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Comprehensive Tracer Testing in the Hellisheidi Geothermal Field in SW-Iceland

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ABSTRACT

The Hengill volcanic region in SW-Iceland encompasses vast geothermal resources that by now are utilized in two geothermal power plants, Hellisheidi and Nesjavellir, with a combined electrical generation capacity of 423 MWe as well as a thermal energy production capacity of 420 MWth, principally used for space heating in the Reykjavík suburban area. The Hellisheidi power plant was commissioned in 2006 with large scale reinjection being a key element of the associated resource management ever since. The main reinjection zones associated with the Hellisheidi power plant are Húsmúli on the NW edge of the geothermal field and Gráuhnúkar in its SW-corner. In order to study the connection between specific reinjection and production wells, and the cooling danger facing some production wells, a comprehensive tracer test was conducted during 2013-15. It involved 6 injection wells, both at Gráuhnúkar and Húsmúli. Thus 6 different liquid phase naphthalene sulfonate tracers were injected into the injection wells, 100 kg of each, and tracer samples collected from a large number of production wells. Several wells showed significant recovery, amounting to as much as 25% for a single well. The tracer recovery was modelled by simple models of flow-paths connecting feed-zones in reinjection and production wells. The model parameters were consequently used to calculate future cooling predictions for those wells exhibiting significant tracer recovery. The results indicated that 2 production wells could be seriously affected (cooling of up to 25-30°C in 15-20 years) during long term reinjection, an adverse effect that must be tackled during the future resource management of the Hellisheidi geothermal resource. Monitoring data collected since large-scale reinjection started at Húsmúli in late 2011 doesn't indicate any significant cooling of the production wells monitored, which contradicts the cooling predictions for the wells showing the greatest tracer recovery. This indicates that the cooling predictions may be too pessimistic in some cases. The recirculation of some of the tracers injected has resulted in recovery through additional flow channels, providing valuable additional information, which needs to be interpreted. This study has also revealed the need to incorporate the possible degradation of some of the naphthalene sulfonates used in the overall interpretation as well as the possible contamination from materials used in casing cement.

1. INTRODUCTION

The Hengill volcanic region in SW-Iceland encompasses vast geothermal resources. It is part of the country's volcanic rift zone, located at a triple junction where two active rift zones meet a seismically active transform zone. The geothermal area covers about 110 km^2 and is one of the most extensive geothermal areas in Iceland. Two geothermal power plants are operating in the Hengill region; Hellisheidi and Nesjavellir, with a combined electrical generation capacity of 423 MWe as well as a thermal energy production capacity of 420 MWth, providing hot water used for space heating in the Reykjavík urban area. The power plants are operated by ON Power (Orka náttúrunnar) which is a subsidiary of Reykjavik Energy (Orkuveita Reykjavíkur). The city of Reykjavík and the municipalities of Akranes and Borgarbyggd own Reykjavik Energy.

Geothermal reinjection, which involves injecting energy-depleted fluid back into geothermal systems, is an integral part of all modern, sustainable and environmentally friendly geothermal utilization projects. It is an efficient method of waste-water disposal as well as a means to provide additional recharge to geothermal systems. Thus it counteracts production induced pressure draw-down and extracts more thermal energy from reservoir rocks, and increases production capacity in most cases. Reinjection can also mitigate subsidence and be used to maintain important surface activity. Reinjection is also essential for sustainable utilization of geothermal systems, which are virtually closed and with limited recharge. Reinjection is either applied inside a production reservoir, on its periphery, above or below it or outside the main production field. Several good examples of successful long-term geothermal reinjection are available, both for low-temperature and high-temperature systems (see e.g. Rivera-Diaz *et al.*, 2016). Cooling of production wells is one of the problems/obstacles associated with reinjection, even though only a few examples of actual cold-front breakthrough have been recorded. This danger can be minimized through careful testing and research. Tracer testing, combined with comprehensive interpretation and cooling predictions (reinjection modelling), is probably the most important tool for this purpose. Tracer tests actually have a predictive power since tracer transport is orders of magnitude faster than cold-front advancement around reinjection wells. Numerous examples are available worldwide on the successful application of tracer tests in geothermal systems (Axelsson, 2012).

Large scale reinjection is a key element of the resource management of the Hellisheidi geothermal system, with the Húsmúli and Gráuhnúkar areas being the main reinjection zones. The main purpose has been maintaining reservoir pressure even though the reinjection has also played a role in the overall environmental management of the power production. In order to study the connections between these two reinjection zones and the production wells in the field, and the cooling danger facing some production wells, a comprehensive tracer test was conducted during 2013-15. It involved 6 injection wells and the use of 6 different liquid phase naphthalene sulfonate tracers, and tracer samples collected from a large number of production wells for over two years.

The paper starts out by reviewing the geothermal utilization in the Hellisheidi geothermal field. Consequently the observed tracer recovery through numerous wells is presented and interpreted, including the amounts recovered and the flow-paths observed. Following that the results of the simulation of the tracer recovery curves, representing the most significant recovery, by simple flow-path models are presented along with cooling predictions for production wells, based on the simulation models. The paper also presents interesting aspects of the effect of tracer recirculation, tracer degradation and contamination, which have surface during the evaluation of the results of the 2013 Hellisheidi tracer test.

2. GEOTHERMAL UTILIZATION ON HELLISHEIDI

The Hellisheidi geothermal power plant is located 20 km southeast of Reykjavík, on the southern flanks of the Hengill central volcano. It is a combined thermal energy and electricity power plant consisting of six 45 MWe high pressure and one 33 MWe low pressure turbine generator units and a 133 MWth thermal energy production unit. It was commissioned in 2006 with the installment of two 45 MWe turbines. The latest additions are the thermal plant commissioned in 2010 and two 45 MWe turbines commissioned in 2011. The plan is to enlarge the thermal power plant in stages to 400 MWth, in order to meet increased demand for space heating in the Reykjavík area in the near future.

The power plants first separation stage, at 8.2-8.5 bar-a, supplies geothermal steam to six high pressure units. The separated water is flashed again to 2 bar-a supplying steam for a low pressure turbine. After this dual flashing, the separated water is piped to the thermal plant. The condensers of the four high pressure turbines preheat fresh water which is then fully heated in heat exchangers with separated water (Hallgrímsdóttir *et al.*, 2012). Separated water is then diluted with condensate and reinjected into the geothermal system. The temperature of the reinjected water is normally between 60 and 80°C but during maintenance of the thermal plant, and the low pressure turbine, temperature can rise to the corresponding stage separation temperatures of 120°C and 173°C.

Up to the present 57 production wells and 17 reinjection wells have been drilled in the Hellisheidi geothermal field (Figure 1). Currently the power plant uses 38 production wells, 13 reinjection wells and three production wells (HE-13, HE-40 and KhG-1) have recently been connected for reinjection. Wells HE-13 and HE-40 are located inside the production field and a separate tracer test is now ongoing to assess the long term in-field reinjection capacity.

The Hellsheidi system is a liquid-dominated fractured geothermal system. The bedrock consists of basaltic lavas, hyaloclastites and intrusions, mainly dykes. Reservoir formations are heterogeneous with a large variation in porosity. The porosity is high in hyaloclastites, lower in the lavas layers and lowest in intrusive rocks. From modelling, the active average porosity of the reservoir rock is estimated to be 10% (Gunnarsson *et al.*, 2011). The average enthalpy of the produced fluid is currently about 1570 kJ/kg, having declined from an initial 1750 kJ/kg. The enthalpy of individual wells ranges from water enthalpy at about 1100 kJ/kg to dry stream enthalpy of about 2700 kJ/kg. The formation temperature distribution is characterized by variability and sharp features. The highest temperature in the reservoir (above 300°C) has been measured at the bottom of the wells in Gráuhnúkar and along the normal faults in Reykjafell mountain towards the southern slopes of Skardsmýrarfjall mountain (Figure 1). Most of the production has been concentrated in these parts of the system, where the enthalpy of produced fluid is high. There is also concentrated production in the north-western part of the field, in Skardsmýrarfjall, from wells that are highly permeable and yield great amounts of fluid with low enthalpy (1100 – 1300 kJ/kg). The production density in these areas can be than 300 (kg/s)/km^2. The production density of Hellisheidi field in general is shown in Figure 2 as it was during 2015, before production started from the Hverahlíd wells. This is considerable production density, which would cause the reservoir pressure to drop more than 10 bar annually, assuming no natural recharge or reinjection. Due to this high production density, it is necessary to reinject a considerable proportion of the water produced, in order to maintain reservoir pressure. Reinjection of the separated water also helps with environmental management in the area.

The Hellisheidi well field has recently been experiencing significant decline in output, producing 32,5 Mton (1050 kg/s) in 2015. Thus the power plant wasn't operating at full capacity. A decline in average fluid enthalpy is also observed to the level of 1570 kJ/kg in 2015. Currently operations are ongoing connecting the well field in Hverahlíd to the power plant through a new pipeline built in 2015. This new addition to the power plant will allow for production of electricity to reach near full capacity.

Two main reinjection zones are utilized in the Hellisheidi field: Gráuhnúkar and Húsmúli. The Gráuhnúkar reinjection field was commissioned in 2006 and the Húsmúli field in 2011. Both reinjection fields penetrate the fault zone on the western flanks of the volcanic system (Figure 1). The Gráuhnúkar field is located SW of the production field and consist of six reinjection wells. Very high temperatures (>300°C) were measured in the deepest parts of wells there, which makes the area a prospect for future production. A new reinjection field was, therefore, planned in the so-called Húsmúli area on the north-western edge of the well field. The first well in the Húsmúli area (HN-09) was drilled in early 2008. Well testing results were promising and seven injection wells were consequently drilled in the Húsmúli area. All are connected to the reinjection system but two wells, HN-11 and HN-13, have very limited reinjection capacity.

Operating the reinjection system has been challenging, mostly maintaining sufficient reinjection capacity, as the operation permit of the power plant only allows limited release of separated water into the shallow ground water in the area. Reinjection capacity of the reinjection well field has had the tendency to decline with time (Gunnarsson *et al.*, 2015) and more wells have been drilled over the years. Since the commission of the power plant in 2006 the extraction of geothermal fluids has increased with the growth of the power plant to a 40 Mton maximum in 2013. The ratio of reinjected fluids increased from 2008 to 2014 from 27% to 56 % with increasing mixing of condensed steam to limit silica scaling. The conversion of three former production wells into reinjection wells (wells HE-13, HE-40 and KhG-1) caused a decrease in average enthalpy and in total production, has raised the reinjection ratio increased to 78% in 2015 (Gunnarsson *et al.*, 2016). The most recent conversion involves the first deep well drilled in the area, well KhG-1, which starts out with the promising reinjection capacity of more than 130 L/s of 80°C fluid. The remaining 22% of the mass extraction from the Hellisheidi system constitute condensed steam, which is used as make-up water in the cooling towers of the power plant.

