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Modeling Flow Profile Using Distributed Temperature Sensor (DTS) System

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Abstract

Distributed Temperature Sensing (DTS) technology uses fiber-optic cable to measure continuous temperature profile along the wellbore. Measurement interpretation can provide valuable information, and one of them is real time flow profiling that helps to monitor the fluid flow in wells. This valuable information can assist real time production decision with no well intervention. However, the complexity of the data analysis limits the use of DTS as a flow allocation technique.

This paper presents a new flow-profiling model using DTS technology. The model is based on steady-state energy balance equation and it handles multiple production zones with its own zonal fluid properties. The model is applicable for gas and oil wells in onshore and offshore environment. The model is integrated into easy-to-use software and it can be run in two modes: forward simulation and flow profiling. The forward simulation calculates temperature distribution along the wellbore for any given production profile, and this mode is critical for the model calibration. It is also very useful for emulating what-if scenarios, like water breakthrough. The flow profiling estimates production profile based on measured temperatures, which is the base for the real time well monitoring.

Our studies with the model show that geothermal profile, fluid properties, formation properties, well completion, and deviation as well as Joule-Thomson effect all play key roles for the model accuracy. Joule Thomson gas cooling effect only occurs at lower pressure while reversal appears at higher pressure region.

The model is tested against synthetic, literature and field examples and good agreements have been obtained. Test results have been presented.

Introduction

Distributed Temperature Sensor (DTS) is the name of the class of instruments that measure temperature continuously through the optic fiber installed along the entire wellbore length. DTS comprises concentric layers of materials: core and cladding. DTS uses physical phenomena such as Raman scattering which transduces temperature into an optical signal. Laser light pulses are generated by the DTS instrument (DTS box) and launched down the fiber sensor. As laser pulses travel down, portion of the light reflects back to the DTS box. Raman backscatter is caused by molecular vibration in the fiber resulting in the emission of photons, which are shifted in wavelength from the incident light[1]. Positively shifted Stokes backscatter is temperature independent, while the negatively shifted Anti-Stokes Raman backscatter is temperature dependent. The intensity ratio of Stocks/Anti-Stokes can be used to calculate temperature.

DTS technology is not new. It was used in fire detection decades ago. Only in recent years, DTS technology has emerged as a valuable tool in the oil and gas industry. Initial applications are for steam flooding and geothermal application. As DTS technology advances, the temperature measurement has become very accurate and reliable. The temporal temperature resolution is 0.1^{o}C at a distance up to 10 km, with a spatial resolution of 2 meters. DTS system generally don't interfere with flow, have much more flexibility for deployment in restricted downhole environments, and can be used for short-term as well as permanent monitoring scenarios.

DTS applications include monitoring, zonal fluid contribution as well as the identification of unwanted fluid entry such as gas and water breakthrough. While other techniques such as Production Logging Tool or single point flowmeter can provide flow information, but no single technique can offer continuous real time wellbore flow allocation.

However, the temperature measurement is rarely the information the customer is after. The information they desire is a parameter to a model that predicts the temperature profile of the well. The parameter is adjusted until the model prediction matches the actual measurement. The model complexity has limited the DTS application. The very first paper that describes a quantitative approach to flow allocation was presented by Nowak in 1953[2]. The technique, similar to pressure transient analysis, was used to determine the cumulative layer injection. Ramey[3] proposed the wellbore temperature prediction model in 1962. His model couples heat transfer mechanisms in the wellbore and transient thermal behavior of the reservoir. The model works for either single-phase incompressible hot liquid or single-phase ideal gas flow in a line-source well. Models of Sagar et al. (1991), Alves et al. (1992), and Hasan-Kabir-Wang (1994) were extended to apply for two phase flows. However, all these models have severe assumptions related to the thermodynamic behavior of the fluid flow and are inadequate for complex problems. Most recently, Hasan-Kabir-Wang (2007)[4] proposed a robust steady-state model for flowing-fluid temperature in Complex Wells. The model divides the wellbore into many sections of uniform thermal properties and deviation angles. The limitation of this model is that solution is not applicable for the section which includes production zones.

The work presented here is based on steady-state energy balance equation and handles multiple production zones each with its own zonal fluid properties. The model is applicable for gas and oil wells in onshore and offshore environment.

Model Description

Non-Production Zone Energy Equation

Temperature difference between the wellbore fluid and the surrounding formation results in energy exchange. Figure 1[4] shows a typical offshore well with a number of changes in deviation angle. The wellbore is discretized into a number of segments. For a control volume (section "j"), under stead-state condition, the energy balance can be written as Equation 1.

