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SOFT ACIDIZING OF DAMAGED GEOTHERMAL INJECTION WELLS. DISCUSSION OF RESULTS ACHIEVED IN THE PARIS BASIN

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ABSTRACT

A new stimulation technique, known as soft acidizing, has been applied to damaged geothermal, district heating, injection wells in the Paris Basin. It consisted of injecting continuously from surface highly diluted HCI solutions mixed with an iron sequestrant additive. The injected acid volume (10 m^3 HCl 15X) is equivalent to that normally squeezed into the reservoir via a drill string during conventional-petroleum/geothermal/ground water well- acid jobs. Only do injection times differ –60 hrs against 1 hr- and the etching process which, in the conventional procedure concerns the reservoir alone whereas soft acidizing addresses both well casing and/or formation damage.

The technique has been successfully implemented in the framework of a field test programme (three geothermal injection wells) encompassing the whole damage spectrum : casing and/or near well formation damage.

The acidizing process has significantly increased well injectivities often above nominal figures and also optimum injection rates. The latter feature is manifest on wells displaying prevailing casing friction losses.

Economic performance may reach pay back times ranging from 8 to 24 months depending on whether additional electric heat supply and electricity consumption or only electric power saving issues are contemplated. Actually the perenniality of the soft acidizing impact may be questioned as suggested by post treatment well monitoring. However none of the tested wells do exhibit the sharp and fast increases in injection pressure noticed in the past.

Extension of the protocol to producer wells and intermittent acid injection through down hole chemical injection lines to secure durable performance of both wells are also discussed.

BACKGROUND AND SCOPE

Geothermal district heating in the central part of the Paris Basin (see location map in Fig. 1) has been, since its implementation in the late 1970’s/early 1980’s, severely penalised by corrosion and scaling damage caused by the hostile thermochemistry of the formation fluid, a tepid (60-80°C), saline (15 to 30 g/l eq. NaCl), slightly acid (pH close to 6 at reservoir conditions) brine with a dissolved gas phase (0.2 to 0.5 vol./vol. GWR) enriched in CO_2 and H_2S, which affected both producer and injector wells (1), (2), (3)

The geothermal reservoir, at a depth of ca 2,000 m, is exploited via the doublet well concept of heat mining which combines a producer and an injector well, the latter pumping the heat depleted brine into the source reservoir at a distance from the producing well securing a temperature breakthrough time higher than 15 years (1).

Due to the consolidated structure of the carbonate host rocks, wells are produced and injected as open hole avoiding any screen/slotted liner completion whatsoever. Wells are in most instances overpressured (3 to 10.5 bar static well head pressures) and their trajectories deviated (30 to 55” slant angles). Production (150 to 350 m^3/h flowrates) is achieved in most cases by artificial lift.

In order to counter corrosion/scaling shortcomings, most of the 35 well doublets operating to date (Fig. 1), whose overall heat loads –expressed in power ratings and yearly heat supply near 300 MW_t/1,200 GWh_t/yr), have been equipped, after due rehabilitation and removal of casing/formation damage, with down hole chemical injection lines aimed at inhibiting at damage initiation, i.e. at the bottom of the producer well, the corrosion/scaling process (3).

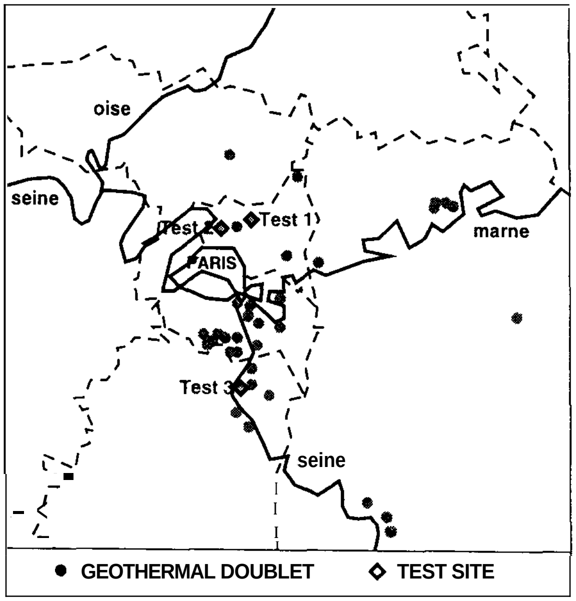

*Fig. 1. Location map of Paris Basin district heating doublets and **soft** acidizing test sites.*

Although continuous down hole injection of chemical inhibitors, combining either anti-corrosion (fatty amins, surfactants), scale (crystal growth inhibitor, dispersants) and/or biocide (sulfate-reducing bacteria scavenging, quaternary ammonia) formulations has significantly slowed down corrosion and scaling kinetics observed in the past (3), progressive impairment of injector and, at a lesser extent though, of producer wells has been noticed on several doublet localities (4) .

Three strategies of restoring well performance could be contemplated (i) mechanical/hydraulic clean-up of well tubulars (1),(2), (ii) conventional down hole acid stimulation of the damaged reservoir, and (iii) acidizing from surface of both damaged tubulars and open hole sections respectively. The latter technique was deemed worth attempting in consideration of its fairly easy implementation, low operating costs and, last but not least, its ability to ultimately remove both well casing and (open hole) formation impairments. **As** a matter of fact this route was perceived initially as a replay of an early field experiment which, as a result of the acid/heavy metal sulphide scale interaction, turned almost into an environmental disaster (5) and regarded accordingly with some scepticism if not retrospective fears. Hence, in order to limit H_2S emanations, the idea of reducing drastically acid concentrations gained some credit and a few field tests were conducted on somewhat empirical bases (6). Finally a series of three tests were carried out recently on presumably contrasted damage injector well settings, and their preliminary conclusions reported in (4).

The forthcoming develop the governing rationale behind the soft acidizing concept, the design/layout of field procedures and an overview of the chemical mechanisms involved. Test results are analyzed in relation to theoretical calculations, selected damage configurations addressing either casing or formation dominated impairments, and post treatment injection pressure records.