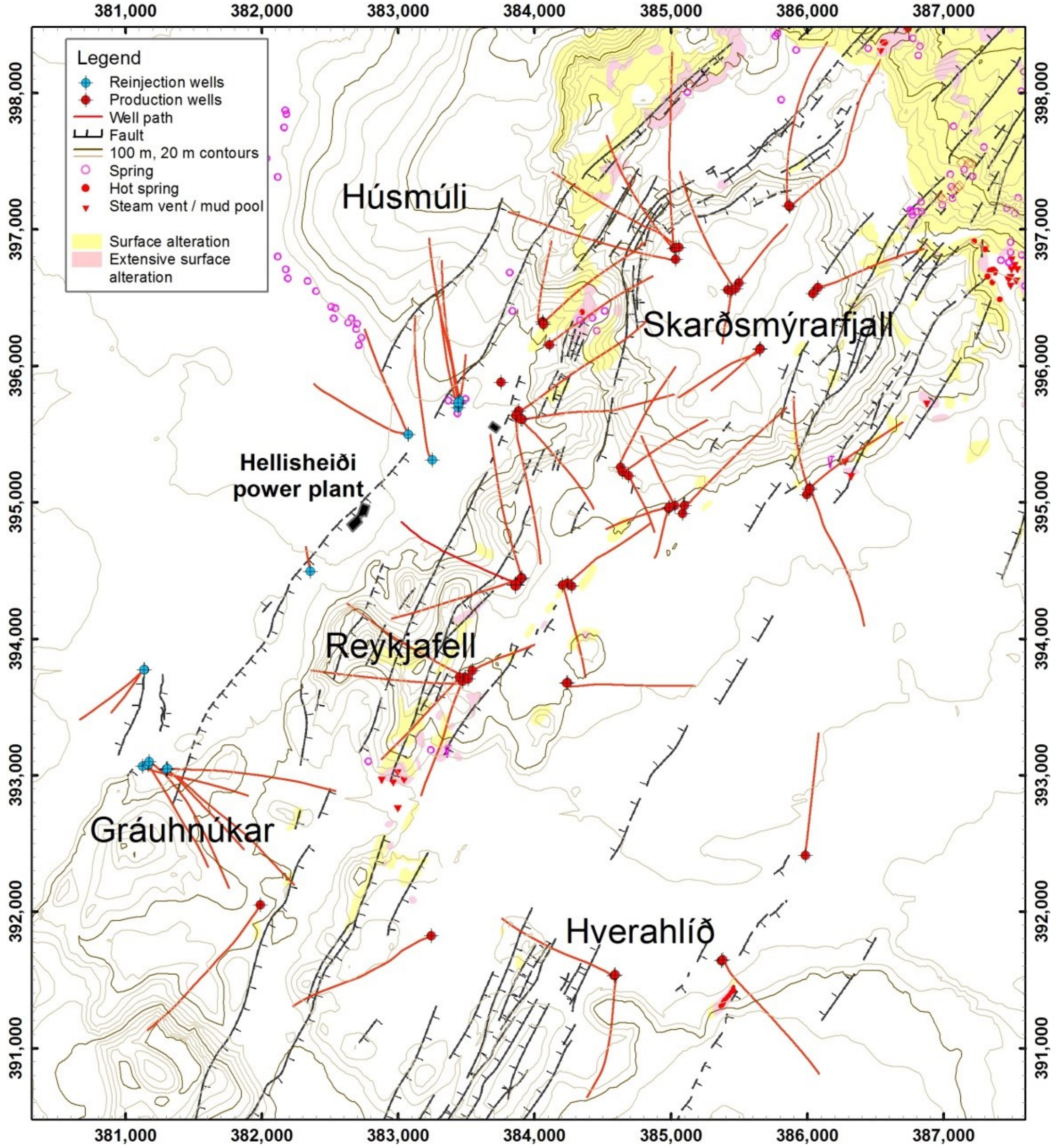

Figure 1: Map of the Hellisheidi geothermal area showing the location and trajectories of production and reinjection wells as well as topographic contours and major faults. Faults, thermal activity and the location of cold springs are from Sæmundsson (1995a and 1995b).

The reinjection capacity of the Húsmúli and Gráuhnúkar fields is normally about 400 L/s and 300 L/s, respectively. Individual well capacity varies from 20 L/s to 100 L/s. The overall capacity varies considerably depending on the temperature of the reinjected water. Both higher permeability and higher down-hole water flow is obtained with lower water temperature (Gunnarsson et al., 2015). High water temperature occurs during maintenance of the heat exchanges and the low pressure turbine. With the addition of well KhG-1 the reinjection capacity is about 800 L/s which is currently sufficient only when both the thermal plant and low pressure turbine are operating. The problem of limited injection capacity has, furthermore, been solved temporally with use of the in-field reinjection wells HE-13 and HE-40.

3. THE 2013 TRACER TEST

This chapter starts out by describing the planning and execution of the 2013 tracer test and consequently presents data on the primary tracer recovery. Following that information on the effect of recirculation of the tracers used is presented and on the associated secondary recovery, which provides valuable information on additional flow-paths. The chapter is concluded by a discussion on the effect of degradation of some of the naphthalene sulfonates used and on possible sources of contamination, which have been revealed.

This tracer test was conducted to define the hydrological flow paths and provide data for evaluating the risk of thermal breakthrough between injection and production wells. The results are fundamental in defining the reinjection strategies for the Hellisheidi field, both in the near and distant future.

Naphthalene sulfonates have proven to be effective tracers in high temperature geothermal reservoirs because they are affordable, easily detectable with fluorescence spectroscopy, thermally stable and environmentally benign (Rose et al. 2002). Six naphthalene sulfonic acids were selected to be injected into 5 reinjection wells and one failed production well close to the Húsmúli reinjection area.

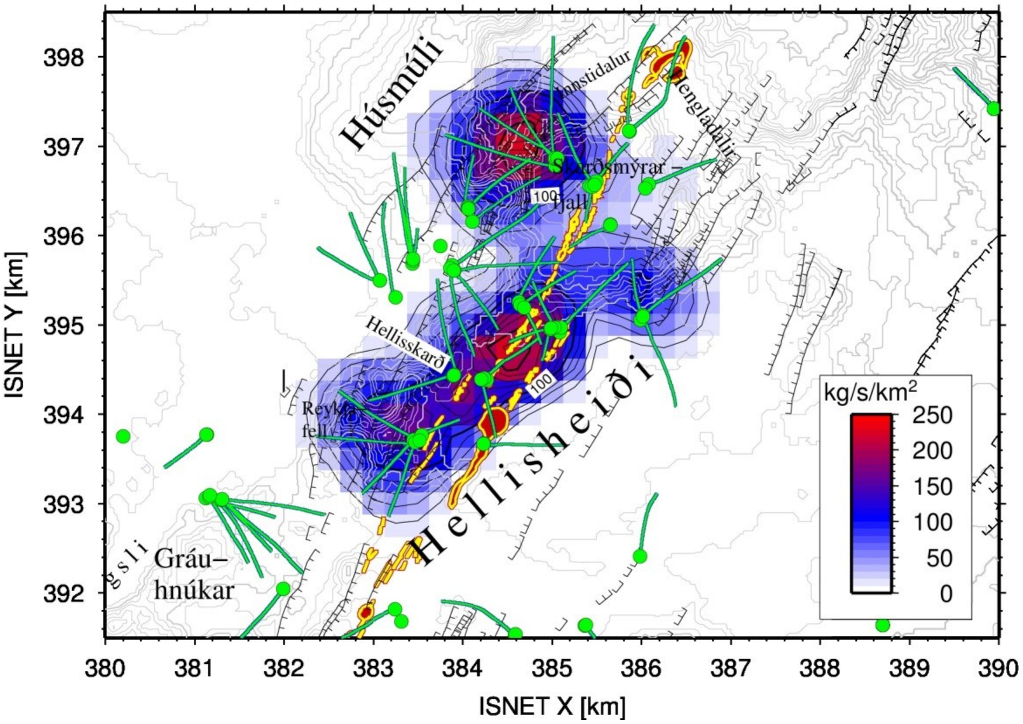

Figure 2: Production density ((kg/s)/km^2) in the Hellisheidi geothermal production area during 2015 (Gunnarsson et al., 2016).

3.1 The Execution of the Tracer Test

The 2013 tracer test in Hellisheidi was the first tracer test in the area using naphthalene sulfonic acids as tracers. Prior to the injection of the tracers 14 wells adjacent to the selected injection wells were sampled and analyzed for the selected naphthalene sulfonic acids. No traces of the chemical selected were found in any of these wells. Naphthalene sulfonic acids are analysed at Iceland GeoSurvey laboratory by high performance liquid chromatography (HPLC) using fluorescence detection. Around 1100 samples from Hellisheidi have now been analyzed for the 6 types of naphthalene sulfonic acids used in the test. Approximately 2/3 of the samples have also been analyzed for 2-NSA and 1-NSA.

A subcontractor executed the mixing and injection of the tracers into the wells. This was done to prevent any tracer contamination of the staff operating the wells and preforming the subsequent tracer sampling. In each well 100 kg of tracer was injected. The tracers were mixed in a tank truck and dissolved in 4 m^3 of water which was more than sufficient for easily dissolving the full amount of each tracer. The tank truck was equipped with a powerful pump and could be used to pump the tracer mixture directly into a reinjection well operating at 8 bar-g. A flexible high-pressure hose was connected the tank truck to a 1½" connection next to the wellhead. The injection of the tracer took 20 minutes. When each injection was close to completion another tank truck provided 10 m^3 of tracer free water, which was subsequently injected into the well after being used for carefully rinsing the inside of the tracer tank. The injection and rinsing process took less the two hours for each well and was executed in all cases without any difficulty. Before mixing, each 25 kg container box of naphthalene sulfonate was sampled for future reference and later used for standard preparation. Each tracer mixture was also sampled before being injected into the wells. Each container box was weighted before and after use for tracer mass verification (Trausti Hauksson, 2013).

Tracer injection occurred on 20-21 June 2013. On the first day tracers 1,5-NDS, 1,3,5-NTS, and 1,3,6-NTS were injected into the Húsmúli wells HN-9, HN-14, and HN-17, respectively. The following day tracers 2,6-NDS and 2,7-NDS were injected into the Gráuhnúkar reinjection field wells HN-10 and HN-8, respectively. The more thermally stable 2,7-NDS and 2,6-NDS (Rose et al. 2002) were selected for injection into the Gráuhnúkar wells because of the high reservoir temperature there. Also on June 21 tracer 1,6-NDS was injected into well HE-8. The well HE-8 is not connected to the power plant because it was unable to sustain sufficient wellhead pressure. Table 1 provides information on the injection wells involved in the tracer test, and the tracers used in each well.

Table 1: Information on the injection wells and the corresponding tracers used in the 2013-14 Hellisheidi tracer test, 100 kg of each tracer were injected.

