Water Injection Management for Resource Maximization: Observations From 25 Years at The Geysers, California

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1. *ABSTRACT*

Injection at The Geysers began in 1969 primarily as a way to dispose of excess steam condensate. The steam reservoir was selected as the disposal target because its high injectivity would assure reliable plant operation, and because injection there could be expected to improve steam production after several years. The thermodynamic conditions at the time were such that injection could reduce but did not immediately increase production.

Greatly increased injection volumes have accompanied development of the geothermal field, Long-term injection management has been guided by reservoir performance studies, including large scale tests of concentrated injection in the most pressure-depleted areas. Several studies are reviewed, including chemical and radioactive tracer tests, geochemical sampling programs, and seismic monitoring. The results have been successfully combined to determine the flow patterns and boiling rates of injected water.

Injected water, either steam condensate or from local creeks, has become a significant source of steam throughout the field. Injection is being used to mine energy from pressure-depleted areas with high rock temperatures. Early reservoir engineering estimates of injectate boiling rate have been confirmed by trends in isotope concentrations in the produced steam.

2. FIELD DEVELOPMENT AND INJECTION

Modem development at The Geysers began in 1955, when B.C. McCabe drilled the first production well since the 1920s into the southeastern part of a shallow (100-700 m) steam zone on the north bank of Big Sulphur Creek. This area is between Units 1&2 and Units 5&6 on Figure 1. The Magma-Thermal Power Project (MTPP) was formed the following year to drill steam wells for generation of electric power.

Development of the shallow reservoir progressed to the northwest along the creek. The generating potential of the area reached 82 MW in 1967 with the commissioning of two 28 MW generating units in a second plant, Units 3&4. Units **1-4** were built with direct contact condensers and forced draft cooling towers. Excess condensate drained from the cooling system into Big Sulphur Creek at an average rate of about 100 t/h, or 0.9 Mt/a.

By 1969, the discharge limits set by the Regional Water Quality Control Board made injection the only practical method for disposing of the condensate. The Geysers area is quite arid, and the condensate discharged to Big Sulphur Creek **from** Units **1-4** was equivalent to about 7% of the average stream flow through the field. During the dry summer months, the ratio was much higher. In addition, ammonia and boron are concentrated in The Geysers condensate in the cooling tower.