THE SOFT ACIDIZING CONCEPT AND ITS FIELD IMPLEMENTATION

The concept and field implementation have been extensively described in (4), and only the main features will be highlighted here.

Basically soft acidizing consists of injecting the same acid volume (ca 10 m^3 HCl 15X) than the one used in conventional acid jobs, but at a much lower rate : total injection time is of 60 hrs vs 1 hr. The geothermal loop is circulated at a low, constant flowrate (around 100 m^3/h), to ensure a significant acid concentration in the well. The HCl geothermal water dilution ratio stands therefore between 0.1 and 0.2 % (as of HCl 15X) i.e. an effective dilution of 0.02 to 0.05 %. The soft acidizing sequence lasts between 50 and 70 hrs, depending on the geothermal flowrate and the acid injection rate.

The time exposure is thought to be sufficient to favour dissolution of more or less indurated iron sulphide scale peaks, which are the main cause of increased casing roughness and subsequent friction losses.

Prior to injection, hydrochloric acid is mixed with an iron sequestrant to avoid supersaturation/ precipitation of, reaction generated, iron based compounds.

The injection of chemical corrosion inhibitor down hole the producing well is maintained at usual rates and concentrations during the experiment, bearing in mind that no incompatibility of the hydrochloric acid with currently used inhibitors was experienced so far. The main purpose for keeping the corrosion inhibition treatment was to be able to regenerate the fatty amine protection film as soon as scaling peaks were dissolved, ensuring therefore a better corrosion prevention on a smoother casing surface.

CHEMICAL MECHANISMS INVOLVED IN SOFT ACIDIZING

A quantity of 10 m^3 of hydrochloric acid is injected during the experiment at a constant rate of 180l/h in a geothermal loop circulated at 100 m^3/h, which yields an injected percentage of 0.18%. The injected acid **has** a volume/volume ratio of 23% (HCl 15X), which means an effective acid dilution in the well of 0.04%, or an effective acid concentration of

460 ppm. **As** a result the total acid quantity of HCl effectively injected amounts to 2560 kg.

Iron sulphide deposits are mainly composed of two main species : Mackinawite Fe_xS_{x-1} (usually altered as iron-rich Pyrrhotite α-FeS or Troilite), and Pyrite FeS_2. Fe-S-H_2O potential-pH diagrams (7),(8) show that the prevailing species at temperatures between 25 and 100°C for the considered range of pH and redox potential are FeS and FeS_2 in presence of aqueous H_2S. Dealing first with the sole FeS dissolution, the chemical reaction can be written as :

$$FeS + 2HCl \leftrightarrow FeCl_2 + H_2S \qquad (1)$$

The free energy ΔG^o of the dissolution reaction is calculated regarding formation free energies of the different components given in (9), leading to :

$$\Delta G^o(25°C) = -6.68\,kJ/mol$$

$$\Delta G^o(70°C) = -3.36\,kJ/mol$$

using the approximate equation

$$\frac{\Delta G^o(T)}{T} = \frac{\Delta G^o(T_o)}{T_o} + \Delta H^o(T_o)\left(\frac{1}{T} - \frac{1}{T_o}\right) \qquad (2)$$

Calculation of the equilibrium state at 70°C for the dissolution reaction is achieved by solving the equation :

$$K^o = e^{-\frac{\Delta G^o(T)}{RT}} = \frac{[FeCl_2][H_2S]}{[HCl]^2} = \frac{1}{4}\frac{\xi^2}{(1-\xi)^2} \qquad (3)$$

where ξ is the percentage of HCl moles that reacted at equilibrium, and AH", K", [ ] the enthalpy, equilibrium constant and activity respectively. Solving equation (3) leads to ξ=0.53, which means that 5.3% (molar ratio) of the hydrochloric acid actually reacted, thus dissolving a quantity of 1630 kg of deposited Troilite casing scale. This mass corresponds to a volume of approximately 350 liters removed from the casing, i.e. an average 0.28 mm decrease in casing wall thickness (steel+deposits).

However, it ought to be emphasized that this calculation is based on simplifying assumptions, namely :

(i) equilibrium is reached instantaneously in the well during the whole injection process, thus assuming infinite reaction kinetics. Finite reaction kinetics would lower the total mass of FeS scale removed from casing walls.

(ii) deposits consist only of Troilite FeS, leaving aside other deposits such as pyrite FeS_2 , the second most commonly encountered species in the Paris Basin reservoir. However since the latter mineral exhibits higher stability and indurated properties it will be less affected by the dissolution process than Troilite.

'Therefore, these calculations should not be taken at face value, but as an indicator instead of the amount of deposits actually removed from the casing. It is noteworthy that soft acidizing aims basically at selective upgrading of casing surface status via dissolution of poorly indurated scale peaks rather than at increasing casing inside diameter by removing large amounts of scale.

Last but not least, $FeCl_2$ scale forming is unlikely in the well since (i) an iron sequestrant is added to the hydrochloric acid to avoid supersaturation/ precipitation of reaction generated, iron based, compounds, and (ii) the maximum quantity expected (2360 kg) stands far below $FeCl_2$ solubility in hot water.

RESULTS

Test well review

Data –well characteristics, injectivity figures and assessed damage diagnostics- of the three cases studied up to date, are listed in Table 1, well locations in Fig. 1.

Well damage is assessed from inspection logging via multifinger caliper tools.

Case study	1	2	3
Well type	injector	injector	injector
Well depth (TD) (m)	2,065	1,774	2,289
Mean deviation (°)	39	0	53
Nominal casing diameter (ID) (mm)	159.4	159.4	159.4
Nominal transmissivity (Darcy.m)	92	19	22
Nominal injectivity index (II) (m3/hr/bar)	10.0	9.7	7.0
II before soft acidizing (m3/hr/bar)	8.2	7.5	6.3
Damage diagnosis	casing damage (high roughness) alone	casing and possibly (light) formation damage	formation damage alone

Table 1. Test well summary sheet.

