# OPTISIM – Innovative Solution to Obtain Formation Flow Profile From Fiber Optics – DTS and DAS

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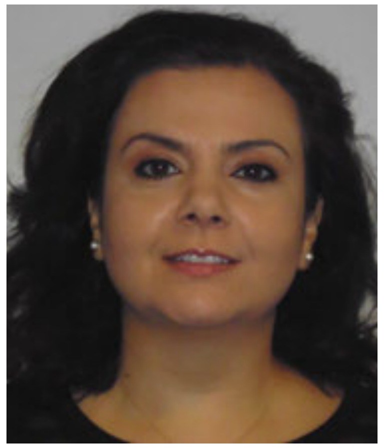

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Over the last decade, Fiber Optics (FO) installations have been gaining significant popularity with Operators as a means to acquiring reservoir measurements. The FO systems were originally patented in the 1960s, with first Distributed Temperature Sensing DTS applications dating back to the 1980s. Significant improvements to the technology as well as application scenarios have been achieved in the last decades, making DTS more and more attractive for a wider range of applications, such as Hydraulic Fracture Monitoring, Vertical Seismic Profiling, Gas Lift Surveillance, Integrity Monitoring, Injection and Production Conformance Monitoring, as well as others.

Recent advancements in Thermohydrodynamic Simulation [1] has allowed Operators to acquire formation flow profiles in their wells with the use of High Precision Temperature (HPT) logging and TERMOSIM™ simulation technique. In a typical HPT survey, a high sensitivity, fast-response temperature sensor, located at the bottom of the toolstring, is run at a stable speed of 2 m/min (or slower), taking readings during a downward pass when the sensor is in touch with the borehole fluid ahead of the tool body, thus avoiding fluid displacement and heat exchange between the fluid and the tool before temperature sensing. The logging procedures have to be designed in a certain way, usually including multiple flowing and shut-in passes to create temperature perturbations, allowing deciphering and quantifying of the flow profile.

TERMOSIM™ software application is designed for temperature and hydrodynamic simulations. It quantitatively analyses temperature logs and can be utilised in the following applications:

For injectors

- Injection profiling across flowing reservoir units
- Quantification of injection loss outside survey intervals
- Identification and quantification of behind casing channeling and wellbore crossflows including those in unperforated zones
- Quantitative characterisation of historical injection zones

For producers

- Production profiling across flowing reservoir units
- Identification and quantification of behind casing channeling and wellbore crossflows including those from unperforated zones
- Location of zones of water breakthrough from nearby injectors

TERMOSIM™ software numerically solves the problems of flow hydrodynamics and heat exchange between the wellbore fluid, completion components, surrounding anisotropic rocks and reservoirs. TERMOSIM™ can flexibly tune a multi-parameter thermohydrodynamic model to match simulated and measured temperatures. It operates in two modes: injection mode for injection temperature modeling and production mode for production temperature modeling. The simulation is based on the assumption that fluid and gas flow in the reservoir radially from and to the well. It also takes into consideration thermodynamic effects caused by fluid and gas flows through a reservoir, behind casing and along the wellbore as well as wellbore and behind-casing cross-flows.

TERMOSIM™ technology is described in more detail on TGT website www.tgtoil.com and in [2]. OPTISIM is an advanced thermal simulator, that builds on decades of Research & Development on the above described industry-proven technology, adding the ability to process and simulate Fiber Optics data. OPTISIM determines and quantifies flow profiles recorded in accordance with a well-specific data acquisition program. It has the ability to identify behind-casing flow and out-of-zone injection or production.

The advantages of Fiber Optic Based Surveillance are:

- Applicability in the wide range of wells, from water injectors and oil producers to polymer/Enhanced Oil Recovery (EOR) wells, deep wells, observation wells etc.
- Low cost of installation compared to dual wellhead completion for pumped wells
- Their non-intrusive nature reduces operational load in the field, logistics and HSSE exposure
- Automated on-demand time-lapse surveillance potential, which further reduces lifetime costs compared to conventional logging
- Fiber Optic based production/injection profiling can support the asset teams in assessing production and injection conformance, allow faster turnaround from the planning of the survey to obtaining the results, taking timely decisions