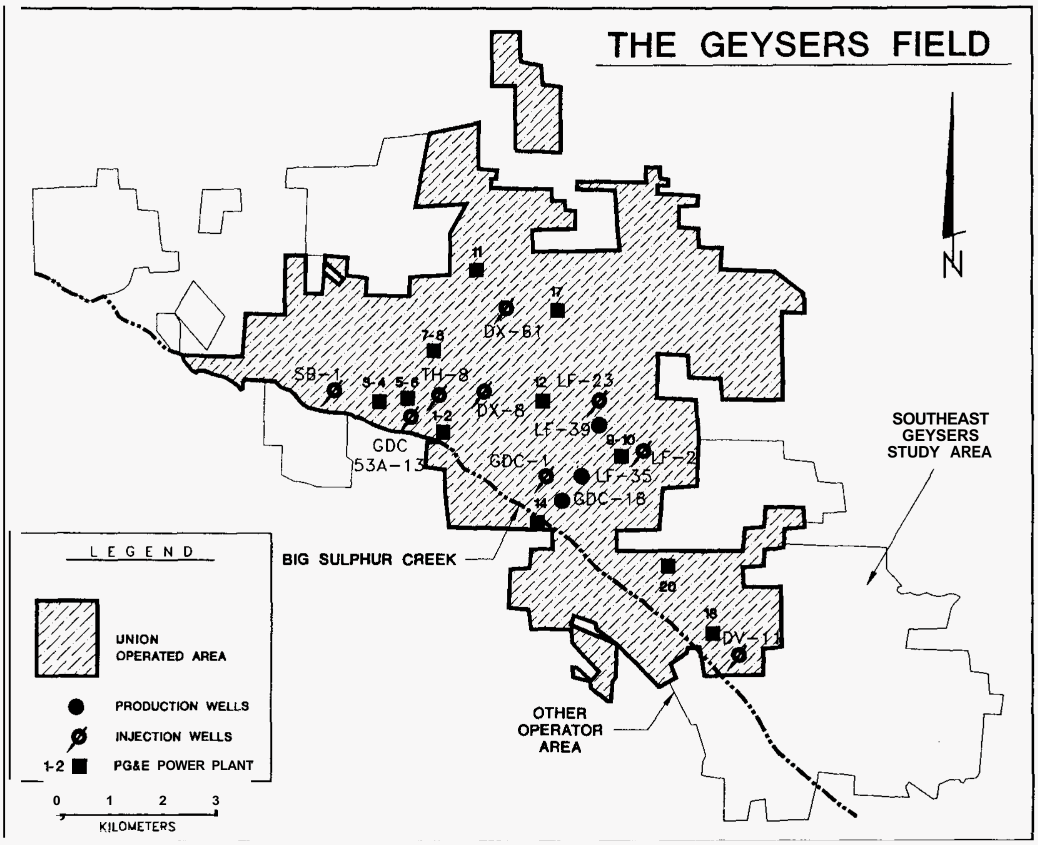

Figure 1. The Geysers, showing the steam field operated by Union Oil Company, and the power plants supplied by it.

In 1965, Union Oil Company of California drilled wells which proved the existence of an extensive deep steam reservoir. This was followed, in 1967, by an operating agreement which joined the interests of Union and the MTPP. Union has operated the Union-MTPP project since 1967, and now holds a 75% interest. Union and MTPP signed contracts in 1970 with Pacific Gas and Electric Co. (PG&E) which provided for additional capacity to be installed in 100 *MW* blocks. Beginning with Units 5&6 in 1971, PG&E adopted plant designs which use two nominal 55 *MW* turbines with either separate generators (Units 5-10) or a single generator (Units 11-20).

Union accepted responsibility for condensate disposal from PG&E in the 1970 contracts. At the time, reservoir pressures were near saturation conditions, and little excess heat was available to boil the injected condensate. Injection wells were therefore sited as far as possible from active production wells (Chasteen, 1975). Idle production wells were converted to injectors by running slotted liners through injection intervals.

Injection wells are regulated by the State of California, Division of Oil, Gas and Geothermal Resources, and by the Federal Bureau of Land Management. These agencies oversee a variety of periodic inspections which ensure the safety of the wells' operation and the protection of any aquifers.

By 1975, injection had grown eight-fold from its beginning. Six wells serviced 522 MW of installed capacity at an average effluent rate of 7.5 Mt/a. Figure 2 shows the growth of injection rates to a peak of 19.2 Mt/a in 1986, mirroring the growth of generation. The decline in injection from 1987 through 1991 reflects the decline in generation during that period. The reversal of the trend in 1992 and 1993 was brought about by the development of supplemental sources of injection water, as will be discussed.

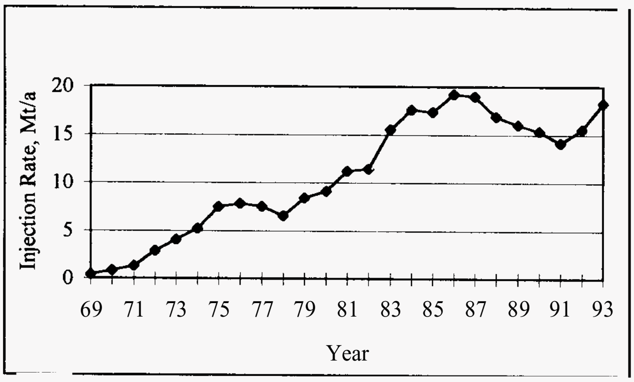

Figure 2. Annual total liquid injected by Union at The Geysers

3. THERMAL ENERGY CONSIDERATIONS

Water's primary role as the means of transporting, rather than storing, thermal energy was recognized in early reservoir engineering studies of The Geysers field ***(Ramey,*** 1968). Although injection began in response to surface environmental concerns, the desirability of returning as much water as possible to the reservoir for eventual heat mining was evident from the start.

Heat energy in The Geysers geothermal system is stored in the rock, in liquid water, in water vapor and in the non-condensable gas. The boiling of liquids in the void spaces leaves a substantial fraction of the original energy content in the rock. **This** provides the thermodynamic condition needed for heat mining using injected water, as *can* be shown by the following calculation.

The low heat capacity of gasses and the low porosity of the rocks of The Geysers reservoir allow **us** to ignore heat storage in the gas and approximate the total heat energy stored above some reference temperature, H_{tot}, as the sum of rock and liquid heat contents:

$$H_{tot} = [\rho_r \bullet C_r \bullet (1-\phi) + \rho_l \bullet C_l \bullet \phi] \bullet \Delta T \qquad (1)$$

where $\rho \equiv$ density, $C \equiv$ heat capacity, $\phi \equiv$ porosity, $\Delta T \equiv$ difference from the reference temperature, and the subscripts r and l refer to rock and liquid, respectively.

