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**Experimental Study of the Storage
of Thermal Energy in
Confined Aquifers**

**Final Report for the Period
July 1, 1977 to December 31, 1979**

Fred J. Molz
A. David Parr
Peter F. Andersen

OFFICE OF ADVANCED CONSERVATION TECHNOLOGIES

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**EXPERIMENTAL STUDY OF THE STORAGE OF THERMAL
ENERGY IN CONFINED AQUIFERS**

Final Report for the Period
July 1, 1977 to December 31, 1979

Fred J. Molz
A. David Parr
Peter F. Andersen

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CONTENTS

	<u>Page</u>
ABSTRACT	1
INTRODUCTION	1
OVERVIEW OF EXPERIMENT	3
DESCRIPTION OF FIRST CYCLE	6
RESULTS OF FIRST CYCLE	9
TECHNICAL PROBLEMS DURING FIRST CYCLE	15
DESCRIPTION OF SECOND CYCLE	19
RESULTS OF SECOND CYCLE	22
DISCUSSION OF SECOND CYCLE	26
SUMMARY AND CONCLUSIONS	30
ACKNOWLEDGEMENTS	33
REFERENCES	33
APPENDIX I	35

ABSTRACT

To aid in testing the idea of storing thermal energy in aquifers, a two cycle experiment was performed by Auburn University in which heated water was stored in a confined aquifer and then recovered. During the first cycle, 54,784 m³ of water were pumped from a shallow supply aquifer, heated to an average temperature of 55°C, and injected into a deeper confined aquifer where the ambient temperature was 20°C. After a storage period of 51 days, 55,345 m³ of water were produced from the confined aquifer. Throughout the first cycle, which lasted approximately six months, ground water temperatures were recorded at six depths in each of ten observation wells, and hydraulic heads were recorded in five observation wells. During the 41-day production period, the temperature of the produced water varied from 55°C to 33°C, and 66% of the injected thermal energy was recovered.

The second cycle injection began on 9/23/78 and continued until 11/25/78 when 58,010 m³ of water had been recovered. The major problem experienced during the first cycle, a clogging injection well, was reduced by regular backwashing. A 63 day storage period ended on 1/27/79 and production of hot water began with an initial temperature of 54°C. By 3/23 this temperature had dropped to 33°C, with 66,400 m³ of water and 76% of the injected thermal energy recovered.

INTRODUCTION

The possibility of using aquifers as natural storage devices for thermal energy in the form of heated water has been considered seriously for the past six years [Meyer and Todd, 1973; Hausz and Meyer, 1975; Meyer,

1976; Meyer, et al., 1976; Lawrence Berkeley Laboratory, 1978]. Related problems involving the natural drift of fluids from the storage zone have been considered also [Molz and Bell, 1977; Whitehead and Langhettee, 1978]. Several experimental studies have been performed with the objective of field testing the aquifer storage concept. Mathey [1978] conducted a five-month injection-production cycle involving an unconfined aquifer with a natural temperature of 11°C. Injection of 494 m³ of water at 51°C over a 9.3-day period was followed by four months of storage and a 28-day recovery of 16,370 m³. Extensive mixing of the hot and cold water, aided by thermal convection in the aquifer, led to a recovery of approximately 40% of the thermal energy injected. A second small experiment involving an unconfined aquifer was performed by Werner and Kley [1977]. Injection of 430 m³ of water took place over a 64-day period. Temperatures were monitored carefully, and a computer model was fitted to the data. No recovery pumping was attempted.

Results of a larger experiment involving a confined aquifer between depths of 40 and 62 m were reported by Molz, Warman, and Jones [1978]. The objective of this experiment was to begin testing the feasibility of thermal energy storage in confined aquifers and to provide data for the calibration of mathematical models describing the simultaneous transport of water and heat in the saturated zone [Papadopoulos and Larson, 1978]. In preparation for the experiment, data related to subsurface geometry, hydraulic, and thermal properties were collected, and a well field, consisting of one injection-production well and 14 observation wells, was constructed near Mobile, Alabama. The subsequent injection of 7,570 m³ of 37°C filtered water from an electric power plant thermal discharge canal resulted in a

67% thermal energy recovery after a storage period of 36.6 days.

The injection process was plagued by serious clogging due to the inability to remove clay and small silt-sized particles by filtration alone. Ultimately, the injection was terminated when increased injection pressure, induced by the clogging, led to failure of the upper confining layer along a well casing.

The objective of the present communication is to describe the results of a second experiment at the Mobile test site which used essentially the same well field facilities which were constructed prior to the preliminary experiment [Molz et al., 1978]. The only modifications involved re-instrumentation of the observation wells, pressure grouting of the original injection well and the well where confining layer failure occurred, construction of a new injection-production well, and construction of one additional observation well. In addition, supply water was obtained from an overlying, semi-confined aquifer and heated with an oil-fired boiler prior to injection.

