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EFFECT OF CONDENSATE INJECTION ON STEAM CHEMISTRY AT THE GEYSERS FIELD

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ABSTRACT

Injection of steam condensate back into The Geysers reservoir produces shifts in the chemistry of produced steam at nearby wells. Specifically, these effects include: (1) changes in the spatial variation of noncondensible gas/steam ratio; (2) changes in the concentrations of stable isotopes ^{18}O and deuterium; (3) shifts in the abundance of gas species Ar, N_2 and NH_3; and (4) changes in calculated gas geothermometers and steam saturation factors. This geochemical information, when combined with other reservoir data, has been used to assist in the targeting of new injection wells.

INTRODUCTION

Studies of steam chemistry at the Northern California Power Agency (NCPA) leasehold at the southeast Geysers steam field have shown that effects of injecting steam condensate back into the reservoir appear at certain production wells as well-defined shifts in isotope composition and gas chemistry. Specifically, injection affects (1) the spatial variation of noncondensible gas (NCG) concentration in steam; (2) the concentrations of stable isotopes oxygen-18 (^{18}O) and deuterium (D); and (3) the concentrations of gas species Ar, N_2, NH_3 and, to a lesser extent, H_2S. These data, plus measurements of gas geothermometer and steam saturation factors, have been combined with other reservoir data to assist in the targeting of a new injection well to be used in a joint injection program.

DATA COLLECTION

Background

Data for this study were obtained during an intensive gas and condensate sampling program initiated by the NCPA in October, 1985 immediately following purchase of the steam field. Prior to that time, the wells had not been sampled on a systematic or regular basis, and only one survey of the entire well field had been carried out, in August 1984. None of the early work included analyses of condensate isotopes. By comparison, steam production and injection of condensate back into the reservoir had begun in January, 1983. As of October, 1985 there were 15 production wells and four wells that had been or were being used for injection. By February, 1987 there were 41 production wells, and four wells that had been used for injection. Through February, 1987, about 30 percent of total steam produced, by mass, had been reinjected into the reservoir. This report is based on data collected until February 1987.

Sampling Program

The chemical sampling program, designed by GeothermEx and initiated by NCPA, included: sampling steam flow during the rig test of each new well; sampling each new production well within a few days of its connection and initial flow to the power plant; sampling each new well three additional times during the first year of production, on a quarterly basis; and sampling each producing well twice a year. With few exceptions the program was carried out as planned, with three full-field surveys between October 1985 and January 1987.

Sampling and Analysis Procedures

Each sample included as a minimum: (1) a gas/steam bomb for determining the NCG composition and ratios of

each NCG component to steam, for analysis on a routine basis; (2) condensate for analysis of dissolved ionic species, on a selected basis; (3) condensate for analysis of the stable isotopes D and ^{18}O, on a selected basis; and, at notably "wet" wells, a water sample obtained with a mini-separator. Associated data records included wellhead pressure, temperature, superheat and total mass flow. The gas/steam bombs were of the conventional design which collects both the NCG and steam condensate into an evacuated flask containing sodium hydroxide and cadmium acetate solution. The condensate samples for isotope analysis were stored in glass flasks. Of these, about one-third were analyzed; the rest have remained in storage.

The chemical analyses of NCG composition and NCG in steam were carried out by Thermochem, Inc. of Santa Rosa, CA. These included CO_2, H_2S, NH_3, CH_4, Ar, N_2, H_2. O_2 was also measured to detect air contamination. Every tenth sample was a duplicate. Condensate samples were analyzed by the University of Utah Research Institute for pH, Ec, HCO_3, SO_4, Cl, F, TDS, H_2S, NH_4+ and 37 cations using ICP analysis. Stable isotopes were analyzed at Southern Methodist University, which received occasional duplicates for quality control.

