PR EEDINGS, Twenty-Second Workshop on Geothermal Reservoir Engineering
St ord University, Stanford, California, January 27-29, 1997
SG TR-155

N IN-ISOTHERMAL INJECTION BEHAVIOUR - INJECTION TESTS, PROGNOSTIC SIMULATIONS AND REVIEW AFTER ONE-YEAR OPERATION OF A GEOTHERMAL SITE IN GERMANY *

Joachim Poppei, Peter Seibt, Dirk Fischer

Geothermie Neubrandenburg Ltd
Lindenstrasse 39
D-17033 Neubrandenburg
Germany

ABSTRACT

Production and injection are non-symmetric processes by the thermal effects themselves. The pressure response of the reservoir to a certain injected volume flow is dependent on the temperature difference between the resident and the injected water, and on the injection history. The greater the temperature differences between the injected and the reservoir fluid, the more important are the temperature effects on the pressure behaviour in the injection well. The aim was to quantify the influence of progressive cooling of the aquifer on injection pressure behaviour.
At the Neustadt-Glewe site put into operation in 1994, there was made use of a reservoir with the relatively high temperature of about 100 "C through a geothermal doublet. By means of reservoir simulation and practical injection tests as well as non-isothermal interpretation, the short- and long-term injection behaviour was investigated at this site. Prognostic simulations prior to start-up of operation, injection tests with subsequent interpretation of thermal effects, and the review of the injection behaviour after the first year of successful operation are described in this paper.

1. INTRODUCTION

The Neustadt Glewe site in Germany was put into operation in 1994. The wells concerned (a doublet with an internal distance of 1,400 m) open a porous sandstone aquifer with an average thickness of about 45 m in a depth of 2,240 m.

As the prevailing conditions are extraordinary in Central Europe (reservoir temperature 99°C; salinity 220 g/l) the Neustadt-Glewe project is supported by comprehensive research programmes.

One specific point of interest was the injection pressure behaviour considering the fluid viscosity changes caused by varying injection temperature.

Since fluid mobility influenced by injection of cooled water plays a major role in pressure transient behaviour, the strong temperature dependence of fluid viscosity and, to a lesser extent, fluid density significantly effect reinjection. The major changes of the dynamic viscosity occur between 20°C and 100°C (Sigurdsson et al. (1983)), which is a typical range for low-enthalpy geothermal energy use in Central Europe.

The complex transient non-isothermal processes during injection within the well, at the bottom hole (sandface) and within the aquifer were described by Benson (1987) and Miller (1980).

Sigurdsson et al. (1983) derived a relationship for the apparent viscosity dependent on injection time and temperature for fixed values of the thermally influenced regions.

Menjoz (1983) gave an expression for the thermal skin as an apparent skin factor caused by the cooled-down near-well area.

The commonly and widely used test interpretation procedure based on hydrogeological engineering is due to fail here because the temperature dependence of density and viscosity is neglected. Benson (1984) analyzed the physical effects during cold-water injection and derived a procedure for non-isothermal test interpretation. In this paper we follow the procedure proposed by Benson to interprete our test results.

To investigate the injection behaviour after one year of operation, the injectivity was measured when the geothermal heating plant was fully operated for the very first time. For interpretation of the results of these investigations, the balancing of the pressure in the reservoir which leads very quickly to steady-state conditions and the state of the site which is influenced thermally by operation have to be considered by numerical simulation. Two simulator codes were applied: CFEST (1987) and TOUGH2 (1987).

2. INJECTION TESTS - MODE OF IMPLEMENTATION AND RESULTS

In 1994, injection tests, accompanied by bottom-pressure measurements, were carried out in the Gt Ng 1/88 and Gt Ng 2/89 geothermal wells.

