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Phase-Specific and Phase-Partitoning Tracer Experiment in the Krafla Reservoir, Iceland

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ABSTRACT

A field-wide tracer test was performed in the Krafla reservoir, starting in August 2013. Tracers were injected into three wells and collected in twenty production wells. The experiment involved both phase-specific and phase-partitioning tracers. Naphthalene sulphonate tracers (2-, 2.6- and 2.7-naphthalene sulphonate) were used to trace the liquid phase. Phase-partitioning tracers were alcohols (methanol and ethanol) collected in steam condensate (vapor phase) and perfluorocarbon tracers (PMCP, PMCH, PDMCH) were used to trace the vapor phase. The alcohols seem to have spread most widely, while the phase-specific tracers had been detected in very few wells at the time this was written (May, 2014). The wide distribution of the alcohols is interpreted with caution however, as the tracer returns are quite variable and high background samples were detected just before injection took place. The results thus far are preliminary as sampling will continue through year 2014.

1. INTRODUCTION

Tracer tests are tests that are routinely performed in geothermal reservoirs to investigate subsurface flow paths. In such tests, one or more chemicals are released into specific injection wells and then samples are collected regularly from production wells to investigate whether and where these compounds return. The information that is gathered is often used to determine if a given reinjection strategy is likely to cause premature cooling of production wells. The tracer returns can also be used to enhance understanding of the geological structure of the reservoir, thus allowing for better information in locating future production wells.

Two tracer tests had been performed in Krafla previous to the one discussed in this paper. The first was conducted under the supervision of The Icelandic Geological Survey (ISOR) in 2005-2007, where 450 kg of KI were injected into well K-26. Samples were collected on a regular basis from 9 wells (K-13, K-15, K-21, K-27, K-29, K-30, K-32, K-33 and K-34) over a period of 20 months. The measured concentration barely reached the detection limit during this period and it was determined that at most 1% of the tracer had been returned to the production wells (Ármannsson et al., 2009).

A second tracer test was performed in 2009 as part of the EU funded HiTI (High Temperature Instruments) project. The test was conducted under the supervision of The French Geological Survey (BRGM) from June 1st until September 1st. Naphthalene sulphonate tracers were injected into wells K-26 (1,5-NDS and 2,6-NDS) and IDDP-1 (1,6-NDS) and samples were collected from 18 production wells (K-5, K-9, K-13, K-14, K-15, K-16, K-17, K-19, K-20, K-24, K-30, K-31, K-32, K-33, K-34, K-36, K-37, K-39). The tracers were recovered relatively quickly in a few of the monitoring wells, but in very low quantities, or around 0,5 % total. Thus it was speculated that the tracers were either being injected into a very large/open reservoir or that the tracers were degrading very quickly under the high-temperature conditions (+350°C) in Krafla. The distribution of the tracer returns indicated that an ENE trending flow path reaching from well K-26 to well K-37. Moreover, there was some indication of a ESE trending flow path going from K-26 to K-30, which corresponds to a previously mapped fault structure in the field (Gadalia et al., 2010).

In the fall of 2012 it was clear that the steam supply for the Krafla power plant could not be met by the IDDP-1 well, because of damages in the wellhead and casing. As a result of that the idea of using IDDP-1 as a reinjection well emerged, where the target would be to mine heat from the magma at the bottom of the well. There had also been some discussion of reinjection into the SE part of the reservoir, where well productivity had been decreasing rapidly, particularly in some of the newer wells. Thus, a tracer test was designed to investigate the feasibility of these two options, with a secondary goal of mapping flow paths in the reservoir.

2. IMPLEMENTATION OF THE TRACER TEST

In this section we describe the selection and injection of tracers for the 2013 tracer test in Krafla. The tracer sampling and analysis is also described briefly.

2.1 Tracer Selection

Both of the previous tracer tests at Krafla were designed to trace the liquid phase through the reservoir. In view of the limited returns it had been speculated that much of the reinjection fluid could be travelling in the vapor phase. Therefore, this tracer test was designed to trace both the liquid and vapor phase. Two world-leading experts on tracer testing, ThermoChem Inc. and EGI at The University of Utah, were consulted with regards to tracer selection. The decision was to inject three different types of tracers:

- Naphthalene sulphonates as liquid-phase tracers
- Perfluorocarbons as vapor-phase tracers
- Alcohols as phase-partitioning tracers that could travel both in the vapor and liquid phase.

These tracers were considered ideal as they were environmentally safe, conservative, absent from the Krafla geothermal fluids and detectable at very low concentrations. The alcohols and naphthalene sulphonates were also relatively inexpensive and easily soluble (with the exception of 2-NMS). The naphthalene sulphonate and perfluorocarbon tracers are also considered thermally stable, although they have not been tested at temperatures above 350°C (to the knowledge of the authors), as expected in the Krafla reservoir.

2.2 Tracer Injection

A map of the injection and production wells that were used in this tracer test is shown in Figure 3, and a cross section of the same wells is shown in Figure 4. The tracers were allocated between wells K-26, K-39 and IDDP-1, as shown in Table 1.

Table 1: Allocation of tracers into the wells in Krafla

	KG-26	*KJ-39*	*IDDP-1*
Naphthalene sulphonate	2.7-NDS	2.6-NDS	2-NMS
Perfluorocarbon	PDMCH	PMCH	PMCP
Alcohol	Ethanol	Methanol	

A tracer injection skid was prepared for injecting the three different tracers. The skid consisted of two pumps, valves, and piping that connected to the tracer containers and wellhead. A schematic diagram of the skid is shown in Figure 1. The larger pump was a centrifugal pump from Movitec (type: VSF 6/26 B) which was connected to a speed converter such that it could be run in the range of 600 to 6400 L/h. The smaller pump was a digitally controlled direct-drive diaphragm pump from IWAKI (type: IX-C150TCR-RF1-E with PVDF/FKM/CE) which could run in the range of 0.2 to 150 L/h. These pumps were be used to pump the ethanol (33%), methanol (33%), and PFC blends, all of which contained flammable liquids. However, these liquids were diluted enough such that there was no need for the pumps to be explosion proof.

