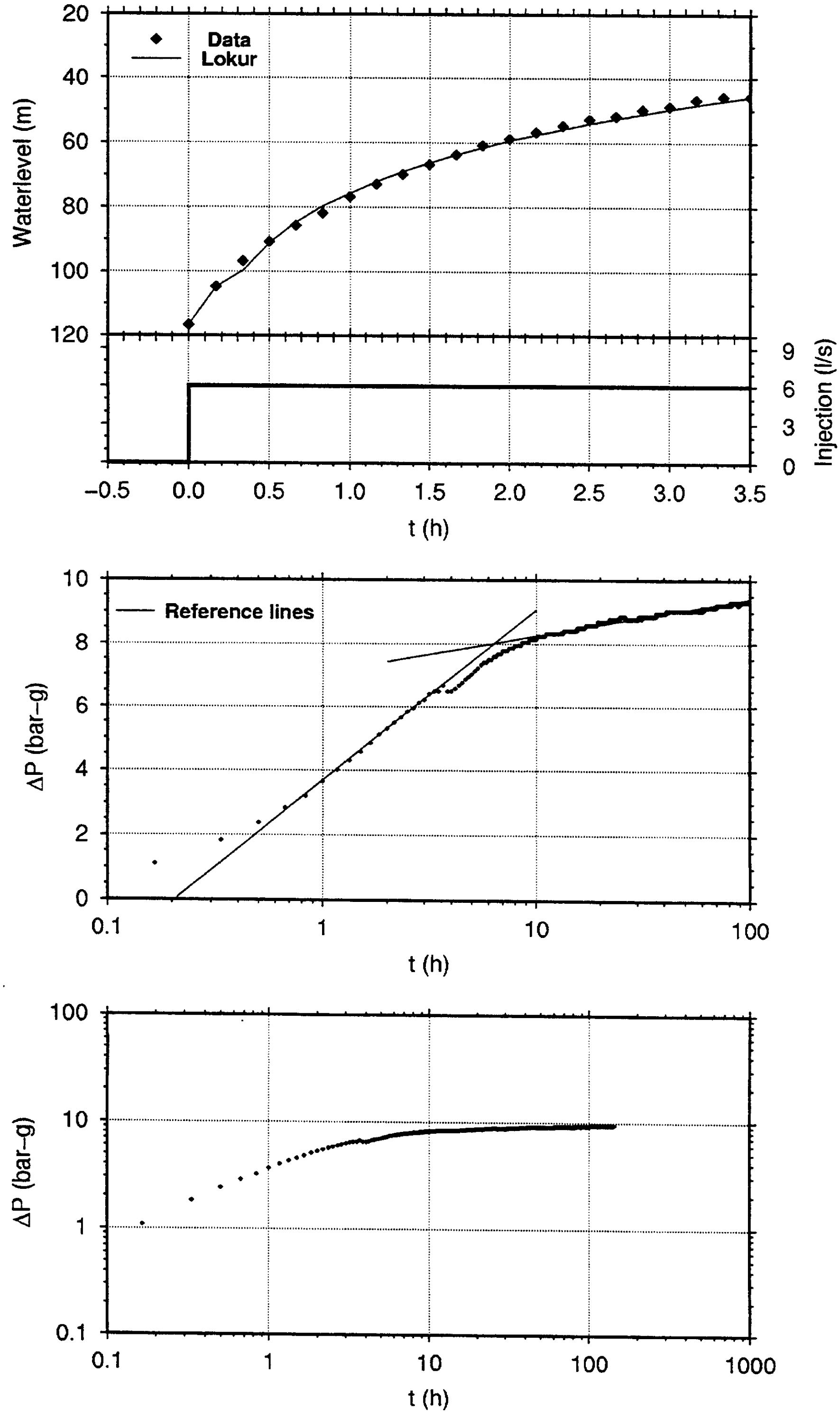


Figure 32. Data from an "injection test" segment of the water level record for well LN-10, starting on January 29th 1998. Further discussion on page 65.

Table 10. *Results of analysing "pump test" data segments from wells LJ-05, LJ-08 and LN-10.*

"Pumping" well	Date	kh/μ (m^3 / Pa.s)	$c_t\, h\, e^{-2s}$ (m / Pa)	$c_t\, h\, x_f^{\,2}$ (m^3 / Pa)
LJ-05	1/12/97	6.5×10^{-8}	-	20×10^{-4}
LJ-08	24/8/98	0.22×10^{-8}	2.3×10^{-4}	-
LN-10	29/2/98	0.20×10^{-8}	3.2×10^{-4}	-

These three "pump test" segments will now be discussed a little further.

The LJ-05 "production test" segment. Figure 30 shows the pressure transient due to the beginning of production of about 38 L/s from the well, on the 1st of December 1997. The data exhibit typical fracture behaviour, as seen by the ½ slope on the log(ΔP) vs. log(t) plot. A single vertical fracture model was, therefore, used for the calculations. The effect of wellbore storage (Hjartarson, 1999) influences the pressure change during the first hours. Boundary effects can be seen as a deviation from the ½ slope line in the figure, after approximately 50 - 60 hours.

The LJ-08 "injection test" segment. On the 24th of August 1998, the rate of injection into well LJ-08 was increased to 8 L/s, after having been 6 L/s for a week. As is evident from the semi-log graph in Figure 31, there is an obvious change in the rate of pressure build-up, after approximately 3 hours. This indicates a pressure-supporting boundary at some distance from the well. The effect of the postulated fracture zone through the geothermal system is probably the reason here. The data the first 3 hours behave according to the Theis model.

The LN-10 "injection test" segment. Injection into well LN-10 started on the 29th of February 1998, at a rate of 6 L/s. Well LN-10 shows a response similar to that of well LJ-08. After about 5½ hours there is a change in the pressure build-up and the effect of a pressure-supporting boundary appears (Figure 32). This is, again, most likely caused by the postulated NE-SW fracture zone. The Theis model was again used for the interpretation of the first 5½ hours.

6.1.3. Interpretation of results

The results of the water level transient analysis presented above will now be interpreted further and discussed in relation to the conceptual model of the Laugaland geothermal system. First, the transmissivity will be considered and then the storativity. Finally, the boundary effects will be considered.

6.1.3.1. Permeability

The water flow in the Laugaland reservoir is believed to be controlled by the SW-NE fracture zone as discussed previously. The "pump test" segments are better suited, than the "interference test" segments, for determining the formation transmissivity. This is because the latter may be expected to be more greatly influenced by the fracture zone, or other fractures that may be located between the wells. Comparison of the results from the two injection tests shows that the estimated transmissivity is around 0.2×10^{-8} $m^3/(Pa.s)$ for both injections wells (see Table 10). The transmissivity, calculated on the basis of the "production test" of well LJ-05, is estimated to be about 7×10^{-8} $m^3/(Pa.s)$, (see Table 10) while results of the "interference test", between production wells LJ-05 and LN-12, gives a transmissivity estimate of about $5 10^{-8}$ $m^3/(Pa.s)$ (see Table 8).

The transmissivity estimates for the production wells are more than an order of magnitude higher than the estimates for the injection wells. In addition the production wells behave according to the fracture model, while the injection wells behave according to the Theis model. This is a confirmation of the existence of the principal fracture zone intersecting the geothermal system. The production wells, therefore, appear to be located inside the principal fracture zone, while the injection wells are located on it's outside. The transmissivity values clearly demonstrate that the main fractures of the system have a much higher hydraulic conductivity than the surrounding non-productive formation.

The transmissivity obtained from the "interference test" between the injection wells (see Table 8) is five times higher than obtained in the "injection tests" of the wells (see Table 10), or about $1\text{x}10^{-8}$ $m^3/(Pa.s)$. This indicates that conductive fractures may be present between the wells, or that the principal fracture zone may influence the estimate.

Although using the single fracture model for the "interference test" segments, between production and injection wells, is not accurate, it should provide an indication on the relative connection between these wells. It seems that well LN-10 is more directly connected to the production wells than well LJ-08, and that the injection wells are more directly connected with LN-12 than LJ-05 (see Table 9). The highest transmissivity value obtained for all the "well test" segments is for the interference test between wells LN-10 and LN-12, or 30×10-8 m3/(Pa.s). This value is even higher (factor of 5) than the values obtained for the production wells themselves, but is not considered reliable because of the inappropriateness of the model used.

If the temperature of the injected water is assumed to have an average temperature of 15°C, as it enters the formation, then its dynamic viscosity is 1.1×10^{-3} kg/(m.s). This gives a permeability-thickness estimate for the injection wells of about 2 Darcy-m (unit: 2×10^{-12} m^3), which will be taken as an estimate of the value for the formation outside the fracture zone. The transmissivity of the fracture zone is assumed to be about 5×10^{-8} $m^3/(Pa.s)$, and the dynamic fluid viscosity at reservoir temperature (96°C) is about 0.3×10^{-3} kg/(m.s). This yields a permeability-thickness estimate of about 15 Darcy-m for the fracture zone.

6.1.3.2. Storativity, fractures and skin factors

The skin factors for wells, fracture effects, and reservoir storativity are not independent parameters, as discussed by Hjartarson (1999). It is not possible to distinguish between these parameters, according to the underlying theory. To obtain a storativity value, which is representative for the geothermal system in question, the effects of fractures and skin must be negligible. Since most geothermal systems are located in fractured bedrock, storativity may, therefore, be difficult to estimate.

The "interference test" between wells LJ-08 and LN-10, should yield the storativity value, which is most representative for the Laugaland system. This is because both wells are located outside the principal fracture zone, and the skin factor does not influence interference tests. According to the LJ-08/LN-10 "interference test", this storativity value ($S = c_t h$) is about 2.4×10^{-8} m/(Pa).

The storativity can be written as (Hjartarson, 1999):

$$S = (\phi c_f + (1 - \phi) c_r) h \qquad (2)$$

This equation can be used to estimate the average porosity of the system. The water compressibility equals $c_f = 5 \times 10^{-10}$ 1/Pa and the rock compressibility can be assumed to be about $c_r = 2 \times 10^{-11}$ 1/Pa. By assuming h = 500 m as the thickness of the reservoir involved in utilisation, an estimate of 6 % for the effective porosity is obtained. For comparison, the effective porosity of the Thelamork reservoir, not far from Laugaland (see Figure 1), has been estimated to be 5-7%, partially by analysing neutron-neutron well logs (Flovenz *et al.*, 1994).

After having obtained a storativity estimate, skin factors and corresponding fracture lengths can be estimated for the wells in question, based on "pump test" results (Table 10). Thus the skin factors for injection wells LJ-08 and LN-10 are estimated to be -4.5 and -4.7, respectively. This indicates that the wells may be intersected by fractures, presumably comparable to the ones detected by the borhole telewiever tool in LJ-08. The LOKUR program was used to estimate the fracture lengths by assuming that the fracture model was valid. Fractures with half-lengths of the order of 10 m were needed to explain (simulate) the skin factor values obtained for the injection wells.

An estimate of the active length of the principal fracture zone may be estimated from the LJ-05 "pump test", and the LJ-05/LN-12 "interference test", if we use the storativity estimate discussed above. From the "pump test", the fracture half-length is estimated to be about 320 m, while the "interference test" yields a fracture half-length of 460 m. This gives a fracture zone length between 0.5 and 1 km. Another estimate on the fracture length may be obtained by using the method discussed in the section on fractured reservoirs in Hjartarson (1999). When applying this method the transmissivity and storativity for the formation outside the fracture zone are used (LJ-08/LN-10 "interference test"). The fracture half-length is consequently obtained on the basis of equation (3.54) in Hjartarson (1999), by using the flow-rate and the resulting pressure change for the LJ-05 "pump test". This yields a fracture length of 4 km. An active fracture zone length around 0.5-1 km is considered more realistic, however. Yet, the principal result is that these calculations support further the existence of a fracture zone intersecting the bedrock across the Eyjafjordur valley, as discussed previously.

6.1.3.3. Boundary effects

The analyses of the "injection tests" show that the injection wells are not directly connected to the principal fracture zone, which the production wells, presumably, intersect. An estimate of the distance from the injection wells to the fracture-zone can be obtained, however, on the basis of equation (3.46) in Hjartarson (1999). This distance is estimated to be about 35 m for both of wells LJ-08 and LN-10. One has to bear in mind that the equation is based on the theoretically homogeneous reservoir discussed by Hjartarson (1999). The distance estimated is, therefore, by no means accurate and should only be considered as a very rough estimate.

The above result shows, however, that the distances from the injection wells to the fracture zone are of the order of a few tens of meters. In Figure 33 the distances from the injection wells to the fracture zone are indicated by circles with radiuses equalling the estimated distance. If a line, which represents the fracture zone, is drawn as a tangent to the circles, it has the geographical direction of NE-SW.

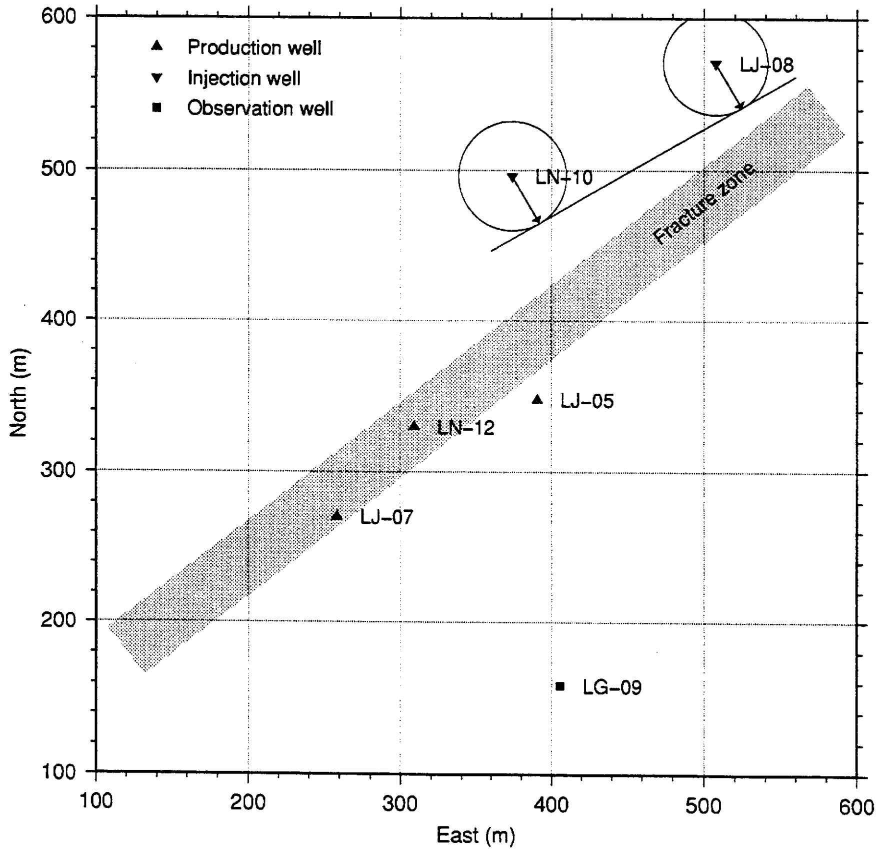


Figure 33. Comparison of the location of the main fracture zone based on boundary effect analysis of the selected "injection test" segments, and the earlier estimation of its location (see Section 5.3.1).

Finally it should be mentioned that in the LJ-05 "pump test", boundary effects are seen after approximately 50-60 hours. They are of the pressure support (constant pressure) type. This may, on one hand, indicate a connection between the main fracture zone and a groundwater system that provides recharge the fracture zone. This boundary effect may, on the other hand, indicate a connection between the fracture zone and another fracture-, or fault system, with higher hydraulic conductivity, possibly a hot water up-flow zone. It is difficult to estimate the distance to such a boundary. It is at least some several hundred meters away, which is reflected in the long time elapsing before the onset of the boundary effect. It must be emphasised that this last part of the interpretation of the water-level transients is highly speculative.

6.2. Step-rate injection tests

Step rate tests are conducted in wells to evaluate their production-, or injection characteristics. Pressure losses due to turbulent flow inside the wells, and in the feed-zones adjacent to the wells, can be estimated from these tests. Step-rate injection tests were conducted, with that purpose, in both of wells LJ-08 and LN-10. The test was repeated in well LJ-08, about nine months after the first test, to determine whether any changes had occurred in the well due to factors such as chemical precipitation and enhanced feed-zone properties due to cooling.

Figure 34 shows the results of the three step-rate injection tests conducted in wells LJ-8 and LN-10. The method of least squares was applied to simulate the step-rate data and to estimate the laminar flow- (B) and turbulence coefficients (C) in the equation:

$$\Delta p = B\,q + C\,q^2 \tag{3}$$

The results are shown in Figure 34 and in Table 11. If the injection rate in well LJ-08 is 8 L/s, for instance, the total pressure change, occurring in the September 1997 test, was 6.8 ± 0.2 bar, while the pressure change during the May 1998 test was 6.6 ± 0.2 bar. Clearly, there have not been noticeable changes in well LJ-08 during the nine-month period between the tests. Such step-rate injection tests should be repeated occasionally in the injection wells in the future.

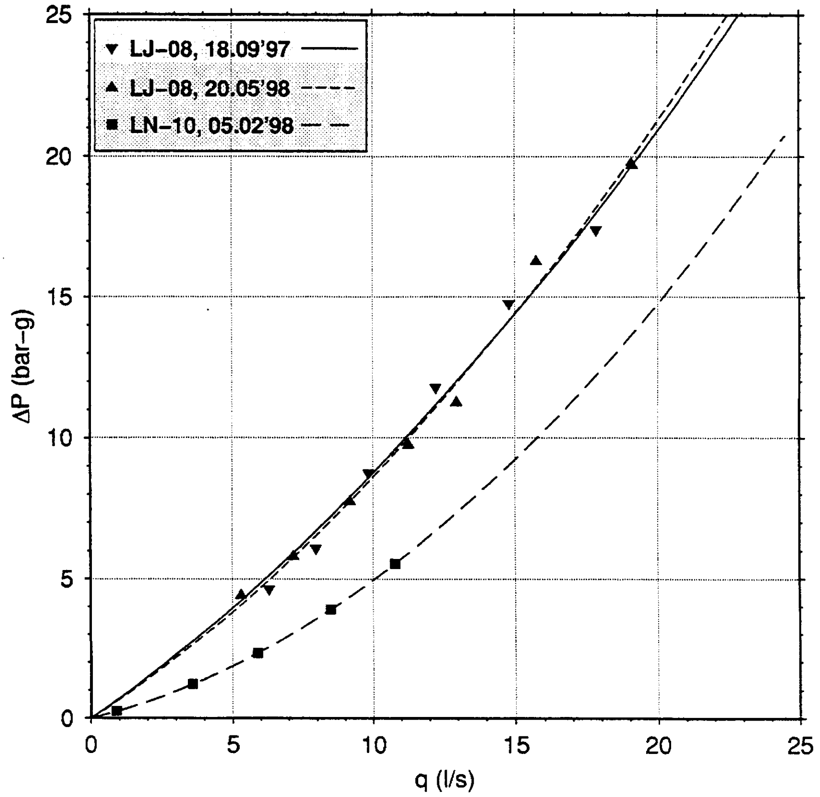


Figure 34. Results of step rate tests in wells LJ-08 and LN-10.

According to the results of the step-rate tests the injectivity of well LN-10 is considerably greater (factor of 2.5-3) than that of well LJ-8, agreeing with an earlier conclusion. The turbulence pressure losses appear to be comparable in these two wells, however, or of the order of 0.02 bar/(L/s)^2. This equals 0.5 bar at an injection rate of 5 L/s, 2.0 bar at a rate of 10 L/s and 4.5 bar at a rate of 15 L/s. Production testing of well LJ-8 at the end of drilling indicated turbulence losses on the order of 0.1 bar/(L/s)^2 (Thorsteinsson, 1988). The fact that turbulence losses appear to be half an order of magnitude less during cold water injection than during production may be the result of thermal contraction of the rock around the feed-zones of the well, which causes the feed-zone fractures to widen. It should be kept in mind, however, that the production test took place about 22 years ago.

Table 11. *Results of step-rate tests in wells LJ-08 and LN-10.*

Well	date	Δp (bar)	rms-misfit (bar)
LJ-08	18/09/97	$0.71\,q + 0.017\,q^2$	0.20
LJ-08	20/05/98	$0.66\,q + 0.020\,q^2$	0.20
LN-10	05/02/98	$0.25\,q + 0.024\,q^2$	0.02

7. TRACER TEST ANALYSIS'

7.1. Background

The possible cooling of production wells, or thermal breakthrough, has discouraged the use of injection in some geothermal operations. In cases where the spacing between injection and production wells is small, and direct flow-paths between the two wells exist, the fear of thermal breakthrough has been justified. However, actual thermal breakthroughs, caused by cold water injection, have been observed in a relatively few geothermal fields (Stefansson, 1997). Changes in flowing enthalpy of production wells have in some cases been interpreted as actual cooling, whereas the enthalpy changes are in fact the result of pressure changes in two-phase reservoirs.

Stefansson (1997) reports that actual cooling, attributable to injection, has only been observed in Ahuachapan (El Salvador), Palinpinon (Philippines) and Svartsengi (Iceland). The temperature of well AH-5 in Ahuachapan declined by about 30°C due to an injection well located only 150 m away, while the temperature of well SG-6 in Svartsengi declined by about 8°C during 4 years of injection. The temperature decline of well PN-26 in Palinpinon was reviewed by Malate and O'Sullivan (1991). The thermal breakthrough occurred about 18 months after reinjection started. Consequently, the temperature declined rapidly, dropping by about 50°C in 4 years.

The cooling effect can be minimised by a proper selection, or location, of injection wells. This can be achieved, in fact, by choosing injection locations at a considerable distance (a few km) from production wells. Yet, to achieve the maximum benefit from injection, i.e. thermal energy extraction and pressure recovery, injection wells should be as close to production wells as possible. For successful injection a proper balance between these two contradicting requirements must be selected. Therefore, careful testing and research are prerequisites for planning successful injection.

Tracer tests are the most powerful tool for studying connections between injection and production wells, and hence the danger of thermal breakthrough. Numerous such tests have been carried out in geothermal fields during the last two decades (Stefansson, 1997). The method has been adopted from similar methods used in groundwater and nuclear-waste storage studies. In principle the tracer breakthrough time should reflect the thermal breakthrough time, and a short tracer breakthrough time reflects a short thermal breakthrough time. As a rule of thumb the thermal breakthrough time is normally one or two orders of magnitude greater than the tracer breakthrough time. As an example the tracer breakthrough time in well PN-26, mentioned above, was of the order of 40 hrs, while the thermal breakthrough time was 18 months, or 13000 hrs.

Numerous models have been developed, or adopted, for interpreting tracer test data and consequently for predicting thermal breakthrough and temperature decline during long-term reinjection (Pruess and Bodvarsson, 1984; Horne, 1985; Stefansson, 1997). These models will not be discussed here. It must be pointed out, however, that while tracer tests provide information on the volume of flow paths between injection and production wells, thermal breakthrough and decline is determined by the surface area involved in heat transfer from reservoir rock to the flow paths, which most often are fractures.

7.2. The Laugaland tracer tests

Three tracer tests were carried out between wells at Laugaland, during the two-year reinjection project. The purpose of these tests was to study the connections between injection- and production wells in order to enable predictions of the possible decline in production temperature due to long-term reinjection. The tests were conducted at different conditions, i.e. for different injection rates and for different wells in use, both injection- and production wells. Two different tracers were used, sodium-fluorescein and potassium-iodide. Some of the principal information on the tracer tests is summarised in below. It should be pointed out that potassium-iodide is a non-reactive and conservative tracer, while the stability of sodium-fluorescein is sometimes questionable. This is discussed more thoroughly in chapter 8.

Table 12. *Principal information on the three tracer tests conducted at Laugland from September 1997 through August 1999.*

Tracer test	1	2	3
Time of injection	25/09/97 14:30	19/02/98 11:10	23/04/99 22:05
Tracer injection well	LJ-08	LN-10	LJ-08
Tracer	Na-fluorescein	Iodide	Na-fluorescein
Amount of tracer	10 kg	34.7 kg	10 kg
Injection rate,			
well LJ-08	8 L/s	8 L/s	21 L/s
well LN-10		6 L/s	
Main production well	LN-12	LJ-05	LN-12
Production rate	41 L/s	33 L/s	39 L/s
Comments		LN-12 some prod.	
No. of samples	600	635	160

The data collected during the tracer tests are presented in several figures in the following section (section 7.3). The results of analysis of the data are, consequently, reviewed in section 7.4.

7.3. The tracer test data

The first test started on September 25th 1997 when 10 kg of sodium-fluorescein were injected instantaneously into well LJ-8. At that time, and until the end of November, LN-12 was the only production well on-line. A constant injection rate was also maintained (see Table 12). This period constitutes the first test because of the controlled and stable conditions of the Laugaland field. Yet the fluorescein recovery was monitored throughout the whole reinjection project. Figure 35 and Figure 36 show the fluorescein recovery data for wells LN-12 and LJ-05, while Figure 41 shows the recovery data for well LN-12 during the first test, in more detail. Fluorescein recovery through well LJ-07 was limited, partly because the well was only in use for a few brief periods and partly because of a very low concentration in the few samples collected.

Great variations can be seen in the tracer return data for the two-year period, mostly caused by variations in production. A high peak in fluorescein concentration is seen, for example, at the end of November 1997 when pumping from well LJ-5 started (Figure 36). The reason for this, as well as most other such peaks, is believed to be an inflow into the well, from shallow feed-zones, when the well is not in use. These shallow feed-zones appear to carry much more of the fluorescein. This causes, consequently, the high concentration when pumping from the well starts after breaks in production. The longer the breaks the higher the peaks are. This is also believed to be the reason for other peaks in concentration seen in the data set for well LJ-05, as well as the reason for similar, but lower peaks seen in the fluorescein recovery data for well LN-12 (Figure 35). The fact that these peaks are lower in well LN-12 propably reflects the fact that LN-12 is cased to a greater depth than well LJ-05 (see Table 1). Hence more of the shallow feed-zones are cased off in the former well. The fact that well LJ-07 is cased to a depth of more than 900 m probably explains the limited recovery through that well.

Other geothermal production wells in the Eyjafjordur-valley, outside Laugaland, have also been monitored for tracer recovery (see Figure 1 and Figure 29). A considerable amount was recovered through production well TN-4 in the Ytri-Tjarnir field about 1800 m north of well LJ-08, as seen in Figure 37. Some fluorescein appears also to be recovered through well GY-03 about 1200 m south of Laugaland (Figure 38). The fact that the concentration remains relatively stable, however, may indicate that this is left-over fluorescein from the tracer test carried out in 1991. The tracer did not appear to be recovered at measurable levels in production wells in the western half of the Eyjafjordur-valley, as seen in Figure 39. Yet, the figure shows a slight increase towards the end of the reinjection project, which may either be the result of some tracer actually being recovered or the result of increased inaccuracy. It should be pointed out that the detection limit for fluorescein was considered to be of the order of 10 ng/L in this study.

The third tracer test, which also used fluorescein, started on April 23rd 1999. This was planned as an exact replica of the first test, involving the same injection/production well-pair, except for a much higher injection rate (see Table 12). The fluorescein data collected during that test are shown in detail in Figure 42.

The first step in analysing tracer test data involves estimating the mass of tracer recovered throughout a test. This is done on the basis of the following equation:

$$m_i(t) = \int_0^t c_i(s)Q_i(s)\,ds \qquad (4)$$

where $m_i(t)$ indicates the cumulative mass recovered in production well number i (kg), as a function of time, c_i indicates the tracer concentration (kg/L or kg/kg) and Q_i the production rate of the well in question (L/s or kg/s, respectively). The results for the fluorescein recovery through wells LN-12, LJ-05 and TN-04 are presented in Figure 43 through Figure 45. These results are also summarised in Table 13. It is also of interest to compare the recovery through each of these wells. This is done in Figure 47 and Figure 48, which show the recovered mass of tracer as a function of cumulative production from each of the wells. The latter figure shows the relationship on a logarithmic production scale.

The results show that during the almost two years since the first injection of fluorescein only about 36% of the 10 kg injected have been recovered. Most of that has been recovered through well LJ-05, and interestingly the recovery through well TN-04 is now approaching the amount recovered through well LN-12. Figure 48 has been used to try to estimate how much of the tracer will be recovered in 5 years (end of 2002), assuming production rates similar to those in the past. The result is that still less than 60% will be recovered. In fact it should take of the order of ten years for all of the tracer to be recovered at the present rate. This will be discussed further below, but has positive implications concerning the danger of cooling due to future reinjection at Laugaland.

When analysing tracer test data, such as in this case, one must keep in mind that some of the tracer recovered through the production wells is injected back into the reservoir. If this is a significant amount it will interfere with the data interpretation and must be corrected for. A computer program, TRCORRC, has been developed for this purpose (Axelsson *et al.*, 1995; United Nations University Geothermal Training Programme, 1994). Figure 40 shows the fluorescein concentration in the return water during the reinjection experiment, while Figure 46 shows the cumulative mass of the tracer injected back into the reservoir. This is only a few % for the first and third tracer tests, which may be considered insignificant amounts.

Table 13. *Summarised information on tracer recovery in the three tracer tests conducted at Laugland from September 1997 through August 1999.*

Tracer test	1	2	3
Time of injection	25/09/97 14:30	19/02/98 11:10	23/04/99 22:05
Tracer injection well	LJ-08	LN-10	LJ-08
Tracer	Na-fluorescein	Iodide	Na-fluorescein
Amount of tracer	10 kg	34.7 kg	10 kg
Injection rate,			
well LJ-08	8 L/s	8 L/s	21 L/s
well LN-10		6 L/s	
Recovery			
until	31/08/99	31/08/99	31/08/99
length of period	23 months	18 months	4 months
well LJ-05	2.1 kg	18.0 kg	0.1 kg
well LJ-07	0.1 kg	0.1 kg	0.0 kg
well LN-12	0.8 kg	0.4 kg	0.5 kg
well TN-04	0.6 kg	0.0 kg	0.0 kg
total	3.6 kg (36%)	18.5 kg (53%)	0.6 kg (6%)
Estimated recovery in 5 years	5.8 kg (58%)	33 kg (95%)	not estimated

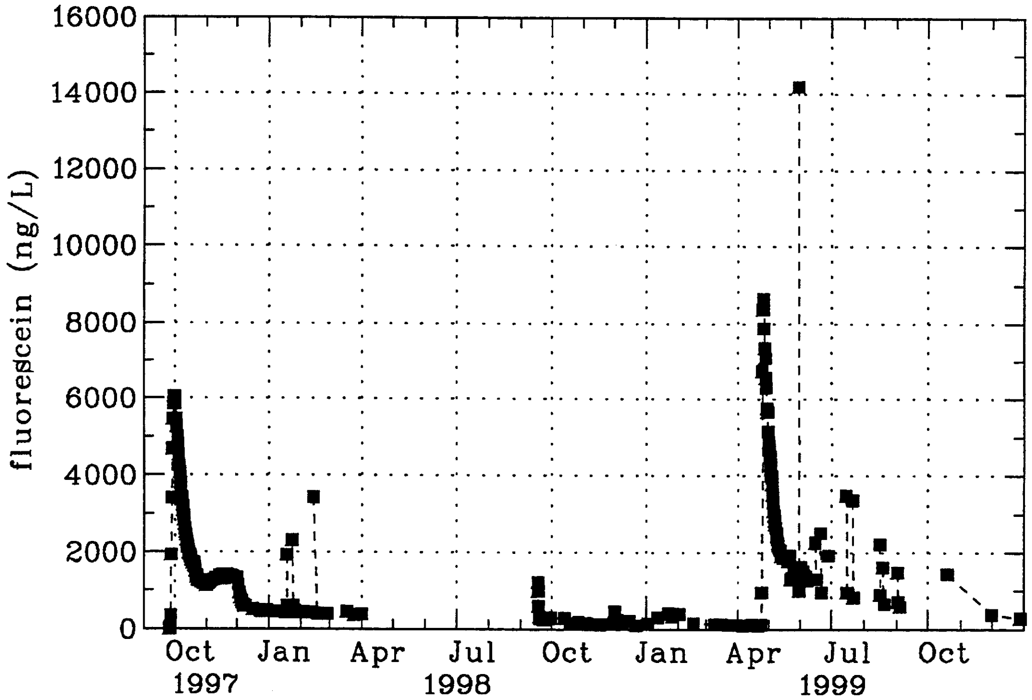


Figure 35. Observed fluorescein recovery in well LN-12. Note that the tracer is injected twice into well LJ-8, in September 1997 and April 1999.

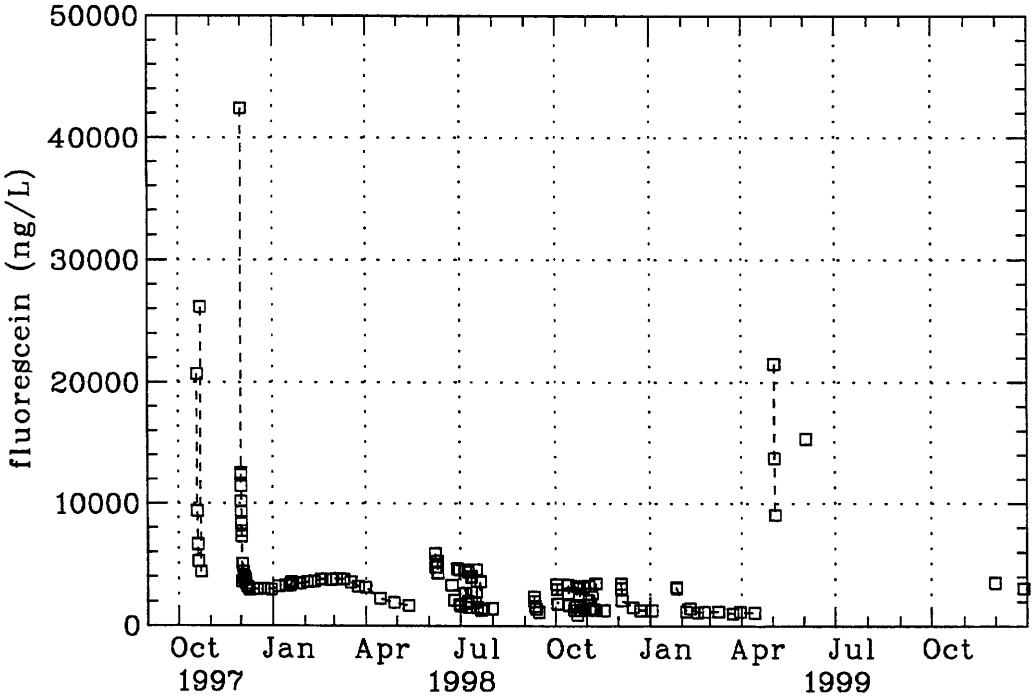


Figure 36. Observed fluorescein recovery in well LJ-05. Note that the tracer is injected twice into well LJ-8, in September 1997 and April 1999.

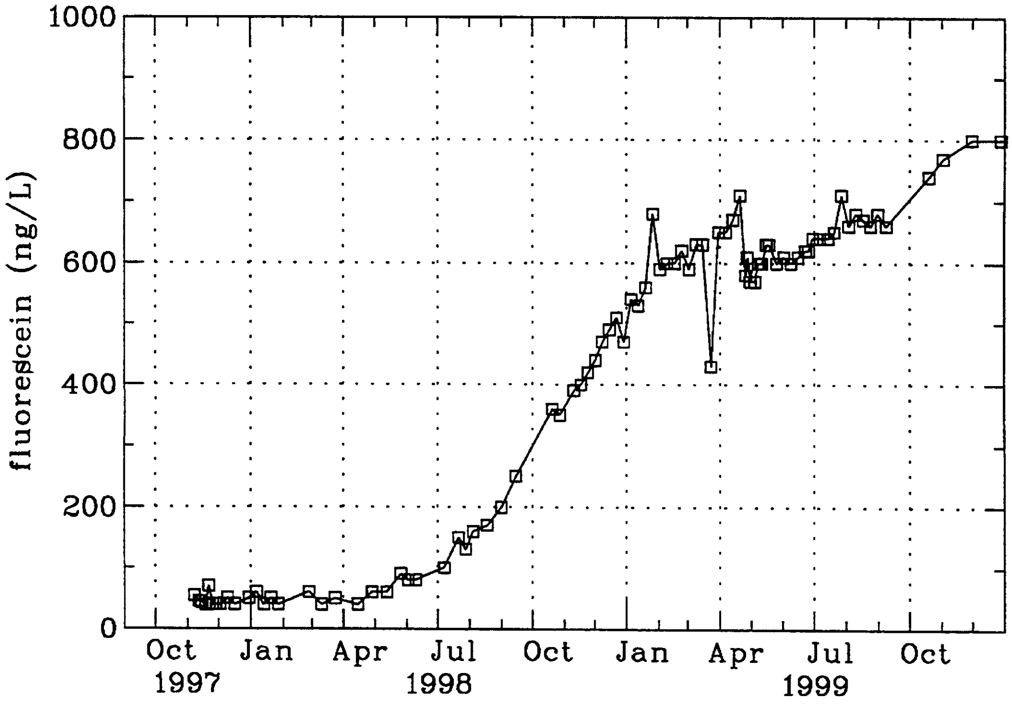


Figure 37. Observed fluorescein recovery in well TN-04 in the Ytri-Tjarnir field 1800 m north of well LJ-08 at Laugaland.

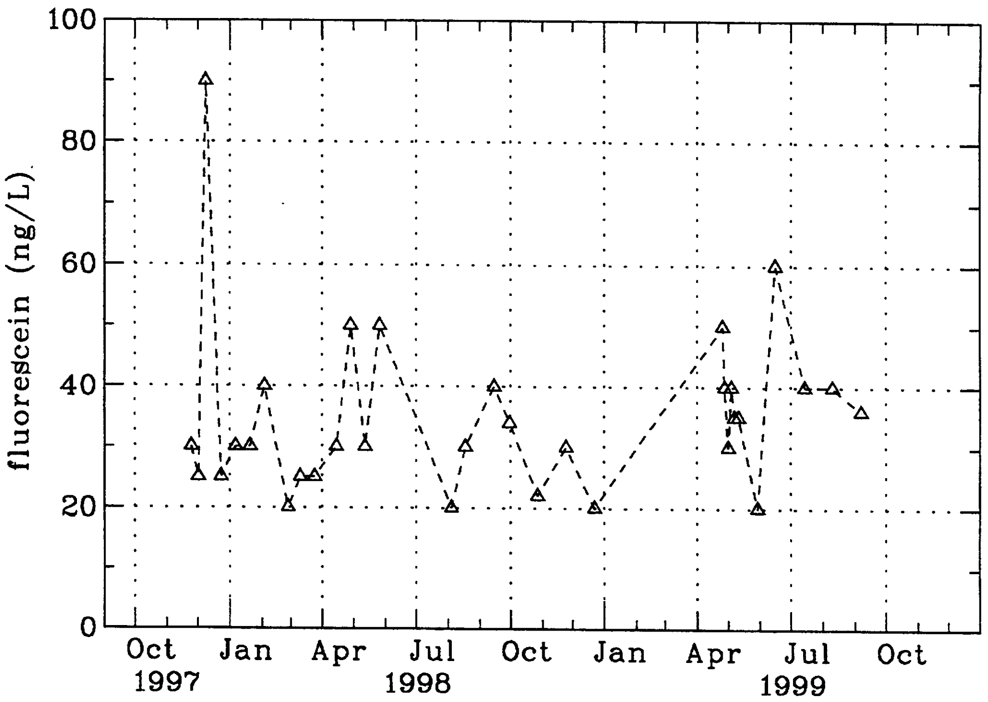


Figure 38. Observed fluorescein recovery in well GY-03 in the Gryta field 1200 m south of well LJ-08 at Laugaland.

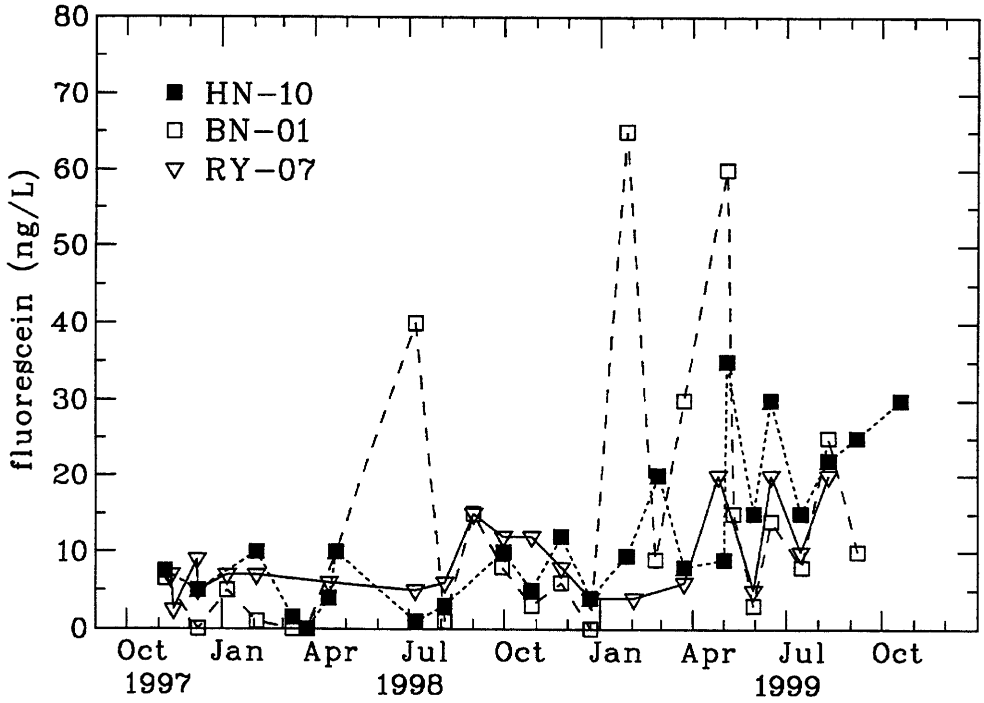


Figure 39. Observed fluorescein recovery in three wells in the Eyjafjordur area outside the Laugaland field.

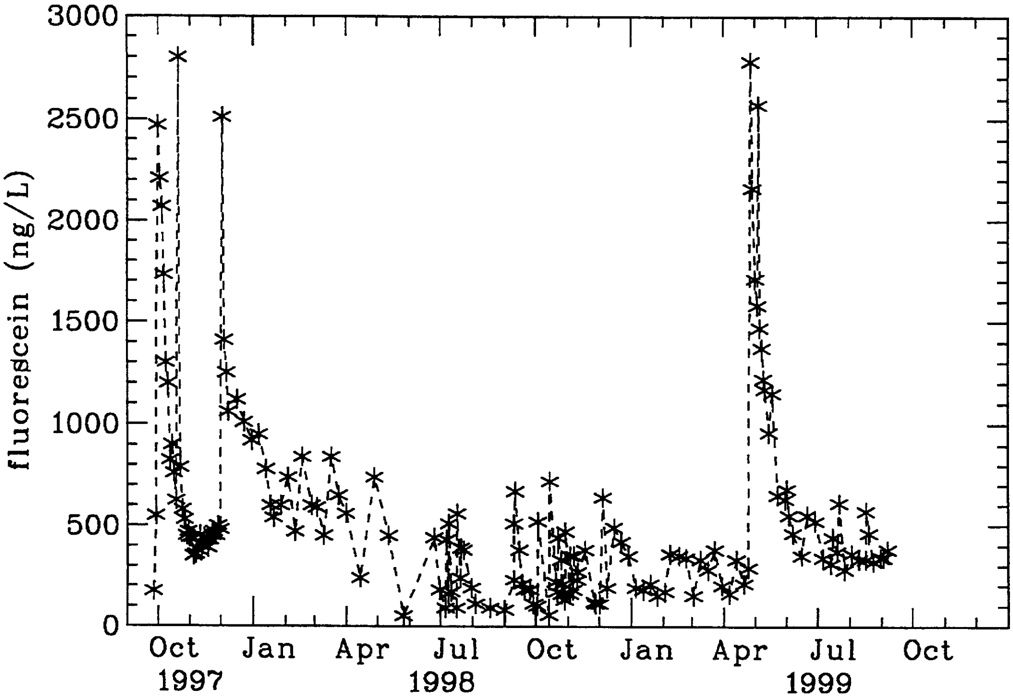


Figure 40. Fluorescein concentration in the return water reinjected at Laugaland.

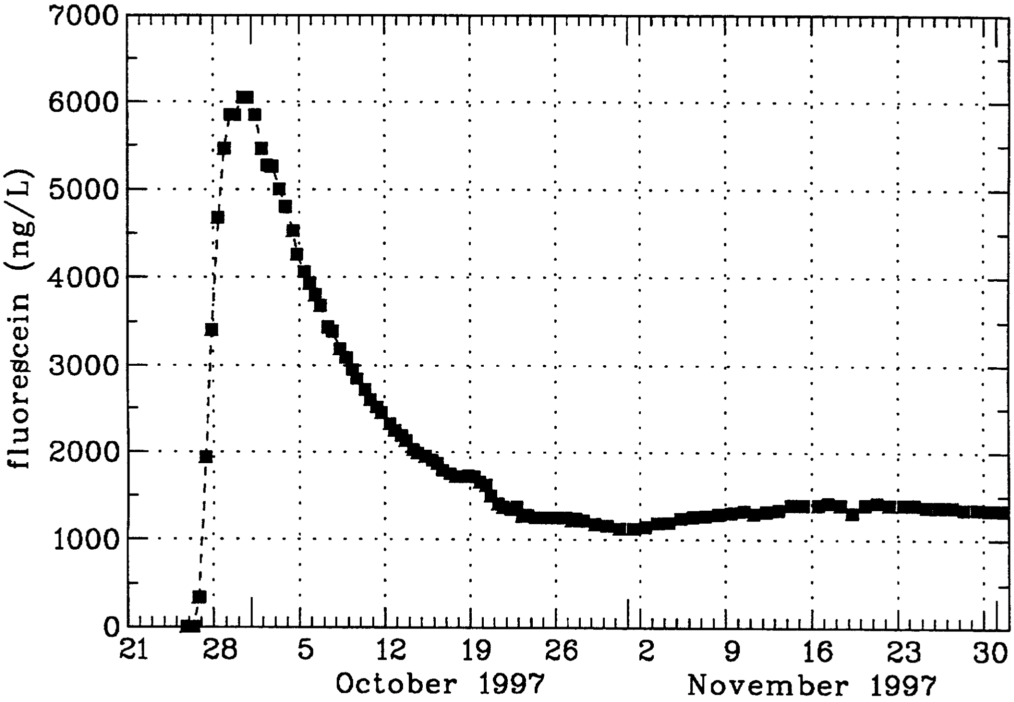


Figure 41. Observed fluorescein recovery in well LN-12 during the first tracer test starting 25/09/97 (8 L/s injection into well LJ-08).

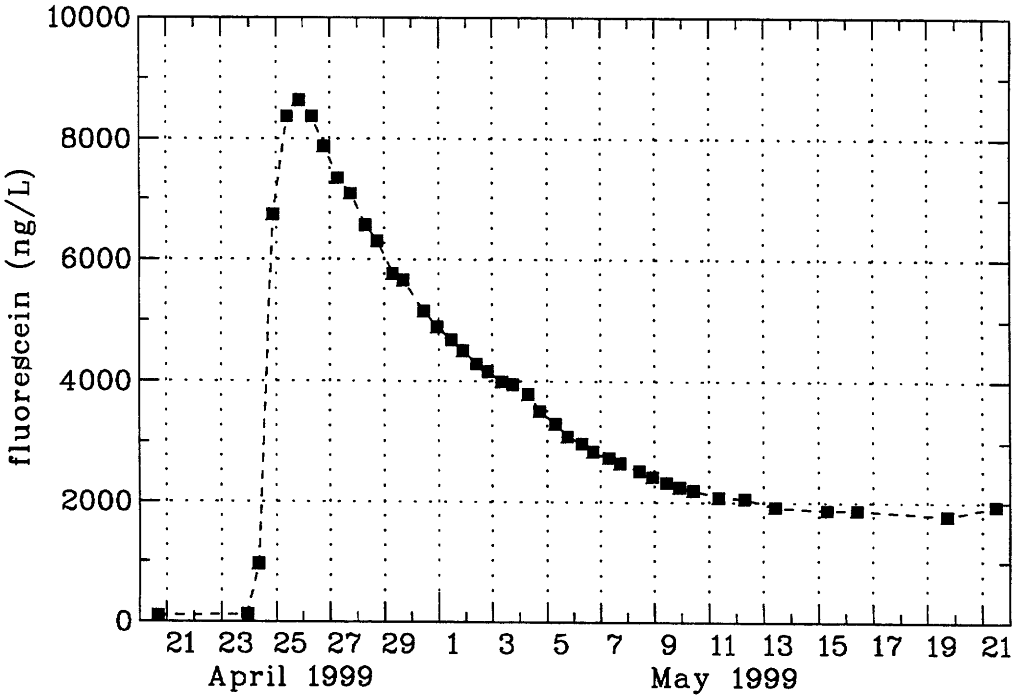


Figure 42. Observed fluorescein recovery in well LN-12 during the third tracer test starting 23/04/99 (21 L/s injection into well LJ-08).

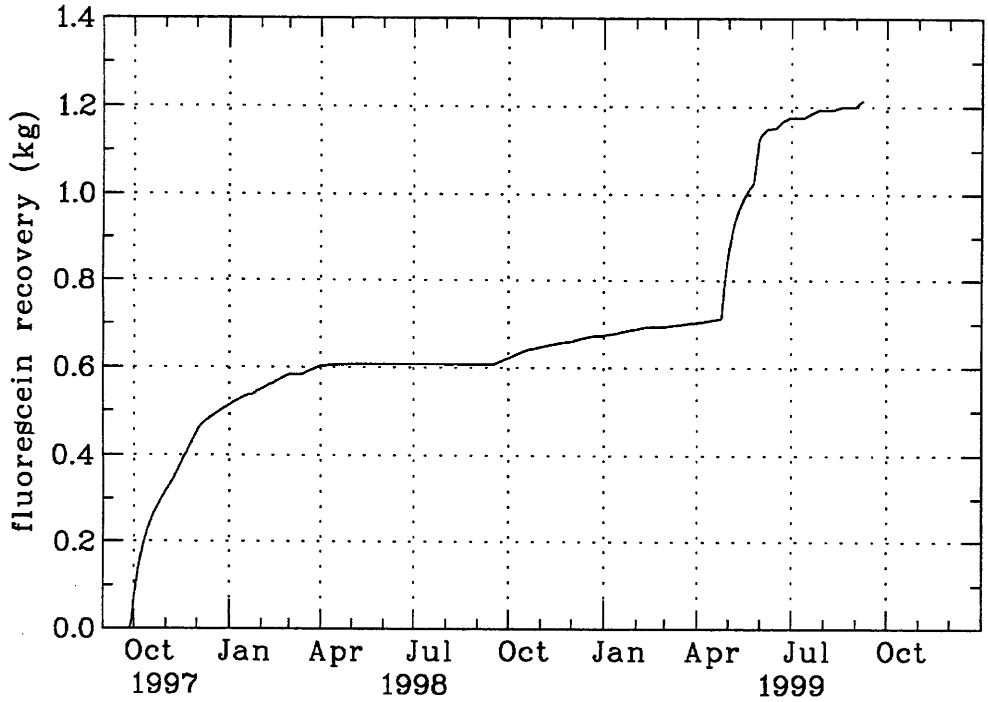


Figure 43. Cumulative mass of fluorescein recovered through well LN-12 during the reinjection project.

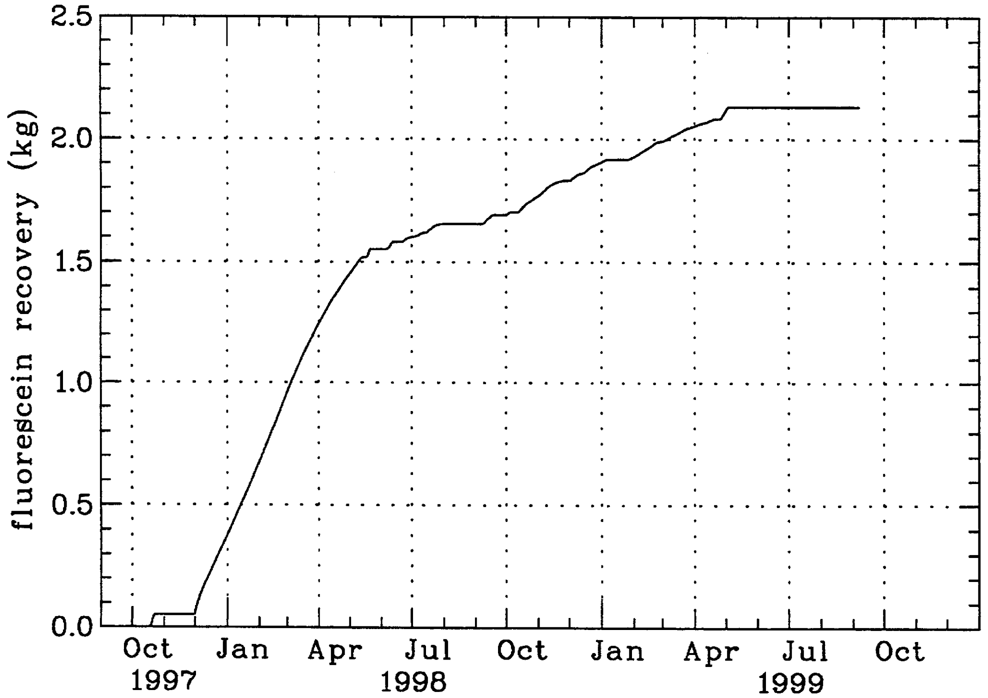


Figure 44. Cumulative mass of fluorescein recovered through well LJ-05 during the reinjection project. No production from the well the last 4 months.

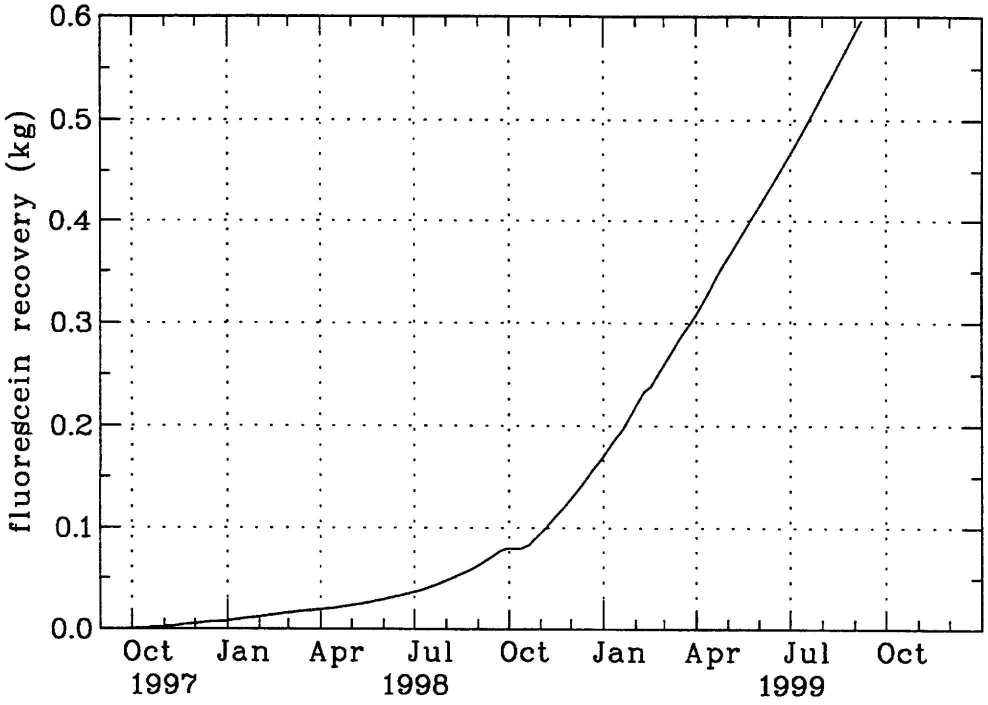


Figure 45. Cumulative mass of fluorescein recovered through well TN-04 in the Ytri-Tjarnir field during the reinjection project.

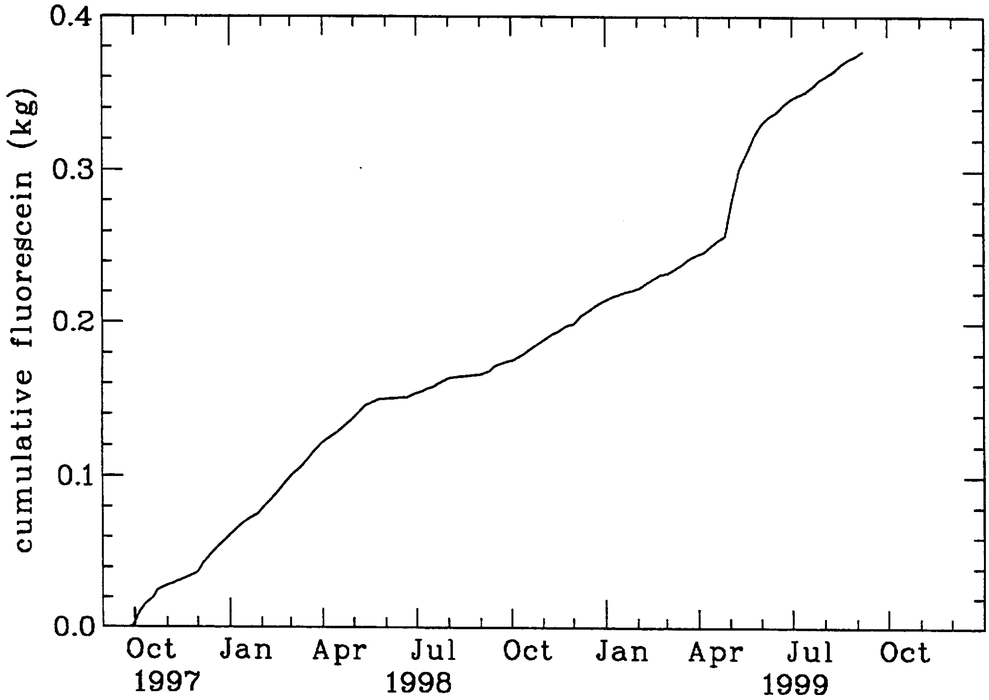


Figure 46. Cumulative mass of fluorescein reinjected back into the Laugaland reservoir, through wells LJ-08 and LN-10, during the reinjection project.

