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PREDICTING INJECTOR PERFORMANCE AT THE PROPOSED
MAGMA-SDG&E FIFTY MEGAWATT GEOTHERMAL
POWER PLANT*

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TABLE OF CONTENTS

	<u>Page</u>
Abstract	7
Background	7
The Injection Well	10
The Probable Character of the Reservoir	11
Some Effects of Heating the Injection Water and Cooling the Connate Water	11
The Water Injection Front	13
Calculated Steady-State Surface Injection Pressures	13
Expected Bore-Hole Pressure Increases Caused by Water Injection	14
Expected Bore-Hole Pressure Increases if Thief Sands are Encountered	16
An Injection Performance Map for the Injection Well	16
A Recent Case History Using the IPM	19
Conclusions	19
References	23

LIST OF ILLUSTRATIONS

<u>Figure</u>		<u>Page</u>
1	Imperial Valley of California	8
2	Pressure Responses in the Well-Bore	15
3	Pressure Responses in the Well-Bore with a Thief Sand	17
4	Injection Performance Map for the Example Niland Injection Well	18
5	Injection History of a Well where Suspended Solids Loading of Water caused Injectivity Variations	20
6	Injection Performance Map for Figure 5	21

LIST OF TABLES

<u>Table</u>		
I	The Change in Density and Volume of a 1.11 sp gr Brine with Changes in Temperature	12
II	The Change in Viscosity of a 1.11 sp gr Brine with Changes in Temperature	12
III	Calculated Injection Front Radius for the Example Well	13
IV	Steady-State Injection Well Surface Pressures (psig) for Various Values of kh (md-ft) and Injection Rate (b/d)	14

PREDICTING INJECTOR PERFORMANCE AT THE PROPOSED MAGMA-SDG&E FIFTY MEGAWATT GEOTHERMAL POWER PLANT

Abstract

The spent brine treating facility at the Magma Power - San Diego Gas and Electric Co. proposed fifty megawatt geothermal power plant in the Niland KGRA is under construction. The spent geothermal brine will be treated in a sludge-bed clarifier, followed by filtration through rapid mixed-media filters for suspended solids removal.

The injection water treating system and the reinjection well are scheduled to be ready for testing by late Spring, 1979. The question of the injection test duration necessary to provide an assessment of the well's long-term injection capability has been raised. This report provides some insight to this question, and includes an advanced method for assessing changes in injection well receptivity, the Injection Performance Map (IPM).

The report also contains data which suggest that three to four months' continuous operation with properly treated injection water may be sufficient to forecast the well's long-term injection potential.

Background

The San Diego Gas and Electric Company and Magma Power Company have completed testing a 10 megawatt experimental test loop located at the Niland KGRA (see Figure 1). During the extensive testing, a considerable effort was directed toward spent brine reinjection.^{1 2 3 4 5 6 7}

Field tests of the 17,000 barrel per day (b/d) pilot injection system showed that sludge bed water clarification followed by rapid (pressure) filtration through mixed-media filters produces a stable, saturated brine containing about 2 parts per million (ppm) of suspended solids. This brine is sufficiently clean to be capable of providing long-term injection, although all factors in the total surface/reservoir system have not been thoroughly evaluated.⁸

Figure 1. Imperial Valley of California, 100 Miles East of San Diego. KGRAs are federally designated Known Geothermal Resource Areas.

Because the ability to reinject spent brine can be a limiting factor in a geothermal power plant, the assessment of long-term injection is of considerable importance. Extrapolation of the results of short-term (few months) injection tests to long time performance is often difficult, and tests of one or more years' duration are considered by many to be more indicative of a system's actual long-range capability. But long-term tests, in addition to being expensive, delay the start of the plant and the generation of power.

A compromise, that is a short-term injection test which generates the best possible data for predicting performance, is often chosen. However, the compromise is only effective if the careful, accurate and frequent collection of all necessary data takes place during the test period. Frequent wireline runs to measure bottom-hole temperatures and pressures, numerous membrane filter tests to assess clarifier and filter performance and well head water quality, and the analysis of many water samples taken from key points in the system are an absolute necessity (and are expensive). Otherwise, the short-term test cannot provide a reliable well performance forecast.

Interpretation follows the gathering of the data. And this stage is most important, because all critical technical questions must be answered to the satisfaction of many listeners.

