RECOVERY OF INJECTED CONDENSATE AS STEAM IN THE SOUTH GEYSERS FIELD

Joseph J. Beall and W.T. Box, Jr.

Calpine Corporation
P.O. Box 11279, Santa Rosa, California 95406

Steven L. Enedy

Northern California Power Agency
P.O. Box 663, Middletown, California 95461

ABSTRACT

Power plant condensate, highly enriched in deuterium (D) relative to reservoir steam, is injected into The Geysers reservoir. The elevated D content of produced steam containing an injection component facilitates tracing of injection-derived steam (IDS). Calculated recovery of IDS peaked in 1987 at nearly 800,000 lb/hr for the Units 13, 16, NCPA-1 and NCPA-2 area of the south Geysers. The cause of the calculated subsequent decline is unclear, but could be due to: (1) less efficient boiling of injected condensate as a consequence of cooling of fracture surfaces within the injected water mass, (2) fractionation of D between injection water and IDS at temperatures below 220°C or, (3) movement of injection water under hydrostatic pressure to depths below the effective "floor" of the reservoir.

INTRODUCTION

Steam condensate is injected into the vapor dominated Geysers reservoir after extensive evaporation in power plant cooling towers. Through evaporation the original condensate becomes highly enriched in the stable heavy isotopes of hydrogen and oxygen, namely deuterium (D) and oxygen-18 (^{18}O) (Figure 1). Unlike many organic tracers, ^{18}O and D are stable at high temperatures. They are not, however, equally suited for use as tracers in a steam reservoir. D, unlike ^{18}O, undergoes very little fractionation between steam and water phases during the boiling of injection water in the reservoir. The steam generated has very nearly the same D content as the water from which it boiled, provided that the boiling occurs at temperatures of 200°C or above. Moreover, the D content of injection-derived steam (IDS) is far less susceptible than the ^{18}O content to changes in concentration resulting from ion exchange between rock minerals and water molecules. This is a consequence of the vastly smaller amount of hydrogen relative to oxygen in Geysers reservoir rocks.

For these reasons, periodic analyses of D in the condensate of producing steam wells provides an accurate means of tracing the movement of IDS in the reservoir (Nuti, Calore and Noto, 1981). In addition, if the initial D content of the uncontaminated reservoir steam is known, along with the D content of the injection water, the contribution of IDS to a well's total steamflow can be calculated from the equation:

$$\frac{D_{\text{initial}} - D_{\text{current}}}{D_{\text{initial}} - D_{\text{injection}}} = \text{IDS Fraction}$$

For this calculation, the initial D value for a well is taken from an early analysis in its production history. The injection water D value is the weighted average of injection water D analyses during the previous 12 months. As noted by Truesdell, and others (1987) and illustrated in Figure 1, the initial D values for steam in the south Geysers field average about -54 ‰. δD for injection water ranges between -8 ‰ and -14 ‰. (For an explanation of notation and ‰ units, see Craig, 1961).

MAPPING THE MOVEMENT OF INJECTION DERIVED STEAM

Figures 2 through 4 illustrate the contoured δD of steam wells in the Calpine Corporation - Northern California

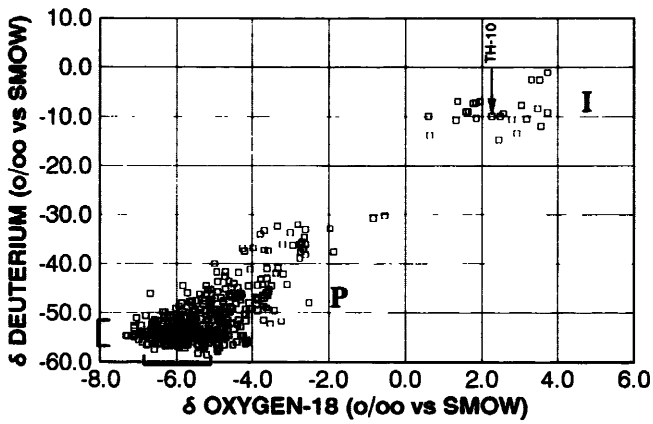

Figure 1. ^{18}O vs D of produced steam (P) and injection water(I) in Units 13 and 16 area of the south Geysers. Bars on ^{18}O and D axes give range of initial steam composition. TH-10 is a water sample recovered during air drilling *(see text for explanation).*