Casing roughness analysis

An estimate of casing roughness has been attempted by calculating, on each sampling interval of the inside diameter (ID) logging record, a unit slope according to the procedure described in (1) .

Figures are algebraic since a co-current oriented peak face (slope counted positive) would oppose a lesser resistance to flow than a counter current one (slope counted negative), a zero slope corresponding to a flat line segment as sketched in Fig. 2.

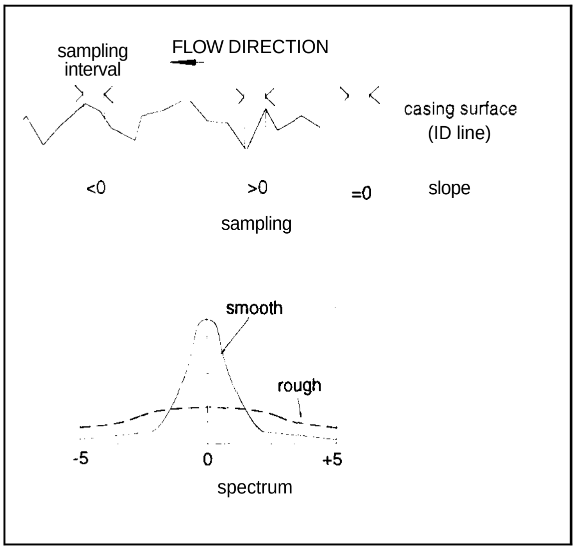

Fig. 2. Roughness appraisal criterion.

It is quite clear that the spectrum over the whole casing length fits a Gaussian distribution.

Averaged ID's fluctuate at a period covering five to ten sampling intervals thus securing a high signal to noise ratio.

According to these criteria a flat distribution would reflect a rough casing surface and a sharp centred distribution be the signature instead of a smooth surface status.

Histograms of slope distributions relating to pre and post acidizing casing caliper logs are displayed, for each test site in Fig. 3. Not to be overlooked is the fact three caliper tools have been utilized while logging casing ID's which required to exercise some normalizing effort in data processing.

Case study 1 shows in 1993 (before clean-up) a scale dominated damage mechanism, with important iron sulphide peaks increasing casing roughness (Fig. 3A). This scaling has been mechanically removed in 1993, (3 years before the soft acidizing test), thus leading to a smoother surface, compatible with the application of an anticorrosion filming agent (down hole chemical inhibition protocol) as previously discussed. However, since this formulation did not include any scale inhibition function between 1993 and 1996, it can be assumed with fair reliability that scaling was the prevailing damage source mechanism resulting in higher casing roughness and friction losses.

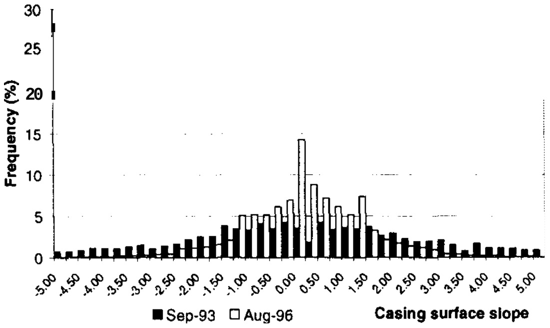

Fig. 3A. Case study 1. Evolution of casing roughness before (prior to mechanical cleanup, 1993, diameter tool n°1) and after (1996, diameter tool n°2) soft acidizing.

Case study 2 shows also in 1993 an irregular profile (Fig. 3B), less important however than in case study 1 (bearing in mind that different logging tools records were utilized). As a consequence damage is attributed to a dominant casing damage (increasing roughness), although a reservoir origin cannot be readily discarded at this stage.

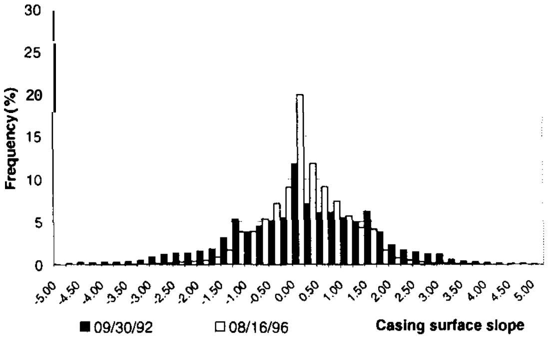

Fig. 3B. Case study 2. Evolution of casing roughness before (1993, diameter tool n°2) and after (1996, diameter tool n°2) soft acidizing.

Case study 3 demonstrates on the contrary a smooth casing surface (Fig. 3C) regardless of the logging tool, compared to the afore mentioned cases, with low casing roughness and friction losses. Reservoir damage (sandface or deep formation impairment) should then be investigated. This hypothesis is substantiated by the workover rehabilitation programme run in 1991, concluded by a conventional reservoir acidizing sequence which allowed to recover well nominal injectivity.

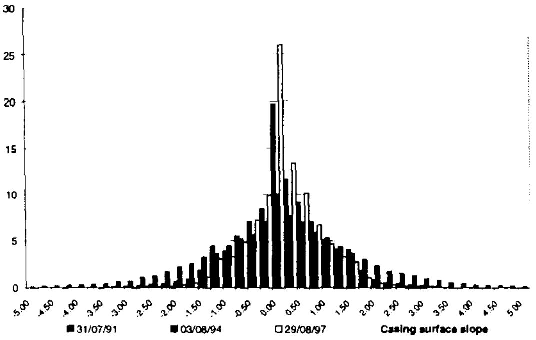

Fig. 3C. Case study 3. Evolution of casing roughness before (1991 –diameter tool n°2- and I994 – diameter tool n°3) and after (1997, diameter tool n "2) soft acidizing.