The greatest energy extraction occurs if **all** of the liquid is boiled from completely saturated rock, and can be calculated **from**:

$$H_{l\text{-}v} = \rho_l \bullet \phi \bullet h_{vap} \qquad (2)$$

where $H_{l\text{-}v}$ is the total energy required for conversion of liquid to vapor and h_{vap} is the heat of vaporization.

For this example calculation, we use a reference temperature of 423 K (150 °C) and an initial temperature of 513 K (240 °C). Between 240 and 150°C, average parameter values are: $h_{vap} = 1940\ \mathrm{Jg^{-1}}$, $\rho_l = 866\ \mathrm{kgm^{-3}}$, $C_l = 4.58\ \mathrm{Jg^{-1}K^{-1}}$, $\rho_r = 2\,600\ \mathrm{kgm^{-3}}$, and $C_r = 0.96\ \mathrm{Jg^{-1}K^{-1}}$. Gunderson (1992) reported Geysers reservoir rock porosities from 0.6% to 5.8%. Taking 6% as an upper bound:

From (I), the total energy stored is $H_{tot} = 2.326 \times 10^8\ \mathrm{Jm^{-3}}$
From (2), complete boiling removes $H_{l\text{-}v} = 1.008 \times 10^8\ \mathrm{Jm^{-3}}$

Boiling therefore extracts no more than 43% of the heat stored in the rock above 150 "C, which would lower rock temperature by 40 °C.

The energy recovery from production of the original reservoir fluids will be proportionately reduced if the original liquid saturation was less than 100%, if the porosity is less than 6%, or if some of the water cannot be produced as steam. If the field-wide average value is closer to 3%, then **full** conversion of liquid to vapor would require only 22% of the original rock heat.

Aside from energy extracted by produced steam, the geothermal system also gains and loses heat energy through conduction. These heat flows have been shown to have a negligible effect on commercial energy production at The Geysers. Ramey (1968) calculated that the very high heat flux in the vicinity of Units 1-4, which he estimated to average $2.2\ \mathrm{Wm^{-2}}$, would require 8 400 years to raise the temperature of a 1524 m column of sandstone 167°C above a normal geothermal temperature distribution. Walters and Combs (1992) reported a heat flux of 0.335 to $0.500\ \mathrm{Wm^{-2}}$ above most of The Geysers producing area. Even assuming infinite heat conduction in the reservoir and no heat **loss** from the reservoir, it would take 19 000 years for natural heat flow at $0.335\ \mathrm{Wm^{-2}}$ to replenish the $1.008 \times 10^8\ \mathrm{Jm^{-3}}$ removed by boiling, as calculated above, over a 2,000 m thickness of reservoir. Since the service life of geothermal power plants is a few decades, conductive heat transfer is clearly of no commercial importance.

Injection into rock which is at saturation temperature and pressure increases the amount of free water present, which may lead to liquid breakthrough into flowing wells. ***As*** production empties the matrix pores nearest the throughgoing fractures, pressure in the fluid drops and superheated rock surface becomes available to boil water. In fractures passing through rocks containing mobile liquid, the ***steam*** temperature is fixed at the saturation temperature associated with the local reservoir pressure. **This** condition prevails even though the temperature in the rock a short distance away in the tight matrix may be much higher.

This situation contrasts with that in fractures passing through rocks with no mobile liquid. In these areas, the temperature of steam in the fracture will rise above the saturation value as heat is transferred from the dry rock. Conditions in the matrix blocks with no mobile liquid are ideal for injected water to mine available heat and generate local pressure support. This conceptual picture is validated by observations of increased steam flow rate and wellhead pressure in the Southeast part of the field (Voge, et al., 1994; Enedy, et *al.*, 1992).

4. RESERVOIR STUDIES

Research began in the early 1970s on predicting and avoiding premature injection breakthrough, and with increasing economic energy recovery. Tracers were identified as essential tools in both of these efforts, and numerous lab and field tests were run to identify suitable materials. Tritium was found to have suitable properties in both its liquid and vapor states to give quantitative information about fluids injected as liquid but produced as vapor. Tritium's principal virtues as a water tracer are its:

- detectability at very low concentrations.
- thermal and chemical stability,
- thermodynamic similarity to water, and
- lowtoxicity

During the 1970s and 1980s Union ran eight different tritium tracer tests, of which *six* produced measureable tracer recovery. These tests are summarized in the table below.