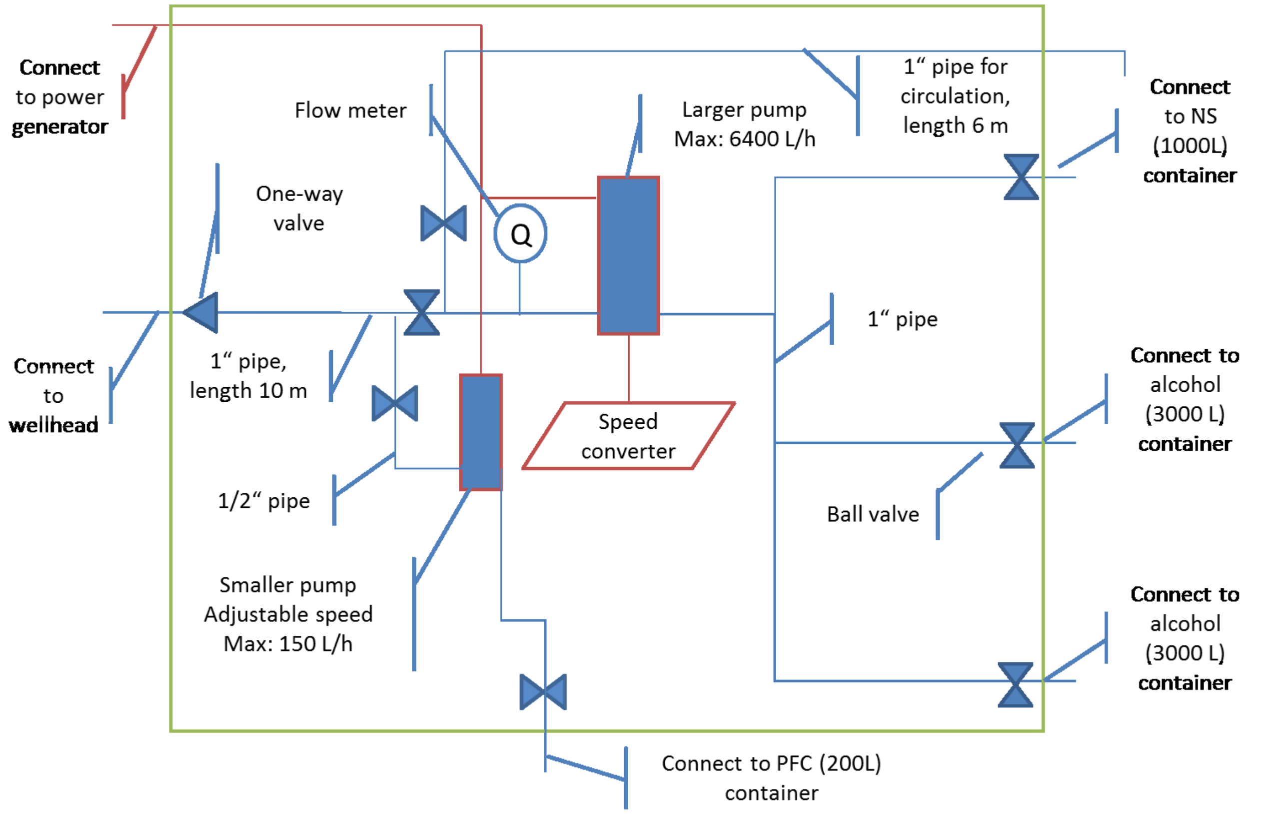

Figure 1: Schematic diagram of tracer injection skid.

Each of the naphthalene sulphonates tracers were dissolved about four weeks before injection where 100 kg of each tracer was mixed in 1000 L of water. A large paint stirrer was used to mix the tracer. Samples of the tracers were taken and sent for analysis as soon as they had been mixed to verify the quality of the mix. Utmost precaution for contamination was taken by cleaning the outside of the tanks thoroughly before shipping and having the mixing done in a remote location (400 km away from Krafla) by a chemist that would not visit Krafla during the test period. The three 1000 L containers were shipped to Krafla the week before injection and placed next to the injection wells. Running the larger pump at full speed meant that the 1000 L of NS tracer could be injected in approximately 10 minutes.

The alcohols (methanol and ethanol, 99% concentration) were stored in 1000 L tanks, and 2000 L of each substance was to be used. The alcohols were diluted into a 36% solution to reduce the flammability of the liquid before injection, by moving the alcohols into two 2750 L stainless steel tanks that were available at Krafla. These tanks were placed next to the allocated injection well on the day before injection took place. Running the larger pump at full speed meant that the 5500 L of alcohol tracer could be injected in less than an hour.

The perfluorocarbons (PFCs) emulsion was prepared by ThermoChem. Two 100 L drums were used for the PFC mixing and injection (total solution volume was approx. 150 L). The solution is injected using the smaller diaphragm pump on the injection skid. The PFC's had to be injected slowly so as to not exceed the PFC solubility limit. For IDDP-1, this required about 5 hours in injection time for the tracer, while the other wells took less time (1.5 and 3.5 hrs).

The entire injection and sampling process was conducted in cooperation with a senior field chemist from ThermoChem and transpired without major incidents. Figure 2 shows the set-up for injection into well K-39.

