PROCEEDINGS, Thirty-Sixth Workshop on Geothermal Reservoir Engineering
Stanford University, Stanford, California, January 31 - February 2, 2011
SGP-TR-191

ACIDISING CASE STUDY – KAWERAU INJECTION WELLS

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ABSTRACT

Brine at the Kawerau Geothermal Limited (KGL) plant was injected into three injection wells (KA43, KA44 and PK4A). Since plant commissioning, the capacity of the wells declined to the point where well intervention was necessary to avoid loss of generation. Investigative work was initiated with multi-rate injection tests which found that the injection index of the wells had declined significantly to approximately half of pre-utilisation levels. Further geochemistry analysis identified that the most likely source of injectivity decline was scaling due to colloidal silica forming in the formation.

KA44 and PK4A were acidised using a standard 10% hydrochloric acid pre-flush followed by a 10%:5% HF:HCL mud acid solution. A 2” coil tubing unit with a 5 hole 45º nozzle bottom hole assembly was used giving a maximum pump rate of 3.5 - 4.0 barrels per minute. Feedzones were acidised one at a time starting with the deeper zones.

Post well injection tests identified that the acidising had recovered the injectivity of the deeper feedzones but the shallower feedzones remain blocked with scale. The injectivity index at PK4A improved from 50 t/h.b to 84 t/h.b while KA44’s gross injectivity index increased from 25 t/h.b to 50 t/h.b. Camera runs carried out before and after acidising revealed excellent scale removal from the perforated liners. Pre and post acidising High Temperature Casing Corrosion (HTCC) logs also showed that the acid had not caused any measurable corrosion in the casings.

INTRODUCTION

Three injection wells (KA43, KA44 and PK4A) were used to inject brine from the Kawerau Geothermal Limited (KGL) plant (Figure 1) since plant commissioning in August 2008.

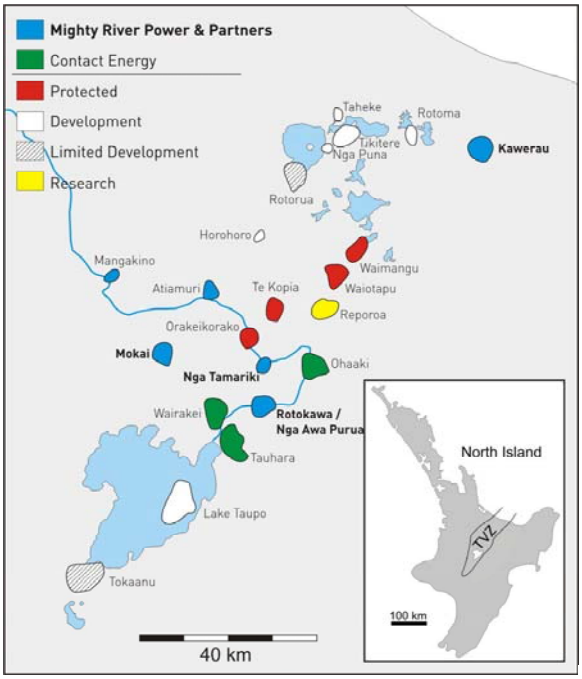

Figure 1: Location of the Kawerau Geothermal Field

Silica precipitation at Kawerau has been a concern since the design phase as the silica saturation index (SSI) is approximately 1.9 at injection temperature. To prevent deposition, an acid inhibition system (or pH modification) was installed at Kawerau (Horie 2009).

Since plant commissioning, routine monitoring of the wells identified declines in the well capacity. Subsequent investigative work was initiated to confirm declines and identify the root cause.

INVESTIGATIVE WORK

As an initial step in the investigation, multi-rate injection tests were carried out on all three wells and identified that the injectivity indices had declined to approximately half of pre-utilisation levels (Table 1). Non- linear injectivity was also observed from the tests suggesting restriction at the well face.

Table 1: Comparison between original well performance and July 2009 performance.