The material in this report addresses many (but not all) of the variables in the proposed test. An early publication date was stipulated, and this makes it necessary to use the "most likely" values for a number of the system parameters because actual data are not available. Specifically, logs of the well and bottom-hole surveys have not been provided, and the petrography, lithology, and static reservoir temperatures and pressure are "best estimates" obtained by examining logs and reservoir data from nearby Magma wells (#3 and #4).

This report contains

- (1) The injection well configuration and fluid properties.
- (2) A reservoir characterization.

- (3) Some effects of heating the injectant and cooling the connate water.
- (4) The progress of the water injection front.
- (5) Calculated injection pressures for varying reservoir permeabilities.
- (6) Expected bore-hole pressure increases caused by water injection.
- (7) Expected bore-hole pressure increases if thief sands are encountered.
- (8) An Injection Performance Map (IPM) for the injection well.
- (9) A recent case history using the IPM.
- (10) Conclusions.

The Injection Well

The following values describe the injection system:

1. Injection interval is 1100-1500 feet (slotted liner).
2. Surface water temperature is 210°F.
3. Reservoir static pressure at midpoint is 563 psi.
4. Reservoir static temperature at midpoint is 370°F.
5. Water viscosity is 0.2 centpoise (effective).
6. Net injection interval is 250 feet (est).
7. Average injection sand permeability is 800 millidarcies (est).
8. Sand porosity averages 28 percent (est).
9. Water specific gravity at 68°F is 1.11 (est).
10. Casing is 13-3/8 inch to 1100 feet, liner is 10-3/4 inch, 1050-1500 feet, with 32 slots per foot, 0.125 inch x 2-1/2 inch.
11. Frac gradient is 0.62 psi per foot (est).
12. Target flow rate is 41,000 barrels per day (about 1200 gpm).

Injection will be through the casing as in the 10 megawatt pilot system injection well. The effective viscosity (item 5) is a weighted average of the viscosity of the injected and connate waters, and follows techniques developed by LLL.^{5 6 7} The injection pump provides a surface pressure up to 400 psig, although surface pressures of 250-300 psig will probably frac the reservoir.

Water quality is expected to be good, with suspended solids of about 2 ppm present. At an injection rate of 41,000 b/d, the equilibrium bore-hole temperature can be calculated to be about 211-212 F.⁴ Water transit

time top to bottom, is about 6-1/2 minutes, so saturated surface water is not likely to cause heavy scale deposits in the casing.

The particulates in the water will most likely be distributed in a deep-bed invasion mode in the reservoir.^{1 3}

The Probable Character of the Reservoir

The shallow sedimentary sections in the interval 1100 - 1500 feet are most likely alternating layered sands and shales. Sand layers at this depth vary from 10 feet to 60 feet in thickness and contain mostly clean, well sorted, well rounded, unconsolidated fine to medium sands. Between the layered sands are layers of relatively impermeable silts and clays, often 5 feet to 30 feet thick.^{1 2 8} Permeabilities of the sand layers vary from about 100 to 2000 millidarcies (md), and up to 20 percent of the sands may consist of "thief" layers of 1 - 2 darcy permeability. The gross 400 foot interval should contain 250 net feet of sand (or less). This type of reservoir has a favorable history of providing sustained, long-term injection, provided that pore damage by excessive solids loading of the injection water is avoided.⁴ In the event of pore damage by hydrochloric acid soluble solids, acidizing can be used to remove part or all of the damage. Acidizing reservoirs as hot as this, however, would require the use of cooling pads to be effective. Strong HF acid (>0.5%) should be avoided and self-generating HF acids would probably be used if damage by HF-soluble particulates occurs.

Some Effects of Heating the Injection Water and Cooling the Connate Water

The injection water, at 210°F, will be heated as it is injected into the 350°F reservoir, cooling connate water in the process. Temperature changes have a three-fold effect on the injection water, (1) viscosity will change (2) density will change, and (3) solubility of dissolved solids will increase or decrease, depending on the system thermodynamics. The temperature changes can be estimated^{3 5 6 7} but this is beyond the scope of this study.

It is important to determine the temperature changes in order to evaluate any scaling tendency of the injected and connate waters. Mineralogical analyses, temperatures and pressures are some of the required input to programs such as Battelle's EQUILIB, which should be considered for use in this system.

Density of the injection water will decrease and viscosity will also decrease as the injection water is heated. The density decrease will increase the injected water volume and the radius of the injection front, which will tend to increase bore-hole driving pressure. But viscosity will decrease as the water is warmed and may partially or totally offset the effect of the density decrease. The density and viscosity data below suggest that water volume change should not have an adverse affect on injection pressures because of the larger decrease in viscosity relative to the volume change.

