ACID STIMULATION OF INJECTION WELLS IN SAN JACINTO GEOTHERMAL PROJECT, NICARAGUA

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ABSTRACT

Acid stimulation with mechanical workover was applied in injection wells SJ1-1, SJ10-1, SJ11-1 and SJ12-1 in the San Jacinto Geothermal Project, Nicaragua to recover lost injection capacity caused by mineral (silica) deposition along the wellbore and also improve their permeability. Detailed well testing and analyses and improved acid treatment design were implemented to increase the effectiveness of the acid stimulation.

The use of memory pressure-temperature-spinner logs and improved well test interpretation became essential for better candidate evaluation, acid treatment design and quantification of pre-acidizing well parameters and evaluation of acidizing results. Further improvements in acid treatment design were also achieved with application of higher main HF acid concentration up to 12% HF acid, increased injection rates and the use of mechanical diverter. Post-acid treatment results showed around 30% to 700% increase in injection capacities.

1. INTRODUCTION

The San Jacinto-Tizate geothermal field is located in northwestern Nicaragua, approximately 20 km northeast of the city of Leon that is centrally situated among a series of active volcanoes (Figure 1). The initial phase of exploration drilling conducted in 1993-1995 by Russian company Intergeotherm S.A. confirmed a liquid-dominated reservoir with temperatures of 260°C – 300°C in the central upflow area and benign chemistry. The San Jacinto-Tizate Geothermal Field was acquired in 2003 by Polaris Energy Nicaragua S.A. (PENSA) who engaged Jacobs (formerly Sinclair Knight Merz, SKM) to evaluate the resource potential and develop and implement a strategy for the commercial development of the resource.

In late 2015, PENSA initiated a program to improve the production and injection capacity for the San Jacinto Unit 3 and Unit 4 (Jacobs 2015). Majority of the injection wells SJ1-1, SJ10-1, SJ11-1 and SJ12-1 ST1 have displayed decline in injection capacities due to mineral (silica) deposition. Thus, PENSA programmed these wells for mechanical workover and acid stimulation to improve their injection capacities and thereby eliminate drilling of new injection wells.

2. CANDIDATE WELLS FOR STIMULATION

2.1 Well SJ11-1

Injection well SJ11-1 is a large diameter forked (2 legs) well. The original leg of the well was completed on 19 June 2011 to a depth of 2012.5 mMD RT (Rotary Table).

Figure 1: San Jacinto-Tizate geothermal project location.

The 9-5/8” perforated liner was run to 1993.6 mMD. The injectivity testing of the original leg indicated an injectivity index of approximately15 tph/bar.

Considering the injectivity index was less than the targeted 30 tph/bar, the well was forked to obtain a higher injectivity and to maximize the injection capacity from the well. The drilling of SJ11-1 fork leg commenced on 21 June 2011 and was completed on 10 July 2011. SJ11-1 fork leg reached a total drilled depth of 1645 mMD after kicking off at the milled window of the 13-3/8” diameter casing at 722.7 m. The 9-5/8” diameter liner was set and landed at 1645 mMD. The drilling of the fork leg recorded total loss circulation greater than 1,050 gpm starting at 1,500 m until total depth of 1,645 mMD.

The change in injectivity in well SJ11-1 occurred shortly after production well SJ12-3 went into the system in 2012. Inspection of the production system, including the separator, has shown that SJ12-3 produced formation which accumulated as fill in SJ11-1. Additionally, SJ12-3 is a high temperature well, and at current separation conditions its produced brine is supersaturated with silica. Silica scaling has been observed in the production system and has undoubtedly impacted the injectivity of SJ11-1.

In October 2013, the three (3) hour vertical discharge did not recover any debris from the well. It was then suspected that more silica had accumulated in the fork leg considering the relatively higher permeability of the forked leg compared with the original hole. However, based on the PTS log conducted in 19 December 2014, the majority of the fluid was exiting at the fork leg suggesting minimal obstruction.

The well has maintained average capacity (~460 tph) for about three years since the initial decline but displayed gradual decline in injection capacity in February 2015.

Injection capacity continued to decline at constant WHP of ~16 barg where the well was accepting approximately ~80 tph before the planned workover and acid stimulation.

The primary objective for the acid stimulation of injection well SJ11-1 is to recover the lost injection capacity (~ 360 tph) by doing the following activities in sequential order:

- Clear the original leg from 1907 mMD to bottom.
- Acidize the original leg and spot acid across casing window. Acid treatment will be conducted at the permeable zone(s) of the original leg and dissolve the likely mineral (silica) deposits and drill cuttings around the wellbore annular space that cannot be addressed by mechanical workover.

