ACIDISATION STIMULATION OF KAWERAU INJECTION WELL PK4A USING HYDROFLUORIC ACID

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ABSTRACT

Injection well PK4a at the Kawerau Geothermal Field was acidised with 10% HCl / 5% HF in May 2017. This work, along with a program of several other acid well work-overs between 2016 and 2017, was conducted as part of a wider investigation to address silica management at Mercury's geothermal fields, several of which have silica saturation indices in excess of 1.7, as described in Addison et al. (2015). Despite the use of various plant designs to reduce the risk of silica polymerization and deposition, injection well decline continues to be an issue.

PK4a was selected as a candidate well for acid stimulation, as it is known to suffer from injection decline that both modelling and laboratory testing supports being a result of silica scaling in the near wellbore formation. PK4a was acidised previously in 2010 also using 10% HCl / 5% HF, however the initial improvement in injectivity was short lived.

The 2017 PK4a acidisation program was optimised based on lessons learned from 2010 and from international case studies, in order to improve the chance of success. The results of this acid stimulation of PK4a are compared against the first acid stimulation of this well., as well the results of acid stimulations reported by other geothermal operators.

1. INTRODUCTION

PK4a injection well is located at the Kawerau Geothermal Field, Bay of Plenty, New Zealand. It is known to suffer from injection decline while operating on brine from the Kawerau Geothermal Limited (KGL) power plant. When it was drilled in 2008, the initial injection capacity of PK4a was 600t/h, and had since declined to ~320t/h in early 2017. Both modelling and laboratory testing supports the decline being a result of silica scaling in the near wellbore formation.

The KGL power plant, produces geothermal brine with a silica saturation index of >1.7 requiring the employment of silica management processes. At the KGL plant, sulfuric acid is added to the geothermal brine in order to inhibit the polymerization of silica. While this technique successfully controls silica at the plant and in the brine handling systems, injectivity decline in the field continues to be an issue. It is suspected that upon contact with the calcite rich Greywacke reservoir rock, the acidified brine is being neutralized and precipitates silica in the near wellbore formation.

PK4a was previously acidized in 2010. Although the initial improvement in injectivity was short lived, it showed that recovery could be achieved, and potentially maintained. High temperature casing caliper HTCC logs conducted in PK4a following the acid stimulation in 2010 and again in 2013 showed that the casing was in good condition and that the initial acid stimulation had no adverse effects on the well casing.

With the 2010 acid stimulation as a base case, and a current injectivity decline rate of 10% p.a, PK4a was selected as a priority for acid stimulation. This selection was supported by the 2016 down-hole survey results which showed that skin (near well damage) is the primary permeability damage mechanism, indicating the damage is treatable with acid.

2. PK4A ACIDISING 2010

PK4a was acidized in 2010 using a Coiled Tubing Unit (CTU) to deliver mud acid (10% HCL / 5% HF) with a 10% HCL pre-flush and a water overflush. Three target permeable zones of varying thicknesses were treated, as shown in Figure 1.

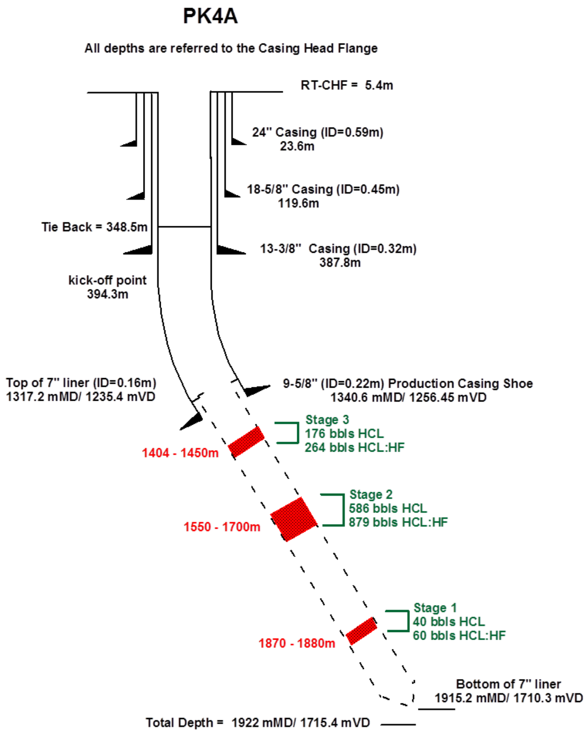

Figure 1: Acid stimulation target zones (red) and amount of acid used to treat each zone in 2010 (green) (Lim et al., 2010).

