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FLUID DIVERSION IN AN OPEN-HOLE SLOTTED LINER – A FIRST STEP IN MULTIPLE ZONE EGS STIMULATION

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ABSTRACT

Achieving multiple zone stimulation in an open-hole section in an EGS well could potentially reduce the cost of EGS power production by 40% or more by increasing flow capacity and production on a per well basis. A first field operational step was taken towards proving this concept in an injection well in a geothermal field. The goal of this operation was to test the use of diverters in temporarily sealing off fractures in a geothermal reservoir and optimizing the injection profile of the given well. Success of this operation could be built upon to improve production of EGS and conventional geothermal reservoirs.

The test well had fluid exiting the wellbore behind both the blank and slotted portions of an un-cemented liner. Heat recovery for reservoir recharge could be improved by forcing injection deeper in the well. Therefore, the goal of the operation was to temporarily seal off the shallow fractures and direct injection deeper in the well. Achieving this goal was made more difficult by the presence of the slotted liner.

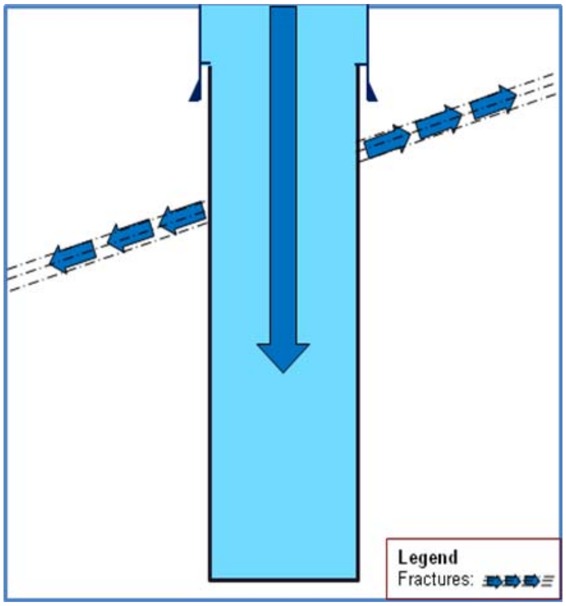
Positive indications were measured after pumping a diverter into the well. Both pressure increase and cooling of the wellbore below the deepest injection point were measured using a conventional PTS logging tool after diverter material was introduced into the injection stream. Results of this operation and subsequent injectivity tests will be presented along with analysis of the data showing the effectiveness of the diverter treatment. The operation was extremely successful at isolating the zones both above and below the top of the slots in the liner.

INTRODUCTION AND BACKGROUND

Increasing the production of conventional geothermal wells would provide significant benefits to operators. Similarly, increasing the flow capacity of an Enhanced Geothermal System (EGS) on a per well basis would also provide significant benefits to potential operators. Stimulation of geothermal wells by pumping large volumes of water has been successfully accomplished and resulted in the improvement of the permeability and flow from these wells. These stimulation treatments have been limited, however, to only fractures that are or will open by pumping water from the surface. For EGS systems, flow capacity has typically been limited to only fractures that can be created by pumping water from the surface to create a limited number of fractures in the open hole reservoir rock.

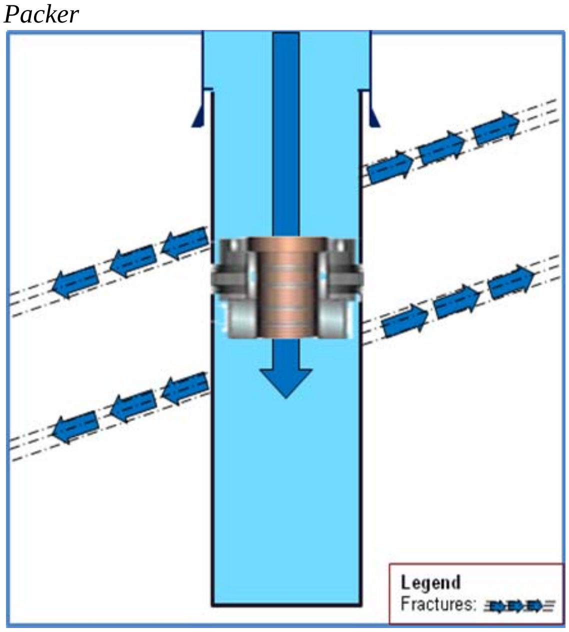
One way to improve the effectiveness of a hydrothermal well stimulation treatment would be to temporarily hydraulically isolate the stimulated fractures in the well and then create and/or stimulate additional fractures. This could improve the overall connectivity of the well to the thermal production source by increasing the permeability and number of fractures that connect to it. Similarly, it may be possible to improve production on a per well basis for an EGS system by creating multiple fractures by first stimulating one set of fractures (See **Figure 1**)