The clearing operation using aerated fluid aims to mitigate the transfer of debris to the fork leg while clearing the original leg. Since transfer of drilling debris cannot be fully ascertained, an option to pump acid across the fork window will be considered to dissolve any drilling materials that may have entered the fork leg during clearing of the original leg.

2.2 Well SJ10-1

Injection well SJ10-1 is a regular diameter vertical hole drilled using PSB Massarenti Rig 6000. The well was spudded on 1200H, 27 February 2008 and completed after 28 days. The loss circulation in the production hole started at 634 mMD which eventually led to total loss circulation starting 978 m. Light mud was used from 634 meter until total loss circulation at 980 m. Drilling was suspected to have been deflected by a network of fractures around the margin of the diorite intrusive which was encountered from 850 m to 982 mMD. This resulted to increase in well inclination reaching 8° at 1094 mMD, even with a pendulum bottomhole assembly, and a twist-off incident experienced at 1132 m as a result of hard and rough drilling. Three (3) overshot fishing assembly trips and a milling job were conducted to recover the fish. Drilling resumed using a slick bottomhole assembly until total depth of 1195 mMD was reached. Water and cold brine was used while drilling without return. The 7” diameter perforated liner was ran and set at 1186 mMD RT with the top of liner at 418 mMD. The rig was released on SJ10-1 at 0700H of 26 March 2008.

Historically, well SJ10-1 has good injection performance. The loss of injectivity in the southern brine injection wells, SJ 1-1 and 10-1, has not been severe. The injection capacity has been maintained by raising wellhead pressures by 1 bar between 2013 and 2014. Based on the result of the 1-3/4” Ø sinker bar run last November 2013, the measured clear depth was at 829 mMD which is 357 meters off-bottom. The obstruction was suspected to be silica flakes and deposits above the main permeable zones.

The primary objective for the workover of well SJ10-1 is to recover the lost injection capacity (~ 225 tph) by clearing the suspected silica fill starting 829 m to bottom. Acid stimulation will also be conducted in the permeable zone(s) and dissolve the likely mineral (silica) deposits and drill cuttings around the wellbore annular space that cannot be addressed by mechanical workover.

2.3 Well SJ1-1

Injection well SJ1-1 is a standard diameter vertical hole drilled using a Russian rig from 13 January 1993 to 12 September 1993. The well was initially drilled to a total depth of 2,322 mMD RT. Observations during drilling indicated a lack of significant permeability in the deeper part of the well. The hole was plugged back with cement to about 1,213 m before running the production liner and completing the well. The liner was hung at 889 mMD.

SJ1-1 was worked over from 10 to 15 May 2010 using aerated fluid. The 9-5/8” casing was cleared to top of liner using 8-1/2” bit in 20 hours The 6-5/8” liner was cleared using 5-1/2” bit using aerated fluid from 891 mMD RT down to 1215.8 mMD in 22 hours. The aerated fluid used for clearing consisted of 4.2 bpm of water combined with 630 scfm of air added with 1.8 gallon per hour of foam. The workover removed large volume of sediments and fragments of silica. Before releasing the rig, an estimated five times the hole volume capacity was pumped downhole at 600 gpm without any wellhead pressure registering.

The primary objective for the workover of well SJ1-1 is to recover the lost injection capacity (~ 248 tph) by clearing the suspected fill at 945 m to bottom. Acidizing will also be programmed to dissolve the likely silica deposits and drill cuttings in the permeable zones and annular space around the wellbore that cannot be addressed by mechanical workover.

2.4 Well SJ12-1 ST1

Well SJ12-1 ST1 was spudded on 07 May 2010, using ThermaSource Rig 104 and completed on 22 July 2010. The 9-5/8” liner was squatted at 1618 mMD (20.4 m off bottom). Additional permeability was not achieved in the original leg due to drilling problems and wellbore instability.

During drilling of the original leg, the circulation loss started at 1400 mMD. The well intersected the problematic oxidized rock (hematite) formation starting 1484 mMD. The problematic horizon was drilled with mud then followed with aerated fluid as soon as loss circulation was encountered. The collapsing nature of the formation coupled with loss circulation above it made drilling below 1515 mMD a challenge. The higher air rates (2,000 scfm) used to regain circulation caused unstable zones to washout. The hole was drilled to 1638.4m using aerated mud. Two stuck pipe incidents, during a connection and after an aborted airlifting attempt, resulted to fishing operations.