Well	Tracer	Tracer injected	Coordinates (x,y)		Wellhead [m a.s.l.]	TD [m]	TVD [m]	Horiz. displ. [m]	Azimuth [°]	Inclination [°]
HN-8	2,7-NDS	2013-06-21	381309	393048	261	2580	2167	1120	102	33
HN-9	1,5-NDS	2013-06-20	383249	395309	265	3012	2760	1070	355	25
HN-10	2,6-NDS	2013-06-21	381175	393098	262	2305	1977	1148	155	41
HN-14	1,3,5-NTS	2013-06-20	383075	395496	263	2032	1806	841	337	29
HN-17	1,3,6-NTS	2013-06-20	383449	395747	270	2192	1774	1217	350	39
HE-08	1,6-NDS	2013-06-21	384,059	396,324	309	2808	2808	-	-	vertical

Daily sampling of the 14 closest monitoring wells started the same day the first injection took place. Also included in the sampling routine were the reinjection pipelines to Húsmúli and Gráuhnúkar. Frequent analysis tracked first arrivals of different tracers and gradually additional wells were included to the monitoring program until all producing wells were included. Several other wells were production tested temporally during the tracer test and these wells were also routinely sampled. Two other tracer tests using naphthalene sulfonic acids were later initiated and are still ongoing in the Hellisheidi field. These tracer tests involve continuous doping of 1-NSA into well HN-16 in Húsmúli, on one hand, and the instantaneous injection of 2,7-NDS and 2,6-NDS into the infield reinjection wells HE-13 and HE-40, on the other hand. These tests have not yet interfered significantly with the interpretation of the 2013 tracer test results. Tracer sampling from all production wells continues in 2016.

3.2 Primary tracer recovery

The main results regarding primary tracer recovery are presented in tables 2 and 3 and in figures 3 – 10. The time of first arrivals of different tracers in production wells is presented in Table 2, with the first tracer to arrive being the tracer from well HN-17 reaching well HE-31. The tracer breakthrough in well HE-31 took only 14 days and shortly after (18 days) the tracer appeared in the next well along the fault line, well HE-48. After 53 days the 1,3,6-NTS tracer appeared in the third well, well HE-44. These three wells combined yield a combined recovery of almost 55 kg of the tracer 1,3,6-NTS, corresponding to 55 % recovery in this part of the production area (Table 3). Much later, the tracer reached well HE-33, but only at a low concentration. Limited recovery observed in the wells adjacent to the south (HE-5, HE-46 and HE-52) indicates a strongly anisotropic permeability along the fault lines. The appearance of the 1,3,6-NTS tracer in wells HE-5 and HE-43 is probably from recirculation of tracer material after the in-field reinjection started in wells HE-13 and HE-40 in the summer of 2014. The total recovery of that tracer is estimated to be 57.5 kg from the wells the tracer appeared in with significant certainty, as shown in Table 3. The recovery curves for each well are presented in Figure 3 and the main transport pattern of the tracer injected into well HN-17 is shown on a map in Figure 7.

Almost an identical pattern is seen in the transport of the 1,5-NDS tracer injected into well HN-9. The first arrival to well HE-31 is after 24 days and only two days later it had appeared in well HE-48 (Table 2). After 81 days this tracer appeared in the third well, or well HE-44. These three wells gave a combined recovery of 25 kg, of the tracer 1,5-NDS, corresponding to 25 % recovery in this part of the field. As with the tracer from HN-17 a limited recovery is observed in the wells adjacent to the south (HE-5, HE-46 and HE-52) indicating anisotropic permeability along the fault lines. The total recovery of the 1,5 NDS tracer is estimated to be 26.3 kg from the wells the tracer appeared in with significant certainty, as shown in Table 3. The recovery curves for each well are presented in Figure 4 and the main transport pattern of the tracer injected into well HN-9 is shown on a map in Figure 8.

The 1,6-NDS tracer was injected into the failed production well HE-8. During the tracer injection condensed steam (8 L/s) was injected into the well as part of another experiment and continued for one month. Returns from HE-8 were mainly observed in well HE-5 until HE-46 was put into production. The wellheads of HE-8 and HE-46 are only a few meters apart. Minor returns were also observed southwards in wells HE-40, HE-43 and HE-41. The total recovery is estimated to be 24.5 kg, almost entirely from wells HE-5 and HE-46. The total recovery in Table 3 does not include the returns in wells HE-31, HE-48 and HE-44 (see chapter 3.2). The recovery curves for each well are shown in Figure 5 and the main transport pattern of the tracer injected into well HN-8 is shown on a map in Figure 9.

The first arrival of the 2,7-NDS tracer injected into well HN-08 in Gráuhnúkar was after 20 days in well HE-30, which showed significant returns with a total recovery of 8.7 kg (Table 3). The tracer fluid continues along the fault lines towards HE-47 also with a significant recovery and then all the way to HE-41 (see figure 10). Here high concentrations of 2-NS were observed with a clear increase in the concentration ratio to 2,7-NDS, both with time and distance from the injection well. Very high temperatures have been observed both in the deeper parts of the Gráuhúkar reinjection wells and especially in wells north of Gráuhnúkar (HE-30, HE-47, HE-45 and HE-41) were temperatures can be higher than 320°C. The laboratory experiments of Mountain and Winick (2012) showed the desulfonation of both 2,7-NDS and 2,6-NDS to form 2-NSA at temperatures above 330°C. Here the reservoir reaches temperatures close to this critical temperature and the desulfonation process is evident in the return curves on Figure 5. As the returns of the 2,6-NDS tracer injected into HN-10 are very small it is assumed that the 2-NS is mostly of 2,7-NDS origin and it's returns can be used for cooling predictions in HN-8 neighboring production wells. The late arrival of the tracer to wells HE-15 and HE-4 was unexpected. After all the distance between the well paths of HH-15 and HN-8 is the shortest between any injection and production well during the 2013 tracer test. This happens in spite of the large pressure difference between the reinjection field and the heavy production from the Reykjafell wells (see Figure 2). Here the anisotropic nature of the permeability appears to be even more extreme than in the Húsmúli field.

Table 2: The first arrivals of different tracers in production wells from June 2013 throughout 2015. Numbers in parenthesis are assumed to involve recirculated tracer (see later). The symbol [*] represents where recovery is not well established and more samples need to be analyzed for verification. Well HE-40 is suspected to be contaminated by cement additives [c] with a constant presence of various naphthalene sulfonic acids.

Well	HN-10 2,6-NDS [days]	HN-08 2,7-NDS [days]	2-NMS [days]	HN-09 1,5-NDS [days]	HE-08 1,6-NDS [days]	HN-14 1,3,5-NTS [days]	HN-17 1,3,6-NTS [days]
HE-31	-	(81)	(<125)	24	(81)	81	14
HE-48	-	(92)	(222)	26	(125)	81	18
HE-44	-	(176)	(<125)	81	(320)	111	53
HE-33	-	-	119*	138	-	222	115
HE-52	-	(<434)	(<434)	<434	<434	<434	<434
HE-46	-	(330)	(<168)	<168	<168	225	222
HE-05	-	-	<125*	-	28	536*	536*
HE-40	c	c	c	c	<49	c	-
HE-43	-	-	<81*	762*	81	407*	671*
HE-41	92	81	81	-	81	-	-
HE-45	-	239	201	-	-	-	-
HE-47	155	43	<81	-	-	-	(284)
HE-30	81	20	<81	-	-	-	(284)
HE-15	522	361	236				
HE-4	818*		665				

Table 3: Information on the estimated mass of different tracers recovered through different production wells during the period from June 2013 throughout 2015. Numbers in parenthesis are assumed to involve recirculated tracer, so they are not included in the sum for different wells. The recovery of 2-NMS is calculated only for wells where 2-NMS is thought to be degraded (desulfonated) from 2,7-NDS. The symbol [*] represents where recovery is not well established and more samples need to be analyzed for verification. Well HE-40 is suspected to be contaminated with naphthalene sulfonic acids from cement additives [c].

Well	HN-10 2,6-NDS	HN-08 2,7-NDS	2-NMS	HN-09 1,5-NDS	HE-08 1,6-NDS	HN-14 1,3,5-NTS	HN-17 1,3,6-NTS
HE-31		(2.0)	( )	12.8	(1.5)	2	25.7
HE-48		(1.6)	( )	9.8	(1.1)	2.2	21.2
HE-44		(0.8)	( )	2.7	(0.4)	1.1	7.9
HE-33			*	0.4		0.9	0.9
HE-52		(<0.1)	( )	<0.1	0.1	0.2	0.1
HE-46		(<0.1)	( )	0.6	8.9	0.3	1.7
HE-05			*		15.2	<0.1	0.2
HE-40	c	c	c	c	0.2	c	-
HE-43			*	*	0.1	*	*
HE-41	<0.01	<0.1	0.3		<0.1		
HE-45	-	<0.1	<0.1				
HE-47	0.3	5.2	1.4				(<0.1)
HE-30	0.2	8.7	2.9				(<0.1)
HE-15	0.3	0.6	0.7				
HE-4	0.3*		0.8				
total (kg)	1.1	14.5	6.1	26.3	24.5	6.7	57.5

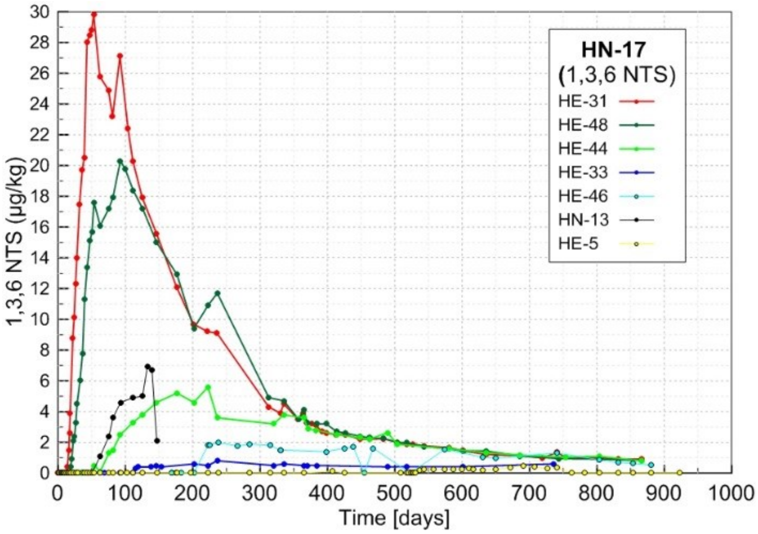

Figure 3: Recovery of 1,3,6 NTS injected into well HN-17 in Húsmúli through Hellisheidi production wells.

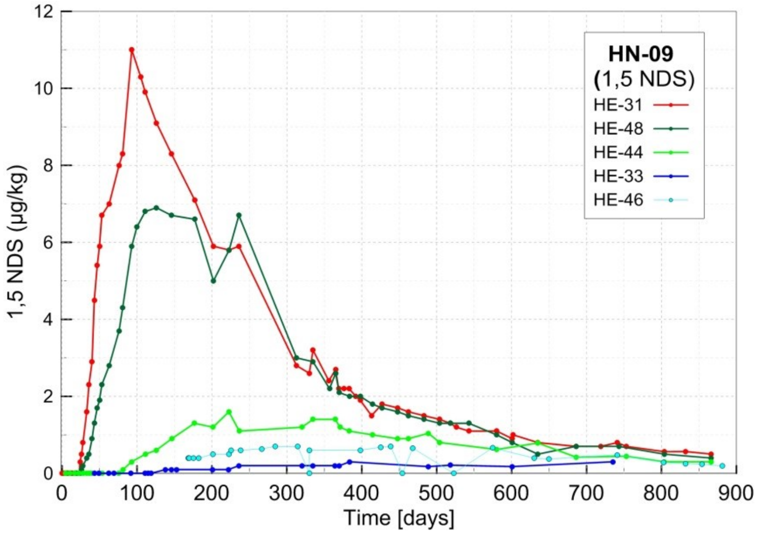

Figure 4: Recovery of 1,5 NDS injected into well HN-9 in Húsmúli through Hellisheidi production wells.