Figure 1: EGS Well with Single Fracture Network



and then temporarily isolate those fractures hydraulically while a second set of fractures is stimulated. One could attempt to do this with some type of mechanical isolation tool such as an open hole packer (See **Figure 2**), but this would require that a drilling rig be present during the stimulation treatments. This would incur additional costs as well as the associated operational risk of packer failure (i.e. getting the packer stuck in the hole, etc.)

Figure 2: Multiple Fracture Creation with Open Hole Packer



A novel way to improve the process of multiple zone stimulation is the use of temporary diverter systems. These systems would allow the temporary sealing of existing or newly stimulated fractures so that new fractures could be stimulated (See **Figure 3** and **4**). This would be accomplished by first stimulating a set of fractures by pumping water from the surface into the well. After this first set of fractures has been stimulated a chemical diverter would be pumped in the well which seals off the fractures. As additional pressure is then applied to the well, a second set of fractures will be stimulated. At the end of the stimulation, injection of cool water will stop, the well will heat back up to its original geostatic temperature, and the diverter materials will degrade and/or dissolve leaving all the stimulate fractures open for circulation and flow during the operation of the EGS field.

One big advantage of using a chemical diverter system over other mechanical systems for creating multiple stimulated fracture networks is the elimination of the need for having a drilling rig on location during the stimulation. In addition, two, three, or more stimulated fractures can be created in succession using a temporary diverter system by simply repeating the process described above multiple times. The more fractures created, the greater the productivity of the wells, and, ultimately, the lower the cost will be to generate electricity in an EGS system.

Figure 3: Creation of Multiple Fractures with Diverters

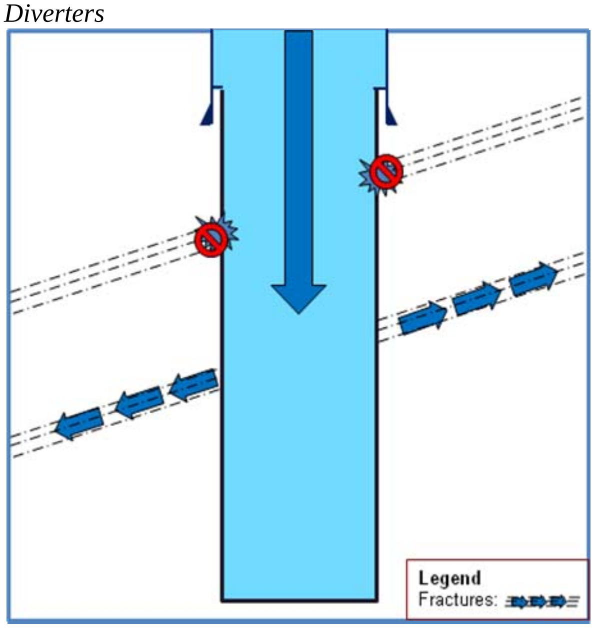
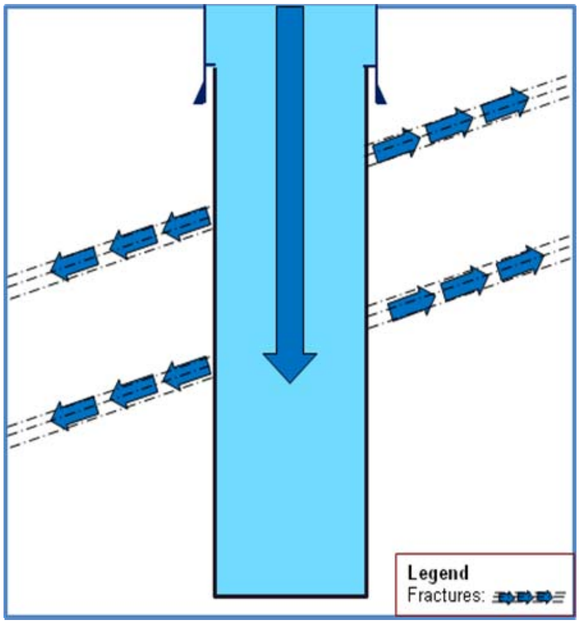


Figure 4: EGS Well with Multiple Fracture Networks



This same method of using chemical diverters could be used in the stimulation of conventional hydrothermal wells as well: The existing producing fractures would first be stimulated (if desired), then a temporary diverter would be pumped in to seal off the existing fractures. Afterwards, additional hydraulic pressure would be applied, and additional fractures would be stimulated to improve production from the well.

