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Applications of Fiber-Optic Real-Time Distributed Temperature Sensing in a Heavy-Oil-Production Environment

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Abstract

Advances have been made to temperature monitoring with the application of distributed temperature sensing with fiber optics over the length of the wellbore to provide data for analysis of the well conditions. With this method, an optical fiber to monitor temperature over the entire length of a well is installed. Custom visualization and analysis software then uses the distributed temperature sensing data that is retrieved to perform analysis of well conditions in environments in which heat management is needed.

The capability to retrieve real-time data allows use of visualization and analytical software to provide rapid qualitative analysis prior to obtaining final quantitative results. This process enables improvement of heat management in heavy oil wells by detection of problem areas within the well. The improvements are provided by the capability to compare a large number of data sets.

The fiber-optic technology was initially deployed in a steamflood well in Bakersfield, California over ten years ago.[1] Since that time, the technology has been applied in many different producing environments and has proven that monitoring of downhole conditions can provide valuable information for production assessment.

This paper will discuss the significant benefits gained from using this technology in heavy-oil monitoring scenarios.

Introduction

Fiber-optic distributed-temperature-sensing (DTS) systems offer cost effective methods for improving recovery capabilities for operations in oilfields producing heavy oil. Monitoring the temperature profile of a well over its entire producing zone or entire length allows state-of-the-art analytical methods to be used. Heavy-oil producing fields generally employ some form of thermal-enhanced oil-recovery technique. In many cases, a field consists of producing, injection, and observation wells. Balancing and using the operation of each type of well offers opportunities to effect recovery costs.

The primary goal for the reservoir engineer is to maximize production while minimizing recovery costs. Several factors of an injection system affect field economics. The steam-injection rate is one of the critical factors; therefore, properly setting the injection rate is an important step for efficient field operation. If the steam injection rate is set too low, overall lower production, loss of the steam chest, and possible loss of reserves can result. If the injection rate is set too high, excessive fuel costs, wasted heat in the casing, sanding problems in producers, premature equipment failures and decreased reliability of well and surface systems can occur.[2,3]

Excessive injection rates can result in early steam breakthrough in the formations and even surface eruptions.[4,5] Early detection and correction of abnormal or improper injection conditions in these wells can alter significantly the economics of the field. Monitoring field temperature conditions is one method that can be used to optimize injection rates.

A technology that would provide continuous systematic temperature analysis of the field would be the ultimate method to optimize injection and recovery operations. However, the cost of such surveillance would be prohibitive. Because of the elevated field temperatures, permanent gauges have proven to be unreliable. Traditionally, wireline logging has been used to provide a solution. Typically, a schedule was established to run wireline logs through tubing or casing. However, in many cases, running a log in a producing well would require pulling the tubing pump. Consequently, a complete reservoir temperature profile was impossible using traditional logging surveillance. In addition, the periodicity of logging information is determined by the number of wells to be logged and the number of logging units available for the field.

Fiber-optic distributed-temperature systems offer excellent capabilities to increase the effectiveness of temperature surveillance. A fiber-optic distributed-temperature-sensing system can be installed on the tubing or casing on either a permanent or semi-permanent basis. It can also be run as a retrievable system much like a wireline logging system.

Basics of Fiber-Optic Distributed-Temperature Sensing

A modern fiber-optic DTS system uses multimode (or in some cases, single mode) optical fiber as the primary sensing element **Fig. 1** compares multimode vs. single mode optical fiber. This fiber sensing element is smaller than a human hair. A DTS system senses temperature much like Doppler radar senses weather conditions. Monochromatic light pulses, generated by a laser source, are sent down the length of fiber from the surface at periodic intervals. As the light pulses strike imperfections in the fiber, some light is scattered and reflected back towards the source (Rayleigh scattering), and some light excites the molecules at the imperfection. These excited molecules scatter light at wavelengths above and below the incident light. One component of scattered light pulses is known as Brillouin scattering, and another component is Raman scattering. **Fig. 2** illustrates Raman and Brillouin scattering. Brillouin scattering results in wavelengths very close to the incident wavelength and is difficult to process for temperature measurements. Raman scattering consists of two wavelengths that are about 440 nm above and below the incident wavelength. These two wavelengths are known as Stokes and anti-Stokes. The longer wavelength, or stokes component, is relatively temperature insensitive, while the shorter wavelength (anti-stokes) increases intensity with an increase in temperature. Thus, by comparing the intensity of stokes and anti-stokes components, the temperature along the length of the fiber can be determined. The results from many pulses of light are averaged to determine the temperature profile along the length of fiber. Present instruments are capable of determining the temperature at each meter interval along the fiber.

Operations

For a DTS system, capillary tubing is run alongside the casing for a permanent installation, or along the production tubing. The latter is referred to as a tubing-conveyed system. The fiber is installed inside the capillary tubing so that it will be protected in the well environment. Although some tubing comes from the mill with the fiber installed, techniques today allow the fiber to be installed on site, either on the spool or insitu after the tubing has been installed in the well. Strapping the capillary tubing to the casing or production tubing requires early planning in the well construction process or re-completion of the well.

Several other fiber conveyance methods have been developed for use in existing wells where capillary tubing for the fiber has not been installed. These methods include using capillary tubing containing fiber (fiber tube), fiber encased in a fiberglass rod, coiled tubing containing a fiber tube, and a hybrid single-conductor electric line with a fiber incorporated in the cable. The capillary tubing can be spooled into and out of the well like wireline or slickline for retrievable surveys where permanently installed capillary tubing is not available. Retrievable spooling operations can be used at depths up to 12,000 feet. For operations in deviated or horizontal wells, the fiber can be run inside coiled tubing. Another deployment method uses pre-installed capillary tubing and a reel of fiber encased in a stiff fiberglass rod. The fiber rod is pushed into the capillary tubing to the desired depth for the survey. When measurements are complete, the fiber rod is retrieved and moved to the next well. This method is typically used for wells that are less than 1000 feet in depth. The hybrid electro-optical cable is run using the same equipment as a single-conductor logging cable. This cable can be used at depths up to 16,000 feet.

