RECENT EXPERIENCES IN ACID STIMULATION TECHNOLOGY BY PNOC-ENERGY DEVELOPMENT CORPORATION, PHILIPPINES

Balbino C. Buñing, Ramonchito Cedric M. Malate, Alexander M. Lacanilao, Francis Xavier M. Sta Ana and Zosimo F. Sarmiento

PNOC-Energy Development Corporation, PNPC Complex, Merritt Road, Fort Bonifacio, Makati, Metro Manila, Philippines

Key words: acid stimulation, geothermal wells, Philippines

ABSTRACT

Ten geothermal wells have been acid-stimulated by PNOC-EDC due to various natures of suspected wellbore problems ranging from inherently low permeabilities to damage by either drilling mud or injected brine silica deposits.

The acid treatment of the wells produced varying results from a low of 60% to a high of 911% improvement in capacity.

Downhole temperature, pressure and spinner (TPS) measurements explain the apparent marginal improvement in some of the wells while actual capacity tests on earlier acidized wells confirm significant increases in individual well performance. The same measurements suggest possibilities for optimizing future acid treatments of geothermal wells with wellbore damage.

INTRODUCTION

The Philippine National Oil Company-Energy Development Corporation (PNOC-EDC) initiated the acid treatment program of its geothermal wells in early 1993.

Four of the stimulated injection wells (PN-2RD, 2R4D, TC-2RD and 1R10) had decline in injection capacities due to silica deposition. Two in-fill production wells (PN-32D and 110D) had been damaged by high viscosity mud (HVM) during drilling, which resulted in productivity below the average level of wells completed within the same production zones.

The rest of the treated wells were stimulated on the basis of low permeabilities indicated in drilling logs and completion test results. Three of the low permeability wells (MG-8D, MG-10D and MN-1) were stimulated using gelled acid. All the other wells were stimulated by matrix acidizing.

Discovery of large differences in measured payzone thicknesses estimated from indexed temperature profiles and those measured with continuous electronic temperature-pressure-spinner (TPS) logs led PNOC-EDC to conduct experiments involving two-stage acid injection in wells 110D and TC-2RD, with the acid volume at the first stage calculated from the payzone thickness derived from TPS logs. The objective was to determine whether the second stage injection would provide further improvement on the well - thus potentially saving in acid/chemical costs in future jobs.

Estimates of improvement in the wells due to acid treatment alone may be deduced from results of downhole logs, while the aggregate improvement considering scale cleanout is reflected in the results of capacity tests after stimulation. Conventional units (Imperial) used by acidizing contractors have been maintained by the authors wherever practicable. Depths and results of tests conducted by PNOC-EDC are expressed in metric units.

ACID TREATMENT DESIGN

Matrix acid treatment is performed to chemically remove damage from the face of the formation. Samples of scale at the target injection intervals are collected during mechanical cleaning of the wellbore, and whenever possible prior to cleanout to establish the appropriate concentration and volume of the acid.

A mixture of 10% hydrochloric acid (HCl) and 5% hydrofluoric acid (HF) has been used as the mainflush in all the wells stimulated. The mainflush is made to dissolve the damaging mineral deposits (mostly silica with minor carbonate assemblages) in the wellbore and in the formation. The mainflush volume used was equivalent to 75 gallons per foot of target payzone to be stimulated (dosing rate). Empirical values of "effective" dosing rate, however, range from 50 to 100 gal/ft based on previous works (Campbell et al., 1981, Messer et al., 1978), depending on the relative abundance of acid-soluble minerals in the target payzones.

Injection of the mainflush is preceded by a preflush solution of 10% HCl. The preflush volume is equivalent to 50 gallons per foot of payzone for a 75 gal/ft mainflush dosing rate. This solution dissolves the iron and carbonate compounds that may later deposit insoluble minerals with the HF acid.

The mainflush is immediately followed by a postflush (overflush) of water for "scavenging" of the dissolved minerals and for rinsing the injection tubing and metal casings of unspent acid in the wellbore. Its volume is estimated to be at least twice that of the acid mainflush.

For three of the 10 acidized wells (MG-8D, MG-10D and MN-1), gelled acid preflush solution was used. The gel additive, a viscosity enhancer and friction reducer, was intended to increase hydraulic efficiency and thus overcome the formation fracture gradient. This gelled acid treatment technique was conceived to test the use of acid stimulation in wells with inherently low permeability with the aim of extending existing fracture networks intersected by the wells, and possibly create new fluid channels from originally vein-filled fractures.