The final installation of the wells - the Gt Ng 2/89 well to be used for injection - was based on the 1993 test results. For identification of the final operational parameters of the installed wells, testing was required as well. Here, the clarification of various problems of thermal water injection could be included as well. The main problem appeared to be the identification of the causes for the low injectivity of the Gt Ng 1/88 well. With due consideration of the results obtained from the previous tests, the assumed fluid reaction in the aquifer (formation of iron hydroxide) should be avoided as much as possible. Therefore, the objective of the protection of the thermal water to be injected from contact with atmospheric oxygen was included in the test concept. This was connected with the following technological steps.

- production lift with chemically inert nitrogen
- separation of the stacking tank volume from air
  - closed corrosion-proof tanks
  - inertisation of the stacking tanks with nitrogen
- reduction of the HCl dosage
- establishment of thermal water control mechanisms with in-situ analysis
  - particle monitoring before and after the filters
  - permanent pH control
  - chemical analysis.

F the injection tests, about 400 m³ of formation w r were produced and re-injected at varying flow ra s.

With the test interpretation procedure (Benson (1984)) transposed in a numerical interpretation programme, the tests were interpreted with due consideration of the thermal effects.

For characterization of their influence on the test procedure and interpretation, two modelling procedures were taken as a basis:

- moving front
- composite reservoir.

The moving-front procedure is applied for injection into a thermally unaffected reservoir. As an example, this procedure is applied in the first stap-rate of the injection test in the Gt Ng 1/88 well.

If the reservoir is affected thermally already in the beginning of the test, e.g. due to preceding injection, then the composite reservoir procedure will be used. Such a thermal effect degrades extraordinarily slowly in the reservoir and may influence the pressure response in the test. The magnitude of the influence depends on the radius of the thermally affected zone („cold spot'). Accordingly, the temperature-pressure-time behaviour can be described also for step-rate tests and falloff tests (cp. Benson (1984)).

Working from the simplified assumption that a sudden and constant temperature change occurs at the sandface

- according to the classical plotting algorithms, the product of permeability and thickness $k \cdot H$ can be determined from the ascent of the semi-log straight line when considering the temporally concrete effectiveness of density and viscosity;
- an additional pressure offset Δp_{th} can be quantified which is caused by the temperature change when compared with the reservoir conditions;
- this pressure offset can be taken for the calculation of a thermally caused fluid skin s_f resulting in the extraction of the actual (thermally unaffected) mechanical skin s_m and the then possible iterative modification of the potential range $t_{log,min}$ which is skin-unaffected.

In the following, the application of these procedures is illustrated using the Gt Ng 1/88 and Gt Ng 2/89 injection tests as an example.

Evaluation of the Gt Ng 1/88 test of 14 July 1994 (1st rate) - „movingfront“ procedure

As to be seen in the double-logarithmic representation, Figure 1, the borehole storage effects are effective over a period of about 250 s.

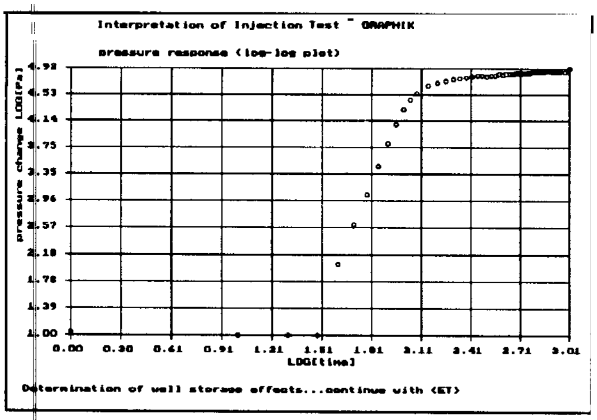

Figure 1. Graphical determination of the duration of borehole storage effects in the Gt Ng 1/88 well, 1st injection rate.

After about 330 s (*log t* = 2.52), a change of the slope caused by temperature effects is to be expected which, however, will remain at a low level due to little temperature change (T_{sf} = 94 °C, T_r = 98 °C).

From this time on, evaluation for *k·H* determination with the injection parameters (ρ_i and η_i) can be done. From the ascent of the straight line, *k·H* is calculated with 29 +/- 2 µm²·m (Figure 2).

