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# Injection Experience in The Geysers, California—A Summary

**K.P. Goyal**

**Calpine Corporation, P.O. Box 11279, Santa Rosa, CA 95406**
**E-mail: keshav@calpine.com**

## ABSTRACT

Injection related benefits and problems, experienced by various operators in The Geysers, are summarized in this paper. Injectate recovery determined by decline curve, isotopic analysis, and cumulative tracer recovery methods are presented. Finally, a revised injection well completion program to reduce adverse injection impacts is discussed.

Annual recovery factors based on the decline curve method vary widely from area to area in The Geysers field ranging from less than 1% to 73%. Recovery factors based on isotopic and ammonia analyses were slightly higher but qualitatively similar to those obtained by the decline curve method. These ranged from 24% to 80%. Tracer tests suggest recovery factors even higher than those obtained by the isotopic analysis. Environmentally benign hydrofluorocarbons (R-134a and R-23) are successfully being used as new tracers in The Geysers field.

## Introduction

Commercial steam production at The Geysers began in September 1960 with the start-up of a 12-MW unit. By 1988, the installed capacity at The Geysers rose to 2000 MW net (Goyal and Box, 1991). Between 1960 and 1969, the steam condensate from the cooling tower was disposed in nearby surface drainages. However, since 1969 environmental regulations have required that the steam condensate be injected into the reservoir for disposal. The ratio of injectate to steam production rose to approximately 24% by 1980 (CDOGGR, 1998). Since 1980, the steam condensate has been supplemented with fresh water from Big Sulphur Creek during periods of high runoff (Gambill, 1991) raising the ratio from 24% to approximately 28% by 1991. Between 1995 and 1997, the injection volumes remained constant at about 60 billion pounds per year but steam production decreased to approximately 140 billion pounds per year mostly due to throttling of the Unocal wellfield. This resulted in an injection-production ratio of 40-45% during 1995-97.

It was not until 1988 that injection became a preferred reservoir management strategy. Several wellfields in The Geysers underwent high decline rates of approximately 30% per year during 1987-88 and makeup drilling could not keep up with this high decline (Goyal and Box, 1991). Various steps were taken by the operators at that time to arrest this high decline rate. These included a hiatus in makeup well drilling, injection relocation to reduce decline rates, start-up of joint injection projects, and development of tracers suitable for The Geysers reservoir.

Tracer tests were conducted to determine the distribution of injection derived steam. The operators also began developing plans to bring additional water to The Geysers. The Southeast Geysers Effluent Pipeline (SEGEP) project became operational on September 25, 1997 and continues to provide approximately 5400 gpm of additional water for injection into Calpine, NCPA (Northern California Power Agency), and Unocal wellfields. These efforts were successful in reducing the decline rate of The Geysers field to below 10%.

Water injection into The Geysers reservoir is beneficial in some areas and detrimental in others, depending upon the fracture distribution, permeability, reservoir pressures temperature, liquid saturation, and rock type. The positive aspects of water injection include providing reservoir pressure support, maintaining steam production rate, and reducing makeup well requirements, noncondensible gas, and corrosive chloride concentrations. Additionally, injection increases steam reserves and the life of the field by recovering a portion of the approximately 90% of the heat stored in the rocks of this vapor dominated system. On the other hand, injection can reduce well productivity by breakthrough of the injected water to a production well through fracture conduits. It can also cause obstructions in the pipeline, wellbore, and/or the fracture path by silica scale build-up and thereby reduce steam flow rate. Injection can also cause open-holes to slough and block steam flow. Workovers, sometimes costly, may be needed to clean such wells.

Calpine became 100% owner of Unocal's portion of The Geysers wellfield in March 1999 when it acquired the 75% share of the latter in the field. However, to distinguish various wellfields in The Geysers, we continue to use Unocal's name here.

