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Wellbore Calcite and Silica Deposition Issues and Solutions: A Case Study at Domo San Pedro

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ABSTRACT

The Domo San Pedro field began commercial operation in 2015 with the commissioning of two back pressure units. In March of 2016, a new condensing unit was commissioned, and by December 2016 it was operating with 4 production wells. In October 2016, well A reached its maximum production and began a steady decline of 0.023 tph/day. Mineral speciation modelling suggested this well was supersaturated with respect to calcite. A mechanical workover was executed in August 2018 but well head pressure and total mass flow data showed the workover was not successful. The issues were identified as calcite and silica scaling in the wellbore and formation. Chemical intervention and stimulation, that did not involve the use of risky Hydrofluoric acid, occurred in July 2019. This paper presents the case history of this well, the information that was studied, the results of the chemical speciation modelling, the design of the chemical intervention, and the preliminary results.

1. INTRODUCTION

This well was drilled in December 2013 to a total depth of 3754.46 mBGL, averaging 14 t/h of steam during first discharging tests, approximately 45t/h of total mass flow. During drilling, several bands of calcite were encountered, but overall, the permeable zones of this well consist of hornblende and biotite granodiorite, with andesitic, aplitic and rhyolitic dykes. In April 2014, an acid fracturing procedure between 2450m and 3750m was proposed and executed. Table 1 summarizes the stimulation program for this intervention.

Table 1: Acid Stimulation Program of 2014

Stage	Fluid type	Volume (m^3)	Flow rate (m^3/min)
1	HCl 10%	7	2.4
2	HCl 15%	28	2.4
3	Gel phase acid	6	2.4
4	KCl 2%	30	2.4
5	Brine	11.4	2.4

After this well work over, the well was discharged once again, with flows estimated at 31 t/h of steam and 100 t/h of total mass flow. However, field necessities at the time required an additional reinjection well rather than a production well, so this well was turned into a reinjection well shortly after.

The well was used intermittently as a reinjection well, with acceptance rates of brine of around 100 t/h with positive wellhead pressures. After several months of being used this way, the well showed a reduced acceptance capacity. It has been speculated that this reduction is a consequence of reinjecting brine oversaturated with respect to silica. Compounded with this, is the fact that the well was only used intermittently, so the brine cooled off significantly between reinjections and allowed for additional silica deposition in the wellbore and fractures.

Eventually, in March 2016, the well was turned back into a production well. After a few weeks of stabilization, the well began to grow its steam production, from an initial average of 25.2 t/h in April 2016, to a maximum of 47.6 t/h in October of the same year. Figure 1 shows the historical trend of steam and brine flow, as well as enthalpy of this well. A continuous upward trend of mass flow was seen from April 2016 to October 2016, when production capacity began a continuous decline at an average rate of 0.023 t/h of steam, per day. Enthalpy, on the other hand, showed a steady trend upward. The authors have speculated this is due to additional flashing inside the well bore, from diminished permeability due to calcite deposition and due to the high enthalpy flashing in the formation depositing calcite and silica.

Finally, on March 31 2019, the well was shut-in due to its low WHP and inability to fully integrate to the steam management system. Just prior to shut-it, the well was contributing 7 t/h of steam with 9.3 bar at wellhead.

