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THE DIXIE VALLEY, NEVADA TRACER TEST

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ABSTRACT

Three injection wells in the Dixie Valley, Nevada geothermal field were tagged with organic tracers. The tracers used were benzoic acid, benzenesulfonic acid, 4-ethylbenzenesulfonic acid, and fluorescein. Six production wells were intensively sampled for 2.5 months. During this period one well, 76-7, showed breakthrough. The presence of benzoic acid and fluorescein in the 76-7 production fluid demonstrated that breakthrough was from well 32-18. Concentration ratios of these compounds varied during the test period, as predicted from laboratory experiments. These ratios predict an average flowpath temperature of 230°C for the early-time data and a range from 218° to 232°C for the later data. These temperatures are consistent with the observed temperatures in the reservoir.

A numerical reservoir model of the Dixie Valley field was employed to predict the results of the tracer tests. The model was used to estimate needed tracer quantities and sampling frequencies. The results of the model are in qualitative agreement with the observed tracer breakthrough. Differences between calculated and observed arrival times may be due to the large mesh size used in the model and a possible underestimate of the average fracture porosity.

INTRODUCTION

The Dixie Valley geothermal resource is a fracture-dominated geothermal system located in west-central Nevada (Fig. 1). The field currently supports a 49.8 MW net power plant that is operated by Oxbow Geothermal Corp. A tracer test at Dixie Valley was conducted by UURI and Oxbow during early winter of 1989 as part of the Department of Energy's Injection Research Program. This experiment was designed to test the application of organic tracers recently developed by UURI (Adams et al., 1986a; 1986b), further refine the predictive capability of the numerical reservoir model developed for the field (Oxbow, 1986, 1987; Doughty and Bodvarsson, 1988) and to determine the effectiveness of Oxbow's injection strategy.

Organic dye tracers have been used for several decades to follow the movement of surface and groundwaters. These tracers have been used with variable success in geothermal systems, in part because their thermal stability was not known. Tracer research at UURI has quantified the rate of thermal decay of the tracer dye fluorescein (Adams and Davis, in preparation) and introduced new organic tracers (Adams et al.,1986a; 1986b). Three of the new tracer compounds were used in conjunction with fluorescein in the Dixie Valley test to identify connections between the injection and production wells.

The Dixie Valley field was chosen as a test site because of the large amount of available geologic and geochemical data, the availability of several injection and production wells, the fault-dominated fluid flow patterns, and the existence of a numerical reservoir model. Modeling of the tracer test by Doughty and Bodvarsson (1988) predicted rapid breakthrough of injected fluids for some injection-production well-pairs. Thus, both tracers and the predictive capacity of the model could be simultaneously tested.

