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INJECTION RECOVERY BASED ON PRODUCTION DATA IN UNIT 13 AND UNIT 16 AREAS OF THE GEYSERS FIELD

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ABSTRACT

Steam production data from 13 wells including and surrounding Unit 13 injection well I-3 and 15 production wells including and surrounding Unit 16 injection well I-5 are analyzed to estimate steam decline rates with and without water injection (Figure 2). Such information is then utilized to estimate the first year recovery factor due to water injection in the southwest area of Unit 13 and the Unit 16 wellfields.

INTRODUCTION

At The Geysers geothermal field, about 20% to 30% of the steam condensate is available for disposal after evaporation in the cooling towers. Initially in 1960, the liquid effluent in The Geysers was allowed to run into Big Sulphur Creek as this was simple and inexpensive (Glenn Horton-personal communication, 1991). However, since 1969 the steam condensate has been injected back into the reservoir.

Several steam field operators have found that water injection into the Geysers' reservoir can be very useful if performed properly (Adams et al, 1991; Enedy et al, 1991: Gambill, 1990). At present, additional fresh water from Big Sulphur Creek and surface collection facilities is also being used to augment injection at The Geysers. There is even discussion of bringing treated waste water to The East Geysers from the city of Clearlake (Geothermal Report, August 1991; Goddard and Goddard 1991). Other means of collecting water such as building an impoundment facility on the Big Sulphur Creek are also being discussed by some operators in The Geysers.

Water injection into the Geysers's reservoir can be beneficial in some areas and detrimental in the other areas depending upon the fracture distribution, reservoir pressure, temperature, liquid saturation and the rock type. The positive contributions of water injection include providing reservoir pressure support, maintaining steam production rate, reducing makeup well requirements, increasing reserves and the life of the field by recovering a portion of the approximate 90% heat stored in the rocks (Dykstra, 1981). On the other hand, injection can reduce well productivity or even drown a production well completely by breakthrough of the injected cold water to a production well through some high permeability fractures. It can also create obstructions in the wellbore and reduce steam flow rate by scale buildup associated with mineral precipitation. Workovers, sometimes costly, may be needed to clean such wells to bring them back to their original productivity.

In this paper, we present the results of injection in two wellfields: Unit 13 and Unit 16 and try to quantify steam recovery due to injection in each wellfield by calculating recovery factors from the production data. A "recovery factor" is defined as the ratio of additional steam provided by injection and the amount of water injected in a given time period. Additional steam is the steam produced at the new decline rate or improvement rate established due to injection minus the steam production calculated at the previous decline rate without injection. The improvement rate is defined as the annual exponential increase in the steam flow rate. This definition is similar to the annual exponential decline rate but it represents an increase in flow rate rather than a decrease.

The recovery factor defined on the basis of production data may be different than that defined on the basis of geochemical data. Beall et al., (1989) and Gambill (1990) have used stable isotope data to estimate the recovery of injected water in the various parts of the Geysers geothermal field. Units 13 and 16 are located in The Southeast Geysers as shown in Figure 1. These units are rated at 140 GMW (gross MW) and 120 GMW respectively. Presently 32 production and 3 injection wells are located in the Unit 13 area and 17 production wells and 2 injection wells in the Unit 16 area. The outline of Unit 13 and 16 wellfields and the location of various production and injection wells used in this study are shown in Figure 2.

