Proceedings World Geothermal Congress 2010
Bali, Indonesia, 25-29 April 2010

Acid Wells in the Krafla Geothermal Field

Kristján Einarsson, Bjarni Pálsson, Ásgrimur Gudmundsson, Sveinbjörn Hólmgeirsson, Kristinn Ingason, Jónas Matthíasson, Trausti Hauksson, Halldór Ármannsson

Landsvirkjun Power, Háaleitisbraut 68, 103 Reykjavik, Iceland

kristjanei@lvp.is

Keywords: Corrosion and scaling

ABSTRACT

Methods to harness the power from acid wells in the Krafla geothermal field are considered. These contain a high level of Cl and their pH<5. Drilling in the past several years indicates that most of the Krafla geothermal field is acidic below 2200 m depth. To further develop the field it is necessary to find methods to harness the power of acid wells. Possible methods are evaluated and preliminary results are discussed.

1. INTRODUCTION

1.1 Acid Fluids in Geothermal Wells

Acid fluids in geothermal wells contain either sulphate or chloride as the major anion. The former generally occur in cool liquid-dominated systems whereas acid chloride fluids are more prevalent in hot vapour dominated systems (See e.g. Moya et al., 2005; Truesdell et al., 1989). Solutions to the problem generally involve NaOH injection either with (Allegrini and Benvenuti, 1970; Bell, 1989; Hirtz et al., 1991; Moya et al., 2005) or without (Villa et al., 2000; Gardner et al., 2001) the use of acid resistant materials for pipes. Dry scrubbing with calcite packed beds has been suggested by Hirtz et al. (2002). In some cases (e.g. Sugiaman et al., 2004) it has proved possible to case acid zones off.

1.2 The Krafla Geothermal System

Exploration drilling in the Krafla geothermal field started in 1974, with the construction of the power plant starting in 1975. On the 20th of December of that year volcanic activity started at Krafla, which continued with intervals until 1984. The volcanic activity severely limited production and it was not until 1997 that unit 2 was commissioned and 1999 that full production of 60 MW_e was achieved (Júlíusson et al., 2005).

During the period of volcanic activity gases from the magma chamber intruded the deeper part of the geothermal system finding their way into some of the wells resulting in corrosion/scaling of the well casings and liners (Ármannsson et al., 1989). After the volcanic activity subsided in 1984 the system slowly returned to more normal conditions. Wells drilled in the past 20 or so years have mostly been successful producers. Exceptions to this are the acid wells, which are of the acid chloride type.

Wells that have shown some acid character are wells KG-4, KJ-7, KG-10, KG-25, KG-26, KJ-27, KJ-29, KJ-33, KJ-35, KJ-36, KJ-38 and KJ-39. Figure 1 shows that these wells are distributed over a large part of the area and what they have in common is that they are generally deep wells. It is now considered that in most parts of the Krafla system at a depth interval below 2200 m acid conditions prevail. It is therefore of high priority to develop methods to harness the power from these wells to achieve the goals of increased production from the field.

In the present paper acid wells in the Krafla geothermal field are discussed, and methods to make them commercial producers are evaluated. The acid wells are defined in terms of chemistry, interaction between inflow zones, and location in the field. Various methods are considered to make these wells productive, including neutralization of the fluid and screening of inflow zones to control corrosion and scaling.

2. PROPERTIES OF FLUID

2.1 Chemical Composition

The concentrations of the major constituents of water and steam from wells KG-12, KG-25 and KJ-36 are shown in Table 1. When comparing the steam gas concentration, the time of sampling should be considered, as the CO_2 concentration in steam in the Krafla system has decreased after the cessation of the Krafla fires (1975-1984).

Table 1: Chemical composition of steam and water from some acid wells.

