Flow Profiling Gas Wells With Distributed-Temperature-Sensing Data

Distributed-temperature sensing (DTS) coupled with a temperature/pressure simulator was used to determine flow profiles from multilayered commingled reservoirs in gas wells. Quantitative individual-layer contributions to gas-flow rates and main water entries were determined, which in turn, helped engineers evaluate production conditions, track individual-layer recovery, identify problem zones, and plan remedial actions.

Introduction

DTS can provide continuous real-time flow information for the entire wellbore. However, DTS analysis is complex, and there is a current lack of user-friendly interpretation software. Production optimization requires continuous production information of each layer to design and plan preventive or remedial actions.

A production-logging tool (PLT), the popular flow-allocation solution, is a snapshot-type survey. Also, PLT results from low-rate or unstable-downhole environments can be misleading. Other methods such as mixed-fluid signatures (e.g., gravity and salt content) are quasicontinuous, but their application is restrictive, requires special contrasting fluid properties, and cannot handle more than three layers.

This article, written by Technology Editor Dennis Denney, contains highlights of paper SPE 103097, "Successful Flow Profiling of Gas Wells Using Distributed-Temperature-Sensing Data," by ***D. Johnson,*** *SPE,* ***J. Sierra,*** *SPE,* ***J. Kaura,*** *SPE, and* ***D. Gualtieri,*** *Halliburton Energy Services, prepared for the 2006 SPE Annual Technical Conference and Exhibition, San Antonio, Texas, 24–27 September.*

Background

It is recommended that the reader review Appendix A in the full-length paper. The discussion shows unpublished work previously developed by the authors and provides the developmental work conducted on the transient analytical/numerical wellbore-temperature and -pressure model. This model was used to perform temperature analysis for flow allocation and fluid identification. One of the first successful applications of this model with actual DTS data was in low-rate oil- and water-producing wells and achieved a good match between DTS data and simulated temperature.

Temperature in Gas Wells

Gas production from a single reservoir was used as a simple example in material-balance calculations. While pressure-transient analysis in gas wells is considered simple (if one uses the pseudopressure approach), wellbore hydraulics in gas wells, sometimes considered complicated, can be simplified by accounting for temperature changes related to frictional and Joule-Thomson effects (JTEs).

The global trend when producing dry gas is to produce multiple small or low-productivity reservoirs commingled in a single well to allow for exploitation of gas that was not considered economically feasible to produce. This scenario can lead to differential depletion, crossflow, and water breakthrough, which can impair gas production and understanding of reservoir dynamics. These scenarios offer many conditions for use of DTS data for better quantification of flow rates and fluid types from individual reservoirs.

JTE. The JTE is the phenomenon whereby fluid that is subjected to a pressure change experiences a change in temperature. The JTE is a cooling of produced gas or a warming of produced water caused by pressure drop during flow through formation, perforations, and wellbore.

Gas wells are ideal for flow profiling by distributed-temperature profiles because of the JTE, making producing zones easily identifiable. With the higher pressure drawdown, the JTE cooling is clearly observed in tight gas wells such as the two analyzed and presented in the field examples in this paper.

Depending on the composition of the fluid, the temperature change may be positive or negative. In many cases, gases will cool and liquids will heat when they experience pressure drop. The Joule-Thomson coefficient (JTC) of hydrocarbon gas depends on the composition, pressure, and temperature and usually exhibits cooling effects in the range of 2 to 20°F/1,000 psi. Water on the other hand, exhibits a warming JTC of approximately 3°F/1,000 psi.

DTS Flow-Allocation System

This DTS flow-allocation system consists of three main components: the data-acquisition system, the wellbore simulator, and the analysis technique.

Data-Acquisition System. This system uses an optical fiber as an array of temperature sensors along the entire well length. In this case, a retrievable system was used. It was lowered to a depth below the lowest perforated interval. To obtain downhole pressure with the retrievable system, downhole memory gauges were run at the end of the fiber-optic line.

The DTS instrument sends and receives laser pulses to measure temperature profiles along the entire length of the wellbore. Complete wellbore-temperature profiles were acquired in real time by use of a PC-based real-time

For a limited time, the full-length paper is available free to SPE members at www.spe.org/jpt. The paper has not been peer reviewed.

data-acquisition and -storage software. Temperature reconciliation and depth calibration were performed with a data-visualization software.

Wellbore Simulator. The flow model required the DTS, downhole-pressure, and surface-flow-rate data. The simulator used wellbore and near-wellbore pressure/temperature simulation, along with error-minimization techniques to match field DTS and downhole-pressure data with the response of flow rate and JTE, in both depth and time domains. Single-layer heat and fluid-flow equations and solutions that solve for transient wellbore pressure and temperature were extended to handle multizone-fluid entries and multirate-flow sequences.

At every timestep, the simulator used geothermal temperature, individual-layer flow rates, and sandface fluid temperature, which considers JTE to calculate the temperature profile from bottomhole to wellhead. The averaged thermal properties of production fluids were calculated by use of mass-weighted mixing rules.

