Fiber-Optic Distributed-Temperature-Sensing Technology Used for Reservoir Monitoring in an Indonesia Steamflood

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Summary

The world's largest steamflood operation is conducted on the island of Sumatra in Indonesia. Fiber-optic distributed-temperature-sensing (DTS) surveys are used in the Sumatra fields to provide valuable data for reservoir management. The DTS profile data can determine the temperature and extent of a "steam chest," a phenomenon that occurs when steam injected into a steam-injection well moves away from the perforations until it encounters an impermeable barrier in the formation. The steam then extends laterally until breakthrough occurs at the producing well. Because oil is produced by gravity drainage, the steam chest (also known as a steam-saturated volume) grows downward. DTS surveys also have the capacity to determine the temperature gradient for either overburden or underburden reservoirs. This information is vital for properly setting steam-injection target rates. The information is also used to mitigate steam breakthroughs and eruptions, as well as to identify bypass oil.

Steamflood operations experience many types of problems, including inefficient injection rates, wasted heat to the casing, sanding in producers, liner failures, and pump failures. There is also an ongoing need to improve the efficiencies of vapor collection systems, well-test stations, and central gathering stations. Based on these challenging problems, periodic wellbore temperature surveys are required to improve heat management and, ultimately, profitability. Conventional temperature logs cannot be run in these wells without first pulling the pumps from the completion. Therefore, a fiber-optic DTS system attached to the production tubing was suggested.

This paper will present case histories of successful applications of fiber-optic DTS surveys that improved steamflood management in this steamflood field in Indonesia.

The benefits from fiber-optic DTS monitoring were

- Significant improvement in the understanding of steam breakthrough zones along the pay-zone interval of production wells
- Improved understanding of the steam path in steam-injector wells
- Improvement of the real-time temperature profile in observation wells to identify steam-zone development and unswept or bypassed oil zones in the steamflood patterns

Introduction

The steamflood field is a multibillion-barrel, heavy-oil-producing field that lies on the central Sumatra basin in Indonesia (**Fig. 1**). The field consists of approximately 4,114 producers, 1,610 steam injectors, and 450 temperature-observation wells. Thermal enhanced oil-recovery (EOR) methods are implemented to reduce oil viscosity and improve oil recovery from this heavy-oil-bearing formation. Active steamflooding began in 1985.

Typically, one steam injector well is surrounded by a pattern of producing wells. Each well pattern in the field will generally include a temperature-observation well to monitor formation temperature response to the steamflood.

This steamflood field includes three primary oil-producing sands. The two deeper sands have a combined pay thickness of approximately 140 ft and range from 400 to 700 ft in true vertical depth (TVD). These sands are the principal oil-bearing sands and account for approximately two-thirds of the original oil in place (OIP). These two sand layers are the primary steam injection targets. The producing sands are unconsolidated, with formation liquid permeability ranging from 100 to 4,000 md. Formation porosity ranges from 15 to 45%. The crude oil is heavy, with API gravity ranging from 18 to 22°API at 60°F.

Because of the highly unconsolidated formations in the steamflood field, completing the wells with sand-control equipment is standard practice. The conventional completion methods that have been used to control sand production are cased-hole gravel packs (CHGP), openhole gravel packs (OHGP), and cased-hole frac packs (CHFP) (see **Fig. 2**). In each completion, a 6⅝- or 4-in. screen liner, depending on the casing size, is installed before performance of the gravel-pack or frac-pack treatment.

With all enhanced recovery techniques, early breakthrough of the injected fluid at a producing well is a major issue because it can significantly impact the production of each individual well. Because of the subsequent consequences to field economics, steam management is critical to the economical operation of all steamfloods. Particularly as the areas mature and begin their rampdown, careful attention is required to identify steam breakthrough so that it can be prevented or mitigated. Immediate attention to assessment and control of this phenomenon can drastically improve the life of a well (Johnson and Sugianto 2002; Sigit et al. 1999).

The process for determining heat requirements for a pattern is complicated, especially with low-density observation wells. Setting injection rates too low will lead to slow steam-chest growth, possible collapse of the steam chest, loss of reserves, and overall lower production. On the other hand, setting injection rates too high will lead to wasted heat in the casing, higher fuel costs, sanding problems in producers, liner failures, pump failures, and overall lower field reliability in the casing-vapor collection systems, well-test stations, and central gathering stations. In some cases, higher rates may contribute to surface steam eruptions.

Because of these challenging problems, periodic temperature surveys must be conducted throughout the field. Therefore, continuous monitoring of temperature profiles in thermal fields is required as part of reservoir surveillance for the purpose of managing heat in the ground. The most commonly used conventional method of performing a temperature profile is to run a wireline log through the tubing or casing, which is run to the depth of interest in observation wells. However, running a wireline temperature tool in these steamflood producing wells without pulling the tubing pump is not possible. Therefore, another method of monitoring temperature was needed.

Fiber-optic technology appeared to offer a surveillance tool that could be used to improve heat management and ultimately im-

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This paper (SPE 97912) was first presented at the 2005 SPE International Thermal Operations and Heavy Oil Symposium, Calgary, 1–3 November, and revised for publication. Original manuscript received for review 1 September 2005. Revised manuscript received 18 December 2006. Paper peer approved 23 February 2007.

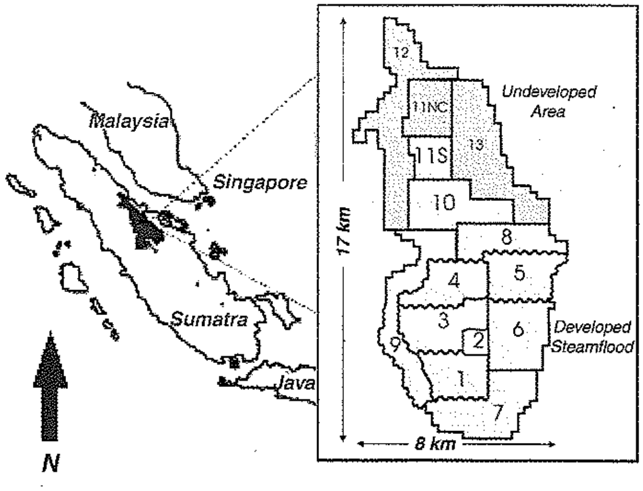

Fig. 1—Steamflood location map.

prove profitability by identifying the sands that were actually producing steam. Since pulling the tubing pump would not be necessary, this technology was chosen to address the difficulties encountered with the traditional techniques.