Power Agency (NCPA) area of the south Geysers. These figures show the D distribution in the reservoir during late 1985 - early 1986 (Figure 2), early to mid 1987 (Figure 3) and late 1987 - early 1988 (Figure 4). Five D anomalies stand out in Figures 2 and 3. Starting with the northernmost and proceeding in a clockwise manner the anomalies are identified as:

1). North Unit 13 (NU13)
2). Unit 16
3). NCPA - 2
4). NCPA - 1
5). Southwest Unit 13 (SWU13)

All, except for the SWU13 D anomaly, are centered on injection wells. The anomalies form from dissemination in the reservoir of IDS. Injection began in the south Geysers area in 1980 with the start-up of the Unit 13 power plant. The NU13 anomaly has experienced injection constantly since that time. A second NU13 injection well (the northern of the two) was added in early 1985 to reduce the amount of water breaking through to nearby production wells.

Injection into the remaining injection-well-associated anomalies began in 1984 to 1985. The rapidity with which D anomalies form is illustrated by the Unit 16 anomaly. Injection there began in October 1985. The data contoured for that anomaly in Figure 2 are from samples collected on February 2, 1986.

D anomalies also decay fairly rapidly with the cessation of injection. Injection in the NCPA-2 anomaly was terminated in April 1987. As shown in Figure 4, that anomaly, over a 1-year period diminished markedly in intensity and should disappear completely as the last injected water is boiled away.

Typically, the IDS component of steamflow from production wells located near injection wells is on the order of 20 to 50 percent. The nearest production well to the NCPA-1 injection well is particularly interesting as 80 percent of its 114,000 lb/hr of steam production (in October 1987) is IDS.

The SWU13 anomaly, as noted above, is not centered on an injection well. It is, however, located near the center of an area of low reservoir pressure which formed as a response to the long term production of shallow, prolific wells. Production wells in both the Calpine and NCPA segments of this area have been characterized in recent years by rapidly falling pressure and increasingly superheated steam (Enedy, this volume). IDS drawn into this pressure sink originates from boiling of injection water which has sunk deep in the reservoir. It then migrates laterally and upward at a steep angle into the anomaly. Lack of continuity between an injection well and the SWU13 anomaly makes difficult a positive identification of the source(s) of injection water. Examination of Figure 3 suggests a connection with the NU13 anomaly.

There is a tendency for the D anomalies shown in Figures 2 through 4 to be elongated in the north to north-northeast direction. This indicates preferential permeability in this direction throughout this part of The Geysers field. It also supports the observations of east-southeast west-northwest extension which have been documented for The Geysers area on the basis of both seismic studies and geodetic measurements (Oppenheimer, 1986.)

ESTIMATED INJECTION RECOVERY FROM PRODUCTION LATE 1985 THROUGH EARLY 1988

As described above, mapping of δD values of produced steam provides an accurate means of tracking the movement of IDS in the reservoir. Of equal importance, from the perspective of reservoir management, is the amount of injection water which is recovered as steam. Maximizing the recovery has the obvious benefits of enhancing reserves and maintenance of reservoir pressure (Bertrami and others, 1985; Horne, 1985; Bodvarsson and Stefansson, 1989).

Figure 5 illustrates the percent of IDS recovery vs. time for the combined Unit 13 anomalies, the Unit 16 anomaly and the combined NCPA-1 and NCPA-2 anomalies. Percent recovery is defined as the total flow rate of IDS divided by the average injection rate for the previous 12 months. Each graph shows a peak in 1987, with percent recovery ranging from 34 to 52 percent.

Table 1 shows the injection recovery rate in thousand pounds per hour (klb/hr) for each D anomaly on various dates over the period extending from late 1985 through late 1988. The same data are shown graphically in Figure 6 for the combined Unit 13 and Unit 16 anomalies (lower curve) and for the total of all anomalies (upper curve). The "total" curve is very similar to the combined Units 13 and 16 curve except that it has a greater amplitude.

