SUCCESSFUL ACID TREATMENT OF A PRODUCTION WELL IN THE TAUHARA FIELD, NEW ZEALAND

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ABSTRACT

A two-phase production well at Tauhara being used for industrial heat supply has been subject to calcite scaling, requiring regular workovers to remove the scale and maintain production flows. These workovers have been performed on an annual basis to fit in with the process plant maintenance programme. The original productivity was more than 100 t/h per bar, but in 2010 the well was unable to sustain flow at the normal production wellhead pressure and subsequent downhole surveys showed the productivity had declined to 20 t/h per bar.

After reviewing well performance, the cause of the productivity decline was assessed to be calcite scale in the feedzone fractures near the wellbore. It was decided the best option to restore the productivity was to acidize the well following the "normal" annual mechanical scale removal.

The well has multiple feedzones and even when "quenched" with cold water there is a strong interzonal flow with wellbore temperatures around 100°C. The challenge of the acidizing process was to achieve a successful acid treatment of the fractures near the wellbore, without attacking and damaging the perforated liner and other downhole equipment.

A treatment program using 15 % HCl followed by a soda ash mix to neutralise any remaining acid, together with a corrosion inhibitor to protect the liner, was designed. This was successful in restoring the well productivity to the original value without causing any damage to the well casing or perforated liner.

1. INTRODUCTION

The well is located in the northwest part of the Tauhara field (Figure 1). It was drilled in 2005 to a depth of 1000 m, with a 10-3/4" perforated liner reaching from 600 to 1000 m depth. The purpose of the well is to deliver steam to the Tenon Plant for timber drying. It went on production in 2006 as an initially good production well with productivity over 100 t/h per bar. However, since then regular workovers to remove calcite scale have been required to maintain production.

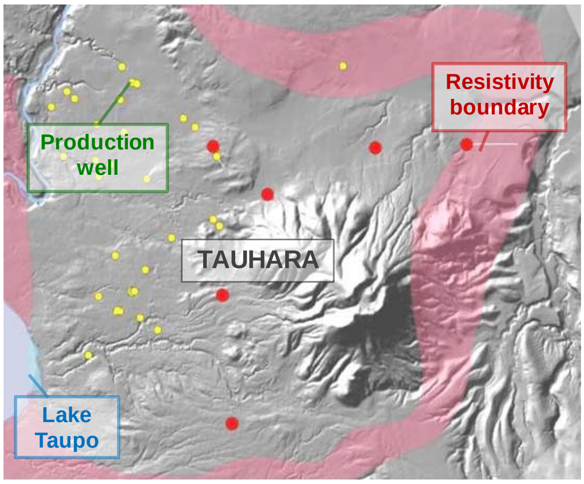

Figure 1: Well layout map for Tauhara Geothermal Field. Wells in depth range 1800-2500m are in red and shallower wells are in yellow.

The first mechanical workover occurred in 2007 and since then regular workovers were necessary in order to keep the well on production. In 2010 the workover was only partially successful as it was difficult to restart the well and, once flowing, to maintain on production, because the maximum discharge pressure (MDP) had declined and was close to the operating pressure of the Tenon Plant. A subsequent flowing survey in March 2010 showed the well productivity had declined to 20 t/h per bar. To improve the well productivity the decision was made to acidize the well in December 2010, following the "normal" annual mechanical scale removal.

2. WELL SPECIFICATIONS

The well has three feedzones, all lying in the Waiora formation. One minor feedzone at 620m depth and two major feed zones at 830m and 940m depth. The feed zones are liquid and the fluid enthalpy is about 1100 kJ/kg. The well layout (production casing and liner) and feedzones are illustrated in all figures showing downhole runs (Figure 2, 3, 6 and 7).