The 2010 acid stimulation of PK4a successfully cleared the silica blockage from the liner holes and resulted in bulk injectivity index (II) improvement from 50t/h.b pre-acidising, to 84 t/h.b post acidising, as report by Lim et al. (2010). However, the injectivity continued to decline once the well was put back in service and the recovered injection capacity was lost within 2 months of being returned to service.

In 2010, the acid placement was considered unsuccessful as unblocking the main bottom zones created a preferential pathway for acid to exit the well. It was suggested that a top-down approach may solve this, prompting the evaluation described in Section 3.2.2.

Some key recommendations from the 2010 campaign that were considered in the 2016-2017 campaign were on the top-down vs. bottom-up coiled tubing unit (CTU) acid-application strategy, and increasing the concentration of HF.

3. PK4A ACIDISING 2017

3.1 Acid Application Strategy

3.1.1 Pumping Technology

There are two ways that were considered for applying the acid down hole; that is, at specific depths for treatment via 2" coil tubing, or all chemical pumped from the surface through the wellhead or side valve (bullhead application). Coil tubing was selected for downhole acid delivery in order to provide targeted acid placement to increase the recovery from specific zones.

3.1.2 Top-down v. bottom-up

A top-down acid application strategy utilising a CTU was chosen based on wellbore modeling studies and the risk assessment carried out between the two application strategies for PK4a.

Wellbore modeling studies using in-house software *Paiwera* were set-up to evaluate the changes in wellbore pressure profile against the reservoir pressure gradient. For the top-down strategy, this means increasing the permeability of the shallower feed zones while injecting at the proposed acid injection rates. The deeper feed zones were increased for the bottom-up strategy. Modelling results showed that a top-down strategy would provide a better chance of stimulating the shallower feed zones. The wellbore pressure profile already favours deeper feed zone injection through a larger pressure differential between the wellbore and the reservoir, owing to the density difference between cold quench water and hot reservoir temperature. A stimulation of the deeper feed zones first, through the bottom-up strategy, could result in poor diversion of acid into the shallow feed zones.

The risk assessment carried out between the two application strategies favoured the bottom-up approach because the coil is moving out of the acidized feed zone depths. The risk of dipping the coiled tubing into the acidized feed zones in the top-down approach could be mitigated by the post-flush injection of fresh water / condensate between acid target zones.

The top-down acid application strategy was also one of the recommendations of the 2010 PK4a acidising results.

3.1.3 Risk of in-flows

Multi-feed zone wells under quench with cold water are at risk of hot inflows and PK4a used to have inflows from its shallower zones. Low rate cold water injection could result in a wellbore pressure gradient that allows for reservoir inflows at the shallower feed zones. Reservoir inflows are usually hot and could affect the corrosion inhibition system or result in further dilution of the acid mixture if additional cooling water is required. Also, if a target zone is inflowing, it cannot be acidized unless the flow direction is reversed. This risk was evaluated using wellbore models.

To model if there are inflows into the well during the acid application, the PK4a wellbore model was edited using mobility corrected injectivity indices on its feed zones. Then, using historical data, the thermal stimulation effect was estimated based on the number of days the well is planned to be on quench prior to acid application. At this thermally stimulated injectivity, the fluid was swapped from hot brine to cold condensate conditions and assessed for inflows.

The wellbore model results indicate a low risk of developing inflows at the current condition of the well.

3.1.4 Selection of zones to be treated

Six 50-m target zones were chosen to be treated to ensure all notable feed zones were acidized. These are zone intervals from 1400-1650m CHF and 1850-1900m CHF. A 50-m zone interval was chosen as a minimum even if the actual feed zone interval is only 10m to ensure coverage.