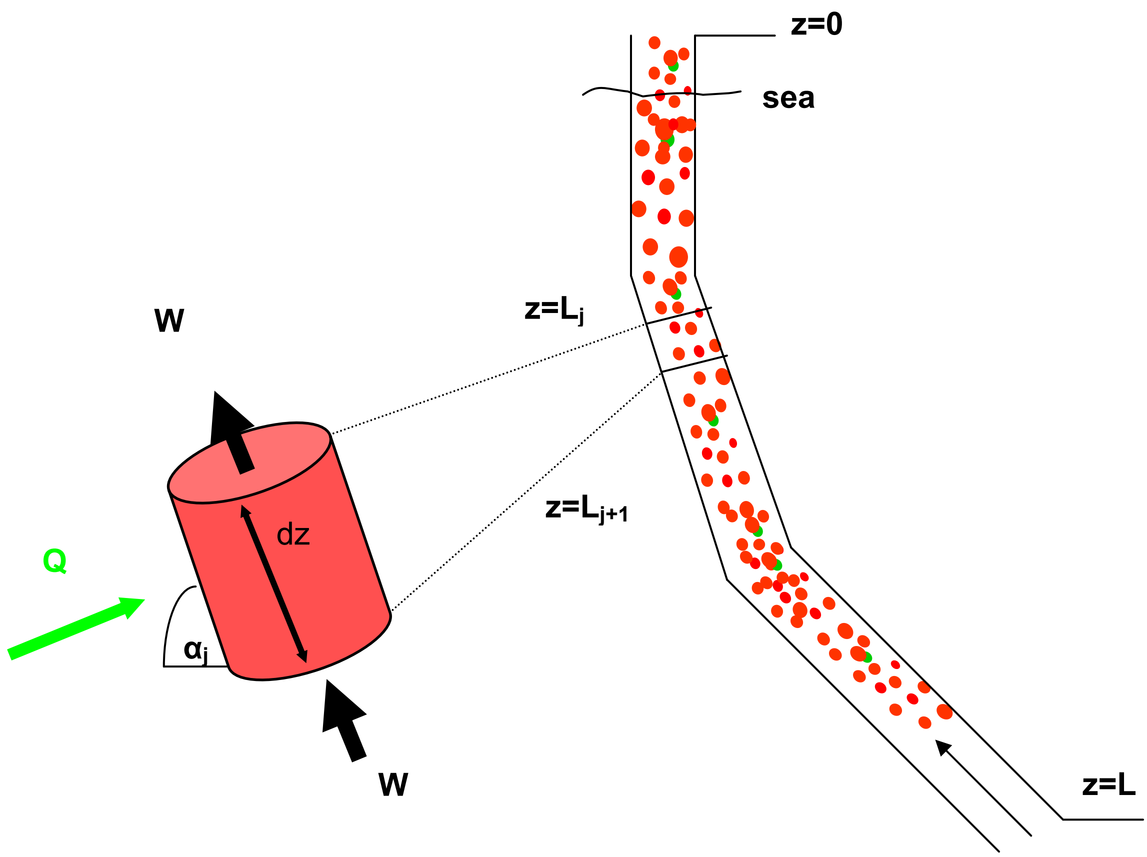

Fig. 1 – Schematic of wellbore sketch for energy balance (non-production zone)

$$\frac{\mathrm{d}H}{\mathrm{d}z} - \frac{g\sin\alpha}{Jg_c} + \frac{v}{Jg_c}\frac{\mathrm{d}v}{\mathrm{d}z} = -\frac{Q}{w}, \qquad \textbf{(1)}$$

Where Q on the right side represents the heat lost from the hot fluid inside the wellbore to the surrounding formation, g_c and J represent appropriate conversion factors. For a fluid undergoing no phase change, enthalpy is a function of pressure and temperature and is given by:

$$\mathrm{d}H = \left(\frac{\partial H}{\partial T}\right)_{\mathrm{p}} \mathrm{d}T + \left(\frac{\partial H}{\partial p}\right)_T \mathrm{d}p = c_p \mathrm{d}T - C_J c_p \mathrm{d}p, \quad \textbf{(2)}$$

Where C_J represents the Joule-Thompson coefficient and c_p is the mean heat capacity of the fluid at constant pressure. Hence, the expression for the wellbore fluid temperature as a function of measured distance is:

$$\frac{\mathrm{d}T_f}{\mathrm{d}z} = C_J \frac{\mathrm{d}p}{\mathrm{d}z} + \frac{1}{c_p}\left[-\frac{Q}{w} + \frac{g\sin\alpha}{Jg_c} - \frac{v}{Jg_c}\frac{\mathrm{d}v}{\mathrm{d}z}\right]. \quad \textbf{(3)}$$

Heat flux per unit length of wellbore, Q, is given by:

$$Q \equiv -L_R w c_p \left(T_f - T_{ei}\right) \quad \textbf{(4)}$$

Where, the relaxation length parameter, L_R, depends on fluid/formation thermal properties and the overall heat transfer coefficient. For a wellbore section surrounded by earth, L_R is given by Eq. 5a, where as Eq. 5b represents L_R for a section submerged under water:

$$L_R \equiv \frac{2\pi}{c_P w}\left[\frac{r_{to}U_{to}k_e}{k_e + \left(r_{to}U_{to}T_D\right)}\right]. \quad \textbf{(5a)}$$

$$L_{Rc} = \frac{2\pi r_{to}U_{toc}}{c_p w}. \quad \textbf{(5b)}$$

Combining these equations we get the following differential equation for fluid temperature, T_f:

$$\frac{\mathrm{d}T_f}{\mathrm{d}z} = L_R(T_f - T_{ei}) + \frac{g\sin\alpha_i}{c_P J g_c} - \phi \quad \textbf{(6)}$$

Where Φ is:

$$\phi = \frac{v}{Jc_p g_c}\frac{dv}{dz} - C_J \frac{\mathrm{d}p}{\mathrm{d}z} \quad \textbf{(7)}$$

The pressure gradient, dp/dz, is the sum of the kinetic head, $(\mathrm{dp/dz})_{\mathrm{A}}$, the static head, $(\mathrm{dp/dz})_{\mathrm{H}}$ and the frictional head, $(\mathrm{dp/dz})_{\mathrm{F}}$:

$$\frac{\mathrm{d}p}{\mathrm{d}z} = \left(\frac{dp}{dz}\right)_A + \left(\frac{dp}{dz}\right)_H + \left(\frac{dp}{dz}\right)_F \quad \textbf{(8)}$$

For gas-liquid (oil and water) system, the problem is to find the right mixture density and friction factor, which requires estimating in-situ liquid holdup from different flow patterns. In this work, Hasan-Kabir multiphase flow model is applied.

