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INJECTION PERFORMANCE EVALUATION IN UNIT 13, UNIT 16, SMUDGEO #1, AND BEAR CANYON AREAS OF THE SOUTHEAST GEYSERS

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ABSTRACT

Steam production data from wells surrounding Unit 13 injection well CA 956A-1 and Unit 16 injection well Barrows-1 were analyzed to estimate annual and cumulative recovery factors due to water injection into these wells. Production and injection data from SMUDGEO#1 and Bear Canyon wellfields were also analyzed to obtain recovery of the injected water in those wellfields. The results of this study may be useful in designing future injection projects in vapor dominated systems.

INTRODUCTION

Several steam field operators have found that water injection into the vapor dominated reservoir can be very useful if performed properly (Goyal and Box, 1992; Enedy et al, 1991; Hanano et al.,1991; Gambill, 1990; Bertrami et al., 1985 and Cappetti et al, 1982). The positive contributions of water injection include providing reservoir pressure support, maintaining steam production rate, reducing makeup well requirements, increasing reserves and life of the field by recovering a portion of the approximate 90% heat which is stored in the rocks of the vapor dominated systems. On the other hand, injection can reduce well productivity or even drown a production well by breakthrough of the injected cold water into a production well through some high permeability fracture conduits. It can also create obstructions in the wellbore and reduce steam flow rate by silica precipitation. Workovers, sometimes costly, may be needed to clean such wells.

In this paper I present the results of injection in four wellfields: Unit 13, Unit 16, SMUDGEO#1 and Bear Canyon, and try to quantify steam recovery due to injection in each wellfield by calculating recovery factors from the production data. The results for Units 13 and 16, already presented in Goyal and Box (1992), have been updated through May 1993. Discussions about SMUD and Bear Canyon wellfields are new.

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 improvement rate established due to injection minus the steam production calculated at a decline rate without injection. The improvement rate is defined as the annual exponential (or harmonic) increase in the steam flow rate. This definition is similar to the annual exponential (or harmonic) decline rate but represents an increase in flow rate rather than a decrease.

Gambill (1990), Beall et al., (1989) and Beall (1993) have used geochemical data such as deuterium isotope and/or ammonia to estimate the recovery of injected water in various parts of The Geysers geothermal field. The recovery factor defined on the basis of production data may be different than that defined on the basis of geochemical data if considered on a well by well basis. However, the combined recovery from all production wells affected by one or more injection wells should ultimately agree by both methods given sufficient time, since (i) the total amount of boiled water should appear as steam in the production wells and be reflected in the production data and (ii) the steam originally to be produced by a given well but replaced by injection derived steam (IDS) should eventually be produced in other well(s). Water injection may create unfavorable situations where the determination of the recovery factor from decline analysis may not produce reliable results. Such situations include (i) a decrease in steam flow rate due to water breakthrough, (ii) scale deposits in the wellbore, (iii) the fluctuating flow rate, and (iv) the completion of additional production wells in injection affected areas which impact the decline rates of nearby production wells as seen in the Unit 16 analysis.

UNIT 13 INJECTION WELL CA 956A-1:

Originally a steam production well since the plant start-up in May 1980, well CA 956A-1 was converted to an injection well on October 30, 1989 as discussed in Goyal and Box (1992). From October 1989 to April 1993, most of Unit 13 injectate was divided between wells CA 956A-1 and an NCPA/Calpine joint injection well C-11 (Enedy et al, 1991) with a small amount going into Thorne-7. Due to lower than expected direct benefits to Calpine, the water from Unit 13 to the joint well C-11 has been stopped effective April 1993. All of Unit 13 steam condensate is now injected into CA 956A-1 and CA 956-2. Originally a production well, well CA 956-2 was converted into an injection well in October 1993.

Production Wells Surrounding The Injection Well CA 956A-1:

Twelve wells surrounding the injection well CA 956A-1 and shown by solid circles in Figure 2 were monitored for their flow rate and decline rate behavior. Most wells displayed a reduction in decline rate but the wells located within the dashed outline exhibited an increase in their flow rate (Goyal and Box, 1992).