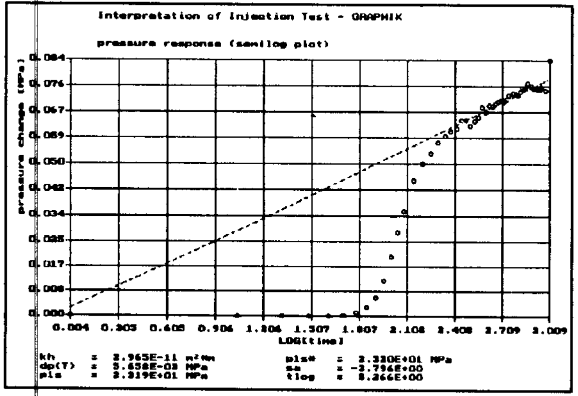

Figure 2. Initial *k·H*-calculation, assuming *s* = 0 (Gt Ng 1/88).

The skin found to be at a very low level leads to a shift of the evaluation range potentially in question to longer terms ($t_{log,min}$ = 5.39). According to iterative evaluation ($\Delta p_{th} \Rightarrow s \Rightarrow t_{log,min} \Rightarrow \Delta p_{th} \ldots$), the admissible skin-unaffected *k·H* range of evaluation results in 66 +/- 19 µm²m and the mechanical skin in +0.05 (Figure 3).

As injection and reservoir temperature differ only slightly, the thermal affect is also at a low level and characterized by a pressure offset of approximately 2%.

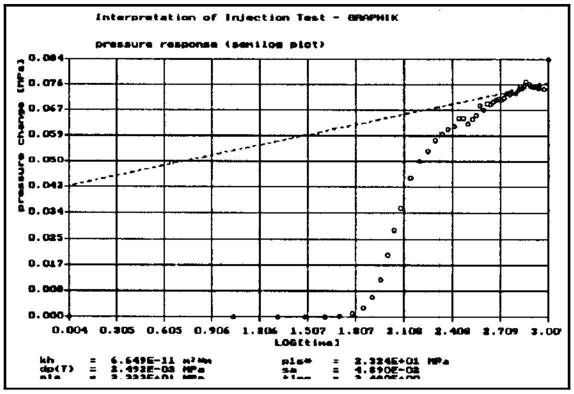

Figure 3. Result of the skin and *k·H*-calculation carried out iteratively (Gt Ng 1/88).

The calculated product of permeability and thickness (*k·H*) corresponds with the production test results. Table 1 compares the identified parameters with the values measured in production tests and laboratory investigations (determination of permeability).

In addition to the summarized results, statistical values with regard to the quality of the linear regression were included (number of measured values for the calculation of the slope, standard deviation of the measured values around the straight line, standard incorrect rating and identity condition or determination coefficient).

The tolerances indicated in the results of the *k·H* products are defined by the standard incorrect rating as a unit of the uncertainty of the slope determination and do not reflect the maximum error of the measurement.

Evaluation of the Gt Ng 2/89 test of 18 August 1994 „composite reservoir“ and „falloff“

The step-rate test in the Gt Ng 2/89 well is to serve as an example for the „composite reservoir" procedure. Figure **4** shows the semi-log straight line for the 3rd injection rate (103 m³/h over 3 hours).

Within the selected range of time, the reservoir properties (ρ_r and μ_r) will be effective. The product of permeability and thickness results in 12 +/- 1 µm²·m from the ascent of the straight line.

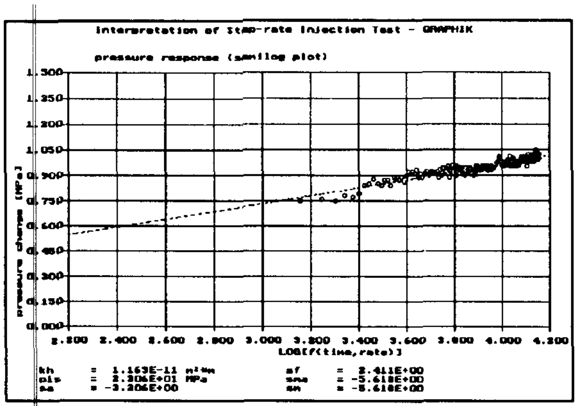

Figure 4. *k·H*-**calculation** for the 3rd rate of the Gt Ng **2/89** step-rate test.

