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NATURAL GEOCHEMICAL
TRACERS FOR INJECTATE FLUIDS AT DIXIE VALLEY

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ABSTRACT

Since September 1988 over 334.5 x 10^9 pounds of flashed brine have been returned to the Dixie Valley geothermal reservoir through three injection areas. As a result of the dual flashing process, the injected fluid is enriched in chloride and the heavy water isotopes and depleted in noncondensable and noble gases relative to the produced fluids. Chloride contents and heavy water isotopes of both produced fluids and injectate have significantly increased over the lifetime of the field, indicating substantial returns of injectate to the production wells. The water isotope data on pre-production reservoir fluids do not support the possibility that the changes in chloride concentration are caused by inflow of nearby indigenous chloride-rich water.

Noble gas concentrations, first obtained in 1997, further support the chloride and water isotope interpretation, indicating that they can be used confidently to quantitatively assess the recycling of injectate fluids. In the Section 7 area there is an apparent continuous recycling of injectate, increasing at 5-7% per year. Currently, the Section 7 wells produce a fluid that is between 60 and 100% recycled injectate, which when combined with the total volume fluid injected provides a very simple estimate of the circulating fracture volume of ~0.12 km^3. Assuming these fractures account for ~1% of the overall reservoir, the reservoir volume in the Section 7 area is ~12 km^3. In the Section 33 part of the field chloride concentrations increased over the first 4 years of production, suggesting that as much as 60% of the produced fluid was recycled injectate. Since then chloride has steadily decreased, such that currently only 37% of the production fluid can be recycled injectate.

INTRODUCTION

Injection of spent production fluids back into the geothermal reservoirs from which they are produced is now widely recognized as the single most important factor in maintaining reservoir pressure and extending the productive lives of geothermal fields. Growing environmental awareness throughout the world also requires that spent geothermal fluids be returned to the reservoir to protect surface and subsurface water sources. Injectate is always colder than reservoir fluids so eventually returning injectate will cool individual production wells and entire reservoirs. The timing of the onset of cooling has ranged from weeks or months in a worst case to decades, or perhaps longer, in rare instances. To predict the likelihood or onset of cooling resulting from injection, it is necessary to develop reliable quantitative techniques to determine the volume of injectate co-produced with the indigenous reservoir fluid and the rate at which the injectate return increases. Ideally these techniques should be applied to reservoirs at the start of production so that baseline conditions are documented and maximum predictive advantage can be obtained.

Numerical models and operating experience have shown that cooling will be preceded by chemical changes, often by a significant amount of time (Pruess and Bodvarsson, 1984). Fluid chemistry is more sensitive than temperature to the emergence of injectate returns in produced fluids. Natural conservative tracers, such as chloride, have long been utilized to monitor injectate returns in production wells.

The Dixie Valley geothermal field in west central Nevada has now operated for 10½ years and over this time its chemistry has been thoroughly documented with quarterly brine (Benoit, 1992), annual noncondensable gas samples (Benoit and Hirtz, 1994), and intermittent stable isotope analyses. In the past two years, analyses of noble gases and their isotopes have been obtained to give a complete evaluation of the available natural chemical tracers in a well documented geothermal field. These data allow: (1) an evaluation of the reliability and limitations of the various natural chemical tracers, (2) a quantitative assessment of the volume of injectate co-produced with indigenous reservoir fluid, (3) the rate at which injected fluids are replacing indigenous fluids, (4) an estimate of the reservoir volume, and (5) an estimate of the relative flux of indigenous fluid into the reservoir (i.e., natural recharge).

DIXIE VALLEY INJECTION HISTORY

Injection of spent brine into the Dixie Valley geothermal reservoir began in September 1988, about 3 months after the field commenced production. Fluid is injected into three geological environments (Figure 1): the shallow range-front fault at depths near 6000 ft in Section 5, the range-front fault at depths of 9000 to 10,000 ft in Section 18, and a Miocene basalt aquifer overlying the southern part of the main reservoir at depths of 7200 to 7400 ft in Section 18 (Benoit, 1992). Injection has been more or less continuous during the following 10 years with no major changes in injection locations or in ratios of fluids injected into three different environments.

