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IMPACT OF INJECTION ON RESERVOIR PERFORMANCE IN THE NCPA STEAM FIELD AT THE GEYSERS

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ABSTRACT

A managed injection program implemented by the NCPA in The Southeast Geysers reservoir continues to positively impact reservoir performance. Injection effects are determined by the application of geochemical and geophysical techniques to track the movement of injectate. This information, when integrated with reservoir pressure, flowrate, and thermodynamic data, is used to quantify the overall performance and efficiency of the injection program.

Data analysis indicates that injected water is boiling near the injection wells, without deeper migration, and is recovered as superheated steam from nearby production wells. Injection derived steam (IDS) currently accounts for 25 to 35 percent of total production in the NCPA steamfield. Most importantly, 80 to 100% of the injectate is flashing and being recovered as steam. The amount of IDS has increased since 1988 due to both a change in injection strategy and a drying out of the reservoir. However, significant areas of the reservoir still remain relatively unaffected by injection because of the limited amount of injectate presently available.

That the reservoir has been positively impacted in the injection areas is evidenced by a decrease in the rate of pressure decline from 1989 through 1992. Correspondingly, there has been a reduction in the rate of steam flow decline in the areas' production wells. Conversely, little evidence of reservoir cooling or thermal breakthrough is shown even in areas where IDS accounts for 80 percent or more of production. Finally, since injection water is a relatively low-gas source of steam, noncondensible gas concentrations have been reduced in some steam wells located within the injection dominated areas.

BACKGROUND

The Northern California Power Agency (NCPA) owns and operates two geothermal power plants with an installed capacity of 246 and a geothermal steam field in the Southeast Geysers. Plant 1 started operation in 1983 and Plant 2 in 1985. The units were operated in a base loaded manner until 1988 and operated as load following units thereafter with an annual average output of approximately 150 MWG. The steamfield, located on Federal Leases CA 949-950, consists of 69 steam wells and seven injection wells located on 12 sites. The injectate is mainly cooling tower condensate supplemented with some rain water collected in two ponds located near the power plants.

Water injection in the NCPA steamfield began with the start of power plant operations in January 1983. In the ten years following startup, 65 billion pounds of water have been injected into nine injection wells. That cumulative mass injected represents approximately 34 percent of total steam produced. Although the percentage of condensate available from the plants remains relatively constant on an annual basis, the net mass loss of fluid, which through 1992 is 123.5 billion pounds, continues to increase. Because The Geysers is essentially a closed system, the rate of reservoir fluid loss and resultant reservoir pressure decline will continue unchecked, unless injection augmentation programs are activated.

The accelerated decline of reservoir pressure starting in 1986 indicated a need to develop an injection augmentation program (Enedy, Grande, Smith 1990). Toward this goal, the NCPA constructed two containment ponds located near the power plants that increase the amount of injectate between 5 to 10 percent annually, depending on rainfall. Further, the NCPA implemented an overall reservoir management program with the objective of maximizing the value of energy production from the geothermal resource. Efficiency improvements implemented by the NCPA and shown to be cost effective include 1) load following operations, 2) improved distribution of injection for reservoir support, and 3) a well workover and cleanout program using the NCPA's drilling rig on an as-needed basis.

Future enhancements planned by NCPA include installation of a new turbine to better utilize low pressure steam. Additionally, the economic feasibility of several other augmentation projects is being considered with the goal of at least doubling the current annualized rate of injection which is between 1,600 -1,800 gallons per minute (GPM).

EVOLVING INJECTION STRATEGIES

The initial operating philosophy regarding injection was to dispose of condensate in "peripheral" wells to minimize the chance of liquid water breakthrough to steam wells. Little consideration was given to individual well injection rates. The original developer of this leasehold (Shell Oil), constructed injection lines to sites located near the edge of the developed area where no productive steam wells existed. That strategy reflected the prevailing concept at that time that condensate injection was primarily a disposal problem without potential reservoir benefit.

Starting in 1986, high flowrate declines were experienced in the Southeast Geysers This led to studies to determine if revised injection strategies could lead to improved reservoir performance. In order to better understand the effects of "internal" injection (i.e., injection within the NCPA developed area), a joint injection project was begun to quantify the ability of the reservoir to support and benefit from augmented water injection. That study, along with other supporting evidence, showed that a properly planned injection strategy could 1) lead to the extraction of additional heat from the reservoir rock, 2) positively impact both reservoir pressures and flowrates, and 3) minimize thermal breakthrough to offset steam wells. (Enedy, Enedy, Maney 1992).

The reservoir still continues to show the ability to support and benefit from increased injection. For this reason, the operating strategy continues to gradually evolve and improve. Injectate is now distributed throughout the reservoir and injected at rates of 500 - 1,500 GPM per well. This strategy of utilizing additional injection wells at lower rates is shown in Table 1, which lists the wells and masses injected from 1988 through 1992. Only two wells were used in 1988 compared to seven wells in 1992. Injection well locations are shown in Figure 1.

Communication of unflashed effluent to steam production wells has not been a major problem in the NCPA steam field, except on a few occasions when rates

