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(54) **METHOD OF INCREASING THE PERMEABILITY OF A SUBTERRANEAN FORMATION BY CREATING A MULTIPLE FRACTURE NETWORK**

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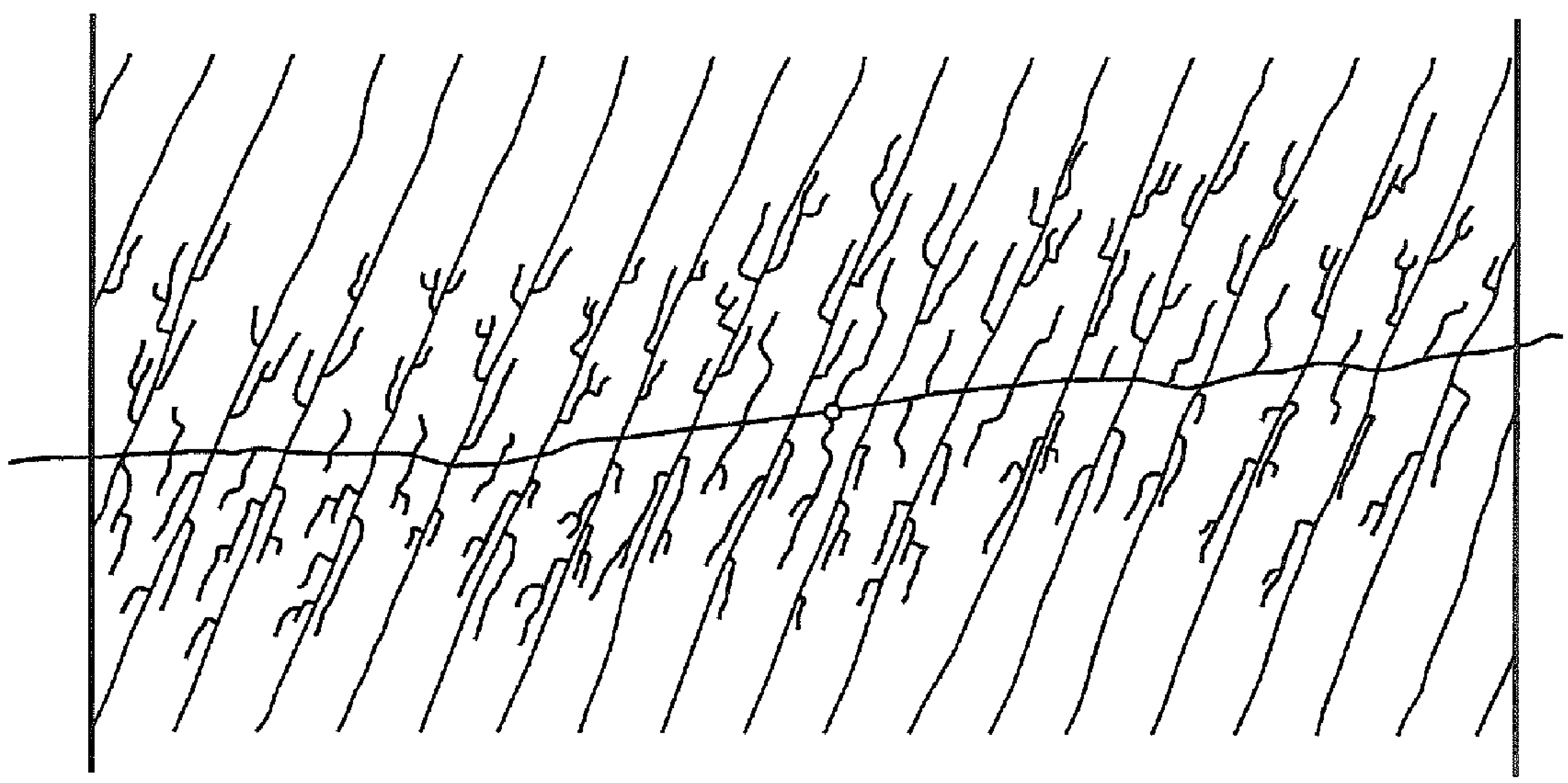
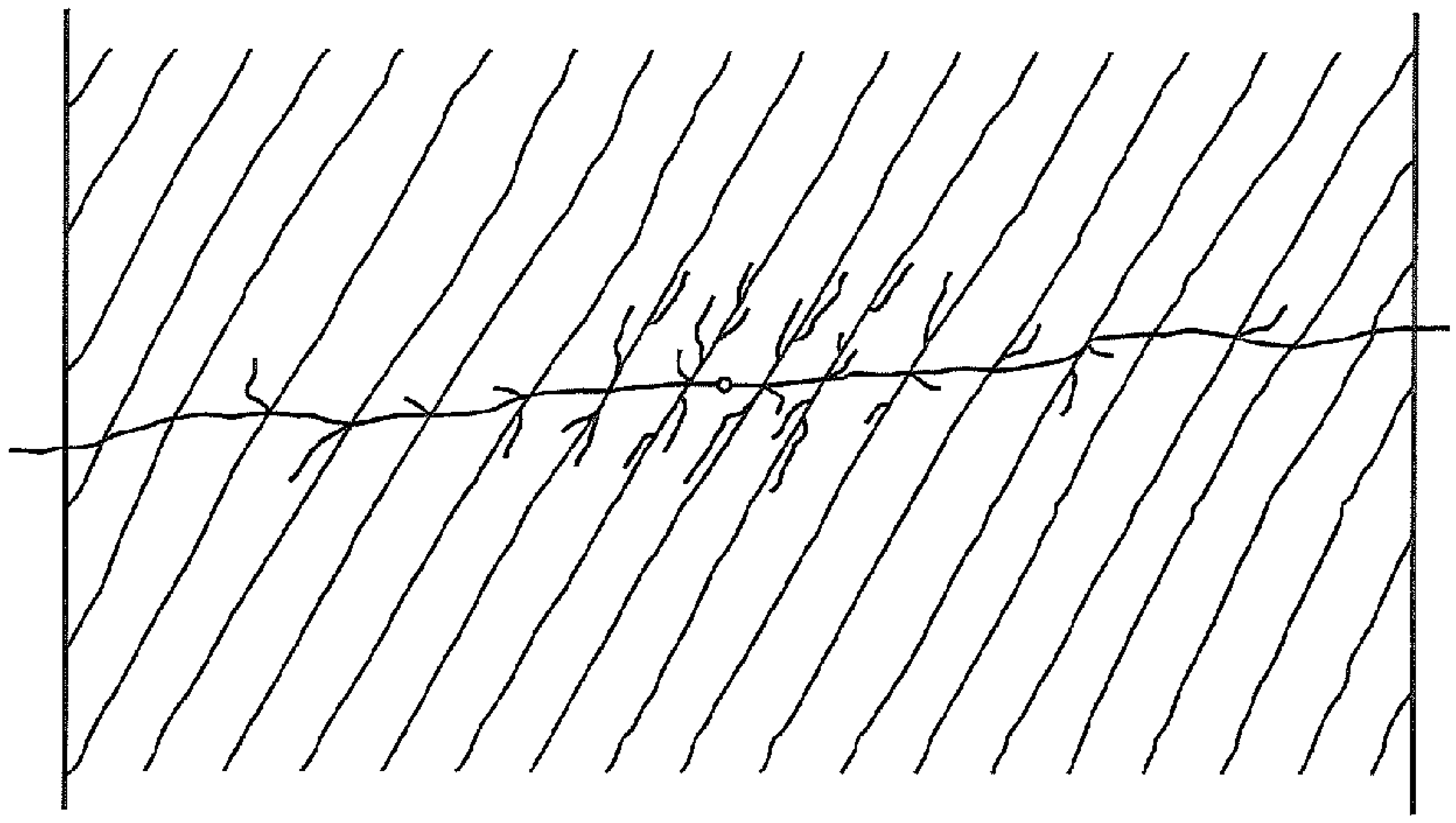
USPC **166/280.1**; 166/308.1