OVERVIEW OF EXPERIMENT

The project site is located in a soil borrow area at the Barry Steam Plant of the Alabama Power Company, about 20 miles north of Mobile, Alabama (see Molz, Warman and Jones, 1978 for details). Shown in Figure 1 is a top view of the well field. The injection-production well is indicated and wells 1 through 14 are observation wells. Temperatures and hydraulic heads were recorded in the inner array of 11 observation wells which are located within the thermal radius of influence. Wells 12, 13 and 14 were used to observe the hydraulic conditions at what is arbitrarily called the boundary of the system. The hydraulic boundary data were recorded primarily

Figure 1. Top view of the existing well field at the Mobile site drawn to scale.

for use in calibrating existing numerical models and are available from the writers. A listing of temperature data is available from the writers.

Two, six-month, injection-storage-recovery cycles constituted the main body of the experiment. The system for supplying, heating and injecting water is shown schematically in Figure 2. Supply water is pumped from a sandy-gravel aquifer located between 25 m and 34 m below the surface. The water is then metered and passed through an oil-fired boiler which raises its temperature from approximately 20°C to 55°C. Injection into the storage formation, which extends from 39.6 m to 61 m below the land surface, takes place through a 9.14 m long stainless steel screen. The storage formation is composed of a medium sand containing approximately 15% silt and clay by weight. A more detailed chemical analysis is listed in Table 1. Aquitards above and below are composed of several different types of clays.

With the exception of well 10, each of the inner observation wells was equipped with thermistors to measure ground water temperatures at six

Table 1. Summary of Physical and Chemical Properties of the Supply and Storage Aquifers

Supply Aquifer

Natural Temperature = 19.5°C

Natural pH = 7.19

(Chemical Analysis for 3/4/78 water sample)

Alkalinity = 7.8 mg/l as CaCO_3

Ca = 1.1 mg/l

Si < 10 mg/l

(Chemical Analysis for 6/20/78 water samples)

	<u>Sample No. 1</u>	<u>Sample No. 2</u>
Alkalinity	3.8 mg/l as CaCO_3	3.8 mg/l as CaCO_3
Fe	0.07 mg/l	0.07 mg/l
Na	3.4 mg/l	0.6 mg/l
Si	6.3 mg/l	9.1 mg/l
Ca	0.33 mg/l	0.21 mg/l

Storage Aquifer

Natural Temperature = 19.5°C

Natural pH = 7.38

(Chemical Analysis for 3/4/78 water sample)

Alkalinity = 172 mg/l as CaCO_3

Ca = 1.3 mg/l

Si = 41 mg/l

(Chemical Analysis for 6/20/78 water samples)

	<u>Sample No. 1</u>	<u>Sample No. 2</u>
Alkalinity	176 mg/l as CaCO_3	176 mg/l as CaCO_3
Fe	0.06 mg/l	0.05 mg/l
Na	7.6 mg/l	11.1 mg/l
Si	10.4 mg/l	9.7 mg/l
Ca	0.05 mg/l	0.38 mg/l

Summary of Sieve Analysis of Storage Aquifer

<u>Grain Size (mm)</u>	<u>Percent Finer by Weight</u>
1.2	96
0.43	88
0.15	22
0.075	15

The 15% passing the #200 sieve (0.075 mm effective grain size) contained both kaolinite and smectite.

Fig. 2. Diagram of the system for supplying, heating, and injecting water into the storage aquifer.

depths. Shown in Figure 3 is a diagram of a typical observation well. Plastic materials were used for well construction, and the thermistors were spaced uniformly in the vertical dimension of the storage aquifer.

DESCRIPTION OF FIRST CYCLE

Shown in Figure 4 is the cumulative injection volume for the first cycle as a function of time. Injection began on March 18, 1978, and continued until June 5, 1978, a total of 79 days. An injection rate varying from $1090 \text{ m}^3\text{day}^{-1}$ (200 gpm) to $545 \text{ m}^3\text{day}^{-1}$ (100 gpm) resulted in an injection volume of $54,800 \text{ m}^3$ at an average temperature of 55°C as shown in Figure 5. A 50.5-day storage period began on June 5, 1978, and was terminated on July 26 when production began and continued for 41 additional days. As shown in Figure 6, the pumping rate was nearly constant at $1363 \text{ m}^3\text{day}^{-1}$ (250 gpm), except for uncontrolled power failures, and resulted in

Fig. 3. Side view of a typical observation well showing details of the well construction and the position of the six thermistors used to record groundwater temperatures.

Fig. 4. Plot of cumulative injection volume as a function of time. The horizontal segments are due to pump shut-downs resulting from power failures and other problems.

Fig. 5. Plot of injection temperatures as a function of time.

Fig. 6. Cumulative volume of water produced from the injection/production well as a function of time.

a production volume of $55,300 \text{ m}^3$. Pumping was stopped when the production temperature reached 33°C , which was 13°C above the ambient groundwater temperature.

RESULTS OF FIRST CYCLE

Shortly after injection began, it became evident that thermal convection was occurring in the observation well closest to the injection well. When injection was stopped, the temperature in the observation well fell about 15°C in a few hours. Upon resuming injection, the temperature returned to its original value as fresh formation water was pushed into the well. Evidently, the temperature recorded by the thermistors was the result of a dynamic equilibrium between formation water moving horizontally through the well screen and thermal convection occurring in the well bore. Convection was controlled by backfilling each observation well within the thermal radius of influence with a clean medium sand. After this was done, the thermistors stabilized and recorded more representative non-uniform temperature distributions in the vertical dimension.

