

Downhole Flow Profiling Using Optical Fiber Distributed Temperature Sensing (Virtual PLT)

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Background

Optical fiber technology deployed in a well allows operators to accurately and frequently monitor the temperature of the fluids in the wellbore from the surface to the end of the fiber with a linear spatial resolution of 0.5 meter and a temperature resolution of less than 0.1 C. Typical temperature surveys of the well may be acquired every 15 minutes, though more frequent surveys can be run to capture transient events. The optical fiber may be permanently installed in the well and attached to the exterior of the production casing/liner or the production tubing.

The optical fiber may also be temporarily deployed in a well through the interior of the production tubing, by spooling it into the well similar to running wireline. For highly deviated wells, it may be conveyed in the well by coiled tubing, by stiff (fiberglass) rod, or by tractor units, and may be left in the well for a period of time to collect data before pulling the fiber from the well.

Interpreting Flow Profile Using DTS

There are two key physical properties associated with oil and gas wells that allow operators to derive some understanding of the distributed flow profile in production wells using DTS observations:

1. Natural geothermal temperature gradient and undisturbed temperature profile of the reservoir as a function of true vertical depth; and
2. Change in temperature of fluids related to the adiabatic expansion or compression of the fluids, called the Joule-Thomson effect. This effect can result in either an increase or decrease in temperature of the fluid (gas or liquid) with a drop in pressure, though in most conditions hydrocarbon gas will drop in temperature with a drop in pressure while water and oil will increase in temperature with a drop in pressure.

The fundamental assumption is that fluids flowing from the reservoir are initially at the temperature established by the geothermal temperature associated with the depth of the reservoir from which they originate. In order for fluids to flow through the reservoir and into the wellbore, a pressure

gradient must exist. The temperature of the fluid will change related to:

1. The Joule-Thomson effect created by the change in pressure (associated with flow from the reservoir into the wellbore, and in the wellbore flowing up the production conduit),
2. Heat transfer to or from the wellbore and reservoir when a temperature difference exists between the fluid and the wellbore/reservoir,
3. Mixing with fluids at other temperatures (enthalpy combination).

Armed with this information, and a good fundamental understanding of fluid flow from the reservoir and fluid flow in the wellbore, an experienced petroleum engineer can interpret the DTS profile to provide a qualitative interpretation of flow profile from the reservoir and along the wellbore. Critical to this interpretation is a good record of the geothermal profile and information about the composition and thermodynamic properties of the fluids produced. (Figure 1)

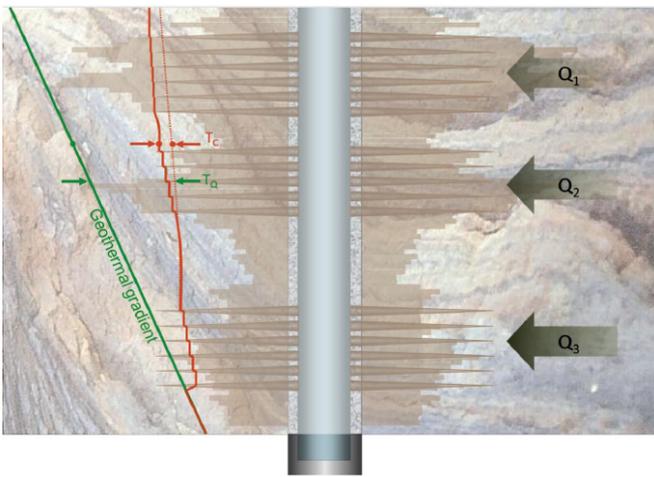


Figure 1 - Geothermal and Flowing Temperatures in a Production Well

Quantitative Flow Profiling Using DTS

It is possible to build mathematical models of the mass transfer, heat transfer and thermodynamic properties of the fluid to produce algorithms that are capable of estimating the temperature profile of fluids flowing from a reservoir into a wellbore, and up the production conduit in a production well. These algorithms have been incorporated in FloQuest™ Production Data Visualisation and Modeling Software, that allows the user to build models of the wellbore, manage and display data from DTS surveys (and other production data) spatially and chronologically, predict temperature profiles from flow profiles, and match DTS surveys to predicted temperature profiles to derive flow profiles. (Figure 2)