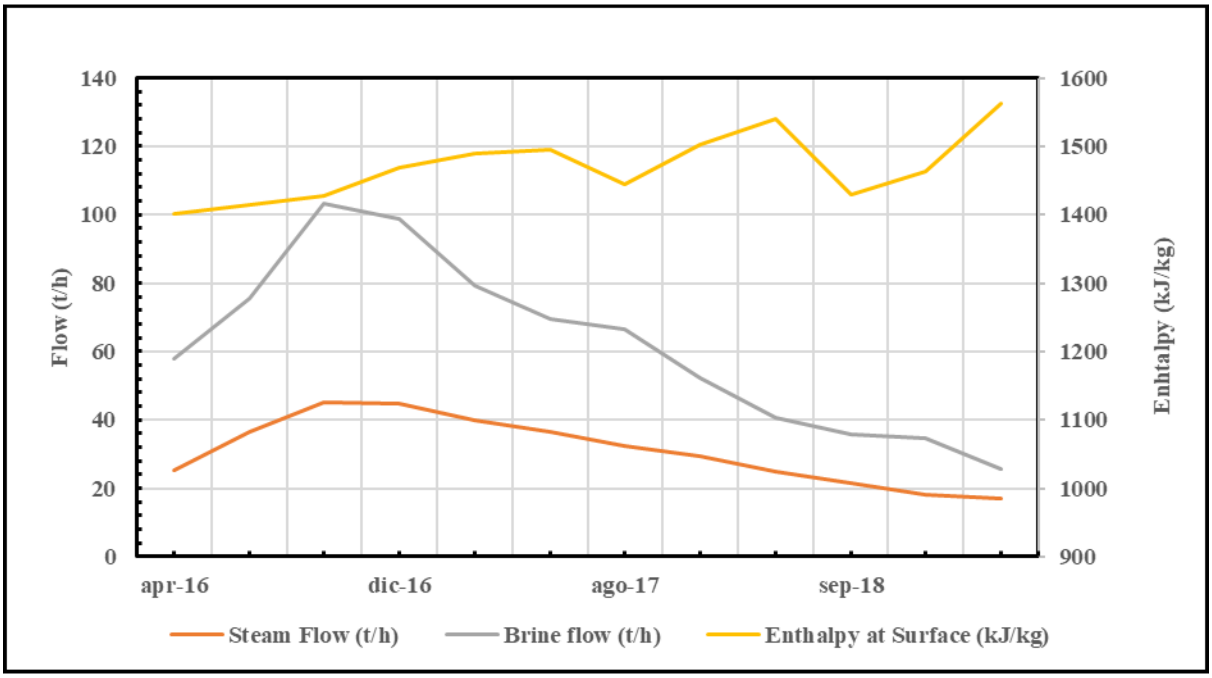

Figure 1: Mass Flow and Enthalpy History of Well A

2. WELL CHEMISTRY

This well discharges brine at the highest pH and total alkalinity of all producing wells at Domo San Pedro, with relatively low content of gas in the steam phase. A summary of the discharge chemistry is presented in Table 2 and Table 3.

Table 2: Average Brine Discharge Chemistry for Well A

pH	Conduct (µS/cm)	TDS (ppm)	Total Alk (mEq/L)	Cl	B	HCO3	SiO2	SO4	Na	K	Li	Rb	Ca	Mg	As	Fe	Al
				(ppm)													
6.97	4762	2988	1.05	1508	43	29	922	16	760	253	14	2.4	12	0.00	2.0	0.1	0.3

Table 3: Average Steam Discharge Chemistry for Well A

Total gas	He	H2	Ar	N2	O2	CH4	CO2	H2S	NH3
%wt									
1.088	0.000	0.018	0.026	0.817	0.000	0.010	92.54	6.55	0.036

From this information, a speciation simulation was carried out using WATCH geochemical speciation program (Arnórsson, Sigurdsson and Svavarsson, 1982). As shown in Figure 2, there is clear oversaturation with respect to calcite and silica. The calcite oversaturation is a direct response high pH, Bicarbonates and Calcium content of the brine, itself a consequence of the calcite bands observed during drilling. The Silica saturation index is in direct response to the high temperatures observed at the bottom of the well (estimated formation temperature of 314°C).