In Eq. 6, T_{ei} represents the surrounding undisturbed earth (or sea) temperature far away from the well. It can be obtained through a geothermal temperature survey. For a well with multiple changes in inclination angle α, or geothermal gradient, g_G, T_{ei} can be expressed in terms of T_{ei} just prior to this section as,

$$T_{ei_{j+1}} = T_{ei_j} - (Z_j - z) g_{G_j} \sin\alpha_j \quad \textbf{(9)}$$

Production Zone Energy Equation

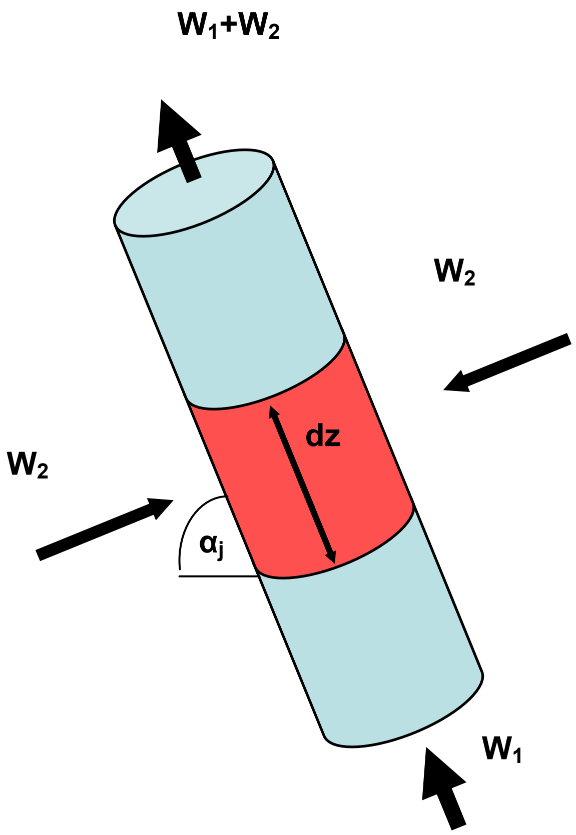

Fig. 2 – Schematic of wellbore sketch for energy balance (production zone)

For the Production zone, the energy equation is

$$-Q = W_1\left(\frac{dH}{dz} - \frac{g\sin\alpha}{Jg_c} + \frac{v}{Jg_c}\frac{dv}{dz}\right) + \frac{W_2 C_p (T_f - T_{entry})}{dz} \quad \textbf{(10)}$$

Inserting equations 2 and 4 into equation 10, we can get the following differential equation,

$$\frac{dT_f}{dz} + \frac{(1-\lambda)}{\lambda}\frac{(T_f - T_{entry})}{dz} = \frac{L_R}{\lambda}(T_{ei} - T_f) + \left(\frac{g\sin\alpha}{Jg_c C_p} - \phi\right) \quad \textbf{(11)}$$

Where

$$\lambda = \frac{W_1}{W_1 + W_2} \quad \textbf{(12)}$$

For the non-production wellbore portion, λ=1, which is the same as equation 6. Equation 11 is very easy to solve by using the finite difference method.

The production zone entry fluid temperature difference is calculated by the following equation,

$$T_{entry} - T_{ei} = \frac{C_J (P_{RES} - P_{wf})}{J_c} \tag{13}$$

At the bottom of the wellbore, the pressure drop, P_{RES}-P_{wf}, is assumed as pressure drawdown. T_{ei} is the formation temperature. Since the formation temperature, pressure drop, and fluid entry temperature at the lowest zone are usually known, equation 13 can also be used to calculate the Joule Thomson coefficient C_J for comparison purposes.

Joule Thomson coefficient

Use of Eqs. 6 and 11 requires values of Joule-Thomson coefficient for the flowing fluid which could be a single-phase gas, a single-phase liquid, or a multiphase mixture of gas and liquid. In all cases, the general expression for the Joule-Thomson coefficient can be derived from Maxwell identities. Equation 14 shows the final expression for the Joule Thomson coefficient,

$$C_J = \frac{1}{c_P}\left(\frac{xT}{Z\rho_g}\left(\frac{\partial Z}{\partial T}\right)_P - (1-x)(1-T\beta)/\rho_L\right) \tag{14}$$

Where β is liquid volume expansion factor with the unit of 1/°F, x is the mass fraction of gas in the two-phase mixture.

It is important to point out that for the single gas phase (x=1); cooling effect is not always the case. It all depends on the gas compressibility factor at two different temperatures at constant pressure, $(\partial Z/\partial T)_p$. At lower pressure, the gas compressibility factor decreases with temperature increases, or $(\partial Z/\partial T)_p < 0$. However, at certain higher pressure regions, the reverse appears. Figure 3 shows the gas temperature profiles at various Bottom Hole Pressures (BHPs) with constant pressure drawdown (250 psi). When BHP equals to 2000psi, the gas entry temperature starts at 111.4°F, 6.4°F lower than the formation temperature (117.8°F). When BHP sets at 4000 psi, the temperature difference decreases to 1.4 °F, a much weaker cooling effect. As BHP increases to 6000 psi, the cooling effect disappears, the temperature starts to increases. With further increases BHP to 8000 psi, the warming effect becomes stronger. This phenomenon was also confirmed in fields by operators.

