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(54) Title: ESTIMATING TILT OF A RESERVOIR

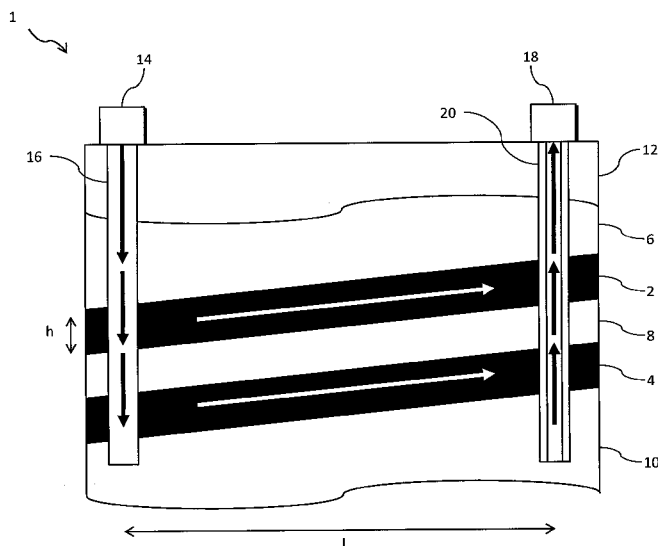


Fig 1

(57) Abstract: There is provided a computer-implemented method for estimating a tilt of a layer of a reservoir, there being a production well extending into the layer of the reservoir configured such that fluid flows from the layer into the production well. The production well further comprises one or more devices arranged to measure a temperature of fluid at one or more locations within the production well at a plurality of points in time. The method comprises: receiving temperature data from the one or more devices, the temperature data being indicative of a temperature of fluid entering the production well from the layer at each of a plurality of points during a period of time; identifying, using the temperature data, a trend indicative of a change in temperature of the fluid entering the production well during the period of time; identifying a velocity of fluid within the layer in a direction of flow of fluid within the layer during the period of time; determining using the identified trend and the identified velocity, an estimate of the change in temperature by distance for the fluid, the distance being in a direction of flow of fluid within the layer; identifying a geothermal gradient indicative of a change with depth in the temperature of rock within and surrounding the reservoir; and determining a measure

of the tilt of a layer in the reservoir based on the estimated change in temperature by distance and the geothermal gradient.

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ESTIMATING TILT OF A RESERVOIR

Technical Field

The following describes systems and methods for estimating tilt of a reservoir.

5 Background

Reservoirs, in particular hydrocarbon bearing reservoirs typically contain fluids such as oil, gas and water in layers of permeable reservoir rock. These layers may be separate, or partially interconnected, which is to say that the fluids may flow between layers at only a limited number of points. The layers may have different characteristics, such as permeability of the reservoir rock and viscosity of the fluid, and consequently fluid may flow along each layer at a different rate.

The layers may have tilt, that is the layers may be angled relative to the horizontal and therefore may change in depth as one traverses the well.

15 In some cases, waterflooding or similar secondary recovery techniques may be used to force additional fluid (hydrocarbons) out of the reservoirs. However the effectiveness of these techniques is diminished if the flood water passes along a layer that is relatively more permeable than the layer occupied by the hydrocarbons.

Enhanced oil recovery (EOR) techniques may be used to increase the effectiveness of the secondary recovery measures. These techniques include injecting aqueous solutions of polymers such as viscosifiers into the well to partially or fully block a higher permeability layer, and thereby enhance the recovery of hydrocarbons from the less permeable layers. For example polymeric microparticles having labile (reversible) and non-labile internal cross links in which the microparticle conformation is constrained by the labile internal cross links may be used. The microparticle properties, such as particle size distribution and density, of the constrained microparticle are designed to allow efficient propagation through the pore structure of hydrocarbon reservoir matrix rock, such as sandstone. On heating to reservoir temperature and/or at a predetermined pH, the labile internal cross links start to break allowing the particles to expand by absorbing the injection fluid (normally water). The expanded particle is engineered to have a particle size distribution and physical characteristics which allow it to impede the flow of injected fluid in the pore structure of the high permeability reservoir layer. In doing so it is capable of diverting subsequently injected fluid into less thoroughly swept zones of the reservoir.

To enable these techniques to be effectively used, it is of benefit to know, or be able to estimate, the flow rate into a production well from the various layers, and the tilt of the layers within the reservoir. Prior methods of measuring flow involve providing flow meters at a number of points in the production well. Alternatively, a sensor can be lowered into a production well to measure flow at different points. The tilt may be estimated by, for example, geological surveys.

Recently, downhole temperature sensors have been installed in wells. These sensors measure the surrounding temperature at a number of points along a well, typically at a spacing of a meter or similar.

It is desirable to be able to use temperature data to estimate the tilt of a reservoir.

Summary of Embodiments

In accordance with at least one embodiment, methods, devices, systems and software are provided for supporting or implementing functionality to estimate the tilt of a reservoir.

This is achieved by a combination of features recited in each independent claim.

Accordingly, dependent claims prescribe further detailed implementations.

According to a first embodiment there is provided a computer-implemented method for estimating a tilt of a layer of a reservoir, there being a production well extending into the layer of the reservoir configured such that fluid flows from the layer into the production well, the production well further comprising one or more devices arranged to measure a temperature of fluid at one or more locations within the production well at a plurality of points in time, the method comprising: receiving temperature data from the one or more devices, the temperature data being indicative of a temperature of fluid entering the production well from the layer at each of a plurality of points during a period of time; identifying, using the temperature data, a trend indicative of a change in temperature of the fluid entering the production well during the period of time; identifying a velocity of fluid within the layer in a direction of flow of fluid within the layer during the period of time; determining using the identified trend and the identified velocity, an estimate of the change in temperature by distance for the fluid, the distance being in a direction of flow of fluid within the layer; identifying a geothermal gradient indicative of a change with depth in the temperature of rock within and surrounding the reservoir; and determining a measure of the tilt of a layer in the reservoir based on the estimated change in temperature by distance and the geothermal gradient.

According to a second embodiment there is provided a computer readable storage medium storing computer readable instructions thereon for execution on a computing system to implement a method for estimating a tilt of a layer of a reservoir, there being a production well extending into the layer of the reservoir configured such that fluid flows from the layer into the production well, the production well further comprising one or more devices arranged to measure a temperature of fluid at one or more locations within the production well at a plurality of points in time, the set of instructions are configured to cause the computing system to perform the steps of: receiving temperature data from the one or more devices, the temperature data being indicative of a temperature of fluid entering the production well from the layer at each of a plurality of points during a period of time; identifying, using the temperature data, a trend indicative of a change in temperature of the fluid entering the production well during the period of time; identifying a velocity of fluid within the layer in a direction of flow of fluid within the layer during the period of time; determining using the identified trend and the identified velocity, an estimate of the change in temperature by distance for the fluid, the distance being in a direction of flow of fluid within the layer; identifying a geothermal gradient indicative of a change with depth in the temperature of rock within and surrounding the reservoir; and determining a measure of the tilt of a layer in the reservoir based on the estimated change in temperature by distance and the geothermal gradient.

According to a third embodiment there is provided a system for estimating a tilt of a layer of a reservoir, there being a production well extending into the layer of the reservoir configured such that fluid flows from the layer into the production well, the production well further comprising one or more devices arranged to measure a temperature of fluid at one or more locations within the production well at a plurality of points in time, the system comprising: an interface arranged to receive temperature data, the temperature data having been collected by the one or more devices, the temperature data being indicative of a temperature of fluid entering the production well from the layer at each of a plurality of points during a period of time; and a processor arranged to: identify, using the temperature data, a trend indicative of a change in temperature of the fluid entering the production well during the period of time; identify a velocity of fluid within the layer in a direction of flow of fluid within the layer during the period of time; determine using the identified trend and the identified velocity, an estimate of the change in temperature by distance for the fluid,

the distance being in a direction of flow of fluid within the layer; identify a geothermal gradient indicative of a change with depth in the temperature of rock within and surrounding the reservoir; and determine a measure of the tilt of a layer in the reservoir based on the estimated change in temperature by distance and the geothermal gradient.

5 Further features and advantages of embodiments will become apparent from the following description, given by way of example only, which is made with reference to the accompanying drawings.

Brief Description of the Drawings

10 Figure 1 shows a schematic diagram of an oil recovery system and a reservoir in respect of which embodiments are applicable;

Figure 2 shows schematic diagram of a section of a production well;

Figure 3 shows schematic diagram of a section of a production well;

Figure 4 shows schematic diagram of a processing system in which embodiments may operate;

15 Figure 5 shows a computer implemented method of estimating flow into a production well;

Figure 6 shows a plot of temperature evolution over time;

Figure 7 shows a computer implemented method of estimating tilt of a reservoir; and

20 Figure 8 shows a schematic diagram of well locations in a reservoir in which embodiments may be used.

Several parts and components of the embodiments appear in more than one Figure; for the sake of clarity the same reference numeral will be used to refer to the same part and component in all of the Figures.

Detailed Description of Illustrative Embodiments

25 Prior to describing examples of embodiments in detail, embodiments will firstly be described in summary form.

According to a first embodiment there is provided a computer-implemented method for estimating a tilt of a layer of a reservoir, there being a production well extending into the layer of the reservoir configured such that fluid flows from the layer into the
30 production well, the production well further comprising one or more devices arranged to measure a temperature of fluid at one or more locations within the production well at a plurality of points in time, the method comprising: receiving temperature data from the one

or more devices, the temperature data being indicative of a temperature of fluid entering the production well from the layer at each of a plurality of points during a period of time; identifying, using the temperature data, a trend indicative of a change in temperature of the fluid entering the production well during the period of time; identifying a velocity of fluid within the layer in a direction of flow of fluid within the layer during the period of time; determining using the identified trend and the identified velocity, an estimate of the change in temperature by distance for the fluid, the distance being in a direction of flow of fluid within the layer; identifying a geothermal gradient indicative of a change with depth in the temperature of rock within and surrounding the reservoir; and determining a measure of the tilt of a layer in the reservoir based on the estimated change in temperature by distance and the geothermal gradient.

Over time, the temperature of the fluid entering the well may change. By monitoring the temperature, and thus the flow rates, such changes in temperature may be identified. These temperature changes may be used to determine information about the reservoir. For instance, the tilt of the reservoir may be determined from the evolution of the fluid temperature over time. The 'tilt' of the reservoir indicates that the depth of the reservoir is not constant. The temperature evolution is therefore caused by fluid passing along the reservoir from a deeper or shallower point. The evolution may take many days, and possibly years, as the fluid takes time to flow to the inflow location. Therefore from the change in temperature, the tilt of the reservoir can be determined, and thus the modelling and mapping of the reservoir may be improved.

In embodiments the trend may be determined over a period greater than a month. In embodiments the method may comprise identifying a flow rate of fluid into the production well from the layer whereby to estimate the velocity of fluid within the layer. In embodiments the method may comprise: identifying a height of a permeable layer containing the fluid within the reservoir, whereby to estimate the velocity of fluid within the layer.

In embodiments the method may comprise multiplying the flow rate by a predetermined constant, whereby to estimate the flow velocity, the predetermined constant being calculated in dependence on the arrangement of at least one injection well in relation to the production well.

