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Assessing the Scaling Potential in Hot Reinjection Wells in the Olkaria Geothermal Field, Kenya

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ABSTRACT

Re-injection of used geothermal waters has become an integral part for sustainable geothermal utilization in the Olkaria geothermal field. The location of the Field inside the Hell's Gate National Park requires an environmentally friendly way of disposing separated brine and condensate. Additionally, increased production capacity has been realized over the years with increased re-injection. Despite the benefits mentioned, one of the major issues associated with re-injection is the possible loss of permeability due to scaling. In this study the potential for scale formation in several hot re-injection wells in the Olkaria geothermal field was evaluated. The first approach assessed the potential of scale formation in re-injection wells prior to production using the WATCH speciation program to obtain the baseline data. The second approach using the PHREEQC geochemical model, simulated mixing of injected fluids and aquifer fluids to assess the scaling potential of the mixed fluid. The mixed fluid composition was then input in the WATCH speciation program to simulate boiling and degassing. The results from the two approaches were then compared for calcite, amorphous silica and anhydrite in the geothermal fluid. The results from this study showed both positive and negative geochemical effects of fluid injection in the Olkaria geothermal field and gives an indication on how to mitigate the undesirable geochemical effects arising from injection into this field.

1. INTRODUCTION

In recent years, reinjection of used geothermal waters has become an integral part of sustainable geothermal utilization projects in the world (Kaya et al., 2010). The notable benefits associated with reinjection include (1) provision of an environmentally friendly method of disposing separated geothermal brine and steam condensate, (2) recharging of the reservoir and providing the necessary pressure support. Pressure decline due to long term exploitation of the geothermal resource is a common observation in geothermal production wells (Axelsson, 2008). Despite these benefits, scale formation is the most problematic process associated with the reinjection and may result in loss of well permeability (Serpen and Aksoy, 2005) Permeability lose will result in the inability to carry out reinjection into the reservoir. Although this is not the only challenge that is related to reinjection, a clear understanding of water-rock interactions and the chemistry of the geothermal fluid is important for a successful reinjection plan (Arnórsson,2000).

The Olkaria Geothermal Area is a high temperature geothermal system in Kenya located on the Eastern segment of the East African Rift. (Figure 1). This field has been under exploitation since the early 80s. Most of the steam is used for power generation in the four main existing power plants and smaller wellhead units. The current installed capacity for geothermal power in Olkaria is 519 Mwe (KenGen, 2016). Direct utilization has recently gained momentum with the current operation of a geothermal spa and usage in the Oserian greenhouses for horticulture farming. Initial decline in production capacity was observed 15 years after the commercial exploitation in the Olkaria East Production Field in the early 90s (Mwangi, 2000). This decline resulted in the drilling of six additional wells to maintain the production. Numerical studies carried out in the mid-80s had suggested that re-injection into this field would reduce this decline rate and hence reduce the required number of make-up wells. Currently, both cold and hot water reinjection is performed in the Olkaria geothermal field. Cold reinjection is used to dispose of cooling tower blowdown which is the condensate from the power plants whereas hot reinjection has been dedicated for disposing separated geothermal brine (Mariaria, 2011).