In order to field test the viability of this idea, a form of temporary diverter was used during an injection treatment of an injection well in an operating geothermal field.

TEMPORARY DIVERTERS – DESIGN, APPLICATION AND BENEFITS

A number of possible temporary diversion systems have been considered for this field test. The optimal system for this application consisted of a gradation of small particles of a specialized material. These particles could be easily suspended in water and pumped into the well at any desired point during the injection test of this well.

For a diverter system of this type to work, the particles must be large enough to bridge off at the fracture face. This ground material had a particle size distribution that aided in the hydraulic sealing of the fractures. Additionally, for this well, the particles had to be small enough so that they would fit through the ¼ inch wide slots that were present in the blank liner that existed in the well.

For normally stressed rock stimulated by pumping from the surface, one would expect that the first group of fractures would be towards the top of the open hole interval. Subsequent fractures to be stimulated would normally occur below the previously stimulated fracture network. This has the advantage of allowing for continuous cooling of the diverters that are sealing the existing fractures above the fracture currently being stimulated. Keeping the diverter cool slows down the degradation process allowing for the sealing of the fractures for a longer period of time.

A material was used that would remain intact during the stimulation treatment, which was expected to be below about 200 ˚F due to the cooling effect of the injection water. After the stimulation the material would then degrade and dissolve into the wellbore fluid. The degradation was accelerated by the increase in wellbore temperature that occurred after the injection of cool water was terminated and the well heated back up toward the geostatic temperature of the surrounding formations. The expected degradation time, based on lab tests, was within days after the stimulation.

One of the major advantages of using the Temporary Diverter System over a mechanical system is that the material could be pumped into the well and effect a seal without a drilling rig on site. This can mean significant potential savings for other stimulation applications since drilling rig mobilization and day rates can be very high and the typical stimulation treatment for an EGS or hydrothermal well is usually multiple days long. In addition, with a self degrading system a rig does not need to be present to spot special chemicals into the well to help remove the temporary diverter, as would be the case, say, if an acidic soluble system were employed.

Another major benefit of this system is that multiple stimulated fracture systems can, at least in theory, be created in rapid succession without having to stop the stimulation process. This means not having to move drill pipe in and out, re-set a packer, etc..

In addition, using the Temporary Diverters over a mechanical system does away with the associated operational risk of a drilling rig. If something goes wrong one can just stop pumping and the diverters will dissolve in the wellbore. An open hole packer, on the other hand, can get stuck, incorrectly set, or cause other operational problems possibly requiring having to re-drill an entire open hole section.

COST ANALYSIS USING GETEM

The GETEM (Geothermal Electricity Technology Evaluation Model) was used to evaluate cost of power production with single and 3 stimulated zones. A summary of the cost of production is given below in Table I. Results demonstrate a significant drop in the overall cost of power. A 40% decrease in power production was achieved with the Flash System @ 250 ˚C and a 50% reduction in cost was achieved with the Binary system @ 175 ˚C.

Table I: GETEM Cost Analysis for Flash and Binary Production with and without Single and 3 Fractures

Flash/ Binary	Temperature (˚C)	Improvement	Cost of Power 2010 (cent/kw)
Flash	250	N/A	11.53
Flash	250	3x flow rate	6.88 (40% Less)
Binary	175	N/A	31.94
Binary	175	3x flow rate	16.02 (50% Less)

Note: Assumed 30 kg/sec base flow rate, 4 km well depth.

