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(54) **Underbalanced drilling method into a gas-bearing formation**

(57) A method of creating a second wellbore section (19), penetrating a subterranean earth formation having at least one gas-bearing zone (3), from a selected location in an existing first wellbore section (1) using a remotely-controlled drilling device (13) under underbalanced drilling conditions, which method comprises:
(a) arranging the remotely-controlled drilling device (13) at the selected location in the first wellbore section (1), in or below a production tube (6),
(b) operating the remotely-controlled drilling device (13) to drill the second wellbore section (19),

(c) controlling the flow of gas produced from the gas-bearing formation through the production tube (6) to the wellhead (8),

(d) using a fluid stream comprising at least a portion of produced gas to transport the drill cuttings resulting from the drilling operation to the wellhead (8) and

(e) controlling the pressure in the production tube (6) such that the linear velocity of the gas does not fall below 1 m/s and does not exceed 75 m/s.

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Description

[0001] The present invention relates to a method of drilling a wellbore from a selected location in an existing wellbore into a gas-bearing formation using a remotely controlled drilling device

[0002] In conventional rotary drilling methods a wellbore is drilled by rotating a drill bit to which downward force is applied. The drill bit is attached to and rotated by a drill string which has a passageway through which a drilling fluid is circulated. The drilling fluid, usually called drilling mud, is generally circulated down the well through the passageway in the drill string, over the drill bit and returns to the surface through an annular space between the drill string and the wellbore wall. The drilling mud may however be circulated in the reverse direction. The drilling mud has a number of functions, including cooling and lubricating the drill bit and drill string, transporting drill cuttings from the bottom of the borehole to the surface, protecting against blowouts by holding back subsurface pressures and depositing a mud cake on the wall of the borehole to prevent loss of fluids to the formation. When drilling through a formation which does not contain a fluid, such as water, gas or oil, the weight and the pumping rate of the drilling mud are selected so that the pressure at the wellbore wall is maintained between a lower pressure at which the wellbore becomes unstable and an upper pressure at which the wellbore wall is fractured. When the wellbore is drilled through a fluid-containing zone, the drilling mud pressure is generally selected to be above the pressure at which fluid starts flowing into the wellbore (formation pressure), and below the pressure at which undesired invasion of drilling mud into the formation occurs. This is generally referred to as overbalanced drilling.

[0003] Drilled wellbores are generally lined with tubular strings, usually steel pipe, referred to as casing. The casing provides support to the wellbore and facilitates the isolation of certain sections of the wellbore adjacent hydrocarbon bearing formations. The casing typically extends down the wellbore from the surface of the well and the annulus between the outside of the casing and the borehole wall is typically, but not necessarily, filled with cement to permanently set the casing in the wellbore.

[0004] As the wellbore is drilled to a new depth, additional strings of pipe are run into the well to that depth whereby the upper portion of the string of pipe (often referred to as "liner"), is overlapping the lower portion of the casing. The liner is then fixed or hung in the wellbore, usually by some mechanical slip means well known in the art.

[0005] The known overbalanced rotary drilling methods have long been recognized as safe methods for drilling a well. However, a significant disadvantage of such methods is that since the drilling mud pressure is higher than the natural formation pressure, fluid invasion frequently occurs, causing permeability damage to the formation.

[0006] Underbalanced drilling differs from the more conventional overbalanced drilling in that the bottomhole circulating pressure is lower than the formation pressure, thereby permitting the well to flow while drilling proceeds. Thus, when drilling through a formation containing oil or gas, production can be obtained from a well prior to completion. Underbalanced drilling can also be used in formations containing other fluids, such as water.

[0007] Advantages that have been claimed for underbalanced drilling include:

- Maintaining wellbore pressure below the reservoir pressure allows reservoir fluids to enter the wellbore, thus avoiding formation damage. Since significant formation damage is avoided, the stimulation requirements during well completion are also reduced, leading to considerable savings.
- During underbalanced drilling there is no physical mechanism to force drilling fluid into the drilled formation. Therefore, lost circulation is kept to a minimum when fractured or high permeability zones are encountered.
- Underbalanced drilling can help in detecting potential hydrocarbon zones, even identifying zones that would have been bypassed with conventional drilling methods.
- Due to the decreased pressure at the drill bit head, underbalanced drilling operations can have superior penetration rates as compared to conventional overbalanced drilling techniques. Along with reduced drilling times, an increase in bit life has sometimes been reported.
- Since there is no filter cake around the wellbore wall, the chances of differential sticking are also reduced.

[0008] Controlling the bottom hole pressure using conventional mud circulation systems requires the mud weight to be increased or decreased. This is a time-consuming process which can result in a significant loss of drilling time. Methods known as managed pressure drilling (or sometimes near balanced drilling) can use a closed, pressurizable mud returns system to enable the operator to drill ahead and make jointed-pipe connections while maintaining an appropriate pressure profile in the well. Generally the bottom hole pressure is maintained just above the formation pressure to prevent significant influx of fluid from the formation into the well, but the overpressure is kept low to minimise formation damage. The closed mud system can comprise (i) a float valve, (ii) a rotating control device, (iii) an enclosed flow line, (iv) a flow choke manifold, separate from the existing rig well control manifold, and (v) a degasser or mud/gas separator system. The separator removes gas from the drilling fluid and dumps cuttings and drill fluid into the rig pit system for solids removal. This allows well influx to flow at a controlled rate while drilling is continued. In such a closed-loop system, the mud can be circulated from the mud pit, through the mud pump, into the standpipe,

down the drillstring, through the float valve and the drill bit, up the annulus, exiting the annulus below the rotating control device, through the flow choke manifold, to the shaker or degasser, and finally back to the mud pit. The mud in the annulus is kept under pressure from pumps to choke by use of the rotating control valve and the flow choke manifold.

[0009] Although similar equipment and methods can be used in both underbalanced drilling and managed pressure drilling they differ in that in underbalanced drilling the intention is to allow production from the well while drilling ahead, whereas in managed pressure drilling influx of fluid from the formation is avoided or minimised. Thus, in the known methods of rotation drilling using underbalanced drilling or managed drilling conditions, the weight of the drilling mud column is reduced, as compared with the traditional overbalanced drilling conditions, and the pressure on the top of the well is controlled by means of a rotating seal and choke valves.

[0010] US 6,305,469 discloses a method of underbalanced drilling which provides a method of creating a wellbore in an earth formation, the wellbore including a first wellbore section and a second wellbore section penetrating a hydrocarbon fluid bearing zone of the earth formation, the method comprising:

- (a) drilling the first wellbore section;
- (b) arranging a remotely controlled drilling device at a selected location in the first wellbore section, from which selected location the second wellbore section is to be drilled;
- (c) arranging a hydrocarbon fluid production tubing in the first wellbore section in sealing relationship with the wellbore wall, the tubing being provided with fluid flow control means and a fluid inlet in fluid communication with said selected location;
- (d) operating the drilling device to drill the new wellbore section whereby during drilling of the drilling device through the hydrocarbon fluid bearing zone, flow of hydrocarbon fluid from the second wellbore section into the production tubing is controlled by the fluid flow control means.

[0011] US 6,305,469 discloses that the drilling device is releasably connected to the lower end of a hydrocarbon production tubing by a suitable connecting device. The hydrocarbon production tubing is then lowered into the casing until the drilling device is near the bottom of the first wellbore section whereafter the production tubing is fixed to the casing by inflating a packer which seals the annular space formed between the production tubing and the casing.

[0012] WO 2004/011766 discloses a method of drilling using a remotely controlled drilling device that uses fluid produced from the formation to transport drill cuttings away from the cutting surfaces of the device in which the drilling device is capable of being passed from the surface to a selected location in an existing wellbore without hav-

ing to pull the hydrocarbon fluid production tubing from the wellbore.