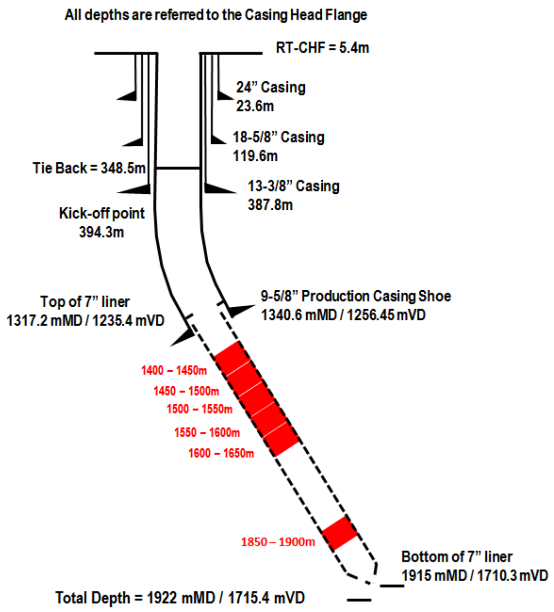

Figure 2: 2017 acid stimulation target zones in PK4a.

The zones were chosen based on a review of available information on PK4a's feed zones, starting from the completion test reports, the post-2010 acidising results, and the 2016 PTS evaluation.

The original zones in the well were identified during completion tests as inflows just below 1400m CHF, a major loss zone at 1544-1595m CHF, and possible loss zones at depth (deeper than 1800m CHF).

The 2016 pre-acidising PTS results showed a broad loss zone from 1400-1600m CHF and a small loss zone at 1775m CHF. The loss zone deeper than 1800m CHF is gone.

3.2 Chemical Selection

Mixtures of hydrofluoric acid are routinely used for the chemical removal of silica deposits. The possibility of using a sodium hydroxide solution for silica removal was considered, however it was ruled out due to the heat and contact time estimated to be required for a successful treatment.

A standard treatment formulation of 5%HF/10%HCl (mud acid) was selected for PK4a. This selection was based on successful solubility testing with the PK4a formation, and the successful use of this formulation for silica removal in other geothermal fields (e.g. Buñing et al., 1995 and Flores-Armenta and Ramirez-Montes, 2010)-. The application of the mud acid would be preceded by a pre-flush with 10%HCl, to ensure the removal of any remaining carbonate material that could form insoluble precipitates with HF (e.g. CaF_2). The application of the mud acid would also be followed with a post-flush of 5%HCl to maintain acid strength in the treatment zone to minimise the precipitation of reaction products. The post treatment acid flush would then be followed with a condensate flush to remove all of the acid mixtures away from the well bore and near wellbore area.

The application rates of the pre-flush, main flush and post-flush stages were selected as a result of a literature review, and discussions with other geothermal operators of the rates typically used in geothermal applications for the successful removal of silica in injection wells (e.g. Flores-Armenta and Ramirez-Montes, 2010).

The application rates selected are shown in Table 1 below:

Table 1: Acid Application Rates

Stage	Formulation	Application Rate	Volume per 50m interval
Pre-flush	10%HCl	50Gal/ft	195bbl
Main-flush	5%HF/10%HCl	75Gal/ft	293bbl
Post-flush	5%HCl	20Gal/ft	78bbl
Final-flush	Condensate		>300bbl

Several chemical options were considered for the delivery of hydrofluoric acid to PK4a:

- HF solution (various concentrations)
- Ammonium Fluoride (to be mixed with HCl)
- Ammonium Bifluoride (to be mixed with HCl)

3.2.1 Ammonium Fluoride / Bifluoride

Ammonium fluoride (AF) and ammonium bi-fluoride (ABF) are a crystalline salts that can be used to produce HF solutions with the addition of acids. Both substances, while less toxic than HF, are toxic and can be highly hazardous to human health. The use of AF or ABF to generate HF requires the addition of acids (typically HCl), which significantly increase the volume of HCl required for an acid treatment as shown in Table 2.

The hazards associated with mixing AF/ABF on site (generation of dust, chemical contact etc.) can be reduced by procuring the chemicals as a pre-prepared solution (dissolved in water). The use of AF/ABF solutions removes the need for a batching facility on site to dissolve the powders. The mixing of the dissolved AF/ABF solutions with hydrochloric acid can be relatively straightforward with a suitable mixing manifold.

The use of AF or ABF solution requires that a significantly higher volume of chemicals are stored and/or handled on the site compared to using a concentrated HF solution, as shown in Table 2.