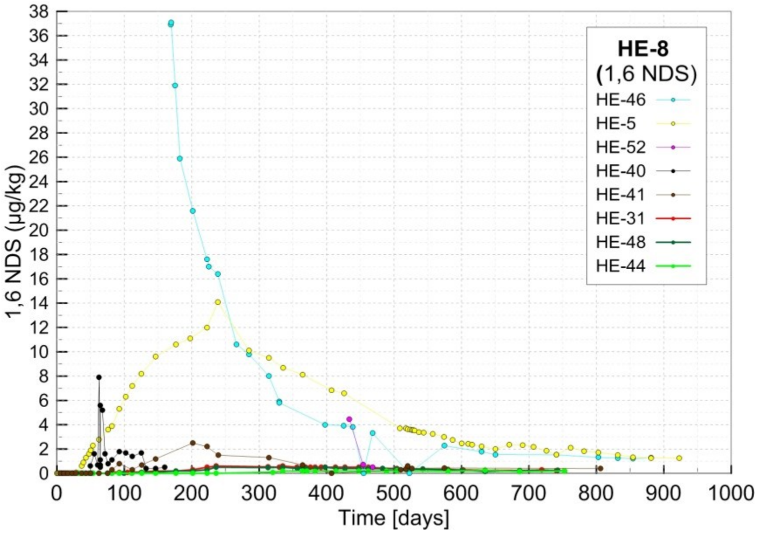

Figure 5: Recovery of 1,6 NDS injected into well HE-8 on Hellisheidi through Hellisheidi production wells.

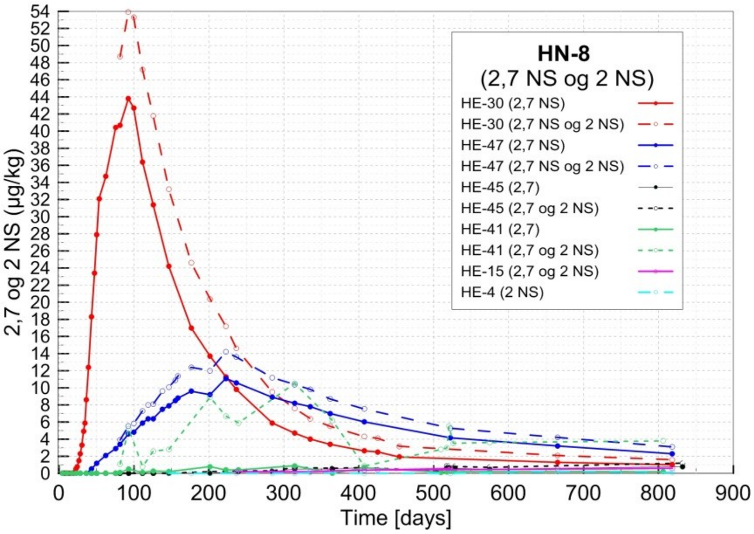

Figure 6: Recovery of 2,7 NDS injected into well HN-8 at Gráuhnúkar through Hellisheidi production wells. Also shown is the sum of the recovery of 2,7 NDS and 2 NS. Here the 2 NS is believed to be a degradation product of the 2,7-NDS injected into well HN-8.

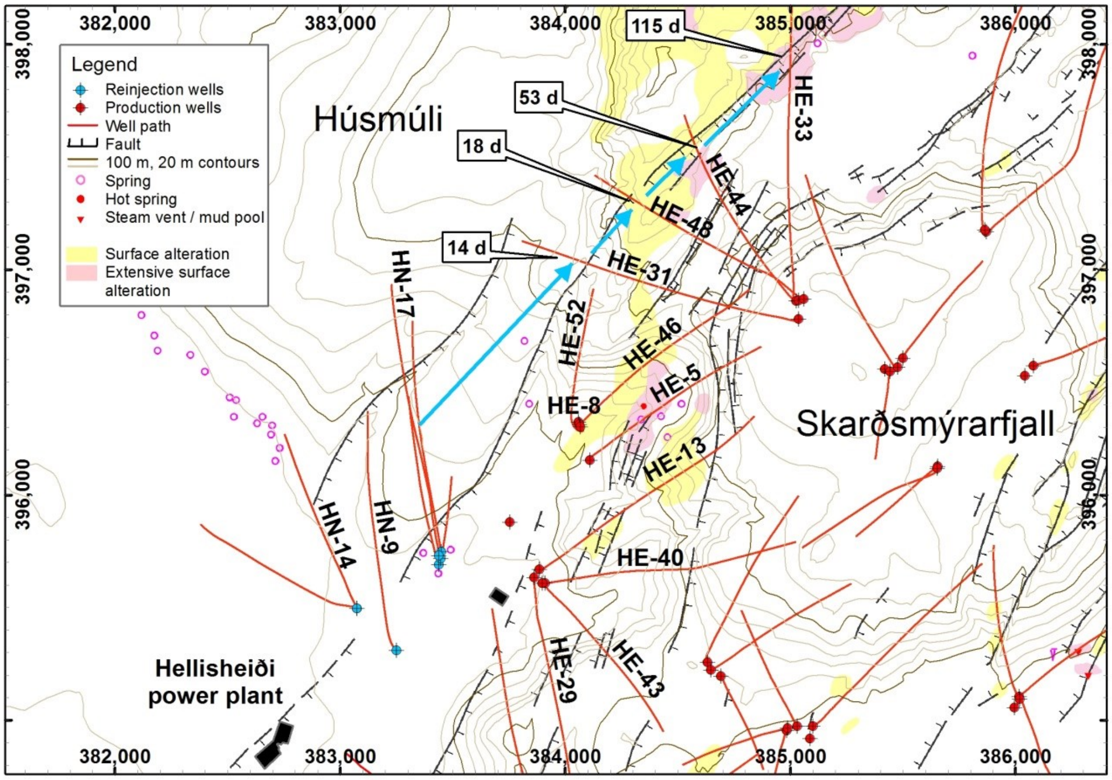

Figure 7: Map showing the main transport of the tracer injected into well HN-17 as blue arrows. Boxes show the travel time (first arrival) from the reinjection well to each production well.

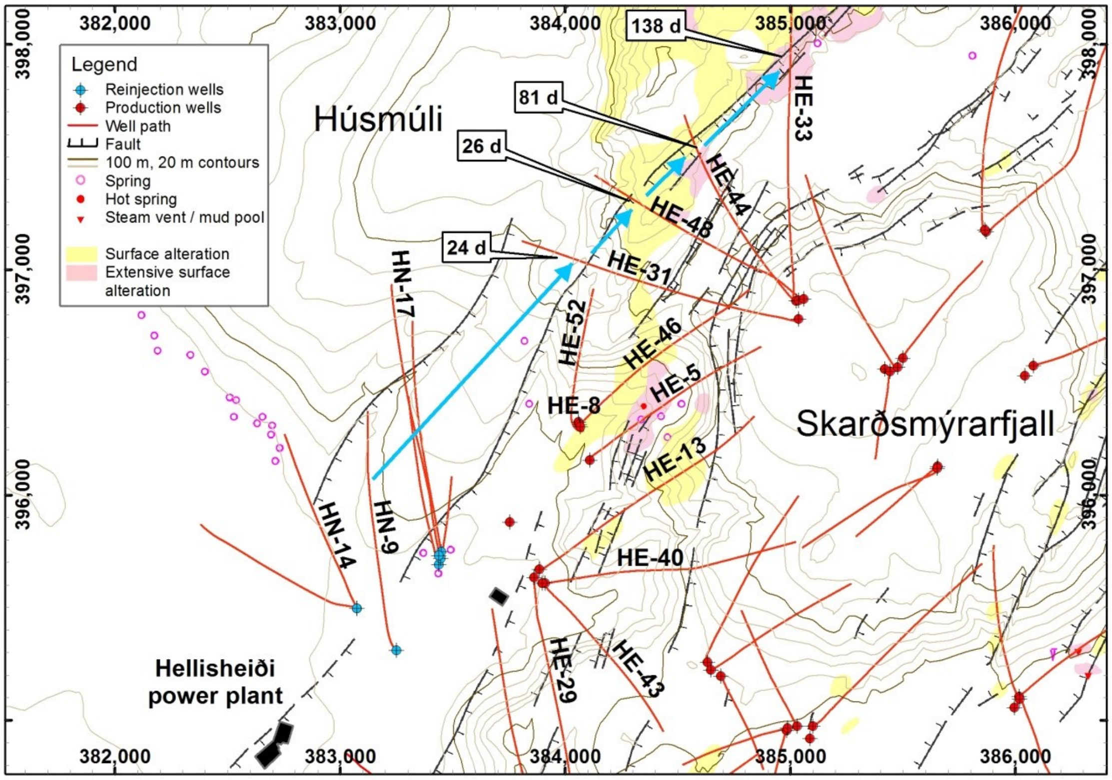

Figure 8: Map showing the main transport of the tracer injected into well HN-9 as blue arrows. Boxes show the travel time (first arrival) from the reinjection well to each production well.

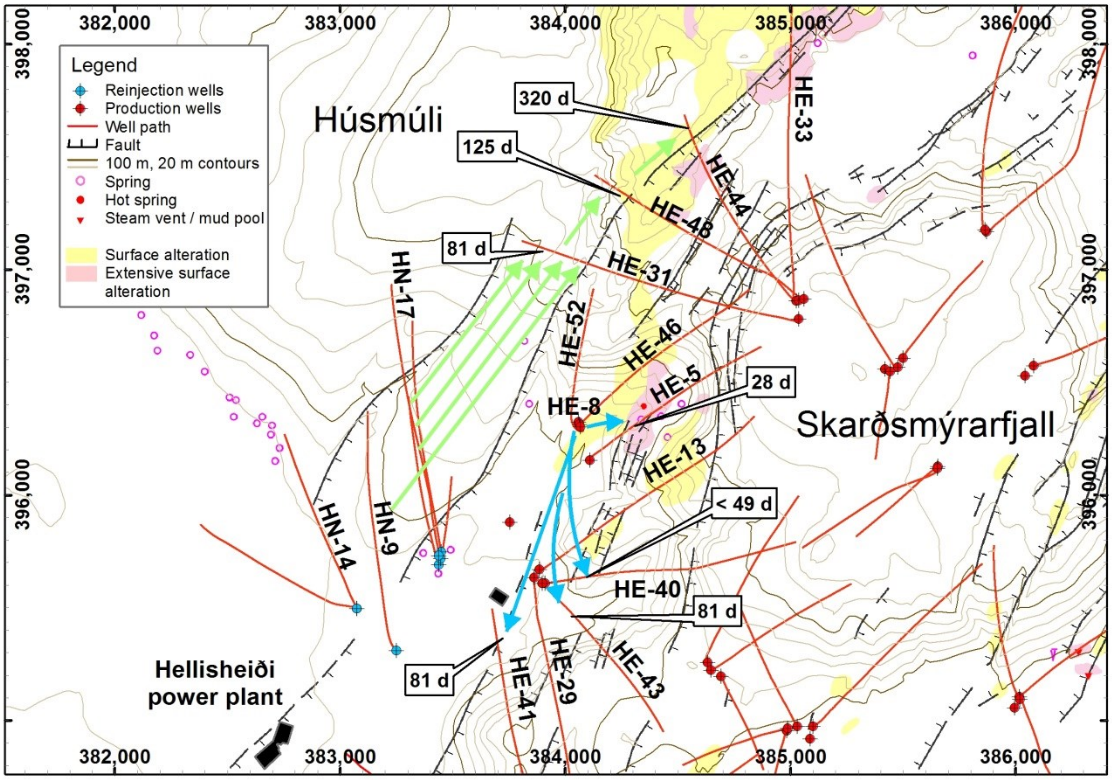

Figure 9: Map showing the main transport of the tracer injected into well HE-8 as blue arrows. The suggested paths of the recirculated tracer material are represented with green arrows. Boxes show the travel time (first arrival) from the reinjection well to each production well.

