EG&G Idaho

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INTEROFFICE CORRESPONDENCE

GL07221

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to R. R. Piscitella

from M. R. Dolenc MRD

subject THE RAFT RIVER INJECTION SYSTEM - MRD-31-78

Recent memos [1,2,3] and verbal discussions have documented and debated the potential of the Raft Injection System. This memo is designed to summarize those memos and document my personal interpretation and recommendations of that system as of September 1978. (All points discussed herein do not reflect the opinions of all Reservoir Engineering.)

The Bliem memo [1] predicts that the nominal plant outflow rate of 2120 gpm can be injected by pressures of less than 700 psi (after five years) and injection rates of 400 gpm (#7), 1280 gpm (#6), and 440 gpm (#3). These rates appear credible, based on injection tests of 290 minutes (#7), 310 minutes (#6), and on flow tests of #3. However, the data is extremely short for predicting five-year injection pressures, boundaries, and interferences. With the well spacing of these three wells being about one-half mile from one another, a likely interference effect is to be expected on longer or continual simultaneous injection into the three wells. The Dolenc memo [2] recommends injection pressures below 700 psi to insure uncontrolled fracture breakdown pressures are not exceeded. Therefore, based on extremely short-term test data, planned injection flow is at the injection capability limit. Because I feel there are too many unknowns and uncertainties in these figures, I initiated a more detailed study of the injection system to determine whether a new well was needed.

My conclusion is that a new well is needed for injection. I foresee possible solutions for improving the capability of wells #3, #6, and #7, but reviewing case histories of injection of fluid worldwide, I find a standby well is necessary. A summary of my investigation and conclusions is documented below.

FORM EG&G-954
(Rev. 2-77)

RRGE-3

The RRGE-3 well is presently cased to 4241 feet. Open-hole exists from this point into a triple-legged configuration that has legs to depths of 5853', 5532', and 5917'. The well was originally drilled as a production well. Tests show a flow of 500 gpm. The bottom hole temperature (301 °F) exceeds by 15 °F the temperature of any other Raft River well.

Injection potential of RRGE-3 has never been tested, but is suspected to be in the range of its flow rate. Low permeability probably restricts flow from this well and similarly would restrict injection into the present open-hole section. To use RRGE-3 for injection, it is my recommendation that remedial work be performed on the middle (cased) portion of this well (3000-4000').

In the drilling of this well, four distinct zones between 3400 and 4100 feet caused lost circulation problems. A review of geophysical logs suggests fracture-permeability accounts for a zone at 3436 feet and a second zone at 3500 feet. What appears to be higher sand-to-shale ratios start at 3775 feet, and when compared with the lithologic log, it is suspected a highly permeable, conglomerate-sand-shale portion of the Salt Lake Formation is present. This section took drill fluid readily and is believed to be a favorable zone for injection.

RRGI-6

RRGI-6 was cased at 1698 feet and is open-hole from there to TD at 3888 feet. It is located about 2600 feet west of RRGE-3. During drilling of RRGI-6, a major lost circulation zone occurred at 2995-3025 feet. This may be fault-related, but the core recovered shows only minor fracturing. The rate of circulation loss increased from 50 barrels per hour to 80 barrels per hour at total depth.

RRGI-6 shows less conglomerate (only minimal amounts at TD). A poor quality Densilog hinders interpretation to some extent, but the electrical log suggests an even higher ratio of sand-to-shale than RRGE-3. It is suspected this characteristic accounts for its injection capability.

The 5.17 hour test conducted May 1, 1978, was reported earlier [3]. Although the short test limits interpretation of boundary conditions, the table presented in that memo suggests injection rates of up to 1200 gpm can be achieved, holding five-year wellhead pressures under 700 psi. Tests planned in the immediate future should confirm or limit this interpretation, but it appears that RRGI-6 should prove to be a successful injection well. A further improvement in its injection performance is suggested by the Goldman memo[5].

RRGI-7

RRGI-7 was drilled to a total depth of 3858 feet, cased at 2044 feet, and open-hole for over 1800 feet. Nevertheless, no faults nor lost circulation zones were noted during drilling nor were any conglomeratic zones observed from drill cuttings.

Geophysical logs suggest porous, permeable zones occurring from 2450-2500 and from 2700-3000 feet and again at 3575-3615 and 3710-3750 feet. These sections will be discussed further in the following paragraphs.

A very short (290 minute) injection test was conducted, which is discussed in cursory form in an earlier memo[2]. The conclusion from that memo is that a boundary may be appearing near the end of that test, and if so, the injection capability of this well may be severely limited if pressures less than 700 psi are maintained. This memo also suggests that breakdown (fracture-initiation) pressures may occur in the range of 700-1400 psi, causing vertical fracturing upward into environmentally undesirable water zones.

Because it is difficult to explain the behavior of this well's injection capability, a comparison of porous, permeable zones was made. This comparison of Epilogs for wells #6 and #7 (no Epilog was obtained on well #3) shows 100 porosity feet for #6 well and 89 porosity feet for #7 well. Therefore, I concluded the injectability is highly dependent on natural fractures adjacent to the wellbore. The enclosed figure shows the comparison of major porous zones from Epilog and the lost circulation zones noted on the lithologic log.