How Fiber-Optic Technology Works

DTS is a technique for measuring temperature distribution along a fiber-optic line. The optical fiber is composed of concentric layers of materials the *core* and the *cladding*. The core is the light-carrying element. The surrounding cladding provides the lower refractive index that enables total internal reflection of light through the core. The backscattered light from the fiber-optic line contains information about the temperature at the point where it originates. The instrument box (DTS box), which pulses the light onto the fiber-optic line at certain predetermined time sequences, also receives the backscattered light spectrum. Hence, the depth at which the information is retrieved also can be determined.

The diagram in **Fig. 3** shows three different sensing configurations that are available: the single-point sensor, the distributed sensor, and the multipoint sensor. For purposes of obtaining as much information as possible, the distributed sensor offers the greatest value in a steamflood operation. For the well and reservoir conditions in this steamflood, a distributed sensor with an effective resolution of 1 m was used.

Application

There are three primary ways that fiber-optic cable can be used in a well survey. The most common method, which uses a retrievable fiber rod or stem that is deployed from the surface into preinstalled capillary tubing, is the one used in this Indonesia steamflood. The

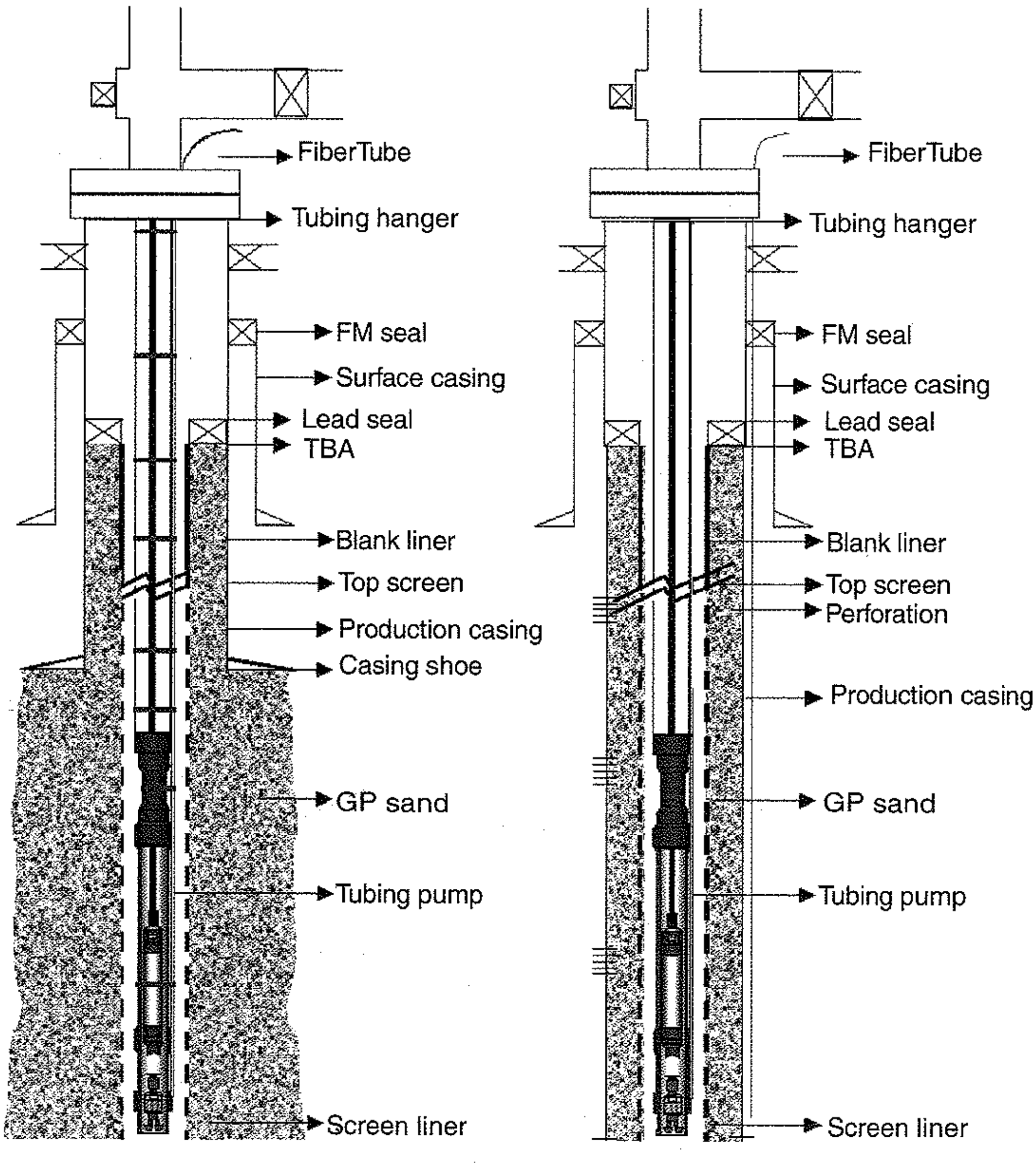

Fig. 2—OHGP (left) and CHGP (right).

