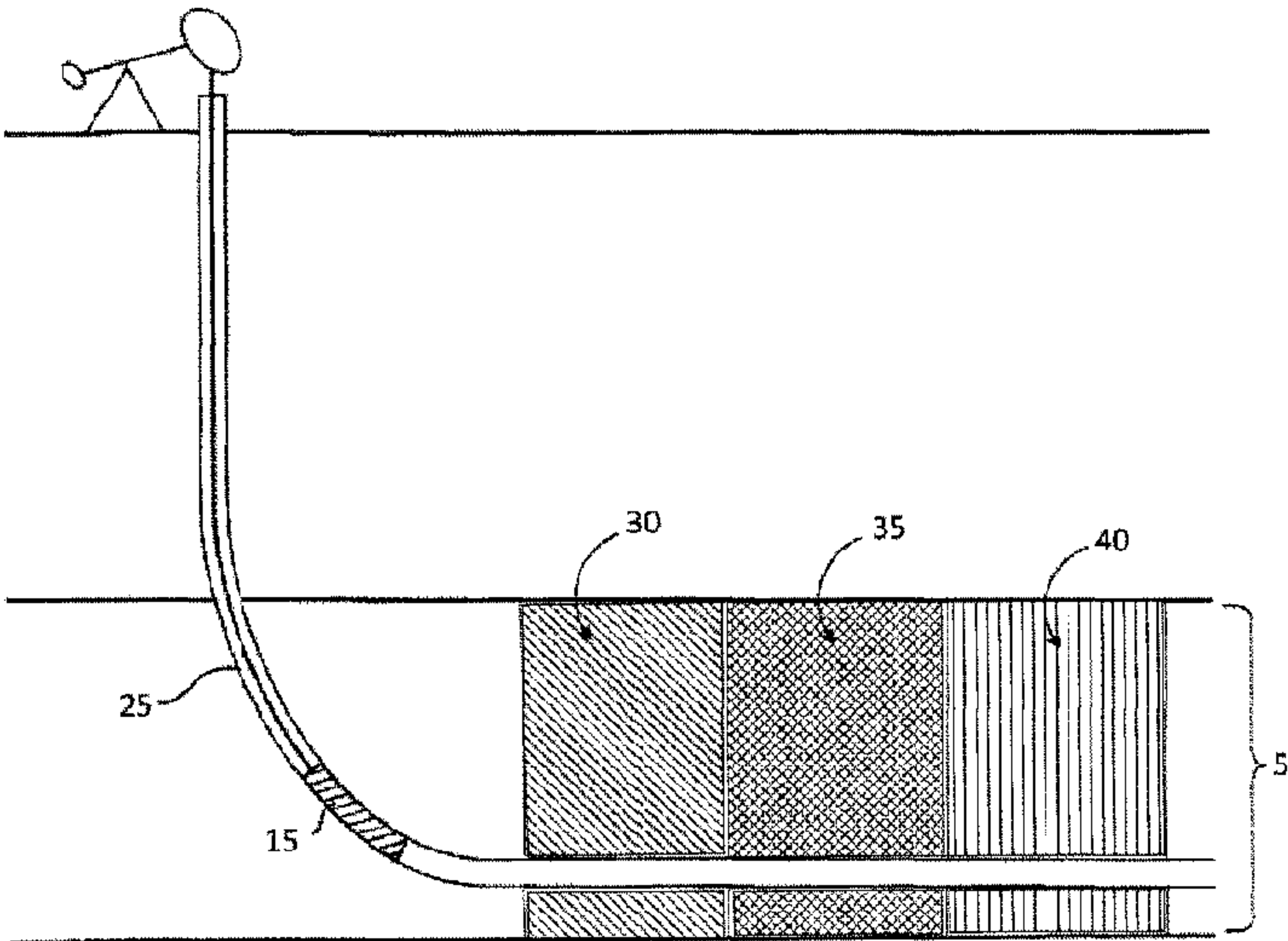




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(54) Titre : PROCEDE POUR AMELIORER LA CONFORMANCE DE L'INJECTIVITE DANS DES FORMATIONS
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(54) Title: METHOD FOR IMPROVING INJECTIVITY CONFORMANCE IN HETEROGENEOUS FORMATIONS



(57) **Abrégé/Abstract:**
A method for improving injectivity conformance of a hydrocarbon bearing heterogeneous subterranean formation by reducing the variance in water saturation throughout the formation, as a means of improving recovery when steam injection is later applied. A solvent plunger is developed by incremental injections of solvent followed by periods of arrest to permit the solvent to mix with the oil in the areas of relatively high water saturation thereby creating a plunger to uniformly displace the water in the formation to achieve water injectivity conformance along the well.

ABSTRACT

A method for improving injectivity conformance of a hydrocarbon bearing heterogeneous subterranean formation by reducing the variance in water saturation throughout the formation, as a means of improving recovery when steam injection is later applied. A solvent plunger is developed by incremental injections of solvent followed by periods of arrest to permit the solvent to mix with the oil in the areas of relatively high water saturation thereby creating a plunger to uniformly displace the water in the formation to achieve water injectivity conformance along the well.

METHOD FOR IMPROVING INJECTIVITY CONFORMANCE IN HETEROGENEOUS FORMATIONS

FIELD OF THE INVENTION

The present invention relates to the field of hydrocarbon extraction from subterranean formations and, in particular, to improving conformance of startup processes while lessening fluid losses overall and increasing injection pressures for hydrocarbon recovery by water/steam injection in formations with varying water saturation.

BACKGROUND OF THE INVENTION

- 5 Heterogeneous hydrocarbon bearing subterranean formations typically encompass a variety of different permeability and pore space saturations and consequently have a broad distribution of relative permeability for flow to different fluids, such as oil and water, that vary from one pore to the next as well as from one region of the formation to the next. Such heterogeneous formations will usually comprise relatively high
10 permeability zones and relatively low permeability zones, making it difficult to efficiently flood the formation by secondary and/or tertiary recovery processes.

Any gas or liquid drive based extraction process, where gas or liquid pressure is used to push the oil out of the formation, is vulnerable to preferential movement through the highest permeability zones and bypass the low permeability zones. In effect, the high
15 permeability zones “thieve” the displacement and/or drive fluids of such processes resulting in decreased sweep efficiency of the secondary or tertiary floods.

In some recovery processes there is a preparatory phase to get the reservoir ready for the subsequent flooding process and this is susceptible to non-conformance of the preparatory process due to the variance in permeability for flow to fluids. In Steam
20 Assisted Gravity Drainage (SAGD) for example, the reservoir between the upper injector well and the lower producer well, comprising a well-pair, has to have the viscosity of the heavy oil or bitumen reduced sufficiently to allow for sufficient mobility to enable initiation of the continuous steam injection and production of the

steam condensate and heated heavy oil or bitumen. This is usually accomplished by heating the region by electrical means or by circulating steam down the length of the well, or by injecting/diffusing solvents into the formation along the length of the well(s), or any combination of the three.

- 5 There have been efforts to speed up the preparatory phase by creating hyper-permeability along the length of the well-pair extending in a plane from the injection well to the production well by injecting fluids, usually water and/or steam at sufficient pressure to reach "dilation pressure" of the formation.

10 These methods have the issue of the variance in reservoir water saturation along the length of the well(s) creating a variance in the rate at which the heavy oil or bitumen is lowered in viscosity and hence the conformance of the preparatory process is affected. For electrical methods this is manifested by the water mobility variance creating a variance in the amount of heat transfer by conduction or the much faster convection.

15 For solvent startup processes the water mobility variance affects the flow of the solvent from the well into the formation. This is because the initial viscosity of the bitumen or heavy oil relative to the water is so high that it is essentially immobile and the solvent is lost by pushing out through the pore space occupied by the mobile water instead of staying in contact with the bitumen long enough to diffuse into and mix with it. In some cases significant volumes of solvent can be lost, or "thieved", through the
20 sections of high water saturation/mobility.

For steam circulation processes the variance in water mobility affects the potential for water or steam condensate to flow from the wellbore into the reservoir and hence the heating rate can vary from just conduction where injectivity is low to much faster forced convection. The injectivity can be such that a significant portion or even all the
25 steam is "thieved" in part of the well and returns are significantly affected.

For dilation methods the water mobility can affect the ability to get to the dilation pressure, and/or affect the conformance of the dilation effect along the length of the well.

The consequent non-conformance of the above mentioned preparatory phases greatly affects the efficiency and efficacy of the subsequent recovery process by having some sections switch to the subsequent recovery mechanism early and continues the thieving aspects as well as the loss of some of the fluids and/or energy away from the well
 5 region.

DESCRIPTION OF THE PRIOR ART

United States Patent Publication No. 2012/0267097 describes a solvent extraction process that attempts to speed up the diffusion of the solvent into the heavy oil/bitumen by first removing solvent blockers, such as mobile fluids (water and gas) residing in heavy oil-containing voids in the formation, through pumping or producing these fluids
 10 from the reservoir; then injecting solvent vapour and providing maximum contact time between injected solvent within the voids to permit the solvent to diffuse into and mix with the heavy oil. This reference is not for conforming startup for a thermal process such as SAGD, but instead is a recovery process in itself. The process does not address the effect of water saturation variance particularly as it relates to reservoir
 15 conformance.

Canadian Patent No. 2,819,707 teaches a method of using solvents instead of steam to dilute the heavy oil / bitumen sufficiently, but is trying to inject a much higher volume of solvent, sufficient to get the entire volume of oil sufficiently mobile. It does not suggest a method of displacing water to conform subsequent recovery processes. The
 20 point is to increase the pressure communication between the wells and not to reduce it.

