Reservoir Characterization by Geochemical Method at the Ogachi HDR Site, Japan

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Abstract

To create the artificial reservoirs for the Hot Dry Rock (HDR) geothermal energy, two hydraulic fracturing tests were performed at the depth of 1000 m and 7f0 m at Ogachi, Akita prefecture, Japan, in 1991 and 1992. After these tests, a 22-day circulation test was carried out through both resewoirs in the late of 1993.

During these tests, geochemical studies were conducted to evaluate the chemical behavior of the geothermal fluid at the reservoirs and then to estimate the reservoirs' character

The flow volume dependent concentration change of the major dissolved components of the flowback water and production water is caused by the mixing between the injected water and the existing formation water, and the interaction between the injected water and the host rock.

According to the results of geochemical study and other prospecting methods during the hydraulic fracturing tests, the 1st (lower) reservoir was controlled by the natural fracture system, whereas the 2nd (upper} reservoir was controlled by the ground stress. In the early time of a 22-day circulation test, the total volume of both reservoirs which connect an injection well to a production well is estimated to be about 14 m^3.

Introduction

To develop the Hot Dry Rock (HDR) geothermat energy concept for the generation of electric power, the Central Research Institute of Electric Power Industry (CRIEPI) has conducted two hydraulic tests and a circulation test at its Ogachi HDR site in Akita prefecture, Japan. Hydraulic fracturing tests were performed from an injection well: the first at a depth of 1000 m in 1991 and the second at a depth of 720 m in 1992. Then, in late 1993, a 22-day circulation test was conducted from the injection well, through the two heat exchange zones of fractured rock, to a production well that had been directionally drilled to intersect both fractured regions.

Geochemical studies were carried out to evaluate the behavior of the fluid in both fractured reservoirs and to provide estimates of the reservoir volume during the hydraulic fracturing tests and the circulation test.

Ogachi HDR Site

The Ogachi HDR Site, located in Akita prefecture in northeastern Japan, is situated in the Sekiryo mountains. In 1990, a well was drilled to a depth of 1000 m for hydraulic fracturing. Also, another well was drilled to a depth of 1100 m for production.

The geological survey , cuttings and core observations, and lithologic log indicate that the geology in this area consists of granodiorite, Tertiary tuff, and Quaternary pyroclastic flow and volcanic lava, and that the granodiorite , as the host rock of the reservoir,starts at a depth of 300 m around the site. There are 10-20 cracks per meter in the granodiorite and many cracks are filled with altered mineral such as anhydrite, gypsum, chlorite, epidote, calcite and pyrite (Kondo,1994). The granodiorite is affected by the "Onikobe-Yuzawa mironite zone" which extends near the site in a N-E direction. Temperature at the bottom of both wells is approximately 230-250°C.

Outline of the tests

In 1990, a welt was drilled for hydraulic fracturing. First, the well was drilled to a depth of 990 m and a casing pipe was inserted to the bottom of the well. After cementing the annulus, the well was drilled to a depth of 1000 m. In 1991, the tst hydraulic fracture test was done at a depth of 990-1000 m. In 1992, the casing pipe was cut off by a reamer at a depth of 711-719 m and a sand plug was filled below this depth. Then, the 2nd hydraulic fracturing test was performed at this depth.

In 1991. the 1st (lower) fracture was created by injecting 10,160m^3 of water at 990-1000 M depth. During injection, the wellhead pressure was approximately 19 MPa. From microseismic acoustic emission (AE) measurements (Hori et al.,1994), the fracture progression direction was estimated to be N20° E (Fig. 1). After injection, the water flowed back from the hydraulic fracturing well for about 4 days, and the total volume of the flowback water is 640 m^3. The flowback recovery defined as a cumulative flow volume ratio of the flowback water against the injection water is approximately 6% (Fig. 2).

In 1992, the 2nd (upper) fracture was created by injecting 5.440 m^3 of water at 711-719 m depth. During injection, the well head pressure was approximately 22 MPa. From the AE measurement, the fracture progression direction was estimated to be N100° E. After injection, the water flowed back from the hydraulic fracturing well for more than 20 days, and the total volume of the flowback water is approximately 1350 m^3 The ftowback recovery is more than 25%.