RECOVERY FACTOR DUE TO WATER INJECTION INTO UNIT 13 WELLFIELD:

The Unit 13 wellfield has three injection wells designated as I-1, I-2 and I-3 (Figure 2). Well I-1 has been in operation since the plant start up in May 1980 and had accepted the total

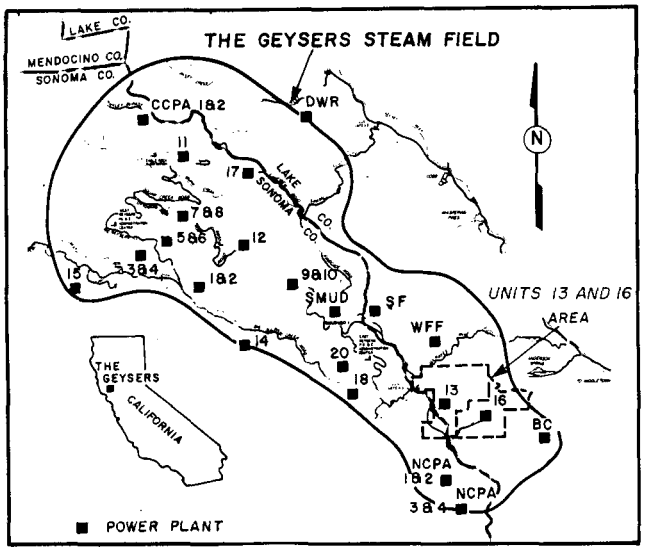

FIGURE 1: The Location Map.

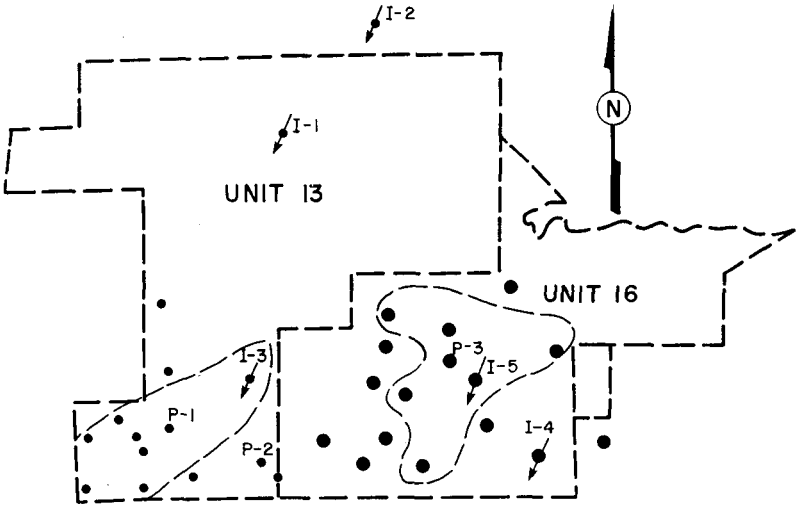

FIGURE 2: Study Area in Units 13 and 16.

plant steam condensate flow which annually averaged to about 1100 gpm until November 1984 when the second injection well I-2 became operational. Well I-2 was necessary to mitigate severe water breakthrough in the production wells offsetting I-1 during 1983-84. Between November 1984 and October 1989, the condensate was divided between these two injection wells. Originally a steam producer, well I-3 was converted to an injection well on October 30, 1989. Since then the water is primarily being split between wells I-3 and an NCPA/Calpine joint injection well (Enedy et al, 1991) with a small amount continuing to be injected into I-2. The third well I-1 is being kept as a standby Unit 13 injection well. The majority of the injected water is believed to exit these wells in fractures which originally produced steam. Perforated liners were used in I-1 and I-2 to allow deep injection below 6100' and 6800' respectively. The injected water in I-3 exits below 4000' depth and no perforated liner is installed in this well.

Thirteen wells surrounding and including the injection well I-3 and shown by solid circles in Figure 2 are monitored for their flow rate and decline rate changes. Most wells displayed a reduction in decline rate but the wells, located within the dashed outline, even exhibited an increase in their flow rate. For example, well P-1 was declining at an annual exponential rate of 18% before the injection. However, after the start of injection into I-3, its flow rate started increasing at an annual exponential rate of 55% (Figure 3). The steam flow rate of this well increased by about 20 klbm/hr after 4 months of injection. Presently, P-1 exhibits a decline rate of 13% which is 5% lower than the pre-injection value of 18%. On the other hand, the flow rate of the nearby well P-2 continues to decline at an annual exponential decline rate of 13% even after the start of injection in I-3 (Figure 4). The productivity changes observed in wells in this area suggests that most of the injected water into I-3 took a southwestern route and

