Near Well Damage. Assessment, Remedial and Prevention. Application to Geothermal District Heating Systems

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Keywords: Geothermal Energy, Well Damage, Corrosion, Scaling, Water Injection.

ABSTRACT

The development of geothermal district heating (GDH) systems applying the multi-doublet (doublet, triplet clusters) concept of Geoheat farming has resulted, in several instances, in well damage and severe exploitation losses whose origin proved often ambiguous.

Based on field observation, monitoring and modelling of a variety of well and reservoir environments, a relevant damage spectrum of the well sand face and near well space is derived according to the assumed/verified source mechanisms induced by either or both fluid production or/and injection processes.

As a result a tentative classification is suggested, which highlights the main identified damage mechanism – native particle entrainment, thermochemical supersaturation/precipitation of sensitive crystal species, formation of long term compaction, flow channeling – which modify the initially assessed/presumed temperature/flow pattern favouring flow path plugging and skin cake build-up.

A methodology is proposed for properly assessing well/formation impairment, implementing efficient remedial/preventive procedures from field tests and predictive modelling.

1. INTRODUCTION

Successful geothermal resource exploration does not imply trouble-free exploitation, a statement born by factual evidence from production/injection histories. For instance the ambitious Paris Basin Geothermal district heating (GDH) scheme, initiated in the late 1970s, in its early development stages underwent severe well and formation damage. Here, during the so-called infantile disease episode inherent to any new energy path, geothermal operators paid a heavy price materialised by the abandonment of 20 GDH doublets out of a total of 54 completed systems, thus scoring a 63% exploitation success ratio, to be compared to the former 99% drilling success ratio!

The major identified well damage and formation impairment shortcomings are listed, alongside their source mechanisms, symptoms and candidate remedial procedures, in Table 1. They will be analysed from their occurrence and remediation/prevention standpoints with emphasis placed on sensitive thermochemical, hydrodynamic and mechanical issues.

2. SENSITIVE WELL DAMAGE AND FORMATION IMPAIRMENT ISSUES

2.1 Thermal and chemical break through

These fatal impacts, inherent to the doublet concept of heat farming and related injection of cooled pressurised brines, may however be mitigated via the design of adequate well architectures and chemical inhibition protocols.

- **Thermal breakthrough**

Assuming a single layer (equivalent) reservoir and a purely convective, piston type, heat transfer, the thermal breakthrough time t_B is usually estimated from the following equation (Landel and Sauty, 1978).

$$t_B\ (\text{hrs}) = \frac{\pi}{3}\frac{\gamma_t}{\gamma_w}\frac{D^2 h_1}{Q} \qquad (1)$$

The foregoing proved to be an oversimplification because many, if not most, sedimentary reservoirs comply with a multilayered structure displaying alternating sequences of pervious reservoir layers and interbedded, hydraulically impervious but thermally conductive aquitard strata, the latter representing a significant heat storage capacity. Hence, following Ungemach and Antics (2014), the corrected thermal breakthrough time t^*_B accounting for conductive heat resupply would be expressed as follows:

$$t^*_B\ (\text{hrs}) = \frac{\pi}{3}\frac{\gamma_t h_1 + \gamma_r h_2}{\gamma_w h_1} D^2 \frac{h_1 + h_2}{Q} \qquad (2)$$

where:

h_1 (m) = net (stacked) reservoir thickness
h_2 (m) = interbedded (stacked) aquitard thicknes
D (m) = top reservoir well spacing
Q (m^3/h) = doublet circulation rate
γ (Jm^{-3} K^{-1}) = heat capacity
ϕ = porosity

Subscripts:
r = rock
t = total reservoir [(fluid(ϕ) + rock(1-ϕ)]
w = fluid

Clearly, the actual breakthrough time is much higher than the usually assessed cooling kinetics neglecting conductive heat resupply.

Hence, as demonstrated by Paris Basin GDH experience (hardly two recorded thermal breakthroughs after 30 year operation) (Ungemach, 2014), bottomhole well spacings close to 1500 m would delay the cooling kinetics, therefore securing prolonged well and reservoir thermal longevities.

Chemical breakthrough kinetics occurs much faster, actually in the fluid to rock heat capacity ratio (i.e. close to 4).

Their impact is merely site-specific as it results from injected water to exposed rock interactions and supersaturation/precipitation, undersaturation/dissolution of sensitive crystal species, heavy metal sulphides, Calcite, Silica, Evaporite, Siderite, Barium sulphate scale among others. If not properly characterised, and inhibited accordingly, cold water injection is likely to favour scaling in production and injection wells.