[0013] Thus, according to WO 2004/011766, a method of drilling a borehole from a selected location in an existing wellbore penetrating a subterranean earth formation having at least one hydrocarbon fluid bearing zone wherein the existing wellbore is provided with a casing and a hydrocarbon fluid production conduit is arranged in the wellbore in sealing relationship with the wall of the casing, comprises:

- (a) passing a remotely controlled electrically operated drilling device from the surface through the hydrocarbon fluid production conduit to the selected location in the existing wellbore;
- (b) operating the drilling device such that cutting surfaces on the drilling device drill the borehole from the selected location in the existing wellbore thereby generating drill cuttings wherein during operation of the drilling device, a first stream of produced fluid flows directly to the surface through the hydrocarbon fluid production conduit and a second stream of produced fluid is pumped over the cutting surfaces of the drilling device via a remotely controlled electrically operated downhole pumping means and the drill cuttings are transported away from the drilling device entrained in the second stream of produced fluid.

[0014] In the method of WO 2004/011766 a tubing can be provided to convey the second stream of produced fluid to the drill bit or to carry the fluid and drill cuttings away from the drill bit. This tubing may extend from the drill bit to the production tubing. The second wellbore can be quite long, e.g. in excess of 1 kilometre.

[0015] The known methods, such as those described in the above-mentioned patent publications, for using remotely controlled drilling devices for underbalanced drilling of boreholes can be particularly useful for drilling into a reservoir formation which contains liquid. However, certain problems can arise when the formation fluids are gaseous or comprise a significant proportion of gas. In particular, the differential pressure between the formation pressure and the surface pressure can result in a very large increase in the volume of gas as it is conveyed from the bottom of the wellbore to the wellhead. As the gas would be carrying the solid drill cuttings, this could result in serious erosion problems, particularly of surface or near-surface equipment. Although the equipment could be protected by the selection of hard-wearing materials or sacrificial coatings, such measures would increase the expense of the equipment and/or its installation and maintenance.

[0016] The present invention provides apparatus and a method for underbalanced drilling a wellbore from a selected location in an existing wellbore penetrating a subterranean earth formation having a gas-bearing zone using a remotely controlled drilling device which over-

comes, or at least mitigates the erosion problems.

[0017] Thus, according to the present invention, a method of creating a second wellbore section, penetrating a subterranean earth formation having at least one gas-bearing zone, from a selected location in an existing first wellbore section using a remotely-controlled drilling device under underbalanced drilling conditions, which method comprises:

- (a) arranging the remotely-controlled drilling device at the selected location in the first wellbore section, in or below a production tube,
- (b) operating the remotely-controlled drilling device to drill the second wellbore section,
- (c) controlling the flow of gas produced from the gas-bearing formation through the production tube to the wellhead
- (d) using a fluid stream comprising at least a portion of produced gas to transport the drill cuttings resulting from the drilling operation to the wellhead and
- (e) controlling the pressure in the production tube such that the linear velocity of the gas does not fall below 1 m/s and does not exceed 75 m/s.

[0018] Preferably, the linear velocity of the gas through the production tube is not less than 5 m/s and more preferably not less than 10m/s. The maximum linear velocity is preferably no more than 30 m/s. A particularly suitable operating range is from 5m/s to 20m/s.

[0019] Methods and apparatus for controlling the pressure in the wellbore are known, for example the known adjustable chokes and choke manifolds. Preferred apparatus includes apparatus known for managed pressure drilling. As well as conventional choke valves, it has been proposed to use devices for controlling the flow of fluid from an oil or gas well which do not rely on movable components. For example, European Patent Application 0305 163 discloses a fluidic apparatus for the control of flow in a fluid line which comprises a vortex amplifier. The vortex amplifier is described as a vortex chamber through which a main flow passes radially to emerge at an axial outlet, the main flow being regulated and controlled by a control flow introduced tangentially into the vortex chamber. The use of such a fluidic control device which has no movable components mitigates the problems arising from wear and corrosion during use, particularly when the fluid comprises corrosive fluids and/or solid particles.

[0020] The linear velocity of gas required to convey the drill cuttings will depend on a number of factors, including the density, size and shape of the drill cuttings and the density, temperature and pressure of the gas. The drilling device can be operated to increase or decrease the depth of cut and thereby change the size of the cuttings. Means may be provided to comminute the drill cuttings. The nature of the formation may also affect the size of the cuttings. The volumetric flow of produced gas at formation pressure may be sufficient to convey

the drill cuttings away from the drilling device. For example, at a depth of around 3000 m the formation pressure may be of the order of 28 MPa. The minimum linear velocity to convey the drill cuttings may be around 5 to 10 m/s depending on the density, size and shape of the drill cuttings and the density, temperature and pressure of the gas. Without the pressure control, the volume of gas would increase substantially as it rose up the well to the wellhead and the resulting increased speed would result in the conveyed drill cuttings causing severe erosion of the well tubing, downhole and surface equipment.

[0021] The drilling device may comprises a pump system having an inlet into which drill cuttings can flow and an outlet arranged to discharge the drill cuttings into the wellbore behind the drilling device. Suitably, the outlet is arranged to discharge the drill cuttings into a part of the wellbore in which fluid is circulated, which fluid, together with the gas from the formation, entrains the drill cuttings and transports the drill cuttings to the wellhead. Thus, for example, where the second wellbore section is being drilled from a first wellbore section through which fluid is circulated, then the outlet can deposit the drill cuttings into the fluid rising to the wellhead from the first wellbore section.

[0022] Liquid could be used to convey the drill cuttings away from the drilling device. Pumps are known that can cope with a significant quantity of solids in the fluid. For example, a positive displacement pump. However, where the drill cuttings are to be conveyed by a fluid which is substantially gas, it is preferable to use a gas circulated by a compressor. However, compressors are not generally suitable for gases containing substantial amounts of solid material. Thus, the system for conveying the drill cuttings from the drilling device preferably comprises a compressor associated with an eductor. Eductors are well known pneumatic conveying devices in which the power of a blower is converted into suction that can be used to entrain and convey particles. The use of an eductor allows gas to be compressed in the compressor and the solid drill cuttings are drawn in to the gas stream without having to pass through the compressor.

[0023] In one embodiment of the invention, the drilling device is releasably connected to the lower end of the production tube prior to the production tube, and attached drilling device, being lowered into position in the first wellbore section. In another embodiment of the invention, the drilling device is arranged in the first wellbore section prior to installation of the production tubing. In a third embodiment of the invention, the drilling device is passed through a pre-installed production tube and arranged, in or below the production tube.

[0024] According to a further aspect of the invention a method of creating a second wellbore section, penetrating a subterranean earth formation having at least one gas-bearing zone, from a selected location in an existing first wellbore section, which first wellbore section is provided with a production tube arranged in sealing relationship with the wall of the wellbore, using a remotely-con-

trolled drilling device under underbalanced drilling conditions, the method comprises:

- (a) passing the remotely-controlled drilling device from the wellhead through the production tube to the selected location in or below the production tubing in the first wellbore section,
- (b) operating the remotely-controlled drilling device to drill the second wellbore section, thereby generating drill cuttings
- (c) allowing a first stream of produced gas to flow directly to the wellhead through the production tube and pumping a second stream of produced gas over the cutting surfaces of the remotely controlled drilling device via a remotely controlled pumping means and transporting the drill cuttings away from the remotely controlled drilling device entrained in the second stream of produced gas,
- (d) allowing the second stream of produced gas and entrained drill cuttings to flow to the wellhead through the production tube and
- (e) controlling the pressure in the production tube such that the linear velocity of the gas does not fall below 1 m/s and does not exceed 75 m/s

[0025] Preferably, the linear velocity of the gas through the production tube is not less than 5 m/s and more preferably not less than 10m/s. The maximum linear velocity is preferably no more than 30 m/s. A particularly suitable operating range is from 5m/s to 20m/s.