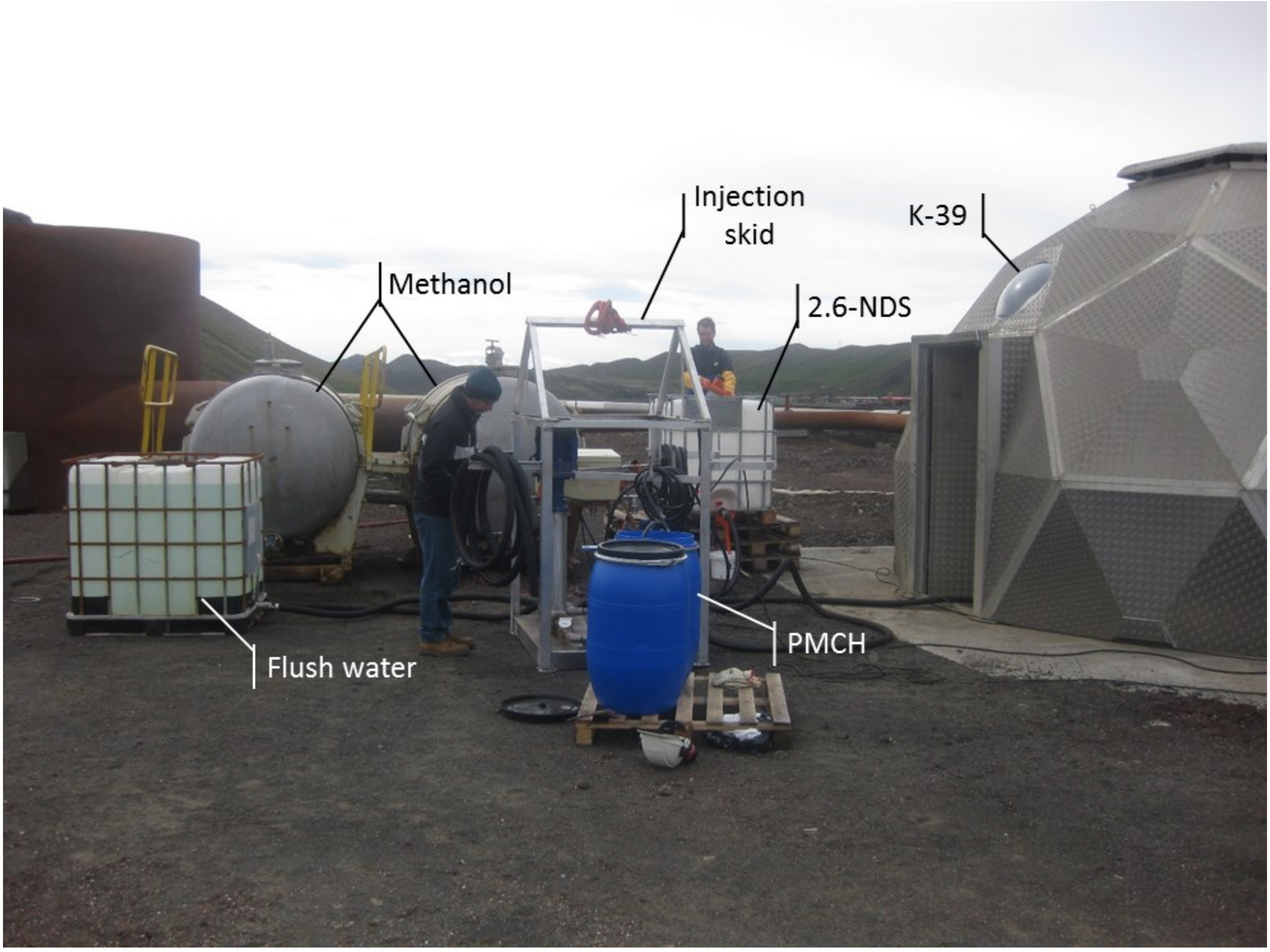

Figure 2: Injection into well K-39.

2.2.1 Injection into IDDP-1

Well IDDP-1 was initially planned as +3.5 km deep well to explore supercritical regions of the Krafla reservoir. However, IDDP-1 hit a magmatic intrusion at 2100 m depth at which point drilling was halted. The well promised to become a good producer until the wellhead and casing were damaged in fall 2012. About 15 l/s of cold water have been injected into IDDP-1 since that time and thus the idea of utilizing it for mining heat from the intrusion arose. The objective of injecting tracer into IDDP-1 was to investigate whether a significant amount of the injected fluid could be mined in nearby wells.

The first tracer injected was the perfluorocarbon PMCP, a total of 25 kg, which were released in the morning of August 7. Between 13:02 and 18:15.

The 2-naphtalene mono sulphonate (2-NMS) tracer was released into IDDP-1 between 18:30 and 19:30 on August 7. The 2-NMS did not dissolve very well in the 1000 L solution and in hindsight it would have been better to have tested the amount needed for the dissolution beforehand. Suspended solids in the solution caused some problems with the pumps on the injection skid but those were solved by flushing the tracer with ~3000 L of cold water.

No alcohol tracer was released into well IDDP-1 as the alcohols were expected to degrade quickly at the extreme (+450°C) temperature that had been measured at that location.

2.2.2 Injection into K-39

Well K-39 was drilled in the fall of 2008. Its initial depth was 2848 m, but a 240 m cement plug was placed in the bottom of the well as it was believed to have hit magma (T logs showed 385°C). K-39 was chosen as an injection well to provide pressure support to the SE part (Suðurhlíðar) of the Krafla reservoir. The main objective of the tracer test was to investigate the possibility significant cooling in nearby wells as a result of the reinjection.

The PMCH perfluorocarbon was injected first in well K-39. The 25 kg were released between 9:18 and 13:00, on August 8. Next came 2,6-NDS, which was injected between 13:10 and 13:22. A large paint stirrer was used to keep 2,6-NDS well mixed during the injection process. Finally, 5200 L of the methanol/water solution was injected, from 13:27 until 14:26.

2.2.3 Injection into K-26

Lastly, a tracer triplet was released in well K-26, which has been used for reinjection in Krafla since 2002. Liquid-phase tracers had been used in K-26 before, but the high temperatures measured there after drilling indicated that much of the fluid may have been carried in the vapor phase.

In the afternoon of August 8th (15:01-16:30), 25 kg of PDMCH perfluorocarbon was injected into well K-26. Thereafter came 2,7-NDS, injected from 17:41 to 17:51. The 2,7-NDS was well dissolved and no additional mixing was needed during the injection process. Finally, 5300 L of the ethanol/water solution was injected, from 17:55 until 18:49.

