Permanent distributed temperature monitoring of oil reservoirs using optical fiber for high temperature applications

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Abstract

The object of this communication is to present technical aspects and field results concerning permanent downhole distributed temperature monitoring employing optical fiber in steamflood reservoir environment.

With the purpose of technology evaluation, a nine spot pilot has been developed and field results have been obtained during three years. Contributions of permanent distributed monitoring to steam injection are highlighted and other possible applications to reservoir management are presented.

Introduction

In oil industry, downhole pressure and temperature distributed sensors can provide strategic information for reservoir monitoring and production optimization.

While permanent distributed pressure sensing techniques are not yet a reality, distributed temperature sensing (DTS) using optical fiber is nowadays employed worldwide in several types of environments. Among the main downhole applications one can mention: steam injection fields monitoring, well stimulation monitoring, gas lift diagnostic and production diagnostic. In Petrobras, this type of monitoring technique aims to the management of brown fields contemplated with steam injection, and to production optimization in subsea horizontal wells.

In steam injection assisted fields, the purposes of DTS application is to anticipate steam breakthrough, to establish a better understanding of the heat flow paths, and to contribute to a more efficient and controlled injection. For this high temperature environment, optical fiber distributed sensing is the most adequate technique.

Castanhal Project

In May 2006 an optical fiber DTS system has been installed in Castanhal field, located at the Sergipe-Alagoas basin, 50 km far from the northeast coast of Brazil. In June 2006, steam injection has been initiated and the temperature has been monitored by the DTS system since then. The purpose of this work is to analyze some of the results obtained with this method during the three years under continuous steam injection.

Castanhal is an onshore, heavy-oil steam assisted field. Figure 1 presents typical gamma ray and density logs. Four sandstone reservoirs can be identified: CPS-1, CPS-2, CPS-3, and CPS-4. The most important net pay is within CPS-2, which is the sole zone supposed to be reached by steam. The reservoir static temperature is 42℃.

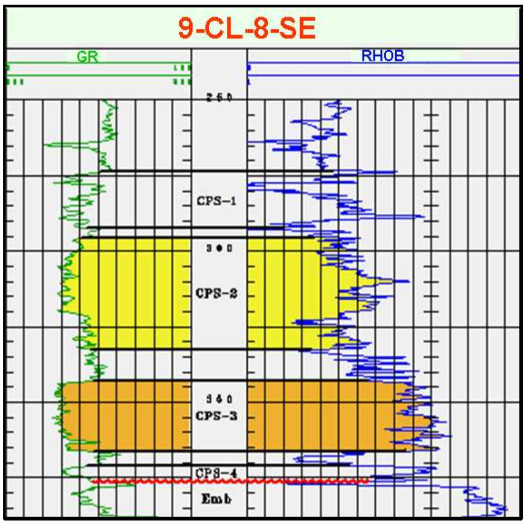

Figure 1: Typical gamma ray and density logs from Castanhal producing zones.

For this injection project, a nine spot has been selected, with a pattern as shown in Figure 2. Continuous injection is performed through SZ-165 well, at a pressure of 1000 psia and a temperature of 287℃. Production is accomplished by SZ-196, SZ-198, SZ-199, SZ-200, SZ-202, SZ-203, SZ-204, and SZ-206 wells.

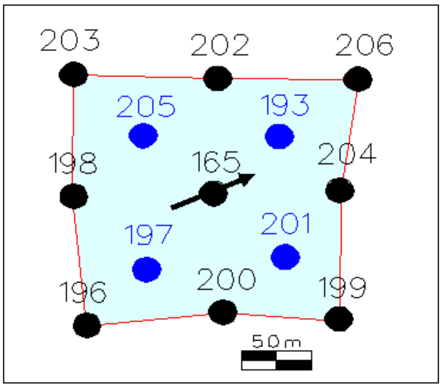

Figure 2: Steam injection nine spot project for Castanhal DTS pilot. SZ-165 is the steam injector. SZ-193, SZ-197, SZ-201, and SZ-205 are the observers, instrumented with DTS optical fibers. Remaining wells are producers.

For monitoring of the steam flow, four observation wells (SZ-193, SZ-197, SZ-201, and SZ-205) have been instrumented with DTS optical fibers. In SZ-197, SZ-201, and SZ-205, CPS-2 has been cemented and the sensing fibers deployed along the entire wellbore up to 10 m below CPS-2 basis. In SZ-193, CPS-2 has not been cemented, but completed with gravel pack; the fiber has only been deployed up to 50 m above CPS-2 perforations (Silva Jr. (2007) describes technical issues concerning fiber deployment).