Tritium Tracer Test Summary

Injection Test (well name)	Date Tracer Injected	Tritium Iniected (Curies)	Tritium Produced (Curies)	Tracer Recoverv (%)
SB-1	8/20/75	20	3.59	18.0
DX-5	10/28/77		36.50	37.0
LF-23	8/5/81		25.20	50.4
GDC53A-13a	3/3/83		1.22	2.4
GDC53A-13b	6/20/84		91.73	91.7
GDC-1	12/5/84	[illegible]	17.24	34.5

The high recovery fractions are indicative of a closed system, an inference also drawn from the sub-hydrostatic initial reservoir pressure (Ramey, 1968; Lipman, *et al.*, 1978). Figure 3 displays the cumulative tracer recovery over time in four tests in widely separated **parts** of the field. The slope of the curves is directly proportional to the rate of production of boiled injectate, and the similarity among the tests is readily apparent.

All of the test results showed that about 15% of the injected liquid boiled each year after injection, until about 80% of the ultimate recovery was reached, By that time tritium was generally found in very small quantities in many wells, and most of the concentrations began to fall below the reliable detection limit. **This** caused a rapid decline in the measured tritium production rate.

The exceptionally high recovery of tracer in the GDC53A-13b ("b") test may be due in large part to the GDC53A-13a ("a") test. Few wells responded to the "a" test by producing tritium in concentrations clearly above the measurement threshold. However, the tracer from the "a" test probably raised the background tritium level. This would have increased the likelihood of measureable responses in the "b" test, which would then have recorded concentrations as the sum of the reponses **from** both tests. **This** hypothesis is supported by analyzing the data shown in Figure 3 for the "b" test as a linear superposition of two Similar response curves with a time delay. The resulting inferred curve for the "b" test is so nearly identical to the one shown for LF-23 that we have omitted it for clarity.

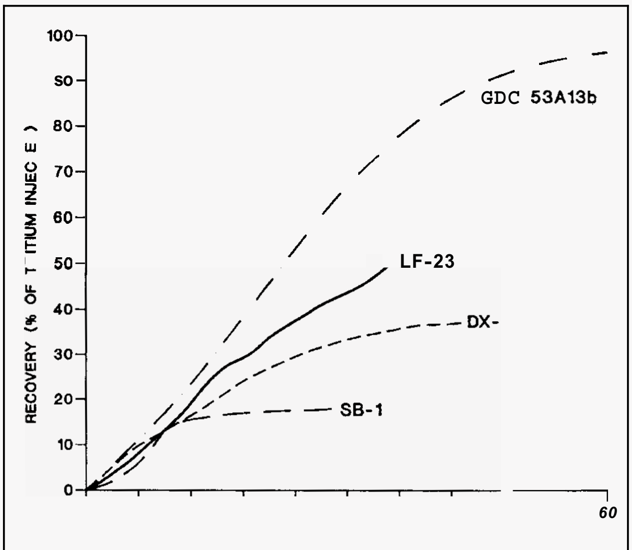

Figure 3. Cumulative recovery **of** tritium tracer in four tests.

The principal drawbacks to tritium for small scale tests are its slow decay and wide dispersion. Fluorescein and Tinopal-CBS were found to be inexpensive alternatives for short tests in which liquid communication with a producing well is suspected. Tests conducted in the shallow steam zone around well Th-8 resulted in tracer recovery in wells up to 300 m from the injection point in less than one hour.

Encouraged by the tracer results, and despite the lack of measurable performance benefits, Union undertook a field scale test program to concentrate injection in a low pressure area. Beginning in 1978, condensate from the Units 7&8 and 12 areas was directed in large part to the Units 1-6 area. The increased mass replacement ratio achieved in this six-year test can be seen in Figure 4. The high replacement ratios shown in Figure 4 after 1990 are due partly to increased surface water injection and partly to reduced production after Units 1-4 were retired by PG&E.

The peak replacement ratio of 80% in 1983 was achieved without insurmountable production interference problems. **This** indicated that the well-fractured rock in that area could provide high enough heat transfer rates to maintain pressure with as little as 10-20 Celsius degrees of superheat.