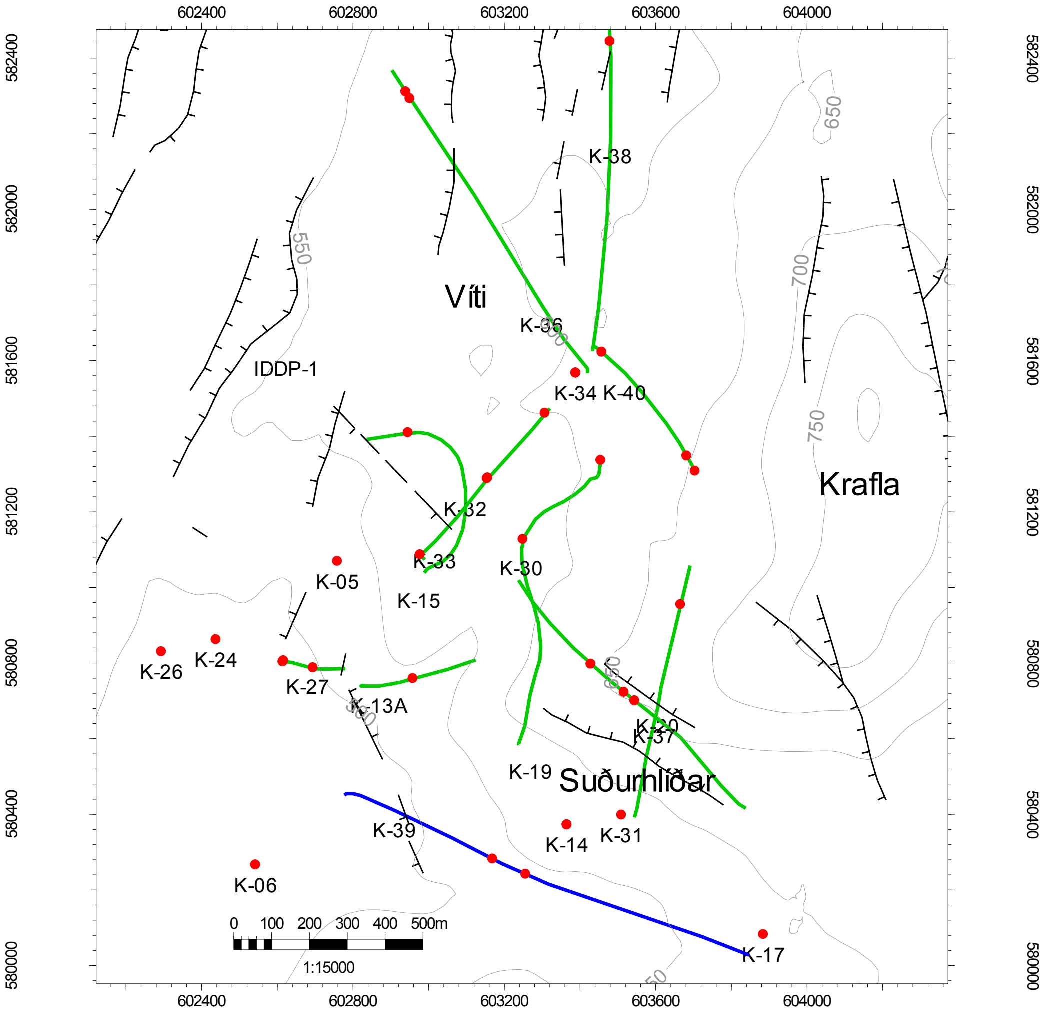

Figure 3: Overview of injection and production wells utilized in the Krafla 2013 tracer test. The three injection wells are IDDP-1, K-26 and K-39. The other 20 wells shown on the map were used for sampling. Main feedzones are illustrated with red dots.

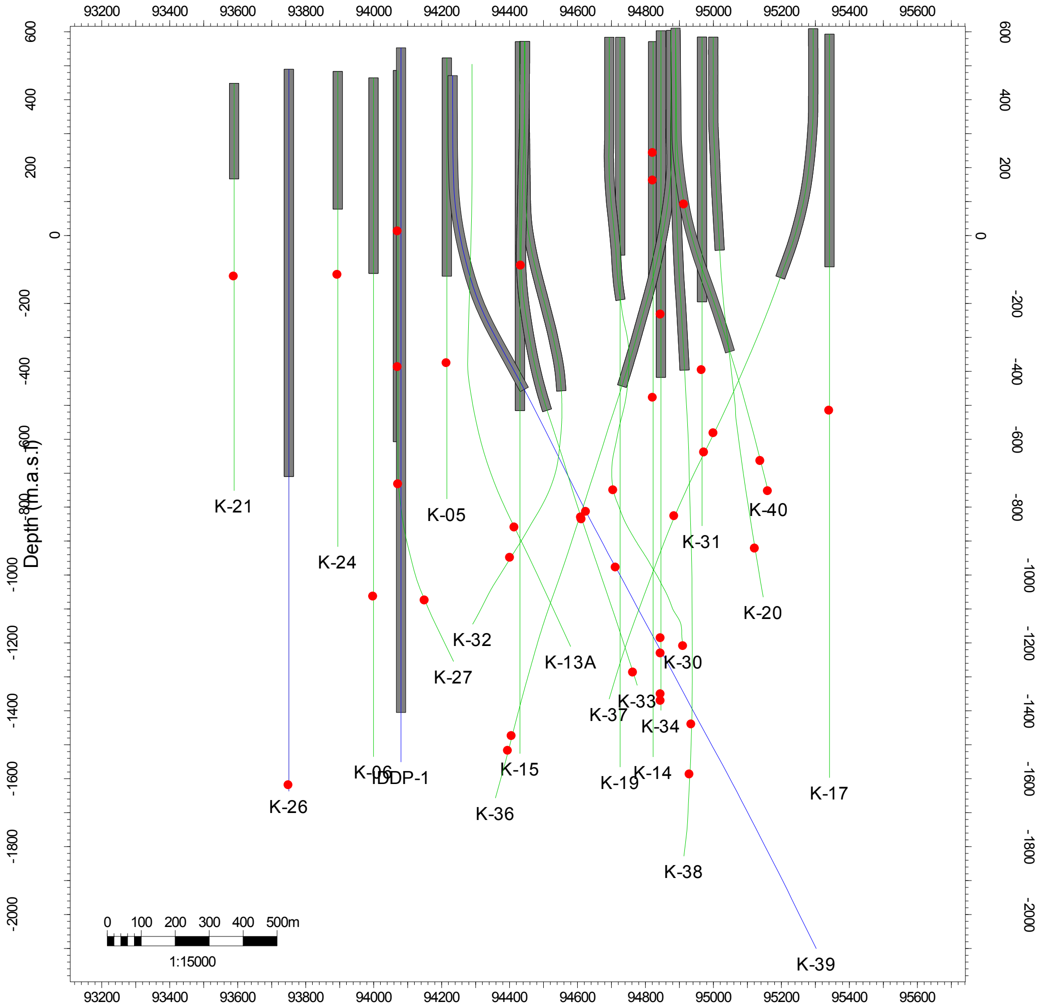

Figure 4: Cross section of injection and production wells utilized in the Krafla 2013 tracer test. The three injection wells are IDDP-1, K-26 and K-39. The other 20 wells shown on the map were used for sampling. Main feedzones are illustrated with red dots on the well trajectory. Well casings are shown with gray boxes.

2.3 Tracer Sampling and Analysis

Monitoring wells for the test were chosen based on which wells were in production or could easily be opened for discharge. These wells were K-5, K-6, K-13, K-14, K-15, K-17, K-19, K-20, K-21, K-24, K-27, K-30, K-31, K-32, K-33, K-34, K-36, K-37, K-40 and KS-1. Liquid phase samples were also collected from the separator station to monitor the concentration of reinjected naphthalene sulphonates.

In the 2009 tracer test it was mentioned that an early peak might have been missed in the 2009 tracer test and previous gas tracer results have indicated rather short breakthrough times. Therefore dense sampling was scheduled for the first week, with a time decrease in sampling frequency, as shown in Table 2. The planned sampling schedule was carefully upheld for the first couple of months but as winter arrived at Krafla, the sampling had to be more flexible to deal with weather conditions. Moreover, the results from the tracer analysis were used to emphasize which wells to collect from on a regular basis.

Table 2: The planned sampling schedule for the tracer test.