From the falloff curves (Figures **5** and 6), the effectiveness of different temperatures ($\rho(T)$) and $\mu(T)$) becomes clear. Initially, the pressure falloff follows **the** injection parameters (ρ_i and μ_i) resulting in $\log\frac{t+\Delta t}{\Delta t} = 1.8$ in the curve corresponding with the reservoir properties (ρ_r and μ_r). Coincident with the pressure rise analysis, from both evaluations *k·H* results in 11 ... 13 µm²·m after correction of the temperature influence.

When injecting thermal water with a temperature of 30 °C and a self-adjusting sandface temperature of 50 °C, the contrast is more distinct than in case of the **Gt** Ng **1/88** test.
The isothermal analysis with an average value of sandface and reservoir temperature (about 74 °C) would result in an 28 % *k·H* error. The thermally qualified fluid skin is around the same order of magnitude as the mechanical skin, i.e. a (isothermally defined) skin would be overestimated by 100 %.

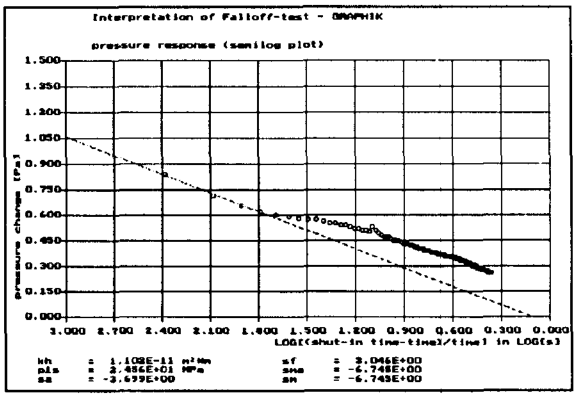

Figure **5**. Interpretation of falloff-test in the Gt Ng **2/89** well, evaluation with the injection fluid parameters.

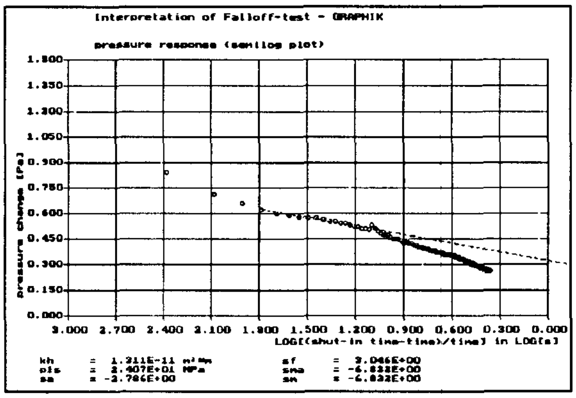

Figure 6. Interpretation of the falloff-test in the Gt Ng **2/89** well, evaluation with the reservoir fluid parameters.

The difference of the reservoir parameters obtained from the production tests and laboratory investigations makes clear in this test that the consideration of thermal effects alone does not explain the deterioration of the injection behaviour.

well	analysis method				fluid parameter		calculated parameter								to compare	
											statistics					
	moving front	composit	falloff	step-rate	injection	reservoir	mechanical skin	fluid skin	thermal offset (Dp_{th}/Dp_{max})	kH - injection test	number of data points	mean deviation	stand. valuation error	correlation coefficient	kH - production test	kH - rock analysis
							-	-	%	µm²m	-	%	%	-	µm²m	µm²m
NG1	X				X		0.05	-	2.4	66.5	19	8.1	28.4	0.422	73.4	38.6
NG2		X X X	 X X	X	 X	X X	-5.6 -6.8 -6.7	2.4 3.0 3.0	22.2 24.1 23.4	11.6 13.1 11.0	179 4 16	8.5 2.5 2.7	3.0 6.9 3.4	0.863 0.991 0.983	35.5	23.4

Table 1. Primary parameters and interpretation of injection test

3. PROGNOSTIC SIMULATION OF REINJECTION

Prior to operation, first calculations to support the forecast of the injection behaviour at the Neustadt-Glewe site were done with the simulator CFEST. The pressure response to time-varying operation conditions (flow rate and injection temperature) was calculated to be maximum 120 m³/h for the first year and found to be up to 1 MPa during that year.