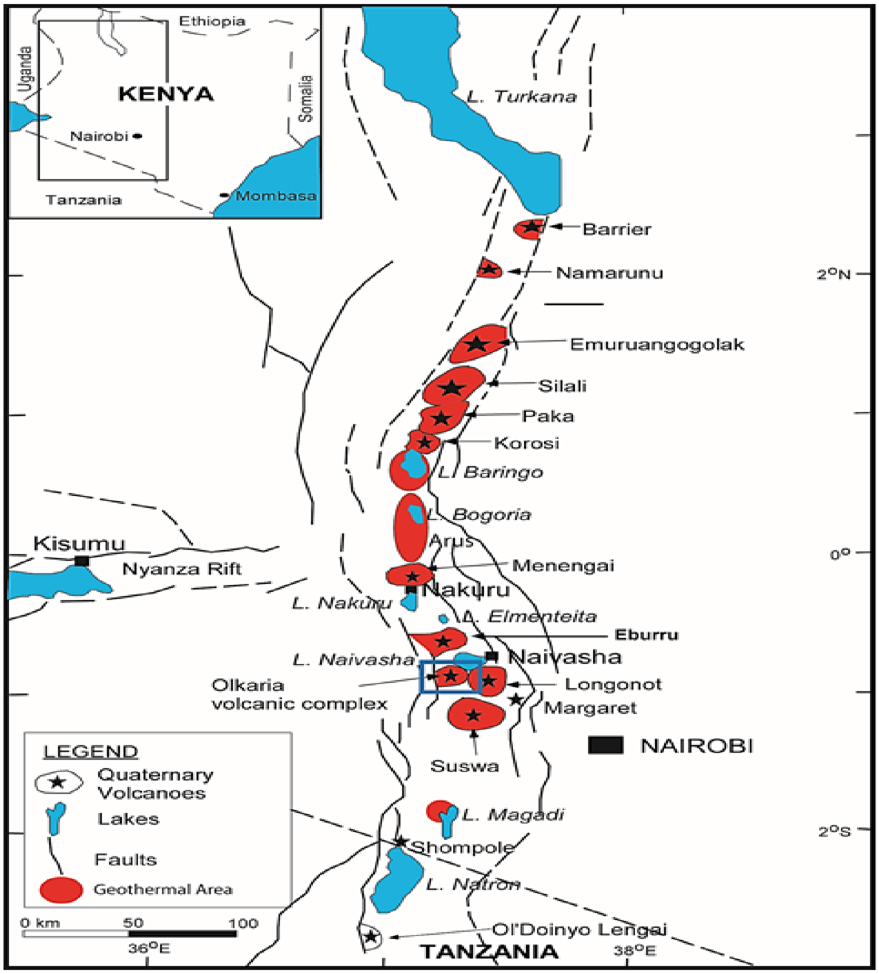

FIGURE 1: Map showing geothermal areas in Kenya (from Ofwona, 2002)

Studies have shown that various techniques can be employed to better understand the reinjection regime in geothermal systems. Chemical tracers for instance, have been used extensively over the years to study reservoir properties and thermal breakthrough in geothermal systems. Geochemical studies on the other hand, have mostly been focused on silica precipitation and its effects on the reservoir properties which contribute to a decrease in permeability. Several numerical modelling of the Olkaria geothermal area have been carried out over the years. In 2012, a review of the energy production capacity of the geothermal area was undertaken by a Consortium composed of Icelandic consulting companies such as Mannvit, Vatnaskil and Verkís and Icelandic Geosurvey ÍSOR,. This review was based on earlier studies done by Western Japan Engineering Consultants, (WestJec). One of the highlights in this review was the need for large scale reinjection strategy for sustaining increased electricity generating capacity. (Axelsson et al, 2013). This plan is however hampered by lack of detailed research required for reinjection exploration

The objective of this study is to model the possible geochemical effect of geothermal reinjection in the Olkaria Geothermal System and assess the scaling potential of hot reinjection into Olkaria wells prior to production and during reinjection. A comparison of the two would enable evaluation of how mixing of fluids can modify saturation states and eventually affect the scaling potential in reinjection wells and in the receiving aquifer.

2. GEOTHERMAL ACTIVITY IN THE OLKARIA GEOTHERMAL FIELD

2.1 History of Utilization and Current Status

The first research at the Olkaria geothermal field started between 1955 and 1959 when two exploratory wells, X-1 and X-2, were drilled but failed to discharge. In the mid-1960s, the Olkaria area was considered as a promising geothermal prospect area after geophysical surveys had been carried out between Lake Bogoria (Figure 1) and Olkaria area. Funding from the United Nations Development Program (UNDP) supported more extensive geoscientific survey which started in 1970. The geothermal resources were further confirmed by six exploratory wells which were drilled between 1973 and 1976 (KPC, 1994). By 1981, the first 15MWe unit was commissioned in the Olkaria East Field. Two more units were commissioned in 1983 and 1986 and the current installed capacity for Olkaria I is 45MWe. Extensive exploration led to the discovery of additional resources in the Olkaria geothermal area. The Greater Olkaria Geothermal Area (GOGA) is divided into several fields based on the characteristics and location. These are; Olkaria East Field, North-East Field, Olkaria Domes, Olkaria South-East Field, Olkaria Central field, Olkaria North-West Field and Olkaria West Field (

Figure 2). The latter is owned by OrPower Inc, an independent Power Producer (IPP). With the exception of the Olkaria North-West Field, the other fields are operated by the mostly state owned Kenya Electricity Generating Company (KenGen). The Olkaria II power plant in the North-East Field was built in two stages; the first two units were built in 2003 with the capacity of 70 MWe and the third unit in 2010 with the capacity of 35 MWe.