The flow rate increase observed in these wells suggest that most of the injected water into CA 956A-1 took a southwestern route and appeared as steam in wells located within the dashed outline (Figure 2). The pressure support to these wells from C-11, located south of the Unit 13 lease boundary, was minimal as suggested by the tracer test conducted in C-11 in February 1991 (Adams et al., 1991). The tracer recovery in Unit 13 wells was of one order of magnitude lower compared to NCPA wells. Additionally, injection into C-11 was stopped from June 1990 to November 1990 but the improved performance of these wells continued (Figure 3). These observations suggest that recovery in these wells is predominantly due to injection into CA 956A-1.

Recovery Factors (RF) due to Injection into CA 956A-1:

The combined normalized flow rate of 12 wells plus CA 956A-1 at 110 psig wellhead pressure (WHP) is presented in Figure 3 from January 1988 to May 1993. Due to conversion of production well CA 956A-1 into an injection well, the flow rate of only 12 wells is plotted after October 1989. Decline rates, shown in Figure 3, are estimated by excluding the data points affected by plant outages and testing. The 13 production wells, including CA 956A-1, exhibit an annual exponential decline of 26% in 1988 and 20% in 1989 before the start of injection into CA 956A-1. During the next four months, the flow rate increased by 110 klbm/hr. This increase was experienced by the 12 wells (13 wells minus CA 956A-1) and was over and above the flow rate of the original 13 wells. Subsequently, the flow rate of these wells declined but at a moderate rate of 10.5% as shown in Figure 3. Injection into CA 956A-1 has helped in two ways: one in reducing decline rates by 9.5% and the other in providing an increase in the flow rate. The injection rate (gpm) averaged over a month since the start up in October 1989 is also shown in this figure which ranges from 300 gpm to 800 gpm.

The hatched area in Figure 3 is used to calculate the recovery of the injected water. In these calculations, it is assumed that the original 13 wells would have declined at 20% harmonic rate starting October 1989. This assumption is consistent with the behavior of these wells in 1988 and 1989 (Figure 3) and is supported by the modeling effort of the Technical Advisory Committee appointed by the California Energy Commission (GeothermEx, 1992).

Cumulative steam recovery and recovery factors (RF) for 3 years are shown in Figure 4. Steam recovery exhibits an increasing trend with time. A cumulative three year recovery factor of 61% is shown in Figure 4b. A slight decrease in the third year RF may be caused by a 30% increase in the injected water in that year as presented in Table 1.

Annual recovery factors (RF) of 56%, 73% and 57% were estimated for the first, second and third year respectively (Table 1). Reduced RF in the third year implies that increased injection did not enhance steam recovery correspondingly. It may be noted that steam recovery in the second and third year was almost equal even though the annual injection in the third year was 30% higher than the second year (Table 1). This suggests that the injection rate should be kept close to the second year level of about 2500 million lbm or 600 gpm for an optimum boiling of the injected water.

First year recovery factor of 56% is lower than 63% reported in Goyal and Box (1992). This difference is mainly caused by the amount of the injection water used in the first year. Previously we considered the annual injection water to be 2.12 billion lbm from October 30, 1989 to September 30, 1990. In this study, we considered the first year injection of 2.36 billion lbm from October 30, 1989 to October 31, 1990 because injection into CA 956A-1 during October 1989 was only for two days.

The annual steam recovery presented in Table 1 can be converted in to MWh by using the Unit 13 steam usage factor of 20.5 klbm/MWh. This suggests that injection into CA 956A-1 provided 64,449 MWh (7.4 MW), 86,976 MWh (9.9 MW) and 88,498 MWh (10.1 MW) in the first, second and third year respectively.

In summary, water injection into the southwest area of Unit 13 provided a total cumulative three year recovery of about 61% and generation of 239,923 MWh. This recovery may be slightly on the high side due to some pressure support provided by water injection into the joint NCPA/Calpine well C-11. To date, no adverse injection effects such as cooling or water breakthrough have been noted in the production wells in this area due to water injection into CA 956A-1.

UNIT 16 INJECTION WELL BARROWS-1:

Originally a steam producer since the plant start-up in October 1985, Barrows-1 was converted into an injection well on October 1, 1990. The water breakthrough to a nearby producer in early 1992 prompted Barrows-1 examination. Its casing was found to be parted at 2500'. This problem was fixed by installing a 6-5/8" liner inside the original casing. The well was put back in service in April 1992. After this repair, it received a major portion of Unit 16 water until November 1993 when the injection rate was reduced to about 100 gpm due to water breakthrough to nearby producers.