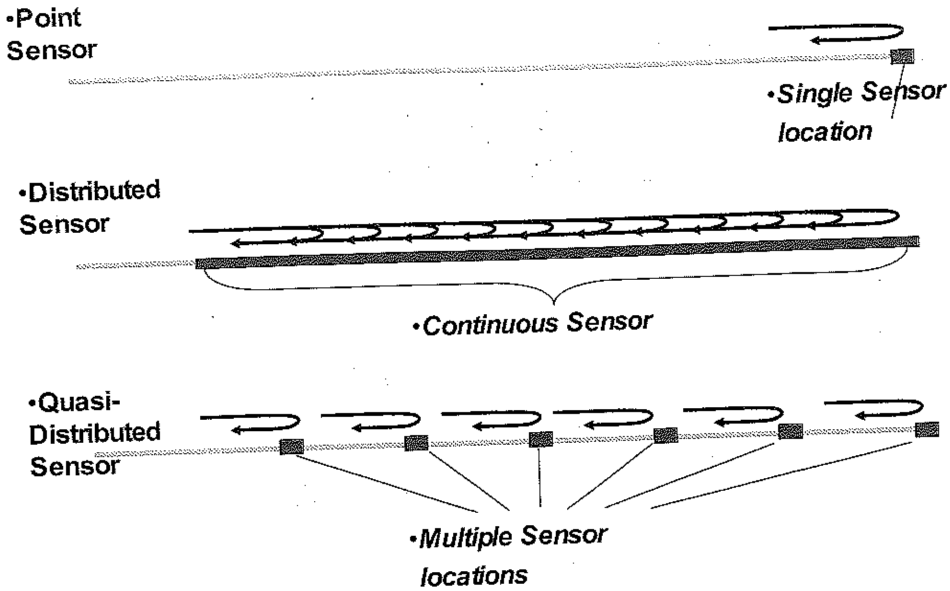

Fig. 3—Fiber-optic sensing configurations.

capillary tubing is clamped along the production tubing; then it is clamped onto the tubing pump and plugged off at the bottom. The wellhead is modified to allow the passage of the capillary tubing. On the surface, a high-pressure release valve is installed, and the well is put on production. The release valve is closed and acts as a safety device in the event that steam breakthrough occurs through the capillary tubing. When production has been stable for a few days, the fiber (in the form of a flexible rod or stem) is inserted into the capillary tubing by means of a specially designed box, and the DTS box is connected to the fiber. Data are recorded continuously from the start of the baseline, during the cooling-down period (when cold water is pumped through the tubing and casing annulus), and throughout the production period. Because the wells are high-temperature wells, reaching temperatures close to 350°F, this method was developed to facilitate retrieval of the fiber-optic sensing device (fiber stem) upon completion of the survey, so that it can be used again for another survey. This approach ensures that the fiber-optic material will not be exposed to a high-temperature environment for long periods of time, which will increase the life of the fiber-optic material. The fiber stem can afterward be used for a survey at another well, thus achieving significant reductions in testing cost and time. Using this procedure, temperature data can be acquired at a relatively low cost. The surface configuration is illustrated in **Figs. 4a and 4b,** showing the modified wellhead to accommodate the fiber tube.

The second most common fiber-optic method uses a 0.156-in.-OD steel tube with preinstalled multimode fiber material. The physical configuration of the fiber is a 50-μ core surrounded by a 125-μ cladding or jacket. The preinstalled fiber tube is used to perform a retrievable survey in production wells with open-ended tubing and pressure equipment. The fiber tube is spooled back onto a cable drum as is done with wireline tubing and is moved from one location to another as required. The retrievable fiber tube is also used for surveys in observation wells. When this method is used, the well pressure must be bled to 0 psi. The fiber tube is run to pick up and note depth on the log. When at final depth, the DTS is connected, and temperature profiling is begun. Temperatures derived by the DTS unit are compared with known temperatures inside the DTS van, in the outside air (ambient), and at the wellhead. A calibrated thermocouple temperature-recording unit is used to generate the comparisons. After data have been saved to disk, the fiber tube is removed from the well, and the wellhead is returned to its initial condition.

The third method is the fiber-pumping method. In this method, the bare capillary tubing is run to the TD and locked in place, and the fiber-optic material is pumped into the capillary tubing. The check valve installed below the capillary tubing allows pumping of the fiber once the capillary tubing is placed as a semipermanent or permanent (cemented in place with casing) system, either single-ended or double-ended. In this type of installation, the fiber is left in place after it is pumped. This method is used for wells where the other two methods cannot be applied.

Other options are also possible but not frequently used. A permanent, preinstalled ¼-in. multimode, metal-encapsulated line can be clamped to the tubing OD to provide ongoing DTS surveys as needed. This option is not often considered because pump failures happen quite frequently, and tubing must be retrieved if a failure occurs.

Candidate Well Selection

Candidate wells are selected based on the purpose of heat management. The factors considered include:

- The well has been categorized as a steam breakthrough well in which the oil production has dropped. Indications of steam breakthrough in these wells include the following: wellhead temperature >250°F, casing pressure >50 psi, and casing blow rate >150 bbl cold-water equivalent per day.
- Difficulties or low confidence levels in the determination of steam-zone intervals using the existing available surveillance data.
- Completions with multiple methods to control sand production. The focus of the survey here would be to determine the feasibility of flow- and loss-circulation phenomena.
- Surface steam eruptions have occurred, and it is suspected that nearby wells are contributing to these eruptions. In addition, there is evidence of shallow hot zones in producers that could lead to steam eruptions on the surface.
- Anomalous steam-chest readings have appeared on surface seismic surveys in some areas, or interval steam injection is not being carried out.
- High-frequency failure with pump stuck because of overheating has occurred more than three times per year. Fiber-optic (DTS) data should be acquired in these wells to facilitate the execution of steam isolation jobs.
- Periodic or routine temperature surveys in observation wells are required to determine steam-chest growth from injector to producer. The surveys are also supported by sigma and carbon-oxygen logs.

Following are actual examples of surveys carried out in the field that show the application and use of fiber-optic DTS for monitoring the reservoir and for steam management.