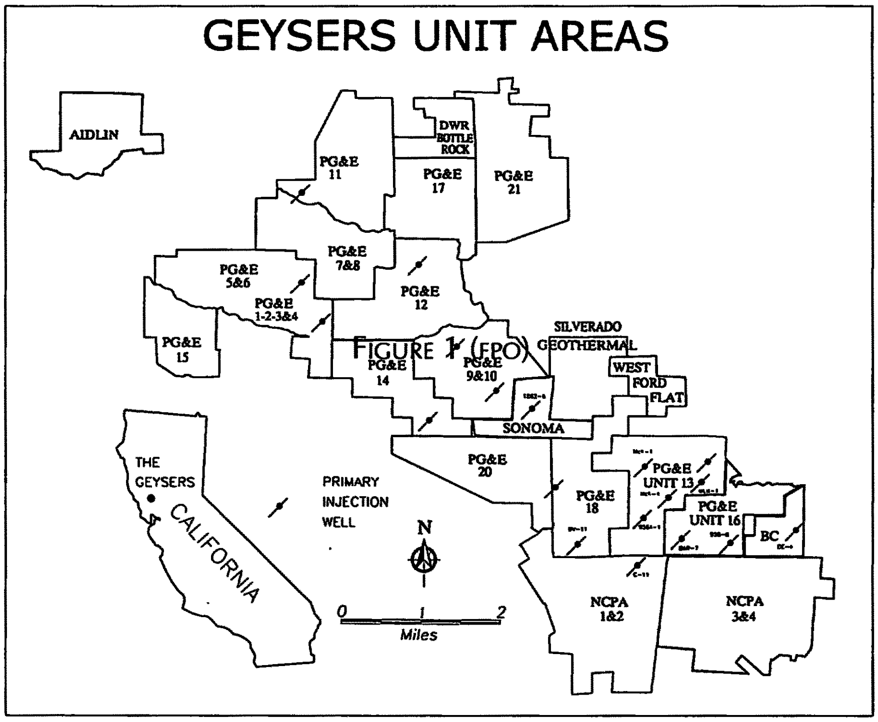


**Figure 1.** Geysers Location Map

In this paper, the results of water injection programs are summarized which include injection benefits in the various areas of the Geysers field, results of tracer tests, and injection related problems.

## Injection Benefits

Injection benefits achieved in wellfields operated by Calpine, NCPA, and Unocal are briefly described below and summarized in Table 1. The outline of various unit areas and the location of injection wells are shown in Figure 1. Injection wells in some wellfields are not shown in this figure because the information about their location is not available in the public domain. Plugged and abandoned injectors are also not shown in Figure 1.

### *Injection Recovery Factors for the Calpine Wellfields*

The effect of injection into Unit 13, Unit 16, Sonoma (formerly SMUDGEO #1) and Bear Canyon wellfields operated by Calpine Corporation is discussed in the following paragraphs. The "recovery factor" is defined as the ratio of additional steam provided by injection to the amount of water injected over the same period of time. Additional steam is the steam produced at the new decline rate or improved rate established due to injection minus the steam production calculated at a decline rate without injection. Injection recovery factors calculated from the production data using decline curve analysis could be different from the injection-derived steam (IDS) obtained from the geochemical data on an individual well basis. However, the combined recovery from all production wells affected by one or more injection wells should agree by both methods given sufficient time (Goyal, 1995).

**Unit 13:** Injection into CA 956A-1 (Figure 1) since October 1989 provided annual injection recovery factors of 56, 73 and 57% for the first, second and third years, respectively, using decline curve analysis (Goyal, 1995). These recovery factors are equivalent to a gain of 7.4, 9.9 and 10.1 MW in the first, second and third years, respectively (Table 1). These recovery factors were the highest amongst all Calpine wellfields and were the result of injection into an area of low reservoir pressure and a high heat transfer characteristics (high fracture density).

Using deuterium isotope data, Beall *et al.* (1989) estimated that 24-52% of the mass injected into wells McKinley-5 and Thorne-7 was recovered during 1985 through 1988 (Table 1). Both wells, located in the northern part of Unit 13, were plugged and abandoned in February 1993 and March 1995, respectively.

**Unit 16:** Using decline curve analysis, annual recovery factors of 20% (3.4 MW) and 51% (7.1 MW) were calculated for the Unit 16 injection well Barrows-1 for the first and second years, respectively, subsequent to the start-up of injection in October 1990. Barrows-1, located approximately 400 ft east of Barrows-7 (Figure 1), was plugged and abandoned in November 1995. Higher reservoir pressure in the Unit 16 area, compared to that in the southwest area of Unit 13, is believed to result in lower injection recovery factors.