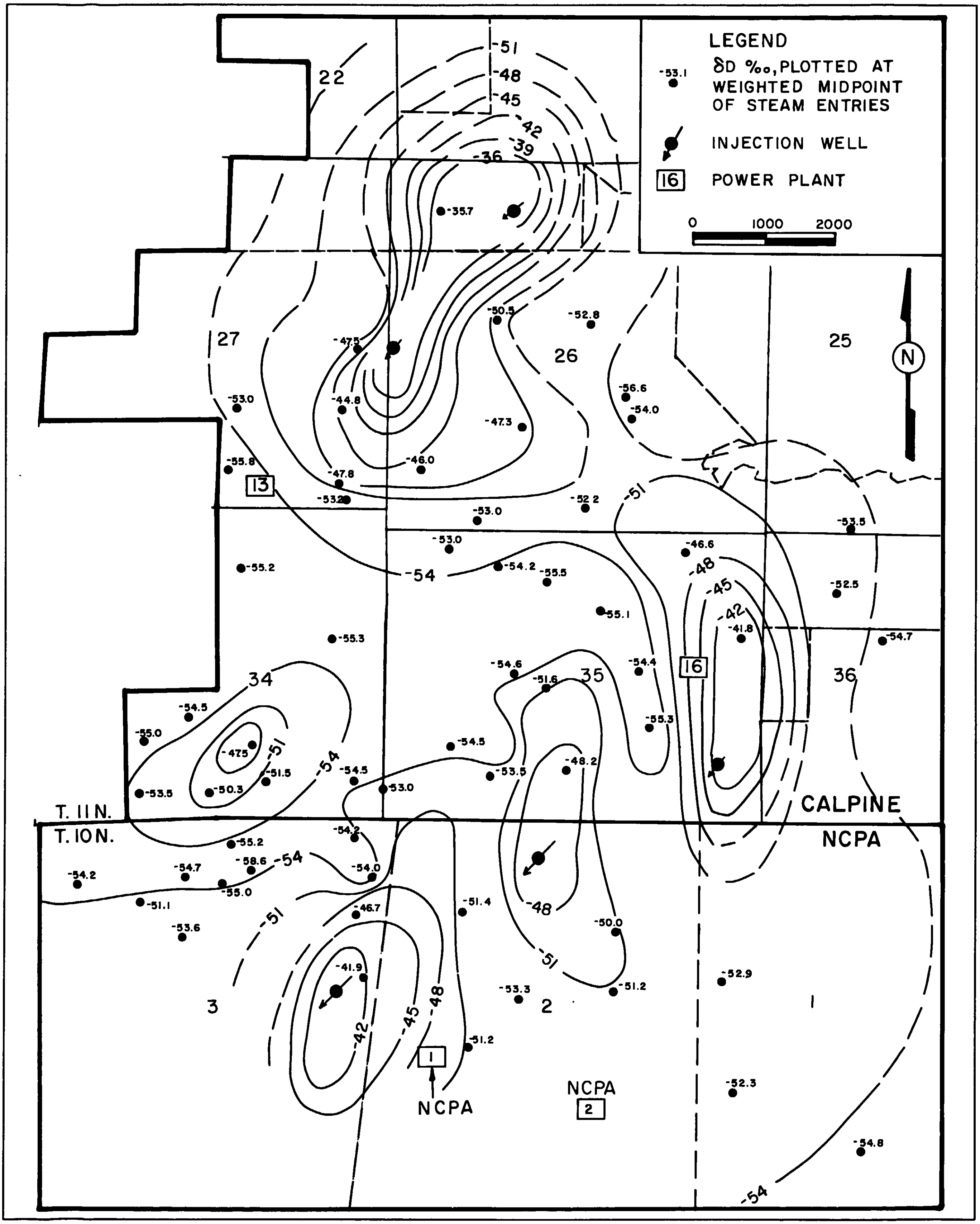

Figure 2. Contoured δD of steam wells in the Calpine Corporation - Northern California Power Agency area of the south Geysers. Data contoured are for the period late 1985 to early 1986.