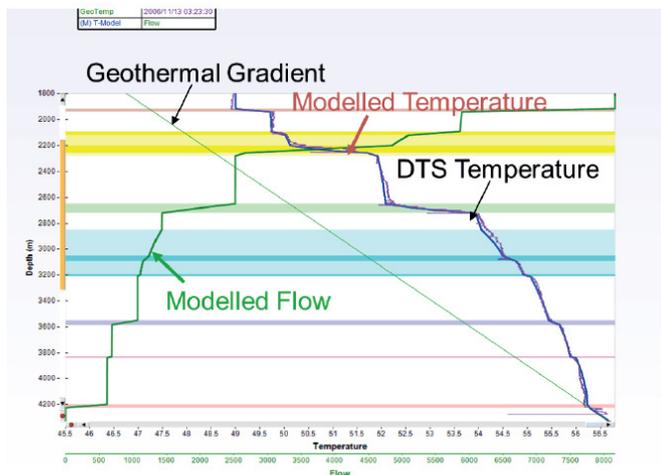


Figure 2 - FloQuest Modeling to Match DTS Temperature and Predict Flow

This modeling works with single phase or multiphase fluids (with a dominant phase) to establish flow profiles if the total well production is known. The interpretation requires the skills of a petroleum engineer who is capable of qualitatively interpreting the DTS data, and understands the impact of the location of the optical fiber in the wellbore on the temperature measured.

The interpretation of DTS data to quantify flow profiles is complicated by the following factors:

1. Poor data or a lack of data quantifying the geothermal temperature profile of the reservoir and overburden;
2. Incomplete information about the well and completion design, including directional drilling data, wellbore sizes, casing and cement information, production conduit information; wellbore/reservoir interface information,

and packer/annulus fluids information.

3. Incomplete data regarding the heat capacity and heat transfer properties of all materials used in the construction of the well;
4. Incomplete information regarding the heat capacity and heat transfer properties of the reservoir and the overburden;
5. Incomplete information regarding the composition and thermodynamic properties of the produced fluid;
6. Poor or incomplete well production data (temperature, pressure, flowrates) and history;
7. Location of the optical fiber in the well (outside casing, in the annular space, in the production conduit);
8. Potential for different flow directions along the flow path of the fluid from the reservoir: in the annulus space between the production liner and the production conduit, and up the production conduit;
9. Potential for flow behind casing due to cement channelling, or flow in the reservoir proximal to the wellbore from one zone to another;
10. Potential for cross-flow through the wellbore between zones in the reservoir;
11. Production from highly deviated or horizontal wells where the geothermal temperature profile is small or non-existent;
12. Production from reservoirs with dozens of layers or zones.
13. Inadequate information to accurately calculate the Joule-Thomson's coefficient where this effect considerably affects temperature profile.

The quality of the flow profile interpretation is improved by additional information, such as DTS profiles from a variety of flow and shut-in conditions, additional wellbore pressure data, information about the permeability and productivity index distribution in the reservoir, and flow data provided by intervention PLTs.

The Challenge of Flow Profiling with DTS for Multi-Phase Fluids

The production of multi-phase fluid, particularly gas-liquid systems (gas-oil, gas-water) and oil-water systems, complicates the derivation of flow profiles from the interpretation of DTS data by adding additional degrees of freedom in the problem and makes the solution using DTS data alone impossible.

The addition of information as previously described, and in particular, distributed pressure measurements and reservoir saturation information can improve the ability to find a flow profile solution.

Distributed pressure measurement (DPM) allows the petroleum engineer to derive the bulk density of the fluid mixture in the production conduit (given a significant vertical depth change in the conduit). With knowledge of the phase properties as a function of pressure and temperature, the phase volume fractions of the fluid in the production conduit can be calculated.

Multi-phase fluid flow adds the following factors complicating the interpretation of DTS and DPM for flow profiles:

1. Potential for counter-current flow or stratified flow in annular and production flow paths due to phase separation and gravity segregation of the fluid phases.
2. Potential for gravity segregation and fluid flow between layers in the reservoir proximal to the wellbore.

Unfortunately, due to the potential for gravity segregation and counter-current flow, the bulk density calculation may not be representative of the phase fractions of the fluids flowing from the reservoir layers into the wellbore.

