Proceedings World Geothermal Congress 2010
Bali, Indonesia, 25-29 April 2010

Acidizing in Geothermal Wells and HCl Corrosion

[1]Niyazi Aksoy, [2]Umran Serpen

[1]Dokuz Eylul University-Izmir-Turkey, [2]Istanbul Technical University- Maslak-Istanbul

[1]niyazi.aksoy@deu.edu.tr, [2]serpen@itu.edu.tr

Keywords: HCl corrosion, acidizing, IPR.

ABSTRACT

Acidizing carbonate reservoirs with HCl is a common method for increasing production in the oil industry. Generally, acidizing is carried out through tubing that runs from the wellhead to the reservoir. In this study, the effects of corrosion on the production casing of a geothermal well were investigated while performing an acidizing operation without using such tubing.

It was found that the effect of corrosion can be reduced to an acceptable level if the temperature can be lowered. Moreover, a suitable corrosion inhibitor would help to decrease the corrosion rate. In summary, a successful and safe acidizing procedure can be implemented through production casing with acceptable risk to the pipe.

1. INTRODUCTION

Generally speaking, corrosion is the result of tendency of metals to be converted to their original state (mineral state) under chemical or electrochemical influence coming from the environment. Under these conditions, materials become worn, their durability is reduced and they lose functionality. Corrosion inhibitors are used to slow the rate of corrosion on materials that are in corrosive environments. In this study, we have evaluated the corrosive effect of HCl acid on API K-55 casings based on the acid concentration and environment temperature. The amount of corrosion was established by measuring weight loss.

Acidizing is a method used in the oil, underground water and geothermal industries to stimulate production in reservoirs; particularly, carbonate rock containing ones. Acidizing is usually applied by pumping the acid through tubing that is lowered to the production zone. In this study, we have investigated whether or not acidizing could be carried out through the production casing installed in a geothermal well with an acceptable level of risk. The study has proved that acidizing can be successfully performed on a well if the temperature within the well can be controlled.

2. CORROSION EXPERIMENTS

The well chosen for acidizing operation had a $9^{5/8}$ inch, K55, 64.7 kg/m production casing. During the acidizing operation from well head through casing without a tubing, there is some risk that this casing would be corroded.

Samples taken from a pipe in the well and from a piece of pipe with the same physical properties were used in this study. After the samples were cut, their surfaces were cleaned and their weight, dimensions and surface area were measured. Pieces of pipe were exposed for specific period of times at fixed temperatures to a solution of HCl with a concentration of 30% as well as to solutions with lower concentrations (28%, 24% and 15%) derived from that acid. The weight of the samples was measured at the end of the time period. Weight measurements were carried out on a scale with a sensitivity of 1/10,000. The temperature of the solution was held constant at 25, 30, 38 and 75°C during the tests. The temperature values cover the range of maximum and minimum temperatures that could be encountered during acid injection.

During the experiments corrosion inhibitor, Rodine 50 (brand name of Henkel) was used. The corrosion inhibitor is a blend of water soluble amine derivates which have substantive properties. It modifies the metal surface by adsorption, thus inhibiting corrosion. Corrosion inhibitor used at a concentration of 1% based on by volume of total hydrochloric acid solution. In order to identify the effectiveness of the inhibitor, the amount of corrosion was also tested without the inhibitor. Assuming that the acidizing operation could take two hours under the worst conditions, the duration of the experiment was kept at approximately 120 minutes. The amount of corrosion per 1 m^2 was calculated by determining the ratio of the amount of weight loss measured during the tests to the surface area of the samples.

Experiment # I: The corrosive effect of 30% HCl using corrosion inhibitor at a temperature of 75°C.

For this experiment, two sets of 30% HCl solution were prepared. Corrosion inhibitor with 1% by acid volume was added to one of the solutions. The temperature of the solution was set at 75°C (Table 1, Table 2).

Table 1: Corrosion rate at 75°C, in 30% HCl and without corrosion inhibitor

Duration, min.	Weight, gr	Weight loss, gr/m^2
0	16.6075	
21	15.6431	1095.9
40	15.2084	1589.9
61	14.6176	2261.3
81	14.1607	2780.5
114	13.0120	4085.8
Corrosion rate : 1914 gr/m^2.h		

Table 2: Corrosion rate at 75°C, in 30% HCl with %1 corrosion inhibitor

Duration, min.	Weight, gr	Weight loss, gr/m^2
0	20.4278	
23	20.0662	324.3
43	19.8153	549.4
64	19.5538	783.9
83	19.3246	989.5
116	18.7505	1504.4
Corrosion rate : 750 gr/m^2.h		

Experiment # II: The corrosive effect of 15% HCl using corrosion inhibitor at a temperature of 38°C

Experiment II was carried out to determine the effect of corrosion at a lower temperature. The concentration of HCl was set at 15%. Temperature was held constant at 38°C throughout the experiment. The results have been presented in Table 3 and Table 4.