Shown in Figure 7 are typical vertical temperature profiles recorded in well no. 5 as a function of time. There is no evidence of thermal convection in the storage formation, and the temperature distribution remained relatively static throughout the storage period. This differs from the results of Mathey [1977] who observed significant convection in his experiment. The differing results are understandable if one considers the Rayleigh numbers for the two porous media, which largely determine when thermal convection will become appreciable [Wooding, 1957, 1962; Katto and Masuoka, 1967; Nield, 1968]. As the Rayleigh number increases, free thermal convection becomes more likely. Since this number for a porous system is proportional to the hydraulic conductivity, the Rayleigh number in the vertical dimension for Mathey's sandy gravel would be considerably larger than the corresponding number for our medium sand-silt-clay material.

Fig. 7. Plots of vertical temperature distributions recorded in well 5. The number next to the curves denotes the time in hours after the start of injection, and the arrows indicate the elevation of the screen in the injection/production well. Letters A-F indicate thermistor positions.

Thus, for roughly the same temperature regime, appreciable thermal convection could occur in one medium and not in the other.

As indicated in Figure 2, the screen of the injection well only partially penetrates the storage formation. Its vertical position corresponds to the elevations indicated by the arrows in Figure 7. This and the observation that the horizontal permeability appears to be an order of magnitude larger than the vertical permeability [Papadopoulos and Larson, 1978], explain the relatively sharp peak in the Figure 7 temperature distributions. Presumably, the temperature plots would be more nearly uniform with depth if the injection well were fully penetrating.

Shown in Figures 8 and 9 are temperature distributions in the vertical plane containing observation wells 1, 3, 4, 7 and 8. Given the fact that

Fig. 8. Temperature distribution near the end of the injection period in a vertical plane containing wells 7, 4, 3 and 8. The vertical scale is exaggerated as indicated in the figure.

Fig. 9. Temperature distribution near the end of the storage period in a vertical plane containing wells 7, 4, 3, and 8. The vertical scale is exaggerated as indicated in the figure.

the injection well is not in the center of the observation well field (Figure 1), this plane is as close as possible to a vertical cross-sectional view containing the injection well. The distribution at the end of the injection period shown in Figure 8 is distorted slightly to the left. This is opposite to the direction of natural ground water drift and is most likely due to a high permeability zone in the aquifer matrix. By the end of the storage period, the distribution shifted to the right as shown in

Figure 9. This is nearly the direction of regional ground water flow. Measurements made before injection was started indicated a natural pore velocity from left to right in Figures 8 and 9 of approximately 0.05 m day^{-1} . Such a velocity would result in a total liquid drift of 2.3 m during the 46.5 day time span between the distributions shown in Figures 8 and 9. Drift of the temperature contours should be less than this in proportion to the ratio of the liquid and matrix heat capacities. This, coupled with thermal dispersion, is the probable explanation for the slight shift in the temperature distribution recorded in the figures.

Shown in Figure 10 is the temperature of the water pumped from the storage aquifer as a function of time. The relatively rapid decrease of temperature with time is probably due mainly to heat conduction and mixing between the warm injected water and the cold native groundwater (hydrodynamic thermal dispersion). An effect of this magnitude would not be unexpected given the nonhomogeneous nature of the storage aquifer and

Fig. 10. Temperature of the water pumped from the storage formation as a function of time.

the partially penetrating injection well (Figure 2). However, as discussed later in this communication, clogging of the injection-production well was observed during injection. If the clogging was non-uniform, certain portions of the formation might be partially prevented from receiving hot water. Upon starting production, the clogging might be reversed rather quickly, and relatively cold water could be pulled into the production well through the newly opened areas. This effect was observed by Brown and Silvey [1977] in their study of fresh water storage in a saline aquifer.

From the recorded temperature and the flow rate of the injected water as functions of time, one can calculate the amount of thermal energy injected above the ambient temperature. A similar calculation can be made for the amount of energy recovered. The mathematical expressions are given by

$$E_{in} = \int_{t_0}^{t_1} \rho C [T_i(t) - T_a] I(t) dt \text{ and } E_{out} = \int_{t_2}^{t_3} \rho C [T_r(t) - T_a] R(t) dt \quad (1)$$

where: ρ = water density, C = specific heat of water, $T_i(t)$ = temperature of injection water, $I(t)$ = injection rate, $T_r(t)$ = temperature of recovered water, T_a = ambient groundwater temperature, and $R(t)$ = recovery rate. The limits t_0 , t_1 and t_2 , t_3 correspond to the time periods of injection and recovery, respectively, and in general, ρ and C are functions of temperature. In practice, the exact expressions given by equations (1) are replaced by the finite-difference approximations (trapezoidal rule):

$$E_{in} = \frac{\bar{\rho C}}{2} \sum_n [T_i(t_n) + T_i(t_{n+1}) - 2T_a] (QI_{n+1} - QI_n) \text{ and}$$

$$E_{out} = \frac{\bar{\rho C}}{2} \sum_m [T_r(t_m) + T_r(t_{m+1}) - 2T_a] (QR_{m+1} - QR_m) \quad (2)$$

where QI = volume of water injected as a function of time, QR = volume of water produced as a function of time, and the "bar" notation indicates average values of ρ and C . Each value of the indices n or m corresponds to a time when temperature and cumulative injection or recovery data were recorded.