TABLE I

The Change in Density and Volume of a 1.11 sp gr Brine
with Changes in Temperature

<u>Temperature, °F</u>	<u>Density, lb/ft³</u>	<u>Volume, ft³/lb</u>	<u>Percent increase in Volume over 68°F</u>
68	69.232	0.014444	0
210	66.447	0.015049	4.2
350	50.078	0.019969	38.3

TABLE II

The Change in Viscosity of a 1.11 sp gr Brine with Changes in Temperature

<u>Temperature, °F</u>	<u>Viscosity, cp</u>	<u>Percent Decrease in viscosity</u>
68	1.115	0
210	0.305	72.6
350	0.128	88.5

Existing models for fluid heating do not simulate layered systems,^{5 6 7} but can be modified to do so. When logs are available for the injection well, it would be advisable to assess the injection water temperature changes and investigate the affects of density and viscosity changes using a layered radial flow reservoir simulator.

The Water Injection Front

In order to estimate well-bore and surface injection pressures, the magnitude of injection front at any time must be known. Assuming that uniform injection takes place over the entire sand interval, the injection front can be estimated.

TABLE III

Calculated Injection Front Radius for the Example Well ($q = 41,000$ b/d; $h = 250$ ft; $\phi = 28\%$)

<u>Years of Constant Injection</u>	<u>Injection Front Radius, Feet</u>	<u>Approximate Spacing, Acres per Well</u>
1	617	40
2	873	
3	1069	80
4	1234	
5	1380	160
10	1951	
20	2760	640
30	3380	800

Calculated Steady-State Surface Injection Pressures

In order to provide a yardstick for injection performance, steady-state surface injection pressures have been calculated for several injection rates and reservoir transmissivities. As stated earlier, logs for the well are not available at this writing, but kh values of the order of 100,000 - 200,000 md-ft are expected. Since the well has no sand control other than that afforded by the 1/8 inch slots, well-bore fillup by back-heaving sand may be encountered, and kh values will be reduced. To account

for these variables and unknowns, injection pressures for kh values from 20,000 md-ft to 500,000 md-ft are provided for injection rates of 20,000 to 50,000 b/d.

TABLE IV

Steady-State Injection Well Surface Pressures (psig)
for Various Values of kh (md-ft) and Injection Rate (b/d)

<u>Injection b/d</u>	<u>kh= 20,000</u>	<u>kh= 30,000</u>	<u>kh= 40,000</u>	<u>kh= 50,000</u>	<u>kh= 70,000</u>	<u>kh= 100,000</u>	<u>kh= 200,000</u>	<u>kh= 500,000</u>
20,000	160	87	50	28	2	-17	-39	-52
40,000	385	237	163	119	67	29	-15	-42
60,000	609	387	276	210	132	75	9	-30

Example: for kh = 70,000 md-ft, and rate = 40,000 b/d,
surface pressure is 67 psig

These data may be useful if injection starts before the reservoir kh is known, as kh values can be retrofitted to values of surface pressure and injection rate. Transient effects, discussed later, will have to be used for proper interpretation of the data.

If kh values are available before injection starts, and if observed surface pressures are significantly higher than those shown in Table IV, serious impairment to injection can be assumed to be taking place.

Expected Bore-Hole Pressure Increases Caused by Water Injection

For the first few months of injection, pressure increases due to the increasing water front radius will occur at a higher rate than the pressure increases which follow. This occurs because radial flow is taking place. Pressure increases in the first few weeks of operation caused by the increasing injection front radius can be substantial at low kh values. At high kh values, the rate of pressure change is relatively small.

A comparison between low and high kh pressure changes is shown in Figure 2. When kh = 20,000 md-ft, a pressure increase in excess of 100 psi

Figure 2. Pressure Responses in the Well-Bore for Two kh Values with a Constant Injection Rate of 41,000 b/d

can be expected in the first 6 months of continuous injection. When $kh = 200,000$ md-ft, the pressure increase is less than 10 psi for the same time period. After 6 months injection, the rate of change of bore-hole pressure per time unit decreases in both cases.

These are typical curves for radial flow injection systems. This is one reason that tests of 6 months duration are often specified. However, if kh is known, the pressure trends can be calculated and tests of less than 6 months duration can provide acceptable results.