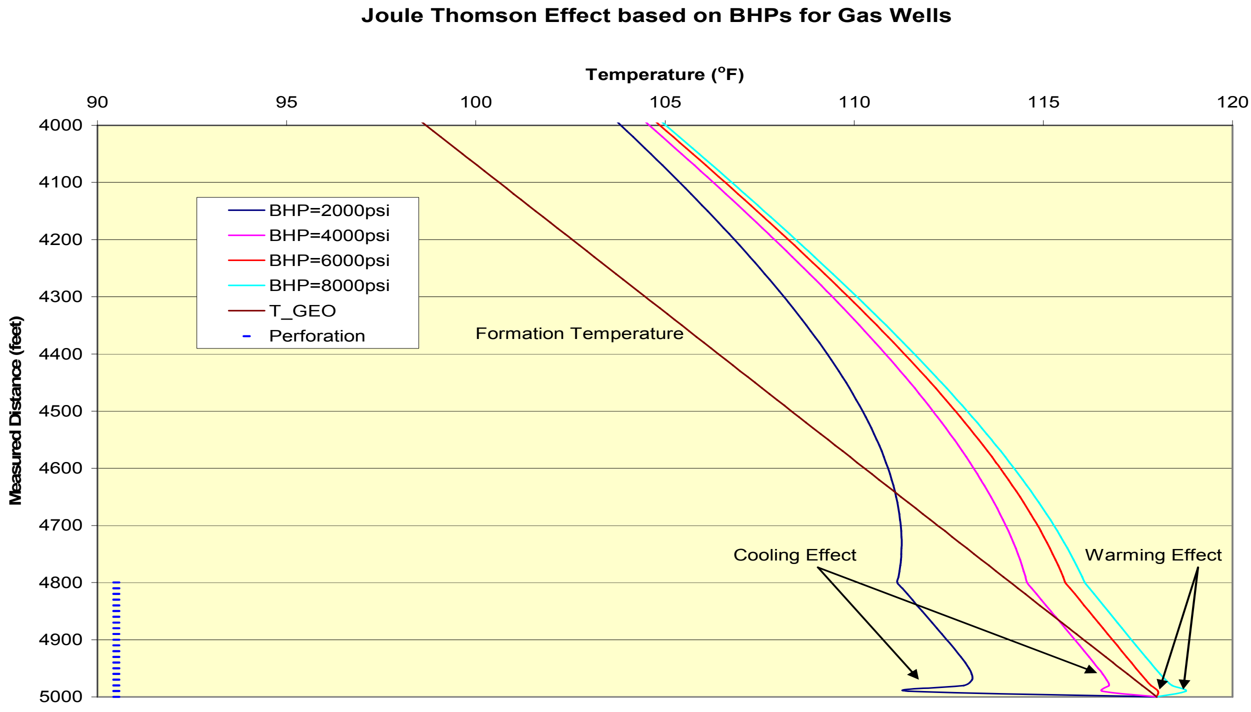

Fig. 3 – Joule Thomson effect at various BHPs for gas wells

Software Description

The model is integrated into easy-to-use software and it can be run in two modes: forward simulation and flow profiling.

Forward simulation: Calculates temperature distribution along the wellbore for any given production profile. This mode is simple and quick, however, it is critical for model calibration. Figure 4 shows the flow chart for this mode,