Considering a three dimensional distribution of the fractures estimated by the AE measurements, a production well was drilled in late 1992, to intersect both fractured regions.

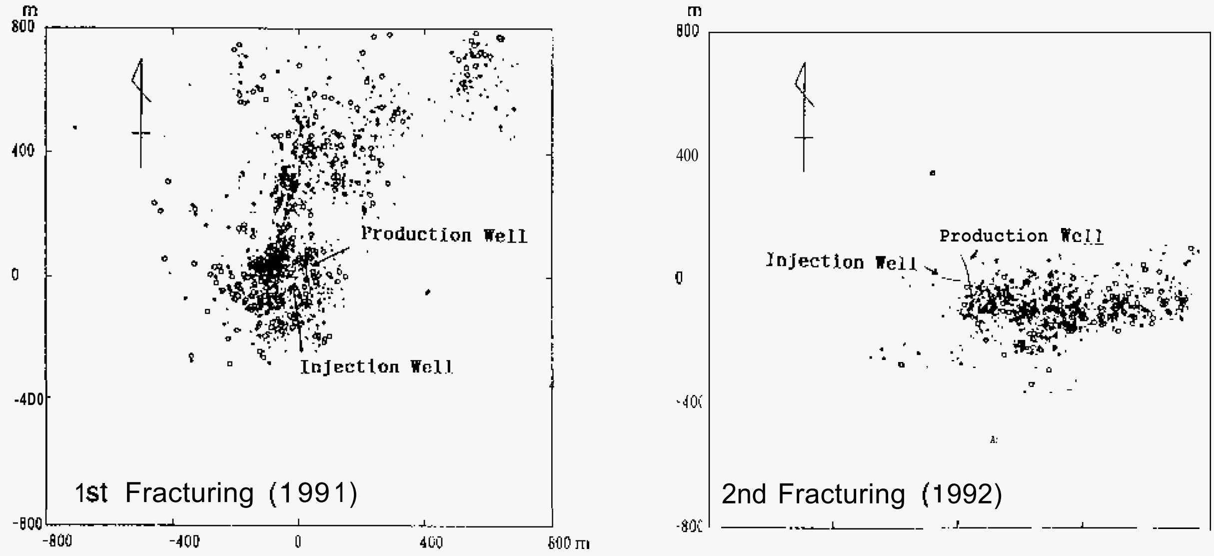


figure 1 **AE Hypocenter** Location **Map** (Hori **et** al.,1994)