DTS Method

The optical fiber DTS technique uses nonlinear optical effects occurring within the fiber core upon excitation by a high-power short optical pulse to correlate the intensity of backscattered signal to the temperature of the fiber environment (see, e.g. Grattan and Meggit (2000)).

Raman or Brillouin effects are the nonlinear processes that may be employed for distributed temperature sensing along an optical fiber, although Brillouin-based DTS is also affected by fiber strain – reason for which the technique is more commonly known as DTSS (distributed temperature and strain sensing). The work developed here employed Raman-based DTS that is only sensitive to temperature variations.

This method provides temperature logs with spatial and temperature resolutions high enough to fulfill reservoir management requirements. With typical commercial DTS systems, 1ºC and 1 m resolutions can be achieved, while some manufacturers claim to be able to provide temperature resolutions as high as 0,005ºC. Tens of kilometers can be sensed with a unique optical fiber. For long distance applications, as in pipeline monitoring, hundreds of kilometers may be surveyed making use of optical fiber amplifiers to elevate the signal intensity. The maximum temperature to which the fiber cable can be submitted to in downhole environments is 275ºC if a mean time between failures of 5 years is expected. Fiber cables can stand higher temperatures during shorter lifetime.

In hydrocarbon environment, special care must be taken, either to protect fiber against hydrogen diffusion or to employ hydrogen insensitive fiber cables, because hydrogen in-diffusion causes irreversible signal attenuation at temperatures higher than 150ºC (see e.g. Tomita (1985)).

Optical fiber cables deployed within oil and gas wells are normally attached to the production or injection tubing. In the present case, although the wells were not injecting or producing, a tubing column was installed to support the optical fiber cable straight along the observer wells (Silva Jr. (2007)).

Results

Optical fiber DTS system has been installed and began to operate in May 2006, one month before steam injection.

Figure 3 presents DTS logs obtained as a function of well depth before injection. In the figure, dashed line represents the top of the first sandstone zone, CPS-1. The main producing zone, CPS-2, stays around 300 m. In these graphs, temperature at the well head is about 30°C (it is important to remark that the data presented here have been collected during the night and that large temperature variations can be observed at the surface under the sun light). Temperature increases as a function of depth, following the local geothermal gradient up to about 250 m, where oil reservoirs are expected to be. The main contribution to the large peaks observed for SZ-197, SZ-201 and SZ-205 comes from the temperature of CPS-2 zone. For SZ-193 log, this peak cannot be seen since the fiber does not reach that zone. Temperatures from 45 to 52°C have been observed at CPS-2 depth, in agreement with expected reservoir temperature in absence of steam injection.

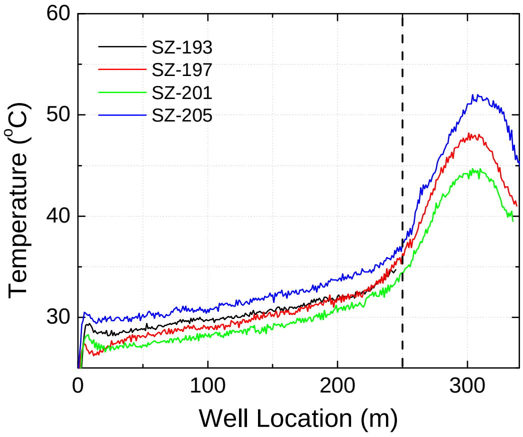

Figure 3: Temperature logs for SZ-193, SZ-197, SZ-201 and SZ-205, obtained with optical fiber DTS system before steam injection. Dashed line represents CPS-1 zone.

Steam injection initiated in June 2006. Two months later, reservoir temperature had already responded to injection, as could be detected in SZ-205 well (see Figure 4).

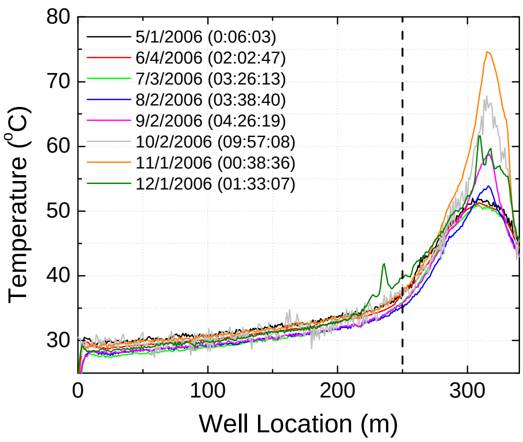

Figure 4: Temperature logs obtained for SZ-205 from May to December 2006. Dashed line represents CPS-1 zone. Legends provide date and time of log acquisitions.