Table 1: Well damage summary sheet

WELL DAMAGE	WELL (S)	SOURCE MECHANISM/CAUSE	SYMPTOMS	REMEDIAL (S)	REMARKS
Thermal breakthrough	P	Cold water injection Short well spacing	Temperature decline	None except adequate sidetrack retargeting	Account for multilayiring in assessing breakthrough times and relevant well spacings
Chemical breakthrough	P	Cold water injection Short well spacing	Water quality changes Induced thermochemical shortcomings, skin increase	Chemical inhibition Sidetrack retargeting	
Casing leak(s)	P, I	Corrosion (external, internal)	Pressure and water quality changes	Cement squeeze, pierced casing lining/cementing	Tracer (radioactive, chemical, fresh water), peak off test, PLT detection
Wellbore narrowing	P, I	In hole scaling (P) Water injection (I) Filter cake build up	Diameter (ID) destruction Well friction losses increase	Well clean up (scrapping, jetting), soft acidizing	Soft acidizing best adapted to casing/liner roughness upgrading
Wellbore fill up	I	Bottom hole settling of suspended particles	Reduced pay interval & injectivity Pressure increase	Wellbore cleanup	
Fluid degassing	P, I	Below bubble point (BPP) production pressure	Two phase flow, annular pressure build-up scaling, corrosion	Lowering ESP depth (low BPP); chemical inhibition below degassing front (high BPP); degassing facility	Special care in wellhead design to cope with accumulated gas, annular pressure and abatement
Particle entrainment	P, I	Water injection Excess sand face velocities Odd well completion	Productivity Injectivity losses	Reduced production rates Particle filtering	
Borehole collapse	P	Excess sand face velocities Poor openhole consolidation	Productivity decrease Bottomhole plugging	Reduced production rates Set up appropriate completion designs	Poorly consolidated formations or/and contrasted rock consolidation sequences
Induced seismicity	I	High injection flowrates & pressures	Increased microseismicity Eventual microearthquake bursts M $\geq$ 3	Reduced injection rates/pressures, sidetrack additional segment (leg)	Active tectonic environments

2.2 Tubular leaks

Here, corrosion is the driving damage mechanism. It can act either internally or externally on casing/liner faces. Internal corrosion van be defeated or at least mitigated by chemical inhibition agents, frequently of the fatty amine family, protecting the exposed metal surface by a monomolecular hydrophobic film (Ungemach, 2007).

Behind casing external corrosion is a consequence of poor cementing, creating microannulus and channeling whose impacts are aggravated by the presence of active aquifer layers. Such a situation occurred on a naturally self-flowing, injector well, which undergone two casing piercing levels, identified further to flowmeter/temperature logging and leak-off tests illustrated in Figure 1.

The competent Mining Authority requested from the geothermal operator an assessment of the impact in terms of thermal and chemical pollution extent within the two communicating aquifers, exploited locally for industrial and domestic water supply.

Relevant modelling, which combined an axisymmetric radial well module coupled, via a casing/cement interface, to a reservoir heat and mass transfer simulator (Ungemach et al., 2011) issued the contamination status depicted in Figure 1, showing an important penetration (up to 140 m) of the thermal and chemical plumes. Fortunately, the long term pollution impact was shown to be minimized thanks to fresh water dilution from exposed aquifers.

In addition, the restoration of well integrity by lining/cementing the damaged tubular enabled to resume GDH exploitation.

2.3 Wellbore narrowing

Although regarded as concerning principally injector wells, as a consequence of solid particle entrainment and (filter cake, fill up) settling (Barkman and Davidson, 1973; Ungemach, 2003) it may also affect producer wells, as exemplified in the following, somewhat puzzling, case study.

The well, completed in 1984, lined in 1995, showed its productivity declining progressively since 2008 then drastically since 2011, a trend illustrated in Figure 2 well delivery curves. In order to produce a relevant diagnosis a series of tests and logs were carried out. Neither did production tests nor flowmeter logs and fluid sampling, skin factors nor distribution of productive layers (Figure 3) show any significant change. On the other hand the nearby injector well performance had proven stable since its completion. In conclusion, the only sensible answer called for an in hole damage, located further to a casing caliper log asan in a hole scale developed over ca 300 m (from 260 to 560 mbgl depths) as shown in Figure 4 which happens to coincide with the build up phase of the highly. inclined (ca 50°) well trajectory .

However, the contribution of a 5 mm diameter decrease does not contribute more than 1 bar to the incurred casing friction losses. So scale roughness remained the sole plausible explanation to productivity decline, an exercise attempted in Figure 2, where the assumed flowrate increasing roughness coefficient matches the reference (last recorded) delivery curve.