[0026] Preferably, each of the remotely controlled drilling device and the remotely-controlled pumping means is electrically operated. More preferably, each of the remotely controlled drilling device and remotely-controlled pumping means is both controlled and powered by electricity. The remotely-controlled drilling device and /or the remotely-controlled pumping means may have a power source that is conveyed with the downhole equipment into the well e.g. a battery. However, the power for the remotely-controlled drilling device and/or the remotely-controlled pumping means is preferably provided from the surface via cable.

[0027] It is envisaged that gas or other hydrocarbon fluids may have been produced from the formation prior to drilling the second wellbore. However, the method of the present invention may also be used where the existing wellbore has been drilled to a selected location immediately above the gas-bearing zone of the formation and the new wellbore extends the existing wellbore into the gas bearing zone. Thus, the new wellbore section may be, for example:

- (a) a wellbore extending into the gas-bearing zone of the formation from a selected location immediately above said zone;
- (b) a continuation of an existing wellbore that further penetrates the gas-bearing zone of the formation
- (c) a side-track well from a selected location in the

production tubing or a selected location in the existing wellbore below the production tubing;

- (d) a lateral well from a selected location in the production tubing or a selected location in the existing wellbore below the production tubing.

[0028] By "side-track well" is meant a branch of an existing wellbore where the existing wellbore no longer produces hydrocarbon fluid. Thus, the existing wellbore is sealed below the selected location from which the side-track well is to be drilled, for example, with cement. By "lateral well" is meant a branch of an existing wellbore where the existing wellbore continues to produce hydrocarbon fluid. Suitably, a plurality of lateral wells may be drilled from an existing wellbore. The lateral wells may be drilled at about the same depth in the existing wellbore i.e. in different radial directions or from different depths in the existing wellbore.

[0029] The person skilled in the art will be well aware that wellbore depths may not be the same as vertical depth so that references to depths in the well bore such as "above" or "below" certain depths generally refer to well bore depths rather than vertical depths.

[0030] The existing first wellbore section may have been cased and/or lined. Where the selected location in the existing first wellbore section is in a cased or lined section below the production tube, a window is first formed in the casing or liner. Where the selected location is within the production tube which is itself in a cased or lined section of the wellbore, windows must be formed in both the production tube and casing or liner. The windows may be formed in the casing using a mill or drill depending on the material of the production tube, casing or lining. The remotely controlled drilling device may comprise a mill and/or a drill or the cutting of the window could be carried out as a separate operation and using different equipment to the drilling of the second wellbore section. It is also possible to use the process to drill a second wellbore section from a first uncased wellbore section.

[0031] The present invention is primarily described as being for drilling new production wellbores, but it can be used for other drilling operations in wellbores through gas-bearing formations. For example, it can also be used to drill through mineral scale that has been deposited on the wall of an existing wellbore and/or on the production tube thereby enlarging the available bore. The present invention can also be used to drill perforation tunnels or to drill out blockages in such tunnels.

[0032] According to the further aspect of the present invention, the stream of entrained drill cuttings may be diluted into the first stream of produced gas with the cuttings being transported to the surface together with the produced gas.

[0033] The cuttings may be removed from the produced gas at processing plant using conventional cuttings separation techniques.

[0034] In some circumstances, some of the cuttings may disentrain from the gas stream and may not be trans-

ported to the wellhead. For example, a portion of the cuttings may disentrain from the produced gas and may be deposited in the rat hole of the first section of wellbore. As the gas and entrained drill cuttings pass through the wellhead equipment at comparatively lower pressure than the bottom hole pressure, the tendency for disentrainment can increase. The wellhead equipment is preferably designed and arranged to minimise the amount of disentrained drill cuttings falling back into the well.

[0035] The person skilled in the art will know of suitable drilling devices and methods of drilling using such devices, including for example, the use of whipstocks to deviate the direction of a drill bit to initiate a lateral or sidetrack wellbore.

[0036] Suitably, the drilling device comprises what is generally known as a "wireline" drilling device. This means that it is operated using a cable rather than a drill string. The remotely controlled drilling device can be passed from the surface to the selected location in the first wellbore section suspended on the cable. Suitable cables are known and include cables comprising wires and/or segmented conductors for transmitting electric power and/or signals from the surface to the downhole equipment. A particularly suitable cable can comprise one or more conductors embedded in an insulating material which is encased by a fluid barrier, such as a steel tube; the cable being provided with an outer protective sheath, such as steel braiding. The cable may form part of an assembly which includes fluid conduits for the produced gas or other fluids in the well. The cable may be connected to the drilling device by means of a releasable connector.

[0037] Methods for sealing around the cable at the surface are known and include grease tubes and annular seals. Such seals are particularly effective for sealing against liquid flow and where the outer surface of the cable is relatively smooth. When a braided cable is used and the wellbore is producing significant amounts of gas, sealing the cable at the wellhead can be more difficult. It is therefore preferred to use a cable in which the interstices of the braided sheath are filled e.g. with a polymeric material.

[0038] A combination of wire line and tubular drill string may also be used. For example, a cable can be run from the surface to a sub-surface housing for a motor that is capable of driving a tubular drill string having at its distal end a drill bit.

[0039] Preferably, the drilling device is electrically controlled and, more preferably, it is provided with an electrically operated steering means, for example, a steerable joint, which can be used to adjust the trajectory of the second wellbore section as it is being drilled.

[0040] Typically, the first wellbore section has an inner diameter of 5 to 10 inches (13 cm to 25 cm) and the production tube has an inner diameter of 2.5 to 8 inches (6 to 20 cm), more typically 3.5 to 6 inches (9 to 15 cm). This means that any tool that is passed down the interior of that well bore has to be small enough in cross-section

to pass through the restriction in order to reach lower levels in the wellbore. This is called through-tubing operations in that any well operations that are to be carried out in the well bore below the end of the production tubing require the equipment to be passed through the interior of the production tube before it can reach the area where the well operation is to be carried out. The alternative would be to remove the production tubing in its entirety from the well bore, which is an expensive and time consuming process. Thus, it is very desirable to be able to pass well tools that are to be used in well operations through the interior of the smaller diameter production tube down below the end of that tube into the larger diameter wellbore and then carrying out well operations with those tools in that larger area of the wellbore.

[0041] Where, according to the present invention, the drilling device is to be passed through the production tube its maximum outer diameter must be smaller than the inner diameter of the production tube, generally by at least 0.5 inch (1.3 cm) and more typically the drilling device is at least 1 inch (2.5 cm) less than the inner diameter of the production tube. The cutting surfaces on the drilling device may be sized to form a second wellbore section having a diameter that is less than the inner diameter of the production tube, for example, a diameter of 3 to 5 inches (7.6 to 13 cm). However, the drilling device is preferably provided with means for creating a wellbore that is of the same or greater diameter than the inner diameter production tube. For example, the drilling device may have an expandable drill bit.

[0042] Optionally, the drilling device can have a first drill bit located at the lower end thereof and a second drill bit located at the upper end thereof. This is advantageous in that the second drill bit may be used to remove debris when withdrawing the drilling device from the wellbore.

[0043] Suitably, the drilling device and/or the cable from which the drilling device is suspended may be provided with sensors which can be connected to recording equipment at the surface e.g. by means of electrical conductors in the suspension cable. Sensors may include devices for determining temperature, pressure, fluid flow rates and solid flow rates.