Well		KG-12	KG-25	KJ-36
Date		1980-06-08	1990-10-29	2008-01-19
Enthalpy	kJ/kg	2887	1786	2803
Flow	kg/s	6,3	44,9	16,9
Sampling pressure	bar	5,9	16,5	4,35
Water (steam)	**kg/s**	**(6,3)**	**21,5**	**(16,9)**
pH		3,01	6,80	3,96
pH-Temp	°C	22,0	20,2	21,9
Cond	µS/cm	455		3250
TDS	mg/kg	229	682	1583
CO2	mg/kg	19100	81,8	8409
H2S	mg/kg	1678	31,7	1356
SO4	mg/kg	9,15	169,9	29
SiO2	mg/kg		308	359
B	mg/kg			3,18
F	mg/kg	0,24	3,61	3,3
Na	mg/kg	0,17	157,9	220
Mg	mg/kg	0,04	0,053	2,21
Al	mg/kg			0,241
Cl	mg/kg	86,3	69,2	885,4
K	mg/kg	0,05	15,4	88,2
Ca	mg/kg	0,18	4,25	44,3
Mn	mg/kg			37,4
Fe	mg/kg	44	15	292
Steam	**kg/s**	**6,3**	**23,4**	**16,9**
CO2	mg/kg	19100	4927	8409
H2S	mg/kg	1678	897	1356
H2	mg/kg	46,8	8,4	27,9
N2	mg/kg		34,3	81,7
CH4	mg/kg		1,41	4,72
Ar	mg/kg			2,05

2.2 Flow Test on Well KJ-36

Well KJ-36 is located southeast of the Víti crater (Figure 1). The well was directionally drilled to northwest to a depth of 2501 m. The main aquifers reached during drilling were at 1600 m and 2300 m well depth (actual depth 2080 m).

Temperature logs from the drilling and heating up periods are shown in Figure 2. Shortly after well completion wellhead pressure reached 128 bars, which was above the well safety pressure. This was because the high temperature fluid (>340°C) in the aquifer at 2000 m depth was flowing up the well and into the aquifer at 1600 m depth (Guðmundsson et al., 2008).