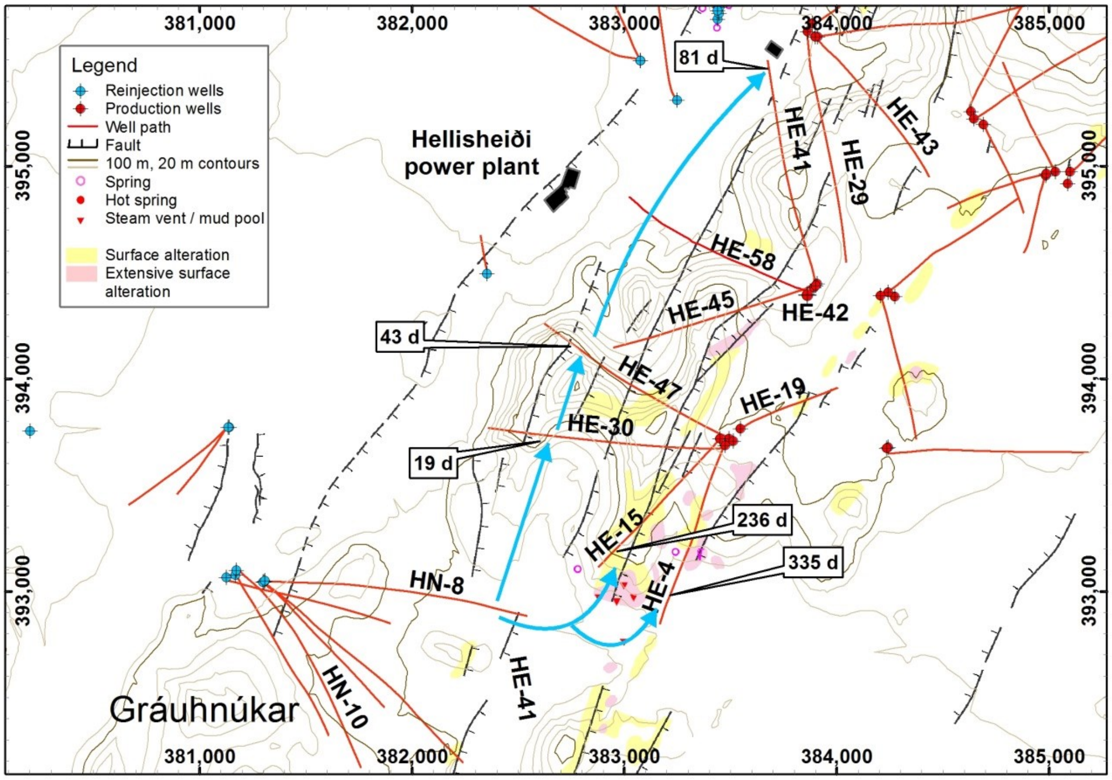

Figure 10: Map showing the main transport of the tracer injected into well HN-8 as blue arrows. Boxes show the travel time (first arrival) from the reinjection well to each production well.

The tracer returns from well HN-14 in Húsmúli are both late and limited (see tables 2 and 3). This is even more so for well HN-10 at Gráuhnúkar. Both wells are located on the southern flanks of the respective injection fields. The Húsmúli and Gráuhnúkar injection fields are significantly loaded and possibly the pressure gradients on the southwestern side of the two fields are high enough to channel the fluids injected into these two wells away from the production areas.

3.2 Effect of tracer recirculation

After use in the power plant all of the separated water is sent to reinjection wells. With large returns in some of the production wells, tracer concentration increases in the reinjection fluids. Measuring the flow and tracer concentration in the pipelines to the injection fields gave an independent recovery calculation for all of the tracers measured. The total tracer mass for each tracer is shown in table 4. The results are similar to the results presented in Table 3. The concentration curves for all tracers in each pipeline are shown in figures 11 and 12. These return curves constitute a weighted average of the total returns from Hellisheidi field.

In the Húsmúli field the tracers injected into wells HN-9 and HN-17 showed a similar recovery pattern, although the returns were greater from HN-17 as it is closer to the production wells. Just next to HN-17, in the same vertical plane, are two other reinjection wells HN-12 and HN-16. Reinjection into the Húsmúli field will therefore mostly follow the path of the tracers injected into HN-9 and HN-17. All tracers with large returns will, therefore, eventually be observed in wells HE-31, HE-48, HE-44 and possibly HE-33.

In Figure 13 the return curve of 1,6-NDS (HE-8) in the Húsmúli pipeline is plotted together with the 1,6-NDS return curves of wells HE-31, HE-48 and HE-44. The sharp increase of the tracer in the pipeline after about 150 days is because of well HE-46 being put into production after being closed for several months. The same sharp increase is observed in well HE-31 and HE-48 approximately 50 days later. The 1,6-NDS concentration than later approaches a similar level as in the pipeline indicating that most of the fluids produced in these wells come from the Húsmúli field.

The same pattern is seen when comparing the concentration of 2,7-NDS (HN-8) in the pipeline to the tracer concentration in the same production wells. This means that the returns of the 1,3,6-NTS and 1,5-NDS tracers include some recirculation and need to be corrected accordingly. Recirculation of some of the tracers injected has resulted in recovery through additional flow channels, providing valuable additional information, which needs to be interpreted.

Table 4: Information on the estimated mass of different tracers recirculated into the reinjection well fields of Gráuhnúkar and Húsmúli during the period from June 2013 to September 2015.

Reinjection field	HN-10 2,6-NDS	HN-08 2,7-NDS	2-NMS	HN-09 1,5-NDS	HE-08 1,6-NDS	HN-14 1,3,5-NTS	HN-17 1,3,6-NTS
Húsmúli	0	7.2	6.2	11.2	9.3	2.2	22.5
Gráuhnúkar	0	9.3	8.8	13.7	12.3	2.6	32.1
total	0	16.5	15.0	24.9	21.6	4.8	54.6

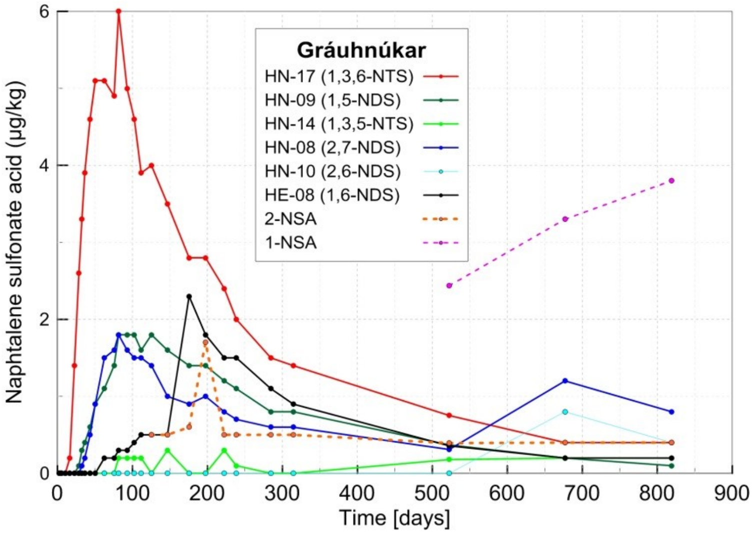

Figure 11: Concentration of recirculated tracers in the reinjection fluid at Gráuhnúkar, labelled according to the corresponding reinjection well. Also shown is the concentration of the degradation compounds 2-NSA and 1-NSA.

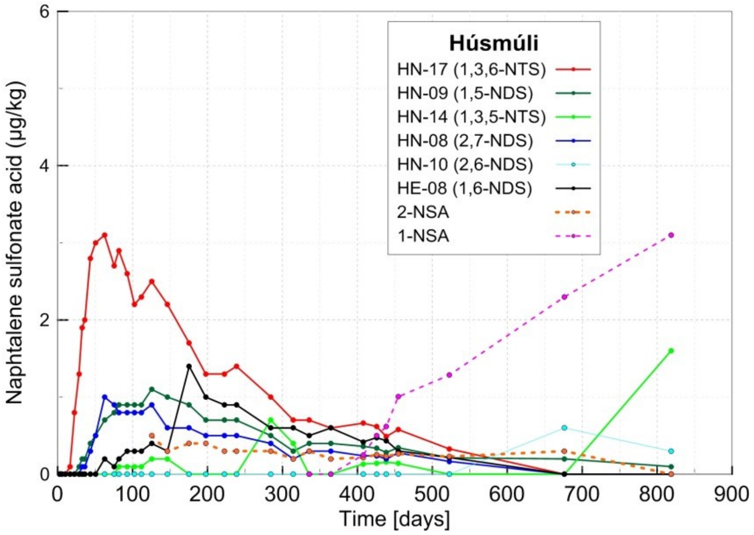

Figure 12: Concentration of recirculated tracers in the reinjection fluid at Húsmúli, labelled according to the corresponding reinjection well. Also shown is the concentration of the degradation compounds 2-NSA and 1-NSA.

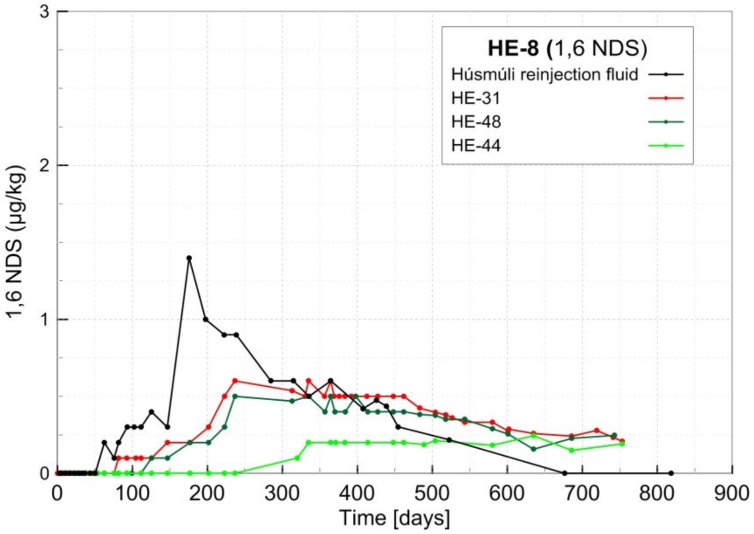

Figure 13: Concentration of the 1,6-NDS tracer in the Húsmúli pipeline and wells HE-31, HE-48 and HE-44. The tracer was originally injected into well HE-8 and then recirculated.