Removal of the scale and more over of its major, roughness contributing, asperities suggest a soft acidizing procedure given the prevailing iron sulphide/calcite scale composition, a technique which proved rewarding in similar circumstances (Ventre and Ungemach, 1998), as evidenced in Figure 5 (roughness sampling and appraisal criteria) and 6 (pre- and post-acidizing roughness frequency curves).

The procedure consists of injecting a 10 m^3 volume of hydrochloric acid at commercial concentration (HCL 15X, @ 23% vol/vol), equivalent to that pumped during a conventional acid job, at low concentration (# 450 ppm, assuming a 175 l/hr acid injection rate and a 100 m^3/h geothermal loop circulation rate), during a 60 hr period, leading to a ca 2500 kg acid consumption.

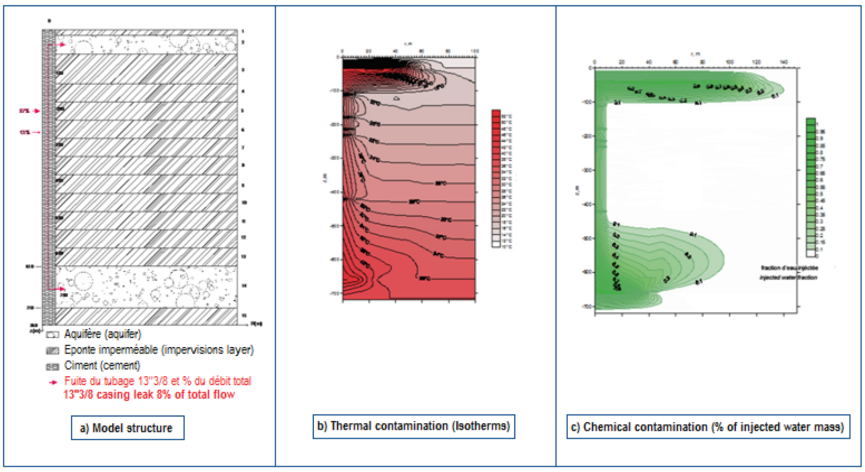

Figure 1: Leaky well simulation

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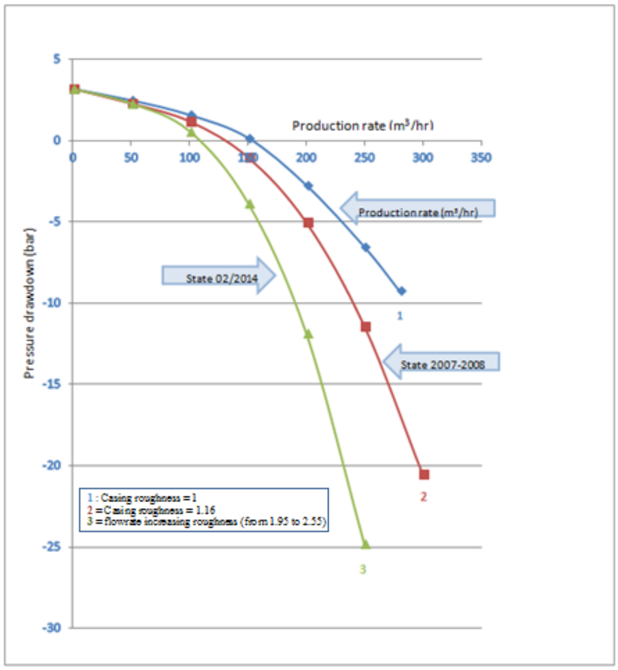

Figure 2: Production well delivery decline curves

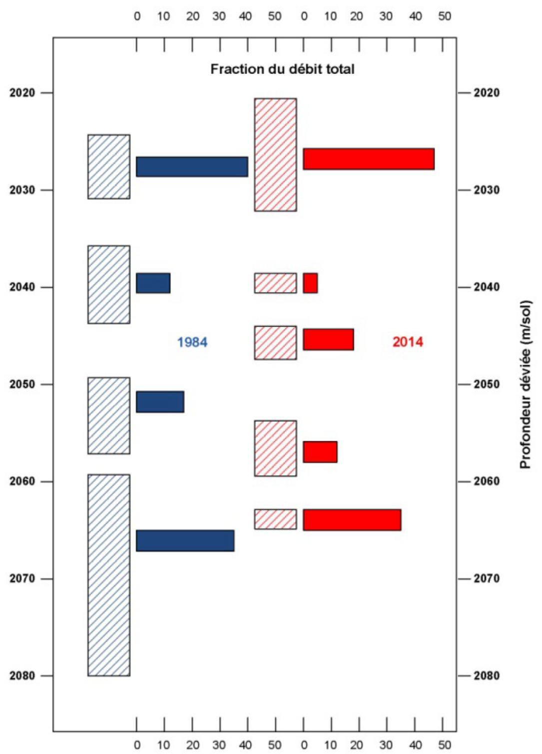

Figure 3: Initial (1984) vs present (2014) flowmeter logs of reservoir interval

Assuming further a sole Iron sulphide species (Troilite Fe S) the dissolution equilibrium reaction is expressed as:

$$Fe\,S + 2\,HCl = Fe\,Cl_2 + H_2S \qquad (3)$$

and the free energies $\Delta G°$ calculated from Weast (1988):