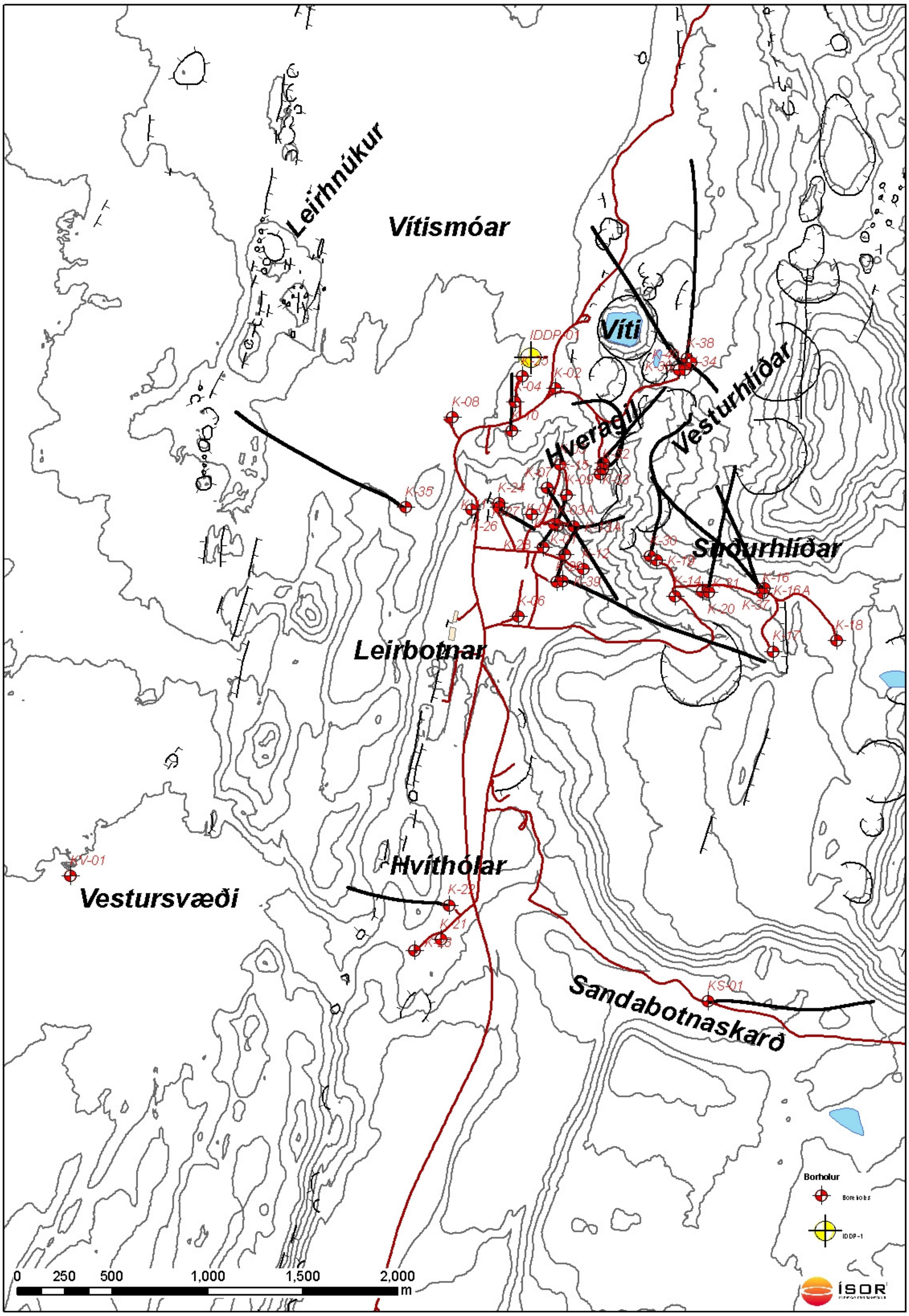

Figure 1: The Krafla area showing all wells.

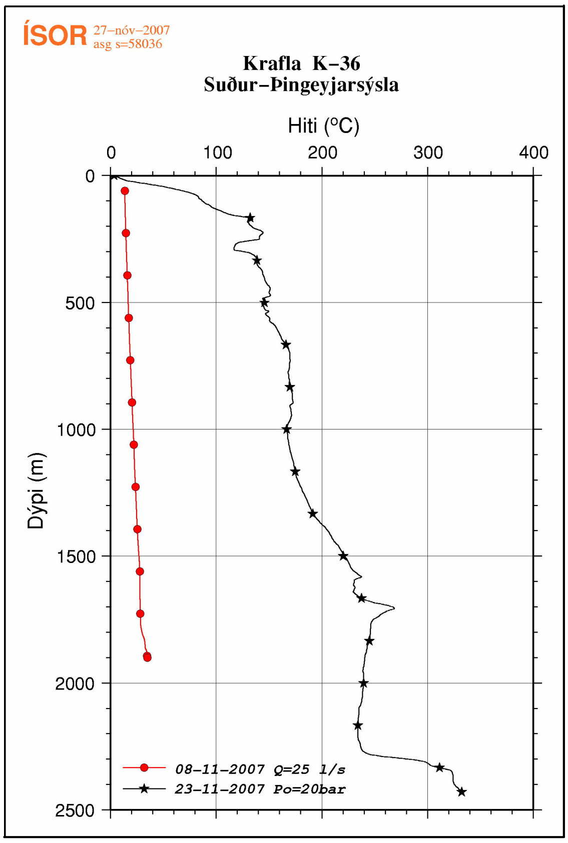

Figure 2: Temperature log of well KJ-36 before first flow test.

The well was first flow-tested December 12, 2007. The well turned out to be very powerful and produced 50 kg/s of steam. The steam contained a high concentration of hydrochloric acid (HCl), which corroded the wellhead rapidly. The test was stopped after 6 days, when a hole had formed in the wellhead pipe (Ármannsson and Giroud, 2007).