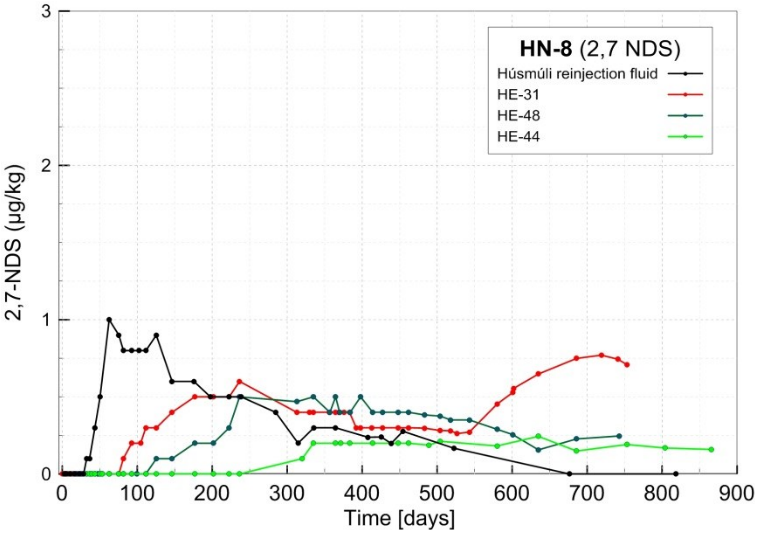

Figure 14: Concentration of the 2,7-NDS tracer in the Húsmúli pipeline and wells HE-31, HE-48 and HE-44. The tracer was originally injected into well HN-8 in Gráuhnúkar and then recirculated.

3.4 Other aspects

Tracer degaradation

This study has revealed the need to incorporate the possible degradation of some of the naphthalene sulfonates used in the overall interpretation of the tracer test results. The reinjection fluid is in all cases considerably colder than the reservoir temperature. Where there is vertical permeability, density differences must drive the fluid downward, and hence the tracers encounter higher temperatures. It is also noted that the further the 2,7-NDS travels the greater is the ratio of 2-NSA. The desulfonation of the 2,7-NDS injected into HN-8 (Figure 5) may e.g. indicate a deeper path of the fluid flow along the fault line towards the westernmost production wells. Based on the assumption that the results of Mountain and Winicks (2012) on the desulfonation temperature apply for the Hellisheidi reservoir, the fluid flow from well HN-8 to wells HE-30, HE-47 and HE-41 must encounter temperatures close to and above 330°C. Both time and temperature could play a role in the process.

Tracers present in the reservoir – contamination from casing cement additives

This study has also revealed the need for awareness regarding possible contamination when using naphthalene sulfonates as geothermal tracers. During this extensive tracer test, more and more wells were sampled for tracer analysis, prior to any actual tracer arrival. As this process unfolded, additional wells were showing tracer recovery in spite of being on the opposite edge of the Hellisheidi reservoir. These surprise "arrivals" were noted in distant wells, where no baseline sampling had been done. Actual recovery was inconceivable and a visit to the storage room and analysis of old samples collected a year before the tracer test, showed traces of various naphthalene sulfonic acids. Further sampling showed that samples from the wells contained a soup of various naphthalene sulfonic acids, in very small quantities, and only with slightly variations in concentration of these elements between samples. The wells involved were HE-11, HE-18, HE-25, HE-40, HE-51 (see Figure 1) and the wells in Hverahlíd (HE-21, HE-36, HE-53 and HE-54). Most of these wells are not connected to the power plant and were being tested temporally when sampled.

As naphthalene sulfonic acids are used as cement dispersants, it was evident that they could be present in the reservoir from the dissolution of cement used in well casing installations or from other drilling materials. On request from Reykjavík Energy, Iceland drilling (Jardboranir), the drilling company that drilled all the wells in Hellisheidi, kindly provided a sample of all of their cement additives as well as other additives used in drilling fluids. These were than dissolved in deionized water at the laboratory of Iceland GeoSurvey and analyzed for naphthalene sulfonic acids. The cement dispersant had a 2-NSA content of about 1% including a significant amounts of 2,6-NDS and 1,6-NDS. The cement retardant contained significant amounts of 2-NSA, 1,5-NDS, 2,6-NDS together with a dozen other peaks in the HPLC spectrum not present in the standard used for this analysis.

Old usable samples from all the wells in question except HE-21 were found in the storage room of Reykjavík Energy. All contained traces of naphthalene sulfonic acids measured in this study except for a sample from well HE-54. These compounds are clearly present in the reservoir around these wells prior to the tracer tests. Also found in the storage room was a series of samples from the initial testing of well HE-3 in 2002, shortly after the well was drilled. Well HE-3 is located in the east part of the well field and has shown no indication of tracer recovery. Well HE-3 was drilled in August 2001 and the first two samples from April 2002 and June 2002 show traces of 1,5-NDS, 1,6-NDS and 2-NSA. No traces of naphthalene sulfonic acids were detected in a sample from September 2002 and the compounds were probably at that point rinsed from the vicinity of the wellbore, at least to a point of no detection. This indicates that the naphthalene sulfonic acids are possibly present in the reservoir fluid next to a new well but after extensive well testing or production, these compounds are slowly rinsed out of the system and will eventually disappear from detection.

4. TRACER TEST INTERPRETATION AND COOLING PREDICTIONS

This chapter presents the results of the interpretation of the most significant tracer recovery data, discussed in the previous chapter, by a simple flow-channel model. Consequently cooling predictions for the corresponding injection-production well-pairs are presented, where these are based on the parameters of the modelled flow-channels. Finally, the chapter presents a comparison between the cooling predictions and limited monitoring data, for the wells most affected, and the implications of that comparison.

4.1 Tracer Test Interpretation

The tracer recovery curves from five Hellisheidi production wells were interpreted through model simulation using the method presented by Axelsson *et al.* (2005); two 2,7 NDS (injected into well HN-8) recovery curves for production wells HE-30 and HE-47, three 1,5 NDS (injected into well HN-9) recovery curves for production wells HE-31, HE-44 and HE-48 and three 1,3,6 NS curves (injected into well HN-17) also for production wells HE-31, HE-44 and HE-48. These are the wells with the most pronounced and well-defined tracer recovery curves. The simple model, the interpretation method is based on, involves a flow channel connecting respective feed-zones in the reinjection and production wells involved. The properties of each flow channel, along with injection and production rates, determine the tracer recovery in the production well involved, with the properties being flow channel length ($\boldsymbol{x}$), flow channel cross-sectional area ($\boldsymbol{A\varphi}$) and flow channel dispersivity ($\boldsymbol{\alpha_L}$). The flow channel length is fixed in the modelling, and taken as the distance between the main feed-zones of the two wells involved. These lengths, therefore, include vertical components as well the horizontal one. The dispersivity describes velocity variations along the flow-path (dispersion), such as due to varying fracture widths and tortuosity, as well as indirectly incorporating tracer diffusion. In addition the simulation estimates the proportion of a tracer (mass fraction $\boldsymbol{M_i}$) travelling through a flow-channel, and hence the fraction of the injected water travelling through that channel.

This method was used to simulate the tracer recovery curves representing significant tracer recovery, which amounted to 8 curves from 5 production wells (more than one of the tracers was recovered through some of the wells), and thus interpret the tracer recovery. The resulting model parameters are presented in Table 5 below, while figures 15 – 19 show examples of five of the simulated recovery curves.

Table 5: Parameters of flow-channel models used to simulate Hellisheidi tracer recovery curves representing significant tracer recovery. Note that for the first 3 well-pairs two flow-channels were needed to obtain a satisfactory data simulation.

Injection well	Production well	Distances (m)	Mass fraction M_i (%)	Average velocity, u (m/s)	Cross-sectional area, $A\varphi$ (m^2)	Dispersivity α_L (m)
HN-8 (2,7 NDS)	HE-30	1550 990	4.7 2.9 $\Sigma = 7.6$	$2.1\cdot10^{-4}$ $6.0\cdot10^{-5}$	4.1 8.8	171 143
HN-8 (2,7 NDS)	HE-47	1910 1340	4.7 0.4 $\Sigma = 5.1$	$7.5\cdot10^{-5}$ $6.6\cdot10^{-5}$	9.8 1.1	689 55
HN-17 (1,3,6 NTS)	HE-31	1430 1370	12.7 12.2 $\Sigma = 24.9$	$2.5\cdot10^{-4}$ $8.0\cdot10^{-5}$	37.3 114	263 236
HN-17 (1,3,6 NTS)	HE-44	2060	7.7	$9.6\cdot10^{-5}$	48.8	449
HN-17 (1,3,6 NTS)	HE-48	1690	17.2	$1.7\cdot10^{-4}$	65.5	510
HN-9 (1,5 NDS)	HE-31	1870	11.5	$1.6\cdot10^{-4}$	53.3	518
HN-9 (1,5 NDS)	HE-44	2290	3.2	$7.7\cdot10^{-5}$	24.8	500
HN-9 (1,5 NDS)	HE-48	2210	7.7	$1.5\cdot10^{-4}$	33.1	497

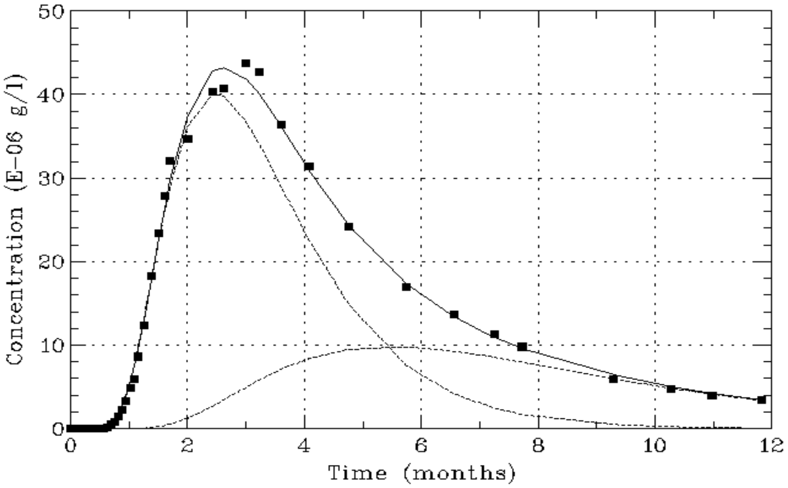

Figure 15: Observed (black squares) and simulated (solid line) recovery of 2,7 NDS (injected into well HN-8) through production well HE-30.

