

Optimizing the Longevity of Injection Wells:
A Resource Point of View

J. N. Hickey and F. A. Teeters

Magma Power Company
Exploration and Development
Brawley, California 92251

Abstract

The life of an injection well in the Salton Sea Geothermal Field depends on: the reservoir, the injection fluid properties, and effective wellbore maintenance. Research demonstrates that matrix permeability deterioration and depth of invasion is a function of: injection fluid total suspended solids and pore fluid velocity. Core analyses from the Salton Sea show predominate pore sizes less than 1 micron, porosity of 20 percent, and permeability of 7 millidarcys. Calculations, based on injection fluid properties, rates, and reservoir conditions, predict permeability damage and depth of invasion may exceed 80 inches. A porosity log before and after injection indicates a reduction in porosity. Analysis of sidewall cores shows that underreaming a wellbore three and one-half inches did not remove all the injection fluid solids, but did increase injectivity.

1.0 INTRODUCTION

Magma Power Company currently operates seven geothermal power plants in the Salton Sea Geothermal Field with a combined total installed capacity of 244 MWe. There are thirty production wells and twenty-three injection wells in operation. The life of an injection well depends on the reservoir, the injection fluid properties, and effective wellbore maintenance

The Salton Sea Geothermal Field is in the extreme southeastern corner of California. It is in a physiographic province referred to as the Salton Trough. The Trough is a low-lying depression bounded on the southwest side by the San Jacinto, Santa Rosa, and Peninsular Ranges, and on the northeast side by the Little San Bernardino and Chocolate Mountains. The Trough is an active continental rift zone in the transition from divergent tectonics of the East Pacific Rise to strike-slip tectonics of the San Andreas Fault system (Elders, 1979). Three northwest-southeast trending right-lateral strike slip faults, San Andreas, San Jacinto, and Elsinore are fundamental structures controlling development of the Trough.

The trough is filled with fluvial-deltaic sediments and associated evaporitic and lacustrine deposits of the Colorado River system (Muffler And Doe, 1968; Van de Kamp, 1973). Formation of the delta perpendicular to the axis of the trough has isolated the basin to the North from the Gulf of California (Fig. 1).

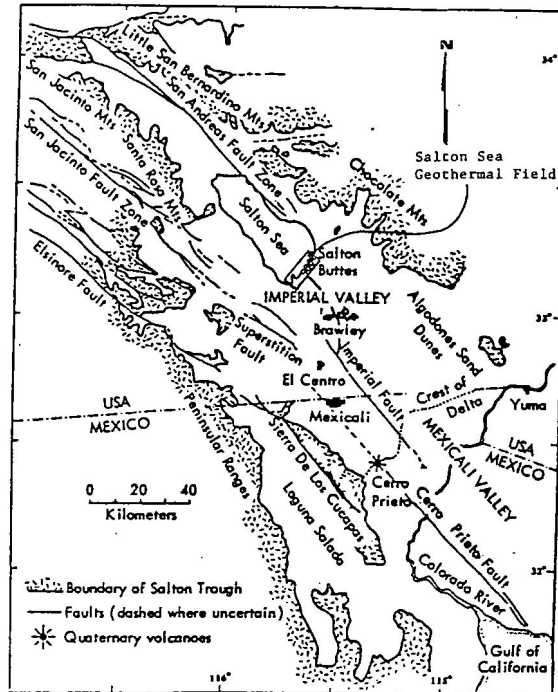


Figure 1. Index map of the Salton Trough: (After Elders, 1979).