[0044] Where the second wellbore section formed by the remotely controlled drilling device comprises a lateral or sidetrack wellbore, it is preferred that the cable from which the drilling device is suspended and/or through which the power and signals are conveyed, lies within a length of tubing. Suitably, the interior of the tubing is in fluid communication with a fluid passage through or around the drilling device. Suitably, the drilling device is attached either directly or indirectly to the tubing. The tubing, which can be plastic or metal, extends from the drilling device along at least a lower section of the cable. Preferably, the tubing extends into the production tube. Suitably, the length of the tubing is at least as long as the desired length of the second wellbore section. It is envisaged that sensors may be located along the section of cable that lies within the tubing and/or along the outside

of the tubing. Where sensors are located on the outside of the tubing, the sensors may be in communication with the electrical conductors of the cable by electromagnetic means. The tubing generally has an outer diameter smaller than the inner diameter of the production tube thereby allowing the tubing to pass through the production tube. Typically, the tubing has an outer diameter in the range 2 to 5 inches (5 to 13 cm). The tubing may extend to the wellhead.

[0045] According to an aspect of the present invention, some produced gas ("first stream") flows directly to the wellhead through the production tube and some produced gas ("second stream") is passed over the cutting surfaces of the remotely controlled drilling device to transport the drill cuttings. The ratio of produced gas between the first stream and second stream will depend on a number of factors, including the temperature, pressure and density of the produced gas, dimensions of the wellbores and equipment and the size, shape and density of the cuttings. There are various known means for arranging the flow of gas over and around the drilling surfaces.

[0046] The second stream of produced gas may be passed to the drilling device through the annulus formed between the tubing and the wall of the second wellbore section and the cuttings entrained in the second stream of produced gas (hereinafter "entrained cuttings stream") may be transported away from the drilling device through the interior of the tubing ("reverse circulation" mode). In another embodiment, the second stream of produced fluid may be pumped to the drilling device through the interior of the tubing while the entrained cuttings stream may be transported away from the drilling device through the annulus formed between the steel tubing and the wall of the second wellbore section ("conventional circulation" mode).

[0047] In an embodiment of the invention, a housing, such as a cylindrical housing, may be attached, directly or indirectly, to the end of the tubing remote from the drilling device, for example, via a releasable connector. Thus, the drilling device may be attached to a first end of the tubing and the housing to a second end of the tubing. The housing can accommodate equipment, e.g. pumping equipment, motors, and/or sensors.

[0048] In an embodiment of the invention, the tubing is capable of transmitting torque and the housing accommodates a motor capable of rotating the tubing and the drilling device at the distal end of the tubing. Thus, a bottom hole apparatus suitable for use in the method of the present invention may be suspended from a cable which cable comprises means for supplying electrical power to the bottom hole apparatus, the bottom hole apparatus comprising (a) a housing which accommodates a motor (b) a drill string rotatable by the motor and (c) a drill bit attached to the opposite end of the drill string to the housing such that the drill bit is rotatable with the drill string.

[0049] Preferably, the drilling device and/or the housing is/are provided with electrically operated traction

means which may be used to advance the tubing and hence the drilling device through the second wellbore section as it is being drilled. Suitable traction means are known and comprise, for example, wheels or pads which engage with and move over the wall of the production conduit and/or the wellbore wall or casing.

[0050] In another embodiment of the apparatus suitable for use in the method of the present invention, the drilling device is provided with one or more electric motors for directly or indirectly rotating a drill bit. Where the drilling device comprises more than one drill bit, each may have a dedicated motor or they may both be driven by the same motor.

[0051] The second stream of produced fluid may be pumped to the drilling device by any suitable means, such as, for example, a remotely controlled electrically operated downhole pumping means. As the fluid is primarily gas, a compressor is preferred. The compressor can be located in one of the housings mentioned previously. Preferably, a filter is provided to prevent drill cuttings entering the compressor.

[0052] The tubing through which the cable passes in the second wellbore section may be used to form a lining in the second wellbore section and the tubing may be provided with at least one radially expandable packer to achieve this. Preferably, when the packer(s) is in its non-expanded state, the tubing together with the packer(s) is capable of being passed through the production tube to the selected location of the first wellbore section from which the second wellbore section is to be drilled. Also, the radially expandable packer(s) should not interfere with the flow of gas, during the drilling operation, through the annulus formed between the tubing and the wall of the second wellbore section. Once the drilling operation is complete, the tubing may be locked in place in the second wellbore section by expanding the radially expandable packer(s). Suitably, the tubing extends into the production tube. Preferably, the upper section of the tubing that extends into the production tube is provided with at least one radially expandable packer(s) such that expansion of the packer(s) seals the annulus formed between the tubing and the production tube. Alternative sealing means may also be used. Once in place as a liner in the second wellbore section, the tubing can be perforated to allow produced gas to flow from the gas-bearing zone of the formation into the interior of the tubing and into the production tube.

[0053] Instead of, or in addition to, using packers, the tubing may be expandable. Expandable tubulars for use in wellbores are known, as are means for expanding such tubulars. The expansion can be accomplished by a mandrel or a cone-shaped member urged through the tubular that is to be expanded or by any other suitable expander tool. A preferred method of expanding tubulars, particularly steel tubulars, is to use a rotating ball expander. Such devices are known and comprise radially extendible rotatable balls. The balls are urged outwardly against the internal wall of the expandable tubular and then the balls

are rotated around the internal surface and are also moved axially along the tubular body so that they describe a helical path. When in its non-expanded state, the expandable tubing should be capable of being passed down through the production tube of the existing first wellbore section to the selected location in the existing first wellbore section from which the second wellbore section is to be drilled. Once the drilling operation is complete, the expandable tubing may be expanded to form a lining for the new well bore section. Suitably, the expandable tubing extends into the hydrocarbon fluid production conduit. The length of the expandable tubing which extends into the hydrocarbon fluid production conduit may be expanded against the wall of the production conduit thereby eliminating the requirement for an expandable packer. The expandable tubing is then perforated to allow the produced gas to flow from the gas-bearing zone of the formation into the interior of the expanded tubing and into the production tube. The expandable tubing may be expanded by (a) locking the drilling device in place in the wellbore, for example, using radially extendible gripping means positioned on the housing of the drilling device; (b) detaching the drilling device from the cable and tubing; (c) pulling the cable to the surface through the production tube and attaching an expansion tool thereto, for example, an expandable mandrel; (d) inserting the expansion tool into the wellbore through the production tube and through the tubing; and drawing the expansion tool back through the tubing to expand the tubing. The drilling device may then be retrieved from the wellbore by: (a) reattaching the cable to the drilling device; (b) retracting the radially extendible gripping means; and (c) pulling the cable and drilling device from the wellbore through the expanded tubing and the production tube and/or actuating electrically operable traction means thereby moving the drilling device through the expanded tubing and the production tube. Alternatively, an electrically operated rotatable expansion tool having radially extendible members may be attached either directly or indirectly to the drilling device, at the upper end thereof. A suitable rotatable expansion tool is as described in US patent application no. 2001/0045284. Suitably, the rotatable expansion tool may be adapted by providing a fluid passage therethrough such that, during the drilling operation, the interior of the tubing is in fluid communication with a fluid passage in the drilling device. The rotatable expansion tool may be releasably attached to the expandable tubing, for example, via an electrically operated latch means. After completion of drilling of the new wellbore section, the rotatable expansion tool is released from the tubing. The rotatable expansion tool is then operated to expand the tubing by drawing the expansion tool and the associated drilling device through the tubing while simultaneously rotating the expansion tool and extending the radially extendible members. Following expansion of the tubing, the rotatable expansion tool and the associated drilling device may be retrieved from the wellbore through the production tube by retract-

ing the radially extendible members before pulling the cable and/or actuating electrically operable traction means provided on the housing of the drilling device. Where a housing is provided at the end of the tubing remote from the drilling device, this housing is preferably released from the tubing and is retrieved from the wellbore prior to expanding the tubing.