The first factor, counter-current flow of different phases, is most prevalent in gas-liquid systems, in low bulk flow velocities, and in deviated or horizontal wells. The separation and segregation of the phases are characterized by the flow regime, and are dependent on the phase volume fraction and the velocities of the fluids. Counter-current flow complicates DTS interpretation as denser liquids at lower temperatures move down in the well, cooling fluids coming up the well. Generally, production from the lowermost zones are most prone to phase segregation and counter-current flow due to the low flow velocities in the production conduit adjacent to these zones. It should be noted that when this behaviour occurs in the annulus surrounding the flow path, it can cause the near-wellbore formation temperature to deviate from the expected profile in that section.

Strong phase segregation and counter-current flow can also make conventional production logging tools ineffective. Production logging tools with the ability to “map” the velocity profile and distribution of the fluid phase within the production conduit can improve the characterization of the phases and flow profile along the length of the wellbore. These PLT tools incorporate multiple spinners to measure velocity and multiple sensors to detect phase, but are still rather crude in their measurement and rely on flow loop correlations for interpretation.

In theory, the phase fraction of fluids flowing from each reservoir layer (in a two phase system) may be derived from the DTS temperature profile if the following conditions exist:

1. The optical fiber is permanently mounted against the wall of the wellbore, separated from the production casing by a cement sheath or insulator so that it is measuring the temperature of the fluid flowing only from that reservoir layer;
2. Good quality geothermal temperature profile data is available;
3. Good quality reservoir pressure profile data is available;
4. The flowing pressure profile immediately inside the production liner is available; and
5. The Joule-Thomson coefficients of the phase constituents are known, non-zero, and are significantly different for each phase.

Under these conditions, the temperature change (from the formation temperature) measured by the fiber is solely due

to the Joule-Thomson effect. The mass phase fraction can then be derived based on the temperature change as a function of pressure change and the mixed Joule-Thomson coefficients.

Additional Benefits of Optical Fiber DTS Monitoring

Additional benefits of distributed temperature monitoring using optical fiber are the ability to detect well integrity and operations based issues, such as:

- Leaking packers
- Tubing or casing leaks
- Flow behind casing
- Leaking Interval Control Valves (Intelligent Completion)
- Actuation of Interval Control Valves or other tools
- Monitoring of Cement Curing and Top of Cement (in wells where fiber is run with the casing)
- Leaking circulation valves
- Leaking Gas Lift valves
- Impending Problems with Electrical Submersible Pumps
- Effectiveness of stimulation fluid distribution and clean-up
- Monitoring of gas lift start up and unloading
- Monitoring liquid level in the annulus of pumping wells (without production packer)
- Identification of zones with water or gas breakthrough
- Identification of hydrate plug formation
- Identification of paraffin or asphaltene plugging

All these assessments are qualitative in nature, and rely on monitoring changes in the temperature profile over the length of the wellbore as a function of time and the operation being conducted (Figure 3). As such, these monitoring capabilities are best served by permanent optical fiber installations.

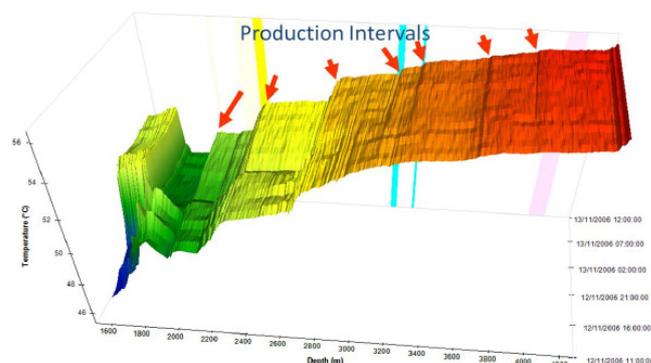


Figure 3 – Temperature Distribution with Depth Over Time in a Flowing Well

Summary

Permanently installed optical fiber DTS provides significant value by using changes in temperature profiles over time to detect well integrity and operations based issues. The measurements acquired from optical fiber distributed temperature measurement, in combination with additional physical and operational data, can be used to qualitatively describe fluid flow profiles within a production well. DTS data with advanced fluid flow, thermodynamic and heat transfer modeling, as provided with FloQuest™ Software, can quantitatively calculate the production flow profile for steady state production. The quality of the calculation is dependent on the quality of physical and operational data available.