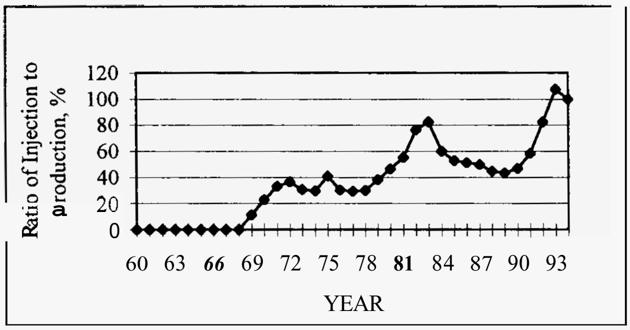

Figure **4.** Mass ratio **of** injection to production, Units **1 - *6.***

Observations of effective heat transfer rates in different areas have been coupled with geologic studies of fracturing to guide injection strategy for the last decade. Key geologic findings were: (1) identification of the felsite as a second lithologic unit within the reservoir (Schriener and Suemnicht, 1980), and (2) inference of contrasting styles of fracturing within the felsite and greywacke (Thompson and Gunderson, 1992; Beall and Box, 1992). These workers concluded that fractures deep within the felsite are relatively sparse and predominantly vertical, while those near the top of the felsite and in the greywacke are more numerous and varied in orientation. Therefore, injecting into greywacke or upper felsite can promote faster heat exchange due to the greater fracture surface area.

Reservoir behavior has also been tracked through geochemical and geophysical monitoring. The natural tritium content of reservoir steam was tested as early as 1967 to detect tritium introduced fiom atmospheric nuclear explosions, and thereby reveal any recent meteoric source. Steam stable isotope data that include both oxygen and hydrogen analyses have been gathered Since 1978. Fieldwide non-condensable gas data collection began in 1977, with limited sampling prior to that time. Microearthquake monitoring was initiated in 1985, and Stark (1990) used microearthquakes (MEQs) to track movement of injected water in the reservoir.

5. CONDENSATE AUGMENTATION

The 1978-84 condensate redistribution program in the Units 1-6 area demonstrated the feasibility of injecting volumes which are large fractions of production. Union therefore embarked in 1980 on a program of developing supplemental water resources. Big Sulphur Creek is by far the largest water course in the area, and the Union-operated project now draws from it at three pumping stations during the rainy season. These stations are located at the site of Units 1&2, adjacent to Unit 14, and south of Unit 20. The combination of highly seasonal runoff and a major drought in the 1980s has imposed practical operating limits of 2-8 Mt/a.

Another major potential source of water is municipal waste water. Negotiations with the city of Santa Rosa in the mid-1980s resulted in a preliminary design and engineering studies, but economic and institutional factors led to abandonment of the proposal. The proposal has recently been resurrected, and the project may yet come to pass.

Much closer to accomplishment is a plan to send secondary-treated effluent from the city of Clearlake to The Geysers via a 42 km pipeline. If final hurdles are overcome, the line may be operating in 1996.

6. RESERVOIR RESPONSE

On a large scale, the effect of injection to production ratios approaching unity can be seen in several ways. If production damage is avoided while injection is increased, the higher ratio implies a lower net mass withdrawal rate. The correlation in the Union area between the rates of **mass** withdrawal and pressure decline has been documented (Barker, *et al.* 1992). **A** critical management issue is whether steam boils from the injected liquid quickly enough to effectively reduce the net mass withdrawal rate. The response of the Units 1-6 and 14 areas to injection augmentation shows that it can. Those units have the highest injection fractions in the Union area, and exhibit the lowest production decline rates.

High rates of injectate boiling should reduce the temperature of the rock and produced fluid. This appears to be happening in Units 1-6 and in the Southeast, as can be seen in Figure 5. This contour map shows the superheat in steam at flowing bottom hole conditions, inferred from production measurements. **A** large area of low superheat in Units 1-6, and the three largest areas of low superheat in Units 9&10, 18 and 20, all correlate with centers of injection.