Using deuterium isotope data, Beall *et al.* (1989) estimated a recovery of 25-32% from 1986 to 1988 due to injection into CA 958-6 (Figure 1 and Table 1). The recovery factors of 29, 65 and 81% were calculated for April 1990, June 1991 and July 1992, respectively, from the IDS values obtained from the ammonia analysis (Beall, 1993 and Goyal, 1995). Higher recoveries in 1991 and 1992 were the result of distribution of injection water between wells CA 958-6 and Barrows-1. Before October 1990, all Unit 16 steam condensate was injected into CA 958-6.

**Sonoma:** Calpine purchased the SMUDGEO #1 power plant in July 1998 and renamed it "Sonoma power plant". The annual recovery factors based on decline curve analysis were minimal in the SMUD area (usually less than 1%; Goyal, 1995) since the start-up of injection into CA 1862-6 (Figure 1) in August 1991 (Table 1). The injection recovery in this area is poor, though the wells produce superheated steam and the reservoir pressure is about the lowest of all the four Calpine wellfields discussed in this paper. The poor heat transfer characteristics (small fracture density) prevent efficient boiling of the injectate.

**Bear Canyon:** Annual injection recovery factor based on decline curve analysis was also found to be poor in this wellfield, approximately 2.9% or 0.2 MW (Table 1). High reservoir

**Table 1.** Injectate Recovery Factors in The Geysers

| Wellfield | Operator | Location | Injection Well(s) | Method Used | Tracer Test Date | Recovery Factor | % IDS/ Tracer Recovery |
|---|---|---|---|---|---|---|---|
| Unit 13 | Calpine | SE Geysers | CA 956A-1<br>CA 956A-1<br>CA 956A-1<br>McK-5+Th-7<br>MLM-1<br>MLM-1<br>McKinley-1 | Decline Curve<br>Decline Curve<br>Decline Curve<br>Deut. Isotope<br>Tritium Tracer<br>R-134a Tracer<br>R-23 | Jul-95<br>Jan-98<br>Oct-98 | 56% in 1989-90<br>73% in 1990-91<br>57% in 1991-92 | 24% to 52% from 1985 to 1988<br>50% recovered in 20 days<br>Approx. 50% recovered in 20 days<br>Approx. 22% recovered in 30 days |
| Unit 16 | Calpine | SE Geysers | Barrows-1<br>Barrows-1<br>Barrows-1<br>CA 958-6<br>CA 958-6<br>CA 958-6+Bar-1 | Decline Curve<br>Decline Curve<br>R-13 Tracer<br>Deut. Isotope<br>Ammonia<br>Ammonia | Feb-93 | 20% in 1990-91<br>51% in 1991-92 | 66% tracer recovered in 30 days<br>25% to 32% from 1986 to 1988<br>29% in April 1990<br>65% in 6/91 81% in 7/92 |
| Sonoma (Former SMUD) | Calpine | SE Geysers | CA 1862-6<br>CA 1862-6<br>CA 1862-6 | Decline Curve<br>Decline Curve<br>R-13 Tracer | Dec-91 | 0.6% in 1991-92<br>0.8% in 1992-93 | 68% tracer recovered from 3 wells in 60 days |
| Bear Canyon | Calpine | SE Geysers | Davies Estate-4<br>Davies Estate-4 | Decline Curve<br>R-13 Tracer | Apr-93 | 2.9% in 1992-93 | Less than 1% recovered in 110 days |
| Units 13 & 16 | Calpine | SE Geysers | SEGEP project | Decline Curve | | 16% in 10 months in 1997-98 | |
| NCPA | NCPA | SE Geysers | Unknown<br>Y-5 | Deut. Isotope<br>Tritium Tracer | 1989 | | 20% to 37% from 1985 to 1987<br>27% tracer recovered in 7 months |
| NCPA 1+U-13+U-18 | Calpine+<br>Unocal+<br>NCPA | SE Geysers | C-11+CA 956A-1<br>C-11 | Decline Curve<br>R-12 Tracer | Feb-91 | 54% in 5 months in 1989-90 | At least 22% tracer recovered in 20 days |
| All Unocal wellfields | Unocal | SE to NW | Unknown<br>Unknown | Oxy.+Deut.Iso.<br>Oxy.+Deut.Iso. | | | 55% to 65% from 1983 to 1988 (R-C method)<br>57% to 80% from 1983 to 1988 (R-C-M method) |
| Unit 18 | Unocal | SE Geysers | DV-11<br>DV-11 | Decline Curve<br>Tr+R-13+SF6 | Apr-94 | 40.7% in 4 months in 1994 | Recovered 114.3% Tr in 107 days. |
| Several Unocal areas | Unocal | Central+NW | Several | Tritium Tracer | 1970s/80s | | 15% per year to a maximum of 80% total |

pressure and poor heat transfer appear to be responsible for slow boiling in this area.