2.0 RESEARCH DATA ON INJECTION FLUID AND DEPTH OF INVASION

Todd et. al (1990) measured the pressure response of injection fluid as a function of: depth of invasion, injection fluid total suspended solids (Tss) concentration, and pore fluid velocity. They used core-plugs from the Clashach Sandstone made up of poorly sorted, subangular grains of 90% quartz, subordinate feldspar, and mica (3% mainly clay illite with traces of kaolinite and chlorite). The average core-plug porosity was 14.5% and permeability ranged from 250 to 1000 millidarcys (md). The core-plugs, 1 inch diameter by 3.15 inch length, were broken and mounted in a multiport pressure-tapped core holder. The taps were arranged at 0.2, 0.5, 1.28, 2.22, and 3.15 inches from the inlet face. During the injection of 60,000 pore volumes of fluid the pressure response was continuously measured. The pore fluid velocity ranged from $0.45 \text{ cm}^3 \text{ s}^{-1}$ to $1.8 \text{ cm}^3 \text{ s}^{-1}$ and alumina particle size ranged from 0 to 3 microns. Deterioration of matrix permeability at each pressure measurement along the core plug is represented by a ratio to the original permeability, generating normalized decline curves of permeability remaining versus pore volumes injected.

The first experiment measured permeability deterioration by injecting fluids with 1-ppm and 15-ppm Tss concentration. The decline curves for each measuring point indicate permeability deterioration to the core occurred over the entire length and would have continued if the core-plugs were longer. Permeability loss at 0.2 inches was greater for the 15-ppm Tss fluid and stabilized with more pore volumes injected, illustrating the tendency of the higher Tss concentration to bridge near the well bore. The observed change in slope with pore volumes injected has been described as particle entrainment and redeposition by Gruesbeck and Coolins (1982). This suggests that enough small pores were plugged to increase the velocity in the remaining pores above some threshold value that maintains the particles in suspension resulting in a stable permeability. Comparing the overall decline curves, the amount and rate of decline was greater for the 15-ppm Tss fluid after 60,000 pore volumes of injection (Fig. 2 and 3).

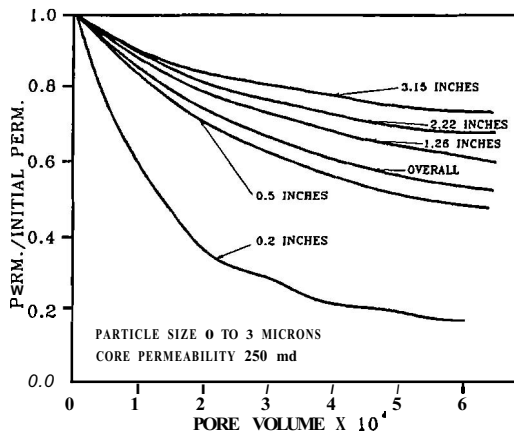


Figure 2. Permeability deterioration for 1-ppm Tss fluid. (After Todd, 1990).

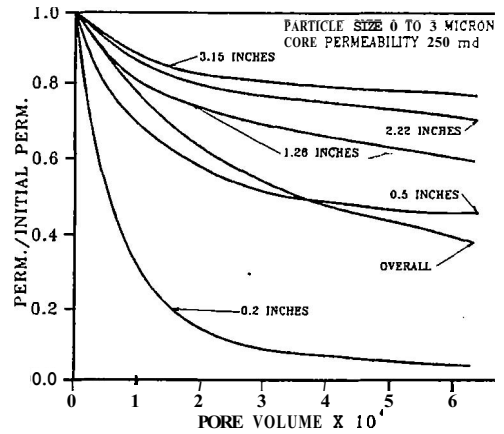


Figure 3. Permeability deterioration for 15-ppm Tss fluid. (After Todd, 1990).

The second experiment measured permeability deterioration, at a constant pore fluid velocity of $90 \text{ cm}^3 \text{ s}^{-1}$ and four different injection fluids. The decline curves again illustrate that permeability deterioration is a function of injection fluid Tss (Fig. 4). For example, after 20,000 pore volumes were injected, the 1-ppm curve deteriorated 30 percent while the 15-ppm curve deteriorated 60 percent.

The final experiment measured permeability deterioration, at a constant injection fluid Tss and four different pore fluid velocities. The data shows permeability deterioration is dependent on pore fluid velocity. There is 85 percent permeability loss at a velocity of $0.45 \text{ cm}^3 \text{ s}^{-1}$ compared to 65 percent permeability loss at a velocity of $1.80 \text{ cm}^3 \text{ s}^{-1}$ for 30,000 pore volumes injected (Fig. 5).