3. INVESTIGATIVE WORK

Initially the annual mechanical scale removals were sufficient to keep the well on production, although some decline in productivity was observed in the 2009 flowing survey. However, after the mechanical workover in January 2010 it was difficult to restart the well and keep it in production, leading to further investigations. A seven day heat-up run in February showed no significant changes in the shut pressure but flowing surveys in March revealed a decline of the productivity reaching a low of 20 t/h per bar, which is less than 20% of the initial productivity. This also caused the maximum discharge pressure to decline, getting close to the operation pressure and making it difficult to keep the well on steady production. As the shut-in pressure was unchanged, the decline in productivity was attributed to calcite scale build-up mainly outside the liner, either in the wellbore annulus (between liner and formation) or in the formation near the wellbore. Hence a mechanical clean out would not be successful on its own and the decision was made to perform an acid treatment in addition to the next mechanical workover (Grant et al, 2011).

The challenge for the acid treatment was to design a recipe to achieve a successful acid treatment without attacking and damaging the liner and equipment. Therefore, in order to stay within the boundary conditions for temperature, soak time (pump rate) and acid concentration, comprehensive investigations were carried out. Samples of the calcite deposits were analysed to design the acid recipe and the actual well temperatures and inflow depths were confirmed, using former PT surveys and an additional injection fall-off test performed prior to the acid treatment.

3.1 Analysis of scale deposits

Down hole samples were collected, in order to determine the mineralogy and acid solubility of the scale deposits. The analyses, performed by BJ Services, were:

1. X-ray Diffraction Analysis

2. Solubility Analysis at 93°C

3. Moisture content at 105°C

It was confirmed that the deposits mainly consist of calcite and the solubility analysis showed a high solubility of about 99% wt/wt using 15% HCl during a soak time of one hour.

3.2 Determining pump rates

To protect the liner and equipment it was decided that a corrosion inhibitor was required. This corrosion inhibitor is only effective below 175 °C, which defined the upper temperature boundary and therefore the minimum pump rate.

From the solubility analysis it was known that to dissolve the acid successfully, a temperature of minimum 93°C and a soak time of about one hour were necessary, defining a maximum pump rate.

The temperature profiles from the initial injection test show that with a pump rate of 45 t/h, the temperature lies within these boundaries for all three feedzones, but gets very close to the upper boundary at the bottom of the well. The next highest injection rate of 92 t/h causes the temperature at the top feedzone to be a little bit below the 93°C but still within an acceptable limit (Figure 2).

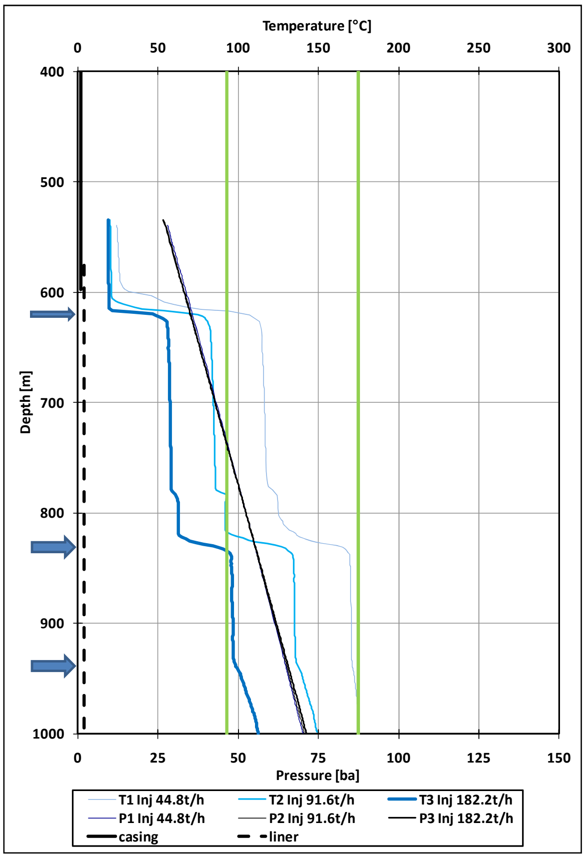

Figure 2: Pressure and temperature vs. depth from original injection tests (2005). The green lines show the temperature boundaries and the blue arrows represent the feed zones.