[0054] Where the new wellbore section is a lateral well, the portion of the tubing which passes through the existing first wellbore section before entering the hydrocarbon fluid production conduit may be provided with a valve comprising a sleeve which is moveable relative to a section of the tubing that has a plurality of perforations therein. When the valve is in its closed position the sleeve will cover the perforations in the section of tubing so that produced fluids from the existing first wellbore section are prevented from entering the production tube. When the sliding sleeve is in its open position the plurality of perforations are uncovered and produced fluids from the existing first wellbore section may pass through the perforations into the tubing and hence into the production tube.

[0055] Suitably, the tubing, particularly when it is a plastic tubing, lies within a sandscreen which extends along the length of the tubing. The sandscreen may be an expandable sandscreen or a conventional sandscreen. Typically, the sandscreen is attached to the cable and/or to the drilling device, for example, via a releasable latch means. Accordingly, once the new wellbore section has been drilled, the sandscreen may be released from the cable and/or the drilling device. Where the tubing lies within a conventional sandscreen, the drilling device generally has a maximum diameter greater than the inner diameter of the sandscreen. It is therefore envisaged that the drilling device may be released from the cable and the tubing, for example, via an electronically releasable latch means thereby allowing the cable and tubing to be pulled from the wellbore through the interior of the conventional sandscreen and the production tube leaving the sandscreen and drilling device in the second wellbore section. Alternatively, the drilling device may be formed from detachable parts wherein the individual parts of the drilling device are sized such that they may be removed from the wellbore through the interior of the conventional sandscreen. Where the sandscreen is an expandable sandscreen, expansion of the sandscreen may allow the drilling device to be retrieved from the wellbore through the expanded sandscreen and the hydrocarbon fluid production conduit.

[0056] The expandable sandscreen may be expanded by methods similar to those described above in relation to the expandable tubing.

[0057] It is also envisaged that where the plastic tubing is formed from an elastic material, the plastic tubing may be temporarily sealed at its end remote from the drilling device. Produced gas flowing into the second wellbore section in the vicinity of the drilling device is then pumped into the interior of the plastic tubing via a pumping means

located in the housing of the drilling device. The plastic tubing is thereby expanded radially outwards owing to the pressure of gas building up in the temporarily sealed interior of the plastic tubing. Thus, the plastic tubing is capable of expanding the sandscreen against the wall of the new wellbore section. Once the sandscreen has been expanded, the gas pressure in the plastic tubing may be relieved by unsealing the end of the plastic tubing remote from the drilling device. The plastic tubing will then contract radially inwards. The drilling device may then be removed from the wellbore by pulling the cable and associated plastic tubing through the expanded sandscreen and the production tube and/or by actuating the electrically operatable traction means provided on the housing of the drilling device.

[0058] The invention will now be described with reference to the accompanying drawings in which:

Fig 1 is a schematic representation of an existing first wellbore section which penetrates into a reservoir formation from which existing first wellbore section a second wellbore section is being drilled under underbalanced drilling conditions.

Fig 2 is a schematic representation of an existing first wellbore section which penetrates into a reservoir formation from which existing first wellbore section, a second wellbore section is being drilled under underbalanced drilling conditions and in which a sandscreen is installed.

Fig 3 is a schematic representation of an eductor device suitable for use with a compressor to entrain drill cuttings in a produced gas stream.

Fig 4 is a schematic representation of a fluidic choke assembly suitable for use in the present invention.

[0059] In Figure 1, an existing first wellbore section 1 penetrates through an upper formation 2 and into a gas-bearing formation 3. A metal casing 4 is arranged in the existing first wellbore section 1 and is fixed to the wellbore wall by a layer of cement 5. A production tube 6 is positioned within the existing first wellbore section 1 and an inflatable packer 7 is provided at the lower end of the production tube 6 to seal the annular space formed between the production tube 6 and the casing 4. A wellhead 8 at the surface provides fluid communication between the production tube 6 and a processing facility 9 via a pipe 10. An expandable whipstock 11 is passed through the production tube 6 and is locked in place in the casing 4 of the existing first wellbore section 1 via radially expandable locking means 12. A remotely controlled electrically operated drilling device 13 is passed into the existing first wellbore section through the production tubing 6 suspended on a reinforced steel cable 14 comprising at least one electrical conductor wire or segmented conductor (not shown). The lower end of the reinforced steel cable 14 passes through a length of steel tubing 15 which is in fluid communication with a fluid passage (not shown) in the drilling device 13. The drilling device 13 is provided

with an electrically operated steering means, for example, a steerable joint (not shown) and an electric motor (not shown) arranged to drive a means (not shown) for rotating drill bit 16 located at the lower end of the drilling device 13. A cylindrical housing 17 is attached to the upper end of the steel tubing 15. The drilling device 13 and/or the housing 17 are provided with an electrically operated pump (not shown) and electrically operated traction wheels or pads 18 which are used to advance the drilling device 13 through a new second wellbore section 19. Although in Figure 1 traction wheels or pads 18 are shown on both the drilling device 13 and housing 17, it may be sufficient to provide such traction devices on one only, preferably the drilling device 13. The cable 14 passes through the housing 17 and the interior of the steel tubing 15 to the drilling device 13. If no housing 17 is used, the equipment in 17 will be carried with the bottom hole assembly including the drilling device 13. The housing 17 or more preferably the drilling device 13 may be provided with a grinding means to comminute the drill cuttings.

[0060] The new second wellbore section 19 is drilled using the drilling device 13, the second wellbore section 19 extending from a window 20 in the casing 4 of the existing first wellbore section 1 into the hydrocarbon-bearing zone 3 and being a side-track well or lateral well. The window 20 may have been formed using a drilling device comprising a mill which is passed through the production conduit 6 suspended on a cable and is then pulled from the first wellbore section 1. Although a whipstock is shown in Figure 1, apparatus and methods are known for initiating a side-track or lateral well using a steerable drill or mill. If the tubing 15 is sufficiently robust, e.g. a steel coiled tubing, then conventional sealing means can be used at the surface. If however conventional sealing means cannot be deployed, e.g. where the tubing 15 is polymeric, then the tubing 15 can be introduced into the wellbore by using valves (not shown) in the production tubing 6 to close off the wellbore so that the tubing 15 can be safely introduced into the production tubing 6. The production tube 6 would effectively be used as a long lubricator. During drilling of the second wellbore section 19, produced gas may be pumped down the interior of the steel tubing 15 to the drilling device 13 via a pump located in the cylindrical housing 17. The produced gas flows from the steel tubing 15 through the fluid passage in the drilling device to the drill bit 16 where the produced gas serves both to cool the drill bit 16 and to entrain drill cuttings. The drill cuttings entrained in the produced gas are then passed around the outside of the drilling device 13 into the annulus 21 formed between the steel tubing 15 and the wall of the second wellbore section 19 ("conventional circulation" mode). Alternatively, produced gas may be pumped through the annulus 21 to the drill bit 16. The drilling cuttings entrained in the produced gas are then passed through the passage in the drilling device and into the interior of the steel tubing 15 ("reverse circulation" mode).

