Thermal Fracturing of Well H-40, Los Humeros Geothermal Field

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Keywords

Los Humeros, thermal fracturing, injection tests, well stimulation

ABSTRACT

Well H-40 was drilled for production in 1997, but the well was not able to sustain flow. After it was monitored to assess its injection capacity, the well was changed to an injection well, but the well did not accept more than 5 tons of fluid per hour (t/h). The well was stimulated by thermal fracturing in three tests made in October 2005. As a result, the well accepted up to 110t/h and can be used as an injection well.

1. Introduction

Well H-40 is located in the central part of the geothermal field of Los Humeros, Pue. at an altitude of 2795 meters above sea level. It was drilled in 1997 in order to increase the steam production in the field, to feed the 35 MW installed there. It is a directional well, which programmed depth was originally scheduled for 2250 m. However, several problems were encountered during drilling, where the drill string was trapped at 2226 m depth, leaving a mechanical fish from 2128 m. Therefore, it was decided to complete the well to that depth, hanging the slotted linner between 1600 and 2127 m depth. The casings diagram is presented in Figure 1.

The lithological column encountered during drilling is depicted in Figure 2, where the temperature records can also be seen, using different shut in times. Using these surveys, three permeable areas were identified: the first between 1610 and 1720 m, the second between 1770 and 1870 m and the third between 1960 to 2120 m. Circulation losses from 10 to 26 m^3 / h were measured from 1639 m depth to the bottom of the well (Figure 2, overleaf).

The results that were obtained during drilling suggested that the well would be a good producer. However, no wellhead pressure was detected during the heating stage and according to the temperature and pressure surveys, the fluid was far away from the saturation curve. Because of that, CFE tried to induce production by pressurizing the well head with air, increasing it to approximately 800 psig. This operation allowed brief discharges of fluids at the surface, but discharge was not sustained. After several attempts in January 1999, it was decided to use the well to monitor the down hole reservoir pressure, installing a nitrogen chamber at 1700 m depth. The chamber remained until February 2001. The down hole pressure fluctuated between 1300 and 1260 psia, and the well head pressure was between 5 and 6 psig during that period.

Once the chamber was retired, the well continued to bleed though a ½" line for several years, without showing any improvement in its thermal characteristics.

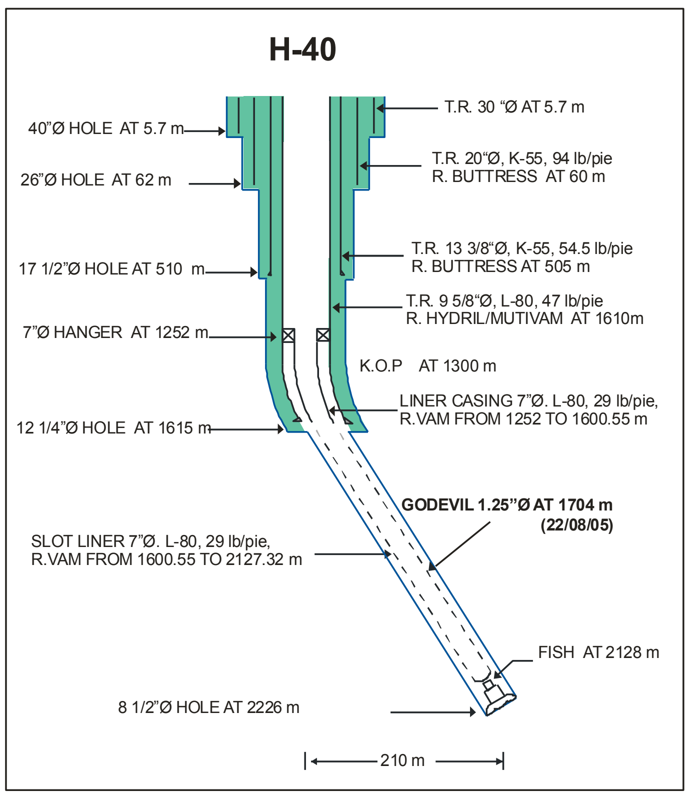

Figure 1. Casing diagrams, Well H-40.

