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First Multi-Well Vapor and Two-Phase Tracer Test in a Geothermal Reservoir, Using Perfluorocarbons and Alcohols

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ABSTRACT

A new class of chemical tracers, perfluorocarbons (PFC), have been tested in the lab and evaluated in a field trial at the Darajat geothermal project, Indonesia. Liquid- and vapor-phase tracers are widely used in geothermal reservoir engineering to trace the path of water injected into the reservoir for pressure support and/or recharge. In the case of a vapor-dominated geothermal system such as Darajat, vapor- and two-phase tracers can be used to trace the amount of steam derived from water injected strategically around steam production wells. Freon compounds, such as chlorofluorocarbons (CFC) and hydrofluorocarbons (HFC), have been used routinely as vapor tracers in geothermal. However, CFC's are no longer available due to ozone-depletion issues, and the only remaining HFC for practical use is R-134a. Sulfur hexafluoride (SF6) is not used due to concerns about possible reaction with silicate rocks in the reservoir under superheated conditions. Two PFC's were tested for thermal and chemical stability and found to be stable to at least 280 ºC in the presence of reservoir rock and water. These compounds are very insoluble in water, so that had to be emulsified for application as "water-to-steam" tracers. Once the water boils in the reservoir they partition to the vapor phase and follow the steam path. The two PFC's were tested along with R-134a and three light alcohols in the first multi-well, vapor and two-phase tracer test for a geothermal reservoir. The PFC's produced similar return curves as the Freon tracer, which all partition strongly to the vapor-phase. There was no evidence of premature phase separation of PFC's from injection water. In spite of their very low solubility, these compounds can be used as vapor-phase tracers in geothermal applications with adequate precautions in application, utilizing appropriate emulsions and controlled injection rates.

The light alcohols are very soluble and considered two-phase tracers in that they partition more evenly between steam and water than the vapor tracers. By using tracers of widely differing solubility we were able to extend the range of boiling fractions that could be tagged as injectate traveled through the reservoir. An additional benefit is that the ratio of the tracers in each sample was used to calculate the fraction of boiling that volatilized the tracers from the injectate into the steam reservoir. In one case unique flow paths were identified in a well that allowed essentially complete separation of steam from early-boiling injectate. The tracer results confirm semi-permeable barriers within the reservoir, which will help design injection distribution strategies for improved injection management, Sugandhi, et al. (2009). The results will be used to develop alternative injection strategies to best manage reservoir performance and maximize heat recovery from reservoir rock.

1. INTRODUCTION

The Darajat geothermal field is located in West Java on the island of Java in Indonesia and operated by Chevron Geothermal Indonesia, Ltd. (CGI). The field, currently the second largest geothermal development in Indonesia, has been under commercial exploitation since November 1994. The 3 units are currently generating 259 megawatts of electricity, fed into the national electrical grid system.

Long-term sustainability of a vapor-dominated geothermal resource is largely determined by the injection of fluids back into the reservoir. Properly managed, injection generates "injection-derived steam" (IDS) as the water boils in contact with hot dry rock in the reservoir. This process can be considered part of an Enhanced Geothermal System (EGS). Without injection the field would dry-out and production would decline. Reinjection of plant condensate can reduce the potential for early reservoir dry-out and field-wide rapid production decline. However, inappropriate injection location, rate and/or duration could lead to premature liquid breakthrough, reservoir cooling and waste of injected water, which are setbacks to the goal of enhancing energy extraction. In addition, injection breakthrough could result in operational problems, such as de-rating of plant output due to low steam quality, requiring modification of surface facilities for improved water separation.

A recent well drilling campaign to support the additional 110 MW power plant, Darajat Unit 3, resulted in an average well deliverability of 34 kg/s at wellhead pressures of 18 bara (equivalent to 21 MW). The successful drilling program has focused management concerns on immediate short term needs to maintain adequate injection capacity, ensuring current plant reliability, in addition to long term strategies. Tracer testing is known to be a powerful tool for understanding the connection between injection and production wells. For a vapor-dominated field, connectivity and flow paths control both the amount of IDS that may be obtained from injection and the potential for water break-through and premature cooling of production wells.

In order to address immediate questions regarding injection benefits and impacts, and to develop a long term injection strategy, it was decided to undertake a multi-well vapor and two-phase tracer test. By using both types of tracers, we planned to quantify the volume of injected water that was being boiled in the reservoir and produced by the surrounding steam production wells and characterize the boiling processes in terms of steam fractions. For time and cost efficiency, it was necessary to inject tracers into three existing injection wells simultaneously. As multiple high-temperature vapor tracers were not available, CGI collaborated with Thermochem, Inc. (TCI), to develop new vapor-phase tracers and to run field tests to confirm the tracer effectiveness.

The multi-phase tracer test was initiated approximately 5 months after the Darajat field commenced injecting into the new reinjection well, DRJ-12, to target the areas of highest superheat and maximize IDS recovery. In addition to refinement of connectivity mapping between injection and production wells, particularly with the recent additional make-up wells drilled, the tracer test was also expected to quantify the volume of injected water that was being boiled in the reservoir and produced by the surrounding steam production wells. A comprehensive review of the potential tracer test effectiveness and long term benefit to injection strategy concluded that an immediate multi-well vapor and two-phase tracer test was the best approach.

2. TRACER SELECTION AND APPLICATION STRATEGY

Selection of appropriate tracers becomes critical in achieving the objectives as it determines the success and cost effectiveness of tracer tests. Two-phase tracers are considered chemical compounds that partition substantially into both the steam and liquid phases, with the ideal two-phase tracer having partitioning identical to water. Artificial two-phase tracers (other than tritium) are currently limited to light alcohols, which have been applied only a few times in geothermal reservoir tracing applications, and never before with vapor-phase tracers. Alcohols have been used as tracers at The Geysers, USA, Matsukawa, Japan, Fukuda (2005), Coso, USA, and Los Azufres, Mexico. The selection of two-phase tracers for Darajat was relatively straightforward- the aliphatic alcohols isopropanol (IPA), n-butanol (NBA) and n-propanol (NPA) were selected based on thermal stability, vapor/liquid partitioning and cost.

Vapor-phase tracers are chemical compounds with high volatility that partition into the steam phase on initial boiling and are useful in nearly all types of geothermal systems. They have been used in liquid-dominated, Upstill-Goddard and Wilkins (1995), two-phase, Bixley et al. (1995), Moore et al., (2000), and vapor-dominated fields, Adams et al. (1991), Beall et al. (1994), Beall et al. (1998). Vapor-phase tracers are of particular importance at vapor-dominated fields such as Darajat and The Geysers (USA), where control of injectate is critical. Injection water must be closely managed to avoid liquid breakthrough into production wells and to distribute the injectate evenly throughout the reservoir. The same principles apply to the EGS process which has the potential to greatly increase worldwide geothermal energy extraction.

The earliest efforts to quantify IDS in the production wells of vapor-dominated systems involved tritium, Gulati et al. (1978), at The Geysers and the stable isotopes of water at Larderello, Italy Nuti et al. (1981). Chlorofluorocarbons (CFC) were used as vapor-phase tracers at The Geysers from 1990 to 1997, Adams et al. (1991), Beall et al. (1994). Unfortunately, they were taken out of production due to their effects on ozone concentrations in the upper atmosphere UNEP (1993).