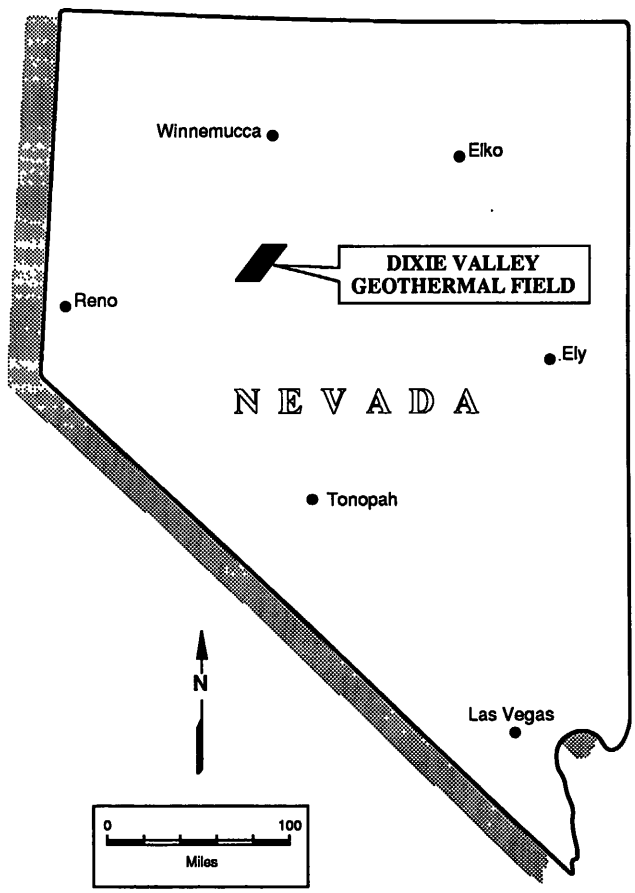

Figure 1. Location of the Dixie Valley geothermal field.

This paper describes the test parameters and results through June, 1989. Sampling and analysis of the production fluids will continue through the remainder of 1989 to test for long-term breakthrough.

DIXIE VALLEY GEOTHERMAL SYSTEM

The producing wells at the Dixie Valley geothermal system are located along the active range-front fault zone that bounds the eastern margin of the Stillwater Range (Fig. 2). These wells produce primarily from the Humbolt Lopolith, which is able to sustain large open fractures (Waibel, 1987). Production depths in wells 45-33, 27-33, 73-7, 74-7, and 84-7, which are completed in the lopolith, vary from 2440 to 3050 m, where temperatures are approximately 250°C.

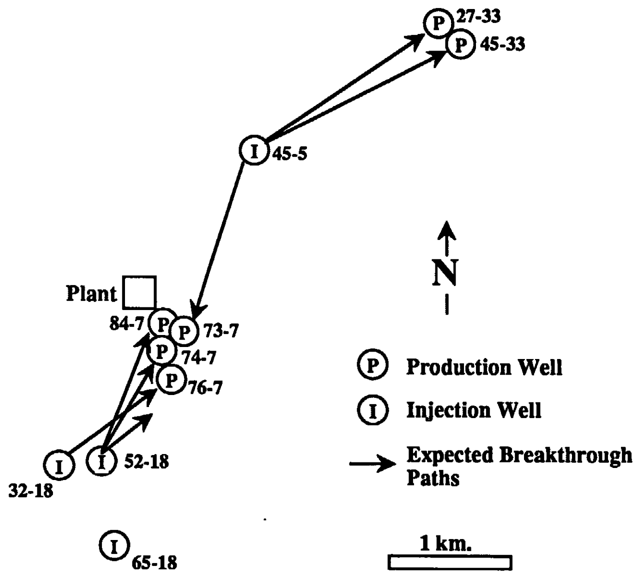

Figure 2. Bottom-hole well locations and expected breakthrough paths for the injected tracers.

Two wells in the southern portion of the field, 76-7 and 32-18, encountered a shallower thermal aquifer in Miocene basalt at approximately 2270 m. Pre-exploitation temperatures in the basalt intervals of these wells range from 213° to 221°C. Production fluid from well 76-7 appears to be a mixture of fluid from the high-temperature, deep reservoir and the basalt thermal aquifer. Measured temperature in well 76-7 rose from a static temperature of 213°C to a flowing temperature of 239°C during initial flow tests, indicating close connection with the deeper reservoir. Well 32-18 produced fluid typical of the basalt thermal aquifer before being put on-line as an injector well.

The injection wells in the Dixie Valley field are widely dispersed (Fig. 2) and are completed in three different reservoir environments. Wells 52-18 and 65-18 are the deepest and inject fluid into the lopolith rocks at approximately 2950 m. Permeability in both wells appears to be related to the range-front fault. Wells 32-18 and 45-5 inject fluid into Miocene basalt at depths of 2290 and 1830 m, respectively. Reservoir analysis indicates that permeability in 45-5 is related to the range-front fault, while that in 32-18 is derived from the basalt horizon. All injection wells have been flow-tested and are in good pressure communication with the production wells. Injection zone temperatures range from 200° to 232°C.