For reservoir simulation, a three-dimensional model and the simulator code TOUGH were used, too. The aquifer is characterized entirely by 6 horizontal layers. For consideration of the heat transfer through caprocks and bedrocks the full three-dimensional characterization and the semi-analytical solution were investigated. Thanks to symmetric conditions, only one half of the basic pattern had to be considered. The model made use of 2640 elements, 7246 connections and 12 timedependent sinks and sources. The time steps are variable.
The initial values of temperature and pressure within the layers are determined by the geothermal gradient of 0.04 K/m and gravity. (Poppei, Fischer (1995))

Figure 7 illustrates the time-varying flow rate caused by the transient heat demand. Additionally, after five years of operation, the regime of exploitation was assumed to change due to the expanding demand for district heat supply.

Figure 8 illustrates the time-varying injection and sandface temperatures. The dash line shows the injection temperature. The sandface temperature line calculated is slightly smoothed due to numerical effects. Wellbore storage effects had been neglected.

The calculated pressure response over this period is given in Figure 9. The pressure build-up caused by reservoir cooling proved to be manageable.

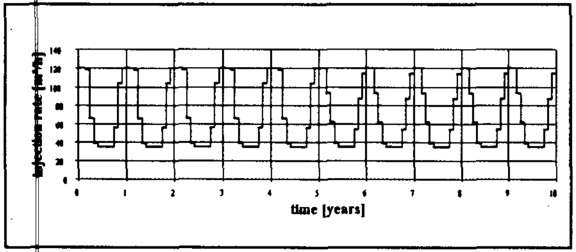

Figure 7. Injection flow rate over 10 years

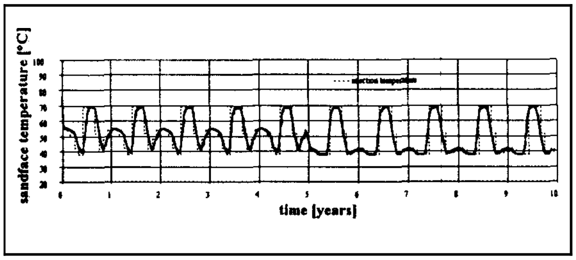

Figure 8. Injection and calculated sandface temperature in the injection well

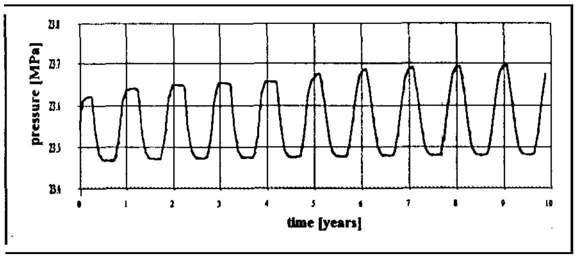

Figure 9. Calculated pressure response over 10 years

4. INTERPRETATION OF THE INJECTION BEHAVIOUR AFTER THE FIRST YEAR OF OPERATION

4.1 Objective
The test was to investigate the injection behaviour of the well. To exclude eventual (chemical and physical) disturbances during the test, an injection test was implemented with the geothermal heating plant being under full operation for the very first time.
With controlled variation both of the rates of production and injection of the thermal water circulation system, the measurement of the sandface pressures and temperatures as well as continuous recording of the rate of injection and well-head temperature, pressure responses were obtained for evaluation of the injection behaviour.
The total measuring time was about 44 hours.