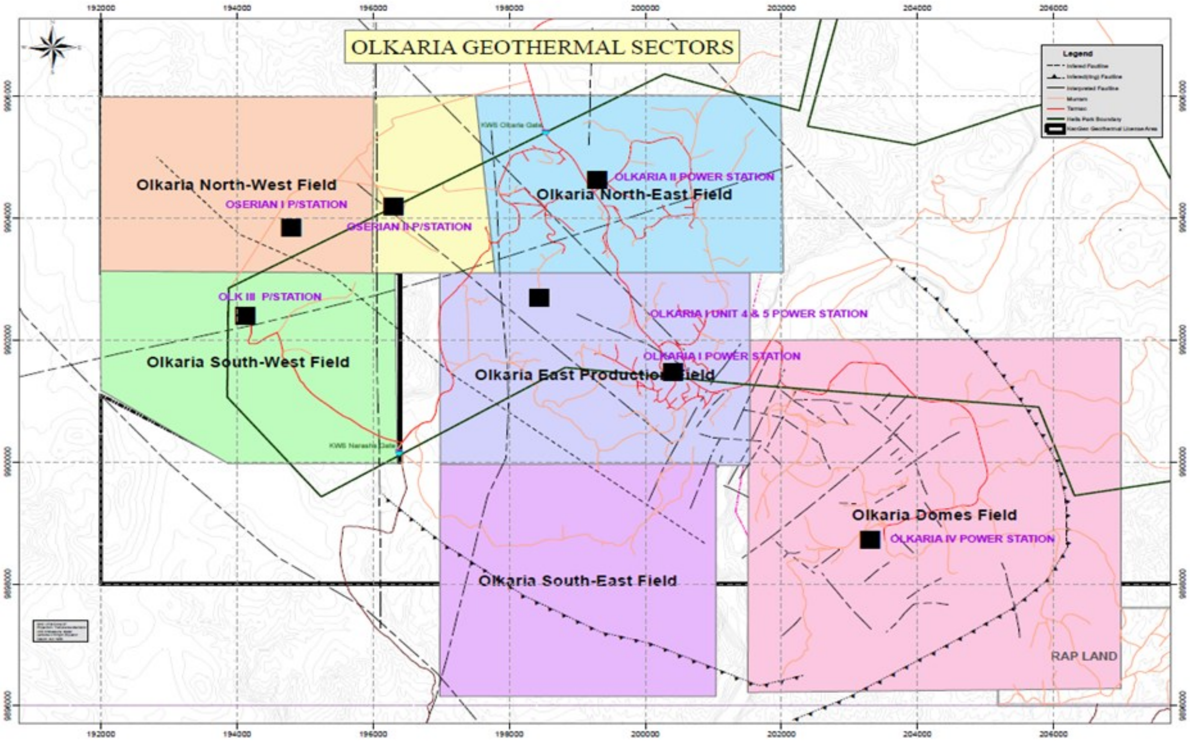

FIGURE 2; Map showing the Olkaria Geothermal Sectors (KenGen Database, 2016)

The most recent additions to the Olkaria Geothermal Field were done in 2014 where two power plants, each with 140 MWe capacity, were commissioned. The first power plant is the Olkaria I addition unit (AU) also in the Olkaria East field and the other one is in the Olkaria Domes where Olkaria IV power plant is located. Apart from the convection flash power plants, KenGen also generates electricity using wellhead technology. This technology allows the wells to be utilized and generate revenues in the short term. Usually in the construction of the conventional power plant those wells would be set to idle and would only be used to supply steam to the powerplants once it has been commissioned

2.2 Reinjection in the Olkaria Geothermal Field

Extensive geoscientific data has been obtained over the years in the Olkaria Geothermal Area. This data has revealed that the Olkaria Geothermal Field can sustain further production and therefore future expansion plans are ongoing. In order to be able to sustain future expansion, resource management programmes started in the mid-90s. As a result, a six-month injection and tracer test was carried out in the Olkaria East Production Field (Ambusso, 1994). The purpose of this test was to determine the effect of the injection on the production wells performance and to evaluate the possibility of implementing long term injection programmes in the field. This experiment was carried out after substantial pressure drawdown which was measured in the wells supplying steam to the Olkaria I power plant, ten years after commercial operations had started. The conclusion from this test was that commencement of reinjection prior to the onset of large drawdown in the reservoir leads to greater sustenance of well production.

The initial practise for disposal of used geothermal waters in the Olkaria Field was so called surface disposal where geothermal brines were disposed of in surface ponds and left to percolate into the ground. However, due to environmental effects of such disposal and the need for geothermal resource management, reinjection strategy was adopted in Olkaria. Currently both hot and cold reinjection is carried out in different sectors of the field. Cold reinjection is used to dispose of cooling tower condensate. Hot reinjection is preferred to minimize cooling of production wells and scaling process (Mariaria, 2011). Several hot reinjection wells are used at different sectors of the Olkaria Geothermal Field. In this study, the following hot reinjection wells will be considered in the modelling approach. The OW- 703 and OW-708, (located in the North East Field), OW-R3 (located in a buffer zone between the North-East Field and the East Field) and OW-911(located in the Domes Field) (Figure 2). Apart from well OW-911 which was commissioned as a reinjection well in 2014, the other three wells have been used since 2003 when the Olkaria II powerplant came on line. The recent addition of the 140 MWe in the Olkaria East Field has seen a change in the reinjection regime such that the separated brines from wells with different chemistries is also being directed to the existing reinjection wells. The data considered for this study is prior to these changes which took place in 2014.

3. CHEMISTRY OF THE THERMAL FLUIDS IN THE OLKARIA GEOTHERMAL FIELD

The chemical composition of the fluids in the Olkaria Geothermal Area have been routinely sampled and analysed at the Olkaria Geochemistry Laboratories over the years. The main purpose of those analyses is to understand the fluid physical and chemical properties, estimate subsurface temperatures, locate recharge zones and identify other reservoir processes such as mixing, boiling and cooling. The chemical composition of the discharge fluids is distinct between fields and also varies within wells located in the same field (Wambugu, 1996). This variability is attributed to the extent of water-rock interaction, boiling processes during the ascend of the geothermal fluid to the surface and possible mixing with cooler fluids (Arnórsson et al, 2007).

The fluids in the Olkaria Geothermal field can be classified as sodium chloride, sodium bicarbonate or a mixture of all those waters (Figure 3). The wells in the Olkaria East and North East Production fields have a near neutral sodium chloride water type whereas those derived from the central part of the field and in the Domes area are a mixture of chloride and bicarbonate end members with alkaline pH. The fluids from the Olkaria west part are predominantly bicarbonate rich. According to Ouma (2007), the Olkaria reservoir is a two phase liquid dominated reservoir which is overlain by a thin steam dominated zone that is widest in the south and thinnest in the north. The top of the reservoir is further marked by impermeable basalts which act as the cap rock for the system.