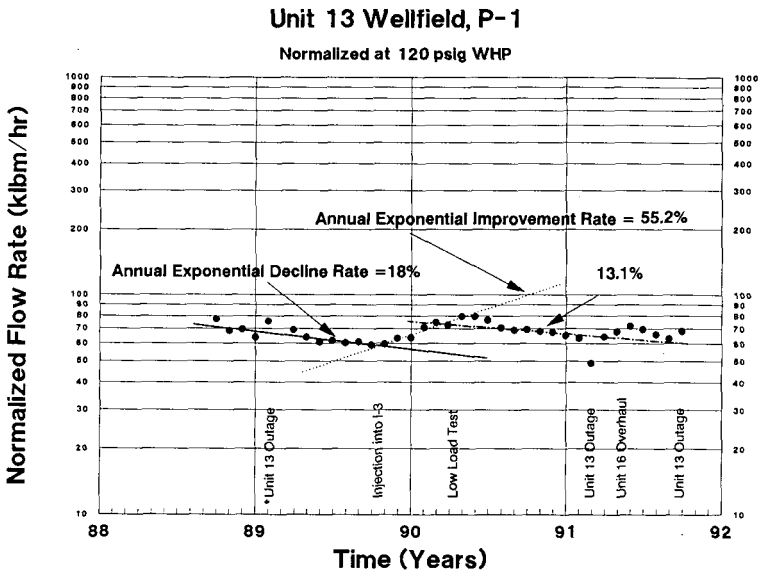

FIGURE 3: Changes in decline rates of P-1 due to injection into I-3.

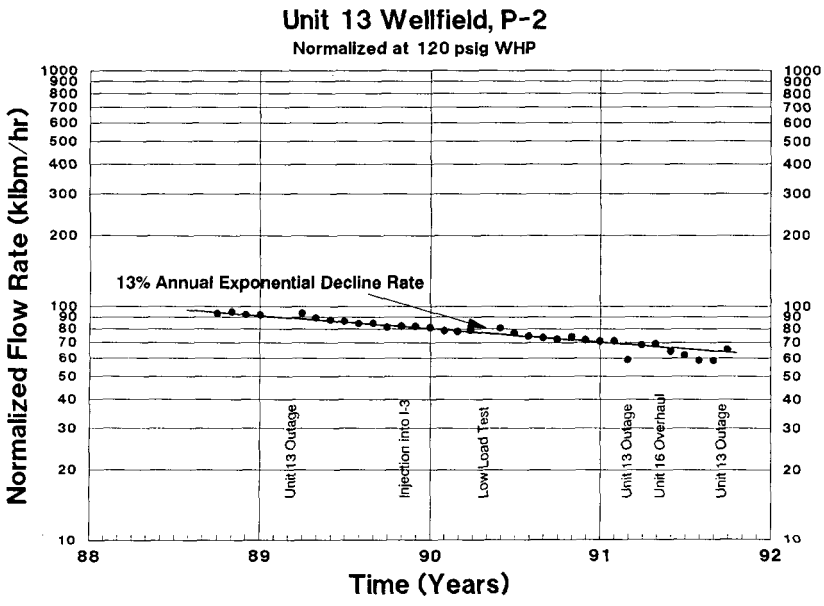

FIGURE 4: Decline rate trends of the production well P-2.

appeared as steam in wells located within the dashed outline (Figure 2).

In this study, a total of 13 wells are evaluated; 8 wells located within the dashed outline showing maximum injection benefit and the 5 nearby wells located outside the dashed outline showing some injection benefit (Figure 2). The combined normalized flow rate of all the 13 wells at 120 psig wellhead pressure (WHP) is presented in Figure 5 from January 1988 to September 1991. Due to the conversion of one production well into injection well I-3, the flow rate of only 12 wells is plotted after October 1989. Various operational activities such as plant outages and reservoir testing are also indicated in this figure.