$\Delta G°$ (25°C) = - 6,68 kJ/mol

$\Delta G°$ (70°C) = - 3,36 kJ/mol

By using the approximate equation

$$\frac{\Delta G°(T)}{T} = \frac{\Delta G°(T_0)}{T_0} + \Delta H°(T_0)\left(\frac{1}{T} - \frac{1}{T_0}\right) \qquad (4)$$

the dissolution equilibrium state at 70°C will be calculated from the equation:

$$K° = e^{\frac{\Delta G°(T)}{RT}} = \frac{[Fe\,Cl_2][H_2S]}{[HCl]^2} = \frac{1}{4}\,\frac{\xi^2}{(1-\xi)^2} \qquad (5)$$

where ξ is the fraction of HCl moles reacting at equilibrium and $\Delta H°$, $K°$ and [ ] the enthalpy, equilibrium constant and activity respectively. Solving equation (5) leads to ξ = 0.53, meaning that 53% (molar ratio) of the mobilized HCl reacted actually, dissolving ca 1 630 kg of Troilife scale (approximately 350 l in volume) removed from the casing wall i.e. about half the thickness of the deposited mass.

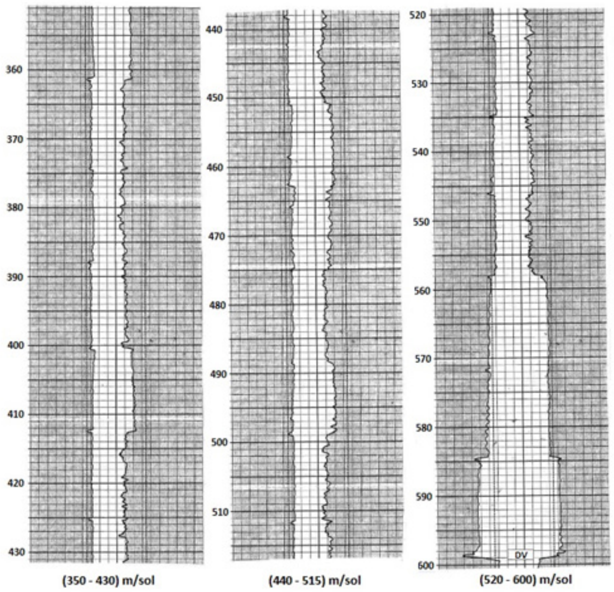

Figure 4: Production casing caliper logs indicating excentralized scale deposition

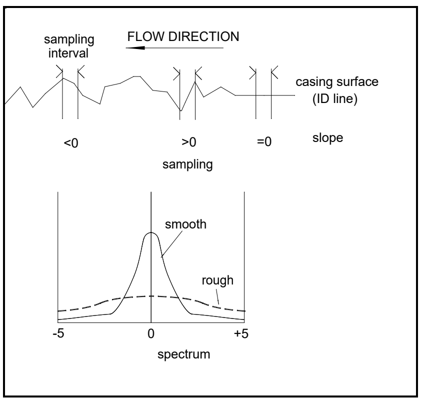

Figure 5: Casing roughness assessment criterion

These calculations should not be taken at face value but as indicative of the amount of deposits possibly removed from the casing.

As a matter of fact they assume equilibrium is reached instantaneously, therefore assuming infinite reaction kinetics, and overestimating the effectively dissolved scale. They elsewhere reduce the scale mineral to the sole Troilite thus neglecting Pyrite (FeS_2) frequently present in such CO_2/H_2S aqueous environments. However since Pyrite represents the ultimate stage of the Iron Sulphide crystallization process, its exhibits higher stability and indurated propertied less concerned by asperities in the dissolution process than Troilite (FeS).

