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A PERFORMANCE EVALUATION OF MAGMA POWER COMPANY'S
REINJECTION WELL #46-7 AT THE EAST MESA KGRA, CALIFORNIA *

Robert M. Jorda
Completion Technology Company
Houston, Texas

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Abstract

The performance of the Magma Power Company's reinjection well #46-7 at East Mesa has been examined. Water was cooled to 100°F(±) to simulate total heat extraction and then tested using membrane filter flow procedures.

The cooled water contains particles which are in the high colloid size range, and formation impairment by these particles is unlikely. There is evidence that acid soluble corrosion products and calcium compounds constitute about two thirds of the particulates, and that the acid insoluble residue contains precipitated silica, insoluble corrosion products, and possibly formation fines carried in the produced water.

Under stabilized conditions, the suspended solids content of the water is less than 2 parts per million. However, during the frequent production well start ups, a higher concentration of suspended solids is carried in the produced water and into the injection well, conceivably augmenting fill in the injector. But most likely, fill occurs when the injection well surges during shut-downs, because of inadequate sand control in the well completion.

At the time of the test, the injection well was found to be severely impaired. Back flowing the well restored the injectivity to a calculated maximum sub-frac injection capacity of about 60,000 b/d of water at T=350°F, which corresponds to a calculated maximum hypofrac injection capacity of about 20,000 b/d of cold water (T=100°F). The water-borne particles found

at the well head are of a size small enough to result in complete particle pass-through in the injection sands, so that impairment from these particles is unlikely unless their size increases significantly in transit from the surface to the injection sands.

The overall long-term injectivity of this system appears favorable because of the low water suspended solids content, the high degree of acid solubility of these solids, the very small size of the solids, and the ease of impairment removal. Any decrease in the frequency of the shut-downs will reduce the fill up rate, and a more efficient solids separator will improve the overall system performance. In an expanded system, completions of the producers and injectors which are designed for better sand control should be evaluated.

Introduction and Scope

Magma is currently evaluating a geothermal resource at East Mesa, Imperial Valley, California. Both production capacity and injection capacity are under study. This report concerns a field test conducted June 13-14, 1978, directed toward an evaluation of the long-term performance of reinjection in a non-flashing heat recovery system. This report includes:

1. Millipore filter test data and interpretation.
2. The apparent source and distribution of suspended solids in the system.
3. The degree of, and possible causes of impairment observed at the time of the test.
4. The magnitude of reinjection capacity improvement caused by back flowing the well.
5. A new concept, the ReInjection Impairment Map (RIM), designed to

A FLOW DIAGRAM OF THE EAST MESA TEST LOOP. AT THE TIME OF THE TESTS, WATER FLOW RATE AVERAGED 9500 b/d. THE PRODUCED BRINE TEMPERATURE WAS ABOUT 350°F. THE PRODUCING WELL HEAD PRESSURE WAS 400 psig AND THE INJECTION WELL HEAD PRESSURE WAS 600 psig.

Figure 1

evaluate the performance of hot water injection as encountered during the test.

6. The RIM which aids in evaluating the well during cold water injection, as would be the case when heat extraction takes place.
7. Recommendations to be considered in the planning of long-term operations.

This study, funded by the Department of Energy through Sandia Laboratories, Albuquerque, was conducted by personnel from Completion Technology Company, Magma Power Company, and Champion Chemicals, Inc.

The Test Loop and Sample Points

The test loop consists of a producing well (#48-7), in series with a 50 barrel sand trap (≈ 7 minutes retention time), a booster pump, and an injection well (#46-7) as shown in Figure 1. During the test period, water flow averaged 9500 barrels per day (b/d) at a temperature of about 350°F. The producing well head pressure was about 400 psig, and the booster pump discharge pressure averaged 600 psig. Sampling was accomplished by cooling the produced water to about 100°F $\pm$, and the water samples were allowed to stand for about 10-15 minutes after cooling to maximize the precipitation of silica and other solids. This was done to simulate the maximum silica (et.al.) precipitation at temperatures which would be encountered at a maximum heat extraction level.