Canadian Patent No. 2,778,135 is similar to the above reference, with the simple addition of suggesting the solvent enhances the startup of SAGD variants and infill wells or step out wells. While it suggests using solvents the stated purpose is to enhance the pressure communication between injector and producer by increasing the
 25 reservoir fluid mobility. This reference is not directed to displacing the mobile water.

Along these same lines, a number of applications to the Alberta Energy Regulator ("AER") for approval amendments to allow for solvent startup show clear examples of using solvent to enhance communication between injector and producer. For example,

the AER application of April 13, 2010, for the Foster Creek Project and the AER application of February 26, 2010, for the Christina Lake Project, both mention the same specific examples of wells in their field which had difficult steam startup due to limited fluid mobility in the reservoir, necessitating the application of solvent to increase the fluid communication.

Cenovus Energy Inc. has disclosed that they are specifically injecting solvent to enhance pressure communication between the wells and use the measure of the amount of increased pressure communication to infer completeness of the preparatory phase.

To increase the efficiency of formation flooding processes, methods for reducing the effect of injectivity variance have been described. Such methods involve plugging or partial plugging of the relatively high permeability zones to bridge the more permeable zones. Previously suggested plugging agents include cement, plastics, coal tar products and by-products, cotton seed hulls, various organic compounds, etc. More recently plugging agents comprising high molecular weight polymers, and cross-linked products thereof have been described.

United States Patent No. 4,098,337 describes a process for improving injectivity profiles and/or vertical conformance by injecting into a heterogeneous formation an aqueous solution containing unhydrolyzed or partially hydrolyzed polyacrylamide and an aqueous formaldehyde solution. The polyacrylamide is permitted to react with the formaldehyde in situ in the relatively high permeability zones to form a hydroxymethylated polyacrylamide gel which reduces the permeability. Such polymeric materials, however, are temperature sensitive and have the tendency to break down, thereby making these processes unreliable particularly when combined with high temperature recovery processes.

This background information is provided for the purpose of making known information believed by the applicant to be of possible relevance to the present invention. No admission is necessarily intended, nor should be construed, that any of the preceding information constitutes prior art against the present invention.

SUMMARY OF THE INVENTION

The present invention relates to the field of hydrocarbon extraction from subterranean formations and, in particular, to improving conformance of startup processes while lessening fluid losses overall and increasing injection pressures for hydrocarbon recovery by thermal methods in formations with varying water saturation.

- 5 The present invention uses solvent swelling of the in-place bitumen, displacing the more mobile connate water to reduce the overall communication between the two wells, as shown in Figures 1 and 2. These Figures show the results from numerical simulation using CMG STARS comparing the fluid mobility/communication without and with the addition of solvent as per the present invention.
- 10 Figure 1 shows the pressure in the upper injector well and the lower producer well for a SAGD well-pair for a scenario where only the injector is undergoing steam stimulation. Note that this is not intended as an example of a specific single well only steam startup process, but merely to show the effect of solvent on the fluid communication between the wells. When the steam circulation begins the upper well shows the most pressure
- 15 rise as it is the source of the pressure energy, but the producer also rises in pressure in tandem, being caused by the steam stimulation of the upper well. The lower well pressure rises because there is native fluid mobility through the mobile water phase present.
- Figure 2 is a scenario wherein solvent is injected into the formation and initially the
- 20 producer pressure rises due to the injection at the injector but it begins to taper off even though the injection is done at the same target pressure (1800kPa in this scenario) as in Figure 1. Then after a soak period, steam is injected into the injector well and even though the same 1800kPa injection pressure is targeted, the pressure rise in the producer is muted relative to the previous scenario in Figure 1. Note that the 1800kPa
- 25 pressure target is attained in the second scenario with solvent and not attained in the first scenario in Figure 1. This is showing the difference between the prior art, in which pressure communication is enhanced by adding a large amount of solvent, and the present invention where a small amount of solvent, injected quickly, displaces the

mobile water, and dissolves into and swells the bitumen which has a lower mobility than the water and affects a lower overall fluid mobility and hence lower pressure communication.

In accordance with one aspect of the invention, the present disclosure describes a method for improving injectivity conformance of a hydrocarbon bearing heterogeneous subterranean formation, the formation having variable water injectivity due to water saturation variance throughout the formation, the method comprising:

- 5 (i) injecting a solvent into the formation, the solvent entering the pore space by displacing the mobile water rather than the more viscous oil, the efficacy of which is enhanced by displacing the water quickly rather than the solvent slowly diffusing into the bitumen phase, hence setting up a scenario whereby the solvent has displaced the mobile water some distance radially into the formation;
- 10 (ii) arresting injection of the solvent for a sufficient period of time to permit the solvent to mix with the oil in the areas of relatively high water saturation to create a homogenized oil and solvent mix, the homogenized oil and solvent mix having a viscosity that is higher than the viscosity of the solvent and higher than the displaced water;
- 15 (iii) periodically monitoring injection pressure, wherein an increase in injection pressure indicates the degree of mixing between the bitumen and solvent and displacement of the water in the formation, creating a plunger-like volume of viscous fluid in place of the more mobile water initially in place;
- 20 (iv) resuming injection of the solvent into the formation, the solvent bypassing areas of the formation comprising the homogenized oil and solvent mix such that the solvent preferentially displaces into areas of relatively lesser water saturation than in step (i) to create the homogenized oil and solvent mix; and
- (v) repeating steps (ii) to (iv) until the homogenized oil and solvent mix has uniformly displaced the water in the formation and water injectivity conformance is reached.

In accordance with another aspect of the invention, the present disclosure describes a method for improving injectivity conformance of a hydrocarbon bearing heterogeneous subterranean formation, the formation having variable water injectivity due to water saturation variance throughout the formation, the method comprising:

- 5 (i) injecting a solvent into the formation, the solvent moving into areas of relatively higher water saturation, because the water is much less viscous and hence much easier to move than the hydrocarbon, displacing the mobile water from the near wellbore region much like a plunger;
- (ii) arresting injection of the solvent for a sufficient period of time to permit the
10 solvent to mix with the oil in the areas of previously relatively higher water saturation to create a homogenized oil and solvent mix, the homogenized oil and solvent mix having a viscosity that is higher than the viscosity of the solvent and the displaced water;
- (iii) periodically monitoring injection pressure, wherein an increase in injection
15 pressure indicates the degree of mixing between the bitumen and solvent and displacement of the water in the formation, creating a plunger-like volume of viscous fluid in place of the more mobile water initially in place;
- (iv) resuming injection of the solvent or another viscous fluid into the formation, to
20 push the solvent-oil mixture further into the reservoir, moving outwards by further displacing the mobile water ahead of it, increasing the radius of effect of the viscous plunger; and
- (v) repeating steps (ii) to (iv) until the viscous oil and solvent mix has sufficiently displaced the water in the formation with the more viscous solvent and bitumen mixture and water injectivity conformance is reached.

BRIEF DESCRIPTION OF THE DRAWINGS

- 25 These and other features of the invention will become more apparent in the following detailed description in which reference is made to the appended drawings.

Figure 1 is a chart illustrating pressure communication in a SAGD well-pair for a scenario where only the injector is undergoing steam stimulation;

Figure 2 is a chart illustrating pressure communication in a SAGD well-pair for a scenario in accordance with the present invention;

- 5 Figure 3 is a schematic drawing illustrating the implementation of the method according to embodiments of the present invention, showing paired horizontal injector and producer wells completed in a heterogeneous hydrocarbon bearing subterranean formation;

- 10 Figure 4 is a schematic drawing illustrating the implementation of the method according to embodiments of the present invention, showing a single horizontal well completed in a heterogeneous hydrocarbon bearing subterranean formation;

Figure 5 is a schematic drawing illustrating the implementation of the method according to embodiments of the present invention, showing a vertical well completed in a heterogeneous hydrocarbon bearing subterranean formation;

- 15 Figure 6 is a schematic drawing illustrating the implementation of the method according to embodiments of the present invention, showing a plurality of vertical injector wells and a single horizontal producer well completed in a heterogeneous hydrocarbon bearing subterranean formation; and

- 20 Figure 7 is a flow diagram showing the water injectivity conformance method according to embodiments of the present invention, to improve conformance of the formation prior to thermal oil production.

DETAILED DESCRIPTION OF THE INVENTION

Definitions

Unless defined otherwise, all technical and scientific terms used herein have the same meaning as commonly understood by one of ordinary skill in the art to which this invention belongs.

As used herein, the terms “oil”, “bitumen”, “heavy oil” and “hydrocarbons” may be
5 used interchangeably to refer to viscous heavy oil deposits found in subterranean formations.

As used herein, the term “about” refers to an approximately +/-10% variation from a given value. It is to be understood that such a variation is always included in any given value provided herein, whether or not it is specifically referred to.

10 Oil production from subterranean formations is generally achieved by heating the formation with hot fluids or steam to reduce the viscosity of the heavy oil so that it is mobilized toward production wells.

One thermal process, known as “huff and puff” or cyclic steam stimulation, and in particular by the acronym “CSS”, relies on steam injected into a formation through a
15 producer well, which is then temporarily sealed to allow the heat to “soak” and reduce the viscosity of the bitumen in the vicinity of the well. Mobilized bitumen is then produced from the well, along with steam and hot water until production wanes, and the cycle is repeated.

Another thermal process, known as steam assisted gravity drainage (SAGD), provides
20 for steam injection and oil production to be carried out simultaneously through separate wells. The optimal configuration is an injector well which is substantially parallel to, and situated proximally above a producer well, which lies horizontally near the bottom of a formation. Thermal communication between the two wells is established, and thereafter as oil is mobilized and produced, a steam chamber develops, initially in the
25 region surrounding the wells and thence growing outward. Oil at the surface of the enlarging chamber is constantly mobilized by contact with steam and drains under the influence of gravity into the lower producer well. Under this scheme, production can be carried out continuously, rather than cyclically.

