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FEASIBILITY STUDY FOR THE THELAMÖRK LOW-TEMPERATURE SYSTEM IN N-ICELAND

Grímur Björnsson, Gudni Axelsson and Ólafur G. Flóvenz

National Energy Authority, Grensásvegur 9, 108 Reykjavík, ICELAND

ABSTRACT

The Thelamörk low-temperature geothermal system in N-Iceland has for the last decade been considered as a possible source of hot water for the Akureyri District Heating Service. A productive well was drilled in the summer of 1992 after 10 years of geothermal research in the area. Following that a feasibility study was performed in order to determine whether harnessing the geothermal system for space heating would be economical. This study consisted of a nine month full scale production test along with partial reinjection and tracer tests. It also involved careful monitoring of production rates, water level changes and chemistry. Finally, the data collected were analyzed on the basis of simple reservoir models. The results of the analysis indicate that the system will sustain a production of 19-20 l/s, initially at 91 °C, for the next 10 years, given that 3 l/s will be reinjected. However, a cooling of 9-12 °C is predicted due to infiltration of colder groundwater and the reinjection. The results also suggest that harnessing the geothermal system will be economical, despite the high cost of exploration and an 11 km insulated pipeline to Akureyri.

INTRODUCTION

Hitaveita Akureyrar (the Akureyri District Heating Service) provides hot water for space heating in the town of Akureyri in Central North Iceland (pop. 16,000). For this purpose water is produced from four low-temperature hydrothermal systems in the vicinity of the town, shown in Figure 1, namely: Glerárdalur, Ytri-Tjarnir, Laugaland and Botn (Axelsson and Björnsson, 1993). In 1992 the annual production from each of these four systems ranged between 13 and 42 l/s of 60-95 °C water (Flóvenz et al., 1993). This amounts to 228 GWh_t of thermal energy, assuming a return water temperature of 30 °C. The production rate has increased by 2 % annually during the last decade and the demand of the space heating market is expected to continue to rise. The total production capacity of the four systems, however, is estimated at only 248 GWh_t/year, assuming the present system of production wells and downhole pumps (Axelsson et al., 1988). This forces Hitaveita Akureyrar to acquire additional sources of energy within a few years.

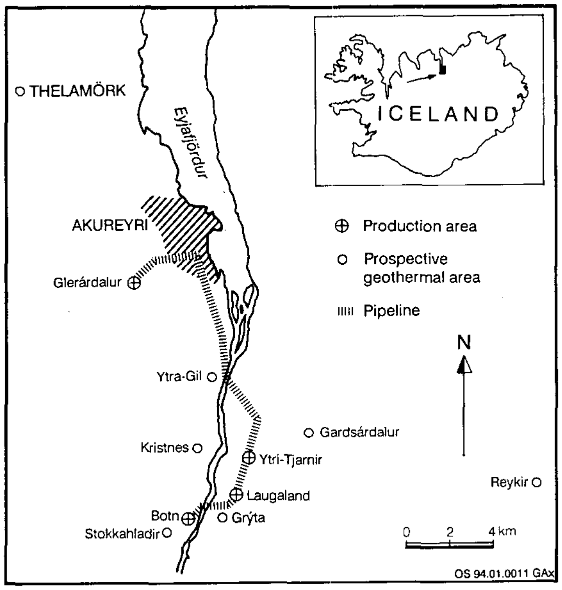

Figure 1: *Location of the Thelamörk field and the geothermal areas presently utilized by Hitaveita Akureyrar.*

The search for more energy has focused on a few unharnessed geothermal fields in the vicinity of Akureyri. One of the areas considered is the Thelamörk geothermal field, located about 11 km north of Akureyri (Figure 1). At Thelamörk the only manifestations of geothermal activity were a small hot spring flowing 0.3 l/s of 45 °C water together with ancient silica precipitation. Yet geothermometers suggested an underlying geothermal reservoir of 90-100 °C. The initial exploration phase, which ended in 1970 (Table 1), was not fully successful. Thus plans for utilization of the Thelamörk field were abandoned.

Rapid development of exploration techniques along with the marginal power capacity of Hitaveita Akureyrar restored the interest in the Thelamörk field in 1983. After conducting resistivity and magnetic surveys, geological mapping and exploration drilling, a successful well was drilled in the summer of 1992. Following that the feasibility of harnessing the geothermal system was studied (Flóvenz et al., 1994). This was done by producing from the new well for nine months and by observing and analyzing the systems response.

Table 1. *Wells drilled in the Thelamörk geothermal field.*

Well	Drilled	Depth (m)	Type
1	1944	375	Expl. well
2	*1965*	*1088*	*Prod. well*
3	1970	667	Expl. well
4	1970	711	Expl. well
5	1989	239	Expl. well
6	1989	361	Expl. well
7	1989	208	Expl. well
8	1989	251	Expl. well
9	1990	367	Expl. well
10	1992	914	Expl. well
11	*1992*	*452*	*Prod. well*

In this paper a brief description of the production test and the data collected is given. The simple reservoir models used to analyze the data are presented along with their predictions on the following:

1. Future water level changes in the reservoir.
2. Reservoir cooling due to infiltration of colder groundwater.
3. Heat mining and water level maintenance by reinjection.