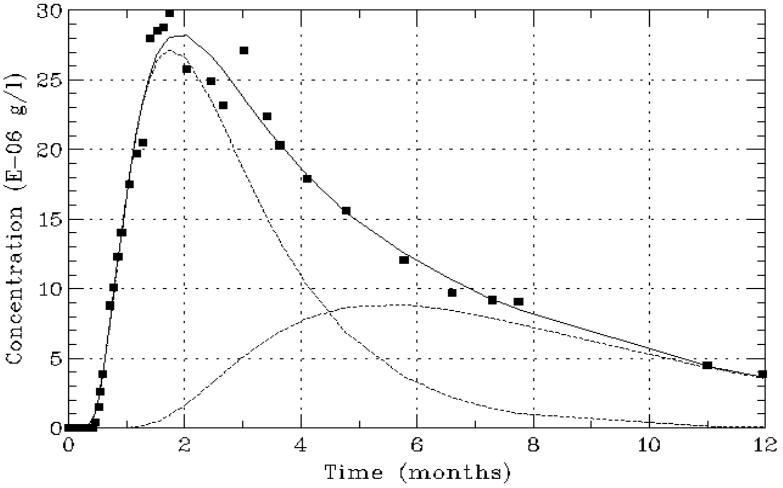

Figure 16: Observed (black squares) and simulated (solid line) recovery of 1,3,6 NTS (injected into well HN-17) through production well HE-31.

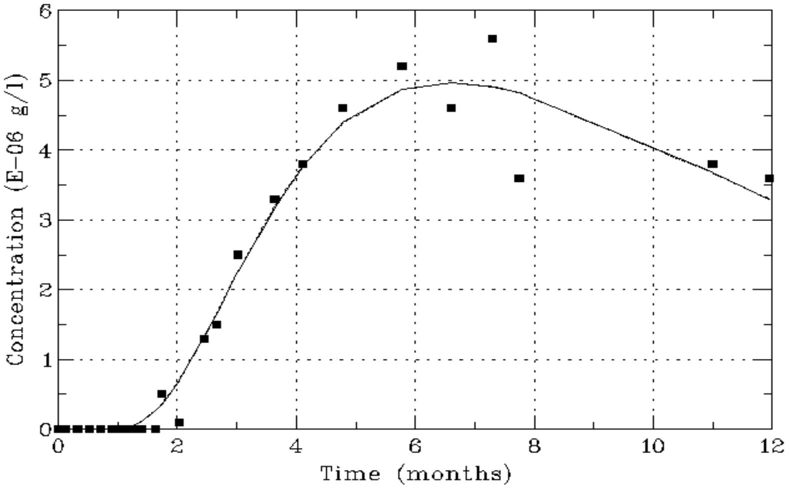

Figure 17: Observed (black squares) and simulated (solid line) recovery of 1,3,6 NTS (injected into well HN-17) through production well HE-44.

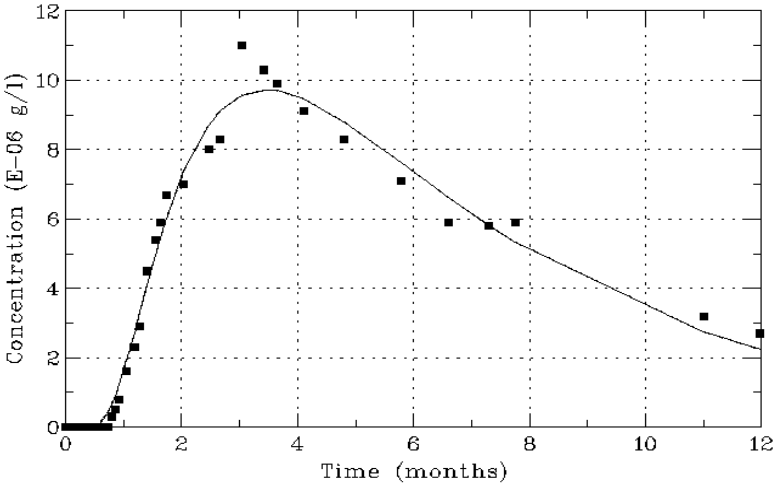

Figure 18: Observed (black squares) and simulated (solid line) recovery of 1,5 NDS (injected into well HN-9) through production well HE-31.

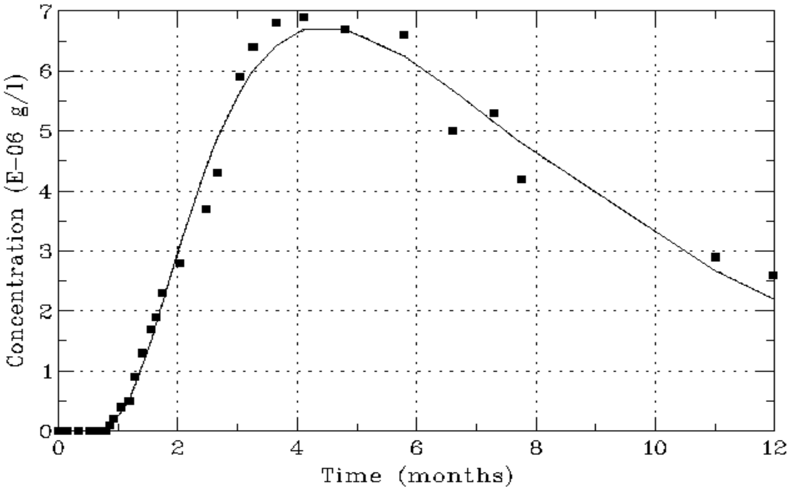

Figure 19: Observed (black squares) and simulated (solid line) recovery of 1,5 NDS (injected into well HN-9) through production well HE-48.

The figures above show a quite good correspondence between the observed and simulated data, hence indicating that the simple flow-path model behind the simulation is quite appropriate. The poorest correspondence is seen in Figure 17, where the data quality is also the poorest. It should be noted that the simulation of the tracer recovery curves was performed about one year into the tracer test, yet there is a good correspondence between the calculated mass recovery presented in Table 3 and the simulated mass fraction presented in Table 5. In three of the simulation cases transport through two flow channels was required to obtain a satisfactory simulation; these can be linked with different feed-zones in the wells involved, as most of these have more than one major feed-zone. In most of the models presented in Table 5 dispersion is relatively large, as seen in the respective recovery curves. This may indicate that the flow channels correspond to complex fracture networks rather than simple flow-paths, as assumed in the simulation model. In the following the parameters of the flow-channels of the models (Table 5), specifically their length and cross-sectional area, are used to calculate cooling predictions for long-term reinjection scenarios.

4.2 Cooling predictions

The results of tracer recovery simulation were, consequently, used to calculate cooling predictions for the cases with significant tracer recovery (see Table 1). The calculation method is described by Axelsson *et al.* (2005). It is mainly based on the cross-sectional area and mass fraction for each flow channel. The former determines the flow-channel surface area, once a realistic aspect-ratio (flow channel height versus width) has been assumed. The latter determines the fraction of the water injected into the reinjection well involved, which travels through the flow channel, eventually cooling the production well. An aspect ratio of 30:1 is assumed here, mainly because a smaller ratio is believed to be overly conservative. In addition a flow-channel porosity of 15% and injection temperature of 100°C are assumed. In addition the cooling predictions for each well-pair are calculated for both direct (one-dimensional flow) and tortuous (assumed circular) flow-paths, with the latter simulating scenarios were the colder reinjected water sinks initially due to higher density, before ascending again to the feed-zones of the production wells. The parameters of the direct flow-paths are based on the model parameters of Table 1, while the parameters of the tortuous paths assume paths that are longer by a factor of $\pi/2$, but with the same flow-path volume. The cooling predictions are calculated for a reinjection period of 20 years, assuming reinjection rates per well comparable to injection rates maintained in the near past.

The results of the cooling predictions indicate limited cooling danger for majority of the cases (injection-production well-pairs) assessed. The cases were significant cooling is predicted are presented in figures 20 – 23.

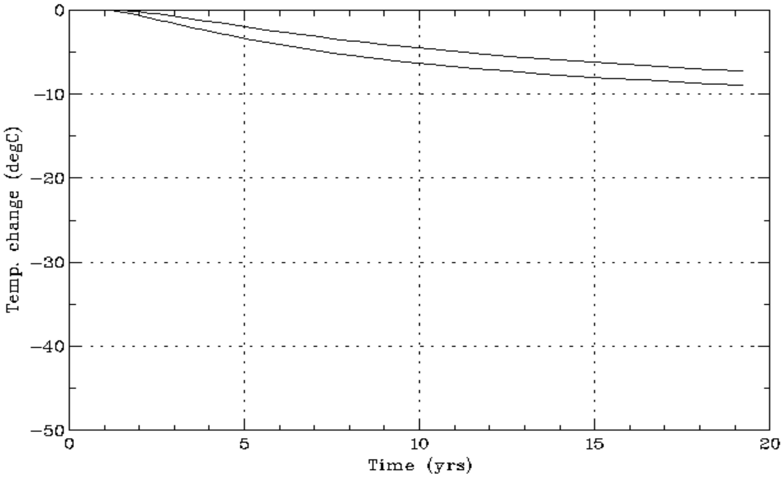

Figure 20: Predicted cooling of well HE-30 during reinjection into well HN-8 (injection rate 55 kg/s), based on the interpretation of the corresponding tracer test data. The lower curve corresponds to a direct flow-path while the upper one corresponds to a tortuous one.

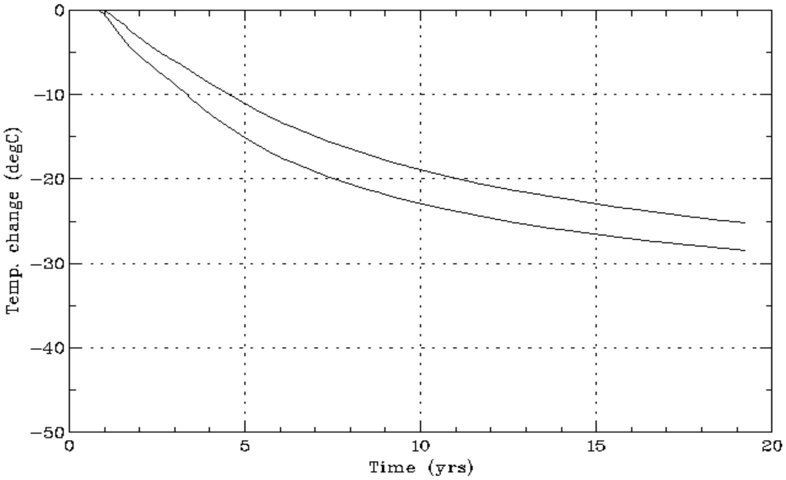

Figure 21: Predicted cooling of well HE-31 during reinjection into well HN-17 (injection rate 100 kg/s), based on the interpretation of the corresponding tracer test data. The lower curve corresponds to a direct flow-path while the upper one corresponds to a tortuous one.