During the pre-acidizing injection tests even the lowest pump rate of 67 t/h caused the temperature in the well to drop below the lower boundary of 93°C (Figure 3). This would usually lead to a decision to use a lower pump rate, but it was decided to stick to the 67 t/h pump rate based on the temperature profiles of the initial injection test. At this pump rate the temperatures in the well are only slightly (maximum 28°C) below 93°C and furthermore in order to let the acid soak for a while the decision was made to cease pumping for about 30min after acidizing which also would give the well the chance to heat-up. After the acid treatment the pump rates would be lowered to 43 t/h for a lesser quenching effect.

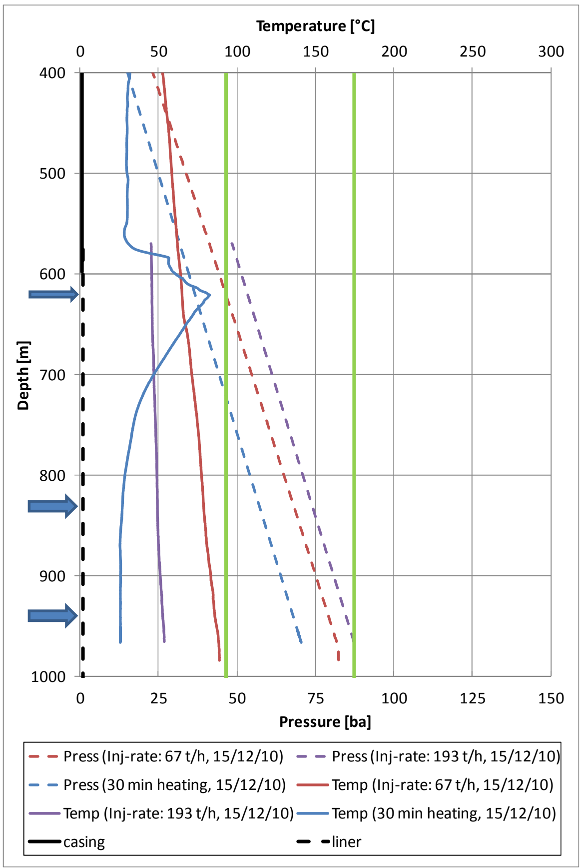

Figure 3: Pressure and temperature vs. depth from pre-acidizing injectivity tests. The green lines show the temperature boundaries and the blue arrows represent the feed zones.

4. ACID TREATMENT

Based on the investigation work an acid treatment program was designed with a 15 % HCl solution at a pump rate of 67 t/h (≈18.5 l/s). Prior to the acidizing the well was quenched through the side valves at a pump rate of 67 t/h. A 5" drill pipe was run down to 806 m in order to focus on the two major feed zones (it was required that the pipe stays at least 20 m above the upper major feed zone at about 830 m). Before pumping the acid the quenching was stopped to prevent dilution of the acid, which was then pumped over a period of 50 minutes. Additionally 60 litres of corrosion inhibitor was pumped during the acid injection to protect the liner and equipment. After the acid treatment, a soak time of about 20 minutes was allowed before after-flushing with water to displace the acid further into the formation (Kalfayan, 2008). Afterwards the quenching was recommenced at a lower rate of 43 t/h (≈12 l/s), to allow higher temperatures and maximise the time for the acid to dissolve the calcite scale. After about one hour 16,000 litres of soda ash solution (150 kg Na_2CO_3 dissolved in water) followed by 8,000 litres of water for after-flushing was pumped into the well to neutralise the remaining acid in the equipment. The pump rates during the acid treatment are shown in Figure 4.

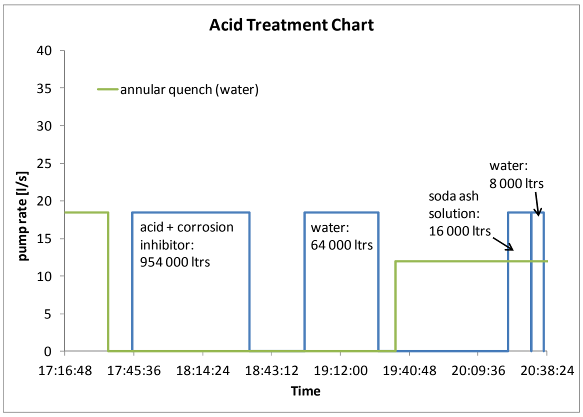

Figure 4: Pump rates during acid treatment.