The combined flowrate of the six production wells averaged 592 kg/sec during the test period. Approximately 55% of the produced fluid was disposed of into the injection wells.

TEST DESCRIPTION

The tracers were inserted as 300 bbl slugs into the injection wells. Multiple tracers with different thermal stabilities were used to uniquely define connections between the injection and production wells, and to determine average temperatures along the flowpaths using experimentally determined tracer decay rates. Benzenesulfonic acid was injected into well 45-5 on January 4, fluorescein and benzoic acid into well 32-18 on January 5, and fluorescein and 4-ethylbenzenesulfonic acid were injected into well 52-18 on February 3, 1989. The tracers were obtained as neutral solutions with concentrations ranging from 10 to 30 wt%.

The amount of tracer required to observe breakthrough was predicted for each injection-production well-pair assuming a detection limit of 60 ppb. After well-pairs that required unrealistically high amounts of tracer to achieve breakthrough were eliminated on economic considerations, seven well-pairs still had the potential for breakthrough. These well-pairs are shown in Figure 2, and a comparison of the calculated quantities and the actual mass of tracer injected are listed in Table 1.

TABLE 1. Summary of model results. BSA = benzenesulfonic acid, BA = benzoic acid (with 150 kg of fluorescein), EBSA = 4-ethylbenzenesulfonic acid (with 50 kg of fluorescein), t_{bt} = time to breakthrough, t_{pk} = time to peak concentration, Calc. M_{inj} = tracer mass calculated to be required to achieve breakthrough, actual M_{inj} = tracer mass actually injected, -- = no breakthrough predicted within one year.

Inj. Well	Prod. Well	t_{bt} (days)	t_{pk} (days)	Calc. M_{inj} (kg)	Actual M_{inj} (kg)	Breakthrough Expected	Breakthrough Observed
65-18	76-7	11	102	382	0	NO	NO
	84-7	15	148	460		NO	NO
	74-7	12	125	4 39		NO	NO
	73-7	34	171	25600		NO	NO
	27-33	--		--			
	45-33	--		--			
45-5	76-7	--	--				
	84-7	49	216	1506	900	NO	NO
	74-7	49	193	1284	BSA	NO	NO
	73-7	49	273	837		YES	NO
	27-33	19	171	270		YES	NO
	45-33	19	154	265		YES	NO
32-18	76-7	1	11	32	100	YES	YES
	84-7	4	45	602	BA	NO	NO
	74-7	9	114	4283		NO	NO
	73-7	5	57	12370		NO	NO
	27-33	--	--				
	45-33	--	--				
52-18	76-7	3	51	162	300	YES	NO
	84-7	6	91	250	EBSA	YES	NO
	74-7	4	68	208		YES	NO
	73-7	9	91	20810		NO	NO
	27-33	--	--				
	45-33	--	--				

Injection was accomplished at each site by pouring the tracers into a frac tank containing 300 bbls of hot flashed geothermal brine. Oxygen concentrations were monitored during mixing of the solutions because of the sensitivity of the tracers to molecular oxygen at elevated temperatures. The solutions were then injected into the well via a centrifugal pump. Because the pump could not overcome the flowing line pressure, brine flow was cut off upstream of the well during the tracer injection and injection occurred under near-vacuum conditions. The injection took approximately one hour, after which full brine flow was reestablished.

All six of the production wells were monitored for return of the tracers using automatic samplers. These battery-powered samplers were built by UURI using commercial microprocessors and automatic valves. The tubing design of these samplers was modified from that of Jackson (1982). The samplers were programmed to run hot brine through the tubing every few seconds to avoid freezing of the sample lines. Use of the automatic samplers reduced the number of technicians required on-site.

Each sample was taken in two one-liter high-density polyethylene bottles. Dye samples were collected in opaque bottles to avoid degradation by ultraviolet light. The benzoic and benzenesulfonic acids were collected in clear bottles preserved with 0.5 ppm sodium azide to prevent biodegradation.