Regardless of the production process used, all thermal production processes have the limitation that steam and heat are lost to the formation. In heterogeneous formations in which water saturation levels vary throughout the formation, steam and heat tend to primarily be lost through the highly water saturated areas in the formation as compared to the lesser water saturated areas. Such thief zones deprive lesser water saturated areas of steam resulting in non-uniformity in steam chamber development throughout the reservoir which then leads to inefficient recovery of hydrocarbons. This is particularly an issue for the circulation or pre-heat startup phase whereby some sections along the well are heated slowly by conduction while others are heated very quickly by convection.

A method according to embodiments of the present invention exploits the tendency of solvents to naturally displace into highly water saturated areas of a formation because the water has significantly more mobility than the more viscous hydrocarbons. The solvent and oil then diffuse into and mix together with each other creating a homogenized oil-solvent mixture with a viscosity higher than the solvent and much higher than the water which was displaced. Overall fluid mobility within the reservoir has been reduced and the difference in fluid mobility of the reservoir is reduced.

Specifically, the method comprises the use of solvents to create a homogenized oil and solvent mix in these areas of relatively high water saturation in order to reduce the effect that these thief zones have on thermal production processes. Uniform displacement of water in the formation by the more viscous homogenized oil and solvent mix may be incrementally achieved, according to embodiments of the invention, until uniform water injectivity conformance is reached. In this way, injection of the solvent and creation of a homogenized oil and solvent mix effectively operate as a plunger displacing water from the formation.

Incremental Development of Plunger - Homogenized Oil and Solvent Mix

Referring to Figure 7, volumes of solvent (i.e. a "solvent plunger") are incrementally injected into the formation to allow the solvent to displace the mobile fluids, primarily mobile water, in the formation to develop the solvent plunger. The solvent plunger is

incrementally developed by injecting an initial volume of solvent 60 into the formation and allowing the solvent to displace into the formation. As described, the natural tendency of solvent is to preferentially displace into areas of relatively highest water saturation, accordingly, the initially injected solvent 60 will preferentially move into areas of relatively highest water saturation. The solvent plunger is allowed to develop by arresting the injection of solvent 70 for a sufficient period of time to permit the solvent to diffuse into and mix with the oil in these areas of previously higher water saturation, thereby incrementally increasing the viscosity and reducing the relative permeability in such region. Specifically, the homogenized oil and solvent mix will have a viscosity that is higher than the viscosity of the injected solvent and much higher than the viscosity of the water and will displace the water in these regions of relatively high water saturation.

An additional increment of solvent is then injected 60 if needed to further develop the solvent plunger. Due to the development of the plunger resulting from the initial injection of solvent 60, the regions that were relatively highest in water saturation now have a lowered fluid mobility such that subsequent injection of solvent will bypass these areas of the formation and preferentially will displace into other regions of previously lesser water saturation than the initially highest water saturation along the well. Repeated iterations of solvent injection 60 and arrest 70 allow the plunger to incrementally develop until the homogenized oil and solvent mix has uniformly displaced the water in the formation.

Once complete plunger development has been determined, and uniform displacement of water in the formation indicated, water injectivity conformance may be considered to have been achieved and solvent injection is terminated for recovery by water/steam injection production processes 90. Completion of pre-treatment of a heterogeneous formation, according to embodiments of the present invention, improves the water injectivity conformance of the formation along the well in addition to lessening the water injectivity overall and, in this way, conformance of the well is improved thereby facilitating subsequent thermal production 90 of the oil.

The choice of solvent will depend on certain factors including both the effectiveness of the solvent and the cost of the solvent. It is preferred to use solvents of relatively high viscosity, high diffusivity and density in balance with water. A density nearer to water is better to avoid having the lighter water in the formation displace the solvent by buoyancy. A higher viscosity is better to effect a higher viscosity of the solvent-oil mixture. Higher diffusivity is better for faster diffusion and mixing of the solvent with the oil.

For example, according to certain embodiments of the present invention, suitable solvents may comprise, but are not limited to, xylene, pentane, butane, diesel, naphtha, or any one of a number of by-products or products from a petroleum upgrader or refinery such as a Fluid Catalytic Cracker Light Cycle Oil (such as is described in the online Environment Canada Oil Properties Database at http://www.etc-cte.ec.gc.ca/databases/Oilproperties/pdf/WEB_Fluid_Catalytic_Cracker_Light_Cycle_Oil.pdf) or combinations of these solvents. Suitable solvents for reducing the viscosity of bitumen in a formation are well known to persons of skill in the art, and such aforementioned list of suitable solvents is not intended to be an exhaustive or complete list.

The type of solvent may further be varied according to some embodiments in order to adjust the effectiveness of the solvent in developing the plunger. For example, the type of solvent used in the initial injection 60 may be different than the solvent used in subsequent injections 60. In further embodiments comprising multiple iterations of solvent injection 60 and arrest 70, the choice of solvent at one or more stages of injection 60 may be different. In other embodiments, the type of solvent used may be the same. For example, solvents of increasing density may be used in each iteration of injection 60 in order to effectively displace the water at later stages of plunger development.

Creation of the homogenized oil and solvent mix, according to embodiments of the present invention, does not require flooding of the reservoir as in solvent production methods known in the art. Relatively small volumes of solvent sufficient to displace the water and to create the homogenized oil and solvent mix are to be injected, according to

embodiments of the present invention. Accordingly, methods of the present invention offer an economical way of achieving water injectivity conformance facilitating extraction of oil in subsequent production processes 90.

Feedback Monitoring of Plunger Development

5 Plunger development can be monitored and, in particular, the progress of water displacement from the formation can be monitored to assess the reduction in water saturation variance along the well. According to embodiments of the invention, the progress of the development of the plunger is monitored after each injection of solvent. In a preferred embodiment, plunger development is monitored throughout the
10 development of the plunger during arrest of solvent injection 70. Various parameters known to persons of skill in the art may be used to monitor plunger development including the exemplary techniques described herein.

In one embodiment, the progress of plunger development can be monitored by measuring the rate of pressure buildup and decline. Injecting the solvent will be easier
15 when injecting into higher water saturation formations. Arrest of solvent injection 70 to allow the plunger to develop will be characterized by a decline in reservoir pressure with time as the solvent displaces into the formation and mixes with oil. By comparing the pressure buildup during the solvent injection and the subsequent 80 rate of pressure decline during the period of arrest of solvent injection 70, the degree of fluid mobility
20 of the reservoir can be assessed, correlating with the reduction of water saturation. In particular, an increase in the pressure required to inject the solvent from iteration to iteration and/or lack of pressure decay during the soak period compared to the initial solvent injection is indicative of water displacement from the formation by the solvent plunger.

25 *Implementation – Well Configurations*

Methods according to embodiments of the present invention are applicable as a conditioning method for improving the water injectivity conformance of a formation. As such, embodiments of the present invention can be widely applied to a variety of

heavy oil production processes that utilize water/steam injection. For example, the method can be employed in enhanced start-up or ramp-up operations.

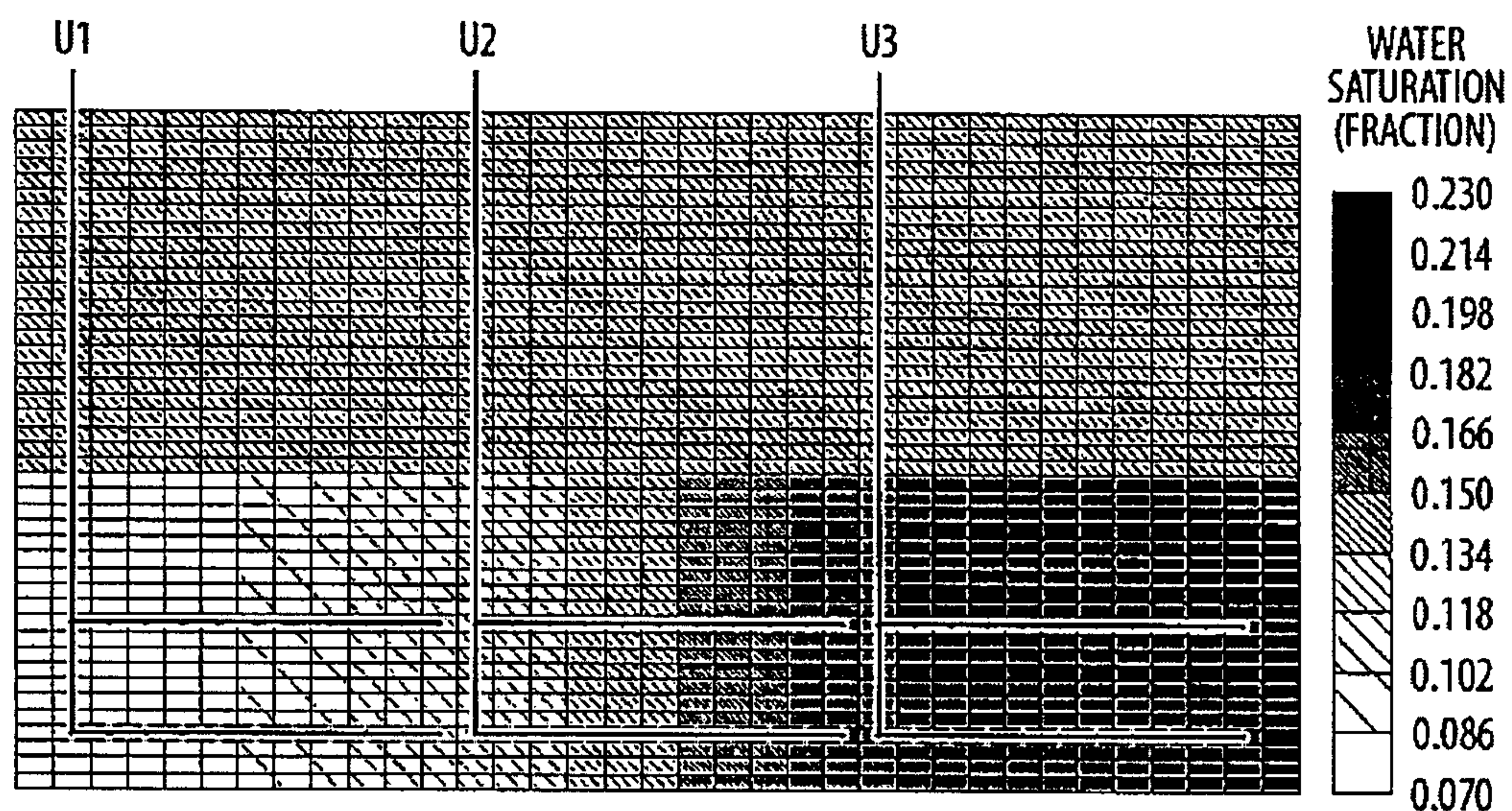
It is further contemplated that the present method can be practiced in a variety of well configurations, for example, in the context of paired injector and producer wells, or a single well cyclic steam stimulation system. As well, it is contemplated that the solvent may be injected through horizontal or vertical injector wells into a subterranean formation containing viscous oil. In this way, methods according to embodiments of the present invention can be used to improve water injectivity conformance in a variety of production system designs.