(57) **ABSTRACT**

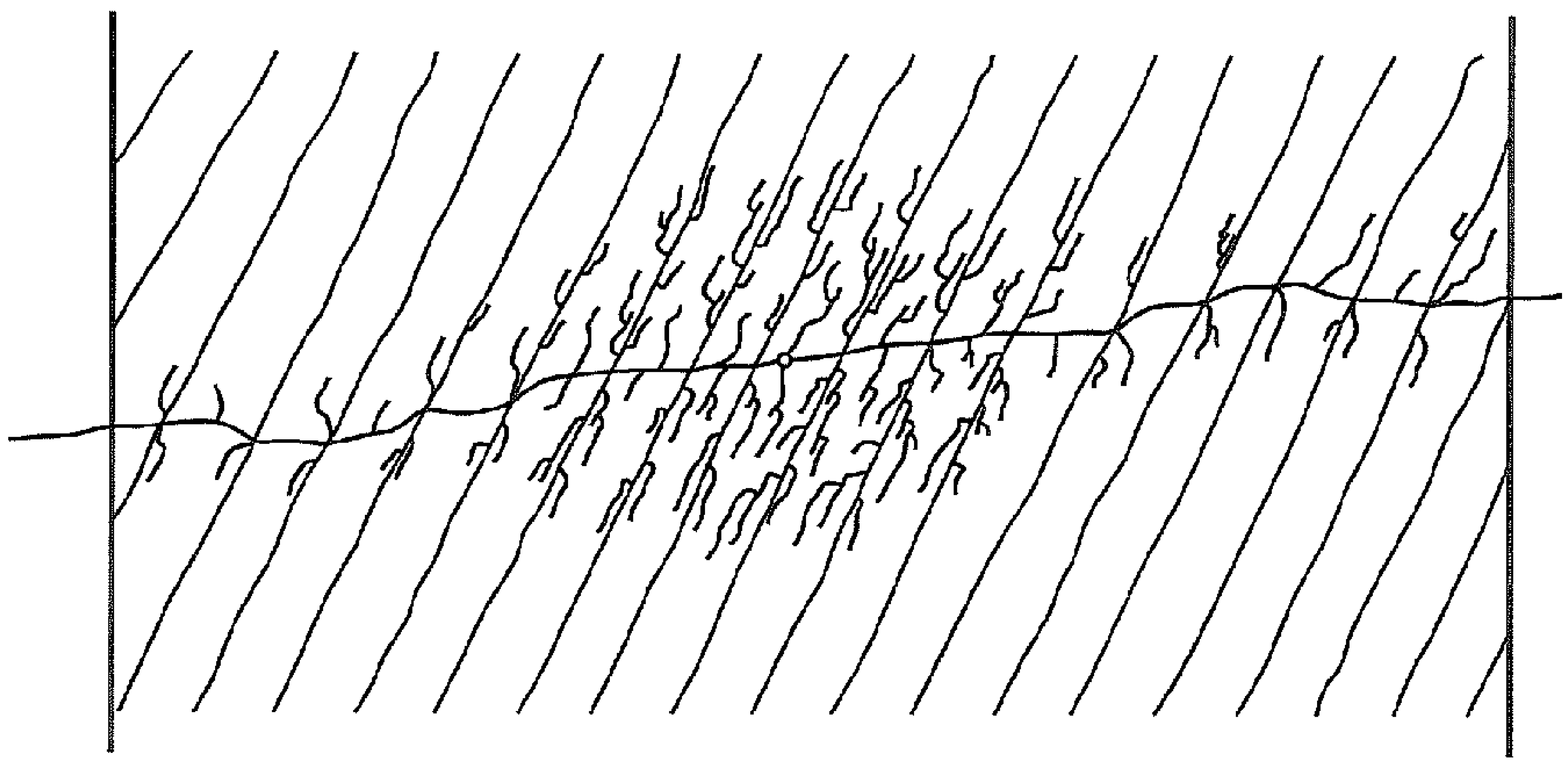
The stimulated rock volume (SRV) of a subterranean formation may be increased by pumping viscous fracturing fluid into the formation in a first stage to create or enlarge a primary fracture, decreasing the pumping in order for the fluid to increase in viscosity within the primary fracture, and then continuing to pump viscous fluid into the formation in a second stage. The fluid pumped into the second stage is diverted away from the primary fracture and a secondary fracture is created. The directional orientation of the secondary fracture is distinct from the directional orientation of the primary fracture. The fluid of the first stage may contain a viscosifying polymer or viscoelastic surfactant or may be slickwater.





(PRIOR ART)

FIG. 1A



(PRIOR ART)