The chemical composition of geothermal fluids is useful in estimating the subsurface reservoir temperatures. Several geothermometers can be used depending on the applications. One of the main assumptions when calculating the temperature using geothermometers is that the temperature dependent chemical equilibria prevails in the source aquifer (D'Amore and Arnórsson, 2000). This assumption does not always hold. However, studies of mineral equilibria in geothermal aquifers indicate that quartz and alkali feldspar equilibria prevail in geothermal fluids with temperatures above150°C-180°C. Hence the temperatures estimations based on quartz and Na-K geothermometers in high temperature reservoirs are valid. The application of the Na/K solute geothermometer as proposed by Fournier and Potter (1982) in the Olkaria Geothermal Field (Figure 4), indicate temperatures between 250°C and 290°C for the East Production Field while the Northeast Production Field indicates temperatures slightly higher than the East Production Field. The Domes Production field waters show temperatures above 270°C for most of the wells. This information is comparable to the temperature estimates based on enthalpy chloride diagrams for the wells in Olkaria which indicate a deep upwelling of a fluid at 320°C to 340°C, its cooling to 280°C before the onset of boiling and mixing in the North East and East Production Fields. In the Domes area, subsurface temperatures are closer to 330°C with reservoir boiling starting at this temperature without initial cooling.

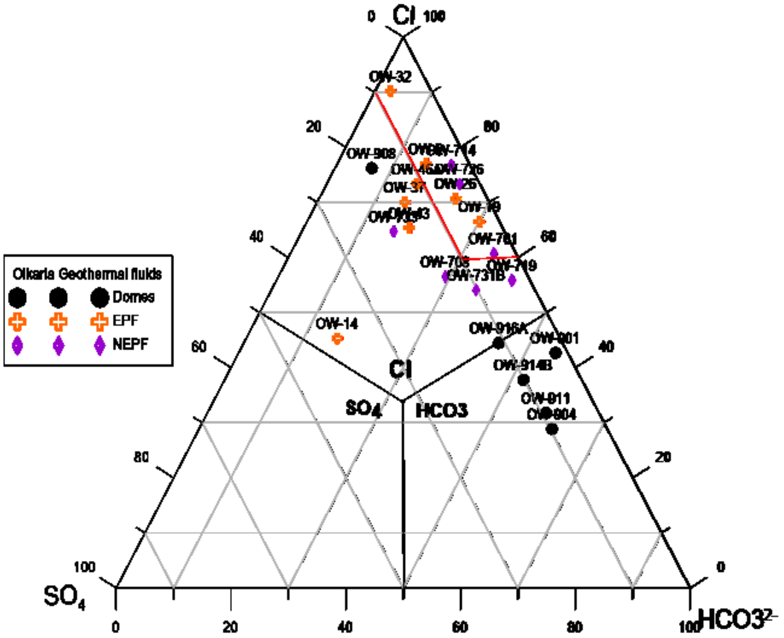

FIGURE 3;Cl-SO_4-$HCO_3$2- ternary diagram for fluid classification in the Olkaria Field

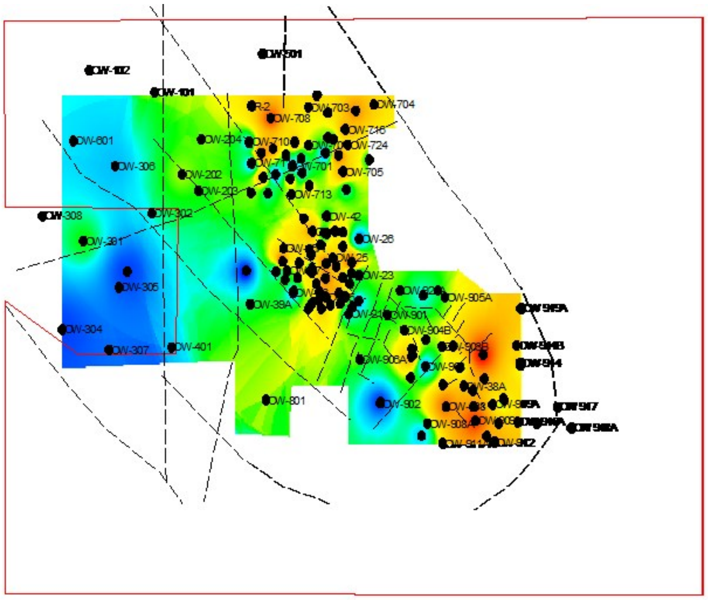

FIGURE 4 : Temperature distribution map in the Olkaria Geothermal Area calculated using Na/K geothermometers (Fournier and Potter 1982)

4. METHODOLOGY

4.1 Sampling and analytical results

Samples discussed in this work have been classified into two: Well discharge data (Table 1) and injected fluid data (Table 2). The well discharge data samples were collected based on high temperature sampling protocol described by Ármannsson and Ólafsson (2006). A Webre separator was connected along the two phase line and was used to sample liquid and steam phases. Sampling of the individual phases is made possible by adjusting the water level inside the Webre separator. A high water level is maintained during sampling the water phase and a low water level when sampling the steam phase. The recommended sampling pressure is usually close to the wellhead pressure. Both the sampling pressure and temperatures were recorded to be used in calculating the steam fraction