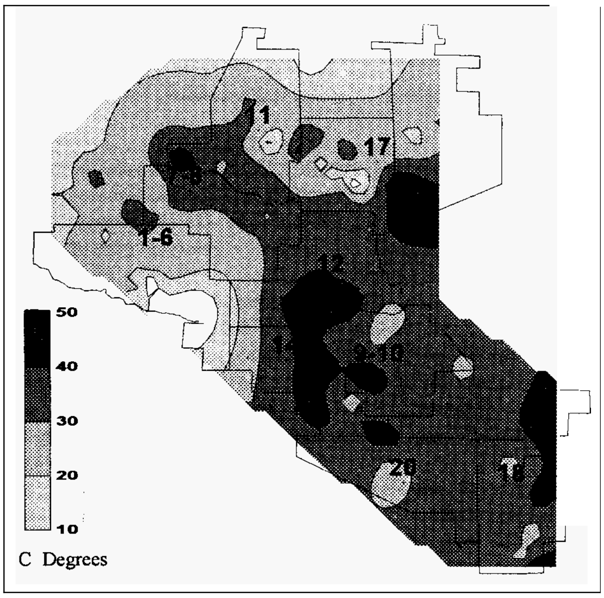

Figure 5. Steam superheat at bottom-hole flowing conditions, calculated from surface measurements, January 1994.

Gambill (1992), presented two simple mixing models for estimating the fraction of production which is injectate-derived steam (IDS). Both methods rely on the distinctive shift in isotopic composition of steam condensate which occurs when it passes through an evaporative cooling tower The average of the ratios of cumulative IDS production to cumulative injection calculated by Gambill is shown in Figure 6 for the years 1983 through 1988. The annual IDS production rate averaged approximately 70% of the mass injection rate during those years.

The mixing model analysis of isotope data can also be used to track the relative contributions of "native" reservoir steam and IDS over time. Figure 7 shows the increasing fraction of IDS observed from the Union leases between 1989 and 1991. IDS production increased with time, as did the ratio of IDS to total steam production. Since the mass of

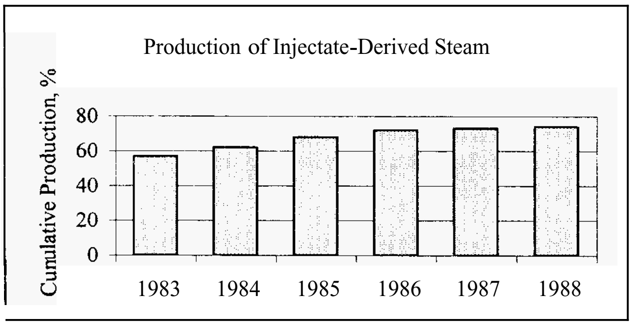

Figure 6. Cumulative production of all previously-injected fluids, derived from stable isotope data, after Gambill (1992).

injected fluid decreased annually over this three year period, a time lag must exist between injection and production of a sizable fraction of the IDS. Unfortunately, directly comparable data are not available after 1992, when the collection point for condensate at some of the plants had to be moved from the cooling tower to the condenser hot well. The question of what steam production would have been without injection during the 1989-91 time period is also unresolved by the isotope data.

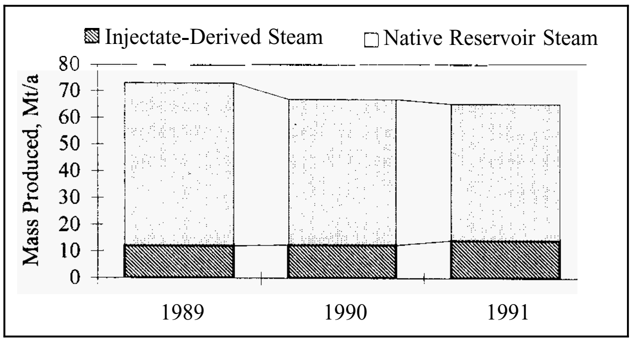

Figure 7. Sources of produced steam, inferred from stable isotope mixing, after Gambill (1992).

On a local scale, the heterogeneity of The Geysers reservoir **leads** to highly variable results For example, two injectors designed to put water into relatively shallow superheated portions of the reservoir produced markedly different responses. LF-2 in the Unit 9&10 area, and DV-I 1 in the Unit 18 area (Figure 1) were put in injection service in 1992 and 1993, respectively.

In the case of LF-2, steam production from nearby wells increased only slightly, and injection created problems with two of them. LF-39, located approximately 150 meters from LF-2, experienced liquid water breakthrough and reduced steam production for the first three months of LF-2 operation. LF-39 returned to superheated conditions within six months of LF-2 startup.

Production well LF-35's problem was liquid breakthrough and silica scaling in the pipeline, which began nine months after the start of LF-2 injection. LF-35 is located approximately one kilometer fiom LF-2, and examination of geologic conditions in the area suggests that water flowed through a permeable zone at a lithologic boundary in the reservoir rocks. Curiously, the liquid breakthrough did not appear to reduce the steam production rate.