EFFECTS OF WATER INJECTION

NCG Distribution

Concentrations of NCG in steam as ppm-wt in January 1987 are plotted on a map of the well field shown as Figure 1. Data points were placed at the approximate surface location of the principal steam entry into each well for construction of the isochrons but the values are not listed on the map. There was no significant difference in the spatial variation of the NCG compared to prior surveys, probably because injection breakthrough already had occurred before the first survey in 1985. NCG concentrations are zoned outwards, from about 350 to 400 ppm-wt along the central north boundary to 2,000 to 6,000 parts per million by weight (ppmw) at locations on the southern, southeastern and southwestern field margins. There is a low in NCG concentration at two wells, the production zones of which are indicated by solid triangles. This low probably is related to injection of condensate at two other nearby points. We believe that NCG concentrations at points indicated by open triangles also are affected by injection, because these wells show a shift in stable isotopes.

Stable Isotope Values

Figure 2 is a plot of D versus ^{18}O showing all isotope data from the leasehold. Excluding steam clearly affected by injection (see below), there is a tendency for δD to decrease as $\delta^{18}O$ increases. The lower boundary of the

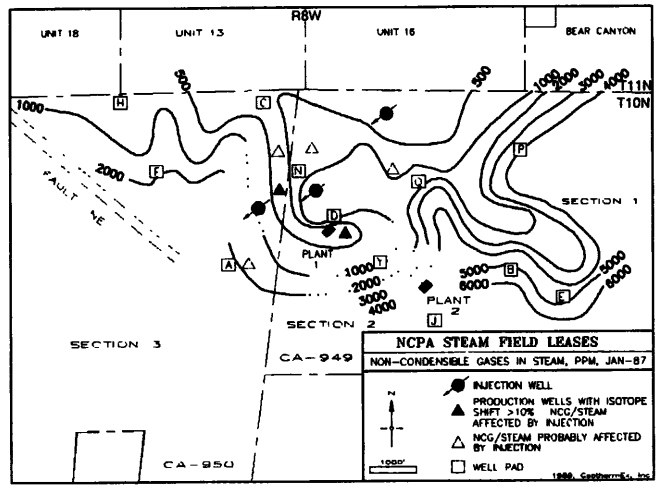

Figure 1. Distribution of noncondensible gases in produced steam, ppm-wt, January 1987.

sample field is created by two linear point distributions along lines L1 and L2. At lower $\delta^{18}O$ there is little to no change in δD (line L1). These samples are from wells to the south, southeast and southwest, near the reservoir boundaries. At higher $\delta^{18}O$ there is a distinct decrease of δD as $\delta^{18}O$ increases (line L2). This characteristic is found in the wells located in the field interior.

Trends L1 and L2 are an expression of the temperature dependence of the vapor-liquid distribution coefficients of D and ^{18}O (Friedman and O'Neil, 1977). Trend L1, among samples from the reservoir boundary, corresponds to processes of vapor and liquid equilibration (boiling, condensation) at about 225°C. In contrast, the slope of Trend L2 among samples from the field interior corresponds to equilibrium processes at about 245 to 255°C.

The injection of power plant steam condensate from cooling towers back into the reservoir is producing at certain wells a large shift in the isotope composition, as shown at the top of the sample field on Figure 2. The

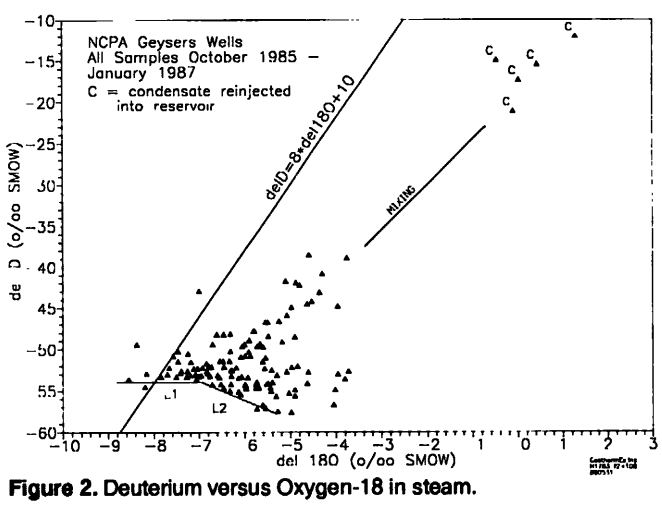

Figure 2. Deuterium versus Oxygen-18 in steam.

condensate, indicated by points C, becomes enriched in the stable heavy isotopes (^{18}O and D) and has a very different isotopic signature from produced steam as a result of nonequilibrium, relatively low temperature evaporation in the power plant cooling towers.