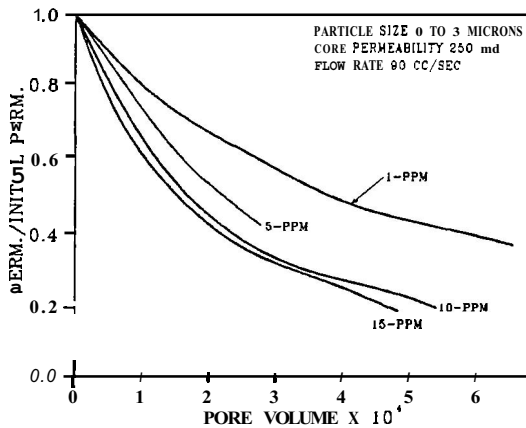


Figure 4. Permeability deterioration as a function of Tss concentration. (After Todd, 1990).

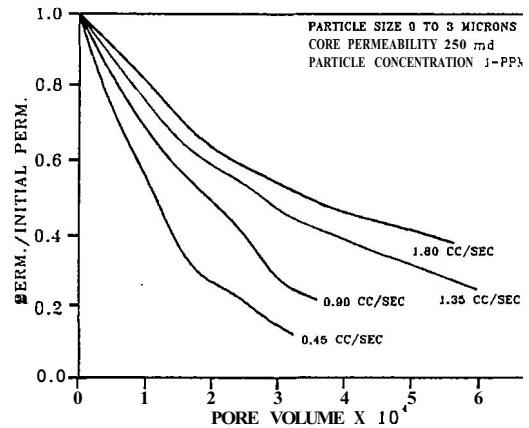


Figure 5. Permeability deterioration as a function of pore fluid velocity. (After Todd, 1990).

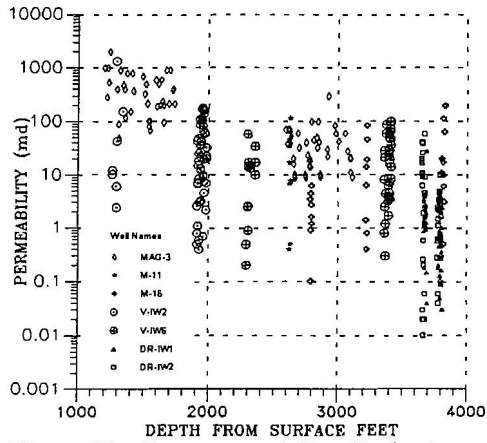


Figure 10. Core permeability Vs depth.

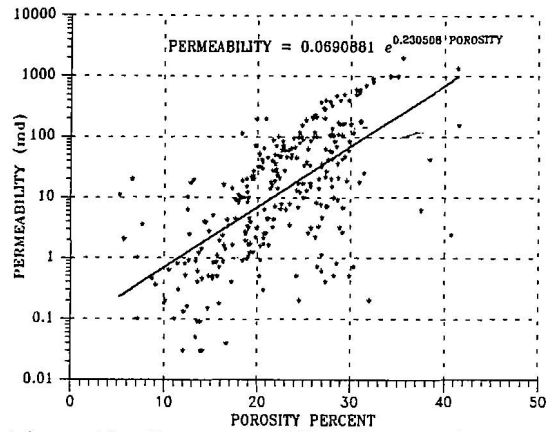


Figure 11. Core permeability Vs porosity.

4.0 SALTON SEA INJECTION FLUID AND DEPTH OF INVASION

Permeability damage and depth of invasion, at the Salton Sea Field, have been calculated using research data from Todd et. al (1990). Calculations assume permeability has a constant area, and an incremental change in permeability will have an incremental change in pore throat area. Because Todd's research used 250 md core-plugs, the area of 1 md, 10 md, 20 md, and 100 md were normalized to 250 md. Applying the normalized data to the depth of invasion measurements in Todd's research, the depth of invasion for a 1 md rock is 100 inches for 1-ppm Tss and 80 inches for 15-ppm Tss. The depth of invasion, for a 20 md rock, is reduced to 21 inches for 1-ppm Tss, and 18 inches for 15-ppm Tss. Figures 12 and 13 present the results for 60,000 pore volumes of injection. The dashed line is a best fit for the straight line portion of the data.