RELATED TESTS

Downhole measurements using a TPS tool were performed in some of the wells before and after acid injection. In general, the pre-acid and post-acid logs were correlated to determine improvement in the wellbore in terms of injectivity indices, changes in temperature and pressure profiles, and payzone thicknesses indicative of enlargement of original payzones or opening up of new zones. Injectivity index is defined as the ratio of the increase in injection rate (pumprate) over the corresponding unit increase in wellbore pressure.

The pre-acid TPS logs were initially intended to constitute the baseline data from which improvement in the wellbore due to acidizing might be gauged. Therefore, they were conducted after the mechanical workover stage (scale cleanout).

Wells MG-8D, MG-10D, MN-1 and 1R10 do not have TPS logs, but injectivity index measurements were taken using clock-driven mechanical downhole temperature and pressure gauges.

Post-acidizing discharge and injection capacity tests were conducted on five of the wells, while the stimulated injection capacities of the rest (except TC-1RD) were estimated based on measured injectivity index and total estimated available head for brine injection.

RESULTS OF ACID TREATMENT

Table 1 lists the wells treated and the reasons for their stimulation. Table 2, contains the acid volumes and concentrations used, together with the payzone depths and thicknesses. The results of the acid treatments are summarized in Table 3.

Table 1. List of acid stimulated wells.

Well Name	Acid Stimulation	Reason for Acidizing
1. PN-32D	Matrix Treatment	Mud damage
2. PN-2RD	Matrix Treatment	Silica Deposition
3. 2R4D	Matrix Treatment	Silica Deposition
4. 110D	Matrix Treatment	Mud damage
5. TC-1RD	Matrix Treatment	Silica Deposition
6. TC-2RD	Matrix Treatment	Silica Deposition
7. 1R10	Matrix Treatment	Silica Deposition/Low Permeability
8. MG-8D	Gelled Acid	Low Permeability
9. MG-10D	Gelled Acid	Low Permeability
10.MN-1	Gelled Acid	Low Permeability

Table 2. Summary of acid treatment data.

Well Name	Target Payzones (mMD)	Main Flush Acid Volume (gals)	Average Pump Rate (bpm)	Average Treating Pressure (psi)
1. PN-32D	1300 - 1550 1900 - 2100	59,709 46,503	8.0 7.5	1595 1900
2. PN-2RD	2700 - 2900	51,168	6.6	2400
3. 2R4D	1300 - 1550 1700 - 1900	61,782 51,072	7.0 7.5	1700 2100
4. 110D	1000 - 1200 1500 - 1700	49,955 48,876	7.0 7.5	1100 1140
5. TC-1RD	1350 - 1500 2350 - 2460	36,792 27,048	4.9 5.2	1280 1500
6. TC-2RD	2050 - 2150	36,918	6.1	1700
7. 1R10	1175 - 1250 1350 - 1450	18,648 24,780	6.1 5.7	1450 1570
8. MG-8D	1880 - 1930 2050 - 2150	12,348 24,612	7.4 5.5	2010 2050
9. MG-10D	2500 - 2650	36,918	5.5	3295
10.MN-1	1700 - 1850	36,036	6.8	2600

Analysis of injectivity indices suggests the following "apparent" improvement in the wells:

Nil: MN-1 (0%)

Low: MG-10D (44%), 1R10 (51%), PN-2RD (63%) and MG-8D (65%)

Moderate: TC-2RD (88%) and PN-32D (91%)

High: TC-1RD (209%), 110D (250%) and 2R4D (866%)

The first well acidized, PN-32D, shows moderate improvement in its tested capacity (Table 3). This well was an in-fill production well drilled towards a high-enthalpy and high-permeability region of Palinpinon-I, and was expected to produce at least 6 MWe based on the average output of the surrounding wells. It had been drilled blind, but injection of 12,290 bbls HVM during problematic drilling stages subsequently damaged the wellbore - thus the need for stimulation by acid treatment.

Initial results of the treatment did not seem to suggest remarkable improvement except for a 0.9 MPa decline in bottomhole pressure at similar pumprates (pre-acid vs. post-acid). After acid treatment, however, the well "kicked" several times during cold water pumping of up to 10 bpm, and actually backflowed when shut for an aborted pressure fall-off test. Discharge tests nevertheless confirmed successful stimulation with a 1.9 MWe increase in output (Table 3). An interesting development is the increase in the output of a nearby production well, PN-24D, by about 0.5 MWe which was observed almost immediately after treatment of PN-32D. These two wells are known to share a common productive geologic structure.