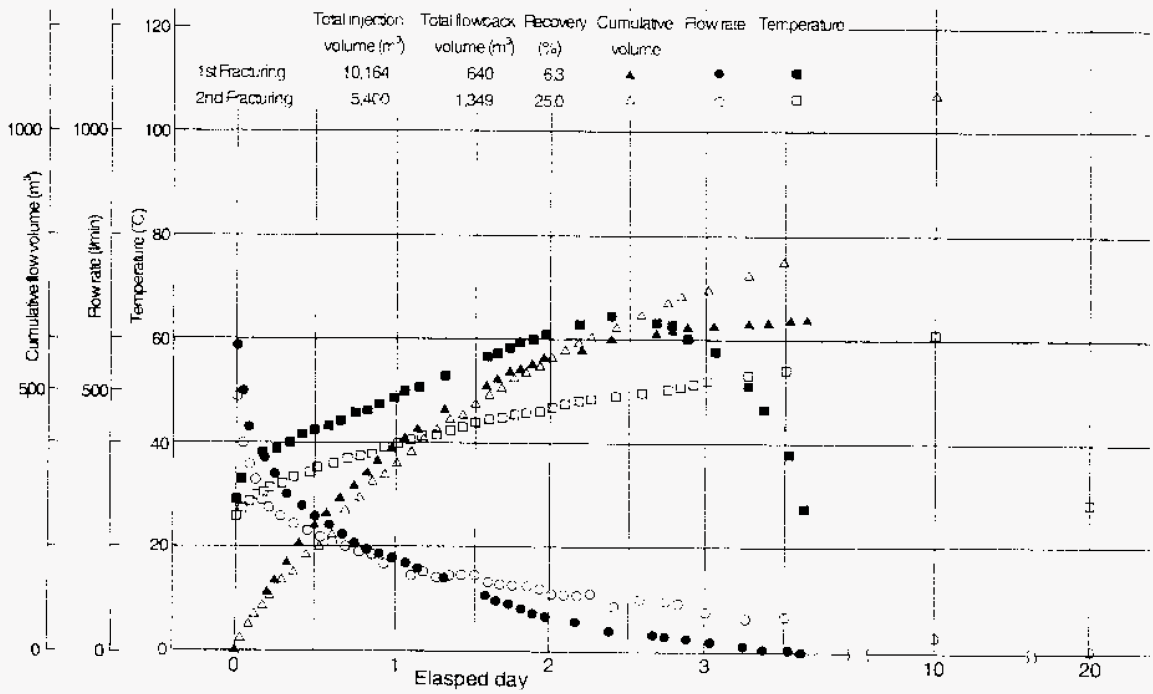


Figure 2 **Result** of **the Flowback** Water **Measurements after** each Hydraulic Fracturing **Test.**

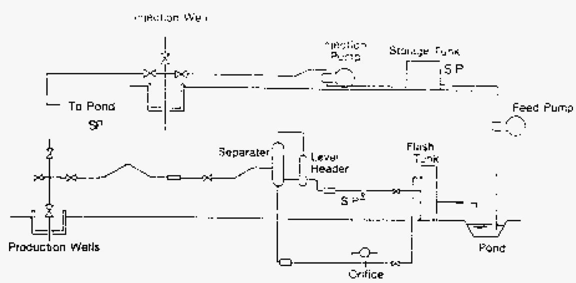


Figure 3 Schematic Diagram **of Surface System for** Hydraulic Fracturing **and Circulation Tests.**

In **1993,** a **circulation test was** conducted for **22 days,** from **an injection well** through **two** heat **exchange zones** of **fractured rock to** a **production well. The injection rate of the water was 850-1200** l/min .

By the **end** of **the circulation test, the cumulative flow volume of injection** water **was approximately 30,000** m^3 **and the** discharge **from the production well was** about **620** m^3. The **production recovery, defined as the ratio** of **the production** flow **rate with respect to the injection** flow **rate, was about 4 %** at the **end** of **the** circulation **test. At the end of** the circulation **test,** the **wellhead temperature for the** production well **was 108℃, and the wellhead pressure for** the **injection** well **was approximately 18 MPa.**

Sampling and Analysis

The injection water, the flowback water from the hydraulic fracturing well and the production water from the production well were sampled as shown in Figure 3. A injection water sample was collected twice during each hydrauliic fracturing test and once every few days during circulation test. After hydraulic fracturing, a flowback water sample was cooled down and collected every few hours in the early stage of the flowback and once every few days in the later stage. During circulation, a production water sample was cooled down and collected every 1-2 hours in the early stage of the circulation and once or twice a day in the later stage.

All samples were analyzed for pH and EC. Then, selected samples were analyzed for Na, K, Ca, Mg, Cl, SO_4, HCO_3, CO_3, B, and SiO_2, and some samples were analyzed for oxygen and hydrogen isotopes.

Hydraulic Fracturing Test

Chemical Character of the Flow Back Water

The concentrations of some components, such as Ca, Mg, Cl and S04, in both flowback waters are much different, while the chemical characters of both injected waters are rather similar. To compare the chemical behaviors of both flowback water, the concentration is standardized as M by using the following formula (*Fig.* 4).

$$M = (X-X_{in})/(X_{fo}-X_{in})$$

X : Concentration in the Flowback Water
X_{in} : Concentration in the Injection Water (River Water)
X_{fo} : Concentration in the Last Sample of the Flowback Water

In the case that the M is zero, it means that the content of the element in the flowback water is same as that in the injection water. A value of M=l corresponds to the concenfration of the element in the last sample of the flowback water.