All membrane filter flow tests were performed using 0.45 micron, white, hydrosol assay Millipore filters housed in a Millipore stainless steel membrane holder. Samples were taken at the producing well head, the sand trap outlet, and the injection well head.

The test procedures which were used are contained in more detail in reference 1, pages 74-83.

The Production and Injection Well Configurations

The producing and injection wells are shown in Figure 2. Both are completed with uncemented liners which have rows of axial slots 1/8 inch wide and 2-1/2 inches long. In the producing well, a 3-1/2 inch lube string houses the turbine shaft of the submersible water pump which is used to keep the water from flashing. The water flows through the annulus between the 3-1/2 inch lube string and 8-3/4 inch production tubing. The pump is set at 863 feet, and it is necessary to shut the pump down two or three times during start-up and re-spacing due to thermal expansion of the shaft as the system heats up before steady-state thermal equilibrium is reached. The pump is shut in once each day to allow servicing the diesel engine which powers the pump.

The injection well consists of a string of cemented 13-3/8 inch oil well casing below which is hung a 10-3/4 inch uncemented slotted liner. Water is injected down the 13-3/8 inch to the liner. Opposite the liner are 900 feet of layered sands and shales, netting about 360 vertical feet of injection sands. The sand layers vary from about 10 feet to 60 feet in thickness, and contain mostly clean, well sorted, well rounded, unconsolidated very fine to medium grain size. The material between the sand sections is generally composed of relatively impermeable silts and clays.

At the time of the tests discussed in this report, there was about 260 feet of fill (unknown composition) in the injector, which covered at least 25 per cent of the sands which comprise the injection interval.

The average permeability of the sands was not reported. Values in the range 200-1000 millidarcies would not be uncommon for shallow sedimentary sections such as this, however.

PRODUCTION EQUIPMENT
SURFACE ENGINE DRIVEN
TURBINE

1. SS DRIVE SHAFT
2. 3 1/2" TUBING
(tube string)
3. 8 3/4" PRODUCTION
TUBING
4. TURBINE PUMP
PSD-860'

Figure 2

THE CONFIGURATION OF THE INJECTION WELL (LEFT) AND THE PRODUCING WELL (RIGHT).

The Millipore Test Data

Figures 3-6 are the Millipore Filter Test (MFT) runs for water from the producing well. Figures 7-9 are MFT runs for water from the sand trap outlet, and Figures 10-13 are MFT runs for water from the injection well head. All of the extrapolated y-axis intercepts, except Figures 7 and 11 are negative, which generally indicates the absence of particles smaller than 0.15 microns. Otherwise stated, all precipitates had probably formed completely at the time of the tests (except Figures 7 and 11). In Figure 7, the positive intercept could be interpreted to mean that precipitation of solids (from molecular clusters to colloids) was still in progress. Figure 11 is "too close to call".

Table I summarizes the physical characteristics of the MFT results. Except for filters 1, 10 and 11 (Figures 3, 12 and 13) suspended solids measure less than 2 ppm. The value of 3.06 ppm (filter No. 1) can be attributed to solids loading after the producing well start up, as reported to have been observed by field personnel. The last two filters, No. 10 and 11 contain the highest suspended solids value in the set, and this cannot be fully explained at this writing. (Perhaps the sand pans in the sand trap should be dumped more frequently.) Their k_c values are consistent with the rest of the data, and an acid solubility analysis (Table II, later) is consistent with other such analyses.

Table I suggests that the effectiveness of the sand trap is questionable. It probably serves best to control solids slugging associated with start-ups, but does not appear to serve any other purpose.

The steady-state k_c values and calculated particle sizes are consistent and provide insight to the injection well's long-term performance assessment (to be discussed later). The largest particles are in the upper range of colloid size.