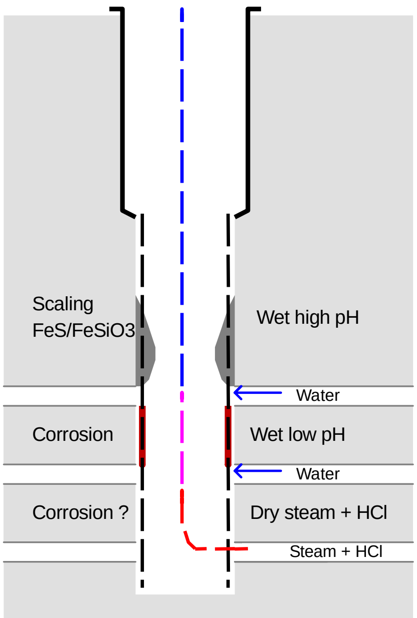

Figure 3: Damage by acid inflow.

Examination of the wellhead showed great damages by acid corrosion and erosion. The corrosion was most rapid at sites with conductive cooling and where the flow speed was high (Pálsson et al., 2007).

The wellhead was fortified and insulated before the second flow test. An extensive monitoring plan was prepared and instrumentation improved. Preparations were made so that well could be killed if it was deemed likely to break loose. This would be the case if the steam would be acid and close to steam saturation. The steam should be at least 10°C superheated otherwise the well would be closed.

Water flowed from the well for a few minutes after the opening of the well. After 1 hour the steam became superheated and the highest superheat value of 15°C was reached after 5 hours. After 24 hours the steam was saturated again.

The pressure was 85 bar when the well was opened and dropped rapidly to 40 bar. The flow reached only 20 kg/s far below the flow obtained in the first test.

After 24 hours the pressure had dropped to 35 bar and the flow to 18 kg/s and was decreasing.

During the flow test the steam was sampled at regular intervals for analysis of pH, Fe, Cl and conductivity. The results are shown in Table 2.

Table 2: Chemical composition of steam from well KJ-36.

Time	pH	Cl	Fe	Conductivity
		(mg/kg)	(mg/kg)	(µS/cm)
18.1.2008 13:10	4,58	87	52	190
18.1.2008 14:00	3,16	160	49	497
18.1.2008 15:00	3,53	135	39	526
18.1.2008 16:30	3,00	115	21	553
18.1.2008 18:10	3,06	87	13	429
19.1.2008 10:55	3,96	881	272	6230
19.1.2008 13:45	3,47	885	292	3250
19.1.2008 20:10	3,62	837	196	5010

The pH was low in all the samples and the concentration of iron and chloride was high. The concentration of iron and chloride decreased when the steam dried up and became superheated. When the superheating dropped and the steam became saturated the concentration of iron and chloride increased drastically. It was obvious that acid (HCl) and iron chloride ($FeCl_2$) were being leached from the well and the corrosion rate was high. It was decided to discontinue further testing and close the well.

The composition of noncondensable gas is shown in Table 3. The first sample was collected from the well prior to the well test. Its hydrogen concentration was high, which is an indication of acid corrosion in the shut well.

Table 3: Gas percentages in steam from well KJ-36.

Time	Sample	CO2	H2S	H2	CH4	N2	Ar
	No	(vol%)	(vol%)	(vol%)	(vol%)	(vol%)	(vol%)
18.1.2008 11:30	4001	52,05	13,75	31,56	0,23	2,28	0,12
18.1.2008 18:10	4006	68,72	23,77	6,07	0,13	1,30	0,04
19.1.2008 13:45	4008	77,00	16,07	5,61	0,13	1,19	0,02

A sample of steam for complete analysis was collected after 24 hours testing when the steam had become saturated. The steam was condensed in a stainless steel cooling coil. The main components of the sample were chloride (Cl) and iron (Fe) as expected. Manganese (Mn) was detected too. Iron and manganese may originate from the casing steel but may also have been leached from the rock. Calcium (Ca) and magnesium (Mg) concentrations were relatively high and must have been leached from the rock by the acid.