DTS systems offer unique advantages over typical logging tools. Once the DTS system is installed in the well, readings are taken over a period of time. Each set of temperature data indicates wellbore temperature over the entire length of the fiber in the well. Readings can be taken very rapidly. The wellbore temperature can be manipulated, and the resulting dynamic temperatures can be recorded very quickly.[3] Best results are obtained when conditions causing major thermal changes in the wellbore vary.

One method of changing the temperature profile is to generate a baseline thermal gradient by closing in the well and allowing it to reach equilibrium or approach the geothermal gradient. This establishes a baseline reference for the well. Then, the well can be brought back on line to observe the changes from this baseline.

Another method used in production or injection wells is the injection of cooler water into the annulus to cool the wellbore along its entire length. Temperature readings are made during the injection process to monitor the cooling progress in real time. Once the wellbore is sufficiently cooled, pumping can be stopped. Temperature surveys are observed as the well is allowed to warm. Additional information is gathered as the well is brought back on production. Areas of rapid change indicate areas of interest within the well. Further value can be obtained from comparing results from long-term monitoring of temperature profiles with results previously obtained.

Data Visualization

Temperature surveys taken during the above operating scenarios can result in a substantial amount of data. Survey data can occur as often as 30 seconds per data set. Longer time periods for each data set are useful when more accuracy is required, but for transient analysis, shorter time periods are preferred. If the zone of interest is 1000 meters long, then there are approximately 1000 data points for each time period or data set. This could result in more than 100,000 data sets per hour. Data volume will increase significantly for a long-term monitoring scenario.

Software has been developed to assist in visualizing these data sets. Proper selection of software visualization tools is critical in the effort to quickly and efficiently identify trends in the reservoir or to conduct wellbore profile analyses. Typically, during the DTS survey, each trace is presented as a temperature-vs-depth plot, and the corresponding data set is added to a survey database. Software with the capability to plot multiple temperature-vs-depth plots, play back a series of temperature-vs-depth plots from a specified time span, and plot a 3-d interpretation of time-vs-temperature-vs-depth has been developed. These plots provide the production or reservoir engineer with the tools to analyze information from an individual well in both the time and depth domains in order to provide well performance comparisons.

The visualization software offers several methods for displaying the data for analysis. One of the methods is to replay the traces sequentially using time compression. A beginning survey time and ending survey time are selected as well as a playback speed. The data is replayed much like a time lapse movie, and the changes can be observed over the period of interest. Observations of this moving temperature trace can confirm the dynamic activity in the well. In order to document the events of interest, the software provides for a multi-trace display suitable for printing. The operator selects the traces of interest to be plotted. Plotting the data using 3-d plots can also yield additional information and offers another method of survey documentation.

Example 1: Duri

Duri, Indonesia is the site of one of the largest steam flood operations in the world. Steam-flood analysis has been conducted in heavy oil environments here for many years. DTS surveys are commonly used to analyze problematic wells, and **Fig. 3** shows a producing well example from the area. A DTS survey was planned for this well. The survey plan called for a baseline measurement to be taken with the well shut in. Then, water was to be pumped into the casing/tubing annulus to cool the well. After the well was sufficiently cooled, it would be allowed to warm, and production would be resumed. Temperature data collected during the test were split into two groups for analysis. The first data group would be comprised of the baseline and cooling phases. The second data group would include the warm back after pumping was ceased and the return to production.

During the survey, the data was replayed using the time compression or time-lapse play-back feature. This aided in determining the traces and time of interest for closer examination. The multi-trace plotting feature was then used to plot some of the data from the baseline to pumping phase of the survey. These data are plotted in **Fig. 4**. The top trace (first trace), which results from the well being shut in and reaching equilibrium, is considered the baseline trace. Each additional trace was taken as water was pumped into the annulus to cool the well. The bottom trace indicates that the well was sufficiently cooled and is in a steady-state condition. Since this well is less than 1000 feet deep, the cooling phase is accomplished in just a few minutes. However, dynamic temperature data are available over the entire period. Note that the temperature spikes at 250 to 300 feet and 420 feet in the intermediate traces. The fact that these areas took much longer to cool indicates possible steam breakthrough. This is the first indication of some sort of anomaly in the wellbore.

Data from the second phase (Stop Pumping / Warm Back / Put on Production Phase) are shown in **Fig. 5**. Here, the trace sequence moves from the bottom to the top of the chart, since the survey is made with the well cooled down. Again, the whole sequence takes place in a matter of minutes — not hours. Note the immediate heating at 420 feet and the heating at 280 feet, which take place just minutes after the pumping has ceased. This rapid change gives an indication as to the severity of the steam breakthrough in the zones surveyed. The additional temperature pulse at 500 feet is an indication of oil production in the gravel pack.

Example 2: Bakersfield

Value can be obtained by analyzing DTS temperature profiles when changes are made to the well. As temperature anomalies are introduced and observed, an interpretation can be performed on sequential changes, which happen over a short period of time. These changes can easily be initiated by varying the well production rates; i.e., changing the well from production or injection to a shut-in state. Similarly, temperature anomalies can be introduced into the well by injecting fluids into the well at various temperatures. The concept allows for a detailed analysis of short-term transient changes in comparison to the static wellbore temperature conditions and subsequently, further understanding of the wellbore and reservoir characteristics.

The following example shows the DTS temperature profiles obtained from a water injection well in the Kern Oil Field. The DTS system was deployed as a retrievable system with an extremely rugged fiber-cable assembly that covers the entire length of the well. This system can easily be spooled into the well for the temperature profiling operation and removed from the well upon job completion. Permanently installed fiber cable assemblies are also advantageous for wells where longer-term monitoring is desired.

The collected temperature surveys identified a baseline temperature profile with the well in a static state during injection. Next, a shut-in period was observed. Once the shut-in temperature profiles stabilized, an injection period was monitored.

DTS Temperature profiles are taken at the following intervals:

1. Baseline injection temperature profile at a 3-minute rate
2. Well Shut-in temperature profile at a 14-minute rate
3. Injection temperature profile at a 3-minute rate.