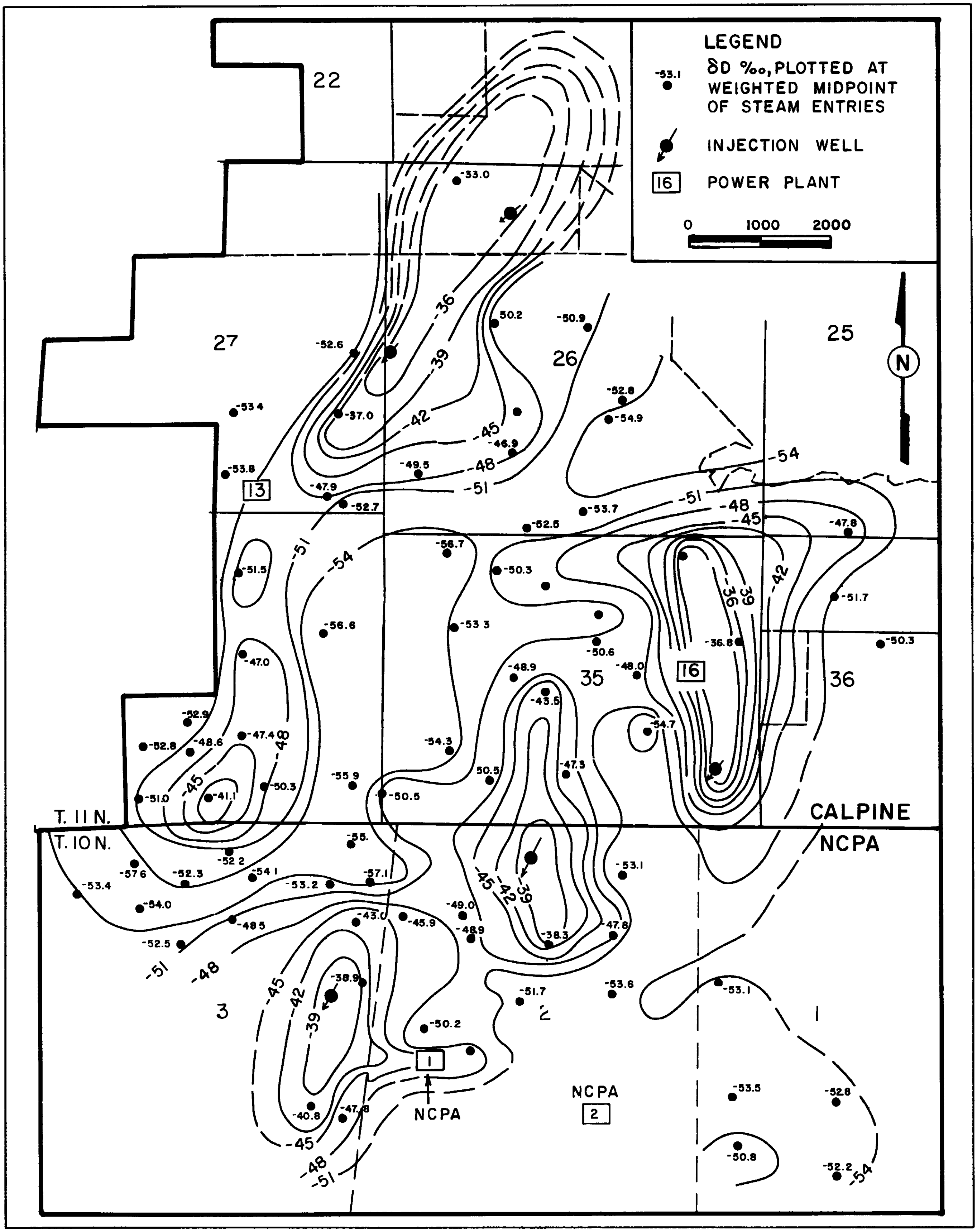

Figure 3. Contoured δD of steam wells in the Calpine Corporation - Northern California Power Agency area of the south Geysers. Data contoured are for the period early to mid 1987.