Well	Original II (t/h/b)	II as of July 2009 (t/h/b)	
		II at low rate	II at high rate
KA43	45	13	25
KA44	97	45	60
PK4A	100	42	75

The decline in injectivity is in contrast to the performance elsewhere. In the absence of deposition problems, injectivity should increase roughly with the square root of the time injecting, as shown in Figure 2. The injectivity is higher under stimulation, for the same time injecting, as cold water is used for injection whereas the waste water is hotter.

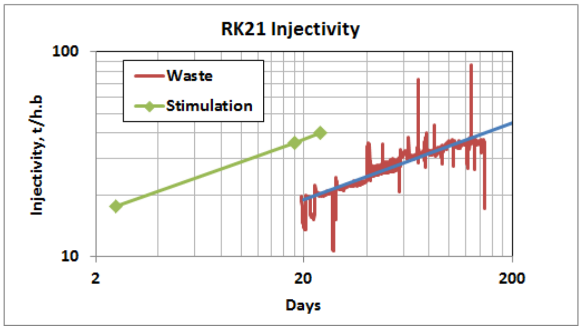

Figure 2: Injectivty history of RK21 during stimulation with cold water and under operation with waste water.

Not only did the Kawerau wells not follow the trend of increasing injectivity with time, but injectivity declined.

Brine was also filtered through a Swagelok 2 µm stainless steel filter at the LP separator and injection wellhead. An environmental scanning electron microscope (E-SEM) was then used to investigate the precipitates. The LP separator filter (Figure 3) had a small amount of debris which mainly consisted of silica. The injection wellhead filter (Figure 4) had a larger amount of material deposited with compositions similar to the LP filter.

Figure 3: Low magnification of the 2µm stainless steel filter from LP brine.

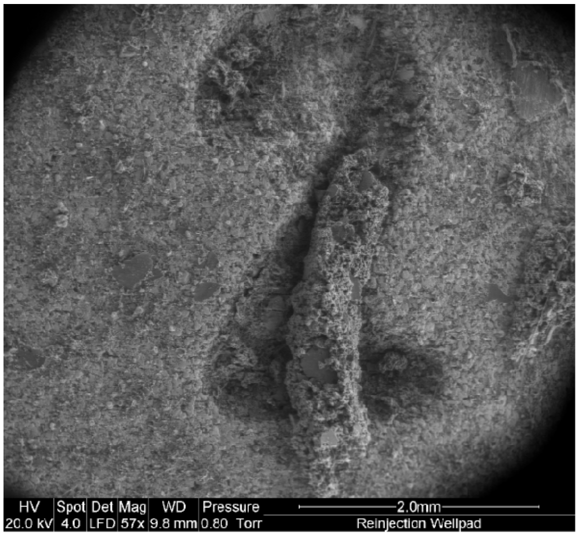

Figure 4: Low magnification of the 2µm stainless steel filter from injection wellhead brine.

Interpreting the results of this test, it was postulated that the most likely cause of scaling is due to colloidal silica scaling. Subsequent downhole camera runs done in all wells identified that the wellbores were relatively clean confirming that the restriction was occurring at the well face.

Unfortunately, both the spinner and camera runs in KA43 also identified a shallow casing break and the subsequent sleeving job was not successful. Thus, plans to acidise KA43 were abandoned and preparation work focused on acidising KA44 and PK4A.

WELL ACIDISING

BJ Services were contracted to design and carry out the acidising. A 2” coil tubing unit with a 5 hole 45º nozzle bottom hole assembly was used giving a maximum pump rate of 3.5 - 4.0 barrels per minute. The use of a CTU was hoped to provide better acid placement as it can be moved to each zone prior to pumping acid.