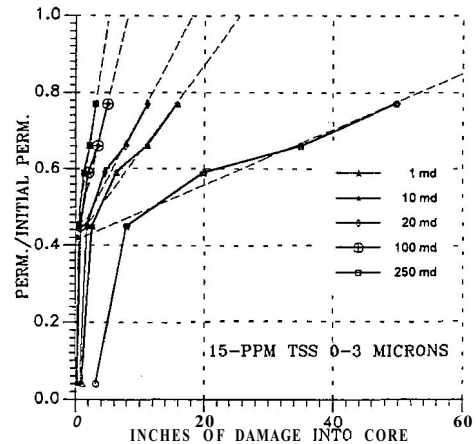
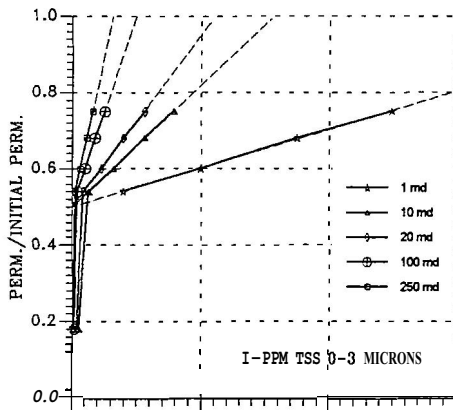


Figure 13. Permeability deterioration as a function of permeability and Tss.

Core studies, injection rates, and well completion's, show that the 15-ppm injection fluid Tss concentration and $0.45 \text{ cm}^3 \text{ s}^{-1}$ pore velocity from Todd's research is closest to injection conditions at the Salton Sea. Application of this to the Salton Sea Field shows that a 10 md rock will lose 50% permeability in 4 inches (Fig. 13).

Permeability deterioration, depth of invasion and results of a recent workover on Sinclair-22 (8/18/93) have been evaluated. There were three steps in the well workover; (1) clean out with a 8.5 inch diameter drill bit, (2) underream from a 8.5 to 12.0 inch diameter, and (3) log and sidewall core. Two methods were used to evaluate permeability deterioration and depth of invasion; (1) correlation of pre-injection Density/Neutron Log (6/28/88) with the Density/Neutron Log after the workover (8/18/93), and (2) the examination of three sample sets, from the cleanout, underreaming, and sidewall cores. Chemical analyses of the samples are not yet available.

There are two principal injection zones, in Sinclair-22. Injection Zone #1 is from 5000 to 5120 feet and Zone #2 is from 5400 to 5600 feet. The first Log correlation is in Zone #1 with the 1988 log in the left column and the 1993 log in the right column (Fig. 14). Fundamental differences in the 1993 Log are; (1) the Gamma Ray scale is 0-100 (GAPI) and 0-2000 (GAPI) for the backup scale, and (2) the 1993 log displays the Photoelectric Factor or (PEF). The PEF curve responds primarily to the rock matrix.

The largest reduction in density porosity, for Zone #1, is from 45 to 21 percent and from 42 to 24 percent in the fractures at 5063 and 5112 feet respectively (Fig. 14). The increase in fluid density from injection only accounts for a 6 percent reduction in density porosity. This suggests that injection solids are the main cause for reduced fracture porosity. The overall matrix porosity for Zone #1 is the same on both logs. There is a slight increase in neutron porosity, possibly caused by reduced wellbore temperature after injection. The gamma ray, on the 1993 log, in Zone #1 shifted to the backup scale. The gamma ray values are 400 GAPI and 600 GAPI at 5063 and 5112 feet respectively. The gamma ray response is from the increased concentration of naturally occurring radioactive material (NORMS) in the solids deposited during injection. The PEF at 5063 and 5112 feet reached peak values of 8 and 9 respectively. The high PEF is responding to precipitates placed in the fracture during injection. The fracture at 5012 is unique because the density porosity shows a 4 percent increase while the gamma ray and PEF reached 1200 GAPI and 10 respectively. The increase porosity is a puzzle, but may be related to tool orientation. A spinner survey prior to the workover showed this fracture received about 40 percent of the total flow.