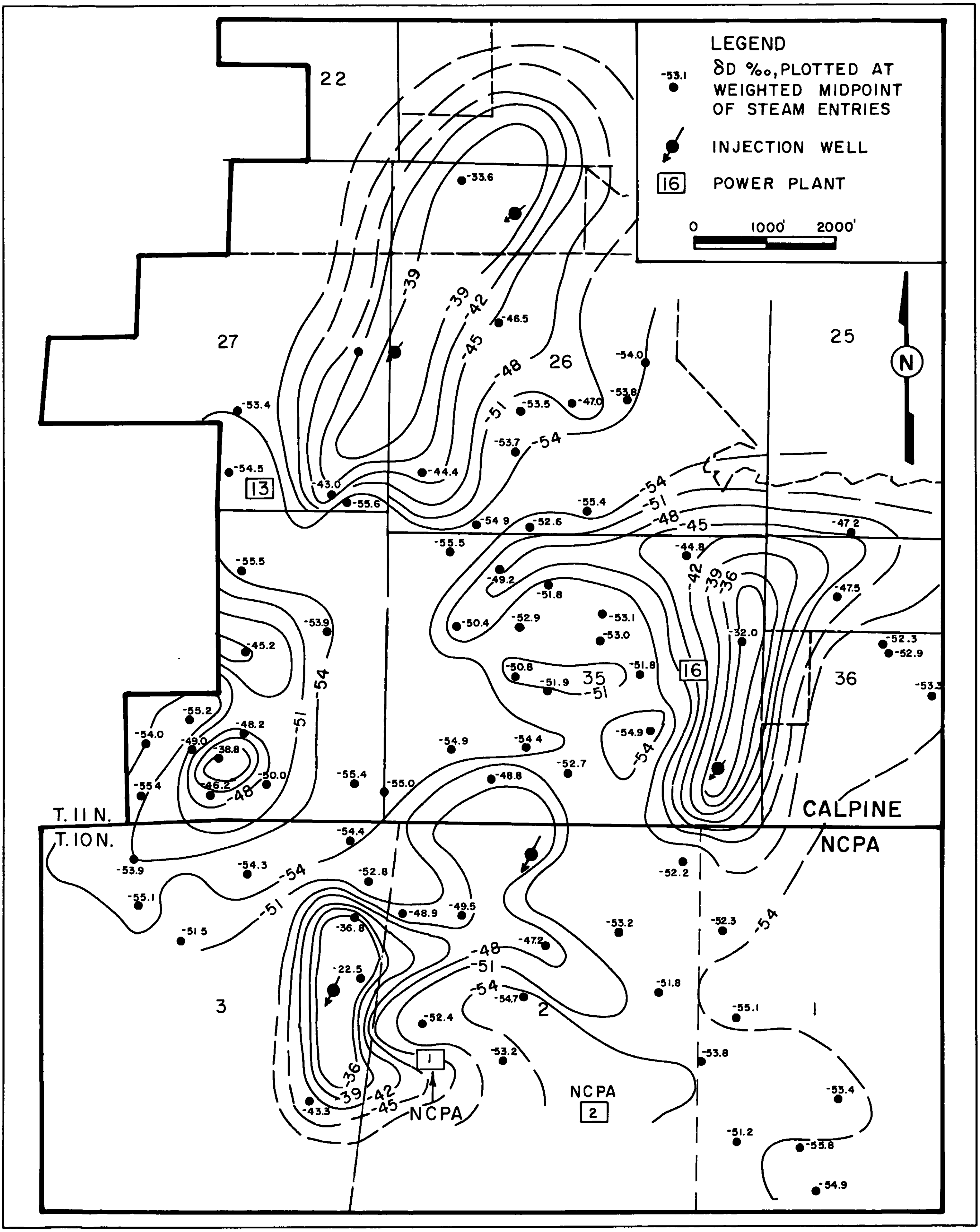

Figure 4. Contoured δD of steam wells in the Calpine Corporation - Northern California Power Agency area of the south Geysers. Data contoured are for the period late 1987 to early 1988.

All of the percent injection recovery curves in Figure 5 and the injection recovery rate curves in Figure 6 show maxima in 1987. The total injection recovery rate for the entire study area peaked at nearly 800,000 lb/hr. The subsequent decline lowered the total to 529,000 lb/hr in October 1988.

CAUSES OF THE DECLINE INJECTION RECOVERY

The observed decline is difficult to explain but is likely the result of a combination of reservoir factors. Average injection rates in individual wells are typically in the range of 400,000 to 700,000 lb/hr. These high rates of injection result eventually in the growth of a body of water in fractures around the injection well. During the growth period, the water front continually advances into hot rock. The continued injection of large quantities of cold water may eventually cool the surfaces of fractures containing the water body and at the water front, resulting in diminished boiling and steam production.