3.2.2 Hydrogen Fluoride Solutions

The use hydrofluoric acid solutions creates significant health and safety challenges due its toxicity, however these challenges are similar (although more extreme) to those presented by the use of AF/ABF solutions. The hazards of hydrofluoric acid solutions increase with increasing concentration. The use of hydrofluoric acid solutions to prepare the acidising mixture (mud acid) has the benefit of requiring a much smaller volume of chemicals that require handling and storage as shown in Table 2. As such the choice between HF and AF/ABF for mixing mud acid comes down to a tradeoff between the hazards of the chemicals used against the volumes of the chemicals required.

In the case a PK4a the decision was made to procure 70%HF solution for the preparation of the mud acid. While the 70%HF solution presented the highest chemical hazard level of the options considered, it presented the lowest overall hazard when chemical mixing, handling and storage factors for the chemical options were taken into account. This was a result of the much lower volume of chemicals that would need to be handled when 70%HF solution is utilised compared the AF/ABF and lower concentrations of HF. The use of 70%HF also enabled the entire HF supply for PK4a to be procured in a single vessel, minimising the need for chemical connections and the risk of leaks.

Table 2: Chemical volumes required for various HF options (includes pre-flush and post-flush acid) based on a 300m treatment interval

	70%HF	50%HF	30%ABF	40%AF
Hydrochloric acid (33%) (L)	131000	131000	168000	204000
HF Solution (70%) (L)	18000			
HF Solution (50%) (L)		26,000		
ABF Solution (30%) (L)			67000	
AF Solution (40%) (L)				63500
Total Chemical Volume (L)	149000	157000	235000	267500

3.2.4 Corrosion Inhibition

The corrosion inhibition system for PK4a was designed to achieve acceptable corrosion rates ($<0.05 lb/ft^2$) at temperatures up to 120˚C. This required the use of a corrosion inhibitor and intensifiers which were supplied by the coil tubing contractor. In addition to use of inhibitor intensifiers the well was swapped from brine service (130˚C) to condensate service (40˚C) two weeks prior the acid stimulation to both remove brine from the well bore area and to cool the well to ensure a suitable temperature for acidising.

4 RESULTS

4.1 Velocity and Temperature Profile

Based on the fluid velocity and temperature profile of PK4a, the acid stimulation has preferentially stimulated deeper feed zones than the acid target zones, most noticeably from 1600-1800m CHF and recovering the deepest feed zone at 1850m CHF as shown in Figure 3.

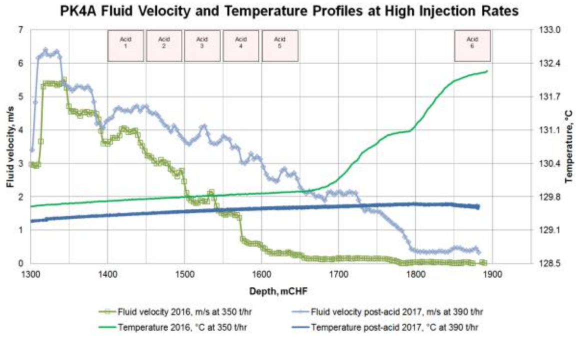

Figure 3. Velocity and temperature profile of PK4a at >350 t/hr hot brine injection along the perforated liner section showing the pre-acid (2016) and the post-acid (2017) profiles. The target zones are shown as squares.

In the post-acid velocity profile, around 29% of fluid is injected from 1400m CHF to 1500m CHF, 64% is injected from 1550m CHF to 1800m CHF, and the balance 7% is injected at zones deeper than 1800m CHF.

Comparing the post-acid velocity profile to the original loss zones, the most notable change observed is the new distributed permeability from 1550-1800m CHF from a narrow and distinct injection zone at around 1544-1595m CHF. In addition, there is notable increase in permeability at 1750-1800m MD, originally a minor zone that appears to have stimulated into a major loss zone.

Table 3 below shows an analysis of changes to feed zone contributions in PK4a over time. Between the 2016 and 2017 feed zone analysis, PK4A was injected with 40°C condensate for around 80 days. This may have changed the feed zone contributions even before acid stimulation. This condensate injection was carried out to thermally stimulate PK4A and arrest its injection decline prior to acidising. A pre-acid PTS profile has shown that the bottom feed zone was already accepting fluid even before acid stimulation.