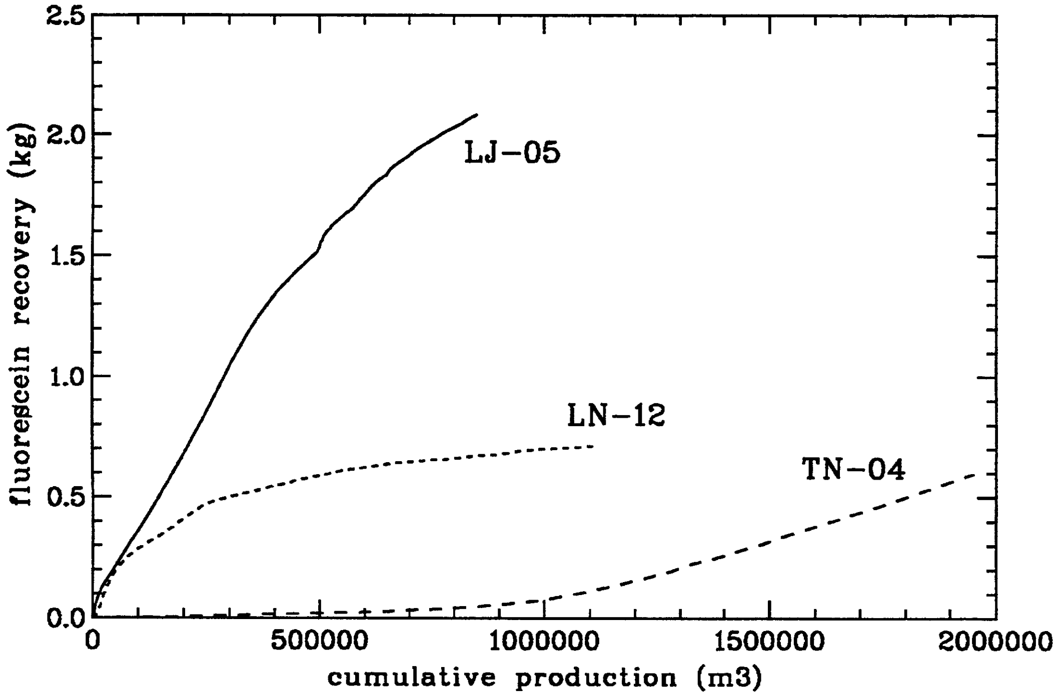


Figure 47. Mass of fluorescein, from the first tracer injection, recovered through wells LJ-05, LN-12 and TN-04 (function of cumulative production from each well).

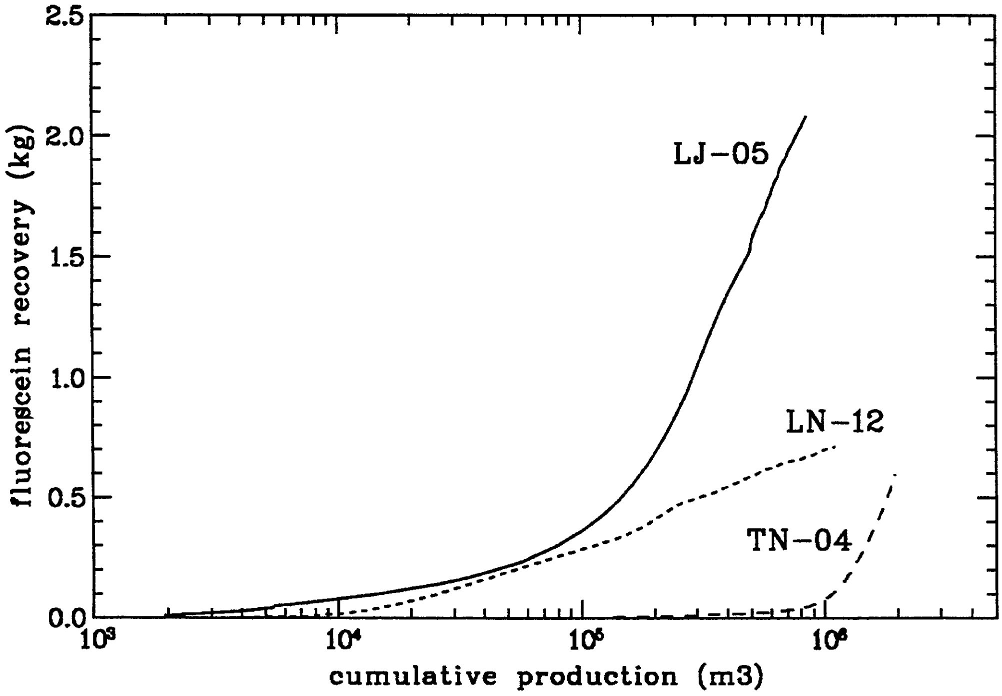


Figure 48. Same as Figure 47, but with logarithmic production scale.

The second tracer test used potassium-iodide instead of fluorescein so that the tracer recovery during that test could be distinguished from the recovery during the first test, which started 4 months earlier. The second test started on February 19th 1998 when 45.3 kg of the tracer were injected into well LN-10. At that time both of wells LJ-5 and LN-12 were on line. Figure 49 and Figure 50 show the observed iodide recovery in wells LJ-05 and LN-12, respectively. Very little iodide was recovered through well LN-12 and no iodide was detected in well LJ-7, partially because of a much higher detection limit for iodide than for fluorescein (1 mg/L). It seems to be quite clear that most of the tracer is recovered through well LJ-05. The same explanation holds in this case for the sudden variations in tracer concentration, i.e. inflow from shallow feed-zones. Again, these variations are more pronounced in well LJ-05.

Figure 52 shows the iodide recovery in well LJ-5 for the first 80 days, or until production was discontinued in the spring. This can be looked upon as the principal test data for the second tracer test. Conditions in the reservoir were not as stable, however, as during the first tracer test. Hot water production was more variable (Figure 17) and until late March either one of wells LN-12 or LJ-7 was also on line. Interpretation of the results of this test is, therefore more difficult. Figure 51 shows the iodide concentration in the return water while Figure 54 shows the cumulative mass of iodide injected back into the Laugaland reservoir. In this case the amount is somewhat greater, or more than 7% of the amount originally injected. This is because the iodide is recovered at a considerably faster rate than the fluorescein. The reason must be the fact that LN-10 was used as a reinjection well rather than well LJ-08.

Figure 53, Figure 55 and Figure 56 show the cumulative mass of iodide recoverd through well LJ-05 during the 1½ year since the second tracer test started. The first figure shows the recovered mass as a function of time, the second as a function of cumulative production from the well and the third also as a function of cumulative production, but on a logarithmic scale. Table 13 also presents information on the mass of iodide recovered. This is actually more than 50%, through one well only, in 18 months. This may be compared to 30% of the fluorescein injected during the first tracer test, which was recovered through the three production wells at Laugaland in 23 months. This obviously indicates that wells LN-10 and LJ-05 are more directly connected than well LJ-08 and the three production wells. It is also clear that well LN-10 is more directly connected to well LJ-05 than the other production wells, most likely because these two wells have much shorter casings than the other wells involved (see Table 1).

It should be pointed out here that Figure 48 and Figure 56 show that the relationships between tracer mass recovery and cumulative production appear to approach a linear relationship on a logarithmic scale. This is used here to predict the recovery in the coming years. In the case of the iodide the recovery is predicted to approach 100% in 5 years time (beginning of 2003) as shown in Table 13. This may be compared to slightly more than 50% in the case of the fluorescein.

Figure 57 shows, finally, a comparison between the tracer recovery through well LJ-05 when well LJ-08 is the injection well, on one hand, and when well LN-10 is the injection well, on the other hand. The figure reflects clearly the much more direct connection between wells LN-10 and LJ-05 than wells LJ-08 and LJ-05.

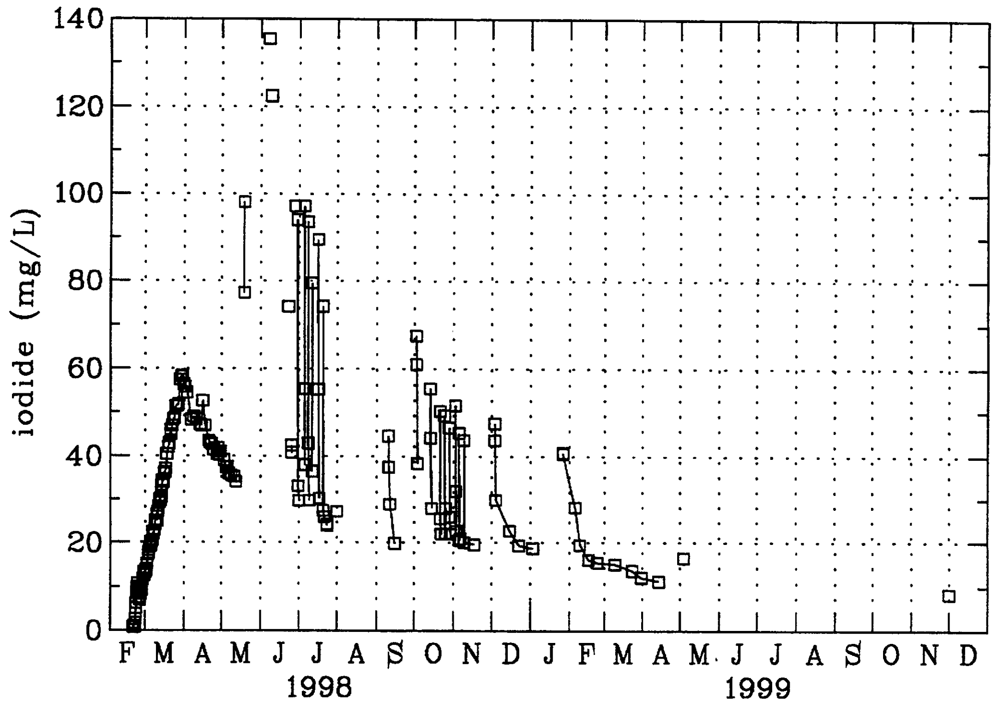


Figure 49. Observed iodide recovery in well LJ-05 during the whole reinjection project, following tracer injection into well LN-10 in February 1998. Peaks associated with starting-up of the well after breaks in pumping.

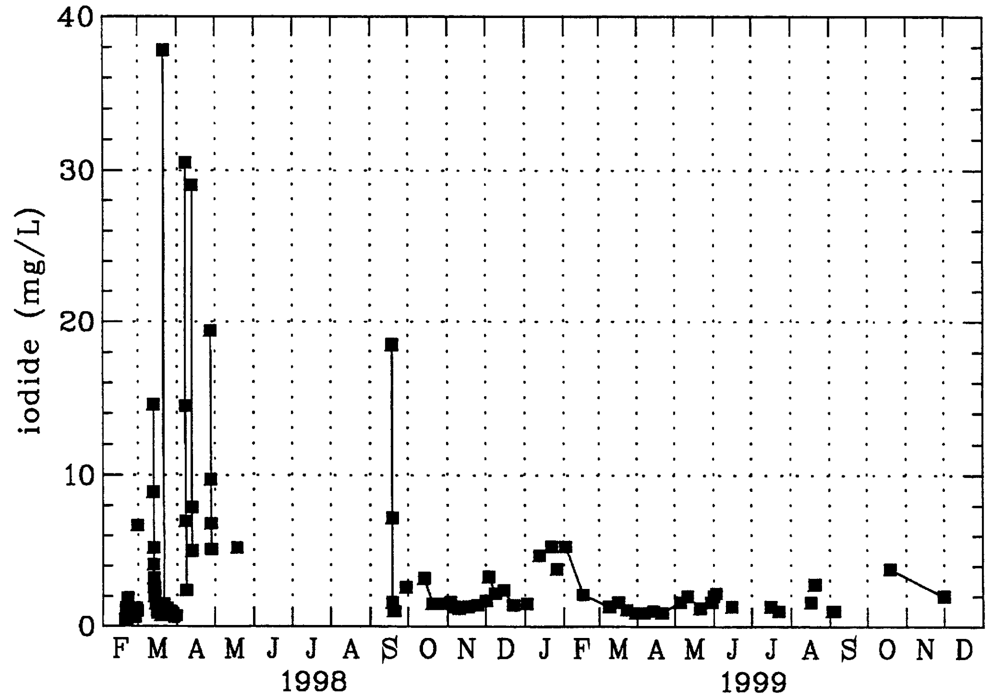


Figure 50. Observed iodide recovery in well LN-12 during the whole reinjection project, following tracer injection into well LN-10 in February 1998.

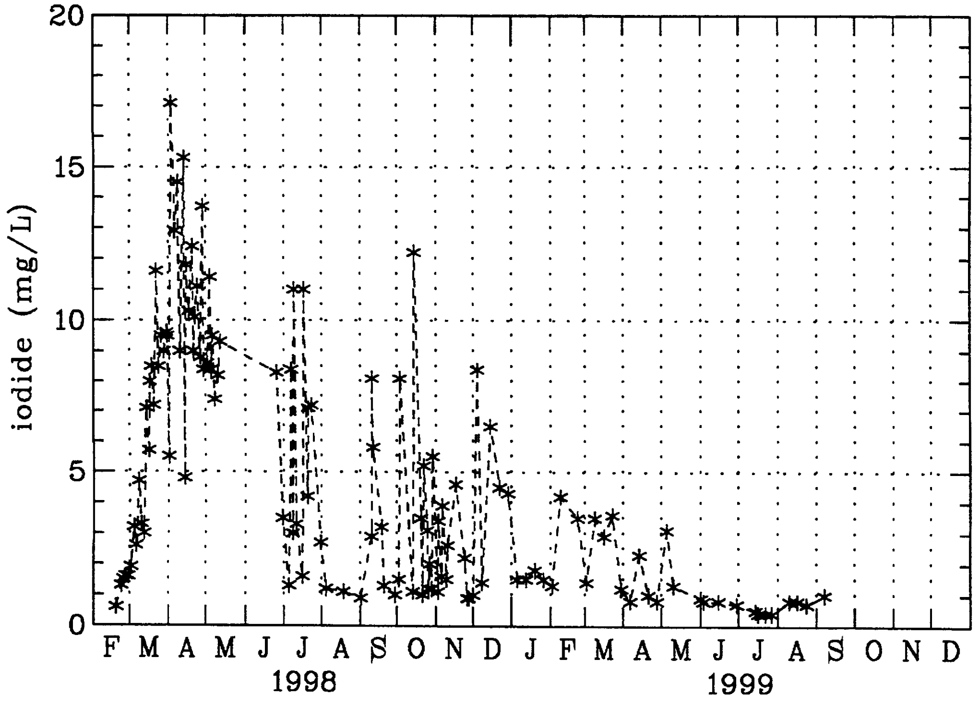


Figure 51. Iodide concentration in the return water reinjected at Laugaland.

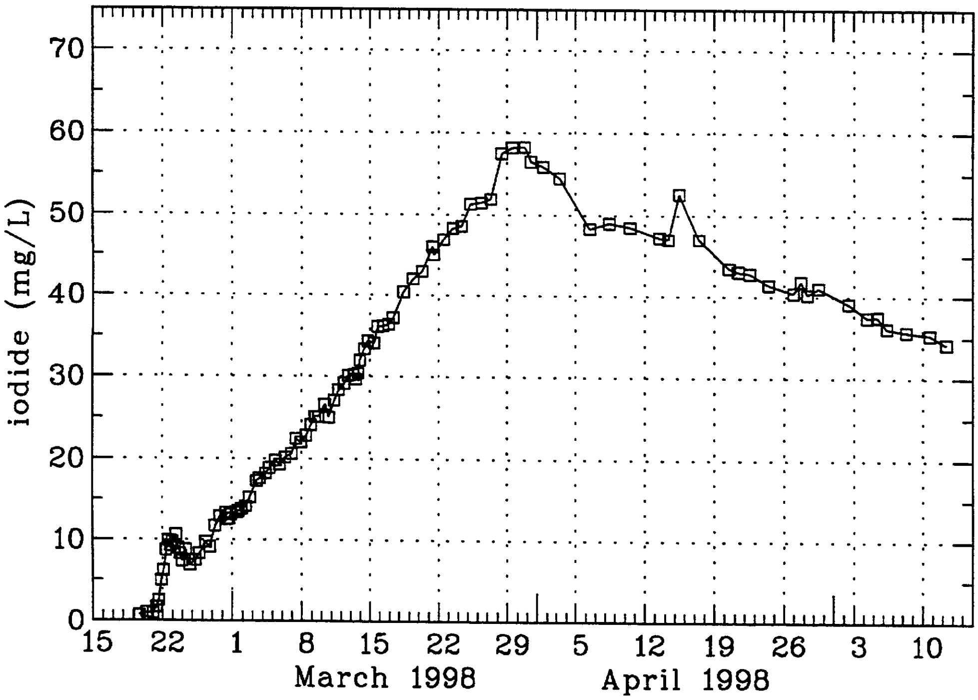


Figure 52. Observed iodide recovery in well LJ-05 during the second tracer test starting 19/02/98 (6 L/s injection into well LN-10).

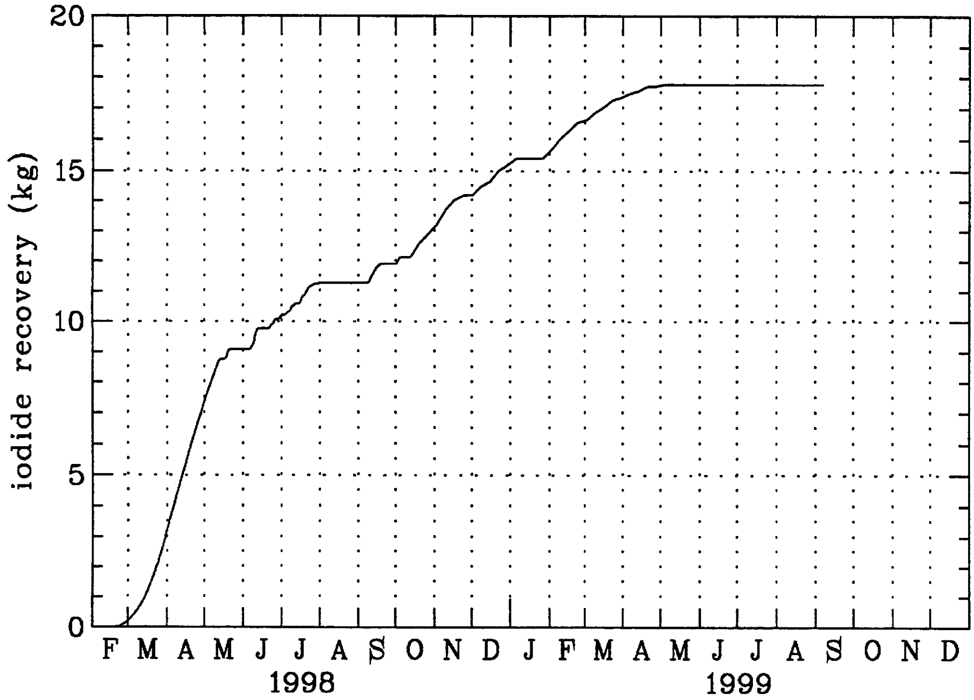


Figure 53. Cumulative mass of iodide recovered through well LJ-05 during the reinjection project.

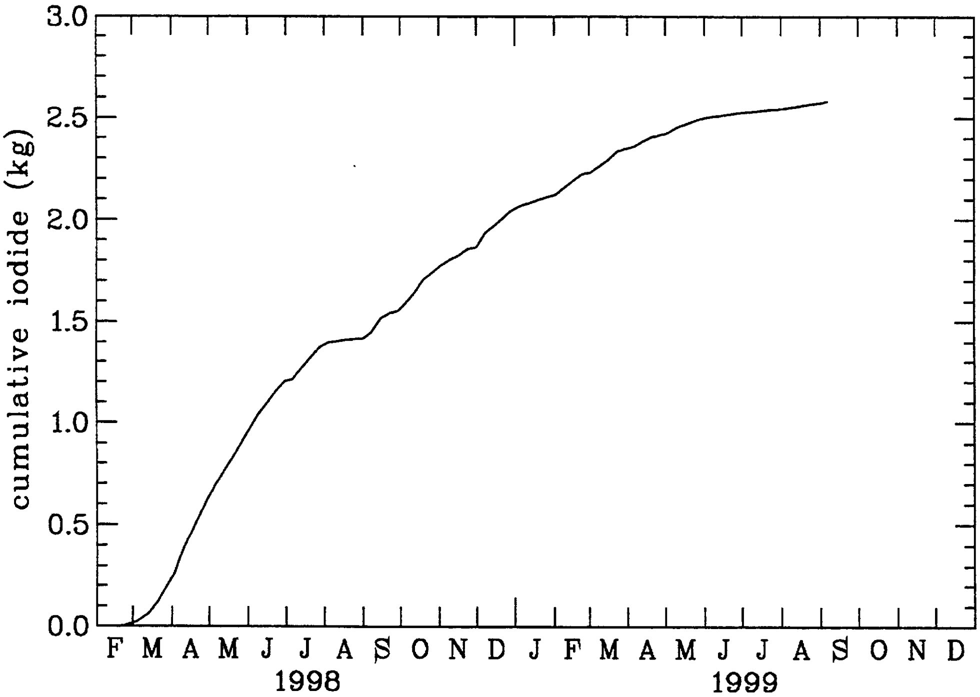


Figure 54. Cumulative mass of iodide reinjected back into the Laugaland reservoir, through wells LJ-08 and LN-10, during the reinjection project.

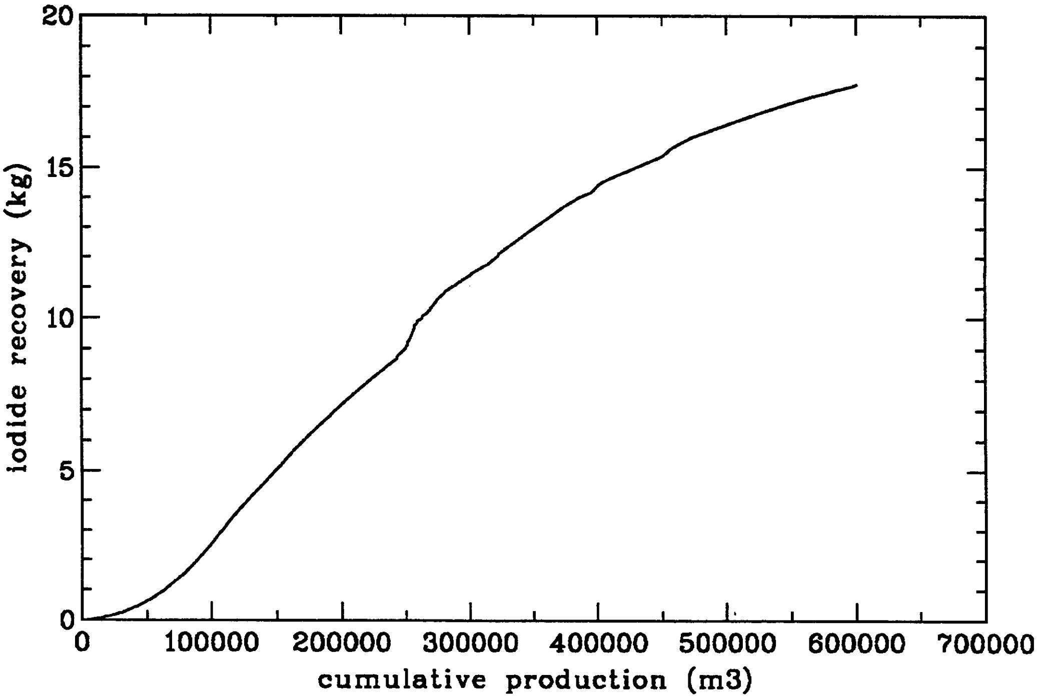


Figure 55. Mass of iodide recovered through well LJ-05 (shown as function of cumulative production from the well).

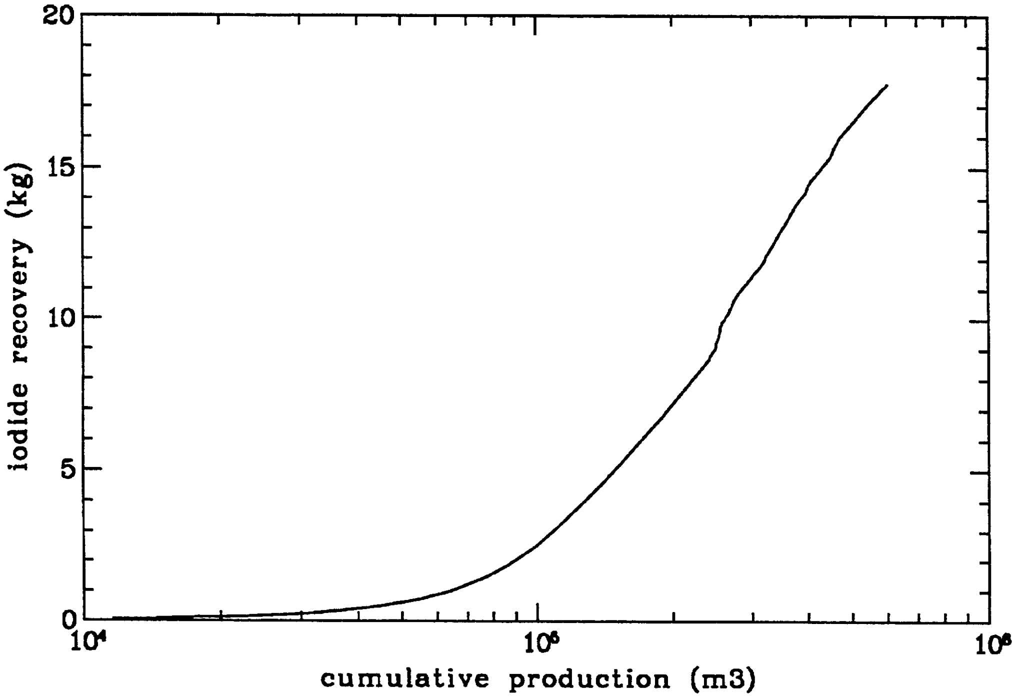


Figure 56. Same as Figure 55, but with logarithmic production scale.

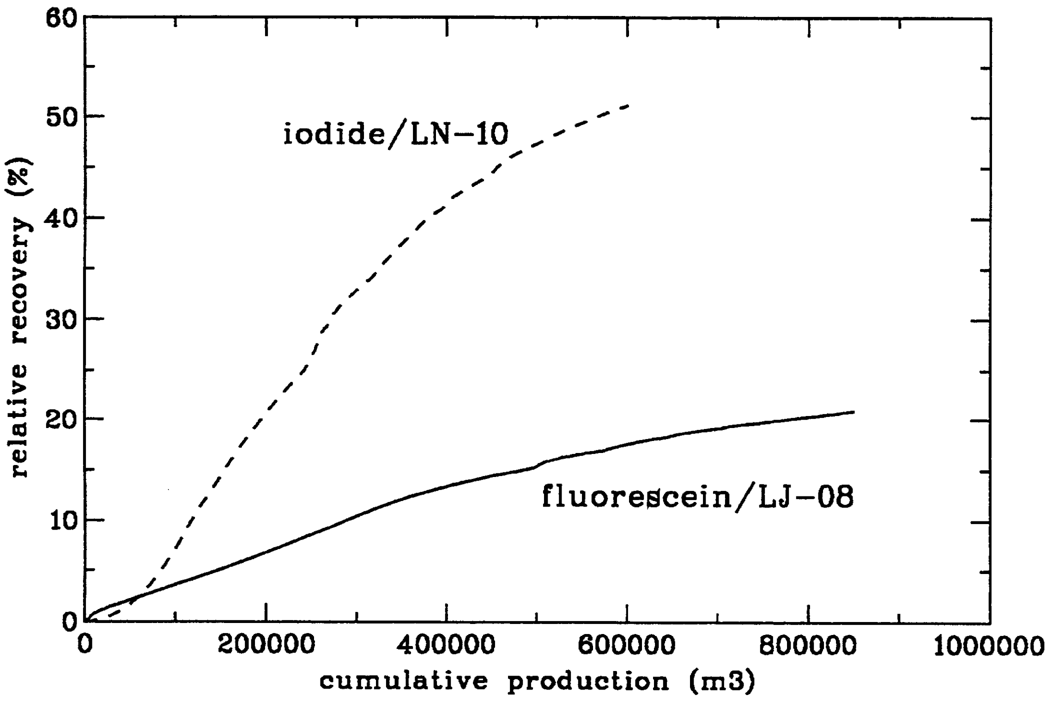


Figure 57. Comparison of the relative tracer recovery through well LJ-05 for the first (injection into LJ-08) and second (injection into LN-10) tracer test.

7.4. Interpretation of the tracer test data

Interpretation of the tracer test data aims at quantifying the danger of cooling of production wells during long-term reinjection. Theoretically, tracer test data yields information on the volumes of flow-paths connecting injection and production wells. With some additional information, as well as some assumptions, this information can be used to predict the cooling of production wells during long-term (years to decades) reinjection. Such predictions for Laugaland will be presented later (in section 13.2).

Estimates of the volumes involved in the transport of the tracers will be discussed below. Some qualitative results are, however, quite obvious on basis of the tracer return data reviewed above. These may be summarised as follows:

1. In general connections between the injection wells and production wells are rather indirect, which is reflected in the slow return of the tracers. This indicates that most of the injected water disperses throughout a large part of the volume of the Laugaland reservoir.

2. Production well LJ-05 appears to be most directly connected with injection well LJ-08. This is a result of the fact that well LJ-05 has a relatively short (96 m) production casing.

3. A direct connection exists between well LJ-08 and the Ytri-Tjarnir geothermal field 1800 m north of Laugaland. It is estimated that between 15 and 20% of the water injected into well LJ-08 will be recovered at Ytri-Tjarnir.

4. The connection between injection well LN-10 and production well LJ-05 is considerably more direct than between wells LJ-08 and LJ-05, which is reflected in more than twice the rate of tracer return. The connection between well LN-10 and the other production wells appears to be much less direct. This is again believed to result from short casings in wells LJ-05 and LN-10.
5. A large part of the injected water exits the injection wells in the shallow part of the Laugaland reservoir, i.e. above 1000 m depth.

The tracer return data reviewed above indicates that the injected water travels throughout the bedrock in the area by two modes:

A. Firstly through direct, small volume paths, such as channels along fractures or interbeds. These flow channels may even be looked upon as kind of pipes containing porous material.

B. Secondly by dispersion and mixing throughout a large part of the volume of the Laugaland geothermal reservoir.

Thus the injection- and production wells appear not to be directly connected through the fracture-zone, which supplies the major feed-zones of the latter. The analysis discussed below aims at determining the volumes involved in both modes of transport. The volumes involved in mode A are estimated on the basis of the actual tracer test data, such as in Figure 41, while the volumes involved in mode B are estimated on basis of the long-term return of the tracers. Hjartarson (1999) and Liu (1999) also present analyses of the mode A transport at Laugaland.

The data in Figure 41 have been analysed on the basis of a one-dimensional fracture-zone, or flow channel model, where the tracer return is controlled by the distance between injection- and production zones in the corresponding wells, the flow channel volume and dispersion. This model is described by Axelsson et al. (1995) and has been used to simulate tracer test data from several Icelandic geothermal fields. Three separate flow channels are used in the simulation for wells LJ-8 and LN-12 and the results presented in Figure 58. These flow channels are assumed to connect the different feed-zones of the injection- and production wells (see Table 2). The properties of the channels are presented in Table 14.

Table 14. *Model parameters used to simulate fluorescein recovery for the well pair LJ-8/LN-12 at Laugaland.*

Channel length (m)	u (m/s)	$A\phi$ (m^2)	α_L (m)	M_i/M (kg/kg)
300	7.3×10^{-4}	0.098	61	0.0087
500	4.8×10^{-4}	0.53	264	0.0304
1000	1.7×10^{-4}	1.08	62	0.0229
total				0.0620

In the table u denotes the mean flow velocity, A the cross-sectional area, ϕ the porosity and α_L the longitudinal dispersivity of the flow-channel. The variable M_i denotes the calculated mass recovery of tracer through the corresponding channel, until infinite time, while M denotes the total mass of tracer injected. The results in Table 14 indicate that only about 6% of the injected water travels through these channels from injection- to production well. Most of the injected water, therefore, appears to disperse and diffuse throughout the reservoir volume, as already mentioned. The volumes of the channels also appear to be quite small. If one assumes an average porosity of 7% the sum of the volumes of the three channels equals only 20,000 m^3.

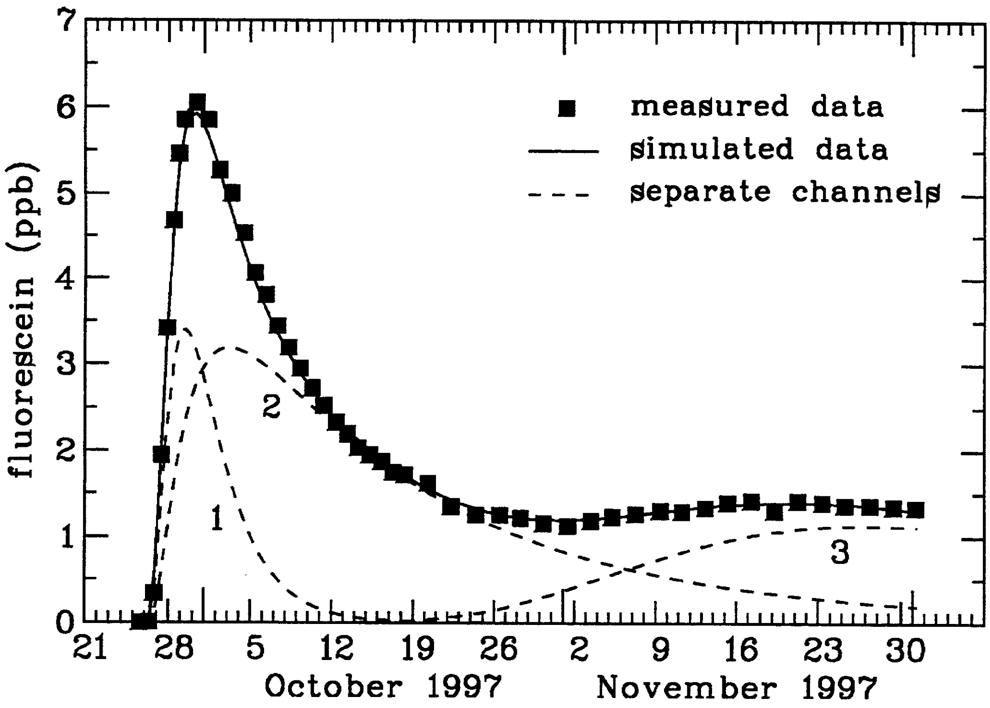


Figure 58. Observed and simulated fluorescein recovery in well LN-12 during the first tracer test. Reinjection into well LJ-8 and production from well LN-12.

The results in Table 14 are the principal results of the analysis of the Laugaland tracer test data. They form the basis for cooling predictions presented later (see section 13.2). It is not possible to interpret the fluorescein recovery data from well LJ-05 in the same manner, because of breaks in production from the well and interference from the other production wells. The fact that the fluorescein is, however, recovered in well LJ-05 at more than twice the rate it is recovered in well LN-12, will be used to enable cooling predictions for well LJ-05 also.

The data from the third tracer test (Figure 42) were also analysed for comparison. The results of this analysis are not presented in detail here, since this data-set was only half as long as the data-set of the first tracer test. This data-set has also been analysed by Liu (2000). The results of the analysis yield approximately the same total volume of flow paths and compareable dispersivity-values. In addition the results in this case indicate that about 5% of the injected water travels through the channels involved, or about 1% less than the analysis of the first tracer test indicates (Table 14). Inspite of a slight difference in the details of the interpretation of these two data-sets, the results indicate that there is not a significant difference in the flow mechanism between injection and production well during 8 and 21 L/s reinjection, respectively. Therefore, the results in Table 14 will be used to calculate cooling prediction, for mode A transport of the injected water (see above), for all reinjection scenarios considered involving well LJ-08.

The observed fluorescein recovery in well TN-4 in the Ytri-Tjarnir field (see Figure 37) was also analysed on basis of the flow-channel model. In this case the part of the data-set, which is clearly related to the tracer injection in September 1997, was analysed. Only a single flow-channel was required. The fluorescein background, which appears to be of the order of 50 ng/L, was subtracted from the data prior to the analysis. This background may be the remnants of the tracer test undertaken in 1991, as already mentioned. The results of the analysis yield a mean flow velocity of $u = 3.5 \times 10^{-5}$ m/s, which equals about 90 m/month, a flow-channel cross-sectional area of $A = 360$ m^2 (assuming a porosity of $\phi = 7\%$), and a dispersivity of $\alpha_L = 97$ m. In addition the calculated relative mass recovery of the fluorescein through this flow-channel, until infinite time, M_i/M equals 7.2%.

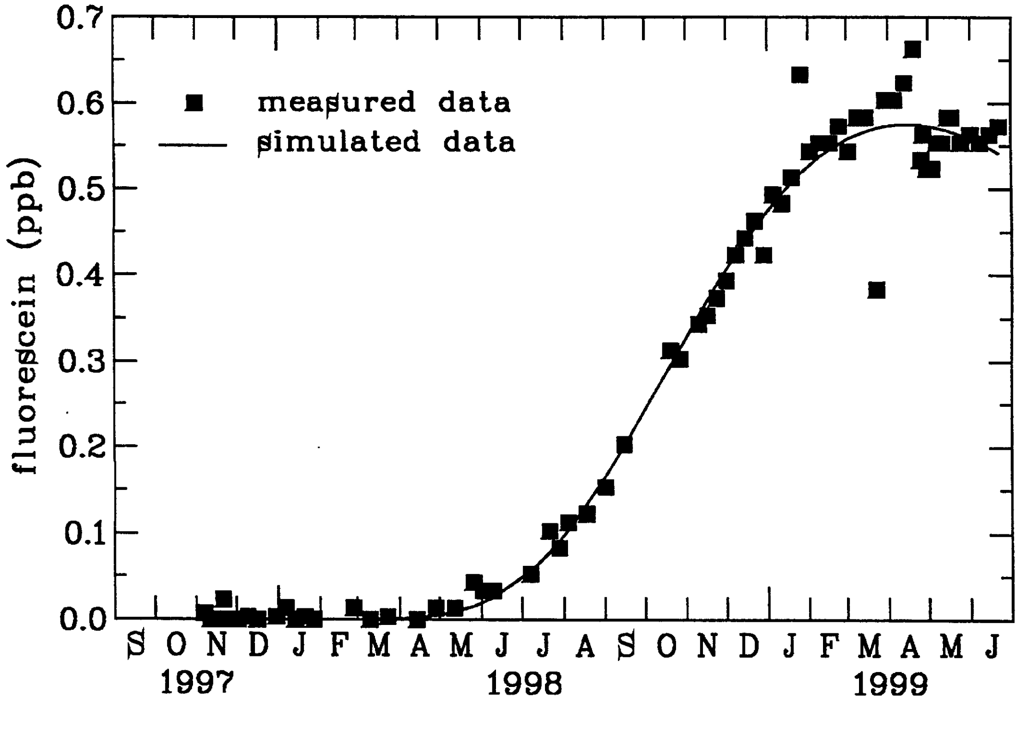


Figure 59. Observed and simulated fluorescein recovery in well TN-04 at Ytri-Tjarnir, 1.8 km north of Laugaland.

This is quite an interesting result. Firstly, because it confirms a direct connection between Laugaland and Ytri-Tjarnir, which previously had been ruled out (see also section 13.1). Secondly, because it provides some quantitative information on this connection. The connection appears to be direct because of relatively low dispersivity (compared to the 1800 m distance between the fields) and small flow-channel volume. If, one one hand, one assumes the flow-channel to be along an interbed, or a fracture-zone, of a few metres thickness, then its average width, or height, is of the order of 100 m. If, on the other hand, the flow-channel is more like a pipe, then its diameter would be of the order of 20 m, only.

If one considers Figure 37, for Ytri-Tjarnir, in detail then the fluorescein concentration in well TN-04 starts to increase again during the summer of 1999, after having stabilised (even decreased). This is believed to be the effect of the second injection of 10 kg of fluorescein in April 1999. At a first glance the speed of the tracer transport does not appear to be comparable for these two cases. The first fluorescein breakthrough occurs after about 7 months, while the second one after about 2.5 – 3 months. This is very simply caused by different injection rates, 8 L/s in the first case but 21 L/s in the latter one, which cause quite different speeds of transport.

Only a fraction of the injected water travels through the flow-channels (volumes) estimated so far, i.e. by mode A transport, as already discussed. Most of it appears to disperse and diffuse through a larger volume of the total reservoir volume. The volume of this sub-part may be estimated very roughly from the long-term return of the tracers. This may be done on the basis of the following equation:

$$c(t) \approx M/(V\phi\rho_w)e^{-(Qt/V\phi\rho w)} \tag{5}$$

where c(t) is again the tracer concentration, M is the mass of tracer injected, V is the volume of the reservoir sub-part, ϕ its porosity, ρ_w the density of the reservoir fluid, Q the production rate (kg/s) and t the time. By plotting ln(c(t)) (natural logarithm) versus Qt, which may be equated with the cumulative production, the long term data should approximately follow a straight line. This is in fact the case for wells LJ-05 and LN-12. The slope of the straight line, consequently, yields an estimate of the product $V\phi$. In the case of the first tracer test an estimate of $V\phi \approx 500{,}000$ m^3 is obtained. It should be emphasised that this is only a very rough estimate. It provides, however, an indication of the very different orders of magnitude involved, the volume involved in the mode A transport being less than 0.3% of the volume involved in the mode B transport.

The tracer test analysis discussed above has focused on recovery of the fluorescein injected into well LJ-08. The recovery of the iodide injected into well LN-10 has not, however, been analysed in detail (see Figure 52). The reason is the complicated production history at the time. Yet it is clear that wells LN-10 and LJ-05 are much more directly connected, than wells LJ-08 and LN-12, as already discussed. Therefore the volumes involved, both in mode A and mode B transfer, must be considerably smaller, and hence the rate of cooling of well LJ-05 due to injection into well LN-10 must be much faster.

Finally it should be mentioned that the results of the analysis presented above should not be looked upon as a unique solution, even though it is considered to be the most likely one. Numerous models have been developed to simulate the transport of contaminats in ground-water systems, and in relation to underground disposal, or storage, of nuclear waste. Many of these models are in fact applicable in the interpretation of tracer tests in geothermal systems. It is often possible to simulate a given data-set by more than one model, therefore a specific model may not be uniquely validated. The transport of solids in fractured rocks and the analysis of tracer tests conducted in fractured geothermal systems are, for example, discussed by Horne (1989), Horne and Rodrigues (1983), Robinson and Tester (1984), Grisak and Pickens (1980) and Neretnieks (1983).

In addition to distance between wells and the volume of flow-paths, mechanical dispersion is the only factor assumed to control the tracer return curves in the interpretation presented above. Retardation of the tracers by diffusion into the rock matrix is neglected (Neretnieks, 1983). Through this effect the chemical used as a tracer diffuses into the rock matrix, when the tracer concentration in the flow path is high. As the concentration in the flow-path decreases, the concentration gradient eventually reverses, causing diffusion from the rock-matrix back into the fracture. This will of course affect the shape of the tracer return curves obtained. In particular, it may cause the flow, through the mode A flow channels discussed above, to be underestimated. Robinson and Tester (1984), on one hand, postulate that matrix diffusion should be negligible in fractured rock. Grisak and Pickens (1980), on the other hand, point out that it may be significant when fracture apertures are small, flow velocities are low and rock porosity is high. This clearly indicates that the great amounts of tracer test data collected during the Laugaland experiment requires further analysis and interpretation, which is beyond the scope of the present work.

8. STABILITY OF THE NA-FLUORESCEIN TRACER

In conjunction with the tracer tests carried out as part of the reinjection project, the stability of the Na-fluorescein tracer in geothermal water from Laugaland system was tested. The behaviour of this tracer compound has not been well established by experiments at lower temperatures (~100°C). It is important to quantify the decay of fluorescein induced by conditions in the path of the geothermal fluid, within the Laugaland system. To simulate these conditions both temperature and water/rock interactions have to be considered, along with other factors known to affect the fluorescence of the tracer. The Na-fluorescein is a water soluble fluorescent dye and is one of the most commonly used tracers in low-temperature geothermal systems (e.g. Gudmundsson *et al.*, 1983; Sabatini and Austin, 1991; Adams and Davis, 1991). Fluorescein is used as a ground water and geothermal tracer because of its low detection limits, ease of analyses and strong colour at low concentrations. Although fluorescein is resistant to biodegradation and is unaffected by variations in water chemistry (Smart and Laidlaw, 1977) it is subject to significant thermal degradation at elevated temperatures. In this experiment the thermal resistance of the Na-fluorescein tracer was tested for temperature up to 100°C as well as adsorption of fluorescein to minerals and alteration products. The experiment was divided into two separate parts for testing these factors, one of which was still ongoing at the time of writing of this report.

8.1. Na-fluorescein stability

In earlier experiments and observations the fluorescence of the tracer is reported to be affected by temperature (Al-Ryami, 1986; Adams and Davis, 1991), salinity (Adams and Davis, 1991), pH (Smart and Laidlaw, 1977; Adams and Davis, 1991; André and Molinari, 1976), background fluorescence (Feuerstein and Selleck, 1963), oxygen (Adams and Davis, 1991) and turbidity and suspended solids (Feuerstein and Selleck, 1963; Sabatini and Austin, 1991; Adams and Davis, 1991).

8.1.1. Temperature

Adams and Davis (1991) conducted experiments to predict the decay rate of fluorescein under conditions found within moderate to high temperature geothermal reservoirs. The results of these experiments indicate that fluorescein behaves as a conservative tracer at temperature below approximately 210°C and will decay less than 10% during a one-month tracer test in such a geothermal reservoir.

Al-Riyami (1986) concluded that fluorescence of Na-fluorescein will be reduced by 50% after 150 hours at 100°C. His experiment was conducted at pH 5-5.5 and any effects of oxygen were ignored, whereas the experiments by Adams and Davis (1991) were carried out at higher pH (6,6 to 8,8) and controlled oxygen levels. The decay of fluorescein at constant pH can be described by a first order rate equation, but at higher temperatures, the thermal decay of the tracer is significant and a correction must be made to account for this degradation (Adams and Davis, 1991).

8.1.2. Salinity

Differences in decay rates due to salinity of the fluid phase have been apparent in high-temperature reservoir-simulation experiments (Adams and Davis, 1991). The effect of salinity on the rate of decay appears to be due to primary salt effect and the decrease in rate with increased salinity implies reaction of the fluorescein compound with a cation in the geothermal fluid. For low-temperature geothermal fluid the salinity does not seem to have a significant effect on the fluorescence of Na-fluorescein.

8.1.3. pH

The Na-fluorescein compound is an anion in solution and therefore thought to be stable under alkalic conditions, pH higher than 7 (Adams and Davis, 1991; Smart and Laidlaw, 1977). As pH decreases, the acid functional groups become protonated and reduce the amount of fluorescence. The change will be instantaneous and directly related to the dissociation constant of the compound, and as pH decreases structural changes occur causing fluorescence to decrease.

8.1.4. Oxygen

Data from experiments that simulated injection conditions show that fluorescein decays rapidly in oxygenated water, but less so at pH higher than 8 (Adams and Davis, 1991). Fluorescein should be injected into a deoxygenated fluid if at all possible.

8.1.5. Adsorption and suspended solids

The presence of suspended sediment raises apparent background fluorescence and reduces effective dye fluorescence because of light absorption and scattering by the sediment particles. According to Smart and Laidlaw (1977) the adsorption of fluorescein onto minerals, clays or organic matter is controlled by their surface charge and pH values. As Na-fluorescein is liable to protonation at higher pH than other dye compounds it has a relatively low resistance to adsorption.

The experiments of Adams and Davis (1991) involved testing the stability of fluorescein in the presence of altered rock. The fluorescein was heated in the presence of the alteration mineral assemblage of quartz, illite, chlorite and epidote, an assemblage common in geothermal systems exceeding temperature of 200 °C. The experiments were conducted at temperatures ranging from 153 to 190°C for 5 – 190 hours. The rate constants observed were within experimental error, indicating no significant adsorption or catalysis.

8.2. Experimental methods and set-up

The two separate parts of the experiment carried out involved Na-fluorescein solutions mixed in a steel tank. In the first part the tank was filled with the fluorescein solution alone but in the latter it contained rock fragments as well, representing the geothermal reservoir of the Laugaland area. This was to imitate the rock/fluid interactions of the reinjected fluid during the tracer tests. The second part of the experiment is ongoing.

8.2.1. Set-up of steel tank

The tank was setup in the cellar of the storage tank in Glerárdalur. This location provided easy access to the geothermal water before it is pumped into the district heating system and is also in the vicinity of HVA headquarters making sampling easy. In designing the tank, the factors affecting the stability of fluorescein described in the previous section, had to be taken into account. This involved the tank to be airtight, purged by N_2 gas on top to keep oxygen out and pressure constant, as water level drops by sampling (Figure 62). The temperature of the solution is kept between 95 to 98°C by a steam heated coil in the tank. The volume of the steel tank is 27.5 L and samples are tapped off through a valve on the lower part of it.

8.2.2. Fluorescein solution

The fluorescein was mixed with geothermal water from the district heating system instead of geothermal fluid from Laugaland wells alone (Table 15). The chemical difference between these fluids is small enough to be ignored as the experiment is an approximation of the conditions in the Laugaland geothermal reservoir.

The Na-fluorescein solution tested in the tank was prepared from a concentrate from the tracer tests carried out earlier in the reinjection project. Stock solution of approximately 2 ppm Na-fluorescein was prepared in a 100 ml bottle, which was emptied into the steel tank. The stock solution of fluorescein was added to the tank when it was about 3/4 full and instantaneously purged by N_2 gas (Figure 63). This was to eliminate oxygen from mixing into the solution and nitrogen gas is then bled into the tank for the duration of the experiment. Immediately after mixing of the Na-fluorescein solution in the tank it was sampled and analysed. The concentration was in the range of the maximum measured during the tracer tests performed, 12.500 ng/L for the previous solution and 10.500 ng/L for the second part of the experiment. An effort was made to measure the concentration of dissolved oxygen in the fluid of part 1, but it was not possible as contamination of atmospheric oxygen could not be ruled out. The oxygen adsorbed to the inside of the tank and to the surface of the rocks in the second part, will be removed by the H_2S in the geothermal fluid during the mixing of the fluorescein solution; oxygen content will, therefore, be minimal.

8.2.3. Rocks and alteration minerals

For the second part of the experiment 8 kg of rock fragments were collected from the ravine of (Munka-) Thvera in Eyjafjordur. The sample is composed of sand and gravel sized, slightly altered, basaltic rocks. The rock type and alteration minerals are representative for the rocks of the Laugaland geothermal system (Table 16).

The rock fragments were placed in the experiment tank and then it was filled with fluorescein solution and sealed as described for the first part of the experiment (Figure 64).

Table 15. *Composition of geothermal water of the district heating system (mg/L).*

Sample	Part 1	Part 2
Date	*09.12.1998*	*14.10.1999*
Number	*19980636*	*19990376*
Temperature	75.3	74.7
pH/T°C	9.87	9.84/21.3
CO_2	17.6	17.8
H_2S	<0.03	-
B	0.20	0.18
Conductivity	247	282
SiO_2	86.7	89.2
O_2	0	0
δD	-98.5	-
δO^{18}	-13.67	-
Na	53.1	52.3
K	0.891	1.01
Mg	0.006	0.004
Ca	3.26	3.37
F	0.46	0.45
Cl	12.0	12.4
SO_4	47.2	43.5
Al	0.10	0.13
Mn	0.0003	0.0003
Fe	0.063	0.0052

- : not measured

Table 16. *Rock types and alteration minerals of selected samples from (Munka-) Thvera ravine.*

Sample	Rock type	Alteration mineral
32920	(olivine) tholeiite basalt	mordenite
32921	(olivine) tholeiite basalt	mordenite/heulandite
32922	(olivine) tholeiite basalt	smectite
32923	plagioclase porphyritic basalt	thomsonite/chabazite
32924	vesiculated basalt	heulandite

8.2.4. Sampling and analysis

The fluorescein was analysed by a Perkin Elmer 204S Spectrophotometer within 7 days of sampling (Benjaminsson, 1984).

Aqueous fluorescein has a maximum excitation wavelength of 490 nm and a maximum emission wavelength of 520 nm at neutral pH. Although temperature and salinity have little effect on its fluorescence, pH does have a strong, but reversible, effect on the peak intensity at pH values below 7 (André and Molinari, 1976). In addition, prolonged exposure to ultraviolet light irreversibly reduces its fluorescence.

Sampling was conducted in the same manner for both parts of the experiment, as frequently as twice a week in the beginning, and the reduced to every 2-4 weeks for the remainder of the experiment. Untreated samples were collected in 60 mL brown glass bottles and kept in a dark place until they were analysed. The bottle was rinsed three times and filled up to minimise the affects of atmospheric oxygen.

8.3. Results

Figure 60 shows the results of fluorescein analyses for the first part of the experiment, which was set up December 9th 1998. The concentration of Na-fluorescein remained constant for up to five months and then suddenly the measured fluorescence increased. This is the result of steam escaping through the joint where the lid is bolted on top of the tank. The tank had been moved during construction in the cellar and the loss of steam was responsible for the Na-fluorescein becoming concentrated in the tank. The leakage was small and did not result in lower pressure within the tank, but as it persisted it resulted in loss of all fluid from the tank, making further sampling impossible. For the duration of at least five months, however, the fluorescence concentration was within what can be expected by analytical variation.

The second test of this experiment started on October 14th 1999. Rocks representing the rocks of the geothermal system of Laugaland were put in the experimental tank along with the Na-fluorescein solution. During the set-up much effort was put into sealing the lid on top of the tank to prevent any leakage. The lid was equipped with an o-ring and then bolted on top of the tank. Otherwise was the set-up carried out was as before. Figure 61 shows the results of Na-fluorescein analyses for the first three months of the second part of the experiment. The variation of fluorescein concentration is not significant for the three months the experiment had lasted at the time of writing this.

The fluorescein tracer mixed into the geothermal water from Eyjafjordur area does not show any signs of breaking down at the experimental conditions. The factors that most strongly affect the fluorescence of fluorescein in solution, ultraviolet light, oxygen and temperatures over 200°C were eliminated from the experimental tank. Temperature of up to 100°C alone does not result in measurable breakdown of the fluorescein compound and the ongoing second part of the experiment shows that the alteration minerals in the basaltic rocks do not adsorb the compound to any extent. The pH of the solution is very favourable to the Na-fluorescein stability.

It is concluded that the recovery of Na-fluorescein during the tracer tests of the reinjection project has not been affected by the temperature or any other physical or chemical conditions tested in this experiment.

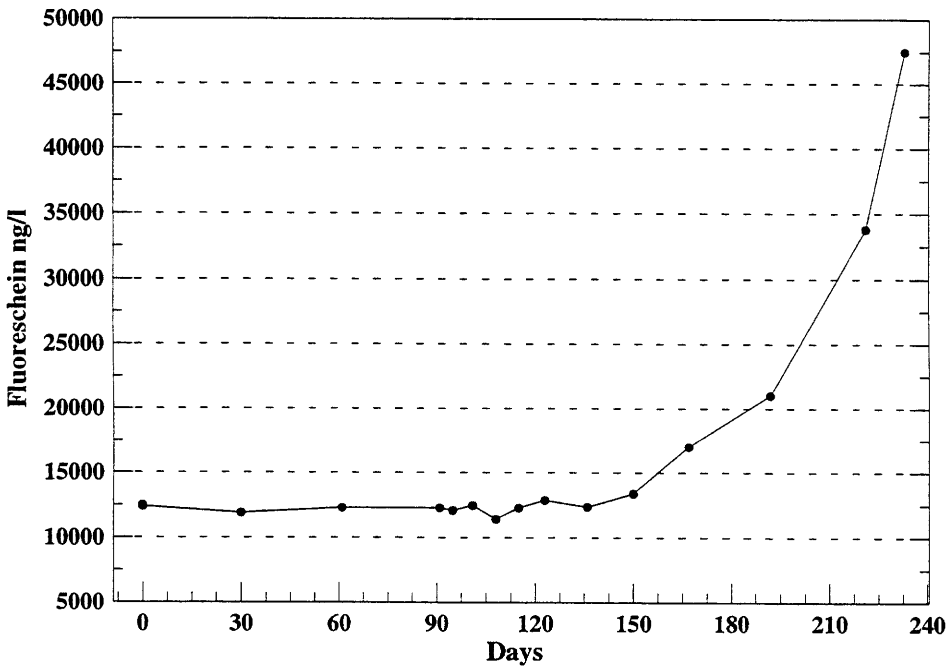


Figure 60. Results of Na-fluorescein analyses for the first part.