Finally, a cost estimate for the Thelamörk project is shown and compared to the cost of space heating by sources of energy, other than geothermal.

In the initial work more complicated, distributed parameter models were considered. They were, however, rejected at this stage due to a very tight time schedule for the feasibility study and the limited data available (i.e. a primitive conceptual model).

GEOTHERMAL EXPLORATION

Like most low-temperature geothermal systems in Iceland, the Thelamörk system was believed to be characterized by near vertical structures, such as fracture-zones or dykes. The upflow of hot water is along permeable parts of these structures. Therefore the geothermal exploration phase aimed at locating vertical formations, in particular the permeable ones. Figure 2 shows the results of the exploration (Flóvenz et al., 1984). On the basis of a ground magnetic survey, together with geological mapping and analysis of drill cuttings, several dykes were located, most of them directed between N and NW. Also located were two NNE-trending faults, dipping to the east. Head-on resistivity profiling located two low-resistivity structures directed NNW and a third one along the Hörgá river, apparently connecting the other two (Flóvenz, 1984).

Due to the complexity of the subsurface structure, five additional exploration wells were drilled in 1989 and 1990 (Table 1) to obtain more detailed information on the system, in particular on the temperature distribution (Flóvenz et al., 1990, Milicevic, 1990). Integrated modeling of the formation temperature, well log data, drill cutting analysis and results of resistivity- and ground magnetic surveys strongly indicated that the upflow zone was restricted to a narrow part of either the low-resistivity fracture along the river or the dyke marked A in Figure 2. The upflow zone might even be restricted to the intersection of the fracture and the dyke. The dip of the fracture along the river was assumed to be about 6 ° to the south. Well 10 was drilled in the summer of 1992 and targeted to intersect the fracture at 600-900 m depth. This well turned out to be unsuccessful and temperature data from the well indicated that the fracture was, in fact, dipping to the north (Flóvenz et al., 1994).

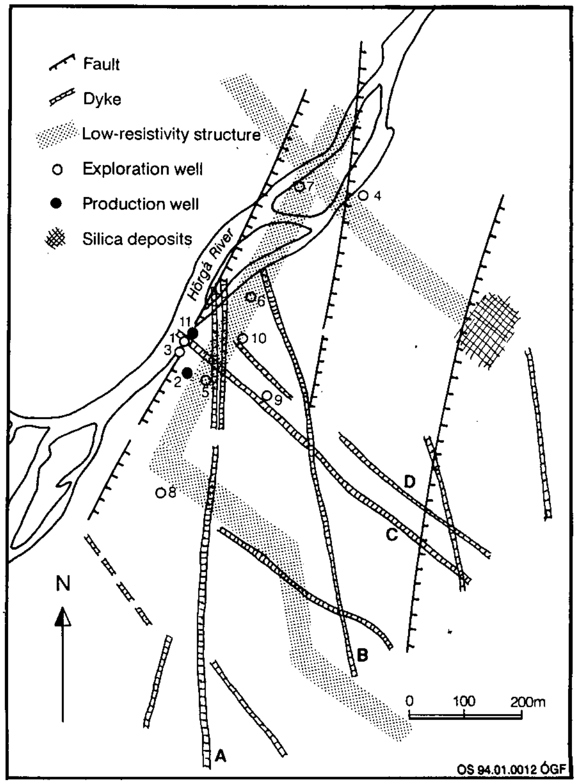

Figure 2: *A geological map of the Thelamörk area showing dykes, faults, low resistivity structures and wells.*

Well 11, which was drilled later that summer, was successful. It intersected highly productive feedzones at 430-450 m depth, and thus confirmed the conclusion on the dip of the permeable fracture. Brief testing by air-lifting at the conclusion of drilling yielded 40-60 l/s of 85-90 °C water. However, a rapidly increasing draw-down was observed in well 11 and most of the exploration wells during these short periods of testing.

THE PRODUCTION TEST

The rapidly increasing draw-down during air-lifting of well 11 indicated that the long-term productivity of the well might be limited, in spite of its great initial productivity. It was, therefore, decided that the Thelamörk field would be tested carefully before any plans of connecting it to Hitaveita Akureyrar would be made. This testing was done by producing from well 11 for a period of nine months. A rotary-shaft pump was installed in the well along with an air tube for water level measurements and a flowmeter. Other wells in the area were also prepared for water level monitoring. Pumping started on November 11, 1992 and continued until August 11, 1993.

During the test 15 - 20 l/s of 91.5 °C water were produced from well 11. In addition about 6 l/s were reinjected into wells 6 and 8 during the last 2 1/2 months of the test. Figure 3 shows the production rate along with the injection into wells 6 and 8. The flow rates, water temperature, chemical concentration of water samples and water level in most of the wells in the area were monitored carefully throughout the test. As an example more than 2500 water level readings were taken.