A traditional 10% hydrochloric (HCL) to 5% hydrofluoric (HF) mud acid was used for this project along with corrosion inhibitors, iron chelating agents and gelling agents. The standard 10% HCL preflush was also used to dissolve carbonate minerals in the formation (Kalfayan, 2008, p70). Both wells were quenched prior to the acidisation and a multi-rate injection test along with downhole camera and High Temperature Casing Corrosion (HTCC) runs was carried out to identify the pre-acidising conditions.

The pre-flush was then carried out followed by the mud-acid mixture. Permeable zones were divided into groups and acidised using a “bottom-up” approach. This approach was used as there were concerns that a “top-down” approach would open shallow zones and introduce hot inflows which will reduce the effectiveness of the corrosion inhibitors.

After each zone was acidised, a water overflush was carried out to displace the mud-acid mixture away from the wellbore (Kalfayan, 2008, p73). It should be noted that while pumping acid into the well approximately 2 barrels per minute of water was pumped into the well from the side valves to keep the well cool and to prevent acid upflows. Information on the acidised zones and mixture amounts are shown in Figure 5 and Figure 6.

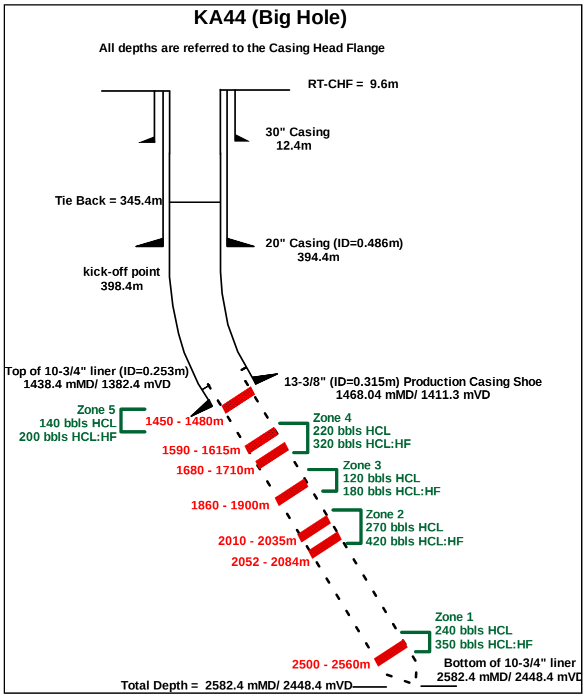

Figure 5: Wellbore schematic of KA44 showing permeable zones (red) and amounts of acid introduced to each zone (green).

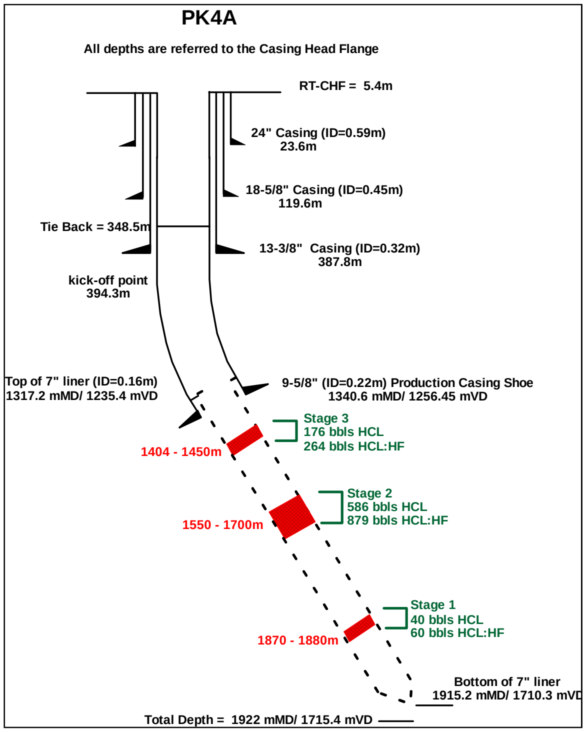

Figure 6: Wellbore schematic of PK4A showing permeable zones (red) and amounts of acid introduced to each zone (green).