The flow velocity of fluid within the reservoir, or the flow rate of fluid entering the

production well and the size of the associated layer in the reservoir (specifically, height) may be used to relate the change in temperature over time to a change in temperature over distance. In many cases the flow of fluid is not linear, since the fluid will enter the well from an arc (or full circle) surrounding the well. As such, a predetermined constant may be used to relate the inflow rate and the height to a velocity of fluid within the reservoir.

In embodiments the method may comprise associating a change in temperature of the fluid entering the production well with a change in depth based on the geothermal gradient of the reservoir whereby to determine a measure of the tilt of the layer. By using the geothermal gradient, the change in temperature with length may be used to determine a change in depth with length, i.e. the tilt, of the reservoir.

According to a second embodiment there is provided a computer readable storage medium storing computer readable instructions thereon for execution on a computing system to implement a method for estimating a tilt of a layer of a reservoir, there being a production well extending into the layer of the reservoir configured such that fluid flows from the layer into the production well, the production well further comprising one or more devices arranged to measure a temperature of fluid at one or more locations within the production well at a plurality of points in time, the set of instructions are configured to cause the computing system to perform the steps of: receiving temperature data from the one or more devices, the temperature data being indicative of a temperature of fluid entering the production well from the layer at each of a plurality of points during a period of time; identifying, using the temperature data, a trend indicative of a change in temperature of the fluid entering the production well during the period of time; identifying a velocity of fluid within the layer in a direction of flow of fluid within the layer during the period of time; determining using the identified trend and the identified velocity, an estimate of the change in temperature by distance for the fluid, the distance being in a direction of flow of fluid within the layer; identifying a geothermal gradient indicative of a change with depth in the temperature of rock within and surrounding the reservoir; and determining a measure of the tilt of a layer in the reservoir based on the estimated change in temperature by distance and the geothermal gradient.

According to a third embodiment there is provided a system for estimating a tilt of a layer of a reservoir, there being a production well extending into the layer of the reservoir configured such that fluid flows from the layer into the production well, the production

well further comprising one or more devices arranged to measure a temperature of fluid at one or more locations within the production well at a plurality of points in time, the system comprising: an interface arranged to receive temperature data, the temperature data having been collected by the one or more devices, the temperature data being indicative of a temperature of fluid entering the production well from the layer at each of a plurality of points during a period of time; and a processor arranged to: identify, using the temperature data, a trend indicative of a change in temperature of the fluid entering the production well during the period of time; identify a velocity of fluid within the layer in a direction of flow of fluid within the layer during the period of time; determine using the identified trend and the identified velocity, an estimate of the change in temperature by distance for the fluid, the distance being in a direction of flow of fluid within the layer; identify a geothermal gradient indicative of a change with depth in the temperature of rock within and surrounding the reservoir; and determine a measure of the tilt of a layer in the reservoir based on the estimated change in temperature by distance and the geothermal gradient.

Figure 1 is a schematic block diagram showing a simplified representation of a fluid recovery system 1 that comprises a multi-layer reservoir. In this example, the reservoir comprises a series of interbedded permeable and impermeable layers. The permeable layers bear fluid (such as oil, gas and water) in the pore spaces within the rock, and are referenced 2 and 4. The impermeable layers are referenced 6, 8 and 10. Above the upper impermeable layer 6 there is a generalized surface layer 12 which may comprise multiple non-oil bearing layers, and (if the reservoir is offshore) a layer of seawater. The composition of this layer 12 is not relevant to this example.

The permeable and impermeable layers make up the reservoir. Penetrating the reservoir is an injection well, comprising a control station 14 and a well bore 16, and a production well, comprising a control station 18 and a well bore 20. The injection and production wells are separated by a distance L as shown. Typically there are many more wells than the two shown here; however two are shown in this exemplary embodiment for simplicity.

When used for a waterflood, the injection well injects water as an injection fluid under pressure into the reservoir. The water flows along each of the permeable layers 2 and 4 as shown by the arrows. The water pushes the oil in the reservoir ahead of it causing the oil to be displaced from the reservoir into the well bore of the production well (again

shown by the arrows). From there, the pressure of the reservoir, optionally aided by pumps located in the well bore of the production well, lifts the oil and water produced from the reservoir up to the surface where it can be stored and refined.

5 The composition of the production well bore 20 will now be described in more detail with reference to Figure 2.

Figure 2 is a schematic diagram showing a simplified representation of a portion of a well bore 20 of a production well. The well bore comprises an annulus 22 which opens onto the rock of the reservoir. Along the annulus runs a central tubing 24 which conveys fluid to the surface. As such, the annulus is located between the central tubing 24 and the wellbore. The wellbore may be an openface wellbore, i.e. one not lined with a casing. The annulus is divided into sections, with section 26 being fully represented, and the surrounding sections 28 and 30 being partially represented in Figure 2. Separating the sections are separators (also known as 'packers') 32 (between sections 26 and 28) and 34 (between sections 26 and 30), which isolate a given section from adjacent sections. Thus the flow of fluid within a given section is isolated from the flow of fluid in other sections. In this example, the packer 32 is referred to as the downstream packer for section 26, and packer 34 is referred to as the upstream packer for section 26. As is well known in the art, downstream and upstream are measured relative to the flow of fluid in the well, and thus the upstream packer is generally located at a greater depth than is the downstream packer.

20 Passing down the well bore, through the annulus, is a downhole temperature sensor (DTS) 36. The DTS is able to measure the temperature of the fluid in the annulus at a plurality of points along its length. The DTS may typically be a fibre optic sensor as is known in the art.

As described above, the annulus 22 is open to the rock of the reservoir, which means that fluid is able to flow into the annulus from the reservoir. While a small amount of fluid may enter the annulus along its entire length, the majority of the fluid will enter the annulus at a number of inflow locations, which are typically fissures in the rock which provide a low permeability path into the annulus and thus carry the majority of the fluid flowing from the reservoir into the annulus 22. Two such inflow locations (i.e. fissures) are shown by arrows 38 and 40.

Fluid, having entered the annulus 22, may flow downstream along the annulus towards an inlet 50 in the central tubing. At the inlet, the fluid may enter the central tubing

from the annulus. The fluid in the central tubing may thus be conveyed to the surface. This process will be described in more detail with reference to Figure 3.

Figure 3 shows a two-dimensional section of the well bore similar to Figure 2.

Similar features are provided with similar reference numerals, and will not be described in detail, suffice to say that annulus 22 surrounds central tubing 24. The annulus is divided by
5 packers 32 and 34 into sections 26, 28 and 30, and a DTS 36 is provided along the longitudinal length of the annulus.

Fluid is shown flowing into the annulus at two inflow locations 38 and 40. The first location 38 is at a greater depth than the second location 40, and is thus upstream of the
10 second location 40. While only two inflow locations are shown, it will be apparent that many more may be present in any given section of the annulus. In addition, while the inflow locations are shown only on one side of the annulus, it will be understood that a fissure creating an inflow location may be present around some, or all, of the circumference of the annulus 22.

15 The flow within the section 26 of the annulus will now be described in more detail. At the upstream end of the annulus (lower portion of Figure 3), the flow of fluid is stagnant. This is because there is no inflow of fluid through the packer 34, and this portion of the annulus is upstream of the first inflow location 38. This stagnant fluid is represented by loop arrow 42.

20 Fluid flows from the reservoir into the annulus at the first inflow location 38. The fluid then flows downstream (i.e. upwards) along the annulus, as represented by arrow 44.

At the second inflow location 40, further fluid flows into the annulus 22. This fluid mixes with the fluid already flowing up the annulus 44.

The fluid flows to the downstream end of the annulus where, as represented by arrow
25 48, it flows into the central tubing via an inlet 50.

In addition, as represented by arrow 52, fluid flows up the central tubing from sections located upstream of the section 26 considered here. The fluid from the section 26, entering the central tubing as represented by arrow 48, mixes with the flow 52 already in the central tubing 24 and will continue to rise until it reaches the surface.

30 DTS 36 measures the temperature of the fluid in the annulus at a plurality of locations, referenced 37A..E. It will be understood that these points are purely exemplary, and the temperature may be measured at many other points in the annulus 22. Point 37A

corresponds to the point at which the fluid in the annulus is stagnant (i.e. flow 42). Point 37B corresponds to a point just downstream of the first inflow 38. Point 37C corresponds to the point just upstream of the second inflow 40. Point 37D corresponds to a point just downstream of the second inflow 40. Finally, point 37E corresponds to a point just upstream of the inlet 50.

Embodiments provide computer systems, and computer implemented methods which may be used to estimate the tilt of a reservoir. To assist in this the flow in a production well as described above may be estimated. To this end, embodiments may include a computer system running flow estimation (FE) software components which enable the system to estimate the flow into and within the production well, as well as enabling the tilt to be estimated.

The computer system may be located in a planning and control centre (which may be located a substantial distance from the reservoir, including in a different country).

Alternatively, the computer system may be part of the control systems of the reservoir, such as control stations 14 and 18 as shown in Figure 1. The FE software components may comprise one or more applications as are known in the art, and/or may comprise one or more add-on modules for existing software.

A schematic block diagram showing such a computer system will now be described with reference to Figure 4. The computer system 200 comprises a processing unit 202 having a processor, or CPU, 204 which is connected to a volatile memory (i.e. RAM) 206 and a non-volatile memory (such as a hard drive) 208. The FE software components 209, carrying instructions for implementing embodiments, may be stored in the non-volatile memory 208. In addition, CPU 204 is connected to a user interface 210 and a network interface 212. The network interface 212 may be a wired or wireless interface and is connected to a network, represented by cloud 214. Thus the processing unit 202 may be connected with sensors, databases and other sources and receivers of data through the network 214.

In use, and in accordance with standard procedures, the processor 204 retrieves and executes the FE software components 209 stored in the non-volatile memory 208. During the execution of the FE software components 209 (that is when the computer system is performing the actions described below) the processor may store data temporarily in the volatile memory 206. The processor 204 may also receive data (as described in more detail

below), through user interface 210 and network interface 212, as required to implement embodiments. For example, data may be entered by a user through the user interface 210 and/or received from e.g. a downhole temperature sensor in a production well through the network 214 and/or may be retrieved from a remote database through the network 214.

5 These data may be generated and/or stored in a number of ways known to the skilled person. For example diffusion coefficients (described below) may be determined in a laboratory from a core sample relating to the reservoir using well known processes. Once determined, this data may be actively sent to the processing unit 202, or stored in a database to be retrieved as required by the processing unit 202. Alternatives will be readily
10 apparent to the skilled person.

 Having processed the data, the processor 204 may provide an output via either of the user interface 210 or the network interface 212. If required, the output may be transmitted over the network to remote stations, such as the control station for an injection well. Such processes will be readily apparent to the skilled person and will therefore not be described
15 in detail.

 As will be described in more detail below, the flow rate and temperature change over time may be used in the estimation of tilt. Examples of computer implemented methods for estimating flow rates within the section 26 will therefore be described below with reference to Figure 5. To put these exemplary methods into context, the temperature
20 changes associated with the flow of fluid into and along the annulus will first be described for a section having two inflow locations (as represented above by arrows 38 and 40), and a stream of fluid coming from upstream in the central tubing pipe (as represented above by arrow 52).