The first major success in PNOC-EDC's acid treatment program was achieved at PN-2RD, the second well stimulated and one of the earliest and highest priority injection wells for the Palinpinon-I production field. Its continued use from 1985 until it was stimulated did not produce any evidence of reinjection returns in the production sector of the field. Periodic measurements, however, recorded a 20 kg/s reduction in its injection capacity by 1988 (Figure 1). The decision to acidize the well was therefore not solely influenced by its capacity decline but also by its being a priority injection well.

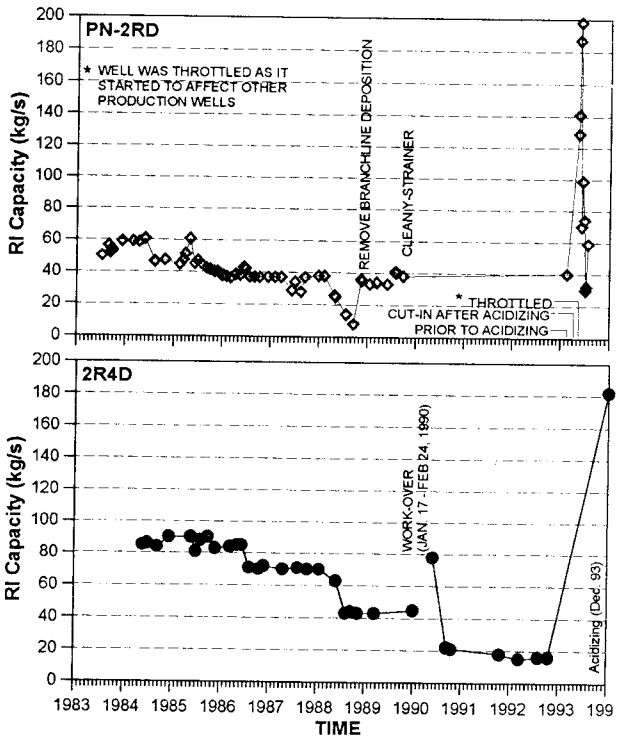

Figure 1. Plot of injection capacity with time of wells PN-2RD and 2R4D.

Initial assessment indicated that the injectivity index of PN-2RD increased by only 63% (Table 3), even lower than the improvement gained at PN-32D. Detailed analysis of the TPS logs later provided the explanation for its apparent low injectivity index. As Figure 2 shows, the well developed an upflow coming from the stimulated payzone at around 2700 mMD which subsequently increased pressures and temperatures in the wellbore. The same upflow existed at zero pumprate before acid treatment and was observed to be exiting the upper zone at around 1260 mMD. After acid treatment, at least 10 bpm of cold water was needed to control the upflow.

Capacity tests after acid treatment showed that the well could accept injected brine in excess of 187 kg/s equivalent to at least a 367% increase from its previous capacity (Table 3). This remarkable capacity increase eventually resulted in rapid reinjection returns to the production sector and induced thermal degradation at production well PN-29D - prompting PNOC-EDC to reduce injection load to the

Table 3. Summary of acid stimulation results.