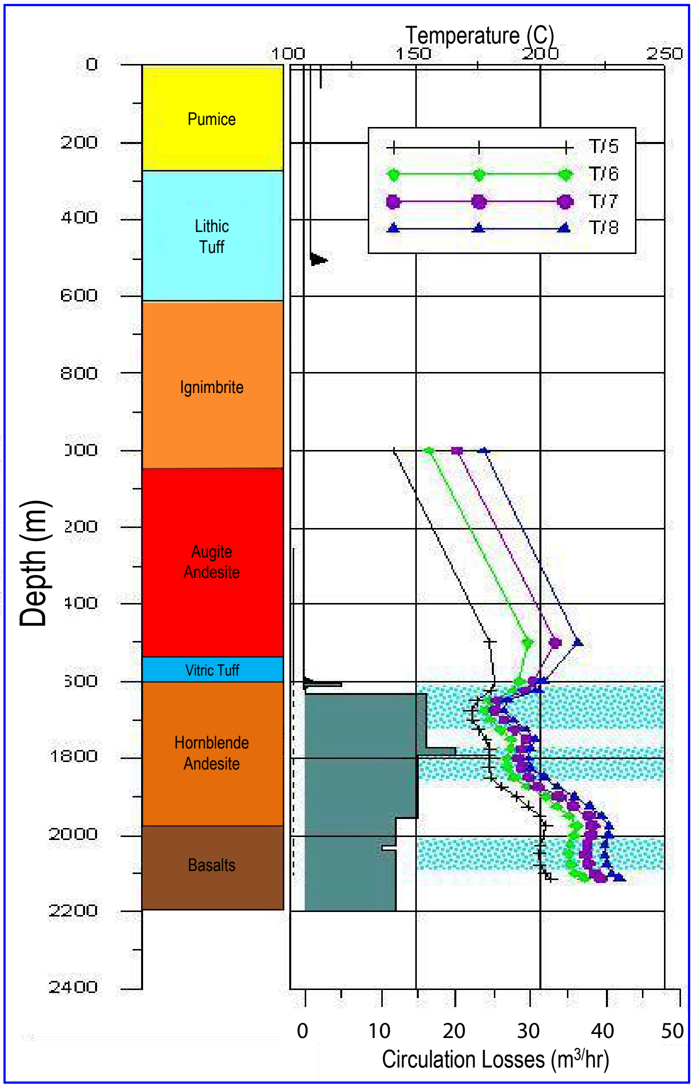

Figure 2. Lithological Column, temperature recovery surveys and circulation losses during drilling.

2. Thermal Fracturing

Thermal shock is the name given to cracking as a result of rapid temperature change. Thermal shock occurs when a thermal gradient causes different parts of an object to expand by different amounts. This differential expansion can be understood in terms of stress or of strain, equivalently. At some point, this stress overcomes the strength of the material, causing a crack to form. If nothing stops this crack from propagating through the material, it will cause the object's structure to fail (Wikipedia, 2008). In order to better understand the rock stresses and the possibilities to fracture the rock, mechanical core testing was done. The core plug has a compressive strength of 15988 psi, with Young´s modulus of 4.7E+06 and Poisson Ratio of 0.188.

The thermal fracture program was developed according to the procedures used in the geothermal field of Krafla, Iceland (Palsson, 2004) and that of Bouillante, France (Sanjuan et al. 2000). Generally speaking, the procedure is to inject cold water for a short period, even if the accepted fluid amount is small, preferably by pumping with positive well head pressures between 10 and 20 bar. At the end of that time, injection is suspended, the well is shut in for 8 hours and this sequence is repeated for three days while monitoring the well injectivity closely (Flores, 2004).

The procedure was undertaken in well H-40 on July 13, 2005. The initial injection of cold water was at zero wellhead pressure, using a mass flow rate of 5 t / h. The flow rate was increased gradually, while some water overflowed in each of those flow rate changes. On 17 July, the fluid injection was suspended for 72 hours and the down hole pressure was measured at 1700 m depth. The fluid injection was restarted from July 20th to the 25th, getting a maximum mass flow capacity of 35 t / h. The injection was suspended for thermal recovery on July 27th. Similar activities were done from October 7th to 10, 12 to 13 and 17 to 18, 2005. At the end of the thermal treatment, the well reached an injection capacity of up to 110 t / h, which was the maximum amount that could be tested since no more water was available.

During those periods, three pressure transient tests were done, to evaluate the product of the permeability thickness (kh) and the skin factor in the well, as we were developing this work. In all pressure surveys setting depth was 1700 m.

3. Pressure Transient Test

The first test took place from October 7 to 10, 2005. In this test the well accepted a peak flow of 60 t / h, which was maintained during 50 minutes. The pressure fall off was measured for 72 hours. It is important to note that while injecting 60 t /h of geothermal fluid, the down hole pressure reached 130 bar, which drops 40 bar when injection stopped. The data obtained were analyzed by standard techniques using Pansystem ™ commercial software.