FIG. 1B

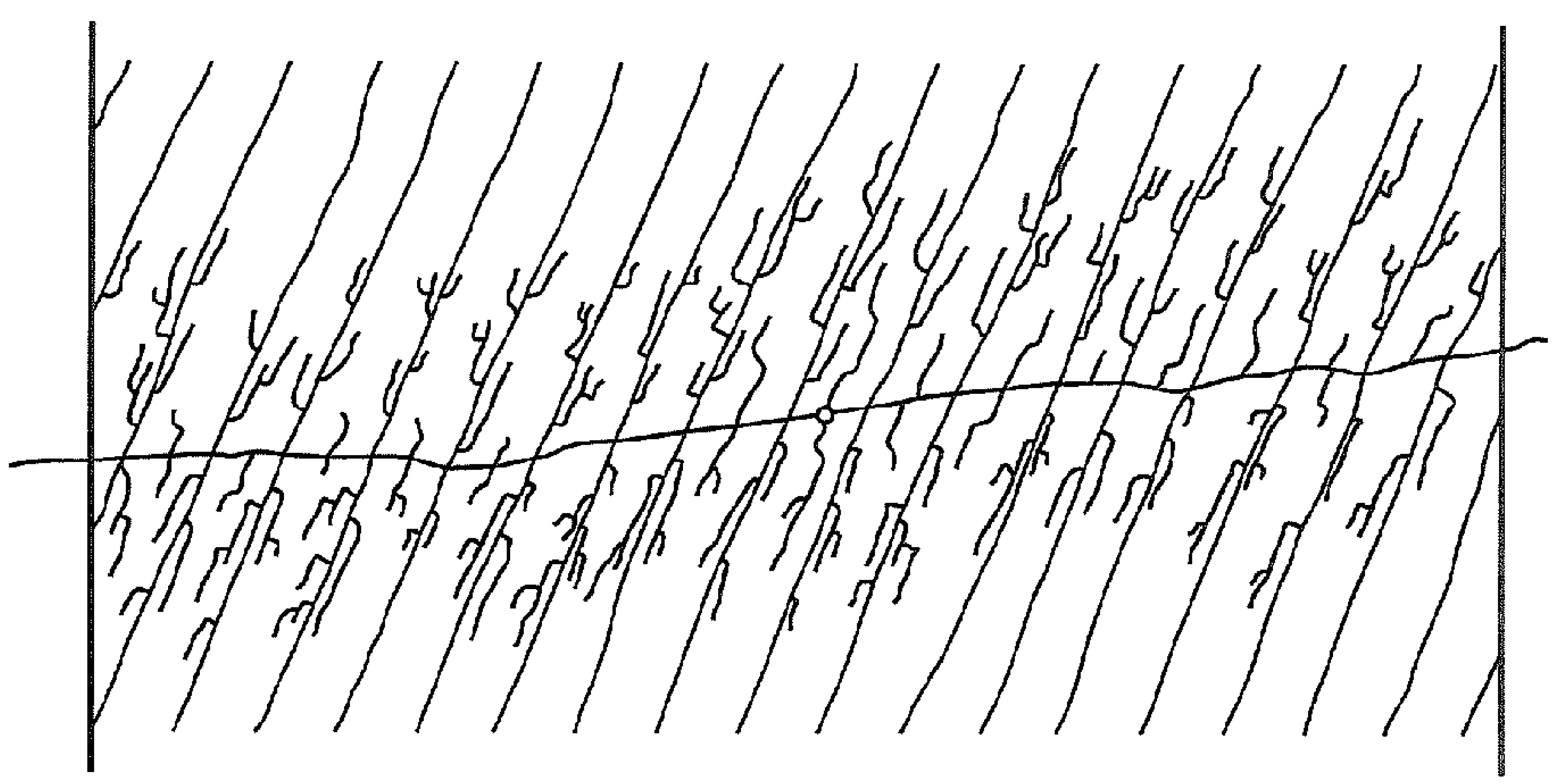


FIG. 1C

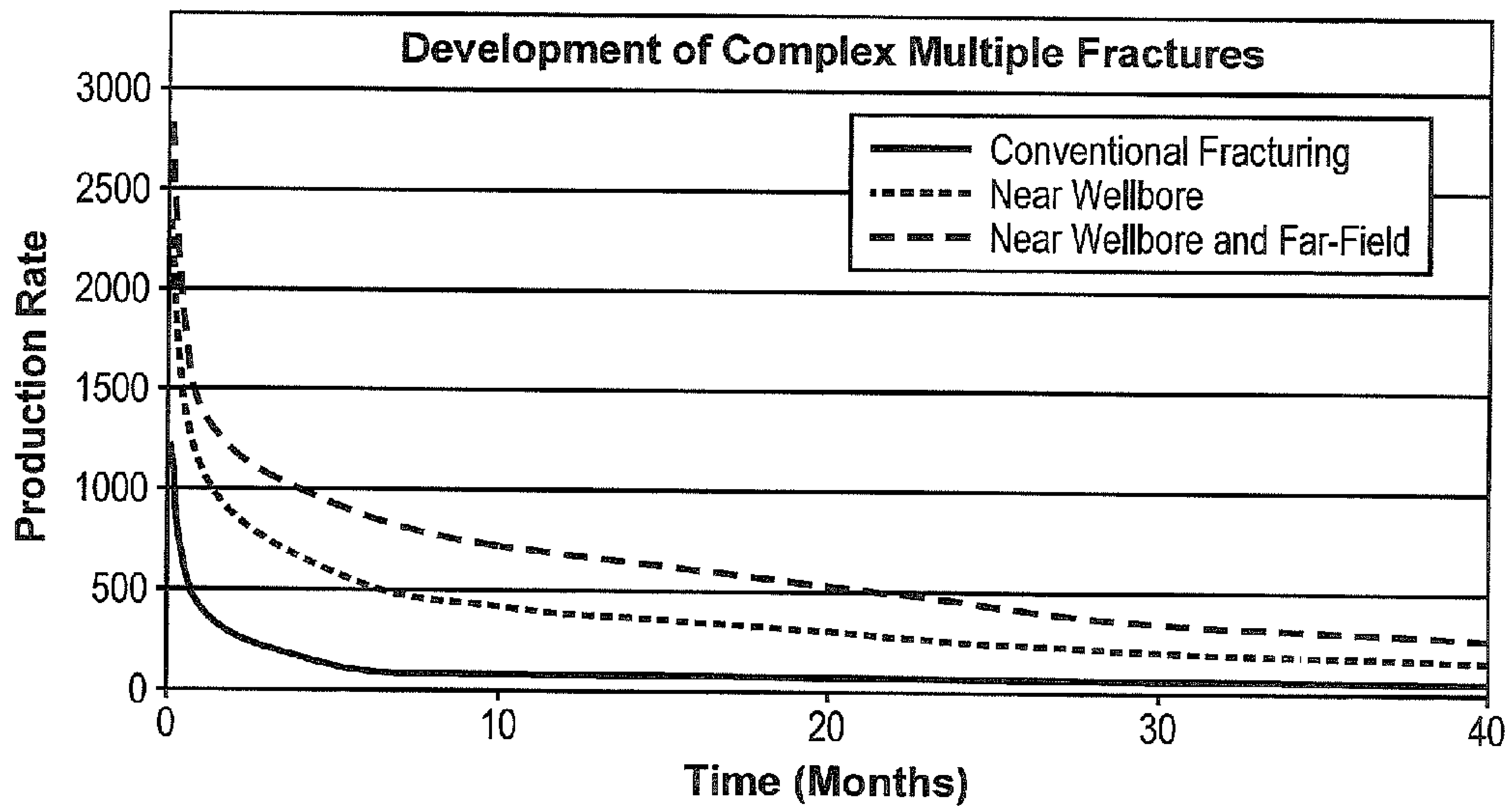

Development of Complex Multiple Fractures
Conventional Fracturing
Near Wellbore
Near Wellbore and Far-Field
Production Rate
3000
2500
2000
1500
1000
500
0
0
10
20
30
40
Time (Months)