Well Name	Injectivity Index (li/s/MPa)				Capacity			
	Original	Pre-Acid	Post-Acid 1	Post-Acid 2	Original	Pre-Acid	Post-Acid	% Improvement
1. PN-32D	18 (WHP=0)	14.9 (WHP=0)	28.5 (WHP=0)	—	2.2 MWe (WHP=0.75)	2.2 MWe (WHP=0.75)	4.1 MWe (WHP=0.68)	86
2. 110D	42 (WHP<0)	77.2 (WHP<0)	254.1 (WHP<0)	270.5 (WHP=0)	4.1 MWe (WHP=0.4)	4.1 MWe (WHP=0.4)	12.4 MWe (WHP=0.95 - 1.0)	202
3. MG-10D	19.1 (WHP=8.2)	9.0 (WHP=3.9 - 7.2)	13.0 (WHP=4.7 - 7.5)	—	0.93 MWe (WHP=0.08)	0.93 MWe (WHP=0.08)	2.3 MWe (WHP=0.57)	—
4. PN-2RD	13 (WHP=0)	62 (WHP<0)	101 (WHP<0)	—	60 kg/s	40 kg/s	187 kg/s	367
5. 2R4D	39 (WHP<0)	17.6 (WHP<0)	170 (WHP<0)	—	90 kg/s	*18 kg/s	*182 kg/s	911
6. TC-1RD	32 (WHP=1.3-1.9)	10.5 (WHP=1.2 - 4.8)	32.4 (WHP=3.1 - 5.3)	—	53 kg/s	8 kg/s	No acceptance	—
7. TC-2RD	14.8 (WHP=0.2)	39.9 (WHP=2.6 - 11)	63.4 (WHP=2.8 - 7)	75.1 (WHP=2.4 - 7)	146 kg/s	57 kg/s	97 kg/s	70
8. 1R10	19.3 (WHP=2.4)	7.8 (WHP=5.5 - 7)	11.8 (WHP=4.1 - 8)	—	35 kg/s	*30 kg/s (WHP=2.9)	*48 kg/s (WHP=2.9)	60
9. MG-8D	13.1 (WHP=5.2)	6.8 (WHP=2.7 - 5.4)	11.2 (WHP=1.0 - 4.4)	—	—	*10 kg/s (WHP=4.2)	*22 kg/s (WHP=4.2)	120
10. MN-1	13.2 (WHP=0.9)	11.7 (WHP<0)	11.7 (WHP<0)	—	—	*20 kg/s	*39 kg/s	95

NOTES:

1. Wellhead pressures (WHP) are in MPag.
2. * Estimates of injection capacity based on the total available head and the measured injectivity index of the well.
3. Post-acid capacity of MG-10D is not yet stable.

well. PN-29D subsequently recovered when injection load to PN-2RD was reduced to 70 kg/s.

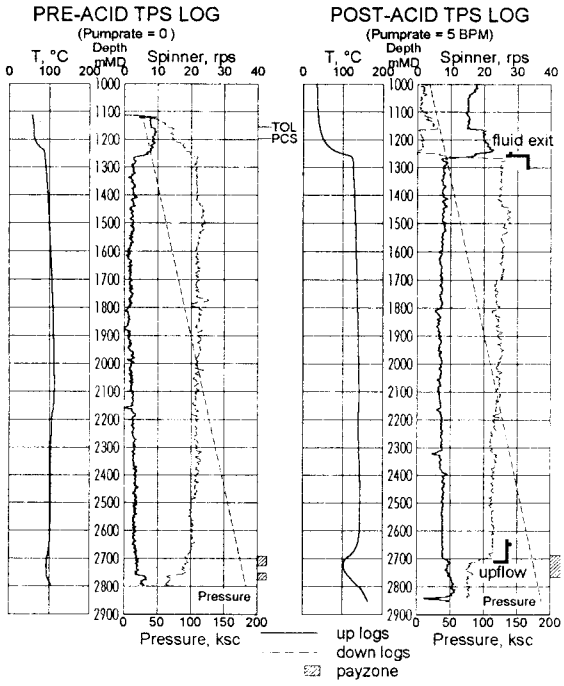

Figure 2. Temperature-pressure-spinner (TPS) logs of well PN-2RD before and after acid treatment. Note that even during injection, downlog spinner response is greater than uplog response.

Both wells share a common geologic structure which cuts PN-2RD at about 1240-1260 mMD. This zone is now believed to have been unintentionally acidized by "upflowing acid" spotted at the 2700-2900 mMD target payzone. Note that the average acid pump rate was only 6.6 bpm (Table 2), much lower than what was found to be required in order to contain the upflow. It is postulated that this adverse effect of the acid treatment could have been avoided if the pre-acid TPS logs were used to determine appropriate acid pumping pressure and flowrates.

The treatment of the next two wells, 2R4D and 110D, was done with high expectations of good results because of similarities in the treatment design and the nature of damage in each well. As the results show, improvement in these wells far exceeded those of the initial acid jobs at PN-32D and PN-2RD (Table 3).

Both wells suffered from induced wellbore damage, 110D by the use of about 6,000 bbls of HVM during drilling of its production open hole, and 2R4D by extensive silica mineralization brought about by its long use as an injection well for silica-supersaturated brine. Well 2R4D had a prior mechanical workover in 1990 which brought its injection capacity almost back to original (Figure 1). Its renewed capacity was, however, almost immediately lost and even went lower than its pre-workover value - providing evidence that damage in the wellbore had already progressed beyond the sandface.