- 10 Illustrative examples of well configurations in which a method according to the present invention may find application are depicted in Figure 3 to Figure 6. A heterogeneous formation in which water saturation levels vary throughout the formation is illustrated herein as defined regions 30, 35, and 40 which respectively represent differing regions of water saturation in the formation 5. For illustrative purposes, the water saturation levels in these regions correspond to region 40 as having the lowest water saturation level, region 35 as having the highest water saturation level, and region 30 as having an intermediate level of water saturation. Due to these varying water saturation levels, there will be variance in water injectivity of the formation 5 along the length of the well.
- 15
- 20 Figure 3 illustrates implementation of an embodiment of the present invention in a SAGD production system in which an injector well 20 and a producer well 10 extend through the formation 5 in a substantially horizontal and parallel arrangement. In an alternative embodiment, the configuration of the wells may comprise a series of substantially vertical wells 50 situated above a horizontal producer 10 as shown in
- 25 Figure 6. Implementation of embodiments of the present invention in single well configurations is further contemplated as illustrated in Figure 4 and Figure 5 respectively showing a horizontal well 25 and a vertical well 45 extending through the formation 5.

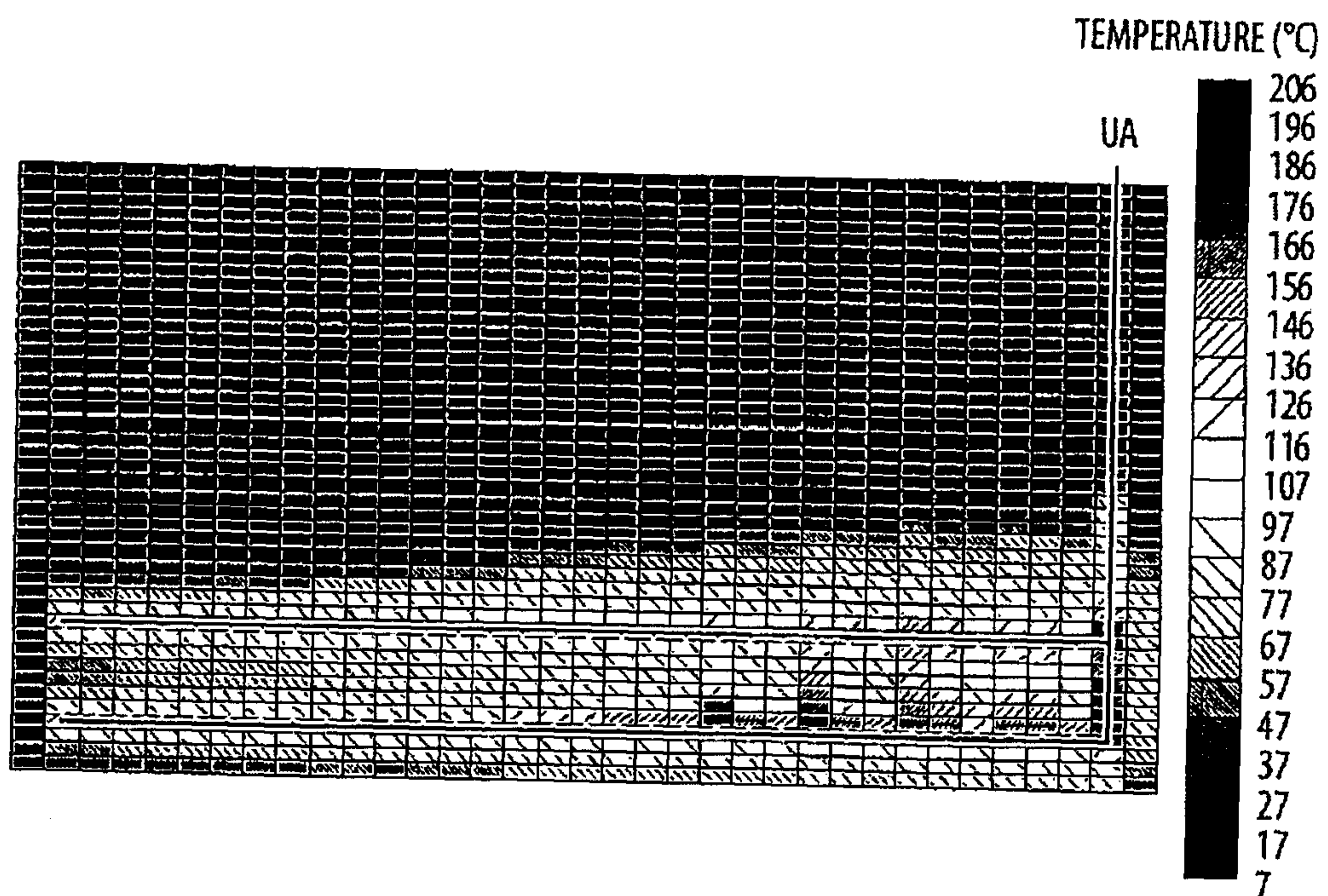
To gain a better understanding of the invention described herein, the following example is set forth. It will be understood that this example is intended to describe illustrative embodiments of the invention and is not intended to limit the scope of the invention in any way.

EXAMPLE

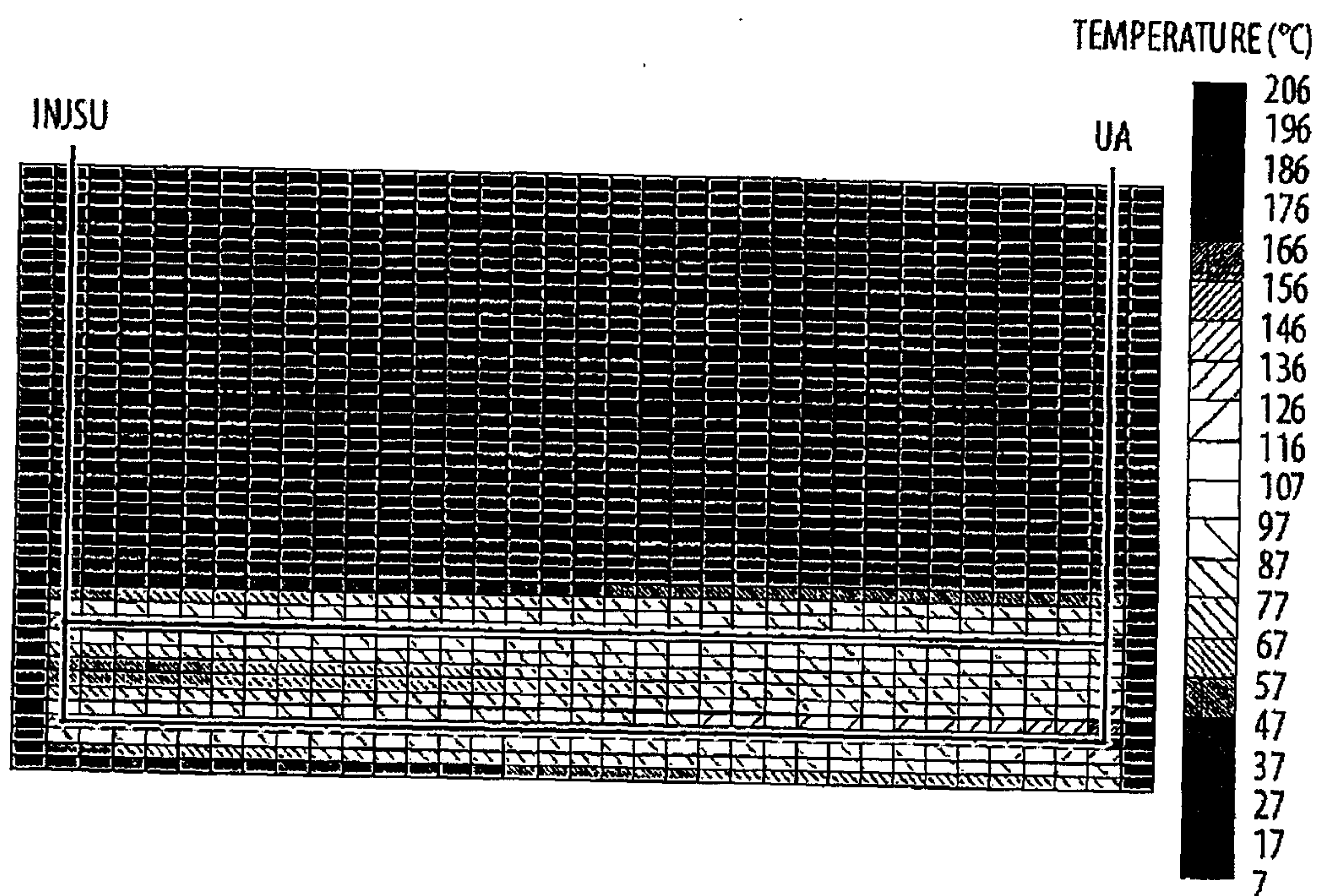
- 5 The following image is of a typical SAGD reservoir with an overall average water saturation of 15% but along the well-pair the water saturation varies from the irreducible saturation of 7% to 23%.