Stimulation Seuuences

*Test well I (**Fig.**4A)*

Soft acidizing lasted 68 hours at constant geothermal (100 m^3/hr) and acid (180 l/hr) flowrates, resulting in a 1.75‰ constant acid dilution during test operation. Well head injection pressure decreases regularly while the injectivity index increases (7.8 to 9.6 m^3/hr/bar) during injection, reaching stabilisation shortly before the end of the test. It was followed by a 15 hr geothermal water flush upgrading again the injectivity index

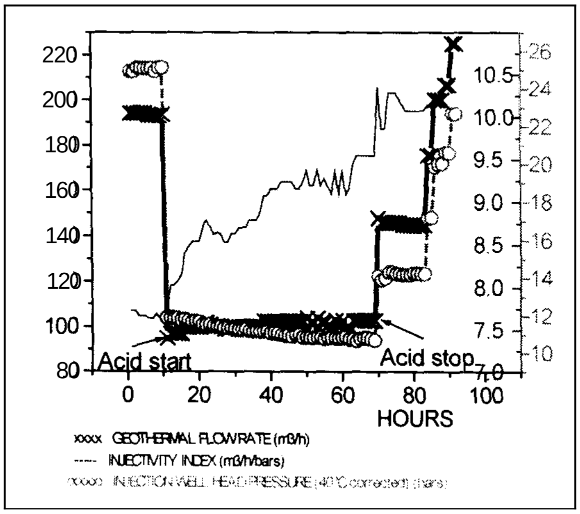

*Fig. **4A.** Case study 1. Flowrate, well head pressure and injectivity index recorded during soft acidizing .*

*Test well 2 (**Fig.4B**)*

The testing was split into three flow/acid dilution periods (25 hrs/ 100 m^3/hr -geothermal flow rate-/ 1.75‰ -acid dilution), followed by 21 hrs/65 m^3/h/ 3.0‰, ending up with 17 hrs/ 100 m^3/hr/ 1.75‰). This phasing was dictated by the fact that injectivity indices reached stabilisation faster and earlier than in case 1. Acid concentration increase in phase 2 acted instantaneously but reached maximum efficiency much faster than in the previous test (the injectivity index stabilised in a matter of hours). The drawdown test performed later confirmed the significant improvement of the injectivity index.

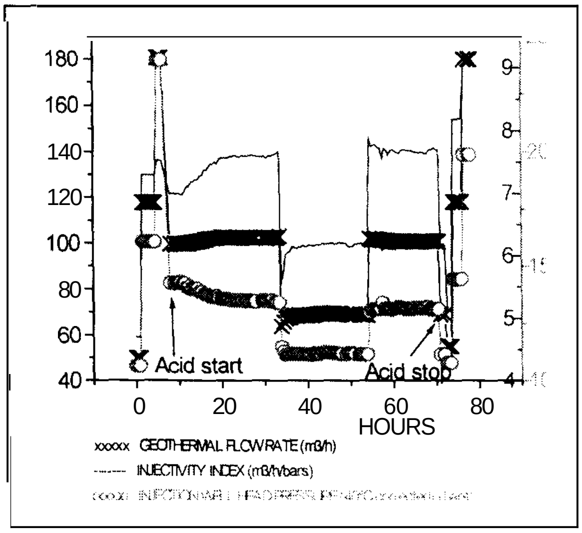

*Fig. **4B.** Case study 2. Flowrate, well head pressure and injectivity index recorded during soft acidizing.*

Test well 3 (Fig. 4C)

The test records shape quite chaotic since no results were obtained with the usual acid dilution (1.75‰). Higher acid concentration was achieved by means of decreasing geothermal flowrate (phase 2, 3.5‰), which boosted the injectivity index but over a short period only. It was then decided to carry out a highly diluted acid flush (225 m^3/hr, 0.8‰, 2 hrs) before resuming the soft acidizing process. The drawdown test performed after acidizing highlights significant gains in injectivity despite poor intermediate results.

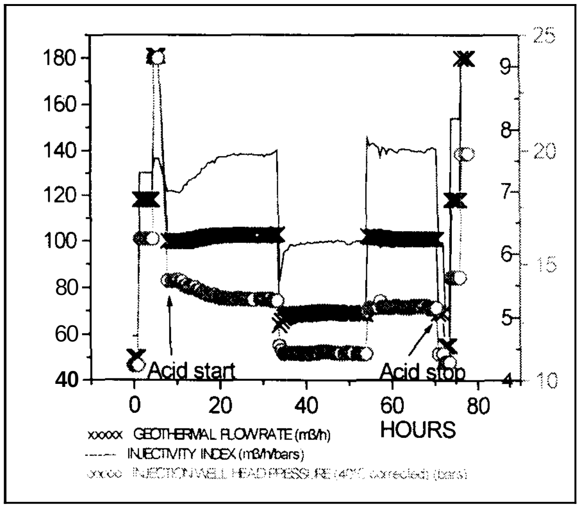

Fig. 4C. Case study ***3.*** *Flowrate, well head pressure and injectivity index recorded during* ***soft*** *acidizing.*

QISCUSSION

Overall test results in terms of nominal, pre and post acidizing injectivity indices vs flowrates patterns are illustrated in Fig. 5.

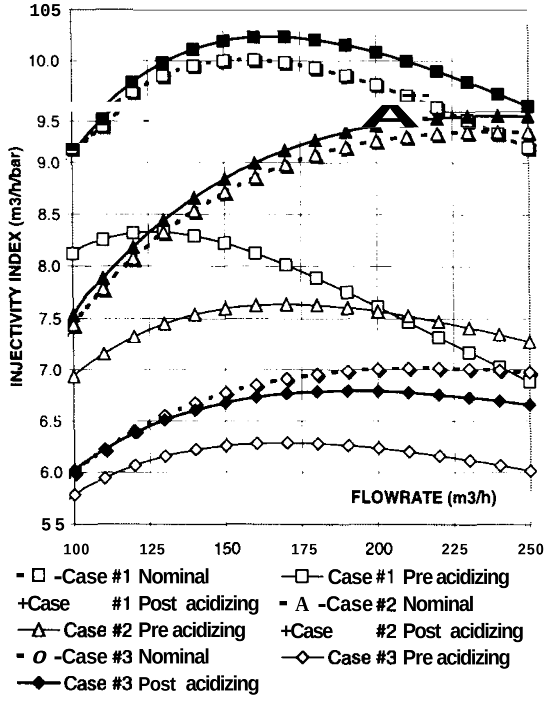

Fig. 5. *Nominal, pre and* ***post*** soft *acidizing injectivity indices vs flow rate patterns,*

Gains in injectivity achieved by soft acidizing are manifest. Test sites 1 and 2 display injectivity indices higher than nominal figures. On test well **3,** the result is less spectacular (injectivity slightly lower than nominal) but still impressive with respect to the pre-acidizing trend and far above initial expectations.