Even before 2R4D's post-acidizing capacity could be tested, TPS logs had already provided strong indications of improvement in the well (Figure 3), namely: 1) a 250-m drop in water level even at 12 bpm pumprate during TPS surveys; 2) a 3.75 MPa decline in near-bottomhole pressure; 3) enlargement of the deeper target payzone; and 4) the induced fluid acceptance at about 1080-1100 mMD. The target zone at 1300-1550 mMD (Table 2), however, does not seem to have been stimulated as the TPS logs suggest.

The immediate response of 110D to acid treatment, on the other hand, bears some similarity with those of PN-32D. Stimulation of the upper zone induced gas flow (mostly CO_2) which eventually raised its water level by more than 50 meters at similar pumprates. A second injection of acid also appeared to have further improved near-bottom permeability, as reflected in the temperature profiles (Figure 4) and slightly increased its second post-acidizing injectivity index (Table 3).

The improvement was eventually confirmed at actual discharge tests after completion of the acid treatment which saw the well producing 12.4 MWe at about 1.0 MPag wellhead pressure (Table 3). The effect of the first acid injection on the discharge capacity of the well could not be determined, however, as the second injection immediately followed the first injection and downhole measurements. The relatively high rates of stimulation success in the first four wells led to a more aggressive acidizing program in PNOC-EDC.

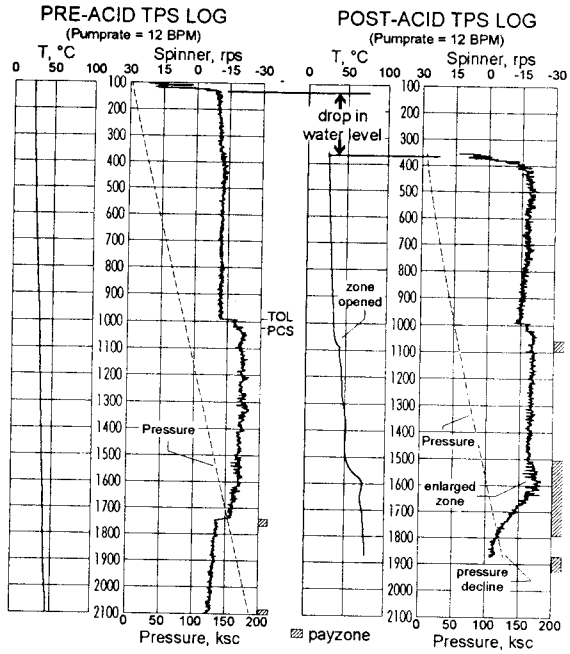

Figure 3. TPS logs of well 2R4D. Post acid log is shallower due to the build-up of dissolved scales st the bottom of the well.

TC-1RD, a moderately permeable injection well, was believed to have shown signs of progressive wellbore damage due to silica deposition. Its original capacity declined by about 40 kg/s in 2 years of utilization, and its injectivity index was found to have decreased to 10.5 li/s/MPa (Table 3).

After acid treatment, however, the well showed rejection of injection load during capacity tests despite the significant increase in injectivity index. TPS logs (Figure 5) recorded a 2.5 MPa increase in wellbore pressure between pre-acid and post-acid cold water pumping conditions at 6 bpm, coupled with a 28°C temperature rise at around 2400 mMD where the post-acid spinner log suggests an inflow.

Correlation of the downhole logs with structural and original completion test records indicate that the stimulated zone from about

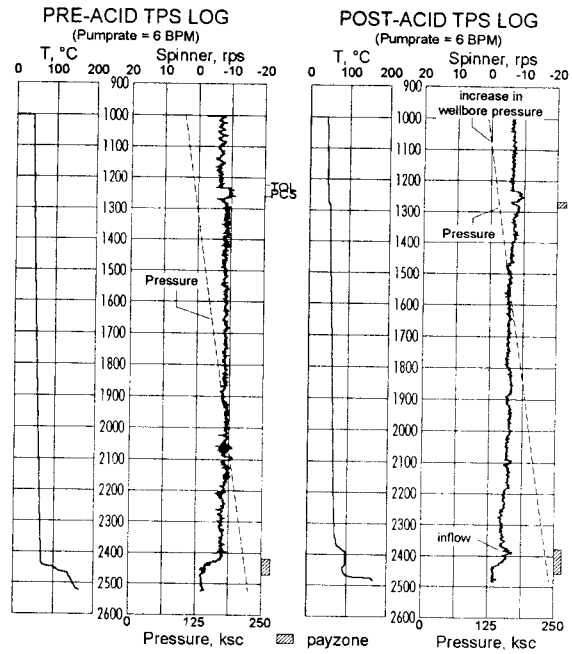

Figure 5. TPS logs of well TC-1RD.