Proper visualization of DTS profiles offers insight into fluid placement and interactions with the reservoir when sequential wellbore temperature traces are analyzed. **Fig. 6** shows the relationship between static injection and static shut-in wellbore temperatures. The transient temperature changes between steady state conditions show an anomaly that can be seen at a depth of approximately 2500 ft. The signature shows the transient wellbore temperature increasing below this depth and cool down above this depth as they approach the reservoir temperatures.

Other interesting anomalies can be identified when the lower end of well near the perforations is examined further. As seen in **Fig. 7**, the warm back rate of temperature from depths of 5500 ft across the perforation provides some additional information. One characteristic of a long-term injection well is the increased length of time it takes for the treated areas to warm back to the reservoir geothermal temperature. As noted in depths from 5500 to 5820 ft, very minor temperature increases were observed in this region above the perforations. A slightly larger temperature increase is seen in the depth range of 5880 to 6300 ft, which is across the perforations. This is significant and implies that a majority of the injection fluids have been treating a 300-ft area above the perforations over a long period of time. Fluid treatment out of zone could seriously reduce production efficiencies of surrounding wells.

To further investigate these anomalies, the wellbore temperatures can be monitored as the well is placed back on production. A series of wellbore temperature traces obtained when the well is placed back on injection is shown in **Fig. 8**. These temperature profiles show a wave of hot fluid being pushed across the perforated interval as new fluid is injected into the well. This 'temperature front' can be visually seen as it is pushed across the perforations and back into the formation.

A closer look at these transient changes is shown in **Fig. 9**. Analyzing the rate of change and slope of the temperature front as it moves downhole with respect to time can lead to a qualitative assessment of the fluid loss as it is injected into the well. It can be seen that the fluid is moving past the upper sets of perforations and is entering the lower sets into the reservoir. The injected fluid is, however, finding its way back up the formation across the back side of the casing or through natural fractures into the area identified directly above the perforations.

Today, the tools are in place to visually play back DTS temperature profiles across the depth and time domains. Future advances related to analyzing DTS temperature profiles will provide tools that will quantify the velocity of the fluid as it crosses the perforations. This will provide a numerical identification of the fluid loss or gain across a series of perforations.

Visualization capabilities add value to the capability to quickly and efficiently interpret and understand transient temperature changes. A hybrid display was created to visualize the complete series of temperature information in a single view and aid in performing a qualitative job analysis. This display is shown in **Fig. 10**.

The curve on the left side of the screen shows two temperature profiles. The pink profile is the initial temperature survey while the blue curve is the profile at the currently selected time shown at the bottom of the plot. This profile shows a temperature profile at 9:50 am, which is the last shut-in profile prior to the well being put on injection.

The profile along the bottom is called the history curve, and it displays the temperature over time at a chosen depth, shown on the top left corner of the history plot. This profile shows the changes in wellbore temperature at a wellbore depth of 5488 ft.

The color map displays the complete series of temperature profiles in depth and time using the same scales as the profile and history plots adjacent to it. The temperature scale can be interpreted using the key to the right.

Also note the red dots shown on the profile and history traces. On the profile plot, this dot corresponds to the depth that is selected for the history plot. On the history plot, this dot corresponds to the time that is selected on the profile plot.

Within this view, trends during the entire series of temperature survey's can easily be identified. The first two thirds of the profiles show the shut-in period [1]. It is easy to identify the depths and rate of warm back in the wellbore. Once the shut-in period stabilized, the well was placed on injection [2]. The step slope of the temperature front indicates a high fluid velocity as the injected fluid is pumped down the well.

Conclusions

Distributed temperature sensing can be a valuable tool in analyzing production in a heavy oil environment. Measurements from injection, monitoring, and production wells can be combined to give a detailed reservoir profile. In addition, DTS surveys can provide data not available from traditional logging tools or downhole gauges. Traditional methods are limited to measuring steady-state conditions or single-point dynamic conditions. DTS surveys provide real-time temperature profiles over the entire length of the well, which does not require sensor or tool movement in the wellbore. This provides a more accurate identification of wellbore temperatures and unique insight into temperature transient effects, which are not available by any other process. By manually and intentionally changing wellbore temperatures, the dynamic temperature profiles that are obtained can provide information that can identify unique or obscure wellbore conditions. Analysis of the temperature data is complimented by additional technology such as visualization and flow profiling software, which offers a suite of tools to tailor the DTS data analysis and documentation to the operator's needs.

Acknowledgments

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SI Metric Conversion Factors

Stokes	x 1.0*	E - 04 = m^2/s
°F	(°F - 32)/1.8	=°C
ft	x 3.048*	E - 01 = m
in	x 2.54*	E + 00 = cm
psi	x 6.894 757	E + 00 = kPa

*Conversion factor is exact.