 The downhole temperature sensor (DTS) 36 in the annulus measures temperature
25 along the annulus and in particular the following changes of temperature:

 (i) a relatively abrupt change (i.e. a jump) in the temperature of the fluid in the annulus at the first inflow location 38;

 (ii) a change (i.e. an evolution) in temperature of the fluid in the annulus between the first inflow location 38 and the second inflow location 40 due to heat transfer from the
30 central tubing to the annulus (i.e. along arrow 44);

 (iii) a second relatively abrupt temperature change at the second inflow location 40;
and

(iv) evolution of temperature downstream of the second inflow location 40 towards the point where the annulus flow enters the main tubing (i.e. along arrow 46) due to heat transfer from the central tubing to the annulus.

It will be understood that in different examples, more inflow locations may be present, and therefore there will be more temperature jumps, and evolutions of temperature. Nevertheless, for this example, only two locations will be considered.

It is assumed that the nature (i.e. the temperature, flow rate and/or composition) of the fluid flowing from further upstream (represented by arrow 52) is known. This is because, for any given section of the annulus, the process described herein is capable of estimating the nature of the fluid flowing into that section from the reservoir, and therefore estimates the nature of the fluid entering the central tubing from that section. The process described herein may therefore be carried out section by section along the well, starting with the foot (i.e. bottom) of the well (i.e. the most upstream section) where the flow in the central tubing 24 is known (and is zero). The analysis of this most upstream section may be used to estimate the nature of the fluid entering the central tubing 24 from this section. Therefore, the nature of the fluid in the central tubing 24 passing to the next downstream section is known. The process may be repeated for each section working downstream, with the fluid entering the annulus at any given section being mixed with the fluid in the central tubing 24 proceeding downstream from that section. Thus, as each section is analysed, the composition, flow rate and temperature of the fluid in the central tubing 24 can be determined.

The temperature of the flow 52 in the central tubing 24 at the upstream packer 34 is denoted as T and the flow rate as Q . It will also be assumed that the flow 52 has a known composition (i.e. mix of oil, gas and water) and hence a specific heat capacity (which may be an average heat capacity of the mixed fluids). The geothermal temperature of the reservoir is higher at greater depths. Therefore the fluid in the central tubing, having flowed from these greater depths, will be at a higher temperature than the fluid in the annulus.

As described above, the region 42 between the upstream packer and the first inflow location 38 is approximately stagnant and so will, in time, assume the temperature T of the central tubing. This temperature may be measured by the DTS 36, once the flow in the well

has stabilised, which is to say when the fluid in region 42 has had the chance to be warmed by the flow in the central tubing 24.

At the first inflow location 38, the temperature in the annulus will jump to the value T_1 which is close to the geothermal temperature (TG_i) at that depth, but may differ owing to the Joule-Thomson effect cooling the fluid as it flows from the rock of the reservoir into the annulus at the inflow location, and to a temperature drift in the geotherm. This Joule-Thomson effect may cause a temperature change which may be represented in terms of a Joule-Thomson coefficient JT , this being a function of the composition of the fluid flowing into the annulus at the first inflow location 38. Thus the temperature T_1 at the first inflow location may be given by the formula:

$$T_1 = TG_i + DT_i + JT \cdot Q_i \quad (1)$$

where:

T_i is the temperature of the fluid at the first inflow location 38;

TG_i is the geothermal temperature at the depth of the first inflow location 38;

DT_i represents a quantity of temperature drift (which will be discussed below);

JT is a Joule-Thomson coefficient for the composition of the fluid entering the annulus at the first inflow location 38, which may be determined from the composition of the fluid; and

Q_i represents the rate of flow of fluid into the annulus at the first inflow location 38.

The geothermal temperature TG_i may be determined using methods known in the art; for example, it may be calculated from survey data or, since the geothermal temperature is relatively static, may be measured as the well is being drilled, or before the flow starts in the well. Therefore a range of values for JT , Q_i and DT_i which are consistent with T_1 to within a specified error tolerance, may be determined using the above formula.

In the early stages of extraction of fluid from the reservoir, the flow into the annulus will likely be pure oil (possibly containing dissolved gases), therefore JT will be known; equally the temperature drift DT_i will be small. As a result, an estimate or range of values for Q_i consistent with T_i may be determined (since JT for pure oil is known). At later time points, JT may be determined from measurements made at the surface of the composition of the fluid in the production well, and from observing the evolution of the flow of fluid in the production well.

The temperature change at the first inflow location 38 may be determined using, for example, the temperatures measured at points 37A and 37B by the DTS 36 as described above in Figure 3.

Subsequently, the flow 44 between the first and second inflow locations 38 and 40 may be analysed. The fluid flowing within region 44 will initially start at temperature T_j and will have a flow rate of Q_i . However, as the temperature (7) in the central tubing 24 is greater than the temperature (T_l) in the annulus, there will be a transfer of heat from the central tubing to the annulus.

This transfer of heat may be modelled by, for example, considering the heat transfer per unit distance (Q_{pa}) along the tubing. Q_{pa} can be calculated using a formula such as:

$$Q_{pa} = \frac{2\pi rk}{\delta} [T - T_a] \quad (2)$$

where:

Q_{pa} is the heat transfer per unit distance;

r is the external radius of the central tubing 24;

15 k is the thermal conductivity of the central tubing 24;

δ is the thickness of the wall of the central tubing 24;

T is the temperature of the fluid in the central tubing 24; and

T_a is the temperature of the fluid in the annulus at a given point along the length of the annulus.

20 In addition, the temperature change of fluid in the annulus may be modelled using the following:

$$Q_{pa} = \frac{dT_a}{dz} \rho C_p M_a \quad (3)$$

where:

Q_{pa} is the heat transfer per unit distance (as calculated above using equation 2);

25 ρ is the density of the fluid in the annulus 22;

M_a is the volume flux in the annulus (i.e. the volume flux of e.g. flow 44 in Figure 3); and

$\frac{dT_a}{dz}$ is the temperature change per unit length of the fluid in the annulus (length here being measured along the longitudinal axis of the annulus).

It will be apparent that the faster the rate at which the fluid flows along the annulus (i.e. the greater the value of M_d), the smaller the rate of change in temperature with height. By contrast, a relatively slow rate of flow will result in a relatively greater change in temperature.

5 Equations 2 and 3 above may be used to refine the value(s) of Q_i calculated using equation 1 and also the composition of the fluid as determined according to the techniques described above.

At the second inflow location 40, fluid flows into the well with a flow rate of Q_2 , at a temperature T_2 , and having a certain composition. As above, T_2 represents the temperature
10 of the fluid entering the annulus at a location corresponding to the second inflow location 40, and thus takes into account the Joule-Thomson effect and geothermal drift at that location. This fluid mixes with the fluid in the annulus, causing the temperature in the annulus to abruptly change.

The abrupt change in temperature (ΔT_2) associated with the second inflow location
15 40 can be modelled by:

$$(T_2 + \Delta T_2) = (CP_2 \cdot Q_2 \cdot T_2 + CP_1 \cdot Q_1 \cdot T_{12}) / (CP_2 \cdot Q_2 + CP_1 \cdot Q_1) \quad (4)$$

where:

T_{12} is the temperature of the fluid in the annulus at a point just upstream of the second inflow location 40;

20 ΔT_2 is the abrupt change in temperature at the second inflow location 40;

CP_1 is the specific heat capacity of the fluid upstream of the second inflow location 40, which may be calculated from the composition of the fluid at that upstream location;

CP_2 is the specific heat capacity of the fluid entering the annulus at the second inflow location 40, which may be calculated from the composition of the fluid;

25 Q_2 is the flow rate of the fluid entering the annulus at the second inflow location 40; and

T_2 is the temperature of the fluid entering the annulus at the second inflow location 40;

Using equation 4, a range of values for Q_2 , T_2 and CP_2 may be estimated for fluid at
30 the second inflow location 40. From CP_2 the composition of the fluid entering the annulus at the second inflow location 40 may also be estimated.

The temperature change at the second inflow location 40 may be determined using, for example, the temperatures measured at points 37C and 37D by the DTS 36.

In a similar manner to that described above, the flow upstream of the second inflow location 40 (i.e. between the second inflow location 40 and the inlet to the central tubing 50) will evolve in temperature as heat is transferred from the central tubing 24 to the fluid in the annulus 22. This transfer of heat may be modelled, using equations 2 and 3 above, and used to refine the values for Q_1 and Q_2 and for the composition of the fluid as calculated above.

These measurements and calculations may be repeated for inflow locations between the second inflow location 40 and the inlet to the central tubing 50.

The estimated flow rates into the annulus (Q_i and Q_i) may be used to determine the flow rate of fluid from the annulus 22 into the central tubing 24, while the temperature of the fluid flowing into the central tubing may be determined from measurements made by the DTS 36. These values may be combined with the flow rate Q and temperature T in the central tubing 24 to determine the flow rate and temperature of the fluid in the central tubing 24 downstream of the inlet 50. Therefore the flow rate and temperature of the fluid in the central tubing within the downstream sections may be determined. The steps described above may be repeated for each section of the annulus proceeding downstream, with the estimates of flow rates and temperature in a given section of the annulus being used to estimate the temperature and flow rate in the central tubing for downstream sections.

It will be appreciated that the temperature changes are dependent on the flow rate of the fluid into the central tubing 24, the composition of the fluid and on any geothermal drift. Therefore at each inflow location, or along the annulus between inflow locations, a range of values for flow rate, composition etc may be estimated. These ranges of values may be arranged in pairs, i.e. such that a certain composition is associated with a certain flow rate. These ranges of values may subsequently be refined using measurement data as will be described in more detail below.

As described above, the temperature at any location along the annulus is dependent on the flow rate and composition of fluid upstream of that location. For example, the temperature change at the second inflow location 40 is dependent, in part, on the flow rate and composition of the fluid entering the annulus at the first inflow location 38. Thus, the

calculations generated using data measured and estimated at any given location may be used to refine the range of values calculated further upstream of that given location.

For example, if a range of values for Q_i is determined for the first inflow location, but parts of that range of values for Q_i are not consistent with the temperature change
5 observed at the second inflow location 40, then the range for Q_i may be modified to remove the inconsistent values. In practice, this may involve defining a set of values which Q_i may take, and then selecting a subset of the values to ensure that only consistent values are maintained.

In addition, other measurements may be made and used to modify or improve the
10 estimates for the composition and flow rate into the well bore. For example, surface measurements of total flow rate and overall composition from the well bore may be used to modify the flow rate and/or composition values calculated for a specific section or even inflow location. In some cases, an overall model for the overall flow in the annulus may be constructed based on the principles described above, and the input values into this model
15 adjusted to achieve a best fit to the temperature data.

In some embodiments, temperature data is received for a number of points in time, and may be used in a model to determine the evolving flow field conditions (i.e. flow rate and composition) in the well bore. The changes may be used to refine current and historic values for the composition and flow rate and to identify gradual changes in, for example,
20 the temperature of the fluid.

A method for estimating the flow of fluid from a reservoir into a section of an annulus (such as section 26 described above) performed by computer system 200, will now be described with reference to Figure 5.

In a first step 54, and in accordance with the set of instructions defined by the FE
25 software components 209, the processor 204 receives temperature data from the DTS 36. The temperature data comprises data indicative of the temperature of the fluid in the annulus 22 at a plurality of points within the annulus at a given point in time. The points may include points 37A..E as described above in Figure 3.