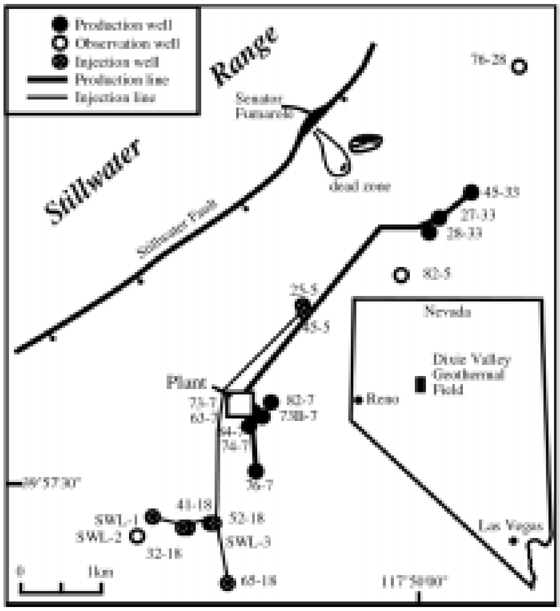

Figure 1: Map showing the location of the Dixie Valley geothermal system, Nevada.

Over the field lifetime, the fluid production rate has averaged about 45 x 10^9 pounds per year. Injection rates gradually increased from 20 x 10^9 pounds in 1989 to about 35 x 10^9 pounds in 1992. Starting in 1997, increased water conservation efforts have increased the injection rate to 37 x 10^9 pounds per year.

Six successful tracer tests in the past 2½ years have conclusively demonstrated that injectate from all three injection environments returns to Section 7 production wells (Rose, 1998). Initial returns for these tracer tests ranged from 25 to 90 days and peak return times varied from 100 to a little over 200 days. No tracer has ever been recovered in any of the production wells located in Section 33.

During the first three years of injection only spent brine was returned to the reservoir. The condensed steam which overflowed the cooling tower was discharged on the surface. In September 1991 injection of the condensed steam began. The condensed steam amounts to an annual average of 300,000 lbs/hour while the rate of injected spent brine is about 3,900,000 lbs/hr. Therefore the condensed steam amounts to about 7.1% of the total injectate. However, pumping limitations reduced the injection of condensed steam to about 250,000 lbs/hr between Sept. 1991 and early 1997. Since early 1997 an annual average of about 300,000 lbs/hr of condensed steam has been injected.

In mid 1997 an injection augmentation program was implemented and over the next year and a half two billion pounds of cold shallow groundwater was injected directly into the reservoir via the 32-18 and 65-18 injection wells. Injection augmentation rates have intermittently varied from about 200,000 to 425,000 lbs/hr.

Overall, the injectate fluid remains dominated by the spent brine. Therefore, it is distinguished relative to the production fluid by being enriched in chloride, ^{18}O and D, and strongly depleted in non-condensable gases.

CHLORIDE CONTENTS

Under geothermal conditions, chloride behaves as a conservative species remaining in the liquid phase during boiling. For this reason it has been widely used as a tracer for injectate. The increase in chloride concentration in the spent brine is proportional to the steam fraction. At Dixie Valley, the dual flash process results in a steam fraction of about 25% so the spent brine chloride concentration is about 1.33 times the preflash concentration. The spent brine is combined with condensed steam from the cooling tower overflow, producing an average chloride concentration for the injectate of 1.20-1.27 times the preflash concentration. This magnitude of enrichment is easily measured by commercially available laboratory techniques.

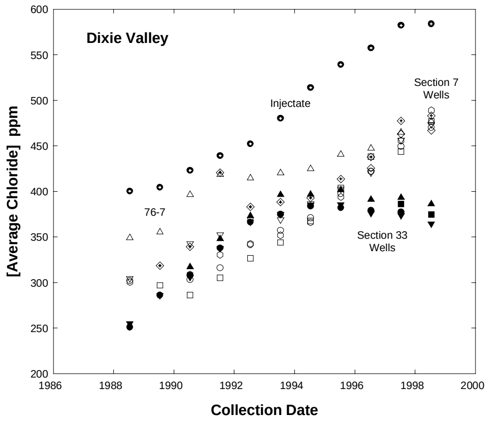

Figure 2: Yearly average chloride concentration in production streams from individual wells and the injectate fluid: injectate, solid circles with cross; open symbols, Section 7 production wells; solid symbols, Section 33 production wells.