	WHP	SSP	Enthalpy	Tref	TDS	pH	B	SO4	Cl	CO2	F	H2S	SiO2	Ca	Li	Na	K	Mg
Well	(bar-g)		(KJ/Kg)	(°C)		@20⁰C	liquid phase values in ppm											
OW-703	8.39	4.94	1257	271	2642	9.2	1.2	24	884	216.5	83	1.42	886	0.2	1.51	710	176	0.1
OW-708	2.41	0.69	1323	246	1165	9.31	2.6	129	507	261	33	0.26	379	0.04	1.5	505	79	0.2
OW-911	4	2.2	1484	226	1120	9.4	1.14	69.2	239.5	444.36	70.28	13.6	618.5	1.32	1.358	461.5	64.47	0.23

Table 1: Water analysis of discharge wells

The second dataset, which include chemical composition of samples from injected fluids, were sampled in a similar manner to one phase wells. In this case a Webre separator was not used. A cooling coil was and appropriate sample preservation treatment was used. Sample preservation methods for both two phase fluids and liquid only phase are the same for all high temperature wells described in this study

Well	TDS	pH	B	SO4	Cl	CO2	F	H_2S	SiO_2	Ca	Li	Na	K	Mg
			liquid phase values in ppm											
OW-703	1430	9.34	2.73	21	622	252.3	26.8	64.6	774	0.077	1.52	528	106.7	0.04
OW-708	1870	9.72	1.81	38.8	585	209.4	73	31.5	836	0.348	1.39	538	112.2	0.02
OW-R3	1930	9.56	2.3	39.2	658	196	67.2	21.3	854	0.176	1.376	524	95.7	0.04

Table 2: Water analysis of injected fluids

4.2 Data Handling

The first step in data handling involved using the analytical data obtained from the separated water and gas samples from well OW-703, OW-708 and OW-911 to obtain aquifer deep fluid composition using the WATCH speciation program version 2.4 (Bjarnason, 2010).

The conductive cooling and adiabatic boiling simulations calculated the mineral saturation indices of anhydrite, calcite, and silica. They were considered as the baseline data prior to reinjection. The reference temperature used for simulation was the measured downhole temperatures. The degassing coefficient representing the completeness of degassing when the fluid boils was 1, 0.5 and 0.1 with 1 representing equilibrium degassing while 0.1 indicating little degassing

The second step involved mixing of reinjected fluid with the aquifer fluid. This mixing simulation was done using the geochemical model PHREEQC version 3.7 (Parkhurst and Appelo, 2013). Various mixing ratios between injected and aquifer fluid were used. These were 1:1, 0.3:0.7 and 0.7:0.3. Those ratios were chosen to simulate how mixing of different amounts of solutions will affect the final mixture concentrations The output from the mixing simulation was then used as an input for boiling simulation using the WATCH speciation program. Results of this simulation revealed the scaling potential of the minerals assessed in the first step. The saturation state of the injected fluid with respect to calcite, anhydrite and amorphous silica was also assessed using the same version of the PHREEQC geochemical program.

5. DISCUSSION

Mineral deposition from boiling fluid largely occurs as a response of cooling and degassing. (Arnórsson et al, 2007). Unlike amorphous silica which has prograde solubility, the solubilities of anhydrite and calcite decrease with increasing temperatures (retrograde solubilities). This means that undersaturation occurs during cooling. Calcite is known to have a pH dependent solubility which decreases with increasing pH.

The dissolution of calcite is defined by:

$$CaCO_3 = Ca^{2+} + CO_3^{2-}$$

Results of the WATCH adiabatic boiling of the aquifer fluid from OW-703 shows that the fluids in the well is saturated with respect to calcite at temperatures of about 180°C and above (using a degassing coefficient of 1). The highest saturation level is attained at temperatures of 250°C after which there is a substantial decrease to undersaturation at temperatures below 180°C. (Figure 5) The onset of boiling either in the wellbore or in the feeding aquifer may be taken to be the cause of this sharp rise in the saturation state. Upon boiling, the fluid pH will rise as a result of degassing and eventually increase the solubility of calcite which is reflected in the saturation state (from the supersaturated state until it reaches an undersaturated state). Similar findings were reported by Wambugu (1996) where the saturation peak indicates the first level of boiling which further implies that effective boiling in the well would take place in the feeding aquifer.