Example 1: Observation Well Surveys (Fig. 5). Every set of producers and injectors has dedicated observation wells. Periodic

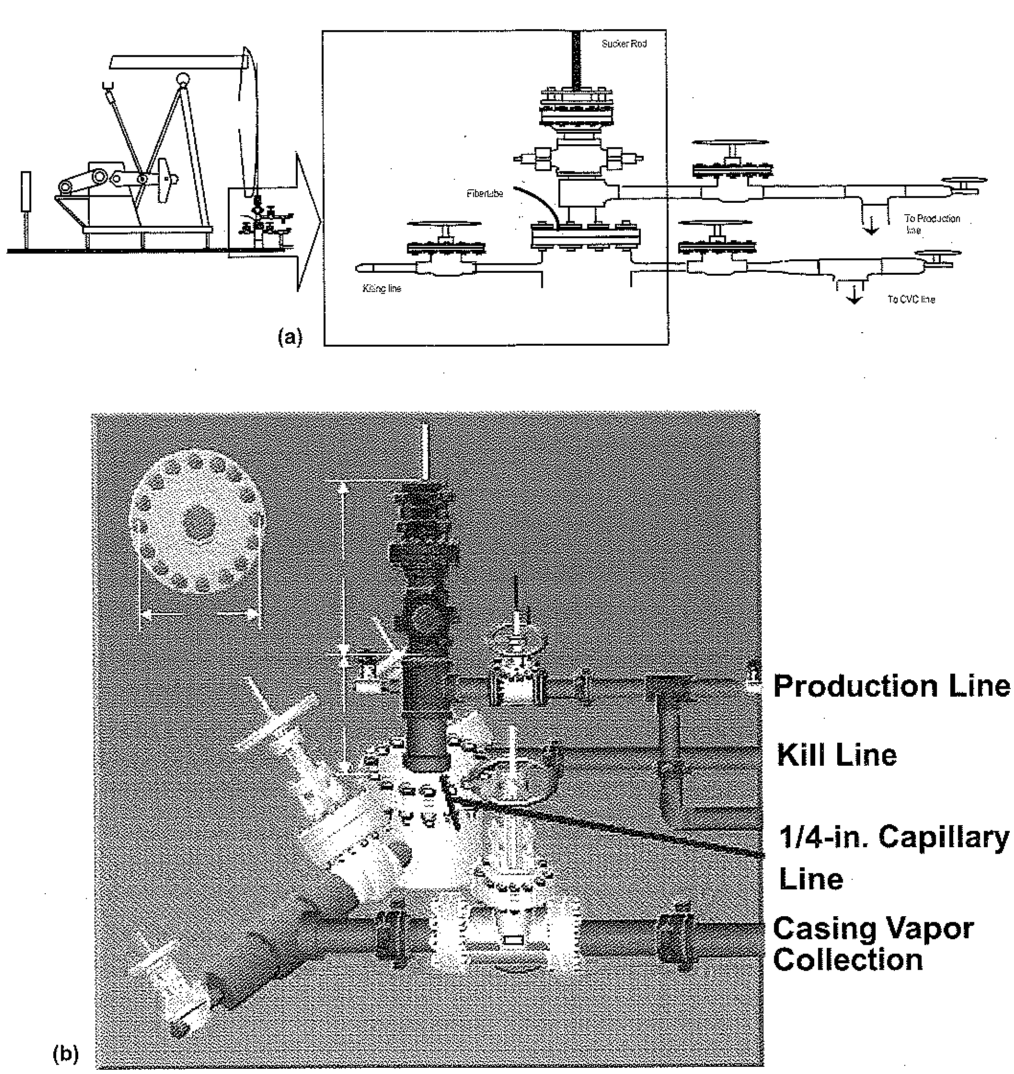

Fig. 4—(a) Surface configuration; (b) wellhead configuration showing production line, kill line, ¼-in. capillary line, and casing-vapor collection (CVC) line.

surveillance is conducted in these observation wells to determine steam-chest movement as well as gas and fluid saturations. The fiber-optic DTS surveys are part of a surveillance program used to estimate formation heating rate, steam-zone pressure (estimated from temperature using steam tables), type of recovery mechanism, and other parameters. This information is further used in reservoir modeling. In addition, the data can be used to optimize oil recovery by producer-injector interval completions.

The observation wells are normally wells completed with cemented pipes of 3½-in. or 2⅞-in. outer diameter and are fluid-filled.

The fiber-optic DTS survey shown in Example 1 is from an observation well. The DTS data in this example represent the temperature surveys carried out at different periods of the steam cycle (i.e., each survey represents the temperature profile for a specific time domain). The data shown here are the cycles from preflood to tailout. The interval from 480 to 550 ft, where steamflood operations were initiated in April 1998, can be seen in Fig. 5. As the steam chest moved from injector to producer, the temperature survey done in the observation well indicates the steam breakthrough at deeper intervals from early stage to mature stage to tailout in 2003.

It is important that the observation wells have good wellbore integrity and are well cemented. Although the observation wells are surveyed twice a year, some wells require surveying on a monthly basis in order to identify actual steam-zone coverage on a timely basis. Similarly, less surveying is required in mature steamflood areas where there is little change of heat content over time.

Two important factors must be considered when interpreting temperature logs from observation wells. First, convection in the wellbore due to high temperature may mask the temperature profile, causing the temperature reading not to appear flat over the interval. Second, if there is contact between air and liquid in the borehole, the temperature profile might become flat because of the flushing of steam into the borehole at the contact point. The wellbore should be full before running the surveys.

Example 2: Steam Breakthrough in a Producer. To determine steam breakthrough in a producer, relatively cooler water is injected, and the well is monitored during the subsequent shut-in. Localized increases in wellbore temperature are associated with immediate production of hot fluid from the producing reservoirs after stopping a water-injection operation. Generally, the heat spreads both up and down the wellbore from the entry location. The upward movement of the heat is usually faster than the downward movement. Also, the thermal front of the injected fluid typically will change upon reaching the horizon of the steam breakthrough.