RESULTS

Given that multi-rate injection tests along with downhole cameras and HTCCs were carried out before and after the acidising, the well improvements can be measured reasonably accurately.

Spinner runs into KA44 (Figure 7) showed that prior to acidising, the bottom zones were almost fully blocked and the majority of fluid was exiting at 2090-2135mMD. Gross Injectivity index (i.e. without compensating for inflows) at this point had decreased to 25 t/h/b. Post-acidising, the spinner profiles were similar to original well conditions suggesting the bottom zones had recovered most of its original performance. Gross injectivity index post-acidising had doubled to 50 t/h/b.

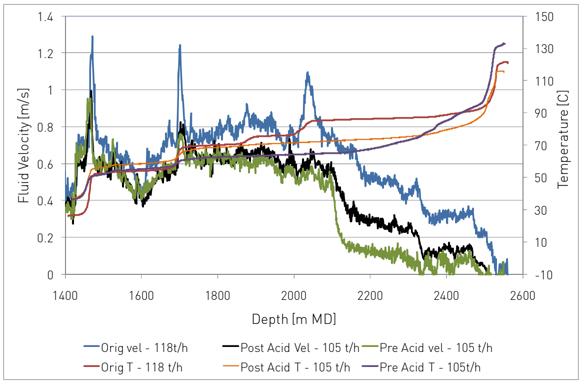

Figure 7: KA44 PTS profiles comparing original performance to pre and post acidising performance.

At PK4A (Figure 8), the spinner runs for the post-acidising run had a large bias with velocities at the casing showing much higher values compared to the pump rate. Applying a correction factor solves this, but a bias still exists from 1700mMD onwards.

However, even with this issue it is still clear that the main zone at 1570-1595mMD is partially blocked prior to acidising. Injectivity index at this point had decreased to 50 t/h/b. Post-acidising, the main zone has completely recovered its original permeability increasing the injectivity index to 84 t/h/b.

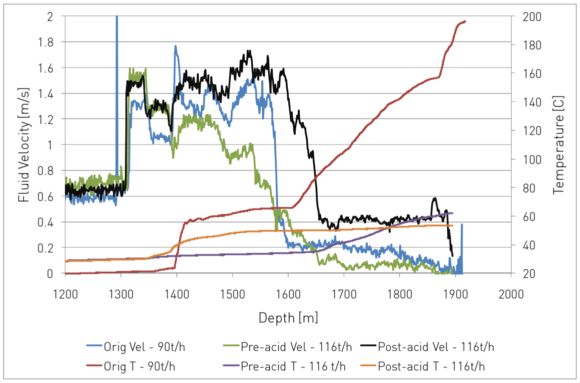

Figure 8: PK4A PTS profiles comparing original performance to pre and post acid performance

In order to further analyse the improvements due to acidising, a zone by zone injectivity index (Table 2 and Table 3) was calculated. This was done using the spinner response and unfortunately a few zones had a different sign due to changes that are too small for the spinner to measure. Regardless of this, the results are still useful as a qualitative tool to compare the effectiveness of the project.

At KA44, the deeper zones achieved the greatest improvement with acidising, particularly the zone at 2295-2335mMD. The shallower zones showed very little improvements. PK4A's calculation showed a similar result with deeper zones achieving the greatest improvements with minimal effect on the shallow zones. However, it should be noted that the spinner bias seen at PK4A's post-acidising run may have affected the calculations.