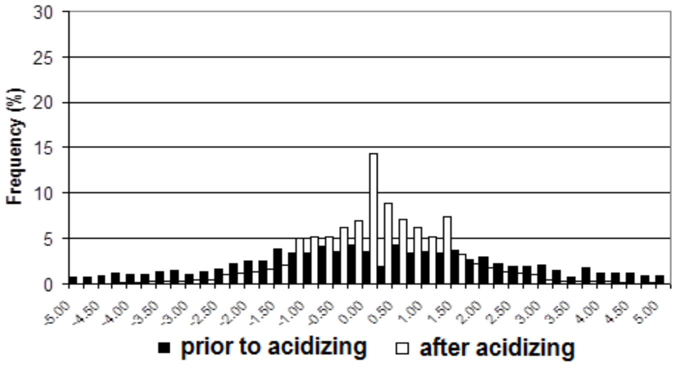

Figure 6: Pre- and post-acidizing casing surface status

2.4 Degassing

Degassing occurs whenever the formation fluid is produced below bubble point pressure (BBP), generating two-phase flow and thermochemical (corrosion/scaling) problem areas in aqueous CO_2 and CO_2/H_2S environments. At low BBPs and gas liquid ratios (GLR), say below 10 bar and 0.5 respectively, adequate depths (> 100 m below dynamic water level) and heads (WHP> 10 bar) of the electrosubmersible pump (ESP) set would achieve single-phase liquid production, preventing pump cavitation and heat exchanger fouling risks. In self flowing mode a degassing/incinerating facility is recommended for toxic and combustible gas (H_2S, CH_4) abatement.

At high BBPs a chemical inhibition line should be placed below the degassing front and a vortex type degassing module be added to the ESP set. Chemical inhibitor agents should be formulated in order to defeat supersaturation/precipitation of the most frequently encountered heavy metal sulphides (Mackinawite, Galena), Calcium (Calcite), Iron (Siderite), Strontium (Strontionite) carbonates, Baryum (Barite) and Calcium (Anhydrite) sulfates – crystal species.

Note that injection of CO_2 to sustain CO_2 partial pressure may also be contemplated (Hartog, 2013).

A tubing string is also required on injector wells to control the buildup of abnormal annular pressures and bleed them accordingly. A design of, a coiled tubing type, combined downhole chemical injection/monitoring line, is described in Section 3.

2.5 Particle entrainment

It addresses chiefly clastic sedimentary, more or less consolidated, interbedded, sand, sandstone, marl and clay alternating sequences subject to pore bridging by suspended particles, of internal and external origins, according to the permeability impairment processes reviewed by Ungemach (2003), illustrated in Figure 7.

The impact of particle entrainment on formation injectibility may be appraised from bottomhole transient pressure plots recorded during injectivity tests, commented on the following case study.

The test site includes two vertical wells, 1200 m distant, intersecting a ~50 m thick interbedded sand, clay and gravel sequence of Lower Triassic age, displaying net pays of 9 and 11 m respectively, completed by wire-wrapped screen/gravel packed assemblies. On well 1 only part of the annular space was gravel packed. On both wells, production and injection tests were carried out at constant 120 m3/h flowrates. Figure 8 injectivity testing sequences demonstrate two contrasted pressure transient behaviours.

On well 1 are noticed an abrupt pressure drop fast stabilizing to a steady-state injection regime and an injectivity index twice lower than the (temperature corrected) productivity index monitored previously. This behaviour suggested the build-up, during injection, of a mechanical damage caused by the upward motion of clay particles in the partly gravel packed annulus, resulting in an external filter cake, bridging pore entries at sandface. This diagnosis could be validated by the highly positive skin factor, derived from fall off test interpretation, which got restored to its initial negative value after removal of the cake by back washing.

On well 2, bottomhole pressures do not reach any stabilization whatsoever after 5 hours pumping and a dramatically decreasing injectivity trend. Here, high injection pressures (in excess of 100 bars at well head) and, moreover, invasion by particles of micrometric size were identified as the major damaging factors. This diagnosis was confirmed by, particle monitoring via millipore filters, which showed that concentrations in solids, in the 3 to 5 µm range, decreased by one half whereas in the 0.2 to 1 µm (colloidal) domain they had undergone a two fold increase.

Another important fact is that the sandface inflow velocities, close to 10 cm/s, widely exceed the 1 cm/s empirical threshold set by the industry (Ungemach, 2003).

These fiels test globally exemplify the problematic of external vs internal particle induced damages. On well 1 external particles appear as the dominant permeability impairment factor and on well 2 the internal particle plugging mechanism prevails instead.

One may suggest that surface particle filtering is the answer. Actually several operators have implemented filtering facilities, including chains of bag to cartridge and millipore units and solid separation cuts down to 1 µm as practiced on the Copenhagen (Mahler et al., 2013) GDH doublet site.

Limiting the impacts of external particle cake buildup and internal particle invasion would suggest instead to design and implement improved well completions and architectures achieving both downhole filter and sandface velocity reduction. In this respect examples of: (i) dual completion aimed at producing simultaneously two superimposed sandy aquifers is depicted in Figure 9, and (ii) a custom designed completion in a multilayered heterogeneous clastic reservoir documented in Figure 10.