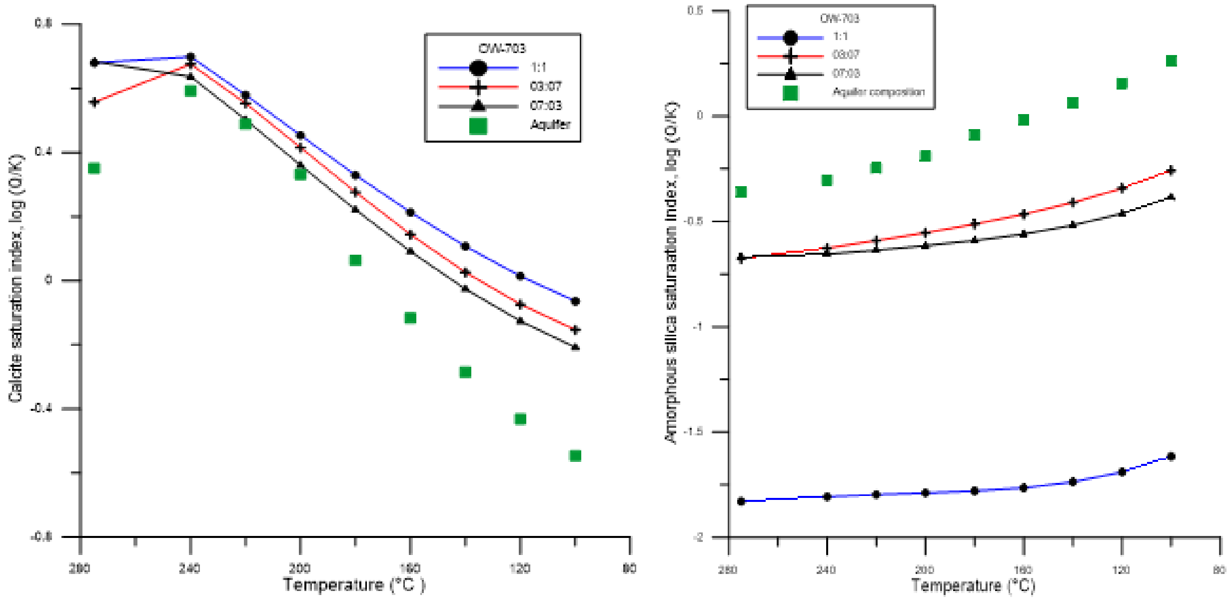

FIGURE 5: Calcite and amorphous silica saturation curves for both aquifer and mixed fluids in well OW-703

Wells OW-708 and OW-911 reflect a different picture when compared to well OW-703. Aquifer fluids in well OW-708 (Figure 6) are undersaturated with respect to calcite from the reservoir temperatures all the way to atmospheric conditions. It can therefore be said that calcite scaling prior to reinjection in this well doesn't seem to pose a risk. However, the same cannot be said as a result of injection and mixing of fluids

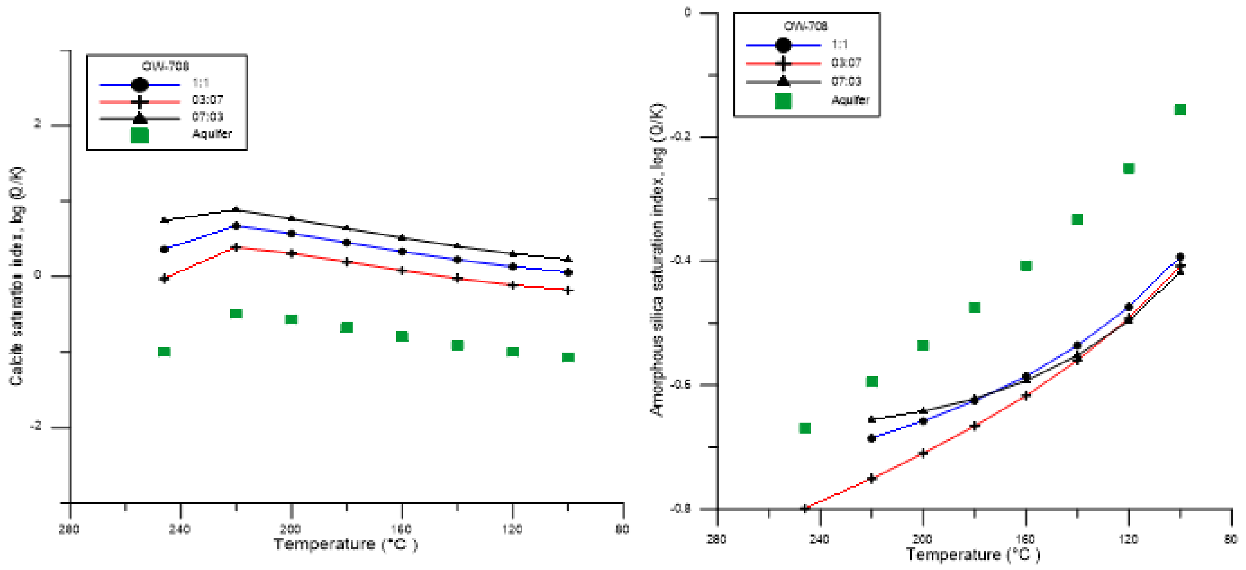

FIGURE 6: Calcite and amorphous silica saturation curves for both aquifer and mixed fluids in well OW-708

Fluids in well OW-911(Figure 7) on the other hand, are supersaturated with respect to calcite throughout the boiling process from the aquifer temperatures of 226 ˚C. At temperatures of around 200˚C-240 ˚C the solubility of carbon dioxide is relatively low and the degassing is rapid. Stratigraphy data for this well indicates that there is a presence of calcite dominance. The presence of platy calcite has been documented in well OW-911A (Njathi, 2012) and is indicative of a boiling system similar to well OW-911. Calcite scaling in the Olkaria Field has been well documented for well OW-202 in the Olkaria Central Field (Opondo, 2015).