Decline rates, shown in Figure 5, are estimated by excluding the data points affected by plant outages and testing. The 13 production wells, including I-3, exhibit an annual exponential decline of 20% before injection into I-3. During the next five months, the flow rate increased at an annual exponential rate of 25.5%. In 1990, the flow rate declined but at a slower rate of 13% as shown in Figure 5. Injection into I-3 has provided help in two forms: one in reducing decline rates and the other in providing a step increase in the flow rate. These effects are clearly shown in Figure 6 which is drawn on the linear scale. The injection rate (gpm) averaged over a month since start up in October 1989 is also shown in this figure which ranges from 300 gpm to 800 gpm. Two straight

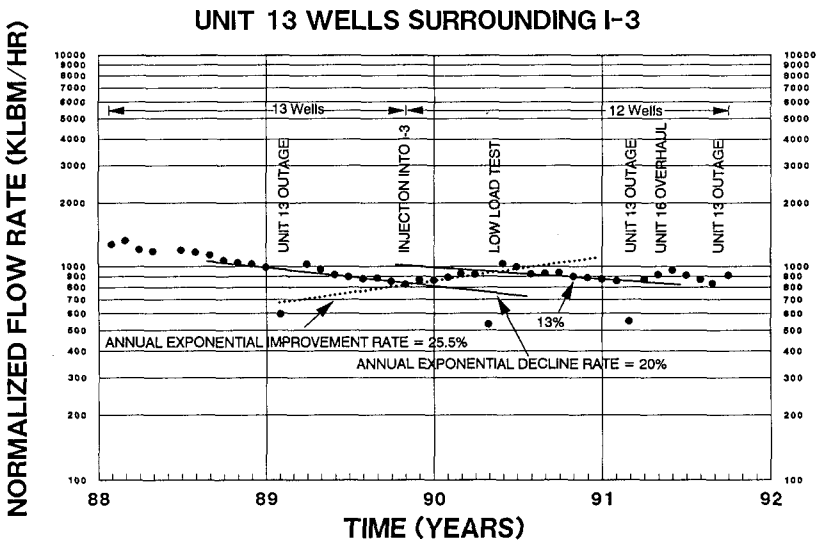

FIGURE 5: Reduction of decline rate due to injection into I-3.

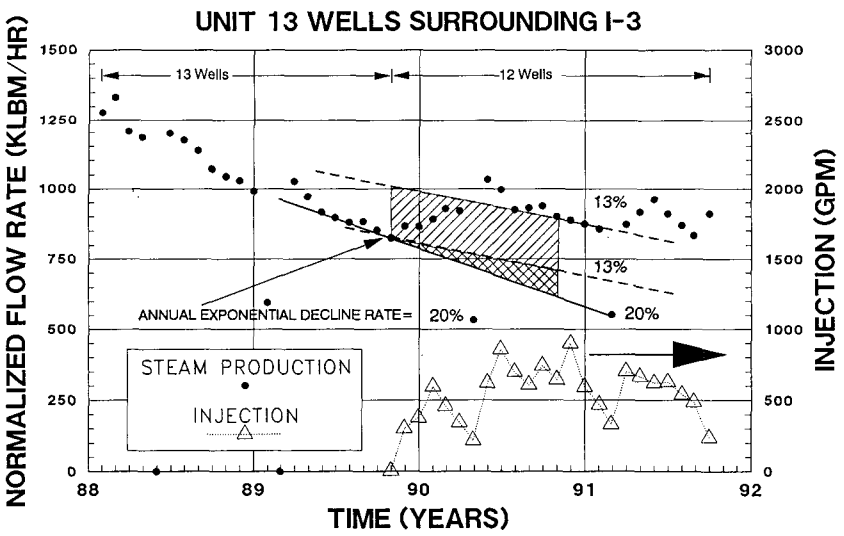

FIGURE 6: Effect of injection into I-3 on some surrounding production wells.

lines indicating annual exponential decline rates of 20% and 13% are also represented in this figure.