Wellfield	Injection Well	Annual Data	First year	Second year	Third year
Unit 13	CA 956A−1	Injection (Mlbm)	2,363.5	2,451.1	3,190.5
		Recovery (Mlbm)	1,321.2	1,783.0	1,814.2
		Recovery Factor	56%	73%	57%
		Recovery (MWh)	64,449	86,976	88,498
		Recovery (av. MW)	7.4	9.9	10.1
Unit 16	Barrows−1	Injection (Mlbm)	2,658.3	2,195.5	
		Recovery (Mlbm)	540.3	1,114.8	
		Recovery Factor	20%	51%	
		Recovery (MWh)	30,017	61,933	
		Recovery (av. MW)	3.4	7.1	
SMUD	CA 1862−18	Injection (Mlbm)	2,027.9	3,375.0	
		Recovery (Mlbm)	11.2	25.9	
		Recovery Factor	0.6%	0.8%	
		Recovery (MWh)	772	1,786	
		Recovery (av. MW)	0.1	0.2	
Bear Canyon	DE−7	Injection (Mlbm)	987.6		
		Recovery (Mlbm)	28.4		
		Recovery Factor	2.9%		
		Recovery (MWh)	1,732		
		Recovery (av. MW)	0.2		

TABLE 1: Annual Injection Data and Recovery Factors

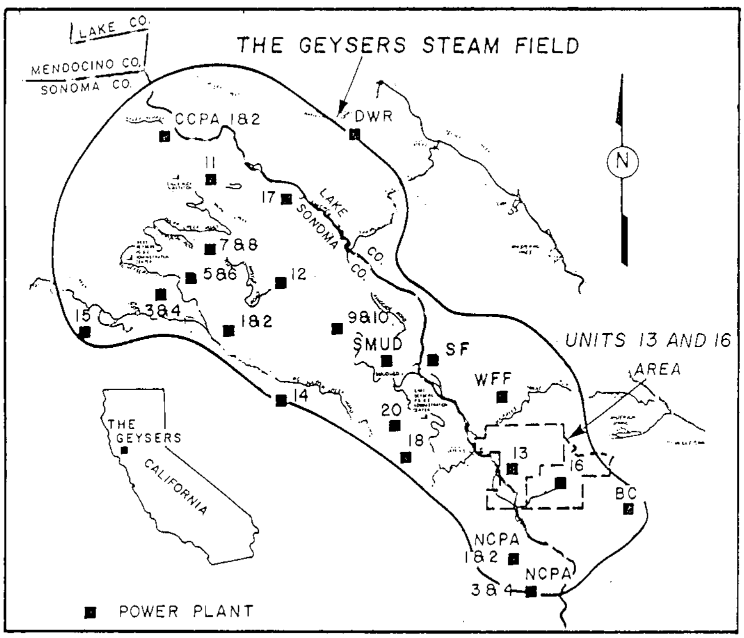


FIGURE 1: The Location Map

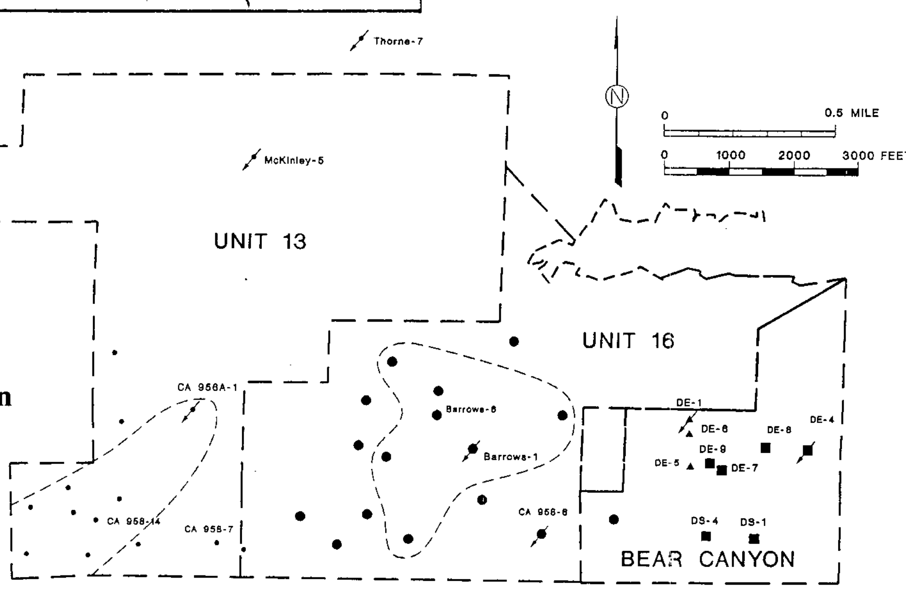


FIGURE 2:

Study Area in Unit 13, Unit 16 and Bear Canyon

Recovery Factors due to Water Injection into Barrows-1:

In the Unit 16 area, a total of 15 production wells are used in this analysis: 7 wells located within the dashed outline showing maximum injection benefit and 8 nearby wells located outside the dashed outline showing some injection benefit (Figure 2). The eastern most well of this group belongs to the Bear Canyon lease. The combined flow rate of all 15 wells normalized at 110 psig wellhead pressure is presented in Figure 5 from March 1989 to April 1993. Due to the conversion of Barrows-1 into an injection well, the flow rate of only 14 wells is plotted after September 1990. All 15 wells display a combined annual exponential decline rate of 12% before the start of injection into Barrows-1. The shift of most of Unit 16 injection to Barrows-1 since October 1, 1990 has reduced the decline rate to 4% as shown in Figure 5. An increase in flow rate, similar to that seen in the Unit 13 area (Figure 3), is not seen in the Unit 16 area. Additionally, the effect of makeup well drilling in 1992 is reflected by an increase in the decline rate from 4% to 20%.