**SEGEP Project:** This injection project became operational on September 25, 1997 and continues to supply approximately 1800 gpm of water to Units 13 and 16 wellfields. By July 1998, a net gain of 250 klbm/hr (approximately 14 MW) over and above the loss of 60 klbm/hr due to conversion to injection wells has been realized. The overall gain of 310 klbm/hr (~17.5 MW) represents a recovery factor of 16% over a period of 10 months (Table 1).

### *Injection Recovery Factors for the NCPA Wellfields*

Using deuterium isotope data, Beall *et al.* (1989) estimated a recovery of 20-37% from 1985 to 1987 based on injection anomalies in the NCPA-1 and NCPA-2 areas. These recovery percentages were derived from the ratio of total flow rate of IDS and the average injection rate for the previous twelve months.

**Joint Injection Project in the Southeast Geysers:** Under a cooperative agreement between NCPA, Calpine and Unocal, water was injected into NCPA's well C-11 (Figure 1) at 800 gpm from October 1989 to April 1993. Calpine and NCPA each provided 50% of 800 gpm of water to this well. The remaining Unit 13 steam condensate of approximately 500 gpm was injected into Unit 13 well CA 956A-1 (Goyal, 1995). Both of these injection wells are located in an area where reservoir pressure was below 220 psig and reservoir enthalpy higher than 1220 Btu/lbm in February 1989. Perforated liners were not installed in these wells and the water was allowed to exit below the casing shoe located at approximately 2200 ft in C-11 and 3000 ft in CA 956A-1.

The flow rate of the nearby 25 wells increased by 360 klbm/hr or 20 MW in five months of injection from October 1989 to May 1990 (Enedy *et al.*, 1991). The annual increase of 2.4 billion pounds of steam represents a recovery factor of 54% for the total injection into wells C-11 and CA 956A-1 (Table 1). The overall benefit was found to almost evenly split between NCPA and Calpine. The benefit to Unocal was less due to larger distance from the injectors.

A tracer test in C-11 (Adams *et al.*, 1991) and subsequent in-house analysis (Goyal, 1995) suggested that Calpine was getting lower than expected benefits from the injection into C-11. Therefore, Calpine's 50% share to NCPA well C-11 was stopped as of April 1993.

### *Injection Recovery Factors for the Unocal Wellfields*

Gambill (1991) used R-C (reservoir-condensate) and R-C-M (reservoir-condensate-meteoric water) hydrogen and oxygen isotope methods to calculate the amount of steam produced from the injected water. For all Unocal wellfields, the ratio of mass of injectate recovered as steam to mass of injected water ranged from approximately 55% in 1983 to 65% in 1988 for the R-C method and approximately 57% in 1983 to 80% in 1988 for the R-C-M method (Table 1).

**Unit 18 Cooperative Injection Project:** A cooperative injection project involving Calpine, DOE, NCPA, PG&E, and Unocal, was planned in the Unit 18 area to enhance understanding of the injection. Well DV-11 (Figure 1), located in a low pressure and high superheat area, started accepting water effective January 6, 1994. The monitoring program consisted of 12 Unocal, 6 Calpine and 6 NCPA production wells. Water injection at rates from 400 to 880 gpm resulted in a steam flow rate increase of 81 klbm/hr and 42 klbm/hr in Unocal and NCPA wells, respectively, in four months (Voge *et al.*, 1994). The effect of DV-11 injection on the Calpine production wells was minimal. For an average injection rate of 606 gpm into DV-11, the above mentioned gain is equivalent to a recovery factor of 40.7% (Table 1). The averaged gas-to-steam mole ratio in the nearby wells decreased by 61% of the pre-injection value and the average dry ammonia content increased by nearly 400% (personal comm., Brian Koenig, 1999).