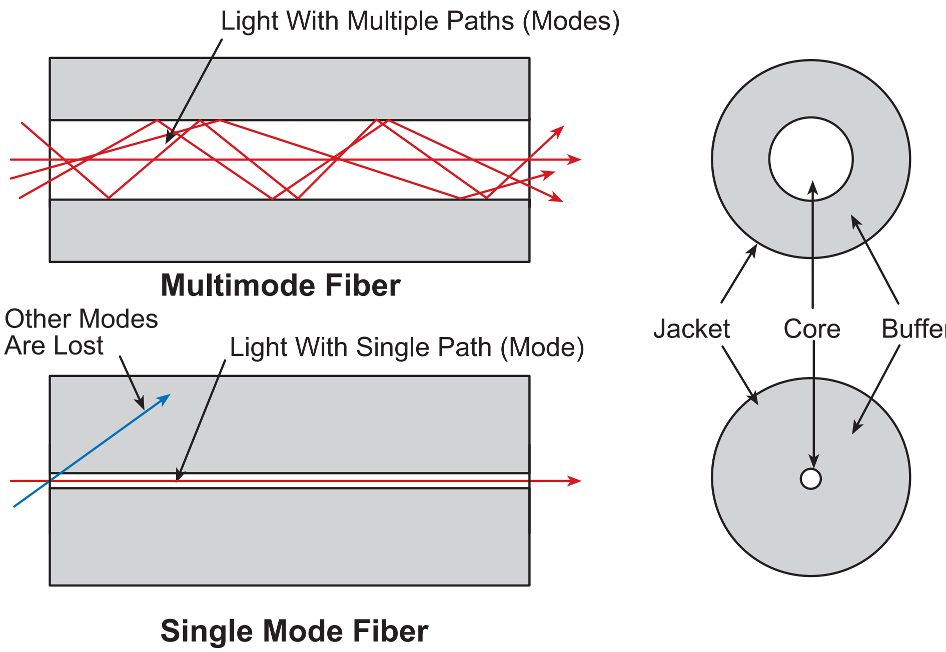

Fig. 1 — Multimode and Single-mode Fibers

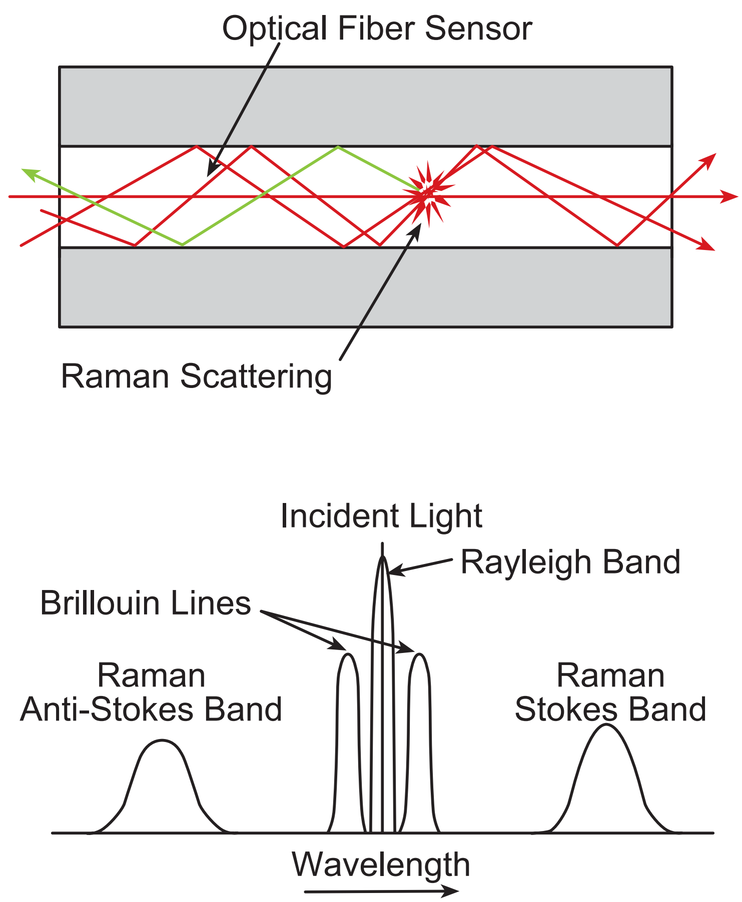

Fig. 2 — Raman Scattering

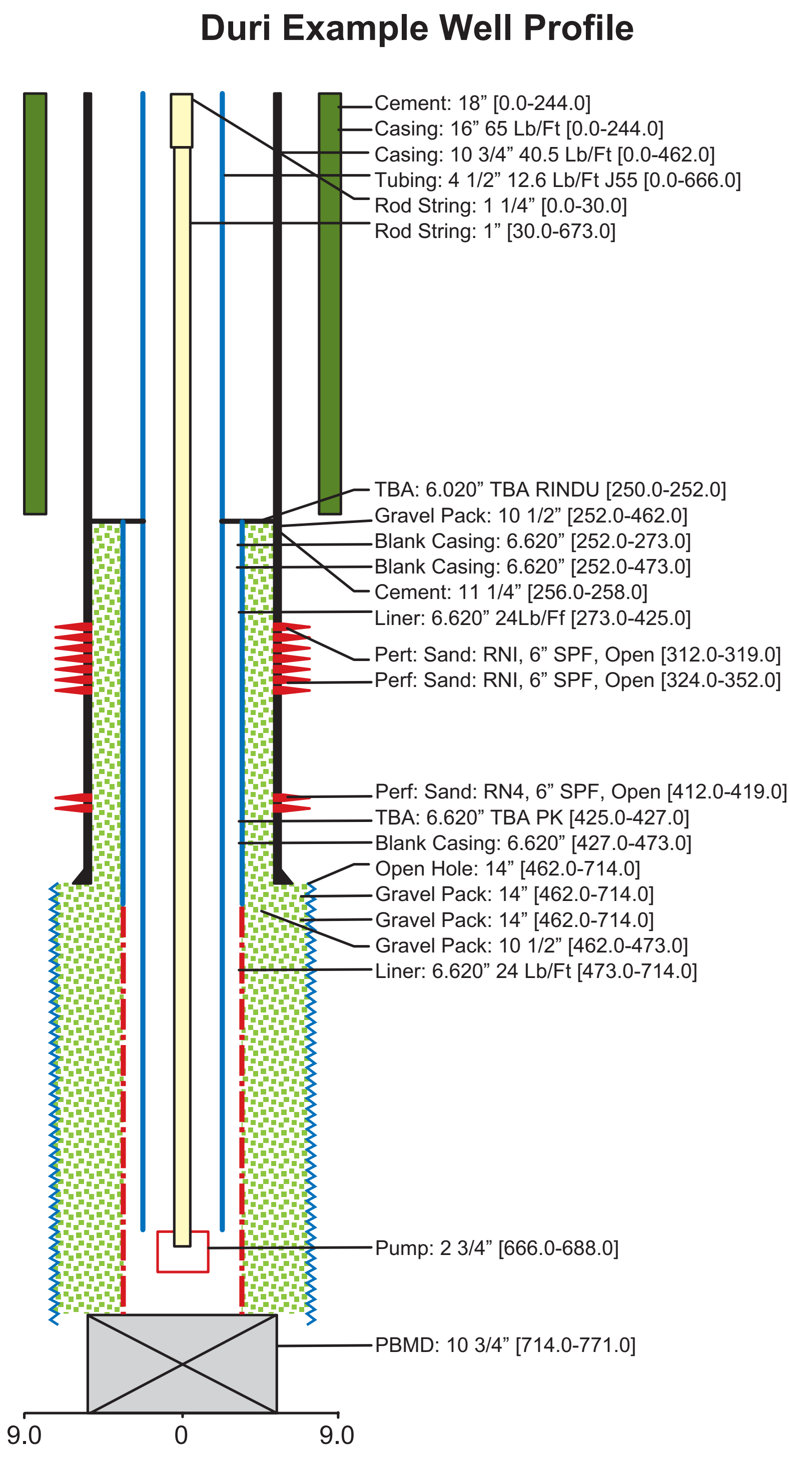