Table 3: Corrosion rate at 38°C, in 15% HCl and without corrosion Inhibitor

Duration, min.	Weight, gr	Weight loss, gr/m^2
0	13.0120	
20	13.0046	8.4
43	12.9926	22.0
79	12.9660	52.3
110	12.9426	78.9
Corrosion rate: 47.4 gr/m^2.h		

Table 4: Corrosion rate at 38°C, in 15% HCl with %1 corrosion inhibitor

Duration, min.	Weight, gr	Weight loss, gr/m^2
0	18.7505	
21	18.7431	6.6
44	18.7352	13.7
80	18.7200	27.4
112	18.6981	47.0
Corrosion rate: 26.4 gr/m^2.h		

Experiment # III: Mixture of 28% HCl+1% corrosion inhibitor at a temperature of 30°C

In this experiment, a concentration of 28% HCl and 1% corrosion inhibitor were used. The temperature of the solution was set at 30°C and investigation was focused on on how well the corrosion could be controlled (Table 5).

Table 5: Corrosion rate at 30°C, in 28% HCl with %1 corrosion inhibitor

Duration, min.	Weight, gr	Weight loss, gr/m^2
0	12.9350	
13	12.8869	54.7
32	12.8706	73.2
66	12.8330	115.9
95	12.8034	149.5
Corrosion rate: 70.4 gr/m^2.h		

Experiment # IV: Mixture of 28% HCl+1% corrosion inhibitor at a temperature of 25°C.

In this experiment, a concentration of 28% HCl and 1% corrosion inhibitor was used. In this experiment, temperature was reduced to 25°C. The results are given in Table 6.

Table 6: Corrosion rate at 25°C, in 28% HCl with %1 corrosion inhibitor

Duration, min.	Weight, gr	Weight loss, gr/m^2
0	18.6273	
15	18.6165	9.7
39	18.5851	37.9
60	18.5611	59.4
82	18.5405	77.9
122	18.4857	127.0
Corrosion rate: 64.5 gr/m^2.h		

Experiment # V: Mixture of 24% HCl+1% corrosion inhibitor at a temperature of 30°C.

In this experiment, a concentration of 24% HCl and 1% corrosion inhibitor was used. The temperature was set at 30°C during the operation. The results are illustrated in Table 7.

Table 7: Corrosion rate at 30°C, in 24% HCl with %1 corrosion inhibitor

Duration, min.	Weight, gr	Weight loss, gr/m^2
0	18.6953	
11	18.6914	3.5
30	18.6691	23.5
65	18.6501	40.5
95	18.6329	56.0
Corrosion rate: 36 gr/m^2.h		

The Experiments II, III, IV and V, in which corrosion inhibitor was used, were performed to determine a suitable working range for temperature and acid concentration. The combined results for these experiments are shown in Figure 1.

3. EVALUATION OF CORROSION EXPERIMENTS

Table 1 and Table 2 show that in the Experiments I and II, after 114 minutes the amount of corrosion in the sample without inhibitor was 4,085.9 gr/m^2, while the amount of corrosion in the solution with corrosion inhibitor was 1,504.4 gr/m^2. The corrosion rates (cr) were 1,914 gr/m^2/h and 750 gr/m^2/h, respectively. In the Experiment II, using a lower temperature (38°C) and concentration, the corrosion rate for the sample without inhibitor was 47.4 gr/m^2/h, while the rate for the sample with inhibitor dropped to 26.4 gr/m^2/h. It was evident that in both experiments, the corrosion inhibitor reduced corrosion.

The Experiments III, IV and V were carried out to find out the corrosion rate at relatively lower temperatures. A water loss test carried out on the well AS-2 where acidizing operation was to be performed (Figure 2), it was demonstrated that the temperature inside the casing could be kept at about 30°C. Therefore, the corrosion rate in the temperature range of 25-30°C was investigated. Concluding, the corrosion rate was found to be 70.4 gr/m^2/h at 30°C and 64.5 gr/m^2/h at 25°C for a solution of 28% HCl if 1% corrosion inhibitor was used. If the concentration of HCl was reduced to 24%, the corrosion rate drops to 36 gr/m^2/h at 30°C (Figure 1). The corrosion experiments show that the amount of corrosion increases proportionaly to the HCl concentration, temperature and duration. The rate of corrosion also increases at high temperatures and high HCl concentrations.