Table 1
Suspended Solids Content of the East Mesa System Water

<u>Figure No.</u>	<u>Filter No.</u>	<u>Sample Point</u>	<u>Susp. Solids</u> <u>(ppm)</u>	<u>kc, md.</u>	<u>Calculated particle</u> <u>diameter, (μ)</u>	<u>Comments</u>
3	1	Producing Well	3.06	0.0034	0.22	Just after start up.
4	5	Producing Well	1.57	0.016	0.48	Stabilized
5	6	Producing Well	0.66	0.021	0.55	Stabilized
6	7	Producing Well	0.35	0.011	0.40	Stabilized
7	2	Sand Trap Outlet	1.4	0.078	0.34	Stabilized
8	3	Sand Trap Outlet	1.45	0.017	0.50	Stabilized
9	4	Sand Trap Outlet	1.12	0.014	0.45	Stabilized
10	8	Injection Wellhead	0.41	0.026	0.61	Stabilized
11	9	Injection Wellhead	1.45	0.024	0.59	Stabilized
12	10	Injection Wellhead	4.23	0.028	0.64	Upset (?)
13	11	Injection Wellhead	3.29	0.016	0.48	Upset (?)

Date 6/13/78 Water Temp 106 °F

Differential Pressure 40 psi

Filter Number 1

Sample Point & Pertinent Data Production

Wellhead, 40 minutes after start-up fol-
lowing 24 hour shut-in.

Cake color - brown

HAc Sol 25.2% HCl Sol 43.8% H⁺ Insol 31.0%

Time, Minutes	Cum. Volume, Milliliters
1	460
2	630
4	900
6	1130
9	1360
12	1580
16	1820
20	2040

CALCULATION

1. Volume at 16 minutes 1820 ml
2. Volume at 9 minutes 1360 ml
3. Difference (Slope) 460 ml/(minutes)^{1/2} (1-2)
4. Water Quality Ratio 900 ppm/md (from graph)
5. Suspended Solids Content 3.06 ppm
6. Cake Permeability 0.0034 md (5 + 4)

Figure 3

Date 6/14/78 Water Temp 116 °F

Differential Pressure 40 psi

Filter Number 5

Sample Point & Pertinent Data Production

wellhead, production stabilized.

Cake color - dark brown

Time,
Minutes

Cum. Volume,
Milliliters

1

1280

2

1980

4

2780

6

3320

9

12

16

20

HAc Sol 51.6 % HCl Sol 23.5 % H⁺ Insol 24.9 %

CALCULATION

1. Volume at 6 minutes 3320 ml
2. Volume at 2 minutes 1980 ml
3. Difference (Slope) 1294 ml/(minutes)^{1/2}
4. Water Quality Ratio 95 ppm/md (from graph)
5. Suspended Solids Content 1.57 ppm
6. Cake Permeability 0.016 md (5 + 4)

Figure 4

Date 6/14/78 Water Temp 110 °F
 Differential Pressure 40 psi
 Filter Number 6
 Sample Point & Pertinent Data Production
wellhead, production stabilized.
 Cake color - tan.
 HAc Sol 83.3% HCl Sol 7.5 % H⁺ Insol 9.2 %

Time, Minutes	Cum. Volume, Milliliters
1	<u>1220</u>
2	<u>2260</u>
4	<u>3840</u>
6	<u> </u>
9	<u> </u>
12	<u> </u>
16	<u> </u>
20	<u> </u>

CALCULATION

1. Volume at 4 minutes 3840 ml
2. Volume at 2 minutes 2260 ml
3. Difference (Slope) 2697 ml/(minutes)^{1/2}
4. Water Quality Ratio 32 ppm/md (from graph)
5. Suspended Solids Content 0.66 ppm
6. Cake Permeability 0.021 md (5 + 4)

Figure 5

Date 6/14/78 Water Temp 114 °F
 Differential Pressure 40 psi
 Filter Number 7
 Sample Point & Pertinent Data Production
wellhead, production stabilized.
 Cake color - tan.

Time, Minutes	Cum. Volume, Milliliters
1	1180
2	2260
4	3840
6	
9	
12	
16	
20	

HAc Sol % HCl Sol % H⁺ Insol %

CALCULATION

1. Volume at 4 minutes 3840 ml
2. Volume at 2 minutes 2260 ml
3. Difference (Slope) 2697 ml/(minutes)^{1/2}
4. Water Quality Ratio 32 ppm/md (from graph)
5. Suspended Solids Content 0.35 ppm
6. Cake Permeability 0.011 md (5 + 4)

Figure 6

Date 6/13/78 Water Temp 110 °F

Differential Pressure 40 psi

Filter Number 2

Sample Point & Pertinent Data Sand trap

outlet. Cake color - brown. Producing

wellhead stabilized after start up.