Table 3: PK4A Feed zone analysis showing changes to feed zone contributions over time

Feed Zone	Depth [mCHF]	Original.	2009	2016	2017
Shallow	1400-1450	Inflow	20%	20%	12%
Shallow	1450-1500	--	2%	23%	17%
Deep	1500-1550	--	1%	20%	--
Deep	1550-1600	90%	35%	28%	10%
Deep	**1600-1650**	--	8%	4%	11%
Deep	1650-1700	--	10%	3%	8%
Deep	**1700-1750**	5%	8%	--	11%
Deep	**1750-1800**	--	1%	2%	24%
Deep	1800-1850	--	--	--	--
Deep	**1850-1900-TD**	5%	15%	--	7%
Inj Rate at PTS	**[t/hr]**	120	122	350	390

4.2 Injectivity Index

The II of PK4a has continuously declined over time due to suspected silica scaling in the near wellbore formation, as summarised in Table 4. The original II of the well following completion was 100 t/h.b, and despite acidising in 2010, continued to decrease to an II of 8.1 t/h.b prior to acidising in 2017.

After acidising in 2017, the injectivity index (II) of PK4a increased to 26.7 t/hr/bar under hot brine injection, as shown in Figure 4. This indicates improved capacity and reduced restriction to flow, requiring generally lower wellbore pressures to inject a similar hot brine flow rate.

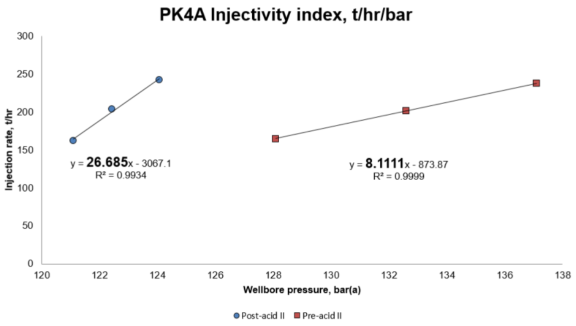

Figure 4. PK4a injectivity index at pre-acid and post-acid multi-rate injectivity tests using similar injection rates.

Table 4: PK4a Injectivity Index

	II (t/h.b)
Original II (2008)	100

2010 Pre-Acidising	50
2010 Post - Acidising	84
2016 Evaluation	15
2017 Pre-Acidising	8.1
2017 Post - Acidising	26.7

4.3 Permeability Improvement

The results of the pressure falloff test indicate an increase in permeability thickness (kh) from ~20,000 md.m to ~44,000 md.m and a reduction in skin from +3 to +0.51. This is consistent with the overall improved performance of the well. The reduced but still positive skin value highlights opportunities for future well stimulation.

The pressure transient analysis was carried out on the *Saphir* module of the *Kappa* software and used the known reservoir fluid properties as inputs. The model chosen was a vertical well with a homogeneous reservoir and an infinite-acting boundary.

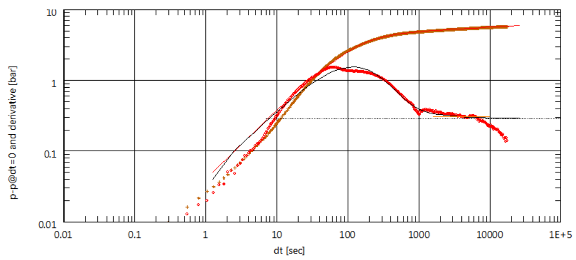

Figure 5. Pressure derivative plot for PK4a showing the measured data in red and the analytical model in black.

5. DISCUSSION

International case studies of HF acid stimulation to remove silica scale have demonstrated significant improvements in injection capacity. For example, Flores-Armenta and Ramirez-Montes (2010) report on acid stimulation at Las Tres Virgenes and Los Azurfres geothermal fields in Mexico. Of the wells acidized, four injection wells with silica scaling showed an average improvement of 78%. Similarly, acidisation of injection wells in the Philippines reported by Buñing et al., (1995) and Malate et al., (1998) showed >100% improvement in injection capacity, and up to 900% improvement in one instance. However, there is little discussion of how long these improvements in injection capacity are maintained following acid treatment.