Figure 2 shows the yearly average chloride contents for both production and injection wells. It only took six to eight months from the start of injection for the chloride content of the Section 33 production wells to increase. Once the increase began, it approximately paralleled the rate of chloride increase in the injectate. In Section 7 there was much greater diversity in early chloride trends among the individual wells. For instance, the chloride content in well 76-7 almost immediately began to increase. Tracer testing documented a rapid return of injectate from well 32-18 to well 76-7 of 9.3 days for initial returns (Adams et al., 1989). In well 82-7 chloride contents actually declined for a year before starting to increase. This suggests that during its first year of production well 82-7 was drawing on a source of relatively low chloride water (maybe the fluid that initially supplied the Section 33 wells) as opposed to the higher chloride injectate.

During 1991 and 1992 the chloride content of all production wells was increasing and closely paralleling the injectate chloride content. However, after 1993 the Section 33 chloride contents stopped increasing and for the past few years have actually been slowly declining. After initially diverging in 1988 and 1989 the Section 7 well chloride contents have more or less converged on a single chloride content. This suggests that mixing of injectate with a relatively large volume of indigenous fluid occurred in Section 7. It took 7 to 8 years to rehomogenize the chloride contents in this section. Attempts to use multiple regression analysis modeling techniques on the Dixie Valley chloride trends were unsuccessful due to a lack of sufficient time variability (Sullera and Horne, 1999).

These general chloride trends and tracer testing results are consistent with co-production of substantial amounts of injectate and a high degree of connectivity between the injection and production wells. However, the validity of the chloride interpretations relies on the assumption that there is only one indigenous geothermal fluid entering the reservoir or individual wells. This assumption is probably not valid at Dixie Valley as every part of the reservoir that was chemically sampled prior to the onset of injection (Section 33, Section 7, deep Section 18, shallow Section 18, and Section 5) had a different chloride content. Preflash chloride contents ranged from 250 ppm (in Section 33) to 400 ppm (in Section 5). The initial in-place-volume of each of the fluids is not known. The Dixie Valley reservoir has an inverse chloride/enthalpy relationship, i.e., the cooler waters have progressively higher chloride contents.

Therefore, increasing chloride concentrations observed over time at Dixie Valley need not reflect only injectate returns. Any inflow of cooler indigenous water would also increase chloride concentrations. Other chemical tracers are needed to discriminate between these possibilities.

WATER ISOTOPES

At Dixie Valley the stable isotopes of water appear to be suitable tracers for differentiating between injectate returns and influx of cooler indigenous water to the production wells. Fortunately, the production fluids at Dixie Valley were extensively analyzed for stable isotopes in 1986, two years before any fluid was injected into the reservoir. These base line data showed that there was virtually no variation in the pre-flash δD values (average: -132‰) and only 0.5‰

range in δ^{18}O values (-15.0 to -14.5‰) between the Section 33, Section 7, deep Section 18 and shallow Section 18 areas of the reservoir (Figure 3). The deuterium contents of the indigenous fluids were independent of enthalpy, whereas ^{18}O contents increased with declining enthalpy. Unfortunately no pre-injection stable isotope data are available from the Section 5 area.

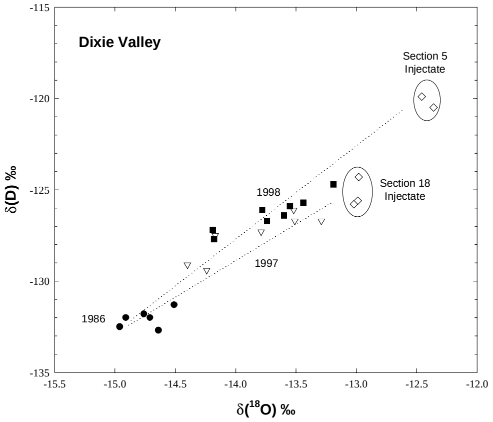

Figure 3: The pre-production 1986 water isotope composition (solid circles) compared to that in 1997 (open triangles), 1998 (solid squares), and 1997-1998 injectate (open diamonds).

During the dual flash process at Dixie Valley, the light water isotopes (^{16}O and H) are preferentially partitioned into the steam fraction, leaving a residual brine enriched in the heavy water isotopes (^{18}Oand D). The degree of enrichment is a function of the steam fraction, the temperature range over which flashing occurred, and whether or not the steam fraction remained in equilibrium throughout the process (batch steam separation) or was continuously removed (Rayleigh-type phase separation) (e.g., Truesdell et al., 1977). At Dixie Valley the removal of about 25% steam from the production fluid will enrich the spent brine in the heavy water isotopes by 0.9-1.3‰ δ^{18}O and 2-6‰ δD relative to the production fluid composition. Although these are small enrichments, they are well within analytical capabilities.