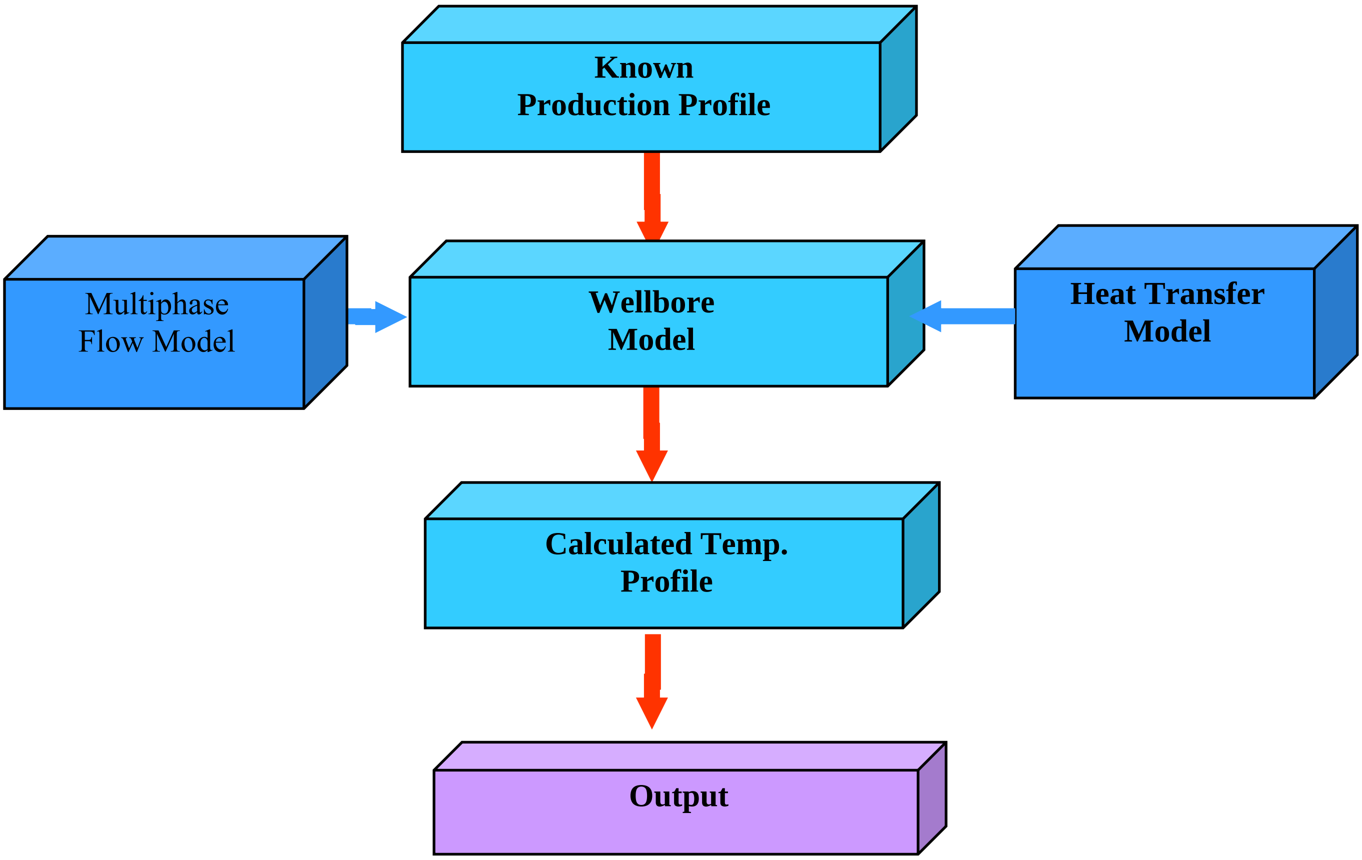

Fig. 4 – Forward simulation flow chart

The forward simulation mode is also very useful for emulating what-if scenarios and identifying the potential error. One of the examples from SPE 90541[5] was used to test the model. There are three production zones: 600 STB/D oil along the 2000 to 2600 ft MD interval, 1200 STB/D oil along the 2900 to 3500 ft MD interval, 200 STB/D oil and 1000 STB/D water entry along the 4400 to 4900 ft MD interval. With reservoir pressure at 2000 psia, pressure drawdown at 50 psia, wellhead pressure at 600 psia, oil gravity equals 40^o API and deviation angle equals 15 degree.

The model run shows wellhead pressure is about 50 psi, much lower than 600 psia as reported. Investigation was carried out to solve this puzzle. Assume the pressure gradient is caused by static head only and mixture density for oil and water is equal to oil density. The case would represent the minimum pressure drop along the well, which results in maximum wellhead pressure. Since the oil density for 40^o API is about 51.48 lb/ft3(=62.4x[141.5/(40+131.5)]). The overall pressure drop along the 4900 feet measured distance is equal to 1692 psi (=4900xsin(75)x51.48/144), this suggests maximum well head pressure should be 257 psi(=1950-1692). In order to have reported wellhead pressure, mixture density should be lower than the given oil density. Hence, system must contain gas, even though it is not mentioned in the paper. Figure 5 shows the pressure drop with and without gas. Figure 6 shows the temperature profile. Note since sizes of the tubing/casing diameters are not reported in the paper, the temperature profile is slightly different from the original report because convection in the annulus and conduction for the tubing and casing are different.