2380-2435 mMD is the intersection of the well with a major reinjection structure in the sector. It is now believed that these data are indications of over-injection into this zone through the other injection wells which intersected the same structure (eg. TC-2RD, PN-3RD), which subsequently raised formation and wellbore pressures.

TC-2RD's stimulation had been expected to recover its original capacity of 146 kg/s. TPS logs indicated this possibility with a final post-acid injectivity index of 75.1 l/s/MPa (Table 3). Recent capacity tests, however, revealed that the well could only accept a maximum of 97 kg/s of brine. The logs indicate that there has indeed been stimulation of the single target bottom zone and also of the upper zone at about 900-1000 mMD (Figure 6) but like TC-1RD, an over-pressured injection sector is believed to be causing limited injection into the well. The linear increase in TC-2RD's injectivity index with

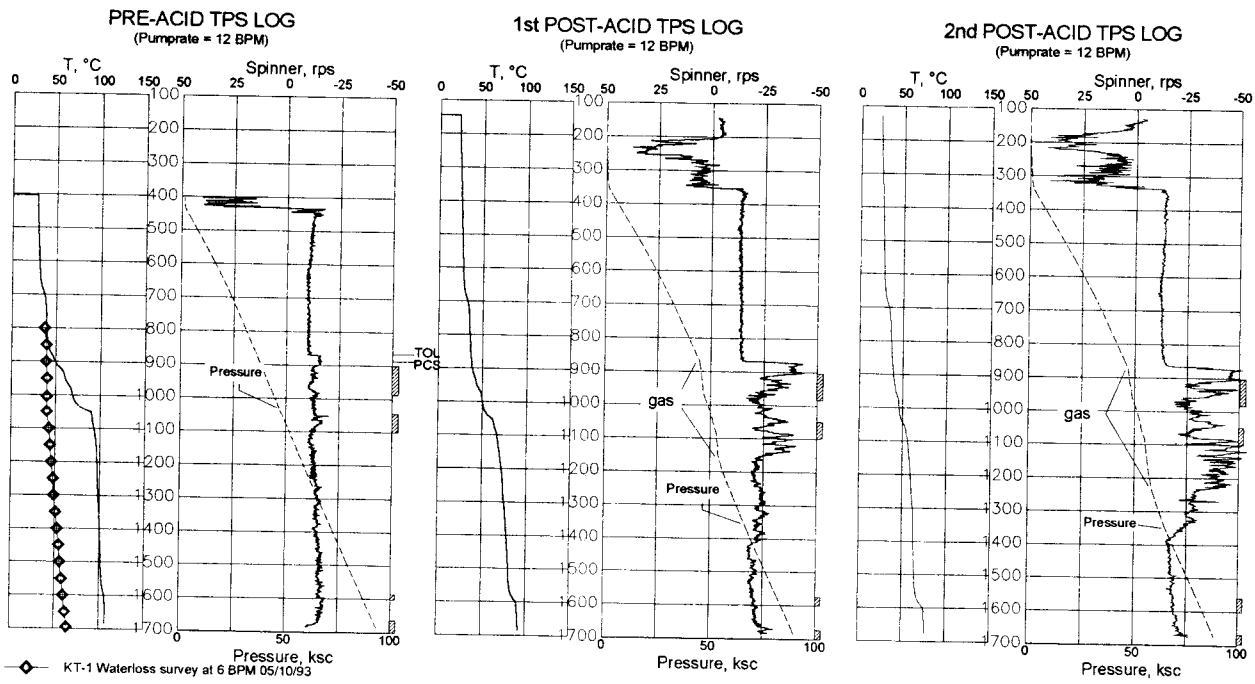

Figure 4. TPS logs of well 110D. Kuster temperature (KT) plot during completion test is shown for comparison.

a second injection (Figure 7) offers some evidence for further improvement in the well with additional acid treatment. Notice that the completion temperature profile (KT profile in Figure 6) and even the pre-acid TPS logs suggest a much smaller thickness of the target bottom payzone than that indicated in the post-acid TPS logs. These observations therefore lead the authors to suspect that the total required acid volume for the treatment of the well, which was primarily based on the payzone thickness, might have been underestimated.