The injection rate (gpm) into Barrows-1 and into the Unit 16 area (Barrows-1 plus CA 958-6) averaged over a month from March 1989 to April 1993 is also shown in figure 5. The injection rate into Barrows-1 and the Unit-16 area ranges from about 300 gpm to 700 gpm and 600 to 1100 gpm respectively (Figure 5).

The hatched area in Figure 5 is used to calculate the steam recovery due to injection into Barrows-1. The following assumptions were made in these calculations.

1. The decline rate of the 15 wells without injection into Barrows-1 is projected as harmonic at 12% rate from September 1990 until March 1992. This assumption is similar to that assumed in Unit-13 calculations.

2. The steam recovery during the next six months (high decline period) after March 1992 is equal to the steam recovery during the first six months. This assumption implies that steam recovery by injection during the 20% decline rate period has not diminished. This is reasonable since the increase in the decline rate is caused by 17% more steam withdrawal from the area by new makeup wells. This increased withdrawal is expected to enhance the boiling rate due to reduced boiling temperature associated with lower reservoir pressures. This assumption was supported by a tracer test conducted in Barrows-1 in February 1993 where 66% of the tracer came back from the surrounding 10 wells in 30 days. More than 80% of the total recovered tracer came from the nearest new makeup well CA 958-16 (J. J. Beall-Personal communication, 1993).

3. The decline history of 15 wells, shown in Figure 5, during 1989-90 and the 12% harmonic projection

FLOW RATE OF WELLS SURROUNDING CA 956A-1

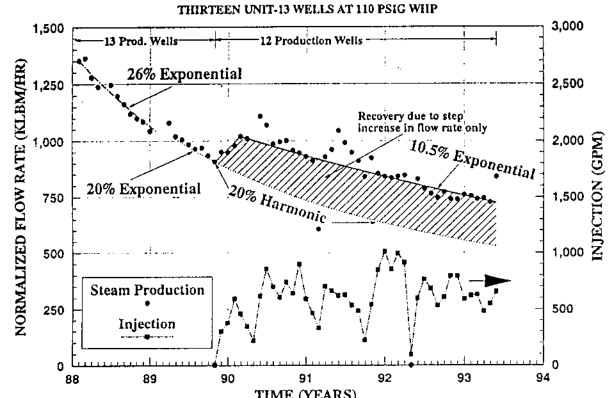
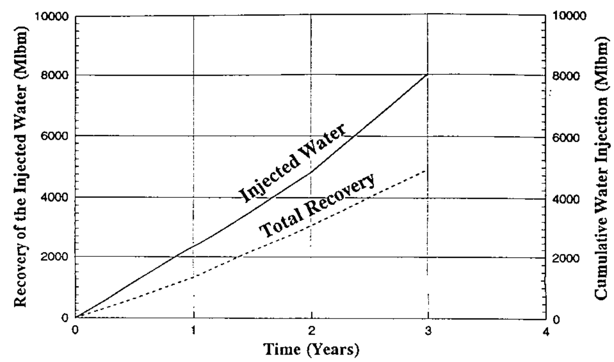