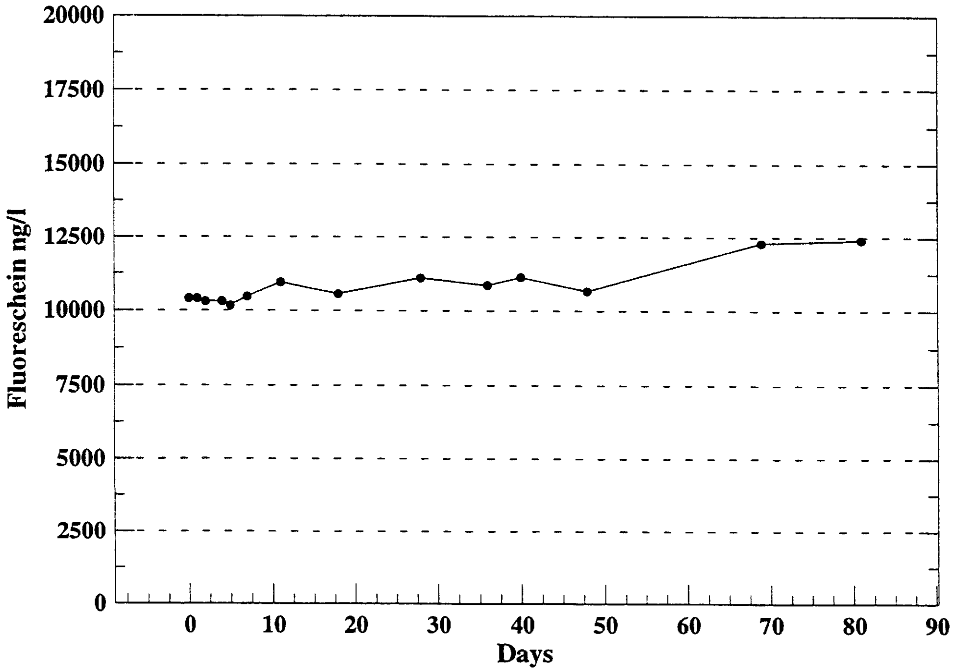


Figure 61. Results of Na-fluorescein analyses for the second part.

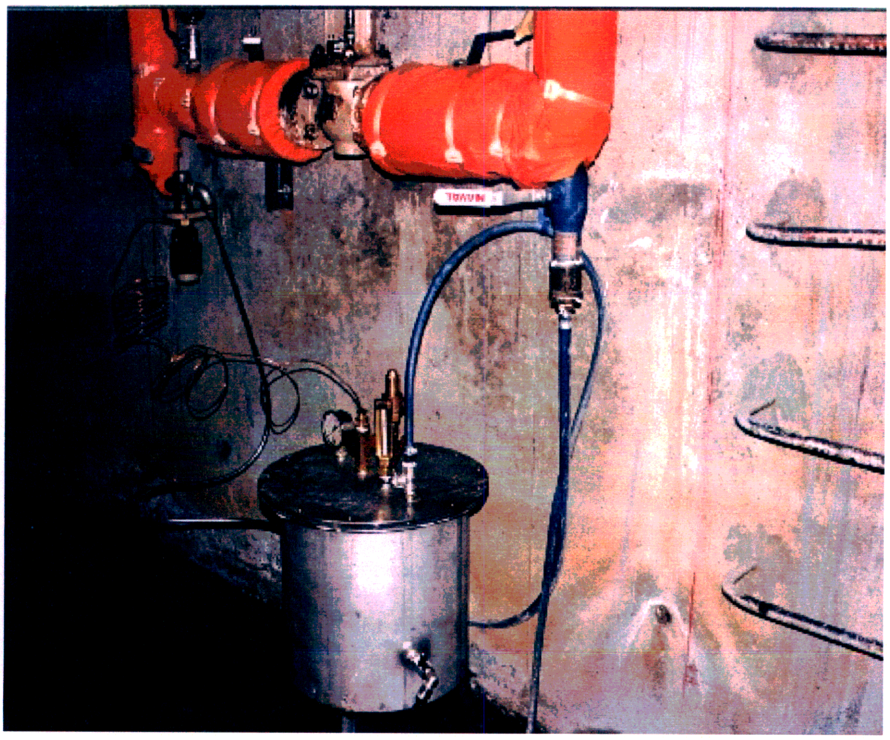


Figure 62. The steel tank located where the experiment was carried out, equipped with thermometer and a pressure gauge on top and a tap on the bottom side.

Figure 63. Concentrated Na-fluorescein soulution being added to the geothermal water in the tank, while purged of oxygen by N_2 gas flow.

Figure 64. Rock fragments in the experiment tank. The photograph shows where steam is led into the coil within the tank.

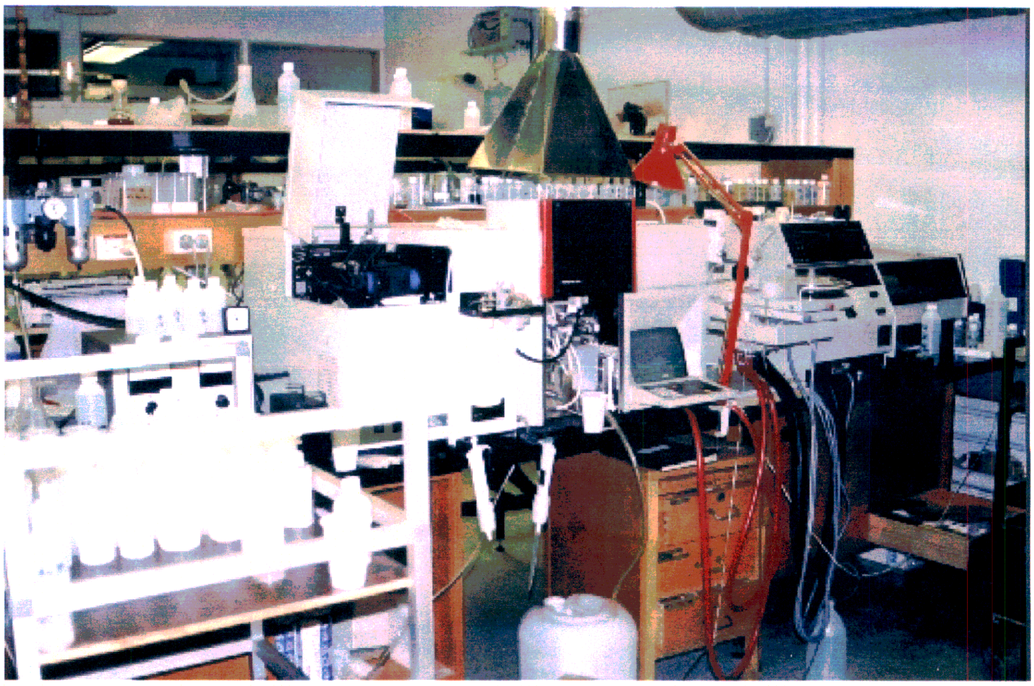


Figure 65. The Perkin Elmer Atomic Absorption Spectrometer at the geochemistry laboratory of Orkustofnun.

9. WATER TEMPERATURE CHANGES

One of the principal dangers associated with injection of colder water, such as return water, into geothermal systems is the danger of premature thermal breakthrough and rapid cooling in production wells (Stefansson, 1997). The purpose of the tracer tests discussed in chapter 7 was to try to quantify this danger. In order to detect any changes in temperature of water produced from the production wells, which might occur during the two-year experiment, great emphasis was placed on continuous monitoring of the temperature, through the computerised monitoring system. Beforehand, any such changes were expected to be quite small, if any. Great accuracy in the measurements was, therefore, required, or of the order of 0.1°C. This is quite difficult at temperatures close to 100°C. The results of the measurements for both of wells LJ-05 and LN-12 are presented in Figure 66, which shows the weekly average water temperature for the wells those weeks they were on-line. Technical difficulties with the water temperature measurements by the computerised monitoring system were, however, experienced during the first two months of the project. Thus no data are presented until the middle of November 1997.

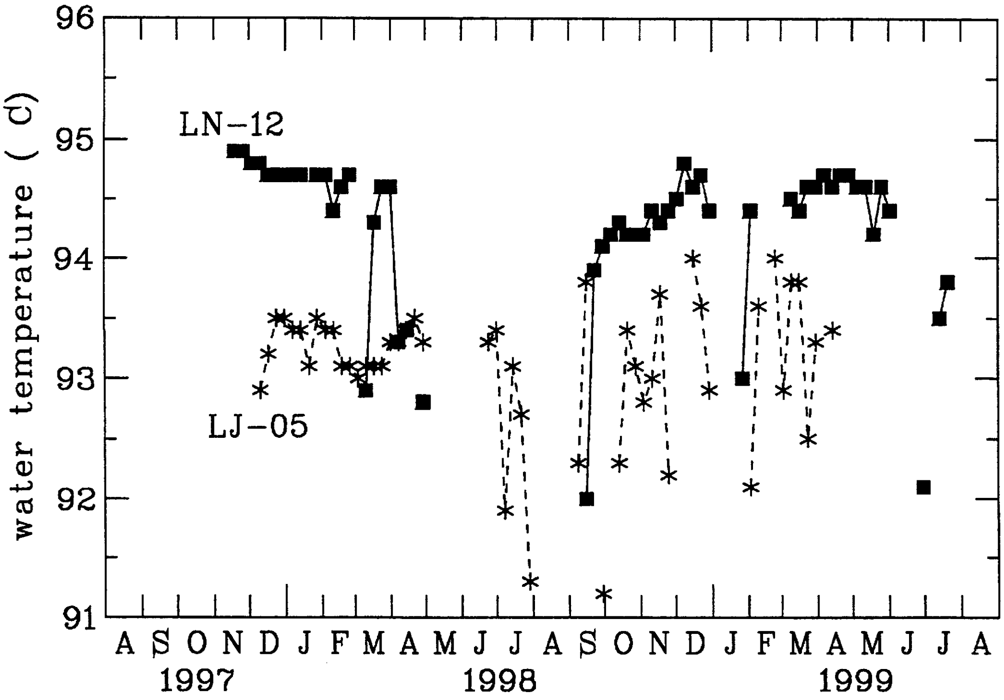


Figure 66. Weekly average temperature of water produced from wells LJ-05 and LN-12 at Laugaland according to the computerised monitoring system.

The figure shows considerable variations in the measured temperature. Therefore, small changes (0.1 - 0.2°C) are quite difficult to detect. The variations are caused by:

(i) small variations in flow-rate,

(ii) cooling of the wells during breaks in production and

(iii) the influence of other production wells.

Water flowing up a geothermal borehole will cool down slightly through heat-flow to the cooler surroundings of the well. When the flow decreases (increases) this cooling becomes relatively greater (smaller). Cooling of the wells during breaks occurs because of conductive cooling of the surrounding rocks and because of internal flow from relatively colder feed-zones down to hotter ones. When other production wells are also on line they cause the relative inflow from different feed-zones to change and thereby the water temperature. The flow from a given production well will also decrease slightly when another well is on-line, thereby causing a drop in temperature according to item (i) above.

To try to determine whether any temperature changes have occurred we can for example compare the highest temperatures measured during different periods (Figure 66). Based on this the temperature does not seem to have declined for either well. For well LJ-05 the highest temperature during the winter of 1998/1999 is even higher than the highest temperature during the winter of 1997/1998. It must be kept in mind, however, that the variations in the weekly average temperature for well LJ-05 are considerable during the project period, or of the order of 2°C.

It is worth noting in the case of well LN-12 that it takes the well a long time to recover in temperature following the summer break during 1998 (Figure 66). According to the operators of the Laugaland field this took unusually long. It is possible that this may be an effect of the reinjection through cooling of a shallow feed-zone in the well (Table 2). This in turn causes the slow recovery of the well because of internal flow from the shallow feed-zone down to the main feed-zones of the well. The decline in the water temperature of well LN-12 during November/December 1997 is believed to result from the fact that well LJ-05 was put on-line at that time (see item (iii) above).

The average measured water temperature of wells LJ-05 and LN-12, during 1994 – 1997, was 93.4 ± 0.9°C and 95.9 ± 0.1°C, respectively. The much higher standard deviation for well LJ-05 reflects greater temperature variations for that well. If we compare these averages with the weekly averages in Figure 66 we conclude that the water temperature of well LJ-05 does not seem to have declined. The temperature of well LN-12 does seem to have declined considerably, however. A large part of this apparent temperature drop is because of a slight measurement discrepancy. This is evident from Figure 67 which shows a comparison between the measurements of the computerised monitoring system and reference measurement made by HVA. The latter were made by a carefully calibrated electronic temperature sensor. The figure shows that this discrepancy is about 0.5 – 1.0 °C.

Based on these results it can, in fact, not be asserted whether any temperature changes have occurred in the production wells at Laugaland, which may be attributed to the reinjection. This is because any changes that may have occurred should be small, or of the order of a few tenths of a degree, and are therefore obscured by other variations (of the order of 1 – 2 °C) discussed above as well as slight measurement discrepancies. It can be stated, however, that the reinjection at Laugaland has not caused a temperature decline greater than 0.5°C, during the two-year experiment.

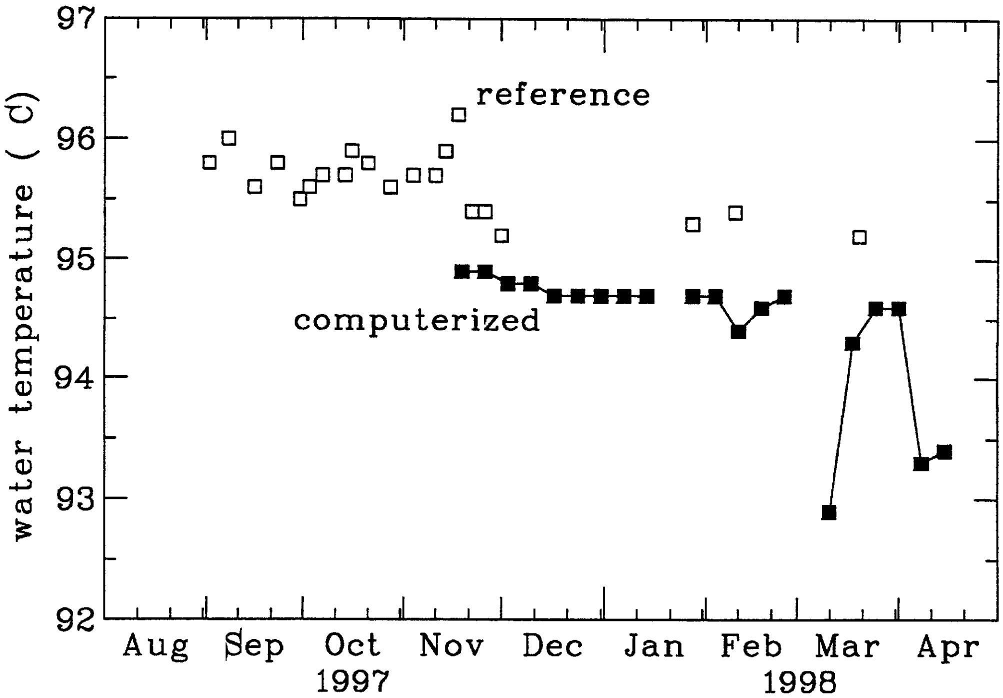


Figure 67. Comparison of average weekly water temperature measurements by the computerised monitoring system for well LN-12 and reference measurements made by HVA.

10. CHEMICAL MONITORING

A significant part of the reinjection project has involved chemical monitoring of the geothermal water pumped from production wells in the Laugaland area, selected nearby areas and of the return water reinjected. This has included regular sampling and analysis of selected elements. The main aim of the chemical monitoring is to detect whether some precipitation of secondary minerals, or cooling in the geothermal system, is induced by the reinjection.

10.1. Chemistry of injected water

On first consideration it would seem possible to use local groundwater for the injection. This idea was soon rejected, because severe problems of magnesium-silicate precipitation have been experienced elsewhere by mixing of geothermal water and the relatively Mg-rich Icelandic groundwater (Kristmannsdottir *et al.* 1989; Sverrisdottir *et al.* 1992). Such deposition might cause the injection wells and its feed zones to clog up and probably cause serious problems for the production from the geothermal system. This was later confirmed by observations and model calculations, for the geothermal water in the area, carried out by Bi (1998).

Table 17. *Chemical composition of the return water (mg/L).*

Date	03.04.1997 A	03.04.1997 B	18.02.1998 Mixed
Temp. (°C)	26.5	25.0	19.9
pH/°C	9.83/20.5	9.83/20.5	9.82/21.9
CO_2	21.2	22.0	19.4
H_2S	<0.03	<0.03	0.09
SiO_2	88.6	94.4	95.3
Na	53.0	53.1	55.3
K	0.96	1.00	0.99
Ca	3.15	2.82	2.96
Mg	<0.001	<0.001	0.002
SO_4	39.7	35.7	37.5
F	0.44	0.49	0.45
Cl	13.5	12.7	12.9
B	0.16	0.17	0.18
O_2	0	0	0.01

Using return water from the district space heating system appeared to be the best choice because its chemical composition is almost identical to the Laugaland geothermal water. Although originally produced from five separate geothermal systems, the difference in water chemistry is very small. The chemical composition of three samples from the return water is shown in Table 17. Two samples are from two separate parts of the domestic heating system respectively (A and B); they are mixed before injection. These samples were taken before the reinjection program started but the third sample is taken a year after the project started. This sample is from the mixed return water after it has been piped 13 km from the town of Akureyri to the Laugaland area. The earlier samples of return water were analysed for major elements as well as for various organic solvents, heavy metals and other elements which the water could plausibly assimilate from the heating system. No such chemicals were found in significant amounts.

10.2. Monitoring of the production wells

The monitoring conducted in the Laugaland geothermal area before the reinjection project started included sampling of all production wells for major and minor chemical analyses once a year and sampling for analyses of selected elements three times a year. Water temperature and conductivity of the geothermal fluid were measured once a week. Even small changes in the concentration of these elements would give an indication of changes in the geothermal system. At the start of injection, samples of water from production wells in Laugaland and the return water were collected daily and analysed for Si, Cl, Ca, K and conductivity. The sampling frequency was increased to twice a day simultaneous to the tracer tests carried out (see chapter 7); the Na-fluorescein ones in September 1997 and May 1999, and the potassium-iodide one in February 1998. As the preliminary results from the first tracer test were acknowledged, a decision was made to sample the water from TN-4 and to a lesser extent the water from Botn and Gryta geothermal areas (Figure 1). Shortly after each of the tracer tests, sampling frequency was decreased and in September 1999 sampling for the selected elements was discontinued. Since then chemical monitoring of the areas has been conducted as before the reinjection project started.

No lasting chemical changes are observed in geothermal fluids of the Laugaland system or nearby geothermal fields during the reinjection experiment in the Laugaland geothermal reservoir (Sverrisdottir *et al.*, 1999). Neither the down-pumping of a considerable amount of return water from the district heating system, nor the injection of two different chemical tracers seems to have affected the chemical properties of the thermal water. Consequently, no deposition is expected to occur in the reservoir during reinjection. This supports the contention that return water from the space heating system is the most appropriate fluid for reinjection, at least in the Laugaland system.

The following sections report the results of analyses for each of the wells sampled during the project and the return water.

10.2.1. Laugaland

The major element composition of the Laugaland geothermal water, prior to injection, was established by sampling and analysis of water from LN-12, the production well at that time. The results of the analysis of this sample and samples for major analyses collected since from the well are presented in Table 18. No significant changes in the water chemistry are detected.

Figures 68 through 72 show the concentrations of SiO_2, Ca, K, Cl and conductivity of the geothermal fluid of LN-12 as a function of time. The variation observed is less than expected for most of the elements in relation to the production of the well. Samples for chemical analyses were collected in conjunction with tracer sampling and this included sampling shortly after the well pump was restarted. This can be observed by variation of SiO_2 and conductivity (Figures 68 through 72) in relation to changes or discontinuity of production in the area.

Table 18. *Chemical composition of the geothermal fluid from LN-12 (mg/L).*

Date	08.09.1997	18.02.1998	06.04.1999
Temp. (°C)	95.8	94.9	95.7
pH/°C	9.76/21.9	9.79/21.7	9.76/21.6
CO_2	18.2	19.0	21.5
H_2S	0.08	0.10	0.09
SiO_2	99.2	97.3	99.2
Na	50.8	54.0	50.2
K	1.11	1.16	1.05
Ca	2.91	3.00	2.85
Mg	0.004	0.001	0.003
SO_4	37.9	39.2	39.1
F	0.37	0.30	0.43
Cl	11.6	11.6	11.7
B	0.16	0.16	0.18
O_2	0	0	0

Changes in production of the well affects the composition of the water, as there is slight chemical difference of the geothermal fluid between different feeding zones within the well. An increase in potassium concentration in February 1998 (Figure 70) can only be attributed to the injection of the potassium iodide tracer in well LN-10. This increase amounted to up to 10% of the potassium concentration and this can be observed in all the production wells of the Laugaland geothermal area (Figures 70, 75 and 80).

Samples were collected less frequently from well LJ-7 and Figures 73 to 77 show the variation of selected elements from all samples collected in the years 1997, 1998 and 1999. No lasting changes are observed but silica and conductivity are more sensitive to changes in production.

The results of analyses of samples from the production well LJ-5 are plotted in Figures 78 to 82. The same trend regarding chemical variation is observed, as for the other two wells described above, except for the chlorine content. The casing in well LJ-5 extends only 96 m depth and this appears to result in more chemical variation induced by production of the area.

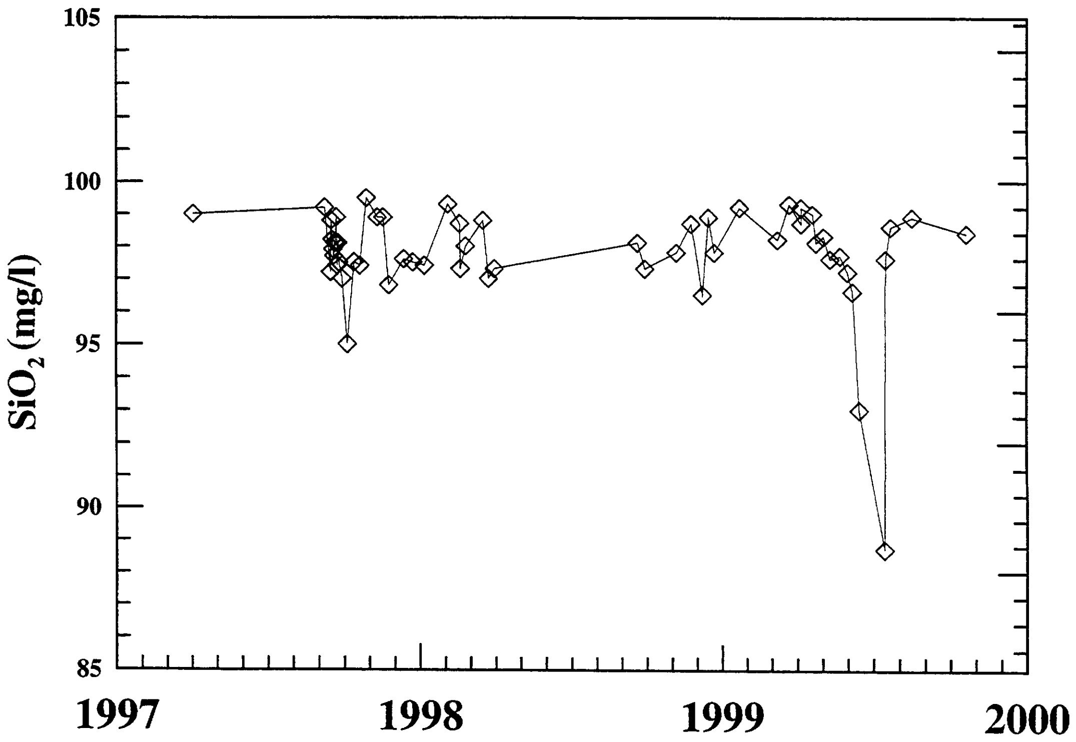


Figure 68. SiO_2 concentration of geothermal water from well LN-12.

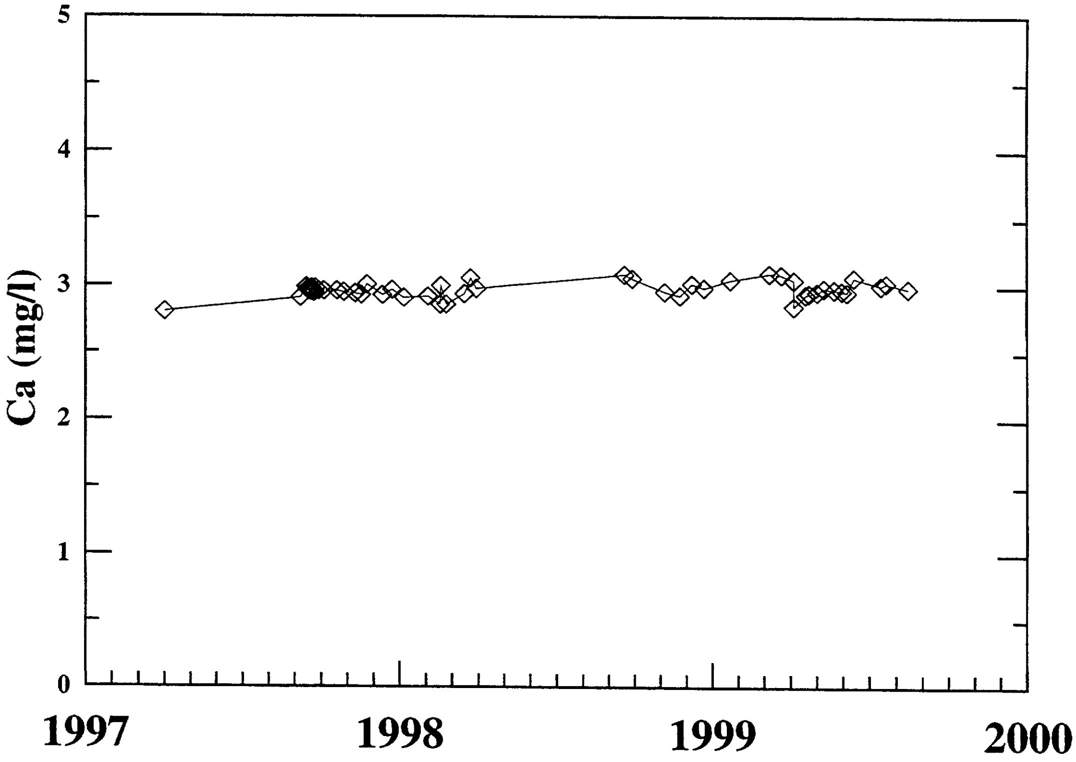


Figure 69. Ca concentration of geothermal water from well LN-12.

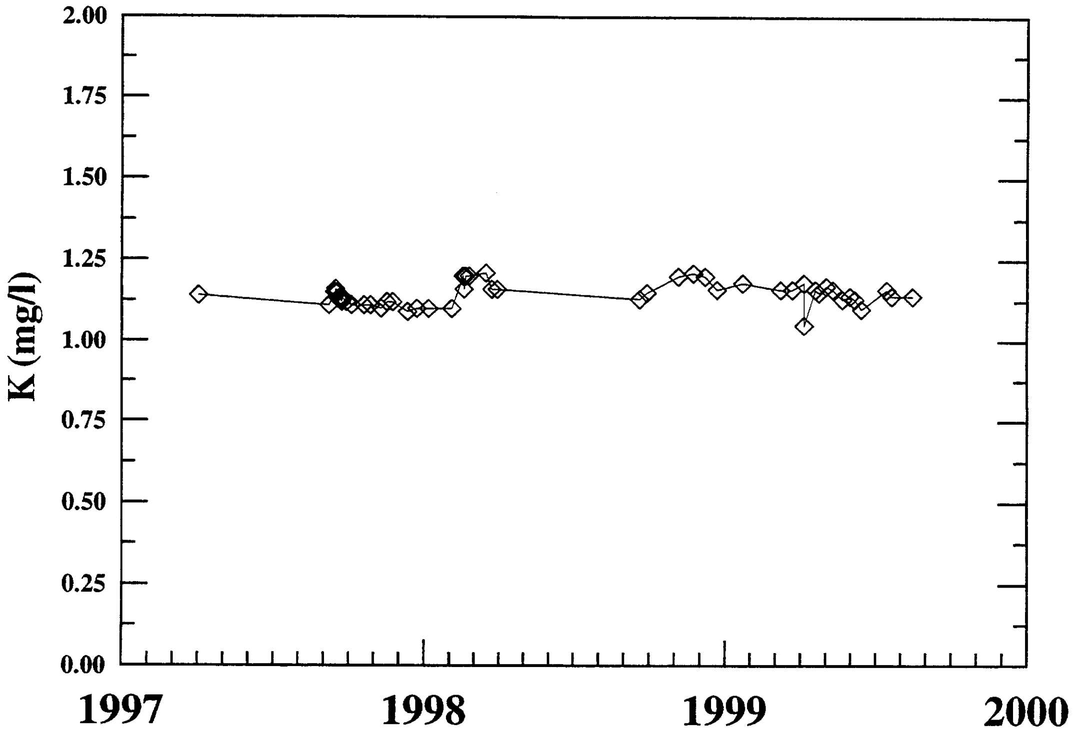


Figure 70. K concentration of geothermal water from well LN-12.

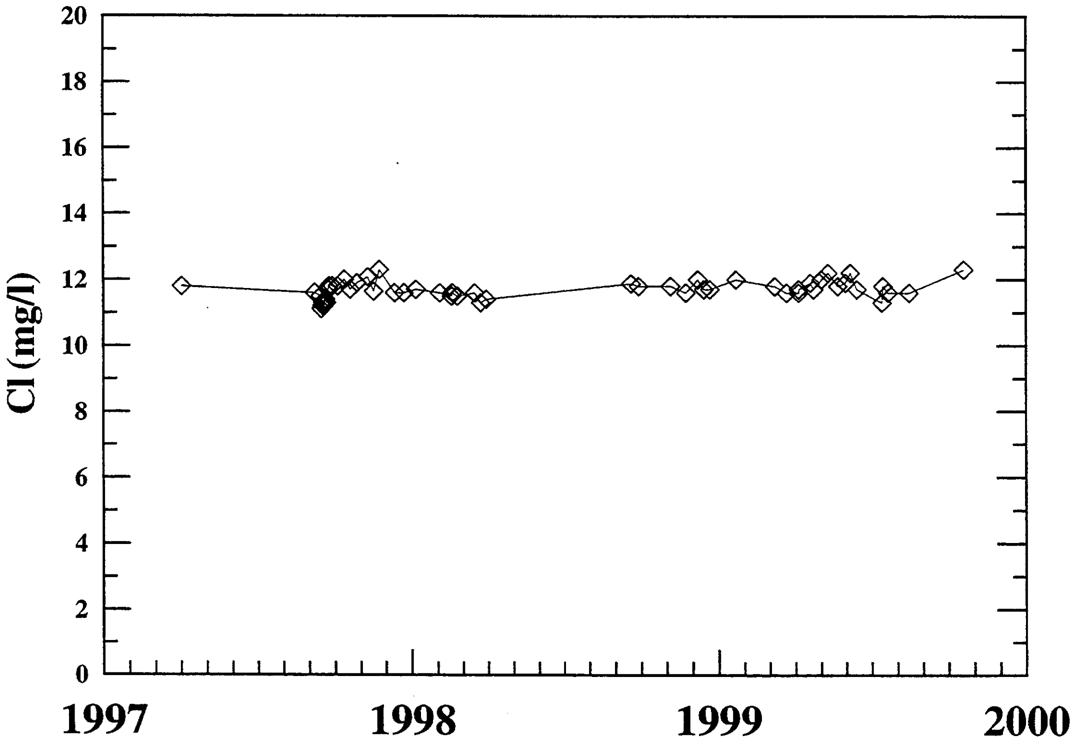


Figure 71. Cl concentration of geothermal water from well LN-12.

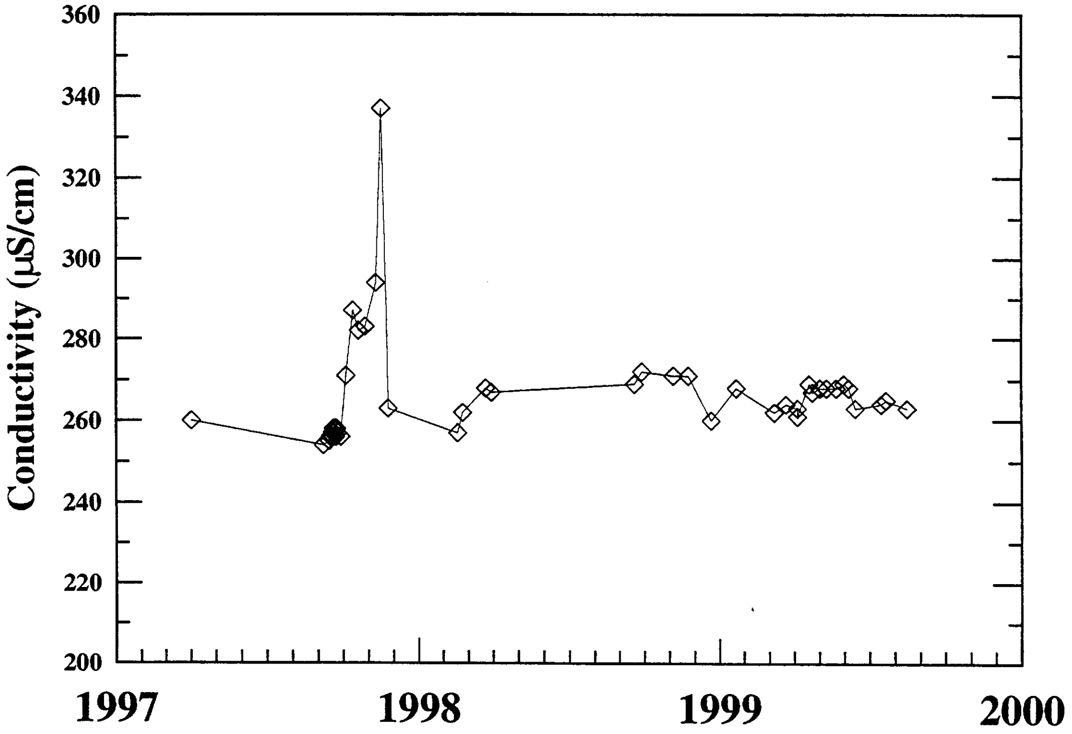


Figure 72. Conductivity of geothermal water from well LN-12.

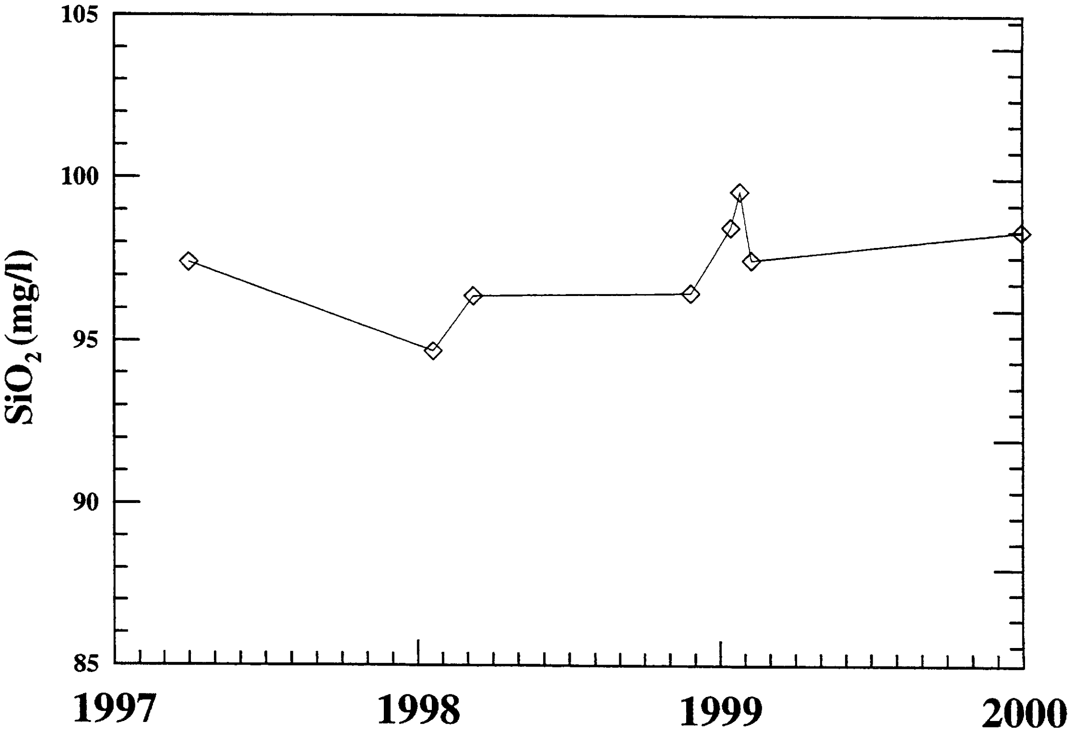


Figure 73. SiO_2 concentration of geothermal water from well LJ-7.

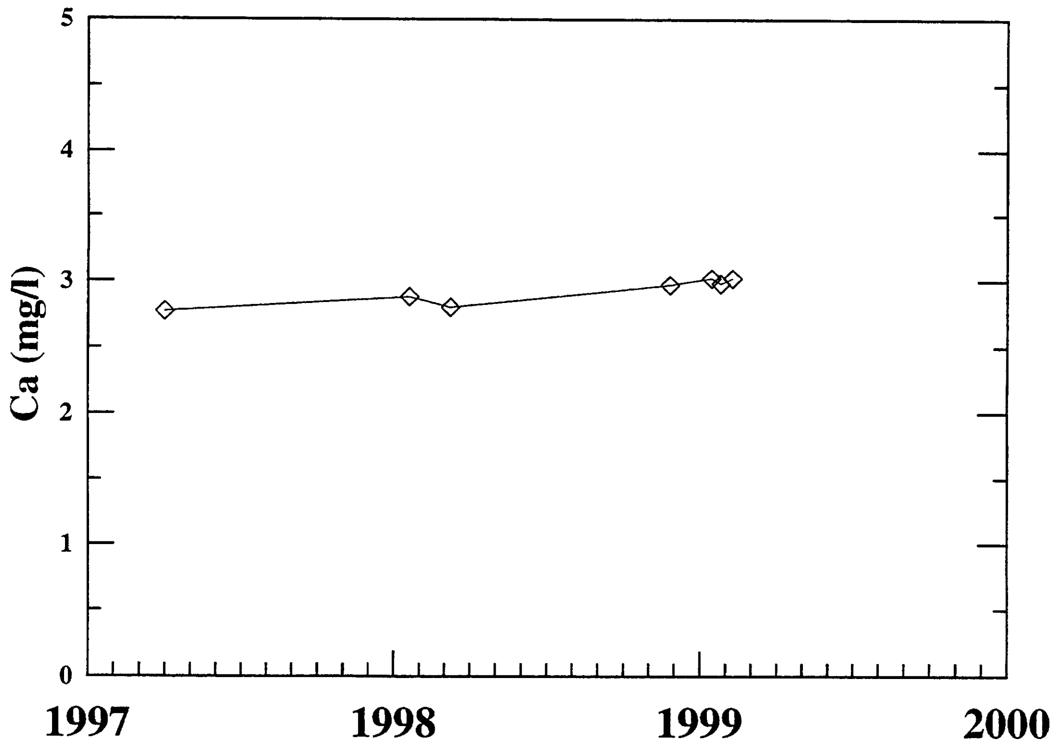


Figure 74. Ca concentration of geothermal water from well LJ-7.

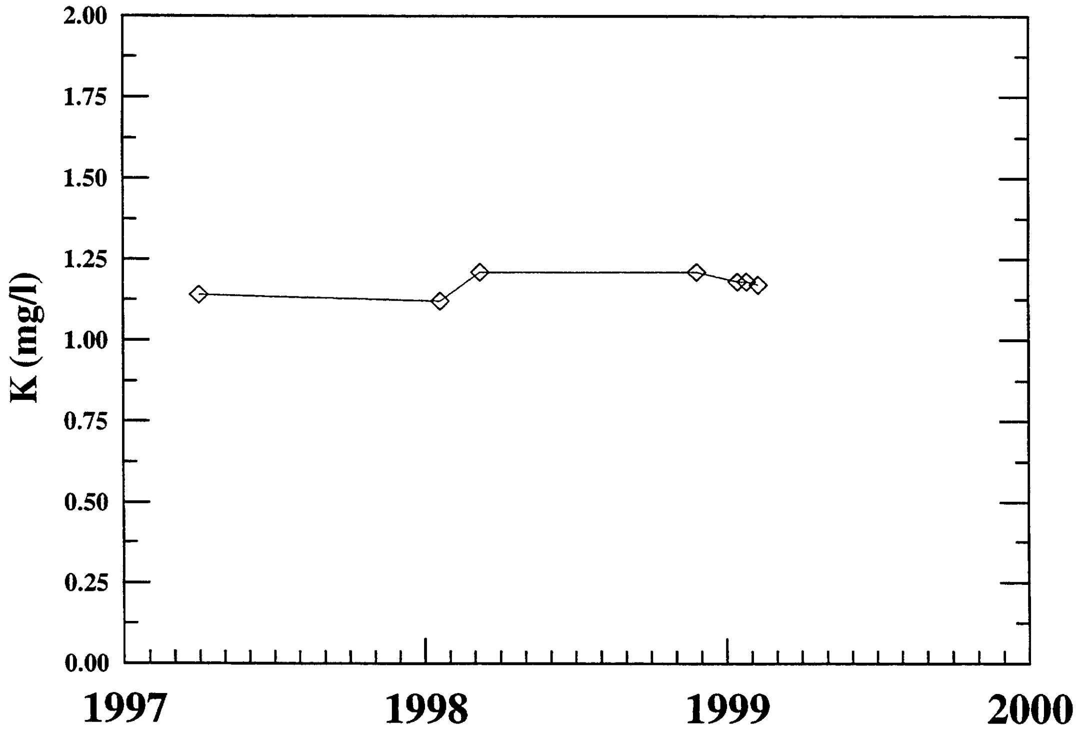


Figure 75. K concentration of geothermal water from well LJ-7.

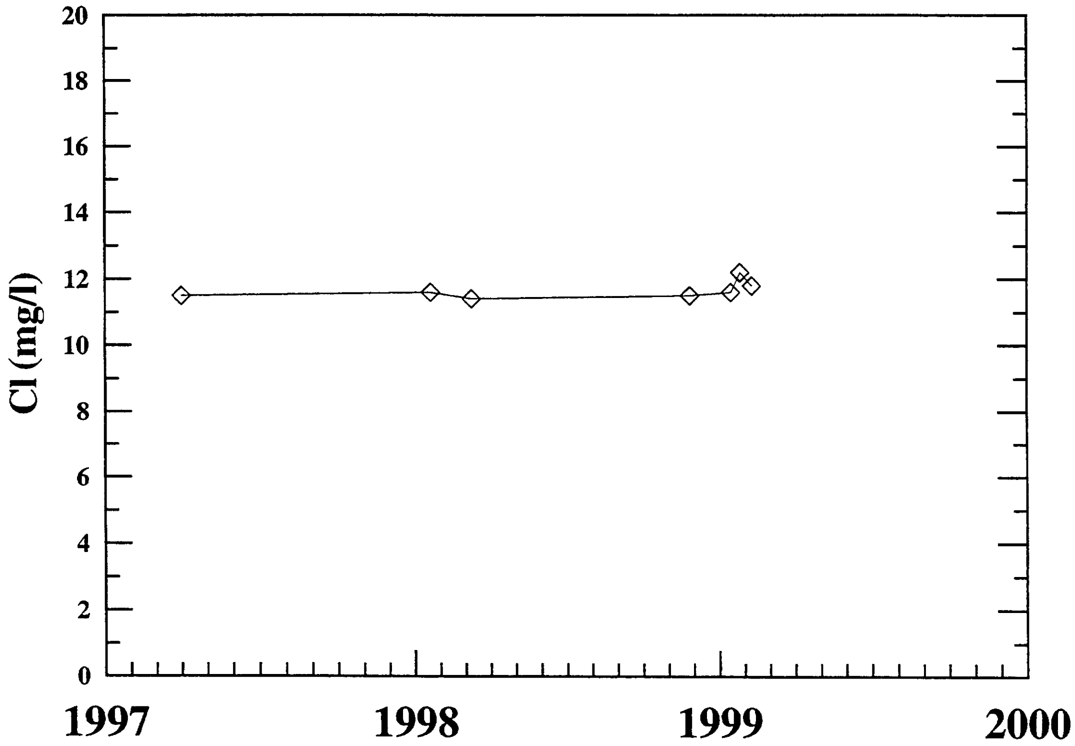


Figure 76. Cl concentration of geothermal water from well LJ-7.

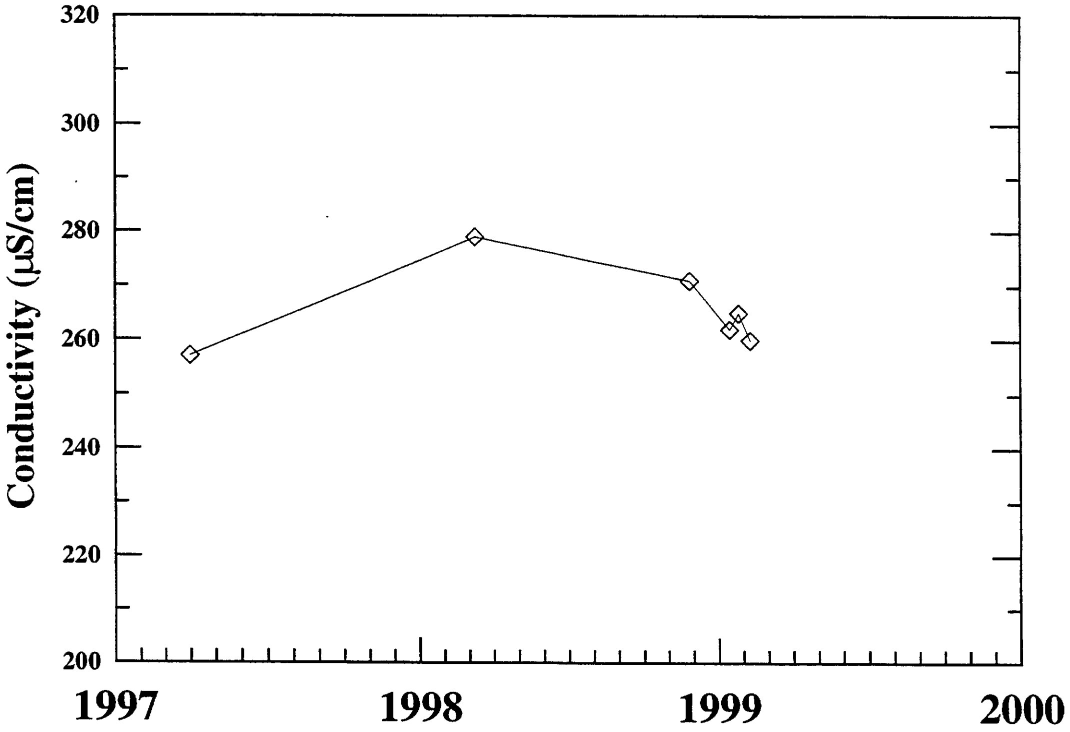


Figure 77. Conductivity of geothermal water from well LJ-7.

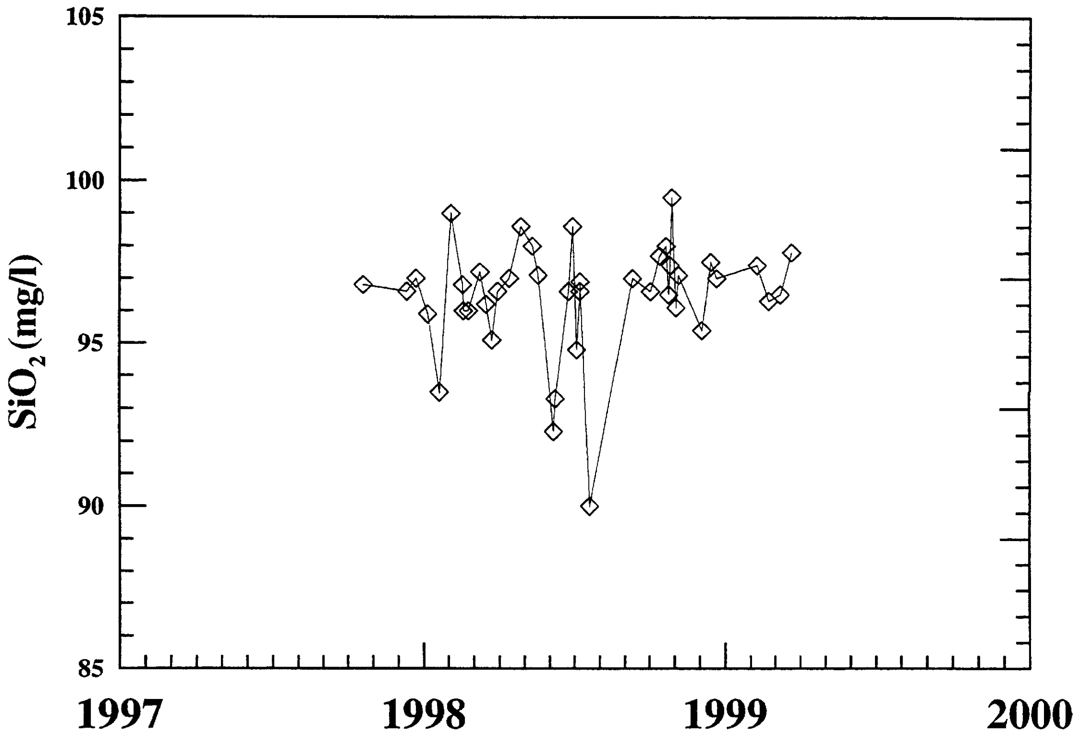


Figure 78. SiO_2 concentration of geothermal water from well LJ-5.

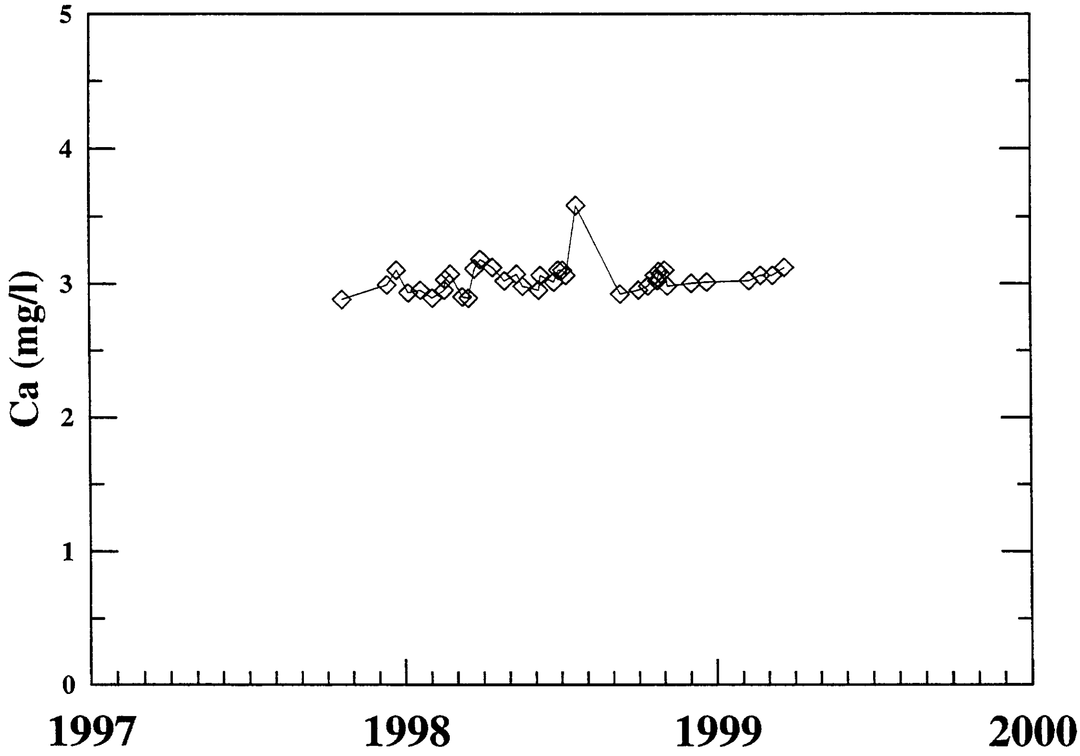


Figure 79. Ca concentration of geothermal water from well LJ-5.

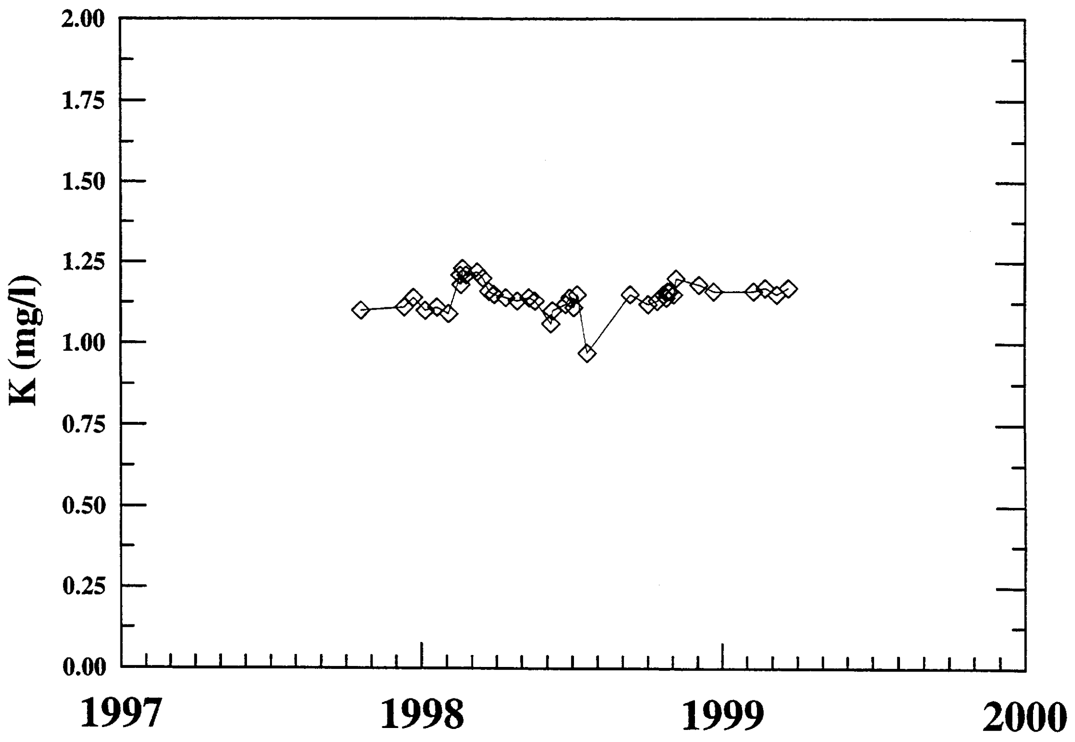


Figure 80. K concentration of geothermal water from well LJ-5.

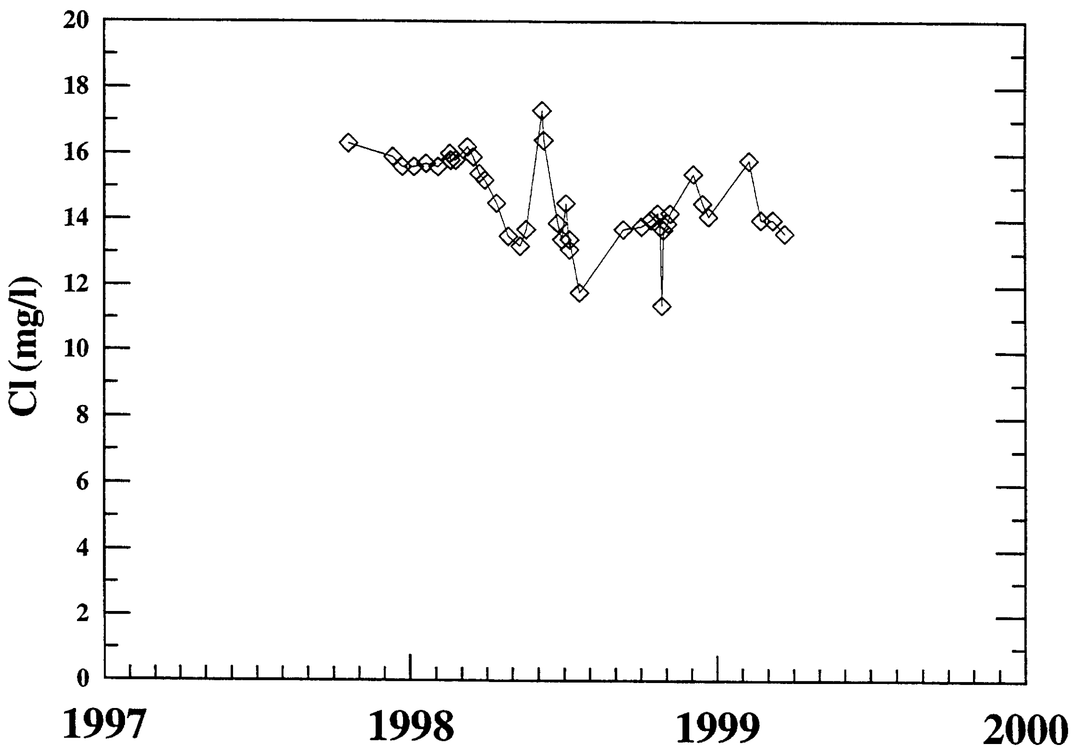


Figure 81. Cl concentration of geothermal water from well LJ-5.