Subhorizontal wells geothermal investigated by Ungemach et al. (2011) and Promis et al., (2011) appear as an pertinent alternative, most relevant wherever thin bedded/low permeability settings prevail.

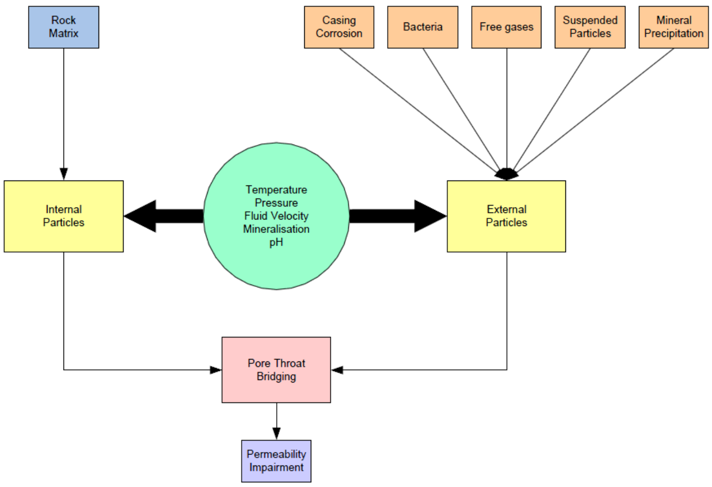

Figure 7: Particle induced permeability impairment schematic

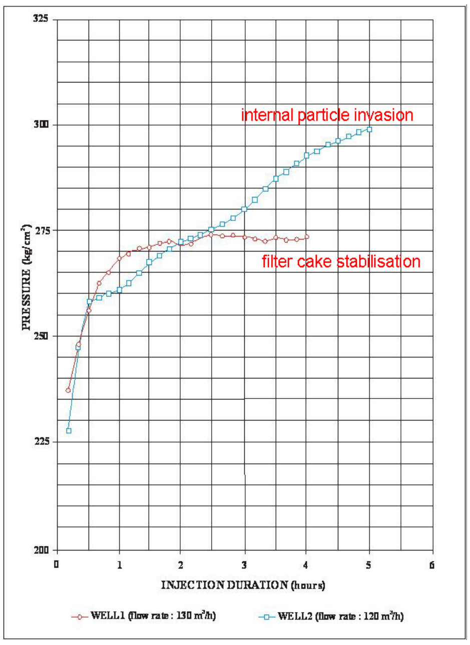

Figure 8: Injection tests. Bottomhole pressure transients

2.6 Induced seismicity

Generally associated with the implementation of the EGS (Enhanced – or preferably Engineered – Geothermal Systems) concept of heat mining, induced seismicity also occurs while completing conventional GDH and CHP (cogenerated Combined Heat and Power) systems located in tectonically active areas.

Restricting ourselves to continental Europe, particularly to the Upper Rhine Graben (URG), a continental rift of known seismic activity, the first EGS geopower plant pioneered on the emblematic Soultz test site in northern Alsace experienced, during hydraulic stimulation of basement fractures, microearthquakes of magnitude (Richter scale) exceeding 2 ML, not physically damaging but perceived reportedly by local residents.

Later, the Basel episode in the very lower part of the URG, triggered a series of damaging seismic events, widely echoed by the media, which were a direct consequence of a massive hydrofrac stimulation, initiated in December 2006 at 4.5 km depth, analysed by Haring et al. (2008) and Deichmann et al. (2013). Massive water injection into a tight, near impervious crystalline basement, confined in an extensively fractured fault compartment, generated an accumulation of stresses which were released and seismic events alike, long after well shutdown further to a seismic event peaking a 3.4 ML, causing the project, to be definitely abandoned.

At Landau (northern Palatinat) a significant microseismic activity accompanied the commercial operation of the CHP plant. It was attributed to increasing injection pressures of the heat depleted brine, indicative of the development of the geothermal reservoir (Baumgaertner, 2013). Here also microseismic shocks were monitored after well shut in. It was assumed that microseismicity would persist with reservoir growth until a stabilized pressure state be reached according to the doublet heat extraction theory. It may also be hypothesized that, cold water induced, thermal stresses contribute to seismic instability.

A similar mechanism was noticed while developing, in the same area, the Insheim CHP project. Here, injection pressures could be reduced and stabilised by sidetracking a twin injection leg, thus enabling the plant to be operated at nominal ratings – 80 kg/s; 3.4 MW_{el} net – (Baumgaertner and Learch, 2014), whereas at Landau the plant was assigned to run at half its capacity. Meanwhile, geothermal operators in the URG have dramatically modified their well stimulation protocols by switching from casual hydrofracking to organic acid (eventually complemented by HCl) based fracture treatments. Therefore new methodologies aimed at mitigating the seismic impacts of water injection along upgraded microseismic monitoring and communication transparency, are being put into practice (Baujard et al., 2014).