The fraction of produced steam that is recycled injectate can be estimated from the magnitude of the shift in δD at each affected well (see also Beall, Box and Enedy, this volume). Some fraction of the injected condensate has to boil before appearing as steam in production. However, the boiling shifts will be roughly parallel to lines L1 and L2, so the effect of boiling on δD of the injected component should be insignificant relative to other uncertainties. Some wells already were affected by injection before the first samples were collected, so that baseline conditions must be assumed using examples from other wells nearby. Doing this, the component of injection at the clearly affected wells varies from about 10 to 40 percent. Figures 9 and 10, below, distinguish two groups of these wells: one has 10 to 20 percent injected component, the other 25 to 40 percent.

Figure 3 shows the injection isotope shift at one well, where about 40 percent of the boiled injectate entered production between June 1986 and January 1987.

Effect on Gas Composition

The effect of condensate injection extends to some gas species as well as the isotopes. With respect to this we have studied Ar, N_2, NH_3 and H_2S, which were of initial interest because the injectate carries dissolved atmospheric Ar, N_2 and O_2. The Ar is not reactive, the N_2 can react with reservoir H_2 to produce NH_3, and the O_2 may react with and remove some reservoir H_2S.

Both Ar and (N_2 + NH_3) expressed as mole percent of the dry NCG show notable increases as δD increases due to injection (Figures 4 and 5). The correlation of (NH_3 + N_2) with δD tends to be stronger than that of Ar, which might be due to larger errors in determining the very low concentrations of Ar. The gas and isotope data, along with histograms of Ar mole percent and (NH_3 + N_2) mole percent (not shown) suggest that Ar in excess of about 0.025 mole percent and/or (NH_3 + N_2) in excess of about 15 mole percent indicate that injected gas is being produced. There is no well with an injection isotope shift that does not show at least one of these gas effects, but there are two wells with gas effects but no isotope effect (Figure 6). This implies, as might be expected, that the injected water and gases tend to segregate and reach production wells separately.

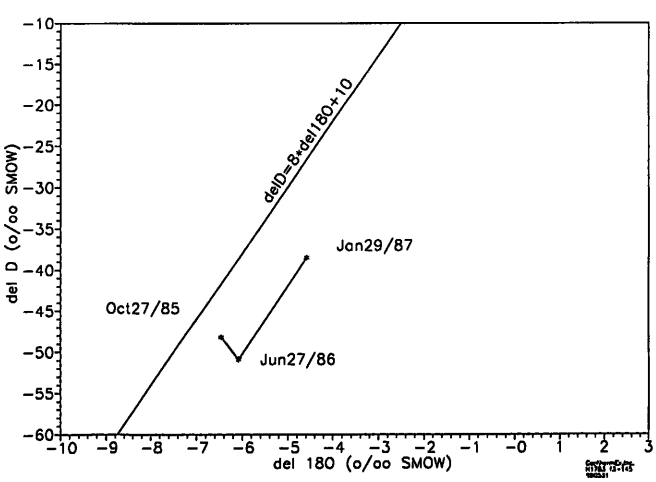

Figure 3. Isotope shift at production well caused by mixing with injected condensate.