- For the example above, as part of the circulation pre-heat phase of SAGD, steam is circulated down each well by injecting it down an inner string to the toe of the well and the steam and condensate returns back to the surface. The pressure required to push the steam and condensate returns to the surface results in a pressure differential with the reservoir and some of the steam enters the reservoir by displacing the mobile water phase, resulting in an uneven temperature profile as shown in the following image. The section where the initial water saturation was highest has heated up significantly more than the rest of the well-pair to the point where the entire volume of oil in the reservoir between the two wells has been heated up and SAGD has already begun while the other sections are still too cold for an efficient startup.



In the following image the same form of circulation was applied but after a solvent plunger application:



Although the invention has been described with reference to certain specific embodiments, various modifications thereof will be apparent to those skilled in the art. All such modifications as would be apparent to one skilled in the art are intended to be included within the scope of the following claims. The scope of the claims should not
5 be limited by the preferred embodiments set forth in the foregoing examples, but should be given the broadest interpretation consistent with the description as a whole, and the claims are not to be limited to the preferred or exemplified embodiments of the invention.

THE EMBODIMENTS OF THE INVENTION IN WHICH AN EXCLUSIVE PROPERTY OR PRIVILEGE IS CLAIMED ARE DEFINED AS FOLLOWS:

1. A method for improving fluid injectivity conformance of a hydrocarbon bearing heterogeneous subterranean formation, the formation having variable fluid injectivity due to water saturation variance throughout the formation, the formation comprising a first area and a second area wherein the first area initially has a higher water saturation than the second area, the method comprising:

(i) injecting a non-aqueous solvent into the formation, the non-aqueous solvent moving into the first area due to the higher water saturation in the first area and thus displacing at least some water in the first area resulting in the first area having a lower water saturation than the second area, while refraining from injecting any other injectant into the formation;

(ii) arresting injection of the non-aqueous solvent for a first period of time sufficient to permit the non-aqueous solvent to mix with oil in the first area to create a first homogenized oil and solvent mix, the first homogenized oil and solvent mix having a viscosity that is higher than the viscosity of the non-aqueous solvent, while refraining from injecting any other injectant into the formation;

(iii) resuming injection of the non-aqueous solvent into the formation immediately after the first period of time, the non-aqueous solvent bypassing the first area due to the higher viscosity of the first homogenized oil and solvent mix such that the non-aqueous solvent moves into the second area and thus displacing at least some water in the second area, while refraining from injecting any other injectant into the formation;

(iv) arresting injection of the non-aqueous solvent for a second period of time sufficient to permit the non-aqueous solvent to mix with oil in the second area to create a second homogenized oil and solvent mix, while refraining from injecting any other injectant into the formation; and

(v) repeating the steps of injection and arrested injection of the non-aqueous solvent until water in other areas of the formation has been displaced and fluid injectivity conformance is reached.

2. The method according to claim 1, wherein the fluid injectivity conformance is determined by monitoring pressure required to inject non-aqueous solvent in steps (i) and/or (iii) and/or a decline in wellbore or reservoir pressure in step (ii) and/or (iv), wherein the change in injection pressure and/or pressure decline indicates the degree of displacement of the water in the formation.

3. The method according to claim 1, wherein each of the first and second homogenized oil and solvent mix has a viscosity that is higher than the water saturating the formation.

4. The method according to claim 1, wherein the non-aqueous solvent is selected from the group of solvents consisting of xylene, pentane, butane, diesel, naphtha, and various petroleum refinery or upgrader products and combinations thereof.

5. A method for improving fluid injectivity conformance of a hydrocarbon bearing heterogeneous subterranean formation, the formation having variable fluid injectivity due to water saturation variance throughout the formation, the formation comprising a first area and a second area wherein the first area initially has a higher water saturation than the second area, the method comprising:

(i) injecting a non-aqueous solvent into the formation, the non-aqueous solvent moving into the first area due to the higher water saturation in the first area and thus displacing at least some water in the first area resulting in the first area having a lower water saturation than the second area, while refraining from injecting any other injectant into the formation;

(ii) arresting injection of the non-aqueous solvent for a first period of time sufficient to permit the non-aqueous solvent to mix with oil in the first area to create a first homogenized oil and solvent mix, the first homogenized oil and solvent mix having a

viscosity that is higher than the viscosity of the non-aqueous solvent, while refraining from injecting any other injectant into the formation;

(iii) monitoring a solvent injection pressure, wherein an increase in the solvent injection pressure from one injection cycle to a subsequent injection cycle indicates degree of displacement of water in the formation;

(iv) resuming injection of the non-aqueous solvent into the formation immediately after the first period of time, the non-aqueous solvent bypassing the first area due to the higher viscosity of the first homogenized oil and solvent mix such that the non-aqueous solvent moves into the second area and thus displacing at least some water in the second area, while refraining from injecting any other injectant into the formation;

(v) arresting injection of the non-aqueous solvent for a second period of time sufficient to permit the non-aqueous solvent to mix with oil in the second area to create a second homogenized oil and solvent mix, while refraining from injecting any other injectant into the formation; and

(vi) repeating the steps of injection and arrested injection of the non-aqueous solvent until water in other areas of the formation has been displaced and fluid injectivity conformance is reached.

6. The method according to claim 5, wherein each of the first and second homogenized oil and solvent mix has a viscosity that is higher than the water saturating the formation.

7. The method according to claim 5, wherein the non-aqueous solvent is selected from the group of solvents consisting of xylene, pentane, butane, diesel, naphtha, and various petroleum refinery or upgrader products and combinations thereof.

8. A method for improving fluid injectivity conformance of a hydrocarbon bearing heterogeneous subterranean formation, the formation having variable fluid injectivity due to water saturation variance throughout the formation, the formation comprising a first area and a second area wherein the first area initially has a higher water saturation than the second area, the method comprising:

- (i) injecting a first non-aqueous solvent into the formation, the first non-aqueous solvent moving into the first area due to the higher water saturation in the first area and thus displacing at least some water in the first area resulting in the first area having a lower water saturation than the second area, while refraining from injecting any other injectant into the formation;
- (ii) arresting injection of the first non-aqueous solvent for a first period of time sufficient to permit the first non-aqueous solvent to mix with oil in the first area to create a first homogenized oil and solvent mix, while refraining from injecting any other injectant into the formation;
- (iii) injecting a second non-aqueous solvent into the formation immediately after the first period of time, the second non-aqueous solvent bypassing the first area due to the first homogenized oil and solvent mix having a viscosity that is higher than the viscosity of the second non-aqueous solvent such that the second non-aqueous solvent moves into the second area and thus displacing at least some water in the second area, while refraining from injecting any other injectant into the formation;
- (iv) arresting injection of the second non-aqueous solvent for a second period of time sufficient to permit the second non-aqueous solvent to mix with oil in the second area to create a second homogenized oil and solvent mix, while refraining from injecting any other injectant into the formation; and
- (v) repeating the steps of injection and arrested injection of additional non-aqueous solvent, comprising the first non-aqueous solvent, the second non-aqueous solvent, another non-aqueous solvent, or combinations thereof, until water in other areas of the formation has been displaced and fluid injectivity conformance is reached.

9. The method according to claim 8, wherein the fluid injectivity conformance is determined by monitoring pressure required to inject non-aqueous solvent and/or a decline in wellbore or reservoir pressure, wherein the change in injection pressure and/or pressure decline indicates the degree of displacement of the water in the formation.

10. The method according to claim 8, wherein each of the first and second homogenized oil and solvent mix has a viscosity that is higher than the water saturating the formation.

11. The method according to claim 8, wherein the first and second non-aqueous solvents are selected from the group of solvents consisting of xylene, pentane, butane, diesel, naphtha, and various petroleum refinery or upgrader products and combinations thereof.

12. The method according to claim 8, wherein the first non-aqueous solvent is the same as the second non-aqueous solvent.

13. The method according to claim 8, wherein the first non-aqueous solvent is different than the second non-aqueous solvent.

14. The method according to claim 13, wherein the second non-aqueous solvent has a different density than the first non-aqueous solvent.