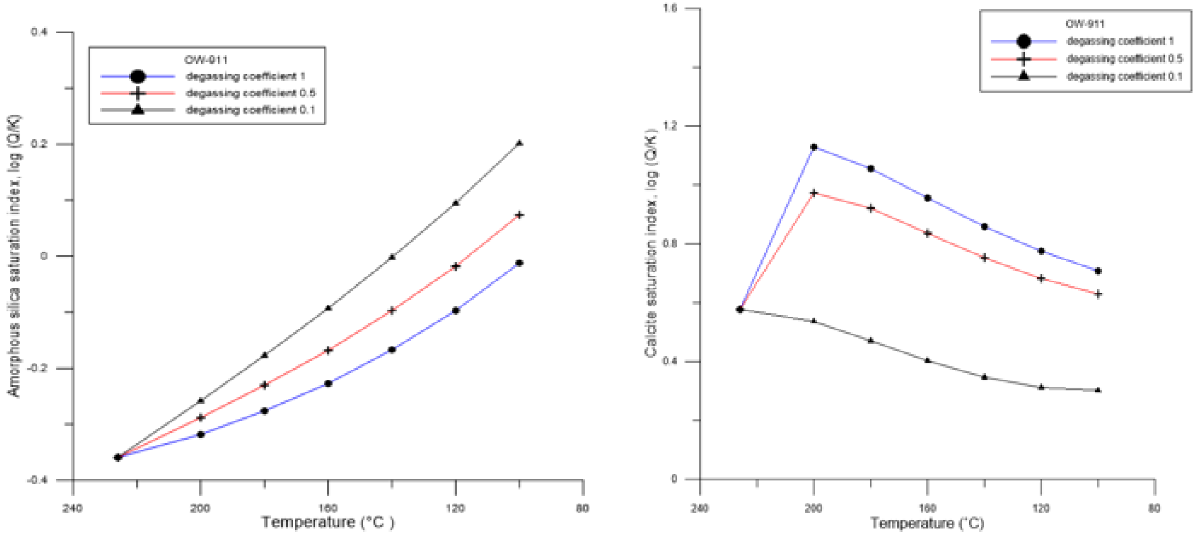

FIGURE 7: Calcite and amorphous silica saturation curves for aquifer fluids in well OW-911

The solubility of quartz in geothermal reservoir conditions determine the concentrations of dissolved silica in the brines. Silica exists in a variety of forms such as quartz, amorphous silica, and chalcedony. Quartz is the most stable and common form of silica in geothermal systems. The difference in solubility between quartz and amorphous silica allows for the exploitation of geothermal systems limiting silica scaling (Brown, 2013). The deep fluid is saturated with respect to quartz and under-saturated with respect to amorphous silica. Adiabatic boiling of the reservoir fluid has two effects 1) it increases concentration of silica due to steam loss 2) lowers solubility of silica due to drop in temperature as the pressure is decreases.

The dissolution of solid silica is given as:

$$SiO_2 + H_2O = H_4SiO_{4(aq)}$$

The pH dependence of silica solubility can play an important role in determining the temperature of injecting fluids. The solubility of amorphous silica increases with increased pH as silicic acid becomes dissociated

The first order dissociation of weak silicic acid can be expressed as:

$$H_4SiO_{4(aq)} = H^+ + H_3SiO_4^-$$

For most dilute geothermal fluids, the pH value of the residual flashed waters is alkaline (1-2.5 pH units above neutral) and in this pH range the solubility of silica is strongly dependent on pH (Henley, 1983). This would further imply that flashed waters from 250°C-290°C reservoirs may not reach saturation as is the situation in well OW-708. (Figure 6) where the fluid is undersaturated with respect to amorphous silica.The pH of geothermal water following steam separation in wellhead separators is a function of composition and temperature and is strongly dependent on the gas removal during single stage and multistage steam separator (Henley, 1983) .The current practice in the operation of production wells in the Olkaria Geothermal Field is to operate them at temperatures higher than that of amorphous silica saturation to minimize the risk of scaling. With this in mind, both wells OW-703 and OW-911, which are at potential risk of scaling need to be operated at temperatures not less than 150°C and 160°C respectively. This approach however limits the amount of energy than can be extracted from the geothermal fluid upon reaching the surface

Results obtained after adiabatically boiling the mixed fluid composition clearly show that mixing of injected fluid with aquifer fluid in the Olkaria Geothermal Field has an effect on the saturation state of the fluids with respect to calcite, amorphous silica and anhydrite. The fluids however remain undersaturated with respect to anhydrite.The mixing ratio affects the change in saturation state of the mixed fluid. Fluids in well OW-703 display a slight departure of calcite saturation compared with the initial aquifer saturation state (Figure 5). The mixing causes an increase in the saturation state of calcite with 07:03 ratio being nearest to that of the aquifer. The effect of mixing on fluids in well OW-703 with respect to amorphous silica, shows that mixing lowers the saturation state of the fluids to a point where it is not seen as a risk during production. A similar scenario is seen in fluids in wells OW-708(Figure 6) and OW-R3(Figure 8) . The reason for these changes can be attributed to the change in pH. The injected fluid which is alkaline with pH values above 9 has a both positive and negative effect on mixing with the dilute neutral aquifer fluid. An increase in the pH value at the aquifer increases solubility of silica whereas the ph dependance solubility of calcite is favoured at low ph values. This would cause the increased solubility of calcite