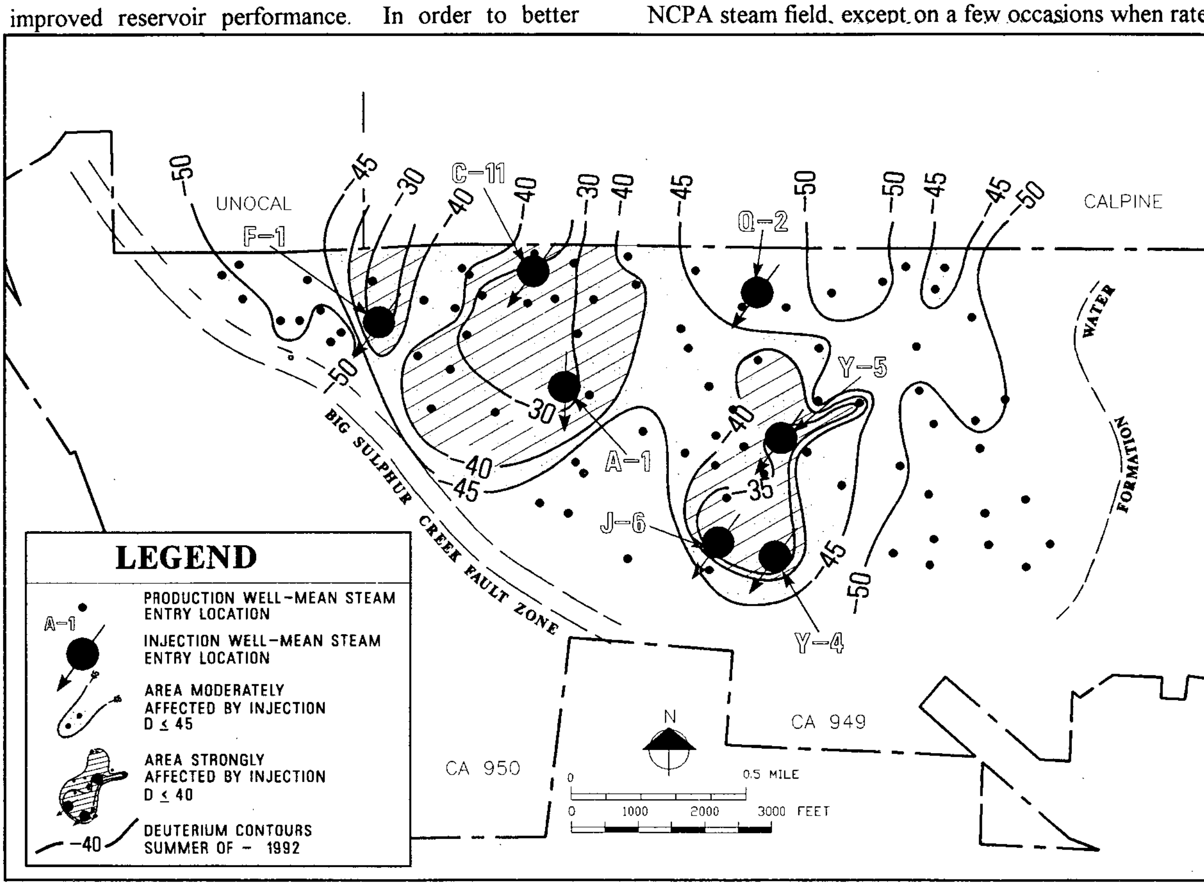

Fig. 1 Fieldwide deuterium distribution from samples taken June through August, 1992

Table 1
Annual Mass Injected And Wells Utilized

	1988		1989		1990		1991		1992	
Well	B-lb	%	B-lb	%	B-lb	%	B-lb	%	B-lb	%
A-1	2.7	34	1.5	20	0.6	8	1.0	15	0.8	9
C-11			0.7	9	1.7	22	2.7	40	2.6	31
F-1							1.0	15	1.0	12
J-6									1.0	12
Q-2					0.5	6			0.3	4
Y-4	5.3	66	2.0	26	3.5	44	1.7	25	1.2	14
Y-5			3.4	45	1.6	20	0.3	5	1.5	18
TOTAL	8.0		7.6		7.9		6.7		8.4	

of injection have been unusually high for a prolonged period of time. At injection rates over 1,000 GPM, injector A-1 communicates with two N-Site steam wells. The only problems experienced below 1,000 GPM occur between injection well Y-5 and steam well D-7, and injection well Q-2 and steam well Q-6.

TRACING INJECTATE MOVEMENT BY DEUTERIUM ANALYSIS

The power plant condensate sent to the injection wells has an elevated deuterium concentration that is a result of the evaporation process in the cooling towers. Consequently, periodic analysis of deuterium in the produced steam provides a means of tracing the movement and quantifying the recovery of injection derived steam (IDS). It is now general practice at The Geysers to use the difference in deuterium concentrations of the original steam and the injected water as a means to trace and quantify the recovery of injected water (Beall, Enedy, Box 1992). Deuterium is useful because it is stable at high temperatures, and undergoes very little fractionation between steam and water phases during the reservoir boiling process. It is also far less susceptible to ion exchange between rock minerals and water molecules than is ^{18}O. However, there are several problems with using deuterium as a tracer including difficulty in determining spatial and temporal patterns since the deuterium is injected continuously in all injection wells. Although, the amount of IDS can be quantified, it is often difficult to determine both the exact sources of the IDS, especially if several injection wells are in close proximity, or the relative contribution of old versus recent injection.

Deuterium concentration is reported as the difference between the isotopic ratios in the sample and a standard. The ratio is of the heavier deuterium to the lighter hydrogen with the small difference in ratios between the sample and the standard reported in per mil (o/oo) relative to V-SMOW (Vienna standard mean ocean water). Additional explanation of the terminology, sampling and testing methods used in isotopic analysis is provided by Reed (1991). For steam without injection, deuterium (D) ranges between -52 to -56 o/oo SMOW. Injectate ranges between -8 and -24 with an average of -16 o/oo SMOW.

Results of a fieldwide deuterium survey taken during the summer of 1992 are shown on Figure 1. The survey indicated that D concentration is increased (i.e., less negative - o/oo values) near active injection wells, with three distinct anomalies centered on the injection areas. These anomalies are somewhat elongated in a north-northeast direction indicating a preferential flow path in this direction. These anomalies are indicated by a cross-hatching on Figure 1, within the -40 per mil contour. The area indicated to be strongly affected by injection represents approximately 30 percent of the reservoir development area, which is very close to the percentage of steam returned as condensate to the reservoir. The most wide-spread deuterium anomaly includes the area of C-11 and A-1. Its large size is probably related to the relatively large amount of injection into C-11 (i.e., 34 percent of all injection in 1992 as shown in Table 1). A small (fourth) deuterium anomaly exists in the northeast portion of the field that is probably related to the operation of an injection well located further north. Injector Q-2 is not associated with an anomaly because it was not an active injector prior to the survey.