Conclusions and Recommendations

To achieve the required injection capability and insure pressure restraints are not exceeded, I personally recommend the following alternatives as most advantageous to the program:

1. Well #6 appears adequate, but the memo[5] noted suggests it could be improved by stimulation.

#3 not Recommend for injection by Res Eng.

2. Well #3 should be perforated and acidized at selected zones around 3500 feet, 3675-3800 feet, and 4025-4100 feet (avoid 3436-ft. zone because of casing collar). It may be desirable to set a packer and cement plug or a drillable or retrievable packer at the bottom of the cased hole, to preserve the high temperatures below, should a dual completion well be later desired.

Not Recommended by Res Eng.

3. Well #7 should be fraced with a sufficient fracture treatment to achieve frac wings in the direction of natural fractures in the vicinity of wells #3 and #6. Core from this well is currently being tested for primary rock properties by Terra Tek.

4. Drill a new well for injection purposes.

The alternatives presented can be implemented singly or together. Well #3 offers a fairly good chance of success, assuming natural fractures did not cement-off completely. Setting the plug or packer will require a workover rig, but the trade-off should be presented to DOE as one of preserving the high temperature, triple-legged production zone for future use should a quick, high-heat content be necessary after 5 MW startup. Or, as briefly mentioned, the dual-completion well discussed verbally by Judd Whitbeck offers tremendous potential of using #3 (bottom section) as a standby producing well.

Well #7 offers no significant alternative of providing any quick relief to the injection needs of the program. We must either accept its injectability performance as the well currently provides or, after adequate rock testing, pursue a funding source to research the effectiveness of fracturing to improve the injectability of the well.

* The alternative of drilling a new well offers flexibility to the program in that no well will be overworked, unforeseen problems such as pump downtime would not affect the power plant, and chemical plugging or long-term boundary effects would not reduce the plant output. A study[4] of case histories of injection systems used throughout the world shows over one-half dozen situations where wells failed for one reason or another, and I have reviewed a number of these case histories of injection of fluid worldwide and find standby wells were required. A summary of some of these case histories is documented below.

1. Upward movement of injected waste near Belle Grande, Florida, was detected in monitor wells. The injection needed to be deepened 500 feet and the liner extended 400 feet deeper (ref. 4, pp. 526-551).

2. Industrial, organic acids being injected into a sandstone, gravel, and limestone aquifer near Wilmington, North Carolina, showed excessive injection pressures in one year, chemical plugging in a year and a half, and upward movement into near-surface aquifers in three years. New wells were required in each case such that six new observation wells were required and three new injection wells were required. Four and a half years after startup, injection terminated because of the problems experienced (ref. 4, pp. 565-584; pp. 851-875).

3. In northeastern Illinois a 15-well brine disposal system has three standby injection wells or 15% of their system dedicated "to keep injection pressures within acceptable limits" and still accommodate the increasing waste-brine rates (ref. 4, pp. 652-663).

One should remember that these injection wells are disposal treatment facilities and, as such, are subject to plugging, maintenance, and other downtime situations. The mathematical treatment of early-time (short-term) data as capable of achieving nominal plant outflow[1] overlooks the fact that wells one-half mile apart, injecting into the same aquifer or fracture system, may interfere with one another. This, in itself, is justification for a standby or additional well. A new well offers flexibility to the program and I strongly recommended it.

Another point should be questioned about past injection completion techniques. This author assumed there was no need to gravel-pack and screen the open-hole injection zones of our wells. However, a review of logs shows that the drillers TD and the loggers TD in wells #6,and #7 indicate a fill of 100 feet in #6 and 60 feet in #7 between drilling and logging. This suggests that the wellbore or formation is sloughing considerably or that insufficient cleanup of the wells occurred. Physical tests of the erodability of the formation will be tested by Terra Tek on #7 core.

Well were cleaned properly

Appreciating the financial constraints of the total geothermal program, the above recommendations are made by me acknowledging the fact that they may be impossible to implement. Recognizing these facts, I propose these recommendations as considerations in future work if they cannot be implemented at this time. Should any of these recommendations be implemented, our support is available.

References

1. C. J. Bliem ltr to T. W. Lawford, CJB-1-78, Injection Capacity for Raft River First 5 MW(e) Pilot Plant, August 18, 1978.

2. M. R. Dolenc ltr to H. M. Burton, MRD-30-78, RRGI-7 Injection Capabilities, September 22, 1978.

3. R. C. Stoker ltr to J. H. Ramsthaler, RCSt-52-78, RRGI-6 Injection Rate Estimates, September 27, 1978.

4. Jules Braunstein, Editor, Second International Symposium on Underground Waste Management and Artificial Recharge, Volumes 1 and 2, American Association of Petroleum Geologists, 931 pages, 1973.

5. D. Goldman ltr to C. A. Allen, DG-3-78 (to be issued).

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Enclosure:
A Comparison of Data on the Injection System Wells

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Attach #1

A COMPARISON OF DATA ON THE INJECTION SYSTEM WELLS