Once the fiber-optic DTS reaches TD, the initial measurement (black line) measures the static wellbore temperature. This baseline temperature ideally would be the geothermal gradient. However, the true geothermal gradient may not be measurable because the measurement would simply take too long. Hence, the baseline temperature is referred to as the constant wellbore temperature for purposes of this evaluation.

In Example 2 **(Fig. 6),** water is injected from 20:45 until 21:18. During the injection period, the thermal front was observed to change at 460 ft and also at 500 ft. It is not unusual to have more than one steam breakthrough horizon in a well.

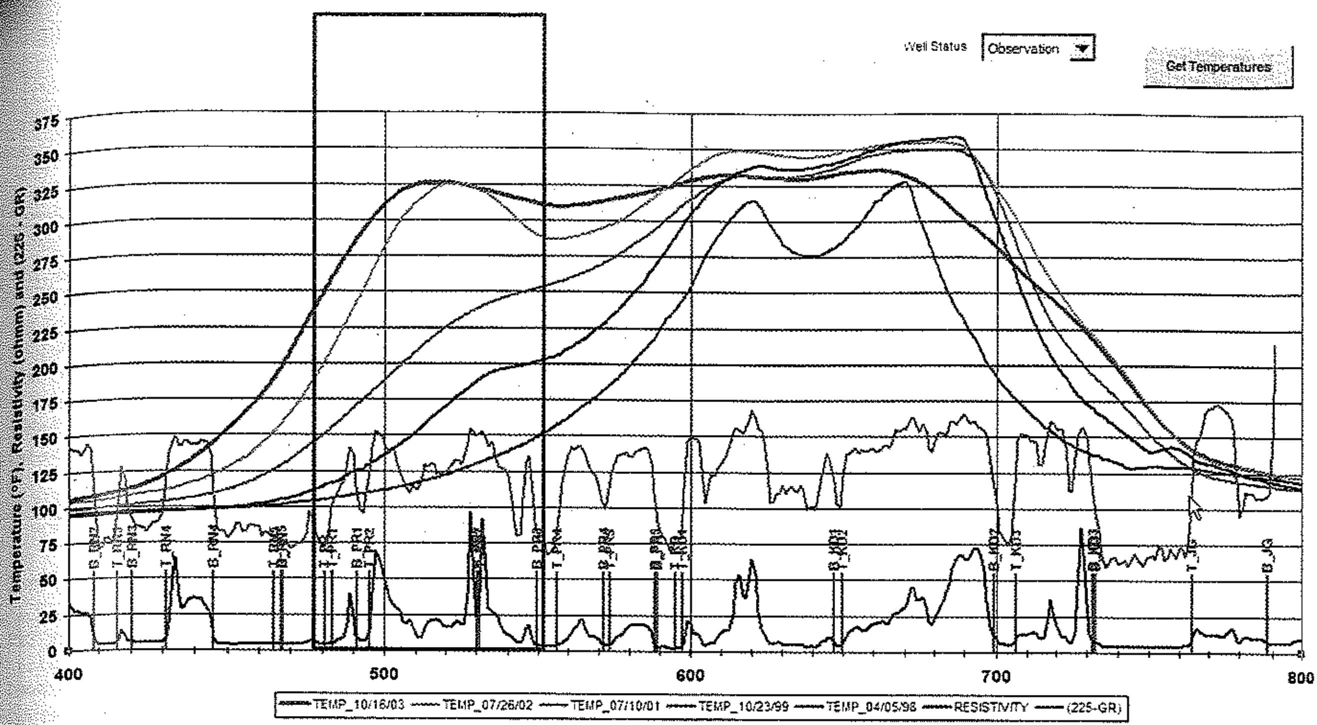

Fig. 5—Example 1: observation well survey.

Example 3: Steam Breakthrough in a Producer. This example involves the same well as in Example 2. In this example **(Fig. 7),** the post-injection response was monitored from 21:22 to 23:22. The well was then put on production at 23:24. Examination of the post-injection DTS survey data was performed to provide further confirmation of the steam breakthrough horizons, as well as to locate the fluid level in the annulus.

The highlighted pink segment of the Example 3 (Fig 7) illustrates the procedure for locating the fluid level in the annulus of this producer. The change in slope identified here is analogous to a change in slope that might be identified from a static fluid gradient. Similarly, changes are identified from the measured DTS response that corresponds to the fluid level.

Log quality is essential in interpreting steam breakthrough intervals. At times, not enough water is pumped to cool the wellbore. Normally, 40 bbl pumped at 2 to 3 bbl/min is sufficient. This may not be true for all cases because of losses that may take place at shallow zones. Similarly, sufficient time should be allowed in cold wellbores for the steam chest to appear. Therefore, data should be collected for at least two to three hours to enable the changes to be observed.