5. RESLUTS

To evaluate the success of the acid treatment, injection and 30 min heat-up PT profiles were recorded straight after the acid treatment, as well as a flowing survey and a casing corrosion (HHCC) log (Stevens, 2000) in January 2011. The following different aspects of the pre- and post-acidizing well tests are compared.

5.1 Productivity

The injectivity and productivity of the well since it was originally drilled are plotted on Figure 5. This shows that the acid treatment was successful, reaching a productivity which is basically in line with the productivity and injectivity when the well was new.

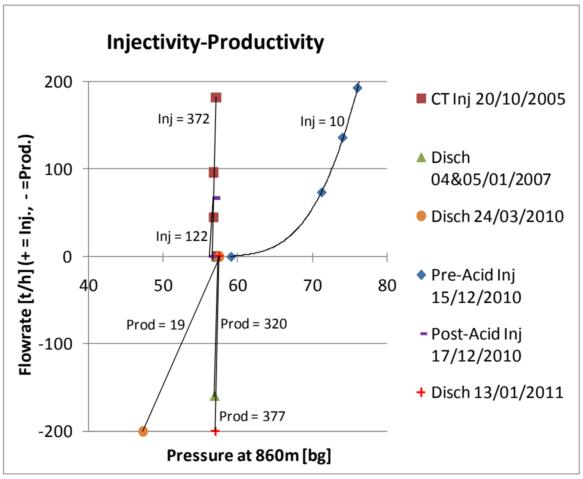

Figure 5: Injectivity and Productivity during well lifetime at 860 m depth.

Compared to the last flowing survey before acidizing (24/03/2010) the productivity after acidizing is more than 19 times higher and even slightly higher than 14 month after completion (Table 1).

Date	Inj./Disch.	Pressure @ 860m depth	Injectivity – Productivity

	rate [t/h]	[bg]	[t/h/bar]
20/10/05	45	56.8	372
	96	56.8	
	182	57.1	
04/01/07	0	57.4	320
05/01/07	-160	56.9	
24/03/10	0	57.6	19
	-200	47.3	
15/12/10	67	71.3	10
	136	74.1	
	193	76.1	
	0	59.1	
17/12/10	67	56.8	122
	0	56.2	
13/01/11	-200	57.0	377
	0	57.5	

Table 1: Summary of injectivity and productivity from Figure 5.

The regaining of the initially high productivity/low drawdown is also seen by comparing the downhole pressures of the different PT runs of the 3.5 month shut (09/05/2006), and the pre- (24/03/2010) and post-acidizing (13/01/2011) discharge tests (Figure 6). The discharge pressure from the post-acidizing test is the same as the 3.5 month shut pressure, which indicates no drawdown. Comparing the 3.5 month shut pressure to the pre-acidizing discharge pressure gives a drawdown of 0.05 bar per t/h.