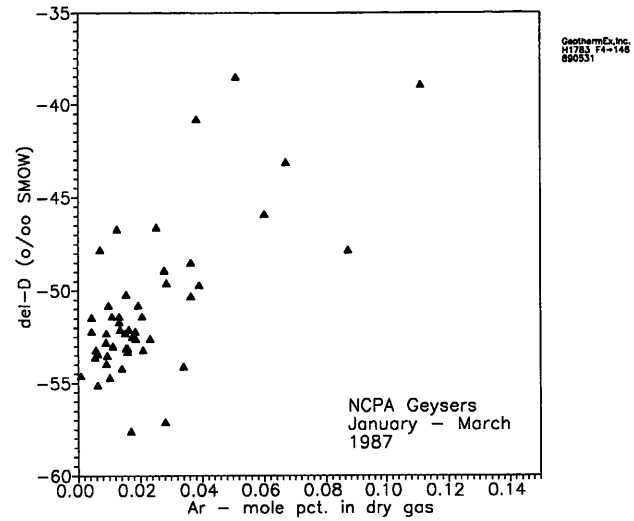

Figure 4. Deuterium versus argon in dry gas.

Almost all of the shift in (N_2 + NH_3) is caused by an increase in NH_3 accompanied by a decrease in H_2, apparently as a result of the reaction $N_2 + 3H_2 = 2NH_3$.

Effects of injection on reservoir H_2S were investigated using graphs analogous to those developed for Ar and (N_2 + NH_3) above, but with little result. H_2S was independent of δD, except at the well which shows the strongest injection isotope effect, and which showed a decrease in H_2S of 15 to 30 ppmw while NH_3 and CO_3 both increased.

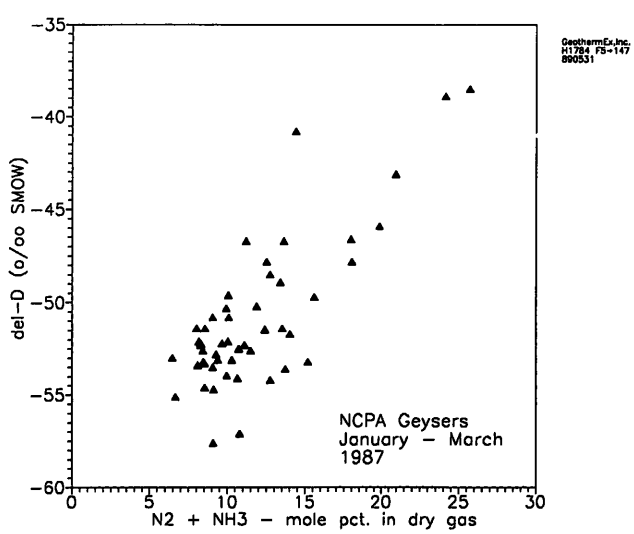

Figure 5. Deuterium versus nitrogen and ammonia in dry gas.

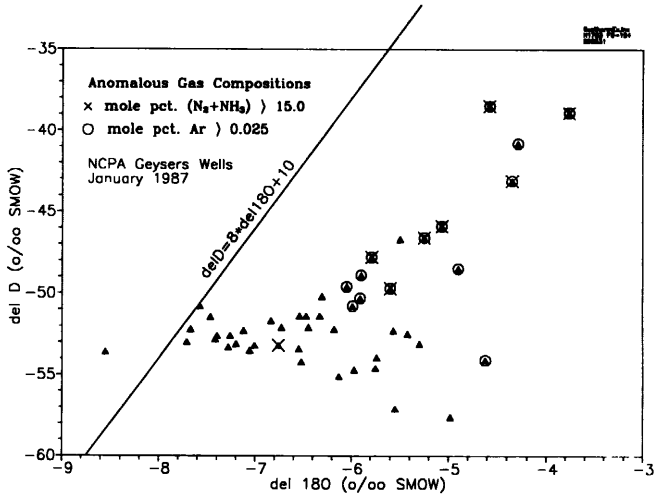

Figure 6. Deuterium versus Oxygen-18 in steam showing effect of injected gas.