## Tracer Testing

During the last 38 years of commercial production at The Geysers, most of the operators have conducted tracer tests to determine the flow path and recovery of the injectate. Natural tracers, oxygen-18 and deuterium as well as ammonia, have been used to trace injected power plant condensate. In addition, the movement of injection waters of all origins (condensate, meteoric, waste) has been studied by means of artificial tracers. Tritiated water spikes are a very well known and reliable tracer. In response to the need for additional tracers, various Freon (refrigerant) compounds have been successfully used. The chlorinated fluorocarbons (CFC's) R-12 and R-13 were tested and of the two, R-13 was more stable and, therefore, more useful (Adams *et al.*, 1991; Beall *et al.*, 1994). The CFC's, because of their capability to damage the earth's protective ozone layer, have been phased out and replaced by environmentally benign hydrofluorocarbons (HFC's). Of the HFC's, R-134a (Beall *et al.*, 1998) and R-23 (personal comm., Beall, 1999) have been tested for tracer use in The Geysers and found to perform satisfactorily. A summary of these tests in various Geysers wellfields is presented below:

### *Calpine Wellfields*

**Unit 13:** Ten curies of tritium were injected into MLM-1 (Figure 1) in July 1995 (Beall *et al.*, 1998). A total of 50% tracer was recovered in 20 days from 11 nearby wells (Table 1). Another tracer test with R-134a was conducted in the same well in January 1998 after the start-up of the SEGEP project. The results of this test were similar to those of the former if adjustment is made for field curtailments (Beall *et al.*, 1998). Two more tests were conducted in 1998, one in McKinley-4 in April and the other in McKinley –1 in October, using R-134a and R-23 tracers, respectively. The main objective of these two tests was to find the flow path of the injectate. For McKinley-1, a cumulative recovery of 22% of R-23 was realized over the 30-day period from ten wells (J. J. Beall, pers. comm., 1999).

**Unit 16:** R-13 tracer was injected into well Barrows-1 on February 24, 1993. Barrows-1, located approximately 400 ft east of Barrows-7 (Figure 1), was plugged and abandoned in November 1995. A tracer recovery of 66% was measured from the ten surrounding wells within 30 days (Beall *et al.*, 1994). More than 80% of the total recovered tracer came from the latest makeup well CA 958-16, which came on-line in March 1992 (Goyal, 1995). Good communication between Barrows-1 and CA 958-16 led to water breakthrough in the latter, resulting in an approximately 100 klbm/hr loss of steam between 1992-94. The injection into Barrows-1 was stopped in March 1994. Another R-13 tracer test was conducted in CA 958-6 on February 14, 1994 (J. J. Beall, pers. comm., 1999). It appeared in five nearby wells within five days. The tracer did not appear in the nearby Bear Canyon well, which was thought to be affected by injection into CA 958-6 based on the production data. The resolution for this conflicting result is not yet achieved.

**Sonoma:** Freon tracer R-13 was injected on December 3, 1991 into well CA 1862-6 (Figure 1). It appeared in 7 nearby wells on the first day (Beall *et al.*, 1994). By the eighth day, R-13 had broken through to 17 wells. A total of 74% of tracer was recovered in 60 days from all wells. Out of this, 68% was recovered from wells CA 1862-18 (55%), CA 1862-19 (12%), and CA 1862-13 (1%). In contrast, the recovery on the basis of production data was minimal (less than 1%) as discussed above and presented in Table 1.

**Bear Canyon:** Freon tracer R-13 was injected into injection well Davies Estate-4 (DE-4, Figure 1) on April 12, 1993 (Beall *et al.*, 1994). The tracer was not seen in any of the wells for the first ten days. Subsequently, a small amount of tracer was recovered from five nearby wells. The cumulative tracer recovery was less than 1%, even 110 days after the test, suggesting a slow boiling in this area (Table 1).

The results obtained by tracer tests were qualitatively consistent with those obtained by the production data most of the time. However, this was not true for the Sonoma and Bear Canyon wellfields. In the former, tracer tests suggest a good recovery, which the production data failed to show. For Bear Canyon, tracer recovery is almost negligible but flow rate data shows at least some recovery (Table 1).