FIG. 3: Effect of Injection Into CA956A-1 on Some Surrounding Prod. Wells.



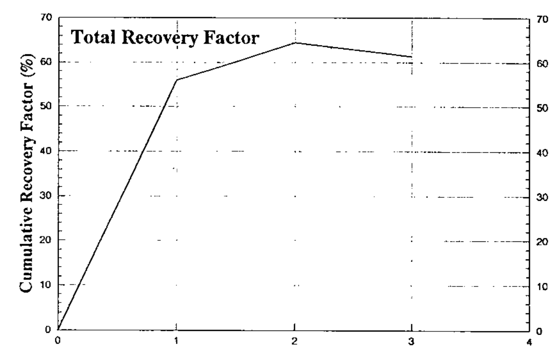


FIG. 4: Total Cumulative Recovery Factors Due to Injection into CA956A-1

WELLS SURROUNDING BARROWS-1 AND CA 958-6

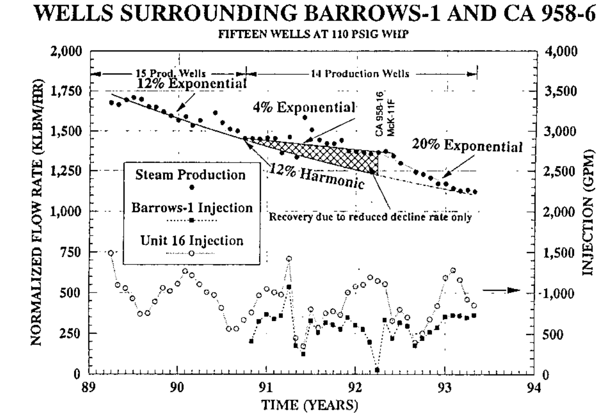


FIG. 5: Effect of Injection in Barrows-1 on Surrounding Wells

from September 1990 already takes into account the injection support provided by the water injection into CA 958-6. A decrease in water injection into this well can only result in an increase in the decline rate of the 15 wells to more than 12%. Therefore, the hatched area shown in Figure 5 and the calculated recovery factors are considered conservative.

Cumulative steam recovery and water injection in Barrows-1 and in the Unit-16 area are presented in Figure 6. A two year cumulative recovery factors of 34% is also shown in this figure. Annual recovery factors of 20% for the first year and 51% for the second year are presented in Table 1. The annual steam recovery in Table 1 is equivalent to 30,017 MWh (3.4 MW) and 61,933 MWh (7.1 MW) in the first and second year respectively for a Unit 16 steam usage factor of 18 klbm/MWh.

In summary, water injection in Barrows-1 provided a two year cumulative recovery of 34%. Recently, a decrease in flow rate of two nearby production wells has been observed. This phenomenon is believed to be caused by water breakthrough from the injection well Barrows-1. Therefore, the injection rate into this well is presently reduced to about 100 gpm.

SMUDGEO#1 INJECTION HISTORY:

The SMUDGEO#1 wellfield is located northwest of Unit 13 as shown in Figure 1. This 78 MWG unit came on line in October 1983 with 11 production wells and one injection well. Presently, there are 19 production wells and one injection well. In fact, total producing legs in the SMUD area are 23 which include one production well with 2 forks and two wells with a single fork each. The outline of the SMUD wellfield and the location of injection and the nearby production wells is shown in Figure 7.