Another possible explanation is that the decline in IDS recovery is not real but a product of the calculations. Fractionation of D under conditions in which boiling occurred at temperatures below 200°C would produce steam with δD values a few per mil (‰) lower (more negative) than the injection water. This would cause calculations of the fraction of IDS which are too low. This would also require that the fractionated injection water left behind in the reservoir after steam separation become progressively enriched in D. During infill drilling of the Thorne-10 well, located near the NU13 D anomaly, water was encountered 1,200 feet distance from the wellbore of the nearest injection well. The water identified in Figure 1 as "TH-10," is identical in both $\delta^{18}O$ and δD to the average Unit 13 injection water. The same result was observed for an analysis of water recovered during infill drilling near the NCPA-2 anomaly. These events strongly suggest that fractionation of injection water during boiling does not occur to any significant extent.

A third explanation involves the possible movement of injection water to depths below the nominal reservoir "floor." High hydrostatic pressures are developed deep in the injected water body as it grows to a large size. This may result in water being forced deep through high angle fractures which are closed under vapor static (low pressure) conditions. By this mechanism, injection water might be forced below the effective floor of the reservoir and unavailable for steam generation. This explanation is compatible with our observations of microseismic activity in the NU13 D anomaly, which, in the study area has by far the longest injection history. Microearthquake epicenters have been observed there to cluster closely around the injection wells. Those events with the best constrained depths, however, averaged several thousand feet deeper than the injection wells. Working against this explanation, however, is the fact that production wells located near injection wells often produce enough water to be a nuisance. There does not seem to have been a general drying up of those wells concomitant with the post 1987 decline in IDS recovery.

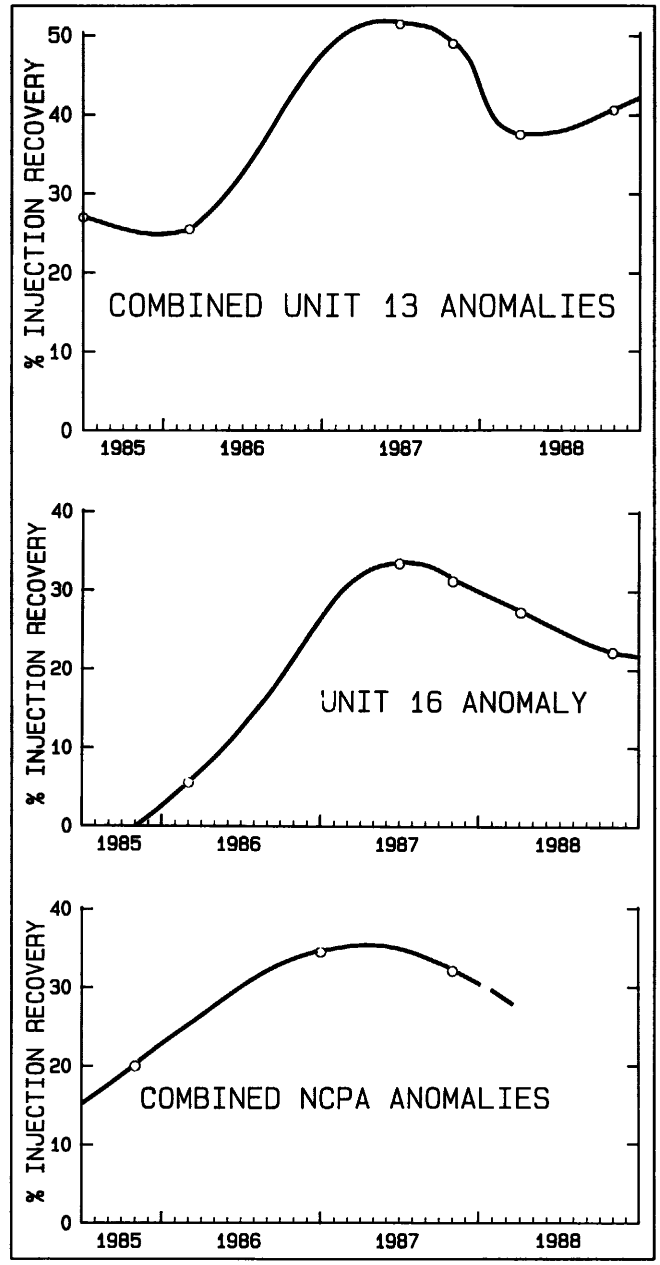

Figure 5. Percent injection recovery vs. time for combined Unit 13 anomalies, Unit 16 and combined NCPA anomalies.