### *NCPA Wellfield*

A tritium test was conducted in 1989 in well Y-5 (Enedy *et al.*, 1991). A recovery of 27% of the tritium was realized from 33 wells within seven months (Table 1).

R-12 and R-13 were used as tracers in C-11 in February 1991. A total of 49 production wells from Calpine, NCPA, and Unocal were monitored during the 51-day test. Due to better detectability, R-12 was analyzed for most wells and R-13 for only three wells. During the entire test, R-12 appeared in 38 production wells and peak transit times occurred within 1 to 11 days. R-12 was found to decay much faster than R-13, which exhibited little or no decay. The calculated recovery factor of 22% over a 20-day period appears to be low due to loss of R-12 as a "gas kick" observed at the plant (Adams *et al.*, 1991).

### *Unocal Wellfields*

A total of eight tritium tracer tests were conducted during the 1970s and 1980s (Barker *et al.*, 1995). These tests showed that about 15% of the injected liquid boiled each year after injection, until approximately 80% of the ultimate recovery was reached (Table 1).

A multiple tracer test involving $SF_6$, R-13, and tritium was conducted in DV-11 (Figure 1) on April 18, 1994 (Voge *et al.*, 1994). Unlike $SF_6$ and R-13, the tritium data were collected on a regular basis, which provided a cumulative recovery of 114.3% over 107 days suggesting that some tritium was recycled (personal comm., Brian Koenig, 1999).

## Summary of Recovery Factors and IDS Results

The following observations can be made from the information discussed above.

1. Annual recovery factors based on the decline curve method were higher than 50% for several areas of The Geysers field such as southwest of Unit 13, the central part of Unit 16, and the areas surrounding NCPA well C-11 and Unocal well DV-11. The recovery in the Bear Canyon and Sonoma wellfields was found to be the lowest, at less than 3%.
2. IDS (injection derived steam) values, calculated from isotopic and ammonia analyses, were slightly higher but qualitatively similar to those obtained by the decline curve method. IDS for most of the Unocal areas ranged from 55 to 80% using oxygen and deuterium isotopes. For the northern part of Unit 13, IDS ranged from 24 to 52%, and for the southeast part of Unit 16, it ranged from 25 to 32% (Table 1).
3. In general, tracer tests suggest recovery factors even higher than those obtained by the isotopic analysis (natural tracers). In the Bear Canyon and Sonoma wellfields, the recovery obtained by tracer tests was not consistent with that obtained by decline curve analysis. Recovery of R-13 was 68% in 60 days from three wells while less than 1% injection recovery was suggested by the production data. In Bear Canyon, less than 1% tracer was recovered in 110 days compared to 3% recovery by the decline curve method.
4. Unocal estimated an average tritium recovery of 15% per year to a maximum cumulative recovery of 80% for most of its areas.
5. Cumulative tritium recovery of 114.3% in 107 days in the Unit 18 area indicates recycling of the tritium tracer.

## Possible Adverse Effects of Injection

Water injection may result in a loss of steam flow due to water breakthrough and/or silica scale deposits in the wellbore of a production well and/or in reservoir fractures. Additionally, it cools the reservoir and, therefore, reduces the boiling efficiency and the enthalpy of steam used to generate electricity. Injection is also found to result in the formation of bridges in the open hole section as well as loss of integrity in some injection wells.

### *Water Breakthrough to Production Wells*

The reduction in steam flow rate due to water breakthrough is found in the Units 13 and 16 production wells that are connected to injection wells by high permeability fracture conduits. High fracture density provides a high heat transfer area and, therefore, is desirable for efficient heat transfer from reservoir rocks to the water. However, it can also provide a conduit for water breakthrough if the water level in the injection well is higher than the location of the steam entries in the nearby production wells. Sometimes a reduction in injection rate can solve this problem. Other times, working over an injection well or directing the water to exit deep in the reservoir may be required. When none of these work because of the existing fracture network, the water injection into a given well has to be stopped. This happened to Unit 13 injection well CA 956A-2. In October 1995, it was converted back to a production well.