Subsequently, in step 56, the processor 204 uses the received temperature data to
30 identify changes in the temperature of the fluid within the annulus 22 between the points, at any given point in time. At least one such identified change may correspond to a change in temperature associated with fluid entering the annulus from the reservoir such as the

change in temperature between points 37A and 37B, and/or between points 37C and 37D described above with reference to Figure 3. At least a further such change may correspond to the transfer of heat from the central tubing to the fluid in the annulus, such as the change in temperature between points 37B and 37C, and/or between points 37D and 37E described above with reference to Figure 3.

In step 58, the processor 204 selects an inflow location for modelling. The selected first inflow location may correspond to the most upstream inflow location 38 of the section of the annulus 26. In selecting the first inflow location, the processor 204 may analyse the temperature data to look for locations (e.g. locations 37A and 37B) between which there is a relatively large change in temperature.

As can be seen in Figure 5, steps 60 to 66 may be repeated for a number of inflow locations. Therefore, these steps will be described below for a first and a second inflow location. It will be assumed that the first inflow location is the most upstream inflow location of the section of the annulus, i.e. inflow location 38, and that the second inflow location has at least one inflow location upstream of it, i.e. is inflow location 40.

In step 60, the processor uses a model for the temperature change for fluid flowing into the annulus 22 at the selected inflow location.

In the case that the selected inflow location is the most upstream inflow location of the section of the annulus (i.e. first inflow location 38), the model may be configured to assume that the fluid flowing into the annulus (reference 38 in Figure 3) displaces the stagnant fluid within the annulus (reference 42 in Figure 3). Therefore the model may be configured to assume that the temperature of the fluid downstream of the selected inflow location is the temperature of the fluid flowing into the annulus allowing for any Joule-Thomson effect (this being caused by the fluid entering the annulus expanding as it leaves the rock of the reservoir). Therefore Equation 1 above may be used to associate the temperature of the fluid within the reservoir (i.e. the temperature measured at point 37B) with the flow rate Q_1 of the fluid entering the reservoir.

In the case that the selected inflow location is not the most upstream inflow location of the section of the annulus (e.g. is inflow location 40); the model may be configured to assume that the fluid flowing into the annulus (reference 40 in Figure 3) mixes with fluid flowing within the annulus (reference 44 in Figure 3). Therefore, Equation 4 as described above may be used to associate the change in temperature (i.e. the change in temperature

between point 37C and 37D) with the expected change in temperature caused by the mixing of the fluid in the annulus (which has a previously estimated flow rate Q_i , temperature and composition) with the fluid from the reservoir (for which the flow rate Q_n and composition are to be estimated). In line with the description above, Equation 1 may
5 be used in conjunction with Equation 4 to estimate any Joule-Thomson effect on the fluid flowing into the annulus.

In step 62, the processor uses the model described above with reference to step 60 to estimate the flow Q_n and composition for the flow into the annulus at the selected (n^{th}) inflow location based on the temperature change between points, identified in step 58
10 above, corresponding to a change in temperature associated with fluid entering the annulus from the reservoir.

In step 64, the processor 204 uses a further model for the heat transfer from the central tubing to fluid in the annulus downstream of n^{th} inflow location (i.e. between the n^{th} inflow location and the next inflow location downstream, or the inlet to the central tubing,
15 if applicable). To model the heat transfer, the model may be configured such that the heat transfer from the central tubing to the fluid in the annulus is assumed to be substantially constant along the length of the tubing. Preferably this involves using equations 2 and 3 as detailed above.

Subsequently in step 66 the processor 204 may use the further model to estimate
20 and/or refine an estimate for the flow into the annulus at the first to n^{th} inflow location (i.e. $Q_{i..n}$) based on the temperature change between points, identified in step 58 above, corresponding to the transfer of heat from the central tubing to the fluid in the annulus and the modelled temperature change. This step may involve estimating the flow rate Q_n , and estimating the composition of the fluid.

25 In step 70, it is determined whether temperature data are available from other inflow locations, and if so, the processor 204 selects the next (i.e. $n+1$) inflow location and proceeds to perform the steps described above from step 60. If there are no more inflow locations, then the processor 204 may perform a similar analysis for other sections of the annulus, represented by the arrow returning to the start point.

30 It will be understood that the above method may be used iteratively to generate and refine estimates of the rate of flow of fluid into the well. For example, the estimate for a flow rate into the well (and for the composition of the fluid) generated by the model in step

60 for the first inflow location may be subsequently refined using the model for the heat transfer from the central tubing in step 64, since Q_i and the composition of the fluid will be modelled in both steps.

In a similar manner, the output from the model for the temperature change at the second inflow location (step 60, for $n = 2$) may be used to refine the previously calculated value of Q_i , which is to say the value of Q calculated in respect of the first inflow location 38. To this end, at each step, a range of values for the composition and flow rate of the fluid may be estimated by the processor 204. This range may comprise a set of pairs of values, each pair being an estimate of flow rate and a corresponding composition. This range or set may be refined by excluding values which are inconsistent with values generated by subsequent iterations of the models.

In some embodiments, measurements may be made of e.g. the temperature in the central tubing, a flow rate in the central tubing (measured by a flow meter) and or the composition of the fluid from the central tubing (e.g. measured from a sample taken at the surface). These measurements may be used to refine the estimates, or ranges of estimates provided by the steps described above.

For example, if a set of values generated in steps 60 and 62 above for the flow rate and composition of fluid flowing into the annulus at a given inflow location contains one or more pairs of values for the composition and the flow rate that are indicative of the fluid having a large proportion of water; and the fluid produced at the surface from the central tubing is almost pure oil (i.e. has a small proportion of water), then these pairs of values for the composition and flow rate may be excluded since they are incompatible with the surface measurements.

In some embodiments, the temperature data may be collected for a plurality of points in time. From this data, previous flow rates may be refined, by e.g. assuming that all changes (in flow rate or composition) are gradual and continuous. Thus subsequent modelling steps may be used to refine previous models.

In some embodiments, a series of temperature measurements may be made for a number of points in time. From these measurements, estimates for changes in the temperature of the fluid entering the well may be made. These changes were represented as factor DT_i , namely temperature drift, in equation 1 above. In some embodiments, the changes in the temperature of the fluid entering the well may be determined by the

processor 204 from the DTS data in conjunction with the determination of estimates for the flow rates in the annulus.

The changes in DT_j may subsequently be used to estimate the tilt of the reservoir. Returning to Figure 1, it can be seen that the layers of the reservoir may not be horizontal
5 between the injection well and the production well. For example, layer 2 of the reservoir can be seen changing in depth. Tilt, in this context, is a measure of the gradient, or slope, in the depth of the reservoir relative to a horizontal line joining the injection well and the production well.

Prior to fluid being extracted from the reservoir, the fluid in the layers of the
10 reservoir will be at the geothermal temperature (i.e. the fluid will, in its source position in the reservoir, have achieved thermal equilibrium with the surrounding rock). Since the geothermal temperature increases with depth, the temperature of fluid in a reservoir will change as the depth of the reservoir changes. It can therefore be expected that, in the example shown in Figure 1, prior to extraction of fluid from the reservoir, the fluid in a
15 portion of the layer 2 near the injection well 16 (which is at a greater depth) will be at a higher temperature than the fluid in a portion of the layer 2 near the production well 20 (which is at a shallower depth).

As fluid is extracted from the reservoir, the fluid within the rock of the reservoir will flow within the reservoir away from the injection well and towards the production well (i.e.
20 along the layers 2 and 4 shown in Figure 1). While there will be some heat transfer between the fluid flowing within the reservoir to the surrounding rock, the magnitude of this heat transfer is relatively small.

Therefore, for any two portions of fluid flowing into the reservoir at different times, a difference in the temperature of the portions of fluid will be caused by a difference in the
25 original temperature of the portions of the fluid, which in turn will have been caused by differences in the geothermal temperature at the source positions of the two portions of fluid. Therefore, a difference in depth for the source positions of the two portions of fluid may be determined from the difference in temperature.

Equally, as the fluid is flowing into the production well, the distance between the two
30 positions, along the direction of flow of the fluid within the layer, may be determined from the rate of flow of fluid into the reservoir. Consequently, for the two portions of fluid, a separation distance may be determined from the quantity of fluid flowing into the well

during the period between the first portion of fluid flowing into the well and the second portion flowing into the well.

Typically, the reservoir will have a relatively continuous flow of fluid, and therefore the temperature will change progressively as the fluid enters the well. Therefore, instead of
5 considering only two discrete portions of fluid, the flow rate of the fluid into the reservoir, and the rate of change over time in the temperature of the fluid entering the production well over time, may be used to determine an estimate of the tilt, i.e. the change in depth by distance. In identifying a flow rate of fluid, a velocity of the fluid through the layer of the reservoir may be determined. This velocity is indicative of the distance moved, along the
10 layer in the direction of flow of fluid within the layer, by a given portion of fluid in a given time.

Figure 6 shows an example graphical output depicting temperature against time for fluid entering a production well, such as production well 20 shown in Figure 1. As can be seen, the temperature of the fluid gradually increases from approximately 71 °C to 72 °C
15 over the course of approximately 2500 days (this temperature change and time period are purely exemplary). The change in temperature has a trend, shown by line 71.

As described above, this is indicative of fluid entering the well at the early part of the reservoir life (i.e. from day 0) and originating at a depth corresponding to a geothermal temperature of approximately 71 °C. In the later part of the reservoir life (i.e. around day
20 2500) this is indicative of the fluid originating at a depth corresponding to a geothermal temperature of approximately 72 °C.

A method of estimating the tilt in a reservoir from a trend in the temperature of the fluid entering a production well from a reservoir which may be performed by computer system 200, according to an embodiment, will now be described below with reference to
25 Figure 7. This method may use information on the flow rate provided by the flow estimation techniques described above, however any other source of flow rate data may be used as appropriate.

In step 72, and in accordance with the set of instructions defined by the FE software components 209, the processor 204 receives temperature data from the DTS 36 for a
30 plurality of points in time. This may, for example, be over the course of many days. Typically temperature data is collected for a period longer than a month, and may be collected for periods over a year in duration. The DTS data may identify the temperature of

fluid within the annulus 22, as described above in Figure 3, alternatively, direct measurement of the temperature of the fluid prior to it entering the annulus (i.e. by a DTS embedded in the reservoir), may be performed. The temperature data may be associated with only a single inflow location as described above in Figures 2 and 3, however in some
 5 embodiments the temperature data may be associated with multiple inflow locations.

In step 74, the processor 204 identifies, from the DTS data, the temperature of the fluid in the reservoir prior to the fluid entering the annulus at each point in time. This may be done by analysing the temperature of the fluid in the annulus to determine the temperature of the fluid in the reservoir at its source position prior to the fluid flowing
 10 through the reservoir layer and entering the annulus, using, for example, the models described above. However, in the alternative, other methods (such as by using direct measurement of the temperature of the fluid in the reservoir prior to the fluid entering the annulus) may be used. In this step, the processor 204 may identify the temperature of the fluid in the reservoir entering the annulus at only a single inflow location as described
 15 above in Figures 2 and 3. Alternatively, the processor 204 may determine temperatures for multiple inflow locations and average these temperatures. As shown in Figure 1, a reservoir may comprise multiple layers; therefore the processor 204 may average the temperatures for the fluid for a single, or for each, layer.