TRACING INJECTATE MOVEMENT BY MEQ MONITORING

Microearthquake (MEQ) activity at The Geysers has been studied since 1975, as recently summarized by Stark (1992). In many areas of the steamfield these events are recognized to have a spatial and temporal correlation with injection. This same correlation was recognized during NCPA's first MEQ survey on the leasehold in 1987, and as a consequence, arrangements were made to have a permanent MEQ recording network extended into this area. The expanded network is managed by Unocal and has been continuously operated

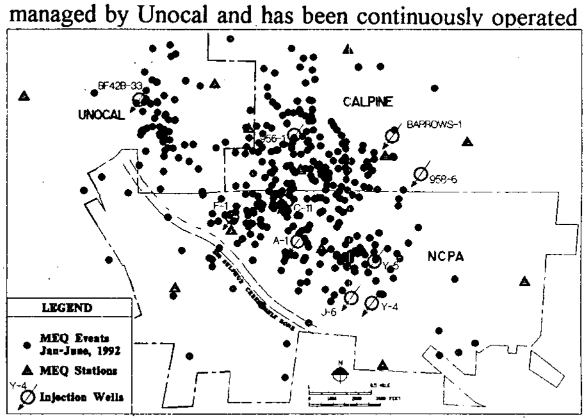

Fig. 2 MEQ epicenters at SE Geysers

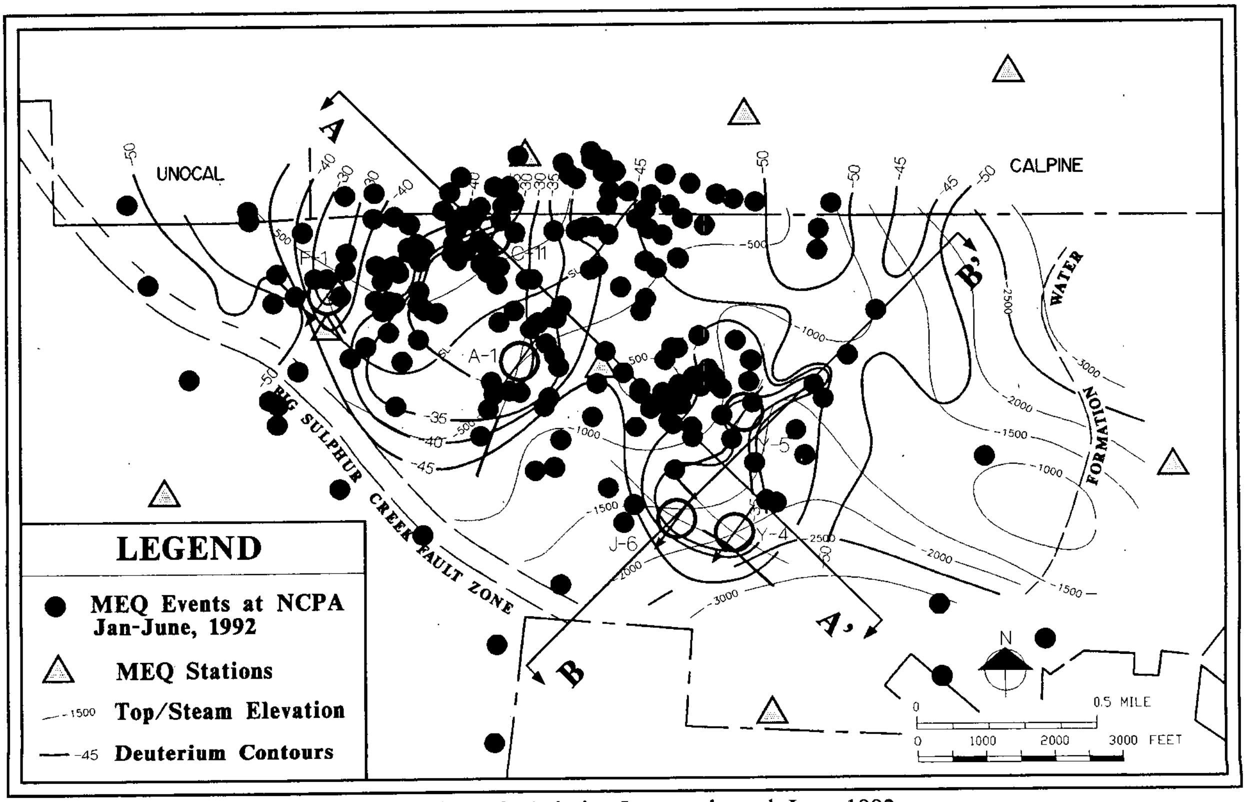

Fig. 3 Epicenters of MEQ events recorded at NCPA during January through June, 1992