Fig. 3 — Duri Well Profile

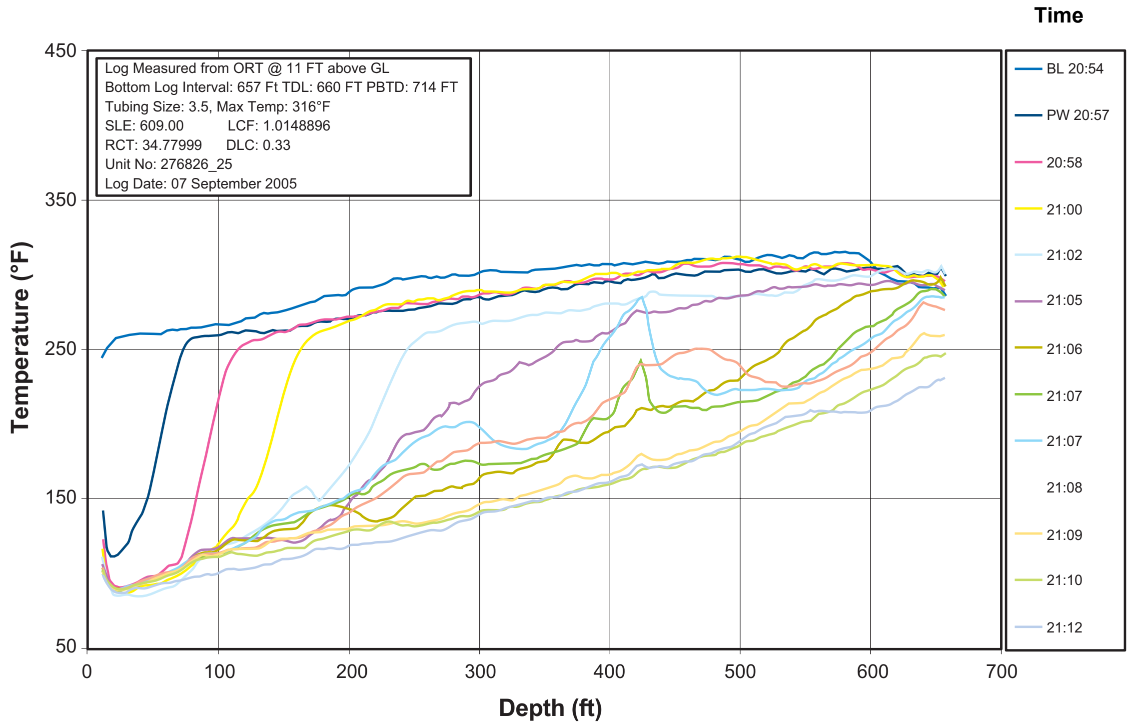

Fig. 4 — Duri Well Baseline to Cooling

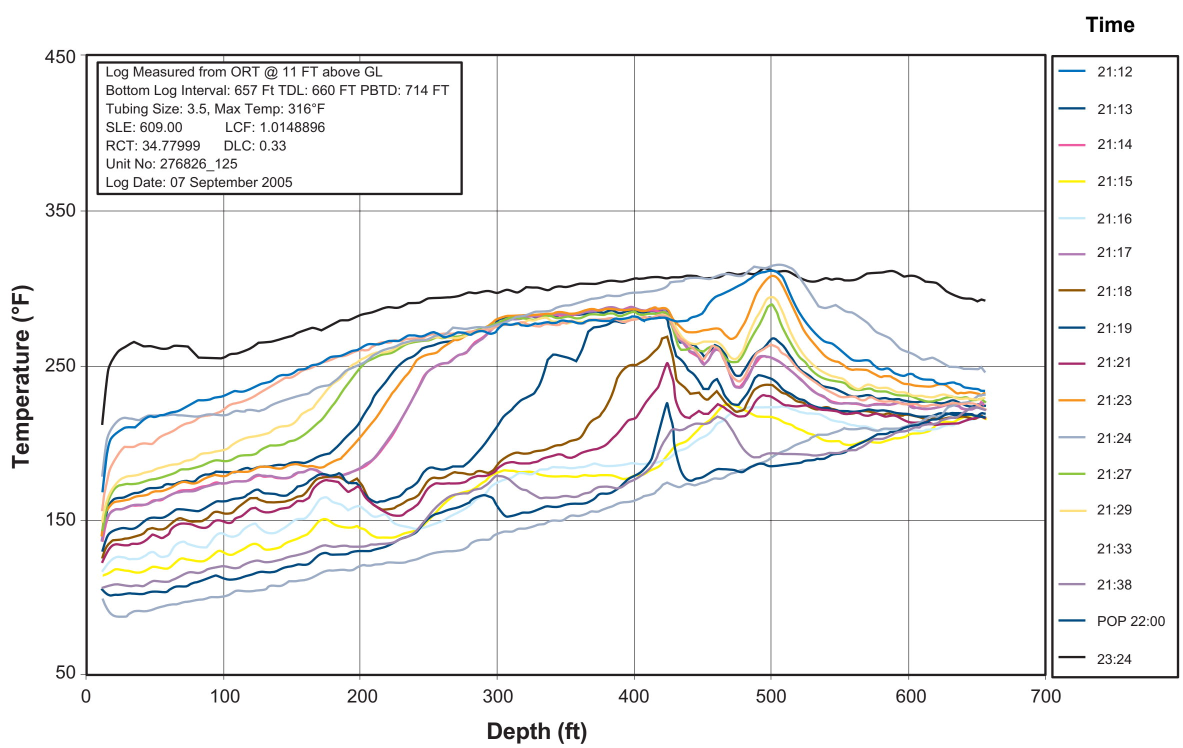