Sampling period	*Sampling rate*	*Number of wells*	*Total samples/period*
Week 1	2 samples/well/day	20	280
Week 2	1 sample/well/day	20	140
Weeks 3-4	3 samples/well/week	20	120
Weeks 5-8	2 samples/well/week	20	160
Weeks 9-26	1 sample/well/week	20	360
Weeks 27-52	1 sample/well/2weeks	20	260
Weeks 52-78	1 sample/well/4weeks	20	130
Total samples			**1,450**

The tracer samples were taken with custom made Webre separators (Figure 5) that were built for each well. These separators allowed the liquid, vapor and gases to be sampled individually (Arnórsson et al., 2006). The vapor and liquid samples were collected in 100 ml PVC bottles. Gas samples were collected in custom made gas-tight bottles containing 100 ml of 15% NaOH. The gas samples were transferred into Tedlar bags (ThermoChem procedure) in order to minimize cost of shipment to the ThermoChem lab located in California, USA.

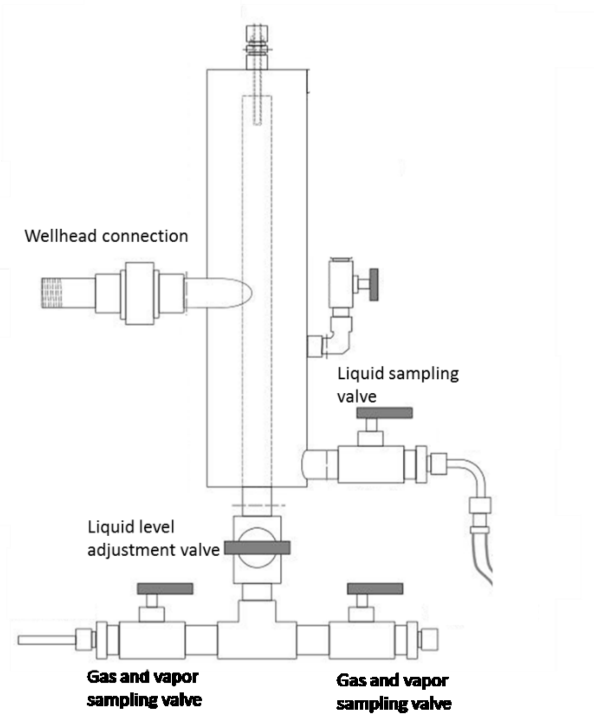

Figure 5: Webre separator used to collect gas, vapor and liquid samples.

Approximately one-third of the samples taken were analyzed in the lab. The selection of these samples was mostly in the hands of Landsvirkjun for both the NS and Alcohol tracers, but ThermoChem selected the PFC samples to analyze. The naphthalene sulfonates were analyzed by ISOR using HPLC (high performance liquid chromatography) with a fluorescence detector, with an estimated detection limit of 0.1-0.3 ppb. The alcohols were analyzed by EGI of the University of Utah, using the Solid Phase Micro Extraction (SPME) GC/MS method. The detection limit for the ethanol was approximately 2-5 ppb but for the methanol it was closer to 35-50 ppb (P. Rose, personal communication). The PFC tracers were analyzed by ThermoChem using a HPLC-MS set up, and the detection limit there was 10-50 ppt by weight in the steam depending on the sample size in the gas bottle and the molecular weight of the PFC used.

3. RESULTS AND INTERPRETATION

A preliminary analysis of the tracer returns has been carried out. The basis of the analysis is the one dimensional advection-dispersion equation, where the concentration of the produced liquid is described by

$$c_P(t) = (m_I F)\left(\frac{q_I F}{q_P}\right)\sqrt{\frac{V_x Pe}{4\pi Q(t)^3}}\exp\left(-\frac{Pe(V_x - Q(t))^2}{4V_x Q(t)}\right) \quad (1)$$

In this equation m_I denotes the total mass injected and F is the fraction of that mass that is produced in the injection well; q_I is the injection rate and q_P is production rate (in the sampling phase); V_x and Pe and the representative volume and Peclet number for the injector-producer flow path; and $Q(t) = \int q_I(t)F dt$ is the cumulative flow of fluid from the producer to the injector over time t. The group $(m_I F)$ represents the total amount of tracer that flows towards the producer, and the group $(q_I F/q_P)$ accounts for the mixing of the injection fluid with other fluid entering the production well.

The fraction of recovered tracer can be estimated by numerical integration of the tracer return curve, i.e.

$$F = \int q_P c_P(t) dt \quad (2).$$

Similarly, one can estimate the volume of the flow path from the first moment of the tracer return curve

$$V_x = \frac{\int Q c_P dQ}{\int c_P dQ} \quad (3)$$

and the Peclet number from the second central moment

$$Pe = \frac{2V_x^2 \int c_P dQ}{\int (V_x - Q)^2 c_P dQ} \quad (4).$$

The cooling effects of the injection process was estimated based on a commonly used model presented by Lauwerier (1955)

$$T_P(t) = \left(\frac{q_I F}{q_P}\right)\left(T_0 - (T_0 - T_I)erfc\left(\frac{\xi}{2\sqrt{\theta(\tau-\xi)}}\right)\right) \tag{5}$$

where T_0 is an estimate of the initial temperature in the reservoir, T_I is the temperature of the injection fluid, and the parameters ξ, τ and θ are defined as follows:

$$\xi = \frac{K_r}{b^2 \rho_w c_w} \frac{V_x}{R \phi_f F q_I} \tag{6}$$

$$\tau = \frac{K_r}{b^2 \rho_{af} c_{af}} t \tag{7}$$

$$\theta = \frac{\rho_{af} c_{af}}{\rho_{am} c_{am}} \tag{8}$$

where b denotes the fracture half aperture, ϕ_f is the fracture porosity, K_r is the thermal conductivity of the rock, $R = 1 + \phi_m(1 - \phi_f)/\phi_f$ is the tracer retardation factor with ϕ_m representing the matrix porosity. The groups

$$\rho_{af} c_{af} = \phi_f \rho_w c_w + (1 - \phi_f)\rho_r c_r \tag{9}$$

and

$$\rho_{am} c_{am} = \phi_m \rho_w c_w + (1 - \phi_m)\rho_r c_r \tag{10}$$

represent the average volumetric heat capacity for the fracture and the surrounding rock matrix, respectively. The thermodynamic parameters needed in equation (5) could be estimated fairly accurately based on existing knowledge of the petrology and reservoir fluid. The largest uncertainties were related to the geometry of the flow paths.

These equations were used to analyze the results that follow. Note that in these equations it is not assumed that multiple injectors can influence a single producer simultaneously. For further discussion on such scenarios we refer to Juliusson and Horne (2013a, 2013b).

