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WELLBORE SOAKING: A NOVEL ACID TREATMENT OF GEOTHERMAL INJECTION WELLS

R. C. M. Malate, J. J. C. Austria, Z. F. Sarmiento*,
P.A. Sookprasong** and E. S. Francia**

*PNOC-Energy Development Corporation, Merritt Road, Fort Bonifacio, Makati City
Metro Manila, Philippines
sarmiezf@energy.com.ph
**BJ Service International Inc., Tomball, Texas, U.S.A.

ABSTRACT

Wellbore soaking has been successfully applied to remove damage in oil and gas wells. The damage (paraffin, asphaltene, scale and other damage) is effectively removed by soaking the wellbore with mud acid, aromatic solvents or other chemicals depending on the type of damage. Majority of the damage that has been observed in geothermal injection wells comes from the deposition of silica causing the decline in their injection capacities. The damage may form in and away from the wellbore and in the surface injection lines.

This paper discusses the application of wellbore soaking prior to the main acid treatment in two of the injection wells in the Botong sector of the Bacon-Manito Geothermal Production Field, Philippines. Results of the acid treatment showed significant improvement in injection capacities compared to previous acid treatment of injection wells without soaking the wellbore.

INTRODUCTION

Skin damage in geothermal injection wells normally results when silica-rich geothermal brine deposits on the sandface of the wellbore and the permeable zones which subsequently forms hard silica scales. PNOC-Energy Development Corporation has generally applied an acid system consisting of a preflush mixture of 10%HCl and mainflush mixture of 10%HCl-5%HF concentration to treat this kind of formation damage (Malate et al., 1997; Buñing et al., 1995).

Treatment volumes were mainly based on a dosing rate of 75 gallons of main acid per linear foot of payzone thickness. The treatment volumes were injected at matrix rates to allow the main acid to move radially and uniformly into the damaged zones. In some cases, high pressure and injection rates were employed to allow the main acid to move deeper and penetrate into the damaged payzone.

Specific Case of Botong Injection Wells

The Botong sector of Bacon-Manito Geothermal Production Field (BGPF) located in the southernmost part of the Luzon island in the Philippines supports the 20 MWe modular power plant that was commissioned in 1997. Due to the very high concentration of silica found in the waste brine, silica inhibition trials were conducted in Botong prior to the commissioning of the power plant and the silica rich waste brine was injected to wells OP-1RD and OP-2RD.

Injection well OP-1RD was utilized during the silica inhibition trials for around two months in late 1995 while well OP-2RD was used in the silica slurry injection tests during the months of November to December 1996 and briefly in April 1997. The injection trials conducted in these wells produced significant reduction in their injection capacities that prompted PNOC-EDC to program a stimulation treatment for these wells in October 1997.

Downhole measurements conducted in these wells revealed several blockages inside the wellbore. Hard silica scales combined with some drilled cuttings were collected from scraper runs, that possibly caused these blockages. These hard silica scales may have not only deposited inside the wellbore but may have also deposited behind the liner and into the permeable zones. Hard silica scales were also found to have deposited in the surface injection lines after the silica inhibition trials.

When hard silica scales has to be drilled out inside the liner, it is very likely that the scales have also formed behind the liner. These hard silica deposits behind the liner are difficult to remove mechanically. Pumping high velocity fluid through nozzles at the end of a coiled tubing may loosen the scales around the perforated liners but this kind of operation was found to be quite expensive.

The problem of treating the solid silica scales behind the liner and the formation damage near the wellbore was then addressed by soaking injection wells OP-1RD and OP-2RD with mud acid prior to the main acid treatment. This option proved to be a better and cheaper alternative than using coiled tubing.

WELLBORE SOAKING

Wellbore soaking has been successfully applied to remove damage in oil and gas wells (Williams et al., 1979). The damage (paraffin, asphaltene, scale and other damage) is effectively removed by soaking the wellbore with mud acid, aromatic solvents or other chemicals depending on the type of damage.

Dissolution tests of the silica scales initially conducted in the field showed increasing silica solubility with time and increased temperature. Results of the solubility tests using regular mud acid (10%HCl-5%HF) after three hours is presented in Table 1 below. The results obtained reinforces the application of wellbore soaking in the acid job design of wells OP-1RD and OP-2RD.

Acid System	Temp.	%Solubility
15%HCl	30°C	0
	80°C	0
10%HCl+5%HF	30°C	~40
	80°C	~97

Table 1. Silica Solubility after 3 hours.

The acid job design for the two injection wells maintained a dosing rate of 75 gallons per foot of targeted payzone using regular mud acid (10%HCl-5%HF). The main acid is preceded by a preflush mixture of 10%HCl at a dosing rate of 50 gallons per linear foot of targeted payzone. The target payzones were determined from the permeable zones identified from pre-acid completion tests.