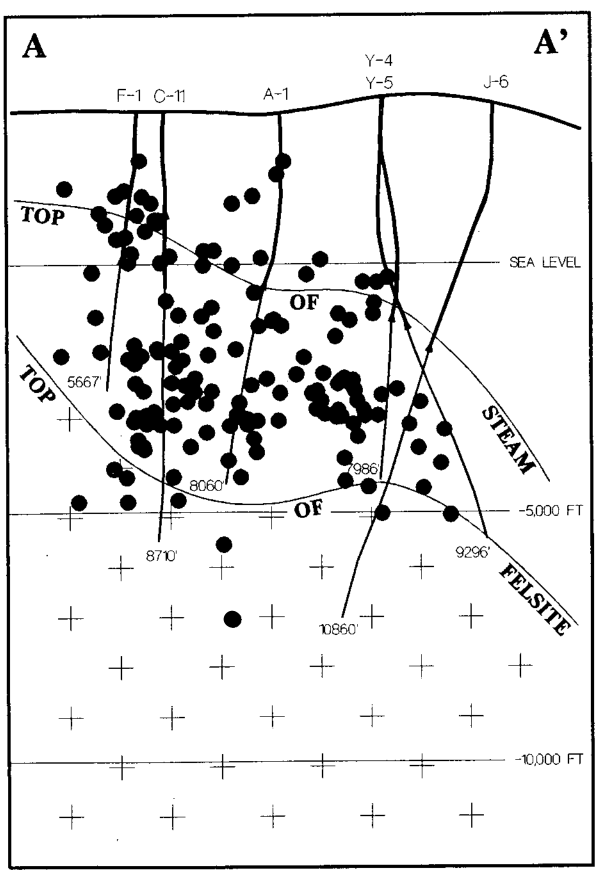

Fig. 4 NW-SE cross section, MEQ hypocenters

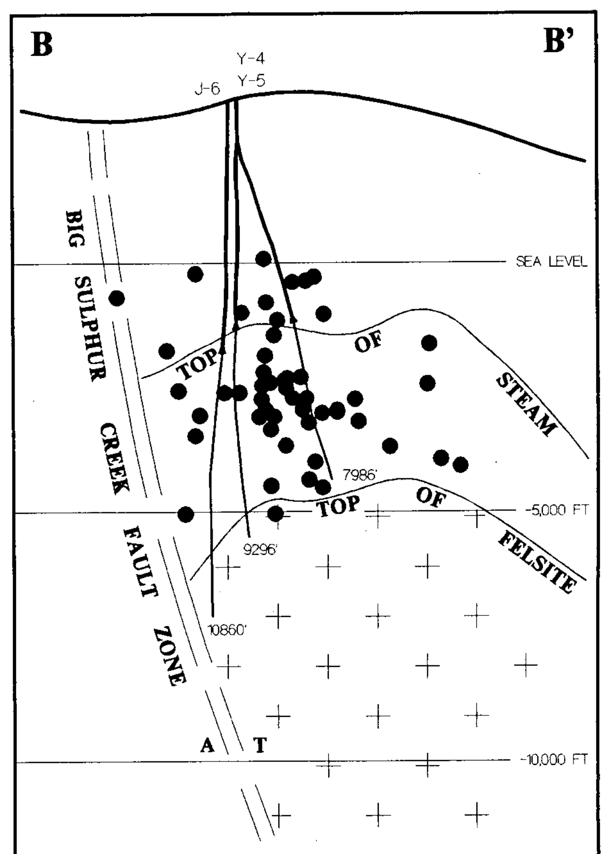

Fig. 5 SW-NE cross section, MEQ hypocenters

since September 1989. Recently, additional recording stations were installed in the Southeast Geysers area by Lawrence Berkeley Laboratory (LBL) and Lawrence Livermore Laboratory. All subsequently recorded events are now being processed in a collective manner.

Figure 2 is a map of Southeast Geysers MEQ events recorded during the first six months of 1992 and processed by LBL. A distinct clustering of events occurs near Unocal's isolated BF42B-33 injection well. Somewhat more widespread clouds of MEQ events occur also near the Calpine 956-1 injector and in the general vicinity of the five NCPA injectors that were active during that same time.

Viewing this data within the NCPA area in more detail, Figure 3 shows those same event locations superimposed on both the Summer 1992 deuterium anomalies presented in Figure 1, and a top of the steam reservoir contour map. The vast majority of MEQ events recorded at NCPA are shown to occur within the deuterium-mapped areas of significant injectate influence. In fact, MEQ events are almost non-existent elsewhere, including throughout the injectate-poor region of the NCPA steam reservoir development area that extends almost a mile east of injection well Y-5.

Figures 4 and 5 are cross sections representing the relationships of the calculated hypocenter depths of these MEQ events to the known injection intervals of the NCPA active injectors, and to the basic geologic/reservoir units present. The MEQ events are shown to take place at depth intervals that rarely exceed the maximum depth of the injection wells in use. The clear indication is that the liquid injectate is boiling near the injectors, without significant migration deeper into the reservoir. The result is that within this NCPA area, under these injection conditions, most of the IDS appears to be immediately available for migration to the surrounding production wells.

QUANTIFYING INJECTATE RECOVERY

It is general practice at The Geysers to use Deuterium in the produced steam to quantify both the amount of injection derived steam (IDS) and the percentage of injectate that is flashing and returning as steam over some reasonable time period. Deuterium surveys of the NCPA wells have been taken once or twice a year since 1985. The contribution of IDS to a well's total flow was calculated assuming each sample is a mixture of a reservoir fluid and condensate and applying a mixing ratio. The well's flowrate potential at 130 psig was then multiplied by the IDS fraction to obtain the IDS flowrate potential at 130 psig. Figure 6 is a plot of both the total IDS flowrate potential and the IDS flowrate potential as a percentage of the total flowrate potential for the NCPA steam field. Figure 7 is a plot of the IDS flowrate potential as a percentage of the average injection rate during the previous six month period. It is a measure of the amount of injectate recovered as steam. The current amount of steam recovered from old versus recent injection has not been quantified on a continuous basis. The injection wells utilized in the three months prior to each survey are annotated on the plots.

As shown on Figure 6, IDS production potential was relatively constant between 1985 - 1988 at 280 to 350 kpph (thousand pounds per hour) at 130 psig. However, starting in 1989, IDS flowrate potential increased to a high of 950 kpph at 130 psig in 1992. This increase in IDS flowrate potential is due to the change in injection strategy that resulted in the use of more injection wells located closer to the producing wells (e.g., C-11, Y-5, F-1) and injection rates averaging 800 GPM per well or less. The IDS flowrate potential in 1992 is 26 percent of total flowrate potential. Actual IDS production varies between 25 and 35 percent of production due to NCPA's load following operation. The deferred production of original steam caused by the increased production of IDS is believed to be small for this case and has not been estimated.

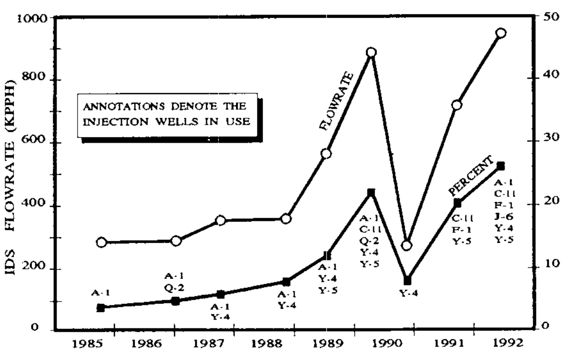

Fig. 6 Injection derived steam flowrate potential and IDS as percent of total flow potential