For the immediate operational concerns CGI needed to test three injection wells at the same time and could not afford to run sequential tracer tests, since each test would require at least 3 to 6 months for completion. But only two vapor-phase tracers were currently proven and available: R-134a and R-23, both hydrofluorocarbons (HFC). These two compounds were first proposed in 1997 as substitutes for CFC tracers, Adams (1997), as they possess good thermal stability and detectability for use in vapor-dominated reservoirs. They have since been used extensively at The Geysers, and were used at Darajat beginning in 1998. The production of R-23 has diminished and the price is now prohibitive for commercial application given its relatively high detection limit by current methods (poor analytical sensitivity) compared to R-134a. This situation had left the geothermal industry with only one vapor-phase tracer that is stable at temperatures to at least 250 ºC and does not adsorb or decay in the presence of rock. Another vapor-phase tracer, SF_6, may have strongly absorbed or decayed previously during a Darajat tracer test in 1998. Therefore the development of new, reliable vapor-phase tracers that could be deployed in a geothermal environment was required.

In early 2008 CGI requested TCI to collaborate in the development and testing of new vapor phase tracers and run field tests to confirm their effectiveness. After an exhaustive literature review of potential compounds, laboratory development started in July, 2008. TCI screened a number of new potential vapor-phase tracer candidates for geothermal application in laboratory oven tests at low concentrations in water and in the presence of reservoir drill cuttings. The tests were run at 250 to 280 ºC for up to 1 week. Testing had to be accelerated given the time-line required for field implementation, so the oven tests were not a rigorous evaluation of tracer properties. However, two new hydrofluorocarbons decayed within 24 hours at 250 ºC and were immediately eliminated. The two PFC's tested had no detectable decay at 250 ºC for several days and no significant decay at 280 ºC after 1 week. This was considered acceptable for field implementation given the reservoir temperature at Darajat is only about 240 ºC.

The vapor-phase tracers selected for this test were tetra-fluoroethane (HFC R-134a), perfluoromethylcyclopentane (PMCP) and perfluoromethylcyclohexane (PMCH). The HFC compound R-134a has a significant solubility in water, about 1500 ppm_w, while the PFC's are very insoluble, probably less than 10 ppm_w. In order to ensure there is no early gas "breakout" or phase separation of the vapor tracers before they reach the injection horizon in the reservoir, they are typically injected at rates that result in concentrations in the injection water below their solubility limit at the surface injection pipeline pressure and temperature conditions. However, a vacuum often exists at the injection wellhead for cold water injectors, so the vapor tracers may not actually be fully dissolved until some distance down the wellbore as pressure rises above vacuum. The relatively high solubility of R-134a allows reasonable injection rates over time intervals of a few hours for quantities on the order of several hundred kg. But PFC's would require very low injection concentrations (<10 ppm) and much longer injection intervals, even for quantities of only 10 or 20 kg PFC, because their solubility is 2 orders of magnitude less than HFC's.

It is important to inject tracers over the minimum time interval possible, providing an ideal injection "pulse" that is easier to interpret in the return curves, and return concentrations that are higher and more likely to be detected. Therefore, efforts were made to increase the solubility of the PFC's in the injection water to facilitate their use. Lab bench tests were run by TCI to find mixtures of solvents that could emulsify the PFC's at concentrations of 10% by weight, in mixtures consisting of at least 50% water, to be used as the concentrated tracer emulsion to be pumped into the well. These emulsions were then tested to ensure they could maintain a homogenous 1% concentration in a solution of 90% water for at least 24 hours. An emulsion chemistry was found that met these criteria and was used to inject the PFC tracers at concentrations of 30 to 40 ppm in the injection water. Without proper emulsification, the PFC's would have separated from water given their high density and may have remained in surface piping and/or passed into the injection horizons as a separate liquid phase in concentrated slugs.

A new analytical method was developed to lower the detection limit for the alcohols. Prior techniques were only sensitive to 0.1 – 0.5 ppm at best in actual geothermal steam condensate, which often contains light hydrocarbons that interfere with the analysis. The Solid Phase Microextraction (SPME) technique for absorption of organic compounds in headspace gas, Mella, et al. (2006), was shown to be not specific and sensitive enough for tracer tests at The Geysers, Wright (2008). Therefore very large quantities of alcohol must be injected in order to generate measureable return curves. By employing a more selective concentration technique coupled with mass spectrometry (GC/MS), detection limits were reduced to 0.01 ppm with very clear and reliable identification of the alcohol tracers. Although the sensitivity of the vapor-phase tracers is still much higher, the "detectability", expressed as the ratio of concentration detected in the produced fluid to initial concentration in the injectate (C/Co), was in the same range for all tracers used in the Darajat multi-phase tracer test.

An unexpected benefit of the new alcohol analytical method was the detection of the breakdown product of IPA. Initial analyses had shown very low IPA recoveries compared to alcohols from other wells and the PMCH used in the same well. Further work identified acetone (AC) in the samples where IPA and PMCH were detected, and the sum of IPA plus AC (IPA+AC) produced a reasonable return curve. Although IPA is known to be less stable than NPA and NBA, the breakdown of IPA to acetone has never been reported in a geothermal tracer test. The breakdown of IPA in the very few geothermal reservoir tracer tests conducted probably did occur, but was just never detected.

The two PFC's, HFC R-134a and three alcohols were injected during early December 2008, as pairs of vapor- and two-phase tracers into three injection wells. A total of 20 production wells were monitored, including all the new make-up wells that had been put on-line to the steam gathering system. The tracer monitoring after injection was conducted for over 180 days in order to fully characterize some late return peaks. The primary tracer injection and recovery parameters are listed in Table 1.

3. TRACER RETURN CURVES AND BOILING FRACTION ANALYSIS

The shape of the Darajat return curves (Fig. 1-3) were all very similar to those seen in the water-saturated regions of The Geysers (Bear Canyon, Fig. 4), with the exception of DRJ-17. This well peaked at 135 days. The fractions of each tracer recovered were similar for the different types of tracers, with the exception of PMCH and IPA+AC. Approximately 25% of each of the vapor tracers was recovered (Freon, PFC), and a few percent or less of the two-phase tracers (alcohols). PMCH and IPA+AC were anomalous in their high recoveries of 31 and 41%, respectively. Since PMCH peaked at 135 days with 31% recovery, the expected exponential decline suggests its eventual recovery may exceed 37%.

Tracers of differing solubility were used to extend the range of boiling fraction that could be tagged as injectate traveled through the reservoir. An additional benefit is that the ratios of these tracers in each sample can be used to calculate the fraction of boiling that volatilized the tracers from the injectate into the steam reservoir. The ratios of the tracer pairs (normalized by the injection mass ratio) are plotted above the return curves in Figures 1-3. It can be seen that the ratios of the tracers injected into DRJ-3 (R-134a and NPA) slowly rise and peak late, at about day 80. The normalized values range from 11 to 84, although most are below 40. In contrast, the ratio of the tracers injected into well DRJ-12 spiked quickly, between day 20 and 25, and rapidly decrease. Their values range from near 0.02 to 75. The ratios injected to DRJ-15 rose from 0.0005 on day 5 to 24 on day 135 (recovered from well DRJ-15).