Shown in Figure 11 is a plot of the thermal energy recovery factor as a function of recovery temperature. This factor is defined as the ratio of E_{out} at any time during production to E_{in} . When production was first started, the water temperature was 55°C and, of course, no energy had been recovered. By the time the water temperature dropped to 45°C , 31 percent of the injected energy had been recovered. Ultimately, when production ceased at a water temperature of 33°C , 66% of the injected energy had been recovered and $55,300 \text{ m}^3$ of water had been pumped from the storage aquifer. This volume is nearly equal to the $54,800 \text{ m}^3$

Fig. 11. Plot of the energy recovery factor, ratio of energy recovered at any time during production to total energy injected, as a function of production temperature. The plot shows that at the end of the production period, 65% of the injected thermal energy had been recovered.

injection volume. The recovery of 66% of the injected energy in the upper 63% of the temperature range and contained in a volume of water essentially equal to the injection volume is much better than previous results [Mathey, 1977; Molz, Warman, and Jones, 1978], although still less than the predicted performance potential of aquifer storage systems designed for maximum energy recovery [Lawrence-Berkeley Laboratory, 1978]. However, the energy left behind in the formation will increase the recovery fraction during subsequent injection-storage-recovery cycles.

TECHNICAL PROBLEMS DURING FIRST CYCLE

The major problem encountered during the first cycle was clogging of the injection-production well during injection. Such a problem was observed in a preliminary experiment [Molz, Warman, and Jones, 1978], but was at least partly of a different nature because of the relatively large suspended solids concentration in the supply water at that time. The present experiment utilized heated groundwater for injection which had a negligible concentration of suspended solids. Shown in Figure 12 is a plot of injection well specific capacity versus time. Because specific capacity is defined as the ratio of pumping rate to drawdown (or "pushup" in the case of injection) this quantity would be expected to decrease with time. However, the magnitude and rate of decrease shown in Figure 12 are much too large to be completely explained in terms of the development of simple pushup in an aquifer of constant hydraulic conductivity. Pumping tests performed on wells equivalent to the present injection well, and the injection well itself during production, stabilized hydraulically within

Fig. 12. Specific capacity of the injection well as a function of time. The specific capacity decreased markedly due to clogging of the formation around the injection well. Capacity was restored somewhat by turning the pump on and off and by backwashing the well.

48 hours after pumping began. This observation, along with a careful chemical analysis of the water in the supply and storage formation (Table 1), which appears to eliminate corrosion or precipitation as a cause of specific capacity loss indicates that the results shown in Figure 12 must be explained in terms of decreasing hydraulic conductivity of the aquifer matrix material. However, the spatial distribution of the conductivity loss is not known.

Further examination of Figure 12 shows that the specific capacity is sensitive to changes in injection rate. This was first observed during pump shut-downs due to power failures associated with thunderstorms. Later on, when well back-washing operations were initiated, even larger gains in specific capacity were realized. It was decided to determine if this type of flow rate-sensitive behavior could be duplicated in the laboratory using disturbed samples of storage aquifer material obtained during coring

operations. Typical results obtained with a commercially-available, constant-head permeameter are shown in Table 2. The saturated hydraulic conductivity would normally decrease markedly with time. A brief surge in head gradient through the sample would increase the conductivity -- sometimes by nearly an order of magnitude. Tapping the permeameter also

Table 2. Saturated hydraulic conductivity (K) values at several different times measured in a constant-head permeameter using a 10 meq ℓ^{-1} $\text{CaCl}_2 \cdot 2\text{H}_2\text{O}$ distilled water solution. Temperatures (T) refer to the percolating solution which is in equilibrium with the laboratory temperature. A single sample was tested.

Date	K cm/hr	T °C
6-3-78	0.260	22
6-5-78	0.206	24
6-6-78	0.154	23
6-7-78	0.118	24
6-8-78	0.171	24
6-9-78	0.120	24
6-12-78	0.068	23
6-13-78	0.059	23
6-15-78	0.047	24
6-20-78	0.078	26
6-20-78	0.328*	25
6-23-78	0.103	20
6-23-78	0.291*	20

* A large hydraulic head difference was temporarily applied to increase the flow.

had the effect of increasing the permeability for a short period of time. Results similar to those displayed in Table 2 were obtained using tap water.