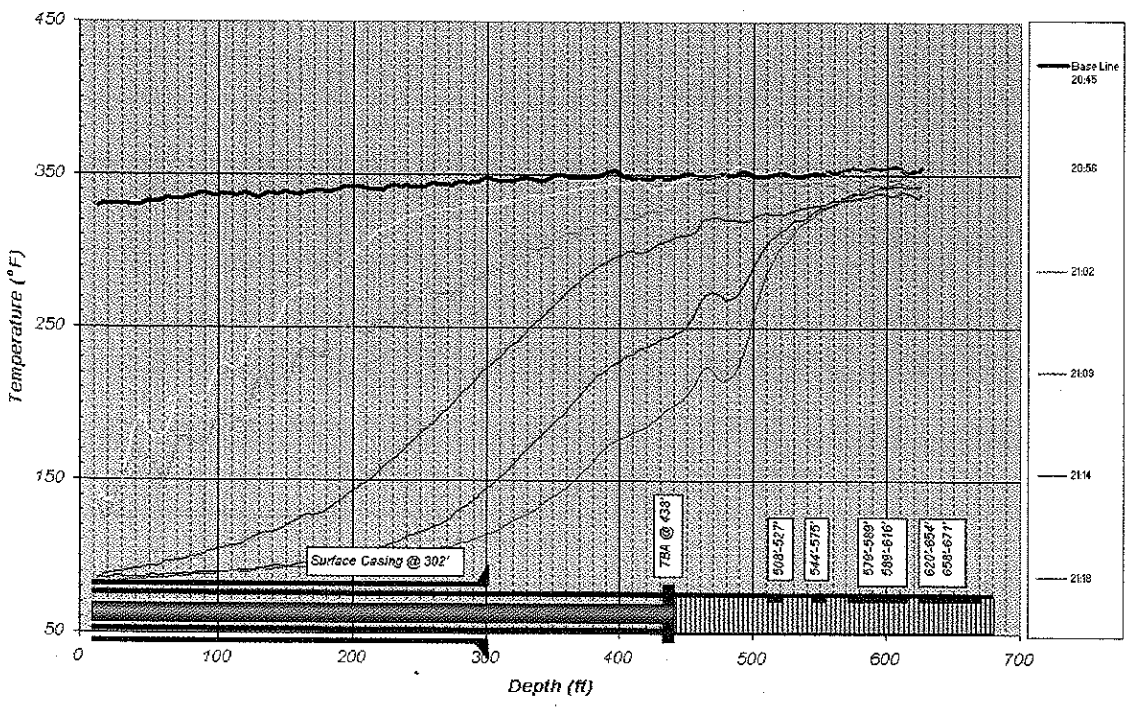

Fig. 6—Example 2: baseline and pumping-water survey to determine steam breakthrough in a producer.

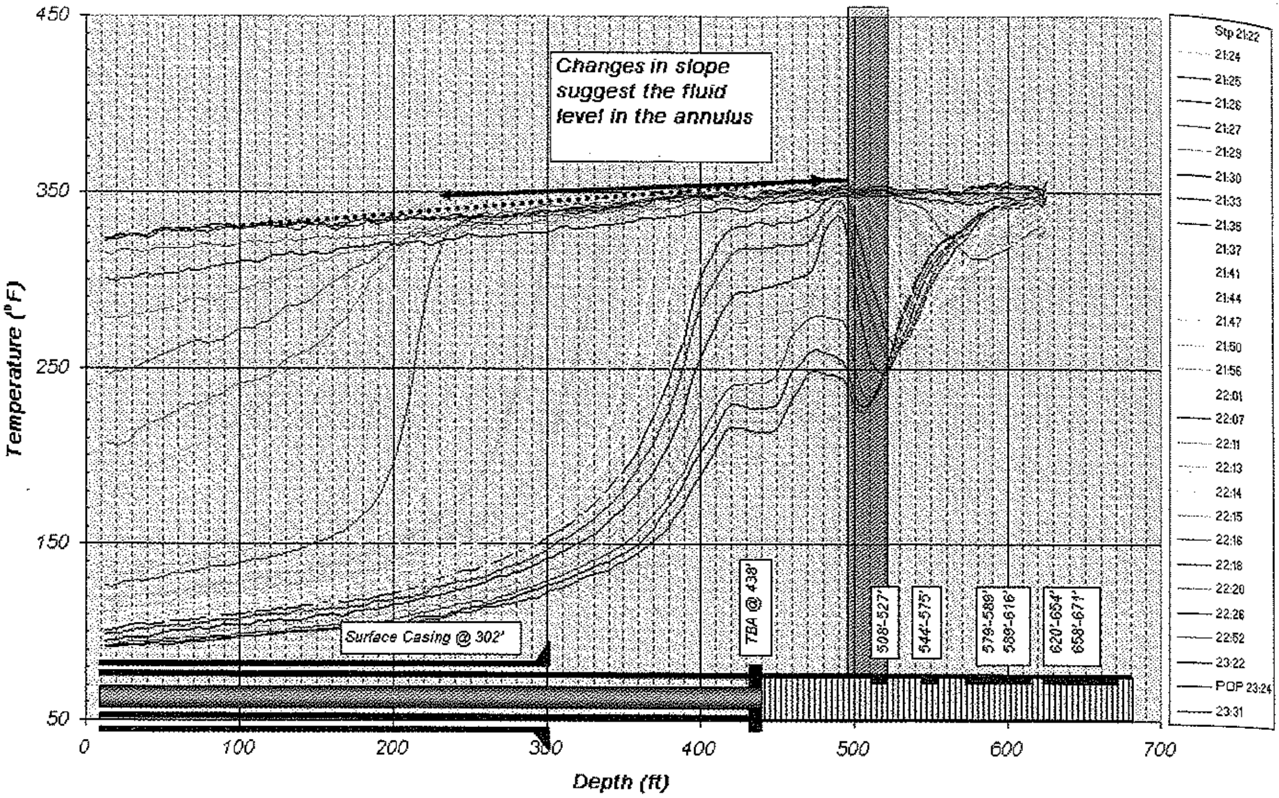

Fig. 7—Example 3: stop pumping water and perform production survey.

Example 4: Potential Shallow Hazards. Shallow heat hazards **(Fig. 8)** are a serious concern for this Indonesia steamflood because they are capable of becoming a ground eruption of steam. Potential shallow hazards are identified as a source of heat that is abnormal in the context of a conventional understanding of a geothermal temperature gradient and is not associated with the known horizons of the steamflood producers or injectors in their respective patterns. Possible causes of these hot-spot anomalies are the following:

- Backflow of heat from the casing vapor collection system into the wellbore annulus during the DTS steam breakthrough survey. This implies that valves, check valves, or both are leaking.
- Shallow sands that have been heated by the injection of steam or hot fluids from other wells.