Frequent monitoring of the test progress was provided by on-site analysis of fluorescein, using a Model 112 Turner digital filter fluorometer. The instrument was calibrated to read in parts per billion (ppb), and was standardized every day. Samples were adjusted to a pH > 9 prior to analysis to standardize the fluorescence. Detection limits for fluorescein were 3 ppb. Benzoic acid and the benzenesulfonic acids are analyzed by high-pressure liquid chromatography at the UURI laboratory in Salt Lake City, Utah. Detection limits for these compounds are approximately 7 ppb.

Sampling frequencies were guided by the results of the on-site monitoring and the predicted breakthrough times. Samples from well 76-7, in which breakthrough was possible within one day, were taken at intervals ranging from every two hours at the inception of breakthrough to every eight hours at the tail. The reservoir model indicated that wells 73-7, 74-7, and 84-7 might to break through within 3 to 7 days, and were sampled every 6 to 8 hours. Wells 27-33 and 45-33 were not expected to break through until the fourth week of the test, and were only sampled once every 12 hours. This sampling schedule was followed from the time of injection to March 17, when the plant was shut down for routine maintenance. Since then samples have been taken at least twice a month from all production wells, and will continue to be collected on this basis throughout 1989.

MODELING STUDIES

During the design phase of the tracer test, the test was mathematically modeled to help determine the quantity of tracer to inject and where and when to look for breakthrough. A three-dimensional porous-medium model developed by the Oxbow Geothermal Corporation (1986; 1987) was used. The mathematical model assumes that fluid flow at the Dixie Valley geothermal field is primarily through high-permeability channels associated with the SW-NE trending range-front fault that separates Dixie Valley from the adjacent Stillwater Range. The model was developed from an integrated analysis of geological, geochemical, and seismological data, natural-state modeling of the system, and modeling of two extensive flow tests; this model is described more fully in another paper in these transactions (Doughty et al., in preparation). The rather coarse spatial discretization of the model, which is appropriate for natural-state, flow-test, and production modeling, is questionable for tracer-test modeling, so the following results should be viewed as general estimates of future behavior rather than detailed predictions. The computer program MULKOM (Preuss, 1983), developed at Lawrence Berkeley Laboratory, was used for the calculations.

A simplified fractured/porous-medium model was derived from the porous-medium model as follows. Assuming a fracture porosity of 1%, the volume of all elements was decreased by a factor of 100, total compressibility (rock plus water) was increased by a factor of 100, and rock heat capacity was increased by a factor of 100. This allows an approximate calculation of fracture flow, maintaining the appropriate pressure decline and thermal front movement. However, it is important to note that the assumption of 1% fracture porosity is only a first-order estimate, which greatly affects the results obtained. Thus, all results should also be considered as first-order estimates.

The fractured/porous-medium model was used to calculate a six-month 60 MW (gross) production period with 61% injection. A 20-minute tracer slug was added to all injection wells after 31 days of production. Figure 3a shows the tracer concentrations in the injection wells, and Figure 3b shows the tracer concentrations in the production wells. All production wells show some tracer within 6 months, although for well 73-7 the level was very low. Figure 3c shows early-time behavior at the production wells. Tracer breakthrough times of 1, 4, and 6 days after tracer injection were estimated for wells 76-7, 84-7, and 74-7, respectively. Tracer breakthroughs in wells 45-33 and 27-33 occur after a much longer time, about 20 days after tracer injection. Tracer breakthrough in well 73-7 is estimated to be the slowest and tracer concentration the lowest.

To better study the connectivity between individual injection and production wells, simulations were done in which tracer was injected into only one injection well at a time. These simulations were carried out for a one-year period. Results are summarized in Table 1.

The wide range of values of injection mass for each injection well, listed in Table 1, shows that the amount of tracer required for 60 ppb detection depends strongly on which production well is being monitored. For example, the results obtained suggest that for tracer injected into well 45-5 to be detected at wells 84-7, 74-7, and 73-7, about 1500 kg of tracer should be injected. However, the same tracer may be detected in wells 27-33 and 45-33 with only 300 kg of tracer injected. Thus, one must weigh the cost of the tracer versus the number of wells in which it will be detected to obtain the best estimate for the amount of tracer that should be injected.