[0061] A plurality of formation evaluation sensors (not shown) may be located: on the drilling device 13 in close proximity to the drill bit 16; on the end of the steel tubing 15 which is connected to the drilling device 13; along the lower end of the cable 14 that lies within the steel tubing 15; and/or along the outside of the steel tubing 15. The formation evaluation sensors can be electrically connected to recording equipment (not shown) at the surface via electrical wire(s) and/or segmented conductor(s) which extend along the length of the cable 14. Where sensors are located on the outside of the steel tubing 15, the sensors may be in communication with the electrical wire(s) and/or segmented conductor(s) of the cable 14 via electromagnetic means. As drilling with the drilling device 13 proceeds, the formation evaluation sensors are operated to measure selected formation characteristics (such as, for example, temperature, pressure, fluid flow and solid particles flow) and to transmit signals representing the characteristics via the electrical conductor wire(s) and/or segmented conductor(s) of the cable 14 to recording equipment at the surface (not shown).

[0062] A navigation system (not shown) for the steering means may also be included in the drilling device 13 to assist in navigating the drilling device 13 through the new wellbore section 19.

[0063] The steel tubing 15 may be expandable tubing. After drilling of the second wellbore section 19, the expandable steel tubing 15 may be radially expanded to form a liner for the new wellbore section 19 and the drilling device 13 may be retrieved by pulling the cable from the wellbore and/or by actuating the traction wheels or pads 18 such that the drilling device passes through the expanded steel tubing and the hydrocarbon fluid production conduit 6. Methods and apparatus for installing expandable tubulars in oil and gas wells are known and any such methods may be used in the present invention.

[0064] Where the steel tubing 15 is not expandable, the steel tubing 15 may be provided with at least one radially expandable packer. The packer(s) may be expanded to seal the annulus formed between the steel tubing 15 and the second wellbore section 19 thereby forming a sealed liner for the second wellbore section 19. Where a pump is located in the housing of the drilling device 13, this pump may be disconnected from the housing and may be retrieved through the interior of the steel tubing 15. Preferably, the pump is a compressor and is associated with an eductor in which the power of the compressor is converted into suction that can be used to entrain and convey the drill cuttings. The use of an eductor allows the gas to be compressed in the compressor and the solid drill cuttings to be drawn in to the gas stream without having to pass through the compressor.

[0065] The liner for the new wellbore section may then be perforated to allow hydrocarbons to flow through the interior thereof into the production conduit 6.

[0066] The new wellbore section 19 can be relatively long, typically in excess of a kilometre.

[0067] When produced gas is conveying the drill cut-

tings from the drill bit 16 to the wellhead 8 at the surface the pressure is controlled in the first and second wellbore sections such that the linear velocity of the gas does not fall below 1 m/s and does not exceed 75 m/s. Preferably, the linear velocity of the gas through the production tube is not less than 5 m/s and more preferably not less than 10 m/s. The maximum linear velocity is preferably no more than 30 m/s. A particularly suitable operating range is from 5 m/s to 20 m/s.

[0068] The gas and entrained drill cuttings flow up the production tube 6 to the wellhead 8 and thence to a processing facility 9 via a pipe 10. The drill cuttings can be separated from the gas at the processing facility 9.

[0069] Fig 2 is similar to Fig 1 and the same elements have the same reference numerals, but instead of steel tubing 15 there is provided plastic tubing 22 and a sand-screen 23. The plastic tubing 22 is in fluid communication with a fluid passage (not shown) in the drilling device 13. The sandscreen 23 is positioned around the plastic tubing 22 and is releasably connected to the drilling apparatus 13. The plastic tubing 22 can, like the steel tubing 15 in Fig 1, be used to transport fluid to or from the drilling device 13. After drilling of the second wellbore section 19, the sandscreen 23 may be expanded, for example, by sealing the plastic tubing 22 and pressurising with gas to expand the plastic tubing 22 which in turn expands the sandscreen 23. By releasing the pressure in the plastic tubing 22, it will deflate sufficiently to allow its withdrawal from the sandscreen 23.

[0070] The eductor 30 illustrated in Fig 3 comprises a nozzle 31 through which compressed gas is supplied. The compressed gas is supplied by a compressor (not shown) that can be driven by any suitable means, such as a high speed electric motor. The nozzle 31 accelerates the compressed gas through a venturi section 32 positioned in a tube 33 creating suction which draws gas and drill cuttings into the tube 33 through holes 34. The drill cuttings are entrained in the gas and conveyed through the pipe 33. The nozzle 31 can be connected to any suitable compressor. The compressor could optionally be within the either of the housings 13 or 17 of Figures 1 or 2. The compressor preferably has a filter to ensure that drill cuttings do not enter the compressor. By the use of the eductor, the compressor can be protected from the passage of drill cuttings which can be entrained into a produced gas stream.

[0071] A fluidic choke assembly suitable for use in the present invention is illustrated in Figure 4. A vortex amplifier 40 comprising a chamber having radial, axial and tangential ports is included in a flow line 41 leading from the well head. The flow from the well head through line 41 enters the vortex amplifier 40 through the radial port. The axial port of the vortex amplifier 40 communicates with the flow line 42 which leads to the processing facility. A separator 43 is positioned downstream of the vortex amplifier 40. The separator can, for example, separate the solid drill cuttings from the gas and/or separate gas from liquid. A branch 44 from the line 42 at a position

downstream of the separator 43 leads to a pump 45 and the output from the pump 45 is connected by line 46 to the tangential control port or ports of the vortex amplifier 40. Control means (not shown) control the pump to achieve the desired flow through the vortex amplifier to achieve the pressure required in the wellbore. A control valve 47 can be included in the flow line 41. The flow in line 41 enters the chamber of the vortex amplifier 40 through the radial port and leaves via the axial port and along line 43. Control flow along line 44 is admitted into the chamber of the vortex amplifier 40 tangentially and deflects the inlet flow to the vortex so reducing the inlet flow. Increasing the control flow increases the pressure drop caused by the vortex and the main flow can be progressively decreased to reduce the main flow outlet. The apparatus can perform the function of a conventional choke but has the advantages that there are no moving parts and the vortex amplifier presents the same flow area to the main flow and throttling is achieved by the control flow. Thus the vortex amplifier arrangement is particularly suitable for the present invention in which the main flow comprises a substantial amount of gas and drill cuttings. As an alternative to using a branch 44 from the main flow, the control flow can be pumped from a separate source of the same or different fluid. For example, when used on an offshore drilling/production facility, sea water could be used.

[0072] A means for separating the drill cuttings from the fluid may be provided upstream of the choke means. This could be a gravity separator.

Claims

1. A method of creating a second wellbore section (19), penetrating a subterranean earth formation having at least one gas-bearing zone (3), from a selected location in an existing first wellbore section (1) using a remotely-controlled drilling device (13) under underbalanced drilling conditions, the method comprising:

- (a) arranging the remotely-controlled drilling device (13) at the selected location in the first wellbore section (1), in or below a production tube (6),
- (b) operating the remotely-controlled drilling device (13) to drill the second wellbore section (19),
- (c) controlling the flow of gas produced from the gas-bearing formation (3) through the production tube to the wellhead (8),
- (d) using a fluid stream comprising at least a portion of produced gas to transport the drill cuttings resulting from the drilling operation to the wellhead (8) and
- (e) controlling the pressure in the first and second wellbore sections such that the linear velocity of the gas does not fall below 1 m/s and does

not exceed 75 m/s.