FIG. 2

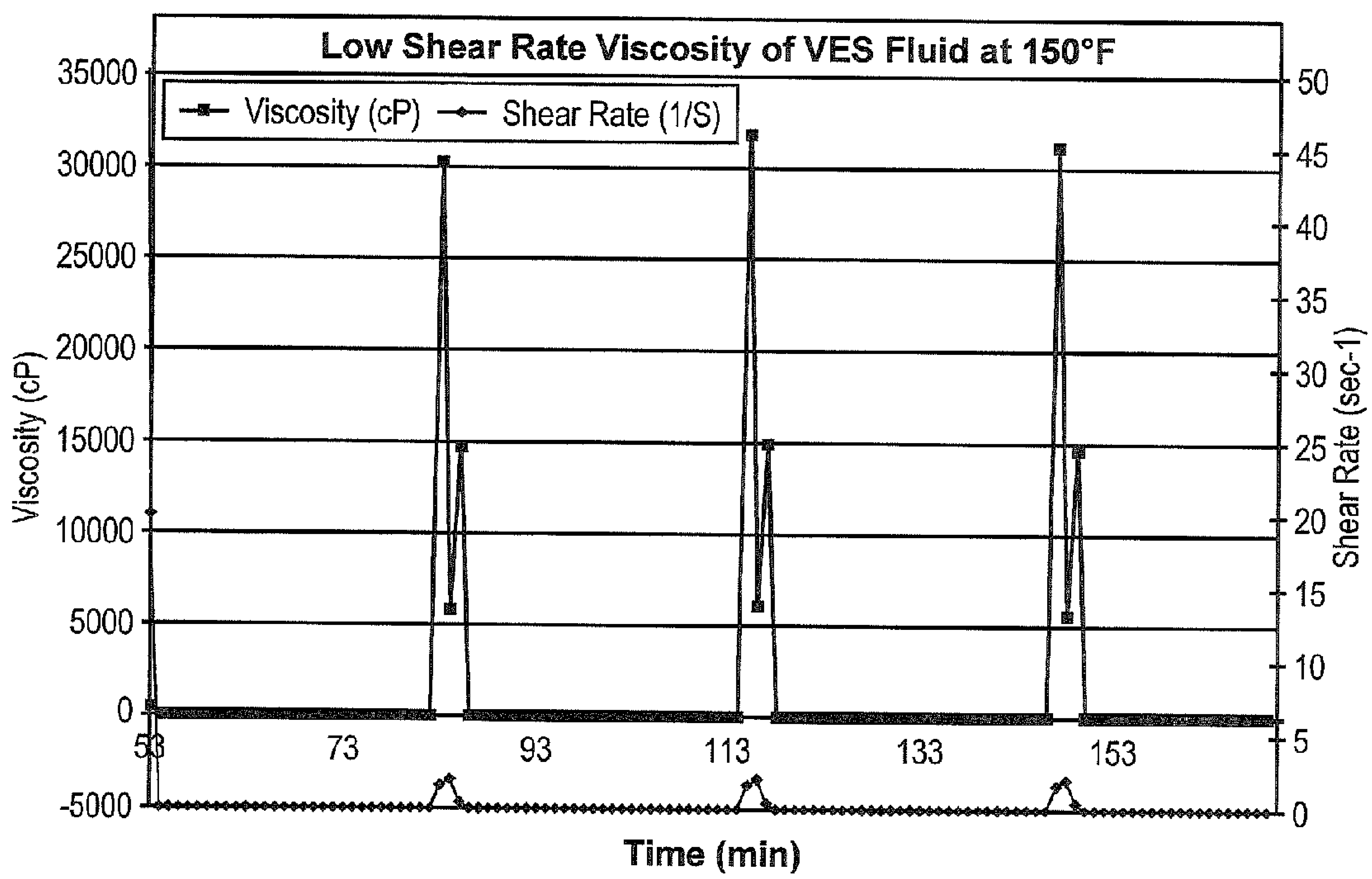

Low Shear Rate Viscosity of VES Fluid at 150°F
Viscosity (cP)
Shear Rate (1/S)
Viscosity (cP)
35000
30000
25000
20000
15000
10000
5000
0
-5000
53
73
93
113
133
153
Shear Rate (sec-1)
50
45
40
35
30
25
20
15
10
5
0
Time (min)