CA 1862-6 was used as an injection well from the plant start up in October 1983 through July 1985. Water breakthrough to nearby producers, resulting from the poor completion of this well, prompted the drilling of a new injection well CA 1862-17. The original injection well CA 1862-6 was redrilled and completed as a producer in September 1985. CA 1862-17 accepted water from July 1985 to August 1991. In an effort to obtain better returns of the injectate, the redrilled well CA 1862-6 was converted to an injection well in August 1991. The former injection well CA 1862-17 was kept as a standby injector for 15 months until it was plugged and abandoned in November 1992 due to the damaged casing.

Injection Well CA 1862-6:

This well has been accepting all the condensate from the SMUD plant since August 27, 1991. No perforated liner was installed in this well, allowing the injectate to leave the wellbore below the casing shoe at 4038'. Recently, due to obstruction in the wellbore injectate started exiting at shallow depth, affecting the nearby producers. Therefore, a workover was performed in December 1993 and a 6-5/8" liner was installed from the surface to 4695'.

A tracer test was conducted in this well in December 1991 by injecting 232 pounds of R-13 Freon tracer (chlorotrifluoromethane). A total of 74% of the tracer was recovered in 60 days, mostly from the wells in the SMUD area. In fact, 68% of the total tracer was recovered from three wells: 55% from CA 1862-18, 12% from CA 1862-19 and 1% from CA 1862-13 (personal comm., J.J. Beall, 1992). The proximity of these wells to the injection well suggests that most of the injected water benefits remained within the SMUD lease (Figure 7).

Recovery Factors due to injection into CA 1862-6:

Consistent with the tracer data, well CA 1862-18 derived the maximum benefit from this injection. Its decline rate decreased from 20% exponential to 15% harmonic (Figure 8). The effect on other nearby wells was too small to analyze. The overall impact of the injection on the flow rate and the decline rate of the nearby 3 wells was minimal as shown in Figure 9.

A flow rate increase seen in 1991 in Figures 8 and 9 was caused by a high header pressure operation of the surrounding PG&E units resulting in reduced steam withdrawal from the reservoir offsetting the SMUD lease (TAC Consortium, 1992). Therefore, the flow rate just before injection is used as the initial condition to evaluate injection benefits in the SMUD area.

The combined normalized flow rate of wells CA 1862-18, CA 1862-19 and CA 1862-13 displays an annual exponential decline rate of 20% during 1989-90. The decline rate reduced to 6% exponential for about 8 months after the start up of injection into CA 1862-6. Thereafter the decline rate increased substantially as shown in Figure 9. The flow rate data from August 1991 to August 1993 suggest an overall decline rate of 20% harmonic. Using the methodology discussed earlier, the net gain in these 3 wells due to injection is zero. Additionally, an injection rate above 500 gpm has a positive impact on the flow rate of these wells as shown in Figure 9.

Using the hatched area in Figure 8 for CA 1862-18, annual recovery factors of 0.6% for the first year and 0.8% for the second year were calculated (Table 1). A two year cumulative recovery factor of 0.7% was also computed. These translate into a two year generation of 2,558 MWh for a steam usage factor of 14,500 pound per MWh (Table 1).

BEAR CANYON INJECTION HISTORY:

The Bear Canyon project is located east of Unit 16 as shown in Figure 2. It is a 24 MWG unit which came on line in September 1988 with only 5 production wells and 1 injection well. Presently it has 8 production wells and one redrilled injection well. The actual producing legs in this wellfield are 11 which include two wells: one with 3 legs and the other with 2 producing legs.