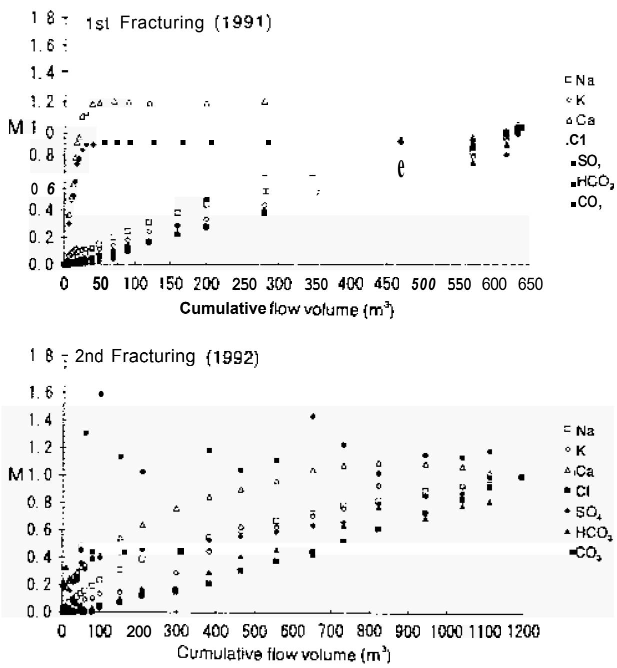


Figure 4 Behavior of the Major Dissolved Species in the Flowback Water.

As chloride is a nonreactive element and it is thought to be of high concentration in formation water, it can be used as an indicator to estimate the mixing ratio of the formation water to the injection water with low Cl concentration. Chloride concentrations of the flowback water after both tests are quite different. The concentration for the 1st test is 10 times that for the 2nd test (Fig. 5). This shows that the flowback water for the 1st test was more influenced by the formation water existing in the natura fractures than that for the 2nd test.

At the 1st test, the concentration-flow volume behaviors of both Ca and SO_4 in the flowback water are very similar and quite different from those of other species (Fig.4). This indicates that a reaction between water and anhydrite ($CaSO_4$), which fills a large part of aperture of natural fracture in granitic rock, has occurred.

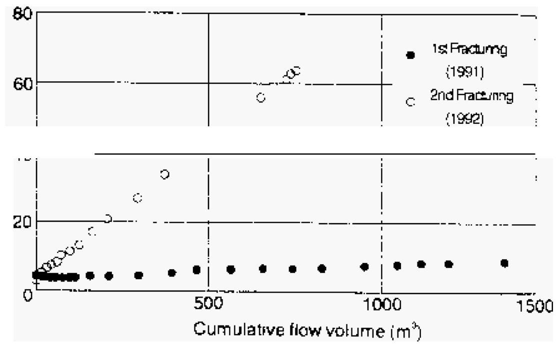


Figure 5 Concentration - flow Volume Behavior of **Chloride** in the Flowback Water.

comparison of both reservoirs

(1) The **recovery** of the 2nd fracturing test is higher than that of the 1st fracturing test. This indicates that the reservoir made by the 2nd fracturing is a closed system in comparison with the 1st reservoir.

(2) According to AE measurement, the progression direction of the 1st fracturing was estimated to be N20° E, and that of the 2nd fracturing was evaluated to be N110° E, respectively. The direction of the 1st fracturing corresponds to the predominant orientation of the natural fractures, whereas that of the 2nd fracturing is concordant with the maximum principal stress.

(3) The increasing tendency of chloride content in the flowback water after the fracturing test can be explained as the result of the mixing of formation water with injection water. The chloride content of the 1st fracturing test is 10 times higher than that of the 2nd fracturing experiment. This indicates that the volume ratio of the formation water to the flowback water at the 1st fracturing is higher than that at the 2nd fracturing, so to speak, the lower host rock has much porosity which contains the formation water (high saline water) in comparison with the upper host rock.

(4) At the 1st fracturing test, Calcium ion behaves almost like sulfate, and both components increase quickly at early time in contrast with other components which Increase gradually. This indicates that the additional calcium and **sulfate** ions **were** supplied by the dissolution of anhydrite ($CaSO_4$) which usually exists along natural fractures.

(5) Considering all the above results, the 1st (lower) reservoir was controlled by the natural fracture system, whereas the 2nd (upper) reservoir was controlled by the ground stress.