Soft acidizing resulted not only in lowering the well head injection pressure and increasing the injectivity index (according to design), but also in moving the injectivity optimum towards higher flowrates, as illustrated in case 1, and, to a lesser extent though, in case 2.

Analvsis of well head pressure/iniectivitv indices

Well characteristics such as casing roughness and skin factor can be derived from injection well head pressure which can be expressed as :

$$P = P_o - P_t + \Delta P_d + \Delta P_{se} + \Delta P_f \qquad (4)$$

where :

P = well head pressure (bar),
P_o = static well head pressure (bar),
P, = thermo-siphon pressure differential corrected to 40°C (bar),
ΔP_d = dynamic bottom hole pressure rise (bar),
ΔP_{se} = skin effect induced pressure variation (bar),
AP, = casing friction losses (bar),
with :

$$P_t = (9.8\ 10^{-5}) Z(\rho_i - \rho_o) \qquad (5)$$

$$\Delta P_d = 0.51 \frac{Q\mu_i}{kh} \log_{10}\left(\frac{0.81kt}{\phi\mu_i c_t r_w{}^2}\right) - 0.51 \frac{Q\mu_0}{kh} \log_{10}\left(\frac{0.81kt}{\phi\mu_0 c_t d^2}\right) \qquad (6)$$

$$\Delta P_{se} = 0.44 \frac{Q\mu_i}{kh} S \qquad (7)$$

$$\Delta P_f = 1.610^{-12} \frac{\mu_i{}^{0.21} C Q^{1.79} L}{r_c^{4.79}} \qquad (8)$$

and :

Z = top reservoir depth (m),
L = length of injection well casing (m),
ρ_i = density of the reinjection fluid (kg/m^3),
ρ_o = density of the reinjection fluid (kg/m^3),
Q = geothermal flowrate (m^3/h),
μ_i = injected fluid dynamic viscosity (centipoise),
μ_o = formation fluid dynamic viscosity (centipoise),
d = doublet spacing at reservoir top (m),
r_w = well radius at total depth (m),
k = intrinsec reservoir permeability (Darcy),
h = effective reservoir thickness (m),
c, = total reservoir compressibility (bar-'),
ϕ = reservoir effective porosity (%),
t = time (hours),
S = injection well skin factor (dimensionless),
C = casing roughness coefficient (dimensionless),
r_c = casing radius (m).

Temperature (°C)	Density (kg/m^3)	Viscosity (centipoise)
40	992	0.66
45	990	0.61
50	995	0.56
55	986	0.52
60	983	0.48
65	980	0.45
70	978	0.42

Table 2. Fluid density and dynamic viscosity at different temperatures.

Equation (4) can be further parameterized as :

$$P = = P'_o + aQ + bQ^n \tag{9}$$

with :

$$P'_o = P_o - P_t \tag{10}$$

$$a = 0.51\frac{\mu_i}{kh}\log_{10}\left(\frac{0.81kt}{\phi\mu_i c_t r_w{}^2}\right) - 0.51\frac{\mu_0}{kh}\log_{10}\left(\frac{0.81kt}{\phi\mu_0 c_t d^2}\right) + 0.44\frac{\mu_i}{kh}S \tag{11}$$

$$b = 1.6\,10^{-12}\frac{L\mu_i{}^{0.21}C}{r_c^{4.79}} \tag{12}$$

n = 1.79,

which allows **us** to calculate both casing roughness C and skin factor S.

Another way of computing roughness coefficient can be derived from the injectivity index II, defined as the ratio of flowrate to well head pressure, i.e. :

$$II = Q/P \tag{13}$$

Maximization of the injectivity index with respect to flowrate requires that the zero derivative be achieved for a flowrate equals to :

$$Q_0 = \left[\frac{P'_o}{b(n-1)}\right]^{\frac{1}{n}} \tag{14}$$

or, after developing from (15) :

$$Q_0 = \left[\frac{P_o r_c^{4.79}}{0.79 \times 1.6\,10^{-12} L\mu_i{}^{0.21} C}\right] \tag{15}$$

(15) offers an additional means for matching the roughness coefficient of the injection casing and incidentally confirms that the optimum II depends on casing roughness alone as would be inferred from common sense.

Thermally induced skin effect

If the soft acidizing experiment takes place right after a change (for instance seasonal) in exploitation (depending on the injection fluid temperature), a new model must be set up to account for temperature (and subsequent density and viscosity) changes close to the injection wellbore.

This situation, illustrated in Fig. 6, coresponds to a peculiar context characterized by a dual mobility setting caused by the displacement of the (previously) cooled formation fluid further to the invasion of the injected hot/cold brine.

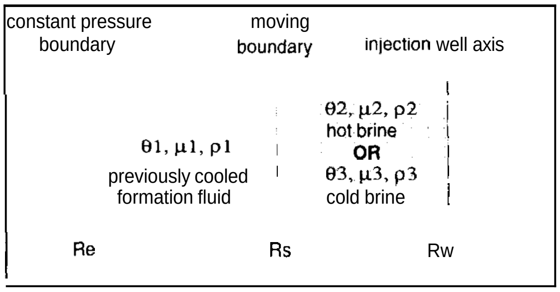

Fig. 6. Modelization of fluid distribution close to and away from the injection well.