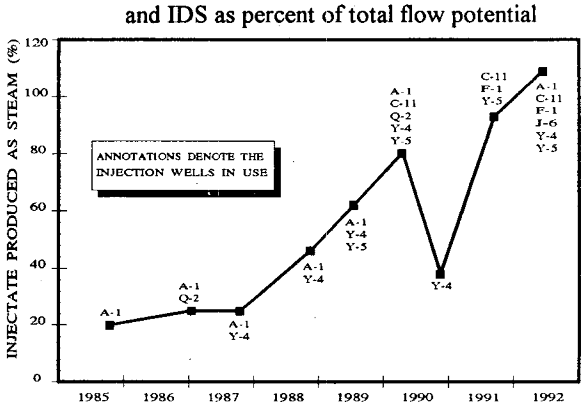

Fig. 7 Percent of condensate recovered as steam, 1985 through 1992

As shown on Figure 7, the percentage of injectate being recovered as steam increased between 1989 and 1992 with values of 93 and 109 percent in 1991 and 1992. The cause of the IDS values exceeding 100 percent of the average injection rate is unclear but could be due to 1) uncertainty in the calculations due to natural fluctuations in the concentration and amounts of deuterium in the injectate, 2) an incorrect assumption regarding the estimate of average injection rate prior to the sampling survey (i.e., a six month average may be high), 3) the wells are actually producing IDS previously injected which would allow for values greater than 100 percent and 4) average well production rates may vary from the flowrate estimated at 130 psig. Due to NCPA's load following operation, actual production of IDS as a percentage of average injection rate varied between 80 and 100 percent in 1992.

IDS production potential decreased in late 1990 because only Y-4 was used during most of the previous summer to dispose of injectate. The other injection wells experienced temporary operating problems at this time. The IDS potential dropped below 300 kpph due to both the low volume of condensate being injected during the previous summer months and the location of Y-4 as a "peripheral" injector.

An example of an individual well's deuterium history is shown on Figure 8 for steam well F-5, which is located near injection well F-1. F-5 has produced IDS since 1989.

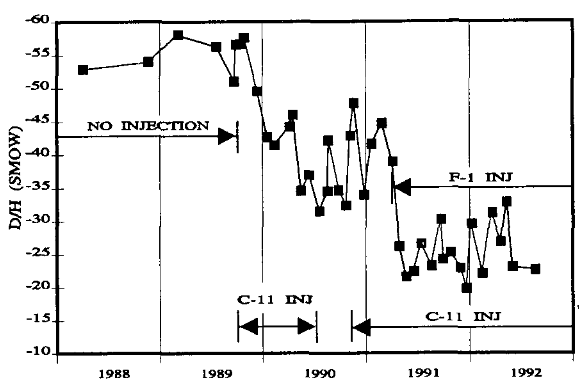

Fig. 8 F-5 deuterium shift, 1988 through 1992

F-5 produced approximately 50 percent IDS starting in 1990 (-35 o/oo). However, with the conversion of F-1, the percentage of IDS increased to over 75 percent (-25 o/oo). Despite the large amount of IDS, and close proximity of this steam well to injectors F-1 C-11, F-5 continues to produce super-heated steam and with no observable decrease in flow temperature. Figure 9 is the plot of two Temperature and Pressure Surveys on F-5. One survey was taken prior to the start of injection in 1989 and the other survey was taken in 1992, following

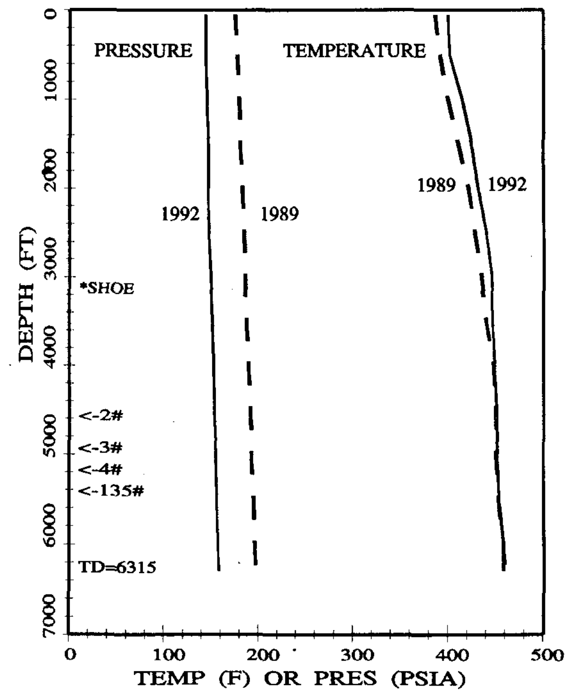

Fig. 9 F-5 T/P/S surveys, Mar., 1989 & Nov., 1992

nearly three years of injection. Continuous injection has not caused any cooling in F-5 as the downhole temperatures are still approximately 460 °F.

RESERVOIR PRESSURE DECLINE

It is general practice at The Geysers to measure reservoir pressure using both pressure buildup tests and the continuous monitoring of observation wells. NCPA routinely conducts static pressure surveys during the spring to develop an isobaric map for the developed area. The rate of decline of static reservoir pressure is a direct measure of the rate of depletion of the reservoir fluid. Also, the decline in reservoir pressure governs the rate of steam flow decline (i.e., the lower the decline in reservoir pressure the lower the decline in steam deliverability).

Figure 10 represents the percentage decline in deliverability caused by pressure decline for the developed NCPA production area between March 1989 and March 1992. It was during this time period that the amount of IDS from wells located near injectors increased. The decline in deliverability pressure for Figure 10 was calculated with Equation 1 and is based on the back-pressure equation. This approach allows for the calculation of a relative rate of deliverability decline caused by pressure decline. Also, a direct correlation can be made between the decline rate in both the low and high pressure areas of the field.

$$\frac{\left(P89^2-143^2\right)-\left(P92^2-143^2\right)\times 100}{\left(P89^2-143^2\right)} \qquad \textbf{(1)}$$

Where *P89* represents the individual well static pressure (psia) taken between February and March 1989 and *P92* represents the individual well static pressure taken between February and March 1992. A pressure of 143 psia is the average wellhead pressure of the field.

Figure 10 shows three areas of reduced pressure decline: 1) an anomaly associated with injectors C-11, A-1, and F-1, 2) an anomaly associated with injector Y-5, and 3) the eastern edge of the productive area. Both of the injection supported anomalies are related to areas of significant deuterium shifts and MEQ activities as previously shown in Figures 1 and 3. An area of reduced decline not associated with injection is the eastern edge of the field. This is an area that produces little or no IDS but has been shown to be influenced by the influx of steam from the edge of the field of higher than average noncondensible gas concentration. (Truesdell, Enedy, Smith, 1993)

The highest degree of pressure support is received from injectors C-11 and F-1 which is partially due to the elevated, but not excessive injection rates. These two wells received half of the available injectate during 1991 and 1992 (Table 1). Also, there are certain reservoir characteristics, including lower pressure and decreased fracture spacing, which increases the recovery of injectate.