Time,
Minutes

Cum. Volume,
Milliliters

1	1220
2	1880
4	2320
6	2710
9	3180
12	3590
16	4150
20	

HAc Sol % HCl Sol % H⁺ Insol %

CALCULATION

1. Volume at 16 minutes 4150 ml
2. Volume at 9 minutes 3180 ml
3. Difference (Slope) 970 ml/(minutes)^{1/2} (1-2)
4. Water Quality Ratio 180 ppm/md (from graph)
5. Suspended Solids Content 1.4 ppm
6. Cake Permeability .0078 md (5 ÷ 4)

Figure 7

Date 6/14/78 Water Temp 100 °F

Differential Pressure 40 psi

Filter Number 3

Sample Point & Pertinent Data Sand trap
outlet. Cake color - brown. Production
rate stabilized.

Time, Minutes	Cum. Volume, Milliliters
1	<u>1140</u>
2	<u>1980</u>
4	<u>2990</u>
6	<u>3680</u>
9	<u> </u>
12	<u> </u>
16	<u> </u>
20	<u> </u>

HAc Sol 57.2% HCl Sol 31.0% H⁺ Insol 11.8%

CALCULATION

1. Volume at 6 minutes 3680 ml
2. Volume at 4 minutes 2990 ml
3. Difference (Slope) 1535 ml/(minutes)^{1/2}
4. Water Quality Ratio 85 ppm/md (from graph)
5. Suspended Solids Content 1.45 ppm
6. Cake Permeability 0.017 md (5 + 4)

Figure 8

Date 6/14/78 Water Temp 110 °F

Differential Pressure 40 psi

Filter Number 4

Sample Point & Pertinent Data Sand trap

outlet. Cake color - brown. Production

rate stabilized.

Time, Minutes	Cum. Volume, Milliliters
1	1180
2	1940
4	2830
6	3560
7	3840
12	
16	
20	

HAc Sol % HCl Sol % H⁺ Insol %

CALCULATION

1. Volume at 7 minutes 3840 ml
2. Volume at 4 minutes 2830 ml
3. Difference (Slope) 1564 ml/(minutes)^{1/2}
4. Water Quality Ratio 78 ppm/md (from graph)
5. Suspended Solids Content 1.12 ppm
6. Cake Permeability 0.014 md (5 + 4)

Figure 9

Date 6/14/78 Water Temp 120 °F

Differential Pressure 40 psi

Filter Number 8

Sample Point & Pertinent Data Injection

wellhead, producing well stabilized.

Cake color - tan.

Time,
Minutes

Cum. Volume,
Milliliters

1

1240

2

2500

3

3580

6

9

12

16

20

HAc Sol 73.2% HCl Sol 12.2% H⁺ Insol 14.6%

CALCULATION

1. Volume at 3 minutes 3580 ml
2. Volume at 2 minutes 2500 ml
3. Difference (Slope) 3398 ml/(minutes)^{1/2}
4. Water Quality Ratio 16 ppm/md (from graph)
5. Suspended Solids Content 0.41 ppm
6. Cake Permeability 0.026 md (5 + 4)

Figure 10

Date 6/14/78 Water Temp 100 °F
 Differential Pressure 40 psi
 Filter Number 9
 Sample Point & Pertinent Data Injection
wellhead. Cake color - dark brown.