RESULTS

Intensive sampling continued through March 17, 1989, when the power plant was shut down for maintenance. At that time fluorescein and benzoic acid had been detected in fluid from well 76-7, demonstrating that breakthrough was from well 32-18. Measured concentrations are shown vs. time in Figure 4. The maximum measured concentration of both fluorescein and benzoic acid was 79 ppb. A hypothetical curve showing the tracer concentrations corrected for thermal decay is shown in Figure 5. These corrections were made using kinetic data for

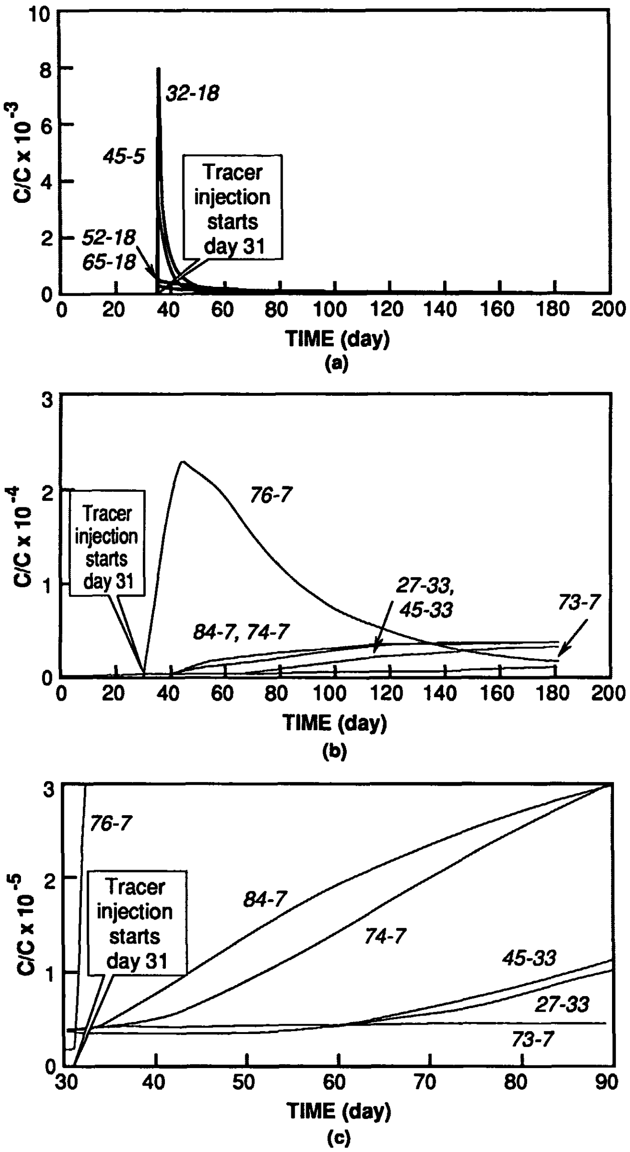

Figure 3. Predicted tracer concentrations in the injection wells (a) and the production wells (b), and predicted early time behavior in the production wells (c).

fluorescein and benzoic acid (Adams and Davis in preparation; Adams et al., in preparation). The average temperature of decay used in the correction factor was derived from a comparison of theoretical and actual fluorescein/benzoic acid ratios (Fig. 6). This comparison indicates an injection-production flowpath temperature of approximately 230°C from the arrival time to the middle of the peak. Ratios in fluid from the later portion of the test indicated temperatures increasing from 218°C just after the middle of the peak to 232°C at the tail. Breakthrough in 76-7 was detected 224 hours after injection, and the peak occurred approximately 570 hours later.