The pressure support associated with injector Y-5 is smaller than the C-11 anomaly. This is due in part to the reduced injection rate into Y-5 (20 percent of injection in 1991-92). Also, this area is at higher pressure than the C-11 area and has fewer productive wells, especially to the south of Y-5. The relative impact of Y-4 and J-6 to this pressure support anomaly is not clear.

The individual well static pressure histories for two NCPA steam wells (F-4 and B-3) are shown on Figure 11. Also, shown on Figure 11 is the combined injection rate into injectors C-11 and F-1. The location of each well is shown on Figure 10.

Well F-4 is an observation well located 2,400 feet southwest of injector C-11 and 500 feet southeast of injector F-1. F-4 is within the deuterium anomaly associated with F-1 and as such receives an elevated amount of IDS. The pressure history for F-4 is dominated by changes in the injection rates of C-11 and F-1. A 3 psi per year decline for the last three years is estimated from the pressure history. By contrast, steam

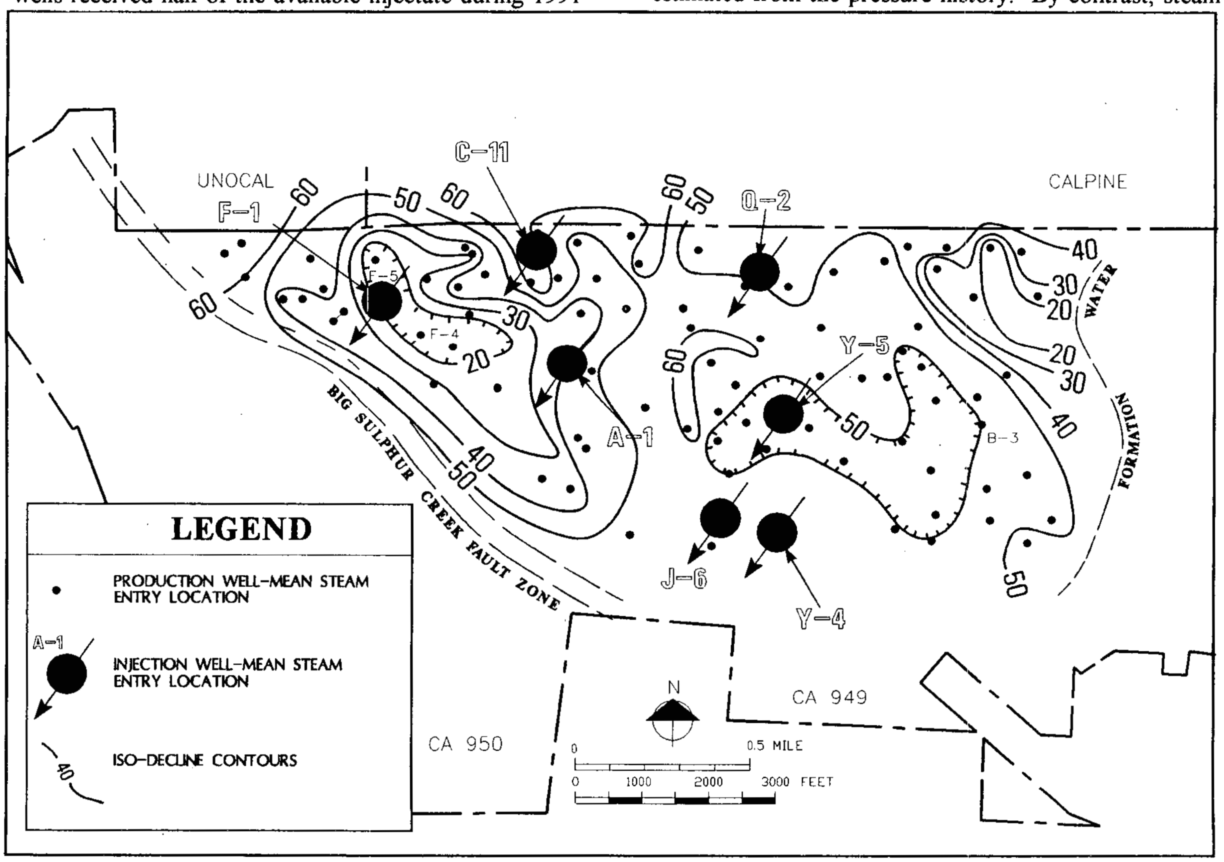

Fig. 10 Percent deliverability decline caused by reservoir pressure decline- Mar89 to Mar92

well B-3 is located near the eastern edge of the field and shows little IDS production. The estimated pressure decline is 18 psi per year.

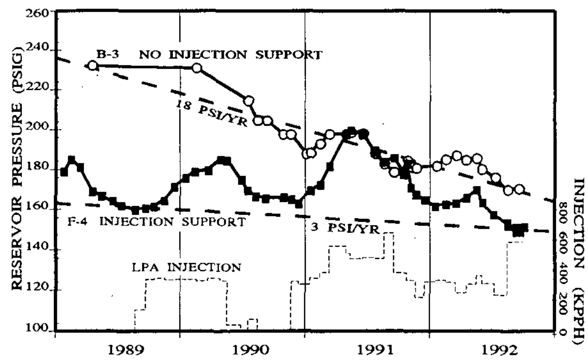

Fig. 11 Reservoir pressure history for steam wells F-4 & B-3, 1989 through 1992

STEAM FLOWRATE DECLINE

Steam flowrate decline is influenced by several factors including reservoir pressure decline, wellhead pressure, interwell interference, and wellbore effects such as bridging in the open-hole, scaling, and condensation. The NCPA routinely calculates the rate of flowrate decline on both an individual well and fieldwide basis. Individual well flowrate declines were calculated for the period August 1991 to July 1992. During this period, the recovery of injectate ranged between 80 - 100 percent and the production of IDS increased to approximately 26 percent of total flowrate potential. The individual well decline rates ranged between 0 and 50 percent with an arithmetic average of approximately 15 percent. The data is plotted and contoured on Figure 12 along with the location of the seven injection wells utilized during this period.