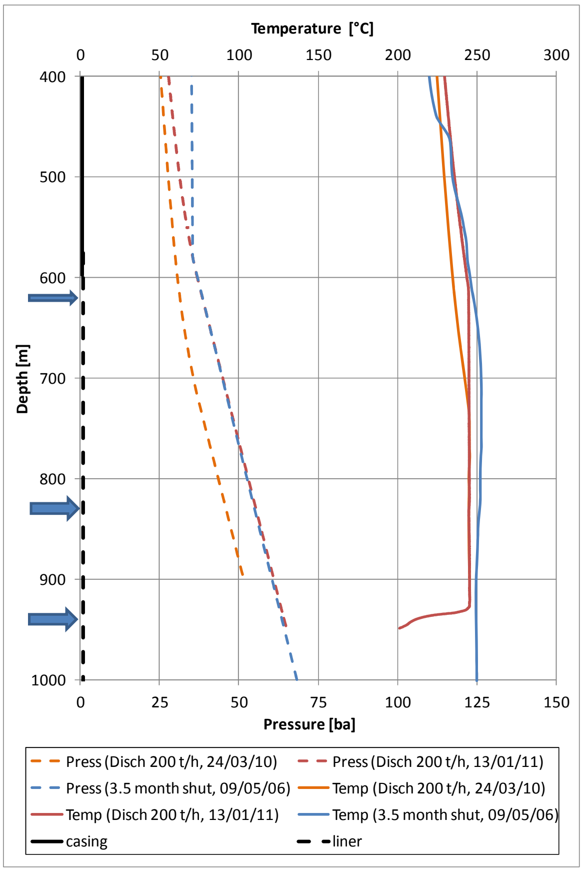

Figure 6: Pressure and temperature vs. depth for 3.5 month shut and pre- and post-acidizing discharge tests. The blue arrows represent the feed zones.

5.2 Fluid velocity

The discharge rate for the post-acidizing flowing survey was 200 t/h. For 200 t/h discharge the theoretical fluid velocity in the liner is:

$$v_{th} = (q/\rho)/A_{Liner}$$

$$= ((200/3.6\ kg/s)/810\ kg/m^3)/(\pi/4*0.25^2\ m^2) = 1.4\ m/s$$

The flowing spinner profile from January 2011 shows that this velocity is reached almost throughout the whole liner above the upper major feedzone at 830 m. Although the data is not exact it appears that about 60% of the flow is from 940 m and 40% from the 830 m feedzone at this time (Figure 7).

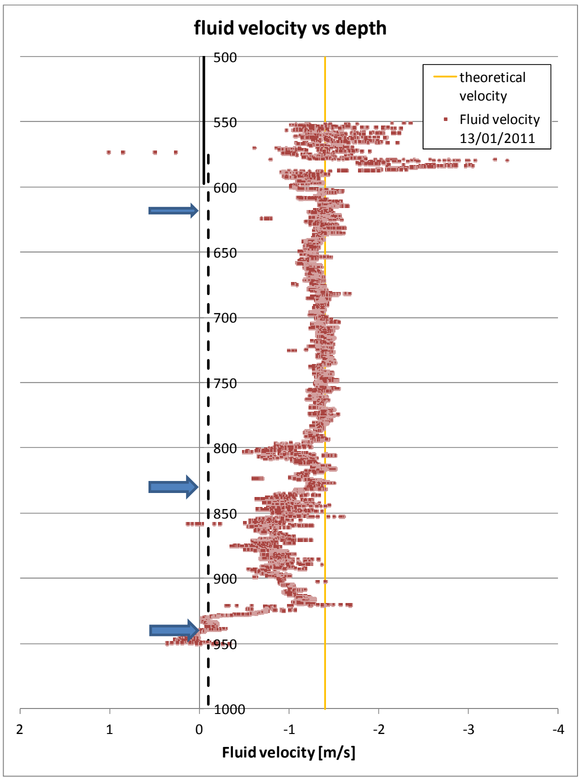

Figure 7: Fluid velocity and pressure vs. depth from post-acidizing flowing survey (200t/h).

5.3 Casing condition

In addition to the well performance tests, hot hole casing corrosion (HHCC) tests were carried out one day prior and two weeks after the acid treatment. This was done in order to check if the treatment had any negative effects on the perforated liner. Comparing the results of the two tests there was no detectable metal loss before and after the acid treatment.

6. CONCLUSION

The different comparisons and evaluations of the well performance show that the acid treatment was fully successful in recovering a marginal productive well and fully regaining its original productivity.

The acid recipe and pump rates need to be chosen wisely to achieve a successful acid dissolution without damaging the equipment.

Even though the downhole temperature for the selected injection rate was below the optimum value (<93°C) during acidizing, the treatment was successful.

The soda ash solution and corrosion inhibitor were effective in protecting the equipment and the liner, as no damage or metal loss could be detected.

The acidizing is less expensive and time consuming than other methods, especially if the scaling is extended to the annulus or into the formation..

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