4. FIELD APPLICATION

The well chosen for the field application is an open-hole well 962 m deep and $9^{5/8}$” production casing was installed at 767 m. During injection tests carried out before the acidizing operation, the injectivity index was 21.6 ton/h bar. The objective was to pump waste geofluid into the well with a flow rate of 550 t/h. Under these circumstances, it was found that water could be pumped at a flow rate of 360 t/h at a wellhead pressure of 24.7 bar with energy consumption of 301 kWh (Figure 3). When the curve was extrapolated to 550 t/h, it was evident that the wellhead pressure would reach 50 bar. Therefore, it was determined that 930 kWh of energy would be required for reinjection. These values were not found feasible because of too much power consumption for reinjection pumping. An alternative decision was taken to carry out acidizing with HCl because main permeable zone in the well is marble.

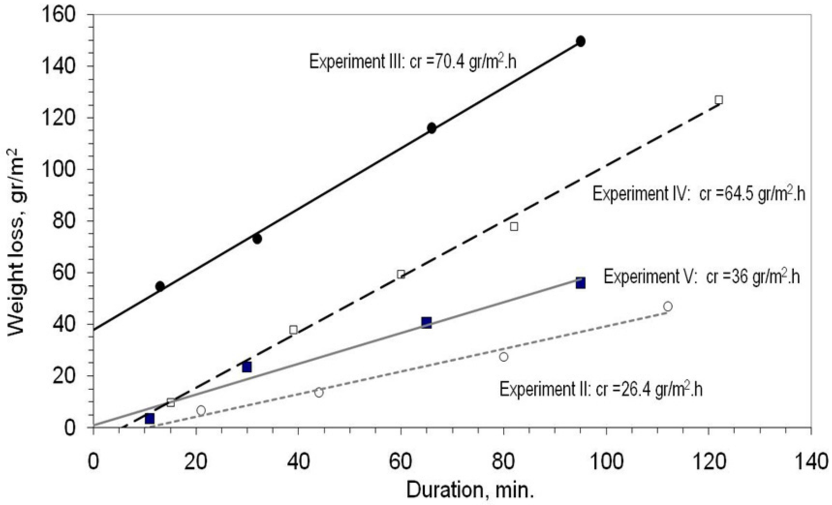

Figure 1: Measured corrosion rates for different temperature and HCl concentration while using 1% corrosion inhibitor.

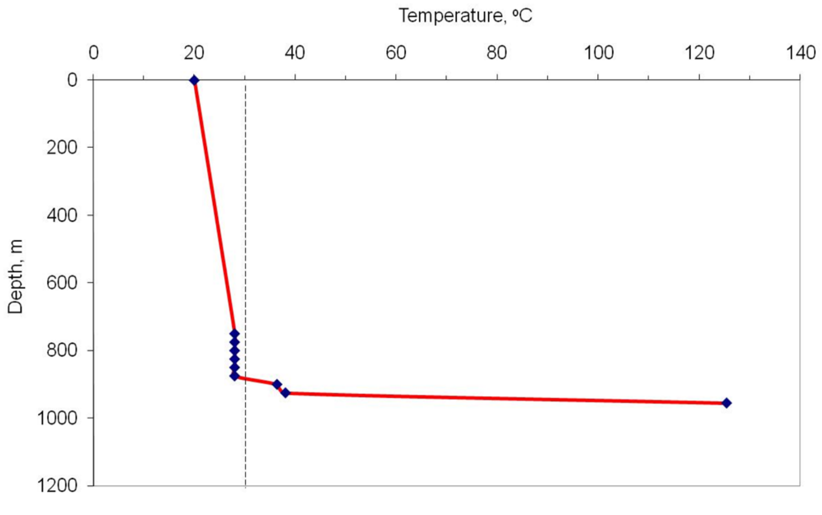

Figure 2: Water loss test in well AS2 shows that it is possible to keep temperature of well lower than 30°C, during acidizing.