2. A method of creating a second wellbore section (19), penetrating a subterranean earth formation having at least one gas-bearing zone (3), from a selected location in an existing first wellbore section (1), which first wellbore section (1) is provided with a production tube (6) arranged in sealing relationship with the wall of the wellbore, using a remotely-controlled drilling device (13) under underbalanced drilling conditions, the method comprises:

- (a) passing the remotely-controlled drilling device (13) from the wellhead (8) through the production tube (6) to the selected location in or below the production tubing (6) in the first wellbore section (1),
- (b) operating the remotely-controlled drilling device (13) to drill the second wellbore section (19), thereby generating drill cuttings,
- (c) allowing a first stream of produced gas to flow directly to the wellhead (8) through the production tube (6) and pumping a second stream of produced gas over the cutting surfaces of the remotely controlled drilling device via a remotely controlled pumping means (13) and transporting the drill cuttings away from the remotely controlled drilling device entrained in the second stream of produced gas,
- (d) allowing the second stream of produced gas and entrained drill cuttings to flow to the wellhead (8) through the production tube (6) and
- (e) controlling the pressure in the production tube (6) such that the linear velocity of the gas does not fall below 1 m/s and does not exceed 75 m/s

3. A method as claimed in claim 1 or claim 2 in which the linear velocity of the gas through the production tube (6) is in the range from 5m/s to 20m/s.
4. A method as claimed in any one of claims 1 to 3 in which the drilling device comprises a pump system having an inlet into which drill cuttings can flow and an outlet arranged to discharge the drill cuttings into the wellbore behind the drilling device (13) which pump system comprises a compressor associated with an eductor.
5. A method as claimed in any one of claims 1 to 4 in which the pressure in the production tube (6) is controlled using a fluidic choke comprising a vortex amplifier (40).
6. A method as claimed in any one of claims 1 to 5 in which the remotely controlled drilling device (13) is a wireline drilling device suspended on a cable (14).

7. A method as claimed in claim 6 in which the cable (14) comprises an outer braided protective sheath in which the interstices of the braided sheath are filled with a polymeric material.

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Fig. 1

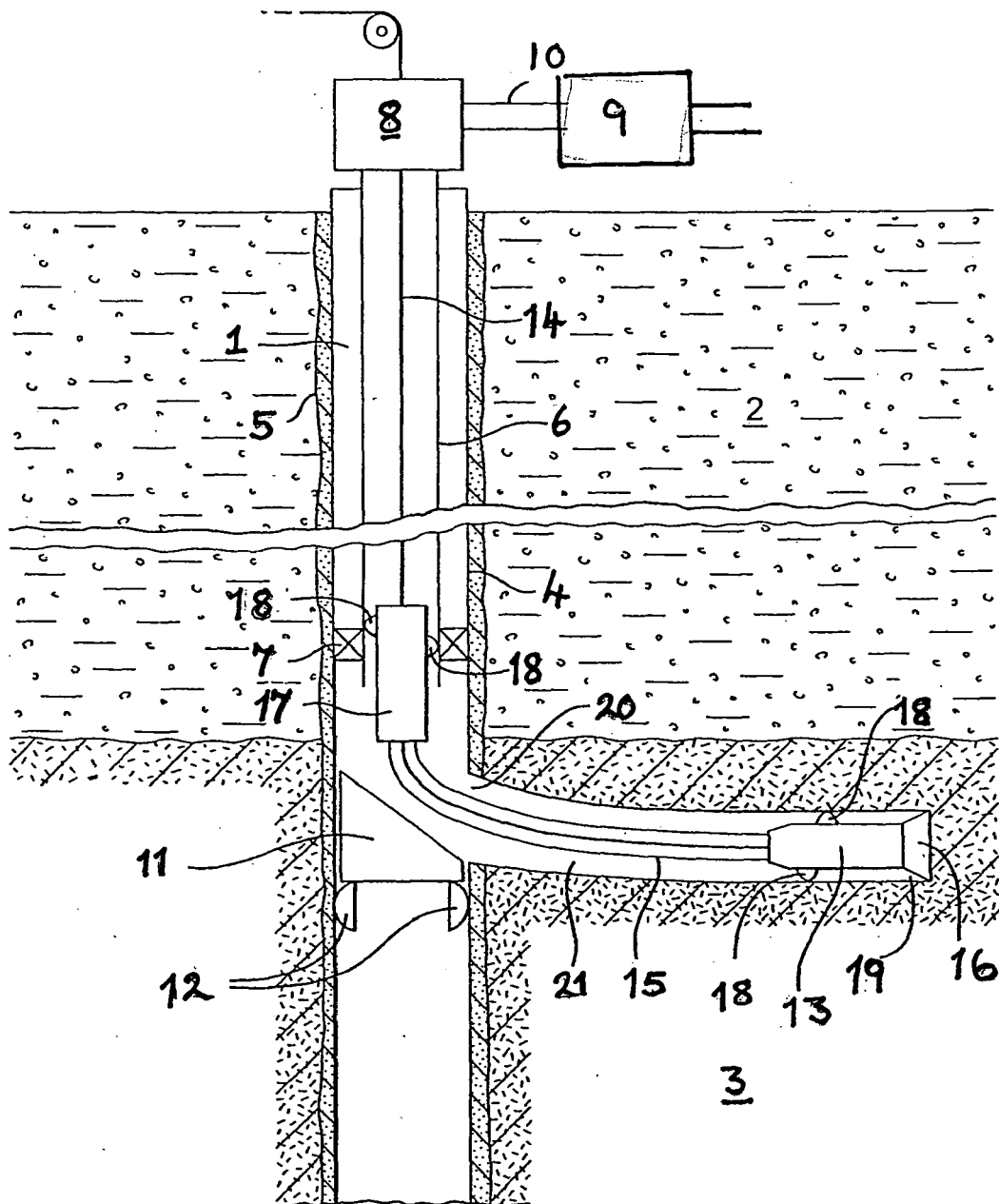
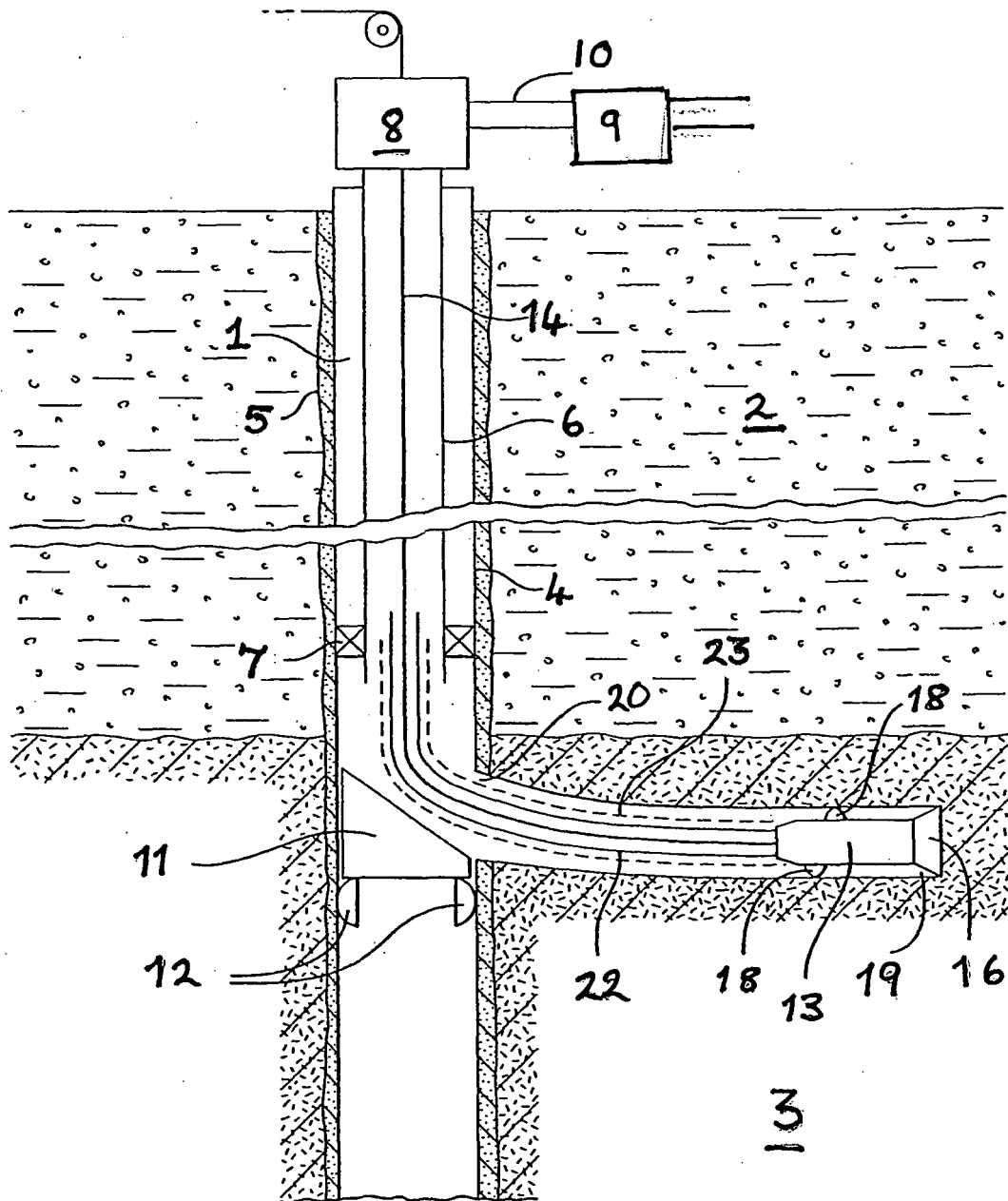
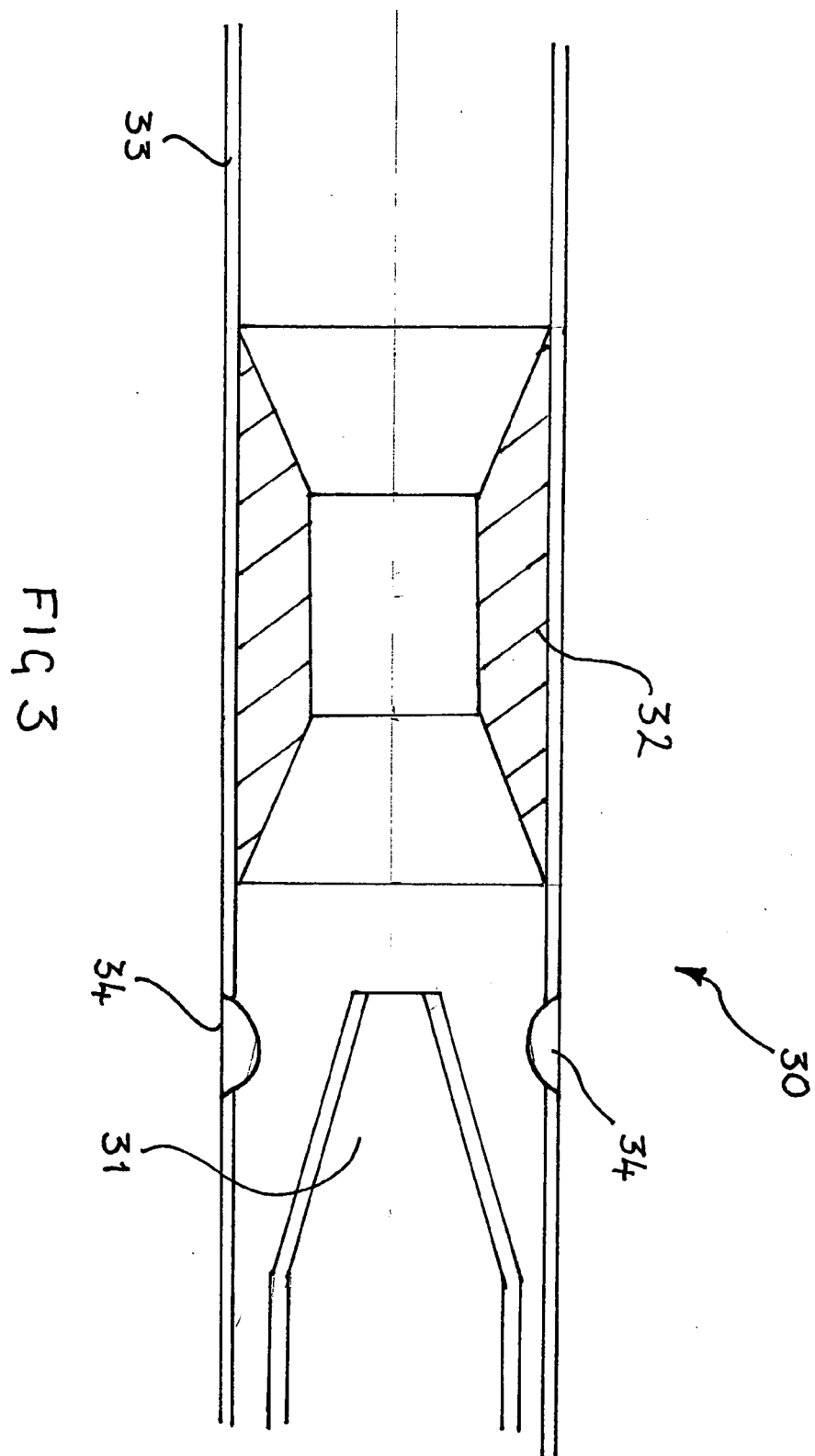