Expected Bore-Hole Pressure Increases if Thief Sands are Encountered

Thief sands have been encountered in several Imperial Valley injection systems, and data showing that about 80 percent of the water is injected into about 20 percent of the sand is not uncommon.^{1 3} Assuming that 80 percent of the water flows into 50 feet of a 2-darcy sand, the pressure will build up as in Figure 3. Like the $kh = 200,000$ md-ft pressure response in Figure 2, the pressure change during the first 6 months is nominal.

An Injection Performance Map for the Injection Well

A technique has been devised which provides a means of evaluating impairment or improvement of injection wells over a wide range of kh values.^{4 8} The Injection Performance Map (IPM) incorporates well geometry, well hydrodynamics and reservoir variables into a single, integrated plot (see Figure 4). Once the IPM is prepared for a specific well and water, kh values can be retrofitted (if unknown), and any impairment (well plugging, sand fill, etc.) can be quickly recognized. Also, the effectiveness of any well workover (improvement) can be evaluated. The IPM reflects steady-state data at $T = 10$ years, and small increases in pressure due to reservoir fill must be recognized and the data adjusted accordingly.

The IPM is not intended to be a substitute for pressure buildup tests and similar, more sophisticated technology. But it has been found to be an improvement over tests such as the three-point injectivity index test, because it accounts for tubing friction, reservoir behavior and other key system variables.

Figure 3. Pressure Response in the Well-Bore Assuming that a Thief Sand Takes 80 Percent (33,000 b/d) of a Constant Injection of 41,000 b/d

Figure 4. Injection Performance Map for the Example Niland Injection Well

A Recent Case History Using the IPM

To illustrate the utility of the IPM, the recent performance of an injection well in South Texas is shown in one customary plot (Figure 5) and in an IPM (Figure 6). The IPM, Figure 6, differentiates between operation in the presence and absence of clay swelling. A 15,000 ppm TDS brine is injected into a clay and shale bearing sandstone having a connate water with a TDS $\sim 200,000$ ppm and clay swelling was expected. It is interesting to note that the IPM was prepared before field data were available, and that the actual system performance closely approximates the "clay-swelling" line before particulate damage occurred.

Because of varying injection rates, the assessment of system behavior from the plots on Figure 5 is difficult to interpret at first glance. However, when pressure-flow rate data from Figure 5 are plotted on the IPM, both the certainty that impairment has taken place, and the magnitude of the impairment become evident. Fortunately, corrective measures and an effective well workover restored injectivity (point 5, Figure 6).

Conclusions

1. A reasonably acceptable prediction of long-term injection well performance at the Niland 50 MW plant may be possible in 2-4 months operation if adequate data are gathered and if water quality is maintained at the target level (~ 2 ppm suspended solids).
2. If lengthy water-treating upsets occur at frequent intervals, the ability to obtain reliable data will be severely reduced.
3. Near-continuous injection during the test period is an absolute necessity. A stream factor greater than 90 percent is probably required.
4. Data required for the test include, but are not limited to:
 - (a) Bottom-hole temperatures and pressures
 - (b) A pressure buildup test prior to and at the conclusion of the test
 - (c) Suspended solids content of the plant inlet water, clarifier inlet, clarifier outlet, filter inlet, filter outlet, and well head, using the 0.45 micron membrane filter.

Figure 5. Recent Injection History of a Well Where Suspended Solids Loading of the Water Caused Injectivity Variations

Figure 6. Injection Performance Map for the Well in Figure 5. Effective kh was reduced from 32,000 md-ft to less than 5,000 md-ft, which is a reduction in specific injectivity of about 85 percent. The numbered circles correspond to points in Figure 5.

- (d) Quantitative analyses of the residue obtained in (c); not required for each membrane, but should be enough to characterize the solids. All membrane filters should be preserved for future analysis.
- (e) Water samples taken from (at least) the sample points in (c) should be collected and preserved. Complete quantitative analysis of water from each sample point is required for input to the EQUILIB program.
- (f) The water pH at the sample points should be measured several times each day.
- (g) Any scale or corrosion product deposit which might become available should be analyzed and part of the sample should be preserved.
- (h) Injection pressure and flow rate should be continuously recorded. An up-to-date histogram (as in Figure 5) and IPM (Figure 6) should be maintained.
- (i) A top-to-bottom, through-the-casing spinner survey should be run within a few days from the start of injection and a few days before the test is concluded.
- (j) Barkman-Davidson type flow tests^{1 2} should be run periodically.

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