Figure 6 suggests a 7% reduction in decline rate and a step flow rate increase of about 190 klbm/hr. This increase was experienced by the 12 wells (13 wells minus I-3) over and above the flow rate of the original 13 wells. Annual steam production of 6.59 and 6.82 billion lbm can be estimated on the basis of 20% and 13% exponential decline rates since October 1989. This suggests a first year steam recovery of about 0.23 billion lbm from the injected water. This is shown by a hatched triangular area in Figure 6. Water injection into I-3 during the first 12 months was about 2.12 billion lbm. The ratio of steam recovery and annual water injection suggest a recovery factor of about 11%.

The step increase of about 190 klbm/hr in steam flow rate and the associated increase in steam recovery is shown by a parallelogram in Figure 6. Assuming an actual recovery equalling 2/3rd the area of the parallelogram, additional steam production of 1.11 billion lbm can be estimated in the first year (Figure 6). This step increase enhances the recovery factor to 63%. Thus the first year recovery factor in the Unit 13 area varies from about 11% to 63%. The former recovery factor is solely based on the change in the decline rate while the latter also includes the step increase in the flow rate.

A tracer test, conducted in the joint NCPA/ Calpine well, indicated a recovery of an order of magnitude lower in Unit 13 wells compared to NCPA wells (Adams et al., 1991). This suggests a minor contribution in the Unit 13 area due to

water injection into the joint injection well. Therefore the calculated recovery factors in the Unit 13 area may be slightly on the high side as they include the effect of water injection into the joint injection well.

In summary, water injection into the southwest area of Unit 13 suggests a recovery factor of 11% due to the reduction in the decline rates only. However, it enhances to 63% if the effect of the step increase in the flow rate is also considered. These recovery factors are believed to be slightly on the high side due to the pressure support provided by the water injection into the joint NCPA/Calpine well. To date, no adverse injection effects such as cooling or water breakthrough have been noted in wells in this area.

RECOVERY FACTOR DUE TO WATER INJECTION INTO UNIT 16 WELLFIELD:

The Unit 16 wellfield has two injection wells I-4 and I-5 as shown in Figure 2. Well I-4 has been in operation since the plant start up in October 1985 and had accepted the total steam condensate of about 1000 gpm until October 1, 1990, when the second injection well I-5, became operational. This change was necessary due to water breakthrough in the production wells offsetting I-4. Since then 70% to 90% of the condensate has been injected into I-5 and the rest into I-4. A perforated liner used in I-4 allows water to exit at 5600'. The injected water in I-5 exits below 4200' and no perforated liner is installed in this well.

Fifteen production wells including and surrounding injection well I-5 and shown by solid circles in Figure 2 are monitored for their flow rate and decline rate changes due to injection into I-5. Most wells displayed a reduction in decline rate and some wells, located within the dashed outline, even displayed a modest increase in their flow rate. For example, well P-3 was declining at an annual exponential rate of 11.5% before the injection into I-5 (Figure 7). Subsequent to injection its flow rate started increasing at an annual exponential rate of 13.5%. Within 4 months, its flow rate increased by 15 klbm/hr. A few other wells located within the dashed outline exhibited smaller gains than displayed by P-3. The combined normalized flow rate at 120 psig wellhead pressure of all the 15 wells shown in Figure 2 is presented in Figure 8 from March 1989 to September 1991. Due to the conversion of one production well into I-5, the flow rate of only 14 wells is plotted after September 1990. Various operational activities are also indicated in this figure.

All 15 wells display a combined annual exponential decline rate of 13.5% before the start of injection into I-5. The shift of most of Unit 16 injection to I-5 since October 1, 1990 has reduced the decline rate to 5.2% as shown in Figure 8. However, a step increase in flow rate, similar to that seen in the Unit 13 area (Figures 5 and 6), is not present in the Unit 16 area as shown in Figure 8.