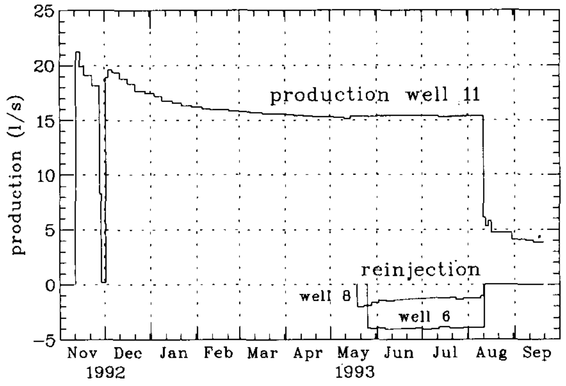

Figure 3: *Rates of production from well 11 and reinjection into wells 6 and 8.*

Figure 4 shows the water level data collected in well 11. It should be noted that the brief water level recovery in December 1992 was due to a failure of the pump in well 11.

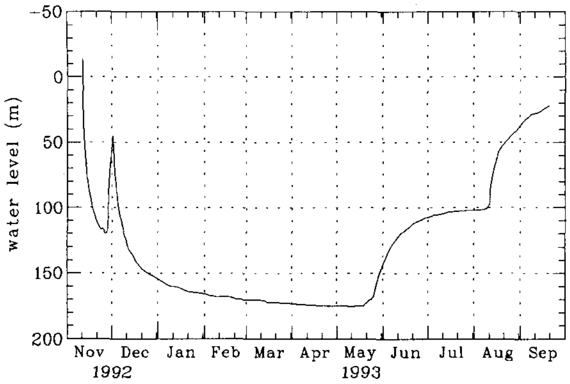

Figure 4: *Water level in well 11 during the pumping test.*

Tracer tests were carried out concurrently with the reinjection in order to evaluate the connections between possible injection wells and the production well. These will be discussed later in the paper.

FUTURE WATER LEVEL

Most of the wells at Thelamörk showed similar water level changes during the production test. The draw-down in well 2 was about 190 m, equaling the draw-down in well 11. In wells 3, 5, 6, 8 and 9 water levels fell by about 160 m. The maximum draw-down in wells 4, 7 and 10, however, was between 10 and 70 m. The similar draw-down in the former group is most likely due to their direct connection to the permeable fracture zone discussed earlier. The water level in the latter group, on the other hand, is dominated by the pressure in the rock matrix outside the fracture zone.

The interference data from the exploration wells were simulated by the response of a conventional Theis-model of an infinite, confined and isotropic layer of porous material. An example of the results is presented in Figure 5, which shows the observed and calculated draw-down in well 6 during the first 16 days of the production test. A transmissivity $khg/\nu = 3.9 \times 10^{-5}$ m^2/s and a storativity $c_t h \rho g = 2.3 \times 10^{-4}$ were estimated for this well pair. The transmissivity corresponds to a permeability thickness (kh) of only 1.3 Dm. This represents the average reservoir permeability in the production part of the geothermal system. This is comparable to the lowest such values estimated for geothermal systems utilized in Iceland (Björnsson and Bodvarsson, 1990).

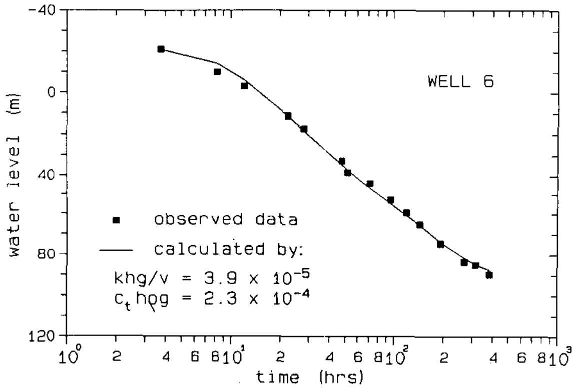

Figure 5: *Simulated interference data from well 6.*

Lumped reservoir modeling was used to simulate the water level data from the production test and to predict the draw-down in the reservoir due to long-term production from well 11 as well as to estimate the reservoir volume. Lumped models have been used successfully to simulate and predict pressure response data from several low-temperature reservoirs in Iceland (Axelsson, 1989 and 1991). An automatic method which tackles the simulation as an inverse problem was applied (Axelsson and Arason, 1992).

Figure 6 shows the three tank lumped model used to simulate the water level data from well 11. The innermost tank, which has a mass storage coefficient κ_1, simulates the production part of the geothermal system. This tank is connected by a conductor σ_1 to the second tank (κ_2), which simulates the outer and deeper parts of the reservoir. The conductor simulates the fluid conductivity between those two parts. The second tank is finally connected to the third tank (κ_3), which simulates recharge to the geothermal system. This tank simulates probably both the deeper parts of the geothermal system and the overlaying groundwater system. Figure 7 shows the match between the observed and simulated water levels.