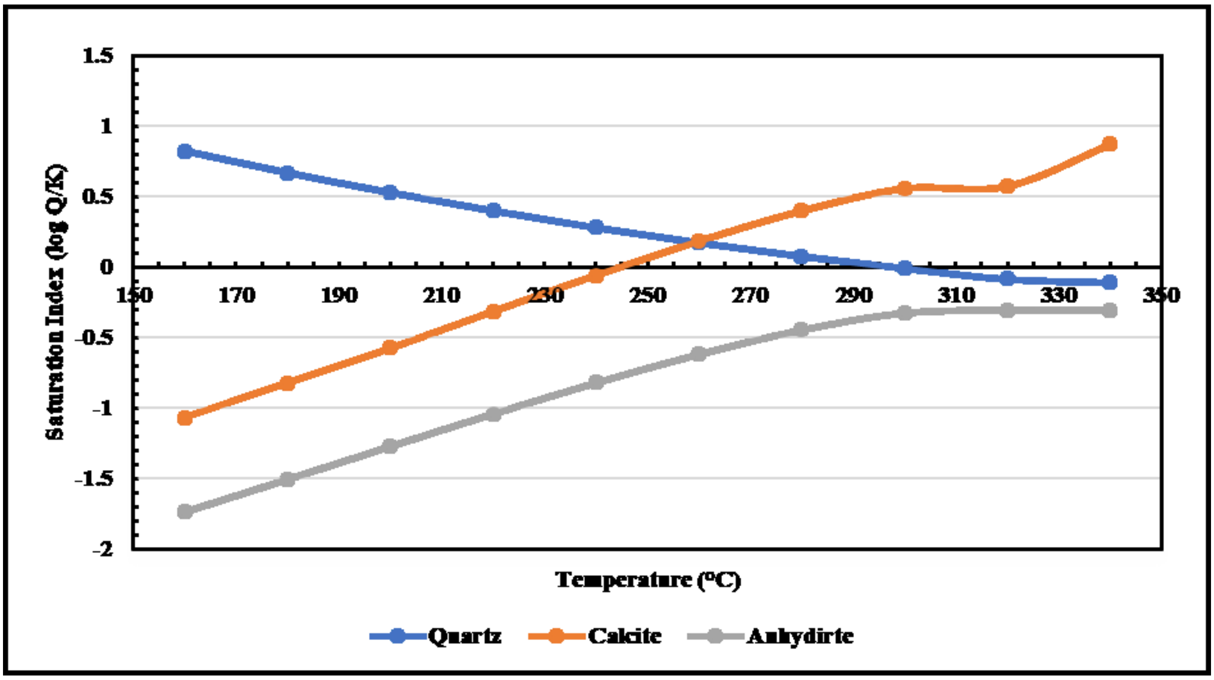

Figure 2: Saturation Index for Selected Minerals for Well A

2.1 Deposit Analysis

The workover and subsequent PTS runs gave us the opportunity to have the scale analyzed. We found there were three feed zones, each with scale consisting of calcite and silica. Scale analysis from Solenis of drilling returns from the mechanical workover in 2018 showed there was between 23.8% and 28.0% SiO2 and between 4.0% and 4.4% aluminum. If there is still a question of whether or not the aluminum and silica come from the granodiorite, or from silica scaling, the fact is that the silica saturation index is near zero, or above, speaks that there is a real chance the deposition comes from aluminosilicates and amorphous silica. Table 4 shows the chemical composition of the deposits recovered during the mechanical workover.

Table 4: Deposit analysis performed by Solenis

Element	Analysis detail at 2579 m (% w/w)	Analysis detail at 2786 m (% w/w)	Analysis detail at 3600 m (% w/w)
Loss on ignition (1000 C)	10.3	9.0	26.6
Carbonate (as CO_2)	9.0	5.0	25.4
Iron (as Fe2O3)	32.4	31.9	20.8
Silicon (as SiO_2)	23.8	28.0	9.1
Calcium (as CaO)	10.2	7.6	28.0
Sulfur (as SO3)	8.2	8.0	5.6
Aluminum (as Al2O3)	4.4	4.0	1.7
Magnesium (MgO)	2.2	2.6	1.5
Sodium (as Na2O)	2.1	< 1.0	< 1.0
Phosphorus (as P2O5)	1.8	2.6	4.8
Gold (as Au)	1.1	ND	ND
Copper (as CuO)	< 1.0	1.0	< 1.0

3. WORK-OVERS OF 2018 AND 2019

3.1 Mechanical Work-Over

A 16-day mechanical workover was planned for July 9 to July 25, 2018. Between the depths of 2579m and 2691m, granular crystal habit calcite with sizes ranging between 1 to 4 mm were recovered in the drilling fluid returns. These depths correspond to the first flash point in the well. Calcite proportion in the returns varies but is generally around 10%. Between 2691m and 2786 m the presence of calcite rises from 15% to 45% in some cases. In this case, the calcite has a granular habit with sizes varying between 1 and 5mm. Alongside the calcite, granodiorite and some andesite is present. Between 3405m and 3477m more granodiorite and calcite return in the drill cuttings. The calcite is mostly present with granular habit and sizes between 1 and 5mm. In the range between 3465m and 3477m, the calcite proportion in the returns varies between 50% and 80%, with a prismatic habit. Finally, between 3489m and 3600m, the presence of calcite in the drill cuttings returned to a range around 20%.

