# DTS SENSING: AN INTRODUCTION TO PERMIAN BASIN WITH A WEST-TEXAS OPERATOR

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ABSTRACT

Distributed temperature sensing (DTS) is an emerging technology that was used by a local operator on 16 wells to determine the effectiveness of acid treatments. The technology uses a fiber-optic cable to read temperature real time, downhole per foot along the wellbore. This allowed the service company to validate fluid placement as well as determine effectiveness of the acid treatment. Effectiveness can also be determined by how much improvement in production takes place after the job. In the case studies observed, effectiveness was determined during the pumping of the job with DTS rigged up to the well. Using this configuration, the operator can decide if a change to the design should be made real time during pumping. The effectiveness of the acid job was dictated by how effective fluid was placed into all zones.

Basic concerns related to acid treatments are: where the acid was placed in the well, where all the acid went, if it went where it was supposed to go in each zone, or if a high percentage of the acid went into the first least-resistant zone and subsequent zones went untreated. If the latter takes place, a portion of investment capital used on gallons of acid is wasted.

Acid treatments can include a wide variation of stimulation methods or processes used to improve the effectiveness of the treatment. These processes include stimulation of the formation using fracturing or at matrix rates, varying the acid percentage, varying the type of acid, using linear, gelled, or crosslinked acid, varying the rate at which acid is pumped, and using particulate and chemical diverters. Historically, on acid jobs, surface readings for pressure and rate were the only real time indicators to judge the effectiveness of the treatment. The legitimacy of this type of interpretation could be questioned because friction pressure encountered could mask what was actually taking place downhole. As the operator attempted these acid treatments and also monitored treatment with DTS, it was observed that what is seen at the surface can be misleading.

## INTRODUCTION

The effort to associate fluid-placement effectiveness with the wellbore is a critical issue if an optimized acid design is desired. DTS literature indicates that the use of temperature readings to monitor fluid placement was initiated more than 70 years ago (Glasbergen et al. 2009). When determining fluid flow inside the wellbore, an understanding of geothermal gradient and internal Joule Thompson effect (JTE) is necessary. Applications where fluid placement and zonal coverage are important include (1) matrix-acidizing treatments, (2) scale-inhibitor squeeze treatments, (3) water-control treatments, (4) water injection for enhanced recovery, and (5) hydraulic-fracturing treatments (Glasbergen et al. 2009). Production profiling is also a candidate for DTS application. Case studies in this paper concentrate on matrix acidizing and production profiling. These were the type of treatments made available during the operator's DTS study.

At the time of the study, wells would be acidized. At this time, running diverter involved using (1) surface-pressure response and, after treatment, (2) production improvement to determine if the acid treatment was effective. If effectiveness was questioned, design changes, such as increasing or decreasing the rate, changing the percent of acid, and dropping diverters, were all tried. Using surface pressure to determine design changes for the current and for the next well is not sufficiently accurate to effectively make these determinations. Fluid friction pressures in the tubular are not always accurately known and have the capability to affect surface pressure and give erroneous bottom hole pressure calculation results. Case studies observed showed evidence during diverter stages that surface pressure indicated diversion, while actual downhole DTS resulted in no diversion. Surface indicators falsely reported a downhole phenomenon because of friction pressure. In other case studies, the diverter would be dropped and there were no surface indicators to show effectiveness. Once again, downhole DTS revealed the opposite; diversion <u>was</u> taking place.

Using knowledge of previous well improvement in production to make changes on the next well may have no value for today's well being treated. When pumping during the diverter stage, operators need to have the capability to read what is happening and react to how the well being treated at the moment with accurate downhole information.

Fluid and gas flow in or out of the wellbore leaves a characteristic temperature signature on the thermal-gradient curve. During production, the concepts are that oil, gas, reservoir fluid will flow from the high-pressure reservoir and flow into or be recovered by the low-pressure wellbore. The liquid recovery will result a warming trend and gas recovery will result a cooling effect. These basic characteristics are required to accurately determine fluid and gas movement. These are the basic concepts used to analyze fluid movement from formation to wellbore.

## GEOTHERMAL GRADIENT

The geothermal gradient is the baseline temperature the earth possesses per unit of depth as depth increases. It is the gradual warming trend as the core reservoir temperature is reached. There exists a geothermal heat source at the Earth's core. This temperature gradient ranges from 0.7 to 2.5°F per 100 ft (Johnson et al. 2006). The well's specific geothermal temperature profile is what the DTS profile will use as a baseline comparison for qualitative analysis.

When fluid flow (liquid or gas) leaves or enters the wellbore, a convectional temperature effect exists. Transient heat-transfer effects on fluid flow indicate state of fluid and direction. Gas entering the wellbore from the reservoir will experience a sudden expansion and therefore a cooling effect is observed, while liquid entering the wellbore is being exposed to a heat source in the reservoir and observation reveals a fluid warming trend. These are temperature anomalies from the baseline geothermal that indicate fluid flow. The fluid flow can now be categorized as completion effects, near-wellbore interferences, or other related events (Johnson et al. 2006).

## JOULE THOMPSON EFFECT (JTE)

The JTE is used as a key indicator for fluid entry during DTS (Seffenson and Smith 1973). The phenomenon takes place as the effect of a fluid is subjected to a change in pressure environment and the temperature change that accompanies the environment. In essence, JTE is the cooling of a gas as it is suddenly expanded, as if flowing out of a choke (perf).

The JTC Equation (Johnson et al. 2006)

$$JTC = \{\partial T / \partial \rho\}_H \quad \text{.........} \quad (1)$$

Because of the JTE, gas wells are excellent profiling candidates, especially when the perforations are spread adequately to see actual production at depth and DTS velocity calculation can be made. A tight-gas well produces with high drawdown-pressure drop, and the JTE can be observed clearly. Depending on the fluid composition and direction, the temperature can experience a positive or negative change from baseline temperature. Gases will cool, while liquids will warm when experiencing the pressure drop during production. Hydrogen gas, depending on pressure, temperature, and composition, will generally experience a cooling effect of 2 to greater than 20°F /1,000 psi. Water will experience a warming JTC of 3°F/1,000 psi (Johnson et al. 2006). Other mechanisms associated with DTS are, during production, the heat that is observed from a liquid that has been exposed to a warm reservoir (heat sink) and produces warming in the near-wellbore region, and the cooling of the wellbore from pumping cool surface fluids downhole.

## DTS

The spontaneous Raman-scattering effect is exploited to implement DTS systems (Ahangrani and Meggitt 2000). In Raman-based schemes, the ratio of Raman antistokes (AS) line to Stokes (S) line intensities is used for temperature monitoring. These measurements are independent of major fiber-loss effects and loss changes caused by fiber ageing and other effects. Temperature sensing along the fiber is then generally achieved through optical time domain reflectometry (OTDR), where light pulses are coupled into at the fiber and backscattered stokes and AS light are detected (Soto et al. 2007).

### Theory

Raman DTS is usually implemented through an OTDU technique by measuring the intensity of backward-propagating radiation over fiber length. In particular, the intensity ratio between temperature-dependant stokes and AS is used to obtain reliable temperature estimations, reducing the impact of fiber loss; the temperature dependence of the ratio can be expressed as

$$I_{AS} / I_S \approx \exp(-(h\,\Delta v_R / kT)) \quad \text{.........} \quad (2)$$

The Raman–based distributed temperature-sensing concept is illustrated in **Figure 1**.

### Technical/Operational

DTS technology can measure the temperature distribution along the wellbore through a fiber-optic cable from surface to total depth of the well. A DTS black box on the surface uses a pulsed-laser source to send a pulse of light down the optical fiber. The return light or "backscatter" is recorded. The backscatter of absorbed and retransmission of light energy is composed of spectral components: Rayleigh, Brillouin, and Raman bands. It is from the Raman band that temperature can be extruded. There are two components in this band, the AS and S, which have a great dependence and weak dependence on temperature, respectively. It is because of the ratio of the intensities of the AS and S that temperature can be calculated. Because the velocity of light through glass is known, by using the arrival time of returned backscatter light, the depth of the temperature profile is calculated. Thus, depth is achieved.

The DTS profile is a set of temperature sample points spaced equidistant along the fiber cable. This "sampling interval" is usually 1 meter in length and the period of time, or "measurement time," ranges from a few seconds to several minutes and even hours. The larger the measurement time, the more accurate the temperature will be (Sierra et al. 2008).

## DIVERSION

Diversion of injected fluids has as a common purpose: the attempt to control the distribution of treating fluids uniformly across a zone or from one zone to another. Without diversion, fluid placement tends to occur in zones of highest permeability, highest solubility, or lowest pressure. The described local stimulation is undesired because it causes an increase in productivity in producers, but typically only for a short period of time. Large portions of the reservoir that should have been treated and have a large portion of the reserves are not treated and have poor to no connection to the wellbore (Fulton et al. 2005). For (water) injectors, in many cases, there are only one or a few places where the fluid is injected. In these cases, the goal is to divert the acid across the entire zone and to remove damage in other places so that the sweep efficiency can be improved.

While most typically associated with matrix acidizing, diversion can also be used in other treatments (i.e., conformance, scale squeezes, sand consolidation, and hydraulic fracturing). The basic understanding is that the original flow distribution across the treated interval should be altered to provide more equal fluid distribution. If fluids are put into the same areas that have previously been acidized, stimulated, or swept, then there is incomplete zonal coverage. The result is incomplete damage removal, no contact with additional hydrocarbon reserves, and ineffective use of the stimulation budget.

Using some method used to alter this flow distribution is called diversion. Its purpose is to divert the flow of fluid from one portion of the interval to another. The diversion method best suited for a particular situation depends on many factors, including and not limited to the type of well completion, perforation density, the type of fluid that is produced or injected after the treatment, casing and cement sheath integrity, bottomhole temperature, and bottomhole pressure.

Many examples of diversion materials and methods have been described in the literature, (Erbstoesser 1980; Nitters and Davies 1989; Rossen 1994; Paccaloni 1995; Lietard 1997; and Parlar 1995). These include but are not limited to

- Use of particulates to build up a filter cake on the parts of the reservoir with low resistance
- Perforation balls that will block off the perforation tunnels that access the low-resistance zones of the formation
- Chemical diverters that build up resistance in zones of the reservoir that are easily accessible
- Relative permeability modifiers (RPMs) that restrict the flow for water
- Foams

The industry's challenge is to understand which diverters work under what conditions. In an acid treatment, the fluid-diversion design is often based on guidelines, rules-of-thumb, and an intuitive idea on how diversion "works." Models are available to predict diversion effects but not always used, and uncertainty on input parameters will affect the results (Rossen 1994; Glasbergen and Buijse 2006). Measurements of effective fluid diversion are almost always limited to changes in surface-treating pressure. An increase in treating pressure is an indication that diversion was effective, whereas no treating-pressure response implies ineffectiveness or no diversion (McCloud and Coulter 1969; Paccaloni 1995).

The focus in this paper is on the effectiveness of the three different diverters investigated during the study:

- A soluble particulate.
- A RPM.

- A chemical diverter in the form of an in-situ crosslinked acid (ICA).