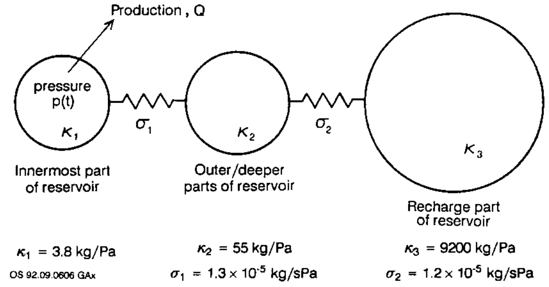

Figure 6: *A lumped reservoir model of the Thelamörk geothermal system.*

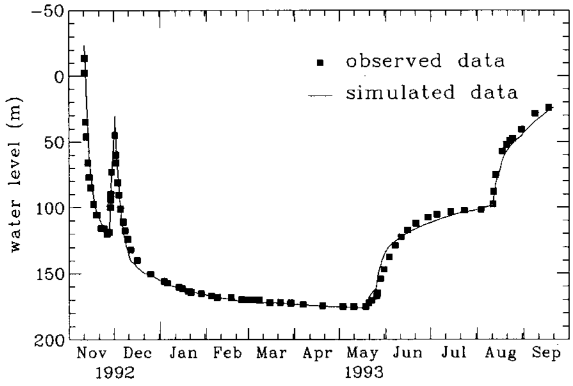

Figure 7: *Observed and simulated water level changes in well 11.*

In this study a closed reservoir model was used rather than an open one. This results in pessimistic water level predictions in contrast to optimistic predictions made by open models. The storage coefficient of the outermost tank was, in fact, adjusted such that the simulated water level declined by 5 m/year at 15 l/s net production. This equals the decline rate observed during the middle of the production test, before the reinjection. It is, however, unlikely that a decline rate so high will persist during long-term production.

The mass storage coefficient of the innermost tank corresponds to a volume of 0.095 km^3, assuming an average porosity of 5 %. The outer and deeper parts of the model (tank 2) simulate a volume of 1.4 km^3, assuming the same porosity. The recharge part of the system appears to be unconfined, which is reflected in a very large mass storage coefficient (Figure 6). The storage coefficient of an unconfined reservoir depends on its area rather than its volume (Axelsson, 1989). The storage coefficient of the third tank corresponds to an area of 0.9 km^2, assuming a porosity of 10 %.

The above results indicate that the reservoir volume, affected by the new well, is small with a low average permeability. The Thelamörk geothermal system appears, however, to be connected to much larger recharge systems, perhaps a geothermal reservoir at greater depth, as well as the surrounding groundwater systems.

Finally, the lumped model was used to predict the water level draw-down in well 11 for three cases of constant future production, for a ten year period. The results are presented in Figure 8 but will be discussed in a later section.

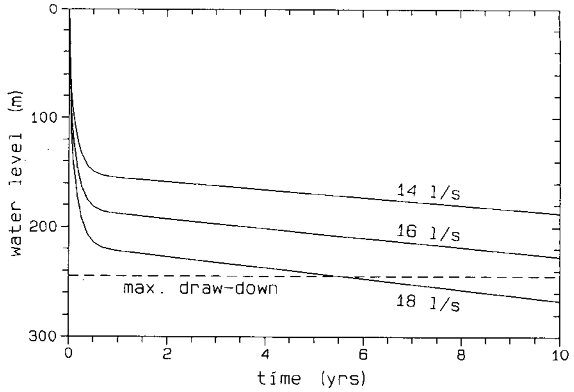

Figure 8: *Predicted water level changes in well 11 at Thelamörk.*

COOLING BY INFLOW OF COLDER WATER

The chemical concentration of the water from well 11 was monitored during the production test. The most noteworthy change was a decline in silica concentration, from 129 ppm initially to 124 ppm in late May, when the reinjection began. This decline is believed to be the result of colder fluids seeping into the production part of the reservoir, partially as internal flow in the exploration wells and partially through fractures extending to the surface. A simple lumped model was used to simulate these data and to predict cooling of the water produced from well 11 in the future. This model is described in more detail in Appendix A.

The match between the observed and calculated silica concentration is shown in Figure 9. In the model mixing of geothermal water and cold groundwater takes place in a small subvolume (V) of the geothermal

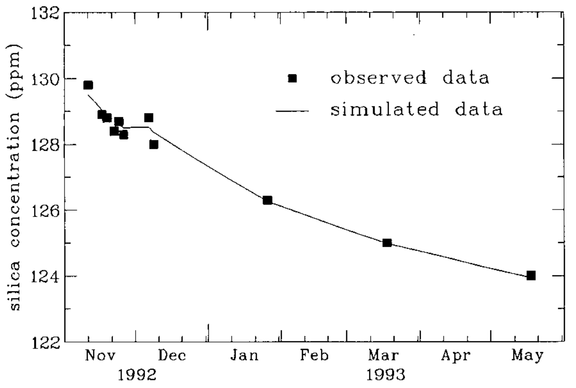

Figure 9: *Measured and simulated silica concentration in water produced from well 11.*

reservoir. The product of this volume and porosity (ϕ) equals 0.0007 km^3. This corresponds to a volume of 0.015 km^3, assuming an effective porosity of 5 %. In the model the base inflow (R) is about 78 % of the production, whereas the colder down-flow (q) is about 22 %, with a silica concentration (C') of 50 ppm. This model does not constitute a unique solution. A greater volume and more down-flow with, however, a greater silica concentration and higher temperature would result in a similar fit. This non-uniqueness does not influence the cooling predictions seriously and the model used predicts, in fact, the greatest long-term cooling. The model is, in other words, pessimistic.