Table 1. Summary of Tracer Chemical Injection and Recovery Parameters

Injection Well	Injection Water Rate	Tracer Name	Amount Injected	Concentration in Injection Water (Co)	Detection Limit (C)	Detection / Injection Ratio C/Co	First Return	Avg. Peak Return	Tracer Recovery
DRJ-3	19.2 lps	R-134a	270 kg	660 ppm	5E-03 ppm	7.58E-06	6 days	20 days	27 %
DRJ-3	19.2 lps	NPA	2145 kg	37250 ppm	1E-02 ppm	2.68E-07	7 days	20 days	3 %
DRJ-12	54 lps	PMCP	24 kg	35 ppm	1E-05 ppm	2.86E-07	6 days	23 days	23 %
DRJ-12	54 lps	NBA	2145 kg	16551 ppm	1E-02 ppm	6.04E-07	7 days	17 days	0.65 %
DRJ-15	45 lps	PMCH	25 kg	37 ppm	5E-05 ppm	1.35E-06	3 days	135 days	31 %
DRJ-15	45 lps	IPA	2080 kg	15407 ppm	1E-02 ppm	6.49E-07	5 days	25 days	41 %

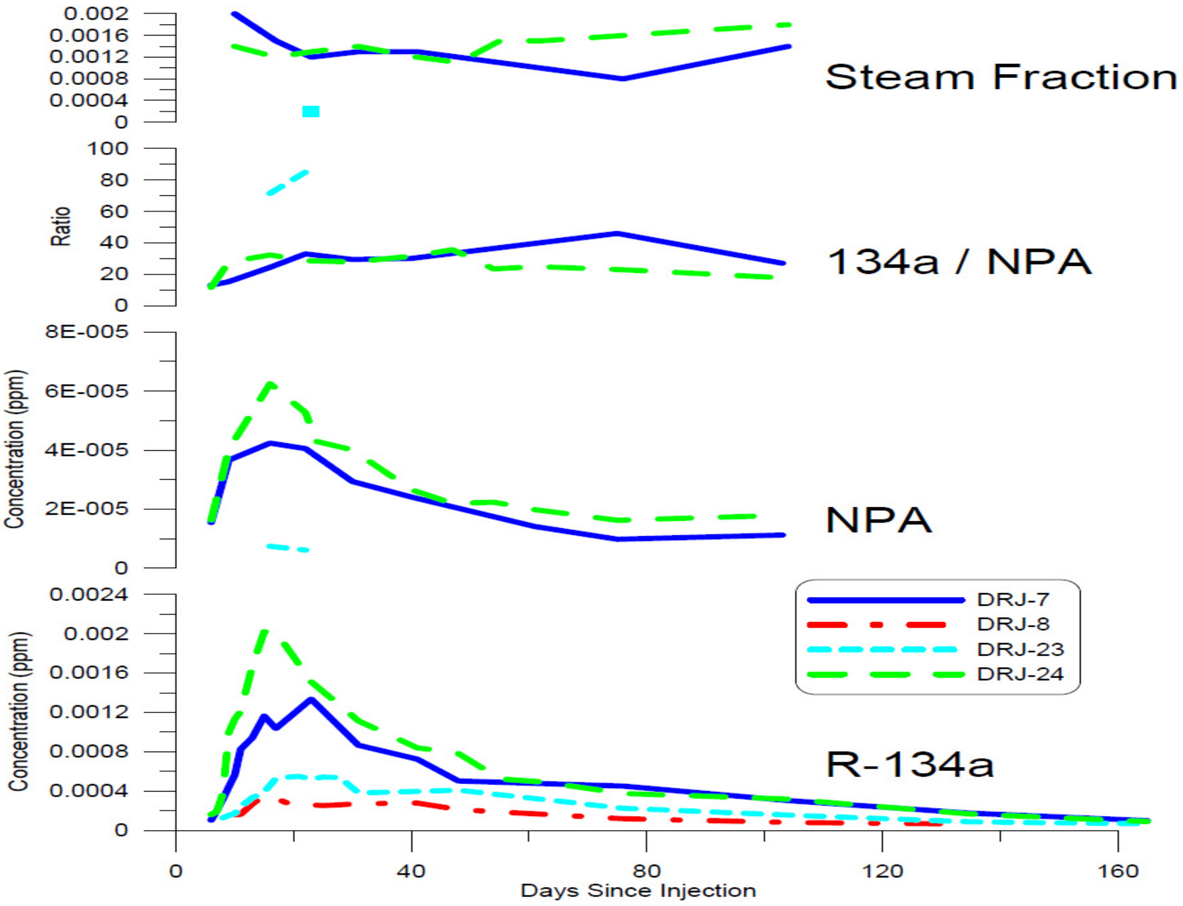

Figure 1. Return curves, normalized tracer ratios, and calculated steam fractions for the tracers injected into well DRJ-3.

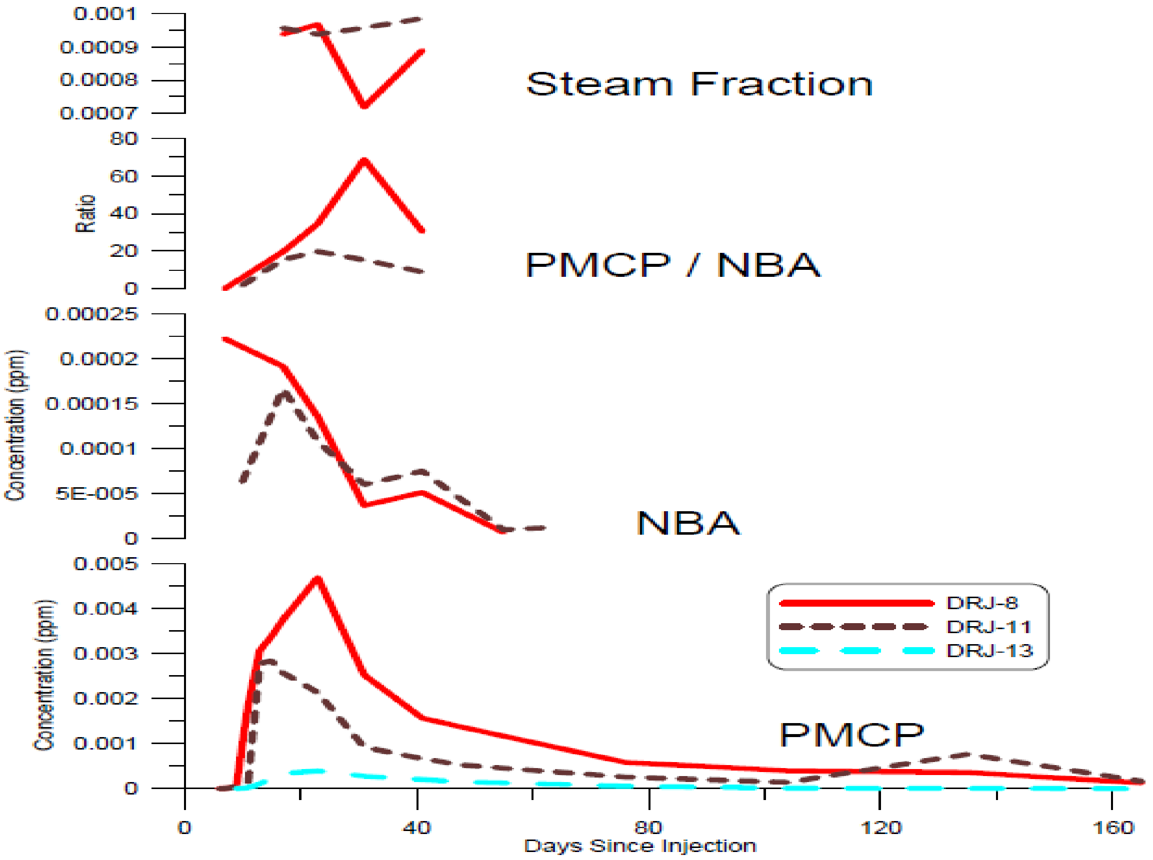

Figure 2. Return curves, normalized tracer ratios, and calculated steam fractions for the tracers injected into well DRJ-12.