In step 76, the processor 204 identifies any trend in the temperature data. This trend
 20 may be over many days, and typically over periods longer than a month. An example of such a trend is shown in Figure 6. In addition, the processor 204 identifies the flow rate of fluid from the layer of the reservoir into the production well during this period. This flow rate may be determined by the processor 204, for example in accordance with embodiments described above, or may be received by the processor 204 from a further
 25 device, such as a flow rate sensor associated with the production well.

In step 78, the processor 204 calculates an estimate of the tilt of the reservoir from the identified trend. The tilt may be calculated using an equation such as:

$$\frac{dT}{dt} = \frac{AQ}{HL} \frac{dT_G}{dx} \quad (5)$$

where:

30 $\frac{dT}{dt}$ is the change in temperature over time (i.e. the trend identified in step 76);

A is a factor calculated based on the arrangement of the injection and production wells;

Q is the flow rate of fluid from the layer into the production well identified by the processor in step 76;

5 H is the depth of the layer (at the production well), which may be determined by methods known in the art from, for example, survey data;

L is the interwell spacing which may be determined from the known locations of the injection and production wells; and

$\frac{dT_g}{dx}$ is the temperature change in the fluid in the direction of the well pair.

10 Collectively, AQ/H represents an indication of the velocity of the fluid within the layer of the reservoir in the direction of flow of fluid within the layer.

Having calculated the temperature change in the fluid in the direction of the well pair, the tilt of the reservoir may be subsequently calculated by assuming that the fluid was originally at, or near, the geothermal temperature, and comparing the geothermal

15 temperature at known depths to the temperature change in the direction of the well pair. The geothermal temperature may be determined using techniques known in the art from, for example, survey data.

The factor A can be determined from the arrangement of the wells in the reservoir. One such arrangement will be described with reference to Figure 8. In Figure 8 a series of
20 production wells are arranged approximately in line with one another, as represented by wells 80A, 80B and 80C. Spaced from, and parallel to, these production wells 80A, 80B and 80C are injection wells 82A, 82B and 82C.

The injection and production wells are arranged in respective lines approximately perpendicular to a gradient of the underlying reservoir. The gradient of the reservoir is
25 represented by the lines 84 (which represent the contours of the reservoir).

As represented by lines 86, the flow between the wells does not always follow the direct path (i.e. the line of minimum distance between the injection well and production well) between the injection and production well, and thus the path length between the relevant wells may vary. Accordingly, using methods known in the art for calculating
30 mean path length and the like, the factor A may be derived based on the locations of the injection and production wells. In this case, the factor A may have a value of 0.065.

While in the above example it is assumed that the temperature of the fluid increases over time, this may not be the case; in other embodiments the temperature may decrease, for example in the event that the reservoir decreases in depth towards the production well.

It is to be understood that any feature described in relation to any one embodiment
5 may be used alone, or in combination with other features described, and may also be used in combination with one or more features of any other of the embodiments, or any combination of any other of the embodiments. Furthermore, equivalents and modifications not described above may also be employed without departing from the scope of the accompanying claims. The features of the claims may be combined in combinations other
10 than those specified in the claims.

For completeness, some examples of how the flow rate in a production well, which may subsequently be used in the estimation of the tilt of the reservoir, will now be described in summary form.

For example, there may be provided a computer-implemented method for estimating
15 flow of fluid into a production well extending into a reservoir comprising fluid, the well comprising a central tubing and an annulus surrounding the central tubing, the annulus being connected to the reservoir so as to receive fluid at one or more inflow locations, and the central tubing having at least one inlet, arranged to allow fluid to flow from the annulus into the central tubing, and being located downstream of the one or more inflow locations,
20 the production well further comprising one or more devices arranged to measure a temperature of fluid within the annulus at a plurality of points along the length of the annulus, the method comprising: receiving temperature data from the one or more devices indicative of a temperature of fluid at a plurality of points along the length of the annulus; identifying a change in temperature of fluid flowing within the annulus on the basis of the
25 received temperature data at the plurality of points; using a model to estimate heat transfer from the central tubing to fluid flowing within the annulus, said model being configured such that the heat transfer is assumed to be substantially constant along the length of the tubing; and estimating a rate at which fluid flows into the annulus from the reservoir at a first inflow location on the basis of the identified change in temperature between the points
30 and the estimated heat transfer.

A production well will generally receive fluid (i.e. water, oil and/or gas) from the well at a number of discrete locations along the length of the well bore. These locations

may be defined by fissures in the underlying rock which serve to transport the fluid towards the well. Fluid will flow from the fissures into the annulus. Within the annulus the fluid from one fissure may mix with fluid from other fissures, and will flow 'downstream' along the annulus (downstream meaning towards the surface). The fluid then flows from the annulus to the central tubing at one or more inlet points. The fluid will subsequently flow downstream along the central tubing to the surface.

These production wells may be provided with "downhole temperature sensors" (DTS) which are one or more devices which measure a temperature of fluid within the annulus at a plurality of points along the length of the annulus.

To properly understand (e.g. model) a reservoir, it is important to understand not only the total flow of fluid out of the production well as a whole, but the flow into the well at each inflow location (e.g. fissure). One reason for this is that reservoirs are typically layered (that is have layers of permeable and non-permeable rock), and fluid only flows along, and from, the permeable layers. By understanding the flow at each inflow location, the makeup of the layers can be better understood, and thus the operation of the wells can be made more efficient.

At a given point, the fluid within the central tubing will be warmer than the fluid within the annulus, having originated from a deeper point in the reservoir. Thus there is a temperature gradient between the central tubing and the fluid in the annulus. This temperature gradient causes heat to flow from the central tubing to the fluid in the annulus.

By identifying a change in temperature of fluid flowing within the annulus on the basis of the received temperature data at the plurality of points and using a model to estimate heat transfer from the central tubing to fluid flowing within the annulus along the length of the tubing it is possible to estimate a flow rate of fluid along the annulus at the point, as the change in temperature will be greater when the flow rate along the annulus is lower, and correspondingly less when the flow rate along the annulus is greater. Therefore, it is possible to estimate a rate at which fluid flows into the annulus at a said inflow location from the change in temperature between the point and the estimated heat transfer.

Thus, it is possible to estimate the flow of fluids into a well using a relatively simple measuring system (the temperature sensor).

In some examples the method may comprise using the model to determine a specific

heat capacity of the fluid and thence estimating a composition of the fluid flowing from the reservoir into the annulus at the first inflow location.

The composition of the fluid (i.e. the oil/water/gas mix) may vary during the lifetime of the well. Equally, the composition of the fluid may change between layers. The
5 composition of the fluid will affect the specific heat capacity of the fluid, and consequently the temperature changes. Therefore, by looking at how temperatures change, the composition of the fluid flowing into and along the well can be estimated, and thus provide data which may be used to increase the efficiency of extraction of fluid from the well.

In some examples the method may comprise: using the model to estimate a rate at
10 which the fluid flows along the longitudinal axis of the annulus, whereby to estimate a rate at which fluid flows into the annulus at the first inflow location.

Examples may also comprise: identifying a temperature of fluid within the central tubing; and determining a temperature gradient between the fluid within the central tubing and the fluid within the annulus, whereby to estimate heat transfer from the central tubing
15 to fluid flowing within the annulus.

In general the fluid in the central tubing and in the annulus will be at different temperatures, typically, the central tubing, in carrying fluid from lower down the well, will be at a higher temperature. Thus the central tubing will warm the fluid in the annulus as the fluid passes along the annulus. By looking at the rate of temperature change of the fluid in
20 the annulus, the rate of flow along the annulus can be estimated. By identifying the temperature of the central tubing, a more accurate estimate can be made.

In some cases the temperature of the fluid in the central tubing may be identified by direct measurement, i.e. by using a further downhole temperature sensor, or by inserting a probe into the central tubing at certain intervals. Alternatively or additionally, the
25 temperature may be estimated based on temperature measurements taken in parts of the annulus upstream of the point in question. The fluid in these parts of the annulus will be assumed to have passed into the annulus at an inlet positioned upstream of the point in question.

In some examples the method may comprise identifying a change in temperature of
30 fluid within the annulus between a point upstream of the first inflow location and a point downstream of the first inflow location; using a further model to estimate a change in temperature of the fluid in the annulus caused by fluid entering the annulus from the

reservoir at the first inflow location; estimating a rate at which fluid flows into the annulus at the first inflow location on the basis of the identified change in temperature and the estimated change in temperature.

5 The method may comprise identifying a geothermal temperature at a depth corresponding to the first inflow location, whereby to estimate a temperature of fluid flowing into the annulus at the first inflow location, wherein the further model is configured to estimate the change in temperature of the fluid in the annulus based on the temperature of the fluid entering the annulus at the inflow location.

10 The fluid flowing from the reservoir will be at the geothermal temperature corresponding to the depth of the inflow location (within a given error margin). This geothermal temperature will be known from surveys etc. In entering the annulus, the fluid will change the temperature of the fluid in the annulus, either by mixing with a flow of fluid within the annulus, or by displacing a stagnant portion of fluid. The rate of flow of fluid into the annulus may be estimated using knowledge of the temperature of the fluid
15 entering the annulus and from the temperature change in the fluid in the annulus.

The further model may be configured: such that fluid flowing within the annulus is assumed to mix with fluid entering the annulus at the first inflow location, and to associate the change in temperature of the fluid within the annulus with a rate of flow and a temperature of fluid flowing within the annulus upstream of the first inflow location and a
20 rate of flow and a temperature of fluid flowing into the annulus at the first inflow location.

In some examples the method may comprise using a yet further model to estimate a change in temperature of fluid flowing into the annulus at the first inflow location, the yet further model taking account of Joule-Thompson expansion of fluid flowing into the annulus at the first inflow location.

25 One advantageous method by which the flow rate can be estimated is by looking at the Joule-Thompson effect on the fluid as it flows from the reservoir into the annulus. Joule-Thompson effect will change the temperature of the fluid, and thus enable the flow rate to be estimated.

The method may comprise using a said model to refine an estimate of a rate at which
30 fluid flows into the annulus at the first inflow location generated by a further said model.

The method may comprise using a said model and/or a said further model whereby to

estimate a rate at which fluid flows into the annulus at one or more second inflow locations.

In some examples the method may comprise using the model and/or further model used to estimate a rate at which fluid flows into the annulus at one or more second inflow locations whereby to refine the estimate of the rate at which fluid flows into the annulus at the first inflow location.

The rate at which fluid flows into the annulus at a given inflow location may affect the changes in temperature at locations downstream of the given inflow location. Accordingly, an improved estimated of the rate at which fluid flows into the annulus at the first inflow location may be made by using further models used to estimate the rate at which fluid flows into the annulus at one or more second inflow locations.

The method may comprise estimating a set of values for rates at which fluid flows into the annulus at the first inflow location, each value being associated with data indicative of a composition of the fluid flowing into the annulus at the first inflow location.

There may be a number of unknowns, not just the flow rate, but the fluid composition, and any changes in the reservoir temperature (described in more detail below). Thus a set of values for rates at which fluid flows into the annulus may be estimated, each value being associated with data indicative of a composition of the fluid flowing into the annulus at the first inflow location.

Subsequently, based on further measurements made elsewhere in the well bore, or knowledge of the composition of the fluid entering the well (from e.g. a historical analysis) some of the values in this set may be subsequently excluded to refine the set.