Due to low output of the original hole, the well was re-entered. ThermaSource Rig 104 re-entered the well on 31 January 2011. The free 9-5/8” production liner was cut and recovered and the12-1/4” diameter hole was sidetracked. The sidetrack leg was drilled sub parallel to the original hole. The sidetrack leg was drilled using aerated water with regular polymer sweep.

The sidetrack hole was initially drilled to a target depth of 2438 mMD. Based on the poor injectivity index value of 5 tph/bar compared with offset wells, the well was further deepened to seek additional permeability. Significant losses were encountered during further deepening. The well was completed to a total depth of 2595 meter on 09 March 2011.

The maximum injection rate for well SJ 12-1 is not well established, but at start-up, the well was accepting around 200 tph at less than 2 bar wellhead pressure (WHP). Currently, the well is accepting 200 tph at 12 bar WHP. This change in injectivity resulted from the development of a blockage in the wellbore that is preventing the injectate from descending to the deeper permeable entries.

Based on the result of 6"Ø and 7"Ø sinker bar run on the 05 June 2014, the measured clear depth was determined at 1560 mMD which is 1000 meters above the bottom of liner (BOL). Blockage is suspected to be silica minerals. Silica may have bridged at the obstruction depth which coincides with a change in the hole profile from a high angle build to a low angle drop in inclination of wellbore. Considerable silica deposition mixed with rock fragments were recovered from the weir box during the discharge attempt (May 2011).

The objective and scope of the workover was to remove the blockage at around 1560 mMD and suspected fill near bottom and recover the lost injection capacity (~ 320 tph). Acid stimulation will also be conducted to dissolve the silica deposits around the wellbore and improve the permeability of the well.

3. CANDIDATE WELLS EVALUATION

The parameters used on evaluating the candidate wells included the correlation of well test, drilling, chemistry and injection performance history. The use of memory pressure-temperature-spinner (PTS) tool was also applied in establishing payzone targets for the selected wells. PENSA also initiated the application of improved welltest interpretation software in improving the analysis of pressure transient data of the wells.

Pre-workover completion tests were conducted in the candidate wells to establish baseline information prior to stimulation. Table 1 below summarizes the results of the downhole tests completed.

Well	SJ11-1	SJ10-1	SJ1-1	SJ12-1
Test Date	26 April 2016	11 May 2016	21 May 2016	03 June 2016
Pre-WO Injection Capacity (tph) / Wellhead Press (Barg)	~80 (~16 barg)	470 (~6 barg)	660 (6 barg)	~150 (15 barg)
Pre-WO Injectivity Index (tph/bar) / Test Depth (m)	15.3 (1800m)	35.8 (800m)	61.4 (930m)	14.1 (1500m)
Wellhead Pressure (bar)	Positive	Zero	Zero	Positive
Transmissivity kh (d-m)	~6.0	~76.7	~59.0	~2.2
Skin (s)	+1	+5.1	+9.8	-1.1

Table 1: Summary of pre-workover completion test results.

4. ACID TREATMENT DESIGN

A matrix acid treatment procedure was applied for the injection wells. Acid solubility tests were conducted in the drill cuttings and scale samples collected for the candidate wells using the industry standard acid concentration of 10% HCl preflush acid mixture and 10% HCl-5% HF mainflush acid mixture (Malate et. al., 1997). Acid solubility results gave moderate average total dissolution rate (<45%) of test samples especially SJ11-1 where significant pure amorphous silica deposits may have likely invaded the permeable zones. Revision of the acid solubility tests led to the application of higher 12% HF acid concentration for SJ11-1 and slightly higher 6% HF acid concentration for the other injection wells. Acid solubility of >60% was attained using 12% HF acid concentration. The application of higher 12% HF acid concentration also resulted to the use of more concentrated liquid HF concentration compared to the usual application of ammonium bifluoride (ABF) salt to generate the HF acid.

A higher 15% HCl preflush acid mixture was also employed in the acid job design to initially dissolve acid soluble deposits and serve as spacer between the mainflush acid and formation brine. The preflush acid volume was based on a dosing rate of 50 gallons per foot of target zone while a dosing rate of 75 gallons per foot of payzone thickness was employed in the mainflush acid volume.

The acid treatment was conducted by injecting the appropriate acid mixtures through an open ended drillpipe (OEDP) set at the target payzones. A combination of 5" and 3-1/2" drill pipes were utilized to maximize hydraulic efficiency. The acid injection process was modified into stages so that the treatment could be applied more evenly across the payzones particularly for wells with multiple zones. This was done by segmenting the target zones into smaller sections (e.g. 50 meters) and treating each zone separately. The end of acid string was spotted just above each target section and correspondingly the calculated acid mixture volume injected into the section. Acid treatment started from the bottom most target zone going up until the shallowest target zone. The acid injection rate was maintained as high as possible (~10 bpm) but below the calculated pressure gradient to achieve improved acid penetration into the desired targets. The acid treatment job summary is presented in Table 2.