The first diverter evaluated was a graded rock-salt particulate. This granular sodium-chloride solid can be used at most temperatures, is most effective in gelled, water-based solutions at less than 180°F, consisted of 60% 2/8mesh and 40% 8/12 mesh particle sizes, and is especially helpful in vugular and/or naturally fractured reservoirs. Effects of rock salt will be temporary if subsequent aqueous fluids following the diverter stages are not salt saturated.

In the next three treatments, the use of a low-viscosity, hydrophilic polymer with insoluble, hydrophobic modifications that tend to associate with each other were evaluated. This associative polymer technology (APT) or use of a RPM resulted in adsorption to the rock and a desired reduction in effective water permeability by at least 80%, without a significant reduction in effective oil permeability which, if placed in the matrix, will be permanent unless removed with an oxidizer. Multiple field and laboratory examples illustrating the effectiveness of this material in both carbonate and sandstone and in both RPM and diversion applications have previously been published (MaGee et al. 1997).

Finally, the in-situ crosslinking capabilities of gelled acid were used as a third diversion mechanism. The ICA is dependent on the spending of the acid so that the pH of the fluid rises to 3 to 4. At this pH range, the polymer crosslinks, viscosity increases, and resistance to penetration of the matrix increases significantly, thus causing fluid to be a diverter to other areas. Acid concentrations are recommended to be less than 15% so that spending occurs, and in cool, less-reactive formations, it can be as low as 3% to help ensure that crosslinking occurs (Yeager and Shuchart 1997; Eoff et al. 2003).

## WELL CANDIDATES AND CALCULATING DTS NUMBER

In the campaign, it was planned to have an inventory of wells to be accessed and ranked by the DTS experts on the order of magnitude for candidate strength. A well that ranks highly in the candidate-selection process will result in DTS analysis that reveals an answer to fluid placement. In contrast, a well not scoring high enough results in analysis that is more difficult or impossible to quantify flow percentage. Parameters that affect the candidate grade selection are injection rate of treatment, length of zone of interest, openhole or perforated zone, and spread of the perforations. A DTS number was calculated to bring a quick answer in determining well-candidate strength. This number and its calculation are described in Glasbergen et al. 2009. The DTS number equation is:

$$N_{DTS} = \frac{ID^2 \cdot h}{C \cdot T_{DTS} \cdot Q_{BH}}$$

ID is the wellbore inside diameter in inches, h is the total measured height in feet, C is a unit conversion of 17.1582, T is data acquisition rate in seconds, and Q is the bottomhole fluid rate in bbl/min.. The DTS number of 2.5 or greater indicated a strong candidate. Between 2.5 and 1.25 is questionable to good, if other criteria for success are present. Below 1.25 has to be looked at more closely before it is decided to invest time and capital on DTS monitoring of a well. The best practice indicates that strong candidates will result in an analysis, while poor candidates will result in no analysis.

## CASE HISTORIES

### Denver Unit 5816—11/25/08

Denver Unit 5816 is a producer in Yoakum county, Section 38, Block AX, located 1 mile east of Denver City, Texas in the Wassom field. The formation is the San Andres with perforation depths of 4,875 to 5,125 ft and it was originally completed in August of 1981. The well is openhole from 5,135 to 5,226 ft. The well was cased with 7-in, 20- and 23. lbf/ft casing to 5,135 ft. The treatment was pumped down 2 7/8-in. tubing with a packer set at 4,750 ft.

The acid and diverter treatment was designed as 17% HCl acid in 2,000-, 3,000-, and 4,000-gallon stages, with diversion in between each acid stage. The diversion strategy was to begin with 1-, then 1.5-lbm/gal course rock salt pumped in gelled saturated brine. DTS data would be used to determine if diversion occurred. If no diversion occurred, the operator would proceed to a polymer diverter and then back to acid. Acid was pumped, followed by diverter 1, rock salt, then diverter 2, then polymer diverter if rock salt did not divert. This was repeated in three acid stages. A 22-month production survey observed average production of oil/water/gas to go from 14/193/267 to 26/299/ 214. This is an annual increase of 80% oil for 2009.

In the treatment, during the acid stage, 80 to 86% of the treatment went into formation above 4,960 ft. This is can be observed in **Figure 2**.

Figure 2 illustrates that 0.85 bbl/min was pumped from 4,959 to 4,967 ft. The surface rate was 6.4 bbl/min. With a surface rate of 6.4 bbl/min, and subtracting the 0.85-bbl/min rate from below 4,959 ft, that leaves 5.5 bbl/min in the upper zones from 4,875 to 4,959 ft, or 86%. At a time of 1:04, after the first rock salt stage, there was 1.15 bbl/min pumped from 4,998 to 5,117 ft. There was now a small amount of fluid increase below 5,000 ft in perforations and the openhole. Diversion took place for a small amount of time. At 1:13 there was no flow below 5,000 ft after the rock salt and flush, as illustrated in **Figure 3**.

At 1:41, during the second acid stage, there was now 60 % flow from 4,875 to 4,892 ft, or 2.56 bbl/min. From 4,892 to 4,925 ft, there was 40% flow, or 1.84 bbl/min. So, flow was back in the top zone, as illustrated in **Figure 4**.

At 1:51 there was 1.35 bbl/min pumped from 5,000 to 5,125 ft. So, 2.85 bbl/min injection occurred above 5,000 ft. This was after the second rock-salt stage. At 2:22, 20% of acid moved from 5,000 to 5,060 ft, as illustrated in **Figure 5**.

Figure 5 is an image after the second polymer diverter, so a percentage of treatment was placed at a lower depth. In retrospect, it appeared treatment fluid injection stayed in the top zones despite diversion efforts. The first rock-salt stage appeared to divert, but was short-lived. The second rock-salt diversion appeared to divert in combination with the polymer diverter. With a combination of rock salt and polymer diversion, it was observed that the acid was placed into zones below 5,000 ft and was sustained longer than with only one diverter. See **Figure 6**.

In conclusion, acid was placed in the region above 5,000 ft with ease. With much effort by way of diversion strategies, as much as 20% of the fluid placement, or 1.35 bbl/min,, was placed for a short time period below this depth. Acid did not get all the way to the bottom perforations. The assumption made was that all previous acid treatments before this one must have treated in the region above 5,000-ft. This is observed as the least-resistive region and has historically taken all acid treatment. Although more diversion was desired, with DTS analysis there appeared to be some acid fluid placement below the 5,000-ft region. In the future, possibly having more diverter volume to be more aggressive with diversion would be an improvement. DTS in real time did indicate, by use of a diverter strategy, some acid was diverted to go in the more restrictive region.

## Midland Farms Unit 507—11/20/08

Midland Farms Unit 507 is an injector well in Andrews county, Section 39, Block 41, located 15 miles southeast of Andrews, Texas. The formation is the Grayburg, with open hole at 4,697 to 4,804 ft and a dolomite lithology. The casing is 5.5 in., set at 4,697 ft. The acid treatment was down 2 3/8-in. tubing with the packer at 4,593 ft.

The treatment design was to pump down 2 3/8-in. tubing at 1 bbl/min. A step-rate test was planned to determine fracture pressure, then rate would be adjusted to pump at matrix rates for the well. Three acid stages were designed using 28% HCl, as a high concentration of acid was desired to get better dissolving capability on a cool dolomite and to use polymer diverter between acid stages.

Post-treatment injection on the well increased from averaging 574 bbl/min at 771 psi at surface to 678 bbl/min at 700 psi at surface after the acid and diverter job on November 25, 2008. See **Table 1**. This was a 104-bbl/min increase at 71 psi less pressure. The injection index went from 74 to 97%, which corresponds to a 30% increase.

When viewing **Figure 7**, notice the prejob-cooling effect on the temperature gradient before 9 a.m. This is the well soon after shut in. At shut in, the wellbore warmed up quickly, after 9 a.m. The job started at 10 AM. The acid stages can be seen at 10:38, 11:15, and 11:50. The flush and diverter can be seen at 10:55, 11:32, and 12:00. Note that at the bottom of the acid stage there was a heating trend, and the diverter was observed to force acid to only go to a depth of 4,725 ft.

Regarding the analysis, a proof of concept was observed first. At 10:31, a velocity shot was taken at 1,800 ft, well above the zone of interest, to demonstrate surface-flow rates were reading correctly. A total of 2.6 bbl/min was calculated using fiber-optic means, as illustrated in **Figure 8**.

At 10:36, an exothermic reaction as acid spent at 4,720 ft can be seen in **Figure 9**.

At this time, it was observed that velocity slowed at a depth of 4,780 ft to 0.6 bbl/min, or 20%. **Figure 10** illustrates how the curves converge. There was 3 - 0.6 = 2.4 bbl/min, or 80% flow, above 4,780 ft.

Next, fluid distribution was calculated (see **Figures 11** and **12**) to be 80% of the acid going into the zone from 4,700 to 4,740 ft, 18% from 4,740 to 4,775 ft, and 2% below 4,780 ft. This was calculated using the slope from the color map. The vertical axis was depth, while the horizontal was time. The slopes were in ft/second. The calculation of 80% corresponded to 0.35 ft/s, and 18% to 0.05 ft/s.

Next, at 10:54 there was slow velocity from 4,700 to 4,720 ft and leakoff or acid spending at 4,730 ft and below. See **Figure 13**.

At 10:58, there was no flow below 4,770 ft. See **Figure 14**.

At 11:05, after the first polymer diverter, there was no sign of diversion. See **Figures 15** and **16**.

The bottomhole (BH) pressure increased and there was no change in temperature profile. At 11:16, there was no flow below 4,774 ft. See **Figure 17**.

As illustrated, all the temperature curves converged. The second acid stage and polymer-diverter stage showed similar activity, no flow below 4,734 ft. See **Figure 18** to view the curves converge.

The color map showed the third acid moving below 4734 ft. See **Figure 19**. This occurred for only a short period. Some, but not much, acid stimulation took place at this depth.

At 12:24, there was a cross flow from 4,715 to 4,728 ft. See **Figure 20.** Curves separate as temperature increases moving downhole.

In conclusion, there was acid stimulation from 4,720 to 40 ft. A small percentage of acid went to 4,700 ft in the beginning and at the end of the procedure. There were flow-distribution changes indicating some diversion had taken place. Overall, it was observed that the polymer diverter did not work as well as desired. An increase in diverter volume would have given a better chance to divert, as it was believed that not enough was pumped. Wormholing was also a contributor to the diversion mechanism not working as well as desired. Lessons learned were to (1) take more diverter to location than designed to supply an option as to how much is pumped, in the event DTS indicates more is needed and (2) using diversion before wormholing would have also made diversion more effective.

### GLDU 33—10/17/08

The last case history discussed in this paper is regarding GLDU 33 located in Andrews County, Texas. This was a water injector with two sets of perforated intervals totaling 280 ft. The treatment was a matrix acid with polymer diverter. DTS was deployed inside capillary tubing. See **Figure 21**.

This well had been on long-term water injection. The retrievable DTS system was deployed in the well before the acid treatment. **Figure 22** illustrates a pretreatment-temperature profile, which can be used to determine long-term water injection.