Assuming the radial distance to the cold water front matches a constant pressure boundary condition and regardless of skin effect and casing friction losses the dynamic pressure rise can be written :

$$\Delta P_d = P_e - P_w = P_e - P_s + P_s - P_w \tag{16}$$

and :

$$\Delta P_d = \frac{Q\mu_1}{kh}\log\left(\frac{r_e}{r_s}\right) + \frac{Q\mu_2}{kh}\log\left(\frac{r_s}{r_w}\right) \tag{17}$$

with

$$r_s = \sqrt{\frac{Qt^*}{\Pi h\phi}} \tag{18}$$

$$t^* = \frac{\rho_w c_w \phi}{\rho_w c_w \phi + (1-\phi)\rho_r c_r} t \qquad (19)$$

where :

ρ_w, ρ_r = water and rock densities,

c_w, c_r = water and rock specific heats.

The sensitivity to this thermal skin effect can be appraised through the following numerical application, assuming a ten year doublet exploitation at constant flowrates and injection temperatures averaged at 135 m^3/h and 50°C respectively.

re = 700 m,

h = 20 m,

kh = 30 Dm,

Q = 100 m^3/h,

μ_1(50°C) = 0.56 cp,

μ_2(70°C) = 0.42 cp,

μ_3(40°C) = 0.66 cp.

$$\frac{\rho_w c_w \varphi}{\rho_w c_w \varphi + (1-\varphi)\rho_r c_r \varphi} = 0.54$$

AP, = 7.4 bars.

The exercise leads, for an the injection sequence extending from 1 hour to 105 days, to the values listed in Table 3.

Time (hr)	r_s (m)	ΔP_d (bar) 70°C inj. brine	ΔP_d (bar) 40°C inj. brine
1	2.39	6.66	7.89
3	4.15	6.53	7.98
6	5.86	6.46	8.03
12	8.29	6.38	8.08
24	11.73	6.31	8.13
72	20.31	6.19	8.21
720 (30 days)	164.23	6.03	8.37
1440 (60 days)	90.83	5.96	8.42
2520 (105 days)	120.2	5.90	8.46

*Table 3. Thermally induced skin effect for injection of **hot** and cold water sequences from 1 hour to 3.5 months.*

Therefore pre and post acidizing tests must be carefully analyzed regarding their implementation dates. For instance, on case study 3 a dynamic pressure decrease of 0.2 bar at 100 m^3/h, between pre (6/6/96) and post acidizing (8/26/96) tests, results from a progressively increasing hot water invaded volume, which suggests that at least part of the injectivity improvement could be attributed to a thermal artefact and not to acid action proper. **As** a matter of fact this contribution should be deducted from the measured gain in pressure (1.5 bar) thus leaving a net pressure gain of 1.3 bar instead.

On the contrary, during winter time, subjected to constantly low injection temperatures (40°C), a progressively augmenting cold water invaded reservoir volume results in a time increasing dynamic pressure. In case study 1 part of the gain due to soft acidizing is masked by a thermally induced dynamic pressure decrease of 0.15 bar (kh=91.6 Dm, Q=200 m^3/h) between pre (12/1/95) and post (3/1/96) acidizing tests, achieving a slightly higher net gain.

Summing up, minimization of thermally induced skin requires that soft acidizing be carried out either in late winter or in summer time.

Analysis of soft acidizing results

Casing roughness and skin factor, alongside induced pressure rises are displayed in Fig. 7 to 9.

Skin values ought to be regarded as merely artificial. Actually they have by themselves no real meaning in the physical sense, only are their relative variations in time of some significance.

Case study 1

As inferred previously from casing caliper logs, roughness is constantly increasing with time, friction losses being multiplied by a factor of 1.7 in less than three years. On the other hand the skin factor does not vary significantly. Soft acidizing impact is manifest on casing roughness which exhibits an almost two fold decrease. Total pressure decrease which amounts to 7 bars at 200 m^3/h recharge is attributed mainly to diminishing friction losses. It would be fair adding that, since then, casing roughness started increasing again, at a much slower rate though, because of scaling shortcomings evidenced in both production and injection wells. This has motivated the modification of the initially injected inhibitor from a single anticorrosiori filming towards a combined anticorrosion-filming/antiscale-dispersant formulation.

Case study 2

The well was much less documented with respect to well head pressure records so that no reliable historical trends could be assessed so far. Only could a 100% increase in casing roughness be inferred between years 1988 and 1996. Soft acidizing did effectively remove scaling peaks, leading to a 5 bar decrease in injection pressure (at 200 m^3/h) as a result of diminishing friction losses, The last test, following the soft acidizing protocol, could not be implemented under steady conditions as indicated by the widely scattered spectrum of computed parameters.