Figure 3 also shows the isotopic history of the produced fluid and injectate between 1986 and 1998. The dominant trend is a progressive enrichment of about 2‰ in δ^{18}O and 8‰ in δD following the commencement of injection. This is consistent with co-production of substantial percentages of injectate but not with inflow of nearby, more chloride-rich Section 18 which have virtually identical isotopic compositions as the pre-production fluids. However, influx of high-chloride Section 5 fluids can not be ruled out because of the lack of pre-production water isotope data.

NOBLE GASES

The noble gases are particularly well suited for tracing injectate because (1) they are chemically inert so their concentrations in the injectate are determined entirely by phase separation and their respective solubilities and (2) their solubilities are low, mass-dependent (solubilities decrease as follows: Xe>Kr>Ar>Ne~He), and are known as a function of temperature up to the critical point of water (Potter and Clynne, 1978; Smith and Kennedy, 1983). At Dixie Valley, the concentration of noble gases in the spent brine will be ~1-10% of that in the pre-flashed production fluid.

In Figure 4, the Xe/Ar ratios [normalized to the ratio in air, F(^{132}Xe)] and the inverse ^{36}Ar concentrations for the 1998 production fluids (at reservoir conditions), the spent brine, and the condensed steam plus cooling tower overflow ("Hot Well") are shown for comparison. Although the noble gas composition of the pre-production reservoir fluid was not measured, it is probably safe to assume that it was not unlike waters that had been in equilibrium with air at ~10-30 °C (i.e., the expected composition of local meteoric recharge) which are depicted in Figure 4 by the solid triangles. For most samples, the compositions of the 1998 production fluids are consistent with a mixture of injectate and meteoric water; the dotted line is a mixing line constructed using the spent brine and 25 °C air-saturated water as end-member compositions. The exceptions appear to have been influenced by air contamination [samples with F(^{132}Xe) < 3] or some other unidentified process (Well 28-33).

The point labeled "2-Stage Phase Separation" is the expected composition of the spent brine. The discrepancy between this and the measured composition is not understood at this time. It likely reflects either a contamination problem in the surface installations or perhaps the partitioning of gas between steam and liquid in the power plant is driven more by kinetics than equilibrium solution processes. However, the discrepancy does not introduce a significant uncertainty in subsequent calculations.

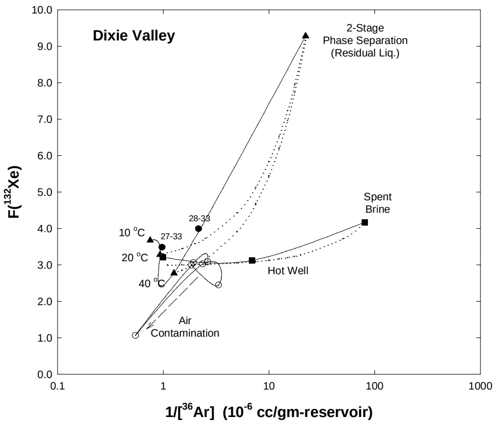

Figure 4: Relative and absolute abundances of noble gases in 1998 production wells (solid circles, Section 33; open circles, Section 7), spent brine, condensate plus cooling tower overflow (Hot Well), and the calculated composition of 10, 20, and 40 °C air saturated water, shallow groundwater used since 1997 to augment injected fluids (solid square adjacent to 20 °C water), and the composition of residual liquid after a two stage phase separation under power plant conditions. Dotted lines are mixing lines between various end-member compositions. The dashed line represents one possible trajectory generated by air contamination.

Using the ^{36}Ar concentration in the measured spent brine and the inferred pre-production concentration (~25 °C air-saturated water) as end-member compositions, a volume fraction (V_{inj}/V_{total}) of co-produced injectate can be calculated for each production well. The calculated volume fractions are shown in Figure 5 as a function of the ^{36}Ar concentration and range from ~10% to ~73%. The data are constrained to a line, which represents mixing between the two end-members. An important feature of using noble gases to calculate injectate contributions is that the calculated volume fractions of injectate are rather insensitive to the assumed end-member concentrations. This is because of the very large concentration difference between the injectate fluids and the original reservoir fluid (note that the x-axis in Figure 4 is a log scale). For instance, if we assume that the "Hot Well" represents the end-member injectate composition, then the calculated V_{inj}/V_{total} ratios would have been underestimated by only ~10%, and ~8% if we assumed the calculated composition for the "2-Stage Phase Separation".