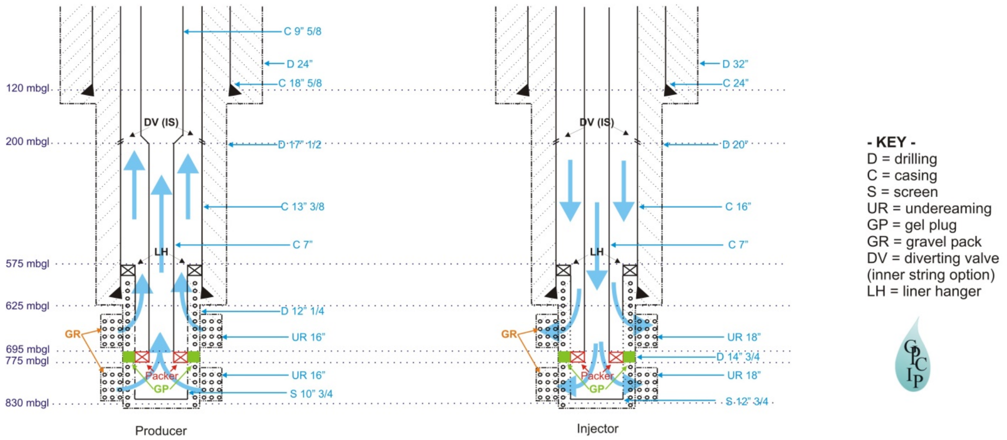

Figure 9: Dual (non mixing) aquifer completion well profile

PROJECTED WELL / RESERVOIR PERFORMANCE

Top reservoir depth	1,500 m
Static WHP	-5 bar
Total pay	400 m
Net pay (h)	110 m
Effective porosity ($Ø_c$)	0.2
Permeability (k)	100 mD
Transmissivity (kh)	11,000 mDm
Skin factor (S)	-2
Formation temperature	90ºC
Average injection temperature	35ºC
Fluid (eq. NaCl) salinity	2.5 g/l
Fluid dynamic viscosity (production) (µp)	0.32 cp
Fluid dynamic viscosity (injection) (µi)	0.73 cp
Total compressibility factor (c_t)	10^{-4} bar^{-1}
Fluid density (ρp) at 90ºC	965.34 kg/m^3
Fluid density (ρi) at 35ºC	994.06 kg/m^3
Target injection rate (Q)	150 m^3/h
WHP (150 m^3/h, 35ºC)	20.5 bar
Sandface velocity (v_{sf})	0.23 cm/s
Velocity at completion outlet (v_c)	0.61 cm/s

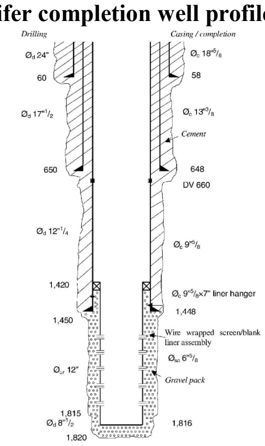

Figure 10: Suggested well completion in a clastic environment

3. DISCUSSION

Statements of low to medium enthalpy geothermal wellbore damage, formation impairment and related environmental impacts are well documented, but assessments of source mechanisms shape often ambiguous and interpretation of precursory signals (when available!) likewise.

Thermal breakthrough predictions, which are essential prerequesites in appraising cooling and chemical breakthrough kinetics, may be questioned unless observation wells be made available when exercising, history matching based, model calibration.

However the sandwich model equivalent to multilayered reservoirs, advocated by Antics et al. (2005), which accounts for conductive heat resupply from confining aquitards proved rewarding in assessing, field validated, cooling kinetics more realistic than those previously anticipated.

Casing leaks have disastrous consequences regarding contamination of intersected aquifers *vis-à-vis*. Unpredictable beforehand they may originate: (i) externally from odd cementing favouring channeling and microannulus damage, and (ii) internally from casing corrosion by a thermochemically hostile fluid if not correctly (and timely) inhibited. Restoration of well integrities requires damaged casing (re)lining, which in turn implies, initially designed, well architectures compatible with lining diameters and production objectives, a constraint to be born in mind while designing new well completions whatever the efficiency expected from corrosion inhibition strategies.