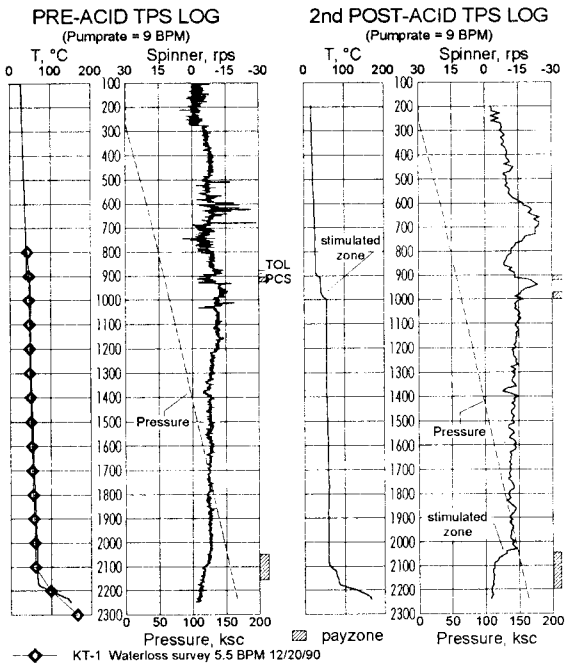

Figure 6. TPS logs of well TC-2RD. Kuster temperature (KT) data was used to determine payzone thickness to be acidized.

Three of the tight wells, 1R10, MG-8D and MG-10D displayed similar responses to acid treatment and mechanical scale cleanout, as follows (see Table 3):

1) Pre-acid injectivity indices, taken after scale cleanout, turned out lower than original values. This is taken as an indication that drilling mud (HVM) left in the hole and agitated during the original completion test had already settled and caked up prior to the mechanical workover - resulting in further damage to the wellbore.

2) Despite the acid treatment, the original injectivity indices were not recovered. However, extrapolation of the post-acid injectivity indices for MG-8D and MG-10D to the maximum wellhead pressures recorded during their original completion tests will bring them close to the original values.

Capacity tests have yet to be conducted on the wells, although initial estimates based on measured injectivity index and available injection head (for injection capacity only) suggests marginal absolute increases for 1R10 and MG-8D (Table 3). The relatively low temperatures measured at MG-8D might eventually lead to the well being used as an injection well.

Initial results of the post-acid capacity test of MG-10D, still ongoing as of this report, suggest slight improvement in the well (Table 3). The well registered a maximum output of 2.3 MWe at 0.57 MPag wellhead pressure with the mastervalve and sidevalve fully opened. The output however was observed to be declining after the test commenced.

The acid treatment of MN-1, on the other hand, appears to have resulted in considerable stimulation. Although the injectivity indices after drillout and after acidizing (Table 3) are within range of the original value (difference could be measurement error), the well recorded vacuum at the wellhead despite the higher pumprates used during pre-acid and post-acid tests. Also a 2 MPa reduction in downhole pressure at similar pumprate (16 bpm) between the pre-acid and post-acid tests provides further evidence of improvement in the well. The injection capacity estimates in Table 3 are therefore considered by the authors to be conservative.

The result of MN-1's acid treatment is the only perceived exception in the author's assessment that acid treatment of originally tight wells may need more than the 75 gal/ft dosing rate and possibly the application of the gel additive in both the preflush and mainflush acid injection to enhance stimulation of payzones.

OPTIMIZING ACID STIMULATION

The large differences between payzone thicknesses interpreted from those recorded by mechanical gauges on one hand and TPS tools on the other hand have been cited earlier. For production wells PN-32D and 110D, temperature profiles recorded by mechanical gauges during completion and heat-up surveys project payzone thicknesses at least 100 m larger than those indicated in the pre-acid and post-acid TPS logs with the pre-acid and post-acid logs providing close correlations. The difference is even larger for the case of injection well PN-2RD (about 300 m). TPS logs from other injection wells TC-1RD, TC-2RD and 2R4D also show similar trends, except that in these wells, payzones delineated during pre-acid TPS surveys appear to have been enlarged by acid treatment.