The geometry determines expected temperature restoration: tubing quick restoration, casing slow restoration (1st dotted line 5550 to 5900 ft), and liner medium restoration (2nd dotted line 5900 to 6249 ft).

Analysis indicated a more delayed temperature restoration at bottom perforations compared to expected upper regions. This indicated much water had been injected.

Limited and delayed temperature restoration was observed at the top perforations compared to expected temperature restoration.

Based on many thermal tracers, a flow distribution over time is shown. **Figure 23** indicates clear sustained diversion occured.

Crossflow indicated that there was a high-pressure zone at the top of the bottom perforations. See **Figures 24** and **25**. Therefore, fluid flowed out of the reservoir at the top of the bottom perfs and moved to a portion of the formation with lower pressure, which was the top perforations.

Initially, it was observed that almost all fluid was placed in the bottom set of perforations, which was the high-pressure zone. This could have been a result of the top set of perforations being heavily damaged. While acid was flowing to the bottom perfs, some top perforations were treated, removing damage. Then, the diverter stage was injected into the bottom perforations and forced more acid to the top and, therefore, more diversion to the top. Damage was removed and a lower-pressure zone opened and forced more to the top. Discussion on the analysis is more defined in other publications (Glasbergen et al. 2010).

No pressure increase was shown during the treatment. The diverter and acid opened up a low-pressure zone, causing it to be in better balance.

## IMPROVEMENT OF JOB DESIGNS

Lessons learned from this campaign involved designing acid on a well-by-well case, depending on what the operator desires to accomplish. If the well is a cool dolomite, the reactivity of the acid can be increased. This can be accomplished by heating the acid, increasing the HCl percentage, or slowing the injection rate to increase the time the acid has on the formation face. Some jobs were pumped with an in-situ crosslinked acid. In these cases, the acid was crosslinked once it partially spent and then broke. For this to occur, the acid has to spend fully and cover a pH scale from strong acid to spent. The pH was the mechanism that determined crosslink and break of the acid. The acid concentration should be lowered to help ensure the spent acid pH reaches the adequate range for proper crosslink and breaking. Again, reducing the rate would also help achieve a high enough pH as the acid spends more thoroughly. Certain jobs had wells in which the tubing had not been pickled. In these cases, the operator can design a volume of acid before the main treatment to pickle the tubing. A good rule of thumb would have been to pump 1,000 gallons of 15% HCl extra per 10,000 ft of tubing to accomplish this task.

To aid in DTS analysis, care should be taken to choose the correct well candidate. Using the DTS number in developing the well candidate inventory will result in better DTS analysis. Also, the use of temperature tracers was important. Trying to cool the fluid with ice was attempted and did not work well because the fluid warmed back up before an adequate tracer could reach the target. Reducing the friction reducer seemed to work well. Temperature tracers are a continuing development as the project moves forward.

It was concluded that taking extra acid and diverter to the jobsite is important. Once the DTS analysis is started, it then becomes evident what acidizing procedure should be attempted. On-the-fly decisions can only be carried out if there is enough acid, diverters, and optional diverters on location.

## CONCLUSIONS

The following conclusions are a result of this work:

- Surface pressure can be masked by friction and is therefore not a valid indicator for what has taken place downhole.
- Diversion can take place without surface indication.
- Surface-pressure response can be a false indication of diversion.
- Rock salt does not always work and, in most designs, will have early indication of success, but diversion will be lost as acid gets to its destination.
- Polymer-diversion fluids used in these cases seemed to work most reliably, but need to arrive on location with enough product to allow options on-the-fly.
- DTS allows for practical adjustment to diversion strategy for the current well.
- Candidate selection using the DTS-number process is highly recommended.

## NOMENCLATURE

| | |
|---|---|
| $\partial$ | = Derivative of |
| JTC | = Joule-Thomson Coefficient, °F/psi |
| H | = Enthalpy, disorder |
| $\rho$ | = density, g/cc |
| T | = Temperature, °F |
| $I_{AS}$ | = Intensity, AntiStokes |
| $I_S$ | = Intensity, Stokes |
| h | = Planck constant |
| $\Delta v_R$ | = Frequency separation between Raman AntiStokes/Stokes and Rayleigh scattering light |
| K | = Boltzmann constant |
| T | = absolute temperature |

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Table 1
Injection Rates and Pressures.

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 1/31/08 | 2/29/08 | 3/31/08 | 4/30/08 | 5/31/08 | 6/30/08 | 7/31/08 | 8/31/08 | 9/30/08 | 10/31/08 | 11/30/08 | 12/31/08 | 1/31/09 | 2/28/09 | 3/31/09 | 4/30/09 | 5/31/09 | 6/30/09 | 7/31/09 | 8/31/09 | 9/30/09 |
| Pressure | | | | | | | | | | | | | | | | | | | | | |
| | 795 | 790 | 788 | 790 | 785 | 760 | 755 | 752 | 750 | 745 | 748 | 750 | 750 | 755 | 752 | 755 | 750 | 680 | 640 | 565 | 550 |
| Rate | | | | | | | | | | | | | | | | | | | | | |
| | 591 | 587 | 564 | 571 | 626 | 586 | 558 | 560 | 561 | 534 | 602 | 815 | 762 | 635 | 728 | 726 | 708 | 698 | 686 | 550 | 550 |
| | | | | | | | | | | | Acid job | | | | | | | | | | |

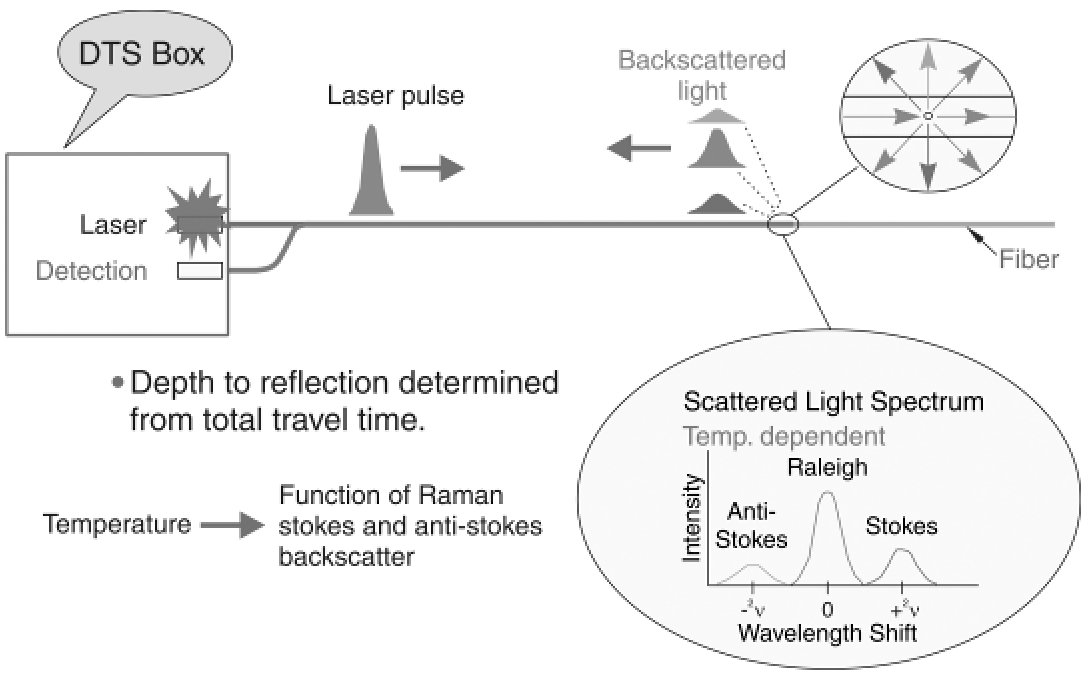


Figure 1—Raman–based DTS concept.

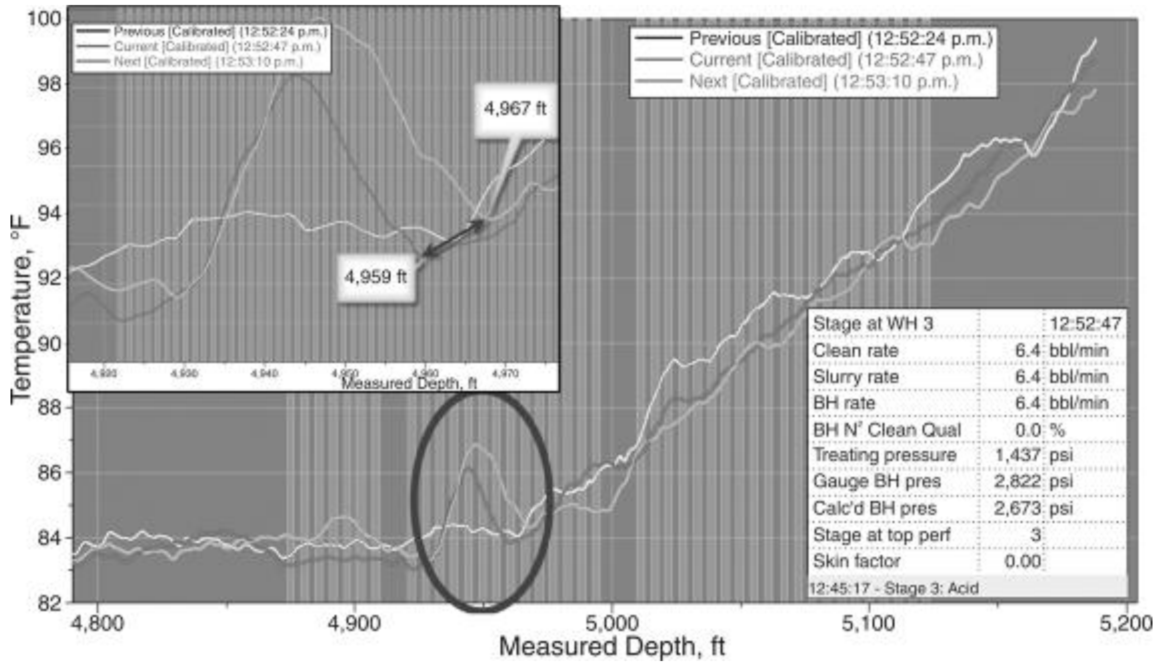


Figure 2— During the acid stage, 80 to 86% of the treatment goes into formation above 4,960 ft.