It seems likely that the observed decrease in hydraulic conductivity is due to clay particle dispersion, migration, and subsequent blocking of the relatively small pores connecting larger pores. The temporary increase in conductivity caused by a sudden increase in head gradient would be due to the flushing out of a significant number of the clogging particles. Such an explanation is consistent with chemical analyses of water samples obtained from the supply aquifer and the storage aquifer. Most cations were more concentrated in water from the storage aquifer, although both waters were well under-saturated. Ions such as Ca, Fe, and Mn occurred in concentrations of less than 1 mg l^{-1} in both waters. Si and Na were in the 10 mg l^{-1} range in the storage formation water, which was two or three times more concentrated than in the supply water. A storage formation water alkalinity of 175 mg l^{-1} as CaCO_3 , versus about 6 mg l^{-1} as CaCO_3 for the supply water, supports the conclusion that the ionic strength of the supply water is significantly less than that of the formation water. It is known that clays equilibrated with water having a relatively high ion concentration have a potential to swell and disperse when placed in contact with water having a relatively low concentration of ions. The phenomenon is initiated by osmotic swelling [van Olphen, 1963, p. 127] and has been observed many times in both the laboratory and the field [Brown and Silvey, 1977]. Aquifers which contain susceptible clays are called freshwater sensitive.

Additional evidence for clay swelling and dispersion was obtained during the production period. Soon after production pumping began, it was noticed that the recovered water contained a material that was causing a slight discoloration. Filtering of water samples along with chemical analyses and x-ray diffraction studies of the filter cake showed it to be composed of both kaolinite and smectite clays. These materials were definitely not being pumped into the storage formation from the supply aquifer. Therefore, they must have originally been part of the storage aquifer matrix. Clay was produced from the storage formation during the entire production period, although the concentration decreased with time. It is estimated that a few 1000 pounds of clay material were removed during production.

A second problem encountered while conducting the first cycle was due to lightning discharges in the near vicinity of the site. Bolts of lightning induced voltages in the lines leading to the observation wells that were of sufficient magnitude to damage the recording equipment. This occurred even though the wires were shielded and the system grounded. On the average, the automatic recording system was down once every week. Consequently, a great deal of manual data tabulation was performed; the problem itself was never really solved during the experiment.

DESCRIPTION OF SECOND CYCLE

The second injection-storage-recovery cycle was very similar to the first, except that production continued for a longer period. Injection began on September 23, 1978, and continued until November 25, 1978, a total of 64 days. Shown in Figure 13 is the cumulative injection volume as a

Fig. 13. Plot of cumulative injection volume as a function of time. The horizontal segments are due to pump shut-downs resulting from power failures and other problems.

function of time. An injection rate varying from $845 \text{ m}^3\text{day}^{-1}$ (155 gpm) to $1172 \text{ m}^3\text{day}^{-1}$ (215 gpm) resulted in an injection volume of $58,010 \text{ m}^3$ at an average temperature of 55°C as shown in Figure 14. A 63 day storage period began on November 25, 1978, and was terminated on January 27, 1979, when production began and continued for approximately 84 additional days. As shown in Figure 15, the production pumping rate averaged $1205 \text{ m}^3\text{day}^{-1}$ (221 gpm) and ultimately resulted in a production volume of $100,100 \text{ m}^3$. Pumping was stopped when the production temperature reached 27.5°C which was 7.5°C above the ambient groundwater temperature.

At various times during the second cycle, careful level measurements were made in order to determine the magnitude of any land subsidence or rebound associated with aquifer thermal energy storage at the Mobile site. The locations of the four measurement stations are shown in Figure 16.

Fig. 14. Plot of injection temperature as a function of time.

Fig. 15. Cumulative volume of water produced from the injection/production well as a function of time.

Fig. 16. Location of stations for measuring relative elevation changes of the land surface due to injection-production activities. Each pad measured 2.4 m by 2.4 m by 0.2 m and was composed of reinforced concrete. The pads were poured 3 weeks before measurements began.

Each station consisted of 3 surveying markers embedded in reinforced concrete. A level was placed on the observation pad located approximately 30.5 m from the injection well. From this location, relative surface elevations of a point on pad C and points on pads B and A were measured.

RESULTS OF SECOND CYCLE

Shown in Figure 17 is the temperature of the water pumped from the storage aquifer as a function of time. Due to the residual heat remaining in the aquifer and surrounding aquitards after completion of the first cycle, the temperature of the produced water during second cycle recovery

Fig. 17. Temperature of the water pumped from the storage formation as a function of time.

dropped more slowly with respect to time than during the first cycle.

This effect can be seen clearly in Figure 18 which is a plot of production temperature versus production volume for both the first and second cycles. Although second cycle production temperature began at approximately 1°C below first cycle, temperatures became identical after a production volume of 4300 m³. Thereafter, for a given production volume the second cycle temperature was always higher than the first.

From the recorded temperature and flow rate of the injected water as functions of time, one can calculate the amount of thermal energy injected above the ambient temperature. A similar calculation can be made for the amount of energy recovered. The equations actually used were discussed previously. Shown in Figure 19 are plots of the thermal energy recovery factors as a function of recovery temperature. These factors are defined

Fig. 18. Plots of production temperature versus production volume. The broken line refers to the first cycle, while the solid line refers to the second cycle.

as the ratio of energy recovered at any time to the total energy injected. The increased energy recovery during the second cycle can be seen clearly. First cycle recovery was terminated at a temperature of $33^{\circ}C$ and a production volume of $55,300 m^3$. At this point 66% of the injected energy had been recovered. During second cycle recovery, $66,400 m^3$ of water had been produced and 76% of the injected energy recovered when the production temperature reached $33^{\circ}C$. When recovery was terminated at a temperature $27.5^{\circ}C$ and a production volume of $100,100 m^3$, 89% of the injected thermal energy had been recovered.