SUMMARY AND CONCLUSIONS

Anomalies mapped in the Calpine/NCPA area of the south Geysers typically are elongated to the north or north-northeast. This indicates preferential permeability

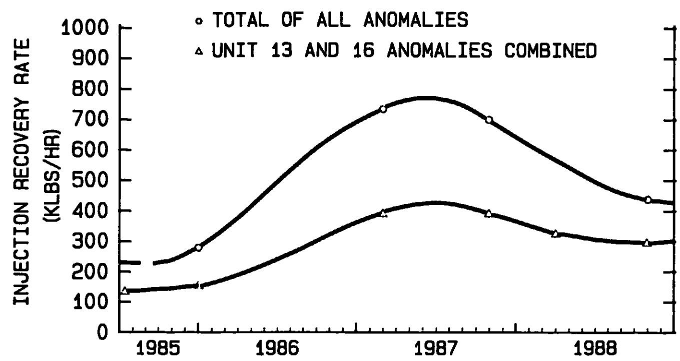

Figure 6. Recovery rate (klbs/hr) vs. time for Unit 13 and 16 anomalies combined (lower curve) and for the total of all anomalies (upper curve).

in that direction, which is compatible with the east-southeast west-northwest extension in The Geysers region.

Of the five anomalies mapped, four are centered on injection wells. The lack of an injection well within the SWU13 D anomaly implies that IDS originated from deep boiling of injection water and migrated up and laterally into the southwest Unit 13 area in response to the reservoir pressure gradient. This area of the reservoir is characterized by low reservoir pressure as a consequence of the long term production of initially very prolific wells. The combination of low pressure, high permeability and increasingly superheated steam (indicating little or no liquid saturation in that part of the reservoir) identified the area around the SWU13 D anomaly as ideal for injection with the goal of maximizing IDS recovery and sustaining reservoir pressure. To this end, NCPA and Calpine have conducted since October 1989 a joint injection program in and adjacent to the SWU13 D anomaly. Preliminary results indicate a high degree of success.

Recovery of IDS during the period from late 1985 through late 1988 peaked in 1987 at about 800,000 lb~~s~~/hr. The cause of the subsequent decline is unclear. The decline may have been partially the result of cooling of fracture surfaces along the boiling front of injection water masses. Based on analyses of injection water recovered during infill drilling from near the NU13 and NCPA-2 D anomalies, it appears that fractionation during boiling of injection water cannot explain this trend. Another possibility is that high hydrostatic pressures deep in the injection water masses allow injection water to migrate deep along high angle fractures which are closed at that depth under vapor static (low pressure) conditions. Deep seismic activity with epicenters clustered closely around the NU13 D anomaly injection wells seems to support this idea. However, the lack of an observed post 1987 drying out of the reservoir areas surrounding injection wells argues against this explanation.

ACKNOWLEDGEMENTS

The authors thank the managements of the Northern California Power Agency and Calpine Corporation for permission to publish this paper. Manuscript typing by J.E. Hathorn and drafting by M. Davenport are gratefully acknowledged.

REFERENCES

Bertrami, R., Calore, C., Capetti, G., Celati, R. and D'Amore, F., 1985. A three-year recharge test by reinjection in the central area of the Larderello field: Analysis of production data, Geothermal Resources Council Transactions, v. 9, pt. 2, p. 293-298.

Bodvarsson, G.S. and Steffansson, V., 1989. Some theoretical and field aspects of reinjection in geothermal reservoirs. Water Resources Research, v. 25, no. 6, p. 1235-1248

Craig, H., 1961, Standard for reporting concentrations of Deuterium and Oxygen-18 in natural waters. Science, v. 133, p. 1702-1703.

Enedy, K.L., 1992. Downhole enthalpy and superheat evolution in Geysers steam wells, this volume, p. 205.

Horne, R.N., 1985, Reservoir Engineering aspects of reinjection, Geothermics, v. 14, p. 449-457.

Nuti, S., Calore C. and Noto, P., 1981, Use of environmental isotopes as natural tracers in a reinjection experiment at Larderello: Proceedings, Seventh Annual Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, CA, p. 85-89.

Truesdell, A.H., Haizlip, J.R., Box, W.T. Jr. and D'Amore, F. 1987, Fieldwide chemical and isotopic gradients in steam from The Geysers, Proceedings, Twelfth Annual Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, CA, p. 241-246.