By November 2006, the temperature detected in this observation well reached 75ºC. The large peak profile appears to be narrower than before injection (Figure 1). Narrow peaks emerged in temperature profile, as can be seen in Figure 4 for the curve recorded in December. At that time, the maximum temperature had decreased by 15ºC. During 2007, several features in temperature profile have been detected as shown in Figure 5 for the case of SZ-205. It is remarkable the narrow peak inside CPS-2 zone. In December 2007, the temperature reached a maximum of 88ºC.

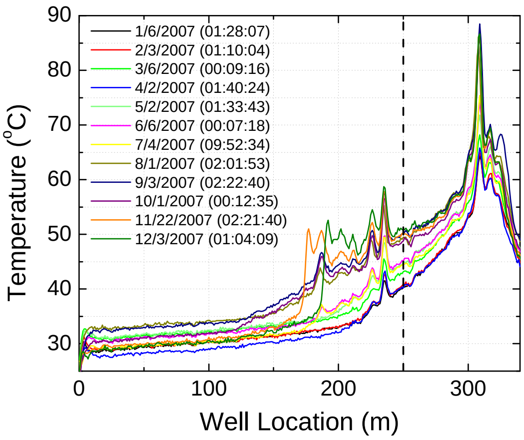

Figure 5: Temperature logs obtained during 2007 for SZ-205. Dashed line represents CPS-1 zone. Legends provide date and time of log acquisitions.

Figure 6 compares the evolution of SZ-205 log profiles from the beginning of steam injection process up to March 2009.

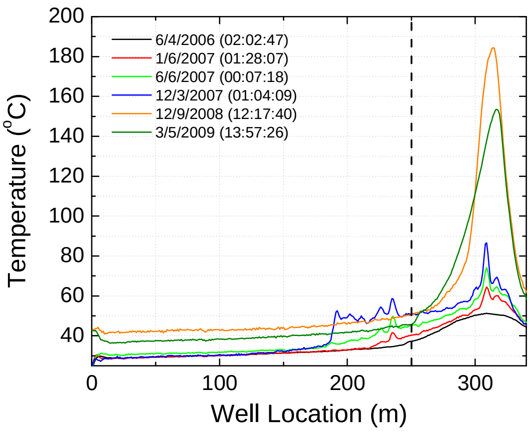

Figure 6: Evolution of SZ-205 temperature profiles from June 2006 to March 2009.

One sees that, besides a strong increase of CPS-2 temperature with time, the current temperature profile does not present the features observed during 2007 but is as smooth as before steam injection (May 1st 2006). It is also remarkable that, at the present date, heat is much more concentrated around the center of CPS-2 zone than in the beginning of steam injection.

Figure 7 schematically represents the temporal evolution of temperature in the observation wells of Castanhal nine spot project. The colored circles indicate the maximum temperature detected in each observation well during 2006, 2007, 2008 and 2009, according to the temperature scale (neither the position nor the shape of the circles should be correlated to spatial distribution of temperature around the wells).

From this representation, it seams to be clear that heat transfer is strongly anisotropic: temperature change is first observed in SZ-205, followed by SZ-201. A small temperature variation is observed in SZ-197, but only two years after steam injection beginning. It can also be observed that SZ-205 temperature reached a maximum during 2008 followed by a decrease, while for SZ-201 the temperature is still rising.

Even if the temperature log acquired in SZ-193 does not provide information from CPS-2, since the sensing fiber has not being deployed up to the bottom of this zone, it has being useful to monitor its profile to check for casing integrity. Casing deterioration has not being observed for any of the observer wells.

Comparing DTS data from the observers with those acquired at the producer well heads, good correlation could be established: it has being observed that SZ-198 and SZ-202 are the first producers to be affected by heat transfer, followed by SZ-204 and SZ-200. Up to the present date, SZ-206 and SZ-196 did not present any change at the well head temperature, which apparently means that they have not yet being affected by steam injection.

Concluding Remarks

The paper presented an application of permanent DTS monitoring on a steamflood oil reservoir using optical fibers.

The continuous monitoring of the wellbore temperature profiles revealed features that would not be observed by any other point monitoring or traditional temperature logging. Actually, flow instability processes, steam breakthrough and casing deterioration may occur during steam injection, which cannot be rapidly detected unless a permanent distributed monitoring system is installed. For the present case, further analysis is still required to define the cause of the observed narrow peaks in temperature profile (Fig. 5) since a real temperature increase in the upper zone could not be ruled out.