Figures 10a and 10b show the sandface temperature and injection rate vs. time (a) and the pressure response vs. time (b), respectively, within the three regimes.

The interpretation of the curves is characterized by two peculiarities:

1. Doublet operation cannot be evaluated according to the classical test interpretation methods, as the balancing of the pressure in the reservoir would lead very quickly to steady-state conditions.

2. Around the injection well, the reservoir is already thermally affected by the one-year injection operation. The cold spot must be considered in the form of a history simulation.

For simulation, the following tasks result therefrom:

- calculation of the temperature distribution within the reservoir with due consideration of the previous operating states
- adaptation of the aquifer parameters to the measured curves during the test phase.

For consideration of the thermo-dependent alterations of the flow behaviour, the complete coupling of pressure and temperature calculations is implemented by the simulation programme taking into account the temperature dependence of density and viscosity. In this way, the fact of temporally and spatially completely different effects of pressure and temperature in modelling, discretisation and time-step control gain special attention.

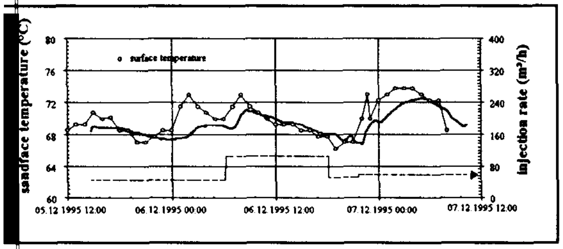

Figure 10a. Gt Ng 2/89 injection test curves: **5 -** 8 December 1995 (sandface temperature and injection rate vs. Time)

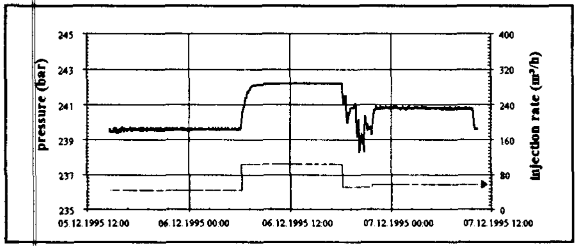

Figure 10b. Gt Ng 2/89 injection test curves: 5 - 8 December 1995 (pressure and injection rate vs. time)

The operating time of the plant from December 1994 - December 1995 was essentially still to be considered as part of the trial phase.
So, in this year only about 250,000 m³ were produced and reinjected at a temperature between 70 and 75 °C, whereas the plant was not operated in June, July and August (the rate of utilization was higher only at the end of 1995/beginning of 1996).
Roughly, the thermal radius may be estimated at 55 m at the beginning of the test. By means of the simulator code CFEST, the first year of operation was post-simulated on the basis of the monthly averages of production and injection rates. The same model then served for post-interpretation of the test.

4.2 Description of the model

The following effects were taken into consideration for calculations:

- complete coupling of the pressure-temperature problem, i.e. density flow with given pressure-specific parameters (permeability, compressibility,...)
- dependence of the thermal water density and viscosity on temperature and mineralisation
- three-dimensionality due to an aquifer layer with wells at the upper and lower edge of the layer
- heat exchange with the surface layers
- compressivity of the pore space
- dispersion.

Fluid:	
mineralisation	= 220 g/l
specific heat capacity c_p	= 3,710 Ws/kgK
density p	= 1,088 kg/m³ at 99°C
viscosity $\mu_{50°C}$	= $9.4 \cdot 10^{-4}$ Pa·s
viscosity $\mu_{99°C}$	= $5.1 \cdot 10^{-4}$ Pa·s
Aquifer:	
effective thickness H	= 45 m
permeability $k_x=k_y=k_z$	= 0.9 ... $1.1 \cdot 10^{-12}$ m²
compressibility κ	= $3 \cdot 10^{-10}$ Pa^{-1}
porosity ϕ	= 0.22
thermal conductivity $\lambda_x=\lambda_y=\lambda_z$	= 2.2 W/m K
heat capacity ρc_p	= $2.4 \cdot 10^6$ Ws/m³K
dispersivity horizontal	= 20 m
vertical	= 2 m
Caprocks:	
thermal conductivity λ	= 2.1 W/m K
heat capacity ρc_p	= $1.88.10^6$ Ws/m³K
temperature T	= 99 °C
Initial conditions:	
pressure p	= 0 Pa
temperature T	= 99 °C
Well spacing	= 1.400 m