The log correlation in Zone #2 is similar to Zone #1. The largest reduction in density porosity is 9 percent, in the fractures, at 5445 and 5470 feet (Fig. 15). The gamma ray values in these fractures are 600 and 400 GAPI respectively; this coincides with PEF values of 5 and 7. There is no damage to the overall matrix porosity in Zone #2 after underreaming. The loss of density porosity in the fractures, at 5445 and 5470 feet, is from injection solids. The gamma ray values, at 5445 and 5470 feet, are responding to the increased concentration of **NORMS** in the solids deposited during injection. The high PEF is responding to precipitates placed in the fracture during injection. The fracture at 5535 feet is unique. The density porosity shows a 3 percent increase while the gamma ray and PEF reached 300 GAPI and 4 respectively; this fracture shows less evidence of active injection and therefore has lower PEF and gamma ray values.

The sample sets, collected during the workover were examined using a binocular microscope and all show evidence of injection solids to some degree. The solids are dark gray to black color, moderately hard to soft, banded or granular. The underreaming samples and sidewall cores showed injection solids in contact with sandstones. The sidewall core in Injection Zone #1 shows a 2mm wide fracture, cross cutting the sandstone, filled with dark green to black, soft, sucrosic injection solids.

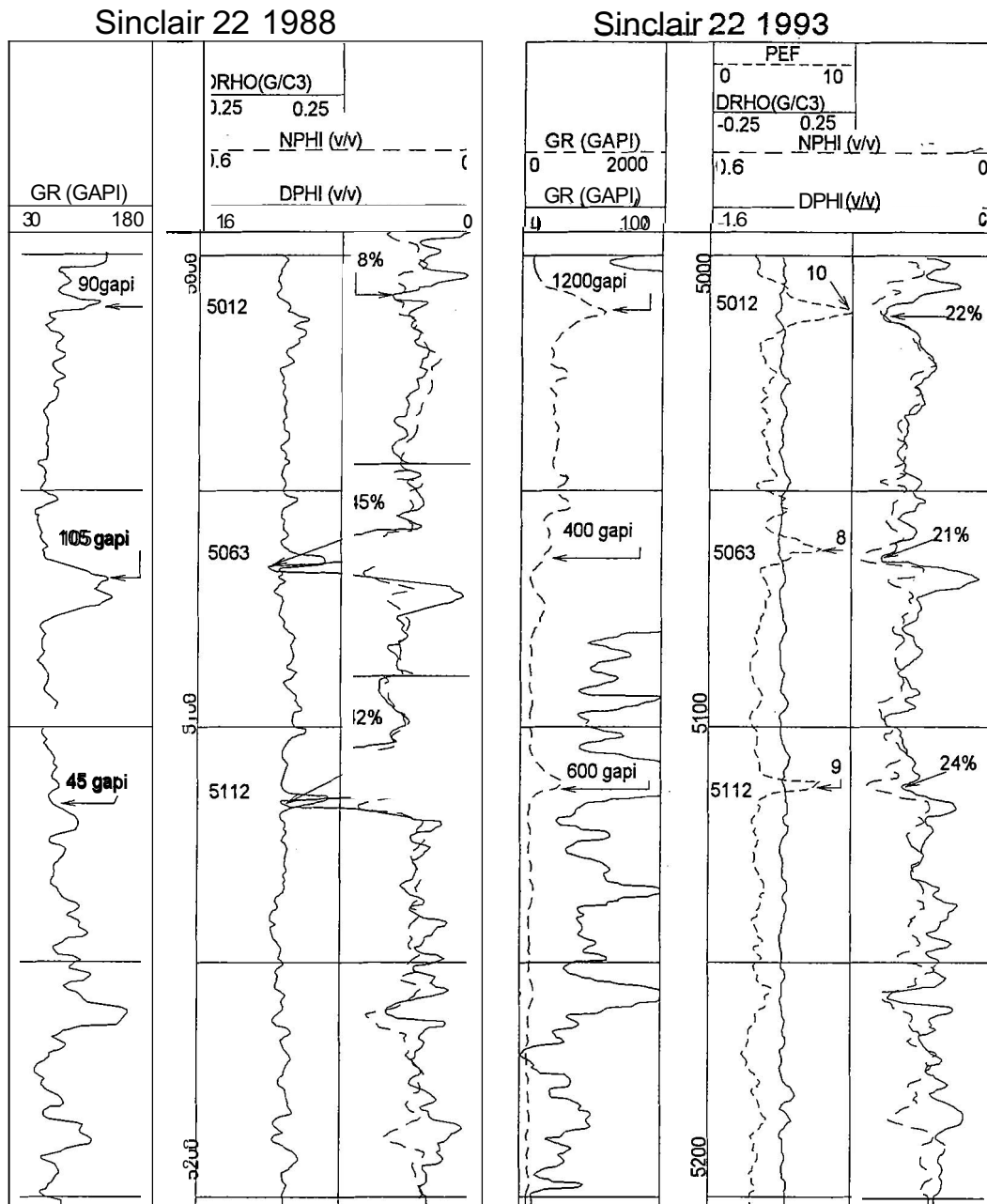


Figure 14. Zone # 1 Density and Neutron Log correlation 1988 before injection and 1993 after workover.