The injection related effects and decline trends for Unit 16 wells are clearly represented in Figure 9 which is drawn on a linear scale. The total injection rate (gpm) into I-4 and I-5 averaged over a month since March 1989 to September 1991 is also shown in this figure. The injection rate into these two wells ranges from about 600 gpm to about 1200 gpm (Figure 9). The first year steam production of 11.47 and 11.95 billion lbm can be estimated for annual exponential decline rates of 13.5% and 5.2% respectively. This suggests an injection related increase of 0.48 billion lbm in the first year as shown by the triangular area in Figure 9. Water injection into I-4 and I-5 during the first 12 months (October 1990 to September 1991) was 3.60 billion lbm. These steam recovery and injection data can be used to calculate a first year recovery factor of 13% for the Unit 16 wellfield.

The actual recovery factor may be higher if either the injection into I-4 is not considered or steam recovery due to injection into I-4 is also considered. Such analysis was not possible since injection into I-4 commenced with the plant start up in 1985.

In summary, water injection into the southwest portion of Unit 16 suggests a recovery factor of 13% which is believed to be on the low side as the steam recovery due to injection into I-4 is not considered. Water production in certain producing wells offsetting I-5 has recently been noticed when the injection rate in I-5 exceeds 900 gpm. In an attempt to reduce this water breakthrough problem, the injection rate into I-5 has been reduced to about 600 gpm.

CONCLUSIONS:

First year recovery factors of 11% and 13% are estimated for the southwest west areas of Unit 13 and Unit 16 respectively. These estimates are based on the reduction in the decline rates due to the effect of water injection into Unit 13 well I-3 and Unit 16 well I-5. A step flow rate increase of 190 klbm/hr, observed in Unit 13 wells surrounding I-3, enhances the first year recovery factor to 63% in the southwest portion of Unit 13. A step increase in flow rate, similar to Unit 13 wells, is not observed in the Unit 16 wells.

Unit 13 recovery factors are believed to be on the high side due to the pressure support provided by the water injection into the joint NCPA/Calpine well. On the other hand the recovery factor in the Unit 16 area is believed to be on the low side since the steam recovery due to injection into I-4 is not considered.

To date no adverse effects to injection such as cooling or water breakthrough have been noted in the southwest area of Unit 13. However, water production in certain producing wells in

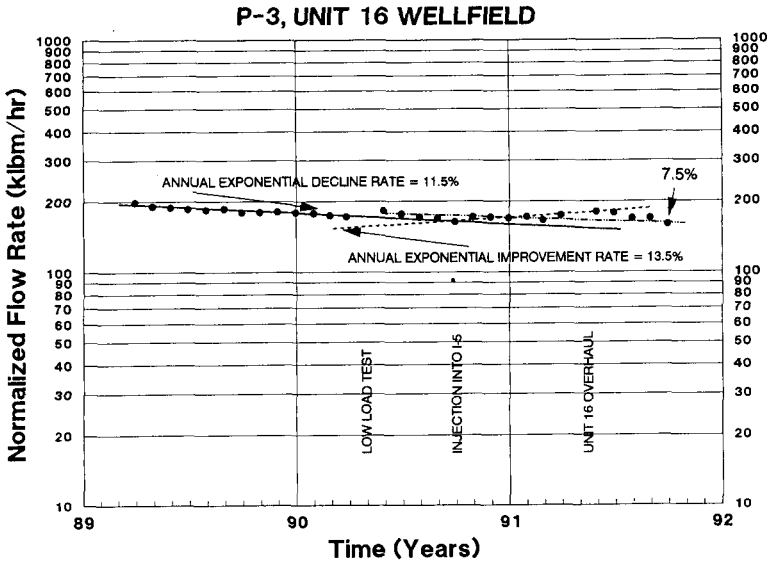

FIGURE 7: Decline rate trends of Unit 16 Well P-3.