Fig. 19. Plots of the energy recovery factor, ratio of energy recovered at any time during production to total energy injected, as a function of production temperature. The plots show that at the end of the first cycle 66 percent of the injected thermal energy had been recovered. At the corresponding point of the second cycle 75 percent of the energy had been recovered.

Shown in Figure 20 are the elevation changes of pads B and C with respect to pad A, which we believe was our most stable reference pad because it was located in a relatively dry, sandy and vegetation-free area. Ideally, pads A and B would have remained at the same relative elevation throughout the experiment, however, there was a relative elevation change of approximately 1 mm between pads A and B.

As soon as injection began, the land surface near the injection well (pad C) began to rise with respect to pad A. The rise continued at a

Fig. 20. Relative elevation changes of pads C (circles) and B (triangles) with respect to pad A as a function of time.

decreasing rate until injection of hot water was terminated. During the storage period, pad C rose slightly and then began to fall. After production pumping was initiated and throughout the production period, pad C dropped back towards the elevation of pad A. At the end of production, pad C was located at nearly its initial elevation with respect to pad A.

DISCUSSION OF SECOND CYCLE

It was noted previously that the major technical problem encountered during the first cycle was clogging of the injection-production well during injection. This problem persisted during second cycle injection but was controlled to a greater extent by a regular well backwashing program. Shown in Figure 21 is a plot of injection pressure versus time. Whenever the injection pressure at the wellhead reached approximately $1.45 \times 10^5 \text{ Nm}^{-2}$

Fig. 21. Plot of second cycle injection pressure as a function of time. The drops in pressure occurred right after backwashing operations.

(21 psi), water was pumped in and out of the injection well for short periods of time. After this procedure was completed, the injection pressure would drop and the flow rate would increase. Shown in Figure 22 is the resulting specific capacity history of the injection well. Unlike the first cycle injection, the average specific capacity between backwashings remained nearly constant with time and the average injection rate was increased by 24%.

Regular backwashing may not account entirely for the increased injection rate during the second cycle. It was estimated that during cycle 1 "a few 1000 lbs. of clay material were removed during production pumping." More careful and regular measurements during cycle 2 indicated an additional removal of 3500 kg of solid material - mostly clay. It is possible that the removal of clay materials during cycle 1 lead to an increased permeability

Fig. 22. Specific capacity of the injection well as a function of time. Between backwashing procedures, the specific capacity decreased due to clogging of the formation around the injection well.

in the storage aquifer during cycle 2. The observed removal of 3500 kg during cycle 2 production also lends more support to the theory that clay particle swelling, dispersion and migration were the fundamental causes of the clogging problem observed in the Mobile experiments.

The rising and falling of the land surface in the vicinity of the injection well relative to the land surface 56.4 m away appeared to be due to thermal expansion and contraction rather than head changes in the storage aquifer and resulting flow into and out of aquitards. There are a number of reasons for this conclusion. First of all, there was little relation between head in the injection-production well and land surface

movement. When injection was terminated the head dropped by approximately 15 m of water. However, the relative land surface elevations changed by only 1.4 mm during the storage period. Secondly, the rise is nearly equal to the fall. If the observed effects were due to aquitard hydraulics, one would expect the consolidation to be larger than the rebound due to particle rearrangement during consolidation and the effect of the overburden weight. For the particular case in question one would expect rebound during injection, at least as much consolidation during storage and further consolidation during production, so that pad C would end up well below its original elevation with respect to pad A. That this pattern did not occur supports the thermal expansion and contraction hypothesis.

Although the rebound and consolidation appear to be due to temperature changes, one cannot explain the results in terms of simple expansion and contraction of the storage aquifer matrix. If the temperature of the entire 22 m thickness of the storage aquifer were increased by 35°C one would expect an expansion of less than $(35^{\circ}\text{C} \times 5.5 \times 10^{-7}^{\circ}\text{C}^{-1} \times 22 \text{ m}) = 4.2 \times 10^{-4} \text{ m} = 0.42 \text{ mm}$ if the matrix was composed of fused quartz grains. This number is approximately an order of magnitude less than the observed expansion. However, the expansion and contraction of water within the clay aquitards would be adequate to give the observed rise of approximately 4 mm. The coefficient of thermal expansion of saturated clays in undrained conditions is on the order of $10^{-4}^{\circ}\text{C}^{-1}$ (approximately 1/3 the volume expansivity of water) which is 182 times greater than fused quartz. Thus the 4 mm rise could be due to heat flowing upward from the storage aquifer and, more importantly, radially outward from the well into the clay strata below observation pad C. Such effects are discussed in some detail by Campanella

and Mitchell [1968]. Although the above argument is based on a coefficient of linear expansion for a fluid which cannot be defined uniquely, it seems adequate in an order-of-magnitude sense to support the idea that heating clay strata can lead to relatively large initial changes in vertical thickness.