Fig. 5 – Stop pumping water and return to production

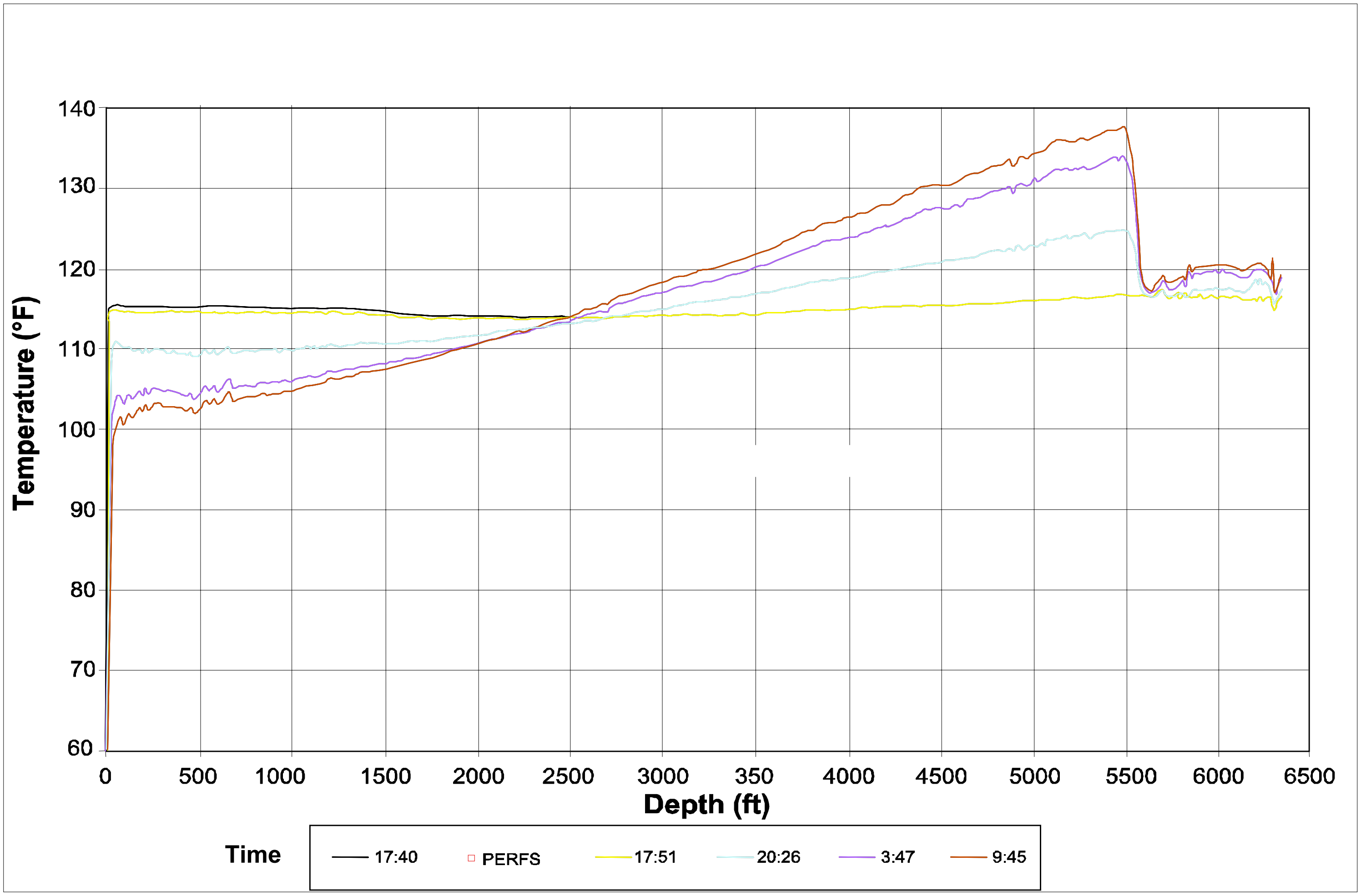

Fig. 6 — Shut-in Temperature Profiles – Full Wellbore

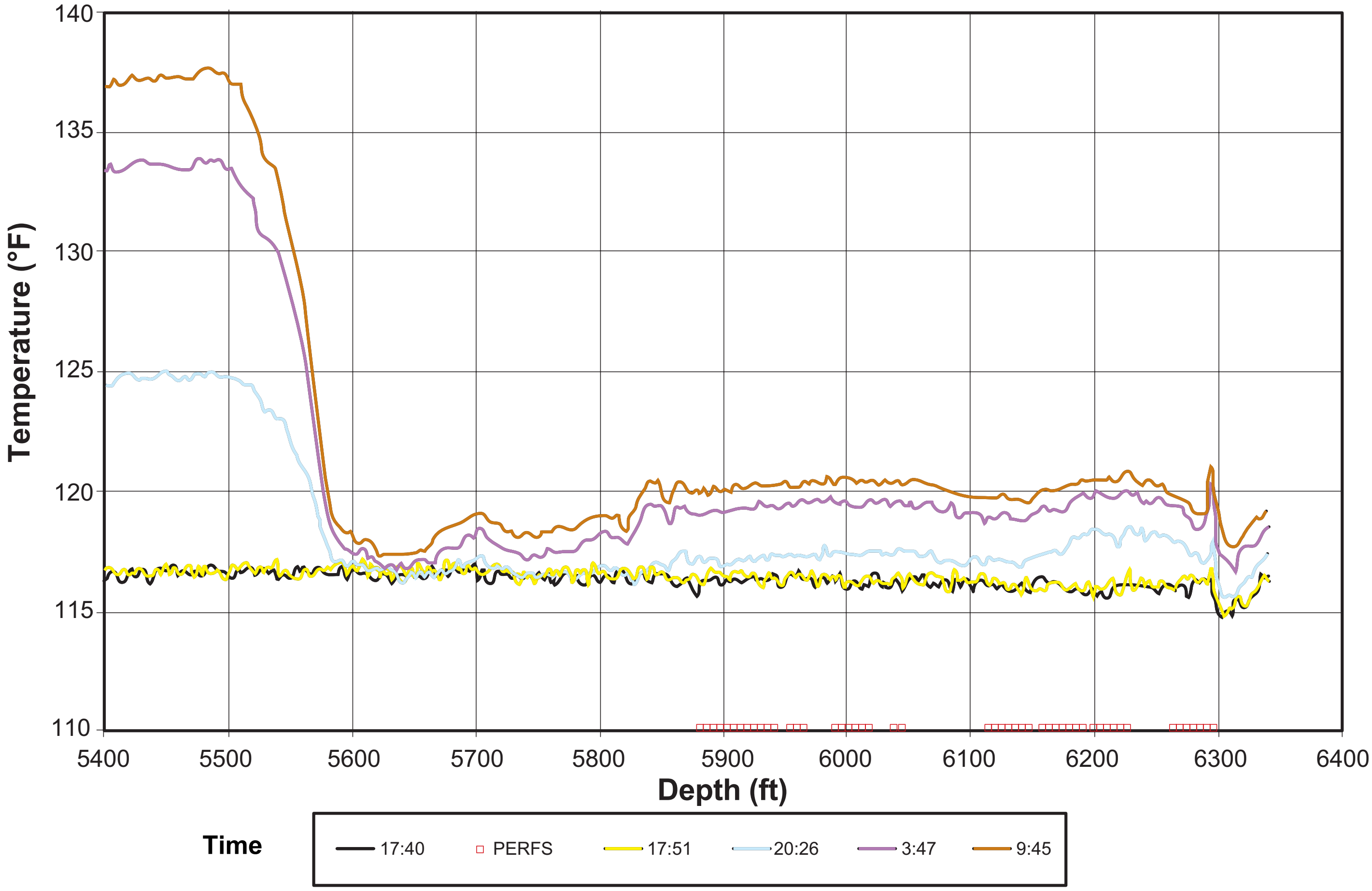