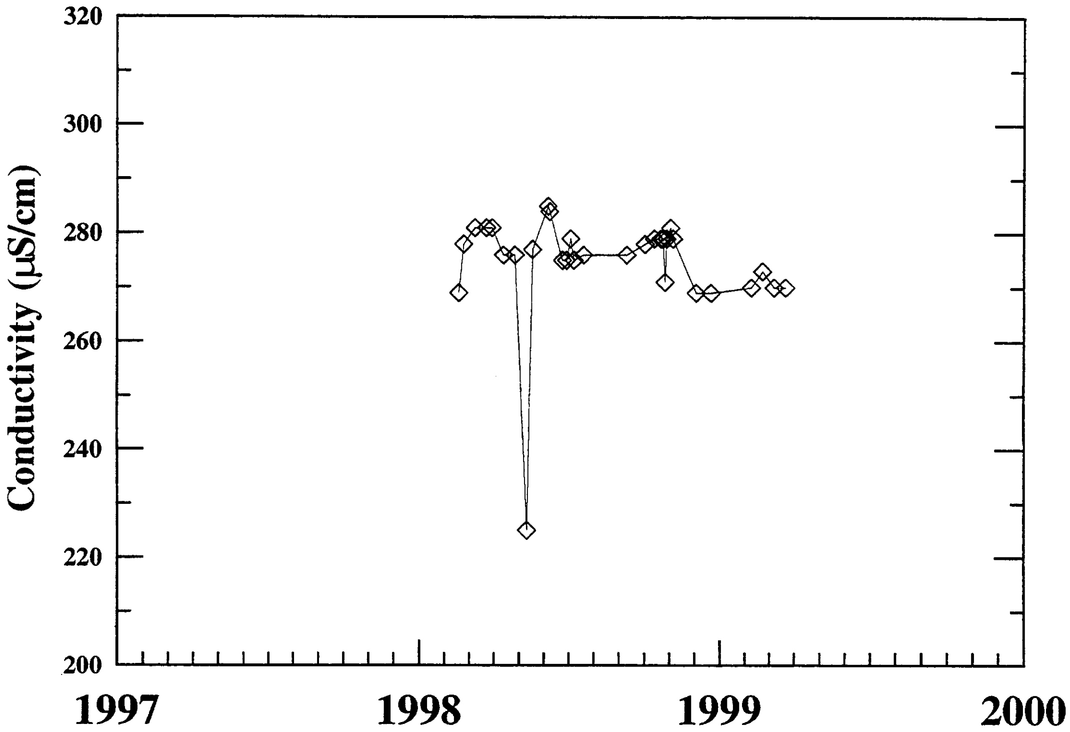


Figure 82. Conductivity of geothermal water from well LJ-5.

10.2.2. Ytri-Tjarnir

Sampling of water from TN-4 at Ytri-Tjarnir started simultaneously with the second tracer test. The first test had revealed a direct connection between the fields of Ytri-Tjarnir and Laugaland. Sampling was performed in the same manner as for the Laugaland wells and element concentration as function of time is shown in Figures 83 through 87. The chemical composition of the water from TN-4 has not changed during the time of the reinjection test as variations observed do not exceed those observed during geochemical monitoring in recent years (Axelsson *et al.* 1998).

10.3. Monitoring of the return water

Figures 88 to 92 show the chemical variations of the selected constituents in the injected return water. No significant changes can be observed in the concentration of these elements in the return water but the variations are more than in the fluid from the production wells. This is a result of mixing of water from the five production fields in various ratios within the district-heating system of Akureyri. Figures 88 and 92 show how the silica concentration and conductivity changed with time and the variations induced by production.

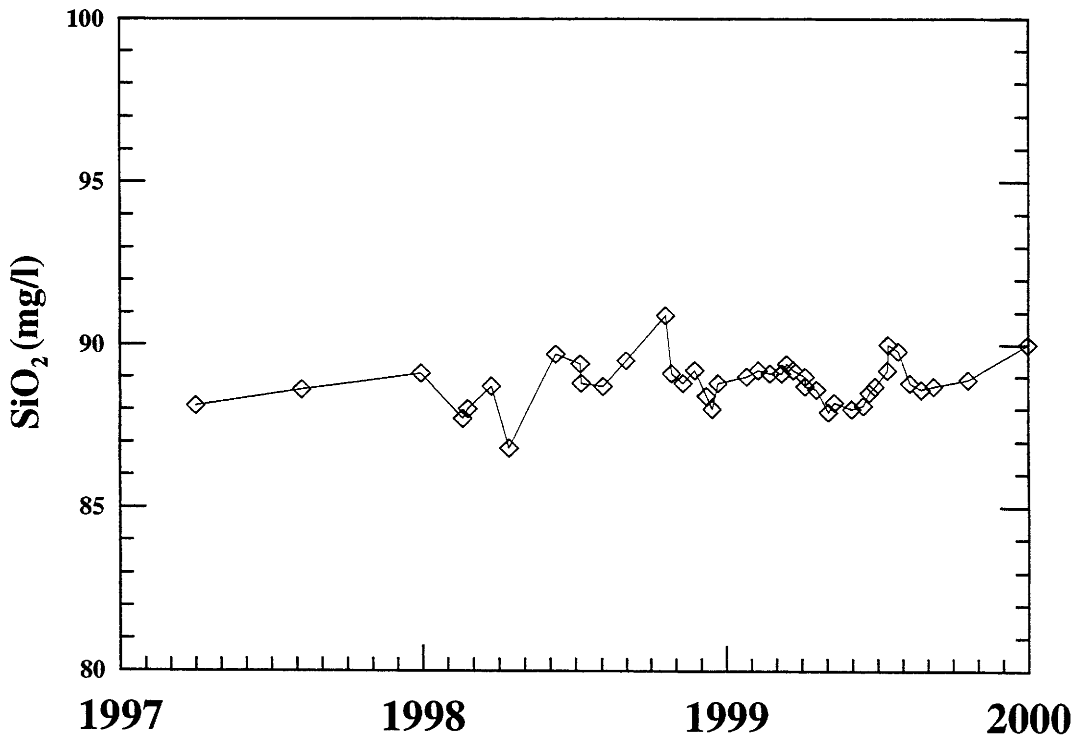


Figure 83. SiO_2 concentration of geothermal water from well TN-4.

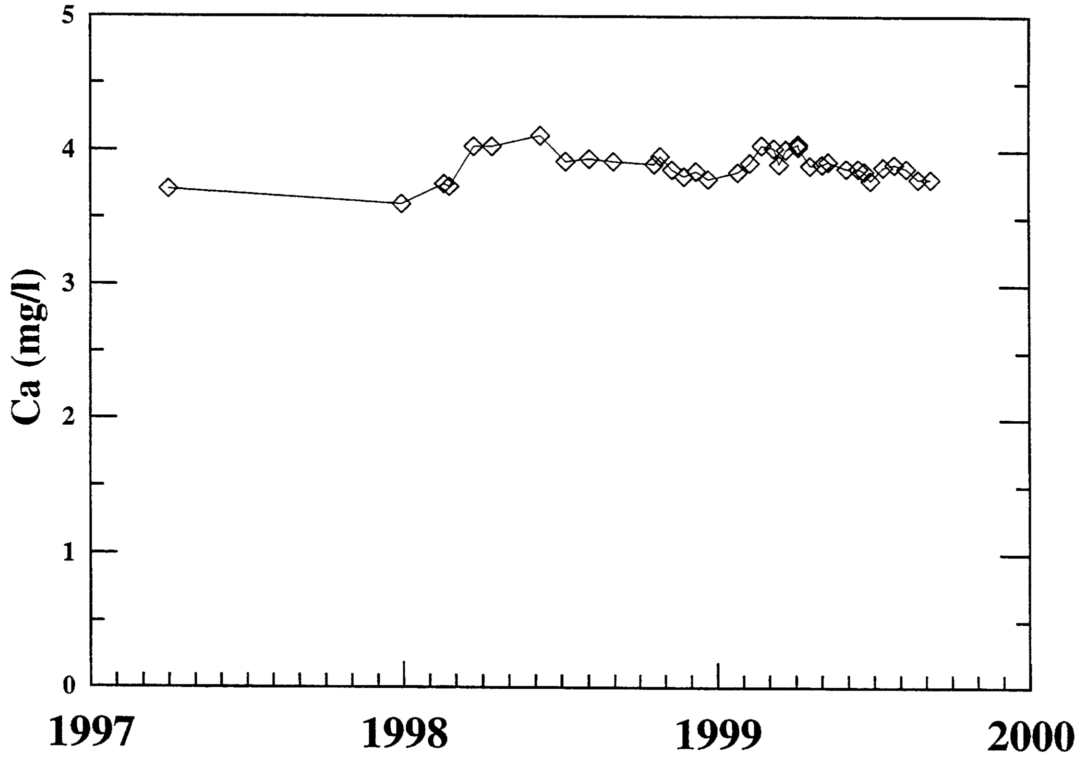


Figure 84. Ca concentration of geothermal water in well TN-4.

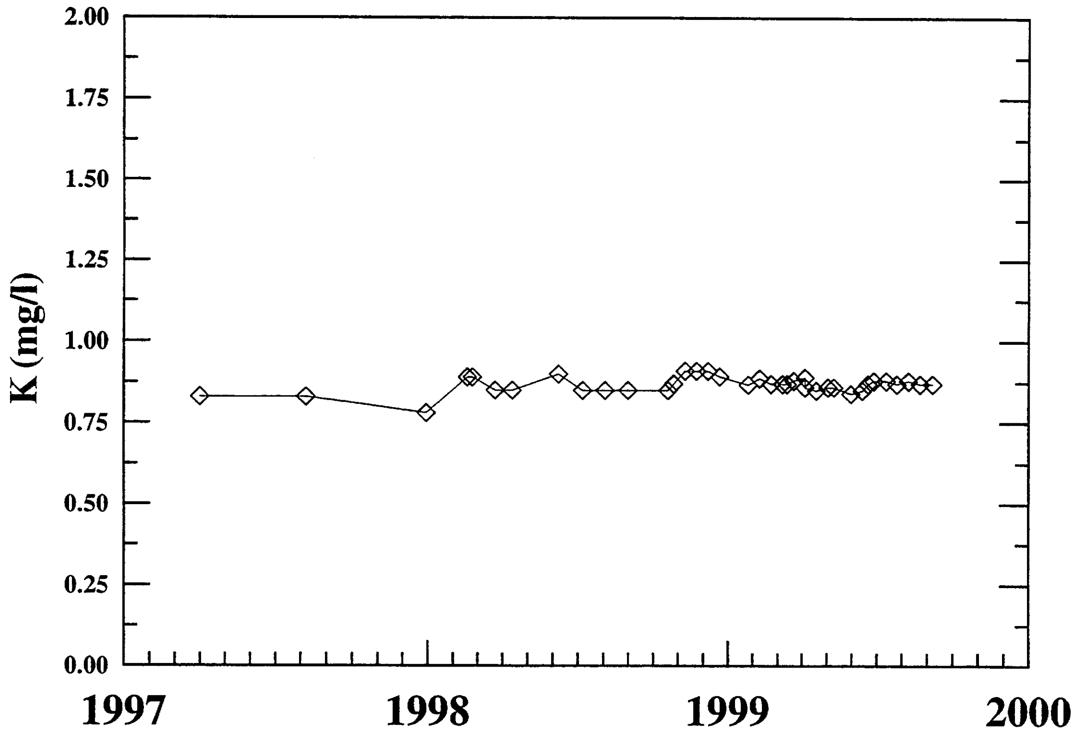


Figure 85. K concentration of geothermal water from well TN-4.

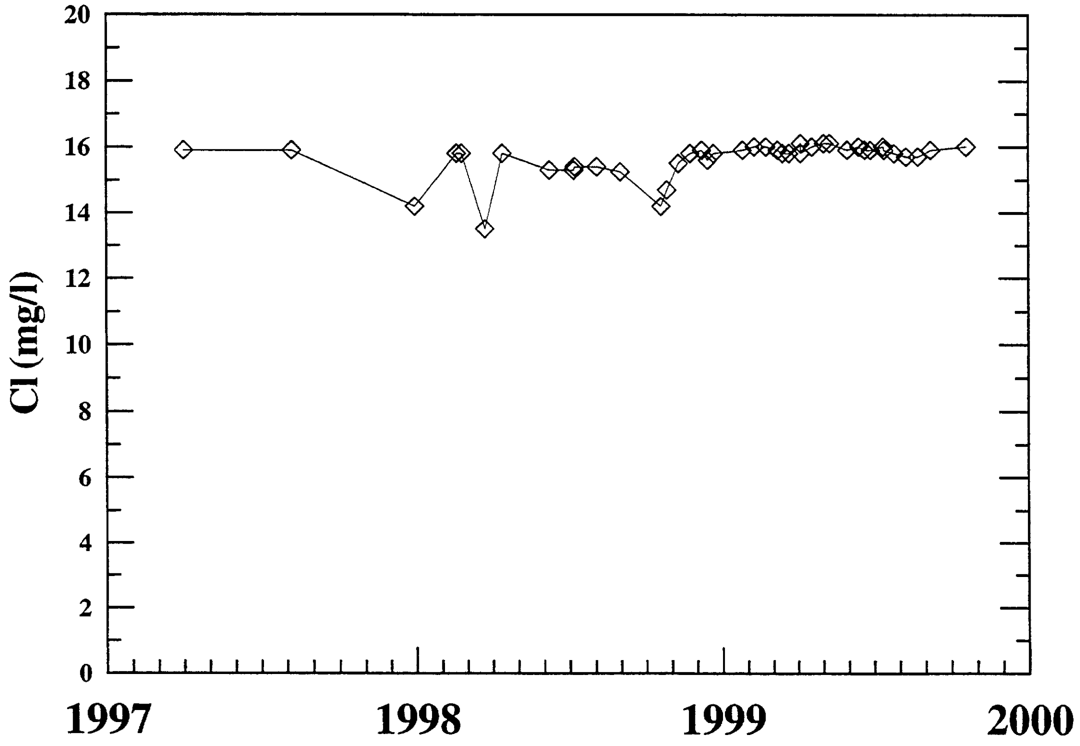


Figure 86. Cl concentration of geothermal water from well TN-4.

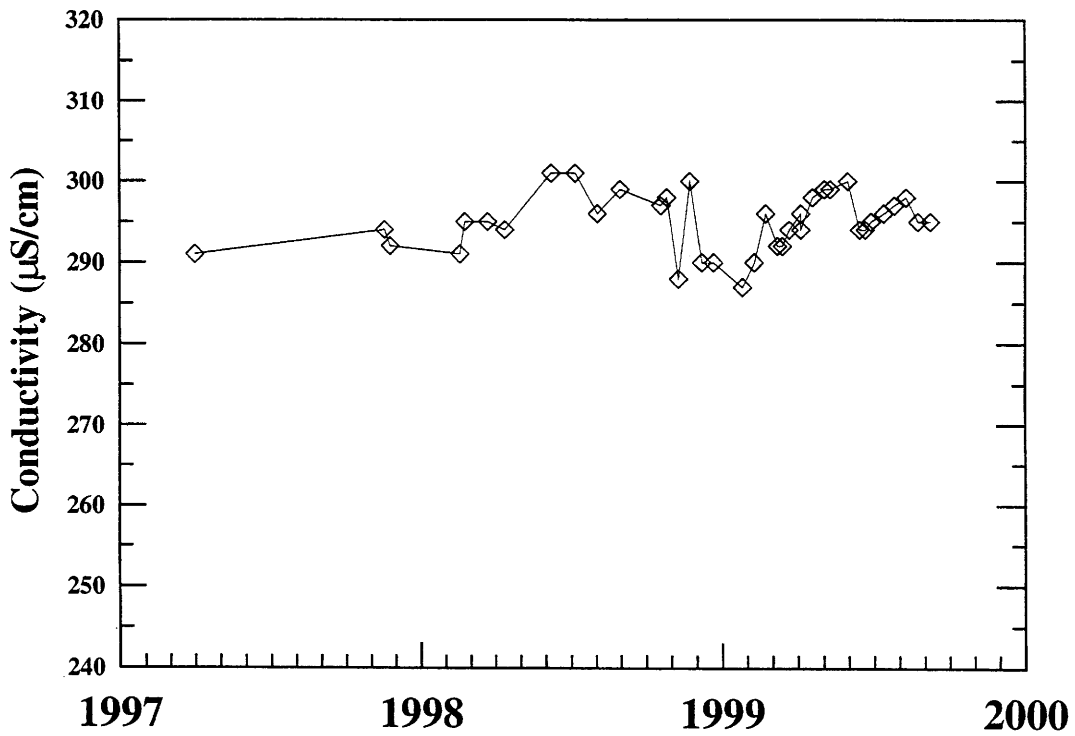


Figure 87. Conductivity of geothermal water from well TN-4

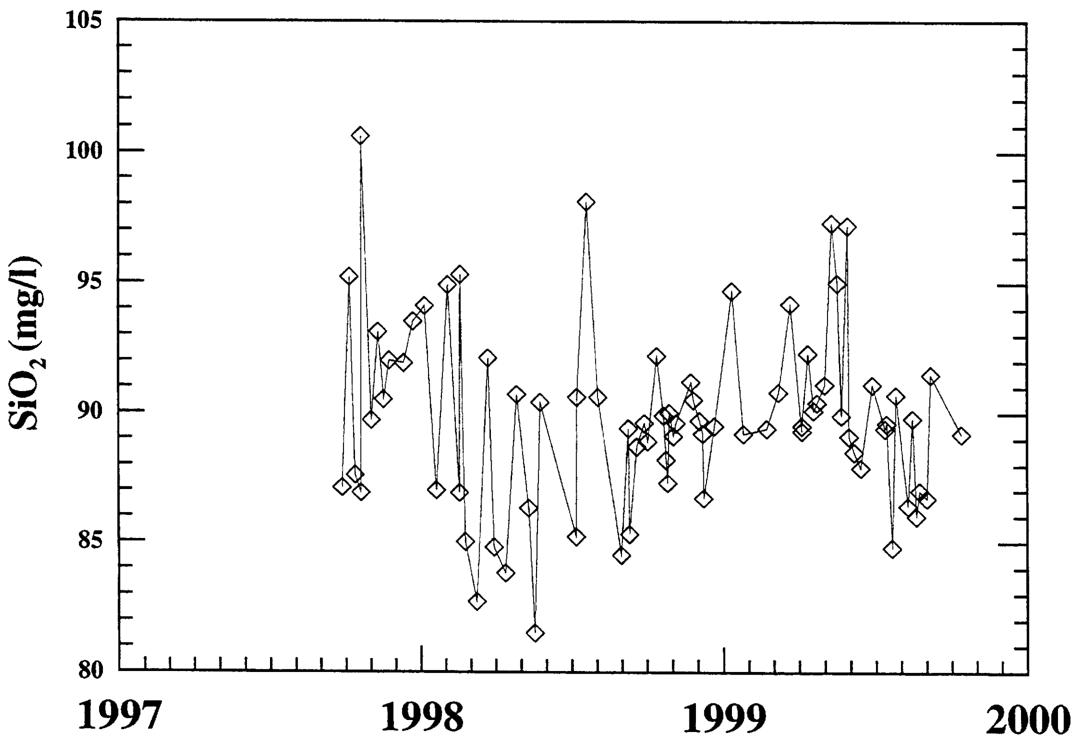


Figure 88. SiO_2 concentration of return water at Laugaland.

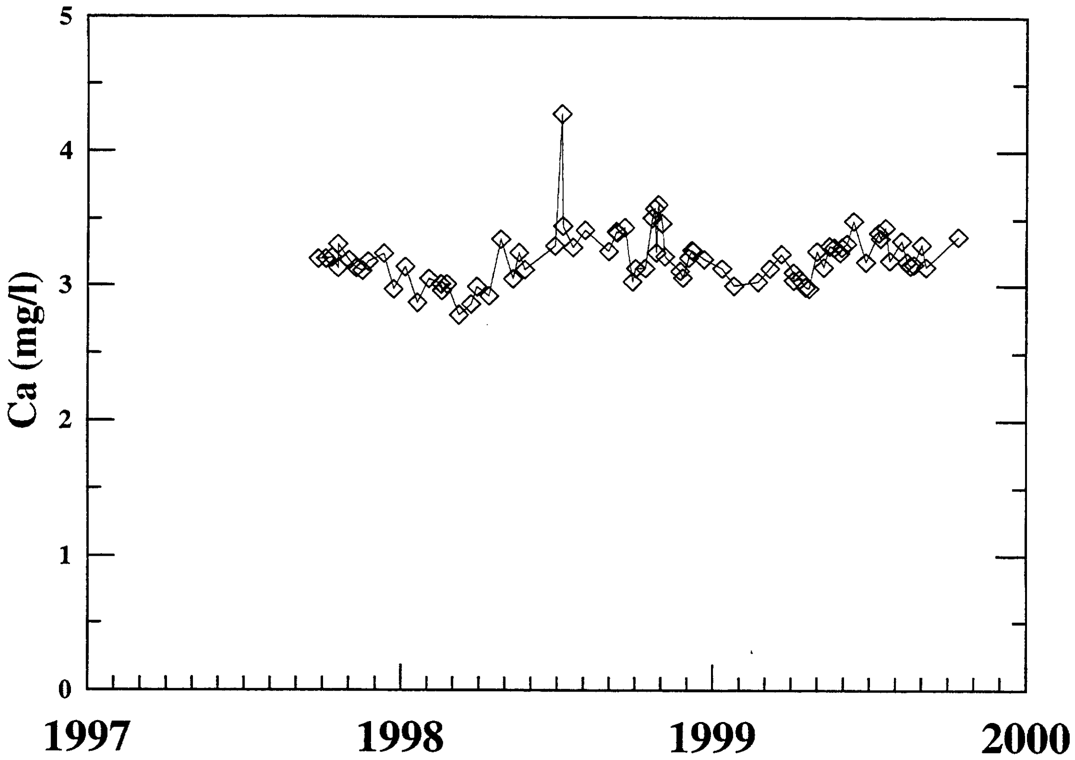


Figure 89. Ca concentration of return water at Laugaland.

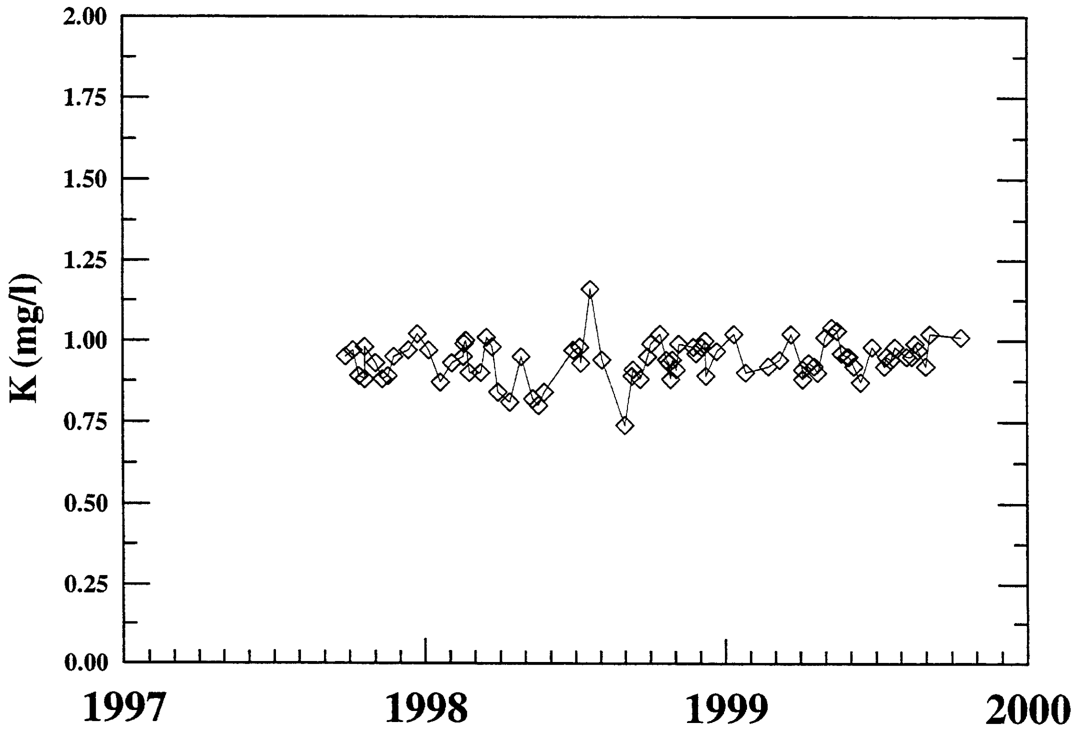


Figure 90. K concentration of return water at Laugaland.

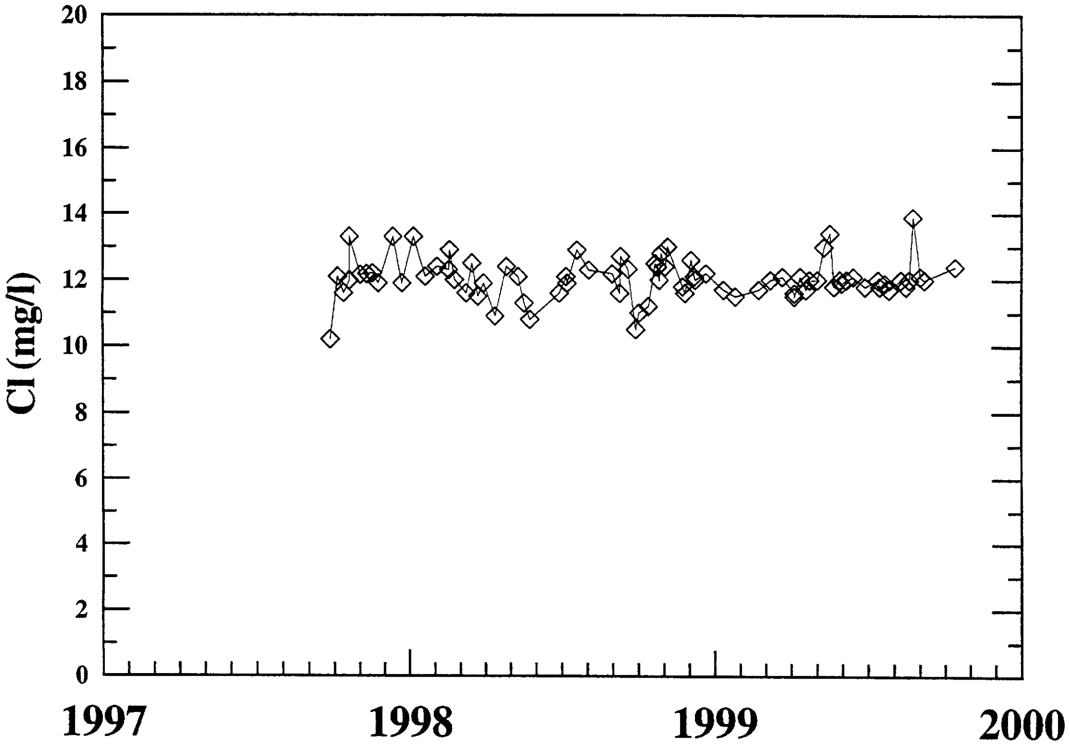


Figure 91. Cl concentration of return water at Laugaland.

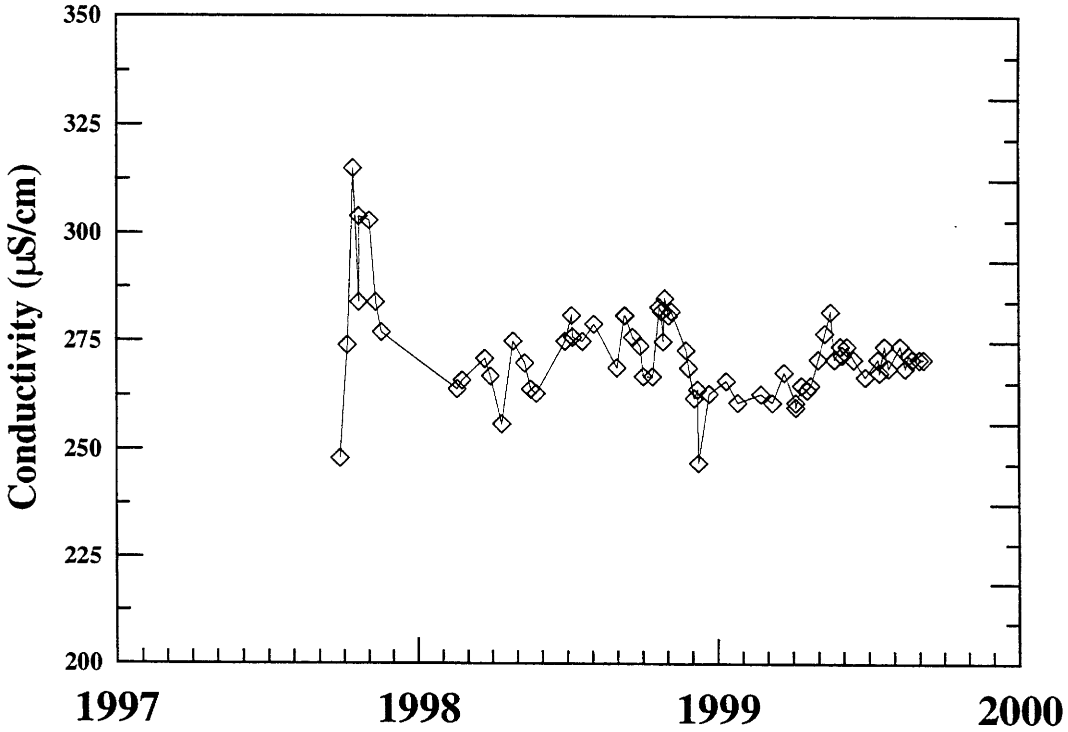


Figure 92. Conductivity of return water at Laugaland.

11. MICRO-SEISMIC MONITORING

The seismic network has been operated almost continuously during the whole experiment. Although the stations work well in recording the seismicity of the region, no micro-earthquake in the vicinity of the site (less than 10 km) was detected. The lack of induced micro-earthquakes can be due to one or both of the following possible explanations. First it may be possible that due to the very fractured rock mass the pressure at depth in well LJ-08 was not increased sufficiently to induce such activity. It is possible that the water losses at shallow depth in the injection well caused a realtively small pressure increase at greater depth. Secondly the rock stresses may be rather isotropic, which means that there may be a lack of deviatoric stresses which are of course needed for triggering micro-earthquakes. The geothermal area has been operated for two decades, with varying water pressures, which mean that the deviatoric stresses may have been released. The rock mass may also be very fractured, which also may reduce stress build-up in the area.

Figure 93 through Figure 97 show examples of some of the data collected during the seismic monitoring. Figure 93 shows typical noise recordings at the six stations. The vertical component is shown for each station, the horizontal components being similar. At one station, AKO, which is the top trace, frequent transients due to water flow close to the station reduce the value of that station for event detection. The event detection is therefore based on transient detection at the remaining five stations.

Figure 94 shows a small earthquake ($M_L = 2.4$) occurring north of Iceland at a distance of 95 km from Laugaland. The four top traces show the recordings at some of the stations in northern Iceland operated by the Icelandic Meteorological Office, the so-called "SIL" stations. The lower six traces show the recordings at the six stations of this project. One can see that these stations produce recordings of similar quality as the "SIL" stations. From the distance to this event, from the frequency content, and from the signal to noise ratio one can conclude that micro-earthquakes within the hydrothermal site down to $M_L = -1$ are expected to be detected.

Figure 95 shows a blow-up of the first part of the signals in Figure 94. The top- and bottom traces are from "SIL" stations, while the six remaining traces are from the six stations around the Laugaland site. At these six stations the first cycle is very similar while the later part of the signals differs due to multipathing. Note the high signal to noise ratio.

Two small explosive devices were detonated April 21st, 1998, to test the seismic network. The upper part of Figure 96 shows the first explosion, which involved about 8 g of high explosives, as recorded at the closest station ALA. This figure is produced by the phase detector and the three bottom traces are the three original recordings east-, north-, and vertical component. The explosion took place at about 300 m depth. The lower part of Figure 96 shows the larger, 75 g explosion as recorded by ALA. Theoretically the amplitude should be about twice as large as for the smaller charge. It is, however, only 1.5 times larger. The frequency of the waves is in the range of 15 - 70 Hz. The signal to noise ratio is about 10. The distance from the shot point to the station is about 350 m, and the next closest station is at 5 times this distance. No signals can be detected from these two explosions at that or the remaining stations. This is reasonable as the damping can be expected to be rather high at such shallow depths.

Finally, Figure 97 shows the amplitude spectrum of the vertical component of the signal of the larger explosion recorded at station ALA (see Figure 96). We see that the peak is between 15 and 70 Hz. The higher frequencies are quickly damped.

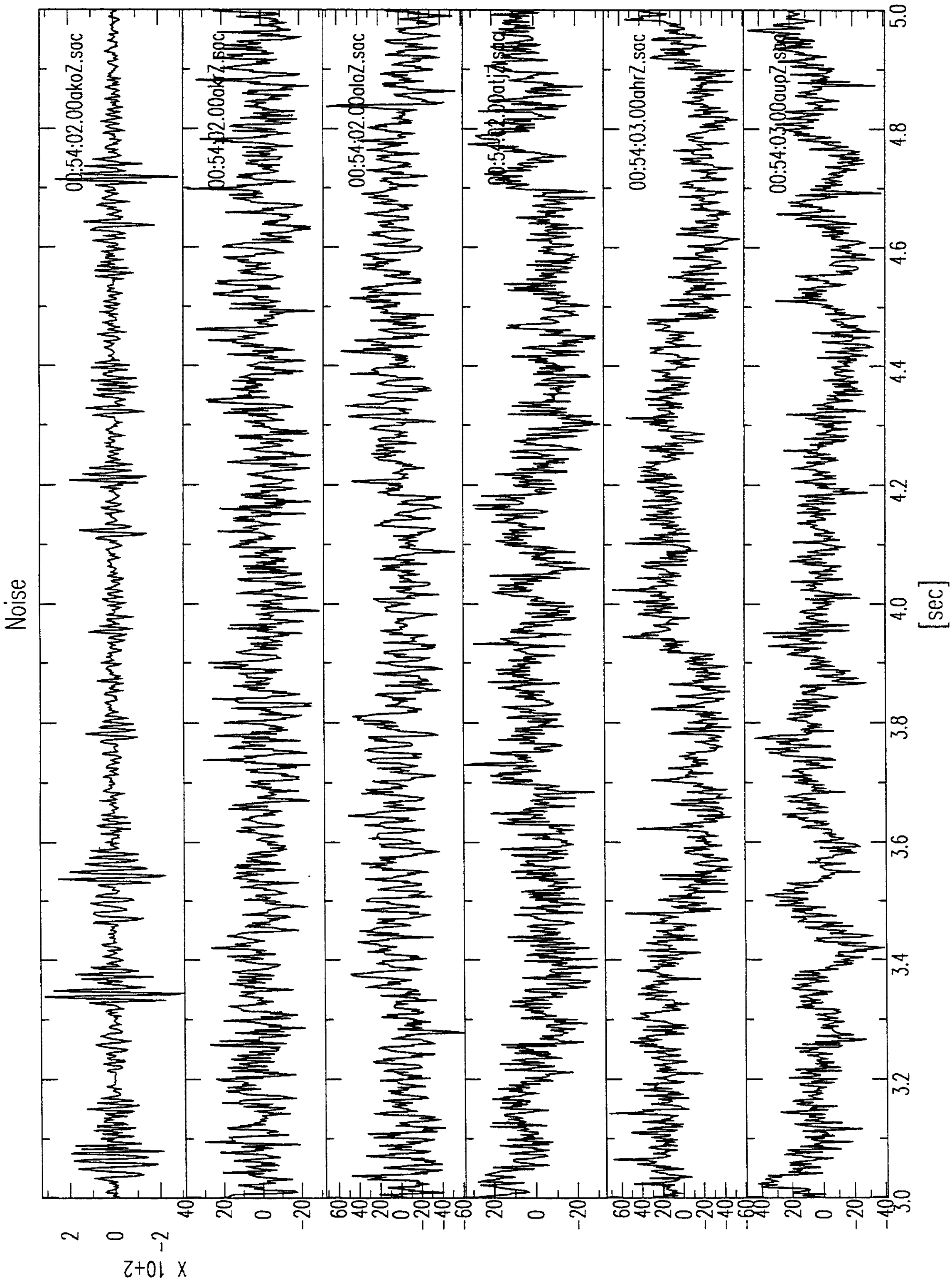


Figure 93. Typical noise recordings at the six seismic monitoring stations.

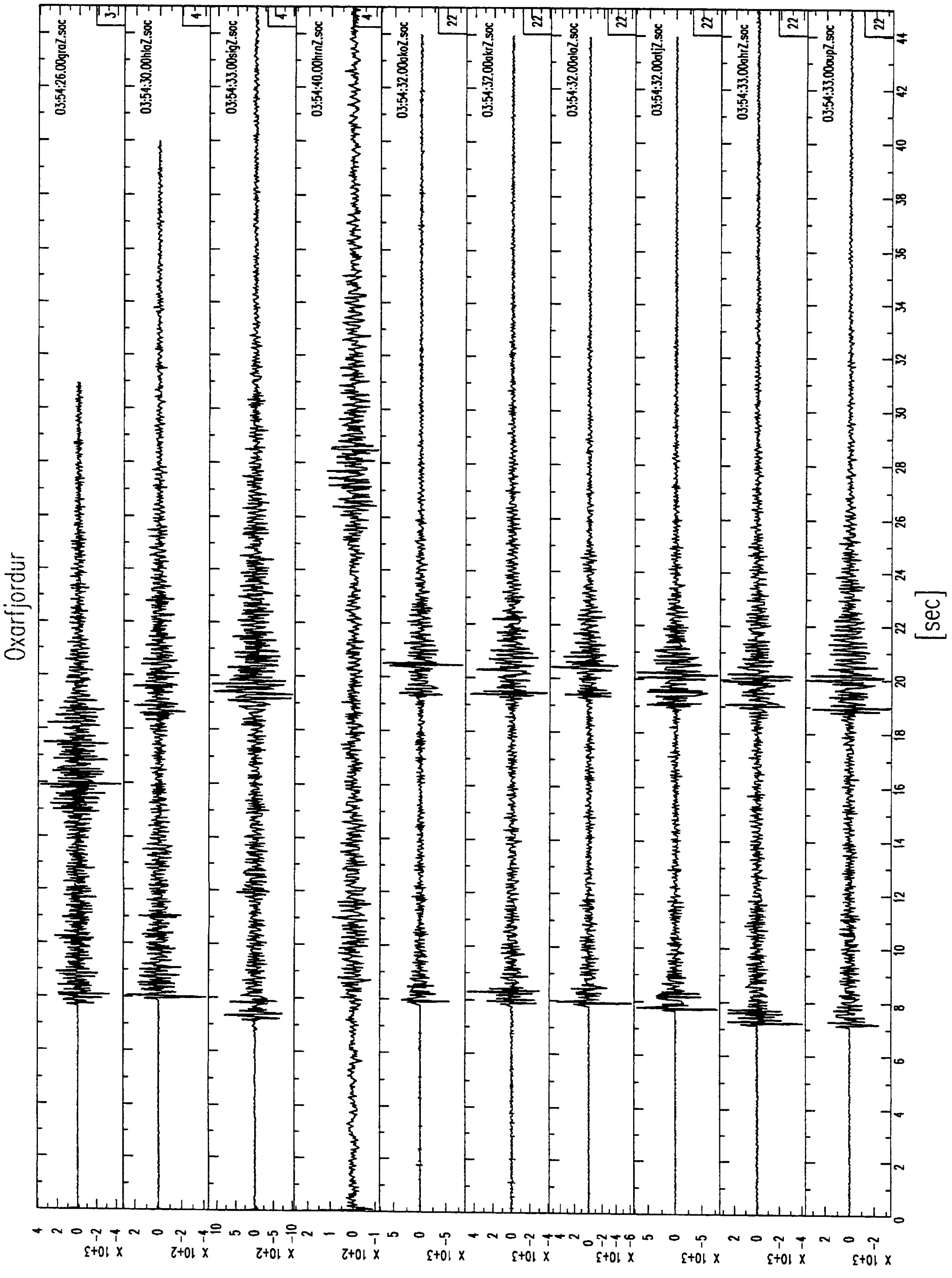


Figure 94. A small earthquake ($M_L = 2.4$) north of Iceland recorded by the seismic network. The top four traces are recordings of the "SIL"-network, shown for reference.

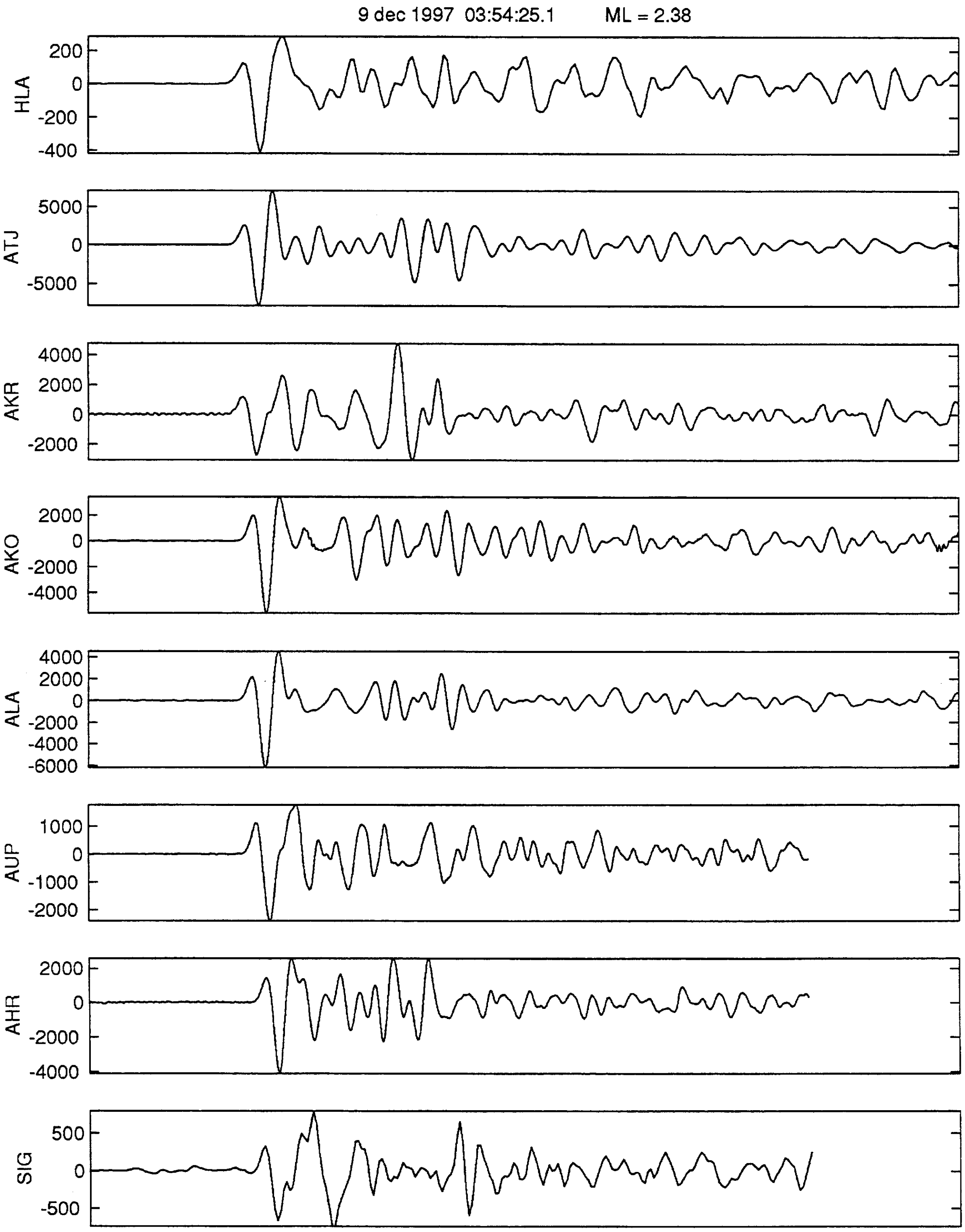
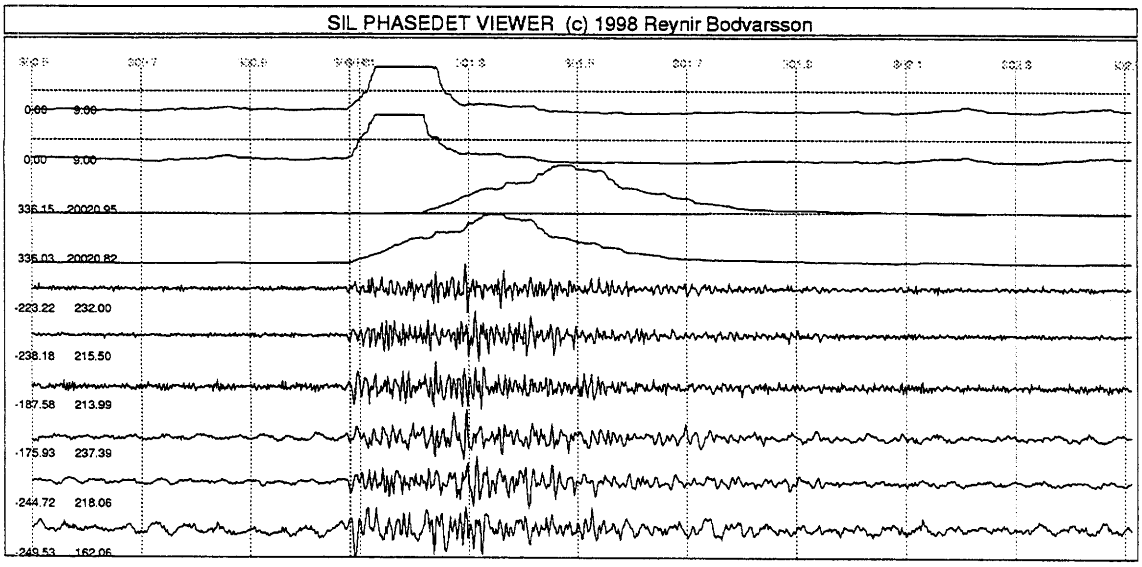


Figure 95. A blow-up of the first part of the signals in Figure 94. The top- and bottom traces are from "SIL" stations, while the rest are from the Laugaland network.

Explosion at 14:50



Explosion at 16:00

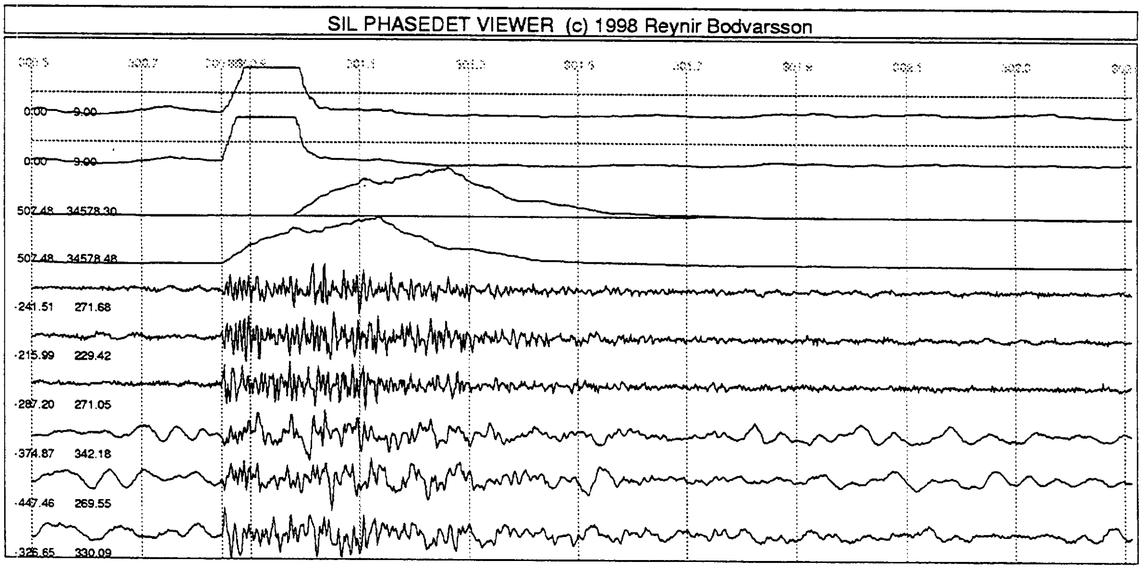


Figure 96. Recordings (station ALA) of two test explosions detonated April 21st, 1998.

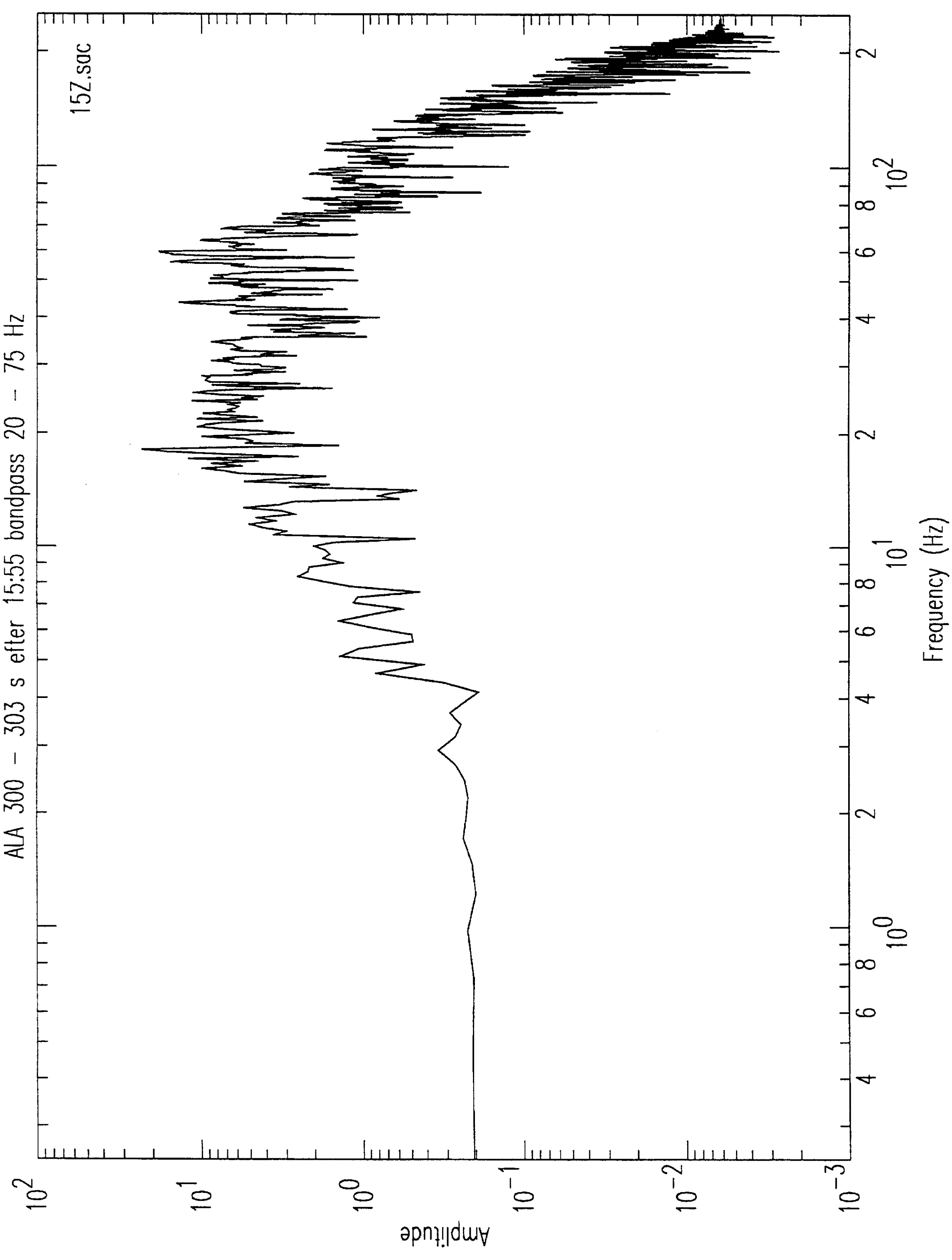


Figure 97. The amplitude spectrum of the vertical component of the signal of the larger explosion in Figure 96.

12. NUMERICAL MODELLING

A part of the reinjection project involved the development of a detailed three-dimensional numerical model of the Laugaland geothermal system and surroundings. The aim of this phase was to simulate most of the available data concerning the Laugaland system, in particular data on the systems natural state (pressure and temperature) and its response to two decades of hot water production, as well as the data collected during the reinjection project. The aim was, consequently, to employ the model to predict the cooling of hot water produced at Laugaland, due to long-term reinjection, and to estimate the additional amount of energy that may be extracted from the Laugaland reservoir through injection. Considerable effort was invested in this work. Yet, it turned out to be too time-consuming to be completed within the framework of the project. The initial phase of the modelling work was completed, however, and its results are presented below.

The development of the numerical model turned out to be considerably more time-consuming than estimated at the beginning of the project. This was partly because it turned out that the model needed to cover a much larger area, than previously anticipated. It had, for example, to include the geothermal systems at Ytri-Tjarnir and Botn (Figure 1), because of the information now emerging on direct connections between all the geothermal fields in the Eyjafjordur-valley. The calibration of the numerical model did also turn out to be more time-consuming, because of its greater size and complexity. The first phase of the modelling work was successfully completed, however. It is, furthermore, anticipated that development of this numerical model, which will eventually incorporate all the geothermal systems in the Eyjafjordur-valley (Figure 1), will continue. This work will hopefully be completed within the next two years, or so. A new version of the *TOUGH2* numerical simulator, *iTOUGH2*, recently acquired by Orkustofnun, will be employed for this purpose. This version uses an inverse approach to the simulation procedure, instead of a forward trial and error approach, which makes the model development considerably less time-consuming.

Because only the first phase of the modelling work has been completed at this point in time, the numerical model will not be used to estimate the additional amount of energy, which may be extracted from the Laugaland reservoir through long-term reinjection. This will be done in chapter 13 through the use of two simpler, but fully applicable, models. It is unlikely in fact, that a detailed numerical model will be able to simulate the tracer recovery through the direct small volume channels as accurately as the simple model used (see section 7.4).

12.1. Revised conceptual model

The basis of any successful model development is a good conceptual model (Bodvarsson *et al.*, 1986). Therefore, the conceptual model of the Laugaland geothermal system, in effect at the beginning of the project, was revised on basis of the information emerging during the project (Hjartarson, 1999). The results of this revision, which mostly involved the emergence of various details rather than being a major revision, are reviewed below.

Analysis of the various independent data-sets, confirms the existence of the Laugaland fracture zone (Hjartarson, 1999). These same data argue that the fracture zone is near vertical and at least 0.5-1 km in extension, with SW-NE direction. Only the production wells in the field intersect the fracture zone, while non-productive wells do not. The fracture zone dominates the water flow in the system and feeds the production wells in the field with 95°C hot water. The water flow in the reservoir rocks, outside the principal fracture zone, is also controlled by fractures, as well as by dikes and interbeds. Fractures, with SW-NE direction, are presumably the only fractures, which are hydraulically conductive. They might be optimally oriented and critically stressed, in the contemporary in-situ stress field at Laugaland. The permeability-thickness of the fracture zone is estimated to be about 15 Dm, and the corresponding value for the reservoir outside the fracture zone is 2 Dm. The storativity of the system is estimated to be 2×10^{-8} m/Pa, which results in a porosity estimate of 6%.

The SW-NE fracture zone seems to be connected to a recharge system at an unknown distance, according to a well test in well LJ-05. This recharge system is, therefore, assumed to be located to the NE or SW from the Laugaland system. This recharge system is worth discussing a bit further. The Laugaland system might partly be recharged by groundwater flow from higher grounds in the NE. Another possibility is that the Laugaland system is recharged by an upflow zone of hot water, in the valley SW of Laugaland, as suggested in Figure 98.

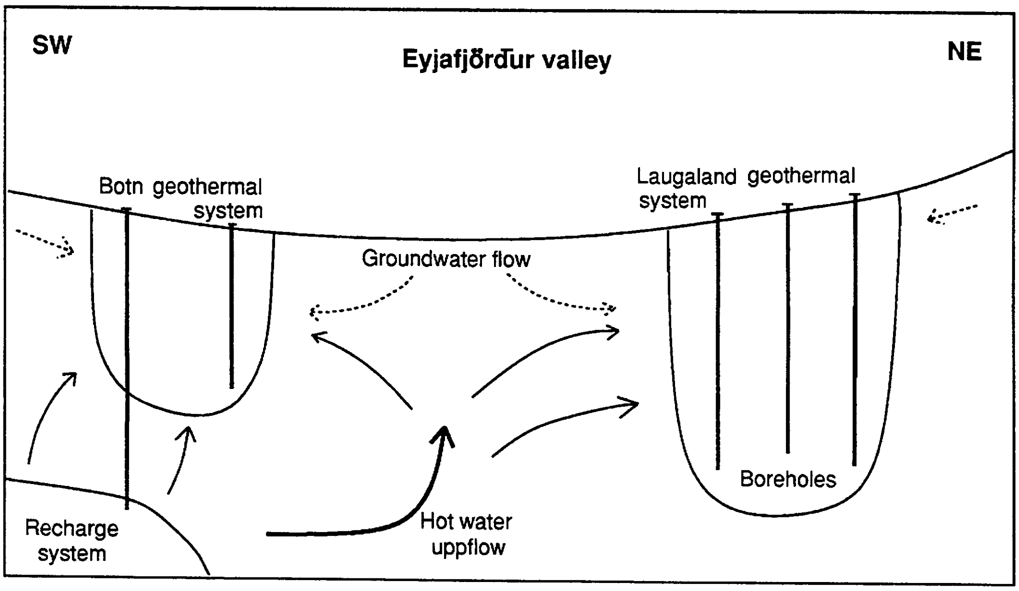


Figure 98. Schematic presentation of the possible hot water up-flow zone in the Eyjafjordur valley, which recharges the Laugaland and Botn geothermal systems.