15. A method for improving fluid injectivity conformance of a hydrocarbon bearing heterogeneous subterranean formation, the formation having variable fluid injectivity due to water saturation variance throughout the formation, the formation comprising a first area and a second area wherein the first area initially has a higher water saturation than the second area, the method comprising:

(i) injecting a first non-aqueous solvent into the formation, the first non-aqueous solvent moving into the first area due to the higher water saturation in the first area and thus displacing at least some water in the first area resulting in the first area having a lower water saturation than the second area, while refraining from injecting any other injectant into the formation;

(ii) arresting injection of the first non-aqueous solvent for a first period of time sufficient to permit the first non-aqueous solvent to mix with oil in the first area to create a first homogenized oil and solvent mix, the first homogenized oil and solvent mix having a viscosity that is higher than the viscosity of the first non-aqueous solvent, while refraining from injecting any other injectant into the formation;

- (iii) monitoring a first solvent injection pressure, wherein the first solvent injection pressure indicates a degree of displacement of water in the formation;
- (iv) injecting a second non-aqueous solvent into the formation immediately after the first period of time, the second non-aqueous solvent bypassing the first area due to the first homogenized oil and solvent mix having a viscosity that is higher than the viscosity of the second non-aqueous solvent such that the second non-aqueous solvent moves into the second area and thus displacing at least some water in the second area, while refraining from injecting any other injectant into the formation;
- (v) arresting injection of the second non-aqueous solvent for a second period of time sufficient to permit the second non-aqueous solvent to mix with oil in the second area to create a second homogenized oil and solvent mix, while refraining from injecting any other injectant into the formation;
- (vi) monitoring a second solvent injection pressure, wherein the second solvent injection pressure indicates a degree of displacement of the water in the formation; and
- (vii) repeating the steps of injection and arrested injection of additional non-aqueous solvent, comprising the first non-aqueous solvent, the second non-aqueous solvent, another non-aqueous solvent, or combinations thereof, until water in other areas of the formation has been displaced and fluid injectivity conformance is reached.

16. The method according to claim 15, wherein each of the first and second homogenized oil and solvent mix has a viscosity that is higher than the water saturating the formation.

17. The method according to claim 15, wherein the first and second non-aqueous solvents are selected from the group of solvents consisting of xylene, pentane, butane, diesel, naphtha, and various petroleum refinery or upgrader products and combinations thereof.

18. The method according to claim 15, wherein the first non-aqueous solvent is the same as the second non-aqueous solvent.

19. The method according to claim 15, wherein the first non-aqueous solvent is different than the second non-aqueous solvent.

20. The method according to claim 19, wherein the second non-aqueous solvent has a different density than the first non-aqueous solvent.