Pressure Profiles

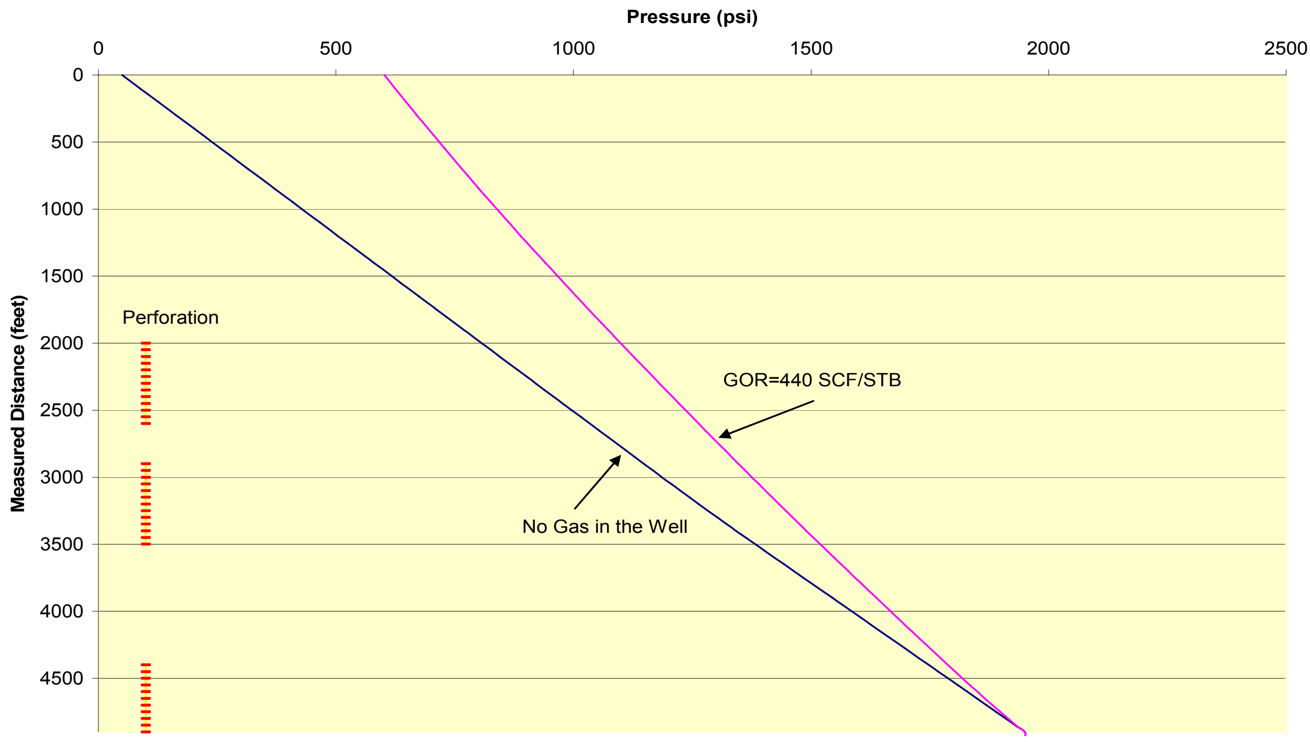

Fig. 5 – Pressure profile suggests gas in the well

Temperature Profile along the Well

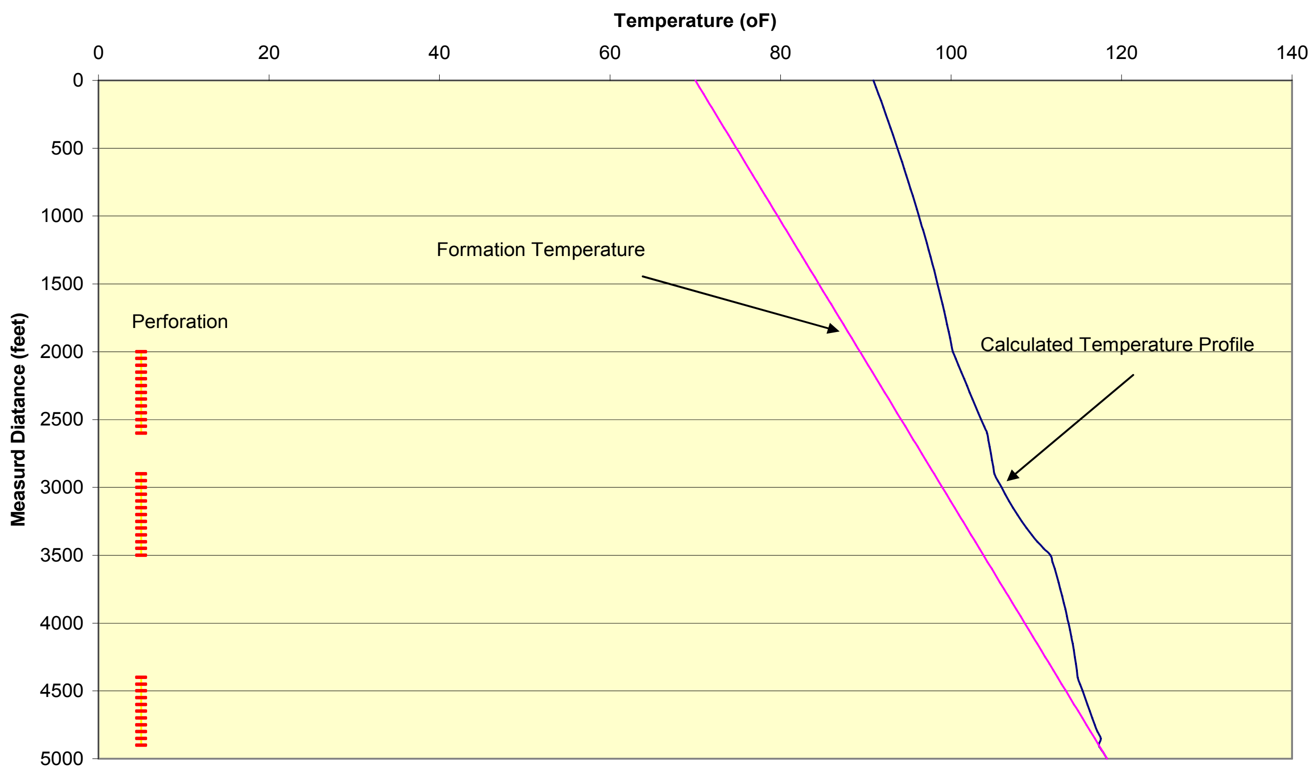

Fig. 6 – Temperature profile along the well

Flow profiling: Estimates production profile based on measured temperatures, one of the main DTS applications. The principle behind the procedure is relatively simple. It starts at the bottom layer, with three user controlled inputs: minimum flowrate, maximum flowrate and a small flowrate interval. For each flow rate, the forward simulation is performed; the calculated temperature is then compared with the DTS measurement for this zone. If the summation of $(T_{cal}-T_{meas})^2$ for this zone is the smallest, the corresponding flowrate would be the rate for this zone. Repeat the process for the upper zones until the top production zone is reached. The outputs give zonal contributions both in percentage and actual values. Figure 7 shows the flow chart for this mode.