Time, Minutes	Cum. Volume, Milliliters
1	1240
2	2120
4	3040
6	3710
9	
12	
16	
20	

HAc Sol 37.9% HCl Sol 42.1% H⁺ Insol 20.0%

CALCULATION

1. Volume at 6 minutes 3710 ml
2. Volume at 4 minutes 3040 ml
3. Difference (Slope) 1490 ml/(minutes)^{1/2}
4. Water Quality Ratio 60 ppm/md (from graph)
5. Suspended Solids Content 1.45 ppm
6. Cake Permeability 0.024 md (5 + 4)

Figure 11

Date 6/14/78 Water Temp 95 °F
 Differential Pressure 40 psi
 Filter Number 10
 Sample Point & Pertinent Data Injection
wellhead. Cake color - dark brown

Time, Minutes	Cum. Volume, Milliliters
1	1080
2	1610
4	2230
6	2710
9	3280
12	3780
16	
20	

HAc Sol 36.8% HCl Sol 35.0% H⁺ Insol 28.2%

CALCULATION

1. Volume at 12 minutes 3780 ml
2. Volume at 6 minutes 2710 ml
3. Difference (Slope) 1056 ml/(minutes)^{1/2}
4. Water Quality Ratio 150 ppm/md (from graph)
5. Suspended Solids Content 4.23 ppm
6. Cake Permeability 0.028 md (5 ÷ 4)

Figure 12

Date 6/14/78 Water Temp 110 °F

Differential Pressure 40 psi

Filter Number 11

Sample Point & Pertinent Data Injection

wellhead.

HAc Sol % HCl Sol % H⁺ Insol %

Time,
Minutes

Cum. Volume,
Milliliters

1	1060
2	1600
4	2180
6	2590
9	3100
12	3530
16	
20	

CALCULATION

1. Volume at 12 minutes 3530 ml
2. Volume at 6 minutes 2590 ml
3. Difference (Slope) 926 ml/(minutes)^{1/2}
4. Water Quality Ratio 210 ppm/md (from graph)
5. Suspended Solids Content 3.29 ppm
6. Cake Permeability 0.016 md (5 + 4)

Figure 13

Generally, injection water containing less than 5 ppm of particulates is considered to be a good quality water, providing that subsequent conditions do not cause a deterioration of the quality (i.e., further precipitation of dissolved solids).

Table II contains acid solubilities of filter residue from the three sample locations. Carbonates (calcium?) and iron compounds (hydroxides?) account for about two-thirds of the total solids. Calcium carbonate precipitation is probably taking place when the pressure of the water is reduced from about 2600 psi (producing well static reservoir pressure, approximate) to 400 psi well head pressure. The iron compounds are corrosion products and the presence of Cu, Ni, and Cr in the acid insoluble residue e-spec analyses (Table III) indicate that corrosion of an unknown rate is occurring.

The presence of Si probably results from the water cooling. And the presence of Al and acid insoluble Fe may indicate that argillaceous fines are being produced in small quantities. The absence of measurable sulfur in the acid-insoluble residue eliminates the possibility of calcium sulfate scale formation.

The total amount of solids formed in the cooled water ($T=100^{\circ}\text{F}\pm$) is trivial. At a production rate of 9,500 b/d, one ppm of suspended solids is less than 4 pounds of solids per day, which should minimize power recovery plant problems as well as injection problems.

Finally, the test data indicate that the solids observed at surface conditions are not capable of plugging the injection well because of their small size. Figure 14 illustrates this. The hatched section shows the most probable range of k_c and k_f values which exist in this system, barring particle growth or added precipitation during the fifty two minutes during

Table II

Overview of the Chemical Nature of the Membrane Filter Residue

<u>Millipore No.</u>	<u>Location</u>	<u>ppm solids</u>	<u>% Carbonates</u>	<u>% Iron Compound</u>	<u>% HCl Insoluble</u>	<u>Principal HCl insoluble constituents</u>
1	Producing Well	3.06	25.2	43.8	31.0	Si, Fe, Zn, Cu, Al, Sb, Ca, Pb, Cd, Ni, Cr
5	Producing Well	1.57	51.6	23.5	24.9	
6	Producing Well	0.66	83.3	7.5	9.2	
3	Sand Trap Outlet	1.45	57.2	31.0	11.8	Si, Fe, Zn, Cu, Al, Sb, Ca, Pb, Cd, Cr
8	Injection Wellhead	0.41	73.2	12.2	14.6	Si, Fe, Zn, Cu, Al, Sb, Ca, Pb
9	Injection Wellhead	1.45	37.9	42.1	20.0	
10	Injection Wellhead	4.23	36.8	35.0	28.2	

TO:

(213) 838-5939

(213) 870-3741

Champion Chemicals Inc.
1604 Missile Way
Anaheim, California 92801

Pacific Spectrochemical Laboratory, Inc.
Chemical and Spectrographic Analysis
2558 Overland Avenue
Los Angeles, California 90064

Attention: Eric Smith

PURCHASE ORDER NO.