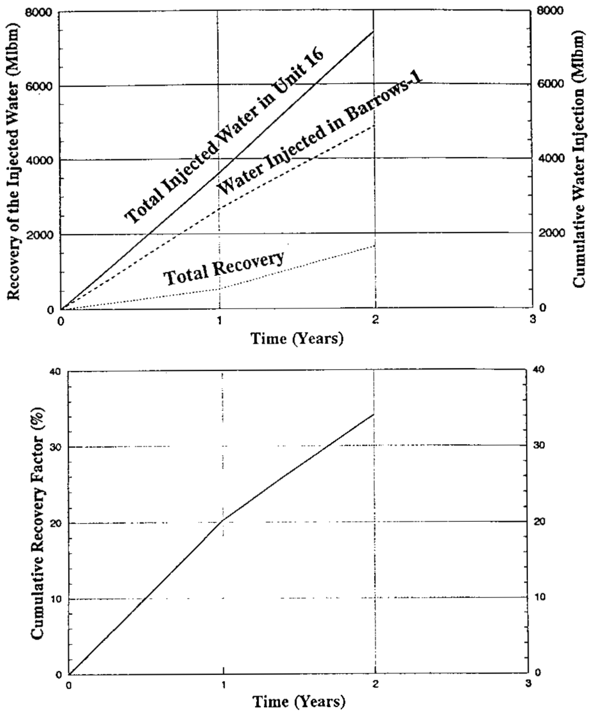


FIG. 6: Cumulative Recovery Factors Based on Injection into Barrows-1.

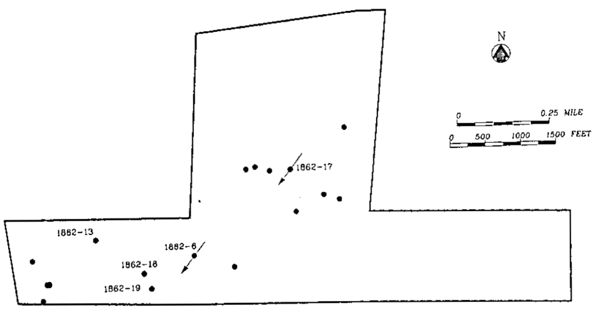


FIGURE 7: Injection Well CA1862-6 & the Surrounding Production Wells in the SMUD Area.

CA 1862-18: NORMALIZED PRODUCTION AT 110 PSIG

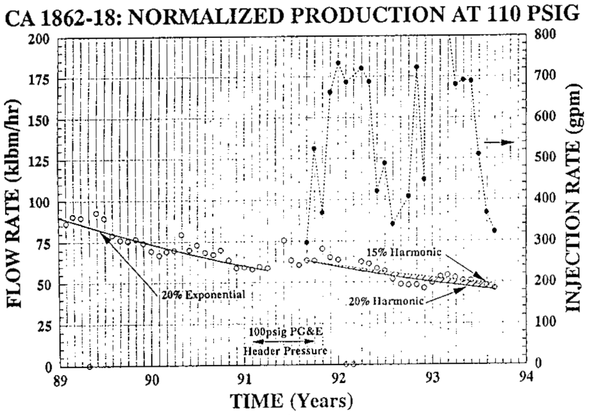


FIG 8: Effect on Injection in CA 1862-6 on the Production Well CA 1862-18.

WELLS SURROUNDING CA 1862-6

Wells CA 1862-13, -18 & -19 at 110 psig WHP

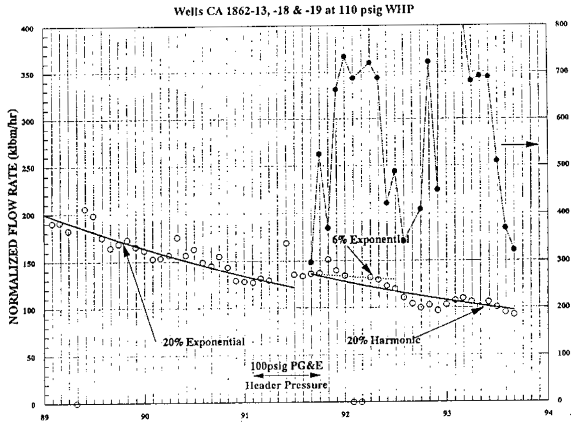


FIG. 9: Effect of Injection in CA1862-6 on the Surrounding Wells.

NORMALIZED FLOW RATE OF DE-7 AT 110 PSIG

BEAR CANYON

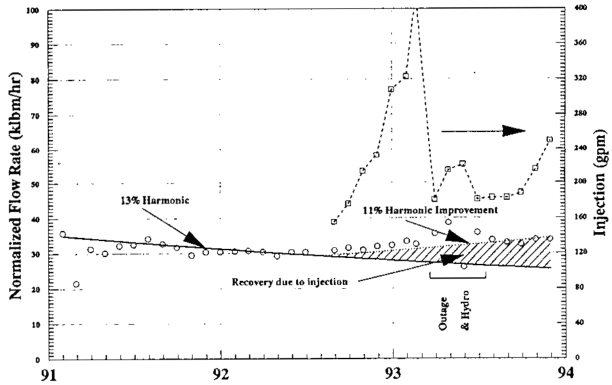


FIG. 10: Effect of Injection in DE-4 on the Flow Rate of DE-7.