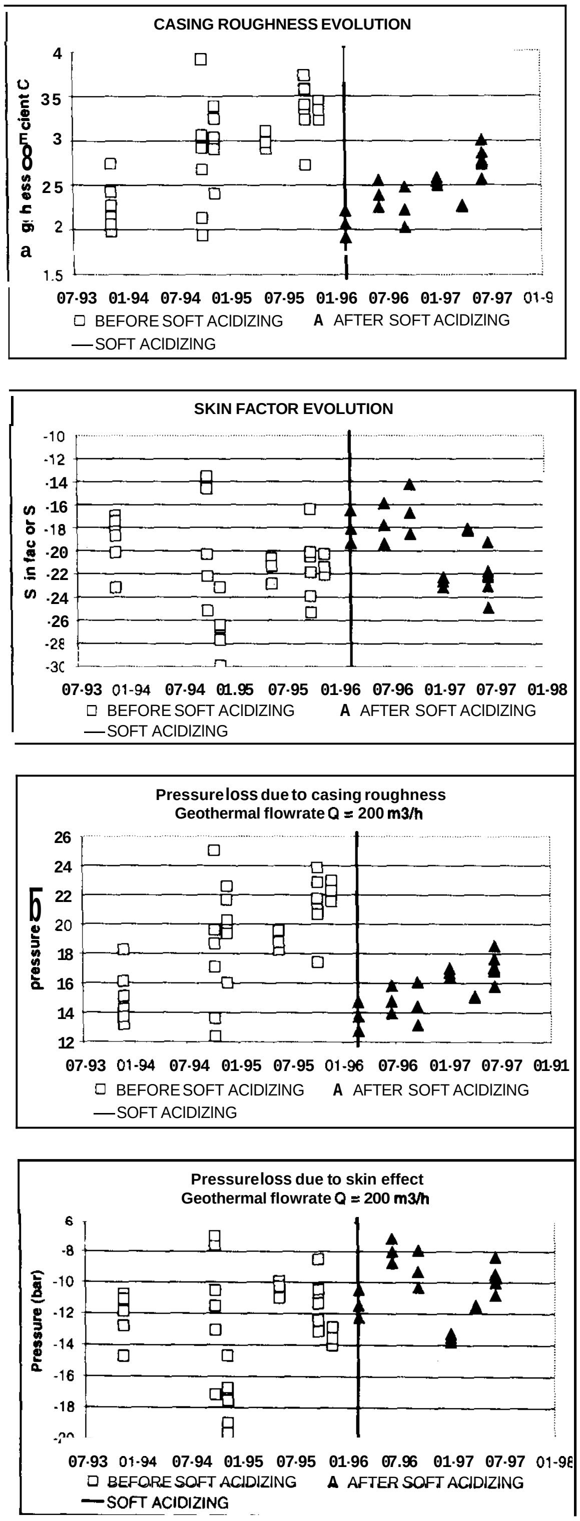

Fig: 7. Case study 1. Evolution of casing roughness, skin factor and associated pressure losses

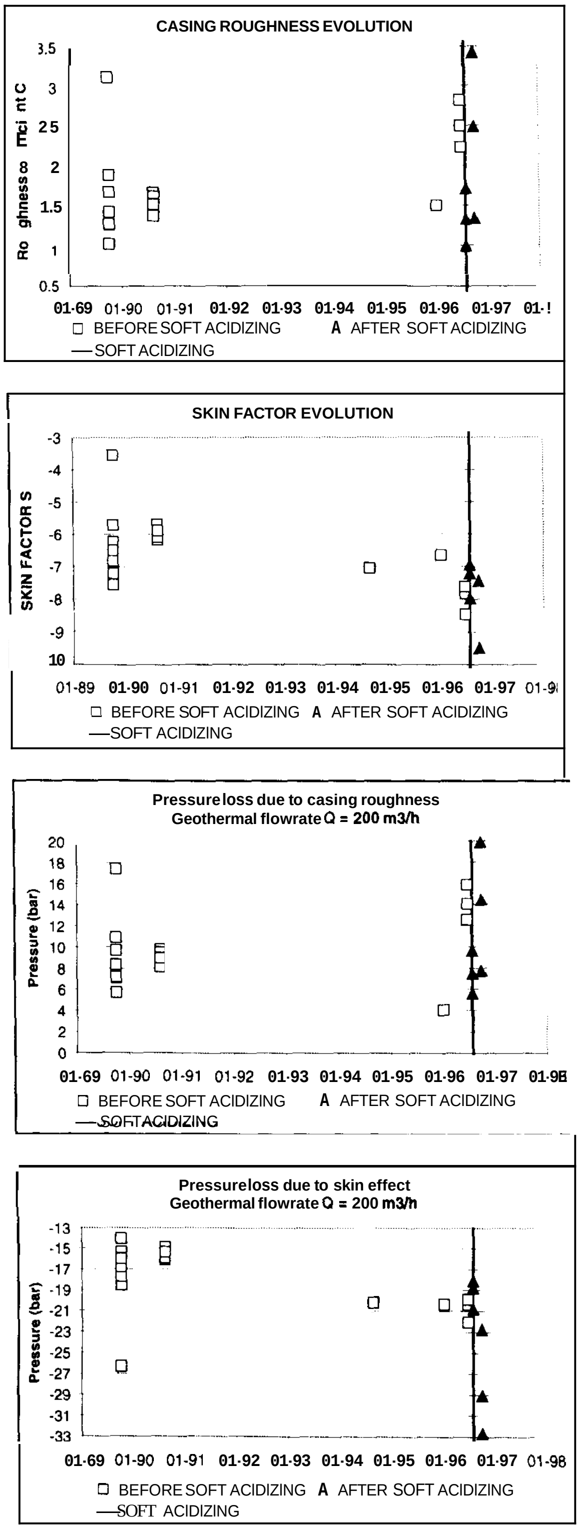

Fig. 8. Case study 2. Evolution of casing roughness, skin factor and associated pressure losses.