Well	Acid String Depth (mMD RT)	Main Acid Volume (bbls)	Average Injection Rate (bpm)	Average Treating Pressure (psig)
SJ11-1	1898.2 1655.0 715.3	293 293 293	8.0 8.5 10.5	1600 1443 1050
SJ10-1	990.2 642.0	293 293	10.2 10.4	1436 853
SJ1-1	1104.0 1001.0 934.0	293 293 293	10.1 8.0 9.3	1782 763 1156
SJ12-1 ST1	2181.0 1404.0	293 293	8.1 8.0	2690 1770

Table 2: Acid treatment job summary.

An attempt to temporary isolate target zones in the original leg of SJ11-1 from the fork leg section of the well was implemented by using mechanical packer. The mechanical packer was set just below the fork window and the acid string set at the window. Setting of the packer was not fully achieved that spotting of the main acid mixture into the fork leg was not fully attained.

5. RESULTS OF THE ACID TREATMENT

Post acid completion tests were conducted in the candidate wells to determine improvement in the wellbore in terms of changes in injectivity indices, changes in temperature and pressure profiles and payzone thicknesses and other reservoir parameters. These tests are basically water loss, injectivity and pressure transient tests patterned after the pre-workover and pre-acid completion tests. The memory PTS tool were also used in the post acid evaluation tests.

5.1 Well SJ11-1

Mechanical cleanout by reaming and de-scaling of the original leg of SJ11-1 was carried out in the 13-3/8" production casing and 9-5/8" liner to 1995 m RKB. Water pumping rates were maintained at 1100 gpm with air assist in the range of 1000-1350 scfm. Fine grained scales were first observed at 900 m. Megascopic analysis of the initial returns at 900 m predominantly gave aluminium silicate minerals. Relatively coarser cuttings were recovered inside the production liner with largely amorphous silica with minor quartz.

Post Workover Completion Test

A post workover completion test was conducted on 01 May 2016 by running in the PTS tool at ~30 m/min for the water loss survey at 300 GPM pump rate. An injectivity test followed with the PTS tool set at 1800 mMD and pump rates of 500 GPM, 800 GPM and 1100 GPM for 2 hours duration for each pump rate. Following this, a pressure falloff test was carried out after the pumps were shut and the falloff monitored for 6 hours.

As illustrated in Figure 2, the post workover injectivity index increased from 15.3 tph/bar to 16.3 tph/bar after the workover, with a corresponding decline in downhole injection pressure for the same pump rate of approximately 20 bars. A decline in water level was also observed (~ 220 meters) after the workover compared to positive water level at the wellhead registered during pre-workover injection test.

The acidizing operation targeted three permeable zones; 1900 mMD, 1650 mMD and the fork window at 715 m. Acid injection into the target depths was successfully conducted on 03-04 May 2016 with the programmed treatment volumes and pump rates. Vacuum wellhead pressures were observed during the acid injection.

A mechanical packer was set in the well to isolate the acid injection into the fork window (722.4m to 730.4 mMD RT) for the third target zone. The mechanical packer appears to have not properly inflated at the setting depth of 741 mMD RT based on the pull test conducted by the Rig before acid injection and during pull out of acid string. Figure 2 also illustrates the results of post-acid injection test conducted in the well.

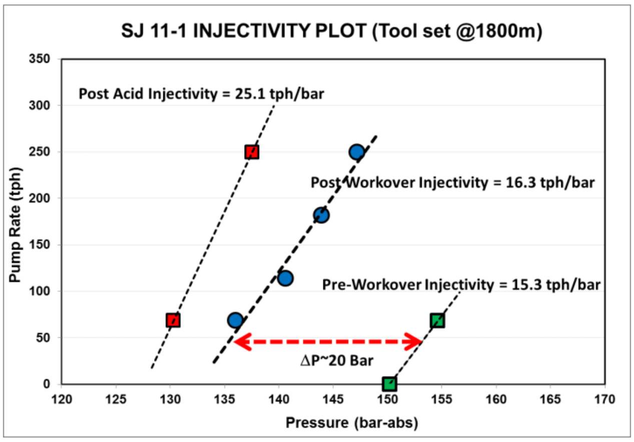

Figure 2: SJ11-1 post acid injectivity against pre- and post workover injectivity with tool set at 1800 m.