The simple model of Appendix A was finally used to predict the possible temperature decline due to down-flow of colder water. This was done for 5 % and 10 % reservoir porosities and assuming that the temperature of the down-flow was 25 °C. The results are presented in Figure 10. An effective porosity of 5 % is considered to be most realistic due to the fractured nature of the Thelamörk geothermal system. This is supported by a negligible temperature decline during the nine month production test.

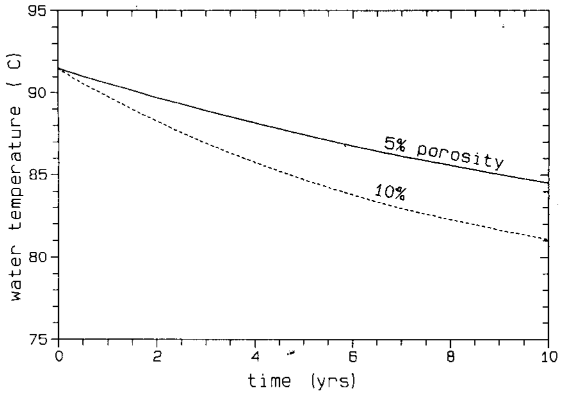

Figure 10: *Predicted temperature decline due to down-flow of colder water for 16 l/s production.*

HEAT MINING BY REINJECTION

The objective of the tracer studies at Thelamörk was to evaluate the nature of the fracture system connecting injection and production wells. The water produced from well 11 was recirculated at rates of 4 and 2 l/s into wells 6 and 8, respectively, from late May until the middle of August, 1993 (Figure 4). The water level of all wells was monitored meanwhile. When a semi steady-state had been reached, a known mass of bromide and fluorescein was injected instantaneously into wells 6 and 8, respectively. Water samples where taken frequently from well 11 and the two tracer concentrations measured. Figure 11 shows the observed data for the bromide injected into well 6. Also shown is the data corrected for the extra bromide that was recirculated from well 11 into wells 6 and 8 (Arason et al., 1993). The corrected data shows that 9.3 kg of the 15.5 kg of bromide injected were recovered, or 60 %. The tracer recovery for well 8 was similar, yet somewhat slower because of the greater distance between wells 8 and 11. About 0.24 kg of fluorescein were recovered compared to the 1 kg injected.

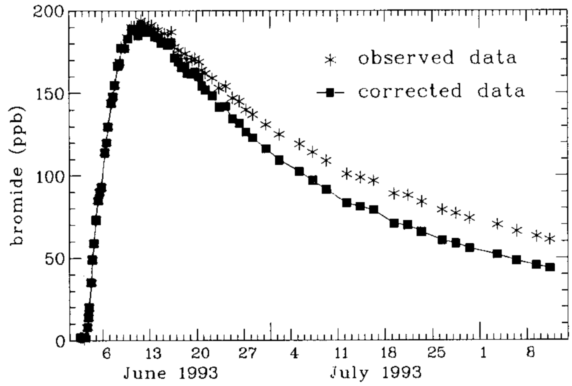

Figure 11: *Observed and corrected tracer recovery curves for the well dipole 6-11.*

The tracer return curves were analyzed by a simple one-dimensional fracture-zone model. A brief description of the method used is given in Appendix B. Figure 12 shows the measured and simulated tracer return curves for the bromide injected into well 6. Two flow channels between the injector and the producer were assumed. The first channel accounts for 15 % of the recovered tracer and is taken to be the shortest distance between the two wells (120 m). The second channel, on the other hand, transported 85 % of the tracer mass. This flow channel is assumed to be a fracture zone connecting the major feedzones of the two wells. Table 2 presents the model parameters used in the simulation.

The variable M_i in Table 2 above denotes the calculated mass recovery of tracer through the corresponding channel until infinite time. According to this study, a maximum recovery of 77 % is predicted for the channels connecting wells 6 and 11. Similar results were

Table 2: *Model parameters used to simulate the tracer recovery of bromide. See Appendix B for nomenclature.*

Channel length (m)	u (m/s)	$A\phi$ (m^2)	α_L (m)	M_i/M
120	1.92×10^{-4}	18.8	51	0.11
320	1.45×10^{-4}	24.0	193	0.66

obtained for the fluorescein injected into well 8, although the predicted maximum tracer recovery is only 40 %.