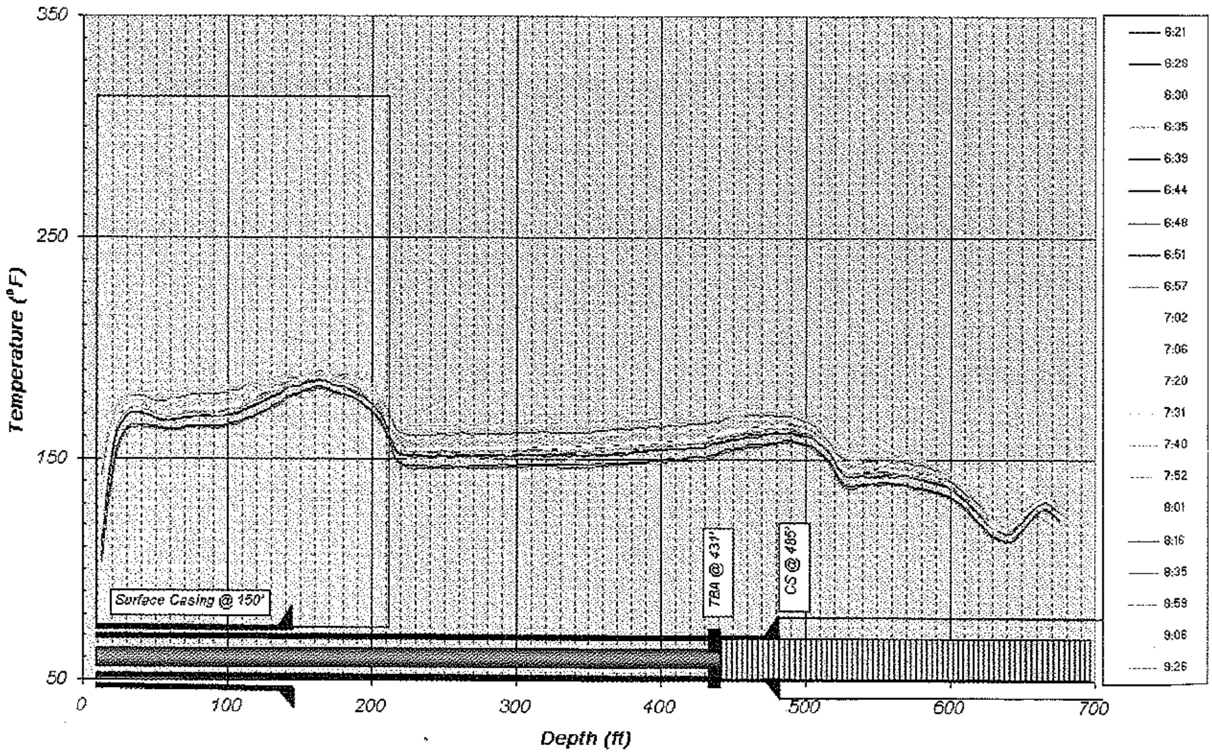

Fig. 8—Example 4: shallow hot-zone analysis to identify potential shallow hazards.

• Casing leaks or behind-casing channeling of steam or hot fluids to shallow sands or to the surface within the surveyed well.

• Faulting across targeted sand intervals, allowing steam migration to other sands.

Example 5: Cold Production Zones. The abnormal heat levels observed in Example 5 (**Fig. 9**) begin at 210 ft. They can be clearly seen in the figure as a temperature increase for all the DTS profiles at this depth. In addition, there is no known steamflood activity at this depth.

Variations in temperature response indicate that fluid is entering the wellbore at a temperature below the wellbore's ambient temperature at the given depth. In Example 5, this is observed at 360 to 380 ft. Other indicators are as follows:

• After water injection has stopped and steam or heat breakthrough occurs, the wellbore will heat back up to its temperature in the original baseline temperature survey.

• During this heating process, with the well put back on production, the potential of locating cold production zones will exist.

• Cold-zone production can be identified if the areas surrounding this cold-zone production heat up more quickly than the zone itself.

• The anomalies interpreted to be cold-production zones will therefore be cooler than surrounding portions of the wellbore.

Therefore, the wellbore zones that are not found to be steam-breakthrough zones (based on the change in slope of temperature during water pumping) are considered cold-zone producers and will generally exhibit cooler temperatures than the balance of the well as it heats back up.

Example 6: Injector-Well Survey. Injector wells are surveyed to detect leaks that may lead to shallow hot breakthroughs. The wells are surveyed by cooling the wellbore and then observing heat flowback intervals. Example 6 (**Fig. 10**) illustrates a situation in which there is a leak in the casing above the perforation. The leak is easily detected by observing a heat anomaly that is not associated with the well entry depths. The approximate depth of the casing leak is highlighted in the pink zone.

Conclusions

1. Fiber-optic technology with a DTS system and single-ended installation is applicable for determining real-time temperature profiles in Indonesian steamflood production wells. Use of this technology has provided a significant improvement in understanding of steam breakthrough zones along the pay-zone interval of production wells (Nath 2005).
2. Fiber-optic technology with the DTS system using a fiber tube is also applicable to processes run to determine the temperature profile in observation wells. These surveys can identify steam-zone development and unswept zones in the pattern.
3. Survey results from this work showed identifiable temperature anomalies even with very small temperature changes. This shows that temperature profiles from DTS surveillance data can provide valuable information for performing steam breakthrough management on a layer-by-layer basis as well as eruption mitigation. In this way, well integrity can be maintained if remedial measures are taken in time.

Acknowledgments

The authors wish to thank the management of PT Chevron Pacific Indonesia and Halliburton Energy Services for their permission and encouragement to write and present this paper.