The diagnostic stage of the test used the derivative technique to identify radial flow, which was analyzed with the semilog technique (Figure 3) and subsequently the results were confirmed using type curves and numerical simulation (Figure 4). The kh product obtained was 1.2 Darcy meters with a skin factor of 1.23.

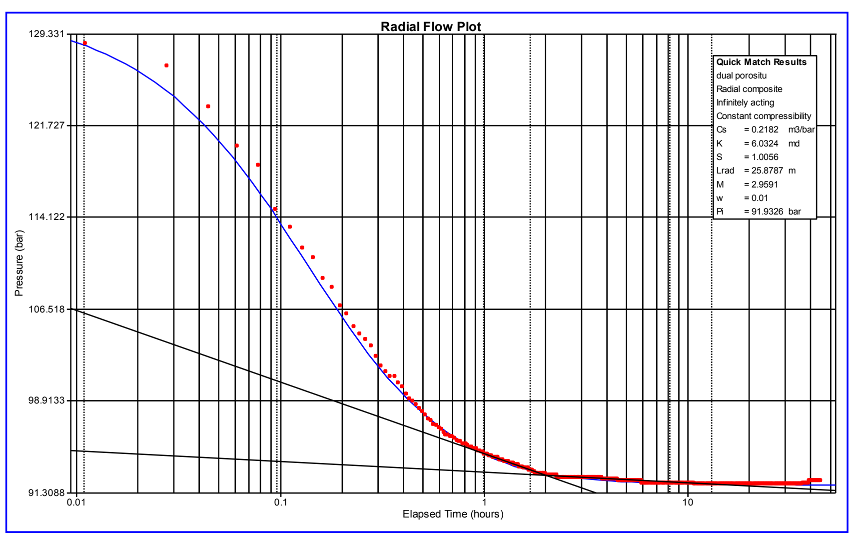

Figure 3. Radial flow analysis for the 1st pressure test.

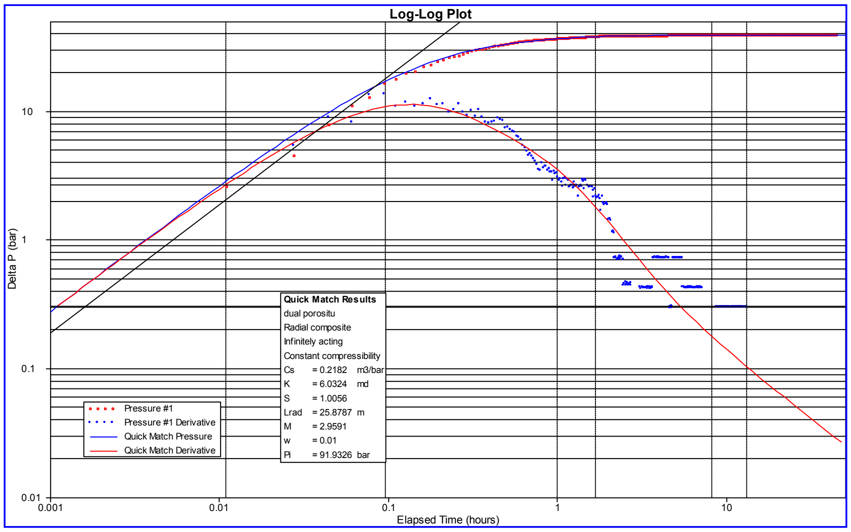

Figure 4. Numerical Simulation of 1st pressure transient test.