Analysis Technique. An initial qualitative analysis of the data was performed to validate depths, synchronize time with other data and known events in the wellbore, identify temperature anomalies, and ensure data consistency and quality. Visualization software, which allowed viewing large quantities of DTS data in flexible formats suitable for quick interpretation, was used to perform quantitative analysis on critical information such as flow direction at all times during the survey, stable- and unstable-flow intervals, possible crossflow and thief zones during shut-in periods, and other unexpected thermal events. **Fig. 1** shows an example of these phenomena. Another piece of critical information identified in this stage of analysis was the occurrence of pivot points, which indicate the geothermal temperature. To ensure that the accuracy of the results of flow-rate allocation is acceptable, the time intervals showing unstable temperature profiles were not selected for analysis because the simulator could not handle complex fluid movement inside the wellbore.

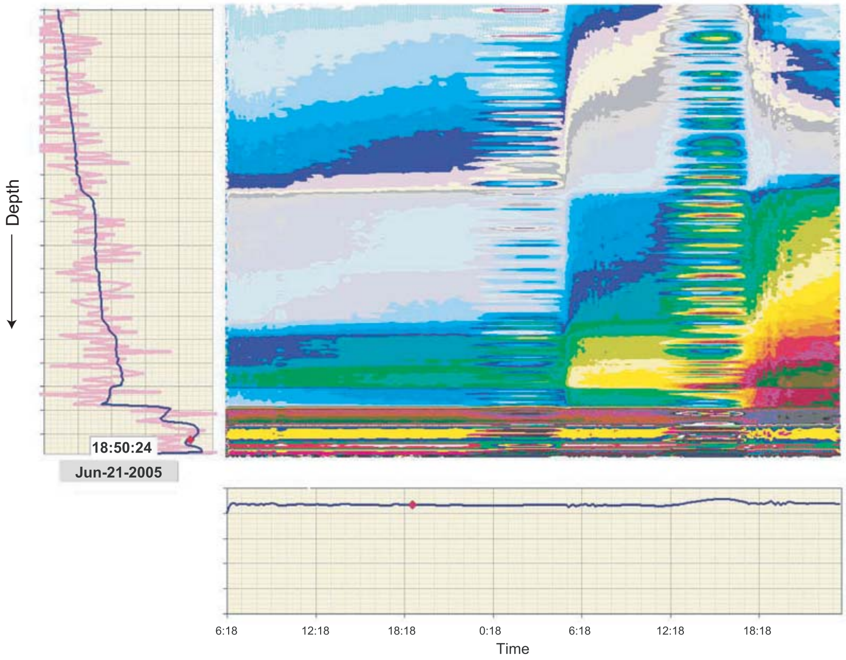

Fig. 1—Data set visualization for a multirate case.

Simulation and Profile Matching

The main matching parameters were thermal conductivity (diffusivity) and specific-heat capacity of the formation and the JTC of the producing fluid. Once these variables were established, the matching process began. The simulated curve was adjusted by changing both the flow volume and the JTE for each perforated zone in a trial-and-error process until a match was found. This process continued in the direction of flow until the entire curve was matched.

The direction of flow always dictates the direction that matching will follow. In producing wells, the matching process begins at the bottom of the well and progresses upward. The profile matching can be broken down into three stages: preliminary matching, simulation, and optimization. In the preliminary stage, the matched uphole section can be extrapolated through the producing intervals. Thereby, the total production rate for each of the three major producing intervals was estimated. This step establishes rate restraints within which the subsequent simulation should agree. An estimate of the JTE cooling at each interval was the difference between actual temperature and the geothermal. The preliminary evaluation of the data was very general and intended only to establish expected values and provide a starting point for the simulation.

During the simulation stage, each major producing interval was examined individually and the curve was refined on the basis of the distribution of production to the various perforated formations. For each fluid-entry point, production rate and JTE at that depth were entered into the model.

Once a reasonable match was made, the optimization stage consisted of crosschecking pressure and rate restraints against measured data and performing an uncertainty analysis. A second portion of the optimization was predicting fluid types at each entry point. To this point, only one phase was considered. The concepts of relative and absolute temperature change must be considered in fluid typing. An absolute temperature change indicates the type of fluid entering the wellbore at that location with no uncertainty. Absolute temperature change is cooling below the geothermal, which indicates gas entry, or a warming of the fluid above the geothermal, which indicates liquid entry. Relative temperature change occurs when, because of the position of the temperature profile relative to the geothermal, the fluid type cannot be determined. An example would be a cooling of wellbore fluid above the geothermal. The cooling could be caused by JTE if the fluid entering is a gas, or it could be liquid entering at a lower temperature than the fluid below. In such cases, where relative temperature changes prevent the identification of the fluid, the JTC can be used. By use of the same equation for calculating reservoir pressure, a JTC can be calculated at each entry. If the production were single phase, the resulting JTCs would be expected to be very similar. A variation in the JTC could be attributed to a second phase. If the JTC for the second phase is known, an estimate can be made of the amount of second-phase fluid entering at that depth.