Injection Well Davies Estate-4 (DE-4):

DE-4 has been accepting all the water from the plant since its start up in 1988. However, the original location of DE-4 was such that it resulted the water being injected to the east of the lease without obvious benefits to the production wells. Therefore, the original leg of DE-4 was plugged and a new leg was drilled towards the production area in June-July 1992. The new leg has been accepting all the water from the plant since August 1992. No adverse injection impact has been observed so far.

A tracer test was conducted in April 1993 by injecting 160 lbm of R-13 Freon tracer to evaluate the potential benefits derived from this well. The tracer was not seen in any of the wells for the first 13 days. Subsequently, a small amount of tracer was recovered from DE-9 followed by Davies State 5206-4 (DS-4), DE-7, DE-8 and DS-1 (J. J. Beall, Personal Communication 1993). The cumulative tracer recovery in the Bear Canyon area was less than 1% even 110 days after the test suggesting a slow boiling process of the injected water in this area. High reservoir pressure and the geology (not so high fracturing) appear to be responsible for slow boiling.

Recovery Factors due to injection into DE-4:

The tracer test indicated a maximum recovery in wells DE-8 and DE-9. However, the effect of injection on the flow rate of these wells was too small to analyze. The data of only one well, DE-7, was analyzable. The normalized flow rate of DE-7 from January 1991 to November 1993 is shown in Figure 10. The injection into DE-4 from July 1992 to November 1993 is also indicated in this figure.

DE-7 displays a 13% harmonic decline rate in 1991-92 until the start up of injection into DE-4 in August 1992. Since then, its flow rate shows an improvement at a harmonic rate of 11% as presented in Figure 10. The recovery of the injected water is shown by the hatched area in this figure. On the basis of this area, a first year recovery of 28.4 million pounds is calculated. This amounts to a first year recovery factor of 2.9% for an annual water injection of 987.6 million pounds. This steam recovery is worth 1732 MWh (0.2 MW) for a steam usage factor of 16.4 klbm per MWh.

CONCLUSIONS:

The highest annual recovery factors of 56%, 73% and 57% were estimated for the southwest area of Unit 13 for the first, second and third year respectively. A three year cumulative recovery factor of 61% was obtained. Low reservoir pressure (low boiling temperature) and large heat transfer area (high fracturing) were thought to be responsible for the efficient boiling of the injectate in this area. Unit 13 recovery factors may be slightly on the high side due to pressure support provided by water injection into the joint NCPA/Calpine well C-11. To date no adverse impact such as cooling or water breakthrough has been observed by the injection into CA 956A-1.

Injection into Barrows-1 provided an annual recovery factor of 20% for the first year and 51% for the second year. The two year cumulative recovery factor was 34%. Higher reservoir pressure and higher fracture connectivity between production and injection wells in the Unit 16 area compared to the southwest area of Unit 13 are believed to result in lower recovery factors. The injection in the Unit 16 area has not been trouble free. Water breakthrough problems do appear from time to time requiring workover of the injection wells.

Injection into the SMUD well CA 1862-6 has provided minimal benefits. One well CA 1862-18 did exhibit a reduction in the decline rate from 20% exponential to 15% harmonic. However, the annual and cumulative recovery factors were less than 1%. The injection recovery in the SMUD area is very poor though the reservoir pressure is almost the lowest out of the four wellfields presented in this paper. The poor heat transfer characteristics in this area (geology) prevent efficient boiling of the injectate. Problems related to water breakthrough and injection well workover were also encountered in the SMUD wellfield.

In spite of slow boiling, injection has been helpful in the Bear Canyon area. Well DE-7 displays a continuous increase in its flow rate since the start up of injection in the redrilled well DE-4. The production data of DE-7 suggests a first year recovery factor of 2.9% and an electric generation of 1732 MWh. No adverse impact is observed by injection into DE-4 so far.

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