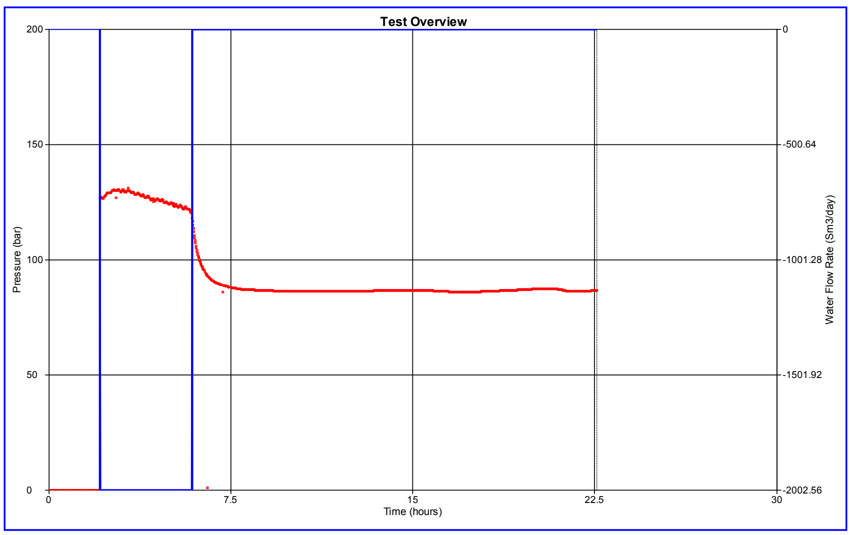

Figure 5. Second pressure transient test.

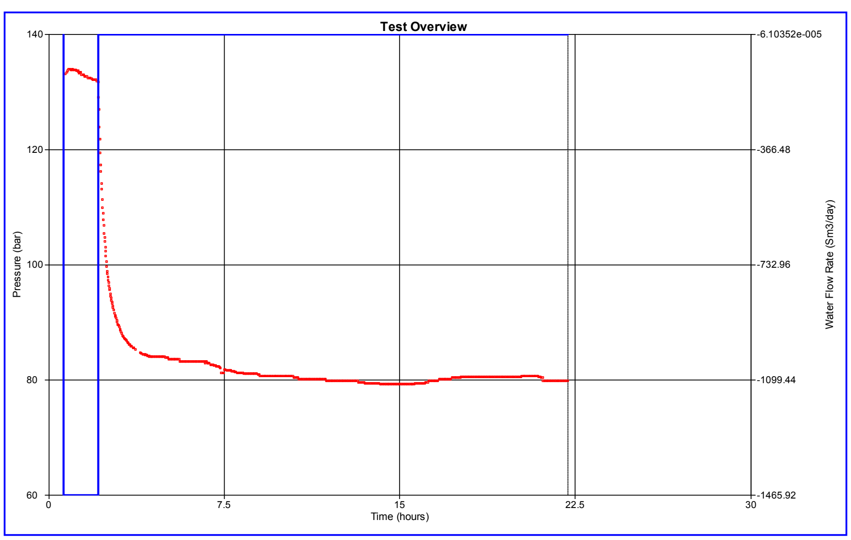

Figure 6. 3rd pressure transient test.

The second test took place from 12 to 13 October 2005. During this testing, the well injection capacity increased to 83.4 t/h, which was maintained for 6 hours. The pressure fall off was measured for 25 additional hours (Figure 5). During this test, the maximum measured down hole pressure was 130 bar, which decreased to 120 bar towards the end of the injection period, without flow rate variation. The total pressure drop in the fall off stage was 40 bar. Unfortunately, this pressure test could not be analyzed for the kh product and skin factor.

Finally, we conducted a third test starting October 17 - 18, 2005. On this occasion the well accepted an average flow rate of 108 t/h, which was maintained for 4 hours before flow was suspended. The pressure fall off was recorded for 24 additional hours (Figure 6).

In this third test the maximum measured pressure was 132 bar. By suspending the injection, the pressure drop was 55 bar. The calculated kh was 7.6 Dm and the derivative shows the characteristic "signature" of a fractured reservoir or dual porosity, which have not been detected in early stages of the treatment (Figure 7, overleaf).

4. Discussion

Ordinarily in an injectivity test, the higher the flow rate, the greater is the down hole pressure at any particular setting depth. Normally when injection stops, pressure will eventually returns to pre test values. If fracturing is caused in the formation, such behavior is different. If the new fractures connect to a different compartment in the reservoir, different reservoir pressure can be obtained, eventually reaching the typical pressure of the reservoir.

When this treatment started, well H-40 did not accept more than 5 t/h and the geothermal fluid began to overflow at the surface. As CFE continued with the treatment, the ability of the well to accept fluids gradually increased until it reached 110 t/h of geothermal fluid.

Figure 8, overleaf, shows the behavior of the down hole pressure measured at 1700 m depth in well H-40 during the three tests discussed above. It can be noted how the down hole pressure in the well diminished as it began to accept more fluids. This is an indication that the treatment was opening up channels that communicate better with the rest of the reservoir. A summary of the results is presented in Table 1, overleaf.

As noted, the static water level in the well was changed from 780 m to 837 m and then to 902 m deep. That is, as a result of the stimulation treatment the static level fell 122 meters.