DESCRIPTION OF OPERATION

In 2010, AltaRock conducted a Diversion System Test on a well with an uncemented, slotted liner. The test well exhibited two low pressure steam entries at shallow depth above the slots. While fractures were encountered at depth closer to TD, they were not highly permeable and the well was not a commercial producer. The objective of the test was to demonstrate the effectiveness of diverter material for the temporary sealing of existing geologic fractures. The specific goals of the diverter test were to:

- Prove the effectiveness of thermally-decomposing diverters to block permeable fractures that are currently taking fluid and to temporarily modify the injection profile by forcing fluid into deeper fractures
- Test the effectiveness of diverters in a slotted liner with ¼ inch slots
- Test the effectiveness of diverters in a highly permeable, naturally-fractured rock

Prior to diverter testing, a Pressure Temperature Spinner survey (PTS) was conducted while injecting at 100-150 gpm to obtain the well's temperature and pressure profile. In order to obtain the pre-test injectivity, the injection rate was increased from 150 gpm to approximately 300 gpm and held constant for one hour, and then increased to 500 gpm for another hour. **Figure 5** below illustrates the pressure (blue) and temperature (red) versus time as the PTS was held stationary at monitored depth in the wellbore before diversion. An injectivity of 1.7 gpm/psi was calculated. The rate from the first injectivity test was not held constant because water was delivered directly from the power plant. Following this injectivity test, the well was shut off and a temperature buildup, pressure falloff test was conducted to calculate pre-testing reservoir properties. A similar step rate injection test and pressure falloff test was conducted after diverter

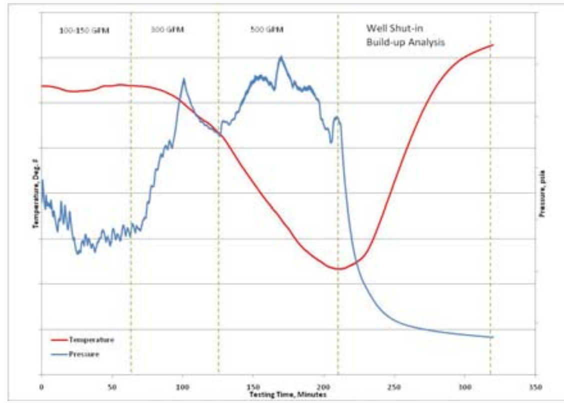


Figure 5. PT vs. Time, pre-diversion

injection and two weeks after the diverter test to compare results. From the test data, Horner analyses were performed on the pressure-falloff, temperature buildup data after each injectivity test to estimate the initial temperature and pressure at total depth. (Horne, 1995)

After the initial injectivity test, the diverters were injected with water at 500 gpm with the PTS tool starting at monitored depth. Injection continued until a pressure increase was observed and the isothermal zone extended deeper into the well. After the first diverter pill, the slotted interval was logged (See **Figure 7**). Then, with the PTS tool parked at monitoring depth, a second diverter pill was injected with water at 500 gpm until similar results were observed.

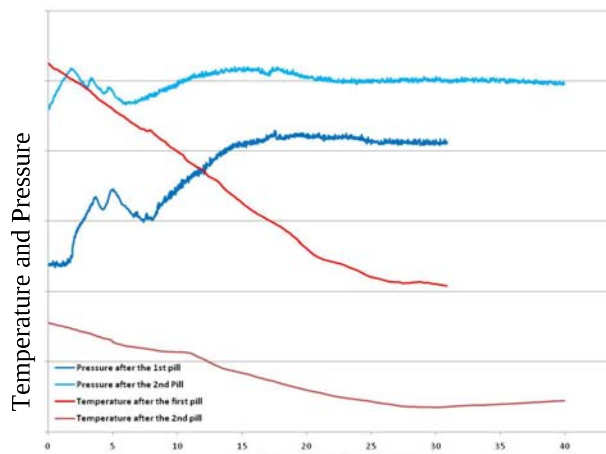


Figure 6. PT vs. Diverter pumping time

Figure 6 illustrates pressure and temperature behavior versus time as the diverter was pumped while the tool was held stationary at monitored depth. The injection rate throughout the pumping of diverters was held at 500 gpm. Note the extent of the temperature drop (red) and pressure rise (blue) caused by the diverters. After the first diverter pill was pumped, temperature dropped 28°F and pressure increased 182 psi. After the second diverter pill was pumped, temperature dropped an additional 7°F and pressure increased an additional 80 psi. This drop in temperature and increase in pressure indicate cold water is being injected pass the tool string at the currently monitored depth. The temperature after the second diversion leveled off after 25 minutes and started to increase gradually. This was most likely the result of improvement in the permeability of the zone due to fracture extension at the higher pressures. This is shown by the post test temperature survey in **Figure 7** which indicates a much larger amount of fluid exiting the well 230 ft below the original deep injection depth. The total drop of temperature for this diverter test was 35°F and pressure increase was 262 psi. Hydro shearing of additional natural fractures may have occurred as indicated by the slow decline in pressure as the test progressed.