3.1 Naphthalene sulphonate returns

The naphthalene sulphonate tracers were not found in significant amounts anywhere but in well K-36, where 2-NMS was detected at up to 125 µg/L. Both 2.6- and 2.7-NDS were detected in K-36 as well, albeit in far smaller amounts (max 3.5 µg/L). The return curve for the 2-NMS was very similar in shape to that for the two NDS tracers and therefore we assume that they are derivatives of the 2-NMS coming from IDDP-1.

The return curve for the 2-NMS is shown in Figure 6. The drop in concentration that is seen in two samples that are taken near the peak (around day 15) is explained by an interruption in the production conditions for the well, i.e. the discharge had to be diverted from the steam-gathering system to a silencer because of maintenance at the power plant.

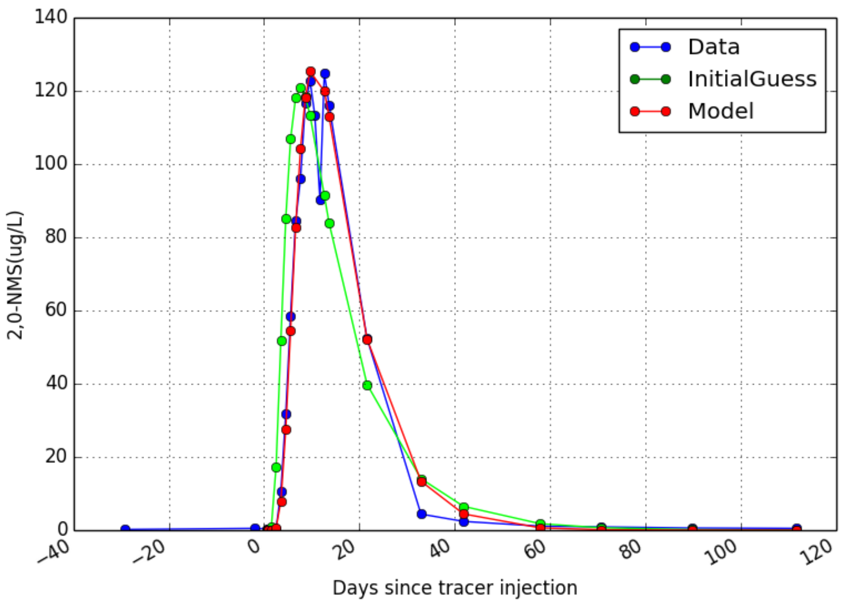

Figure 6: Tracer returns in well K-36 from well IDDP-1. The estimate with the green line was computed based on equations (2)-(4) but the red line is based on a curve-fit of equation (1) to the measured data (blue).

The shape of the tracer return curve indicated that a one dimensional advection-dispersion model would fit the data well. An initial guess of the appropriate parameters was estimated using equations (2)-(4). These parameters were fine-tuned by fitting equation (1) to the data, where the two aforementioned points around day 15 were excluded from the data set.

Table 3: Estimates of tracer return fraction, flow path volume and Peclet number for the connection between IDDP-1 and K-36.

IDDP-1 to K-36	*F* *[-]*	*Vx* *[m³]*	*Pe* *[-]*
Initial guess	*0.30%*	*113*	*3.6*
Model estimate	*0.30%*	*116*	*6.7*

It should be noted here that the flow path volume is unexpectedly small, and in fact on the same order of magnitude as the volume of the injection and production wells, which has not been accounted for. An explanation for this could be that a very thin and small fracture that connects the two wells, which fits nicely with the low (0.3%) tracer return fraction.

The cooling effects of the injected fluid could be computed, using equation (5), however, the results indicate that only 0.3% of the injected fluid travels from IDDP-1 to K-36. That means that the contribution of injection fluid from IDDP-1 in the fluid produced in K-36 is about 0.7% and therefore the cooling effects of the injection will be negligible.

3.2 Perfluorocarbon returns

The PMCH perfluorocarbons, which were injected in well K-39, were detected in wells K-14 and K-19. Beyond that, no other PFC tracers had been found at the time this was written.

The return curve for PMCH in well K-19 is shown in Figure 7. The one dimensional advection-dispersion equation clearly fits the return curve very well, indicating that there is one predominant flow path between the two wells.

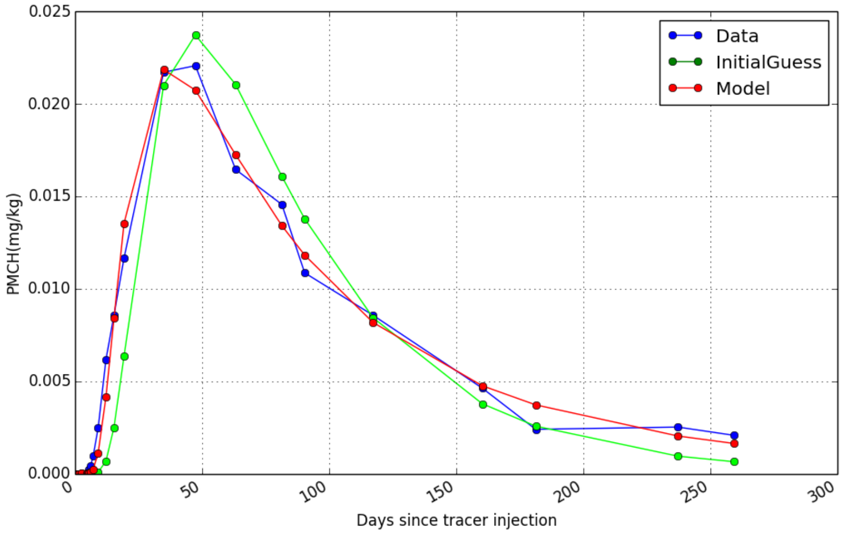

Figure 7: Tracer returns in well K-19 from well K-39. The estimate with the green line was computed based on equations (2)-(4) but the red line is based on a curve-fit of equation (1) to the measured data (blue).

The estimated parameters for the tracer returns in K-19 are shown in Table 4. In this case the estimated volume of the flow path is much greater than that of the wells and thus leaving out the wellbore volume is ok. The effects of low density of the tracer as it travels through the reservoir have not been reviewed, however, which may or may not have a large impact on the predictions.

Table 4: Estimates of tracer return fraction, flow path volume and Peclet number for the connection between K-39 and K-19.