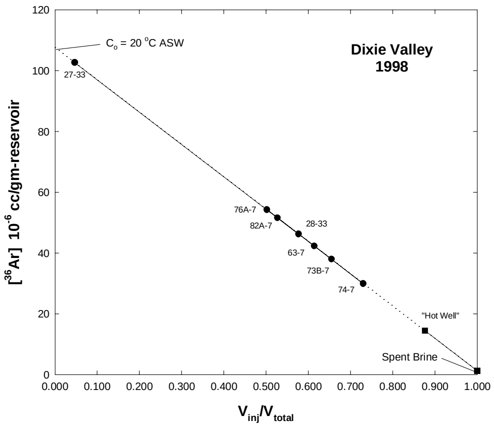

Figure 5: The volume fraction of injectate fluid calculated from the ^{36}Ar abundances assuming that the well data represent mixtures of 20 °C air saturated water and spent brine.

Volume fractions of injectate can be calculated from the chloride and water isotope data in much the same manner:

$$\frac{V_{inj}}{V_{total}} = \frac{([Cl,\delta^{18}O]_{measured} - [Cl,\delta^{18}O]_{init.resevoir})}{([Cl,\delta^{18}O]_{injectate} - [Cl,\delta^{18}O]_{init.resevoir})}$$

Because the production stream chloride concentration and water isotope composition are time dependent, both the chloride and $\delta^{18}O$ of the injectate will also be time dependent; therefore it is not clear what value should be used in calculating the volume fraction of injectate. A sensitivity analysis of the time dependency was performed utilizing injection concentrations ranging from values obtained at the same time to allowing a delay of two years for injectate return. The maximum difference in Vinj/Vtotal was 14% which indicates timing is not overly critical for this technique. For simplicity, we calculate a lower limit to the volume of co-produced injectate by comparing the measured concentrations and isotopic compositions to the composition of the injectate measured at the same time. For the initial reservoir compositions, we use the average pre-production 1986 compositions: chloride = 300 ppm and 250 ppm for Section 7 and 33 wells, respectively, and $\delta^{18}O = -14.84‰$.

The volume ratios of co-produced injectate fluid calculated from the noble gas, chloride and water isotope data are compared in Figure 6 for 1998.

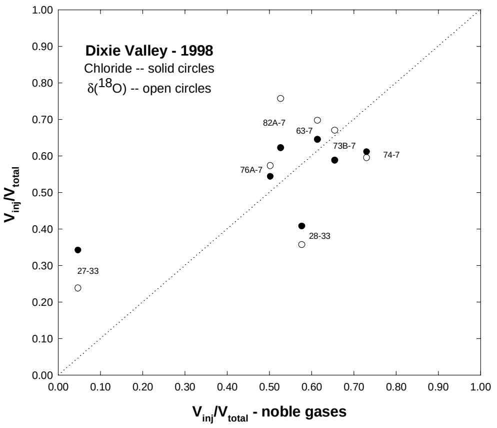

Figure 6: Comparison of the 1998 volume fraction of injectate calculated from noble gas data, chloride (solid circles) and water isotopes (open circles).

Except for Well 27-33, the agreement is very good and quite remarkable given the various assumptions and uncertainties. Therefore, at Dixie Valley the noble gas data support both the chloride and water isotopic interpretations that there are strong injectate returns to the Section 7 producers.

PROPORTION OF INJECTATE VOLUME OVER TIME

The good agreement between the three natural tracers for co-production of the injectate fluid suggests that at Dixie Valley chloride concentrations can be used with confidence to assess the volume fraction of injectate fluid in the production streams. This is very important because chloride data for the production and injection streams exist for the entire 1988-1998 production/injection period (Figure 2). The lower limit values for the V_{inj}/V_{total} ratios for the individual production wells, calculated as described above, are shown as a function of time in Figure 7.