A higher post acid injectivity index of ~25.1 tph/bar was obtained compared with the pre-workover injectivity index of 15.3 tph/bar at 1800 meters test depth. A decline in downhole pressures (~30 bars) was also observed after the post acid injectivity test, which meant restriction to flow was reduced and hence improved acceptance of the well.

The water level reached a depth of ~280 meters during post acid injection test of the original leg compared to positive water level at the wellhead observed during pre-workover injection test. A small additional decline in water level (~10 meters) was observed after acid injection into the fork leg. The total decline in water level after acid injection is indicative of additional improved acceptance of the well.

A higher post acid injectivity index of ~20.3 tph/bar was also obtained for the combined legs compared with the pre-workover injectivity index of 12.3 tph/bar at 700 meters test depth. A decline in downhole pressures (~30 bars) was also observed after the post acid injectivity test, supporting the well's improved acceptance. Figure 3 shows the post acid injection test results for the combined legs.

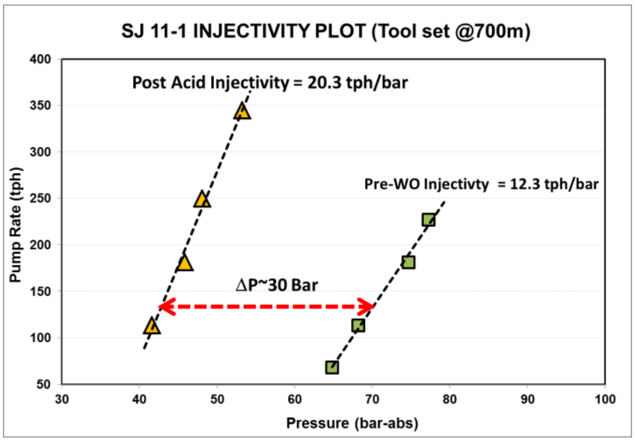

Figure 3: SJ11-1 post acid injectivity against pre- and post workover injectivity with tool set at 700 m.

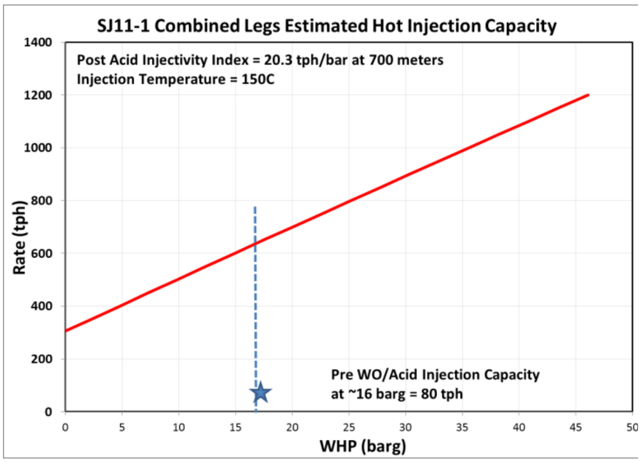

Figure 4: SJ11-1 estimated hot injection capacity after workover and acid stimulation.

The estimated hot brine injection capacity of SJ11-1 against delivery pressure is shown in Figure 4. A hot brine injection capacity of around ~640 tph is modelled using the post acid injectivity index of 20.3 tph/bar at a delivery pressure of 15 barg. For comparison, the well was accepting about ~80 tph at ~16 barg WHP before the workover and acidizing operation.

5.2 Well SJ10-1

Mechanical de-scaling of the 9-5/8" production casing was conducted on 12 May 2016 with water pumping at 700 gpm and 900 scfm of air assist. The 7" liner was de-scaled next with water pumping at 700 gpm and air assist to target fill at ~823 mMD RT. Returns of fine grained scales were first observed at 729 mMD. Megascopic analysis of the initial returns at 729 m predominantly gave aluminium silicate minerals. The de-scaling operation was continued at 968 mMD with a decrease in water pumping down to ~500 gpm with soap and air assist at ~1300 cfm. Relatively coarser cuttings were recovered with largely amorphous silica with minor quartz.

The relatively moderate improvement gained in workover component of original leg of SJ11-1 influenced the decision to forego the conduct of post workover completion test for the other candidate injection wells and prioritize the acidizing component of well enhancement.

The acidizing operation targeted two zones; 640 mMD and 990 mMD, both measured from the rig floor. Acid injection into target depths was successfully conducted on 14-15 May 2016 with programmed treatment volumes and target pump rates. Vacuum wellhead pressures were also observed during acid injection. After the acid stimulation, a post acidizing completion test was carried out, consisting of: a sinker bar run to maximum cleared depth, waterloss survey and injectivity test followed by monitoring of the pressure fall-off. Figure 5 below illustrates the results of post-acid injectivity test conducted in the well.