June 27, 1978

TABLE III

SEMIQUANTITATIVE ANALYSIS

	Injection well #10-M 6/20/78	Producing well #7-M 6/20/78	Desander out. #4-M 6/20/78	Desander out. #2-M 6/20/78
Si-	1.9%	14.2	52.2	21.2
Fe-	29.	15.	8.4	9.2
Zn-	1.8	5.1	5.5	3.5
Cu-	0.71	1.6	0.87	0.92
Al-	0.76	1.1	0.82	1.3
Cr-	0.085	0.58	0.41	0.32
Sb-	1.0	10.	1.9	1.5
Ca-	1.7	5.4	1.9	1.6
Ba-	ND<0.20	0.50	0.39	0.35
As-	0.40	1.2	0.45	0.29
B-	0.020	0.076	0.036	0.037
Mg-	0.15	0.63	0.49	0.38
Pb-	0.40	1.6	0.99	0.89
Mn-	0.069	0.47	0.12	0.12
Na-	18.	TR<0.80	13.	9.4'
Ga-	ND<0.008	ND<0.03	0.045	trace
Ni-	0.12	0.70	0.18	0.18
Cd-	0.20	1.9	0.58	0.76
Mo-	TR<0.006	TR<0.02	0.024	0.032
Sn-	0.19	0.21	0.049	0.18
V-	ND<0.004	ND<0.02	ND<0.004	TR<0.004
Ag-	0.0076	0.024	0.0026	0.0024
Ti-	0.040	0.14	0.021	0.052
Co-	0.020	ND<0.010	ND<0.003-----	
Sr-	0.15	0.20	0.21	0.076
K-	TR<0.30	ND<1.0	TR<0.30	1.1
Other elements	nil	nil	nil	nil
Total Ash	0.0144 Gms.	0.0013 gms.	0.0039 gms.	0.0053 gms.

NOTE THE ABSENCE OF SULFUR

RECEIVED
JUL 3 1978

CHAMPION CHEMICALS, INC.
ANAHEIM, CALIF.

Respectfully submitted,

PACIFIC SPECTROCHEMICAL LABORATORY, INC.

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THE RELATIONSHIP BETWEEN k_c AND k_f FOR THE FLOW OF PARTICLE-LADEN FLUID THROUGH POROUS MEDIA. THE HATCHED RECTANGLE OUTLINES THE REGION WITHIN WHICH MAGMA POWER WELL No. 46-7 LIES. ANY APPRECIABLE INCREASE IN PARTICLE SIZE WILL SHIFT THE IMPAIRMENT BEHAVIOR FROM PASS-THROUGH TO DEEP BED, WITH THE FORMATION OF A DEEP DAMAGE COLLAR HIGHLY PROBABLE.

Figure 14

which an element of water is in transit from the well head to the injection interval. The system appears to be operating at the upper limit of the Region 3, or the "pass-through" segment of the impairment map on Figure 14. If particle growth can be restrained, long-term injection without significant impairment should be possible. It would be of value to collect cooled water samples and hold the samples in an autoclave at 350°F for about one hour, and examine the "cooked" water, using MFT techniques, for any possible change in k_c values.

Extensive information on the construction and interpretation of the method in Figure 14 may be found in reference 1, pages 8-17. A method for water sample "cooking" and testing appears in reference 2, pages 37-45.

The Cause and Degree of Existing Impairment

At the time that Magma #46-7 was tested, the water injection rate was about 9,500 b/d with a surface pressure of 600 psi. There was about 260 feet of fill in the hole at the time, obscuring at least 25 per cent of the injection sands. Assuming that only 75 per cent of the net available sands were open to injection, the calculated effective wellbore water conductivity was 2880 md-ft. If the sands have an ultra-conservatively estimated average permeability of only 50 md, the theoretical kh should be 18,000 md-ft. Otherwise stated, the permeability against which the injection fluids were flowing was an apparant 11 millidarcies with 25 per cent of the interval blocked. If the water was going behind the liner, into the entire injection interval, the apparent permeability can be calculated to be 8 md. Using the observed kh and very conservatively estimated minimum theoretical kh values, a well impairment in excess of 80 per cent existed at the time these observations were made.