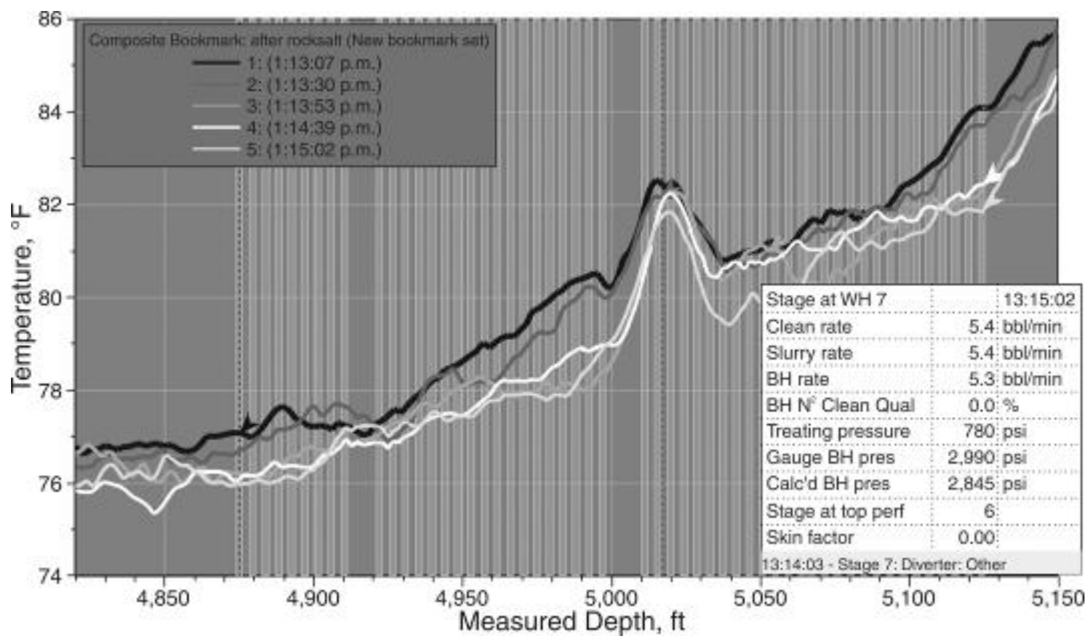


Figure 3—At 1:13, there is no flow below 5,000 ft after the rock salt and flush.

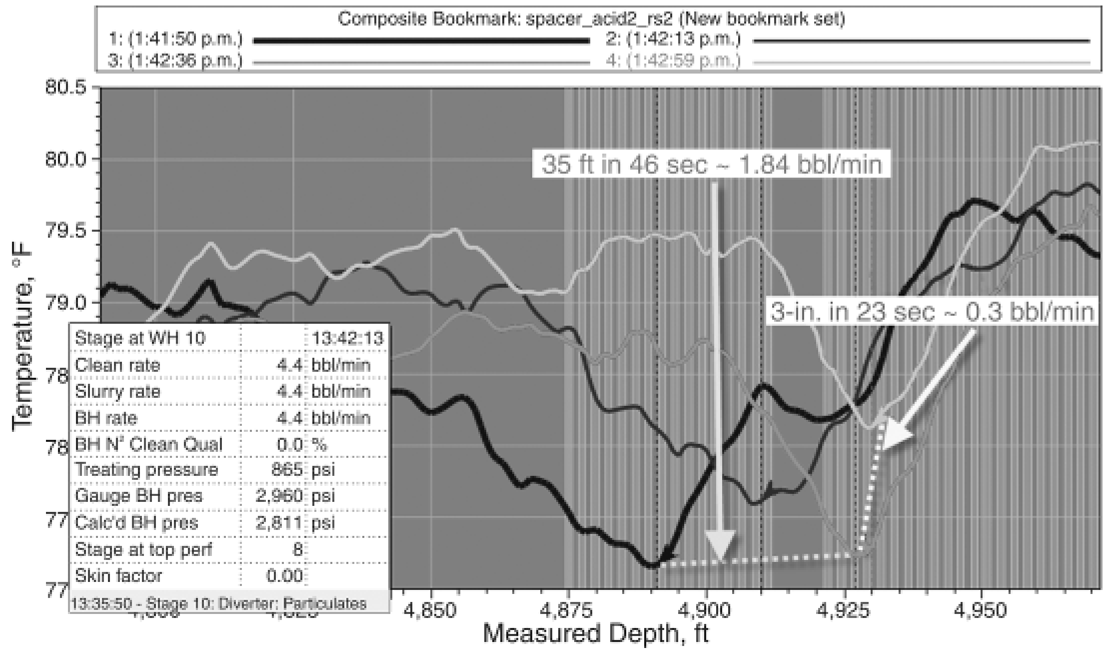


Figure 4—At 1:41, during the second acid stage, there is now 60 % flow from 4,875 to 4,892 ft, or 2.56 bbl/min. From 4,892 to 4,925 ft, there was 40% flow, or 1.84 bbl/min.

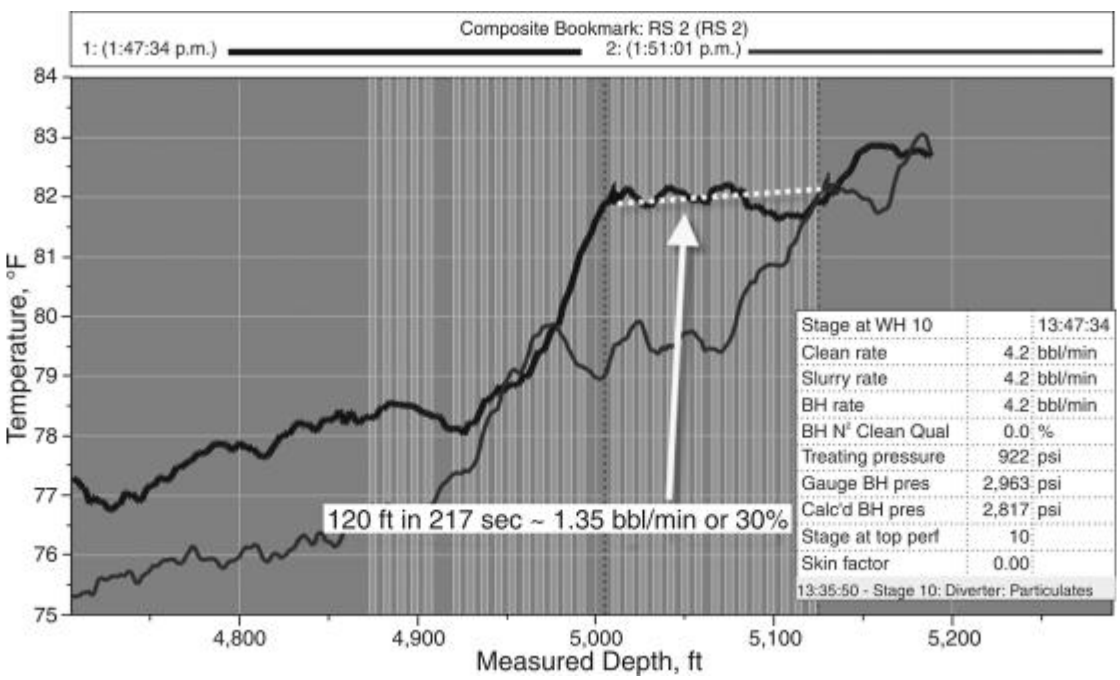


Figure 5—At 2:22, 20% of acid moves from 5,000 to 5,060 ft.

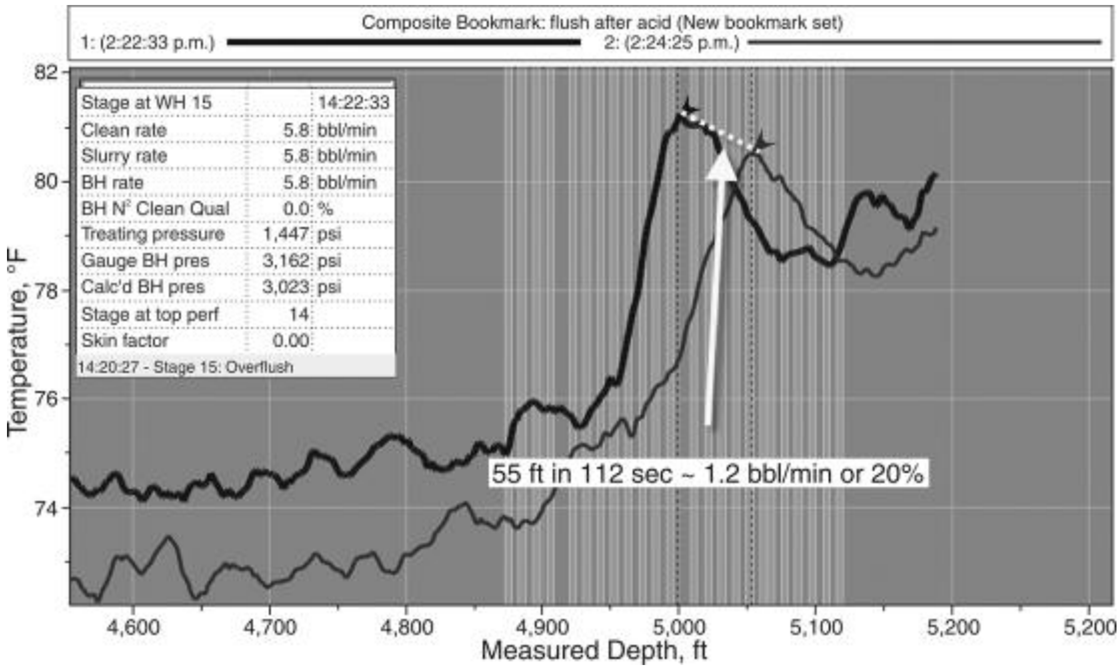


Figure 6—The second rock-salt diversion appeared to divert in combination with the polymer diverter. With a combination of rock salt and polymer diversion, it was observed that acid treated in zones below 5,000 ft sustained longer than with only one diverter.

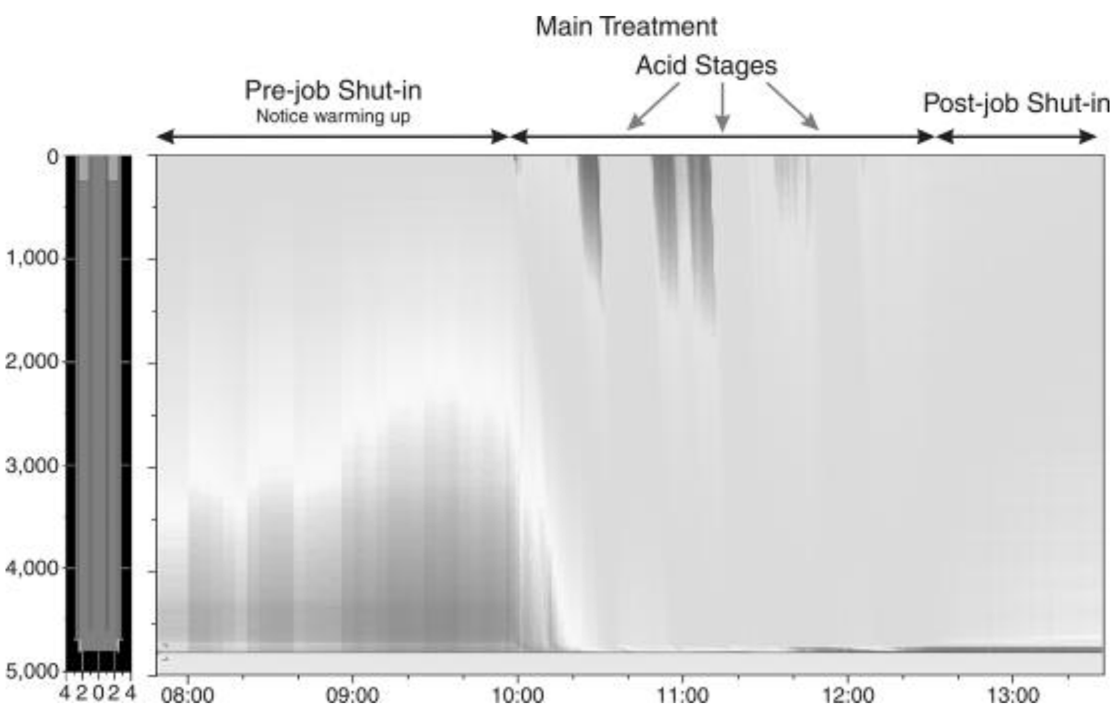


Figure 7—Prejob-cooling effect on temperature gradient before 9 a.m.