*Table 2: Zone by zone injectivity index for KA44 to two significant figures. Figures with * signifies inaccurate values.*

Zone	Type	Original II (t/h/b)	Pre-acid II (t/h/b)	Post-acid II (t/h/b)
1450	In	-8.3	-0.30	2.1*
1680	In	-21	-0.030	1.5*
2075-2135	Out	42	17	23
2295-2335	Out	27	1.5	16
2500	Out	2.2	-0.60*	2.0

*Table 3: Zone by zone injectivity index for PK4A to two significant figures. Figures with * signifies inaccurate values.*

Zone	Type	Original II (t/h/b)	Pre-acid II (t/h/b)	Post-acid II (t/h/b)
1404	In	-4.6	-3.6	-1.9
1570-1595	Out	62	53	67
1870-1880	Out	-6.4*	-0.60*	8.0

Downhole camera runs at KA44 (Figure 9) showed little change in well condition as the wellbore was very clean in the first instance. Several parts of the liner showed some minor scaling which was not evident post-acidising. Given that most of the scaling occurred at the wellface behind the perforated liner, camera runs are not ideal as a measure of success for the project.

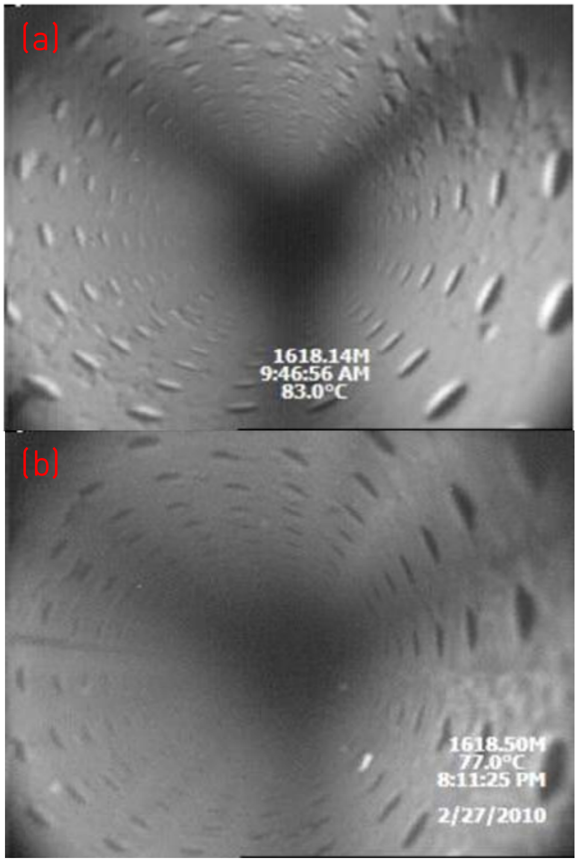

Figure 9: (a) Pre-acidising downhole camera run at KA44 showing slight scaling in the liner. (b) Post-acidising downhole camera run at KA44 showing cleaned liner.

However, the camera runs and HTCC at KA44 did identify that there was no change in casing thickness confirming that the corrosion inhibitors used were effective. Another interesting observation is that there was no evidence of acid in the 13-3/8” production casing which suggested no upflows of acid.

The downhole camera run at PK4A (Figure 10) showed that the perforations were scaled up prior to acidisation. The blockages were particularly worse near the main feedzone where injected fluids exited the well. Introduction of acid managed to fully dissolve all scale in the perforations. Again, due to the scaling occurring mainly at the wellface, this result should not be used as a measure of success.