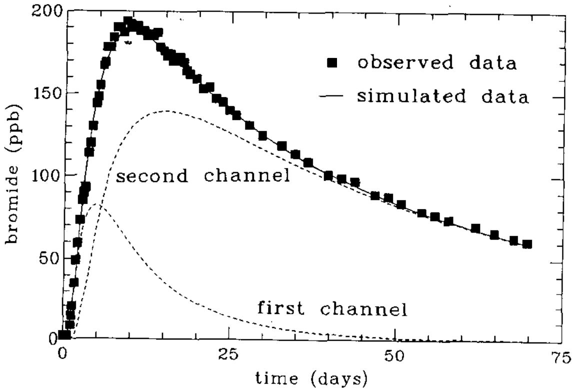

Figure 12: *Observed and simulated tracer recovery curves for the well dipole 6-11.*

The fracture properties obtained through the tracer studies were finally used to estimate the heat absorbed by the injected fluid in the fracture system. The one-dimensional fracture model applied is presented in Appendix B. The assumption is made that the fluid passes a fracture zone of width 1 m and porosity 30 %. This gives, according to table 2, a flow channel height (h) of 80 m for the well dipole 6-11.

Figure 13 shows the predicted temperature of injected water as it enters well 11. Several injection rates into wells 6 and 8 were considered. The study indicates an effective heat mining for all the cases. Mixing calculations for well 11 show, however, that injection rates should be limited to 1-2 l/s per well for less than 2 °C cooling of the produced fluid. Note that the 30 °C temperature of the injected fluid corresponds to the return temperature of geothermal water used locally for space heating.

PREDICTING THE OVERALL RESERVOIR PERFORMANCE

The reservoir models described above simulate and predict independently three different aspects of the response of the Thelamörk geothermal system to production and injection. Their results, presented in figures 8, 10 and 13, may be combined to predict the overall performance of the system. The fact that the data were not integrated into a single reservoir model probably results in more pessimistic predictions. It is, for example, unlikely that the reservoir will behave as a closed system during long-term production if a considerable inflow of colder groundwater takes place.

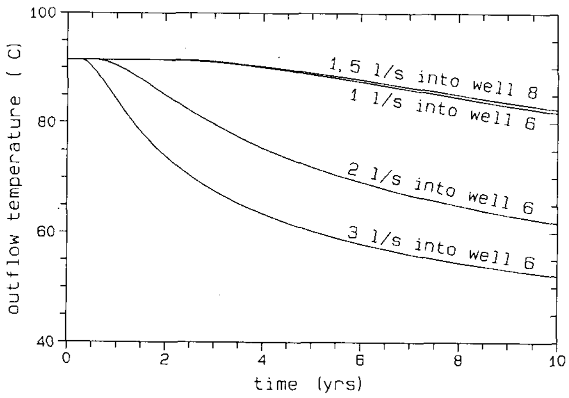

Figure 13: *Heat mining for a few cases of injection into wells 6 and 8. The injection fluid temperature is 30 °C.*

The key result of this study, as requested by Hitaveita Akureyrar, is an estimate of the production capacity and, furthermore, a production strategy for the Thelamörk reservoir. The production capacity is limited by a maximum 245 m draw-down in the production well, assuming a conventional rotary shaft pump. Another limit is the production temperature of well 11. The down-flow study indicates that a cooling by some degrees during a period of ten years is very likely, due to infiltration from above. In addition, reinjection will lead to some cooling. The reinjection, on the other hand, reduces the pressure draw-down and thereby allows an increase in production.

Figures 8 and 10 show that the Thelamörk system sustains a maximum, net production of 16-17 l/s for the next decade, and 7 - 10 °C temperature decline is predicted at the end of this time period. Mixing calculations, based on Figure 13, also show that 1.5 l/s injection into each of wells 6 and 8 will result in an additional 2 °C cooling of well 11 for this production. Because of the reduced draw-down, an injection of 3 l/s will increase the total production to 19-20 l/s, although the net production remains 16-17 l/s. This provides a 20 % increase in flowrates from well 11 and a 15 % increase in the thermal energy recovered.

ECONOMICS OF THE THELAMÖRK PROJECT

Table 3 presents a simplified evaluation of the economy of exploiting the Thelamörk field. Two production scenarios are considered, one without injection and the other with reinjection of local return water. The evaluation is based on a project lifetime of 20 years, such that the above predictions on water temperature have been extrapolated for another 10 years resulting in the average water temperature shown in the table. The 20 year project lifetime is very conservative, as the geothermal system is expected to supply hot water for much longer. However, drilling of a new production well may become necessary during these 20 years, due to the foreseen cooling of well 11. The numbers in table 3 are based on an exchange rate of 72.5 Icelandic kronur per U.S. dollar.

Table 3. *Economy of exploiting the Thelamörk field.*

Assumptions	Case A	Case B
Production rate	16 l/s	19 l/s
Local use	3 l/s	3 l/s
Pumping to Akureyri	13 l/s	16 l/s
Reinjection	0 l/s	3 l/s
Average water temp.	86 °C	84 °C
Cooling in pipeline	7 °C	6 °C
Thermal energy[1]	23.4 $\mathrm{GWh_t}$/yr	28.2 $\mathrm{GWh_t}$/yr
Exploration & drilling	$ 620,000	$ 620,000
Pipeline, pumps etc.	$ 1,100,000	$ 1,100,000
Interest rate	6 %	6 %
Project lifetime	20 yrs	20 yrs
Pumping costs	$ 46,000/yr	$ 55,000/yr
Operating costs	$ 21,000/yr	$ 21,000/yr
Energy price	9.3 mills/$\mathrm{kWh_t}$	8.0 mills/$\mathrm{kWh_t}$

[1] assuming a 30 °C return water temperature.