**Case Study**

OPTISIM data interpretation was performed for a vertical water injector in the Middle East. The well was drilled in May 2016, completed as cased/cemented with permanent DTS installed outside the casing, and put on stream in June 2016 with a target injection rate of 200 m3/d. The field is char-



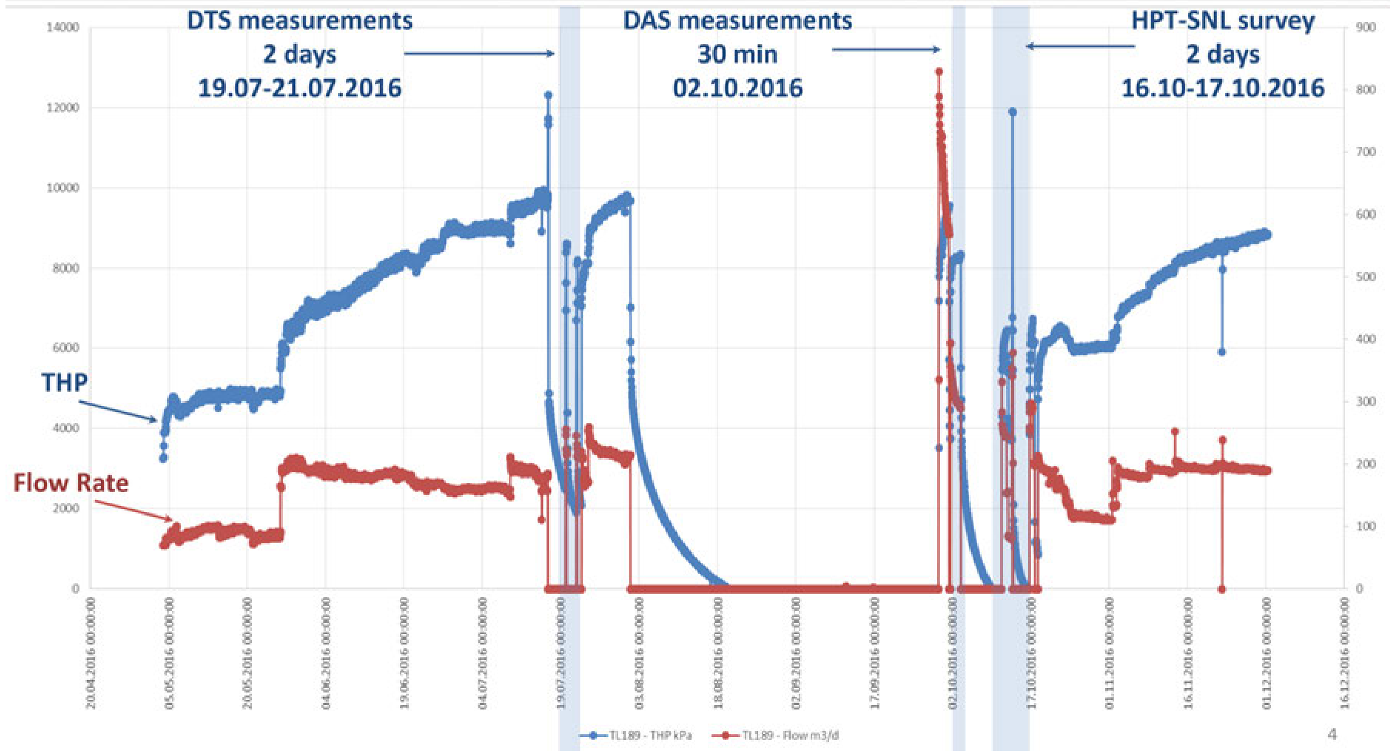


*Figure1. Well injection history and timing of surveys*

acterized by thinly laminated sandstone with highly variable permeability, interbedded with shales. This makes achieving injection conformance a very difficult task.

DTS data had been acquired over the period of 2 days (Fig.1) with static data recorded at the end of 3.5 days shut-in period, followed by an injection period, during which the flowing data were collected. Then, the well was shut-in again, allowing the gathering of the transient data.

This well's fiber optic installation is Distributed Acoustic Sensing (DAS)-enabled. The DAS data were collected on October 2 (Fig.1). Later in October, an HPT-SNL survey was performed.