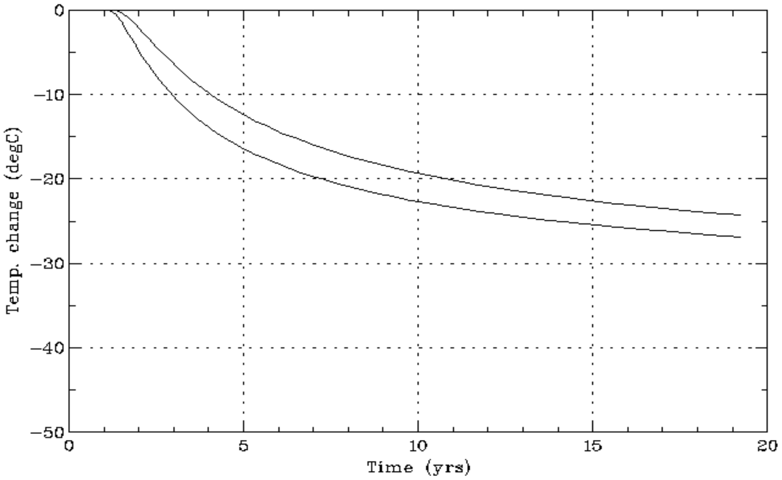

Figure 22: Predicted cooling of well HE-48 during reinjection into well HN-17 (injection rate 100 kg/s), based on the interpretation of the corresponding tracer test data. The lower curve corresponds to a direct flow-path while the upper one corresponds to a tortuous one.

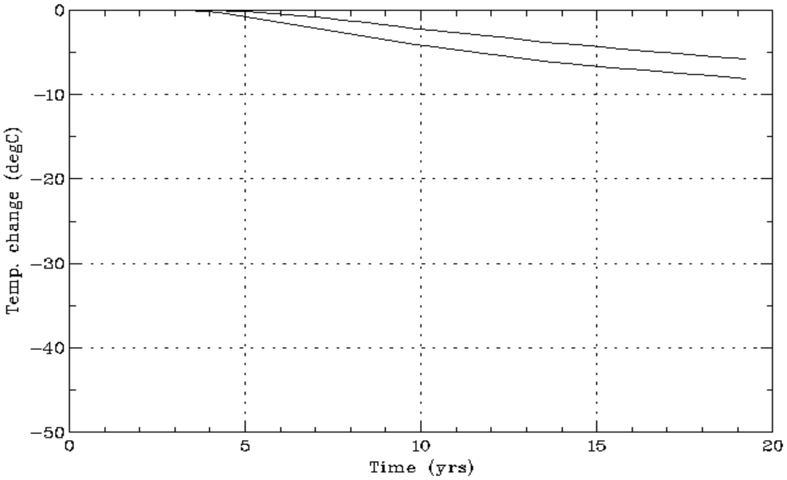

Figure 23: Predicted cooling of well HE-44 during reinjection into well HN-17 (injection rate 100 kg/s), based on the interpretation of the corresponding tracer test data. The lower curve corresponds to a direct flow-path while the upper one corresponds to a tortuous one.

As expected, the greatest cooling is predicted for wells HE-31 and HE-48, the wells with the greatest tracer recovery. It's, however, noteworthy that there is a relatively small difference between the predictions for straight and tortuous flow-paths. This is because the flow-path volume is the same for both, determined by the average transfer transport velocity. The predictions are calculated for flow-channels with an aspect-ratio of 30:1 and a porosity of 15%. These values are simply based on what is considered likely, i.e. considering general geological constraints. A larger aspect ratio, as would be the case for a relatively thin fracture-zone, and a smaller porosity, would result in a slower predicted cooling, and vice versa. The cooling predictions are, therefore, a somewhat uncertain. A comparison with actual monitoring data is beneficial, if such data are available, as will be demonstrated in the following sub-chapter.

4.3 Comparison with Monitoring Data

Monitoring data collected since large-scale reinjection started at Húsmúli in late 2011 doesn't indicate any significant cooling of the production wells involved, which contradicts the cooling predictions for the wells showing the greatest tracer recovery. This indicates that the cooling predictions may be too pessimistic in some cases. Figure 24 shows output monitoring data (total flow and enthalpy) for four wells, including wells HE-31, HE-44 and HE-48 where the greatest cooling is predicted (see above). They all show increasing mass-flow and relatively stable enthalpy, thus no clear indications of cooling. They increased mass flow may be aided by the reinjection through increased reservoir pressure. It should be kept in mind, however, that the output measurements are relatively uncertain. Yet the general trend is clear.

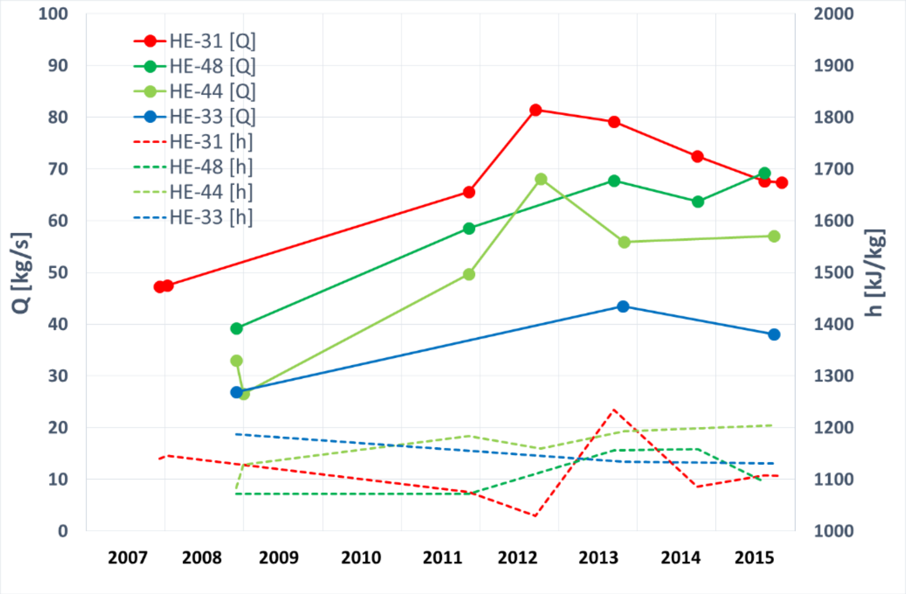

Figure 24: Output monitoring data, i.e. total mass-flow (Q) and enthalpy (h), for several production wells (see Figure 7 for their location) in the Hellisheidi field (from Gunnarsson et al., 2016).

A more accurate way of monitoring the cooling of production wells involves temperature logging of the wells, preferably during discharge. One of the wells with the greatest predicted cooling, well HE-31, was temperature logged during discharge at the end of 2015, 4 years after injection started at Húsamúli. The results are presented in Figure 25 along with two older temperature logs. No clear cooling can be seen from the figure. Unfortunately no other production wells with great tracer recovery have been temperature logged during discharge recently.

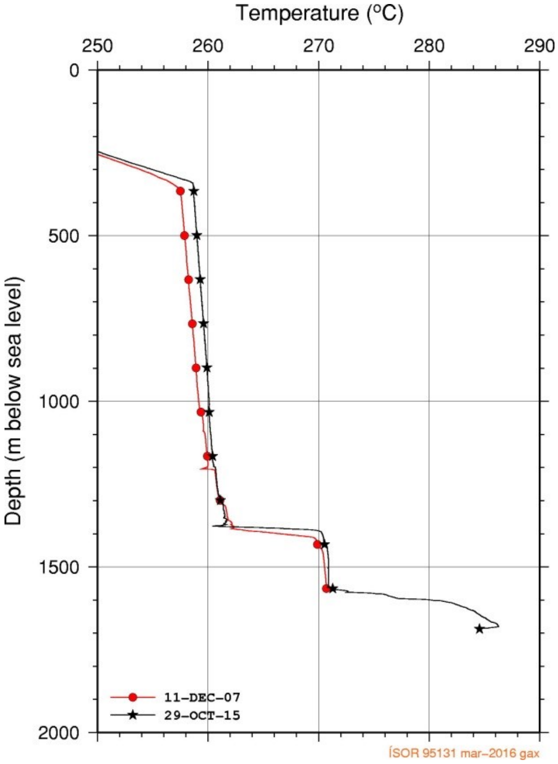

Figure 25: Temperature logs measured in well HE-31 during discharge. The one measured on October 29, 2015 shows no indication of cooling after more than four years of operation of the Húsmúli reinjection field.

The question is why the cooling predictions turn out to be too conservative? This is probably because the flow paths are not as simple as assumed; perhaps they consist of fracture networks where the fluid is in touch with much greater rock surface area than the predictions assume. This may also be influenced by the injected fluid sinking to greater depth, due to higher density, where it encounters higher temperatures, while the cooling predictions have in fact already estimated the effect of longer flow paths, as discussed above. Finally the flow dispersion observed through the tracer recovery curves is not taken into account in the cooling predictions presented here.

Results as these may be used to calibrate reinjection cooling predictions more accurately than simply on the basis of tracer data. Yet it must be kept in mind this this is always extremely case-specific, as in some cases flow-paths are certainly as assumed in the predictions above, or even more direct. There are only a few examples available in the literature where older cooling predictions based on tracer recovery data are compared with temperature monitoring data; Bjarkason (2014) presents one such example where predictions and observations approximately match.

5. CONCLUSIONS

This paper describes the outcome of a comprehensive tracer test conducted during 2013 in the Hellisheidi geothermal field in SW-Iceland, which had the purpose to study the connection between specific reinjection and production wells, and the cooling danger facing some production wells. It involved 6 different liquid phase naphthalene sulfonate tracers that were injected into 6 injection wells, and tracer samples collected from a large number of production wells for more than 2 years. The following are the main results of the test and associated analysis:

1) Several wells showed significant recovery, amounting to more than 25% for a single well. The tracer injected into well HN-17 (1,3,6-NTS) had the greatest recovery (58%), through 7 production wells, while the tracer injected into well HN-10 (2,6 NDS) had the smallest recovery (1%), through 3 wells.
2) Most of the tracers injected appear to travel along flow-paths along a major fault zone on the western flanks of the Hengill volcanic system.
3) The tracer recovery through several of the wells was successfully modelled by simple models of flow-paths connecting feed-zones of reinjection and production wells. The model parameters were consequently used to calculate future cooling predictions for those wells exhibiting significant tracer recovery. The results indicate that two production wells could be seriously affected (cooling of up to 25-30°C in 15-20 years) during long term reinjection, an adverse effect that must be tackled during the future resource management of the Hellisheidi geothermal resource.
4) Monitoring data collected since large-scale reinjection started at Húsmúli in late 2011 doesn't indicate any significant cooling, however, which contradicts the cooling predictions for the wells showing the greatest tracer recovery. This indicates that the cooling predictions may be too pessimistic in some cases.
5) The recirculation of some of the tracers injected has resulted in recovery through additional flow channels, providing valuable additional information, which needs to be interpreted further.
6) This study has also revealed the need to incorporate the possible degradation of some of the naphthalene sulfonates used in the overall interpretation.
7) It has also demonstrated that contamination from casing cement additives may interfere with tracer tests applying naphthalene sulfonate acids.
8) The Hellisheidi 2013 tracer test has provided comprehensive and extensive information, which should be interpreted and modelled further, beyond what has been presented in this paper.

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