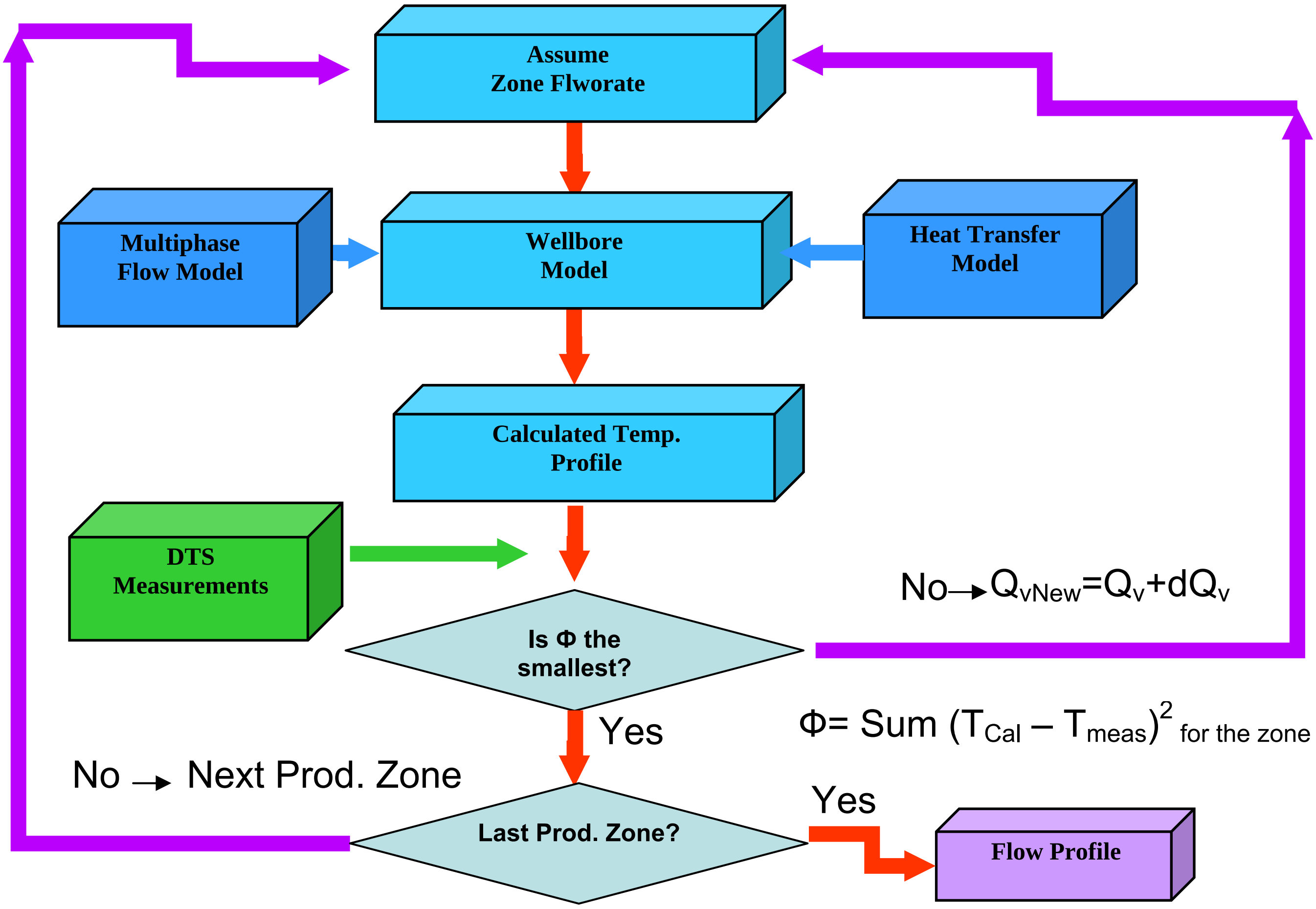

Fig. 7 – Flow profiling flow chart

A low permeability gas well was used to validate the model. Initial gas flow rate is high. DTS was installed during the workover after about two years. Because of the fiber fault, Sumitomo unit was borrowed and used without fiber calibration. Initial attempt was made to calculate the flow profile based on the raw data. Oscillation of the data, greater than 5°F at some locations, made the model run unsuccessfully. The raw data was smoothed through forward simulation based on well completion details, geothermal and fluid properties, as shown in Figure 8.

Flow profiling was performed based on the smoothed DTS measurement. The result was compared with PLT data, as shown in Fig. 9. An almost perfect match was obtained. This clearly demonstrates the importance of fiber calibration, where successful flow profiling relies upon.