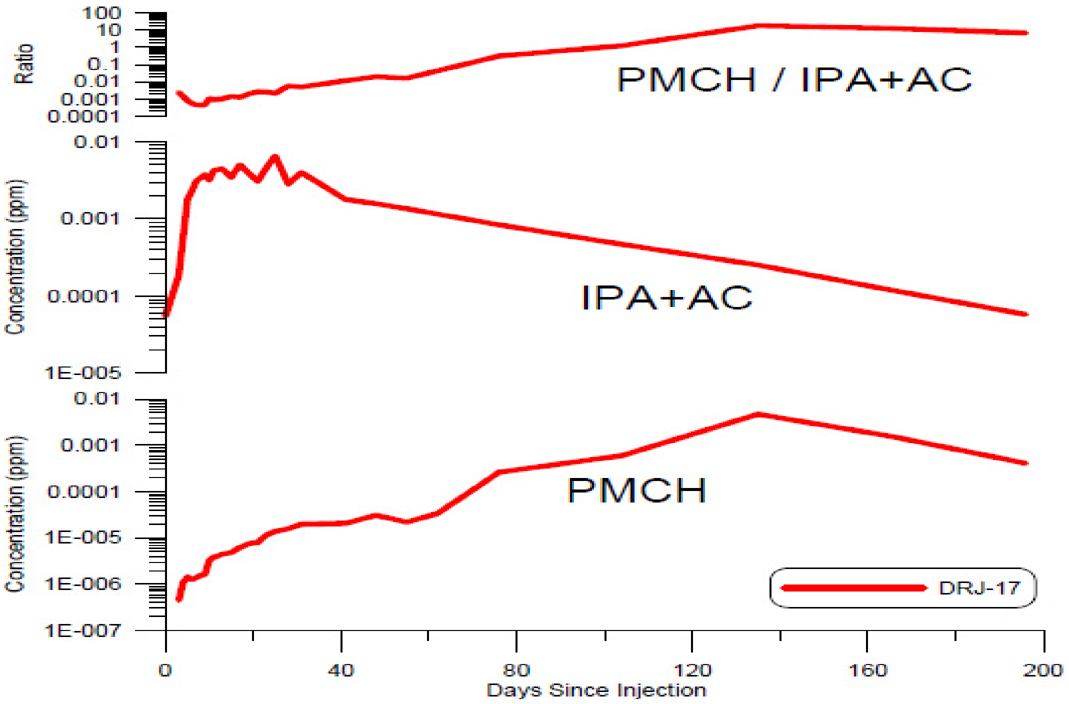

Figure 3. Return curves and normalized tracer ratios for the tracers injected into well DRJ-15.

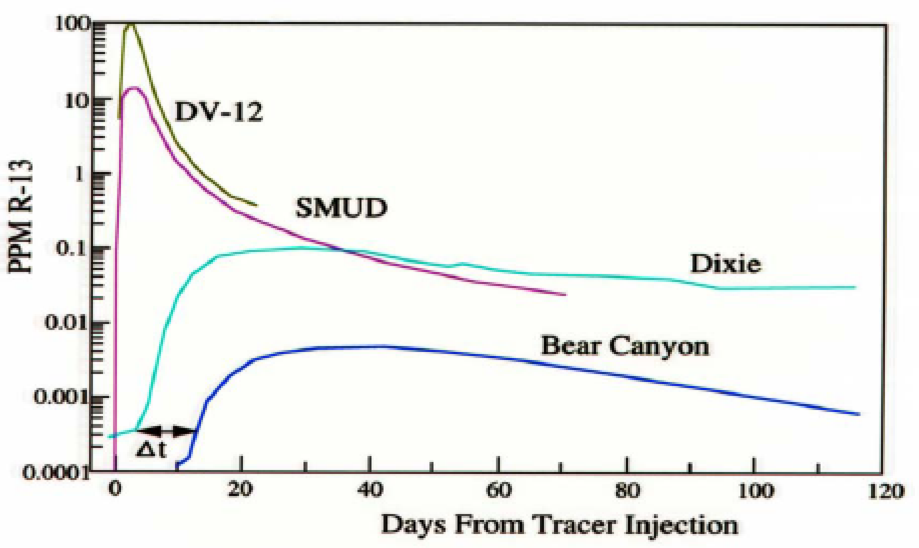

Figure 4. Examples of return curves from The Geysers (Dixie Valley, Liquid-dominated field, shown for reference).

The use of tracer pairs has the potential to reveal differences in the behavior of individual injection wells, and the different patterns of the tracer ratios in each of the injection wells in this test demonstrate that. At the present time only the boiling fractions can be calculated with certainty. However, as more of these tests are performed and interpreted, and the tracer properties quantitatively determined by rigorous lab tests, they will provide a wealth of information on subsurface fluid flow.

The ratio data from the tracer tests were compared to the results of boiling models to obtain estimates of the steam fraction at which they were released. The boiling scenarios examined were single-stage, continuous, and multiple-stage, using the methodology of Adams et al. (2001). The distribution coefficient for R-134a was taken from Adams and Kilbourn (2000) and those for NPA and NBA from Adams et al. (2004). Distribution coefficients for PMCP, PMCH, and IPA and AC were estimated based on available literature data and extrapolation to higher temperatures.

The model results and the ratio data for the tracer pair R-134a and NPA injected into DRJ-3 are shown in Figures 5-7. The steam fractions derived from the models are also included in Figures 1-2 and listed in Table 2. Note the tracer ratios are not normalized in Tables 2 and 3.

Table 2. Steam Fractions Calculated from Ratios of Tracer Pairs R-134a/NPA

DRJ-07 days	Ratio 134a/NPA	Steam fraction	DRJ-23 days	Ratio 134a/NPA	Steam fraction	DRJ-24 days	Ratio 134a/NPA	Steam fraction
7	0.23	0.0022	17	1.27	0.0004	7	0.21	0.0023
10	0.27	0.0020	23	1.51	0.0002	10	0.50	0.0014
17	0.43	0.0015				17	0.57	0.0012
23	0.58	0.0012				23	0.51	0.0013
31	0.52	0.0013				31	0.49	0.0014
41	0.53	0.0013				41	0.56	0.0012
76	0.82	0.0008				48	0.63	0.0011
104	0.48	0.0014				55	0.42	0.0015
						62	0.44	0.0015
						76	0.41	0.0016
						104	0.32	0.0018

Table 3. Steam Fractions Calculated from Ratios of Tracer Pairs PMCP/NBA.