Well/near wellbore damage, named generically wellbore narrowing, addresses both injector and producer wells and either internal (in hole) casing deposits or/and external (well/reservoir) sandface pellicular plugging (positive skin film) involving two different source mechanisms and remedial procedures. Whereas the in hole scale, where casing roughness prevails over scale thickness, is best removed by soft acidizing, hydromechanical (rockbit/jetting tool assembly) cleaning is best suited to pellicular film destruction. Still the suspected thermochemical damage driving mechanism needs to be properly diagnosed and an inhibition strategy designed accordingly.

Dissolved gas (CO_2, H_2S, CH_4…) enriched geothermal fluids, exhibiting high bubble point pressures (BPP) and gas liquid ratios (GLR) provoke, when depleted in hole, degassing, pump (ESP) cavitation and corrosion/scaling damage, which to be defeated/mitigated require:

(i) at exploration level (whether the fluid is gas rich or not!), bottomhole fluid sampling aimed at PVT analysis providing BPP, GLR and solution gas (gas chromatography) and separated liquid (ICAP analysis) phase compositions. If not fulfilled, future doublet exploitation will resemble a shot in the dark and face severe post completion shortcomings.

(ii) setting the ESP, equipped with a vortex type gas separator, at appropriate depth,

(iii) run in hole a chemical inhibition line below the degassing front for injecting the best candidate inhibitor agents, and

(iv) set up a two (three, in case of crude oil slugs) phase gas/liquid separation surface facility.

With respect to water injection, stringent filtration criteria may not be necessary when reducing flowrates and sandface velocities would suffice in limiting internal (native) particle entrainment and (injected) formation invasion. Would larger flow capacities be sought, appropriate well architectures/completions, additional, sidetracked, production/injection legs, subhorizontal well and multiple completion designs – should be implemented. A similar strategy should like wise be contemplated regarding the seismic risk issue which requites to mitigate injection pressures and sandface velocities.

Last but not least, the downhole chemical injection/fluid sampling/fibre glass (P, T) line depicted in Figure 11 (Ungemach, 2014) should meet most of the aforementioned bottomhole monitoring/ thermochemical inhibition requirements and become a production management standard.

4. CONCLUSIONS

The most sensitive well damage and formation impairment issues have been reviewed and their impacts on GDH/CHP exploitation discussed from a sustainable development viewpoint.

The foregoing suggest the following guide lines to be drawn in order to prevent or/at least mitigate/repair well/formation damage, bearing in mind that the main parameters to be controlled address cooling kinetics, fluid thermochemistry and solubility of identified sensitive crystal species, solution gases, sandface velocities/internal particle entrainment and induced microseismicity.

(i) well designs should focus or architectures accommodating adequate (top reservoir) well spacings, deep pumping chambers and diameters easing, whenever needed, damaged casing lining/cementing or sidetracking; also not to be overlooked are the selection of reliable cement slurries and placement (preferably single stage) procedures seeking efficient annular protections;

(ii) at exploration stage bottomhole fluid sampling at reservoir conditions and PVT analysis are deemed mandatory for characterizing the fluid thermochemical facies and assessing its corrosion/scaling tendancies;

(iii) at exploitation stage chemical inhibition below the degassing front or better at the last casing shoe depth via *ad hoc* downhole chemical inhibition lines should be implemented and serviced simultaneously to plant start up;

(iv) production features ought to be continuously monitored via custom designed multifunctional – chemical inhibition, fluid characteristics, pressure/temperature – downhole control lines, and damage precursory indicators collected accordingly;

(v) background noise and induced microseismicity require due monitoring prior to and after well stimulation and during doublet exploitation in active tectonic/seismic areas known to populate the EU territory;

(vi) given the poor public acceptance/awareness of well stimulation practice, soft, organic acid based, chemical stimulation protocols are strongly recommended alongside communication transparency.

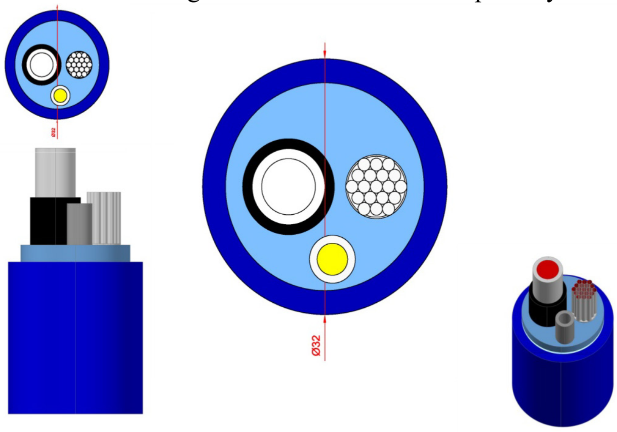

Figure 11: Downhole chemical injection/optical fibre control line

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