Circulation Test

Behavior of the production water

The chemical composition of the production water changed in the early stage of the circulation test **and** approached the composition of the injected water,while the injected water composition was rather constant (Fig. 6).

The Na concentration vs. Cl concentration **plots** for water samples collected from the production **well** lie **along** a **line** (Fig. 7). The line corresponds to **an** Na:Cl molar ratio of 0.48:0.52.

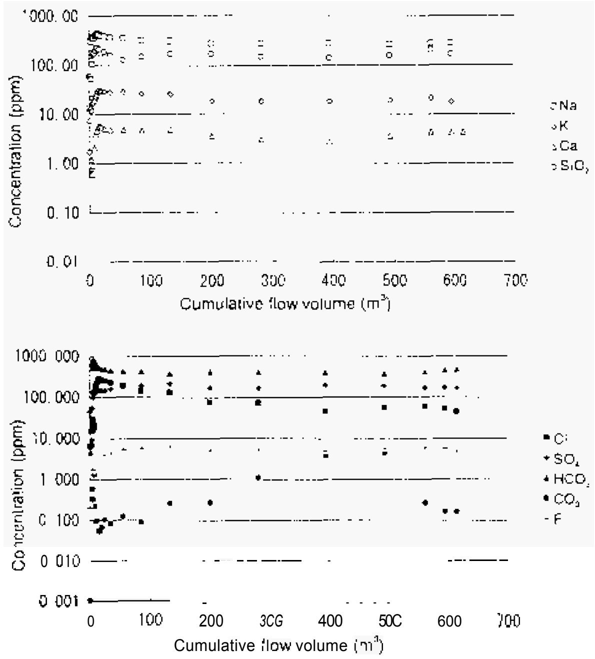


Figure 6 Concentration - flow Volume Behavior of the Major Dissolved species in the Production **Water.**

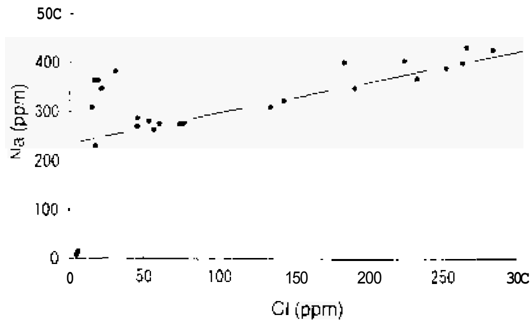


Figure 7 Crossplot of Na versus Cl for **Water Sample** Collected from the Production Well.

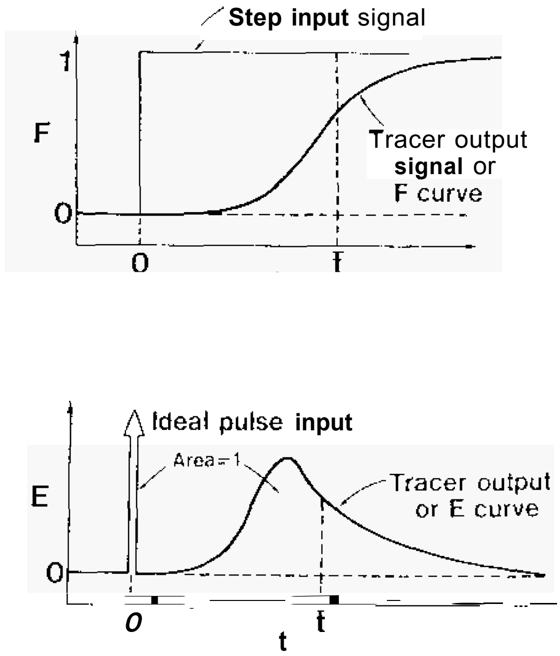
When the **make-up** water **that had a** different composition **from the** reservoir water was injected, the foftowing geochemical behavior occurred in the underground reservoir : 1) displacement of the reservoir water with the injected water along the passage of the fluid, and 2) a water-rock interaction reaction between the host rock and the injected water.

As shown in Figs. 6 and 7, the **changes** in the **chemical** composition of the produced geothermal fluid with time are mainly caused by the displacement process, i.e., mixing of the injected water and the indigenous geothermal fluid.