Table 2. Model parameters for simulation

In the near-well region, the minimum mesh spacing for rectangular discretization is 0.5 m. In order to avoid boundary influences, the model area is surrounded by super-elements with 1,000 m mesh spacing.

The model area is discreted by 969 nodes per layer (totally 1,938 nodes) and 900 elements. The maximum time step for the annual simulation is 6 days. Upstream-weighting has been abstained from.

4.3 Results of the calculations

Since the heads (or pressures) adjust themselves factually immediately depending on the monthly simulation regime, their results are of no importance. The temperature distribution after the first year is shown in Figure **11.** The radial distribution around the injection well is not disturbed yet by the dipolar arrangement of the wells.

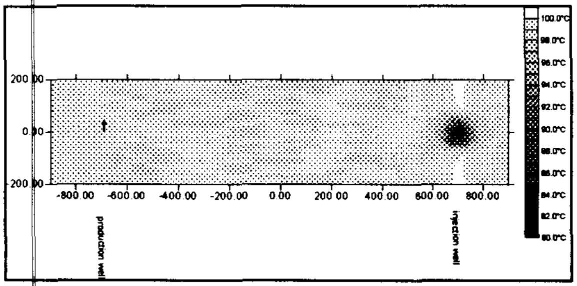

Figure **11.** Temperature distribution as a result of one-year injection

The temperature and pressure distribution calculated in this way was taken as initial distribution for test simulation (assuming that the mean volume flow of December applied also to the period from **1** to **5** December immediately before the beginning of the test)

Beside a series of investigations into the sensitivity of essential model parameters, permeability was varied within the range of 0.9 ... **1.1** 10^{-12} m² which was deducted from the present geological knowledge.

For simulation, the test was abstracted with four different volume flows. The short-time pump shut-offs caused by blackouts were compensated by the assumption of a phase of mean volume flows of **52.5** m³/h over **3.45** hours.

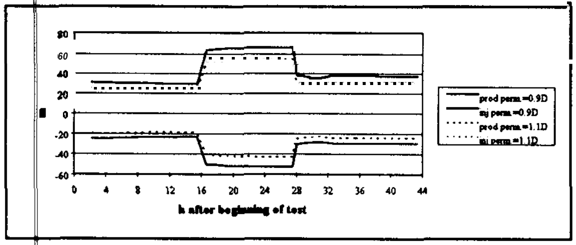

Figure **12.** Calculated head change in production and injection well for two different permeabilities

Figure **12** shows that the head changes (referred to the initial value 0) are not symmetric in the production and the injection wells, as temperature influence becomes effective.

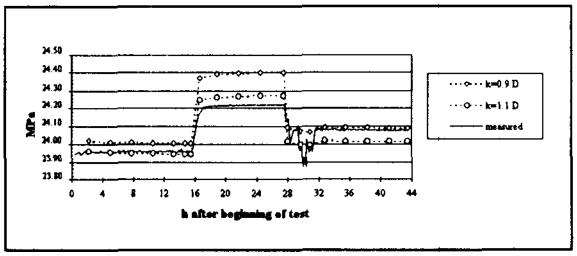

Figure **13.** Comparison of measured and calculated injection pressure

Subsequently, the injection conditions have been deteriorating by about **2 ... 3 %** through thermal influence alone compared to the conditions prevailing prior to commissioning of the plant. Injectivity has been reduced by about 7 % (calculated) ... **11 %** (measured) aompared to (isothermal) productivity. (The deviation of the measured values from the calculated ones is due to the scattering of the measured injectivity values around **199 +/- 23** m³/(h MPa) in the measuring cycle.)