This idea is supported by the following facts. Water level changes, due to production at Laugaland, are observed at Hrafnagil and Grisara, on the west-side of the valley, and at Ytri-Tjarnir and Klauf, north and south of Laugaland, respectively. However, no water-level changes, due to production at Laugaland, are observed at the Botn field, south-west of Laugaland (Axelsson *et al.*, 1998a). The up-flow zone might be located between the Botn and the Laugaland fields and, therefore, prevent pressure transients between the fields. Further support for this idea comes from the fact that during the tracer test in 1997, tracer was recovered at Ytri-Tjarnir and Gryta, but not in the fields on the west side of the valley (see chapter 7 above). This hypothetical up-flow zone might, therefore, hinder water flow from the Laugaland field to the west-side of the Eyjafjordur valley. In the detailed numerical model of the Botn system, a powerful recharge system is included below 1500 m depth (Axelsson and Bjornsson, 1993), which supplies the Botn reservoir with hot water. This hypothetical up-flow zone, which recharges the fracture zone at Laugaland, might in fact be the same as the recharge system for the Botn reservoir. This hypothesis needs to be studied further.

12.2. The *TOUGH2* numerical simulator

The TOUGH2 code is a general-purpose numerical simulation program. It can be used to simulate one, two and three dimensional, multi-component, multi-phase transport of mass and heat in porous and fractured media. The acronym TOUGH stands for transport of unsaturated groundwater and heat. The TOUGH code was developed at The Lawrence Berkeley National Laboratory (LBNL) in California in 1983-1985 and the second version (TOUGH2) was released in 1991. The simulation capabilities available through TOUGH2 are quite diverse. The main application areas are in geothermal reservoir engineering, nuclear waste isolation studies, environmental assessment and re-mediation and saturated and unsaturated zone hydrology.

A TOUGH2-model consists of a number of elements connected to each other. For each of these elements the basic mass- and energy equations are set up, which define the accumulated mass and heat in every element, the fluxes of mass and heat through element surfaces and possible point sources, or sinks, of mass and heat. The equations are discretised in space by using the integral finite difference method and solved between consecutive time steps by the Newton-Raphson iteration scheme. Details on the TOUGH2 code can be found in the TOUGH2 User's Guide, Version 2.0 (Pruess *et al.*, 1999). General information can also been found on the official TOUGH2 home page (http://esd.lbl.gov/TOUGH2/).

12.3. The Laugaland numerical model

In this section the TOUGH2 numerical model of the Laugaland system, as developed during the first phase of the model development, is described. The numerical model is based on the conceptual model of the Laugaland field and was required, beforehand, to simulate the high system pressure prior to production, as the natural state, and the water level history from 1975 to 1998. The model was, consequently, used to estimate the pressure increase and the possible cooling of the Laugaland system, due to long-term reinjection into well LJ-8.

Figure 99 and Figure 100 show schematically the model grid developed for the demonstration project. It is oriented with the x-distance directed SW-NE, setting the model fracture-zone parallel to the fracture-zone of the conceptual model, which extends through the Laugaland system. The model consists of 3591 elements, 2565 of which are active, with 9938 connections between elements. The size of active model elements varies from 2.5×10^{-5} km^3 in the fracture-zone to 0.5625 km^3 at the model boundaries. The surface area of the model covers 12.25 km^2. It is divided vertically into 7 layers with a total depth of 3.7 km.

Layers 1 and 2 simulate the groundwater system in the Eyjafjordur valley. Layer 1 is inactive, representing a constant pressure boundary. Layer 3 has very low vertical permeability, which simulates the 200 m thick caprock of the system that is mostly responsible for the high initial pressure in the system. The production reservoir between 500 and 2000 m depth is simulated by layers 4 and 5 with centres at 600 and 1350 m depth, respectively. Layer 6 represents the deeper part of the Laugaland geothermal system. The bottom layer, like the top layer, is also a constant pressure boundary. The model is closed at all sides resulting in horizontal isolation. The model assumes porous media. The fracture extending through the geothermal system is also simulated by porous media, but with high uniform permeability. It is 5 m in thickness and extends through the entire model. The fracture is divided into two parts. The upper part (fracture 1) intersects layers 2, 3 and 4 while the lower part (fracture 2) intersects layers 5 and 6. Ten rock types are used in the model, as is shown in Table 19. The permeability is reduced laterally outside the inner model in layers 4, 5 and 6 (rock name Jadar). Uniform rock density of 2650 kg/m^3, heat conductivity of 2.1 W/(m°C) and heat capacity of 950 kJ/(kg °C) is assumed in the model at this stage.

Table 19. *Permeabilities and porosities in the numerical model (TOUGH2) for the Laugaland system.*

Rock name	Porosity (%)	Horizontal perm. (mD)	Vertical perm. (mD)
Layer 1	20	0.1	0.1
Layer 2	10	40	0.4
Layer 3	4	2.0	0.01
Layer 4	7	4.0	0.3
Layer 5	7	1.7	0.4
Layer 6	7	1.7	0.5
Layer 7	7	0.85	0.85
Jadar	7	1.2	0.5
Fracture 1	7	40	40
Fracture 2	7	2000	2000

12.3.1. Production history simulations

A fairly good simulation of the initial pressure, and water level history, of the Laugaland system did result after a considerable time had been invested in calibrating the numerical model. Figure 101 shows the result, i.e. a comparison of the measured and simulated water level history for well LJ-8, due to production in the Laugaland field during the last two decades. It should be emphasised that this is the result of the first phase of numerical modelling for Laugaland, only. Well LJ-5 was assumed to be the only well on-line in the simulations, producing from a feed-zone at 1350 m depth.

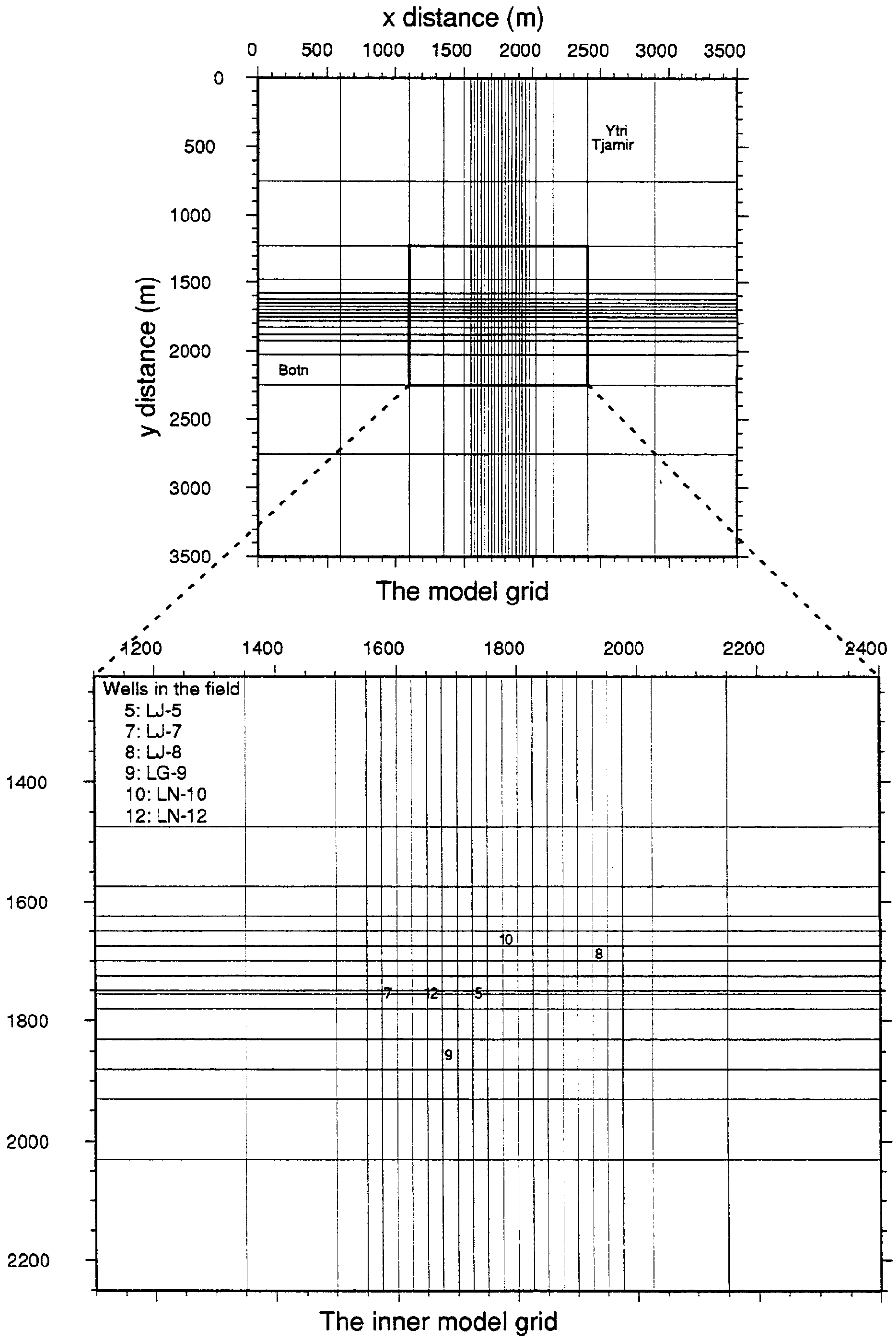


Figure 99. Subdivision of each of the horizontal layers of the numerical model for the Laugaland geothermal system, and surroundings, into grid-blocks.

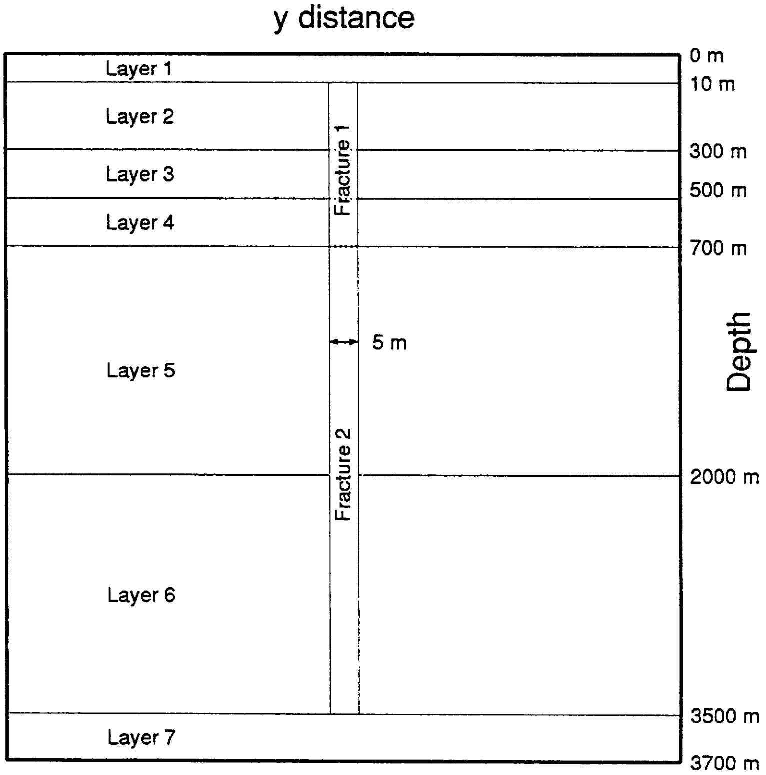


Figure 100. Vertical structure of the numerical model for the Laugaland geothermal system. The seven layers and the vertical SW-NE trending fracture-zone are shown.

To simulate the high system pressure in the natural state, a constant-rate source yielding 10 L/s of 105°C water was placed at 2750 m depth in a fracture element, at the SW boundary of the model. In the natural state the model discharged geothermal fluid to the surface at Laugaland at a rate of 2.7 L/s, with a temperature of 49°C. This simulates the small Laugaland hot spring, which prior to production discharged about 2 L/s of 55 °C hot geothermal water (Bjornsson *et al.*, 1979).

To get a reasonable fit with the water level history it was found necessary to incorporate the hot water production at the Ytri-Tjarnir field, and part of the production at the Botn geothermal area (Figure 1). This is quite an interesting result, which supports strongly what is presently believed, i.e. that these geothermal systems are not fully isolated from each other. The overall effect of annual production at Ytri-Tjarnir, from Mars 1978 to 1998, according to the model, is a water-level draw-down of about 100 - 120 m in the Laugaland reservoir. This corresponds to about 3-4 m/(L/s). An independent estimate finds this effect to be about 2-3 m/(L/s) (see section 13.1.1). These results are quite comparable, in particular considering the fact that the time-scales are not comparable.

It is, furthermore, assumed that about one third (about 10 L/s) of the average annual production from well HN-10 at Botn influences the Laugaland part of the model. The resulting water level draw-down at Laugaland equals about 20-50 m, according to the model. The numerical model development thus supports that the three production areas are directly connected, and when simulating one field the production from the others has to be taken into account.

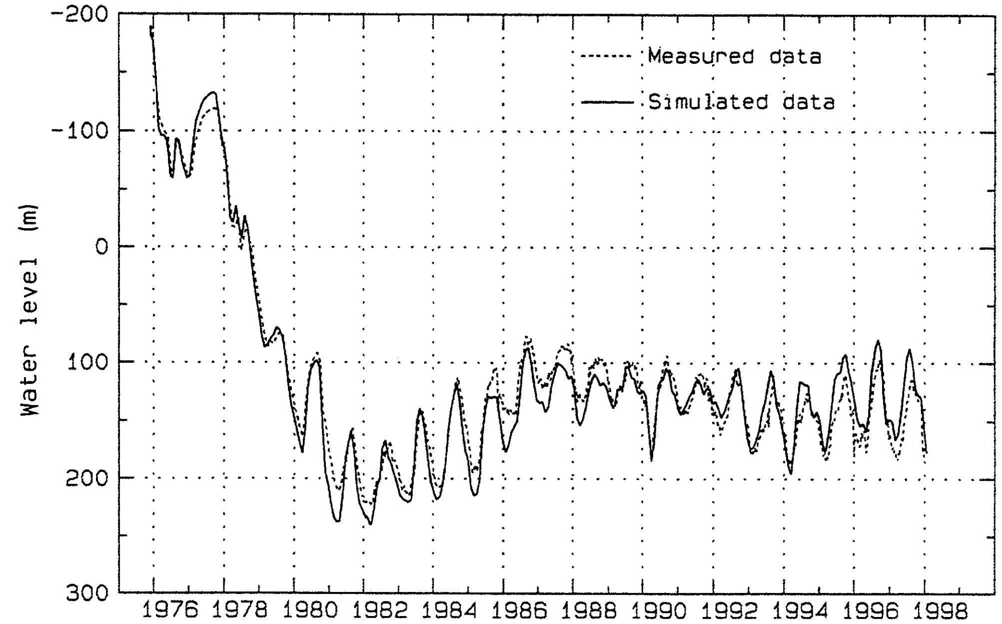


Figure 101. The water level history of the Laugaland field, up to the beginning of reinjection, simulated by the numerical model, preliminary results.

The volumes of boundary elements, in layers 4, 5 and 6, at the NE edge of the numerical model were increased by a factor of 10 to prevent boiling in the system. This indicates that there is not enough fluid in-place in the model. The model, therefore, appears to be too small, or there is insufficient recharge allowed in the model.

The results presented here are only the results of the first phase of numerical model development for the Eyjafjordur geothermal fields, as already mentioned. In addition to using the iTOUGH2 software, the next phase should involve the development of a larger numerical model, which would incorporate and simulate all three production fields simultaneously, as well as data from observation wells in the area. In addition the great amount of data collected during the reinjection project should be incorporated.

12.3.2. Effect of long-term reinjection into well LJ-8

The first phase of numerical modelling for Laugaland, discussed here, was concluded by some simple calculations aimed at estimating roughly the effect of long-term reinjection. The results could, consequently be compared with the results of other methods used in this report to estimate the long-term influence of reinjection. These calculations involved estimating the effect of 15 L/s of 15°C hot water being reinjected into well LJ-8 for 30 years. In accordance with the results of section 5.1 it is assumed in the simulation calculations that (1) 7.5 L/s exit the well constantly through a feed-zone at 150 m depth, (2) 3.0 L/s through a feed-zone at 600 m depth and the rest, (3) 4.5 L/s, through a feed-zone at 1350 m depth. The principal results of the model calculations are presented in Figure 102 through Figure 106. It should again be emphasised that these are only preliminary results.

The first figure shows simply the water level recovery, resulting from the reinjection, calculated at different depth-levels in the centre of the numerical model (i.e. in the elements corresponding to well LN-12). Firstly, the results in the figure show clearly a much greater pressure recovery at shallow levels in the Laugaland reservoir, which is in perfect agreement with what has been observed (see section 4.2). Secondly, the results indicate that greater pressure increase at shallow levels will cause the relative importance of the small shallow feed-zones, in production wells LJ-05 and LN-12, to increase, which has already been inferred from the tracer recovery data and water temperature measurements. Thirdly, the recovery results may be used to roughly estimate the possible increase in production, due to the reinjection. Based on results presented later (Figure 109) the 80 m water level recovery should enable an increase in production, equalling roughly 55% of the reinjection rate. The pressure recovery at shallower depths will cause an additional increase in production. This result is in a good agreement with preliminary results presented by Axelsson *et al.* (1998c).

The next four figures show the calculated cooling of the numerical model at four different depth levels. It should be pointed out that the numerical model, at the present state of development, can not simulate the tracer recovery and consequent cooling through the mode A transport discussed earlier (small volume direct flow-channels). The cooling calculated by the model may, in fact, be looked upon as constituting the mode B cooling only. The cooling calculated by the numerical model does not affect the production wells significantly, in particular at the depth corresponding to the main feed-zones of these wells (1350 m in the model).

In conclusion, it may be stated that even though the results of the development of a detailed three-dimensional numerical model for the Laugaland geothermal system presented here are only preliminary, they are in a good agreement with the results of other calculations on the effect of long-term reinjection into well LJ-08.

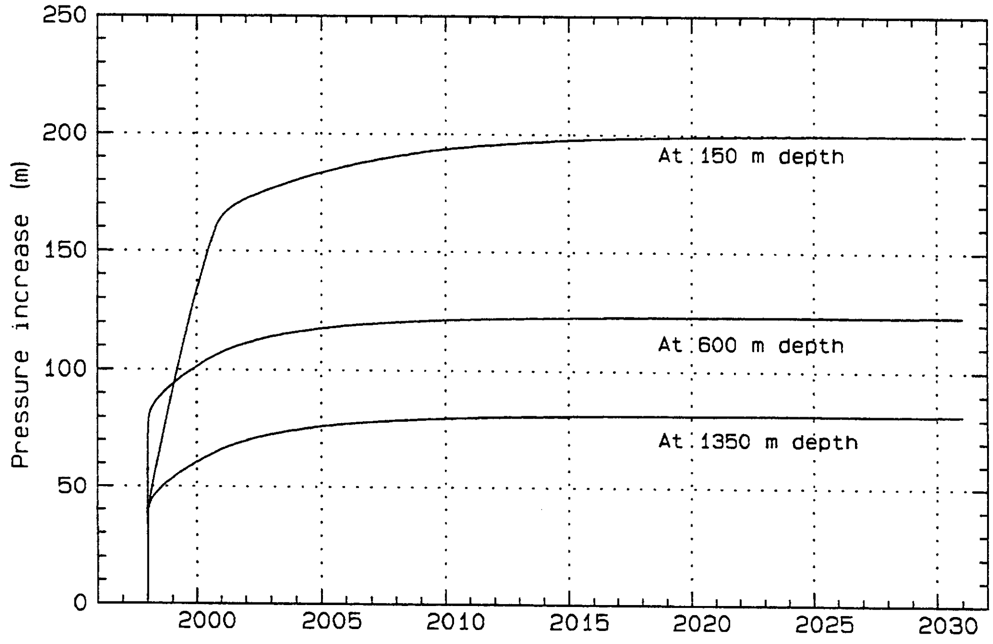


Figure 102. The pressure recovery resulting from 15 L/s continuous reinjection into well LJ-08, as calculated by the numerical model at three different depths in the centre of the Laugaland reservoir (Well LN-12), preliminary results.

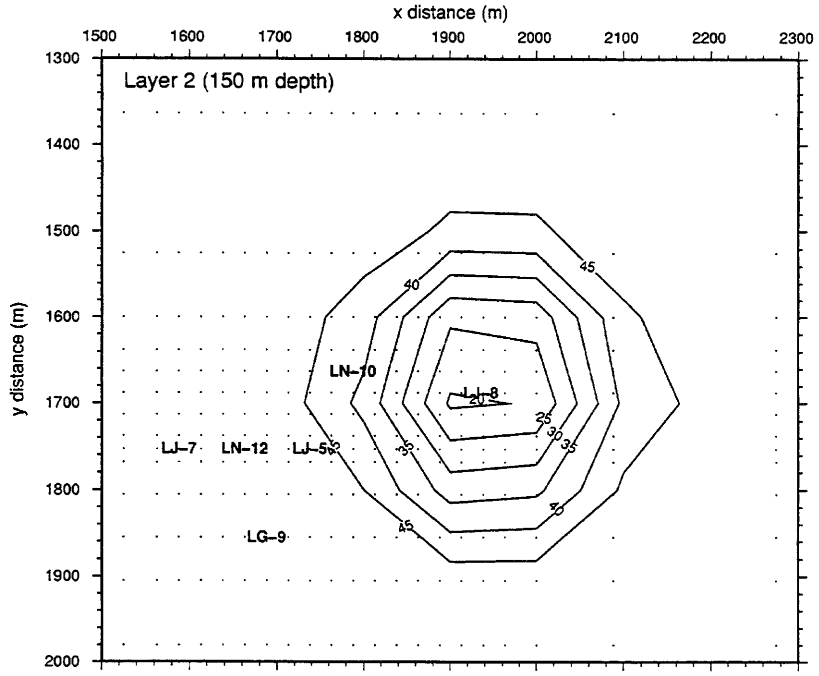


Figure 103. Calculated temperature distribution in layer 2 (150 m depth) of the numerical model after 30 years of continuous 15 L/s reinjection into well LJ-08 (15°C return water), preliminary results.

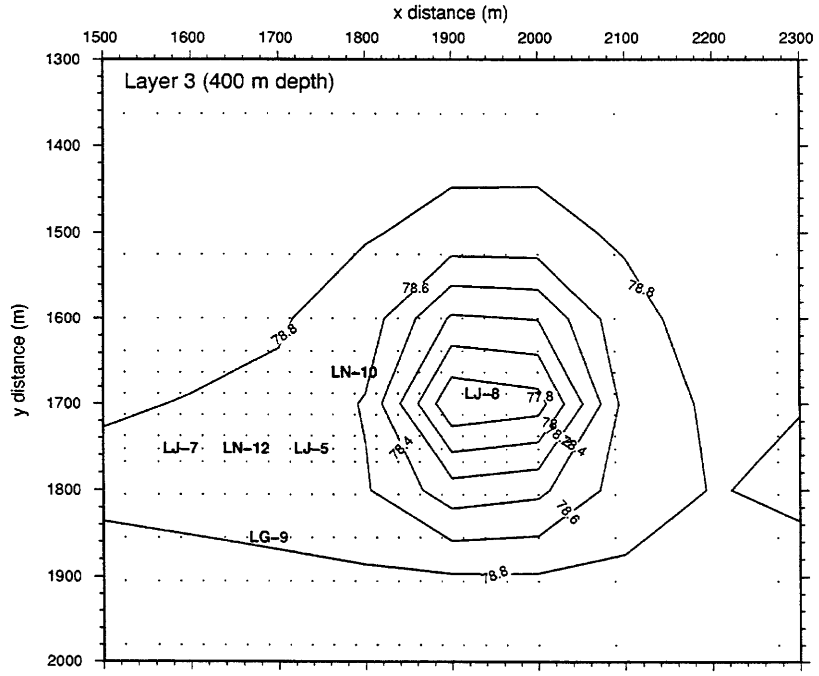


Figure 104. Calculated temperature distribution in layer 3 (400 m depth) of the numerical model after 30 years of continuous 15 L/s reinjection into well LJ-08 (15°C return water), preliminary results.

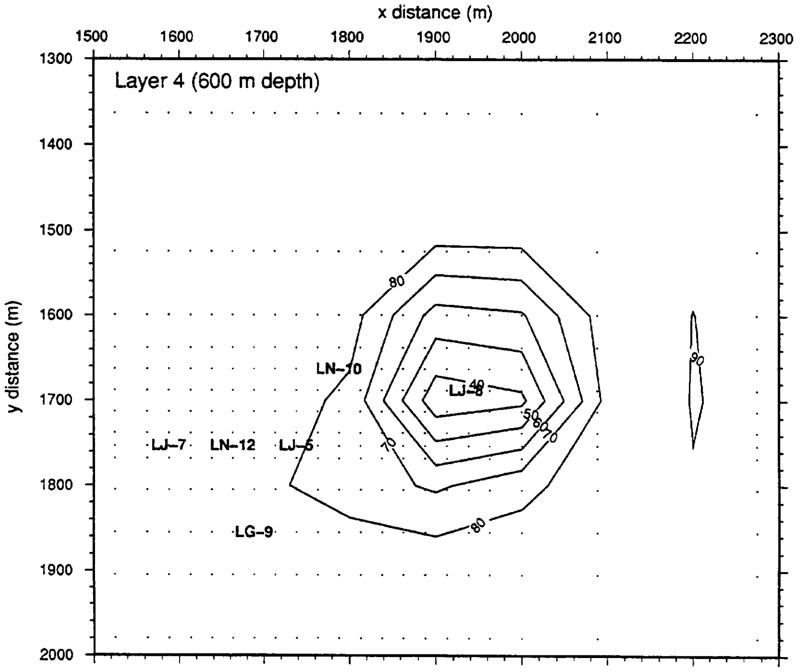


Figure 105. Calculated temperature distribution in layer 4 (600 m depth) of the numerical model after 30 years of continuous 15 L/s reinjection into well LJ-08 (15°C return water), preliminary results.

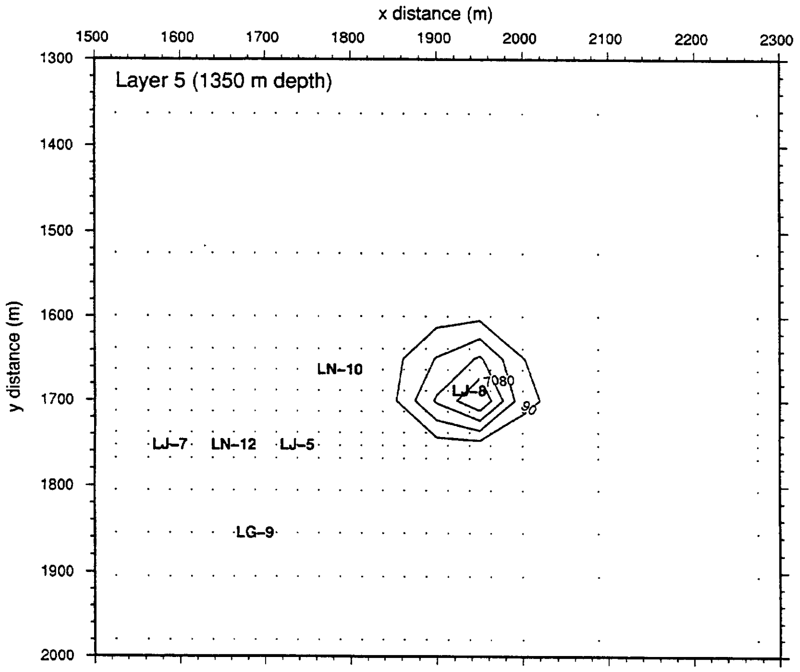


Figure 106. Calculated temperature distribution in layer 5 (1350 m depth) of the numerical model after 30 years of continuous 15 L/s reinjection into well LJ-08 (15°C return water), preliminary results.

13. BENEFITS OF THE REINJECTION

Four key issues determine whether reinjection into a geothermal system will be beneficial in terms of increasing energy extraction from the system:

A. The reinjection must result in a water-level or pressure recovery.

B. The reinjection must not cause a too great cooling of production wells.

C. The reinjcetion must not cause significant scaling, or corrosion, in reinjection wells or in surface equipment.

D. The reinjection must be economically viable.

The first two aspects will be discussed in the present chapter, while the fourth aspect will be discussed in chapter 15. The third aspect is not believed to be an issue of concern in the case of reinjection of return water at Laugaland (see chapter 2).

13.1. Reduced water-level draw-down

A reduced water level draw-down, or water-level recovery, is anticipated as the main benefit from reinjection at Laugaland. This, in turn, increases the production potential of production wells in the field, i.e. the rate of production may be increased without increasing the water-level draw-down. This section presents the results of an assessment of this benefit based on the data collected during the reinjection project, as well as older data on water level changes in the Laugaland reservoir. It should be pointed out that this can not be done directly since it is not known exactly how the Laugaland reservoir would have responded, during the project period, without reinjection. Instead this must be done through modelling, and comparative analysis, of the water level data available.

Previous analysis, mainly based on the water level changes in September 1997, indicates that the injection of 8 L/s into well LJ-8 caused comparable water level changes in production well LJ-5 as a 5.4 L/s reduction in production (Hita- og Vatnsveita Akureyrar *et al.*, 1998). This indicates that about 2/3 of the injection into well LJ-8 will potentially enable an increase in production, on the time scale under consideration (about 1 month). The long-term effect was expected to be somewhat greater.

During the summer of 1998 short tests were conducted to try to estimate the water-level recovery due to the reinjection. This was done by discontinuing injection into the two wells for one to two week periods and carefully monitor the consequent water-level changes in well LN-12. Unfortunately the time-scale of these tests was rather short and they were also significantly influenced by short-term water level transients caused by intermittent production from well LJ-05. Yet, the results clearly indicated that the short-term influence from reinjection was less than anticipated on the basis of the 1991 injection test (see section 2.3).

This result demonstrates that water-level recovery due to reinjection into wells LJ-08 and LN-10 will mainly be a long-term benefit. Reinjection into these wells can, therefore, not be used for short-term power enhancement, i.e. through intense reinjection for brief periods of great power demand. The reason for this is believed to be the fact that the reinjection wells are more directly connected to the upper part of the geothermal system (above 1000 m depth), through shallow feed-zones, while the production wells mainly produce from feed-zones below 1000 m depth (see Table 2). The connection between these two parts of the geothermal system appears to be rather poor, because of lower permeability. Yet, the interesting thing is that wells LJ-08 and LN-10 also have feed-zones in the deeper part of the geothermal system, which explains why these wells can be used to monitor pressure changes in the production reservoir. Water-level changes in these wells can, therefore, either be caused by pressure changes in the deep or shallow part of the Laugaland geothermal system.

In order to quantify the long-term effect of reinjection on the water level in the production wells the 20 year water level history of the Laugaland field, up to the beginning of reinjection, was simulated by a lumped parameter model. The deviation between observed and simulated data, during the period after reinjection started, was consequently used to estimate the benefit. The results of this analysis is presented below, but first the basics of lumped parameter modelling will be reviewed.

13.1.1. Lumped parameter modelling

Simple analytical models as well as complex numerical models are used to simulate geothermal systems (Axelsson *et al.*, 1996, Bodvarsson *et al.*, 1986). In simple models the real structure and spatially variable properties of a geothermal system are greatly simplified, such that analytical mathematical equations, describing the response of the model to hot water production may be derived. These models, in fact, often only simulate one aspect of a geothermal systems response. Detailed and complex numerical models, on the other hand, can accurately simulate most aspects of a geothermal systems structure, conditions and response to production. Simple modelling takes relatively little time and only requires limited data on a geothermal system and its response, whereas numerical modelling takes a long time and requires powerful computers as well as comprehensive and detailed data on the system in question. The complexity of a model should be determined by the purpose of a study as well as the data available. Numerical modelling for the Laugaland geothermal system is discussed in chapter 12 above.

Simple modelling has been used extensively to study and manage the low-temperature geothermal systems utilised in Iceland, in particular to model their long-term response to production. Lumped models, in particular, have been used extensively to simulate data on water level and pressure changes in these geothermal systems. Lumped models can simulate such data very accurately, even very long data sets (several decades). Axelsson (1989) has described a method that tackles the simulation as an inverse problem. It automatically fits the analytical response functions of the lumped models to observed data by using a non-linear iterative least-squares technique for estimating the model parameters. Being automatic it requires very little time compared to other forward modelling approaches, in particular detailed numerical modelling. Today, lumped models have been developed by this method for 14 low-temperature and 2 high-temperature geothermal systems in Iceland, as well as geothermal systems in China, Turkey, Eastern Europe and El Salvador, as examples. Some examples of this are presented by Axelsson (1989 and 1991) and Bjornsson *et al.* (1994).

The theoretical basis of this automatic method of lumped parameter modelling is presented by Axelsson (1989), and in fact Bodvarsson (1966) discussed the usefulness of lumped methods of interpreting geophysical exploration data. The computer code *LUMPFIT* has been used since 1986 in the lumped modelling studies carried out in Iceland (Axelsson and Arason, 1992).

A general lumped model is shown in Figure 107. It consists of a few tanks and flow resistors. The water level or pressure in the tanks simulates the water level or pressure in different parts of the geothermal system. The resistors simulate the flow resistance in the reservoir, controlled by the permeability of its rocks. The first tank simulates the innermost (production) part of the geothermal reservoir, and the second and third tanks simulate the outer parts of the system. The third tank is connected by a resistor to a constant pressure source, which supplies recharge to the geothermal system. The model in Figure 107 is therefore open. Without the connection to the constant pressure source the model would be closed. An open model may be considered optimistic, since an equilibrium between production and recharge is eventually reached during long-term production, causing the water level draw-down to stabilise. In contrast, a closed model may be considered pessimistic, since no recharge is allowed for such a model and the water level declines steadily with time, during long-term production. In addition, the model presented in Figure 107 is composed of three tanks, in many instances models with only two tanks have been used.

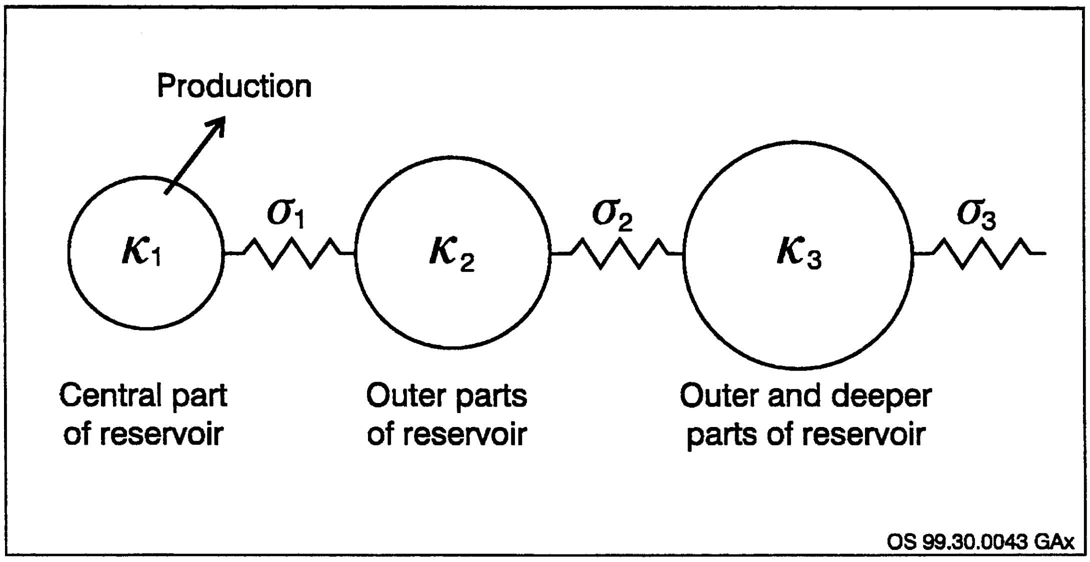


Figure 107. A general lumped parameter model used to simulate water level or pressure changes in geothermal systems.

Hot water is pumped out of the first tank, which causes the pressure and water level in the model to decline. This in turn simulates the decline of pressure and water level in the real geothermal system. When using this method of lumped parameter modelling, the data fitted (simulated) are the water level data for an observation well inside the well-field, while the input for the model is the production history of the geothermal field in question.

13.1.2. Simulation of the Laugaland water-level history

A lumped parameter model for the Laugaland geothermal system was first developed in 1989 and consequently revised in 1993 (Flovenz *et al.*, 1993). The model was again revised for the purpose of this study. The results of the simulation are presented in Figure 108, which shows that the model appears to simulate the data reasonably well. It should be mentioned that the 1993 model did not simulate the last few years of the water-level history very well and that the reason for this is believed to be an interference from production in the Ytri-Tjarnir field north of Laugaland (Figure 1). This interference has previously been considered minimal, but is now believed to be at least of the order of 2 – 3 m for each L/s produced at Ytri-Tjarnir (Axelsson *et al.*, 1999). Considering that the average yearly production at Ytri-Tjarnir has been of the order of 30 L/s during the last few years this interference could be of the order of 50 – 100 m. Similarly the interference at Ytri-Tjarnir due to production at Laugaland (35 - 45 L/s) may be of the order of 70 – 140 m. This effect was also discussed in the previous chapter on the numerical model development.

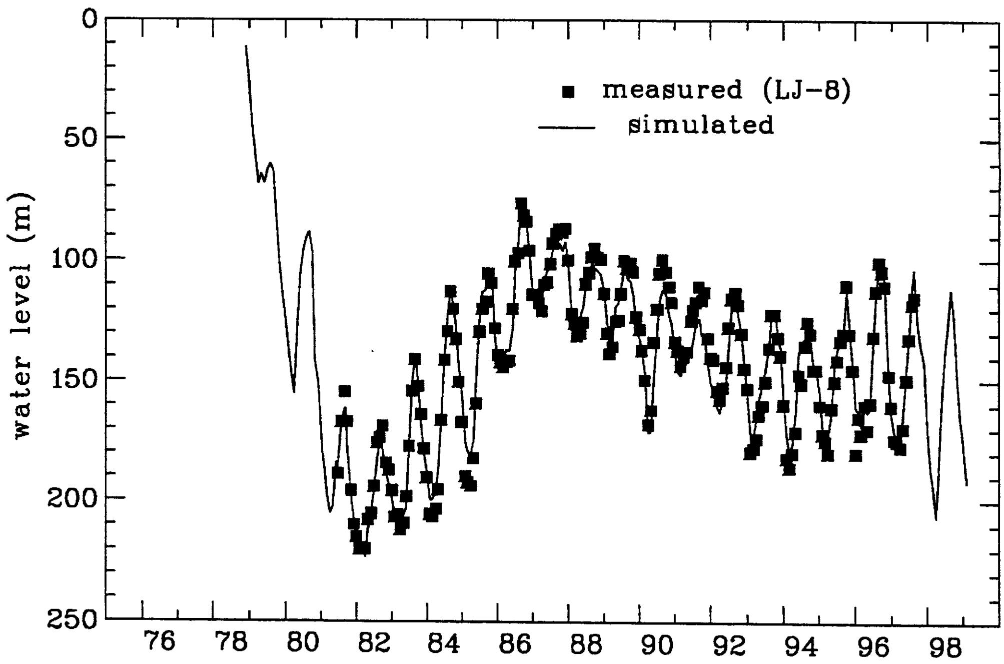


Figure 108. The water level history of the Laugaland field, up to the beginning of reinjection, simulated by a lumped parameter model.

The properties of the lumped parameter model for Laugaland are presented in Table 20 below. These are the storage coefficients of the tanks, κ_i, which are defined such that if a mass m is removed from the tank the pressure in the tank drops by $\Delta p = m/\kappa_i$, and the conductances of the resistors, σ_i, which are defined such that the flow over a resistor $q = \sigma_i \Delta p$, where Δp is the pressure drop over the resistor. Tank number i simulates a volume of the reservoir V_i such that $\kappa_i = \rho_w c_t V_i$ where ρ_w is the density of the water in-place in the reservoir and c_t is the compressibility of the reservoir rocks given by $c_t = c_w\phi + c_r(1-\phi)$, where c_w is the water compressibility, ϕ the porosity and c_r the compressibility of the rock matrix. The volume $V_i = A_i h$ where A_i is the surface area of the corresponding part of the reservoir and h its thickness. Estimates of the volumes and areas are presented in Table 20.

The reservoir permeability may be estimated on the basis of the σ-values. Assuming horizontal and radial flow between cylindrical tanks, $\sigma_i = 2\pi h(k/\nu)/\ln(r_{i+1}/r_i)$ with k the reservoir permeability, ν the kinematic viscosity of the water and r_i and r_{i+1} estimates of the distances from one tank to the next. The permeability estimates are also presented in Table 20.

Table 20. *Properties of the lumped parameter model used to simulate the water-level history of the Laugaland geothermal system.*

Tank	κ_i (kg/Pa)	Volume[1)] (km^3)	**Surface area**[2)] (km^2)
1	268	5.17	3.45
2	1750	33.8	22.5
3	20100	388	258
Resistor	σ_i (kg/sPa)	r_{i+1}/r_i[3)] (km/km)	**Permeability**[4)] (Darcy)
1	0.0000675	1.96 / 0.53	0.0028
2	0.0000195	6.19 / 1.96	0.00071
3	0.0000108	12.8 / 6.2	0.00025

1) Assuming $\phi = 0.07$ (7%) and $\rho = 960$ kg/m^3
2) Assuming h = 1500 m
3) Distances between tanks
4) Assuming h = 1500 m and $\nu = 3.0 \times 10^{-7}$ m^2/s

The surface area of the first and second tank corresponds to an area of approximately 5 km × 5 km. This is much larger than the Laugaland well field itself, which is only of the order of 250 m × 350 m, but reflects the fact that the hydrological system influenced by production at Laugaland is quite large. The surface area of the third tank is unrealistically large, however, corresponding to an area of 16 km × 16 km, which may indicate that the long-term response of the reservoir is partially controlled by free-surface mobility rather than rock-water compressibility alone.

The most important parameter of any hydrological reservoir is its permeability. The permeability estimates in the table are very low, or between 0.3 and 3.0 mDarcy, the higher value corresponding to the innermost part of the system. The permeability seems to decrease with distance from Laugaland. The equivalent permeability thickness (kh) estimates are 0.4 to 4 Darcy-m. These results confirm the low permeability nature of the Laugaland geothermal system. It should be kept in mind, however, that the interference from the Ytri-Tjarnir field is neglected here, which most likely results in lower permeability estimates for the outer parts of the hydrological system.

Figure 109 shows the calculated response of the lumped parameter model to constant rate production. It clearly shows how the semi-logarithmic rate of draw-down increases after about 1 – 2 years, reflecting lower permeability outside the central part of the Laugaland system. The change in slope may also, partially, result from interference from Ytri-Tjarnir, but hot water production started there about two years later than at Laugaland.

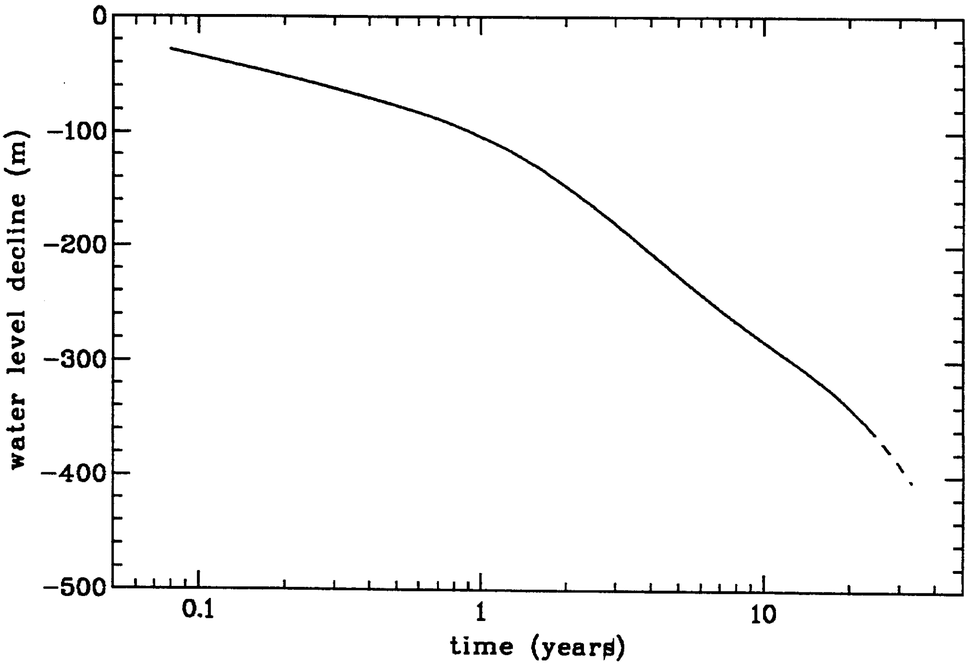


Figure 109. Calculated pressure decline of the lumped model for the Laugaland geothermal system during steady 40 L/s production, logarithmic time-scale.

We now turn our attention to the estimate of the benefit from reinjection, which is obtained with the help of the lumped parameter model. Figure 108 shows the calculated response of the model up to late 1998 while the measured water level is only available up to the beginning of September 1997, when well LJ-08 ceased being an observation well and became an injection well. The calculated response does not assume any reinjection. Measurements of the water level in wells LJ-05 or LN-12 are, however, available since this time. To be able to compare these with the calculated values, the latter were transposed to water level values for well LJ-05. This transformation is based on Figure 110, which shows the corresponding relationship for 1997. The water level measurements for well LN-12 used were also transposed to LJ-05 values by adding the elevation difference between the wells. The water level measurements were also corrected for turbulence pressure losses in wells LJ-05 and LN-12 by subtracting 20 m for the former and 25 m for the latter.

The results are presented in Figure 111. It shows clearly that the depth to the water level was about 20 m less in late 1998 then it should have been according to calculations by the lumped parameter model, which do not assume reinjection. This water level recovery may clearly be attributed to the reinjection into wells LJ-08 (and LN-10). It may be noted that the measured water level drops, and rises, more rapidly than the water level calculated by the model. This is because the response of the model is based on observations in well LJ-08 through the years, which does not respond as quickly to changes in production as the production wells (LJ-05 and LN-12).

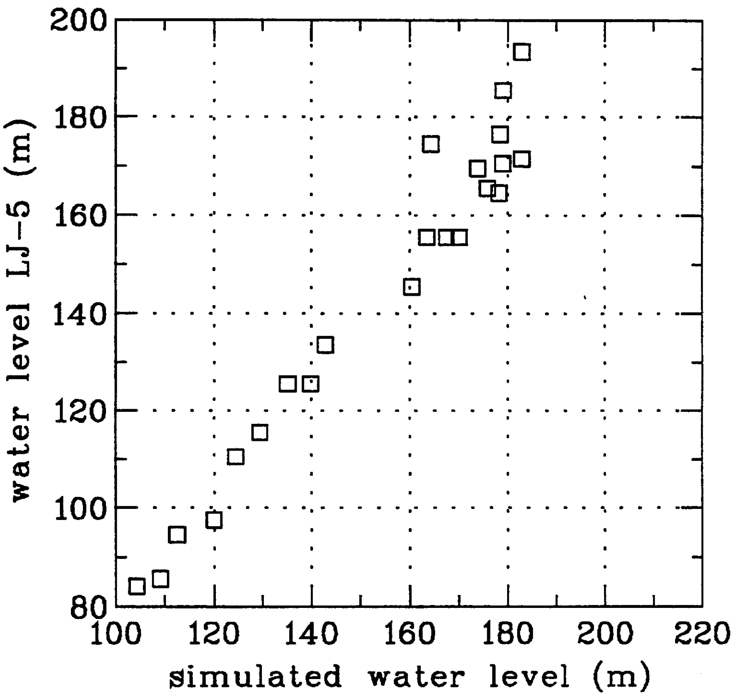


Figure 110. The relationship between the water level in well LJ-05 in 1997 and the water level in Well LJ-08 calculated by the lumped parameter model.

The 20 m water level recovery suggested by Figure 111 indicates that reinjection influences the water level in the production wells as if production was reduced by about 2/3 of the mass reinjected. This is the same result as arrived at earlier. Therefore the response of the model was calculated again, this time after subtracting 67% of the reinjection from the production used as input for the model. The results are presented in Figure 112, which shows clearly that the calculated water level now simulates the water level variations quite well, in particular the minimum and maximum levels during summer- and winter time, respectively. Again the measured water level drops, and rises, more rapidly, however, than the water level calculated by the model.

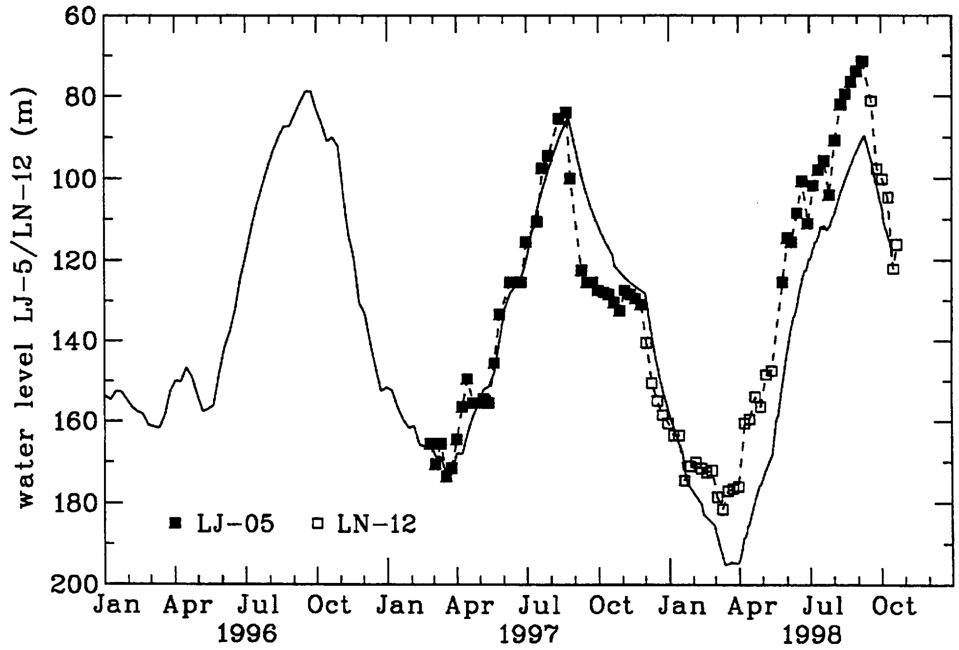


Figure 111. Comparison between the measured water level in wells LJ-05 and LN-12, on one hand, and water level changes calculated by a lumped parameter model, on the other hand. *No reinjection is assumed.*

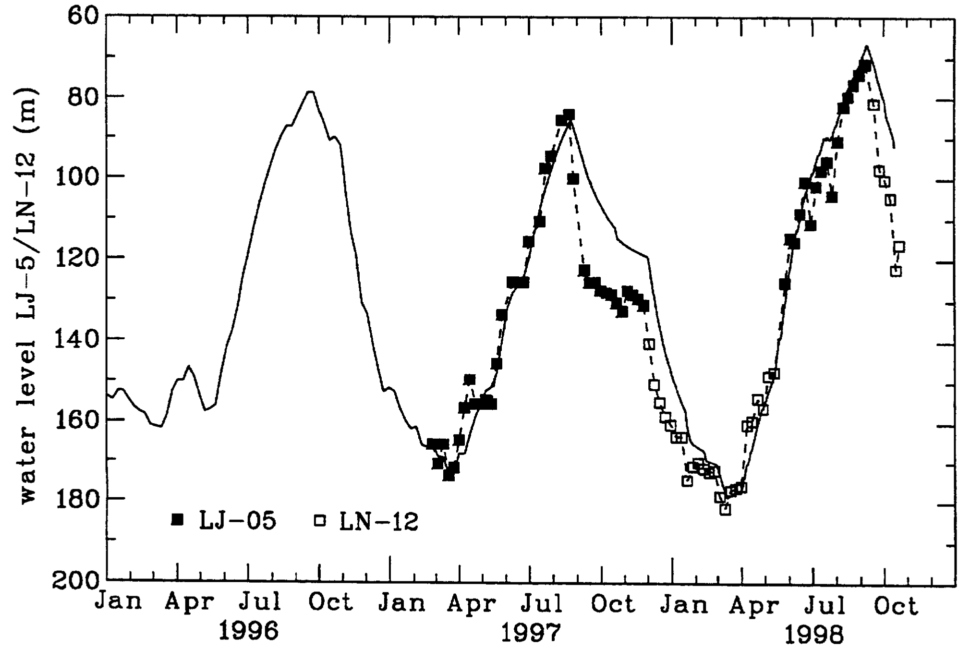


Figure 112. Comparison between the measured water level in wells LJ-05 and LN-12, on one hand, and water level changes calculated by a lumped parameter model, on the other hand. *A 67% benefit from the reinjection is assumed.*

The results of the analysis discussed above may be summarised as follows. ***The results indicate that the hot water production rate at Laugaland may be increased by 60-70% of the reinjection rate, without causing additional draw-down.*** It appears that the short-term (days) benefit will be minimal, while the long-term (years) benefit may be expected to be even greater than the 60-70%. This will not be quite clear, however, until reinjection has been in operation for a few more years. It may also be mentioned that some water level recovery has been observed in the Ytri-Tjarnir geothermal field about 2 km north of Laugaland, which also may most likely be attributed to the reinjection.

13.2. Predicted water temperature changes

The results of section 7.4 were finally used to predict the temperature decline of the production wells, during long-term reinjection into well LJ-08, for a few different reinjection scenarios. These are cases of 10, 15 and 20 L/s average yearly reinjection. Some shorter term variations in injection rate are, of course expected, but are discounted in the calculations. According to the results of the previous section, these cases should result in an increase in the potential of the field of about 7, 10 and 13 L/s, respectively. Only mode A cooling is considered at this stage, while mode B cooling will be discussed later. Axelsson *et al.* (1995) and Hjartarson (1999) present the methods used in calculating the predictions. These are based on the same flow-channel model as the tracer test analysis (chapter 7).

The cooling of the water travelling through the flow channels, or more correctly the heating-up of this water, depends on the surface area of the channels rather then their volume, as already discussed. Therefore, some assumptions must be made on the geometry of the channels. Here the geometry, which results in the most pessimistic predictions was selected, i.e. the geometry with the smallest surface area for a given flow-path volume. This is the case where the width and height of a flow-channel are equal. Figure 113 and Figure 114 present the results of the calculations, the former for well LJ-05 and the latter for well LN-12. For both cases 40 L/s production was assumed for the production wells. The results in Table 14 were used directly to calculate the temperature decline of well LN-12. The temperature decline for well LJ-05 was calculated based on the assumption that about twice the amount of injected water travelled through comparable small volume flow-channels in the case of that well, compared to the well-pair LJ-08 and LN-12. The slightly shorter distance was also taken into account. Therefore it must be emphasised that the predictions for well LJ-05 are not as reliable as for well LN-12.

The predictions indicate that the temperature of the water pumped from wells LJ-05 and LN-12 will decline between 1 and 4.5°C, in 30 years, depending on which production well is used as well as the rate of reinjection. It is likely that an average reinjection rate of 15 L/s can be maintained at Laugaland. This will only cause a temperature decline of 1.5°C for well LN-12, in 30 years, according to the predictions. In the following section the estimated increase in energy production, for these reinjection/production scenarios, will be presented, wherein these cooling predictions are taken into account.

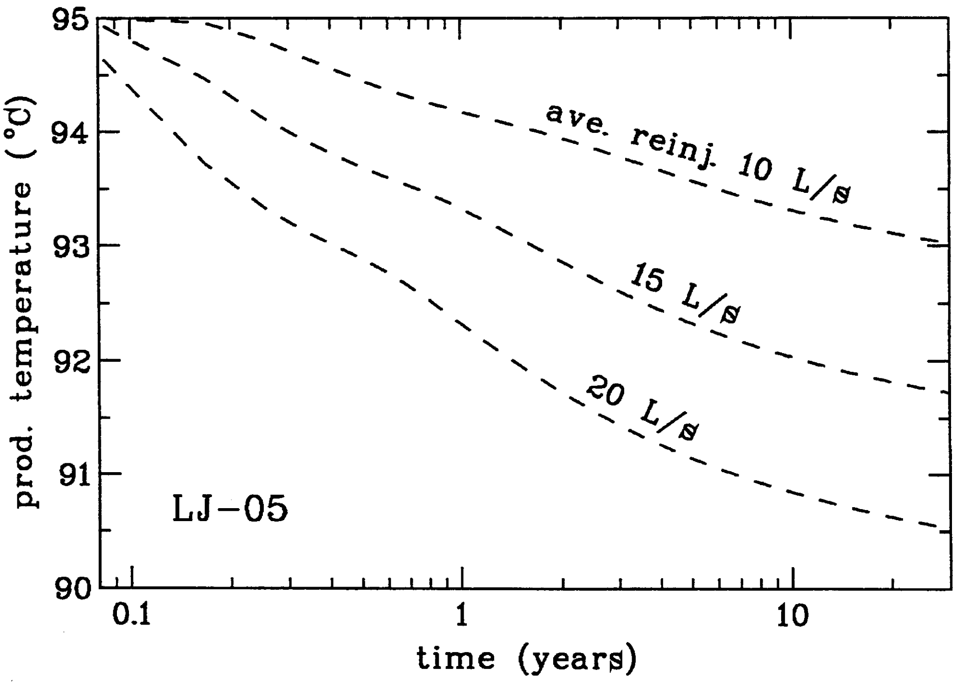


Figure 113. Estimated decline in the temperature of well LJ-05 for three cases of average long-term reinjection into well LJ-8, due to flow through the three channels simulated in Figure 58.