As it can be seen in the testing, the latest skin factor was negative, which showed the stimulation of the well due to the thermal cracking effect causing either strain changes or shear dislocation in the rock.

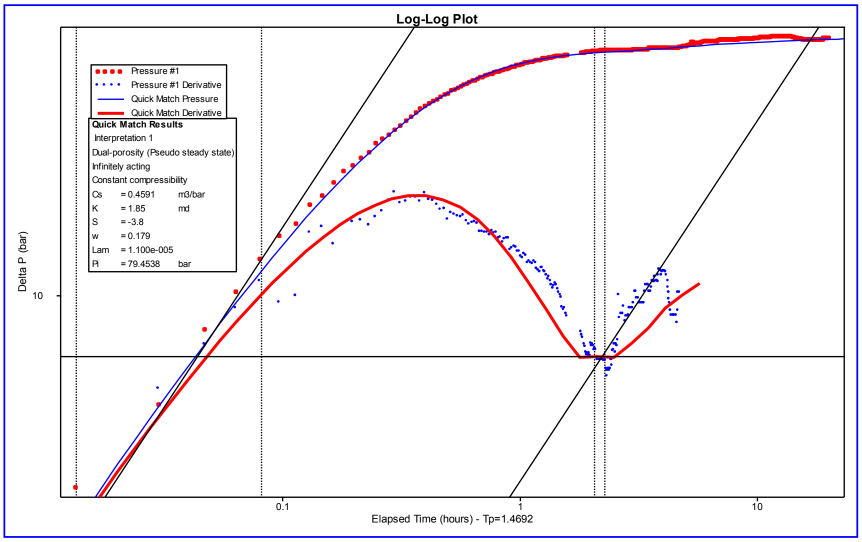

Figure 7. Numerical Simulation for 3rd transient pressure test.

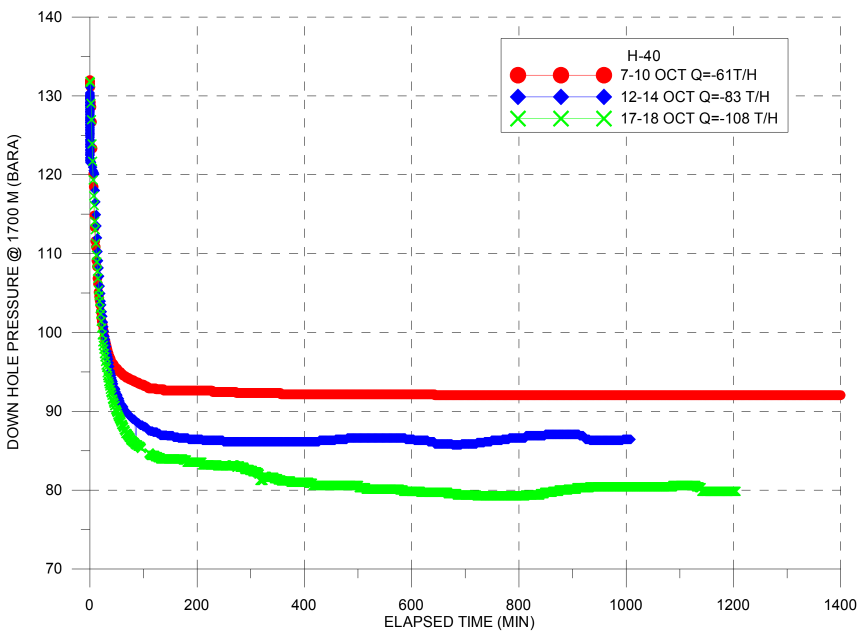

Figure 8. Pressure fall off behavior during the tests.

Table 1. Pressure transient testing results in well H-40.

Date	Flow Rate (t/h)	Static Water Level (m)	kh (mD-m)	Skin Factor
7-10/Oct/05	-61	780	1224	1.23
12-14/Oct/05	-83	837	ND	ND
17-18/Oct/05	-108	902	396	-3.41

The same procedure has been recently applied in well H-43 at the end of the drilling process. The well did not experience circulation losses during drilling, even though fracturing was detected, but after the thermal treatment the well accept more than 150 t/h. After shut in, the well produced around 50 t/h of steam.

5. Conclusions

This thermal fracture treatment was conducted successfully between July and October 2005 in well H-40 showing positive results. This has been corroborated both with the increase of injection flow rate and transient pressure testing results.

The treatment allowed savings to CFE, since there is no necessity to drill a new injector well for the system.

6. References

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