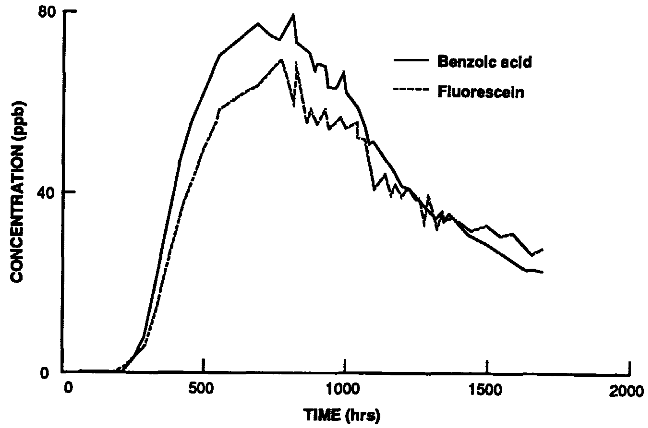

Figure 4. Measured concentrations of fluorescein and benzoic acid in the production fluid from well 76-7. The tracers were injected at time = 0 hours.

COMPARISON OF MODEL PREDICTIONS WITH FIELD DATA

We predicted that the first breakthrough would be from well 32-18 to well 76-7, in agreement with the tracer test results. Because calculated breakthrough time t_{bt} is very sensitive to both the detection limit assumed and mesh discretization errors, it may be more useful to compare t_{pk}, the time of peak concentration at a production well. For the 32-18 to 76-7 breakthrough, t_{pk} = 800 hours (correcting for fluorescein decay), while the predicted value is 264 hours (~11 days). As the concentration peaks will depend near linearly on fracture porosity, we can introduce a correction factor of 800/264 = 3.4 and conjecture that if we had assumed a fracture porosity of 3.4% instead of 1%, then all predicted values of t_{pk} would be increased by a factor of 3.4. Referring to Table 1, we see that for the well pairs for which breakthrough is expected, increasing t_{pk} by a factor of 3.4 would make t_{pk} greater than the duration of the tracer test. This is consistent with the actual tracer test, in which tracer was not observed in any production well other than 76-7.

Of course, our model predicts breakthrough times that, when multiplied by 3.4, are short enough to be observed, which is not consistent with the actual tracer test. This points out the need for a finer calculational mesh and more sophisticated treatment of fractured/porous medium interactions for accurate predictions of tracer tests.

ESTIMATION OF FLOWPATH VELOCITIES AND TEMPERATURES

The results of the tracer test can be used to calculate minimum velocities and average temperatures of the injection fluids. Velocities for the most direct path of the tracer slug were calculated using the time of breakthrough (Fig. 5) and the distance between wells 32-18 and 76-7 (1128 m). The

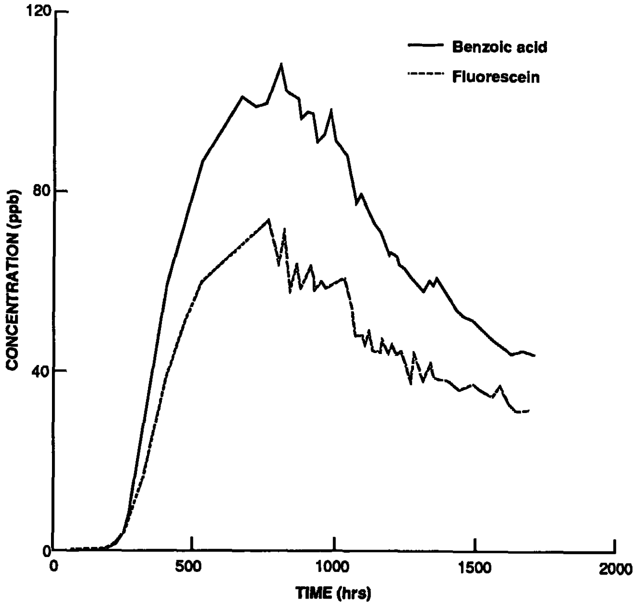

Figure 5. Hypothetical return curve in which tracers are corrected for thermal decay at the average temperature indicated by the tracer ratios.