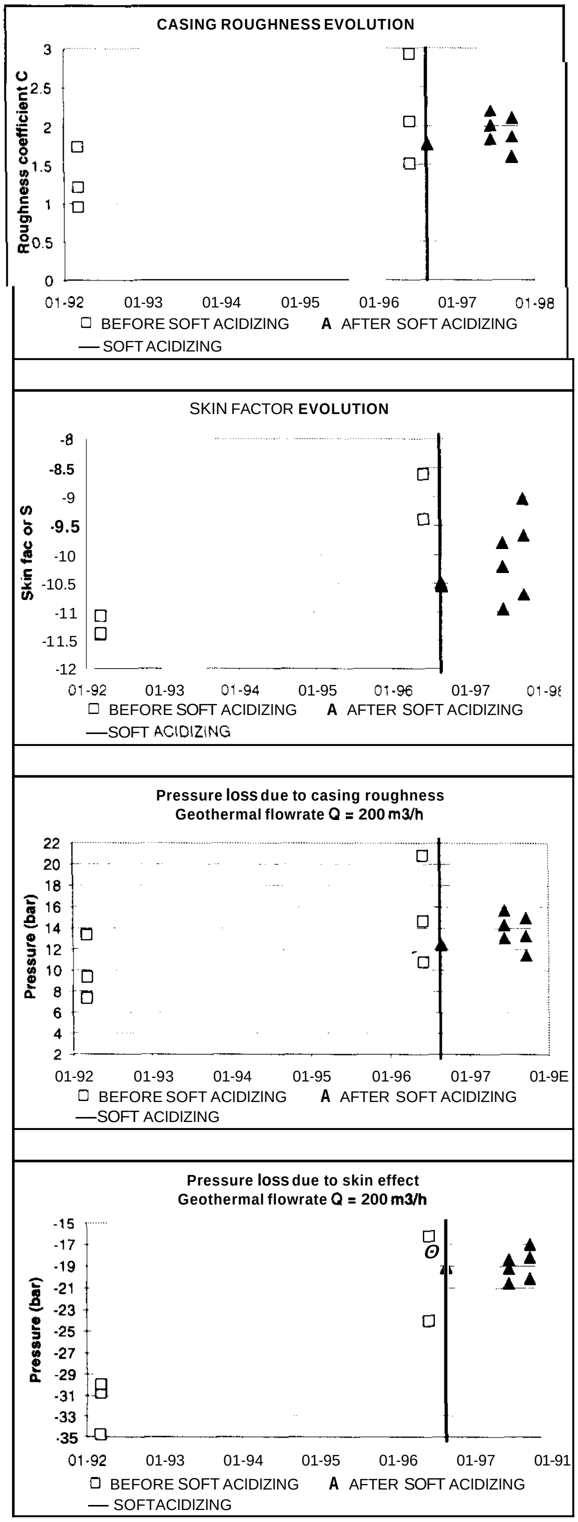

Fig. 9. Case study 3. Evolution of casing roughness, skinfactor and associated pressure losses.

Case study 3

The test well raised considerable interest owing to its non damaged casing status assessed from logging evidence. Although preacidizing pressure testing shows some increase in casing roughness (questionable however owing to the quality and amount of available data), the major contribution is clearly related to skin impairment (sandface plugging). As anticipated, soft acidizing did not show any marked improvement in casing roughness. Skin factor analysis proved on the contrary quite rewarding as, for the first time, a significant improvement (from –9 to –10.5) of the skin factor was noticed. Finally a 3.7 bar decrease in well head pressure could be reached at a 200 m^3/h flowrate of which 60% (1.6 bars) allocated to skin upgrading.

It was therefore shown that the field of application of soft acidizing could be extended from casing scale peak dissolving to sand face damage removal. It is believed the latter effect occurs whenever a sufficient quantity of acid remains to leach the reservoir seated scale. It is likely this has been the case on test site 3 where less acid was mobilized to dissolve casing located scale peaks owing to a fairly clean casing status.

ECONOMICAL IMPACT

Cost efficiency of the process is appreciated by balancing operation costs against injectivity gains, the latter resulting in electric power (injection pumping) savings and, in most instances, additional supplies of geothermal heat.

The exercise applied to the three test sites leads to the following pay back times :

- case study 1 (power savings and additional heat supplies) : 9 months,
- case study 2 (power savings alone) : 24 months,
- case study 3 (power savings and additional heat supplies) : 10 months.

The question however remains on how long will the benefits of this damage removal procedure last. Until now only limited downgrading of well performance has been noticed (below 20% of the achieved result), one to two years after field testing. It is quite clear that either continuous or intermittent (batch type) acid treatment, operated from the production well via the downhole chemical injection line, would best secure this objective.

CONCLUSIONS

The following conclusions may be drawn from in depth evaluation of soft acidizing experiments carried out on three, open hole, geothermal injection wells completed in a, low temperature, carbonate reservoir environment.

(i) long duration pumping of strongly diluted (0.02 to 0.05%HCl) acid solutions proved momentarily successful in restoring performances of three damaged geothermal injector wells. Implemented protocols allowed to recover nominal well injectivity indices and injection pump ratings,

(ii) injection protocols (acid dilution rates, water flush) could be designed in order to adjust to varying damage source mechanisms, (either casing scaling or/and near wellbore sandface impairment) thus covering the whole well damage spectrum,

(iii) the procedure does not require any interruption of geothermal district heating operation (and related heat sales) nor of down hole chemical inhibition,

(iv) pre and post treatment injectivity index vs geothermal flow patterns proved reliable indicators of well (tubulars and completion) behavior thus enhancing damage diagnosis and removal efficiency,

(v) despite unanswered acid reaction kinetics soft acidizing is deemed effective in dissolving poorly consolidated, iron sulphide dominated, scaling peaks known to affect casing roughness and subsequent friction losses particularly sensitive in a high flowrate (200 m^3/hr)/ low casing inside diameter (7”) context. This selective dissolving process obviously prevails over massive scale removal, which would require much higher acid quantities. Hence its substitution to mechanical/hydraulic workover procedures, in order to achieve significant increases of, scale affected, casing inside diameters is illusory,

(vi) as far as open hole damage is concerned, it is expected the water flush, assimilated to a prolonged dilute acid squeeze, addresses the dissolution of a pellicular (positive skin) sandface plugging rather than the removal of a deep formation invasion impairment. Whenever casing scale and open hole damage coexist it is believed that a prolonged soft acidizing sequence could meet both dissolving/removal requirements,

(vii) cost effectiveness of the procedure has been appraised through pay back times ranging from 9 to 24 months depending on whether gains in geothermal heat supplies add to injection pump power savings,

(viii) perenniality of soft acidizing impact is still a pending question. Ultimately the answer will consist of a, preventing rather than remedial, ad-hoc programme aimed at initiating acid treatment at the bottom of the producing well, via the down hole chemical injection line, by injecting either continuously or momentarily (shock treatment) acid solutions compatible with both exposed materials and inhibitor agents used outside. Those issues will be soon investigated and relevant programmes implemented on sensitive well doublets undergoing casing and formation damage.

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