3. POSSIBLE SOLUTIONS

The wells in Krafla have been damaged by acid inflow. Acid (HCl) in steam from deep aquifers corrode the liner and cause scaling and blocking of the well as shown in the following sketch (Figure 4).

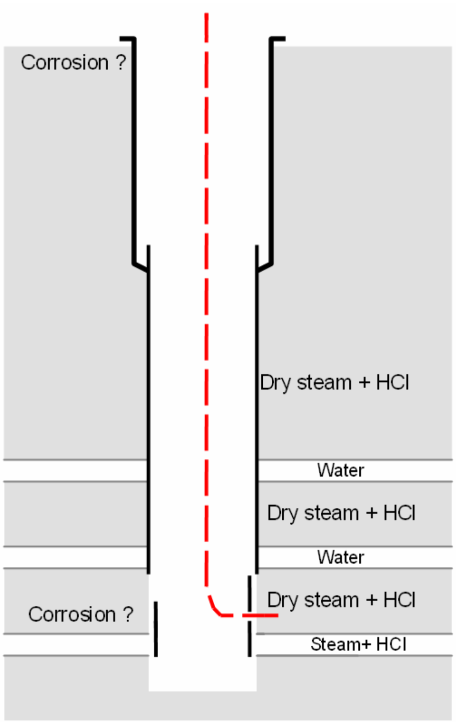

Figure 4: Deep casing.

Until now no satisfactory solution has been found for utilizing the acid reservoir in Krafla but several ideas have been put forward and some tried.

3.1 Repeated Reaming or Acidification of Clogged Wells

Clogged wells have been reamed but have clogged rapidly again. The well casing and liner have been damaged in such operations. Different reaming technology such as the use of a tubular coil with jet stream and acidification may be a better approach as such an operation will also clean the inflow veins. This is being considered.

3.2 Blocking of Water Inflow and Producing Dry Acid Steam

This was tried in well KG-12 where the liner depth was increased to 985 m and shallow aquifers blocked off. This was partly successful as the well was used for many years despite a sudden decrease in output after about one and a half year of operation. The steam became saturated after a few years operation and in the end the well became too low in pressure to be usable. The effect of such deep casing is shown in Figure 5.

This approach may be more successful for deeper and hotter wells with superheated steam only. Cost of wells with 2000 m casing is being investigated.

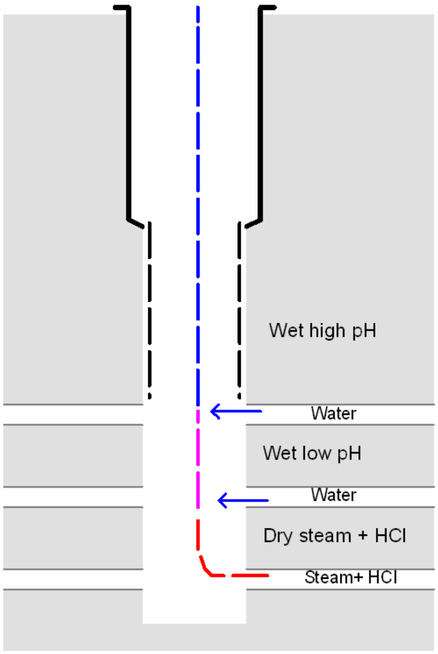

Figure 5: No perforated liner in acid zone.

3.3 Operate Well Without Liner with Downhole Mixing with Alkaline Water

The construction of a well without a liner is shown in Figure 6. The idea is to avoid corrosion of the liner and subsequent precipitation of iron sulfide and silica in the well. The plan was to try this for well KG-25 1995 but postponed because of drilling difficulties. The risk of collapse of well zones without a liner must be considered.