A threefold increase (3x) in injectivity index was obtained after the acid stimulation/workover of the well. A higher post acid/post workover injectivity index of ~123 tph/bar was obtained compared with the pre-workover injectivity index of ~36 tph/bar at 800 meters test depth.

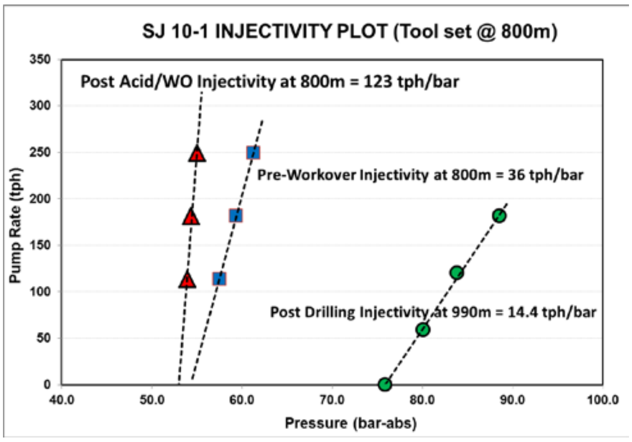

Figure 5: SJ10-1 post acid injectivity against pre-workover injectivity with tool set at 800 m.

The water level of SJ10-1 during water injection at 500 gpm showed a significant decline after completing the acid stimulation of the well. The post acid water level while pumping 500 gpm dropped to approximately 215 meters compared to the pre-workover water level of approximately180 meters. The drop in water level indicates a significant increase in storage capacity of the well.

The estimated hot brine injection capacity of SJ10-1 against delivery pressure is shown in Figure 6 below. A conservative hot brine injection capacity of around ~675 tph has been modelled using the post acid injectivity index of 123 tph/bar at a delivery pressure of 6 barg. The well was initially modelled to accept hot brine at around ~470 tph for the same delivery pressure before the workover and acid stimulation of the well.

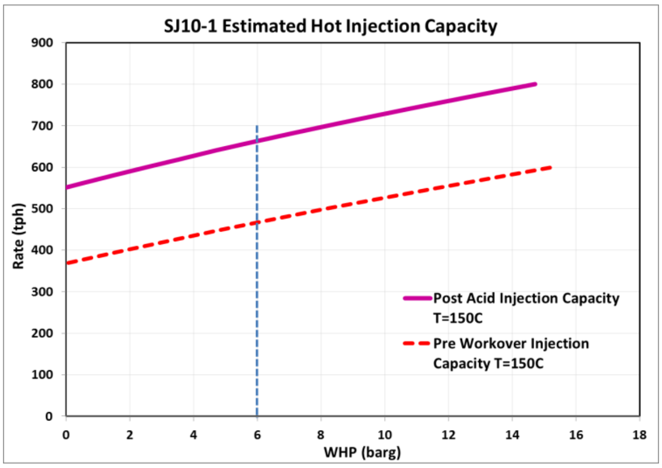

Figure 6: SJ10-1 estimated hot injection capacity after workover and acid stimulation.

5.3 Well SJ1-1

The mechanical workover of injection well SJ1-1 comprised of clearing the 9-5/8" production casing followed by the 6-5/8" liner. Average water pumping rates during the workover were 450-700 gpm with air assist in the range of 1000-1550 scfm. The well was successfully circulated and unloaded at 1222 mMD with 450-600 gpm and 1350-1550 scfm air assist after an earlier unsuccessful attempt to unload the well at the top of liner.

The acidizing operation targeted three permeable zones; 940 mMD, 1006 mMD and 1100 mMD, all measured from the rig floor. Acid injection into target depths was successfully conducted on 24-25 May 2016 with the programmed treatment volumes and pump rates. Zero wellhead pressure was observed during acid injection.

A post acid and workover completion test was carried out after completing stimulation program. Figure 7 below shows the results of post-acid injectivity test conducted in the well. The water level of SJ1-1 during water injection at 500 gpm showed a significant decline after completing the acid stimulation and workover of the well. The post acid water level while pumping 500 GPM dropped to around ~220 meters compared to the pre-workover water level of ~180 meters. The drop in water level suggested a significant increase in storage capacity of the well.

A significant increase (2.6 times) in injectivity index was obtained after the acid stimulation/workover of the well. A higher post acid injectivity index of ~158 tph/bar was obtained compared with the pre-workover injectivity index of ~61 tph/bar at 930 meters test depth.