FIG. 3

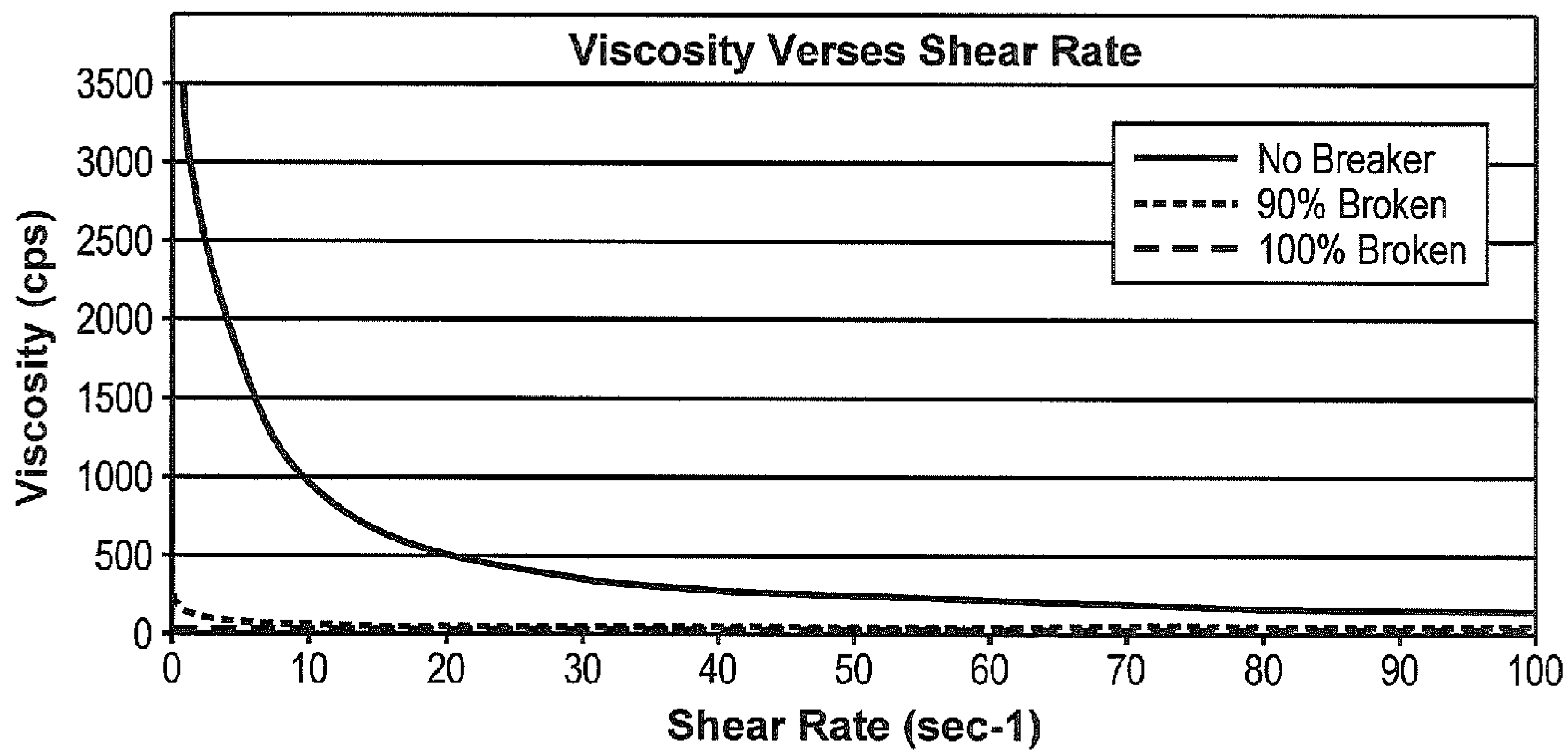

Viscosity Verses Shear Rate
No Breaker
90% Broken
100% Broken
Viscosity (cps)
3500
3000
2500
2000
1500
1000
500
0
0
10
20
30
40
50
60
70
80
90
100
Shear Rate (sec-1)