In contrast to the negative effects associated with operation of LF-2, water injection into DV-11 has been highly successful (Voge, *et al.*, 1994). Steam production from nearby Union wells increased 36 t/h, while an additional 22 t/h was detected in the adjoining NCPA area. This represents a recovery of more than 40% of the injectate as produced steam during the test interval. The average produced steam temperature measurements in nearby Union wells declined only 10°C, and the wells remained superheated.

Microseismic records in the area have been interpreted as showing directions of fluid movement. The distribution of events recorded during the first ten months of the test are shown in Figure 8. These suggest movement southward, along a path near the top of the felsite, and straight down into the felsite. These flow patterns are consistent with the contrasting fracture orientations discussed above.

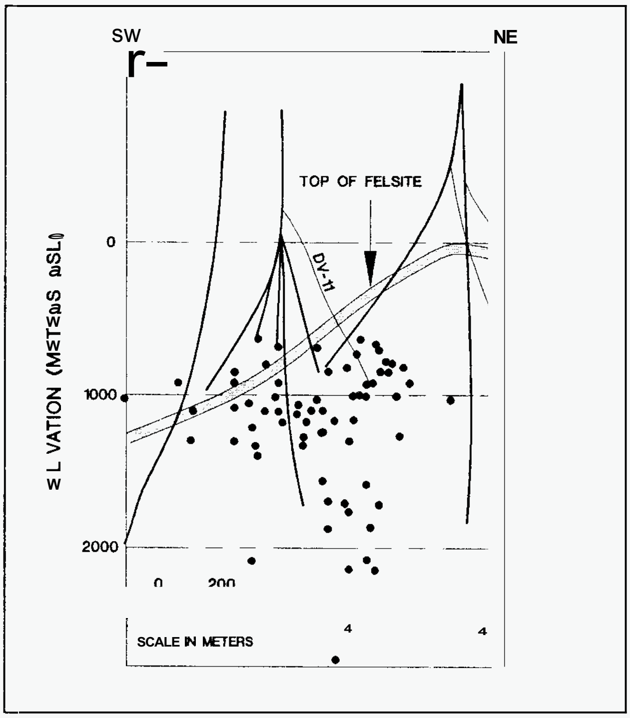

Figure 8. Microearthquakes recorded during injection in well DV-11. Dots show projections, onto a NESW cross section, of all hypocenters within 457 m lateral distance.

Similar results, including pressure and steam rate increases, were reported for superheated, pressure-depleted regions of Larderello, Italy (Bertrami, *et al.*, 1985), and in the test of NCPA well C-11 in the Southeast Geysers Study Area (Enedy, *et al.*, 1992).

Reservoir steam chemistry changes in areas affected by injection in the Union area are similar to those reported in the adjoining NCPA area (Klein and Enedy, 1992), and in Larderello (Bertrami *et al.*, 1985). The five nearest neighbors of injection well DV-11 exhibited a 39% reduction in the concentration of noncondensable gas (NCG) in the first four months of injection. The ammonia fraction of the dry gas rose by 274%, from 6.9 to 25.8 mole%. The concentration of chloride in the steam declined by one third, to a value of 0.125 $mg \cdot kg^{-1}$. **This** reduction may be the result of dilution by chloride-free **IDS,** or by scrubbing of chloride in the reservoir by liquid water, as proposed by Haizlip and Truesdell (1992).

7. SEISMICITY

Geothermal reservoirs are generally found in seismically active areas, so the possibility of links between seismic activity and operations continues to be of interest to field operators, scientists and the public. Scientists have variously suggested that Geysers seismicity is: (1) unrelated to geothermal operations (Hamilton and Muffler, 1972); (2) broadly induced by steam withdrawal (Eberhart-Phillips and Oppenheimer, 1984); or (3) locally induced by water injection (Ludwin and Bufe, 1980; Stark, 1990).

Batini, *et al.* (1985) studied seismicity at Larderello, Italy. They concluded that injection induces **MEQs** with a magnitude ceiling of 2.0. Larger events showed little or no correlation with injection. The authors suggested that injection, by inducing **MEQs,** could relieve stresses that might otherwise lead to larger quakes.