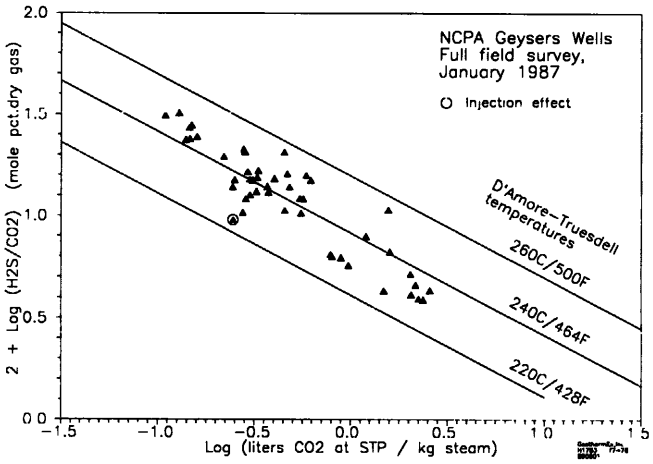

Figure 7. H_2S/CO_2 versus CO_2 in steam.

Gas Geothermometers and Steam Saturation Factors

The H_2S/CO_2 geothermometer of D'Amore and Truesdell (1980), plotted on Figure 7, is unaffected by injection. There is scatter in the data, but the results generally are compatible with an average reservoir temperature of 240°C, and suggest that temperatures beneath well pads in the southeast (Figure 9) are 10 to 15°C lower than in the center of the field. Gas compositions of wells affected by injection may be shifted toward lower than natural CO_2/kg steam, but H_2S/CO_2 appears to have re-equilibrated except at the well which also shows the strongest isotope effect (Figure 7).

Reservoir steam saturation Y is defined as the fraction of H_2O present as vapor phase in the reservoir divided by the total H_2O (vapor plus liquid) in the reservoir. Y has been estimated using various chemical relationships that express changes in gas solubilities and chemical equilibria with temperature (D'Amore, Celati and Calore, 1982). The

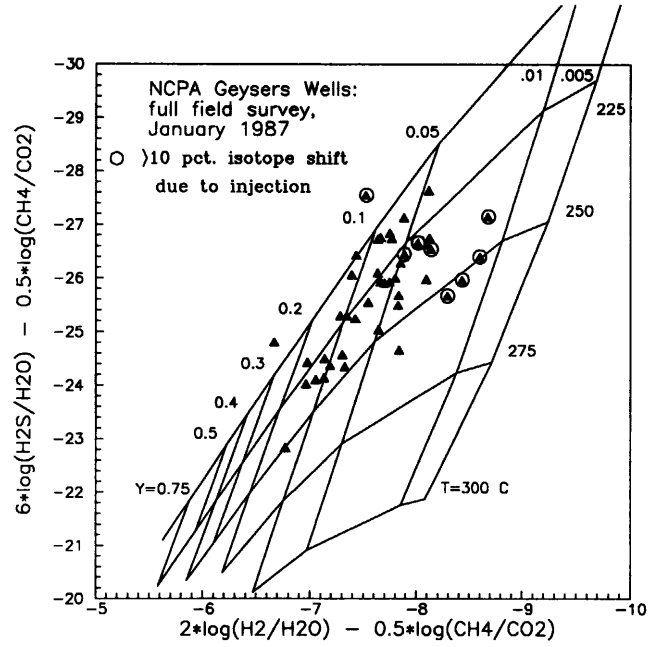

Figure 8. Reservoir temperature and steam saturation from gas equilibrium calculation.

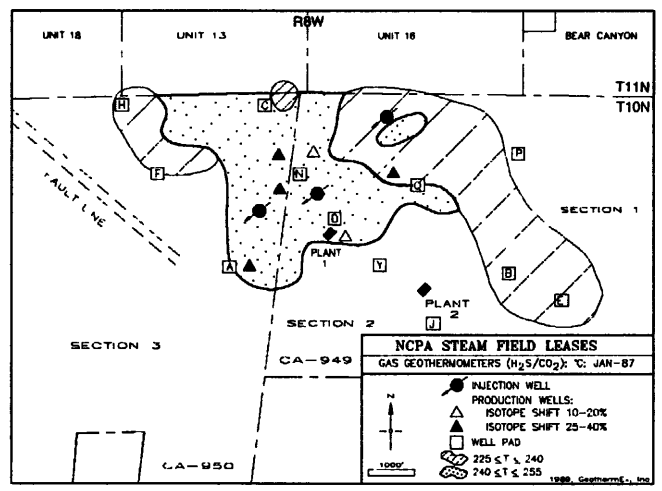

Figure 9. Distribution of temperatures from H_2S/CO 2 geothermometer, °C, January 1987.