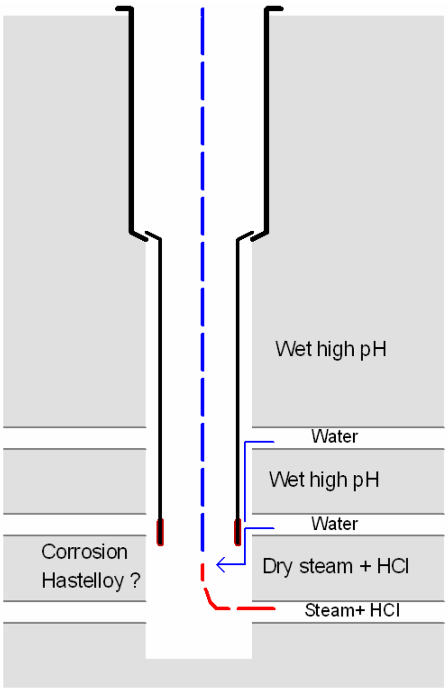

Figure 6: Slotless liner down to acid inflow.

3.4 Operate Well with a Slotless Liner Down to Acid Inflow

A slotless liner in the upper production zone is a possible solution. The alkaline water will then flow down the well behind the liner and mix with the acid flow (Figure 7).

Collapse of the upper zone will be avoided by this approach. Acid resistant liner material will be needed to avoid corrosion at the mixing point.

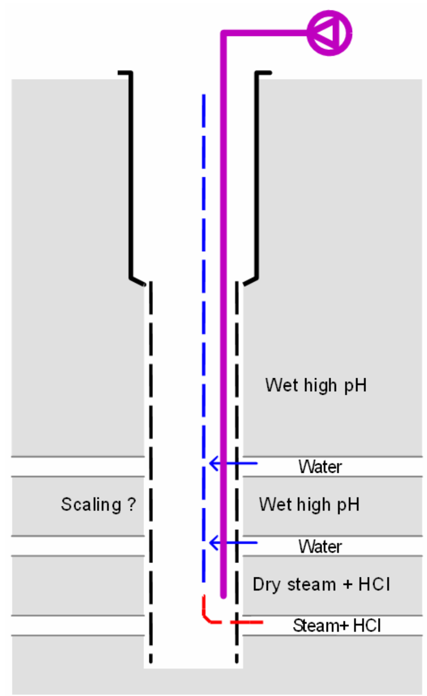

Figure 7: Neutralization of acid inflow.

3.5 Use of Acid Resistant Material for Liner, Casing and Wellhead

Acid resistant material such as titanium or high alloy steel may resist the acid fluid. Such materials are costly and can only be justified if the well is a good producer. This is being investigated.

3.6 Injection of Alkaline Solution and Neutralizing the Acid Inflow

The flow system during such injection is shown in Figure 8. This approach is promising if no minerals accompany the acid inflow such as would be the case for superheated steam. On the other hand if the acid inflow is wet and has leached minerals from the rock rapid clogging of the well is to be expected when the minerals precipitate from the alkaline mixture. Careful pH control and scaling inhibitors may therefore be needed.

Injection of corrosion inhibitors may also be useful. The effectiveness, cost and environmental effect of such inhibitors will have to be considered. This is being investigated.

3.7 Injection of Alkaline Water into the Acid Aquifer to Neutralize and Cool It Down

50 kg/s of alkaline separator water is being injected down to 2200 m depth in well KG-26 since year 2002. Such injection can be more widespread and increased. Drilling of production well in the vicinity of well KG-26 to try this approach is a possible step.

The IDDP well may be a good candidate for deep injection. If water is injected to a depth of 2500 to 3000 m it may generate steam usable by shallower wells. This needs to be modelled.

4. DISCUSSION

The following wells are currently under investigation:

1. Well without liner – KJ-39:

Attempts were made to retrieve the slotted liner from well KJ-39. This was partly successful and the liner from casing shoe at 8xx m to 15xx m was retrieved. The well has been monitored since with no indication of collapse.

2. Neutralization of acid inflow – KJ-38:

Well KJ-38 was drilled during the summer of 2008 and is a non-productive investment due to the high acidity of the fluid. This well is considered a good candidate for neutralization by injection of alkaline solution.

A research project on the feasibility and cost of such a system is currently under way.

3. Deep casing – IDDP:

The IDDP well is the first well in the Krafla geothermal field with a deep casing, 1958 m. Experience from this well may be valuable in determining the feasibility of this solution for future wells.