The process may be iterative, that is, as more data is received, and more temperature changes identified, the sets may be progressively improved.

The annulus may be divided into a plurality of sections, each section having one or more inflow locations, and the central tubing has an inlet open to the annulus and located at the downstream end of each section, the method may comprise: estimating flow rates of fluid from the reservoir into a first said section; estimating a flow rate of fluid from the first section into the central tubing through a first said inlet from the flow rates of fluid from the reservoir into the first section; estimating a flow rate of fluid within the central tubing downstream of the first section based on the estimated flow rate of the fluid through the first inlet from the first section; estimating flow rates of fluid within a second said

section using the estimated flow rate of fluid within the central tubing.

The annulus may be divided up into sections. In general, fluid cannot pass from one section to the other, e.g. the sections are isolated (it will be understood that a small amount of fluid may pass the separations). Thus each section may be analysed substantially
5 independently. Moreover, a determined flow rate in one section, may be used to determine a flow rate along the central tubing, and thus in the determination of a flow rate in a downstream section. Therefore, in embodiments, the process of estimating the flow rates starts with the section located at the upstream end of the well (e.g. at the deepest point), and result for each section is used in subsequent sections.

10 In some examples the method may comprise receiving data indicative of one or more of measurements of the temperature, composition and rate of flow of fluid in the central tubing, and using the measurement data to validate data generated by the models.

In some embodiments, the temperature, composition and flow rate of fluid in the central tubing may be measured. This may be done at the surface, by taking a sample of the
15 fluid produced by the well. The measured data may be used to estimate the flow rate in the production well. In some embodiments, such measured data may be used to modify a set of flow rate values to improve accuracy.

The method may comprise: receiving temperature data for fluid flowing into the annulus at the first inflow location at a plurality of points in time; and identifying a change
20 over time in a temperature of the fluid flowing into the annulus at the first inflow location.

Claims

1. A computer-implemented method for estimating a tilt of a layer of a reservoir, there being a production well extending into the layer of the reservoir configured such that fluid flows from the layer into the production well, the production well further comprising one
5 or more devices arranged to measure a temperature of fluid at one or more locations within the production well at a plurality of points in time,

the method comprising:

receiving temperature data from the one or more devices, the temperature data being indicative of a temperature of fluid entering the production well from the layer at each of a
10 plurality of points during a period of time;

identifying, using the temperature data, a trend indicative of a change in temperature of the fluid entering the production well during the period of time;

identifying a velocity of fluid within the layer in a direction of flow of fluid within the layer during the period of time;

15 determining using the identified trend and the identified velocity, an estimate of the change in temperature by distance for the fluid, the distance being in a direction of flow of fluid within the layer;

identifying a geothermal gradient indicative of a change with depth in the temperature of rock within and surrounding the reservoir; and

20 determining a measure of the tilt of a layer in the reservoir based on the estimated change in temperature by distance and the geothermal gradient.

2. The method of claim 1, wherein the trend is determined over a period greater than a month.

3. The method of claim 1 or claim 2, comprising identifying a flow rate of fluid into the
25 production well from the layer whereby to estimate the velocity of fluid within the layer.

4. The method of any of claim 3, comprising identifying a height of a permeable layer containing the fluid within the reservoir, whereby to estimate the velocity of fluid within the layer.

5. The method of claim 3 or claim 4, comprising multiplying the flow rate by a
30 predetermined constant, whereby to estimate the flow velocity, the predetermined constant being calculated in dependence on the arrangement of at least one injection well in relation to the production well.

6. The method of any of claims 1 to 5, comprising associating a change in temperature of the fluid entering the production well with a change in depth based on the geothermal gradient of the reservoir whereby to determine a measure of the tilt of the layer.

7. A computer readable storage medium storing computer readable instructions thereon
5 for execution on a computing system to implement a method for estimating a tilt of a layer of a reservoir, there being a production well extending into the layer of the reservoir configured such that fluid flows from the layer into the production well, the production well further comprising one or more devices arranged to measure a temperature of fluid at one or more locations within the production well at a plurality of points in time,
10 the set of instructions are configured to cause the computing system to perform the steps of:

receiving temperature data from the one or more devices, the temperature data being indicative of a temperature of fluid entering the production well from the layer at each of a plurality of points during a period of time;

15 identifying, using the temperature data, a trend indicative of a change in temperature of the fluid entering the production well during the period of time;

identifying a velocity of fluid within the layer in a direction of flow of fluid within the layer during the period of time;

determining using the identified trend and the identified velocity, an estimate of the
20 change in temperature by distance for the fluid, the distance being in a direction of flow of fluid within the layer;

identifying a geothermal gradient indicative of a change with depth in the temperature of rock within and surrounding the reservoir; and

determining a measure of the tilt of a layer in the reservoir based on the estimated
25 change in temperature by distance and the geothermal gradient.

8. A system for estimating a tilt of a layer of a reservoir, there being a production well extending into the layer of the reservoir configured such that fluid flows from the layer into the production well, the production well further comprising one or more devices arranged to measure a temperature of fluid at one or more locations within the production well at a
30 plurality of points in time,
the system comprising:

an interface arranged to receive temperature data, the temperature data having been collected by the one or more devices, the temperature data being indicative of a temperature of fluid entering the production well from the layer at each of a plurality of points during a period of time; and

5 a processor arranged to:

identify, using the temperature data, a trend indicative of a change in temperature of the fluid entering the production well during the period of time;

identify a velocity of fluid within the layer in a direction of flow of fluid within the layer during the period of time;

10 determine using the identified trend and the identified velocity, an estimate of the change in temperature by distance for the fluid, the distance being in a direction of flow of fluid within the layer;

identify a geothermal gradient indicative of a change with depth in the temperature of rock within and surrounding the reservoir; and

15 determine a measure of the tilt of a layer in the reservoir based on the estimated change in temperature by distance and the geothermal gradient.

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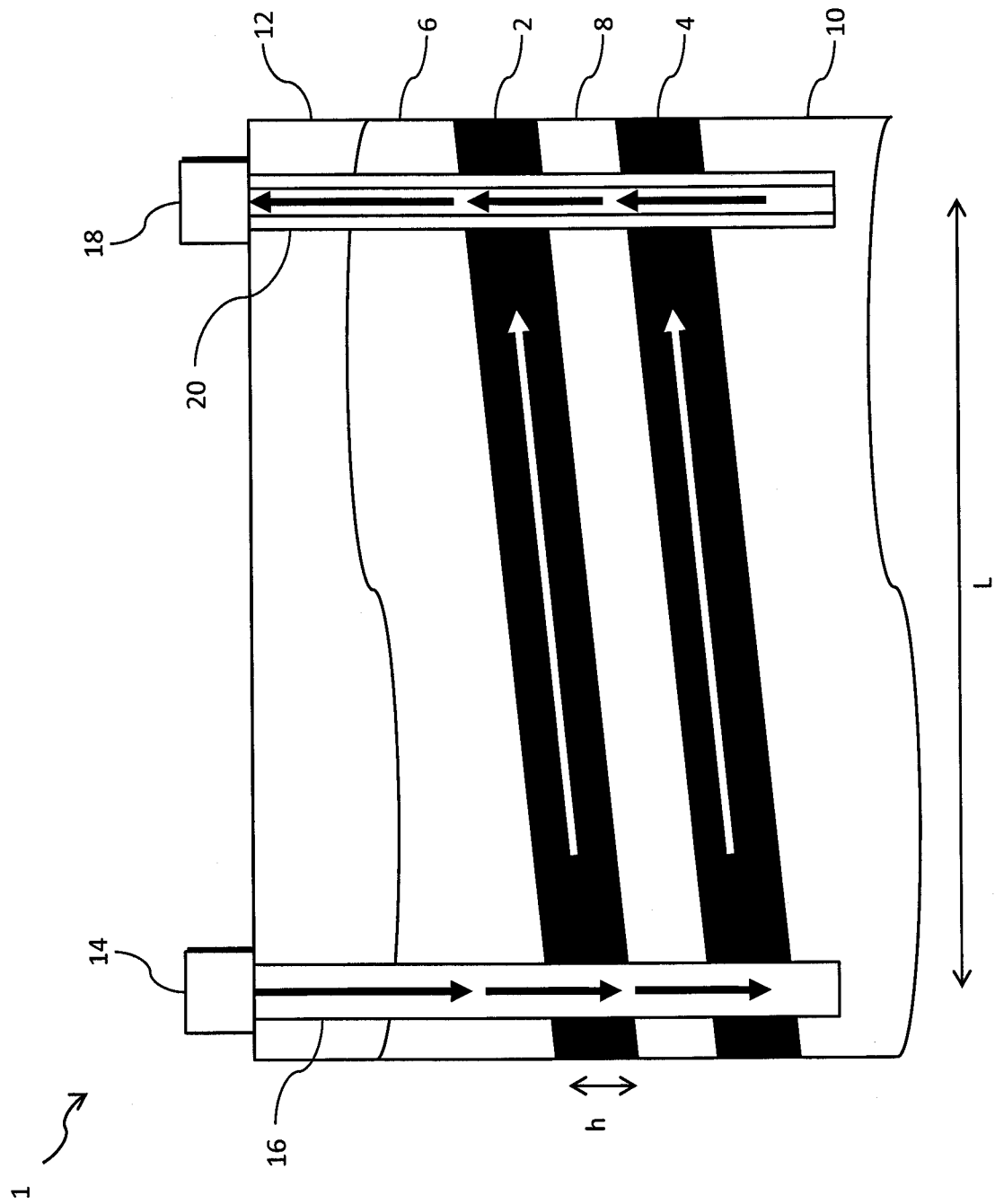