The results of all the data processing and interpretation of all the three surveys are summarized in Fig.2.

Looking at the acoustic data first, one can see that out of the three active zones captured by the HPT-SNL logging, only two zones were detected by DAS. The DAS data were very noisy, so heavy amount of processing and filtering were required in order to 'clean up' the picture. It was also found that all the informative noise in the DAS was in the very low frequency range (below 50 Hz).

In the temperature panel, blue lines represent injection logs for HPT and DTS (illustrated in Fig.2). The discrepancy in absolute tempera-

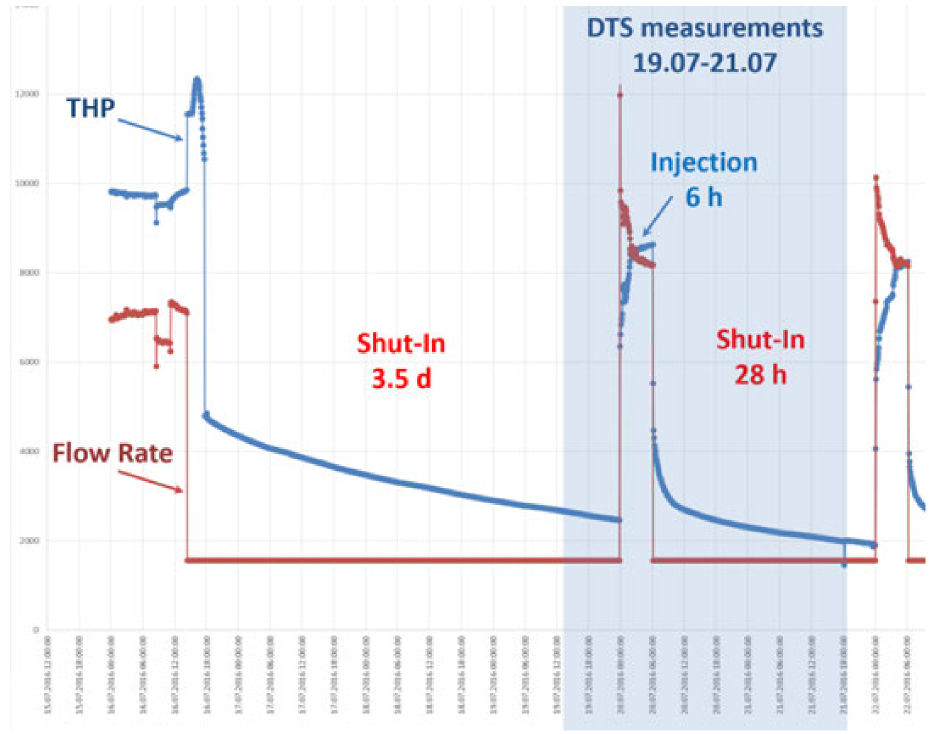


*Figure 1a. DTS procedure*

ture is most likely due to the different timing of the two surveys. One can see high level of noise in the DTS logs (STD ±0.2 °C, while HPT STD ±0.005 °C). This masked the minute details in the flowing log, making it possible to match only the average injection temperature (dashed lines represent the simulated temperature response).

The lines from green to brown represent the transient logs of 1, 2, 4, 10 and 28 hours of shut-in times accordingly. It is the transient logs that allowed to simulate the temperature response in this well, as opposed to the HPT survey, where all the matching was done by the flowing and the static passes. It can also be observed that the later transient logs give