The Section 33 reservoir (dash-dot line) has behaved in a very different manner than the Section 7 reservoir (dotted line). The very rapid rise in the volume of injectate fluid co-produced with Section 33 reservoir fluids suggests a very high degree of connectivity between the injectors and the Section 33 producing wells. However, in late 1992 or early 1993, the volume of co-produced injectate began to decline. Two possibilities can explain this trend. Perhaps there was a change in the hydraulic connectivity at this time that was induced by water table drawdown isolating the Section 33 reservoir from a fracture or pathway supplying the injectate or the decline could reflect inflow of fresh water. Alternatively, the early rise in chloride concentration in the Section 33 production stream resulted from the invasion of the Section 33 reservoir with any of the other known higher chloride indigenous fluids. It is hoped that in the future we will be able to confirm one or the other possibility by further analysis of the existing water isotope data.

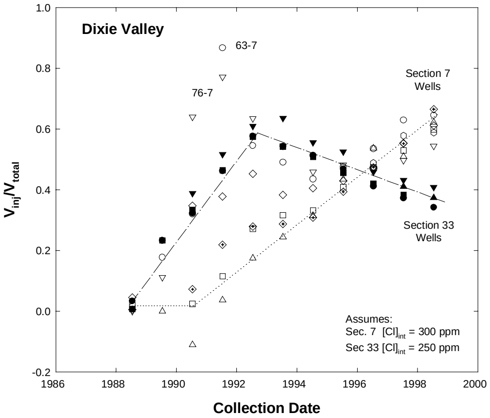

Figure 7: The yearly average volume fraction of injectate calculated from the chloride data of Figure 2, using the 1986 pre-production initial reservoir compositions of 300 ppm Cl (Section 7 wells) and 250 ppm Cl (Section 33 wells). Symbols are the same as in Figure 2.

The volume of co-produced injectate in Section 7 wells has generally increased linearly with time at a rate of ~5-7% per year. This implies that the flux of injectate into the Section 7 production reservoir exceeds the flux of indigenous geothermal fluid (natural recharge) into the reservoir. It is also noteworthy that the range in chloride concentrations between Section 7 wells has diminished over the same period of time resulting in a rather homogeneous fluid which is ~61% injectate. The true volume fraction of injectate may be as high as 100%, because after 1994 the chloride contents in the Section 7 producers have exceeded the initial injectate concentrations.

There is a simple way this data can be used to estimate a fracture volume for the system. This volume includes the fractures in the Section 7 reservoir as well as those that connect the reservoir to the injection wells. The estimate assumes that the injectate fluid gradually replaced the original fluid by pushing the latter out of the fractures and into the production wells. If so, then once the production fluids reached a chloride content equal to the original injectate concentration, the total volume injected would approximate the local fracture volume. This required ~6½ years and took 206 x 10^9 lbs. of injectate, corresponding to a fracture volume of ~0.12 km^3. If it is further assumed that the porosity provided by the fracture network is ~1%, this implies a reservoir volume of ~12 km^3.

CONCLUSIONS

Perhaps the most challenging aspect of geothermal reservoir engineering is to be able to predict thermal breakthrough, the onset of cooling in production wells resulting from cool fluids returning from injection wells. Addressing this challenge requires (among other things) the ability to quantitatively assess and model injectate returns. At Dixie Valley, good agreement between the calculated volume fraction of injectate in the production stream (V_{inj}/V_{total}) determined using three independent natural tracers (Cl, noble gases, and water isotopes) suggests that chloride changes can be used as a viable proxy for monitoring injectate returns.

The natural chemical tracers provide definitive evidence for the presence of injectate in the Section 7 production stream and that the volume fraction of injectate has consistently increased with time. The rate of increase has been constant and on the order of 5-7% per year. Presently, the injectate fluid comprises ~60-100% of the production stream. A simple calculation implies a circulating fracture volume in the Section 7 area of ~0.12 km^3. Assuming that these fractures make up ~1% of the overall volume of this part of the reservoir, the local reservoir volume is ~12 km^3 in size.

In Section 33 the estimated volume fraction of injectate quickly increased to a maximum value of ~ 60% in the four years between late 1988 and late 1992. Since 1992, it has steadily declined to a present value of ~37%. This trend is difficult to interpret. The early initial increase may have resulted from either injectate returns or invasion of a higher chloride fluid indigenous to the system. The decline may indicate that a change in the hydraulic connectivity occurred in mid 1992, perhaps induced by water table draw down isolating the Section 33 reservoir from a fracture or pathway supplying the higher chloride fluid.

Continued monitoring of the production and injectate fluid chloride, water isotopes, and noble gas concentrations could lead to a better understanding of the relative flux of the indigenous geothermal fluid into the reservoir and provide additional constraints for future modeling efforts.

ACKNOWLEDGEMENTS

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