The source of the 260 feet of fill is, at present, speculative.

One can generate numbers and investigate possible causes of fill, such as:

- (1) 260 feet of fill in an 10-3/4 inch liner = 130 cubic feet
- (2) 100 ppm of solids, at 9,500 b/d, over 2 month's time, at a bulk density of 150 lb/cu. ft., has a volume of about 130 cubic feet.
- (3) Conclusion: Water-borne solids cause the fill.

But the water did not have a constant solids loading of 100 ppm. Even if the water did contain about 100 ppm of particulates, the solids would have to be 50± microns size to screen out. This means that particules, averaging about 0.5 microns in diameter at the surface, would have to increase in size by a factor of 100 in less than one hour (transit time, well-head to liner). Such a size increase is unlikely, but only autoclave tests or actual samples of the fill can answer this question.

Another, possibly more acceptable source of the fill is back-flowed sand which enters the well each time injection stops. The sands are not consolidated, and sand can easily enter the liner through the 1/8 inch wide slots. Sand entry is common where unconsolidated sands exist in intermittently operated injection wells in the Gulf Coast, in California, and other locations where adequate sand control is not a part of the well completion. When opportune to do so, a bailer should be run on a wire line or sand line to recover fill samples for sieve analysis and chemical analysis and verification of the source of the fill.

Injectivity Improvement by Backflow

The injection well was back flowed a few weeks after the June 13-14 tests. Flashing of the produced liquids made catching samples of any back flowed fill impractical. After back-flow, the well took water at a rate

of just under 26,000 b/d with an injection surface pressure of 250 psi. Several conclusions can be drawn from the results of the back flow.

- (1) The apparent kh after back flow can be calculated to be 21,600 md-ft. This represents an effective permeability of about 60 md over an interval of 360 net feet of sand, and an overall well-bore conductivity improvement of 7.5 over the impaired well.
- (2) The large improvement in injectivity suggests that the impairment was of an uncemented nature, and that extensive down-hole cementation of the impairing particles (such as precipitating scale would cause) did not occur.
- (3) The impairment was located in, or very close to the wellbore.

The improved injection continued for several days without apparent deterioration. However, the effective permeability of 60 md indicates that even this very successful remedial treatment has not improved the well to its maximum injectivity, since 60 md is below the 200-1000 md probable permeability range.

Future injection wells should be cored, or examined using computer-aided log analysis to obtain better permeability data in the injection interval. However, the well analyses report prepared by George P. Zebal and Associates (not included in this report-proprietary to Magma Power Co.) was of considerable value in determining the overall injection interval characteristics.

Even though the well has a high injection capacity, there is, as previously stated, evidence that impairment still exists. When it is convenient to do so, the slotted liner should be washed with a pushout washer (such as the McGaffey-Taylor) to try to clean out the slots. Parallel-sided slots, such as the ones in the injection well, are known to be very susceptible to plugging by sand particles (reference 3), and

a positive clean-out tool like the M&T push out washer can remove such plugging.* If the well is cleaned thoroughly with a push-out washer and if effective permeabilities in the range 200-1000 result, consideration should be given to providing sand control completions in future injection wells, if a cost trade-off between the expense of additional injection wells and the cost of sand control completions indicates that sand control will be cost-effective.

The ReInjection Impairment Map Concept and Application

A new analytical technique, the ReInjection Impairment Map (RIM) has been prepared for well #46-7. The RIM, shown in Figure 15, plots injection well surface pressure against water injection rate for a family of wellbore conductivities, or kh values, expressed in millidarcy-feet.

The advantage of this RIM over other assessment parameters is that a wide variety of pressures and flow rates can be precisely related to well conductivity in an analysis which encompasses the total system hydraulics. Impairments or improvements are easily detected, because they appear as the reflection of the actual down-hole driving pressures.