Fig 1

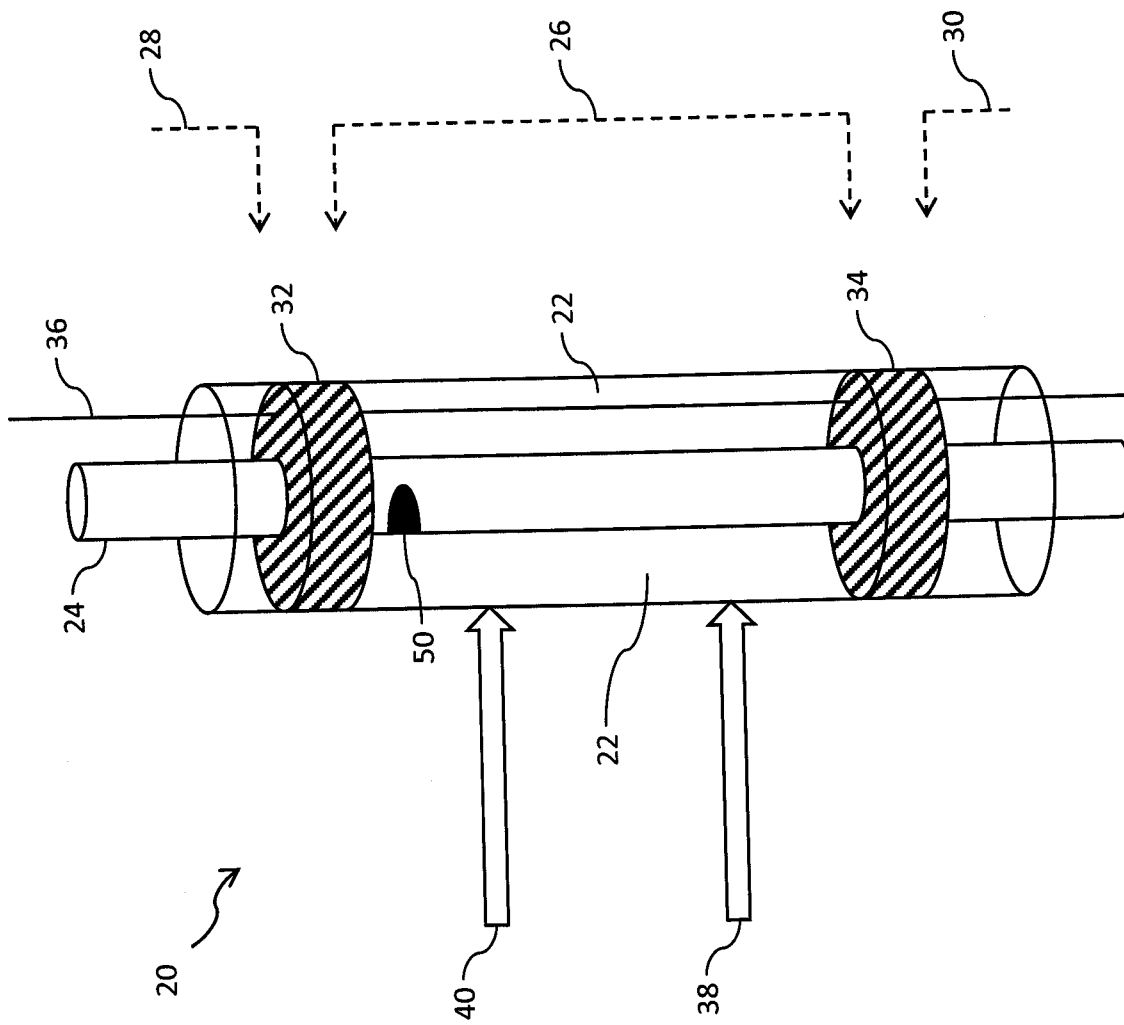


Fig 2

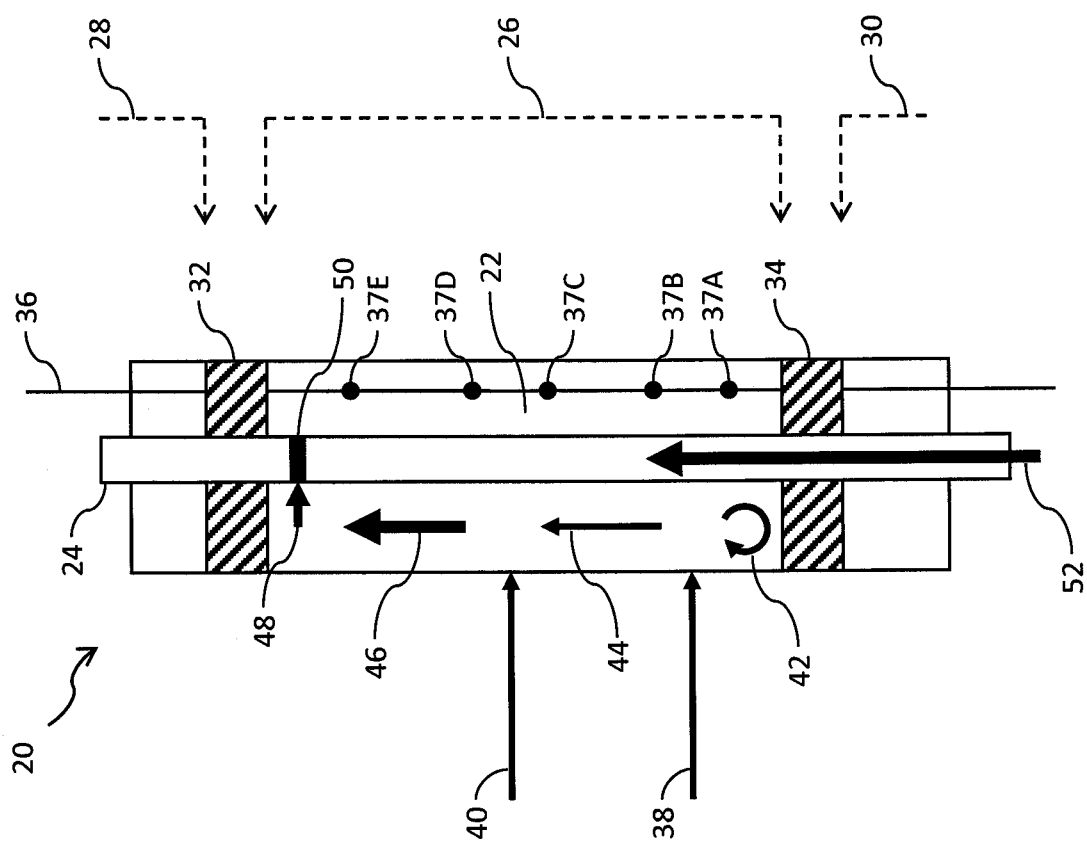


Fig 3

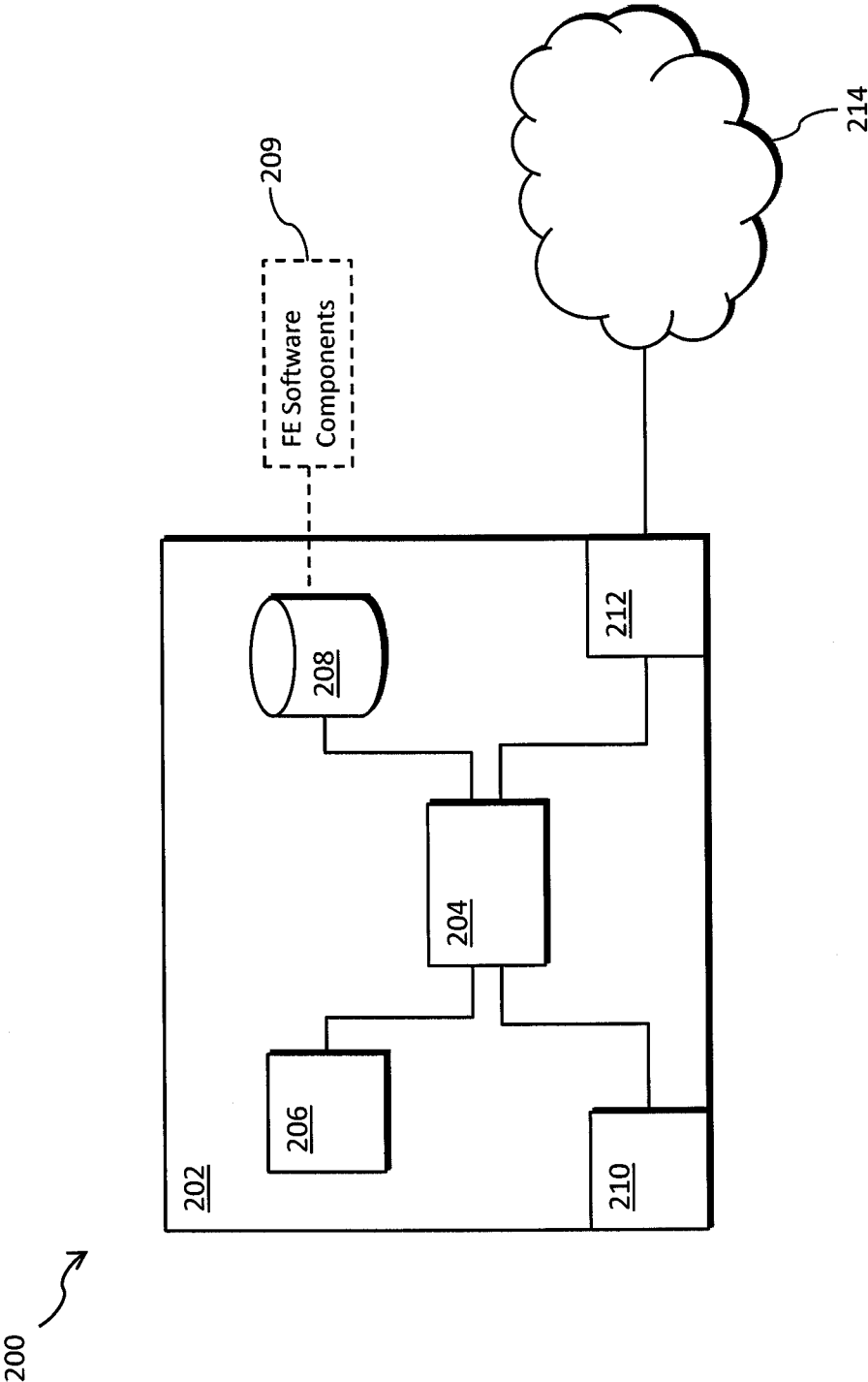


Fig 4