FIG. 4

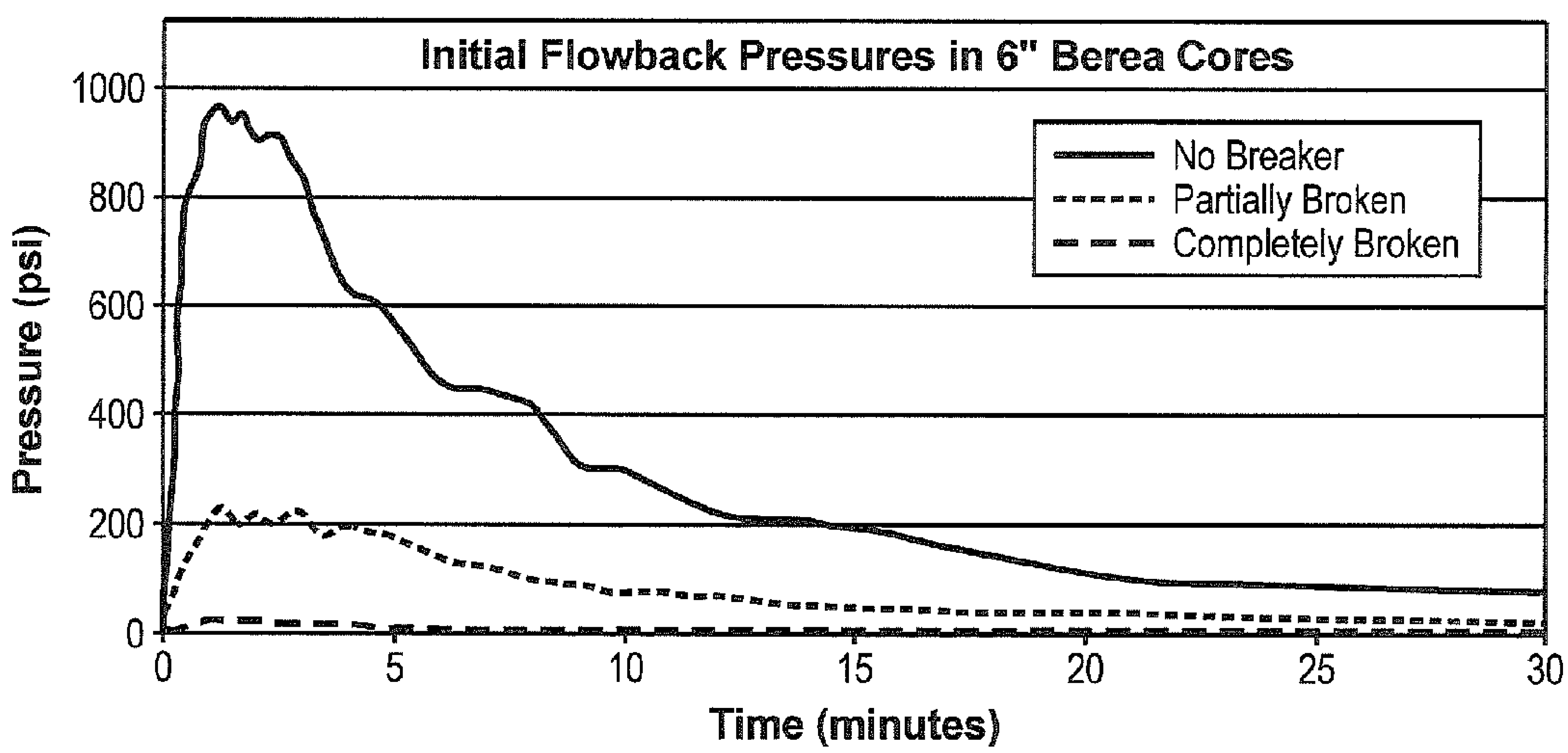

Initial Flowback Pressures in 6" Berea Cores
No Breaker
Partially Broken
Completely Broken
Pressure (psi)
1000
800
600
400
200
0
0
5
10
15
20
25
30
Time (minutes)