K-39 to K-19	*F* *[-]*	*Vx* *[m³]*	*Pe* *[-]*
Initial guess	*2.1%*	*6366*	*4.5*
Model estimate	*2.3%*	*8985*	*2.2*

Although only 2.3% of the injected tracer goes towards K-19, this amounts to a significant fraction of the fluid produced in the well, as K-19 has a rather low production rate. This quantity is represented by the mixing group $(q_I F/q_P)$ which equals 32% in this case (note that the concentration values measured in the lab are those of the sampled phase and $q_P = q_{P.sampled\ phase}$, and thus the group needs to be scaled by the factor $q_{P,sampled\ phase}/q_{P,total}$). This means that there is some risk of significant cooling from the injection operations.

The cooling effects were calculated using equation (5) with the assumption that the fracture porosity was 20%, matrix porosity 0.1%, and fracture width 1 m. The matrix temperature was taken as 320°C and the reinjection fluid at Krafla is at approximately 125°C. The rock heat capacity was 2500 J/m^3/°C and thermal conductivity was 3 J/m/s/°C. It should be noted that the cooling estimates are highly dependent on the fracture aperture and porosity assumptions, i.e. as these become larger the sooner a cooling effect would be seen. Moreover, the cooling predictions are more severe when one assumes that the fluid travels in a single fracture, as opposed to an ensemble of fractures or a homogeneous rock matrix. In any case, the predictions shown in Figure 8 indicate that there is not much reason the worry about cooling in well K-19 as a result of injection in K-39 for the next 10 years or so.

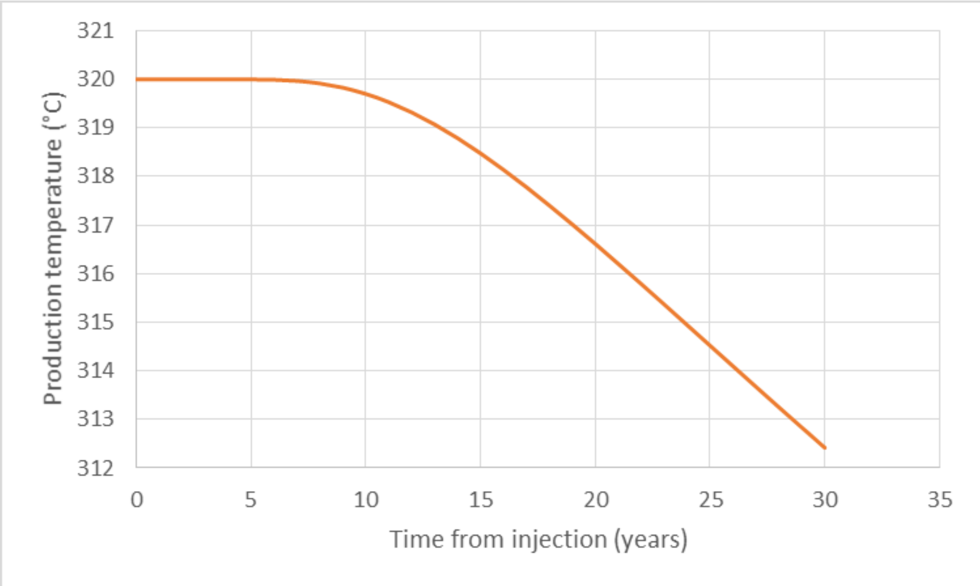

Figure 8: Cooling predictions for well K-19 as a result of injection in K-39 given several assumptions (see text) about the shape and properties of the flow path connecting the two wells.

As mentioned earlier, some PFC returns were also seen in well K-14. These are shown in Figure 9, but further interpretation has been deferred until more data has been collected.

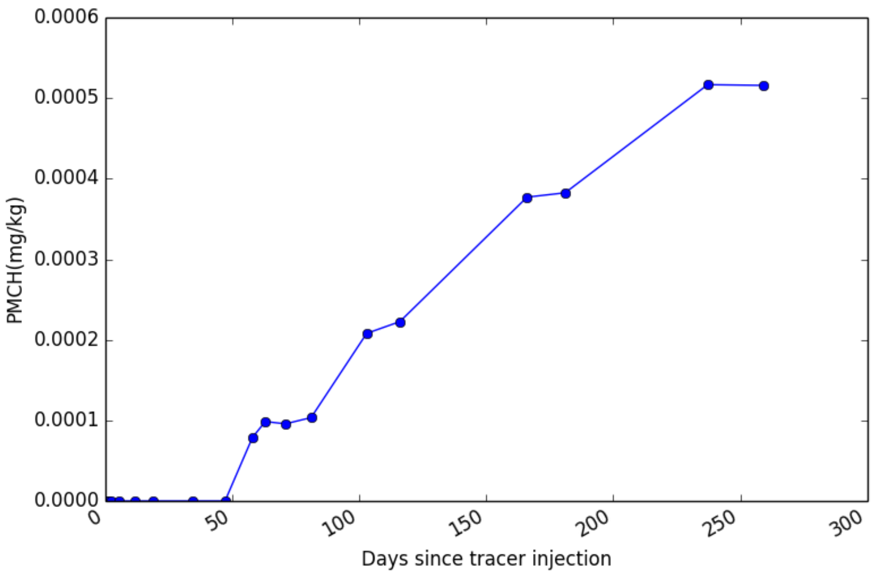

Figure 9: Tracer returns in from well K-39 in well K-14.

3.3 Alcohol returns

Both ethanol and methanol were found in detectable amounts in most of the wells that were monitored. The amount detected was very variable, however, a typical example of which is shown in Figure 10. It seems unlikely that the physics of the reservoir would produce such variable response curves, and therefore we will not interpret the multiple peaks as signs of multiple flow paths. It seems more likely that the cause is related to the sampling or analysis procedure. This is supported by the fact that high concentrations were found in some samples that were taken the day before injection took place.

It should also be noted that the ethanol probably degraded by a considerable amount in the reservoir, and turned into methanol partially. This causes at least two complications in any potential interpretation: a) any cooling predictions based on this data would be overly optimistic and; b) the methanol returns must be attributed to either well K-26 or well K-39, so what comes from where cannot be distinguished.