5. CONCLUSIONS

The main selection criteria for the possible solutions are initial cost and operational cost. The lowest investment is the well without the slotless liner. This may be a feasible solution, as the experience from KJ-39 indicates. Operational cost for a well without liner is yet an unknown. However, such wells may require regular maintenance such as reaming.

A downhole injection system is under investigation. There are indications that this involves a high operational cost as well as the initial investment. This may however be the only solution available for the existing acidic wells.

Deep casing up to 2000 m depth is a high initial investment. In this design the wet shallow aquifers are screened off and deeper dry steam aquifers are targeted. A scrubber is required on the surface to clean the steam. Therefore operational and initial costs are high.

Investigations of the possible alternatives available will continue. Preliminary results suggest that future wells will be either without the liner in the production zone or with deep casing to screen off shallow aquifers.

REFERENCES

Allegrini, G. and Benvenuti, G.: Corrosion characteristics and geothermal power plant protection. U.N. Symposium on the Development and Utilization of Geothermal Resources, *Geothermics*, 2, Part 1, 865-881, (1970)

Ármannsson, H. and Giroud, N.: Well KJ-36, Krafla. First Chemical Analysis Results and Possible Corrosion Problems (In Icelandic). ÍSOR-07287, 6 pp, (2007)

Ármannsson, H., Benjamínsson, J. and Jeffrey, A.W.A.: Gas changes in the Krafla geothermal system, Iceland. *Chem. Geol*. 76, 175-196, (1989)

Bell, D.: Description of an operational desuperheating and chloride scrub system. *Geotherm. Resourc. Counc. Trans*., 13, 303-307, (1989) Gardner, A.B., Rivera, N.N., Santos, R.M., Toreja, J.S., Villaseňor, L.B. and Gallup, D.L.: *Proceedings 22nd Annual PNOC EDC Geothermal Conference, Manila Philippines*, 155-159, (2001)

Guðmundson, Á, Steingrímsson, B., Ármannsson, H. and Thórhallsson, S.: An estimate of the state of well KJ-36, Krafla at the beginning of the year 2008. ÍSOR Memo, 3 pp, (2008)

Hirtz, P.N., Broaddus, M.L. and Gallup, D.L.: Dry steam scrubbing for impurity removal from superheated geothermal steam. *Geotherm. Resourc. Counc. Trans*., 26, 751-754, (2002)

Hirtz, P., Buck, C. and Kunzman, R.: Current techniques in acid-chloride corrosion control and monitoring at the Geysers. *Proceedings 16th Workshop on Geotherm. Res. Eng. Stanford University, Stanford, Ca*., 83-95, (1991)

Júlíusson, B.M., Pálsson, B. and Gunnarsson, Á.: Krafla Power Plant in Iceland – 27 Years of Operation. Proceedings World Geothermal Congress 2005 – Antalya, Turkey 24-29 April 2005, 4 pp.

Moya, P., Nietzen, F. and Sanchez, E.: Development of the neutralization system for production wells at the Miravalles geothermal field. *Proceedings World Geothermal Congress 2005, Antalya, Turkey*, 10 pp.

Sugiaman, F., Sunio, E., Molling, P. And Stimac, J.: Geochemical response to production of the Tiwi geothermal field, Philippines. *Geothermics*, 33, 57-86, (2004)

Truesdell, A.H., Haizlip, J.R., Ármannsson, H. And D'Amore, F.: Origin and transport of chloride in superheated geothermal steam. *Geothermics*, 18, 295-304, (1989)

Villa, R.R., Siega, F.L., Martinez-Oliver, M.M., Salonga, N.D., Ogena, M.S., Garcia, S.E., Buning; B.C., Lichti, K.A., White, S.P. and Sanada, N.: A demonstration of the feasibility of acid well utilization: The Philippines' well MG-9D experience. *Proceedings 20th Annual PNOC EDC Geothermal Conference, Philippines*, 25-32, (2000)