DRJ-08 days	Ratio PMCP/NBA	Steam fraction	DRJ-11 days	Ratio PMCP/NBA	Steam fraction
7	6.0E-05	0.0020	10	0.005	0.0014
17	0.055	0.0009	17	0.043	0.0010
23	0.097	0.0009	23	0.055	0.0009
31	0.193	0.0007	31	0.043	0.0010
41	0.085	0.0009	41	0.025	0.0010

Figure 5 shows the predicted concentrations of the tracers in the liquid and steam phases at the time of boiling as a function of the steam fraction. This single-stage model, Henley (1984), represents the single-stage boiling process, which models a closed system- essentially a large chamber is which the liquid is always in equilibrium with the steam, and no tracer can escape. The difference in solubility of the two tracers is evidenced by the drop in concentration of R-134a, while NPA holds relatively steady. This is reflected by the ratio shown in the top plot, which drops with increasing steam fraction. The drop is not rapid because this is a closed system, and the ratio change is from dilution by the later boiling NPA. In open, continuously boiling systems, as discussed below, the ratio drop is much more rapid due to escape of the less soluble R-134a out of the open system.

A completely open system with infinitely small boiling steps is modeled by continuous boiling, Drummond (1981). It can be seen in Figure 6 that the steam fractions are much smaller for a given ratio drop. Both single-stage and continuous boiling are considered to be end-members of what actually happens under most geological circumstances, Drummond (1981).

The multiple-stage model (Figure 7 and 8) is a compromise between the single-stage and the continuous boiling model, Henley (1984). It is an open system, but with boiling-step sizes and the number of steps finite and specified. This model was used to calculate the steam fractions shown in Figures 1-2. For consistency, the step size was chosen by lowering it until the first step matched the highest measured ratio of the tracer test data, in this case the data from DRJ-23. The number of steps was increased until the range of the measured ratios was covered.

The highest ratio in the data set is a significant quantity. The theoretically highest ratio can be calculated from an infinitely small step size. There was a question when processing the data as to whether to use the injected concentration ratio or the injected mass ratio of the injected tracers. They were not identical because of practical considerations in injecting tracers with very different solubility. The theoretically highest ratio calculated from the injected concentrations was compared to the tracer test data, and it was found that the data exceeded this ratio. This indicates that the slug of two-phase tracer (alcohol) surrounded by a longer slug of vapor tracer (HFC, PFC) may have homogenized during transport in the steam. When the data was adjusted to the mass ratio, they fit well with the theoretically maximum ratio. The result of this adjustment was not significant in terms of the calculated steam fraction. The difference in time scale for injection of each tracer was therefore not significant, which simplifies the interpretation.

The steam fractions calculated from the multiple-stage boiling model for the DRJ-3 and -12 tracers are shown versus time in Figure 9 and listed in Tables 2 and 3. They declined rapidly early in the test, then leveled off, and finally increased towards the end. In general, the behavior and magnitude of injectate boiling from wells DRJ-3 and DRJ-12 are very similar.

The tracers injected into DRJ-15, PMCH and IPA+AC, were only slightly different in chemical properties from those injected into DRJ-12. However, their returns into DRJ-17 cannot be simulated with the simple models used for DRJ-3 and -12. As Figure 10 shows, the return curves from DRJ-17 are in stark contrast to the others in this test.

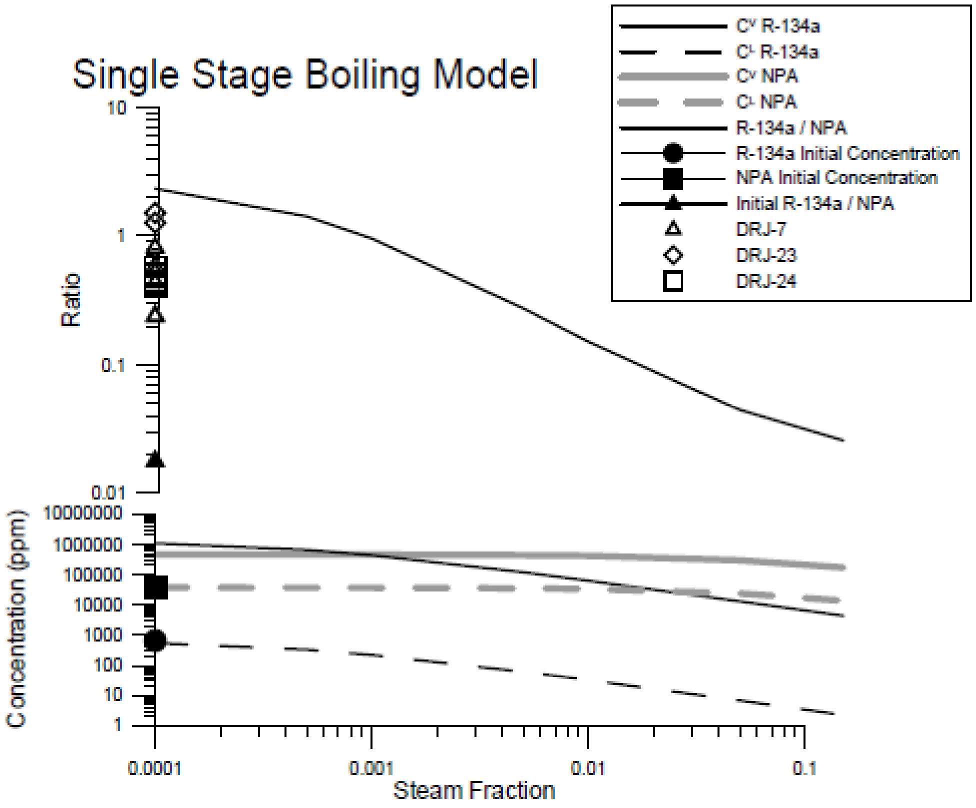

Figure 5. Simulation results for single-stage boiling of the tracer slug injected into DRJ-3.