A disadvantage of the RIM is that a separate map must be constructed for each well geometry, temperature, and reservoir configuration (this takes about 4 hours, using computer programs, and could take 10-18 hours if calculated by hand).

The RIM for water at $T=350^{\circ}\text{F}$, which approximates the condition during the June 13-14 tests and the subsequent well back-flow, demonstrates the improvement in kh attributed to the back flow.

A permeability of 250 millidarcies would result in a kh of 90,000 md-ft, which would provide an extremely high injection capacity for well 46-7.

* Chevron's Hyperjet tool is a recommended alternate method.

POINT "A" REPRESENTS THE WELL PERFORMANCE BEFORE BACK FLOW.
 POINT "B" REPRESENTS THE IMPROVED PERFORMANCE AFTER BACK FLOW.

THE REINJECTION IMPAIRMENT MAP FOR WELL 46-7, THE RIM IS BASED ON
 A WATER VISCOSITY OF 0.185 cp, AND $R_e = 1000$ FEET, $R_w = 6$ INCHES.
 FRAC PRESSURE IS JUST UNDER 700 psi.

Figure 15

The RIM includes the hydraulics and hydrodynamics of the reservoir, the tubing friction, and hydrostatic driving forces. The RIM is an extension of the Injection Well Performance Analysis (IWPA) that is discussed in detail in reference 1, pages 23-35.

The RIM for Cold Water Injection

Because of the sensitivity of water viscosity to temperature, the RIM plots for hot water and cold water will differ. For this study, a spent water temperature of $T=100^{\circ}\text{F}$ was used in the MFT runs to present a "most severe" operating condition in the analysis of generated suspended solids. To be consistent (and perhaps conservative), another RIM at $T=100^{\circ}\text{F}$ has been generated (Figure 16). If the kh of 21,600 md-ft represents the maximum attainable wellbore conductivity, the maximum hypofrac capacity of well #46-7 is about 20,000 b/d at $T=100^{\circ}\text{F}$. A kh of 30,000 md-ft provides a maximum capacity of about 27,000 b/d, and a kh of 40,000 md-ft provides a capacity of 37,000 b/d, etc., from Figure 16.

RIM plots for other water temperatures can be prepared by the interested reader using the methods in reference 2, pp. 23-35. Water viscosity data for temperatures up to about 360°F are available in standard handbooks of Physics and Chemistry, and the other required information is usually available to the project operator.

Conclusions and Recommendations

1. Magma Power Co. well #46-7 has a kh of at least 21,600 md-feet, and sustained injection of 20,000 b/d water at $T=100^{\circ}\text{F}$ at sub-fracture pressures is possible unless chemical instabilities not found in this study are encountered.

THE REINJECTION IMPAIRMENT MAP FOR WELL 46-7 AT A WATER TEMPERATURE OF 100°F, AT WHICH TEMPERATURE THE WATER VISCOSITY IS 0.7 cp. THE R_x VALUES AND FRAC PRESSURE REMAIN THE SAME AS FIG. 15.

Figure 16

2. Well #46-7 was badly impaired at the time that the field tests reported in this study were performed. Subsequent back-flow improved the injectivity of the well at least seven-fold.

3. The possibility that well #46-7 can be developed into an injector with a capacity of 2-3 times its present capacity is favorable. To evaluate this, fill samples are required and slot-cleaning should be attempted in the liner.

4. There are no apparent reasons why the high quality of the injection water cannot be maintained. Sophisticated and costly water treatment equipment is not anticipated to be required for a large-scale project in which the source waters examined in this study are used.

5. Region 3 ("pass-through") distribution of water borne particulates indicates that loss of injectivity from water-borne particulates is unlikely.

6. The problem of injection wellbore fill-up can be minimized by reducing the number of shut-ins. In a large plant, a tank with enough water to maintain continuous flow at a fraction of the normal injection rate during intervals when other equipment is down would greatly reduce the tendency for back-flow and possible sand-fill of the injector. A flow stream of only one-tenth of full flow would be adequate. A flapper valve in the tubing would be a less-effective substitute for partial flow, but would be better than no control at all.

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