

DOWNHOLE TEMPERATURE CALCULATION

Field of the Invention

- 5 The present invention relates to calculating a downhole temperature in a hydrocarbon well installation.

Background of the Invention

- 10 The safe and efficient operation of an offshore oil or gas well relies on a knowledge of the reservoir characteristics and the ability to control the flow of fluid from the well. This requires knowledge of the temperatures and pressures at various positions downhole in the well, which enables an operator to control more efficiently the flow of fluid or gas from the well and enables reservoir engineers to develop a model or simulation of the reservoir and calculate
15 reserves, etc. The temperature of the reservoir fluid entering the well is also an important measurement, as it allows the operator to detect water or gas breakthrough.

- The downhole technology now becoming available for measuring fluid flow, temperature and pressure in offshore oil and gas wells is proving to have poor reliability when operating in the
20 harsh downhole environments of existing wells. With the move to deeper water wells with their harsher down-hole environment and higher temperatures (up to 200 degrees C) and pressures (up to 1000 bar) there is a need to improve measurement reliability. The current sensor technology, providing the required accuracy and resolution, is based on quartz crystals which can survive the harsh environments, but the weak link is the associated
25 downhole electronics, cables, connectors and communication system that all have poor mean time between failures, in the downhole environment.

- Current downhole instrumentation, therefore, does not provide the necessary reliability required for the safe and efficient operation of offshore deepwater wells and there is a need
30 to improve the reliability of down-hole temperature and pressure measurements.

- The difficulty of using electronics based sensors downhole can be avoided by using distributed fibre-optic sensing techniques which have the intrinsic capability of being more reliable than traditional sensing in that no downhole electronics is required. However, this
35 technology is currently at an early stage in its operational lifecycle. In any event, using sensors mounted on a Christmas tree located on the seabed, to provide estimates of

downhole temperatures and pressures, will provide an essential back-up in the event of failures, for example, of the fibre-optic cable.

Summary of the Invention

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According to the present invention, there is provided a method of calculating a value representative of a downhole temperature in a hydrocarbon well, the well comprising production tubing inside outer tubing, there being an annulus between the tubing and the casing which annulus receives a hydraulic control line supplying hydraulic fluid for the control
10 of a downhole device, the method comprising sensing the pressure of hydraulic fluid in the control line at the wellhead and using a measurement of that pressure to calculate a value representative of a downhole temperature.

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The device could be at a first downhole zone, there being a further downhole device at a second downhole zone with a further control line in the annulus which supplies hydraulic fluid for the control of the further device, the method comprising sensing the pressure of hydraulic fluid in the further control line at the wellhead to calculate a value representative of a further downhole temperature.

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The sensing of pressure could be carried out at a tree at the wellhead.

Preferably, the temperature of production fluid is sensed at the wellhead and a measurement of that temperature is used to calculate the or each value representative of a downhole temperature.

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The sensing of temperature could be carried out at a tree at the wellhead.

This invention enables a substantial improvement of the reliability issue by providing an alternative method of determining the downhole production fluid flowing temperature, without the need for downhole temperature and pressure measurement. The possibility of being
30 able to calculate and infer downhole fluid temperatures by using the results from sensors mounted on subsea electronic equipment on Christmas trees installed on the seabed (i.e. at the wellhead and avoiding the necessity for downhole sensors) will provide a major advantage in terms of production well operation and sensor back-up.

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The flow of fluid from a reservoir is controlled by means of hydraulically operated valves (or chokes) positioned within the well, usually at the depths of the various reservoir zones, so

that fluid can be drawn from each zone as required into the main well borehole. The fluid flow is contained within an inner main well bore pipe (production tubing), while the hydraulic control lines for valve operation are contained within an outer annulus surrounding the main production tubing. The annulus also contains chemical fluid which is passed down it for cleaning purposes.

The produced fluid, which is at a high temperature, heats the production tubing, which in turn heats the fluid in the annulus. The hydraulic control lines, which are housed in the annulus, are heated along with the annulus fluid. The pressures in the control lines are affected by the temperature and consequently a change in temperature results in a change of pressure.

- 10 The pressure of the fluid in a control line can be used to determine the average temperature of that line. When interval control valves (ICVs) are set at different depths, the difference in average temperatures between the lines allows the determination of the average temperature in the separate sections of the annulus, hence the temperature of the fluid flowing into the different sections of the well.
- 15 When the production fluid contains water or gas, its temperature will change and this can be detected as a change of pressure in the control lines allowing the operator to take the necessary controlling actions.

Brief Description of the Drawing

- 20 Fig. 1 shows schematically part of a hydrocarbon well installation to which the invention may be applied.