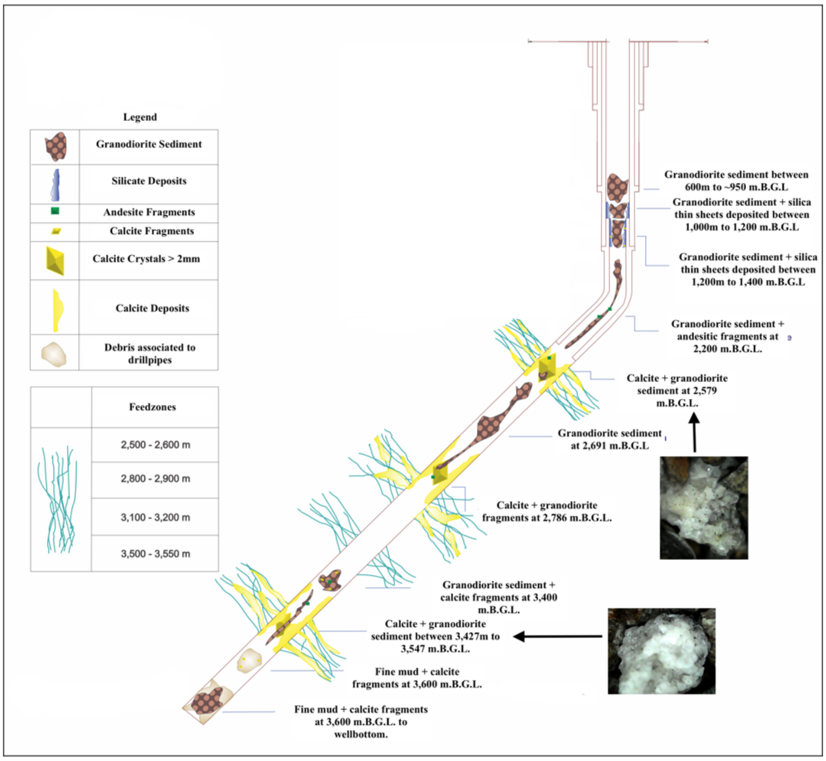

Figure 3: Mechanical obstructions found during 2018 workover

3.2 Chemical Work-Over

Following the negative results of the 2018 mechanical workover, and the decreasing production capacity of this well, a chemical workover was proposed and executed in July 2019. As mentioned before, by March 2019, the well was nearly dead, with a steam flow of 7 t/h and maximum wellhead pressure of 9 bar. Whilst Hydrofluoric acid was used in other parts of the world the risk, cost and unpredictability of results ruled out this option except as a very last resort. A new concept had been used in New Zealand by Solenis that was successfully removing silica without use of acids at all. After careful consideration of all options Grupo Dragon decided to adopt the non-HF method in combination with 10% HCl to open this well up.

Solenis had developed a new corrosion inhibitor that was about 10% of the cost of many other inhibitors used in acid jobs, After four sets of corrosion test results all aligned from a world recognized laboratory in Houston, Dragon agreed to use this new very low toxicity inhibitor during the acid stage of calcite removal. For the stage of silica removal, the solution formulation was not corrosive so did not require inhibitors.

The Solenis method is under patent approval at the moment but includes techniques that ensures the chemical reaches into the formation. Something during offline clean with coil units does not always achieve as per some previous experiences by power producers in New Zealand.

As shown in Table 5, there are 3 main stages for the acid workover. Stage 1 consists of HCl 10%, aimed at dissolving the calcite deposits in the wellbore and the formation. Stage 2 consists of HCl 10% + Formic acid 10%. Because the formic acid does not react with calcite as quickly as HCl, this stage has the advantage of extending the reaction with calcite to locations deeper inside the formation, allowing for an enhanced permeability in the drain radius of the well. Finally, Stage 3 consists of an alkaline solution aimed at dissolving silicate deposits that may be occurring alongside calcite deposition because, as seen in Figure 2, there is also a super saturation with respect to silica.

The workover began on July 18, 2019 with the pumping of 206.9 m3 of HCl 10%. Table 5 shows a summary of the activities included in the acid workover. There was no need to identify special interest zones inside the wellbore because the bull heading technique guaranteed the entire wellbore was in contact with the acid solution. This has an advantage over coiled tubing placement of the acid. In the latter technique, the usual procedures require permeable zones to be identified with drilling logs and PTS surveys. This can sometimes be difficult, as there might be areas inside the wellbore that have been damaged during drilling and are “hidden” during surveys. In this case, these zones might be ignored, and no acid will be programmed to be pumped there. By flooding the entire wellbore, there is guarantee that all zones, regardless of whether or not they have been successfully identified, will be treated with the acid solution.

Table 5: Acid Stimulation Program for 2019

Stage	Fluid type	Volume (m^3)	Flow rate (m^3/h)	Placement Method
1	HCl 10%	206.9	48	Bullheading
2	HCl 10% + Formic Acid 4%	86.3	48	Bullheading
4	Alkaline Solution	98.8	17	Coiled Tubing Unit

During Stage 1, 206.9 m^3 of HCl 10% were pumped at a constant rate of 47.7 m^3/h. A close monitoring of flow rate and pressure was kept during the entire operation. Figure 4 show the behavior of these variables during the entire workover. What aided the operation was that the wellhead pressure of the well was negative, suggesting the well was accepting all of the solution. As can be seen, the pressure during this stage was low, meaning it was possible to increase the flow rate. However, the pumps were not capable of pumping a higher volume of solution.