Evaluation of the Reservoir Volume

For **a** pulse injection of tracer into the reservoir, the resulting tracer response from the production well with time can be represented by an E-curve (residence time distribution : **RTD** (Robinson **and** Tester 1984)). In a similar way, with no tracer initially present in the system, the exit record for a **step** input of tracer will show an F-curve response (Fig. 8). The E-curve is related to the F-curve as

$$E=dF/dt.$$



Figurc 8 Outline of the F Curve and the E Curve (Levenspiel, 1972).

The Cl data during circulation **were** treated to calculate the defined modal volume. **Chloride** ion is relatively inert so that tracer-like behavior is **expected** to **be** accounted for in the reservoir. The degree of the displacement, or the contribution of the indigenous geothermal fluid in the sample expressed as M, is evaluated by the Cl concentration (C) as follows;

$$M(t)=(Cp-C(t))/(Cp-Cm(t-a))$$

where the subscript p denotes the initial concentration of production water, which can be collected in the production well **immediately after** the displacement of the reservoir water, **and** the subscript **m** denotes the Concentration of injected water, t is the circulation time, and a is the breakthrough time derived from the tracer test.

Figure-9 shows the ratio of **M** to the flow volume (v). Several **dots** with start which values are 1.0-0.2 are affected by the river water in the production **well** injeacted before the circulation test to estimate the permeability of the production well. Except these dots, this curve can be regarded as an F-curve when the injected water is injected as a step input.

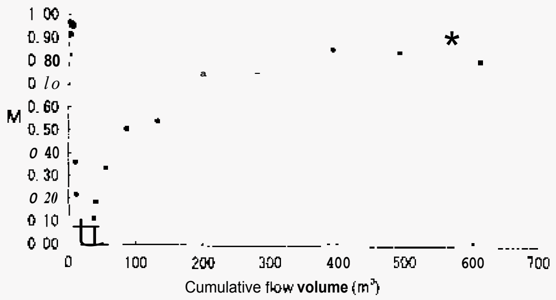


Figure 9 The Ratio of the Injection Water Volume to the Produced Water Volume.

The modal volume of the RTD (E) curve (Fig. 10) was defined by dM/dv , the differential coefficient of the ratio **M** wrth the flow volume **v**. The obtained value can be considered **as** the **representatwe** volume of **the** relating reservoir passage. In consequence, the reservoirs connecting the injection **well** to the production well have volume of $19m^3$, including the well bore volume.

The well-bore volumes, from the most shallow feed point to the well head of the production well is about $5m^3$. **Consequently,** the volume of the reservoirs can be calculated as about $14m^3$.

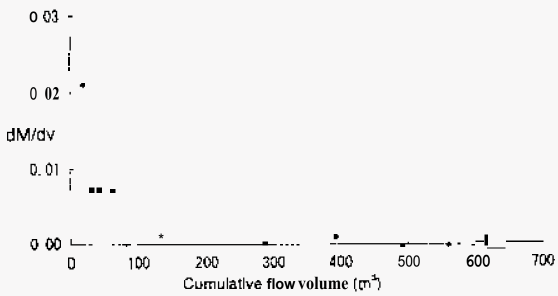


Figure 10 The E Curve obtained by differenciating the F Curve.

CONCLUSION

Considering results of the geochemical measurement and another **methods** during both hydraulic fracturing tests, each reservoir is characterized as follows;

(1) Chemical behavior of the flowback water from both reservoirs is **caused** by mixing **of the** injection water and existing formation water, and water rock interaction **between** host **rock** and injected water.

(2) Behavior of the chloride indicates mixing, that of calcium and sulfate indicates water-rock interaction. **However,** values for the **three** elements **are** higher in the lower reservoir than the upper reservoir.

(3) The lower reservoir is estimated to be created along the natura cracks **and** fractures which contain high saline water as the existing formation water and which are filled with the altered minerals such as anhydrite, gypsum **and** so on.

(4) The creation of upper reservoir is estimated to be controlled mostly by ground stress.

Judging from results of the geochemical measurement, especially the chloride-time behavior, during the 22 days circulation test, the reservoir volume connecting the injection well to the production well is calculated to be $14m^3$ approximately.

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