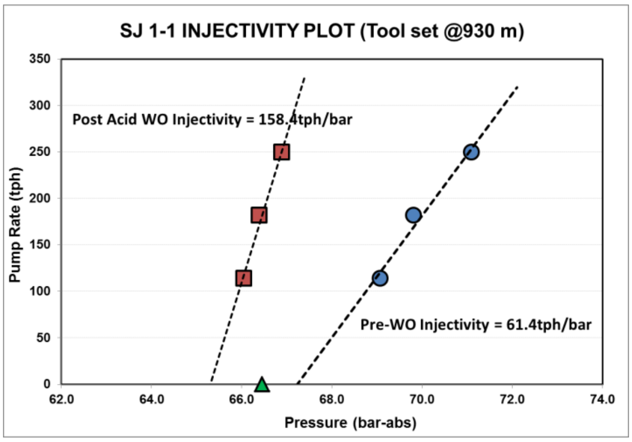

Figure 5: SJ1-1 post acid injectivity against pre-workover injectivity with tool set at 930 m.

The estimated hot brine injection capacity of SJ1-1 against delivery pressure is shown in Figure 8 below. A conservative hot brine injection capacity of around ~850 tph has been modelled using the post acid injectivity index of 158 tph/bar at a delivery pressure of 6 barg. The well was initially modelled to accept hot brine of around ~660 tph at the same delivery pressure before the acid stimulation and workover of the well.

5.3 Well SJ12-1 ST1

Mechanical de-scaling of the 13-3/8" production casing was conducted on 03 June 2016 using a 12-1/4" drill bit and an initial water pumping rate of 1,100 gpm and air rates of 550-1475 scfm. Positive returns were observed during the scales drill-out with air assist. Megascopic analysis of scales recovered at 100+ meters showed major presence of alumina silicates with minor amorphous and quartz silica.

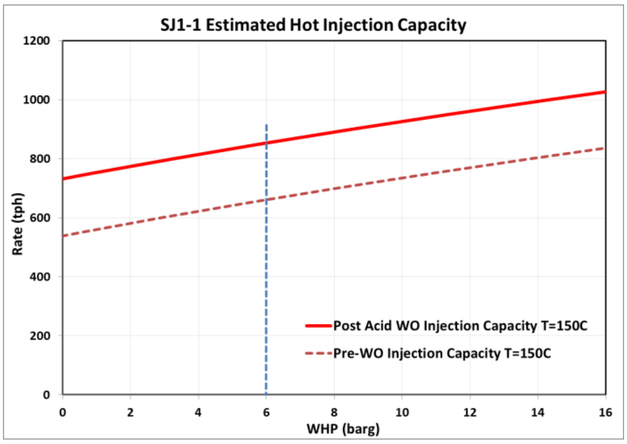

Figure 8: SJ1-1 estimated hot injection capacity after workover and acid stimulation.

De-scaling of the 9-5/8" production liner with water followed by pumping at ~900 GPM with air assist to target obstruction at 1571 mMD RT. Return of fine grained scales was observed upon entering the production liner. Megascopic analysis of the initial returns at 850 m predominantly gave quartz with traces of aluminium silicate minerals and some corrosion products.

The acidizing operation targeted two zones; 1400 mMD and 2250 mMD RT. Acid injection into target depths was successfully conducted on 10 June 2016 with programmed treatment volumes and pump rates. Zero wellhead pressure was observed during acid injection.

After the acid job, a post acid and workover completion test was carried out, consisting of: a sinker bar run to maximum cleared depth, waterloss survey and injectivity test followed by monitoring of the pressure fall-off. The sinker bar survey using a 1-3/4" SB tool was conducted on 11 June at 500 gpm and showed a maximum cleared depth of 2550 mMD RT. The waterloss survey at 500 gpm pump rate showed a larger and more pronounced permeable zone from ~1420 to 1620 mMD RT based on the spinner responses. Waterloss survey also revealed zero pressure at the wellhead.

The water level during the water injection at 500 gpm showed a significant decline after completion of the acid stimulation of the well. The post acid water level while pumping 500 gpm dropped to approximately 190 meters compared to the pre-workover water level at the surface CHF. The drop in water level suggests a significant increase in storage capacity of the well.

Figure 9 below shows the results of post-acid injectivity test conducted in the well. A post acid injectivity index of approximately 13.4 tph/bar was obtained at test depth of 1500 mMD RT, similar to the pre-workover index of 14 tph/bar but with a considerable reduction in pressure resistance (ΔP~18 bars) compared with the downhole pressures obtained before the workover of the well. Zero wellhead pressures were monitored during the post acid injectivity test.