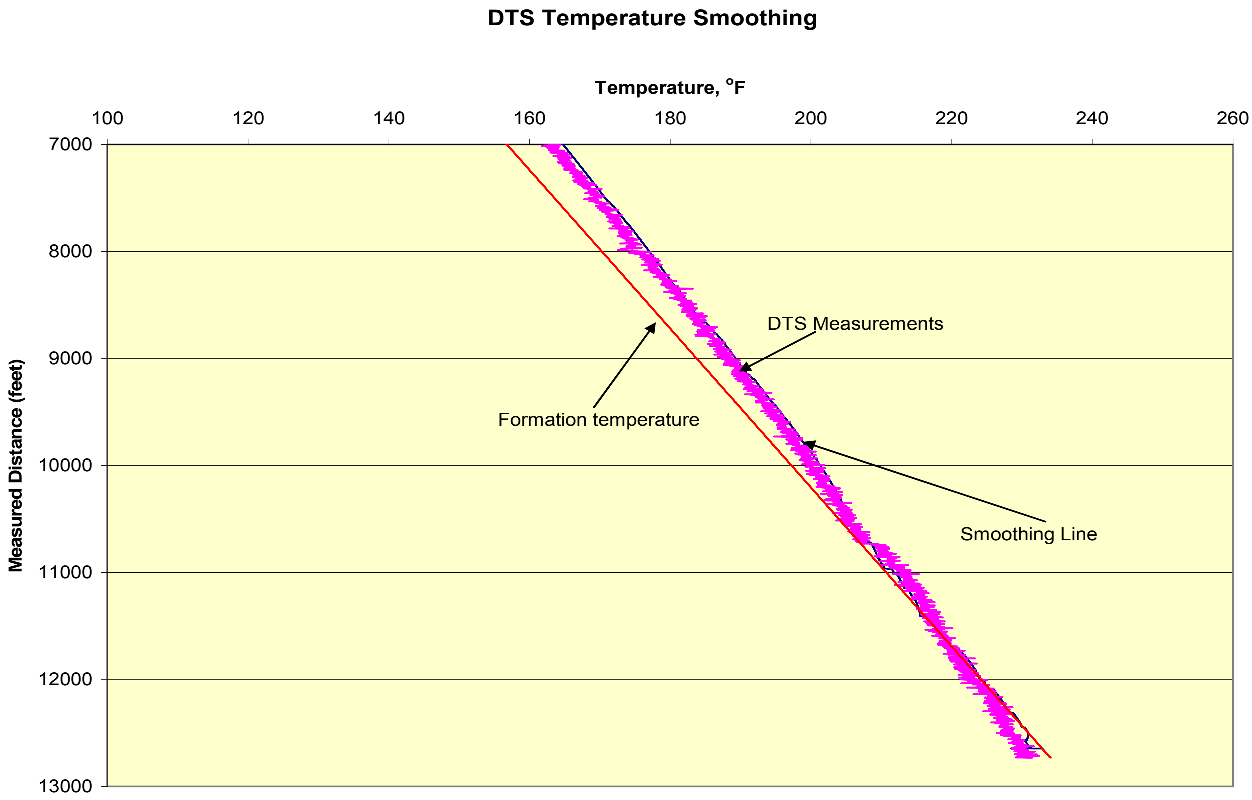

Fig. 8 – DTS temperature smoothing

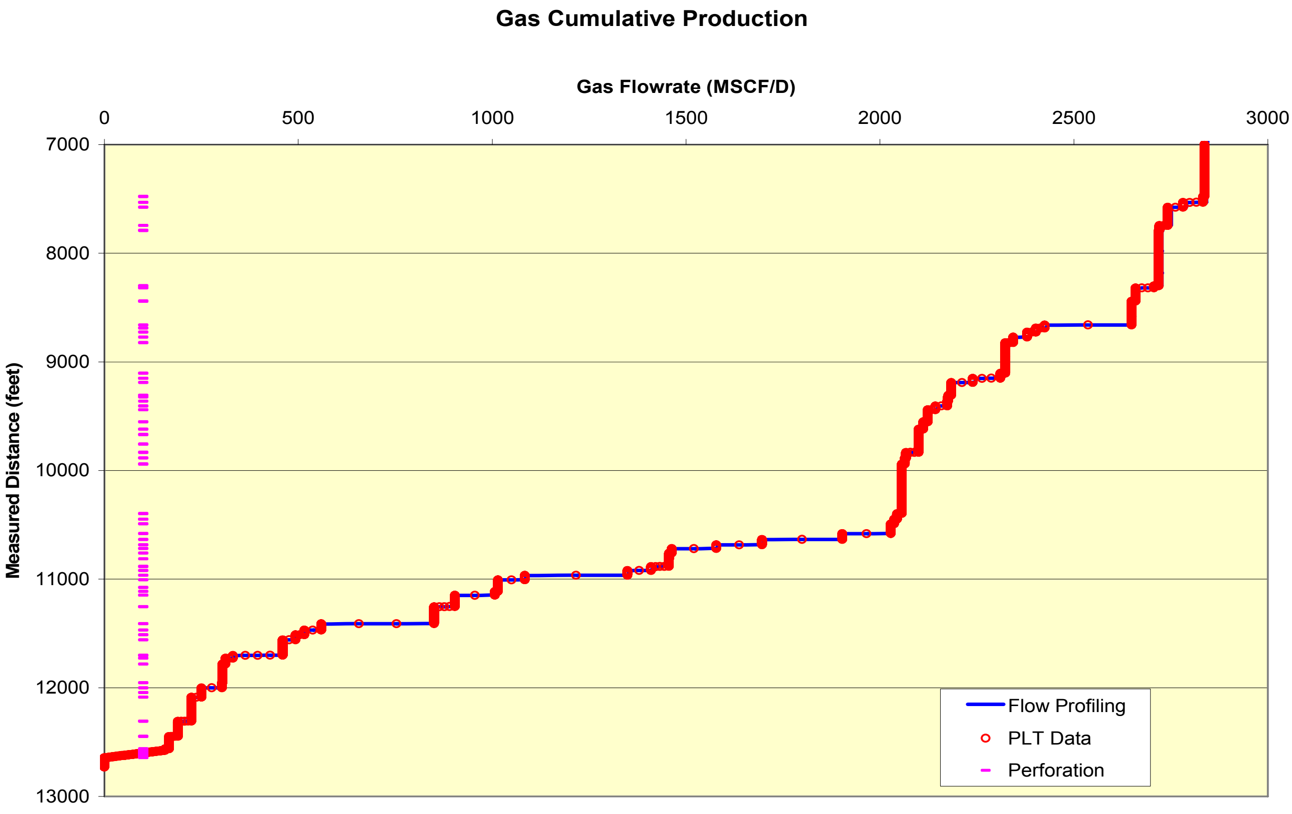

Fig. 9 – Flow profiling based on DTS smoothed measurement

Conclusions

This paper presents a new flow-profiling model using DTS technology. The model is based on rigorous steady-state energy balance equation with good agreements having been obtained against synthetic, literature and field examples. The model shows Joule Thomson gas cooling effect only occurs at lower pressure while reversal appears at higher pressure region. The model can provide a temperature profile based on assumed conditions, which is very valuable for sensitivity studies as well as design purposes. The model also provides flow profiling both in actual values as well as percentage for gas, oil and water based fluids based on DTS measurements. This is very important for well monitoring, zonal contribution as well as the identification of unwanted fluid entry such as gas and water breakthrough. A successful model run depends on accurate DTS measurements.

Nomenclature

c_p = specific heat capacity of fluid, Btu/lbm-°F
C_J = Joule-Thompson coefficient, (°F)/(lb$_f$/ft^2)
g = gravitational acceleration, ft/sec^2
g_c = conversion factor, 32.17 lbm-ft/lbf/sec^2
g_G = geothermal gradient, °F/ft
H = fluid enthalpy, Btu/lbm
J = Btu to ft.lb$_f$ conversion factor
k_e = thermal conductivity of earth, Btu/hr-ft-°F
L_R = relaxation parameter, ft^{-1}
p = pressure, psi
Q = heat flow rate per unit length of wellbore, Btu/hr/ft
Q_v = fluid flow rate STB/D for liquid or MSCF/D for gas
t_D = dimensionless time, hr
T_D = dimensionless temperature
T or T_f = fluid temperature, °F
T_{ei} = undisturbed earth or formation temperature, °F
U_{to} = overall-heat-transfer coefficient, Btu/hr-ft^2-°F
U_{toc} = overall-heat-transfer coefficient for offshore, Btu/hr-ft^2-°F
v = velocity, ft/s
w = mass rate, lbm/hr
x = gas mass fraction (quality), dimentionless
z = variable well depth from surface, ft
Z = gas compressibility factor, dimensionless
α = well inclination (to horizontal) angle, °
β = volume expansivity, ° F^{-1}
ρ = fluid density, lbm/ft^3
ϕ = lumped parameter defined by Eq. 7, °F/ft

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