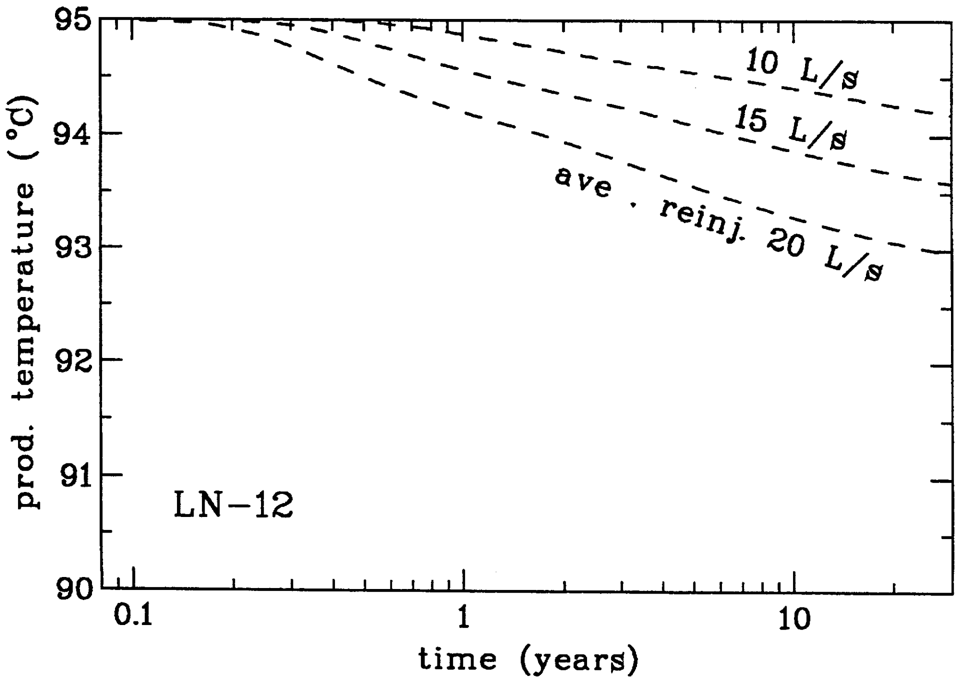


Figure 114. Estimated decline in the temperature of well LN-12 for three cases of average long-term reinjection into well LJ-8, due to flow through the three channels simulated in Figure 58.

It should be pointed out that comparable cooling predictions have not been calculated for well LJ-07, using well LJ-08 as a reinjection well. On one hand, it is to be expected that the cooling of this well will be even less than that predicted for well LN-12. On the other hand, the benefit of reinjection (i.e. water level recovery) is not expected to be as great as that for wells LJ-05 and LN-12, owing to the greater distance from well LJ-08 and a much deeper casing.

It should also be pointed out that cooling predictions have not been calculated for the well-pair LN-10/LJ-05. This is partly because the available tracer return data could not be analysed accurately due to various disturbances, as discussed previously. It is clear, however, that well LJ-05 will cool down considerably more if well LN-10 is used as an injection well instead of, or in addition to, well LJ-08. Therefore, it not is recommended to use well LN-10 for long-term reinjection. Yet it is noteworthy that the tracer injected into well LN-10 was only recovered to a very limited extent in wells LJ-07 and LN-12. Therefore, the possibility of using the well as an injection well and wells LJ-07 and LN-12 only, as production wells, should be considered. This needs further study, however.

The injected water, which does not travel through the direct, small volume, flow-channels, may also cool the production wells to some degree. This effect may be estimated on the basis of the volume involved in the mode B transport, as estimated in chapter 7 ($V\phi \approx 500{,}000$ m^3). Cooling due to this mode of transport of the injected water can, however, not be predicted with any accuracy. It was estimated for two extreme cases, which may be considered to be optimistic and pessimistic scenarios:

(1) One continuous porous volume with 7% average porosity, with a total volume of 7,000,000 m^3. In this case, and assuming 15 L/s average reinjection, the thermal breakthrough time is estimated to be of the order of 17 years.

(2) A larger volume, wherein the flow is manly restricted to the reservoirs fracture-network, having an effective porosity of 1%. In such a case the total volume involved would equal 50,000,000 m^3 and the thermal breakthrough time would equal about 100 years.

These result indicate that some cooling, in addition to the short-term cooling previously predicted, is to be expected to occur somewhere in the time-span of 10 – 100 years after reinjection starts. It is unlikely that this cooling will start until after some decades. It is also expected to be very slow. This may be more accurately predicted after a few years of reinjection, through the use of the numerical model now being developed. The preliminary results of this modelling, presented in chapter 12, support the contention above.

13.3. Predicted increase in energy production

To estimate the increase in energy production enabled through long-term reinjection into well LJ-08, the results of sections 13.1 and 13.2 are simply combined. The results are presented in the following four figures. Figure 115 and Figure 116 present the additional energy production per month, for wells LJ-05 and LN-12, respectively, while Figure 117 and Figure 118 present the cumulative additional energy production for theses wells during the whole 30-year period being considered here.

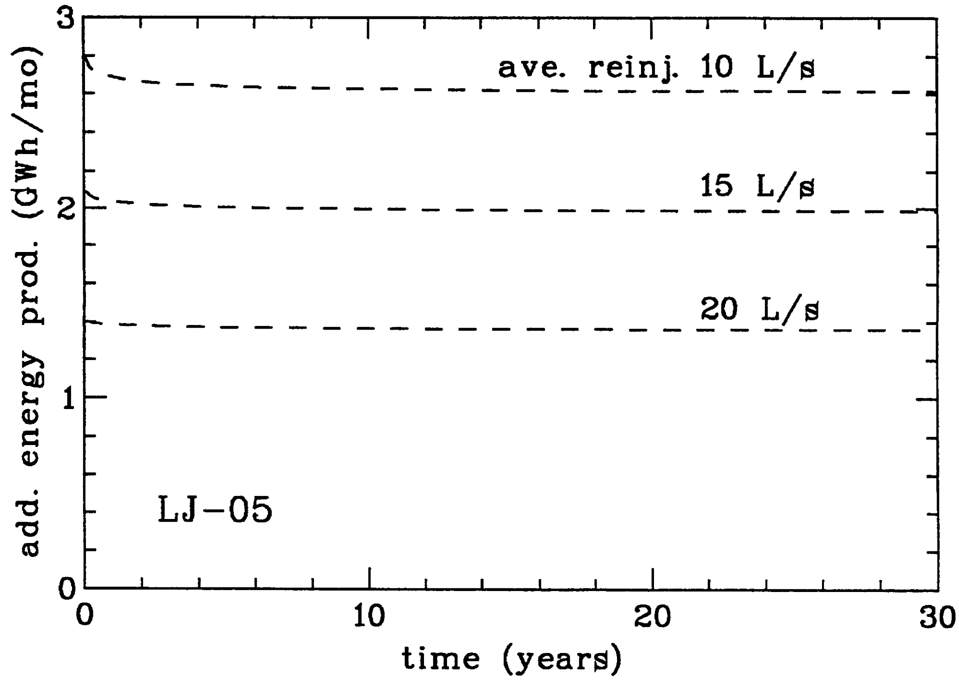


Figure 115. Estimated additional energy production resulting from reinjection into well LJ-8. Calculated for three cases of average injection and assuming production from well LJ-05.

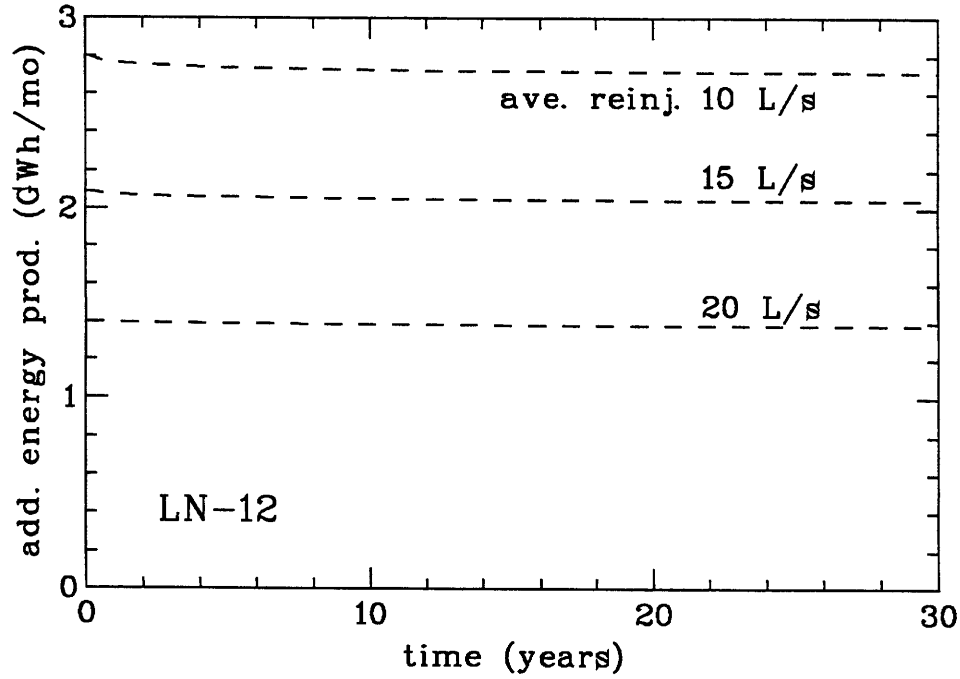


Figure 116. Estimated additional energy production resulting from reinjection into well LJ-8. Calculated for three cases of average injection and assuming production from well LN-12.

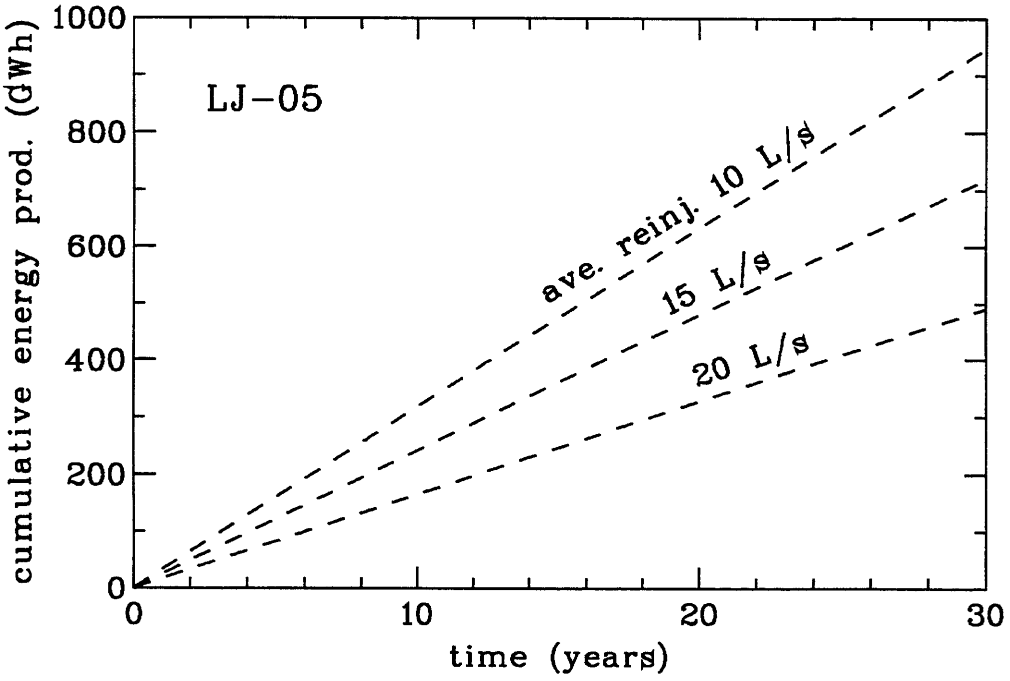


Figure 117. Estimated cumulative increase in energy production for 30 years of reinjection into well LJ-8. Calculated for three cases of average injection and assuming production from well LJ-05.

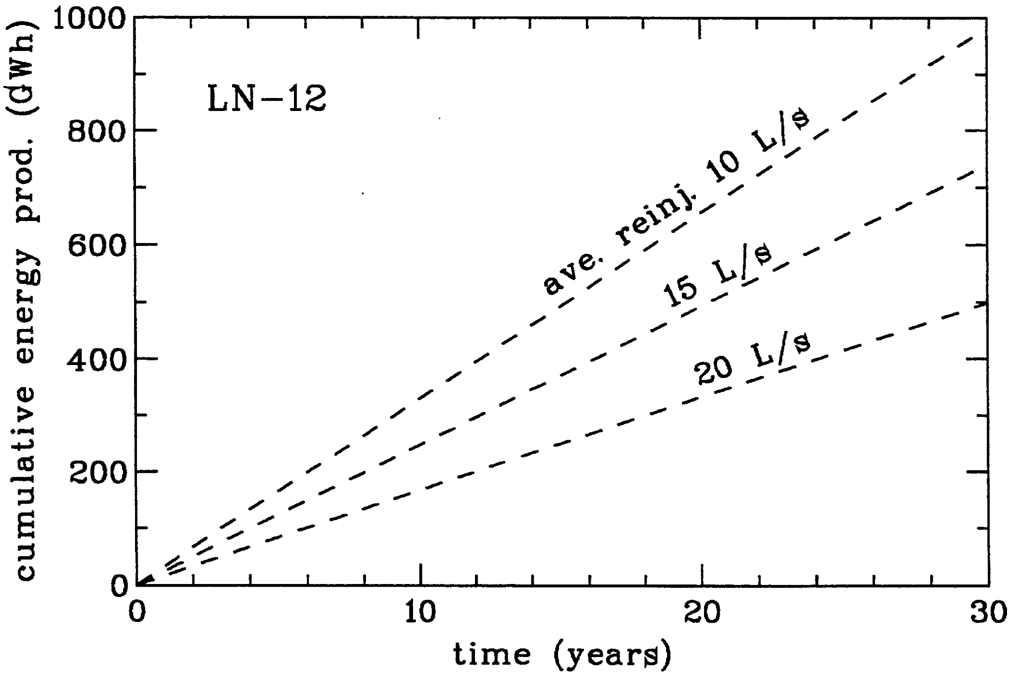


Figure 118. Estimated cumulative increase in energy production for 30 years of reinjection into well LJ-8. Calculated for three cases of average injection and assuming production from well LN-12.

It should be kept in mind that these results imply that either one of wells LJ-05 and LN-12 are in use, not both. If both wells are in use the predicted increase in energy production will be the average of the increase of each of the wells, not the sum.

It is considered likely that an average long-term reinjection rate of about 15 L/s may be maintained at Laugaland. The maximum rate will be 21 L/s during the winter-time, when the return water supply is sufficient. During the summer-time the reinjection rate may, however, decrease down to 10 L/s. Therefore, the above results indicate that future reinjection will enable an increase in energy production amounting to roughly 2 GWh_t/month or 24 GWh_t/year. This may be compared to the average yearly energy production from Laugaland during the last ten years, which has amounted to about 100 GWh_t/year. For this reinjection/production scenario the cumulative energy production, during the 30 year period considered, could reach more than 700 GWh_t.

These results provide the basis for an analysis of the economics of future reinjection at Laugaland, and in other comparable geothermal fields, which is presented in the next chapter.

14. ECONOMIC ANALYSIS

14.1. The results of the Laugaland experiment

In the initial plans for the reinjection project the total project cost was estimated, as well as the expected energy output and calculated payback time. These numbers were presented in Annex I of the project contract. Now, actual numbers for the project cost are available, which allows a comparison with the original plan. These numbers are presented in Table 21.

Table 21. *Planned and actual project cost, payback time and energy prices.*

	Original plan (ECU)	Actual cost (Euros)
Total project cost	1,835,239	2,204,100
Investment cost	1,118.881	1,284,580
Energy production (GWh_t/year)	16	24
Maintenance cost	20,979	20,979
Electricity	32,168	20,489
Staff	69,930	41,958
Total annual operating and maintenance cost	123,077	83,426
Pay-back time	3.2 years	2.5 years
Life span of installation	20 years	20 years
Unit customer price ECU/kWh	0.029	0.025
Interest rate	6%	6%
Energy price in ECU/kWh	0.0138	0.0081

The table shows that the total cost in Euros was 20% higher than initially expected. This discrepancy, however is almost entirely due to changes in exchange rate of the Icelandic currency (kronur, ISK) into Euros. When the project contract was signed the rate was 85 ISK/ECU but at the end of the project the exchange rate was 71.5 ISK/Euro, the main change occurring early on in the contract period. Thus, if calculated in ISK, the total project cost was 156,491,100 ISK compared to an initial estimate of 155,995,315 ISK, which is 0.3% from the initial plan. Although the total project cost is very close to the initial plans, negative as well as positive deviations in the cost of individual phases of the project did occur.

At the beginning of the project the expected increase in energy production was about 16 GWh_t/year, but the final results indicate that a 24 GWh_t/year increase will be possible, or about 50% more then expected. Based on the experience of the last two years, the basic operating and maintenance cost for running the injection, is now considered to be 56% of the initial estimate, both because of lower consumption of electric energy for pumping and less manpower to run the injection. Based on the actual numbers we calculate the payback time of the investment to be 2.5 years instead of 3.2 years as initially expected. Similarly, if we calculate the price of the additional energy obtained through the injection it turns out to be 0.0081 Euro/kWh compared to the initial value of 0.0138 ECU/kWh.

Of course the energy price obtained from this project cannot be adapted directly to other geothermal areas, but it gives a very important indication as to what may be the expected result for reinjection in similar geological environments.

14.2. Application of the results to other geothermal fields

We have shown that reinjection into fractured geothermal systems in low permeability crystalline basement reservoirs is technically possible as well as being economically viable for our specific case. Consequently we have to consider to what extent we can apply these results to more general cases. We have to keep in mind that in the case of Laugaland the drilling of specific reinjection wells was not needed for the purpose of reinjection. Existing, but abandoned wells, which were drilled 20 years ago and were considered unsuccessful because of low productivity, were used instead.

We can use our result to calculate the feasibility of using reinjection into a fractured geothermal system, for a more general case, where we take into account drilling of specific reinjection wells. In general we can subdivide the investment cost into the following items:

- Collection of return water.
- Return pipeline.
- Injection wells.
- Pumps and on-site equipment.

In the Laugaland case the geothermal water is used directly for space heating at Akureyri, at an approximately 13 km distance from the geothermal field. In Akureyri enough return water is collected from the houses to make the reinjection possible. Therefore, spending additional capital on recollecting the return water was not needed, it was already available. In many cases where direct use is practised the return water is not collected. In such cases we have to take the cost of the collection of return water into the investment cost.

The cost of the return pipeline is highly site specific depending on distance, type of pipeline and cost of pipeline construction. The distance can vary drastically from case to case. In cases where the geothermal fluid is not used directly but the heat is transferred through heat exchanges at the geothermal field itself, the cost of collection of return water and the return water pipeline is negligible. For such cases the investment cost would be considerable lower than in the Laugaland case. We have also demonstrated that it is possible to use simple polyethylene pipelines for the purpose of piping the return water back to the field, which is considerably cheaper than using ordinary steel pipes.

Although it was not necessary to drill special reinjection wells at Laugaland it must be assumed to be necessary in the general case. Such injection wells, however, are relatively simple and inexpensive. Based on drilling prices in Iceland for low temperature geothermal wells, drilling of a 1500 m injection well could cost about 0.25 MEuro. Two to three such wells might be necessary to allow for an average injection of 15 L/s, depending on the injectivity of the wells. Thus, if drilling of three 1500 m deep injection wells had been necessary the total investment cost could have been as much as 0,75 MEuro higher. In that case we would obtain payback time of 4 years and energy price of 0.0109 Euro/kWh, which still is highly profitable.

The cost of pumps and other on-site equipment obtained from our demonstration project can be assumed to be typical for other cases. In addition to the cost of investment and running and maintenance the energy output is crucial for the feasibility of reinjection projects. Apart from the injectivity there are mainly two parameters that control the additional energy obtained by the injection, i.e. the temperature of the reservoir and the thermal breakthrough time for the injection scenarios assumed. In the case of Laugaland these parameters are rather favourable, but even though we assume only half of the energy for a general case and include drilling of injection wells the resulting energy price would still be quite low, or of the order of 0.016 Euro/kWh.

Thus we may conclude that the Laugaland reinjection project has demonstrated that large scale water reinjection into fractured geothermal reservoirs, in low-permeability crystalline rocks, is technically possible. The resulting energy prices are very low, and can compete with prices for any other energy source.

15. DISSEMINATION

Great emphasis has been placed on dissemination throughout the duration of the Laugaland reinjection project, both locally in Iceland as well as internationally. This dissemination will, furthermore, continue, even though the project as such has ended. Below is a list of the main venues of dissemination:

(1) An ***information brochure*** was published at the beginning of the project in 1997, both in Icelandic and English. This brochure was distributed widely. In addition, two ***information posters*** were produced, which are now on display at the headquarters of HVA and at Orkustofnun.

(2) At least 15 ***internal reports***, or memorandums, were published at Orkustofnun throughout the project. These were all in Icelandic and are not included in the list of refemeces below. Their combined number of pages equalled 78.

(3) The project, and its results, was presented through lectures and posters at various conferences and workshops. In all cases the associated material was published in ***conference- or workshop proceedings*** (Axelsson *et al.*, 1998a, 1998c & 1998d; Axelsson and Stefansson, 1999; Hauksdottir *et al.*, 1999). Some of these papers are enclosed in Appendix B at the end of this report.

(4) Part of the comprehensive reservoir data collected during the project was analysed during a ***MSc-project*** completed at the University of Iceland in June 1999 (Hjartarson, 1999). The main results of this work were also presented in an open lecture at the University.

(5) Part of the tracer recovery data did provide the basis for project work of one of the international fellows at the ***United Nations University Geothermal Training Programme*** in Reykjavik in 1999 (Liu, 1999), as well as provide material for specific training in geothermal reservoir physics.

(6) The project was also presented at a few ***meetings*** with the staff, and Board of Directors, of HVA, as well as other interested parties.

(7) The Laugaland project was, furthermore, presented in national and local ***newspapers*** in Iceland.

(8) The project was submitted to the ***Energy Globe Awards 2000***, which were presented in Linz, Austria, on March 8th 2000. It will also be presented on a CD-Rom presenting the projects competing for the Energy Globe Awards 2000.

(9) The reinjection project will be presented at the ***World Geothermal Congress 2000***, to be held in Japan from May 31st through June 7th 2000. A copy of the paper, which will be included in the Congress Proceedings is enclosed in Appendix B. The results of the project will also be presented at a short course on reservoir monitoring and management prior to the Congress.

(10) Initially the intention was to convene a ***final workshop*** in Akureyri in late 2000 to present and review the results of the project, as well as to bring together experts on reinjection from other parts of the world and operators of various geothermal fields.

This was not included in the contract with the European Commission. Therefore, a proposal was sent to the Commission in 1999, requesting support for such a workshop. Unfortunately the Commission decided not to support that proposal.

(11) The intention is to submit one or more papers, dealing with different aspects of the project and its results, to international ***scientific journals***, such as Geothermics. The plan is also to reissue the ***information brochure*** (1) published at the beginning of the project.

16. SUMMARY AND CONCLUSIONS

This report has described the background, progress and results of the reinjection project carried out in the Laugaland geothermal field in N-Iceland, for the two-year period from September 1997 through August 1999. Considerable space has, in particular, been devoted to the results of analysis of the comprehensive and extensive data set collected in conjunction with the project. Energy from the Laugaland geothermal system has been utilised for space-heating in the near-by town of Akureyri, but its productivity has been limited by low permeability and limited recharge. The purpose of the reinjection project was to demonstrate that energy production from fractured low-temperature geothermal systems may be increased by reinjection, through the extraction of some of the thermal energy in-place in the 90 – 100°C hot resevoir rock.

The progress of the Laugaland experiment was mostly according to schedule. At the end of August 1999 about 910,000 m^3 of geothermal return water had been reinjected, or about 14.4 L/s on the average, which corresponds to about 36% of the production from the field during the same period. A comprehensive monitoring program was implemented as part of the reinjection project. This involved monitoring of production- and injection rates, water temperatures, wellhead pressures and water-levels by an automatic monitoring system. Also included were three tracer-tests, monitoring of associated micro-seismic activity, chemical monitoring, step-rate injection tests and temperature logging of the injection wells before and during injection.

The principal results of the Laugaland project are highly positive. It appears that energy production from the field may be increased significantly, and economically, through reinjection. The main results of the Laugaland reinjection project are summarised below, while more detailed results for each of the project phases are presented in the respective chapters:

1. Analysis of temperature profiles measured in well LJ-08, the main injection well at Laugaland, during injection shows that the injected water exits the well through four well defined feed-zones (at 320, 600, 1335 and 1875 m depth). About $^2/_3$ of the water injected exits the well above 600 m depth, while the main feed-zones of the production wells are located below 1000 m depth. Two of these feed-zones correlate with fractures, striking SW-NE and dipping to the N, which were observed by a borhole televiewer. Only these fracture, out of almost 30 observed by the televiewer, are believed to be hydraulically conductive. The present analysis supports the existence of a principal fracture-zone extending through the Laugaland area, which is near vertical and striking N50°E.
2. Analysis of water level data collected during the reinjection project shows that the three production wells (LJ-05, LJ-07 and LN-12) are directly connected through the principal fracture-zone, which is estimated to be 0.5 – 1.0 km in length and have a permeability thickness of 15 Darcy-m. Injection wells LJ-08 and LN-10 are clearly outside the fracture-zone. The permeability thickness of the geothermal reservoir outside the fracture-zone is estimated to be about 2 Darcy-m. Repeated step-rate injection tests in well LJ-08 reveal no noticeable changes in the injectivity of the well, which might have been attributed to chemical precipitation or thermal effects.

3. A total of more than 1400 tracer samples have been collected and analysed from production wells at Laugaland and in near-by areas, in conjunction with the three tracer tests carried out as part of the reinjection project. The tracer return data indicate that the injected water travels through the bedrock in the area by two modes: (A) Firstly, through direct, small volume flow-paths, such as along fractures or interbeds. (B) Secondly, by dispersion and mixing throughout a large part of the Laugland reservoir. These results are used to predict temperature changes in production wells during long-term reinjection. The tracer-return data also show that a direct connection exists between well LJ-08 and the Ytri-Tjarnir field 1800 m north of Laugland.

4. The results of two experiments simulating reservoir conditions indicate that the Na-fluorescein tracer used neither decays at the reservoir temperature in question, nor interacts with the alteration minerals in the basaltic rocks of the reservoir, at the relevant time-scale.

5. Measurement discrepancies and other variations mask minor changes in the temperature of the production wells at Laugaland, which possibly may have occurred during the project because of the reinjection. It can be asserted, however, that the two-year reinjection experiment did not cause a temperature decline greater than about 0.5°C.

6. Part of the reinjection project involved detailed monitoring of the chemical content of the hot water produced from production wells at Laugland and in nearby geothermal fields. No significant chemical changes were observed in any of the wells, indicating that no deposition, or other chemical reactions, are expected to occur in the geothermal reservoir during future reinjection of return water of comparable composition.

7. The six station micro-seismic network in operation during the project was expected to detected some seismic events, down to size $M_L = -1$, caused by the high-pressure reinjection. No such events were detected indicating that, either the pressure increase at great depth in the fractured Laugaland reservoir was not sufficient, or that the deviatoric stresses needed to trigger such events have been released through two decades of hot water production and greatly varying reservoir pressure at Laugland.

8. The first phase of the development of a detailed, three-dimensional numerical model of the Laugland geothermal system and surroundings has been completed. Even though they are only preliminary, the results are in a good agreement with the results of other calculations on the effect of long-term reinjection in the field. The development of the numerical model will continue with the aid of the most up-to-date simulation software, the *iTOUGH2*-code from LBL in Berkeley, California.

9. Estimation of the reservoir pressure (water level) recovery at Laugaland due to the reinjection indicates that hot water production in the area may be increased by 60-70% of the reinjection rate, in the long term, without causing additional pressure (water level) draw-down. The temperature of water produced through well LJ-05 and LN-12 is predicted to decline by 1.5 and 3°C, respectively, in a few years time, assuming 15 L/s average future reinjection into well LJ-08. Some additional

temperature decline is possible during the following decades, which may be predicted more accurately in a few years time. Future reinjection at the above rate will, therefore, enable an increase in energy production amounting to about 24 GWh_t/year, which equals roughly ¼ of the average yearly energy production at Laugaland during the last decade. The results of the Laugland project show that increased energy extraction, through reinjection of return water, is technically viable in the area.

10. Economic analysis indicates that the price of additional energy produced through future reinjection at Laugaland will be about 0.008 Euro/kWh, and that the payback time for the project investment will be 2.5 years. This price can compete with the price of most, if not all, other energy sources. Extending this result to other low-temperature geothermal areas and including the cost of drilling a few specific reinjection wells, as well as assuming the energy recovery not to be as favourable as at Laugland, the energy price should still be below 0.016 Euro/kWh.

11. Emphasis was placed on dissemination throughout the project. This included publication of information brochures and posters, presentations at a number of international conferences and workshops, such as the World Geothermal Congress 2000 in Japan, in addition to some newspaper articles several internal reports. The data collected also provided the basis for a MSc-thesis at the University of Iceland, and a project report at the United Nations University Geothermal Training Programme.

Reinjection is practised in many geothermal fields in the world, in most cases to dispose of waste water due to environmental reasons (Stefansson, 1997). Reinjection with the purpose of extracting more of the thermal energy in the hot reservoir rocks, and thereby increase the productivity of a geothermal reservoir, has not been practised in many areas. This is more in line with the Hot Dry Rock concept. Injection has, furthermore, not been part of the management of the numerous low-temperature systems utilised in Iceland. Preliminary results of the Laugaland reinjection experiment are positive, and indicate that reinjection will be an economical mode of increasing the production potential of the Laugaland system. The current reinjection system will, therefore, hopefully be an important part of the management of the geothermal reservoir for decades to come. The results of the project will hopefully also encourage other operators of fractured low-temperature geothermal systems to consider injection as a management option.

Even though the Laugaland reinjection project has been successfully completed, some related work is expected to continue. The following may be mentioned:

A. Continued careful monitoring of the different aspects of the reinjection. Particular emphasis must be placed on accurate water temperature measurements.

B. Continued monitoring of the tracer recovery for the next 1 – 3 years.

C. Further analysis and interpretation of some of the data collected during the project.

D. The great amount of tracer test data collected during the Laugaland experiment requires further analysis and interpretation. Some attention needs to be given to possible retention mechanisms, such as matrix diffusion.

E. It is anticipated that development of the numerical model, which will eventually incorporate all the geothermal systems in the Eyjafjordur-valley, will continue. This work will hopefully be completed within the next two years, or so. A new version of the *TOUGH2* numerical simulator, *iTOUGH2*, will be employed for this purpose

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APPENDIX A: PRINCIPLES OF GEOTHERMAL LOGGING

In geophysics the word "log" indicates a continuous measurement of a parameter with time or, in space. In a borehole measurement a sonde is moved up or down a well at constant speed while it measures down-hole conditions. Therefore, the term "borehole-log" indicates a log of a parameter with depth. The data collected is transmitted trough a cable to a registration unit on the surface or stored in the sonde for later reading. The sondes are of many types, suited for measuring the various parameters involved. The main objectives of geothermal logging is to gain information on well performance and well conditions and more importantly, obtain information on physical properties and structure of the geothermal reservoir in question.

When a well penetrates a reservoir its state is disturbed and the parameters measured in the well are not the same as in the undisturbed reservoir prior to the wells existence. This has to be kept in mind when interpreting well-log data. If a single well is logged, only a one-dimensional array of the reservoir parameters is obtained, while a three-dimensional view of the geothermal system can be obtained if many wells are logged. By measuring repeatedly, the time behavior of the geothermal system involved can be derived.

A typical geothermal well is logged many times during its lifetime, with various logging instruments, providing useful information. The temperature log is probably the most useful log for geothermal wells. By measuring the temperature as a function of depth one can obtain information on reservoir temperature, location of aquifers, temperature gradient and heat flow. Overviews of geothermal well logging, and an introduction to techniques and interpretation, are found in Stefansson and Steingrimsson (1990) and Grant *et al.* (1982). They are the main references used in writing the review of the theory of temperature logging below.

Temperature logging

Temperature logs are essential to locate feed-zones and to estimate reservoir temperature. This information is vital to the understanding of a reservoirs nature. But temperature logs do seldom show the actual reservoir temperature. During drilling (or injection) the circulation fluid cools the borehole down, and temperature logs show disturbed temperature conditions. It may take the well a long time to achieve reservoir temperature after the circulation is stopped and the disturbances may never disappear because of internal flow between feed-zones, for instance. By monitoring how the well recovers in temperature, important information is obtained that can be used to identify, with careful interpretation, water entries in the well and zones of circulation losses can be studied. It is therefore important to do repeated temperature log measurements during well warm-up

Four examples of typical temperature profiles in geothermal wells will be discussed below as well as how their feed-zones are identified.

Identifying feed-zones

Permeable zones such as fractures, dikes and leaky interbeds are the regions where hot and cold water flows in and out of a well. During drilling the circulation fluid may enter the permeable zones and cool them relatively more than the rest of the formation. If the well is not flowing after drilling, these zones may warm up more slowly. On the other hand, the permeable zones heat up more rapidly than the rest of the well, if the well is flowing. Thus permeable sections of the well usually show up as temperature anomalies, either hot or cold.

Figure 119 shows four examples for a well with three aquifers at depths a, b and c. Cases A and B show temperature profiles that may be observed during injection while case C shows a profile that may be observed if the well is flowing. Case D, however, shows a temperature profile for the closed well and a linear rock temperature profile, for comparison. Profile A arises when there is water loss at all three feed-zones. Below the two upper feed-zones the fluid flow decreases compared to the flow above the feed-zones. The conductive heat flow from the formation to the wellbore causes a faster rise in temperature. The breaks in the temperature profile, where the flow rate down the well decreases, therefore, correspond to the feed-zones.

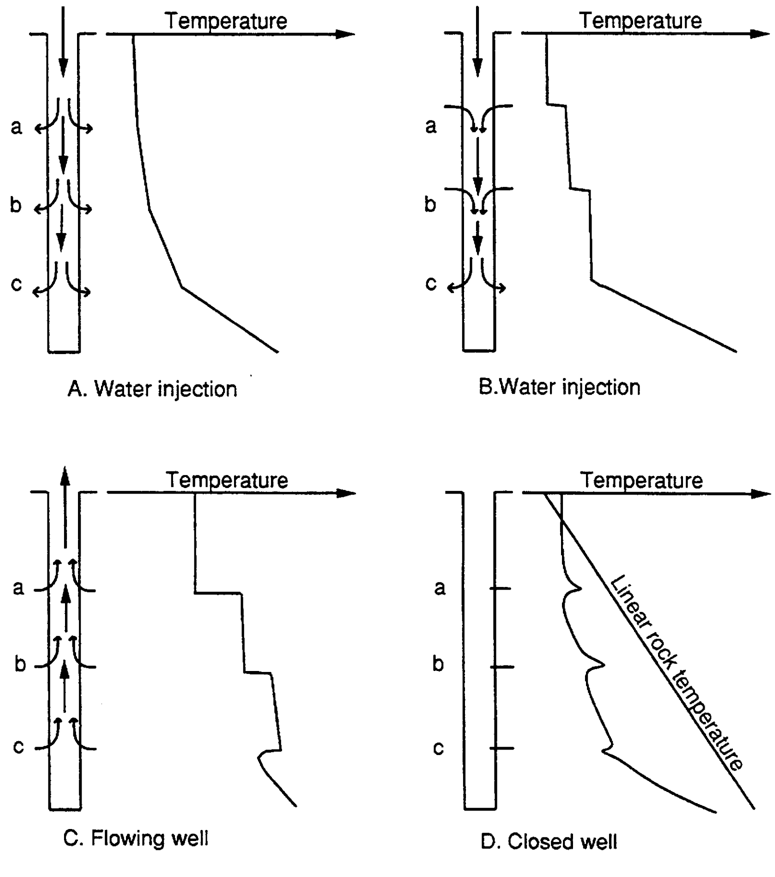

Figure 119. Temperature profiles in a flowing (closed) well with feed-zones at depths a, b and c. Arrows indicate direction of fluid flow (from Stefansson and Steingrimsson, 1990).

Case B shows the temperature profile where fluid enters the wellbore through the two upper feed-zones, a and b. The inflow of hotter fluid is identified as steps in the profile. All the fluid leaves the well at feed-zone c and below that depth the well is heated by conduction only. The difference in profiles A and B clearly demonstrates how the down-flowing fluid gradually warms up in case A, while steps in the profile are observed in case B. In the flowing well (profile C) steps are also observed in the temperature profile because fluid, with increasing temperature with depth, is entering the well. There is no fluid flow in the well in case D and the feed-zones can be seen as positive or negative temperature anomalies.

Flow between feed-zones in a closed well is also common. The flow is usually from an upper feed-zone downwards to a lower one, as shown in case B on Figure 119. This creates convection cells between the feed-zones in the well, which are nearly isothermal. They can be identified by the uniform and faster warm-up of the section involved, than in the rest of the well. Temperature profiles in wells can be distorted by various mechanisms as seen in the examples presented above. In actual wells a combination of the mechanisms described may result in unclear, or conflicting, data, which can be difficult to interpret.

Well LJ-08 was temperature logged during injection on four occasions during the first year of the reinjection project. The profiles are all quite similar to the profile in case A previously discussed. The theory behind the interpretation method employed in analysing these profiles is reviewed below.

Water loss in flowing well

The locations of water loss zones in a well can be determined by interpreting injection temperature profiles. By knowing, in addition, the temperature of the injected water, the injection rate and the temperature of the formation prior to the injection, the amount of water loss through each zone can be estimated. This is done through equating the energy flow from the formation into the well and the energy required to heat up the injected water, as it flows down the well. The governing equation, based on the conservation of energy at steady state conditions, is:

$$\partial E(z)_t / \partial z = Q \qquad \text{(A.1)}$$

where $E(z)_t$ denotes the total energy flux in the well, Q the radial heat loss from the rock matrix to the well, per unit length, and z is the depth co-ordinate. The energy flux for liquid phase water can be written as:

$$E(z)_t = q(z)\, c_w\, T(z) \qquad \text{(A.2)}$$

c_w is the heat capacity of the water, q(z) is the mass flow of water at depth z and T(z) is the temperature of the water, also at depth z. The heat loss from the rock matrix to the well, Q, is calculated as follows. By assuming radial symmetry, and that vertical variations in the temperature are slow, the heat transfer in the rock matrix outside the well-bore is governed by the thermal diffusion equation:

$$(1/r)\,\partial[\,r\,\partial T/\partial r\,]/\partial r \;=\; (1/\alpha)\,\partial T/\partial r \qquad \text{(A.3)}$$

where $\alpha = k_r\,/\,(\rho_r c_r)$ is the thermal diffusivity of the rock, with k_r the thermal conductivity, ρ_r the rock density and c_r the heat capacity of the rock. Vertical heat transfer is neglected. Initially the reservoir temperature is assumed to be independent of radial distance, denoted by T_r. After the flow starts in the well, the reservoir temperature is undisturbed, and equal to T_r some distance from the well. The temperature of the borehole wall equals T. The boundary and initial conditions are better described by:

$$T\,(r_w,t) \;=\; T \;\text{ for }\; t \geq 0 \qquad \text{(A.4)}$$

$$T\,(r,t) \;=\; T_r \;\text{ for }\; r \rightarrow \infty,\; t \geq 0 \qquad \text{(A.5)}$$

$$T\,(r,0) \;=\; T_r \;\text{ for }\; r > r_w \qquad \text{(A.6)}$$

where r_w denotes the well radius and T_r the undisturbed reservoir temperature. Carslaw and Jaeger (1959) present the solution to this problem. It can be approximated by:

$$Q \;\approx\; 4\pi k_r\,(\,T_r - T\,)\,[\,\ln(4\alpha t/r_w^2 - 2\gamma)\,]^{-1} \qquad \text{(A.7)}$$

when $4\alpha t/r_w^2 >> 1$. Here $\gamma = 0.5772$ is Eulers constant. By inserting this into equation (A.1), and using equation (A.2), one finally gets (Hita- og Vatnsveita Akureyrar *et al.*, 1998):

$$q(z)\,c_w\,\partial T/\partial z \;\approx\; 4\pi k_r\,(\,T_r - T\,)\,[\,\ln(4\alpha t/r_w^2 - 2\gamma)\,]^{-1} \qquad \text{(A.8)}$$

This equation describes the flow of energy into the well, which heats the injected water up, on its way down the well, as observed by a temperature log. This equation assumes constant injection rate and temperature, as well as no additional heat losses, caused by fluid convection in the vicinity of the well. During the injection history these are, however, varying slowly with time and equation (A.8) is, therefore, only an approximation of the actual situation.

Equation (A.8) can be used to simulate a temperature profile during injection, in a forward manner, by assuming the flow-rate into each feed-zone and assuming that $\partial T/\partial z$ is constant in the intervals between the feed-zones. The flow-rates can then be varied until the calculated profile matches the measured profile. In a similar way the flow rate down the well, and thereby the flow rate into each feed-zone, can be estimated by using:

$$q(z) \;\approx\; 4\pi k_r\,(\,T_r - T\,)\,/\,[\,\ln(4\alpha t/r_w^2 - 2\gamma)\,c_w\,\partial T/\partial z\,] \qquad \text{(A.9)}$$

Bjornsson has developed a multi feed-zone borehole simulator, named *HOLA* (Bjornsson, 1987; Bjornsson *et al.*, 1993), which solves the differential equations that describe energy, momentum and mass flow in a vertical well numerically. The *HOLA* simulator can, therefore, be conveniently used to simulate temperature profiles measured during injection. The *HOLA* program was used to simulate temperature profiles measured during injection into wells LJ-08 and LN-10 in the Laugaland field, and consequently estimate the flow rate into each feed-zone. The simulation results are presented in chapter 5 of this report.

APPENDIX B: SELECTED PAPERS PRESENTING THE LAUGALAND REINJECTION PROJECT

A. Axelsson, G., G. Sverrisdottir, O.G. Flovenz, F. Arnason, A. Arnason and R. Bodvarsson, 1998: Thermal energy extraction, by reinjection, from a low-temperature geothermal system in N-Iceland. *Draft Proceedings 4th Int. HDR Forum*, Strasbourg, France, September 1998, 10 pp.

B. Sverrisdottir, G., S. Hauksdottir, G. Axelsson and A. Arnason, 1999: Chemical monitoring during reinjection in the Laugaland geothermal system, N-Iceland. *Proceedings of the 5th International Symposium on Geochemistry of the Earth's Surface*, Reykjavik, Iceland, August 1999, 547-550.

C. Axelsson, G. and V. Stefansson, 1999: Reinjection and geothermal reservoir management – associated benefits. *Proceedings of a Workshop on Geothermal Energy*, Ljubljana, Slovenia, November 1999, 85-104.

D. Axelsson, G., G. Sverrisdottir, O.G. Flovenz, F. Arnason, A. Arnason and R. Bodvarsson, 2000: Thermal energy extraction by reinjection from the Laugaland geothermal system in N-Iceland. To appear in the *Proceedings of the World Geothermal Congress 2000*, Kyushu - Tohoku, Japan, May - June 2000, 6 pp.

DRAFT PROCEEDINGS, 4th Int. HDR FORUM
Strasbourg, September 28 - 30, 1998

THERMAL ENERGY EXTRACTION, BY REINJECTION, FROM A LOW-TEMPERATURE GEOTHERMAL SYSTEM IN N-ICELAND

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ABSTRACT

A long-term reinjection test is now underway in the Laugaland geothermal system in N-Iceland, the first such project undertaken in an Icelandic low-temperature area. The Laugaland system is embedded in low-permeability fractured basalts and its productivity is limited by insufficient recharge. More than sufficient thermal energy is, however, in-place in the 90 - 100 °C hot rocks of the system. The purpose of the reinjection project is to extract some of this thermal energy and to demonstrate that energy production from fractured low-temperature geothermal systems may be increased by reinjection. The Laugaland reinjection test is a cooperative project involving a few companies and institutions in Iceland, Sweden and Denmark, partly supported by the European Commission. Between 8 and 14 kg/s have been injected since the test started on the 8th of September 1997. A comprehensive monitoring program has been implemented as part of the reinjection project. Also included are some tracer-tests, monitoring of associated micro-seismic activity, step-rate injection tests and temperature logging of the injection wells. The reinjection experiment will continue through the year 1999. Preliminary results indicate that reinjection is a highly economical mode of increasing the production potential of the Laugaland system and reinjection is expected to be an important part of the management of the Laugaland reservoir for decades to come.

INTRODUCTION

Laugaland is the largest of five low-temperature geothermal fields utilized by *Hita- og Vatnsveita Akureyrar* (*HVA*) for space-heating in the town of Akureyri in Central N-Iceland (Figure 1). Since late 1977 hot water production from the field has varied between 0.9 and 2.5 million tons annually (Flóvenz et al., 1995). Because of a low overall permeability and limited recharge this modest production has lead to a great pressure drawdown. It continues to increase with time if constant rate production is maintained. This forced the production from the field to be reduced by about 50% in the early eighties. Therefore, reinjection has for long been considered a possible way to improve the productivity of the Laugaland system.

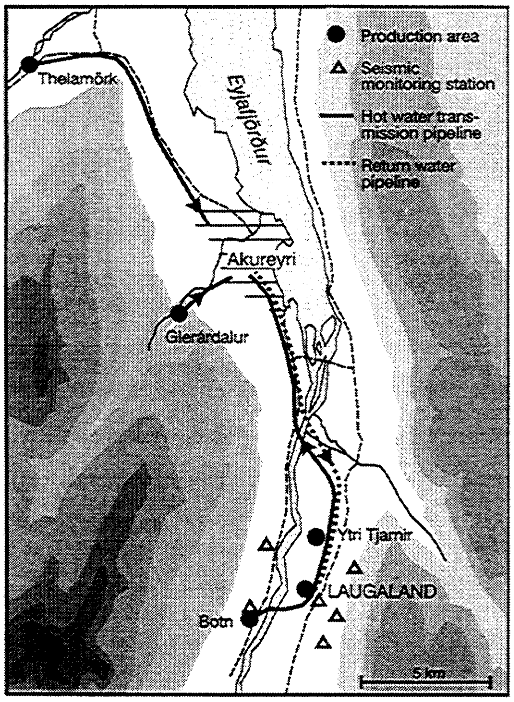

Figure 1. *Location of the Laugaland area.*

The Laugaland geothermal system is a typical fracture controlled system, embedded in 6-10 Myrs. old flood basalts, wherein the hot water flows along open fractures in otherwise low-permeability rocks. Twelve wells have been drilled in the area, only three of which are sufficiently productive to be used as production wells. Information on the wells currently in use in the field, as production-, observation- or injection wells, is presented in Table 1, and their locations are shown in Figure 2.

Table 1. *Wells in use in the Laugaland field.*

Well	Drilled	Depth (m)	Use
LJ-05	1975	1305	Production well
LJ-07	1976	1945	Production well
LJ-08	1976	2820	Obs./injection well
LG-09	1977	1963	Observation well
LN-10	1977	1606	Obs./injection well
LN-12	1978	1612	Production well

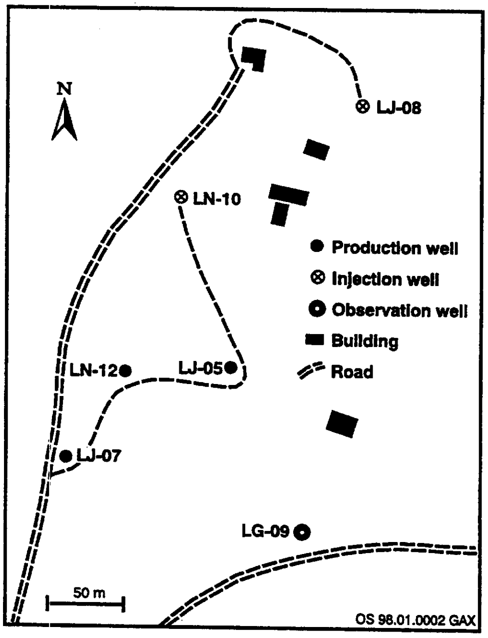

Figure 2. *Wells in the Laugaland geothermal field.*

The production- and water-level history of the Laugaland system is presented in Figure 3, showing the rapidly increasing draw-down the first few years, which reached about 400 m at the beginning of 1982. A drastic reduction in production reversed this trend, however.

The productivity of the Laugaland geothermal system is limited by a low permeability and limited recharge. Most of the thermal energy in the geothermal system, however, is still stored in the 90 - 100 °C hot reservoir rock-matrix. More water is in fact needed to recover some of that energy. Therefore, *HVA* has been planning long-term reinjection during the last several years. In 1996 the Thermie sub-program of the European Commissions Fourth Framework Programme for Research and Technological Development decided to support such an experiment. This is a cooperative project involving a few companies and institutions in Iceland, Sweden and Denmark. Work on the project started in late 1996, while actual reinjection started on the 8th of September 1997. It is the first long-term reinjection project to be started in an Icelandic low-temperature area (Stefánsson et al., 1995).

This paper describes the Laugaland reinjection project, which will continue through the fall of 1999. Data collected during the first year of the project will be presented along with the results of some preliminary analysis. The following chapter describe briefly the current conceptual model of the field, as well as the results of a short injection experiment conducted at Laugaland in June 1991.

PREVIOUS WORK

Exploration of the Laugaland field started in the early 1970s and extensive sets of geological, geophysical, chemical and reservoir engineering data are available for the field. In addition to these data, production response monitoring has provided a continuous 17 year record of weekly production, pressure draw-down and water temperature, in addition to some chemical monitoring data (Axelsson et al., 1998).

These data are the basis of the current conceptual model of the system, which involves a near vertical SW-NE trending fracture-zone, with a moderate permeability, maintained by recent crustal movements. The permeability of the lava-pile outside the fracture-zone has been reduced drastically by low-grade alteration. Successful wells in this area are either located very close to or they intersect this fracture-zone. In the natural state, prior to production, convection in the fractures transferred heat from a depth of a few km to shallower levels. The heat was consequently transported into the low-permeability rocks, outside the fracture-zone, mostly by heat conduction. This convective/conductive heat transfer is believed to have been ongoing for the last 10,000 years, at least.

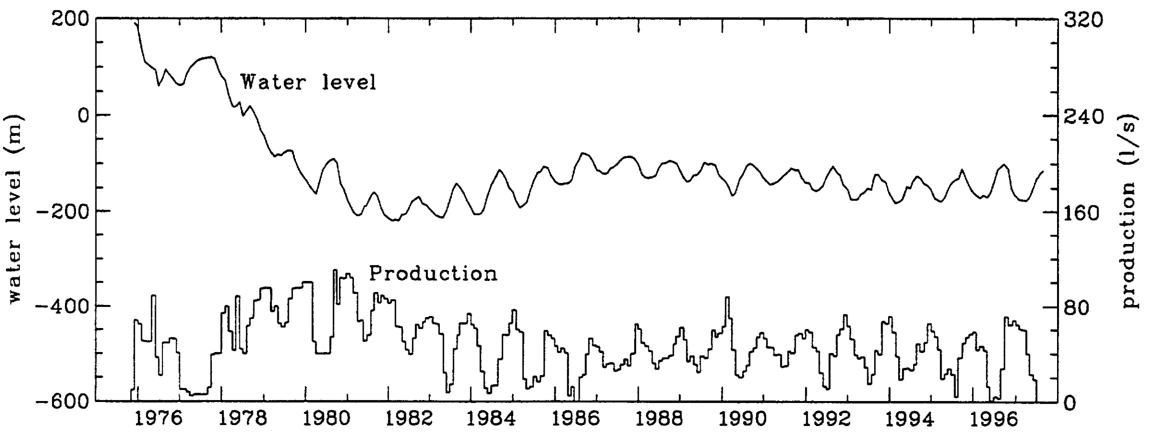

Figure 3. *Production history of the Laugaland field.*

The reservoir engineering data have been analyzed to derive the reservoir characteristics of the Laugaland geothermal system. This includes lumped parameter modeling which has been used to simulate the pressure draw-down history of the geothermal system (Axelsson et al., 1988; Axelsson, 1989). The average permeability of the system is only of the order of a few mD and the reservoir volume is of the order of a few km^3. A distributed parameter model has, so far, not been developed for the Laugaland geothermal system.

A small scale injection experiment was carried out at Laugaland in the spring of 1991, described by Axelsson et al. (1993, 1995 and 1998). It lasted about 5½ weeks and involved wells LJ-8 and LJ-5. In addition to monitoring of the water-level in observation wells, and the production temperature of well LJ-5, a tracer test was conducted to investigate the connection between the injection- and production wells. Two different tracers were employed, sodium-fluorescein and sodium-bromide. In the 1991 experiment the tracer-return was very slow, which was interpreted as indicating that the injected water diffused into a very large volume and that wells LJ-5 and LJ-8 were not directly connected. The models commonly used to interpret tracer test data from Icelandic geothermal systems are discussed by Axelsson et al. (1995 and 1998). The water level data, on the other hand, indicated that the reduced draw-down because of the injection should allow a considerable increase in production.

The simple model used to interpret the tracer test data was consequently used to predict the outcome of long-term (20 yr.) injection. It should be kept in mind, however, that these predictions are inaccurate due to the short duration of the 1991 experiment and the simplicity of the model. The principal results, for a case of continuous 10 kg/s injection of 15 °C return- or ground-water into well LJ-8 and 48 kg/s average production from two of the production wells, were a 5°C decline in the temperature of water produced in 20 yrs, yet a integrated increase in energy production for this 20 year period of about 400 GWh. This can be compared to the annual energy production of *HVA*, which during the last few years has been on the order of 240 GWh.

THE REINJECTION PROJECT

The results of the test in 1991 indicated that injection should be viable as the means to increase the production potential of the Laugaland geothermal system. At first injection of local surface- or ground-water was considered. That idea was abandoned, however, since serious problems may be associated with the injection of such water. The most serious of these is the possibility of deposition of magnesium-silicates in the feed-zones of an injection well, which may cause the well to clog up in a relatively short time, rendering further injection impossible. Using return water from the Akureyri district heating system is ideal, because its chemical composition is almost identical with that of the reservoir fluid. This, however, is more costly, since it requires the construction of a return water pipeline from Akureyri to Laugaland. Therefore, a few companies and institutions in Iceland, Sweden and Denmark applied for a grant to the European Commission, in the beginning of 1996, for undertaking this project. Later that year the Commission decided to support the proposed experiment.

The project includes the following phases:

1. Manufacture and installation of a 13 km return water pipeline from Akureyri to Laugaland (see Figure 1). A 150 mm, buried, uninsulated high-density polyetylene plastic pipe is used to minimize the installation cost.

2. Installation of high pressure pumps at the two proposed injection wells, LJ-8 and LN-10, as well as pumps in Akureyri for pumping the water to Laugaland. Installation of a computerized control- and monitoring system.
3. Installation of a network of six ultra sensitive, automatic, seismic monitoring stations around Laugaland (see Figure 1). This network should locate all micro-earthquakes of magnitude $M_L \geq -1$, which may be induced by the injection, in particular during periods when the reinjection will be carried out at well-head pressures between 20 and 30 bar. Thus some information on the locations of the fractures involved will hopefully be obtained (Slunga et al., 1995).
4. Continuous reinjection for a period of two years, along with careful monitoring of the reservoirs response to the injection. Also monitoring of any associated seismic activity. Injection of chemical tracers to study the connections between injection- and production wells.
5. Analysis of data collected, development of a numerical model for the geothermal system and predictions of the response of the three production wells to long-term reinjection. Determine the most efficient and economical mode of utilizing the Laugaland geothermal system. Estimation of the overall feasibility of reinjection in fractured low-temperature geothermal reservoirs.
6. Dissemination of the results in a final report and at a workshop at the conclusion of the project.

The total project cost is estimated at 1.8 million ECU. The Thermie sub-program of the Programme of Research and Development of the European Commission supports the project by a 0.64 million ECU contribution. At the end of October 1997 the first three phases had been completed according to schedule. The fourth phase started in September 1997 and is expected to continue until the end of July 1999. Work on the fifth phase has started with some preliminary data analysis and modeling.

The following are the principal participants in the project:

- *HVA*, the Akureyri District Heating Service, is the project coordinator. *HVA* was responsible for installation of the return water pipeline and the pumps used, controls the reinjection as well as being responsible for monitoring the geothermal systems response to the injection.
- *Orkustofnun*, the National Energy Authority of Iceland, is responsible for the scientific part of the experiment, as well as analysis of the data collected and consequent modeling. *Orkustofnun* has also planned the reinjection and monitoring in cooperation with *HVA*.
- *Uppsala University* in Sweden was responsible for installing the seismic network, and is responsible for its operation (in cooperation with *Orkustofnun*, the *Icelandic Meteorological Office* and *HVA*) as well as for analyzing any micro-earthquake data collected.
- *Hochest Danmark A/S* produced the return water pipeline in cooperation with an Icelandic sub-contractor, *Set hf.*
- Icelandic State Electricity, or *Rarik*, provides the pumps used for the reinjection as well as the electrical power for operating the pumps.

In addition several companies and institutions have been involved in the project as subcontractors or suppliers.