Areas of reduced flowrate decline shown on Figure 12 correlate with areas of injection with the exception of the reduced decline rate near the eastern edge of the field. Reduced decline rate anomalies are centered on injectors A-1 and Y-5. Also, the decline rates of steam wells located near C-11 and F-1 are often lower than the field average or lower than wells located increasing distances from those injectors. Many of the wells showing reduced decline rates are located near areas of increased production of IDS and MEQ activity.

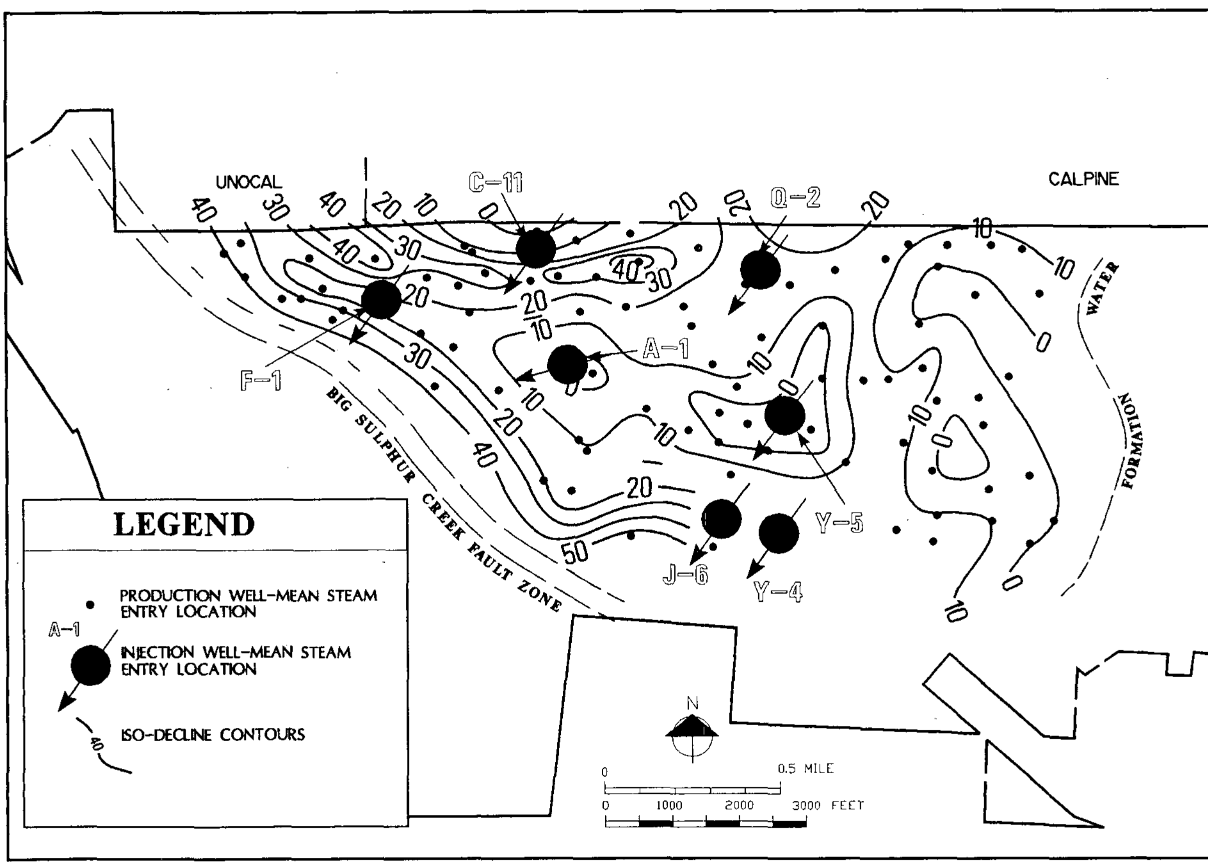

Fig. 12 Annual percentage flowrate decline map, August 1991 to July 1992

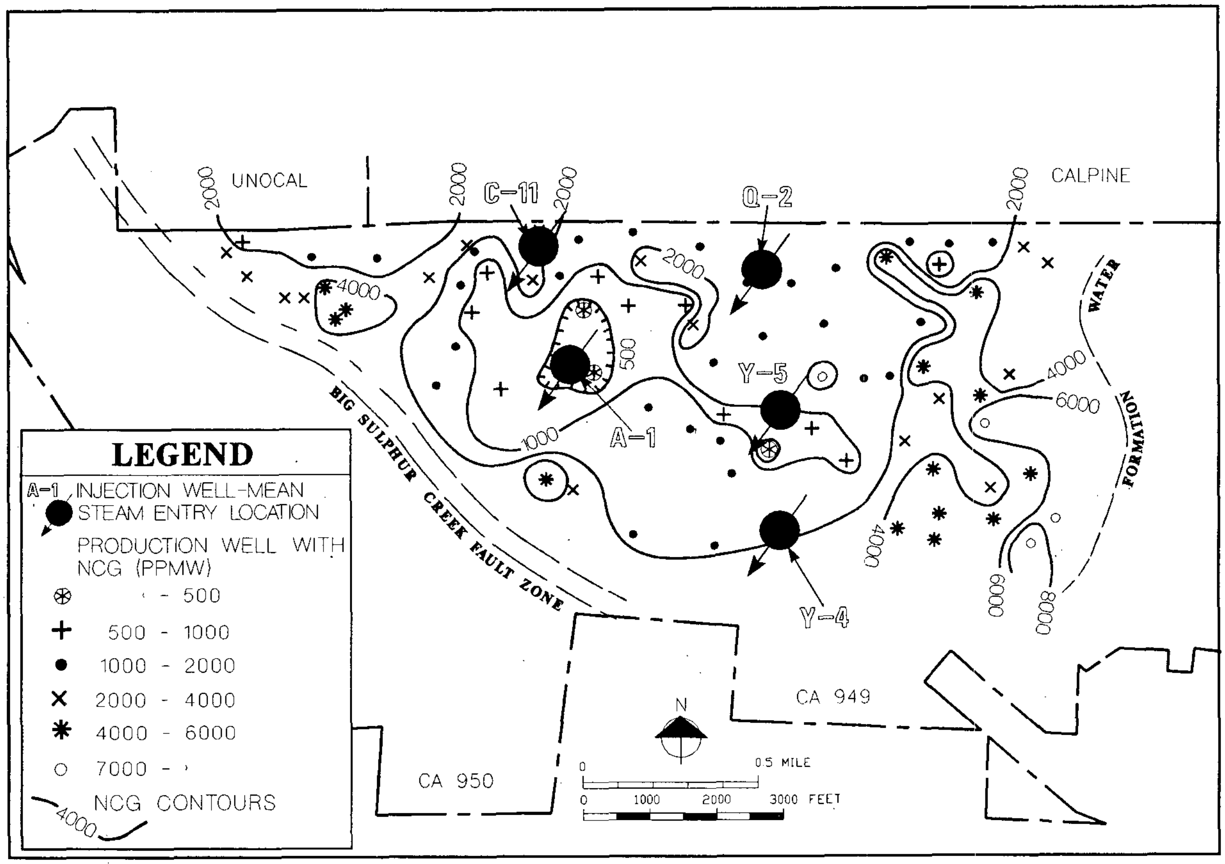

Fig. 13 Fieldwide NCG distribution from samples taken July 1991

NCG DISTRIBUTION

Many of the wells showing injection effects as measured by stable isotope analysis also demonstrates a decrease in noncondensible gas concentrations, including H_2S, and CO_2. Also, these same wells often show evidence of increased NH_3, N_2, and AR (Klein, Enedy 1992).

Figure 13 is the distribution of NCG on the NCPA lease. The gas concentration generally increases from the center of the field toward the reservoir boundaries to the east and west with the highest concentrations being near the eastern boundary. The eastern and western boundaries are affected by an influx of higher gas steam that may be caused by Rayleigh condensation processes (Truesdell, Enedy, Smith, 1993). Steam wells within the 1,000 ppm contour, located near Injection wells A-1, Y-5 and C-11, have reduced gas concentration due to the relatively large component of injection derived steam. IDS is a low-gas source of steam. It is an economic and environmental benefit to produce steam with lower gas concentration as less chemical abatement is required at the power plants. NCPA plans to inject water into wells located near the eastern and western boundaries of the steamfield with the dual purpose of mining the heat of the rock and decreasing the NCG production.

Figure 14 is a plot of NCG versus deuterium concentration. A trend showing lower gas concentration for steam wells with a greater concentration of deuterium (i.e., more IDS) indicates that injection decreases gas concentrations in produced steam.

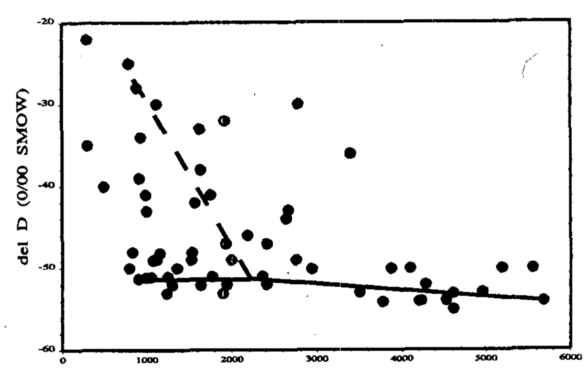

Fig. 14 NCG versus deuterium - July, 1991

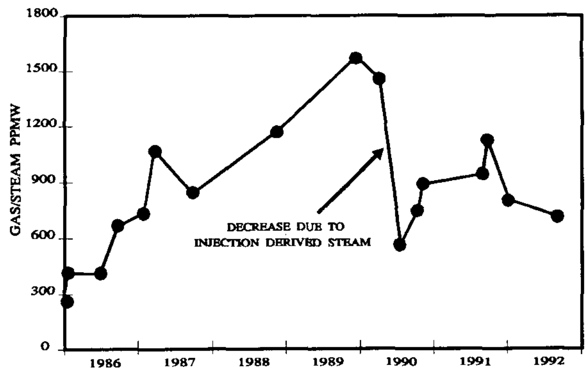

Fig. 15 Gas/Steam history, 1986-92