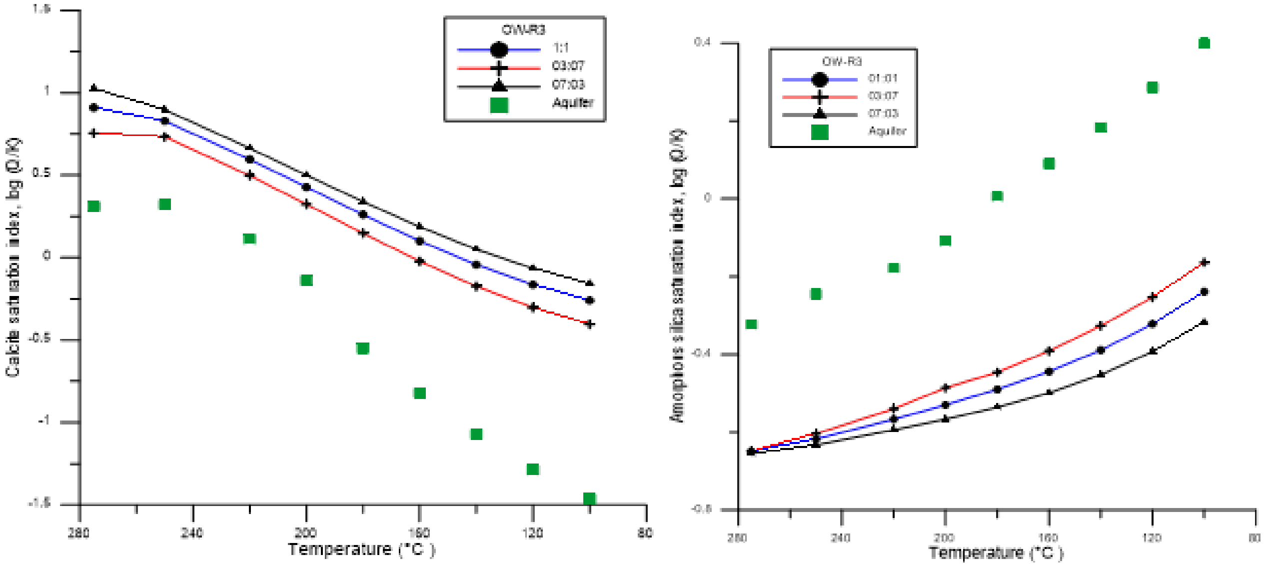

FIGURE 8:Calcite and amorphous silica saturation curves for both aquifer and mixed fluids in well OW-R3

It is important to emphasize that the limitations in the number of phases, components, and species contained in the pitzer.dat and phreeqc.dat databases could not allow comparison of the saturation level for amorphous silica with the minteq.v4.dat without modifications of the database which was not done during this study.

6. CONCLUSION

The assessment for potential scale formation in hot reinjection wells OW-708, OW-703 and OW-911in the Olkaria field prior to production show that the fluids from the three wells are undersaturated with respect to anhydrite. Furthermore, fluids from well OW-708 is undersaturated with respect to both calcite and amorphous silica. Fluids from well OW-911, on the other hand, is supersaturated with respect to calcite and has a higher risk of scaling compared to well OW-703 which reaches supersaturation at temperatures above 160°C. The current practice of operation to minimize silica scaling is to operate them at temperatures above that of amorphous silica saturation. With this in mind, well OW-703 and OW-911 need to be operated at temperatures above 150°C and 160°C respectively.

Comparison of the saturation states prior to injection and as a result of mixing of injected fluid with aquifer fluid confirm that mixing of fluids as a result of reinjection in the Olkaria geothermal field has both positive and potentially negative impacts. However, since only mixing of injected fluid and aquifer fluid was simulated in this study, additional of other equilibrium phases to the model may change the outcome especially when incorporated with residence time of the fluid in the aquifer. Consideration of mixing with other fluids recharging the system may equally change the outcome of the model

Based on the study, the following recommendations should be considered:

- The limitations in the databases within the PHREEQCI program may require comparison with other geochemical modelling programs which can incorporate the high temperature conditions common in geothermal reservoirs
- The practise of converting production well with low production capacity to reinjection wells should be done with caution and should additionally incorporate thermodynamic information from geochemistry to aid in decision making
- Well OW-911 should be closely monitored as it poses a risk of facing calcite scaling problems
- The absence of aluminium and iron chemical analysis data from the sampled fluids excluded the assessment of possible formation of metal scales such as pyrite which is a common alteration mineral in the Olkaria Geothermal Field hence it will be prudent to routinely analyse the fluids for these components together with other trace elements
- More studies on how mixing of reinjected fluids with other fluids can modify the saturation indices in the reinjection well and receiving aquifer should be carried out in the Olkaria Geothermal Field. These studies should also include both thermodynamics and kinetics studies to be able to complement reservoir data on reinjection and also build up the information database which is helpful when carrying out numerical models

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