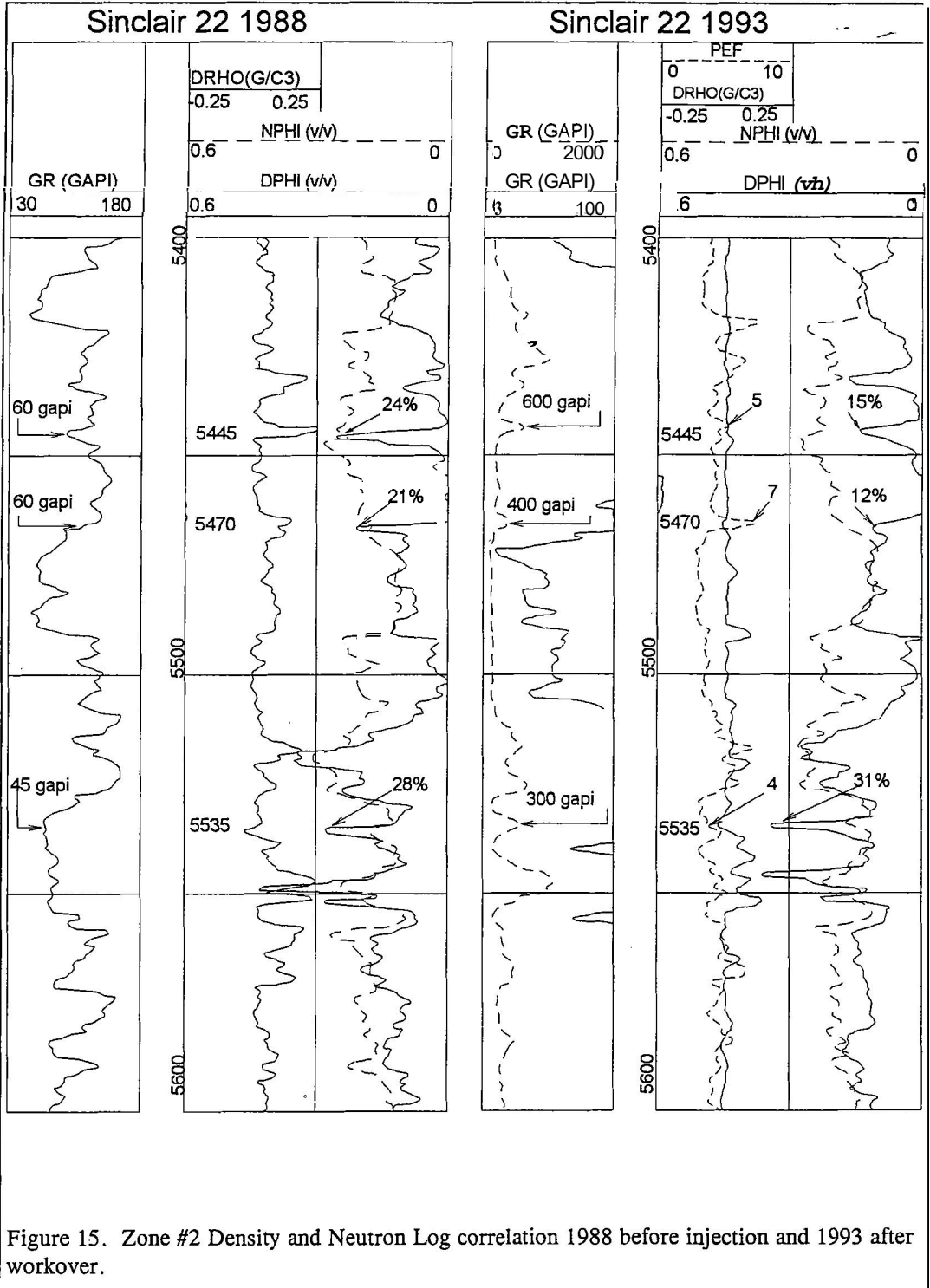


Figure 15. Zone #2 Density and Neutron Log correlation 1988 before injection and 1993 after workover.

Examination of thin section samples from the clean out inside 9 5/8 casing shows that the samples are all scale. The scale is amber to dark brown, with 1/8 to 1/4 mm banding. Locally the banding is light gray to translucent with occasional opaque grains. Under polarized light the scale is isotropic. Thin sections between 5900 to 6200 feet in open hole, show scale with 5 to 10 percent rock fragments. The main differences between the scales are in the textures. Banded scale forms inside casing and granular scale in the open hole. The scale composition appears to be amorphous Iron Oxide and the color variations are apparently related to the iron concentration. Thin sections, from the underreaming, show injection solids in contact with the sandstone, but no injection solids in the matrix. A comparison of thin sections from pre-injection drill cuttings and post underreaming sidewall cores shows no evidence of injection solids in the matrix of the sidewall cores confirming that underreaming the well removed major skin damage. Sidewall core thin sections in the fractures show injection solids are present. Injection Zone #1 at 5017 and 5063 feet and Injection Zone #2 at 5416 feet have about 5 to 10 percent injection solids present.

5.0 INJECTION WELL MAINTENANCE