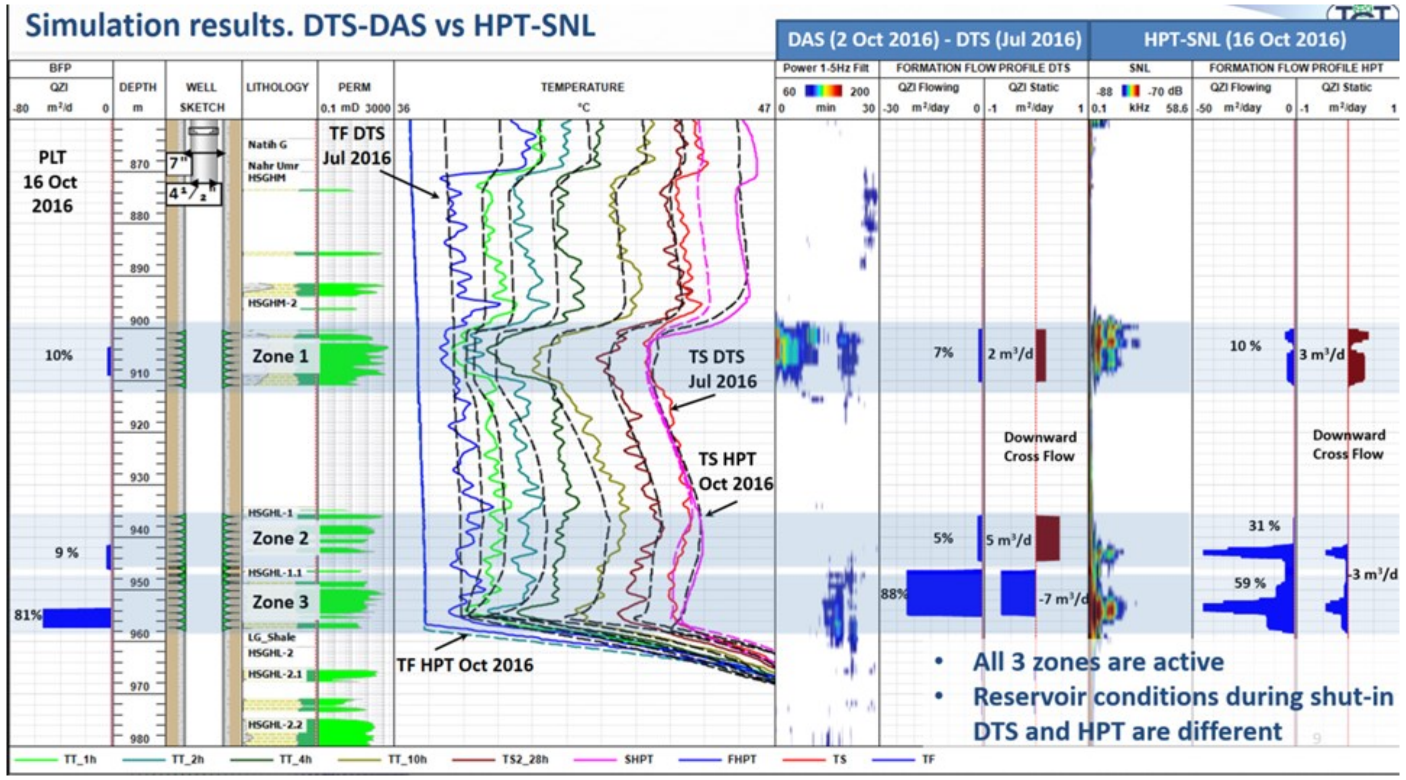


*Figure 2. Results of DTS-DAS and HPT-SNL surveys*

better matching than the early ones (dashed lines). The two rightmost curves are the static passes from DTS and HPT (marked on Fig.2). Both methods give adequate identification and quantification of the formation flow profile (see respective panels). Note that in static conditions, both surveys identified crossflow between the zones. Difference in the crossflow distribution is caused by the changed well and reservoir conditions. DTS, taken soon after the well had been put on stream, shows two upper zones producing and only the lower zone accepting water. Whereas in October, we can see only the upper zone producing and the two lower zones accepting.

During injection, all three zones have been identified as active in both surveys. Variance in the profile distribution in again caused by the changed well and reservoir conditions between the two time periods.

**Summary**

On DAS:

- Informative noises across Zone 1 and Zone 3 were detected. Noise across Zone 2 was not detected
- Overall, good correlation with SNL
- Informative noise is lower than 50 Hz
- Data are very noisy, additional processing required

On DTS:

- DTS data are noisy (STD (DTS) ±0.2 °C, while STD (HPT) ± 0.005 °C)
- Injection profile was identified by OPTISIM. Most useful information was derived from transient logs
- Good correlation between DTS and HPT results were found
- Discrepancy between HPT and DTS injection profiles is explained by different survey dates, well and reservoir conditions

**References**

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