The bottom section of well OP-1RD was initially soaked prior to the main acid treatment since this is where majority of the hard silica scales were collected. All the targeted payzones of well OP-2RD were soaked before the main acid injection. Around 50 bbls of the mainflush acid volume prepared were used in the soaking process for each section. The main acid was pumped through the acid string at very low rates (~2-3 bpm) and the wells were shut-in for around 4 hours by closing the quenching lines. The wells were shut during the soaking period to initiate temperature recovery thereby increasing the rate of silica scale dissolution.

The acid treatment data for the two wells is summarized in Table 2 below.

Well	Target Zones (mMD)	Main Flush Volume (bbls)	Average Injection Rate (bpm)	Average Treating Pressure (psig)
OP-1RD	1625-1650	132	17.0	2560
	1750-1800	140	9.0	3120
	1840-1890	285	8.6	2800
	1950-2000	258	9.1	2680
	2650-2766	247	9.0	2900
OP-2RD	800-900	253	10.6	2600
	1275-1325	250	10.2	2700
	2000-2100	575	9.2	2540

Table 2. Summary of mainflush acid treatment data.

STIMULATION RESULTS

Pre-acid and post-acid treatment tests were conducted on these wells to gauge the wellbore improvement gained from the acid treatment jobs. Improvement indicators used in the analysis of the stimulation results include increases in injectivity index, changes in downhole temperatures and pressures and other wellbore/reservoir parameters.

Pressure transient data of the stimulated wells were analyzed using a welltest interpretation software Saphir (Kappa Engineering, 1995). Pressure derivative responses were also incorporated in the welltest analysis.

The welltest model is generated by superposing the pressure or pseudo-pressure responses obtained during the pre-acid and post-acid injection tests (multi-rate analysis). An infinite acting reservoir/boundary condition was imposed throughout the model generation and the calculated drop in downhole pressures (ΔP) was used in analyzing the post-acid pressure responses.

A regression analysis in the log-log and semi-log pressure responses was also applied to obtain the best-fit values of the reservoir parameters. The values obtained from the log-log and semi-log simulation analyses were comparable to the initial estimated values obtained using the semi-log straight line match.

The two wells registered significant reduction in downhole pressures (~1.5 MPag) during the post-acid injection tests. The drop in downhole pressure during the post-acid completion test signifies a decrease in flow resistance due to dissolution of mineral deposits within and around the wellbore.

Considerable improvement in well characteristics were attained after the acid treatment as indicated by the results of the post-acid welltest analysis. The injectivity index increased by around 8 li/s-MPa for OP-1RD and approximately 35 li/s-MPa for OP-2RD. The increase in injectivity together with the reduction in downhole pressure provides a two-fold increase in the calculated injection capacity of both wells. Injection capacity of OP-1RD increased from 30 kg/s to 70 kg/s (133%) while the capacity of OP-2RD similarly increased from 70 kg/s to 137 kg/s (96%). Increased negative skin values were also obtained from both wells indicating that initial skin damage has been removed.

The stimulation results obtained in OP-1RD and OP-2RD were also compared with the result of an acid stimulation job conducted in an injection well in one of the other projects operated by PNOC-EDC. Injection well 5R-7D in the Malitbog sector of the Leyte Geothermal Production Field was also used in one of several silica inhibition trials conducted in the area sometime in 1995. The well also suffered a significant decline in injection capacity after about six months of testing. The permeability of the well is similar to injection well OP-1RD. This well was treated with the same acid mixture used in Botong wells but was not soaked in regular mud acid prior to the main acid injection.

The improvement in injection capacity gained in wells OP-1RD and OP-2RD is greater than the increase in injection capacity in well 5R-7D (Table 4). Acidizing of well 5R7D resulted in an increase of 22 kg/s (25%) in injection capacity compared with 40 kg/s (133%) and 67 kg/s (96%) for wells OP-1RD and OP-2RD respectively.

The results of the acid treatment and comparison with the previous acid job in Leyte are summarized in Tables 3 and 4 respectively.

Wellbore Parameters/ Calculated Injection Capacity	OP-1RD		OP-2RD	
	Pre-acid	Post-acid	Pre-acid	Post-acid
Injectivity Index, li/s/MPa	19.3	27.2	23.0	57.6
Skin Pressure drop, ΔP, MPag	-	1.5	-	1.5
kh, darcy-m	1.2	1.3	3.5	3.8
Skin	-1.4	-2.8	-1.2	-4.8
Injection Capacity, kg/s	30	70	70	137

Table 3. Summary of acid treatment results.

Well Name (Location)/ Parameter	5R7D (LGPP)	OP-1RD (BGPF)	OP-2RD (BGPF)
Increase in Injection Capacity, kg/s	22	40	67
% increase	25	133	96

Table 4. Comparison with injection well 5R-7D.

SUMMARY

Wellbore soaking prior to the main acid treatment was successfully applied in injection wells OP-1RD and OP-2RD resulting to significant improvement in their injection capacities. Soaking the silica deposits in regular mud acid mixture (10%HCl and 5%HF) for a period of time increased silica dissolution in the acid mixture. The stimulation results obtained produced better improvement in injection capacities compared to previous stimulation jobs without soaking the wellbore.

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