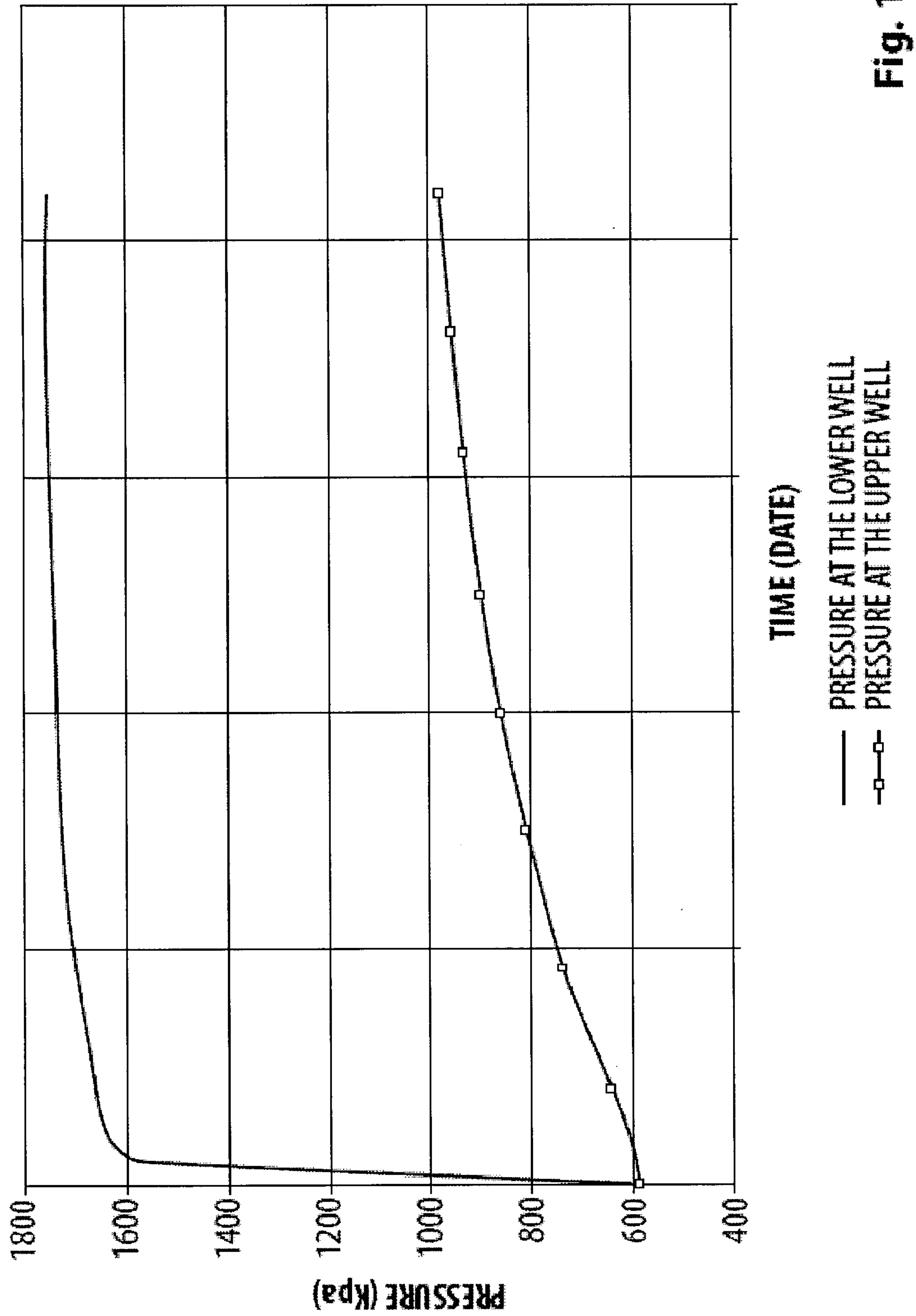


Fig. 1

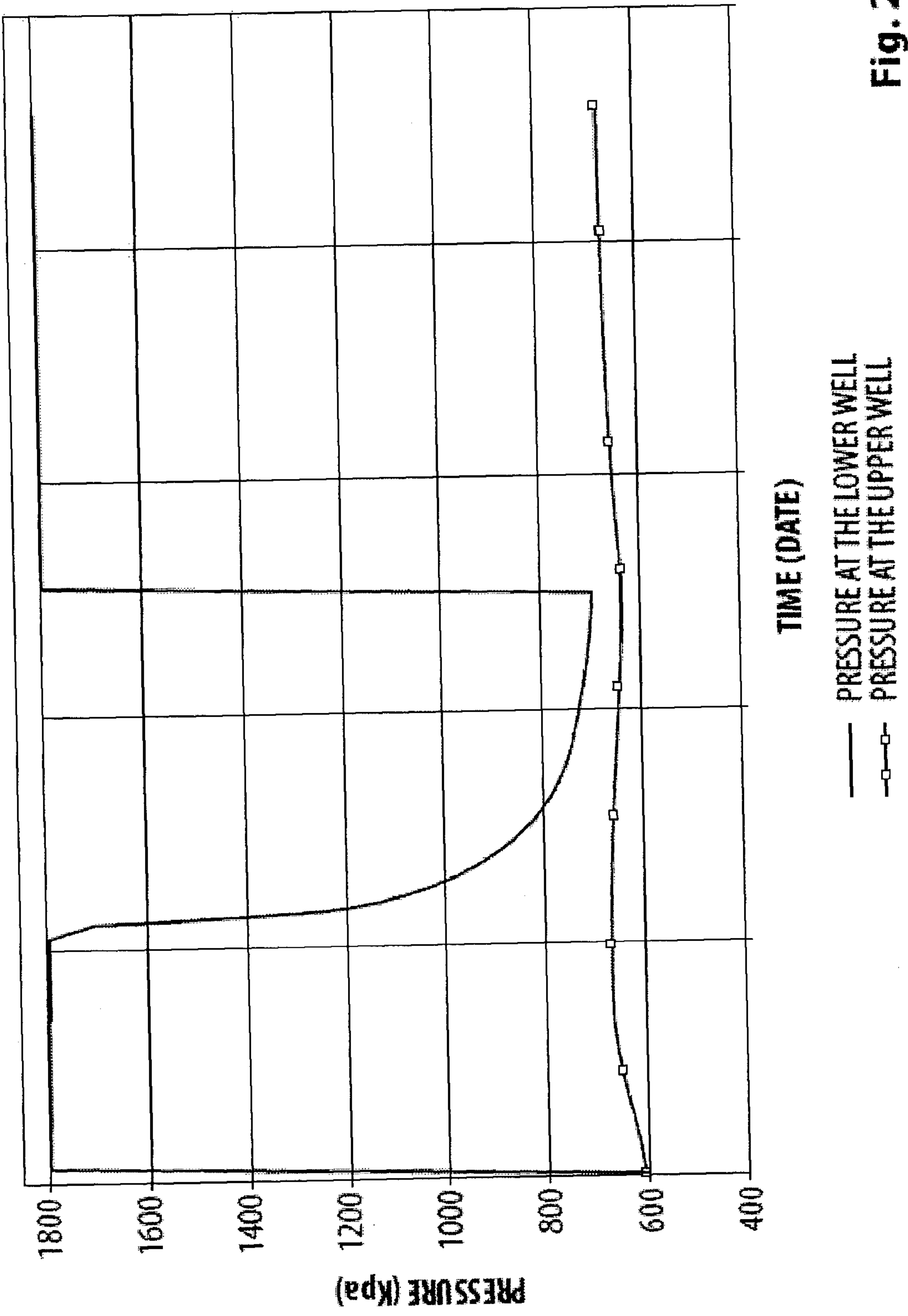
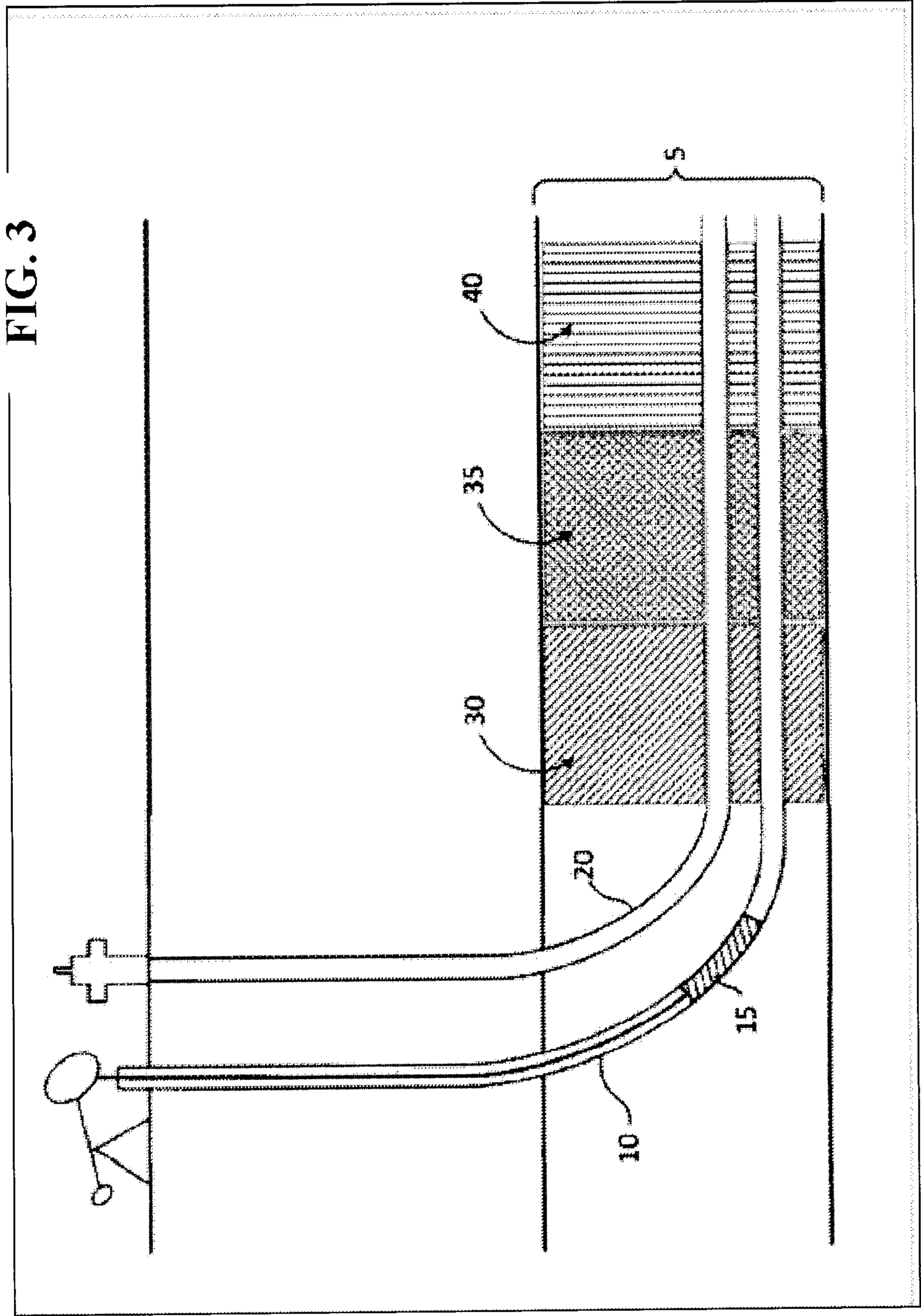