Fig. 7 — Shut-in Temperature Profiles – Perforated Interval

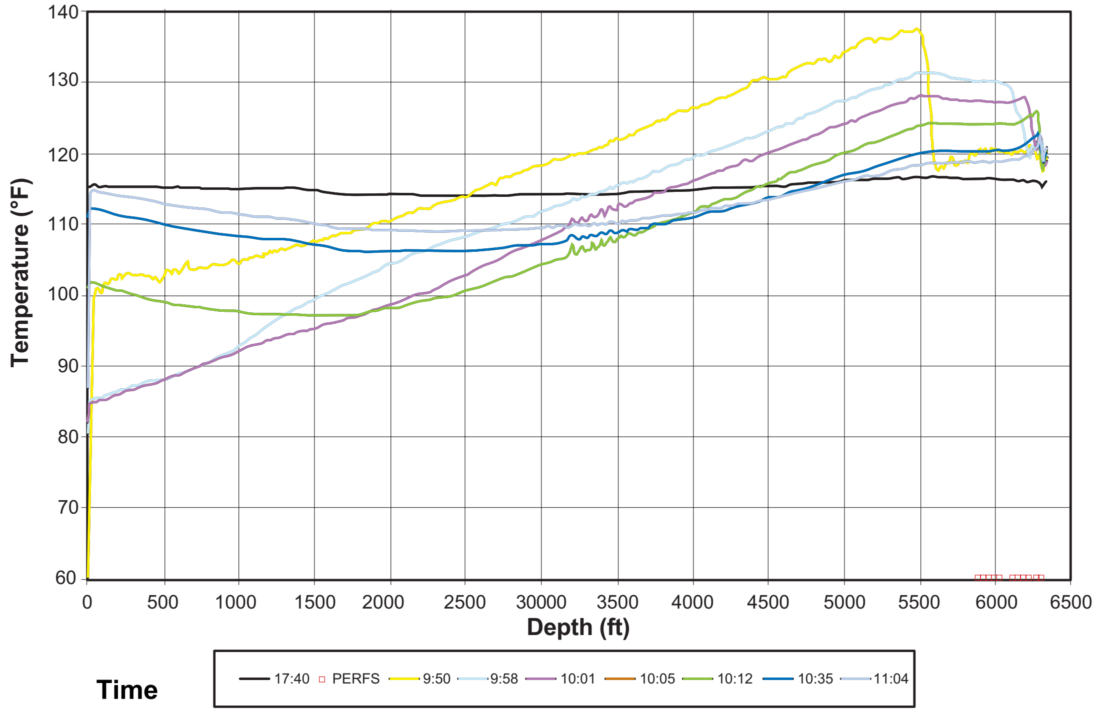

Fig. 8 — Injection Temperature Profiles – Full Wellbore

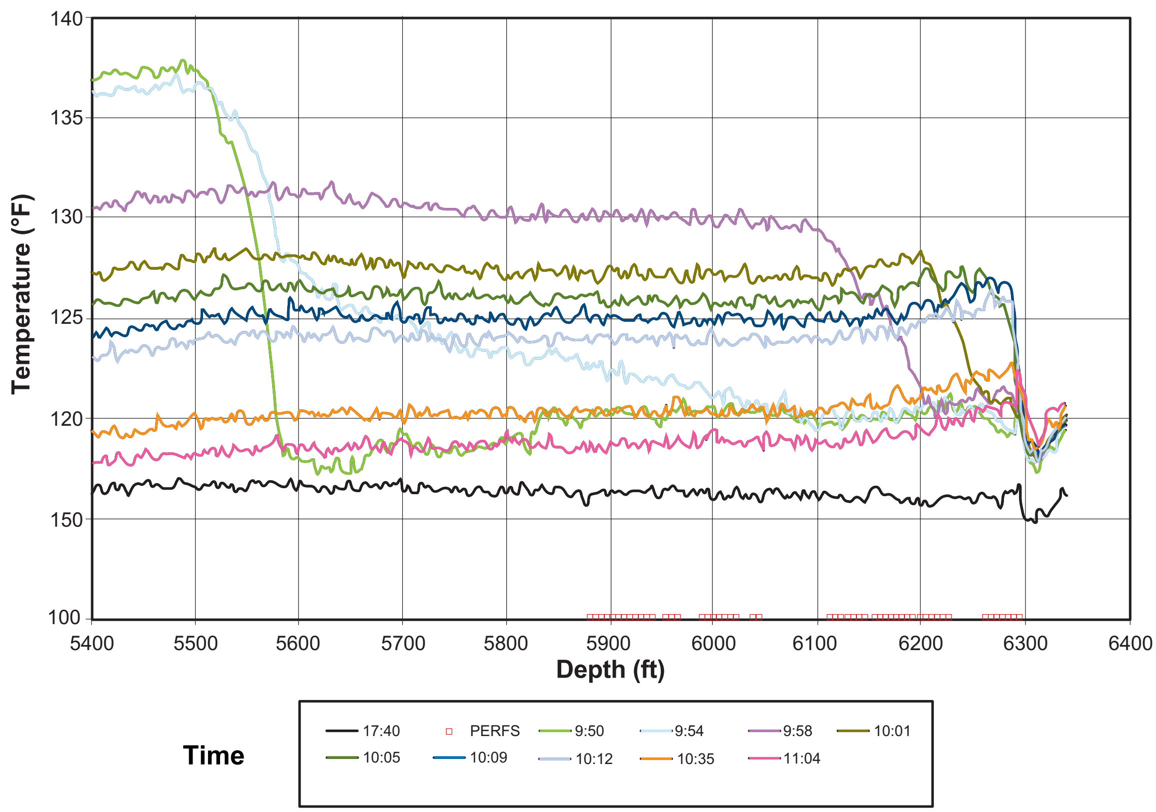