Injunctivity decline is the primary measurement of well performance. Table I shows original injunctivity, injunctivity before the workover, and injunctivity after the workover. The data illustrates a 31 percent improvement from July 1993 and 78 percent of the original, after increasing the diameter 3 1/2 inches (underreaming), indicating that underreaming does not completely restore fracture permeability.

Table I. Sinclair 22 Injunctivity

DATE	RATE @ 100 psig	PERCENT OF ORIGINAL
June 1988 Original	2350 kph	100 %
July 1993 Before workover	1100 kph	47 %
August 1993 After workover	1828 kph	78 %

6.0 CONCLUSION

Research data clearly demonstrate, for a given core-plug, that matrix permeability deterioration and depth of invasion are a function of injection fluid Tss, and pore fluid velocity. Applying research findings to the Salton Sea core data provides a reasonable approximation of permeability deterioration and depth of invasion. It is difficult to apply experimental data, to account for pore throat area changes in an injection well formation; because of the probable existence of induced and naturally occurring microfractures in the reservoir.

Log correlation and thin section analyses are viable methods for evaluating injection fluid depth of invasion. Comparison of density logs confirms that underreaming restored the matrix porosity and identifies fracture zones with major porosity reduction caused by injection solids. The samples support log analysis and the conclusion that matrix permeability and depth of invasion are a near-wellbore phenomenon except for fractures zones.

The use of underreaming for wellbore maintenance is limited by diameter and the ability to completely restore fracture permeability.

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