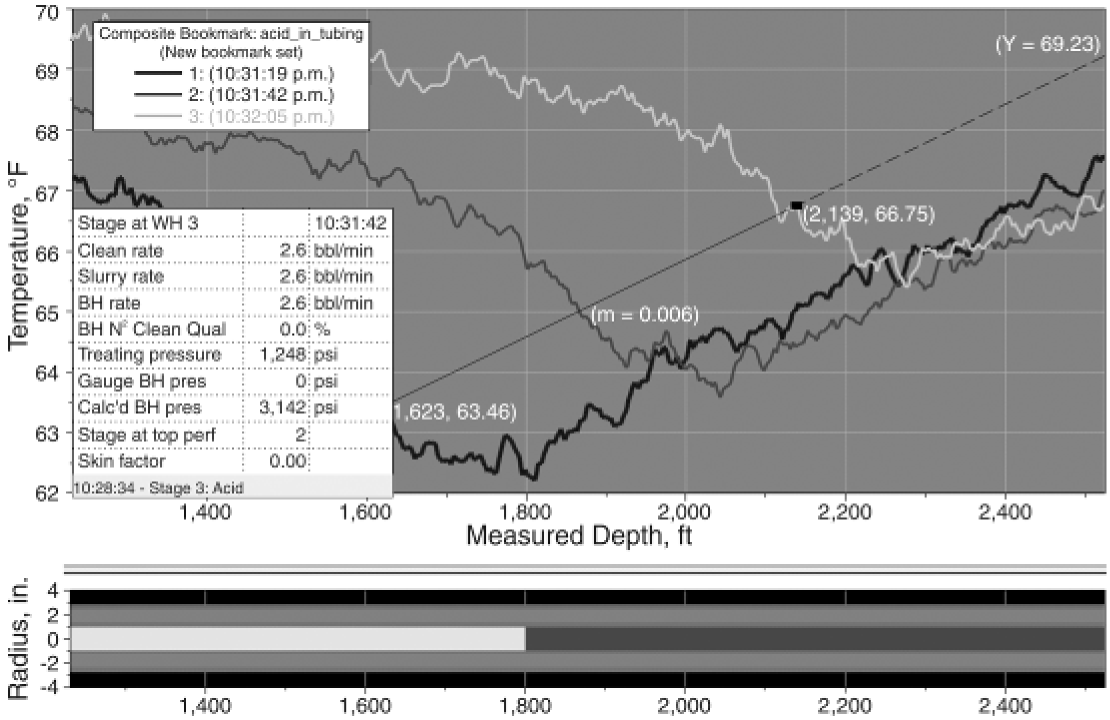


Figure 8—A total of 2.6 bbl/min was calculated using fiber-optic means.

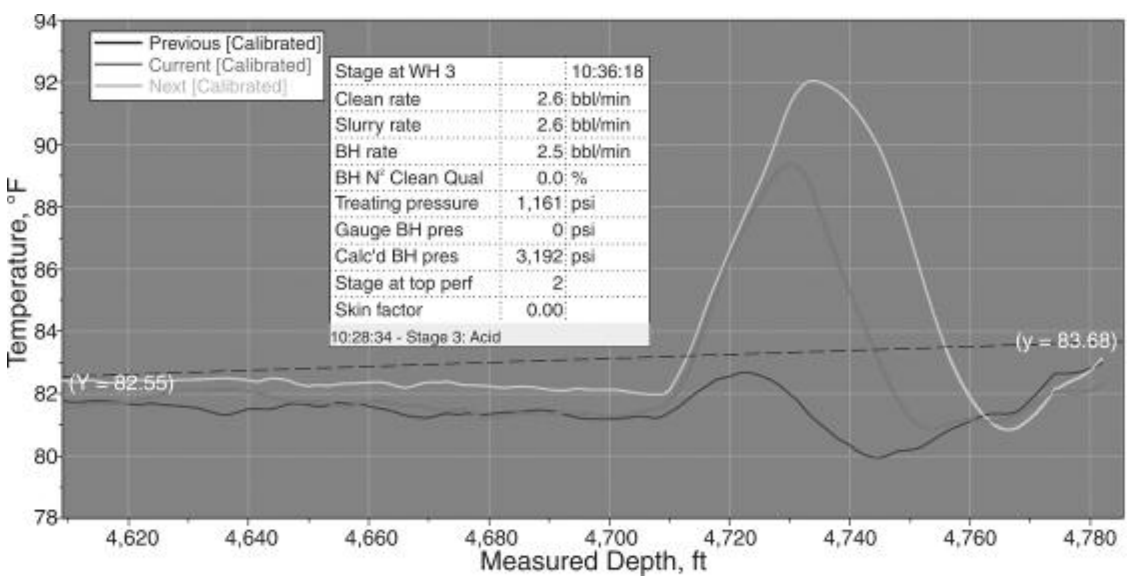


Figure 9—At 10:36, an exothermic reaction as acid spends at 4,720 ft.

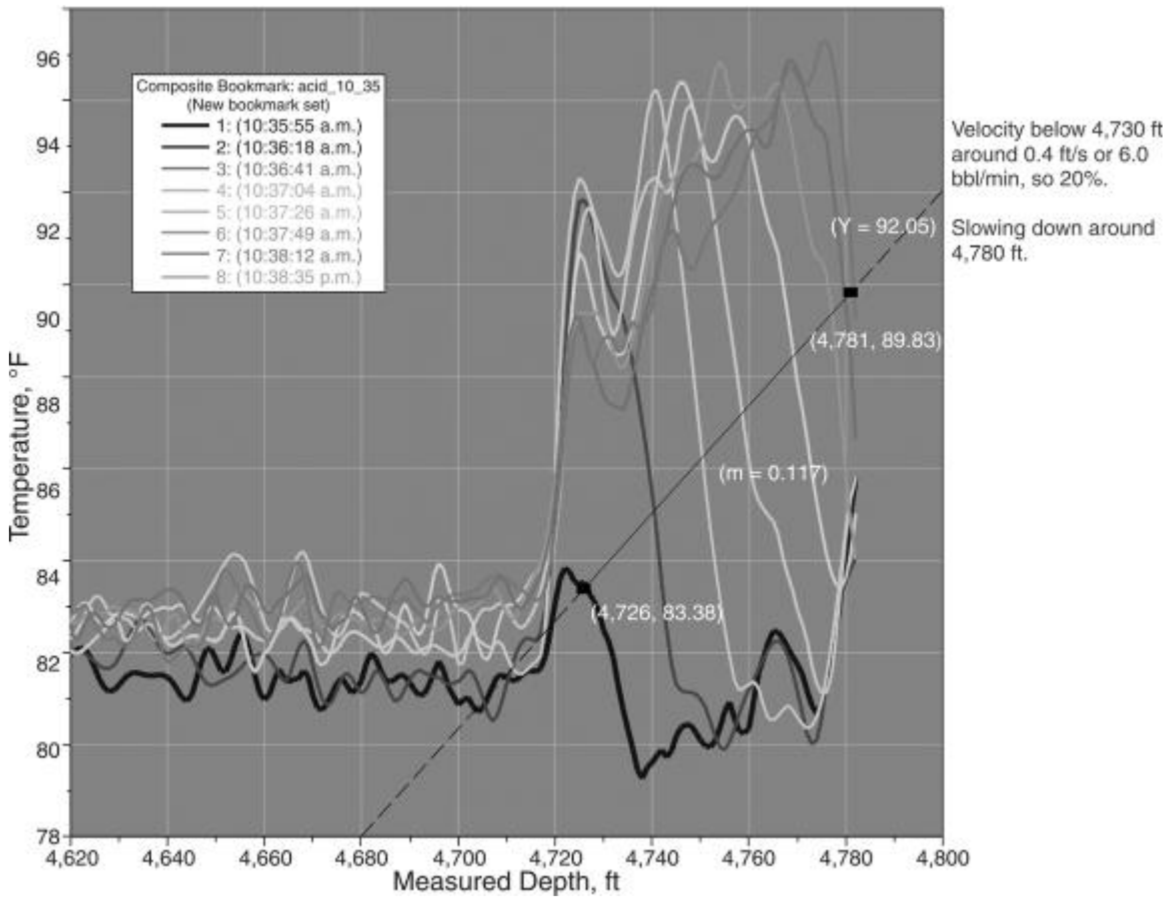

Figure 10—At this time, it was observed that velocity slowed at a depth of 4,780 ft to 0.6 bbl/min, or 20%.