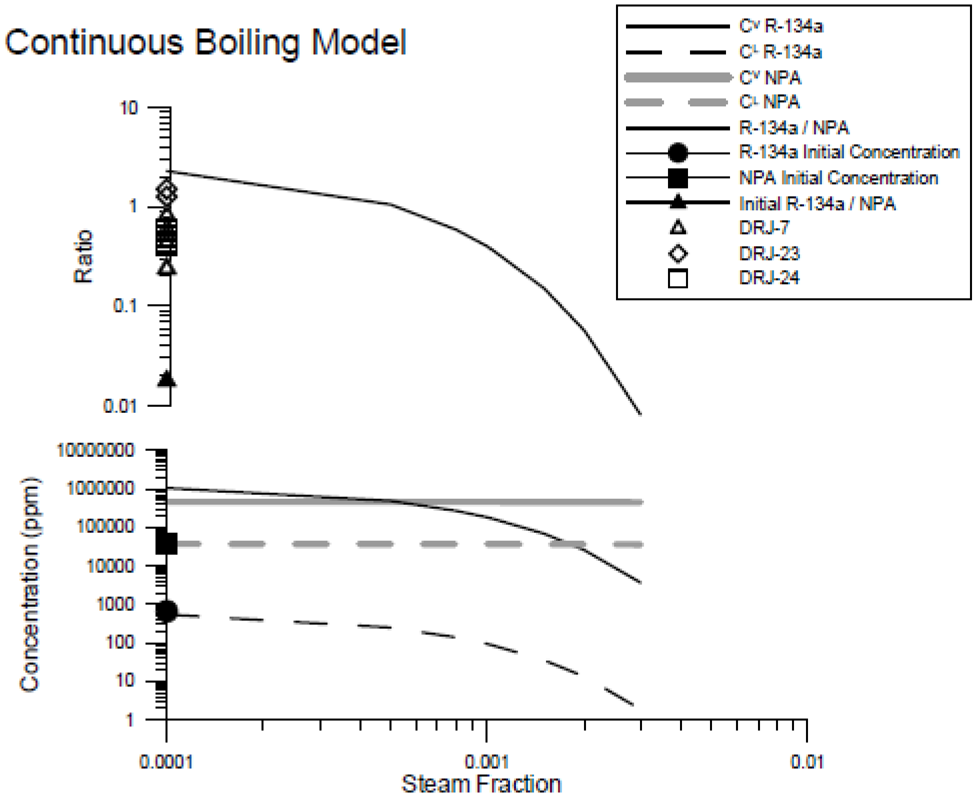

Figure 6. Results of a simulation of continuous boiling of the tracer slug injected into DRJ-12.

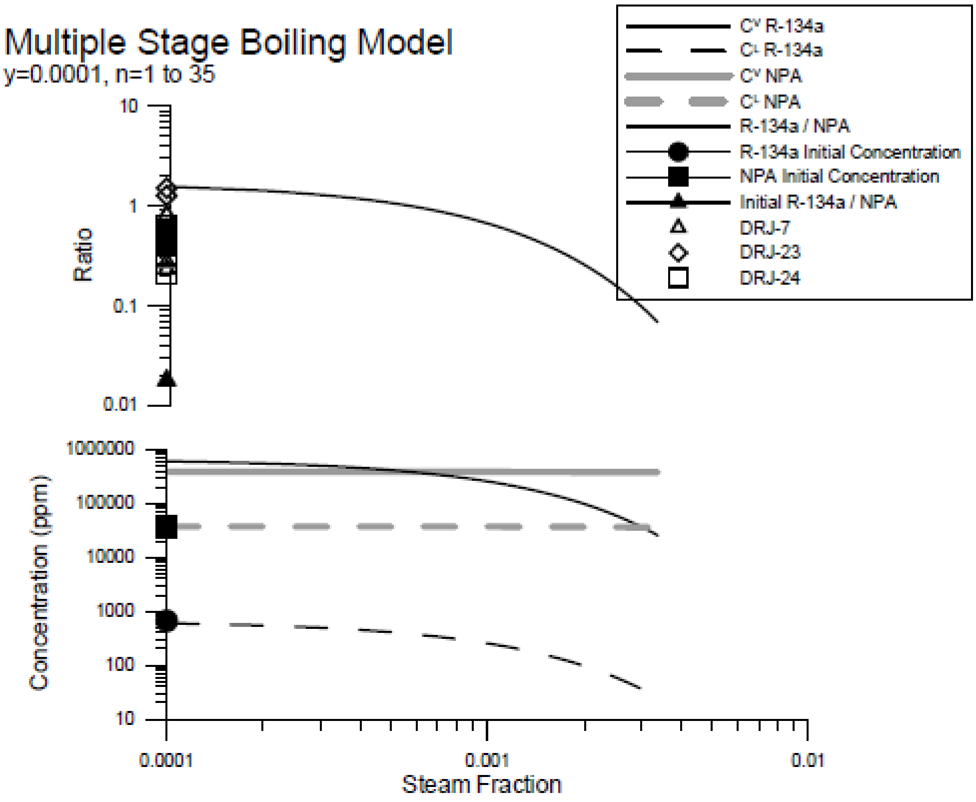

Figure 7. Results of a simulation of multiple-stage boiling of the tracer slug injected into DRJ-3.

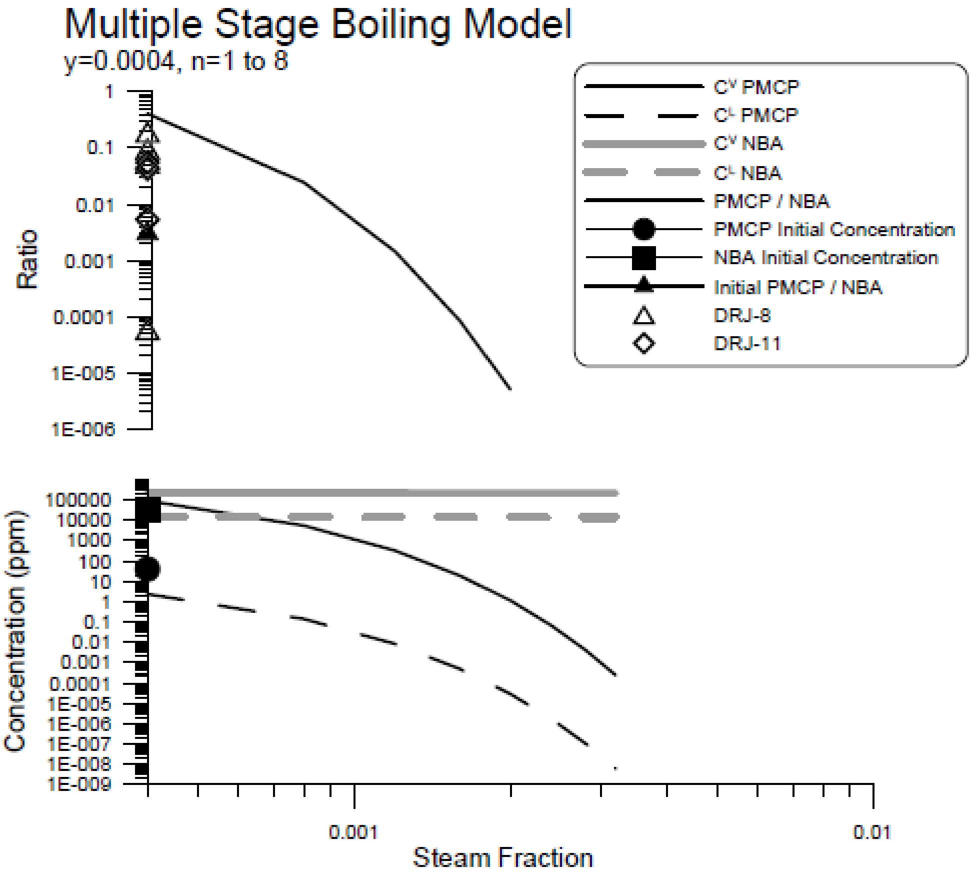

Figure 8. Results of a simulation of multiple-stage boiling of the tracer slug injected into DRJ-12.