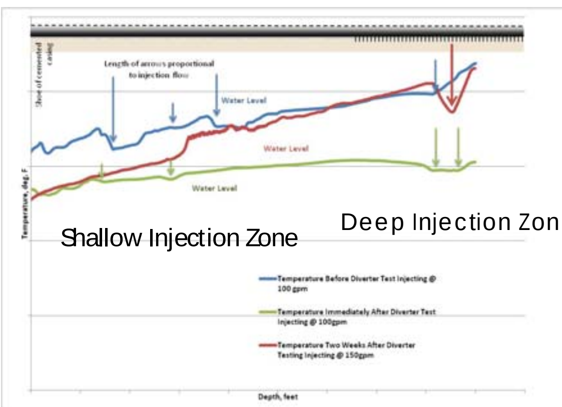


Figure 7. Temperature vs. Depth

Figure 7 illustrates temperature versus depth at various times as the PTS tool was lowered in the wellbore to the monitored depth while injecting. The pre-diverter test temperature (blue) indicates original injection points at 4 different injection zones. It appears that highly depleted steam zones were pulling water above the slotted liner behind the blank pipe. We infer that this phenomenon was causing slug flow in the annulus above the fluid level and produced the cooling visualized on the temperature survey above the slots. We expect this behavior to be transient. After the first diverter pill, we logged up to the top of the slots and saw additional injection deeper than the originally observed injection zones. After the second pill of diverter injection, the temperature survey (green) showed that the shallow depth injection zones are successfully plugged showing little to no injection. An isothermal zone now exists showing that the injectate was pushed deeper. The temperature survey a day after the diverter testing demonstrated minimal shallow injection and a very large injection zone within the deep injection zone. The log run two weeks after diversion showed no flow exiting at the upper zones; this is likely the result of the deeper water level depth (red). This injection profile is not as large as the one exhibited right after diverter testing in (green). One possibility for this is that since the diverters dissipated, the fractures created from the diverters also closed up.

The pressure versus depth from the PTS tool while injecting **(Figure 8)** throughout the test is also a good indication of diversion. The original fluid level was detected as shown by the change in the pressure profile (blue). The pressure increased after the first pill of diverter was pumped (red) because the injection rate increased from 100 gpm to 500 gpm. After the diverter test, the injection rate returned to 100 gpm. The water level after the first diverter pill was projected to be higher, and the post diverter testing survey result (purple) indicated an 150 ft increase in water level. This increase in water level indicates a successful diversion, but also indicates that the diverter remained in the fractures to some extent.

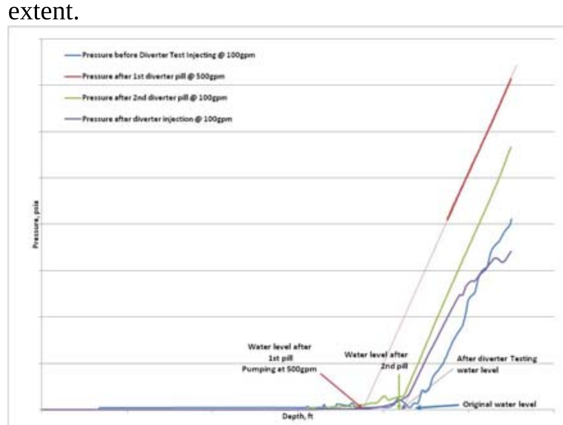


Figure 8. Pressure vs. Depth

A second injectivity test was also performed one day after diversion to test the degradation of diverters. An injectivity of 0.75 gpm/psi was calculated. We believe this injectivity is lower than the pre-diverter test injectivity because the diverters are still in place and needed a few more days to completely degrade. This diverter material is designed to degrade to lactic acid with passage of time and exposure to temperature. Conceptually, as the well heats back up under normal injecting conditions, all of the original fractures should be re-opened. In order to assess the degradation of the existing diverter material and the modified injection profile, a third PTS logging run, along with step-rate injectivity testing and pressure fall off/temperature build up, was conducted two weeks after initial diverter testing.