At The Geysers, Stark (1990) reported temporal correlations between injection and **MEQs** at wells GDC-18 and DX-61. We investigated whether these correlations were subject to the magnitude ceiling reported by Batini, *et al.* (1985). Stark's correlations were based in part on proprietary Union data with no calculated magnitudes. To investigate the magnitude dependence, we therefore relied on the USGS CALNET earthquake catalog (Eberhart-Phillips and Oppenheimer, 1984), which contains a continuous record of Geysers events (with magnitudes) dating back to **1976.** The CALNET data set for The *Geysers* has a long-term magnitude threshold of 1.2 (D. Oppenheimer, personal communication), but thresholds of 0.7 for the GDC-18 area and 0.8 for the DX-61 area were estimated by applying standard b-value analysis to the temporal and spatial windows considered. To avoid spurious effects due to changes in event detection capabilities, only events above those threshold magnitudes were considered. The vast majority of events presented by Stark (1990) were of magnitude less than 2.0. Typically, **MEQs** of magnitude less than 2.0 are barely felt, or not felt at all (Richter, 1958).

Figure 9 shows seismicity in the GDC-18 area during the period in which the well was in service as an injector. The events below and above magnitude 2.0 are shown separately, along with the mass injected each month. The larger events are about an order of magnitude less common than the smaller ones. In fact, the larger events are so infrequent that we extended the time window analyzed by Stark (1990) in order to display more of them. Moreover, the larger events do not appear to vary in any obvious relationship to the injected volumes. The smaller **MEQs** appear to more closely relate to injection, although there are numerous events which show no relationship to injection. Figure 10 displays the same type of data for the vicinity of DX-61, again showing that the smaller events far outnumber the larger events. The variations in frequency of the smaller **MEQs** do not track injection rates as well as in the GDC-18 data, and the larger events appear more poorly related

In conclusion, the CALNET records of the cases analyzed by Stark (1990) suggest that the magnitude ceiling for injection-induced seismicity observed at Larderello, Italy by Batini, et al., (1985) exists at The Geysers also

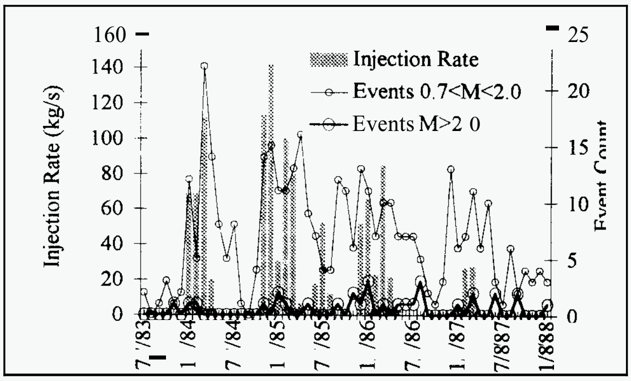

Figure 9. Monthly injection rates and event counts at GDC-18. Events recorded by USGS at depths >914 m subsea, within 1219 m square centered on wellhead.

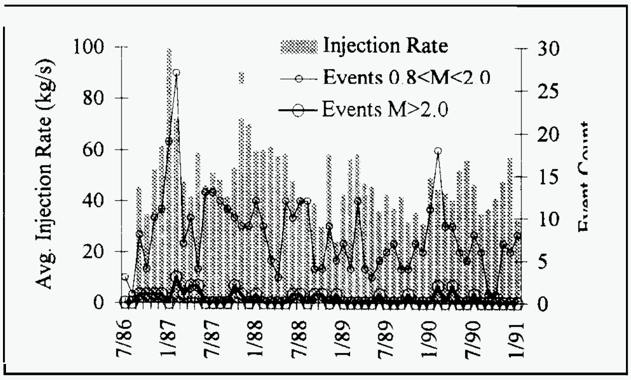

Figure 10. Monthly injection rates and event counts at DX-61. Events recorded by USGS at depths from 914 to 3048 m subsea, within 1219 m square centered on wellhead.

8. CONCLUSIONS

1. Production response to injection varies greatly with reservoir heterogeneity and thermodynamic conditions. The practical limit on injection rate in various parts of The Geysers has ranged from a small fraction to more than 100% **of** production. The time lag between first injection and initial production response has varied from hours to years.

2. Tritium, other tracers, and stable isotopes **of** hydrogen and oxygen have been used to trace long-term fluid movement and to measure boiling rates. These methods have been used to determine the fraction of produced steam derived from injectate, but not the change in total production caused by injection.

3. The association of microearthquakes with injection at The Geysers appears to be limited to events of magnitude less than 2.0, as was found for **MEQs** near injection wells at Larderello.

4. Injection appears to reduce the amount and concentration of both chloride and total noncondensable gasses in produced steam.

9. ACKNOWLEDGEMENT

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