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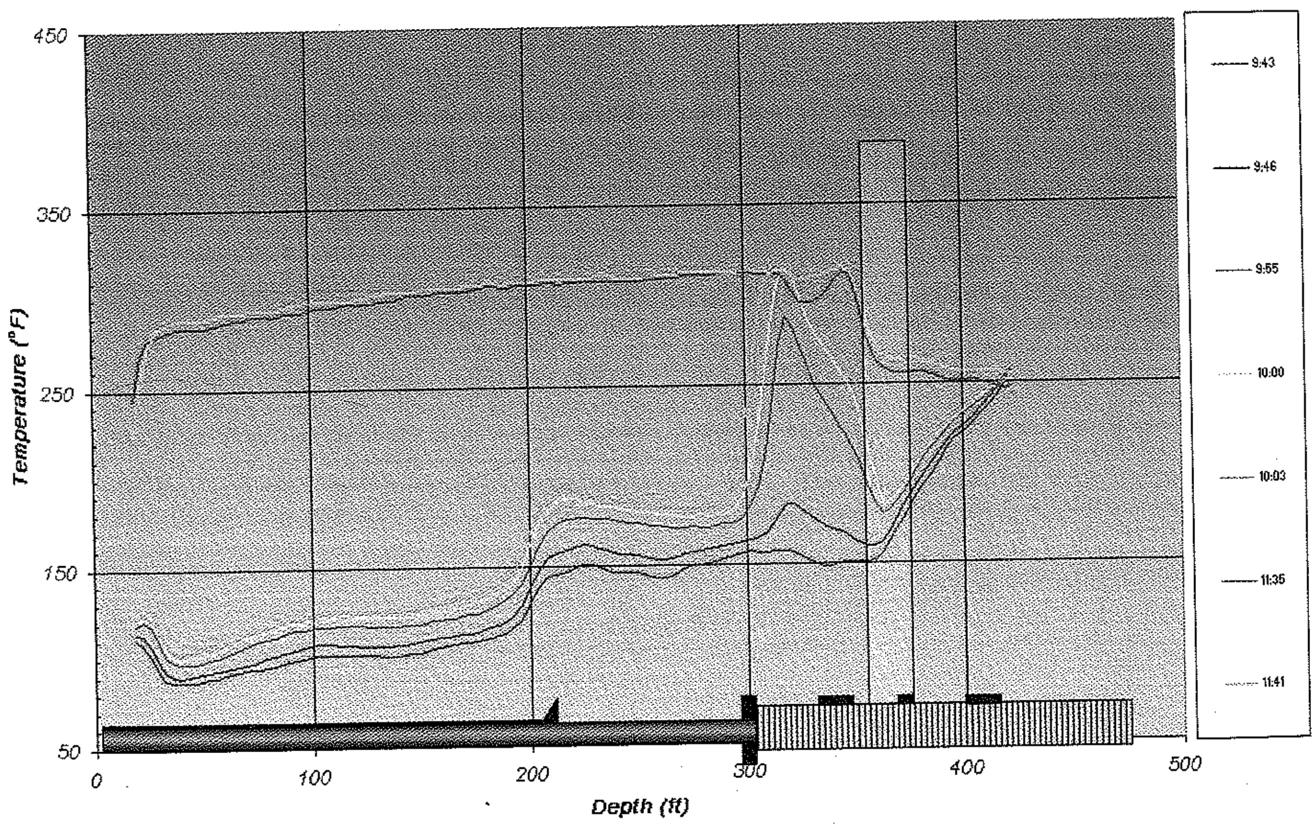

Fig. 9—Example 5: identification of cold-production intervals.

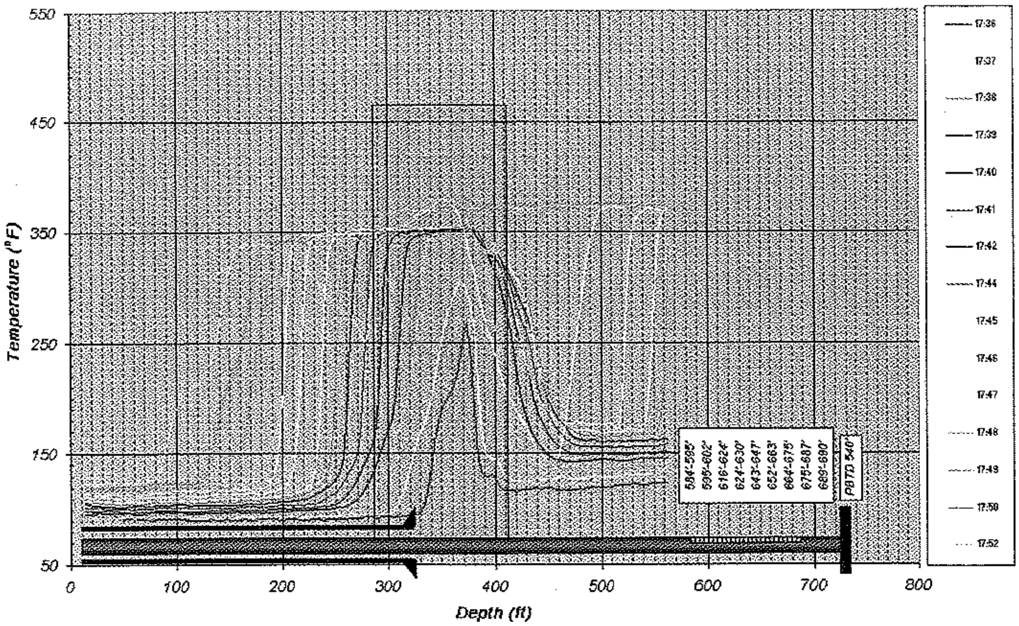

Fig. 10—Example 6: steam-injector well survey to identify leaks.

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SI Metric Conversion Factors

°API	141.5/(131.5+°API)		= g/cm^3
bbl ×	1.589 873	E–01	= m^3
bbl/min ×	2.649 788	E–02	= m^3/h
ft ×	3.048*	E–01	= m
°F	(°F–32)/1.8		= °C
in. ×	2.54*	E+00	= cm
psi ×	6.894 757	E+00	= kPa

*Conversion factor is exact.

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