Description of an Embodiment of the Invention.

- 25 In order to illustrate the method of calculation of downhole temperatures, the well configuration shown in Fig. 1 is shown as an example. In this example, the well configuration has two zones, Zone A at a depth of 3000 metres and Zone B at a depth of 3100 metres, from which production fluid can be drawn. An interval control valve 1 is fitted at each zone depth, to control the flow of fluid and each has its own hydraulic control line 2. The production fluid flows through the main production tubing 3 whilst chemical cleaning fluids can be passed down the annulus formed between outer tubing 4 and the inner production tubing 3. The annulus also contains the hydraulic control lines 2 which provide for control of the interval control valves 1. A subsea control module (SCM) for operating directional control valves (DCVs) is disposed at the wellhead. The pressure of the hydraulic
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control is measured in the SCM, and the variation in this pressure is used in the method of the present invention to infer temperatures further downhole. The calculations necessary to perform the temperature inference may be carried out either in a subsea electronics module (SEM) of the SCM, or, preferably, at a master control station (MCS) located topside.

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As an option the control lines could have check valves (or pilot operated check valves) included downstream of the pressure measurement (i.e. not between the downhole device and the pressure sensor) to limit the volume of hydraulic fluid in the system that can affect the calculation.

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Typically, the temperature at the well head is 340K (degrees absolute) while the temperature at Zone A is 373K. When the production fluid contains water or gas, its temperature will change and this can be detected as a change of pressure in the control lines. The following analysis illustrates how a hypothetical decrease in temperature of 5K in the fluid flowing from Zone B, due to e.g. water or gas content of the production fluid, will consequently lead to a measurable change in the pressure in the control lines at the wellhead.

Sensitivity Analysis - Flowing temperature change detection

$$T_{\text{abs_Z1}} := 373\text{K}$$

Absolute temperature at Zone 1

$$T_{\text{abs_WH}} := 340\text{K}$$

Absolute temperature at wellhead

$$T_{\text{av_1}} := \left[\frac{(T_{\text{abs_Z1}} - T_{\text{abs_WH}})}{2} \right] + T_{\text{abs_WH}} = 356.5\text{K}$$

Average temperature from Zone 1 to wellhead

$$D_1 := 3000\text{m}$$

Measured depth of Zone 1

$$D_2 := 3100\text{m}$$

Measured depth of Zone 2

$$T_{\text{Grd_1}} := \frac{(T_{\text{abs_Z1}} - T_{\text{abs_WH}})}{D_1} = 0.011\text{K/m}$$

Temperature gradient to Zone 1

$$T_{\text{Norm_2}} := (T_{\text{Grd_1}} \cdot D_2) + T_{\text{abs_WH}} = 374.1\text{K}$$

Expected temperature at Zone 2 based on temperature gradient

$$T_{\text{av_TD_Norm_simple}} := \left[\frac{(T_{\text{Norm_2}} - T_{\text{abs_WH}})}{2} \right] + T_{\text{abs_WH}} = 357.05\text{K}$$

Average temperature with normal gradient

$$T_{\text{WI_2}} := T_{\text{Norm_2}} - 5\text{K} = 369.1\text{K}$$

Flowing temperature at Zone 2 with water influx

$$T_{\text{av_1_2_Norm}} := \left[\frac{(T_{\text{Norm_2}} - T_{\text{abs_Z1}})}{2} \right] + T_{\text{abs_Z1}} = 373.55\text{K}$$

Average temperature between Zones 1 and 2 with normal gradient

$T_{av_1_2_WI} := \left[\frac{(T_{WI_2} - T_{abs_Z1})}{2} \right] + T_{abs_Z1} = 371.05K$	Average temperature between Zones 1 and 2 with water ingress at Zone 2
$T_{av_TD_Norm} := \left[T_{av_1} \cdot \left(\frac{D_1}{D_2} \right) \right] + \left[T_{av_1_2_Norm} \cdot \left(\frac{D_2 - D_1}{D_2} \right) \right] = 357.05K$	Average temperature with normal gradient (should match simple version above)
$T_{av_TD_WI} := \left[T_{av_1} \cdot \left(\frac{D_1}{D_2} \right) \right] + \left[T_{av_1_2_WI} \cdot \left(\frac{D_2 - D_1}{D_2} \right) \right] = 356.969K$	Average temperature with water influx
$\Delta T := T_{av_TD_Norm} - T_{av_TD_WI} = 0.081K$	Change in average temperature of control line going to Zone 2
$\alpha_f := 0.000207 K^{-1}$	Volumetric coefficient of thermal expansion of the fluid
$\alpha_v := 0.000036 K^{-1}$	Volumetric coefficient of thermal expansion of control line (= three times the linear one)
$\beta := 0.0004 MPa^{-1}$	Compressibility factor of the fluid (relative change in volume per unit change in pressure)
$E := 200000 MPa$	Elastic modulus
$D := 8 mm$	Diameter of control line
$t := 2 mm$	Thickness of control line
$\alpha_f \cdot \Delta T = 1.669 \times 10^{-5}$	Thermal expansion of fluid
$\alpha_v \cdot \Delta T = 2.903 \times 10^{-6}$	Thermal expansion of control line
$\Delta P := \frac{[(\alpha_f - \alpha_v) \cdot \Delta T]}{\beta + \left(\frac{D}{t \cdot E} \right)} = 3.283 \times 10^4 Pa$	
$\Delta P = 4.762 psi$	Change in pressure measured at the control line for Zone 2, neglecting annulus pressure changes and flow proportions
$\Delta T = \frac{\Delta P \cdot (\beta + (\frac{D}{t \cdot E}))}{(\alpha_f - \alpha_v)}$	Equation expressed to predict change in temperature for a measured change in pressure.