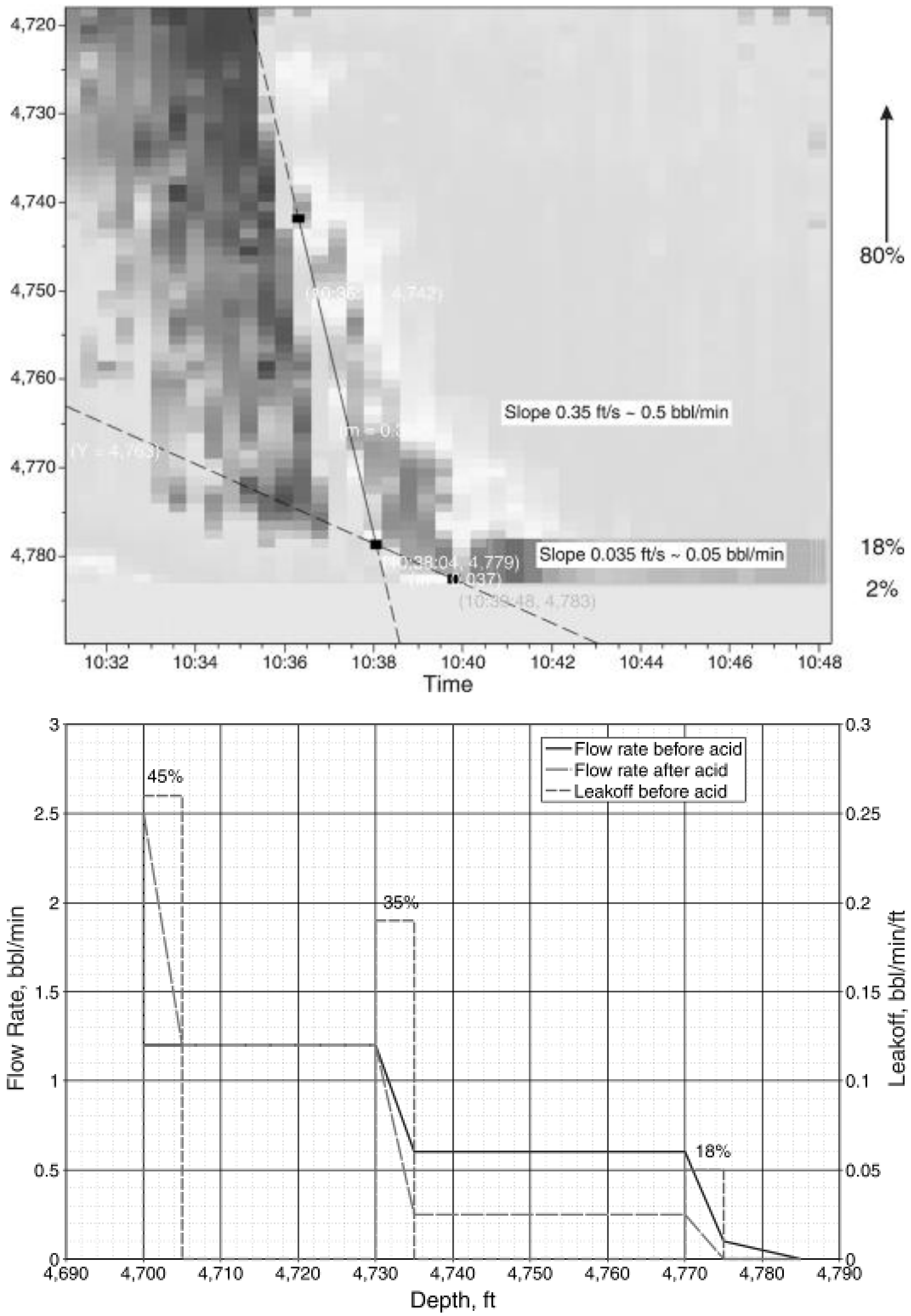

Figure 11 and 12 —Fluid distribution calculated.

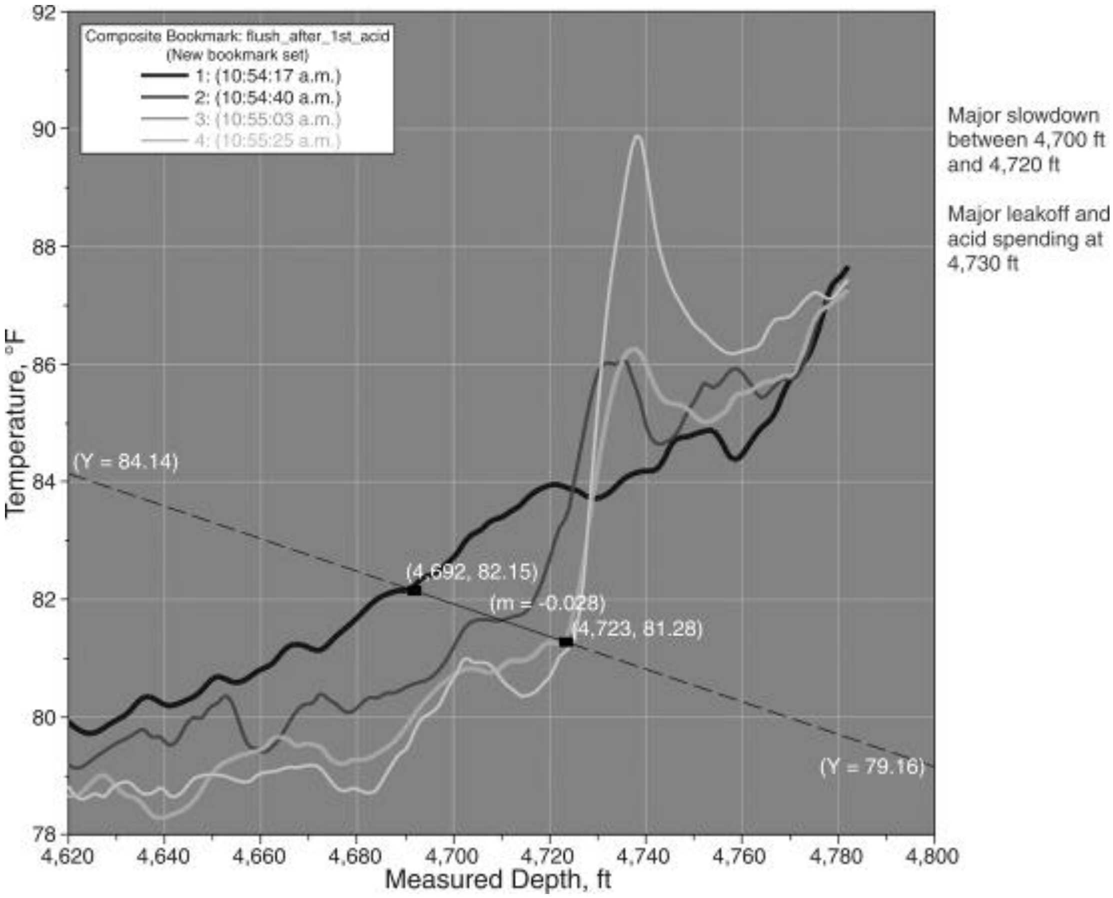


Figure 13—At 10:54, there was slow velocity from 4,700 to 4,720 ft and leakoff or acid spending at 4,730 ft and below.

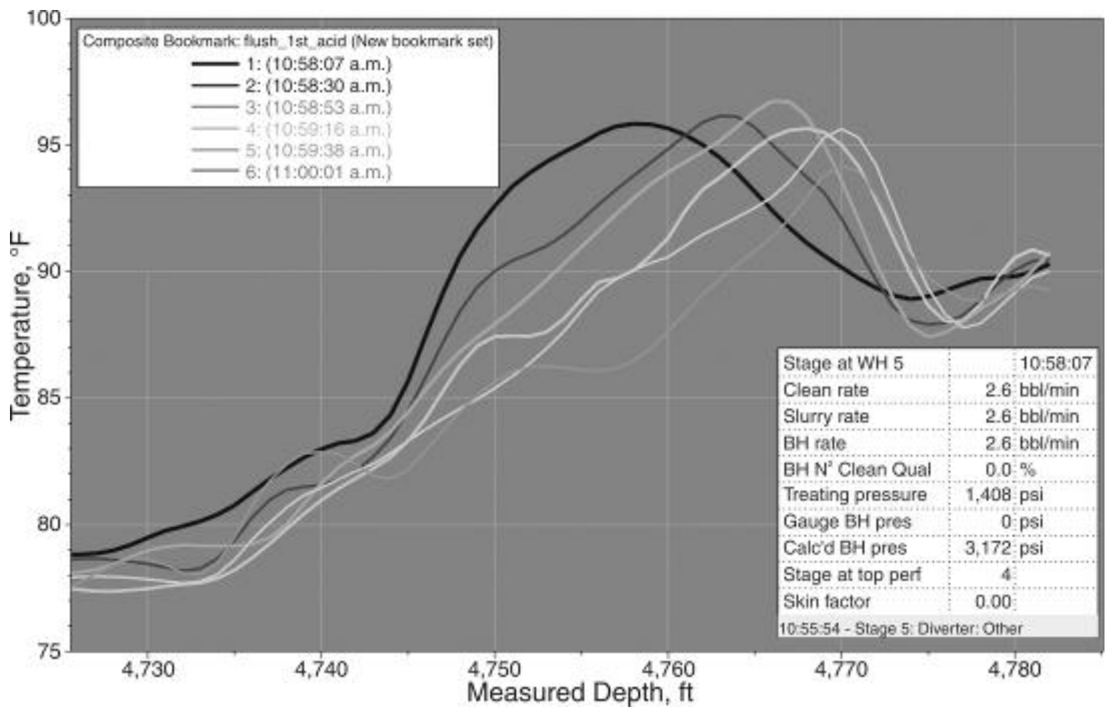


Figure 14—At 10:58, there was no flow below 4,770 ft.

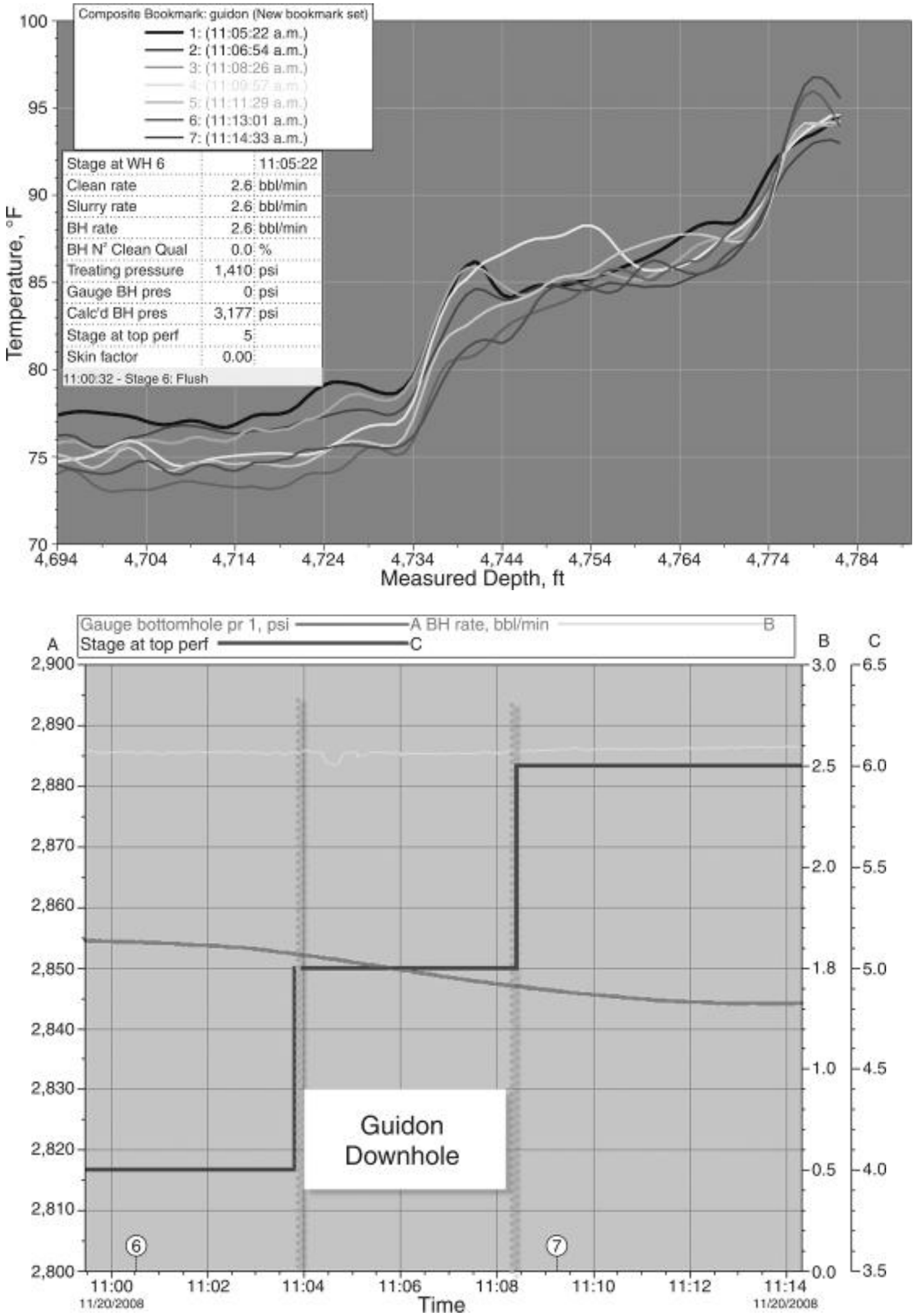


Figure 15 and 16—At 11:05, after the first polymer diverter, there was no sign of diversion.