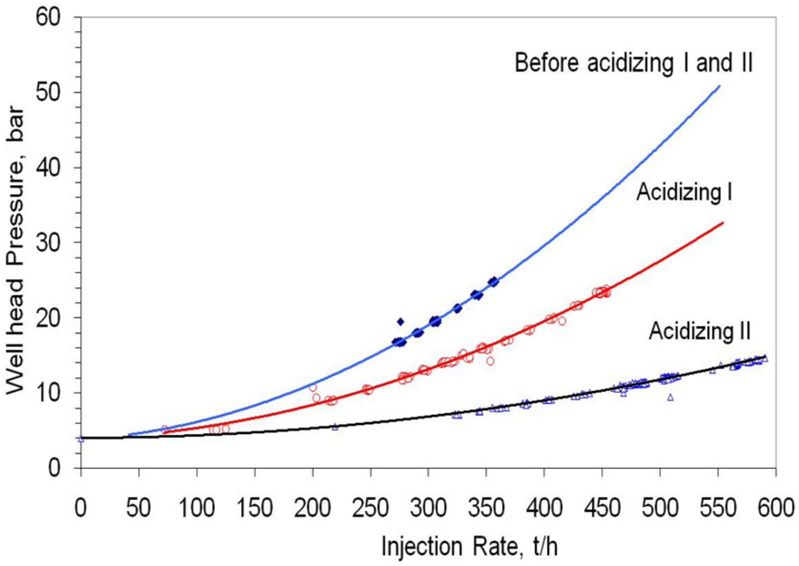

Figure 3: Injection performances for AS2, before and after acidizings.

According to Equation 1, 73 kg of HCl dissolves 106 kg of calcium carbonate. The reaction is very fast and is over in a few minutes. In order to carry out a successful acidizing operation, it was necessary to pump substantial amount of HCl down the well and consequently, to penetrate into the reservoir as far as possible. When acidizing through tubing, the diameter of the tubing limits the amount of acid that can be pumped. If a lower concentration of acid is used to avoid corrosion, either the amount of HCl to be pumped into the well will also be reduced or larger acid storage tanks would be necessary at the surface. Therefore, an acid concentration of 28% was chosen for the acidizing operation. The acid concentration of HCl that is available on the market is about 30% at most.

$$2HCl + CaCO_3 \Rightarrow CaCl_2 + H_2O + CO_2 \qquad (1)$$

In order to cool down the well, 100 tons of cold water was pumped into the well before performing the acidizing operation. Then 29 m^3 of HCl acid was pumped into the well from the acid tanks using an acid pump in 35 minutes. Then, the acid was displaced to the reservoir by geothermal water with an equivalent volume of the well. The flow rate of the displacement operation was 250 m^3/h, and the wellhead pressure was observed to drop from 11 bar down to 5 bar during the displacement operation; in other words, the injectivity index was seen to increase while the acidizing was taking place. After all of the acid was displaced into the reservoir, we waited 30 minutes and then began injection again. The data that was obtained has been presented in Figure 3. After performing acidizing for the second time, it was possible to pump fluid at a flow rate of 550 t/h with 13.5 bar of wellhead pressure using 220 kWh of energy. The injection has been in progress non-stop for over three years (Serpen and Aksoy, 2007). Tests that were carried out showed that the new injectivity index is 51 t/h bar.

An evaluation of the situation with regard to corrosion reveals the following: The total internal surface area of the 9$^{5/8}$" pipes in the well is 538 m^2. Because the displacement operation was carried out at 250 m^2, the displacement of all the acid in the casing was completed in 7 minutes. During the procedure, the wellhead was exposed to acid for 35 minutes while the bottom end of the tube was exposed for 7 minutes. The average duration of exposure to acid over the length of the tube was 21 minutes. Under these conditions, the total amount of corrosive loss in the tube was calculated to be 12.6 kg.

5. CONCLUSIONS

It is possible to carry out HCl acidizing through a production pipe with acceptable/ negligible risk by controlling the temperature of the geothermal well and by using a suitable corrosion inhibitor.

Performing an acidizing procedure through a production pipe results in a rapid, low-cost solution without the need of a workover operation, and the success of the acidizing procedure can be verified while the procedure is being carried out.

REFERENCES

Aksoy, N. ve Filiz, Ş.: Kızıldere Jeotermal Enerji Sahasında Üretim Kuyularının Asitleme ile Canlandırılmasına Bir Örnek: KD-15, Procedings *Sondaj Sempozyumu'98*, 62-66, 19-20 Kasım, İzmir (1998) (Turkish).

Serpen U., Türeyen, Ö.İ.: Acidizing Geothermal Wells, Proceedings, GRC Annual Meeting, GRC Transactions Vol. 24, pp. 683-688, 24-27 Sep., S. Fransisco (2000).

Serpen, U. ve Aksoy, N.: Reinjection Experience in Salavatli-Sultanhisar Geothermal Field of Turkey, Proceedings, 29 th NZ Geothermal Workshop, Auckland, (2007).