Fig. 2





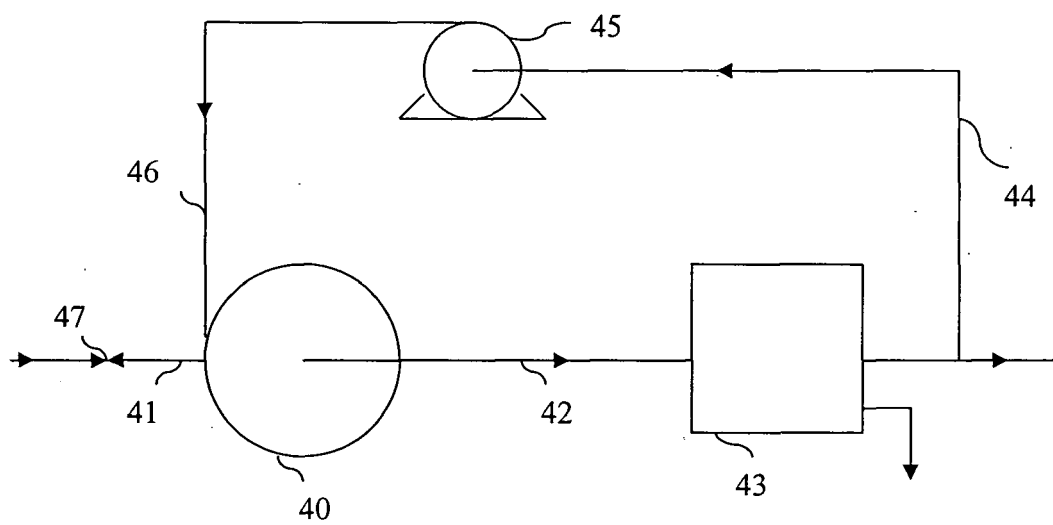


Fig 4



European Patent
Office

EUROPEAN SEARCH REPORT

Application Number
EP 06 25 2153

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Place of search The Hague		Date of completion of the search 26 September 2006	Examiner Dantinne, Patrick
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**ANNEX TO THE EUROPEAN SEARCH REPORT
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