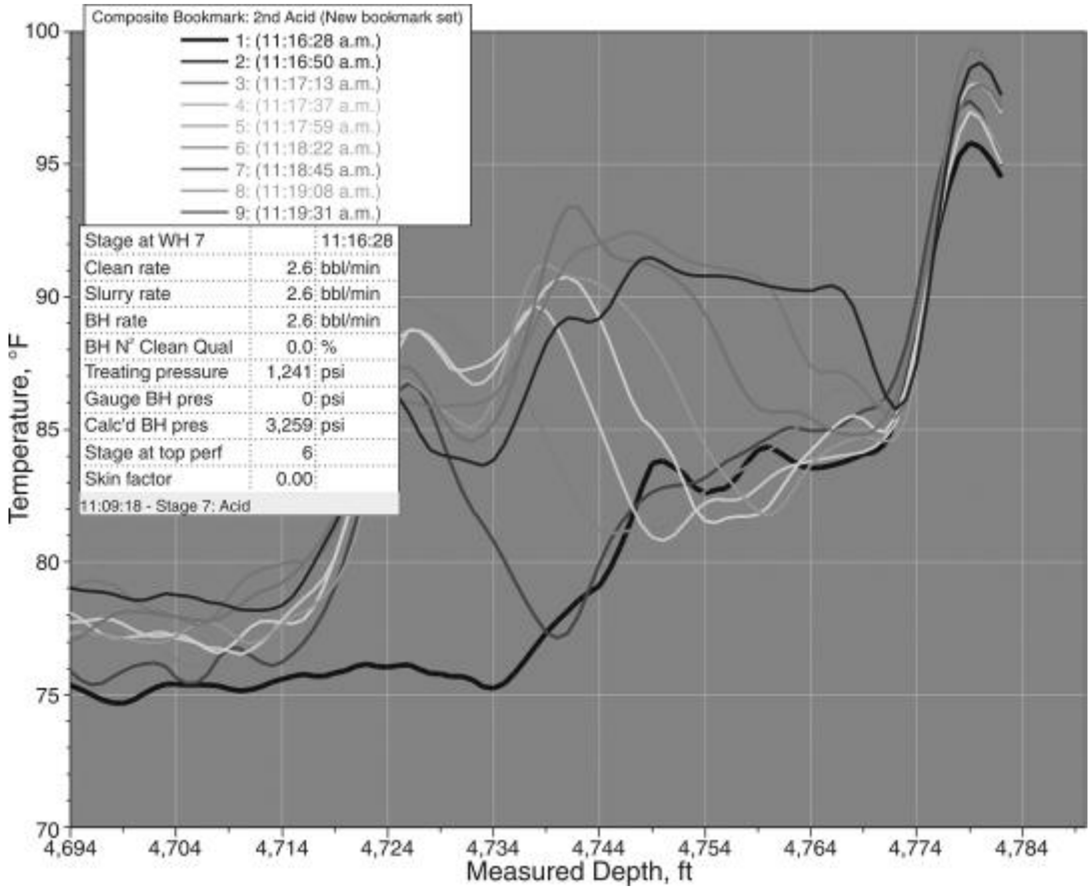

Figure 17—At 11:16, there was no flow below 4,774 ft.

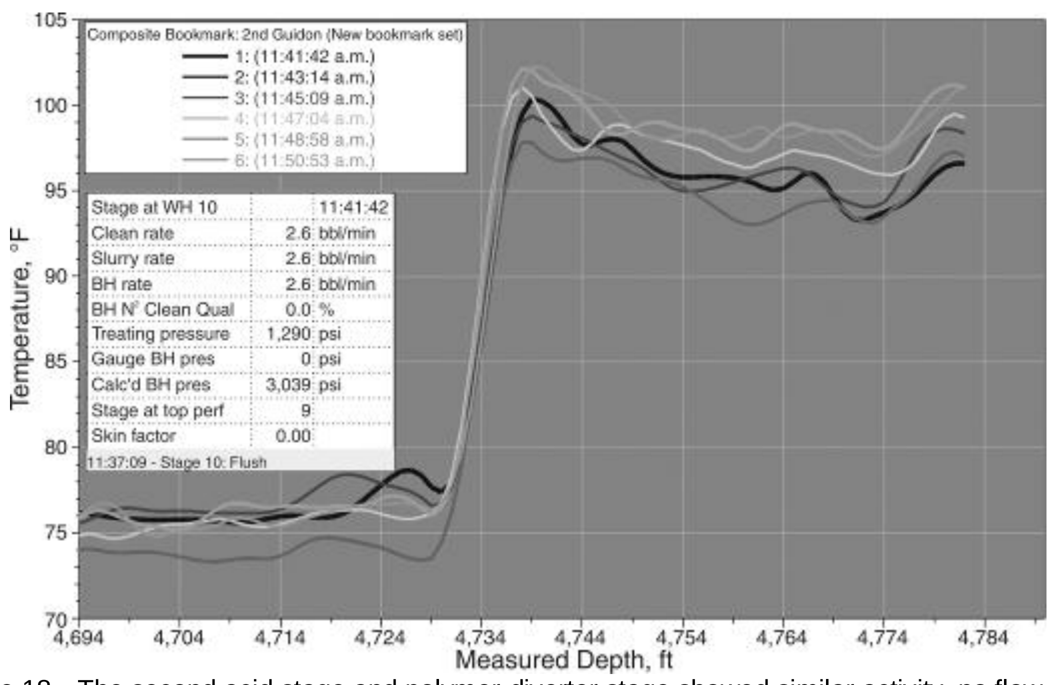

Figure 18—The second acid stage and polymer-diverter stage showed similar activity, no flow below 4,734 ft.

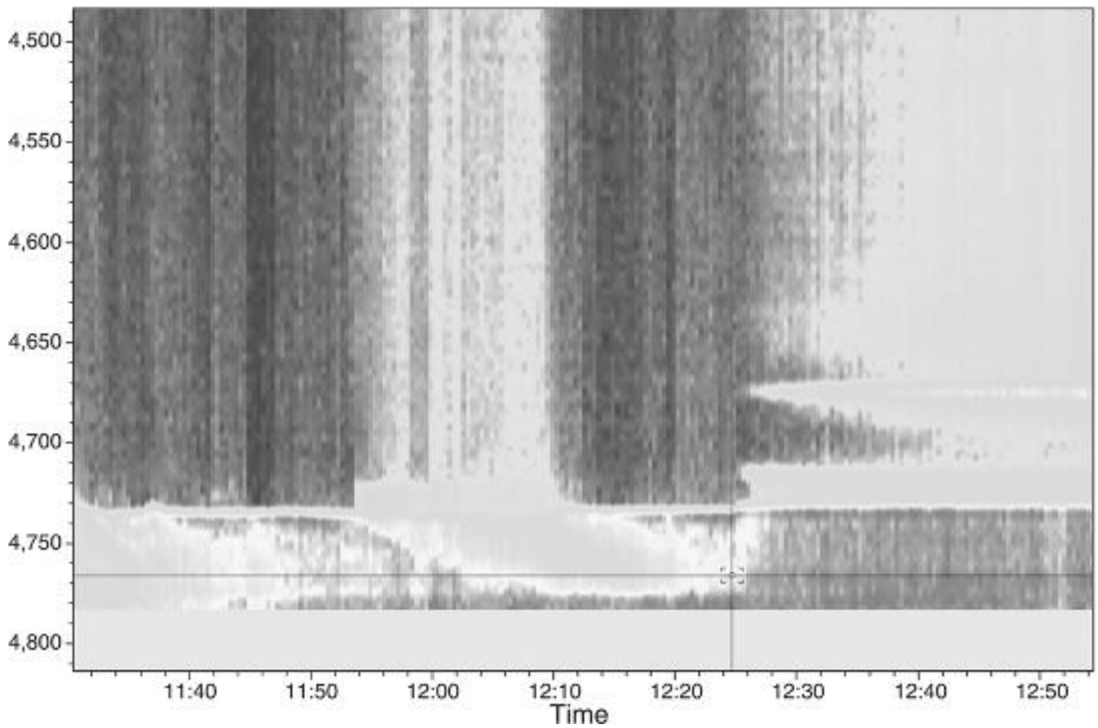

Figure 19—The color map showed the third acid stage moving below 4734 ft.

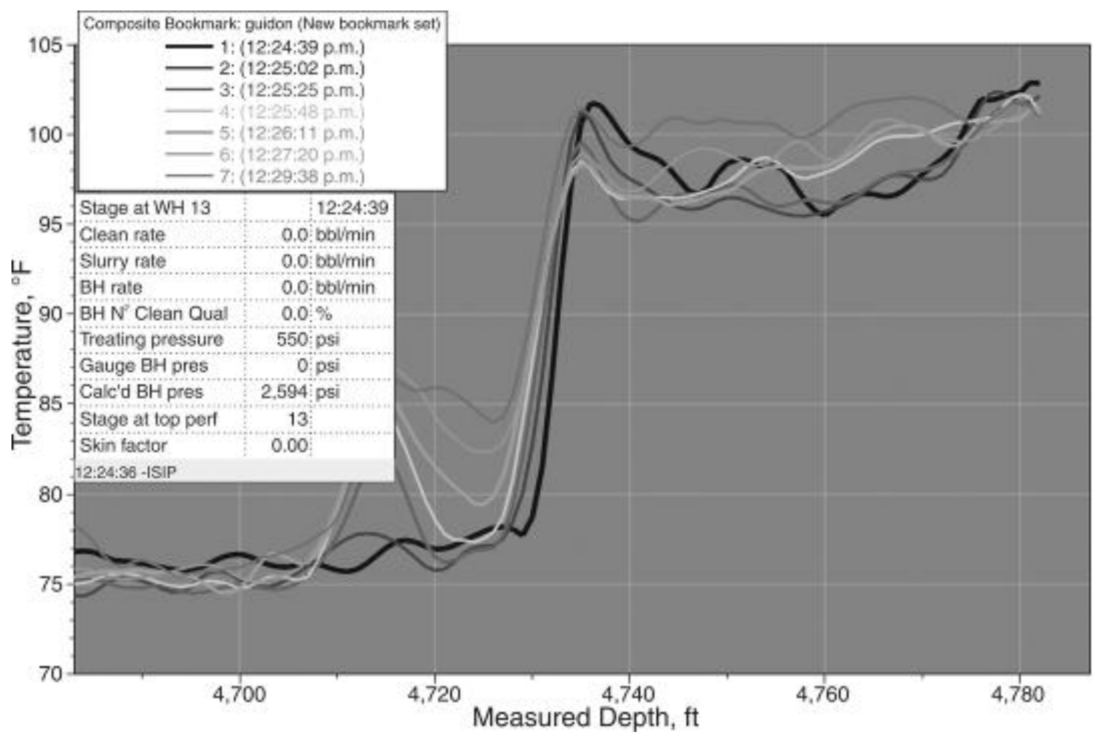

Figure 20—At 12:24, there was a cross flow from 4,715 to 4,728 ft.