The system installed in observer wells has been useful to indicate preferential paths of heat flux within the pilot. In a future work, monitoring could be extended to the producers, and the temperature logs be used to infer flow rates, as proposed, e.g. by Curtis (1973).

To take full advantage of permanent DTS system, it is indispensable to establish a good interface with reservoir management tools. Correlation of DTS profile with permanent in-well seismic (Hornby 2005), microseismic

(Keul 2005) and surface 4D seismic data (Thompson), as well as reservoir and geological information, can give a good indication of the movement of water, gas, or steam injection fronts, improving reservoir understanding.

Processing DTS data is complex. It is imperative to learn how to deal with such high volume of information to optimize the tool utilization. Interpretation softwares are commercially available but have elevated costs that may not be upheld by brown field assets budget.

For production optimization in subsea horizontal wells, the goal of a tool like DTS is to predict water or gas conning and oil production distribution. From the point of view of reservoir management, the value of information of this application must be proved since water may be in thermal equilibrium with oil. From the point of view of well technology, the challenges for subsea implementation are the need for packers with feed-throughs, optical fiber wet-mateable connectors and wet disconnect tool to allow the deployment of the fiber optic behind the sand control system.

Acknowledgments

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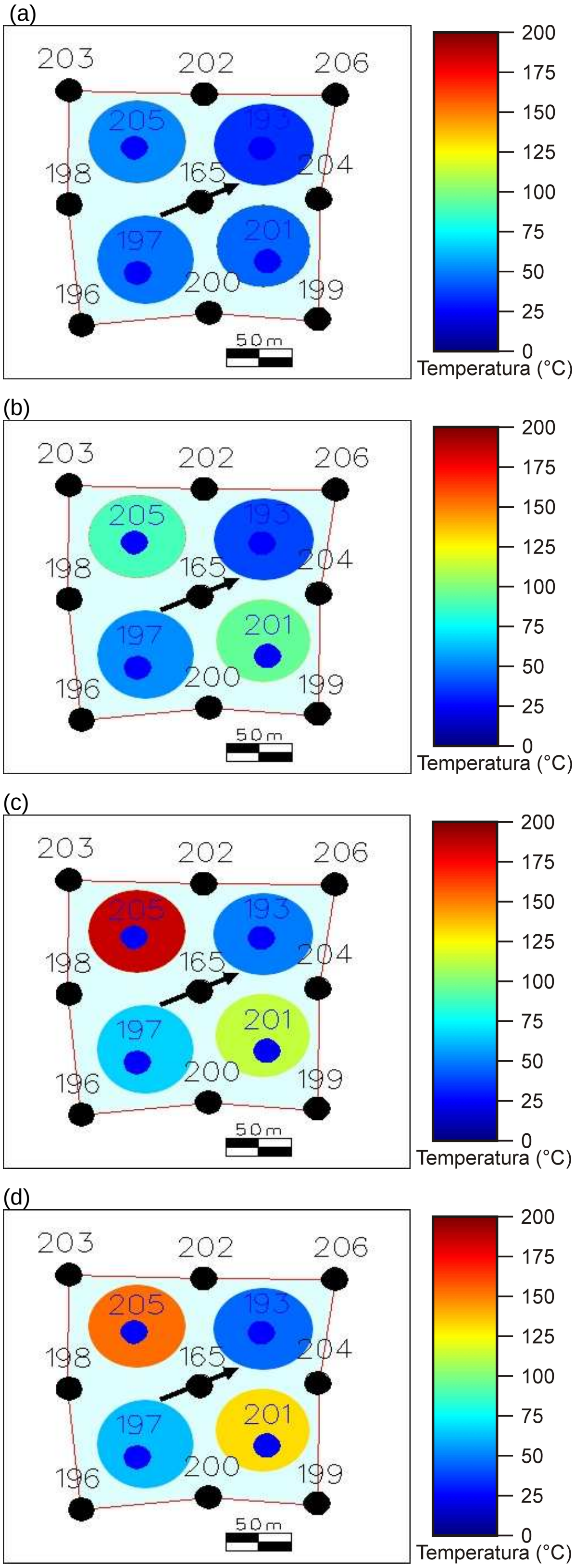

Figure 7: Maximum temperature achieved in wells SZ-193, SZ-197, SZ-201 and SZ-205, during: (a) 2006; (b) 2007; (c) 2008; (d) 2009.