The calculated different heads refer to the locally identified density values. When transferring the calculated injection pressure values at these densities to the measured depth of the bottom hole pressure gauge **(2263** m), the calculated and measured pressure values may be compared directly. Figure **13** shows that the assumption of the higher permeability **(1.1·10^{-12} m²)** is justified. For this reason, reservoir damage cannot be proven, although obviously thermal effects cause subsequent increase of the injection pressure (that is why the indication of any injectivity, as a change of pressure per volume flow, will be reasonable only when injection temperature and history will be given as well).

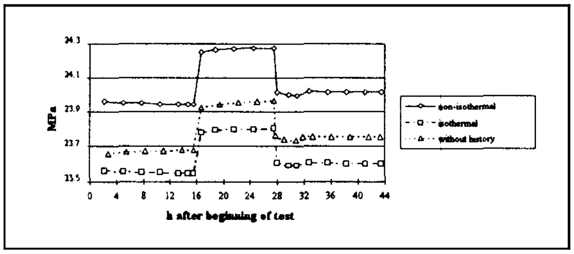

Figure **14.** Thermal effects during injection test (calculated)

The increase of the injection pressure (or reduction of the injectivity) results both from the altered density of the fluid column in the well and from the altered transmissivity in the thermally influenced section.

The calculated pressure change in the reservoir is shown in Fig. 14 ($k = 1.1 \cdot 10^{-12}$ m²). The dotted line (history being neglected) illustrates the calculated pressure in undisturbed thermal conditions in the reservoir, as they were prevailing approximately before commissioning of the plant in 1994.

5. CONCLUSIONS

Neglecting any other possible effects (entry of particles, clogging...), injection and production are non-symmetric processes by the thermal effects themselves. The pressure response of the reservoir to a certain injected volume flow (commonly denominated as injectivity index) does not represent a property of the reservoir, but is dependent on the temperature difference between the resident and the injected water and on the injection history.

Any evaluation of an injection test has to pay due consideration to these effects. From the injection test, the farmost temperature-independent reservoir property *kH* can be deducted, and by means of this value and a suitable simulator, the injection behaviour can be predicted with due consideration of the operational life and the regime of the plant.

6. REFERENCES

Benson, S.M. (1984), „Analysis of injection tests in liquiddominated geothermal reservoirs", LBL-Master Thesis, Stanford.

Benson, S.M. et al. (1987), „Analysis of thermally induced permeability enhancement in geothermal injection wells", 12th Workshop on Geothermal Reservoir Engineering, Stanford.

Gupta, S.K. et al.(1987), „Coupled Fluid, Energy and Solute Transport (CFEST) Model: Formulation and User's Manual", Technical Report BMI/ONWI-660, Office of Nuclear Waste Isolation, Battelle Memorial Institute, Columbus, Ohio, 1987.

Menjoz A. (1983), 'Identification des paramètres et reponse d'un reservoir geothermique durant un essai d'injection non isotherme de courte durée", BRGM report n° 83 SGN 885 IRG.

Miller, C.W.(1980), „Wellbore storage effects in geothermal wells": Soc. Pet. Eng. J., 20, pp. 555-566.

Poppei, J.; Fischer, D. (1995): Prognostic simulation of reinjection - Research project Neustadt-Glewe geothermal site, Germany, Proceedings of the TOUGH Workshop '95, LBL-37200.

Pruess, K.(1987), „TOUGH User's Guide" , LBL-20700, SAND 86-7104.

Sigurdsson, O., Bodvarsson, G.S. and Stefansson, V.(1983), 'Non-isothermal injectivity index can infer productivity and reservoir transmissivity", P. Kruger, H.J. Ramey, Jr. (eds.), Geothermal Reservoir Engineering, Second Workshop Summaries, Stanford Univ., Stanford, Cal. (USA), pp. 211-216.

---

[1] This paper covers part of the research work supported by the EC within the framework of the JOULE II programme „Improvement of the Injectivity Index of Argillaceous Sandstone"