PRELIMINARY RESULTS

Reinjection started on the 8th of September 1997. Until the 28th of January 1998 about 8 kg/s were injected continuously into well LJ-8. Since that time about 6 l/s have also been injected into well LN-10, raising the combined injection rate to 14 l/s as shown in Figure 4. Stable injection rates have been maintained, except for brief periods when the reinjection has been varied or discontinued. A total of 320,000 tons had been injected in early August 1998. The temperature of the injected water has been in the range of 6 - 21 °C, while the temperature drop in the 13 km return water pipeline has been of the order of 5 °C.

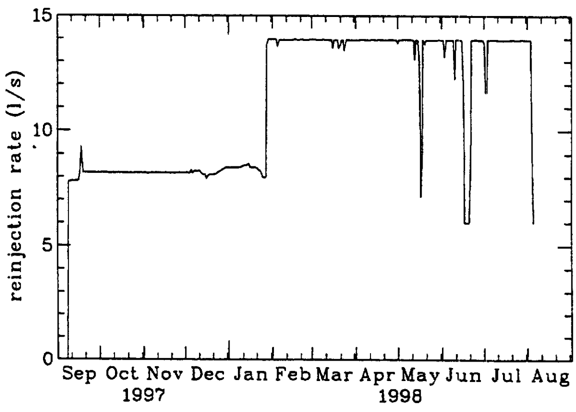

Figure 4. *Daily average reinjection into wells LJ-8 and LN-10 during the first year of the project.*

Figure 5 shows daily average hot water production from the Laugaland field during the first year of the project.

About two weeks prior to the start-up of the reinjection, production from one of the production wells, LN-12, was initiated after a summer break. This was done to create semi-stable pressure conditions in the reservoir when reinjection would start. During the period from the end of August until the end of November 1997, LN-12 was the only production well in use in the area. Therefore, this period provides a good opportunity for studying the effects of reinjection into well LJ-8. During last winter the production was more variable, because of greater hot water demand (Figure 5). From December through March two wells were continuously on line, either wells LN-12 and LJ-5 or wells LJ-5 and LJ-7. Intermittent production from well LJ-5 was also required during the following summer, because of unusually cold weather. Interpretation of data collected during the summer will, therefore, be more difficult. A total of 1,250,000 tons were produced from the field from late August 1997 until the beginning of August 1998. The reinjection during the same period equals about 26% of the total production.

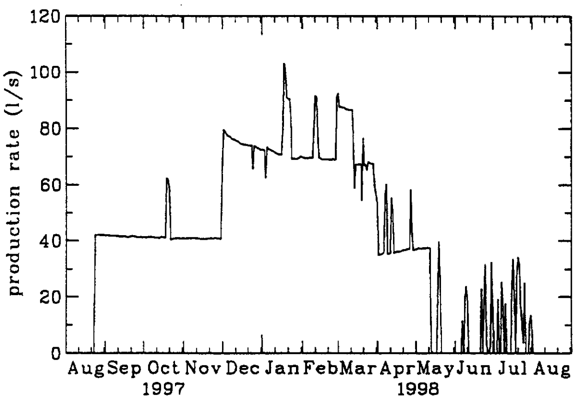

Figure 5. *Daily average production from wells LJ-5, LJ-7 and LN-12 at Laugaland during the first year of the project.*

Figure 6 shows the well-head pressure of injection well LJ-8, which slowly increased to about 8 bar-g at the end of November 1997. Before the injection started the water-level in the well was at a depth of 126 m. Until the end of March 1998 the well-head pressure did not increase, because of increased production from the field. The last several months the pressure has been rising again, in phase with rising reservoir pressure (water level), having reached slightly more than 11 bar-g at the beginning of August. The well head pressure of LJ-8 has been somewhat greater than anticipated on the basis of the 1991 test. This is the result of much colder water being injected presently than in 1991, i.e. 6 - 21 °C instead of 80 °C, resulting in a viscosity contrast of about 3.5. The first few months the well-head pressure also increased steadily, even though the reservoir pressure was relatively stable (see later). The cause for this has not been resolved, but it may also be the viscosity contrast between injection- and reservoir fluid, as well as thermal effects in the reservoir around well LJ-8. It should be noted that some of the variations in the well-head pressure of well LJ-8 are simply caused by variations in the temperature of the injected water.

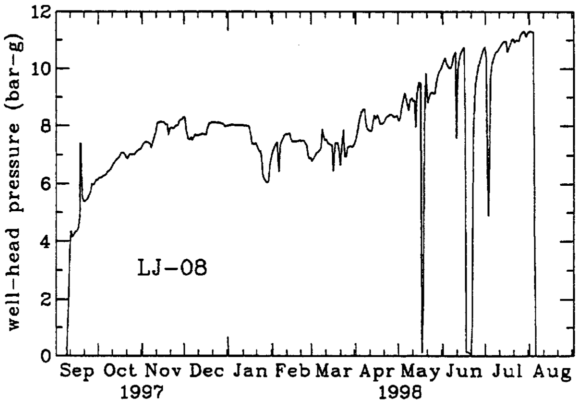

Figure 6. *Well-head pressure of well LJ-8 during the first year of the project.*

Well LN-10 responds quite differently to injection than well LJ-8. In a couple of days, after injection into the well started, the water level in the well rose by about 100 m. Since then the water level in the well has changed very slowly, from a depth of about 10 m in the beginning of February to a well-head pressure of about 2 bar-g in the beginning of August. The injectivity of well LN-10, therefore, appears to be about 30% greater than the injectivity of well LJ-8. A steady increase in water level/pressure for the first months after injection is started, such as observed for well LJ-8, is not seen in well LN-10.

Water level changes

Figure 7 shows the water-level changes observed in three wells in the Laugaland field during the first year of the injection project. These are well LN-10, which is situated about halfway between the production wells and well LJ-8 (Figure 2), and production wells LJ-5 and LN-12. The water level in LN-10 is presented for the period while the well was used as an observation well, prior to it becoming an injection well. The water-level measuring device in well LJ-5 broke down at the end of May 1998. At about the same time water level monitoring became possible in well LN-12, when the pump in the well was removed for maintenance. The water level is also monitored in one additional observation well in the Laugaland field, well LG-9, as well as in several observation- and production wells as far as 2 km away from Laugaland. These data are not presented here.

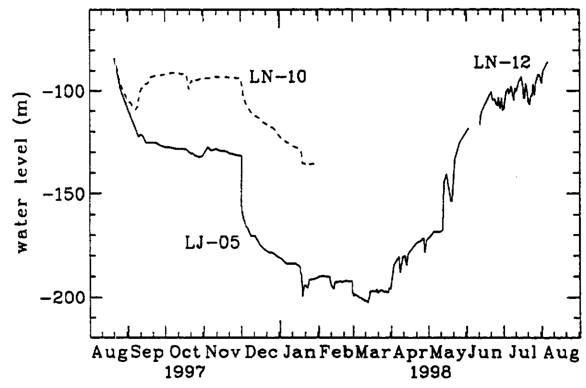

Figure 7. *Water-level changes in three wells at Laugaland during the first year of the project.*

The effects of the start-up of the reinjection in early September 1997 can clearly be seen in the figure. The water-level in LN-10 rises by about 15 m, but stabilizes in LJ-5 after being declining rapidly due to production from well LN-12. It should be noted that wells LJ-5 and LN-12 are directly connected, through the same fracture zone, while well LN-10 does not intersect that zone. Other changes in water level are the results of changes in production, such as the rapid decline in early December 1997, which is the result of well LJ-5 being added on line, and the rapid rise in May 1998, which is the result of production from the Laugaland wells being discontinued for the summer.

These data will be modeled and analyzed carefully in order to extract information on the effect of reinjection into wells LJ-8 and LN-10, on the water level in the production wells. A reduced water level draw-down is anticipated as the main benefit from reinjection. Preliminary analysis, mainly based on the water level changes in September 1997, indicates that the injection of 8 l/s into well LJ-8 caused comparable water level changes in production well LJ-5 as a 5.4 l/s reduction in production. This indicates that about 2/3 of the injection into well LJ-8 will potentially enable an increase in production, on the time scale under consideration (about 1 month). The long-term effect is expected to be somewhat greater. This is only a preliminary result, however, which needs to be studied more carefully with specific tests aimed at extracting this information and modeling.

Step-rate injection tests

Figure 8 shows the results of three step-rate injection tests conducted in wells LJ-8 and LN-10. The purpose of these tests is to estimate the injection characteristics of the wells, in particular pressure losses due to turbulent flow inside the wells, and in the feed-zones next to the wells. The test was repeated in well LJ-8 to determine whether any changes had occurred in the well, such as due to deposition in the feed-zone fractures. This has obviously not occurred in well LJ-8 (Figure 8).

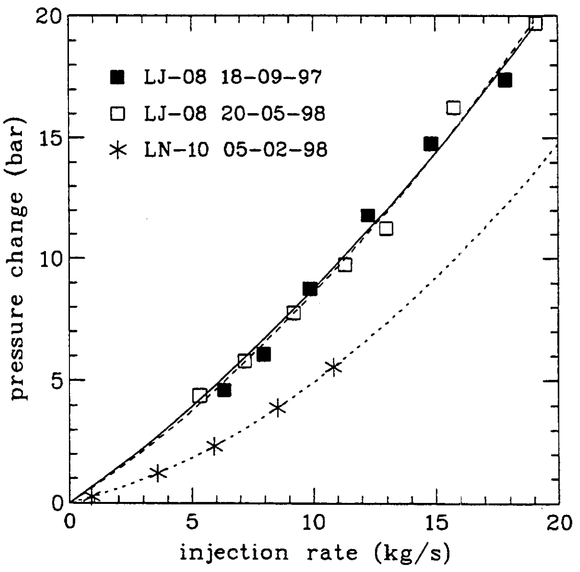

Figure 8. *Results of three step-rate injection tests conducted in wells LJ-8 and LN-10.*

According to the results of the step-rate tests the injectivity of well LN-10 is considerably greater than that of well LJ-8, agreeing with an earlier conclusion. The turbulence pressure losses appear to be comparable in these two wells, however, or of the order of 0.02 bar/(l/s)^2. This equals 0.5 bar at an injection rate of 5 l/s, 2.0 bar at a rate of 10 l/s and 4.5 bar at a rate of 15 l/s. Production testing of well LJ-8 at the end of drilling indicated turbulence losses on the order of 0.1 bar/(l/s)^2 (Thorsteinsson, personal information). The fact that turbulence losses appear to be half an order of magnitude less during cold water injection than during production may be the result of thermal contraction of the rock around the feed-zones of the well, which causes the feed-zone fractures to widen. It should be kept in mind, however, that the production test took place about 22 years ago.

Analysis of temperature logs

Figure 9 shows two temperature logs measured in well LJ-8. One measured before injection started, representing the undisturbed temperature conditions of the well and the other measured after 70 days of reinjection. At about 2000 m there is an obstruction in the well, which actually is more than 2800 m in depth. Temperature logs measured prior to, and during injection, are also available for well LN-10. These logs are not presented here, since there is unfortunately an obstruction in that well at a depth of about 470 m, while the well extends to a depth of more than 1600 m.

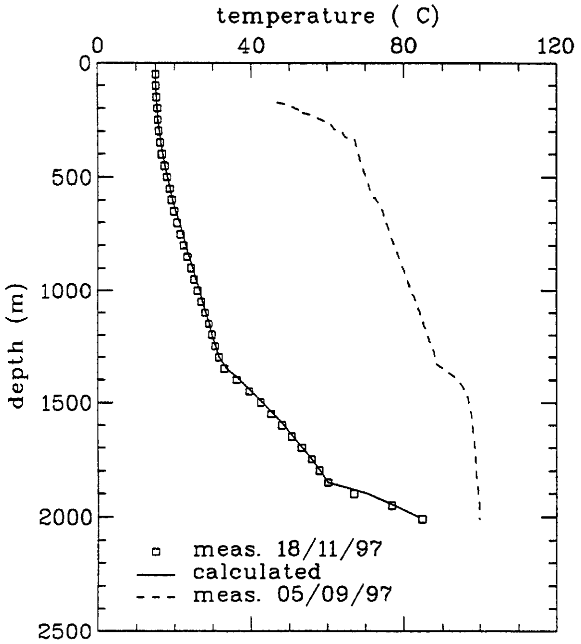

Figure 9. *Two temperature logs from well LJ-8, measured prior to and during reinjection. Also shown is a simulation of the second log by a wellbore simulator.*

The temperature log measured during injection into well LJ-8 clearly shows that the injected water exits the well at several exit-points (feed-zones), the deepest one being below 2000 m. An analysis of the log enables a determination of the water flow-rate as a function of depth in the well, and hence a determination of how much water exits the well at each exit-point. The basis for this is the following equation, which equates the flow of energy into the cooled well, by heat conduction, with the energy required to heat the injected water as observed.

$$(1)\quad qc_w \frac{dT}{dz} = 4k\pi\,(T - T_r)\,\left[\,\ln\left(\frac{4kt}{\rho_r c_r r_w^2}\right) - 1.154\,\right]^{-1}$$

Here q denotes the flow-rate in the well at depth z, T the temperature in the well at that depth, T_r the undisturbed reservoir temperature given by the log measured prior to injection, while c_w and c_r are the heat capacities of water and rock, respectively, k the heat conductivity of the rock, ρ_r its density and r_w is the radius of the well. The temperature log was interpreted (simulated) with the aid of a wellbore simulator (Björnsson, 1987). The results are presented in Table 2.

Table 2. *Results of a simulation of a temperature profile measured during 8 l/s injection into well LJ-8.*

Exit point depth (m)	flow rate (l/s)
380	3.5
600	1.2
1330	2.7
1850	0.7
below 2000	0.1

The main exit points appear to be at depths of around 380 and 1330 m. Slightly less than half of the injected water appears to exit the well in the deeper part of the reservoir, below 1000 m. The main feed-zones of the production wells are below that depth. That part of the injection should directly influence the production wells, while the water exiting at 380 m depth is not expected to fully do so.

It should be mentioned that the above estimates are believed to be as reliable as flow measurements done with spinner tools, which may be rather inaccurate at such low flow rates. A televiewer log is available for well LJ-8, which has not been fully analyzed. It indicates, however, that the exit-point at around 600 m is a narrow fracture, striking N-S and dipping to the east, while the exit-point at 1330 m looks more like an inter-bed.

Tracer tests

Two tracer tests have been carried out between wells at Laugaland, during the first year of the reinjection project. The purpose of these tests has been to study the connections between injection- and production wells in order to enable predictions of the possible decline in production temperature due to long-term reinjection. The first test started on September 25th when 10 kg of sodium-fluorescein were injected instantaneously into well LJ-8. Consequently its recovery was monitored accurately in well LN-12, the only production well on-line at the time. The results until the end of November 1997 are shown in Figure 10. At that time pumping from well LJ-5 started, and the previously stable conditions were disturbed. Yet, the fluorescein recovery is still being monitored. During the period from the beginning of December 1997 till the beginning of May 1998, when LJ-5 was on-line, fluorescein was recovered at an almost constant concentration of 3.3 ppb in that well. The concentration in well LN-12 dropped to about 0.5 ppb during the same period.

Other geothermal production wells in the Eyjafjördur-valley, outside Laugaland, have also been monitored for tracer recovery (see Figure 1). As shown in Figure 11 some fluorescein has been recovered in production well TN-4 in the Ytri-Tjarnir field about 1800 m north of well LJ-8. This indicates a rather direct connection between these two fields. An increase in the concentration during last summer is most likely a result of increased reservoir pressure at Laugaland (Figure 7). No tracer has been recovered in production wells in the western half of the Eyjafjördur-valley.

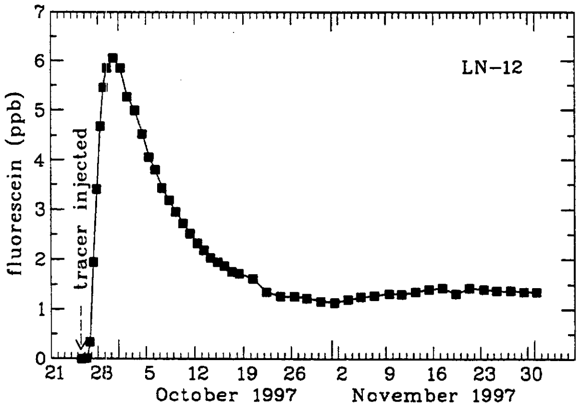

Figure 10. *Observed fluorescein recovery in well LN-12 during injection into well LJ-8.*

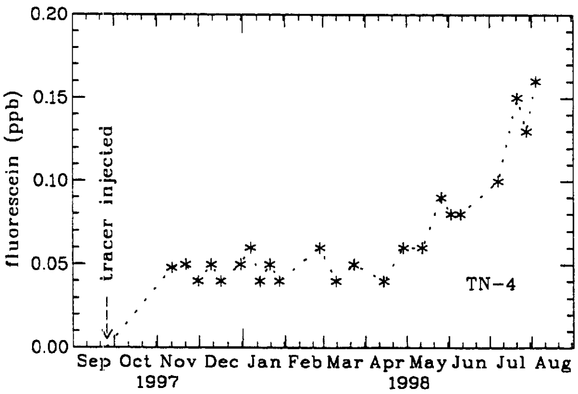

Figure 11. *Observed fluorescein recovery in well TN-4 1800m north of Laugaland.*

The second tracer test started on February 19th 1998 when 45.3 kg of potassium-iodide were injected into well LN-10. At that time both of wells LJ-5 and LN-12 were on line. Figure 12 shows the iodide recovery in well LJ-5 for the next 80 days, or until production was discontinued in the spring. Conditions in the reservoir were not as stable during this tracer test as during the previous one. Hot water production was more variable (Figure 5) and until late March either one of wells LN-12 or LJ-7 was also on line. Analysis of the results of this test will therefore be more difficult. Iodide was recovered in neither well LN-12 nor well LJ-7.

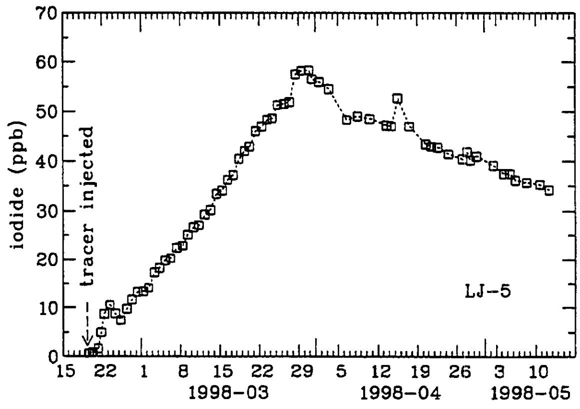

Figure 12. *Observed iodine recovery in well LJ-5 during injection into well LN-10.*

A preliminary analysis of the data presented in Figure 10 has been carried out and will be discussed briefly in the following. The data from both tracer tests awaits further analysis, however. Yet some conceptual results are available at this time. Even though the tracer breakthrough-times were relatively short, or only of the order of 24 - 48 hrs for the two tests, the tracer recovery has been very slow. Until early May about 1.5 and 0.6 kg of fluorescein had been recovered through wells LJ-5 and LN-12, respectively. This amounts to 21%, of the tracer injected initially, in about 7½ months. At the same time about 9.7 kg of iodide had been recovered through well LJ-5, or about 28% in 2½ months. This indicates that the injection- and production wells are not directly connected through the major feed-zones of the latter. They appear to be connected through some minor fractures or inter-beds. Therefore, most of the injected water appears to diffuse through a very large volume of the reservoir.

It is also clear that well LJ-5 is somewhat better connected to the injection wells than production wells LJ-7 and LN-12. This is most likely through the upper part of the Laugaland reservoir, above 1000 m depth, since well LJ-5 is only cased to a depth of 96 m. Wells LJ-7 and LN-12 are cased to depths of 930 and 294 m, respectively. Well LJ-8 is cased to a depth of 196 m, while well LN-10 is only cased to a depth of 9 m.

The data in Figure 10 have been analyzed on the basis of a one-dimensional fracture-zone, or flow channel model, where the tracer return is controlled by the distance between injection- and production zones in the corresponding wells. This model is described by Axelsson et al. (1995) and has been used to simulate tracer test data from several Icelandic geothermal fields. Three separate flow channels are used in the simulation for wells LJ-8 and LN-12 and the results presented in Figure 13. The properties of the channels are presented in Table 3. It should be kept in mind, however, that these are only preliminary results.

Table 3: *Model parameters used to simulate fluorescein recovery for the well pair LJ-8/LN-12 at Laugaland.*

Channel length (m)	u (m/s)	A ϕ (m^2)	α_L (m)	M_i/M
300	7.8×10^{-4}	0.083	54	0.0077
400	3.8×10^{-4}	0.67	199	0.0303
1000	1.7×10^{-4}	1.17	66	0.0241
total				0.0621

In the table u denotes the mean flow velocity, A the cross-sectional area, ϕ the porosity and α_L the longitudinal dispersivity of the flow-channel. The variable M_i denotes the calculated mass recovery of tracer through the corresponding channel, until infinite time, while M denotes the total mass of tracer injected. The results in Table 3 indicate that only about 6% of the injected water travels through these channels from injection- to production well. Most of the injected water, therefore, appears to diffuse throughout the reservoir volume. The volumes of the channels also appears to be quite small. If one assumes an average porosity of 7% the sum of the volumes of the three channels equals only 20,000 m^3.

The results in Table 3 were finally used to calculate the temperature decline of well LN-12 during injection into well LJ-8, due to the flow through these channels. The results are presented in Figure 14. It should be emphasized again that these are only preliminary results. The injected water, which does not travel through these channels, may also cool the production well to some degree. According to the results in the figure, 10 l/s injection will cause a temperature decline of less than 1°C in 20 years.

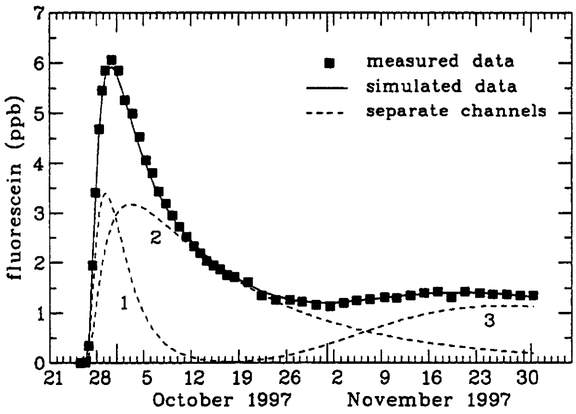

Figure 13. *Observed and simulated fluorescein recovery in well LN-12 during injection into well LJ-8.*

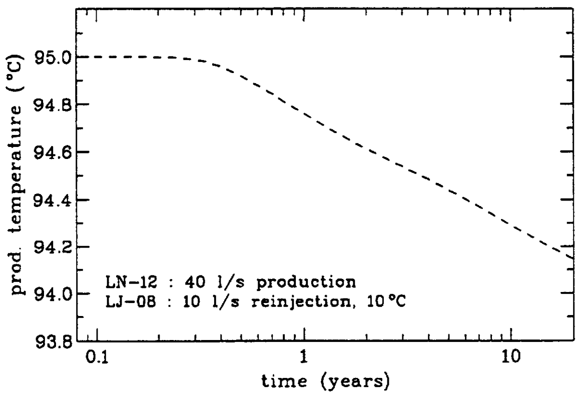

Figure 14. *Estimated decline in the temperature of well LN-12 during injection into well LJ-8, due to flow through the three channels simulated in Figure 13.*

The constant tracer recovery in well LJ-5 during the first tracer test may be used to estimate a volume of mixing and consequently a thermal breakthrough time for injection into well LJ-8 and production from LJ-5. This approach assumes that a porous volume is involved, rather than different flow channels such as before. The results indicate a breakthrough time of about 80 years. Therefore, the tracer test results indicate that an untimely thermal breakthrough or a rapid production temperature decline are not to be expected in production wells in the Laugaland field during reinjection, in particular during injection into well LJ-8.

Micro-earthquake activity

Finally it should be mentioned that no micro-earthquakes have been recorded during the first year of the reinjection project. The highest well-head pressure achieved has been around 11 bar-g, but during a later stage of the project well-head pressures of up to 30 bar-g are expected. Micro-earthquakes are more likely to occur at such pressures.

CONCLUDING REMARKS

During the first year the progress of the Laugaland reinjection project has been mostly according to schedule. Work on the main phase, actual reinjection, which started in early September 1997, will continue until the end of July 1999. During the fall of 1998 injection into well LJ-8 will continue at a maximum rate such that a well-head pressure of up to 30 bar-g will be achieved. This stage will also involve a tracer test aimed at determining whether new flow channels open up at higher pressures. Consequently, the last half year of the reinjection experiment will be used for further testing. During the remainder of the project, until the fall of 1999, emphasis will be placed on data analysis and numerical model development, which currently has started to a limited extent, as well as on analysis of the economics of long-term reinjection.

Reinjection is practiced in many geothermal fields in the world, in most cases to dispose of waste water due to environmental reasons (Stefánsson, 1997). Reinjection with the purpose of extracting more of the thermal energy in the hot reservoir rocks, and thereby increase the productivity of a geothermal reservoir, has not been practiced in many areas. This is more in line with the HDR-concept. Injection has, furthermore, not been part of the management of the numerous low-temperature systems utilized in Iceland. Preliminary results of the Laugaland reinjection experiment are positive, and indicate that reinjection will be a highly economical mode of increasing the production potential of the Laugaland system. The current reinjection system will, therefore, hopefully be an important part of the management of the geothermal reservoir for decades to come. The results of the project will hopefully also encourage other operators of fractured low-temperature geothermal systems to consider injection as a management option.

ACKNOWLEDGEMENTS

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Chemical monitoring during reinjection in the Laugaland geothermal system, N-Iceland

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ABSTRACT: During a long term reinjection experiment which is now underway to extract thermal energy from 90-100°C hot rock in the Laugaland geothermal system, North-Iceland, extensive chemical monitoring has taken place. Since the startup of reinjection in September 1997 until late February 1999, 590,000 m^3 or 12.5 l/s on average, of 6-21°C warm return water from the district heating system of Akureyri has been pumped down into the geothermal system. No chemical changes have been observed in the geothermal water pumped from the production wells in the area during this 17 months period of reinjection. This indicates that the reinjection of this water does not induce significant cooling and subsequent precipitation of secondary minerals in the geothermal system.

1 INTRODUCTION

The Laugaland geothermal system in N-Iceland is the largest of 5 separate geothermal fields utilized for space heating for the town of Akureyri for 20 years (Flóvenz, et al. 1995) (Figure 1). The geothermal systems are embedded in fractured, low-grade hydrothermally altered basaltic rocks. The Laugaland geothermal field comprises three production wells, LJ-05, LJ-07 and LN-12 and two reinjection wells LJ-08 and LN-10 (Figure 2). At Ytri Tjarnir field one production well (TN-04) is currently in use.

1.1 *The reinjection project*

The productivity of the Laugaland system is limited by insufficient recharge and continuously increasing pressure draw-down. A reinjection project, aimed at extracting some of the thermal energy stored in the 95-100 °C hot rocks, is underway and will continue through the year 1999. The work is a cooperative project of companies and institutions in Iceland, Sweden and Denmark supported by the European Commission. Preliminary results regarding the thermal extraction have been published in a Mid-Term report to the E.C. (Hita- og Vatnsveita Akureyrar et al. 1998). The focus of this work will be on the chemical monitoring during the reinjection project.

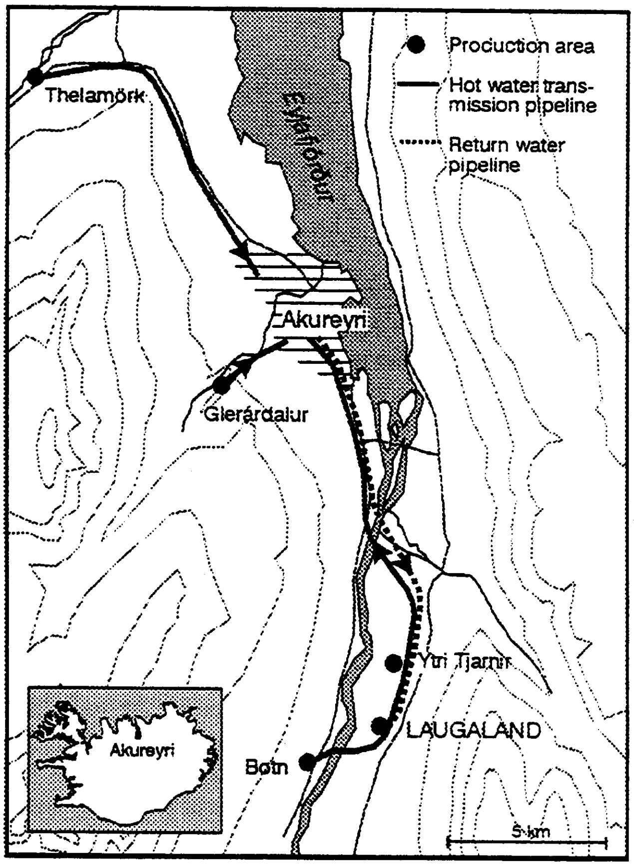

Figure 1. Location of the Laugaland geothermal field.

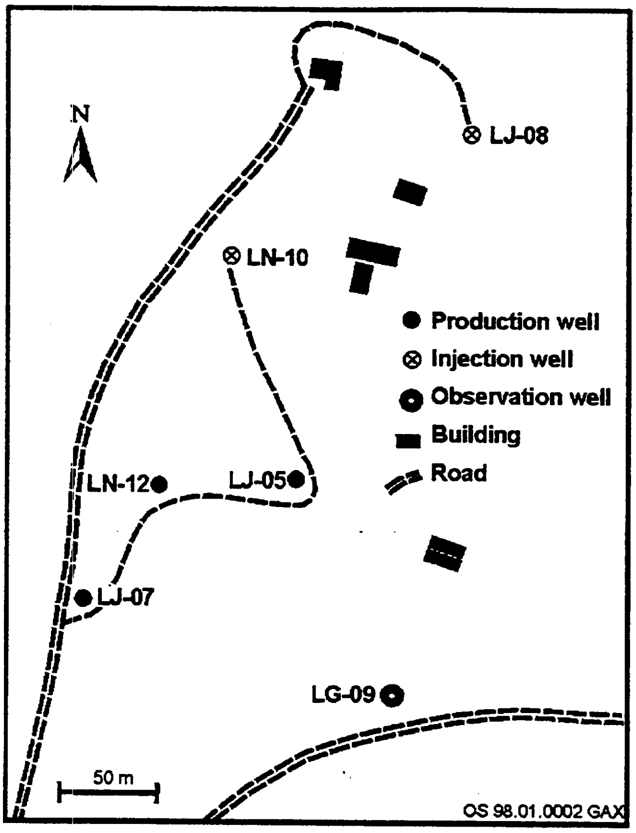

Figure 2. Wells in the Laugaland geothermal field.

1.2 *Tracer tests*

Important parts of the reinjection project are three tracer tests, two of which have already been carried out. The first one started two weeks after the beginning of the reinjection as 10 kg of sodium fluorescein dye were injected into well LJ-08. In the second tracer test 45.3 kg of potassium iodide were injected into well LN-10 simultaneously with the start of injection into that well. The water from LN-12 contained the highest concentration of the fluorescein dye of the wells sampled. Within a week from the tracer test the concentration reached a maximum of 6 µg/l. This means that extensive dilution is taking place in the reservoir; the total recovery by February 1999 was 30 %. On the contrary, the concentration of iodide reached a maximum of 60 µg/l in water from LJ-05, as late as 5 weeks after injection. Total recovery of potassium idodide in February 1999 was 45 %. As the dilution of the tracers by the pressured pumping into the system is so effective, no lasting effects on the chemistry of the geothermal water are expected.

The preliminary conclusions about the two tracer tests indicate that the injection- and production wells of the Laugaland area are not directly connected through the fracture-zone, which supplies the major feed-zones of the latter (Hita- og Vatnsveita Akureyrar et al. 1998). These tracer tests also indicate a connection between the Laugaland and Ytri-Tjarnir geothermal fields.

1.3 *This work*

Chemical monitoring has included regular sampling and analysis of selected elements in the geothermal water pumped from production wells in the Laugaland area. Samples from nearby areas were analysed as well. The main aim of the chemical monitoring is to detect whether if some precipitation of secondary minerals or cooling in the geothermal system is immediately induced by the reinjection.

2 CHEMISTRY OF INJECTED WATER

On first consideration it would seem possible to use local groundwater for the injection. This idea was soon rejected, because severe problems of magnesium-silicate precipitation have been experienced elsewhere by mixing of geothermal water and the relatively Mg-rich Icelandic groundwater (Kristmannsdóttir et al. 1989, Sverrisdóttir et al. 1992). Such deposition might cause the injection wells and its feed zones to clog up and probably cause serious problems for the production of the geothermal system. This was later confirmed by observations and model calculations for the geothermal water in the area done by Bi Erping (1998).

Table 1. Chemical composition of the return water (mg/l).

Date	03.04.1997 A	03.04.1997 B	18.02.1998 Mixed
Temp. (°C)	26,5	25,0	19,9
pH/°C	9,83/20,5	9,83/20,5	9,82/21,9
CO_2	21,2	22,0	19,4
H_2S	<0,03	<0,03	0,09
SiO_2	88,6	94,4	95,3
Na	53,0	53,1	55,3
K	0,96	1,00	0,99
Ca	3,15	2,82	2,96
Mg	<0,001	<0,001	0,002
SO_4	39,7	35,7	37,5
F	0,44	0,49	0,45
Cl	13,5	12,7	12,9
B	0,16	0,17	0,18
O_2	0	0	0,01

Using return water from the district space heating system appeared to be the best choice because its chemical composition is almost identical to the Laugaland geothermal water. Although originally produced from 5 separate geothermal systems, the difference in water chemistry is very small. The chemical composition of three samples from the return water is shown in Table 1. Two samples are from two separate parts of the domestic heating system respectively (A and B); they are mixed before injection. These samples were taken before the reinjection program started but the third sample is taken a year after the project started. This sample is from the mixed return water after it has been piped 13 km from the town of Akureyri to the Laugaland area. The earlier samples of return water were analysed for major elements as well as for various organic solvents, heavy metals and other elements which the water could plausibly assimilate from the heating system. No such chemicals were found in significant amount.

Table 2. Chemical composition of the geothermal fluid from LN-12 (mg/l).

Date	08.09.1997	18.02.1998
Temp. (°C)	95,8	94,9
pH/°C	9,76/21,9	9,79/21,7
CO_2	18,2	19,0
H_2S	0,08	0,10
SiO_2	99,2	97,3
Na	50,8	54,0
K	1,11	1,16
Ca	2,91	3,00
Mg	0,004	0,001
SO_4	37,9	39,2
F	0,37	0,30
Cl	11,6	11,6
B	0,16	0,16
O_2	0	0

The major element composition of Laugaland geothermal water prior to injection was established by sampling and analyseis of water from LN-12, the production well at that time. The results of the analysis of this sample and one collected from the well 6 months later are presented in Table 2. No significant changes in the water chemistry are detected.

3 CHEMICAL MONITORING

From the start of injection, several samples of water from production wells in Laugaland and nearby geothermal fields have been collected and analysed for Si, Cl, Ca and K. Even small changes in the concentration of these elements would give an indication of changes in the geothermal system. At the beginning of the reinjection project these samples were collected daily from the Laugaland area but less frequently in other areas. Few months after the project started sampling frequency was decreased until after the start of the second tracer test in February 1998 when it was increased again for a while.

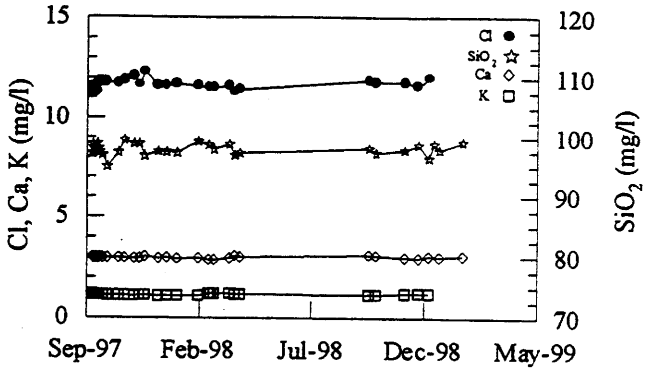

Figure 3. SiO_2, Ca, K, and Cl concentrations of geothermal water from LN-12.

Figure 3 shows the concentration of SiO_2, Ca, K, and Cl in the geothermal fluid of LN-12 as a function of time. The variation observed is less than expected for most of the elements in relation to the production of the well. A slight increase in potassium concentration in February 1998 can be attributed to the injection of the potassium iodide tracer. This increase amounted to up to 10% of the potassium concentration and was observed for about 4 weeks after the injection. After that the potassium concentration has been diluted to what is normal for the water. Production from LN-12 was discontinued during the summer 1998 but monitoring of other wells in the area confirmed that chemical changes during the period had not occurred.

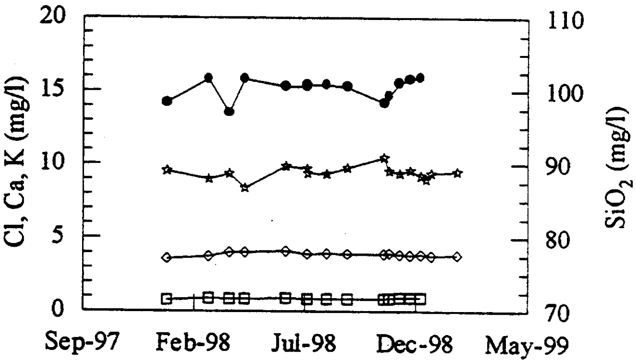

Figure 4. SiO_2, Ca, K, and Cl concentrations of geothermal water from TN-4. Legend as in Figure 3.

As the preliminary results from the first tracer test were acknowledged, a decision was made to sample the water from TN-4 for analysis of selected elements. This started simultaneously with the second tracer test. The chemical composition of the water from TN-4 has not changed during the time of the reinjection test (Figure 4). Variations observed do not exceed those observed during geochemical monitoring in recent years (Axelsson et al. 1998).

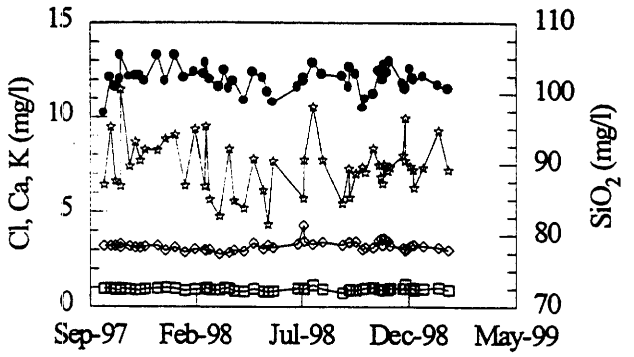

Figure 5. SiO_2, Ca, K, and Cl concentrations of return water. Legend as in Figure 3.

Figure 5 shows the chemical variations of the selected constituents in the injected return water. The variations are greater than observed for the fluid from production wells, LN-12 and TN-4. This is a result of mixing of water from the 5 production fields in various ratios within the district-heating system.

4 CONCLUSIONS

No lasting chemical changes are observed in geothermal fluids of the Laugaland system or nearby geothermal fields during the first 17 months of an ongoing reinjection experiment in the Laugaland geothermal reservoir. Neither downpumping of a considerable amount of return water from the district heating system, or injection of two different chemical tracers seem to affect the chemical properties of the thermal water. Consequently, no deposition is expected to have occurred in the reservoir during the reinjection.

Although this work presents only preliminary results of the chemical part of the project, they support the contention that return water from the space heating system is the most appropriate fluid for reinjection, at least in the Laugaland system.

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REINJECTION AND GEOTHERMAL RESERVOIR MANAGEMENT - ASSOCIATED BENEFITS

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Key Words: injection, geothermal resource management, thermal energy extraction, Laugaland system, low-permeability, tracer tests.

ABSTRACT

Water injection is presently an integral part of field operations in about 25 geothermal areas world-wide. In most cases the purpose is to dispose of wastewater due to environmental reasons. Yet, reinjection is increasingly becoming an important part of geothermal resource management. In these cases injection is used to counteract pressure drawdown and for extracting more of the thermal energy in place in geothermal reservoirs. In spite of causing an initial increase in operation costs, reinjection will in most cases prove to be an economical way of increasing energy production from a geothermal reservoir. Injection is one of the most complex aspects of geothermal exploitation. Therefore, careful planning and research are prerequisites for successful injection. The most serious problems associated with injection are cooling of production wells (thermal breakthrough) and silica scaling in surface equipment and injection wells. In addition, long-term injection into sandstone reservoirs has met limited success. A two-year reinjection experiment was recently completed in the Laugaland low-temperature geothermal system in N-Iceland that provides good examples of the different aspects of reinjection research. The system is embedded in low-permeability fractured basalts and insufficient recharge and continuously increasing pressure drawdown limit its productivity. More than sufficient thermal energy is, however, in-place in the 90 - 100°C hot rocks of the system. The purpose of the experiment was to demonstrate that energy production from fractured low-temperature geothermal systems might be increased by reinjection, and the associated thermal energy extraction. The results of the Laugaland reinjection project are encouraging. Water level measurements indicate that hot water production from the field may be increased significantly by reinjection, and tracer test results show that an untimely thermal breakthrough is not to be expected in production wells in the field. Therefore, reinjection is expected to be an important part of the management of the Laugaland geothermal system in the future and provide a highly economical mode of increasing the production from the system.

1. INTRODUCTION

Fluid injection is currently carried out in several geothermal fields in the world. In most cases it involves reinjecting the waste geothermal fluid back into the reservoir. Reinjection started out as the means to dispose of wastewater in an environmentally friendly way. Theoretical studies, as well as field experiments, have shown that injection may also be used to counteract pressure drawdown due to production, i.e. for pressure support, and for extracting more of the thermal energy in place in geothermal reservoirs. Most of this energy is stored in the reservoir rocks, and only a minor part in the reservoir fluid. Therefore only a fraction of the energy may be utilised by conventional exploitation. Reinjection is a method of geothermal energy production, which can greatly improve the efficiency, and increase the longevity, of geothermal utilisation. It also contributes to the sustainability of geothermal energy production. Therefore, injection is increasingly becoming an important part of geothermal resource management. Yet, injection is one of the most complex aspects of geothermal exploitation. Thus, careful planning, testing and research are prerequisites for successful injection.

In this paper, we review briefly the vast experience on geothermal reinjection now available worldwide. In addition to discussing the successful application of injection, the various problems associated with the method, and the most up-to-date solutions will be reviewed. Emphasis will be placed on the role of research in planning injection. Stefansson (1997) presents a more comprehensive review of the worldwide geothermal reinjection experience.

This paper also reviews the outcome of a two-year reinjection experiment recently completed in the Laugaland low-temperature geothermal system in N-Iceland. This experiment provides good examples of the different aspects of reinjection research. The Laugaland system is embedded in low-permeability fractured basalts and insufficient recharge and continuously increasing pressure drawdown limit its productivity. More than sufficient thermal energy is, however, in-place in the 90 - 100°C hot rocks of the system. The purpose of the experiment was to demonstrate that energy production from fractured low-temperature geothermal systems might be increased by reinjection, which extracted some of this thermal energy. The Laugaland reinjection experiment was a co-operative project involving a few companies and institutions in Iceland, Sweden and Denmark, supported by the Thermie sub-program of the European Commissions Framework Programme for Research and Technological Development. During the Laugaland experiment great emphasis was placed on a program of comprehensive data collection, analysis and interpretation. The results of the Laugaland reinjection project are encouraging for the future use of reinjection. More information on the Laugaland experiment may be found in Axelsson et al. (1998a & b).

2. WORLWIDE REINJECTION EXPERIENCE

2.1 Introduction

Geothermal reinjection started out as a method of disposing of wastewater from geothermal power plants in order to protect the surrounding environment. It started as early as 1969 and 1970 at The Geysers in California and the Ahuachapan field in El Salvador, respectively. Unfortunately, reinjection in Ahuachapan was discontinued in 1982. Today injection is still mostly practised to dispose of wastewater due to environmental reasons, but it is also used for pressure maintenance, and for extracting more of the thermal energy in place in geothermal reservoirs. Injection is also of help in reducing land subsidence caused by large-scale geothermal production. Waste water from geothermal power plants, return water from direct applications such as space heating, ground-water, surface-water and even sewage water is injected into geothermal reservoirs. Even though injection will cause an initial increase in operation costs, it will in most cases prove to be an economical way of increasing energy production from a geothermal system. Injection can not yet be considered a very widespread method of reservoir management. Its role is slowly increasing in significance, however, as more successful injection experiments are completed and more emphasis is put on sustainable energy production globally.

2.2 Injection in operation

Table 1 lists the 25 geothermal fields worldwide where injection is presently an integral part of field operations. It is a revised version of the table presented by Stefansson (1997). The most recent additions to the table are the Berlin field in El Salvador (Montalvo and Axelsson, 1999) and the

Laugaland field in N-Iceland, which is discussed later in this paper. A brief discussion of a few selected case histories is presented in the following.

Reinjection at The Geysers started with the purpose of disposing of steam condensate but during the last two decades reinjection has aimed at improving the reservoir performance (Stefansson, 1997; Barker, 1995). In addition to the condensate, surface water and recently sewage water, piped long distances, is injected (Atkinson, 1998). Declining electricity production at the Geysers is believed to result from a limited natural recharge. Injection replaces the recharge to some degree, and hence improves the performance of the Geysers reservoir. An increase in steam production rates has been reported for the field, as well as an increase in reservoir pressure monitored in observation wells. This indicates that the injection at The Geysers has slowed the decline in electricity production down considerably.

At Larderello in Italy reinjection started in 1974, also as the means of disposing of steam condensate. Reinjection is now an integral part of field operation that is aimed at enhancing heat recovery from the reservoir rocks (Stefansson, 1997; Capetti, 1995). Several studies and long-term tests performed in the Larderello field have revealed a significant increase in steam production as well as some reservoir pressure recovery, which may clearly be attributed to the reinjection (Figure 1). No temperature decline, caused by the reinjection, has been observed in the Larderello field

Environmental considerations were the main reasons for employing reinjection of waste water in the geothermal fields utilized for power production in the Philippines (Stefansson, 1997). To some degree reinjection is also adopted to improve reservoir performance, in particular in the Tiwi field. In contrast to the above examples reinjection is not practiced in the four high-temperature fields utilized in Iceland, i.e. Krafla, Namafjall, Nesjavellir and Svartsengi. Disposing of geothermal wastewater at the surface in the young volcanic environment is not considered to have an adverse environmental effect. The reinjection experience for most of the other fields in Table 1 is either reviewed by Stefansson (1997) or some of the references listed in that paper.

2.3 Reservoir cooling and tracer tests

The possible cooling of production wells, or thermal breakthrough, has discouraged the use of injection in some geothermal operations. In some cases where the spacing between injection and production wells is small, and direct flow-paths between the two wells exist, the fear of thermal breakthrough has been justified. However, actual thermal breakthroughs, caused by cold water injection, have been observed in a relatively few geothermal fields (Stefansson, 1997). Changes in flowing enthalpy of production wells have in some cases been interpreted as actual cooling, whereas the enthalpy changes are in fact the result of pressure changes in two-phase reservoirs.

Stefansson (1997) reports that actual cooling, attributable to injection, has only been observed in Ahuachapan (El Salvador), Palinpinon (Philippines) and Svartsengi (Iceland). The temperature of well AH-5 in Ahuachapan declined by about 30°C due to an injection well located only 150 m away, while the temperature of well SG-6 in Svartsengi declined by about 8°C during 4 years of injection. Figure 2 shows the temperature decline of well PN-26 in Palinpinon as reported by Malate and O'Sullivan (1991). The thermal breakthrough occurred about 18 months after reinjection started. Consequently, the temperature declined rapidly, reaching about 50°C in 4 years.

The cooling effect can in fact be minimised by a proper selection, or location, of injection wells. In particular by choosing injection locations at a considerable distance (a few km) from production wells. Yet, to achieve the maximum benefit from injection, i.e. thermal energy extraction and pressure recovery, injection wells should be as close to production wells as possible. For successful injection a proper balance between these two contradicting requirements must be selected. Therefore, careful testing and research are prerequisites for planning successful injection. It may be mentioned that the appropriate injection rate, for the Thelamork field in N-Iceland, was determined by optimizing the additional thermal power, which was estimated would result from the injection (Axelsson et al., 1995).

Tracer tests are the most powerful tool for studying connections between injection and production wells, and hence the danger of thermal breakthrough. Numerous such tests have been carried out in geothermal fields during the last two decades (Stefansson, 1997). The method has been adopted from similar methods used in groundwater and nuclear-waste storage studies. In principle the tracer breakthrough time should reflect the thermal breakthrough time, and a short tracer breakthrough time reflects a short thermal breakthrough time. As a rule of thumb the thermal breakthrough time is normally one or two orders of magnitude greater than the tracer breakthrough time. As an example the tracer breakthrough time in well PN-26, mentioned above, was of the order of 40 hrs, while the thermal breakthrough time was 18 months, or 13000 hrs.

Numerous models have been developed, or adopted, for interpreting tracer test data and consequently for predicting thermal breakthrough and temperature decline during long-term reinjection (Pruess and Bodvarsson, 1984; Horne, 1985; Stefansson, 1997). These models will not be discussed here. It must be pointed out, however, that while tracer tests provide information on the volume of flow paths between injection and production wells, thermal breakthrough and decline is determined by the surface area involved in heat transfer from reservoir rock to the flow paths, which most often are fractures.

Axelsson et al. (1995) describe a few tracer tests carried out in geothermal fields in Iceland during the early nineties. Four such experiments are discussed along with the theoretical models used for analyzing the data collected. Tracer tests carried out in the Laugaland geothermal field in N-Iceland during 1997-1999 are discussed later in this paper.

2.4 Silica scaling

Silica scaling in surface equipment and injection wells is another issue, which may be associated with injection. This may be one of the more difficult problems associated with reinjection, in particular in high temperature fields. Geothermal fluids are in equilibrium with the rocks at reservoir conditions. After flashing in a power plant, the separated fluid becomes supersaturated in SiO_2 and silica will precipitate from the fluid. This is a complex process partly controlled by temperature, pH of the fluid and the concentration of SiO_2. The problem of silica scaling may be avoided, in most cases, by proper system design. Stefansson (1997) discusses this issue in more detail with particular reference to the experience in Japan, New Zealand and the Philippines.

2.5 Sandstone injection

In most of the cases discussed above the reservoir rocks are predominantly fractured. But geothermal resources are also widespread in sedimentary rocks, in particular low enthalpy geothermal energy. Geothermal energy is at present tapped from such rocks in the P.R. of China, France, Hungary and Romania, to name a few countries. Reinjection into sandstone reservoirs has been attempted at several locations, but with limited success (Stefansson, 1997). Reinjection into limestone aquifers has been successful, however, where attempted. During many sandstone reinjection tests the injectivity of injection wells decreases very rapidly, even in hours or days, rendering further reinjection impossible. The reasons for this are not fully understood, but most likely the aquifers next to the injection wells clog up (fine sand and precipitation particles). Research aimed at solving this problem is currently being carried out in Europe (Stefansson, 1997).

In three locations solutions to this problem have apparently been found. The first is the Tanggu geothermal area in the P.R. of China, where a novel approach, whereby the flow is reversed, was used during a reinjection experiment (Axelsson and Dong, 1998). The solution involved installing a down-hole pump in the injection well that is used to produce from the well for a period of a few hrs. once its injectivity has dropped after a period of reinjection. During a reinjection test in 1996 the injection well needed to be cleaned after reinjection periods of 7-11 days. After cleaning, its injectivity was fully restored. A similar approach is adopted in Neustadt-Glewe in Germany, apparently with success.

The second location where a solution to the sandstone injection was found is Thisted in Denmark, where 45°C water from a sandstone reservoir is utilised in a district heating plant and hence reinjected (Mahler, 1998). The solution in Thisted involves a very sophisticated closed loop system wherein the reinjection water is kept completely oxygen free as well as passed through very fine filters (one micron). The solution also involves not allowing injection after plant construction work, and other breaks in operation, until the water is checked clean and oxygen free. In addition pressures are kept up by nitrogen bottles when the plant is stopped. This system has been in operation since 1984.

2.6 Injection experiments

In addition to the fields where injection is already part of field operation, injection tests of one form or another have been carried out in at least 30 additional geothermal fields worldwide. Some of these have already been referred to in this paper. Those ongoing, or completed, in 1996 are listed by Stefansson (1997) and relevant references provided. The references provided by Stefansson also include papers on several laboratory experiments as well as theoretical studies involving pressure maintenance, thermal effects and tracer analysis. The remainder of this paper deals with the two year reinjection experiment at Laugaland and provides examples of the different aspects of reinjection research.

3. THE LAUGALAND REINJECTION PROJECT

3.1 Background

Laugaland is the largest of five low-temperature geothermal fields utilised by *Hita- og Vatnsveita Akureyrar* (HVA) for space heating in the town of Akureyri in Central N-Iceland (Figure 3). Since late 1977 hot water production from the field has varied between 0.9 and 2.5 million tons annually (Flovenz et al., 1995). Because of a low overall permeability and limited recharge this modest production has lead to a great pressure drawdown. It continues to increase with time if constant rate production is maintained. In the early eighties the draw-down reached about 400 m, which forced the production from the field to be reduced by about 50%. Therefore, reinjection has for a long time been considered a possible way to improve the productivity of the Laugaland system.

The Laugaland geothermal system is a typical fracture controlled system, embedded in 6-10 Myrs. old flood basalt, wherein the hot water flows along open fractures in otherwise low-permeability rocks. Twelve wells have been drilled in the area, only three of which are sufficiently productive to be used as production wells. Information on the wells currently in use in the field, as production-, observation- or injection wells, is presented in Table 2, and their locations are shown in Figure 4. More details on the Laugaland system may be found in Axelsson et al. (1998a & b).

Most of the thermal energy in the Laugaland geothermal system is still stored in the 90 - 100 °C hot reservoir rock-matrix. More recharge water is in fact needed to recover some of that energy. Therefore, HVA has been planning long-term reinjection during the last several years. A small-scale injection experiment was carried out at Laugaland in the spring of 1991, described by Axelsson et al. (1995 and 1998). It lasted about 5 ½ weeks and involved wells LJ-8 and LJ-5. The results of a tracer test were interpreted as indicating that the injected water diffused into a very large volume and that wells LJ-5 and LJ-8 were not directly connected. Water level data, on the other hand, indicated that reduced drawdown because of the injection should allow a considerable increase in production.

In 1996 the Thermie sub-program of the European Commissions Fourth Framework Programme for Research and Technological Development decided to support a two year reinjection experiment in the Laugaland area. This was a co-operative project involving a few companies and institutions in Iceland, Sweden and Denmark. Work on the project started in late 1996, while actual reinjection started on the 8th of September 1997. The experiment ended in late 1999, but reinjection is expected to continue. It is the first long-term reinjection project carried out in an Icelandic low-temperature area (Stefansson et al., 1995).

The Laugaland reinjection project is described below. Data collected during the project will be reviewed along with results of data analysis and interpretation. The analysis and interpretation phase had not been completed at the time of writing of this paper, however. More details on the project can be found in Axelsson et al. (1998a & b).

3.2 The reinjection project

The results of the test in 1991 indicated that injection should be viable as the means to increase the production potential of the Laugaland geothermal system. At first injection of local surface- or ground water was considered. That idea was abandoned, however, since serious problems may be associated with the injection of such water. The most serious of these is the possibility of deposition of magnesium-silicates in the feed-zones of an injection well, which may cause the well to clog up in a relatively short time, rendering further injection impossible. Using return water from the Akureyri district heating system is ideal, because its chemical composition is almost identical with that of the reservoir fluid and the concentration of Mg is very low. This, however, was more costly, since it required construction of a return water pipeline from Akureyri to Laugaland. Therefore, a few companies and institutions in Iceland, Sweden and Denmark applied for a grant from the European Commission, in the beginning of 1996, for undertaking this project. Later that year the Commission decided to support the proposed experiment.

The project included the following phases:

1. Manufacture and installation of a 13 km return water pipeline from Akureyri to Laugaland (see Figure 3).

2. Installation of high-pressure pumps at the two injection wells, LJ-8 and LN-10, and pumps in Akureyri for pumping the water to Laugaland as well as installation of a computerised control- and monitoring system.

3. Installation of an automatic network of six ultra sensitive seismic monitoring stations around Laugaland.

4. Continuous reinjection for a period of two years, along with careful monitoring of the reservoirs response to the injection and any associated seismic activity. Three tracer tests to study the connections between injection- and production wells.

5. Analysis and interpretation of data collected, including development of a numerical model for the geothermal system, predictions of the response of production wells to long-term reinjection and analysis of the economics of future reinjection.

The total project cost is estimated at 1.7 million USD. The Thermie sub-program of the Programme of Research and Development of the European Commission supported the project by a 0.7 million USD contribution. The first three phases had been completed at the end of October 1997. The fourth phase started in September 1997 and continued until early fall 1999. Work on the fifth phase was ongoing at the time of writing of this paper.

The principal participants in the project are: HVA (the Akureyri District Heating Service), Orkustofnun (the National Energy Authority of Iceland), Uppsala University in Sweden, Hochest Danmark A/S and Rarik, Icelandic State Electricity.

3.1 Principal results

Reinjection started on the 8th of September 1997. Since then injection into well LJ-8 has been mostly continuous, varying between 6 and 21 kg/s. From the end of January until the middle of August 1998 about 6 kg/s were also injected into well LN-10. The combined injection rate during the whole project is shown in Figure 5. A total of 910,000 tons had been injected at the end of August 1999, or about 14.4 kg/s on the average. The temperature of the injected water has been in the range of 6 - 22 °C.