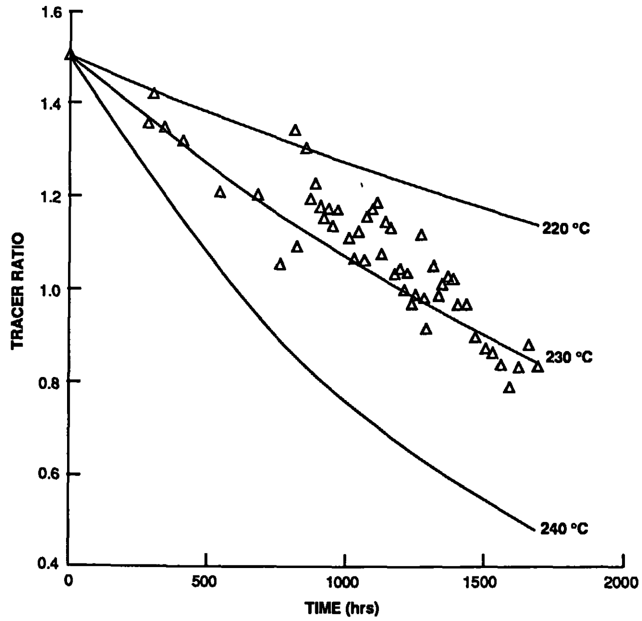

Figure 6. Actual tracer ratios in fluid from well 76-7 compared to ratios calculated with the assumption of constant temperature along the injection-production flowpath.

minimum velocity for the tracer front was 5.0 m/hr and for the peak 1.4 m/hr. Because both wells are completed in basalt at similar depths, the most probable path for the injected fluid was through the basalt horizon.

Tracer ratios combined with kinetic data for thermal decay of the tracers can be used to derive temperatures along the postulated injection-production flowpath in the basalt. Calculations to match the tracer ratios measured in the production fluid of well 76-7 were performed by varying times and temperatures along the hypothetical flow-path. The models assumed that the initial temperature was the injection temperature, and that the final temperature was the production temperature of well 76-7. Although the temperature distributions inferred from the model are not unique, they clearly indicate that the injected tracers would have had to spend at least 50% of the time at a temperature greater than or equal to 225°C. This temperature is higher than the pre-exploitation temperatures in the basalt, which ranged from 213° and 221°C in wells 32-18 and 76-7, respectively. However, there is evidence that production from well 76-7 pulls fluid from the high-temperature reservoir through the basalt. Thus, the difference between the calculated injection flowpath temperatures and the pre-exploitation temperatures may imply that the basalt aquifer has heated up during exploitation due to movement of reservoir fluid through the basalt.

CONCLUSION

Newly developed organic tracers have been used in conjunction with numerical reservoir modeling to design and test the existing injection strategies used in the Dixie Valley geothermal field. Connections between three injection and six production wells were tested using three sets of tracers. Multiple tracers were used in this test to uniquely identify connections between injection and production wells.

A numerical reservoir model was used in the design phase of the tracer test to predict which wells were likely to show breakthrough, and to calculate the mass of tracer required. This model predicted that the first breakthrough would be from injection well 32-18 to production well 76-7, which is in agreement with the test results. Actual arrival times were 3.4 times longer than those calculated from the model, possibly reflecting a low estimate of fracture porosity.

Benzoic acid and fluorescein were detected in production fluid from well 76-7, demonstrating that breakthrough was from injection well 32-18. Concentrations of the tracers in the production fluid ranged from a few ppb to 79 ppb. Excellent resolution of the tracer return curve was obtained throughout the length of the test. The measured ratios of fluorescein to benzoic acid in the production fluid changed during the length of the test due to thermal decay. The rate of change that was measured agrees well with that predicted from experimental data on tracer stabilities and with temperatures measured in the Dixie Valley field.

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