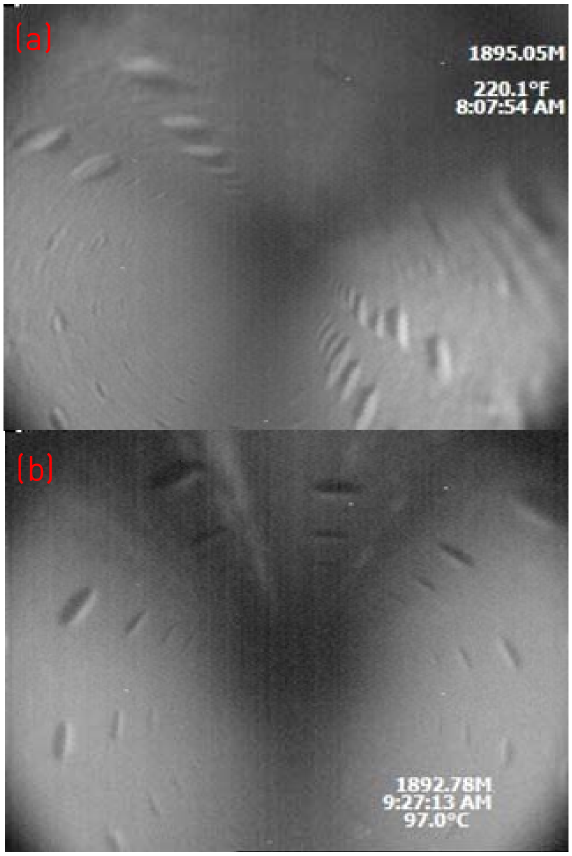

Figure 10: (a) Pre-acidising downhole camera run at PK4A showing scaled perforations. (b) Post-acidising downhole camera run at PK4A showing unblocked perforations.

Similar to KA44, both the camera and HTCC runs showed no noticeable corrosion due to acid. As expected, the 9-5/8” casing also showed no evidence of contact with acid.

DISCUSSION

From the pre and post acidising multi-rate injection test, it is clear that the acid had a preferential flow path to the deeper zones even with placement with the CTU. This phenomena isn’t too surprising as it is common for the deeper zone to be the largest exit point as hydrostatic gradient provides a greater driving force. Moreover, the deeper zones at KA44 and PK4A are the most permeable.

The "bottom-up" approach also reduced the chance of placement as once the deeper zones are unblocked it opens a preferential pathway for the acid to exit the well. A "top-down" approach may have allowed for better acid placement as the bottom zones would have remained blocked as the top zones are acidised. Plus, the hydrostatic pressure and additional water introduced during the acid stages will reduce any upflows of acid allowing the deeper zones to be sequentially acidised.

Concerns with the shallow zones inflowing causing the corrosion inhibitors to lose effectiveness using the "top-down" approach could possibly be mitigated by a few methods. The most obvious would be to use inhibitors with higher temperature limitations or by introducing a large quantity of cold water to quench the top zone. Both methods will unfortunately increase the overall cost of the project.

Increasing a higher concentration of HF acid (say 9%) and lower amounts of HCL acid should theoretically provide a more effective mud acid mixture (P Rae 2010, pers. comm.. 29 April). There are also several proprietary mud acid mixtures available that contains higher amounts of HF which are safer to handle.

CONCLUSIONS

Since plant commissioning in August 2008, all three KGL injection wells (KA43, KA44 and PK4A) have declined due to silica scaling in spite of pH modification inhibition. Downhole camera runs identified very little scaling in the wellbore, confirming that the decline in injectivity is due to silica scaling at the wellface.

PK4A and KA44 were acidised with a CTU using a standard 10%:5% HCL:HF mud acid with a 10% HCL preflush. Multi-rate injection tests carried out before and after acidising showed that the deeper zones improved post acidification but the shallow zones did not. Injectivity index of both wells did improve substantially post acidising, but did not fully recover its original capacity. Downhole camera and HTCC runs confirmed that the corrosion inhibitors were effective in preventing acid attack on the casing and liner.

The results also confirmed that acid placement was unsuccessful as once the main bottom zones are unblocked, a preferential pathway opens for acid to exit the well. A "top-down" approach may be more successful with acid placement compared with a "bottom-up" as it allows for the bottom zones to remain blocked as the shallow zones are acidised. Increasing the HF concentration may also increase the effectiveness of the mud acid.

ACKNOWLEDGEMENTS

The authors wish to thank the management of Mighty River Power for the review and permission to publish this paper and all staff who have been involved with this project. Also, the authors would like to thank Phil Rae (InTuition Energy Associates), David Addison (Thermal Chemistry) and Julius Dacanay (SKM) for their help and support during this project. Lastly, thank you to BJ Services New Zealand for services rendered.

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