Steam well F-5 is an example of a well producing reduced concentrations of NCG as a result of increased IDS. The gas history for F-5 is plotted as Figure 15. The well is located within an area that has produced IDS since 1989. Gas concentration for F-5 steadily increased between 1987 - 1989. However, following startup of off-set injector C-11 and later F-1 gas concentration was reduced by approximately 50 percent.

CONCLUSIONS

1. MEQ activity related to injection indicates that liquid injectate is boiling near the injectors without significant migration deeper into the reservoir. The resulting injection derived steam is readily available for lateral migration within the reservoir.

2. Based on deuterium analysis, the flashed injectate is produced by wells located near the injectors. The areas strongly influenced by injection (-40 per mil or less) represent approximately 30 percent of the field, which is very close to the percent of steam returned as condensate. This suggests that the rate of production of IDS is almost equal to the rate of injection. Large areas of the reservoir are not receiving injection support due to the limited amount of available condensate.

3. Deuterium analysis also indicates that the production of injection derived steam increased between 1989 and 1992 to a high in 1992 of 950,000 pounds per hour or 26 percent of total flowrate potential. The amount of injectate being recovered as steam also increased to a high of 80 - 100 percent in 1992. The increase in IDS recovery is believed primarily due to the change in injection strategy. The new strategy results in the use of more injection wells located closer to the producing wells together with lower individual well injection rates.

4. Wells located within the injection areas show significant reductions in the rates of reservoir pressure and flowrate decline. Also, noncondensible gas concentrations have decreased in many steam wells influenced by injection.

5. Based on the above analysis, the overall impact of ten years of injection is clearly favorable. The benefits of augmenting condensate injection are increasing because the need for injection within the "dry" areas of the field continues to grow as the supply of condensate available for injection continues to decrease. NCPA presently views augmented injection as a reservoir management tool that will extend field life and increase electrical production from its geothermal power plants.

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