### *Bridges in Reservoir and Production Wells*

The precipitation of silica upon boiling can form scale in the formation as well as in the wellbore resulting in a reduction in steam flow rate. The sloughing of the formation can also create obstructions in the wellbore causing a reduction in steam flow rate. A chisel-like tool, called a bridgebuster, is usually used to remove scale/bridges from the wellbore. On the other hand, there is no economical way to remove scale/obstructions formed in reservoir fractures. Obstructions in the reservoir are believed to have occurred in two Calpine wells: McKinley-10 in January 1993 when it lost 25 klbm/hr of steam and Davies Estate-6 (DE-6), which lost 23 klbm/hr of steam following injection into Davies Estate-1 from April 7 to July 21, 1992. A bridgebuster tool went to total depth (TD) in DE-6 without encountering any bridges in the wellbore in December 1992. Similarly, no bridges were found in McKinley–10 during three bridgebuster cleanout efforts made between January 1993 and September 1995. These efforts suggest that the wellbores of these two wells were clear of obstructions and the flow was reduced due to possible plugging of the fractures in the reservoir. DE-6 regained flow rate within a year as suggested by its open-hole flow test on October 6, 1993, but McKinley-10 has not recovered. It is hypothesized that the microseismic activity in the Bear Canyon area has loosened the scale in the fractures and cleared the way for the steam to flow. But the same appears to be unsuccessful in the Unit 16 area.

## Reservoir Cooling

The thermal front from injection well CA 956A-1 (Figure 1) took five years to reach the production wells (Goyal, 1998). A wellhead temperature drop of 5-8°F occurred in producers between late 1994 and December 1997. Assuming The Geysers reservoir as a homogeneous porous fractured reservoir, Goyal (1998) estimated a maximum reservoir temperature drop of 45°F. Such a large temperature drop is expected to reduce boiling efficiency to some extent even at the resulting reservoir temperature of approximately 425°F. This finding of slow boiling in this area has recently been confirmed by a tracer (R-134a) test conducted in CA 956A-1 on February 24, 1999. The tracer, which was expected to appear within hours of injection in the nearby production wells, did not show up until the next day (J. J. Beall, pers. comm., 1999).

### *Bridges in Injection Wells*

Sloughing of formation units (such as argillite, serpentine, or chert) around injection wells forms bridges in these wells (J. J. Beall, pers. comm., 1999). Several Calpine injection wells are found to develop bridges after injecting water for approximately one year. These bridges force the water to exit at a shallow depth. Sometimes, this water reaches a nearby production well through the interconnecting fracture network causing its steam production rate to drop. Calpine has started installing liners past the argillite, serpentine, and chert units in the reservoir to solve such problems.

### *Casing Collapse in Injection Wells*

A 6-5/8" liner in a newly drilled injection well, Barrows-7, was found to be parted at approximately 1400 ft above the first steam entry about one month after the start of injection. Thermal cycling appears to have caused this failure. Two Unit 13 injection wells, McKinley-5 and Thorne-7, with liners perforated below 6100 ft and 6786 ft, lasted for approximately 13 and 10 years, respectively. Another Unit 16 injector, Barrows-1, with no liner, lasted for approximately 5 years. The casing of these wells has been found to be parted or collapsed due to thermal shock, corrosion, and/or a poor cement job.

## Conclusions

Annual recovery factors vary widely in The Geysers field from a low of less than 1% in the Sonoma wellfield to a high of 73% in the southwest area of Unit 13. Highest injectate recovery is achieved in the areas with low reservoir pressures, high superheat, and high permeability. Some risk is always associated with the high permeability. It provides a high heat transfer area but can also provide fracture conduits for water to reach a production well causing water breakthrough and steam production loss.

In cases where the water level in an injection well is higher than the steam entries in a nearby production well (shallow injection without a liner), water breakthrough can occur. Therefore, a liner to direct water deep in the reservoir (below the steam entries of the nearby production wells) is used in most Calpine injection wells. Shallow injection can work in wells located far away from production wells. An injector with a liner is found to last for ten or more years if we discount our recent bad experience with the newly drilled injection well Barrows-7.

Injectate recovery obtained by the decline curve method and isotopic analysis is found to be qualitatively similar for most wellfields. For the Sonoma wellfield, these methods provided inconsistent results.

Recoveries based on injection derived steam (IDS) from chemical analyses were consistently higher than those obtained by decline curve analysis. Recoveries based on tracer tests were found to be the highest amongst all methods discussed in this paper. Newly discovered tracers R-134a and R-23 are found to work in the Geysers field and are environmentally friendly.

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