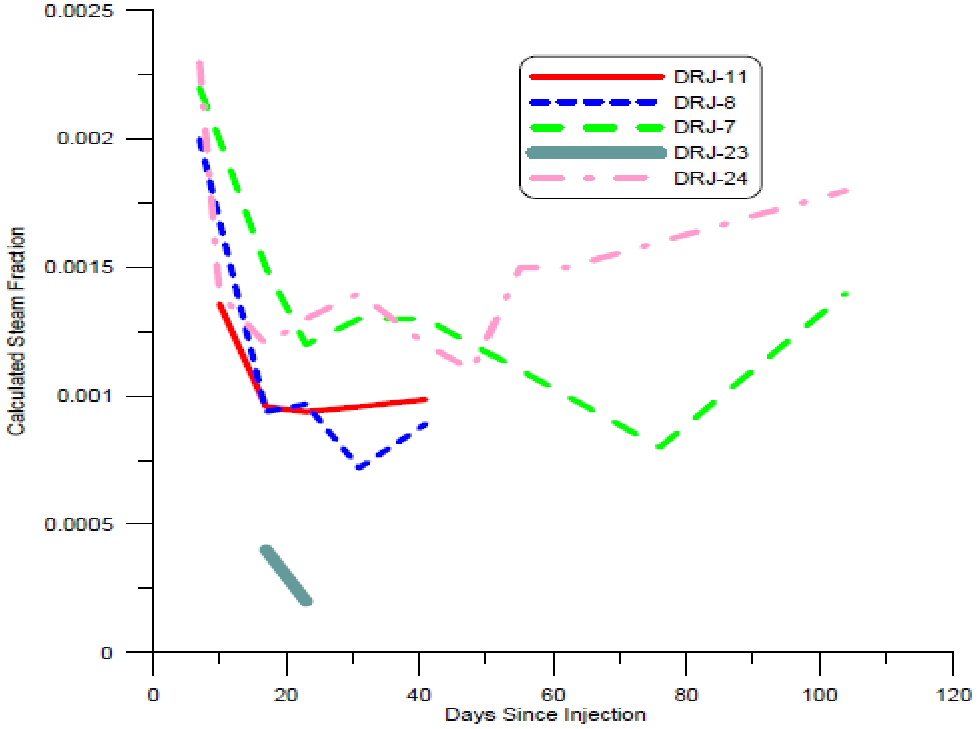

Figure 9. Comparison of steam fractions using the multiple-stage boiling model for R134a/NPA and PMCP/NBA tracers

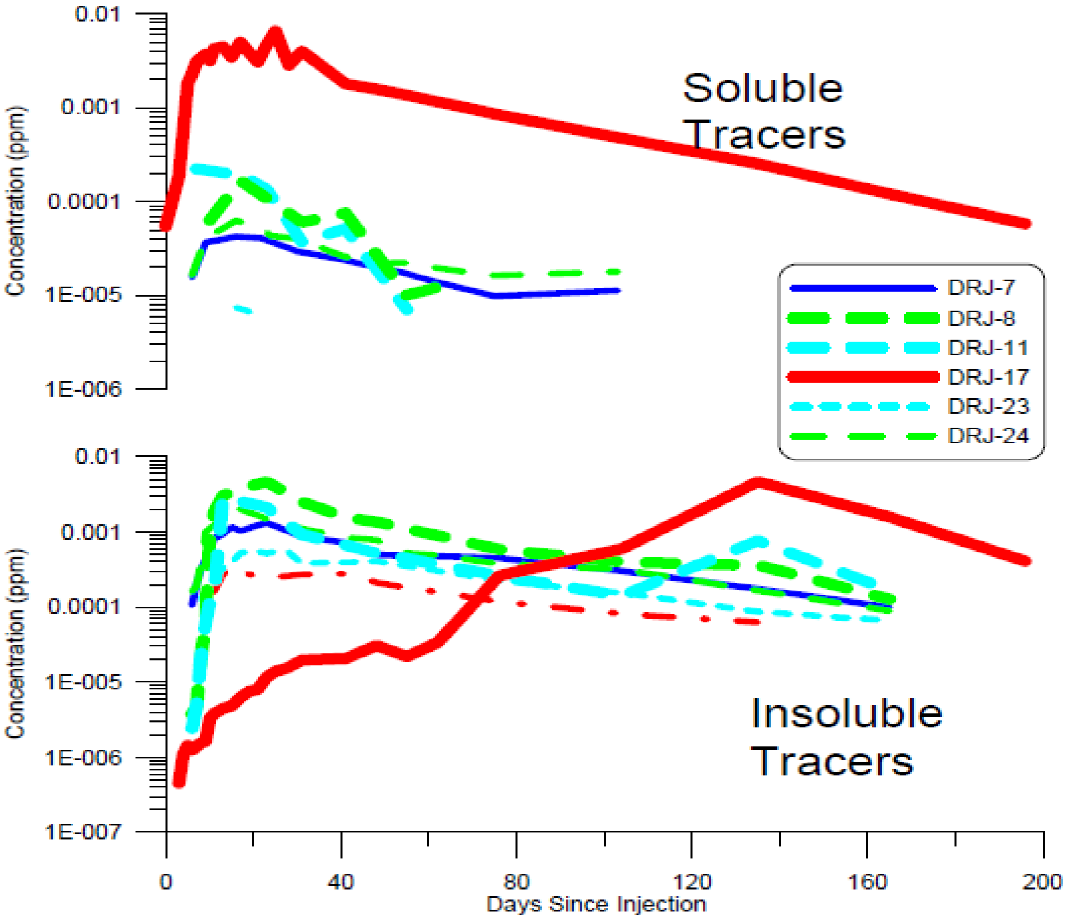

Figure 10. Comparison of all return curves. “Soluble Tracers” are alcohol, “Insoluble Tracers” are Freon and PFC.