chemical methods are approximations, but they can assist the observation of spatial and temporal trends in production. For example, when a production well shows decreasing Y, as determined from chemical relationships, there may have occurred an increase in reservoir liquid such as recently reinjected condensate. Figure 8 (after D'Amore and Truesdell, 1985) is an example of determining Y and temperature simultaneously as functions of gas composition. Wells with a shift in δD of 10 percent or greater clearly are shifted towards lower Y and possibly also towards lower temperature. Figure 10 shows the areal distribution of YH_2, determined from equilibria involving H_2, CH_4, CO_2 and H_2O (the X-axis of Figure 8) plus temperature.

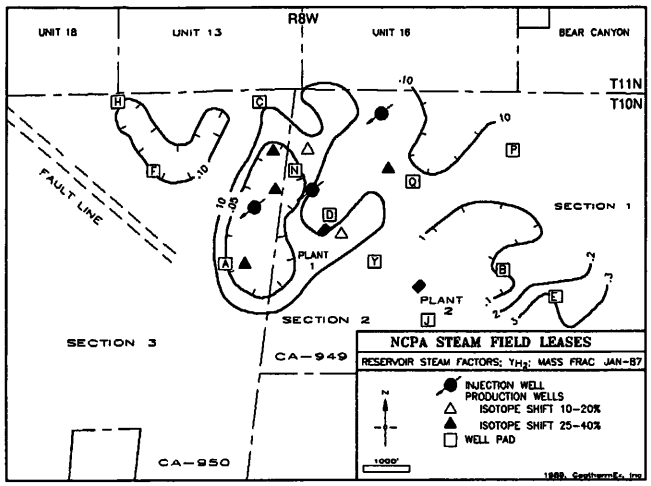

Figure 10. Distribution of reservoir steam factor YH_2, January 1987.

Injection shifts such as on Figure 8 may be caused by changes in gas/steam, and/or by changes among gas component ratios. In this case, it appears that a change in H_2/H_2O predominates, except at the one well with anomalously low H_2S (Figure 7). The H_2/H_2O change is probably related to the production of NH_3, discussed above.

AREAL DISTRIBUTIONS AND TARGETS FOR FUTURE INJECTION

To help determine locations for future injection wells, maps have been prepared showing: (1) the areal distributions of NCG/steam (Figure 1); (2) injection isotope effect (Beall, Box, and Enedy, this volume); (3) areal distribution of two generalized groups of wells with chemical temperatures in range 225-240°C and 240-255°C (Figure 9); (4) areal distribution of steam saturation factor (Figure 10) and; (5) high enthalpy and superheat (Enedy, this volume).

On these maps, the combined areas of higher temperature (geothermometer temperatures >240°C), high steam saturation factor (YH_2 >0.10), no shifts in the stable isotopes, reservoir steam enthalpies >1,220 BTU/16m, and static reservoir pressures <220 psig identify an area near the C-Pad on Figure 1 as ideal for an injection experiment with the goal of maximizing the recovery of flashed injectant.

CONCLUSIONS

Injection of steam condensate into The Geysers reservoir affects the following:

1. The spatial variation of noncondensible gas in steam.
2. The concentration of stable isotopes ^{18}O and D.
3. The concentrations of gas species Ar, N_2, H_2 and NH_3.
4. The concentrations of H_2S, but only when parameters 1-3 are strongly affected.
5. The steam saturation (Y) factors, particularly the form calculated using H_2, H_2O, OH_4 and CO_2.

At some production wells the gases are affected by injection but the stable isotopes are not, indicating that injected water and gases have segregated in the reservoir. Mapping the combined effects 1 through 5 can be used to assist the location of new injection wells.

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