Fig. 9 — Injection Temperature Profiles – Perforated Interval

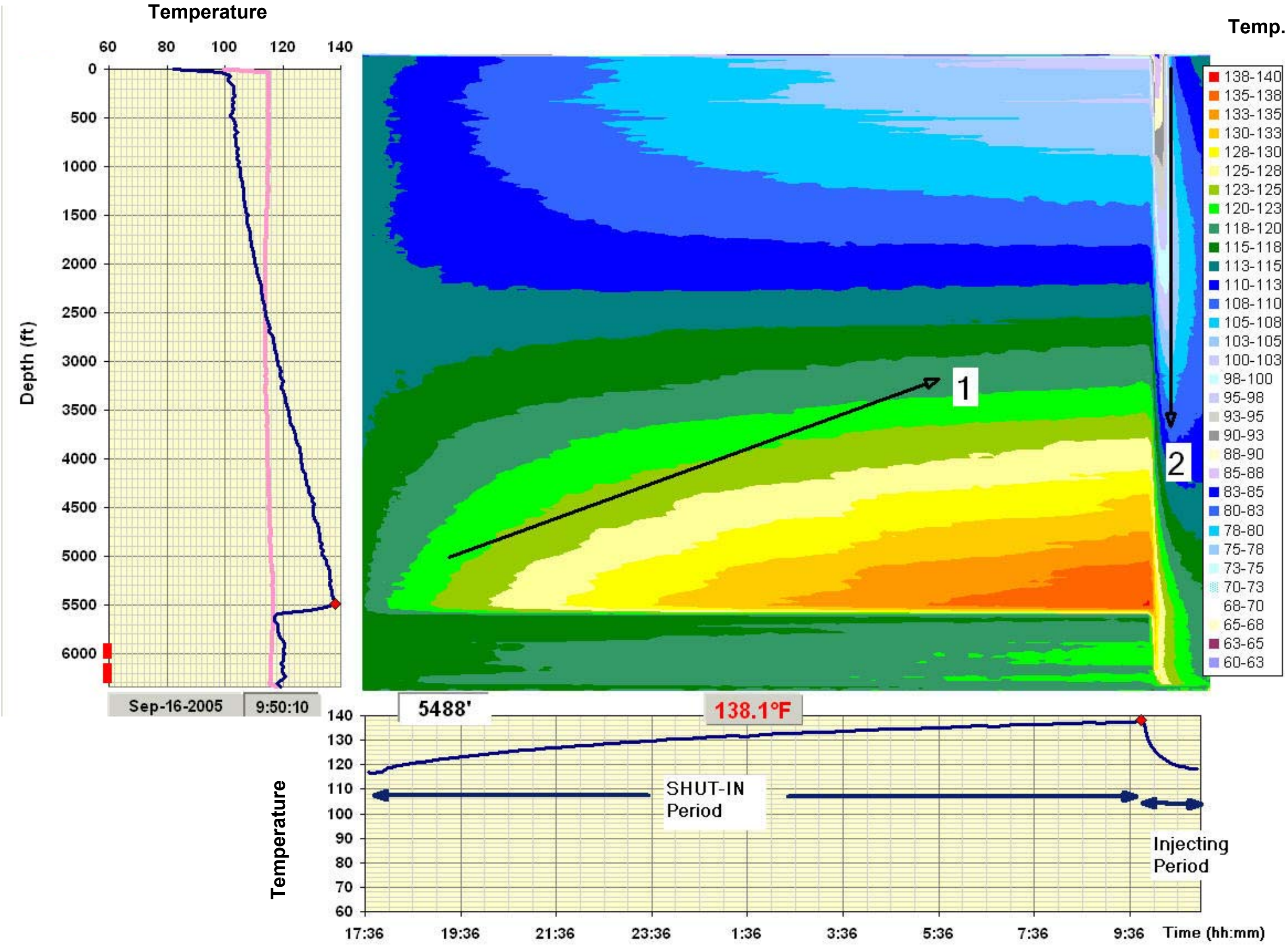

Fig. 9 — Injection Temperature Profiles – Perforated Interval