SUMMARY AND CONCLUSIONS

First cycle injection of water into a confined aquifer began on March 18, 1978, and continued until June 5, 1978. Prior to injection, the water was heated with an oil-fired boiler to an average temperature of 55°C. Ultimately, 54,784 m³ of water were pumped into the storage aquifer. Clogging of the formation surrounding the injection well reduced the injection rate from the planned 1090 m³ day⁻¹ (200 gpm) to as low as 545 m³ day⁻¹ (100 gpm). Injection was 95% continuous, however, with short stops due to power failures, a burned-out transformer, and three short backwashings (Figure 12). Throughout the entire experiment, groundwater temperatures were recorded at six depths in each of ten observation wells, and hydraulic heads were recorded in five observation wells. In order to prevent significant thermal convection, most of the observation wells recording temperatures had to be backfilled with sand.

After a 51-day storage period, during which time there was only a small amount of regional groundwater drift, first cycle pumping of water from the storage aquifer began at a nearly constant rate of 1363 m³ day⁻¹ (250 gpm). Initially, the temperature of the recovered water was 55°C and diminished at an average rate of 0.5 degree per day. Very little heat was lost from the storage formation through the confining layers. Hydrodynamic thermal dispersion within the storage aquifer was probably

an important dissipation process. Additional mixing due to clogging and unclogging of the formation could have played an important role also. On September 5, 1978, first cycle recovery ceased after a total of 55,345 m³ of water above ambient, and 66% of the injected thermal energy had been recovered.

On the basis of laboratory and field studies, it was concluded that the clogging mentioned previously, which caused a large decrease in the specific capacity of the injection well, was due to the freshwater-sensitive nature of the storage aquifer. Clay particles would swell, disperse, and migrate until they became trapped in the relatively-small pores connecting the larger pores. Thus, the clogging phenomenon is viewed as a colloid chemistry problem largely independent of temperature. It may, however, depend on pore velocity. Except for waters high in calcium, moderate increases in temperature would be expected to increase the hydraulic conductivity rather than decrease it. Of course, other detrimental reactions such as those related to corrosion and scaling would tend to increase with temperature.

As predicted by theory, an increase in energy recovery was observed with multiple injection-storage-recovery cycles. At the Mobile site, second cycle recovery was 76% in the temperature range from 55°C to 33°C. Recovery at the end of the first cycle in the same temperature range was 66%. The recovery increase was due mainly to residual heat remaining in the aquifer after the first cycle was completed.

Clogging of the injection/production well during injection posed less of a problem during the second cycle. A regular backwashing program was probably the main contributor to the observed 24% increase in average

injection rate. Although the large quantity of clay pumped out of the storage aquifer during first cycle production may have contributed to an increased permeability during second cycle injection, there was no observed increase in the second cycle production rate that could be attributed to this increased permeability. In fact, the production rate decreased by 18% during recovery. An additional 3500 Kg of clay were removed during second cycle production.

During 2nd cycle injection, a concrete observation pad (pad C) near the injection/production well rose approximately 4 mm with respect to another pad located 56.4 m away. During storage pad C fell approximately 1.4 mm, and then fell more rapidly during production to very near its original elevation. This observed rebound and subsidence appears to be due to thermal expansion and contraction of water within clay strata rather than head changes in the storage aquifer or thermal expansion and contraction of the storage aquifer matrix. Such temperature induced rising and falling of the land surface should not pose an important problem in most situations.

Future research should be directed toward establishing methods for controlling clogging problems in storage aquifers. This problem area is of prime importance, and injection difficulties are likely to be the rule rather than the exception in future aquifer storage systems. Several possibilities for minimizing clogging include increasing the ionic concentration of the injection water and using the storage formation itself as a source of supply water [Molz, Warman, and Jones, 1978]. Research should also be directed toward procedures for selecting storage aquifers that will have minimum susceptibility to clogging and other geochemical problems.

Several scientists at the Lawrence-Berkeley Laboratory are performing computer simulations of the experiments described in this report. Their results will contribute to a more detailed future analysis of the data resulting from the Mobile experiments.

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APPENDIX I

Geometric Data for the Well
Field and Storage Aquifer at the
Mobile Site

Top view of well field and cartesian coordinates of wells

POSITION	ELEVATION (M) Ft.	
	M	Ft.
TOF	-39.32	(-129)
a	-42.37	(-139)
b	-51.51	(-169)
BOF	-60.5	(-198.5)

WELL NO. 1 POSITIONELEVATION (M) Ft.

	M	Ft.	
TOF	-38.83	(-127.4)	Datum is a spike located in an electrical power pole
a	-39.75	(-130.4)	
b	-43.65	(-143.2)	
c	-47.55	(-156.0)	
d	-51.45	(-168.8)	
e	-55.35	(-181.6)	
f	-59.25	(-194.4)	
BOF	-60.17	(-197.4)	

WELL NO. 2 POSITIONELEVATION (M) Ft.