Fig. 2



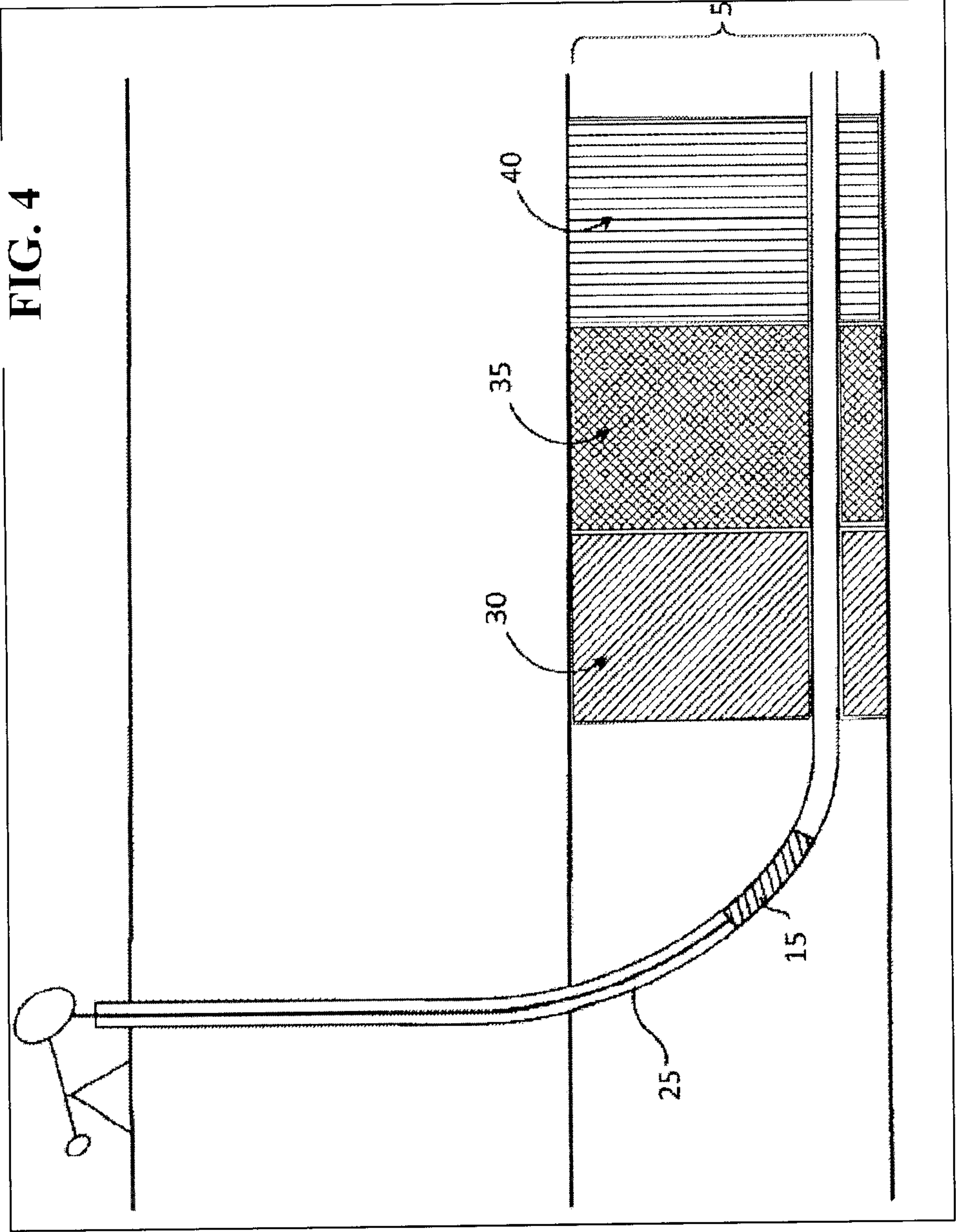


FIG. 5

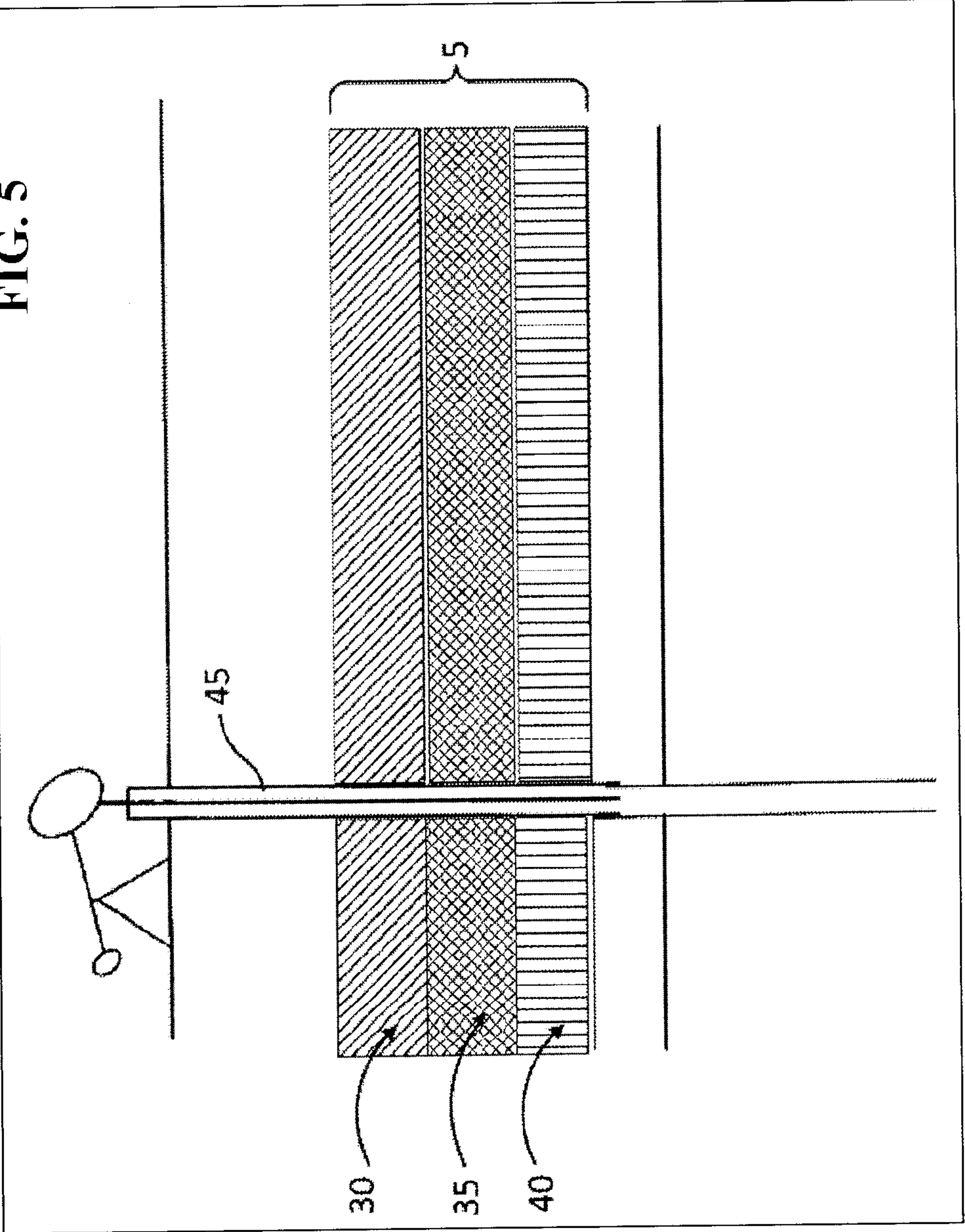
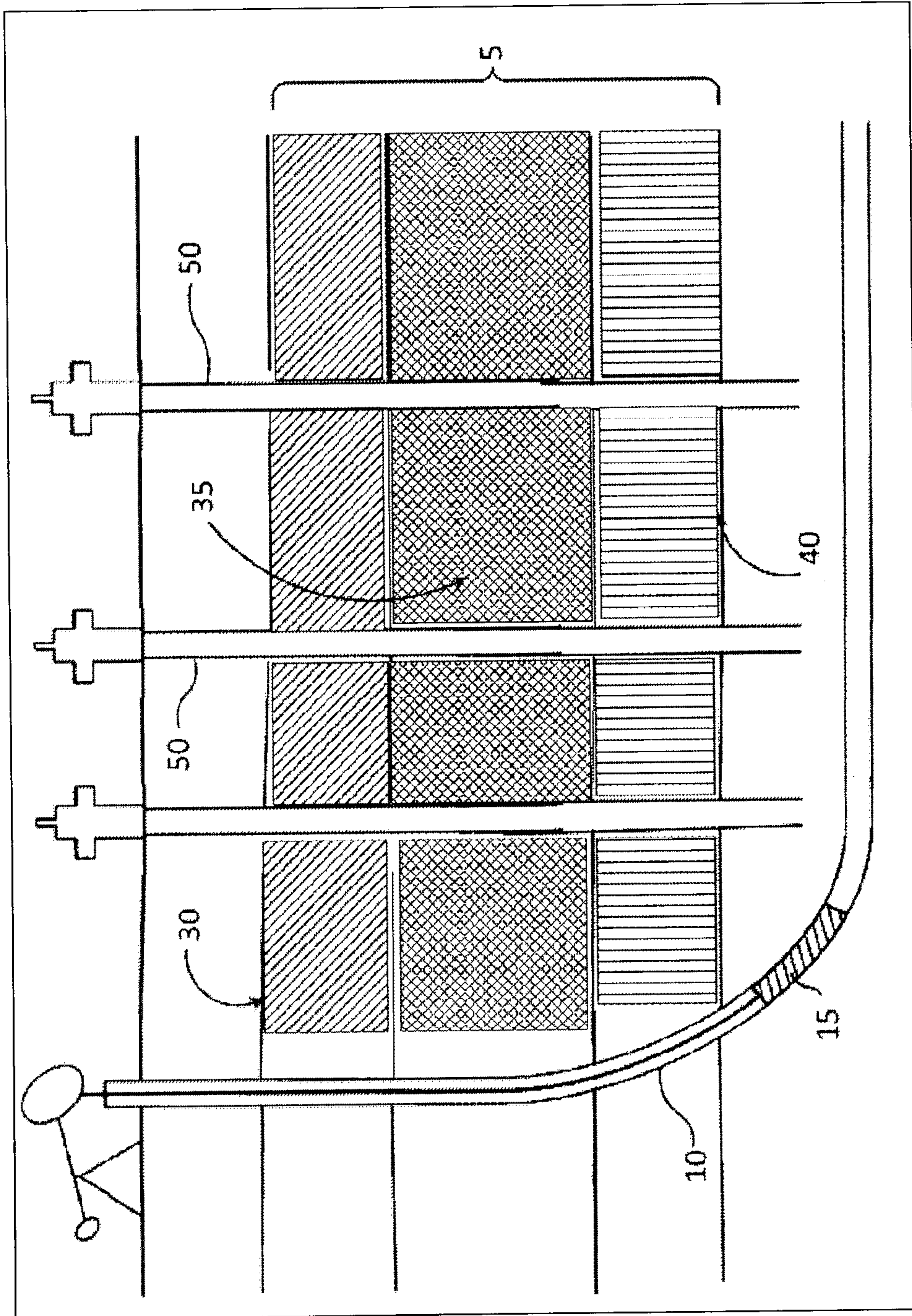


FIG. 6



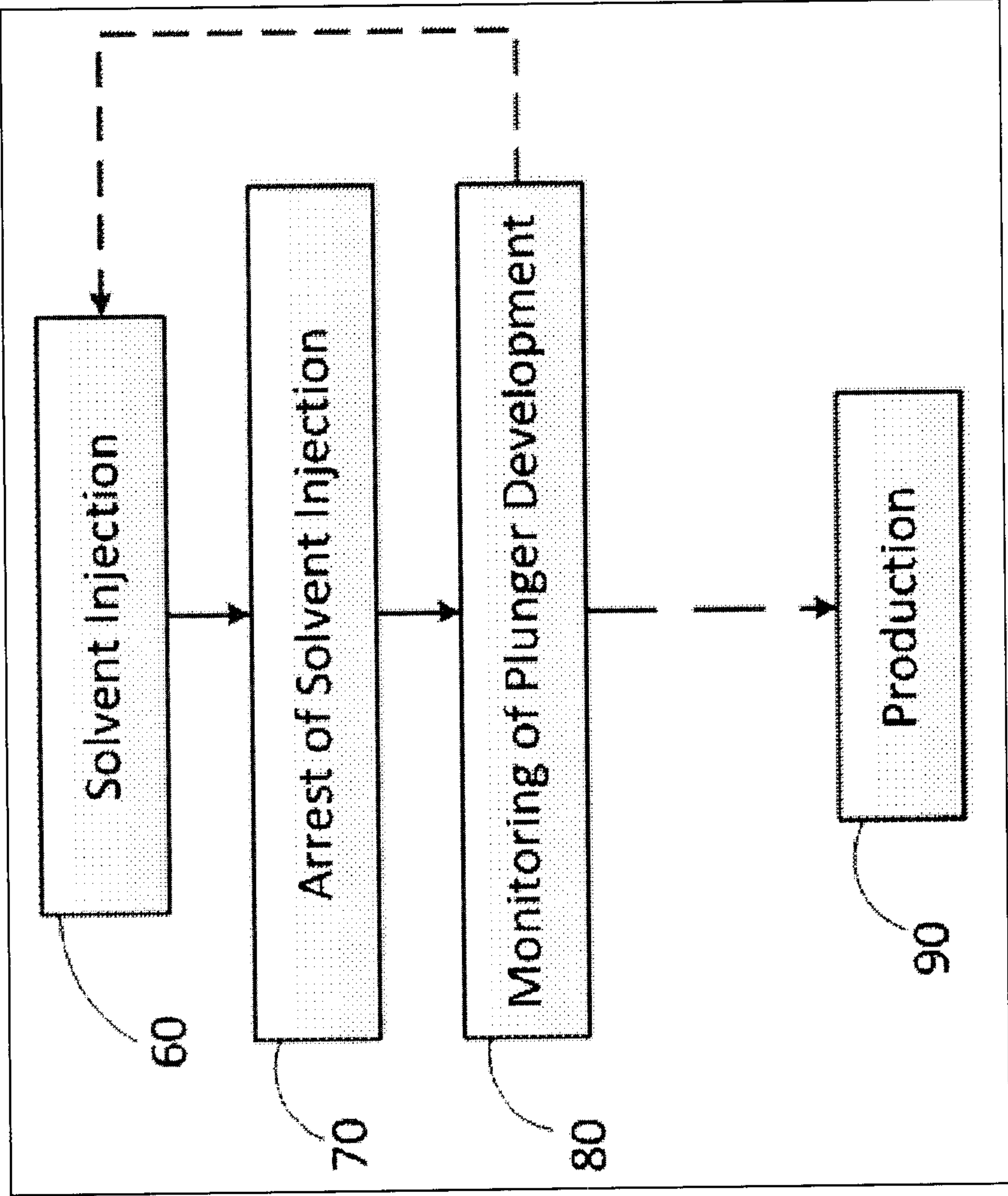


FIG. 7