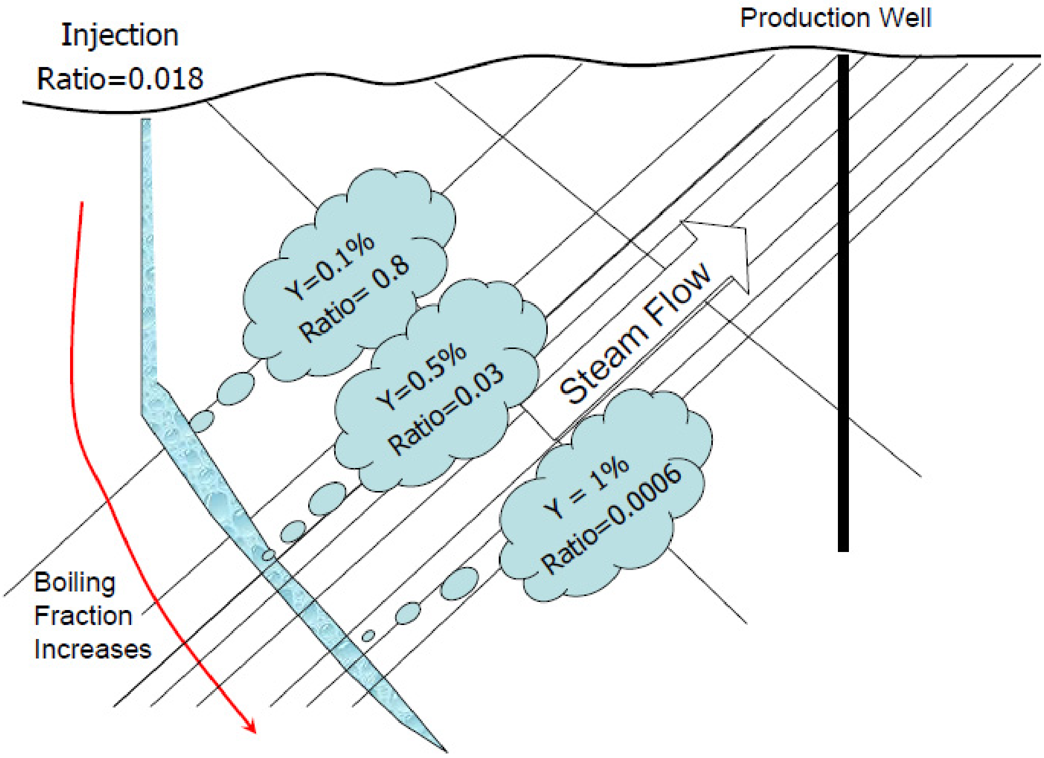

Figure 11. Schematic representation of the multi-stage boiling model used to calculate steam fractions for DRJ-3.

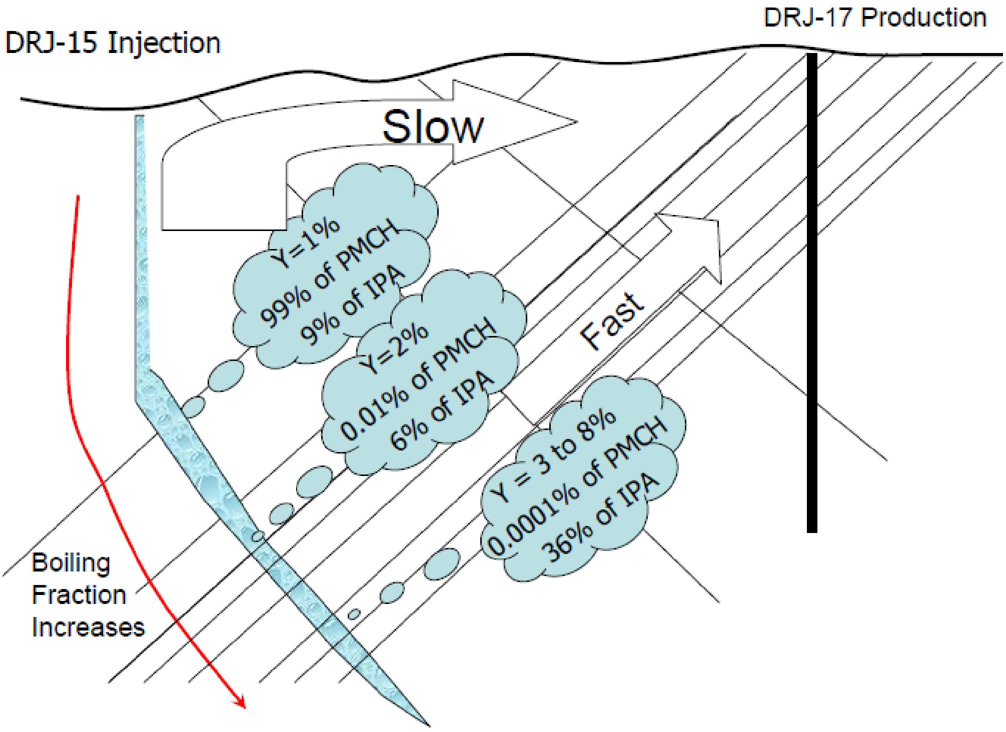

Figure 12. A schematic of the decoupling mechanism for the tracers injected into DRJ-15.

The soluble tracer IPA+AC is very high at the beginning of the test, while the less soluble vapor tracer PMCH is very low and then increases throughout the test (PMCH finally peaked on day 135). The increase with time in these ratios (Fig. 3) is the reverse of what boiling would produce. This discrepancy, plus the separation of the two-phase and vapor tracer peaks by over 100 days, indicates that the return curves were decoupled. A plausible mechanism for this would be two sets of fractures, either intersecting the injection well or out in the reservoir, each connecting to parts of the reservoir that are isolated from each other in some way. The injection fluid would have boiled at the first set encountered and lost from 1 to 10% of the tracer slug. As little as 1% boiling would have removed 90% of the PMCH, producing the very low ratio in the remaining fluid recorded by the early samples from DRJ-17. The upper limit, 8%, is the steam fraction in which 41% of the IPA/AC is left in the liquid phase (i.e., 41% of the IPA/AC was actually recovered before significant PMCH was produced).

The upper limit is an unlikely scenario but is included for the sake of completeness. Subsequent intersections allowed the remaining IPA/AC-rich fluid to boil and flow quickly to DRJ-17. The velocity of the alcohol slug was similar to alcohols injected into DRJ-3 and -12. The concentrations, however, were much higher (Figure 10). The vapor-tracer, PMCH, in contrast, traveled at a much reduced rate to the production well DRJ-17, taking over 5 times as long to peak. The peak concentration of PMCH was very high, as high as the vapor tracer peaks generated from injection wells DRJ-3 and DRJ-12. Considering that time is proportional to dilution in tracer transport, as illustrated in Figure 4, the connection of the first fluid entries (exits) in DRJ-15 to DRJ-17 is also very strong.

Unfortunately, the boiling fractions cannot be calculated from the ratio of the two tracers injected into DRJ-15 because they were decoupled. However, it can be calculated that 1% of the injectate boiled at the first fracture set to lose 90% of the PMCH, and 8% must have boiled from the remaining fluid to recover 41% of the IPA/AC. If it is assumed that the first appearance of tracer in DRJ-17 is only due to the “second boiling” in which the alcohol is the main tracer, the ratio calculations yield a steam fraction of a few percent. The multi-stage boiling process modeled for injection wells DRJ-3 and DRJ-12 is illustrated in Figure 11, and the decoupled process assumed to occur in DRJ-15 is illustrated in Figure 12.

4. CONCLUSIONS

A new class of vapor-phase tracers, PFC compounds, was demonstrated in the lab and field to provide comparable results to HFC tracers, with the potential for use at much higher temperatures. In using a new analytical technique for alcohol tracers, Isopropanol was shown to rapidly breakdown to acetone at 240 ºC, but including the breakdown product still provided useful results. By combining vapor and two-phase tracers in the same injection wells, boiling fractions can be estimated.

The injection wells DRJ-3 and DRJ-12 appear to be functioning very similarly. They both provide about a tenth of a percent of their mass as steam to the production wells before merging with the liquid reserves of the reservoir. The transit times and tracer peaks are also very similar, although the two-phase tracer indicates that DRJ-12 has a somewhat stronger connection. The relatively long tracer arrival times and low steam fractions suggest high water saturation in the regions tested by these two wells. The rapid peak return in DRJ-8 for alcohol injected into DRJ-12 may be predictive of thermal and injection water breakthrough to this well.

The relatively high fraction of steam provided to DRJ-17 by DRJ-15 may reflect the extremely high output of that well. Cooling and liquid breakthrough are possible with so much boiling close to the production well, but the injection well DRJ-15 may be critical to DRJ-17 production. This relationship could be managed and optimized.

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