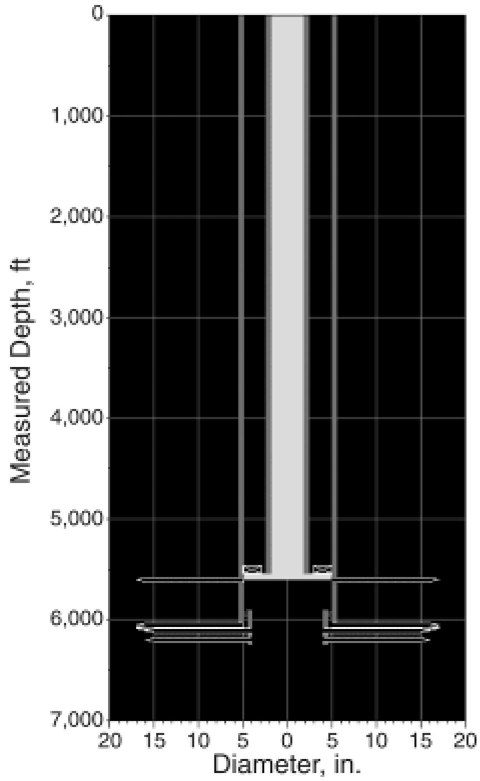

Figure 21—This treatment was a matrix acid with polymer diverter. DTS was deployed inside capillary tubing.

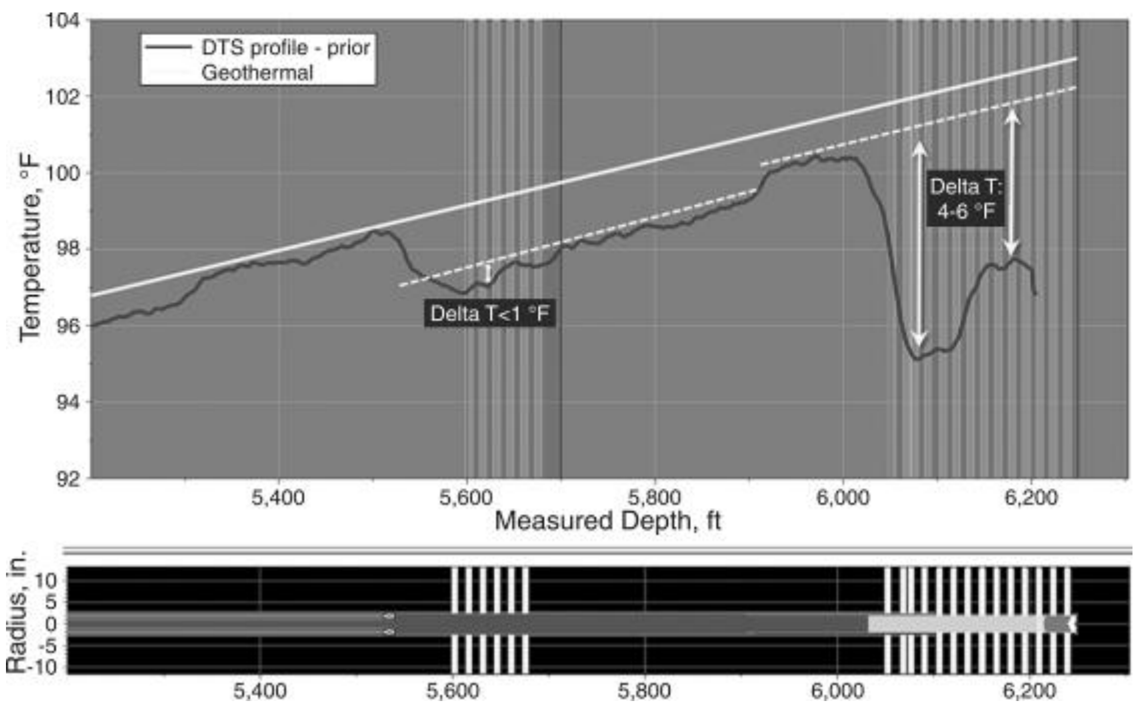

Figure 22—A pretreatment-temperature profile, which can be used to determine long-term water injection.

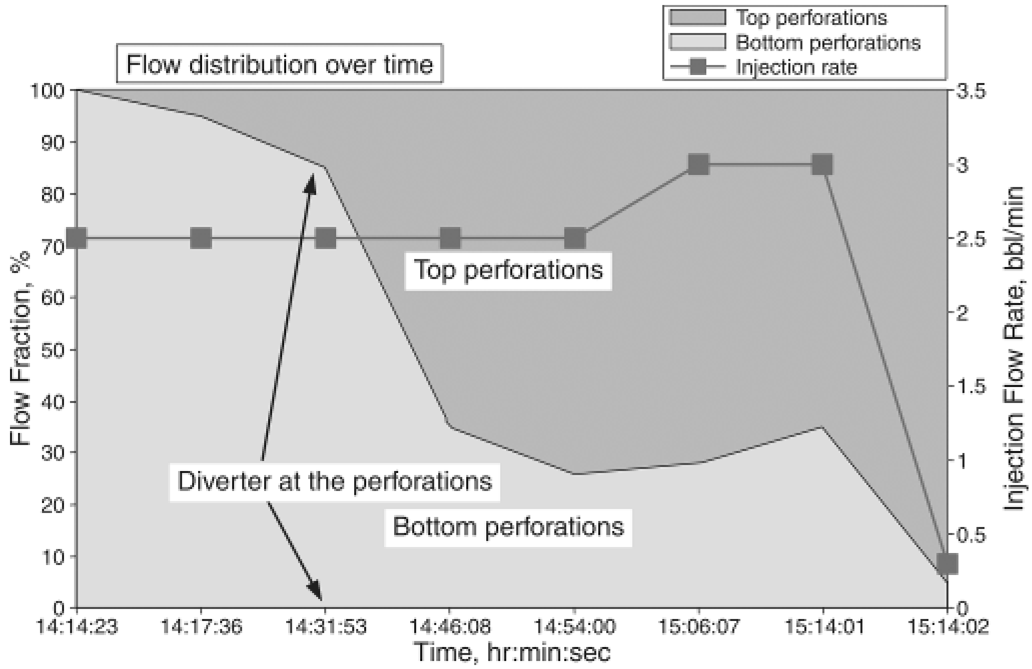

Figure 23— Based on many thermal tracers, a flow distribution over time is shown.

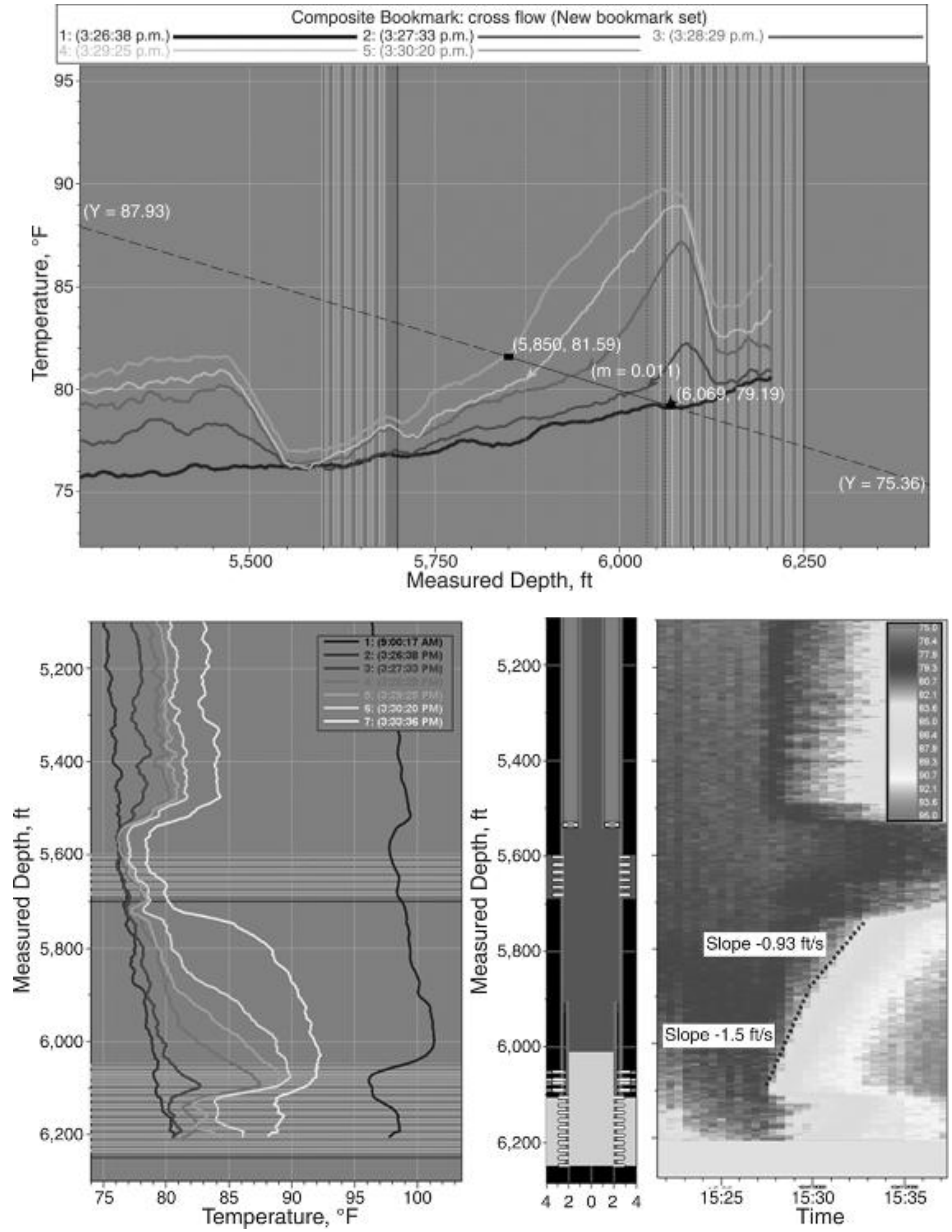


Figure 24 and 25—Crossflow indicated that there was a high-pressure zone at the top of the bottom perforations.