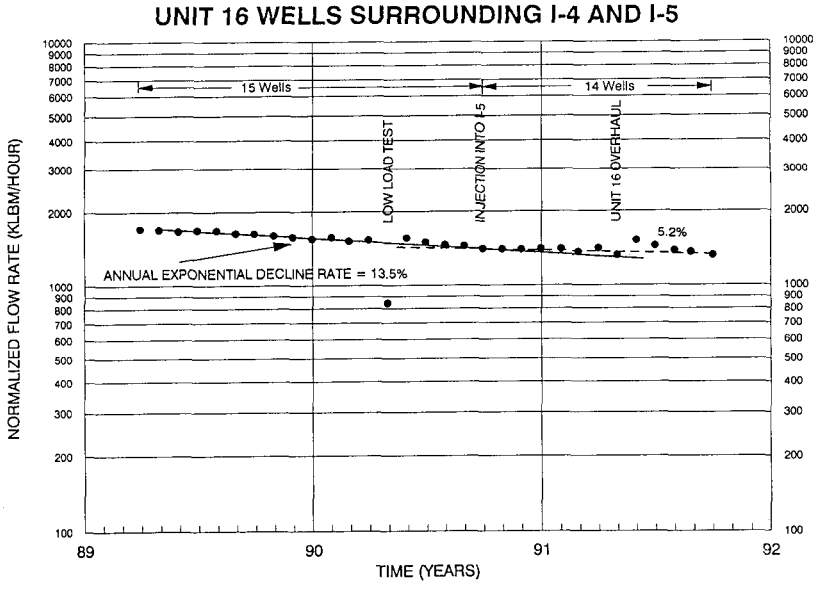

FIGURE 8: Reduction in decline rate due to inject-into I-5.

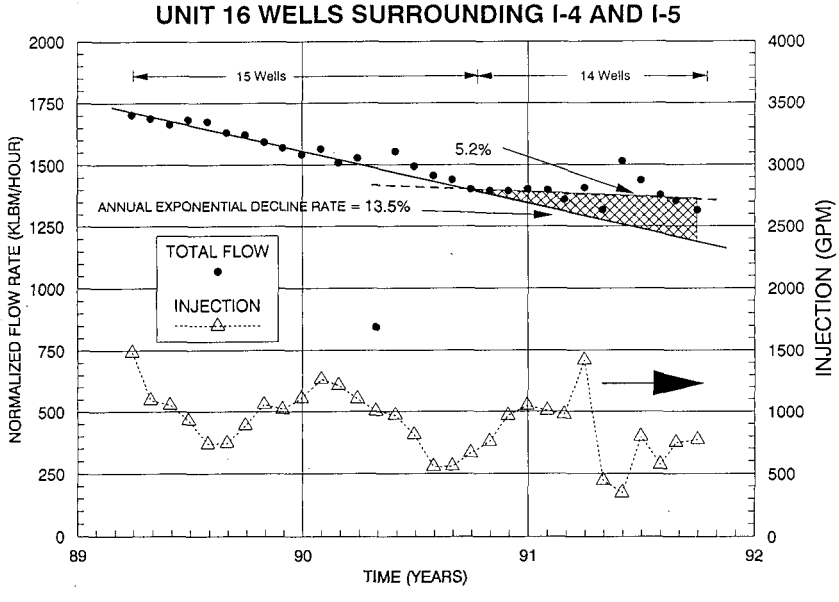

FIGURE 9: Gain in steam production due to injection into I-5.

the southwest area of Unit 16 has been noticed when the injection rate into I-5 exceeds a certain value.

The annual recovery factors are expected to continue or perhaps increase as reduced decline rates are maintained. The ultimate recovery factors in these areas are not known and depend upon reservoir hete-rogeneity, fracturing, heat transfer efficiency from rocks to water, and reservoir temperature, pressure and liquid saturation conditions.

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