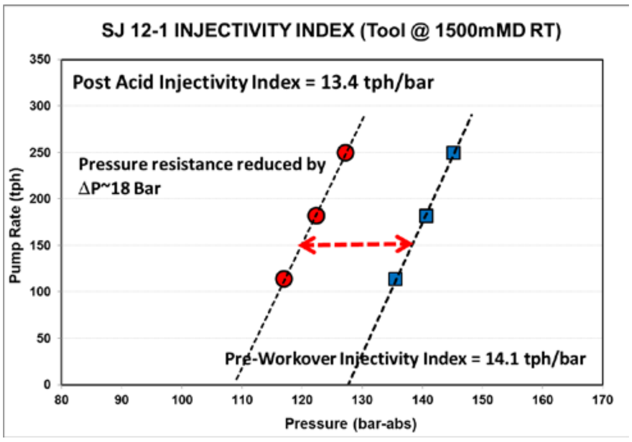

Figure 9: SJ12-1 ST1 post acid injectivity against pre-workover injectivity with tool set at 930 m.

The estimated hot brine injection capacity of SJ12-1 ST1 against delivery pressure is shown in Figure 10. A conservative hot brine injection capacity of approximately 480 tph has been modelled using the post acid injectivity index of 13.4 tph/bar at a delivery pressure of 15 barg. The well was initially modelled to accept hot brine at approximately 150 tph at the same delivery pressure before the acid stimulation and workover of the well.

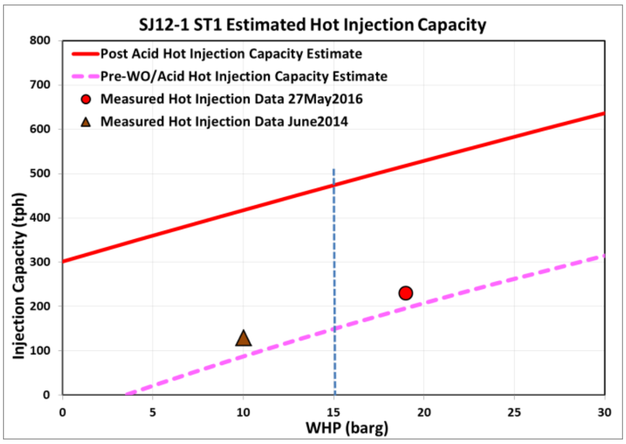

Figure 10: SJ1-1 estimated hot injection capacity after workover and acid stimulation.

Post acid pressure transient data were also analyzed using the welltest interpretation software Ecrin (Kappa 2008). The results are summarized in Table 3 below.

Improvements in well characteristics were attained after the acid treatment as indicated by the results of the post-acid welltest analysis. Transmissivity values of the wells appreciated and enhanced storage capacity was realized with the improvement in storativity. High positive skin values were reduced and negative skin values achieved after stimulation. The damage attributed to silica was substantially reduced if not completely eliminated. Increases in injectivity indices were achieved along with the decline in injection pressures that resulted to overall improvement in injection capacity by a minimum of 190 tph for SJ1-1 and a maximum of 560 tph for SJ11-1. In relative terms, injection capacities increased from 30% for SJ1-1 and 700% for SJ11-1.

Well	SJ11-1	SJ10-1	SJ1-1	SJ12-1
Test Date	03 May 2016	15 May 2016	25 May 2016	11 June 2016
Post-Acid Injection Capacity (tph) / Wellhead Press (Barg)	640 (~15 barg)	675 (~6 barg)	850 (6 barg)	480 (15 barg)
Post-Acid Injectivity Index (tph/bar) / Test Depth (m)	25.1 (1800m)	123.0 (800m)	158.4 (930m)	13.4 (1500m)
Wellhead Pressure (bar)	Zero	Zero	Zero	Zero
Transmissivity kh (d-m)	6.3	77.8	60.5	2.6
Skin (s)	-5.0	-0.1	-0.1	-4.8

Table 3: Summary of post-acid completion test results.

6. SUMMARY

Significant improvement in overall well characteristics was achieved through the application of acid stimulation on injection wells affected by mineral (silica) deposition. The improvements attained were considerable increase in injection capacities, higher injectivites, reduction of skin, and increase in transmissivity and storativity. The effectiveness of the acid treatment was enhanced with appropriate acid treatment design, proper candidate evaluation and improved well testing and analysis before and after the acid treatment. Acid stimulation techniques such as staged acid injection and maximized acid injection rates were found to be beneficial in the treatment design. Post-acid treatment results showed around 30% to 700% increase in injection capacities thereby realizing a total gain of around 1,200 tph of injection capacity.

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