Immediately post acidising, PK4a showed ~90% recovery in injection capacity from 320t/h pre-acidising to ~610t/h. However, due to the thermal effects of operating the well on condensate (40°C) for two weeks prior to acidising, the well experienced decline in injection capacity associated with de-stimulation as the surrounding formation has heated up. In order to identify and isolate this thermal de-stimulation trend, it was compared to that observed following the operation of PK4a on condensate for 80 days in 2016. The comparison showed that decline post acidising in 2017 moves into a second linear trend after approximately 10 days post acidising, marking the end of thermal de-stimulation (**Figure 6**).

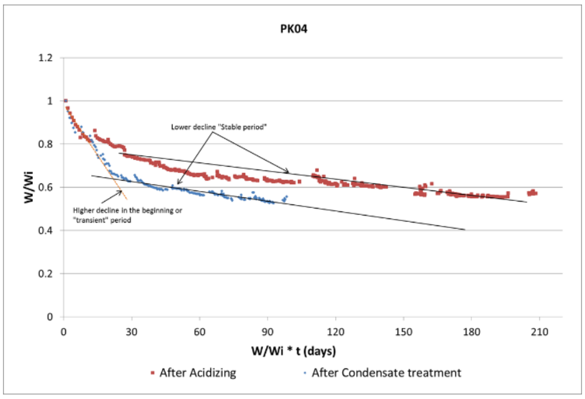

Figure 6: Comparison of decline rate following condensate treatment in 2016 (blue line) and after acidising in 2017 (red line)

12 months post acidising, the capacity of PK4a has declined to ~350t/hr – 30t/hr above the pre-acid stimulation capacity. The decline appears have occurred in 3 stages, initial rapid thermal destimulation for ~10 days, followed by a period of higher than normal (pre-acidising) decline for approximately 50 days, and then a return to a more typical long term decline rate.

The improvement seen in injection capacity in PK4a following the 2010 acidising only lasted for around two months. With the optimization of the acidising program, we were able to significantly increase the longevity of this improvement, as shown in Figure 7.

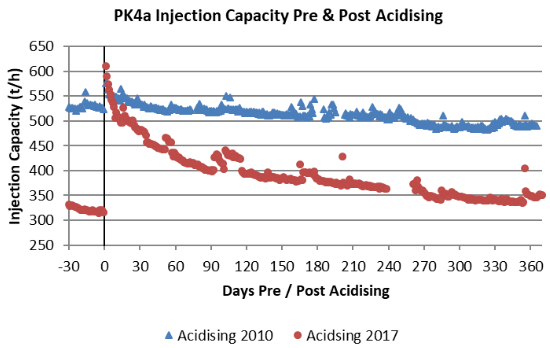

Figure 7: Comparison of PK4a injection capacity pre and post acidising in both 2010 and 2017.

Using a CTU to spot-apply acid has advantages and has been successful in other scale blockage removal but it has been underwhelming in regards to stimulating specific target feed zone depths. Our experience in 2010 and in the 2016-2017 campaign has shown that targeting feed zones for acid stimulation is a challenging exercise because of the lack of cost-effective options for fluid diversion. If cost effective fluid diversion cannot be achieved, the use of bull-head acid stimulation may provide a similar level of performance to coil acidising, but at a lower cost.

6. CONCLUSION

The acid stimulation of injection well PK4a has successfully increased the capacity of the well, however the improved capacity has deteriorated over time, with a slight improvement in capacity remaining 12 months after acidising. As a result, it appears that the cost effectiveness of this approach to acidising is marginal when used to maintain injection capacity. A change to bullhead application of the acid is likely to increase the cost effectiveness of this acidising in Kawerau injection wells.

The use of concentrated HF solution (70%) enabled the acid stimulation team to minimise the volume of chemicals on the site. This enabled simplified chemical logistics and while requiring comprehensive chemical safety – the lower volumes minimized the likelihood of a chemical handling incident through a reduced requirement to handle chemicals. The reduced volume of chemicals required also resulted in a lower overall chemical cost for the acid stimulation.

Fluid diversion has proven be an ongoing challenge for acid stimulations with coil units for Mercury. Bullhead acid treatments may prove more cost effective than coil treatments if better diversion cannot be achieved.

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