As can be seen, this analysis results in an equation from which one may infer the change in the average temperature in a particular zone from a measured change in pressure in the

control lines. Some assumptions have been made which are explained in the text but these are unlikely to affect the results significantly.

This derivation of temperatures at the various zones in a well thus provides a basic understanding of the theory behind the proposed method of inferring downhole temperatures by measuring the change in pressure in hydraulic control lines which pass through the various well zones to the fluid control chokes which they control.

When the production fluid contains water or gas, its temperature will change and this can be detected as a change of pressure in the control lines allowing the operator to take the necessary controlling actions.

The pressure measuring sensors fitted at the wellhead Christmas tree may need to be of higher resolution in order to measure the change in pressure to the accuracy required but this is more a cost than an availability issue.

Advantages of using the Invention

This invention provides a potential solution to the reliability issue by providing an alternative method of determining the downhole flowing temperature without the need for downhole temperature and pressure measurement. The possibility of being able to estimate this by using the results from pressure sensors mounted on subsea electronic equipment on Christmas trees on the seabed (i.e. avoiding the necessity for down-hole sensors) is a major advantage in terms of operational and back-up purposes.

In a complex, multi-completion well with multiple sets of down-hole temperature and pressure sensors, the failure of one could be accommodated for by using the absolute measurement of a surviving set of sensors and the pressure measurement in control lines as described previously. If all downhole sensors fail, then a quantitative measurement would be difficult, but a qualitative indication would be possible to allow identification of which zone is producing water and/or gas.

Overall, the provision of an alternative method of measuring and calculating downhole fluid temperatures can make a significant contribution to:

- providing higher availability/reliability and increased fault tolerance
- providing accelerated production profiles; and

reducing well intervention frequency to carry out repairs thereby reducing costs and improving overall operational safety conditions.

- 5 The move to multilateral and multizone wells (which will reduce the number of wellheads, the amount of gas burnt off and risk of oil pollution) will also be assisted by the availability of additional means of downhole fluid temperature estimation.

CLAIMS

What is claimed is:

1. A method of calculating a value representative of a downhole temperature in a hydrocarbon well, wherein the hydrocarbon well comprises a production tubing inside an outer tubing, an annulus is provided between the production tubing and the outer tubing, and the annulus receives a hydraulic control line supplying hydraulic fluid for the control of a downhole device, the method comprising:

sensing a pressure of the hydraulic fluid in the hydraulic control line at a wellhead;
and

using the sensed pressure of the hydraulic fluid in the hydraulic control line to calculate the value representative of the downhole temperature.

2. The method according to claim 1, wherein the downhole device is at a first downhole zone, the hydrocarbon well further comprises an additional downhole device at a second downhole zone, and the annulus further receives an additional hydraulic control line supplying hydraulic fluid for the control of the additional downhole device, the method further comprising:

sensing a pressure of the hydraulic fluid in the additional hydraulic control line at the wellhead to calculate the value representative of the downhole temperature.

3. The method according to claim 2, wherein the sensing of the pressure of the hydraulic fluid in the additional hydraulic control line is carried out at a tree at the wellhead.

4. The method according to claim 1, wherein the sensing of the pressure of the hydraulic fluid in the hydraulic control line is carried out at a tree at the wellhead.

5. The method according to claim 1, further comprising:

sensing a temperature of a production fluid at the wellhead; and

using the sensed temperature of the production fluid to calculate the value representative of the downhole temperature.

6. The method according to claim 5, wherein the sensing of the temperature of the production fluid is carried out at a tree at the wellhead