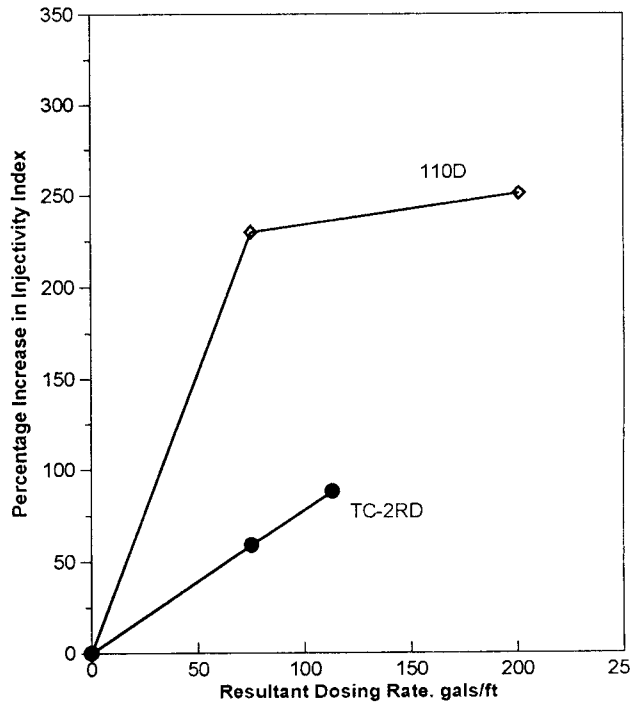

Figure 7. Plot showing the increase in injectivity index corresponding to acid dosing rate for wells 110D and TC-2RD.

Based on the observed effectiveness of acid treatment of the above wells for which payzone thicknesses were used to calculate acid volumes, and in conjunction with the above observations, the following is postulated:

1) Pre-acid TPS logs may provide a better estimate of payzone thickness in mud-damaged production wells than mechanically recorded temperature data;

2) For purposes of acidizing silica-damaged injection wells, TPS logs taken during completion of the wells may provide the best estimate for the thickness of payzones to be stimulated. Also, pre-acid TPS logs may result in an under-estimation of the required acid volume based on results in well TC-2RD.

As shown in Figure 7, the results of the two-stage injection at TC-2RD suggest that additional acid injection may still lead to further improvement in injectivity index. This contrasts with the results for 110D where the first dose of acid, which volume was derived from the pre-acid TPS logs, appear to have effected the "optimum" level of improvement the well could sustain. It is further postulated that the linear increase in TC-2RD's injectivity index with effective dosing rate (Figure 7) is related to the perceived underestimation of its target payzone thickness and hence the volume of acid used in the treatment. Figure 6, as earlier discussed, illustrates the underestimation of payzone thickness in TC-2RD.

SUMMARY

Despite the significant percentage improvement in the stimulated wells, it appears that with the present acid treatment design, stimulation produces large absolute capacity increases (see Tables 2 and 3) only in those wells with confirmed temporary wellbore damage effected by mud or mineral deposition on both the sandface and the productive horizons. However, it is postulated that increasing the acid mainflush dosing rate beyond 75 gal/ft may be able to provide further improvement in wells with inherently low permeabilities such as MG-8D, MG-10D, 1R10 and MN-1. Also, the addition of the friction-reducing and viscosity-enhancing additive gel to both the preflush and mainflush acid solutions may induce stimulation of the target payzones beyond those achieved in wells MG-8D, MG-10D and MN-1. Additional experimentation is, nevertheless, recommended to determine whether this is possible, and if indeed possible to make an estimate of the optimum dosing rate for tight wells such as the above.

Consequently, optimizing acid volume through accurate measurements of payzone thicknesses may only be applied in wells with confirmed temporary wellbore damage, and not in those with natural low permeabilities. TPS measurement during completion of wells is highly recommended for this purpose.

Optimization may play a critical role in the acid treatment of injection wells where one or more "original" or damaged payzones are unwanted channels for reinjection returns to the production sector. In these areas, the design should consider both accurate payzone thickness measurement and determination of appropriate acid pumprates and injection pressures.

ACKNOWLEDGMENT

The authors wish to thank the management of PNOC-EDC for their permission to publish this work.

REFERENCES

Campbell, D.A., Morris, C.W. and Verity, R.V. (1981). Geothermal Well Stimulation Experiments and Evaluation., SPE 10316.

Completion test reports of PN-32D, PN-2RD, 2R4D, 110D, TC-1RD, TC-2RD, 1R10, MG-8D, MG-10D and MN-1. PNOC-EDC Internal Reports.

Messer, P.H., Pye, D.S. and Gallus, J.P. (1978). Injectivity Restoration of a Hot-Brine Geothermal Injection Well. *J. Pet. Tech.*, (September 1978), 1225-1230.