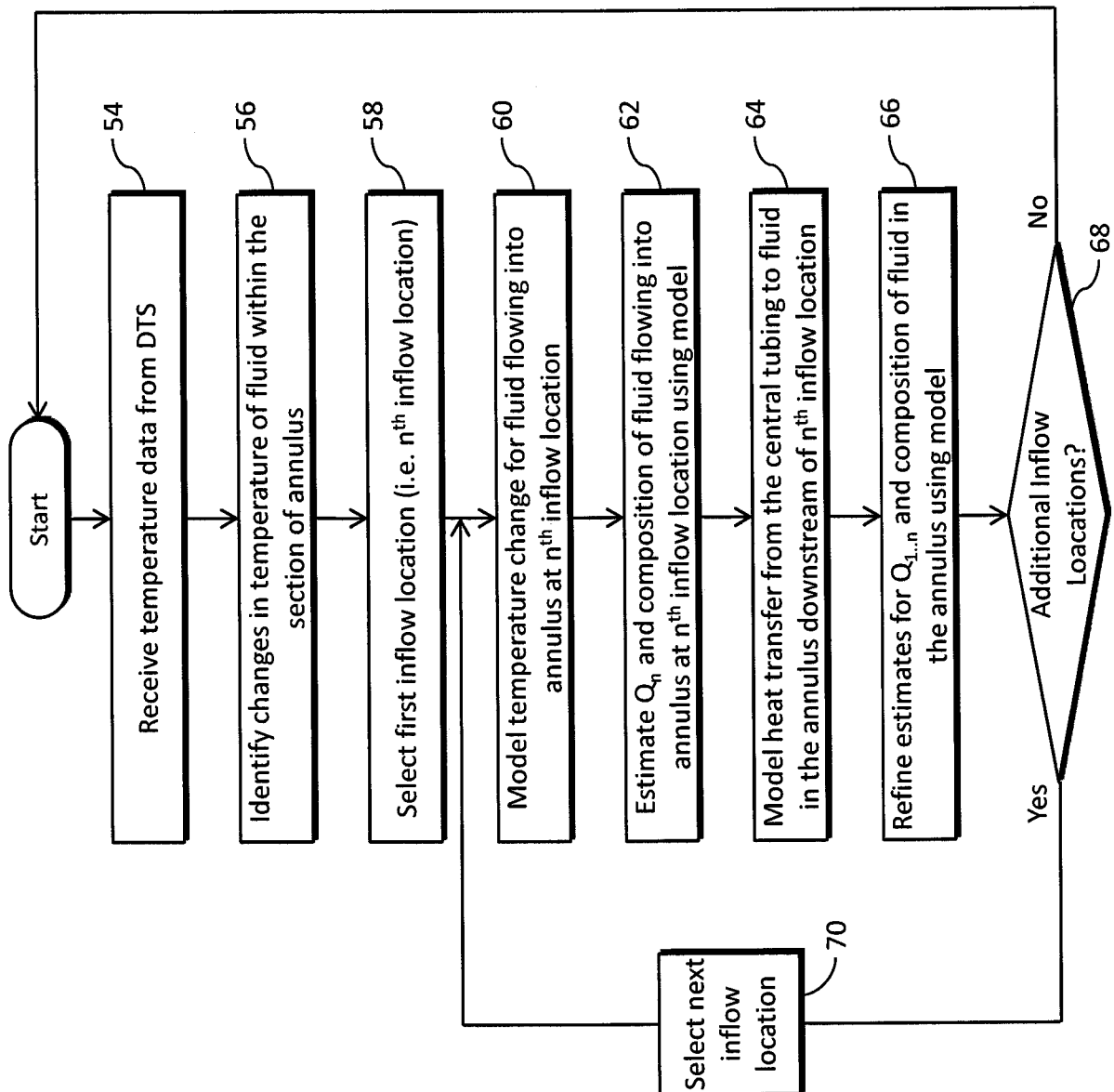


Fig 5

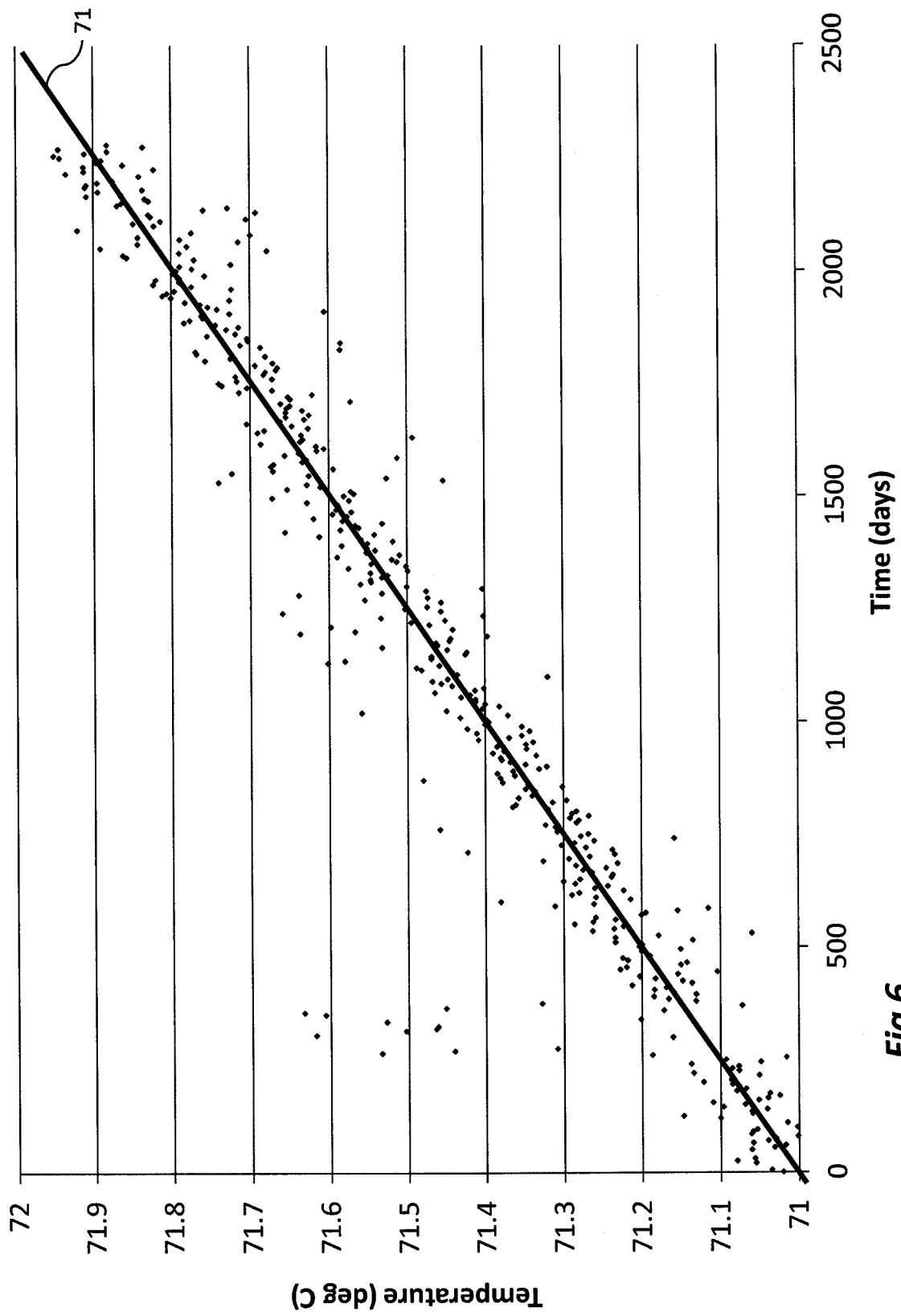


Fig 6

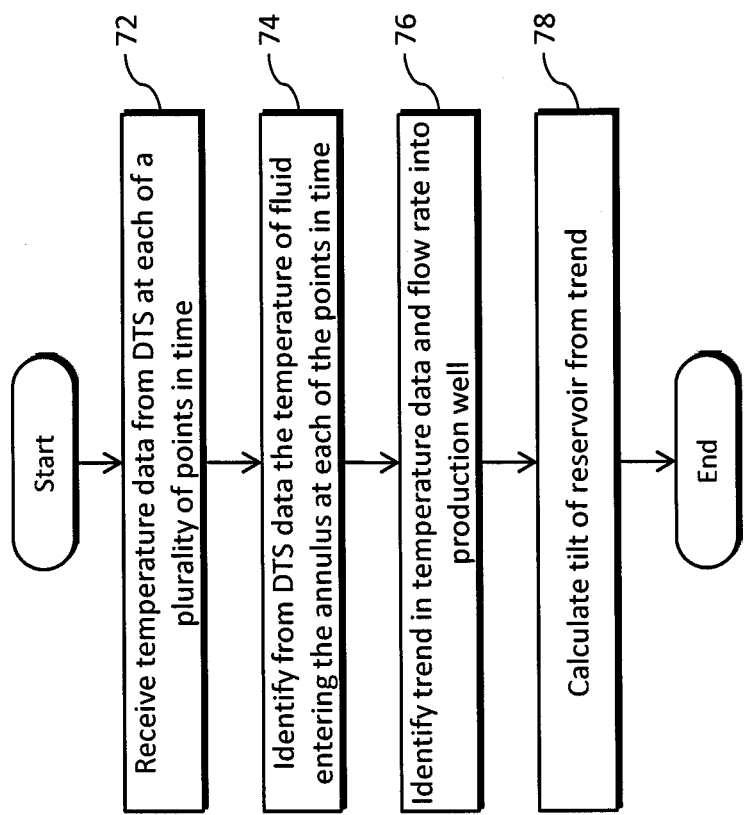


Fig 7

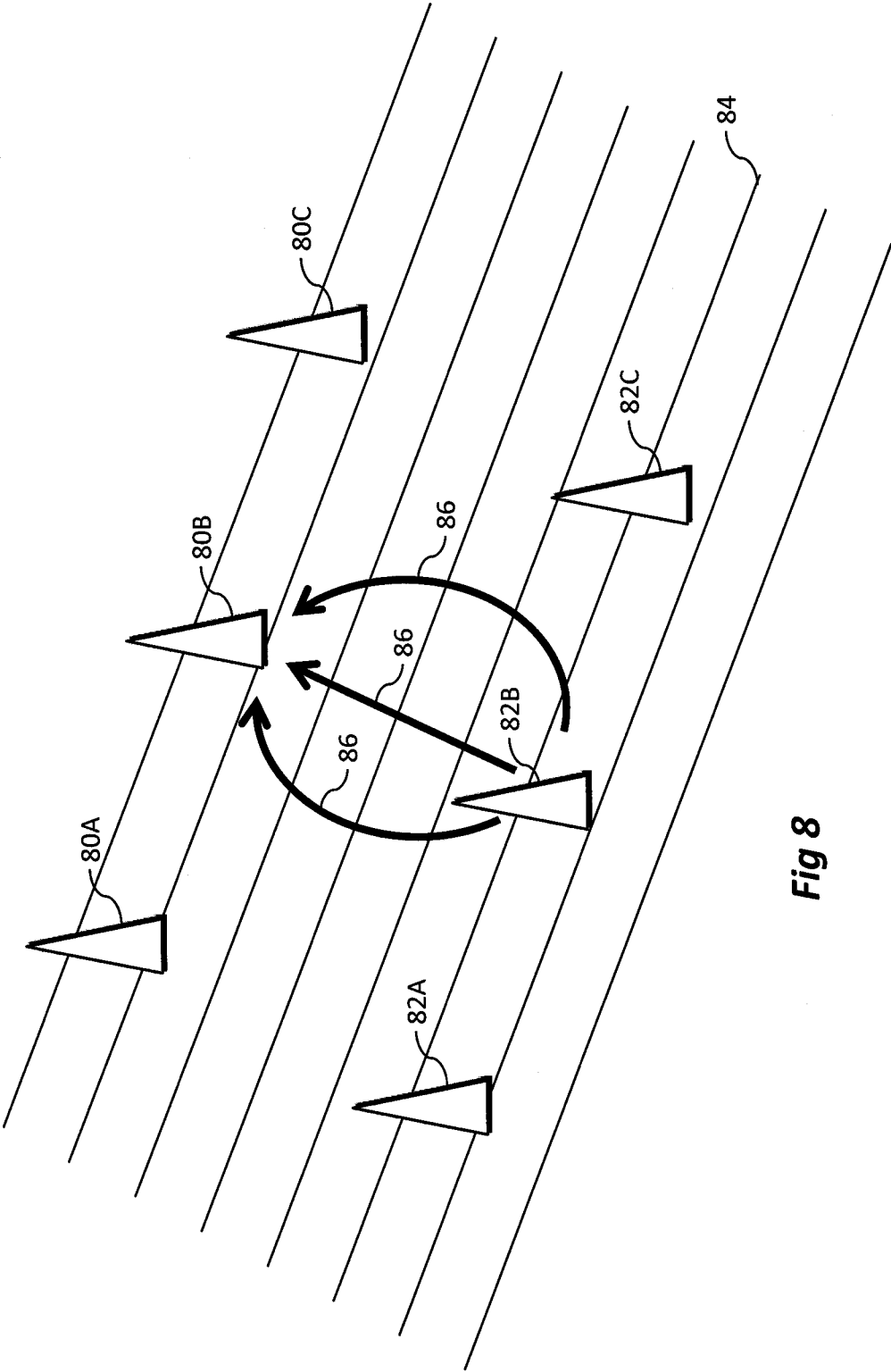


Fig 8