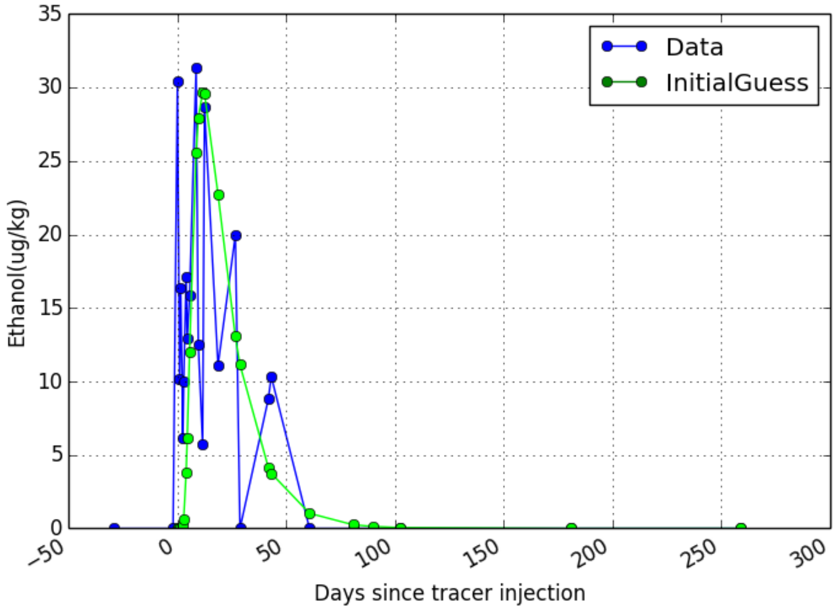

Figure 10: Ethanol tracer returns in well K-14 from well K-26. The data shows a variable return curve, typical of what was seen in most of the other wells.

Since the alcohol return data seemed to be influenced by some sort of error, we were hesitant to rely on it strongly for interpretation. Therefore the data were only analyzed using equations (2)-(4) and to the relative difference in returns. The results are summarized in Table 5 and Table 6.

Table 5: Summarized results of tracer returns from well K-26 (ethanol). The color scale is relative for each column, red is high and blue is low.

Well	*F* [-]	*FqI/qP* [-]	*Vx* [m^3]	*Pe* [-]
K-06	0.01%	0.02%	7	6.9
K-13	0.02%	0.10%	21	4.6
K-14	0.01%	0.35%	19	4.7
K-15	0.01%	0.06%	12	10.9
K-17	0.01%	0.09%	9	10.7
K-19	0.01%	0.43%	32	3.5
K-20	0.00%	0.03%	2	12.6
K-21	0.01%	0.02%	7	127.7
K-24	0.01%	0.03%	48	4.4
K-27	0.00%	0.00%	1	74.5
K-30	0.04%	0.21%	93	2.4
K-31	0.00%	0.02%	0	#N/A
K-32	0.02%	0.04%	26	5.5
K-33	0.00%	0.07%	2	5.1
K-34	0.00%	0.01%	2	20.1
K-36	0.01%	0.06%	9	4.1
K-37	0.00%	0.13%	2	4.6

K-38	*0.00%*	*0.00%*	*0*	*#N/A*
K-40	*0.00%*	*0.01%*	*2*	*111.9*
KS-1	*0.00%*	*0.01%*	*0*	*1.6*

For well K-26 the main results are that it has the strongest connection to K-30, i.e. the largest fraction of tracer is measured in K-30. On the other hand, one might expect that wells K-14, K-19 and K-30 and K-37 could be affected by reinjection in K-26, i.e. these receive the largest contribution from K-26, although the effect would small. This indicates that the fluid entering K-26 flows East (to K-30/K-37) and ESE (to K-14/K-19), which is consistent with the findings of the 2009 tracer test and fractures that have been mapped in the field.

Table 6: Summarized results of tracer returns from well K-39 (methanol). The color scale is relative for each column, red is high and blue is low.

Well	*F* [-]	*FqI/qP* [-]	*Vx* [m^3]	*Pe* [-]
K-06	*0.04%*	*0.06%*	*31*	*20.4*
K-13	*0.18%*	*0.47%*	*82*	*3.7*
K-14	*0.25%*	*3.71%*	*227*	*3.6*
K-15	*0.03%*	*0.13%*	*25*	*10.7*
K-17	*0.05%*	*0.30%*	*47*	*13.3*
K-19	*0.07%*	*1.04%*	*96*	*7.3*
K-20	*0.01%*	*0.10%*	*9*	*41.2*
K-21	*0.07%*	*0.08%*	*47*	*13.0*
K-24	*0.08%*	*0.12%*	*94*	*30.5*
K-27	*0.00%*	*0.00%*	*#N/A*	*#N/A*
K-30	*0.27%*	*0.58%*	*307*	*5.0*
K-31	*0.00%*	*0.00%*	*#N/A*	*#N/A*
K-32	*0.11%*	*0.10%*	*100*	*5.4*
K-33	*0.01%*	*0.13%*	*3*	*4.5*
K-34	*0.06%*	*0.12%*	*16*	*9.0*
K-36	*0.01%*	*0.05%*	*4*	*47.1*
K-37	*0.02%*	*0.74%*	*11*	*3.7*
K-38	*0.00%*	*0.00%*	*#N/A*	*#N/A*
K-40	*0.00%*	*0.01%*	*2*	*#N/A*
KS-1	*0.08%*	*0.27%*	*95*	*19.3*

The returns from well K-39 show that the largest fractions are recovered in wells K-13, K-14 and K-30. This is relatively consistent with the PFC returns although a stronger signal would have been expected in well K-19. Assuming that all of the methanol originated in K-39, leads one to predict that the reinjection in K-39 would influence K-14 the most. However, the 3.7% contribution would not affect the production temperature by a significant amount. In general, the fluid injected in K-39 seems to head N or NNW. This seems to indicate that the Eastward stream lines interpreted from the K-26 returns do not reach as far as K-17, but turn North, most likely towards the pressure depression that has been measured around well K-34.

5. CONCLUSION

This paper describes the implementation and tentative interpretation of a tracer test that was performed in the Krafla geothermal field in 2013 and 2014. Out of the 8 different tracers were injected, only four were detected in the monitoring wells, in reliable amounts.

The one liquid phase tracer that was detected was 2-NMS, which was injected in well IDDP-1 and found in well K-36. The return curve was very smooth and indicative of a relatively small but simple flow path. Only a small fraction of the injected tracer was found in K-36 and therefore reinjection in IDDP-1 is not expected to have a strong cooling effect in K-36.

The gas phase tracer PMCH, which was injected in well K-39, was found in well K-19, and to a smaller extent in K-14. Our interpretation of the results indicated that approximately one-third of the fluid produced in K-19 originated in K-39. Therefore some cooling might be expected, but the onset of cooling would not occur until approximately 10 years from now, if our (conservative) assumptions on the geometry of the flow path are correct.

Both of the partitioning tracers, ethanol and methanol, were detected in most of the wells in the field. The nature of the response curves leads us to believe that something may have gone awry with the sampling or analysis. In any case, a overall interpretation of the returns seems to indicate that fluid from K-26 flows in an Eastward direction (towards K-13 and K-30) but then turns North, as it enters the central Suðurhlíðar region.

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