Figure 6 shows the daily average hot water production from the Laugaland field during the two-year project. The production has varied between 0 and 130 l/s and a total of 2,550,000 tons were produced from the field from the end of August 1997 until the end of August 1999. The reinjection equals about 36% of the total production during the experiment. The production has been quite variable, mostly reflecting varying hot water demand in Akureyri. During the winter time two wells are commonly on line, either wells LN-12 and LJ-5 or wells LJ-5 and LJ-7. During a few shorter periods constant production was maintained to create semi-stable reservoir conditions. This was done to facilitate various tests and consequent data interpretation. The longest such period was from the end of August until the end of November 1997, when only well LN-12 was on line.

Figure 7 shows the wellhead pressure of injection well LJ-8, which varied between 4 and 11 bar-g during the first year of the project. During the second year of the project injection rates were higher, causing a wellhead pressure as high as 28 bar-g. Before injection started the water level in the well was at a depth of 126 m. Variations in production, and the consequent variations in reservoir pressure (water level), influence the wellhead pressure of well LJ-8, in addition to variations in injection rate. Some wellhead pressure transients may also be attributed to variations in viscosity and thermal effects. The injectivity of well LN-10 appears to be about 30% greater than the injectivity of well LJ-8.

The data presented in figures 5-7 were all collected by the automatic monitoring system. In addition to these data, water level measurements were taken on a regular basis in a number of wells inside, and outside, the Laugaland field. The comprehensive monitoring program also included: temperature logging of the injection wells, monitoring of production water temperatures and chemical content, as well as three tracer tests. All these data are presently in the process of being analysed, and interpreted. The analysis has focused on three main aspects: (1) water level changes, which yield information on reservoir properties and the pressure recovery resulting from the reinjection, (2) borehole logs, which yield information on the feed-zones of the injection wells, and (3) tracer tests, which provide information on the connections between injection and production wells, and hence the danger of premature, and rapid cooling, of the latter.

The principal results of the analysis are presented below, but the details await the final report for the project. First the current conceptual model of the Laugaland system is described briefly.

Conceptual model of the Laugaland system

The conceptual model of the Laugaland system has been revised on the basis of the data collected during the reinjection project (Axelsson et al., 1998a; Hjartarson, 1999). The model involves a near vertical fracture-zone, trending close to N50°E, with a moderate permeability, maintained by recent crustal movements. The permeability of the lava-pile outside the fracture-zone has been reduced drastically by low-grade alteration. Successful wells in the area are either located very close to or they intersect this fracture-zone. In the natural state convection in the fractures transferred heat from a depth of a few km to shallower levels. The heat was consequently transported into the low-permeability rocks outside the fracture-zone, mostly by heat conduction. This convective/conductive heat transfer is believed to have been ongoing for the last 10,000 years at least.

Water level changes

Figure 8 shows the water-level changes observed in three wells in the Laugaland field during the two-year injection project. These are observation well LG-09 and production wells LJ-5 and LN-12. Water level records, not presented here, are also available from a number of other wells, inside as well as outside the Laugaland field.

The details of the water level record will not be discussed here. It actually constitutes a series of pressure transient tests several of which have been analysed as such (Hjartarson, 1999). The main results of this analysis are that the production wells intersect the NE-SW fracture zone, which has an estimated permeability thickness of about 15 Darcy-m. The injection wells are clearly outside this zone. The permeability thickness of the low-permeability rocks outside the fracture-zone is estimated to be about 2 Darcy-m.

A reduced water level drawdown is anticipated as the main benefit from reinjection. The water level data were, therefore, also analysed carefully in order to quantify the effect of reinjection on the water level in the production wells. This was done by simulating the 20 year water level history of the Laugaland field by a lumped parameter model (Axelsson, 1989). The deviation between observed and simulated data, after reinjection started, was consequently used to estimate the benefit. The results indicate that the hot water production rate may be increased by 60-70% of the reinjection rate, without causing additional drawdown. It should be mentioned that the short-term (days) benefit is minimal, and that the long-term (years) benefit is expected to be somewhat greater than 60-70%. Some water level recovery has been observed in a geothermal field about 2 km north of Laugaland, which also may most likely be attributed to the reinjection.

A few step-rate injection tests have been conducted in wells LJ-8 and LN-10. The purpose of these tests was to estimate the injection characteristics of the wells, in particular pressure losses due to turbulent flow inside the wells, and in the feed-zones next to the wells. The test was repeated in well LJ-8, after about 9 months of steady reinjection, to determine whether any changes had occurred in the well, either due to deposition in the feed-zone fractures or thermal effects. No significant difference was noted between the tests (Axelsson et al., 1998b).

Analysis of temperature and televiewer logs

Several temperature logs are available for well LJ-8 during injection. A log measured before injection started, representing the undisturbed temperature conditions of the well, is also available. Figure 9 shows two of these logs as examples. At about 2000 m there is an obstruction in the well, which actually is more than 2800 m in depth. Temperature logs measured prior to, and during injection, are also available for well LN-10. There is unfortunately an obstruction in that well at a depth of about 470 m, while the well extends to a depth of more than 1600 m.

The temperature logs measured in well LJ-8 during injection clearly show that the injected water exits the well through a few distinct exit-points (feed-zones), the deepest one being below 2000 m. An analysis of the log enables a determination of the water flow-rate as a function of depth in the well, and hence a determination of how much water exits the well at each exit-point. The basis for this is a balance between the flow of energy into the cooled well, by heat conduction, and the energy required to heat the injected water as it descends in the well (Axelsson et al., 1998b). The temperature logs were interpreted with the aid of a wellbore simulator (Bjornsson, 1987) and an example of a simulated profile is shown in Figure 9. The average results of the analyses of different profiles are as follows (Hjartarson, 1999):

depth	*fraction of inj. rate*
320m	*49%*
600m	*20%*
1335m	*20%*
1875m	*10%*
below 2000m	*1%*

The main exit points appear to be at depths of around 320, 600 and 1335 m. About 30% of the injected water appear to exit the well in the deeper part of the reservoir, below 1000 m. The main feed-zones of the production wells are below that depth. That part of the injection should directly influence the production wells, while the water exiting at 320 m depth is not expected to fully do so.

A televiewer log is available for two sections of well LJ-8, 500-1050m and 1220-1350m, measured by Potsdam Geoforschung Zentrum in 1996. This log was analysed to study the nature of the two exit points in these sections (Hjartarson, 1999). The results indicate that the exit-points at 600 and 1335 m depth are near vertical fractures, striking NE-SW and dipping to the NW. Of a number of fractures seen in the televiewer log, only these two strike NE-SW. This happens to be the same direction as that of the main fracture-zone, suggesting that this may be an optimal direction in the current stress field.

Tracer tests and cooling predictions

Three tracer tests were carried out between wells at Laugaland, during the reinjection project. The purpose of these tests was to study the connections between injection- and production wells in order to enable predictions of the possible decline in production temperature due to long-term reinjection. The first test started on September 25th 1997 when 10 kg of sodium-fluorescein were injected instantaneously into well LJ-8. Consequently its recovery was monitored accurately in well LN-12, the only production well on-line at the time. The results until the end of November 1997 are shown in Figure 10. At that time pumping from well LJ-5 started, and the previously stable conditions were disturbed. The fluorescein recovery was monitored until the end of the project, however, and the tracer has been recovered in all three production wells.

Other geothermal production wells in the Eyjafjordur-valley, outside Laugaland, were also monitored for tracer recovery (see Figure 3). A significant amount of fluorescein was actually recovered in production well TN-4 in the Ytri-Tjarnir field about 1800 m north of well LJ-8 (Axelsson et al., 1998b). This confirms a direct connection between these two fields. No tracer has been recovered in production wells in the western half of the Eyjafjordur-valley.

The second tracer test started on February 19th 1998 when 45.3 kg of potassium iodide was injected into well LN-10. At that time both of wells LJ-5 and LN-12 were on line. Conditions were not as stable during this tracer test as during the previous one, because hot water production was more variable. Iodide was only recovered in well LJ-5, but neither in well neither LN-12 nor well LJ-7. The third, and final tracer test was conducted in the spring of 1999. This was actually a repetition of the first test, carried out to study the effect of increased injection rate (21 instead of 8 l/s). These data have not yet been fully analysed.

Even though the tracer breakthrough-times were relatively short, or only of the order of 1 – 2 days, the tracer recovery has been very slow. Until early October 1998 about 1.7 and 0.6 kg of fluorescein had been recovered through wells LJ-5 and LN-12, respectively. This amounts to 23%, of the tracer injected initially, in a little more than 12 months. At the same time about 12 kg of iodide had been recovered through well LJ-5, or about 35% in 7 ½ months. This indicates that the injection- and production wells are not directly connected through the major feed-zones of the latter. They appear to be connected through some minor fractures or inter-beds.

It is also clear that well LJ-5 is somewhat better connected to the injection wells than production wells LJ-7 and LN-12. This is most likely through the upper part of the Laugaland reservoir, above 1000 m depth, since well LJ-5 is only cased to a depth of 96 m. Wells LJ-7 and LN-12 are cased to depths of 930 and 294 m, respectively. Well LJ-8 is cased to a depth of 196 m, while well LN-10 is only cased to a depth of 9 m.

The data from the first tracer test (Figure 10) have been analysed on the basis of a one-dimensional fracture-zone, or flow channel model, where the tracer return is controlled by the distance between injection- and production zones in the corresponding wells, the flow channel volumes and dispersion. This model is described by Axelsson et al. (1995) and has been used to simulate tracer test data from several Icelandic geothermal fields. Three separate flow channels are used in the simulation for wells LJ-8 and LN-12 and the simulated results presented in Figure 10. Axelsson et al. (1998b) and Hjartarson (1999) present the details of the analysis.

The main results are that, on one hand, the volumes of the channels appear to be quite small, or with a sum of the order of 20,000 m^3 (assuming an average porosity of 7%). On the other hand, only about 6% of the injected water appears to travel through these channels from injection- to production well. Most of the injected water, therefore, appears to diffuse throughout the much larger volume of the reservoir.

The model was finally used to calculate the temperature decline of well LN-12 during injection into well LJ-8, due to the flow through these channels. The results are presented in Figure 11. It should be pointed out that the injected water, which does not travel through these channels, may also cool the production wells to some degree. According to the results in the figure, 10 l/s injection will cause a temperature decline of less than 1°C in 20 years.

Finally it should be mentioned that changes in the temperature of water produced from wells LJ-5, LJ-7 or LN-12, which may be attributed to the reinjection, have not been observed. The small change predicted (Figure 11) might be masked by minor changes caused by variations in flow-rate and production pattern. Furthermore, no changes have been observed in chemical content.

Micro-earthquake activity

The seismic network was designed to locate all micro-earthquakes of magnitude $M_L > -1$, which might be induced by the injection. Thus some information on the locations of fractures involved was anticipated (Slunga et al., 1995). No micro-earthquakes were recorded during the two-year reinjection project, however. Not even during stages of the project when wellhead pressures of up to 30 bar-g were realised. This is believed to result from the fact that about 70% of the injected water exits well LJ-8 above 1000 m depth, where stresses are relatively low.

4. SUMMARY AND CONCLUDING REMARKS

The principal lessons to be learned from geothermal reinjection experience worldwide, as well as the main results of the Laugaland reinjection experiment may be summarised as follows:

Fluid injection is presently an integral part of field operations in at least 25 geothermal areas worldwide. It started out as a method of disposing of waste water from geothermal power plants for environmental protection about 3 decades ago. Injection has significantly improved reservoir performance of major geothermal areas such as The Geysers in California, Larderello in Italy as well as a few fields in the Philippines. Yet, injection is still not a widespread method of reservoir management. This is in spite of the fact that experience, and theoretical studies, have shown that injection is an economical mode of improving reservoir performance, by maintaining reservoir pressure and enhancing thermal energy extraction from geothermal reservoirs.

The possible cooling of production wells, or thermal breakthrough, has discouraged the use of injection in some cases. This danger has been overestimated, since actual thermal breakthroughs have only been observed in isolated instances. Cooling due to cold water injection can be minimized by a proper selection, or location, of injection wells, based on careful testing and research. Tracer tests are the most powerful tool for this purpose.

Silica scaling in surface equipment and injection wells is another issue, associated with injection in high temperature geothermal areas, which often is more difficult dealing with than the danger of rapid thermal breakthrough. This may also be minimized, however, by proper system design.

Long-term reinjection into sandstone reservoirs has not been successful in many of the geothermal fields where it has been attempted. Wells have experienced a rapid decline in injectivity for reasons which are not fully understood. Yet, in Thisted in Denmark, Tanggu in the P.R. of China and in Neustadt-Glewe in Germany, two different solutions to this problem have been applied with considerable success.

Even though analysis and interpretation of data collected during the Laugaland reinjection project had not been completed at the time of writing of this paper, available results are highly positive. On the one hand, an untimely thermal breakthrough or a rapid production temperature decline is not expected in production wells during long-term injection into well LJ-8. On the other hand, hot water production from the field may be increased by 60-70% of the reinjection, without causing an increased pressure draw-down. Thus, production from the Laugaland field may be increased by about 10 l/s, at an average injection rate of 15 l/s. This is equivalent to an increase in energy production of about 24 GWh/yr., which equals about 25% of the current yearly energy production at Laugaland.

Reinjection with the purpose of extracting more of the thermal energy in the hot reservoir rocks, and thereby increase the productivity of a geothermal reservoir, such as at Laugaland, has not been practised in many areas. This is more in line with the HDR-concept. Injection has, furthermore, not been part of the management of the numerous low-temperature systems utilised in Iceland. The poitive results of the Laugaland reinjection experiment indicate that reinjection will be a highly economical mode of increasing the production potential of the Laugaland system. The current reinjection system should, therefore, be an important part of the management of the geothermal reservoir for decades to come. The results of the project will hopefully also encourage other operators of fractured low-temperature geothermal systems, in Iceland as well as worldwide, to consider injection as a management option.

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Table 1. Geothermal fields where injection is part of field operation

Country	Field
Costa Rica	Miravalles
El Salvador	Berlin
Mexico	Los Azufres
Nicaragua	Momotombo
USA	The Geysers
	Dixie Valley
	East Mesa
	Heber
	Coso
	Roosevelt Warm Springs
	Desert Peak
	Niland
Japan	Otake
	Hatchobaru
	Matsukawa
Philippines	Tongonan
	Palinpinon
	Tiwi
	Bulalo
	Mt. Apo
	Bacman
France	Paris Basin
Iceland	Laugaland
Italy	Larderello
New Zealand	Ohaki

Table 2. Wells in use in the Laugaland field.

Well	Drilled	Depth (m)	Use
LJ-05	1975	1305	Production well
LJ-07	1976	1945	Production well
LJ-08	1976	2820	Obs./injection well
LG-09	1977	1963	Observation well
LN-10	1977	1606	Obs./injection well
LN-12	1978	1612	Production well

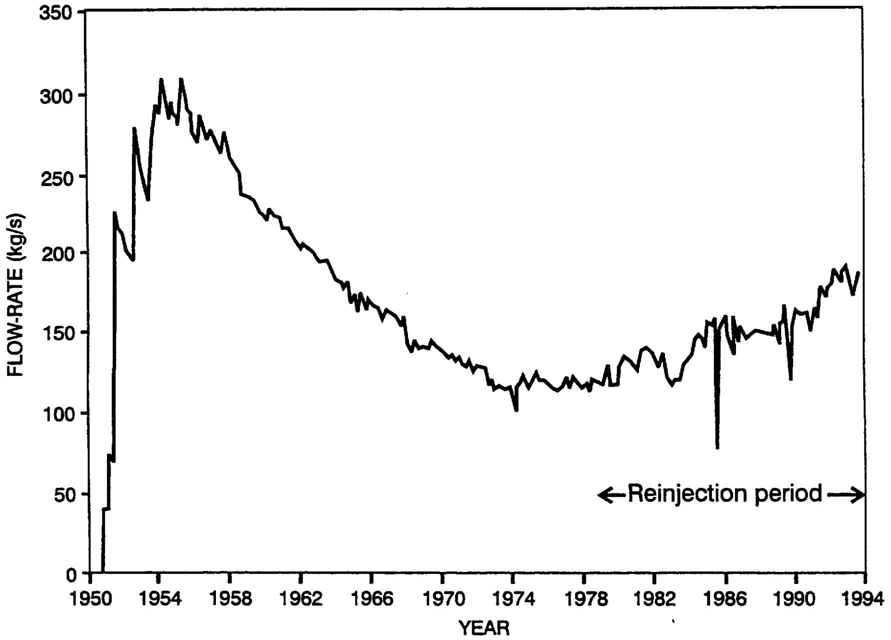

Figure 1. Flow-rate history of wells in the Larderello – Valle Secolo area, Italy. From Capetti et al. (1995).

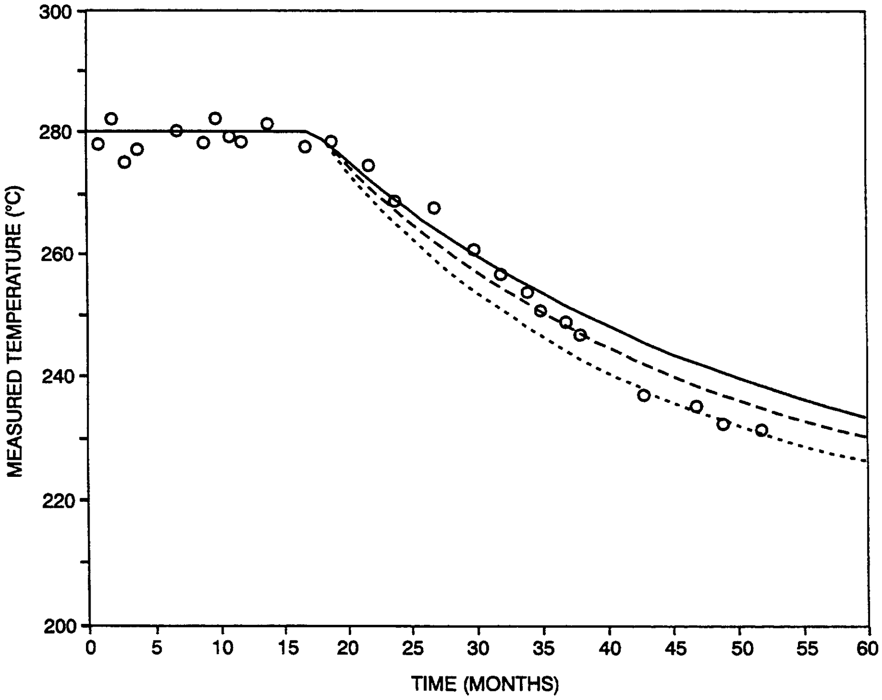

Figure 2. Measured and simulated temperature decline in well PN-26 in the Palinpinon field, Philippines. From Malate and O'Sullivan (1991).

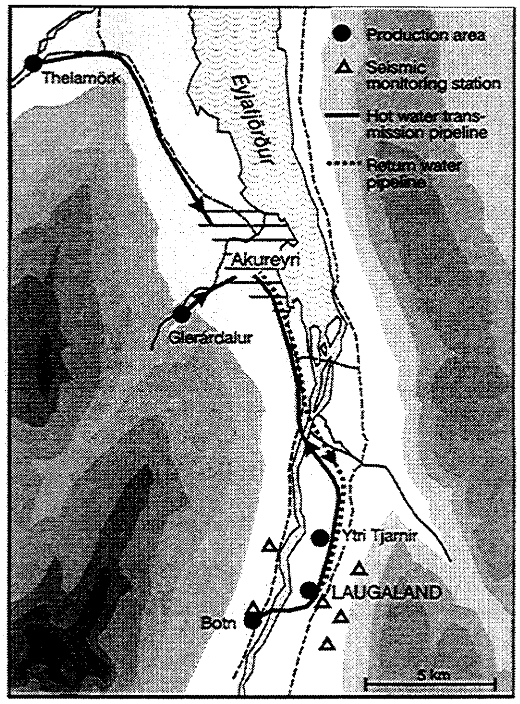

Figure 3. Location of the Laugaland geothermal area.

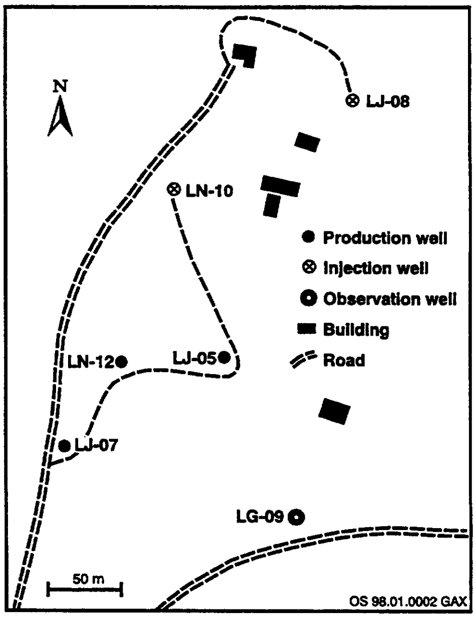

Figure 4. Wells in the Laugaland geothermal field.

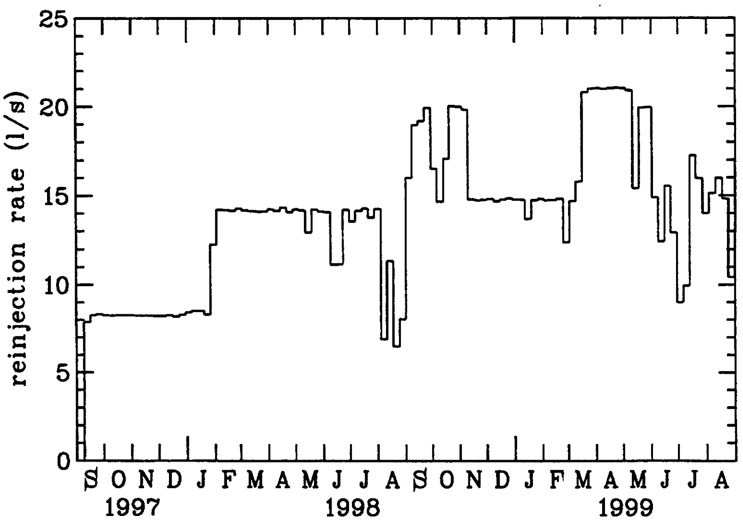

Figure 5. Daily average reinjection into wells LJ-8 and LN-10 during the reinjection project.

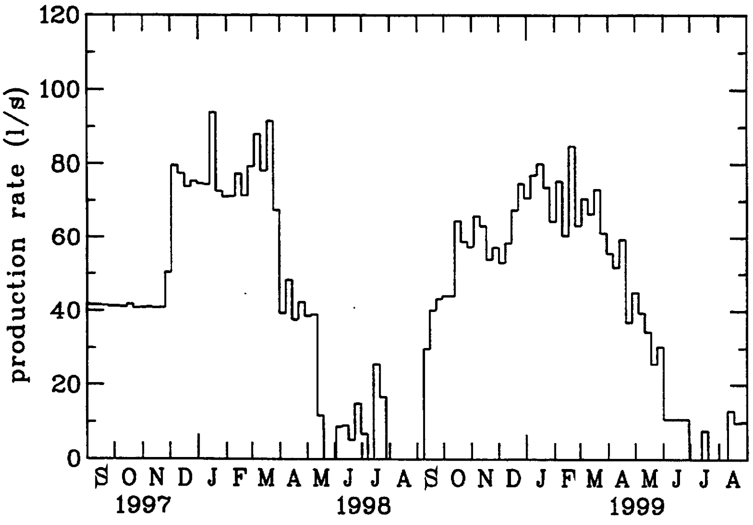

Figure 6. Daily average production from wells LJ-5, LJ-7 and LN-12 at Laugaland during the reinjection project.

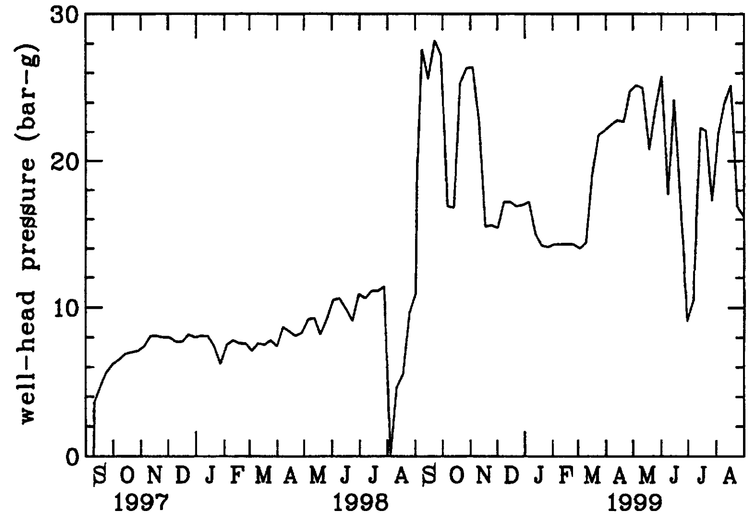

Figure 7. Well head pressure of well LJ-8 during the reinjection project.

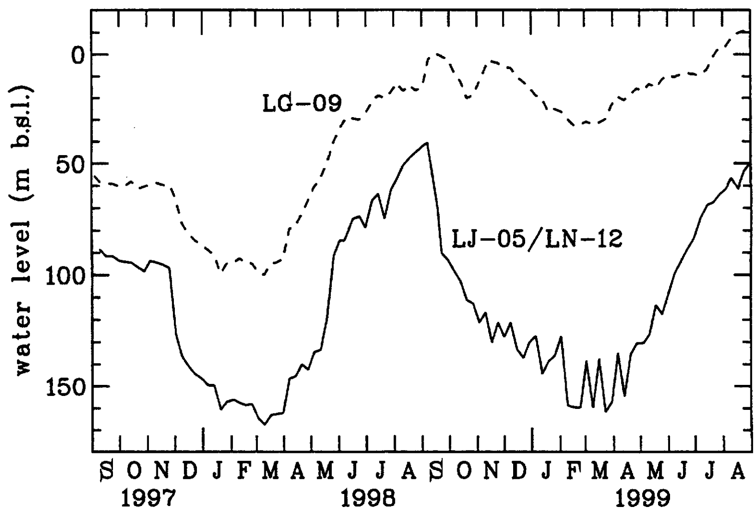

Figure 8. Water level changes in three wells at Laugaland during the reinjection project.

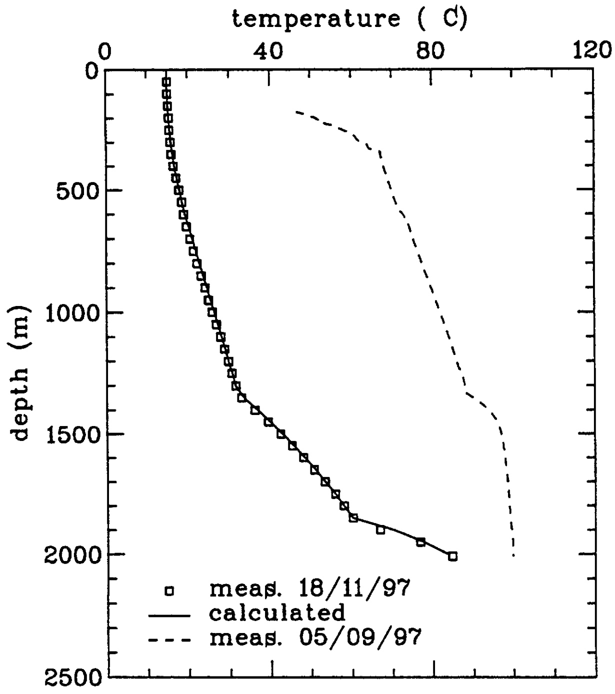

Figure 9. Two temperature logs from well LJ-8, measured prior to and during reinjection, Also shown is a simulation of the second log by a wellbore simulator.

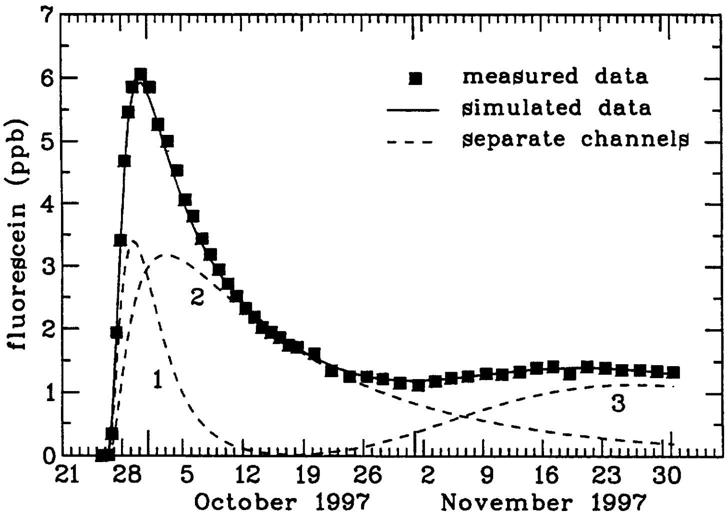

Figure 10. Observed and simulated fluorescein recovery in well LN-12 during injection into well LJ-8.

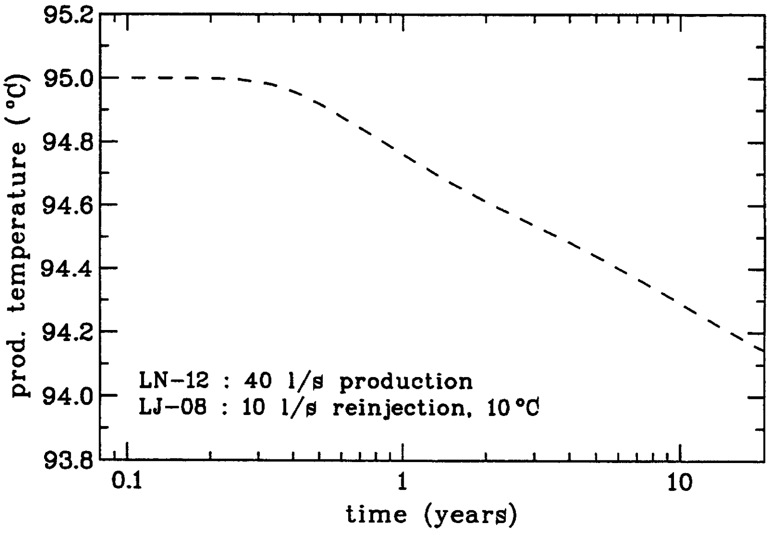

Figure 11. Estimated temperature decline for well LN-12 during injection into well LJ-8.

THERMAL ENERGY EXTRACTION BY REINJECTION FROM THE LAUGALAND GEOTHERMAL SYSTEM IN N-ICELAND

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Key Words*:* reinjection, low-permeability, thermal energy extraction, Laugaland system

ABSTRACT

A two-year reinjection experiment was completed in late 1999 in the Laugaland geothermal system in N-Iceland, the first such project undertaken in an Icelandic low-temperature area. The Laugaland system is embedded in low-permeability fractured basalt and its productivity is limited by insufficient recharge. More than sufficient thermal energy is, however, in-place in the 90 - 100 °C hot rocks of the system, some of which may be extracted by injection. The purpose of the reinjection project was to demonstrate that energy production from fractured low-temperature geothermal systems might be increased by reinjection. The Laugaland reinjection test was a co-operative project involving a few companies and institutions in Iceland, Sweden and Denmark, partly supported by the European Commission. Between 6 and 21 kg/s were injected into two reinjection wells and a comprehensive monitoring program was implemented as part of the reinjection project. Also included were three tracer-tests, monitoring of associated micro-seismic activity, step-rate injection tests and temperature logging of the injection wells. Results of the experiment indicate that reinjection will be a highly economical mode of increasing the production potential of the Laugaland system and reinjection is expected to be an important part of the management of the Laugaland reservoir for decades to come.

1. INTRODUCTION

Laugaland is the largest of five low-temperature geothermal fields utilised by Hita- og Vatnsveita Akureyrar (HVA) for space heating in the town of Akureyri in Central N-Iceland (Figure 1). Since late 1977 hot water production from the field has varied between 0.9 and 2.5 million tons annually (Flovenz *et al.*, 1995). Because of a low overall permeability and limited recharge this modest production has lead to a great pressure drawdown. It continues to increase with time if constant rate production is maintained. In the early eighties the draw-down reached about 400 m, which forced the production from the field to be reduced by about 50%. Therefore, reinjection has for long been considered a possible way to improve the productivity of the Laugaland system.

The Laugaland geothermal system is a typical fracture controlled system, embedded in 6-10 Myrs. old flood basalt, wherein the hot water flows along open fractures in otherwise low-permeability rocks. Twelve wells have been drilled in the area, only three of which are sufficiently productive to be used as production wells. Information on the wells currently in use in the field, as production-, observation- or injection wells, is presented in Table 1, and their locations are shown in Figure 2. More details on the Laugaland system may be found in Axelsson *et al.* (1998a & b).

Most of the thermal energy in the Laugaland geothermal system is still stored in the 90 - 100 °C hot reservoir rock-matrix. More recharge water is in fact needed to recover some of that energy. Therefore, HVA has been planning long-term reinjection during the last several years. A small-scale injection experiment was carried out at Laugaland in the spring of 1991, described by Axelsson *et al.* (1995 and 1998). It lasted about 5 ½ weeks and involved wells LJ-8 and LJ-5. The results of a tracer test were interpreted as indicating that the injected water diffused into a very large volume and that wells LJ-5 and LJ-8 were not directly connected. Water level data, on the other hand, indicated that reduced drawdown because of the injection should allow a considerable increase in production.

In 1996 the Thermie sub-program of the European Commissions Fourth Framework Programme for Research and Technological Development decided to support a two year reinjection experiment in the Laugaland area. This was a co-operative project involving a few companies and institutions in Iceland, Sweden and Denmark. Work on the project started in late 1996, while actual reinjection started on the 8th of September 1997. The experiment ended in late 1999, but reinjection is expected to continue. It is the first long-term reinjection project carried out in an Icelandic low-temperature area (Stefansson *et al.*, 1995).

This paper describes the Laugaland reinjection project. Data collected during the project will be reviewed along with results of data analysis and interpretation. The analysis and interpretation phase had not been completed at the time of writing of this paper, however. More details on the project can be found in Axelsson *et al.* (1998a & b).

2. THE REINJECTION PROJECT

The results of the test in 1991 indicated that injection should be viable as the means to increase the production potential of the Laugaland geothermal system. At first injection of local surface- or ground water was considered. That idea was abandoned, however, since serious problems may be associated with the injection of such water. The most serious of these is the possibility of deposition of magnesium-silicates in the feed-zones of an injection well, which may cause the well to clog up in a relatively short time, rendering further injection impossible. Using return water from the Akureyri district heating system is ideal, because its chemical composition is almost identical with that of the reservoir fluid.

This, however, was more costly, since it required construction of a return water pipeline from Akureyri to Laugaland. Therefore, a few companies and institutions in Iceland, Sweden and Denmark applied for a grant from the European Commission, in the beginning of 1996, for undertaking this project. Later that year the Commission decided to support the proposed experiment.

The project included the following phases:

1. Manufacture and installation of a 13 km return water pipeline from Akureyri to Laugaland (see Figure 1).

2. Installation of high-pressure pumps at the two injection wells, LJ-8 and LN-10, and pumps in Akureyri for pumping the water to Laugaland as well as installation of a computerised control- and monitoring system.

3. Installation of an automatic network of six ultra sensitive seismic monitoring stations around Laugaland.

4. Continuous reinjection for a period of two years, along with careful monitoring of the reservoirs response to the injection and any associated seismic activity. Three tracer tests to study the connections between injection- and production wells.

5. Analysis and interpretation of data collected, including development of a numerical model for the geothermal system, predictions of the response of production wells to long-term reinjection and analysis of the economics of future reinjection.

The total project cost is estimated at 1.7 million USD. The Thermie sub-program of the Programme of Research and Development of the European Commission supported the project by a 0.7 million USD contribution. The first three phases had been completed at the end of October 1997. The fourth phase started in September 1997 and continued until early fall 1999. Work on the fifth phase was ongoing at the time of writing of this paper.

The principal participants in the project are: *HVA*, the Akureyri District Heating Service, *Orkustofnun*, the National Energy Authority of Iceland, *Uppsala University* in Sweden, *Hochest Danmark A/S* and *Rarik*, Icelandic State Electricity.

3. PRINCIPAL RESULTS

Reinjection started on the 8th of September 1997. Since then injection into well LJ-8 has been mostly continuous, varying between 6 and 21 kg/s. From the end of January until the middle of August 1998 about 6 kg/s were also injected into well LN-10. The combined injection rate during the whole project is shown in Figure 3. A total of 910,000 tons had been injected at the end of August 1999, or about 14.4 kg/s on the average. The temperature of the injected water has been in the range of 6 - 22 °C.

Figure 4 shows the daily average hot water production from the Laugaland field during the two-year project. The production has varied between 0 and 130 l/s and a total of 2,550,000 tons were produced from the field from the end of August 1997 until the end of August 1999. The reinjection, therefore, equals about 36% of the total production during the experiment. The production has been quite variable, mostly reflecting varying hot water demand in Akureyri. During the winter time two wells are commonly on line, either wells LN-12 and LJ-5 or wells LJ-5 and LJ-7. During a few shorter periods constant production was maintained to create semi-stable reservoir conditions. This was done to facilitate various tests and consequent data interpretation. The longest such period was from the end of August until the end of November 1997, when only well LN-12 was on line.

Figure 5 shows the wellhead pressure of injection well LJ-8, which varied between 4 and 11 bar-g during the first year of the project. During the second year of the project injection rates were higher, causing a wellhead pressure as high as 28 bar-g. Before injection started the water level in the well was at a depth of 126 m. Variations in production, and the consequent variations in reservoir pressure (water level), influence the wellhead pressure of well LJ-8, in addition to variations in injection rate. Some wellhead pressure transients may also be attributed to variations in viscosity and thermal effects. The injectivity of well LN-10 appears to be about 30% greater than the injectivity of well LJ-8.

The data presented in figures 3-5 were all collected by the automatic monitoring system. In addition to these data, water level measurements were taken on a regular basis in a number of wells inside, and outside, the Laugaland field. The comprehensive monitoring program also included: temperature logging of the injection wells, monitoring of production water temperatures and chemical content, as well as three tracer tests. All these data are presently in the process of being analysed, and interpreted. The analysis has focused on three main aspects: (1) water level changes, which yield information on reservoir properties and the pressure recovery resulting from the reinjection, (2) borehole logs, which yield information on the feed-zones of the injection wells, and (3) tracer tests, which provide information on the connections between injection and production wells, and hence the danger of premature, and rapid cooling, of the latter.

The principal results of the analysis are presented below, but the details await the final report for the project. First the current conceptual model of the Laugaland system is described briefly.

3.1 Conceptual model of the Laugaland system

The conceptual model of the Laugaland system has been revised on the basis of the data collected during the reinjection project (Axelsson *et al.*, 1998a; Hjartarson, 1999). The model involves a near vertical fracture-zone, trending close to N50°E, with a moderate permeability, maintained by recent crustal movements. The permeability of the lava-pile outside the fracture-zone has been reduced drastically by low-grade alteration. Successful wells in the area are either located very close to or they intersect this fracture-zone. In the natural state convection in the fractures transferred heat from a depth of a few km to shallower levels. The heat was consequently transported into the low-permeability rocks outside the fracture-zone, mostly by heat conduction. This convective/conductive heat transfer is believed to have been ongoing for the last 10,000 years at least.

3.2 Water level changes

Figure 6 shows the water-level changes observed in three wells in the Laugaland field during the two-year injection project. These are observation well LG-09 and production wells LJ-5 and LN-12. Water level records, not presented here, are also available from a number of other wells, inside as well as outside the Laugaland field.

The details of the water level record will not be discussed here. It actually constitutes a series of pressure transient tests, however, several of which have been analysed as such (Hjartarson, 1999). The main results of this analysis are that the production wells intersect the NE-SW fracture zone, which has an estimated permeability thickness of about 15 Darcy-m. The injection wells are clearly outside this zone. The permeability thickness of the low-permeability rocks outside the fracture-zone is estimated to be about 2 Darcy-m.

A reduced water level drawdown is anticipated as the main benefit from reinjection. The water level data were, therefore, also analysed carefully in order to quantify the effect of reinjection on the water level in the production wells. This was done by simulating the 20 year water level history of the Laugaland field by a lumped parameter model (Axelsson, 1989). The deviation between observed and simulated data, after reinjection started, was consequently used to estimate the benefit. The results indicate that the hot water production rate may be increased by 60-70% of the reinjection rate, without causing additional drawdown. It should be mentioned that the short-term (days) benefit is minimal, and that the long-term (years) benefit is expected to be somewhat greater. Some water level recovery has been observed in a geothermal field about 2 km north of Laugaland, which also may most likely be attributed to the reinjection.

A few step-rate injection tests have been conducted in wells LJ-8 and LN-10. The purpose of these tests was to estimate the injection characteristics of the wells, in particular pressure losses due to turbulent flow inside the wells, and in the feed-zones next to the wells. The test was repeated in well LJ-8, after about 9 months of steady reinjection, to determine whether any changes had occurred in the well, either due to deposition in the feed-zone fractures or thermal effects. No significant difference was noted between the tests (Axelsson *et al.*, 1998b).

3.3 Analysis of temperature and televiewer logs

Several temperature logs are available for well LJ-8 during injection. A log measured before injection started, representing the undisturbed temperature conditions of the well, is also available. Figure 7 shows two of these logs as examples. At about 2000 m there is an obstruction in the well, which actually is more than 2800 m in depth. Temperature logs measured prior to, and during injection, are also available for well LN-10. There is unfortunately an obstruction in that well at a depth of about 470 m, while the well extends to a depth of more than 1600 m.

The temperature logs measured in well LJ-8 during injection clearly show that the injected water exits the well through a few distinct exit-points (feed-zones), the deepest one being below 2000 m. An analysis of the log enables a determination of the water flow-rate as a function of depth in the well, and hence a determination of how much water exits the well at each exit-point. The basis for this is a balance between the flow of energy into the cooled well, by heat conduction, and the energy required to heat the injected water as it descends in the well (Axelsson *et al.*, 1998b). This analysis was carried out with the aid of a wellbore simulator (Bjornsson, 1987) and an example of a simulated profile is shown in Figure 7. The average results of the analyses of different profiles are as follows (Hjartarson, 1999):

depth	*fraction of inj. rate*
320m	*49%*
600m	*20%*
1335m	*20%*
1875m	*10%*
below 2000m	*1%*

The main exit points appear to be at depths of around 320, 600 and 1335 m. About 30% of the injected water appear to exit the well in the deeper part of the reservoir, below 1000 m. The main feed-zones of the production wells are below that depth. That part of the injection should directly influence the production wells, while the water exiting at 320 m depth is not expected to fully do so.

A televiewer log is available for two sections of well LJ-8, 500-1050m and 1220-1350m, measured by Potsdam Geoforschung Zentrum in 1996. This log was analysed to study the nature of the two exit points in these sections (Hjartarson, 1999). The results indicate that the exit-points at 600 and 1335 m depth are near vertical fractures, striking NE-SW and dipping to the NW. Of a number of fractures seen in the televiewer log, only these two strike NE-SW. This happens to be the same direction as that of the main fracture-zone, suggesting that this may be an optimal direction in the current stress field.

3.4 Tracer tests and cooling predictions

Three tracer tests were carried out between wells at Laugaland, during the reinjection project. The purpose of these tests was to study the connections between injection- and production wells in order to enable predictions of the possible decline in production temperature due to long-term reinjection. The first test started on September 25th 1997 when 10 kg of sodium-fluorescein were injected instantaneously into well LJ-8. Consequently its recovery was monitored accurately in well LN-12, the only production well on-line at the time. The results until the end of November 1997 are shown in Figure 8. At that time pumping from well LJ-5 started, and the previously stable conditions were disturbed. The fluorescein recovery was monitored until the end of the project, however, and the tracer has been recovered in all three production wells.

Other geothermal production wells in the Eyjafjordur-valley, outside Laugaland, were also monitored for tracer recovery (see Figure 1). A significant amount of fluorescein was actually recovered in production well TN-4 in the Ytri-Tjarnir field about 1800 m north of well LJ-8 (Axelsson *et al.*, 1998b). This confirms a direct connection between these two fields. No tracer has been recovered in production wells in the western half of the Eyjafjordur-valley.

The second tracer test started on February 19th 1998 when 45.3 kg of potassium iodide was injected into well LN-10. At that time both of wells LJ-5 and LN-12 were on line. Conditions were not as stable during this tracer test as during the previous one, because hot water production was more variable. Iodide was only recovered in well LJ-5, but neither in well neither LN-12 nor well LJ-7. The third, and final tracer test was conducted in the spring of 1999. This was actually a repetition of the first test, carried out to study the effect of increased injection rate (21 instead of 8 l/s). These data have not yet been fully analysed.

Even though the tracer breakthrough-times were relatively short, or only of the order of 1 – 2 days, the tracer recovery has been very slow. Until early October 1998 about 1.7 and 0.6 kg of fluorescein had been recovered through wells LJ-5 and LN-12, respectively. This amounts to 23%, of the tracer injected initially, in a little more than 12 months. At the same time about 12 kg of iodide had been recovered through well LJ-5, or about 35% in 7 ½ months. This indicates that the injection- and production wells are not directly connected through the major feed-zones of the latter. They appear to be connected through some minor fractures or inter-beds.

It is also clear that well LJ-5 is somewhat better connected to the injection wells than production wells LJ-7 and LN-12. This is most likely through the upper part of the Laugaland reservoir, above 1000 m depth, since well LJ-5 is only cased to a depth of 96 m. Wells LJ-7 and LN-12 are cased to depths of 930 and 294 m, respectively. Well LJ-8 is cased to a depth of 196 m, while well LN-10 is only cased to a depth of 9 m.

The data from the first test (Figure 8) have been analysed on the basis of a one-dimensional fracture-zone, or flow channel model, where the tracer return is controlled by the distance between injection- and production zones in the corresponding wells, the flow channel volumes and dispersion. This model is described by Axelsson *et al.* (1995) and has been used to simulate tracer test data from several Icelandic geothermal fields. Three separate flow channels are used in the simulation for wells LJ-8 and LN-12 and the simulated results presented in Figure 8. Axelsson *et al.* (1998b) and Hjartarson (1999) present the details of the analysis.

The main results are that, on one hand, the volumes of the channels appear to be quite small, or with a sum of the order of 20,000 m^3 (assuming an average porosity of 7%). On the other hand, only about 6% of the injected water appears to travel through these channels from injection- to production well. Most of the injected water, therefore, appears to diffuse throughout the much larger volume of the reservoir.

The model was finally used to calculate the temperature decline of well LN-12 during injection into well LJ-8, due to the flow through these channels. The results are presented in Figure 9. It should be pointed out that the injected water, which does not travel through these channels, may also cool the production wells to some degree. According to the results in the figure, 10 l/s injection will cause a temperature decline of less than 1°C in 20 years.

Finally it should be mentioned that changes in the temperature of water produced from wells LJ-5, LJ-7 or LN-12, which may be attributed to the reinjection, have not been observed. The small change predicted (Figure 9) might be masked by minor changes caused by variations in flow-rate and production pattern. Furthermore, no changes have been observed in chemical content.

3.5 Micro-earthquake activity

The seismic network was designed to locate all micro-earthquakes of magnitude $M_L > -1$, which might be induced by the injection. Thus some information on the locations of fractures involved was anticipated (Slunga *et al.*, 1995). No micro-earthquakes were recorded during the two-year reinjection project, however. Not even during stages of the project when wellhead pressures of up to 30 bar-g were realised. This is believed to result from the fact that about 70% of the injected water exits well LJ-8 above 1000 m depth, where stresses are relatively low.

4. CONCLUDING REMARKS

Even though analysis and interpretation of data collected during the Laugaland reinjection project had not been completed at the time of writing of this paper, available results are highly positive. On the one hand, an untimely thermal breakthrough or a rapid production temperature decline is not expected in production wells during long-term injection into well LJ-8. On the other hand, hot water production from the field may be increased by 60-70% of the reinjection, without causing an increased pressure draw-down. Thus, production from the Laugaland field may be increased by about 10 l/s, at an average injection rate of 15 l/s. This is equivalent to an increase in energy production of about 24 GWh/yr., which equals about 25% of the current yearly energy production at Laugaland.

Reinjection is practised in many geothermal fields in the world, in most cases to dispose of waste water due to environmental reasons (Stefansson, 1997). Reinjection with the purpose of extracting more of the thermal energy in the hot reservoir rocks, and thereby increase the productivity of a geothermal reservoir, has not been practised in many areas. This is more in line with the HDR-concept. Injection has, furthermore, not been part of the management of the numerous low-temperature systems utilised in Iceland. The positive results of the Laugaland reinjection experiment indicate that reinjection will be a highly economical mode of increasing the production potential of the Laugaland system. The current reinjection system should, therefore, be an important part of the management of the geothermal reservoir for decades to come. The results of the project will hopefully also encourage other operators of fractured low-temperature geothermal systems to consider injection as a management option.

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Table 1. Wells in use in the Laugaland field.

Well	Drilled	Depth (m)	Use
LJ-05	1975	1305	Production well
LJ-07	1976	1945	Production well
LJ-08	1976	2820	Obs./injection well
LG-09	1977	1963	Observation well
LN-10	1977	1606	Obs./injection well
LN-12	1978	1612	Production well

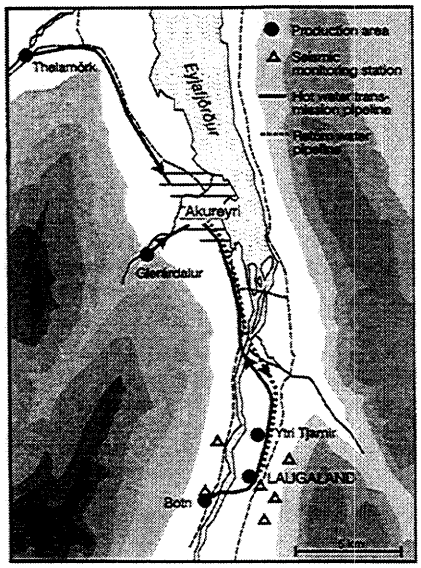

Figure 1. Location of the Laugaland geothermal area.

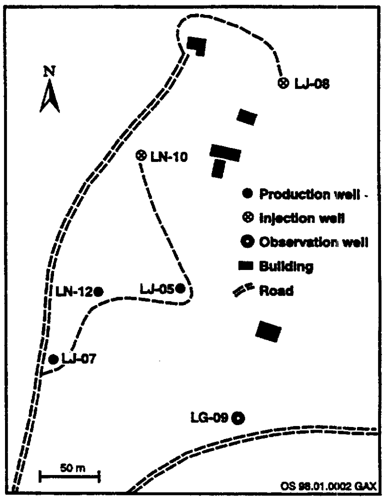

Figure 2. Wells in the Laugaland geothermal field.

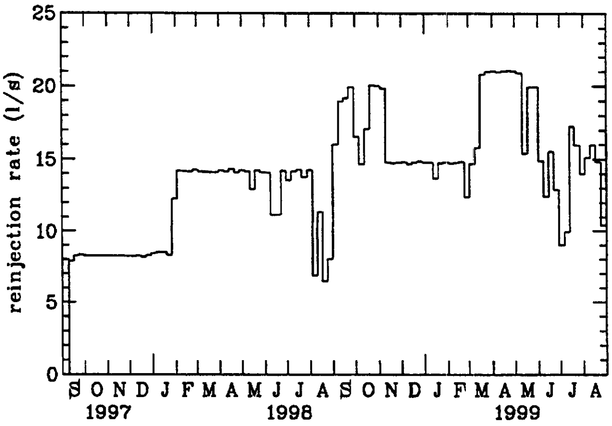

Figure 3. Weekly average reinjection into wells LJ-8 and LN-10 during the reinjection project.

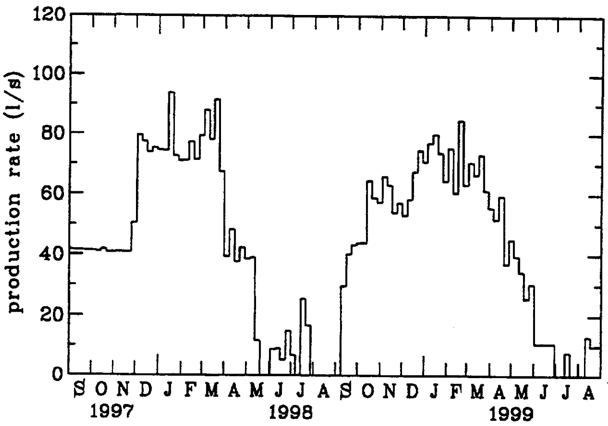

Figure 4. Weekly average production from wells LJ-5, LJ-7 and LN-12 at Laugaland during the reinjection project.

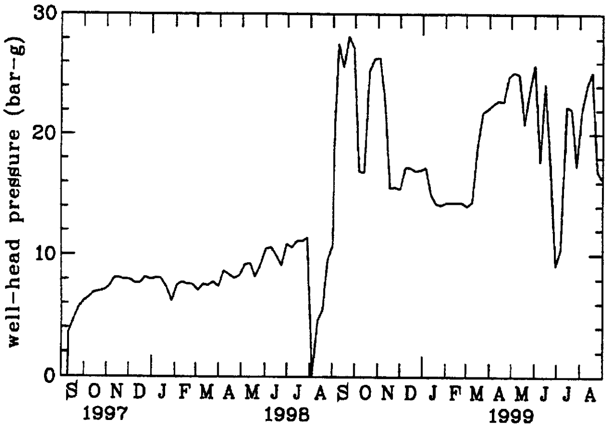

Figure 5. Well head pressure of well LJ-8 during the reinjection project.

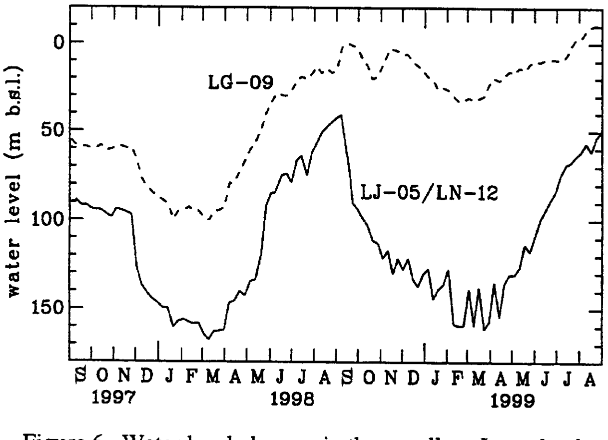

Figure 6. Water level changes in three wells at Laugaland during the reinjection project.

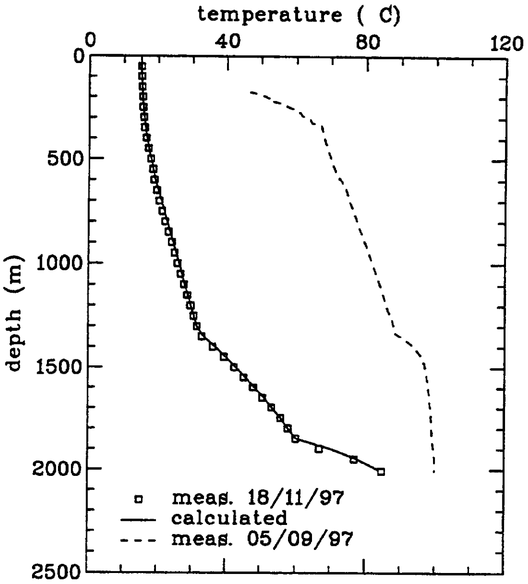

Figure 7. Two temperature logs from well LJ-8, measured prior to and during reinjection, Also shown is a simulation of the second log by a wellbore simulator.

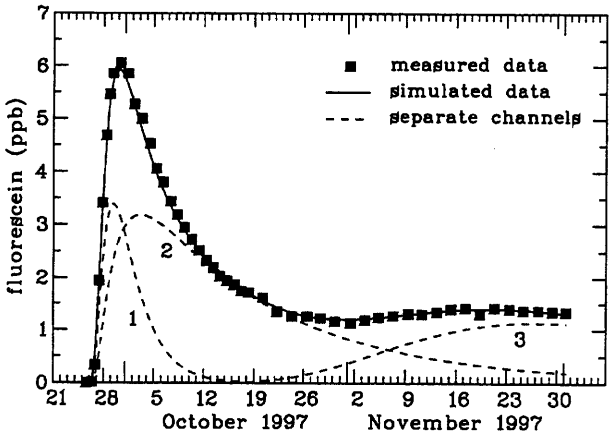

Figure 8. Observed and simulated fluorescein recovery in well LN-12 during injection into well LJ-8.

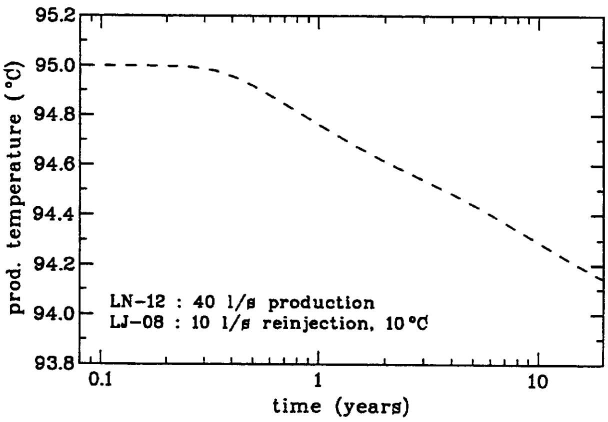

Figure 9. Estimated temperature decline for well LN-12 during injection into well LJ-8.