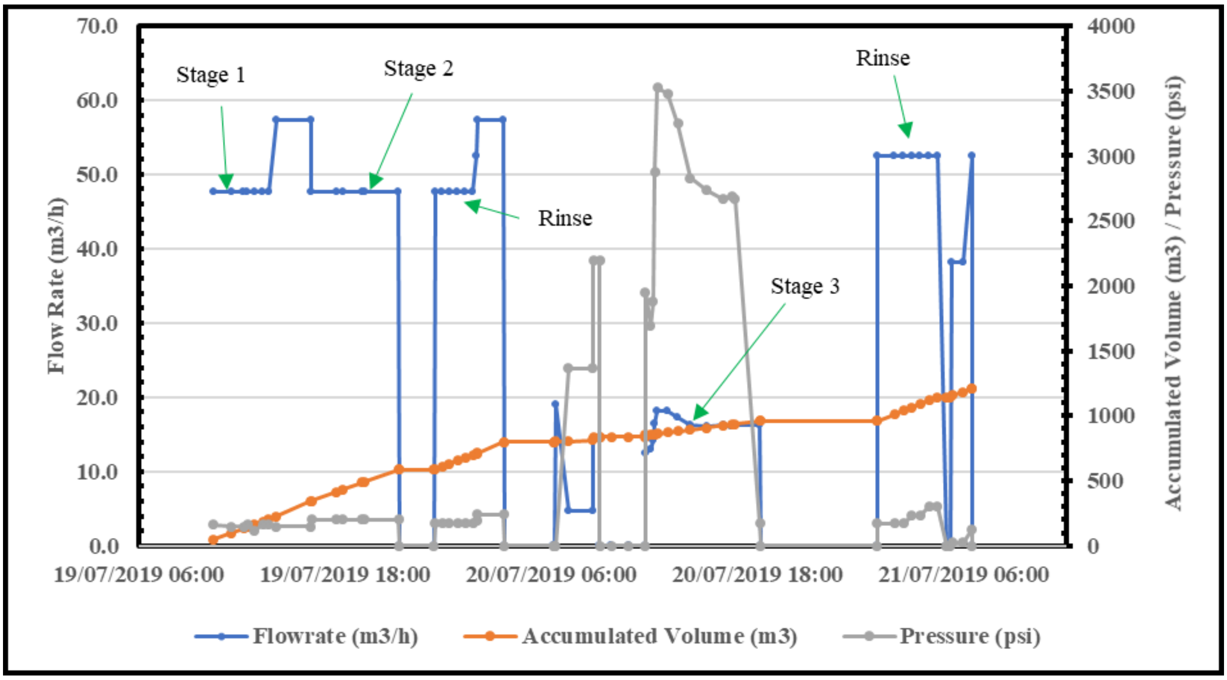

Figure 4: Monitoring during acid workover

Stage 2 consisted on pumping 86.9 m3 of HCl 10% + Formic Acid 4% at roughly the same rate as Stage 1. At this stage, once again, the pressure was relatively low and the well allowed for a faster flow rate, but the operation was limited to the flow capacity of the pumps used in the operation.

Stage 3 consisted on pumping 98.8 m3 of alkaline solution using the coiled tubing. The pressure was considerably higher during this stage, as high friction forces come into play when pumping through the CTU.

4. RESULTS OF STIMULATION

After integrating the well to the steam system, a reliable steam measurement was possible. As shown in Table 6, the steam supply difference after the workover is 18.6 t/h, roughly equivalent to 2.6 MW, and an improvement of 351%. The brine flow increase is considerably larger, but that is due to the fact that, at the time this writing was submitted, the well was still discharging the fluids used in the workover. The wellhead pressure increase is close to 2.5 barg. Unfortunately, because of operational delays, the pressure build-up test programmed to measure the new permeability and skin conditions was postponed until August, past the submitting deadline of this paper. Nonetheless, they are expected to show an improvement compared to the conditions of the well prior to the workover.

Table 6: Pre and Post Treatment Parameters

Parameter	Before Shut-in	After acid workover
Steam Flow (t/h)	7.4	26.0
Brine Flow (t/h)	14.8	60.3
Wellhead Pressure (barg)	9.36	11.4
Permeability (md)	0.2	N/A
Skin	-3.2	N/A

5. CONCLUSIONS

A chemical workover method which does not include hydrofluoric acid has been tested at the Domo San Pedro geothermal field, in Mexico. Using a combination of HCl 10% and HCl 10% + Formic Acid 4% for calcite removal, alongside an alkali solution for attacking silica deposits. Preliminary results show an improvement on the well performance without the need for using hydrofluoric acid

6. ACKNOWLEDGEMENTS

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