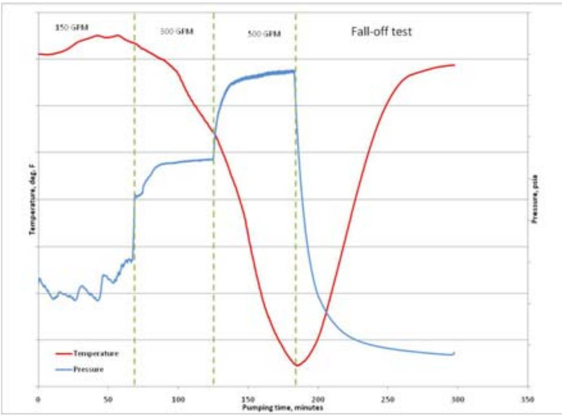


Figure 9. PT vs. Time, post-diversion

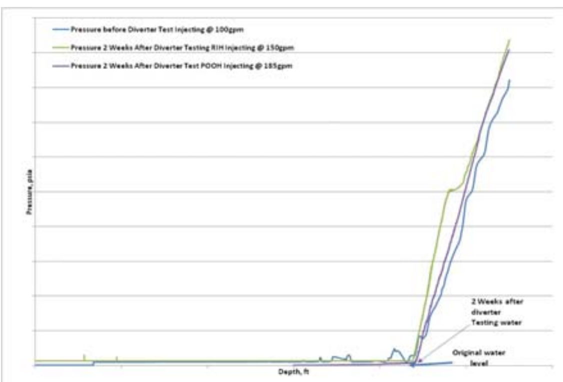


Figure 10. Pressure vs. Depth Comparison two-weeks after diversion

The original fluid level detected compared with the fluid level post diversion are shown in **Figure 10**. The survey result post diverter testing (purple and green) indicated a new water level at approximately 200 feet lower. This decrease in water level indicates that more injection occurs deeper and the diverters are gone. **Figure 11** illustrates the pressure (blue) and temperature (red) versus time as the PTS was held stationary at monitored depth two weeks after diversion. Similar step-rate injection rates were repeated and the well was shut in for approximately 3 hours. The pressure reading during the 500 gpm injection shifted suddenly showing possible hydro shearing of additional natural fractures. An injectivity of 0.85 gpm/psi was calculated. This injectivity is higher than the post-diverter test injectivity, indicating the diverters had completely degraded, but lower than the pre-diversion test because injection at upper steam zones no longer appears to be occurring.

The lowered temperature profile and increased permeability compared with pre-diverter testing is an indication we pushed the injectate deeper and either opened up existing fractures or created new fractures.

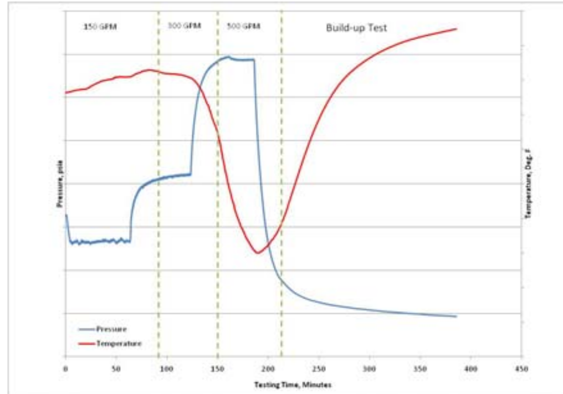


Figure 11. PT vs. Time, two weeks post diversion

CONCLUSIONS

The goals of the first field trial of diverter material are considered to be satisfied. The test showed that highly permeable fractures could be temporarily sealed with a chemical diversion system. The test also proved that the presence of a slotted liner with ¼" slots did not pose a problem to proper diverter placement. Thirdly, results from the test showed that the injection profile in well could be modified temporarily and that fluid could be pushed deeper into the wellbore. Finally, transmissivity calculations (kh) before and after the test imply full degradation of the diverter material since the value held steady at approximately 55,000 md-ft.

Table II. Summary of Coleman 8-5 Test Results

	Injectivity, gpm/psi	Permeability-thickness(kh), md-ft	Permeability, md	Injection Zones	Fluid Level, compared with pre-test
Before Diverter Test	1.7	55,021	67.1	4 injection zones	Datum
One day after Diverter Test	0.75	54,731	91.2	4 injection zones	150 ft higher
Two weeks after Diverter Test	0.85	54,302	181	1 injection zone	230 ft lower

<u>REFERENCES</u>

Horne, Roland. (1995), *Modern Well Test Analysis*, p. 54-61.