	M	Ft.	
TOF	-40.05	(-131.4)	Datum is a spike located in an electrical power pole
a	-40.97	(-134.4)	
b	-44.87	(-147.2)	
c	-48.77	(-160.0)	
d	-52.67	(-172.8)	
e	-56.57	(-185.6)	
f	-60.47	(-198.4)	
BOF	-62.00	(-203.4)	

WELL NO. 3

POSITION	ELEVATION (M) Ft.	
	M	Ft.
TOF	-39.26	(-128.8)
a	-40.17	(-131.8)
b	-44.07	(-144.6)
c	-47.93	(-157.4)
d	-51.89	(-170.2)
e	-55.78	(-183.0)
f	-59.38	(-194.8)
BOF	-59.30	(-194.8)

Datum is a spike located in an electrical power pole

WELL NO. 4

POSITION	ELEVATION (M) Ft.	
	M	Ft.
TOF	-39.01	(-128.0)
a	-39.93	(-131.0)
b	-43.83	(-143.8)
c	-47.73	(-156.6)
d	-51.63	(-169.4)
e	-55.53	(-182.2)
f	-59.44	(-195.0)
BOF	-64.62	(-212.0)

Datum is a spike located in an electrical power pole

WELL NO. 5

POSITION	ELEVATION (M) Ft.	
	M	Ft.
TOF	-38.90	(-127.3)
a	-39.72	(-130.3)
b	-43.62	(-143.1)
c	-47.52	(-155.9)
d	-51.42	(-168.7)
e	-55.32	(-181.5)
f	-59.22	(-194.3)
BOF	-60.75	(-199.3)

Datum is a spike located in an electrical power pole

WELL NO. 6

POSITION	ELEVATION (M) Ft.	
	M	Ft.
TOF	-39.11	(-128.3)
a	-40.02	(-131.3)
b	-43.92	(-144.1)
c	-47.82	(-156.9)
d	-51.72	(-169.7)
e	-55.63	(-182.5)
f	-59.53	(-195.3)
BOF	-60.75	(-199.3)

Datum is a spike located in an electrical power pole

WELL NO. 7

POSITION	ELEVATION (M) Ft.	
	M	Ft.
TOF	<u>-38.71</u>	(-127.0)
a	<u>-39.62</u>	(-130.0)
b	<u>-43.53</u>	(-142.8)
c	<u>-47.43</u>	(-155.6)
d	<u>-51.33</u>	(-168.4)
e	<u>-55.23</u>	(-181.2)
f	<u>-59.13</u>	(-194.0)
BOF	<u>-61.87</u>	(-203.0)

Datum is a spike located in an electrical power pole

WELL NO. 8

POSITION	ELEVATION (M) Ft.	
	M	Ft.
TOF	<u>-38.34</u>	(-125.8)
a	<u>-39.26</u>	(-128.8)
b	<u>-43.16</u>	(-141.6)
c	<u>-47.06</u>	(-154.4)
d	<u>-50.96</u>	(-167.2)
e	<u>-54.86</u>	(-180.0)
f	<u>-58.77</u>	(-192.3)
BOF	<u>-62.73</u>	(-205.8)

Datum is a spike located in an electrical power pole

WELL NO. 9

POSITION	ELEVATION (M) Ft.	
	M	Ft.
TOF	-38.98	(-127.9)
a	-39.90	(-130.9)
b	-43.80	(-143.7)
c	-47.70	(-156.5)
d	-51.60	(-169.3)
e	-55.50	(-182.1)
f	-59.41	(-194.9)
BOF	-60.02	(-196.9)

Datum is a spike located in an electrical power pole

WELL NO. 10

POSITION	ELEVATION (M) Ft.	
	M	Ft.
TOF	-40.75	(-133.7)
a		()
b		()
c		()
d		()
e		()
f		()
BOF	-60.87	(-199.7)

Datum is a spike located in an electrical power pole

WELL NO. 11

POSITION	ELEVATION (M) Ft.	
	M	Ft.
TOF	-33.47	(-126.2)
a	-39.38	(-129.2)
b	-43.28	(-142.0)
c	-47.12	(-154.8)
d	-51.08	(-167.6)
e	-54.99	(-180.4)
f	-58.89	(-193.2)
BOF	-60.72	(-199.2)

Datum is a spike located in an electrical power pole

WELL NO. 12

POSITION	ELEVATION (M) Ft.	
	M	Ft.
TOF	-36.04	(-124.8)
a		()
b		()
c		()
d		()
e		()
f		()
BOF	-62.42	(-204.8)

Datum is a spike located in an electrical power pole

WELL NO. 13 POSITIONELEVATION (M) Ft.

	<u>M</u>	<u>Ft.</u>	Datum is a spike located in an electrical power pole
TOF	-38.16	(-125.2)	
a	_____	()	
b	_____	()	
c	_____	()	
d	_____	()	
e	_____	()	
f	_____	()	
BOF	-59.30	(-196.2)	

WELL NO. 14 POSITIONELEVATION (M) Ft.

	<u>M</u>	<u>Ft.</u>	Datum is a spike located in an electrical power pole
TOF	-57.86	(-124.2)	
a	_____	()	
b	_____	()	
c	_____	()	
d	_____	()	
e	_____	()	
f	_____	()	
BOF	-60.96	(-200.0)	

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