Completion Effects

In these cases, a long-term shut-in that allows enough time for completion effects to dissipate may be more appropriate. Completion effects are most important during shut-in and low flow rates and can be negligible during high flow rates.

In the example wells detailed in the full-length paper, completion effects visible during flowing periods were used to calibrate wellbore depths accurately. The primary method used was to locate unevenly spaced perforation intervals just as long or short joints of pipe are used when correlating depth with a collar locator.

Field Example

This gas field is a complex shale-dominated deltaic-environment deposit. The main challenge in evaluating this environment is sand distribution and the resulting fluid distribution because the length of sand unit is the biggest controlling factor of fluid distribution. This gas reservoir has a gross thickness of 7,000 ft.

The wells are completed as monobores, and the production philosophy is to open the sands from bottom moving up. As a result of the uncertainty with fluid distribution, produced gas is associated with water. Because of excessive water production in some instances, wells load up and remedial water-shutoff treatments must be undertaken.

Results. Much wellbore information can be determined from the temperature profile under different drawdowns by understanding the JTC and the near-wellbore pressure drop associated with each flow rate. Use of a simple Darcy equation can assist in determining near-wellbore conditions, assuming that the fluid composition exiting the flow unit has not changed significantly.

The absolute direction of the temperature change in reference to the geothermal further enables the operator to identify where water entry is taking place. **Fig. 2** shows this temperature effect. Comparing the memory-production-log data for each sand unit showed that the match was reasonably good.

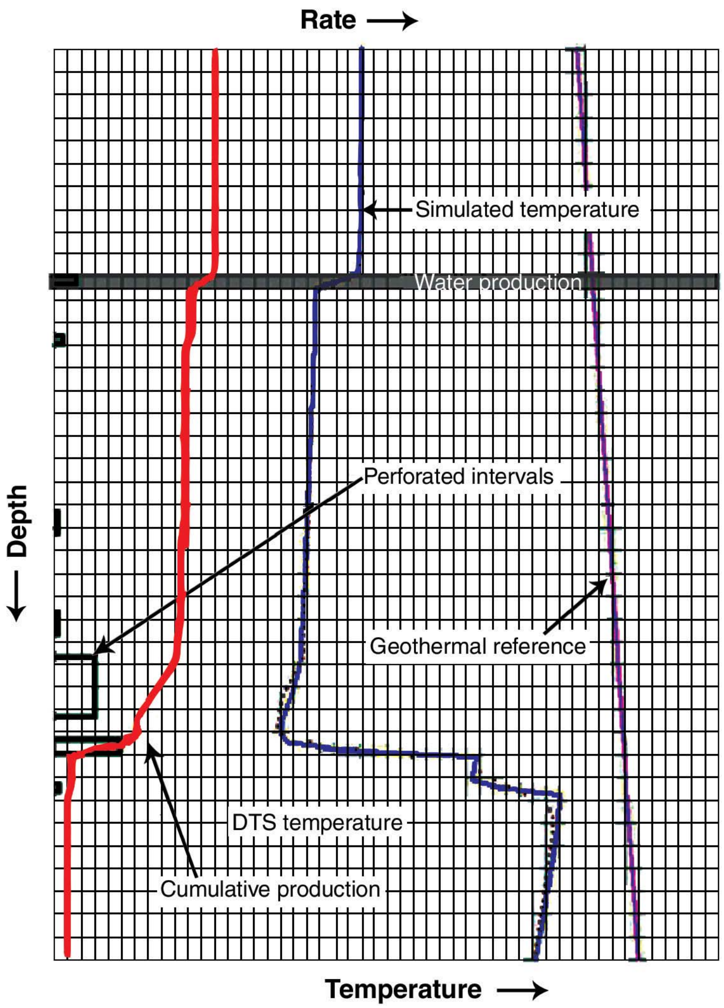

Fig. 2—Water-producing zone showing water effects over a 2,000-ft pay interval.

Comparison With PLT

Flow profiles of the lower zones, as determined with simulation and PLTs, were essentially the same. However, upper zones showed some differences that can be attributed to spinner instabilities. The unstable spinner sections had been “averaged” to construct the calibration graphs. Water-entry identification was the same in both types of surveys. On the basis of survey results, indentifying the water source could be made with a relatively simple technique. The surface rates were still showing that the reservoir energy would be capable of handling the water production at that time. As a result, the planned water-shutoff treatment was deferred.

More surveys were planned to acquire a better understanding of the economics for this type of monitoring. These data will facilitate making provisions in the completion design for permanent installations.

Conclusions

The use of DTS technology can help operators identify water-breakthrough intervals. The best approach to manage water breakthrough is preventing its occurrence. However, because water breakthrough often is unavoidable, identifying breakthrough just before or immediately as it occurs would be an effective solution.

Real-time DTS offers this opportunity. The real value of DTS temperature-profile data comes from observing rapid temperature changes over short periods of time. Monitoring wellbores with permanent DTS installations can detect temperature changes associated with various phenomena quickly, and over time, an operator can learn to interpret changes that might imply an impending water-breakthrough event in a gas well. JPT