The energy price in the table may be compared to the following 1993 consumer prices in Iceland:

Geothermal heating in Akureyri	29 mills/$\mathrm{kWh_t}$
Average hot water price	11 mills/$\mathrm{kWh_t}$
Heating by oil	42 mills/$\mathrm{kWh_t}$
Electricity for space heating (government subsidized)	34 mills/$\mathrm{kWh_e}$

This comparison shows that the Thelamörk project will be highly economical in spite of the relatively high cost of exploration and drilling, a long pipeline and a limited productivity of the geothermal system. Case B will be more economical notwithstanding a greater temperature decline and will provide an additional income for Hitaveita Akureyrar of about $ 35,000 per year. This happens to be approximately the cost of drilling a 500 m deep reinjection well.

CONCLUDING REMARKS

The main conclusions of the feasibility study for the Thelamörk low-temperature system are:

1. The geothermal system is characterized by a fracture zone, and a few dykes. It is very small in volume ($\approx 1\ \mathrm{km}^3$) and has a low permeability thickness (≈ 1 Dm). This leads to a great pressure draw-down during production.
2. The results of lumped modeling indicate that the maximum, long-term production from well 11 is on the order of 16-17 l/s, (maximum draw-down 245 m). Injection of local return water (3 l/s) can increase the total production to 19-20 l/s.
3. The production reservoir appears to be connected to the overlying groundwater system. Some cooling due to down-flow of colder water may, therefore, accompany long term production.
4. Injection and tracer studies show that well 11 and possible injection wells are directly connected, most likely through the reservoir fracture system. Therefore, injection rates must be restricted to 1-2 l/s per well, for an efficient heat recovery.
5. The initial temperature of the water produced from well 11 is 91.5 °C. Colder down-flow and reinjection may result in a 9-12 °C temperature decline during 10 years of production.
6. The production cost for hot water from the Thelamörk field is estimated at 9.3 mills/$\mathrm{kWh_t}$ without reinjection and 8.0 mills/$\mathrm{kWh_t}$ if 3 l/s are reinjected. This shows that a reinjection program (wells and surface equipment) will pay off in 2-3 years.
7. An energy price of 8-9 mills/$\mathrm{kWh_t}$ compares favorably with the average hot water consumer price in Iceland of about 11 mills/$\mathrm{kWh_t}$. Therefore, small scale geothermal projects, such as Thelamörk, appear to be economical.

On the basis of this study, Hitaveita Akureyrar has already decided to exploit the Thelamörk area. Hot water from the field is expected to start flowing to Akureyri in the fall of 1994.

The cooling predicted may cause well 11 to cease to be economical sometime in the future. However, the known strike and dip of the upflow zone allows for a precise location of a new production well that will intersect the upflow at a greater depth than well 11, where little or no cooling is expected.

Finally, it should be mentioned that Thelamörk is the first low-temperature geothermal system in Iceland where such extensive testing is carried out before plans for utilization are made. The production test and its analysis may serve as a model for other similar projects in the future.

ACKNOWLEDGEMENTS

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APPENDIX A: DOWN-FLOW OF COLDER GROUNDWATER

A simple model is used to simulate the effects of down-flow of colder groundwater into a geothermal system during production (see also Wang, 1991 and Flóvenz et al., 1994). The model is presented in Figure A.1. It consists of an infinite groundwater system with a water temperature T' and solute concentration C'. The production part of the geothermal system has a volume V, variable temperature $T(t)$ and solute concentration $C(t)$. The initial temperature and concentration are denoted by T_0 and C_0. In addition there is a constant inflow of R kg/s from the outer and deeper parts of the geothermal system with temperature T_R and concentration C_R. A variable production of Q kg/s starts at time $t = 0$. The down-flow of groundwater is q kg/s, which is also variable. The conservation of the solute involved is given by:

$$V \frac{d(\rho_v \phi C)}{dt} + Q C = q C' + R C_R \qquad \text{(A-1)}$$

where ρ_v is the density of water and ϕ the porosity of rocks in the production part of the system. This equation may be rewritten:

$$\frac{dC}{dt} + \alpha (q + R) C(t) = \alpha q C' + \alpha R C_R \qquad \text{(A-2)}$$

$$\text{with} \quad \alpha = 1 / (V \rho_v \phi)$$

The production may be approximated by

$$Q(t) \approx Q_i \quad \text{for} \quad t_{i-1} \leq t < t_i , \quad i=1,2,\ldots \qquad \text{(A-3)}$$

with $t_0 = 0$. One may also define:

$$C_i = C(t_i) \quad \text{for} \quad i=0,1,2,\ldots \qquad \text{(A-4)}$$

with $C_0 = R$. In most instances one can assume that pressure changes occur much more rapidly than changes in chemistry and temperature. Therefore $q(t)$ may be considered to be constant during each of the time intervals defined in equation (A-3), i.e. $q_i \approx Q_i - R$. The solution to equation (A-2) is then given by:

$$C_i \approx C_{i-1} e^{-\alpha Q_i \Delta t_i} + \frac{(Q_i - R)C' + RC_0}{Q_i} (1 - e^{-\alpha Q_i \Delta t_i}) \qquad \text{(A-5)}$$

$$\text{for} \quad i=1,2,\ldots$$

The conservation of energy in the model is given by:

$$V \frac{d((\rho c)T)}{dt} + c_v Q T = c_v q T' + c_v R T_R \qquad \text{(A-6)}$$

where (ρc) is the volumetric heat capacity of the reservoir and c_v the heat capacity of water. This equation is of exactly the same form as equation (A-1) above. The solution for the temperature of the water produced is therefore given by:

$$T_i \approx T_{i-1} e^{-\beta Q_i \Delta t_i} + \frac{(Q_i - R)T' + RT_0}{Q_i} (1 - e^{-\beta Q_i \Delta t_i}) \qquad \text{(A-7)}$$

$$\text{for} \quad i = 1, 2, \ldots \qquad \text{with} \quad \beta = \frac{c_v}{V(\rho c)}$$

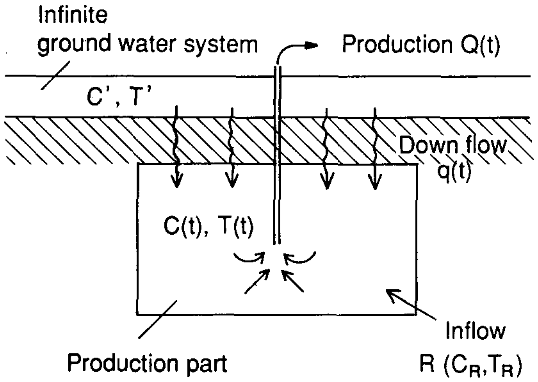

Figure A.1: *The simple model used for simulating down-flow of colder groundwater.*

APPENDIX B: HEAT MINING BY INJECTION

The model used to simulate tracer return curves and predict heat mining by injection is shown schematically in Figure B.1. A constant mass flowrate, q, is pumped into an injection well and a constant mass rate, Q, pumped from a production well. A basic assumption in the formulation is that the flow channel, connecting the two wells, is along a narrow fracture zone. Furthermore, a near one-dimensional flow is assumed in the channel. The cross sectional area of the flow channel is $A = h \times b$, where h is its height and b is the width. The porosity of the flow channel is ϕ and its longitudinal dispersivity is denoted by α_L. Molecular diffusion is neglected. The differential equation describing the tracer concentration in the channel, C, is as follows (Javandel et al., 1984):

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

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

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

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

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

The analysis of tracer return curves provides an estimate of the cross sectional area A of the flow channel and, hence, the total contact area between the reservoir rock and the flow channel. Given the flow channel inlet temperature T_n, the channel height, length and width as well as the undisturbed rock temperature T_0, one can estimate the temperature of the injected fluid at any distance x along the flow channel. This is based on a formulation which considers a coupling between the heat convected along the flow channel and the heat conducted from the reservoir rock to the channel fluid. The solution to similar problems is, for example, presented by Carslaw and Jaeger (1959) and Bödvarsson (1972). The analytical solution for the fluid temperature $T_q(x,t)$, is:

$$T_q(x,t) = T_n + (T_0 - T_n)\, \mathrm{erf}\left[\frac{kxh}{c_w q \sqrt{\kappa(t - x/\beta)}}\right] \qquad \text{(B-3)}$$

valid at times $t > x/\beta$, with β defined as $q/\rho_w hb$. Here k is the thermal conductivity of the reservoir rock and κ its thermal diffusivity. In addition, ρ_w is the density and c_w the heat capacity of water. The temperature of the produced fluid, assuming a constant temperature, T_0, for all feedzones in the production well, except the one connected to the flow channel, is finally given by:

$$T(t) = T_0 - \frac{q}{Q}\left(T_0 - T_q\right) \qquad \text{(B-4)}$$

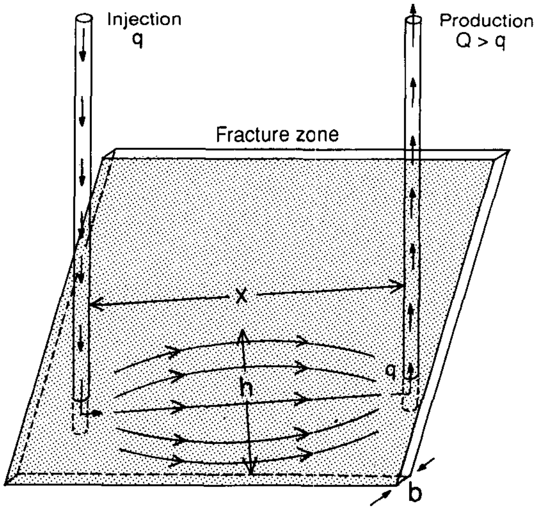

Figure B.1: *A simple model of a fracture-zone connecting a reinjection-production well dipole.*