FIG. 5

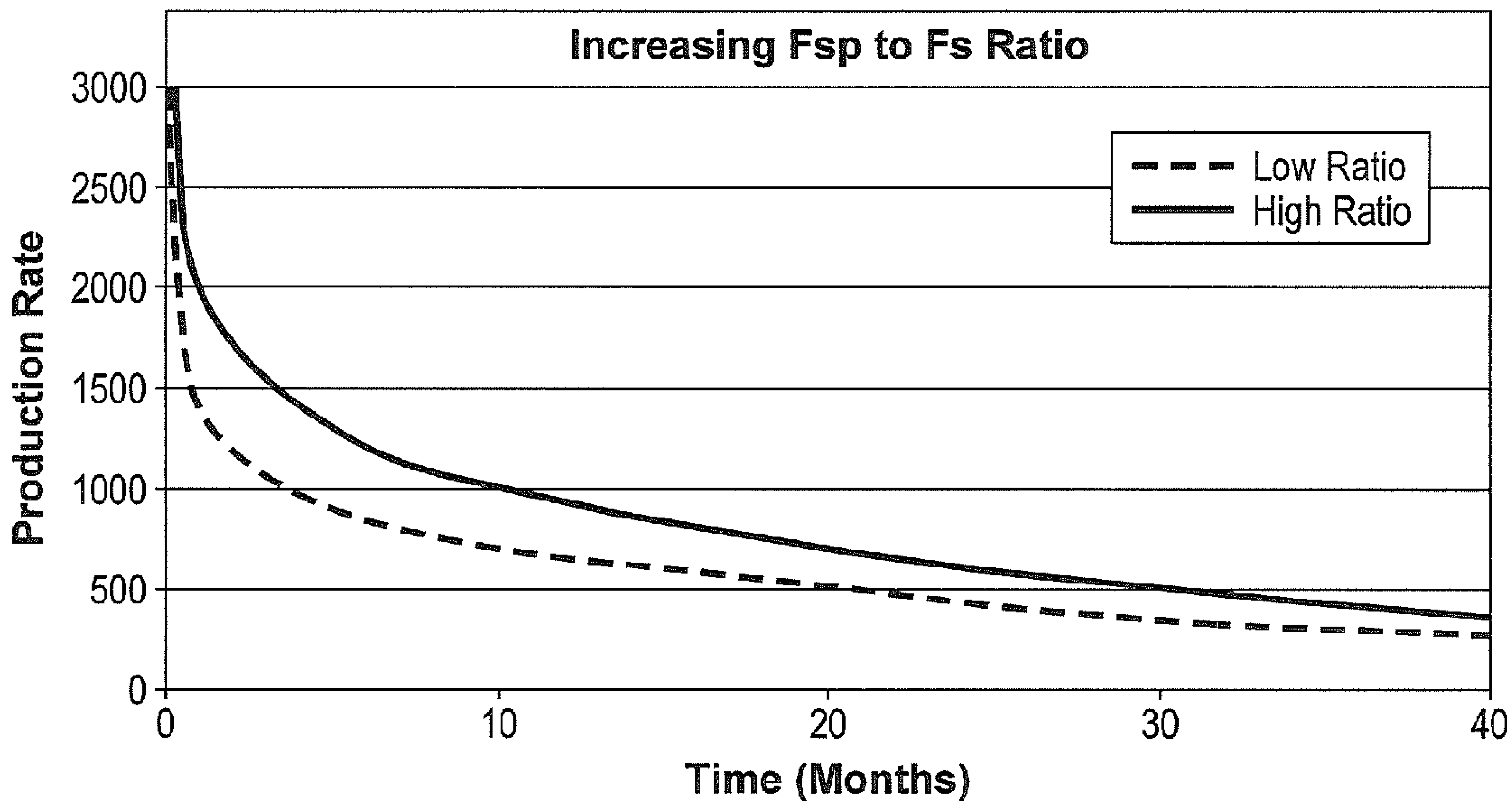

Increasing Fsp to Fs Ratio
Low Ratio
High Ratio
Production Rate
3000
2500
2000
1500
1000
500
0
0
10
20
30
40
Time (Months)

FIG. 6

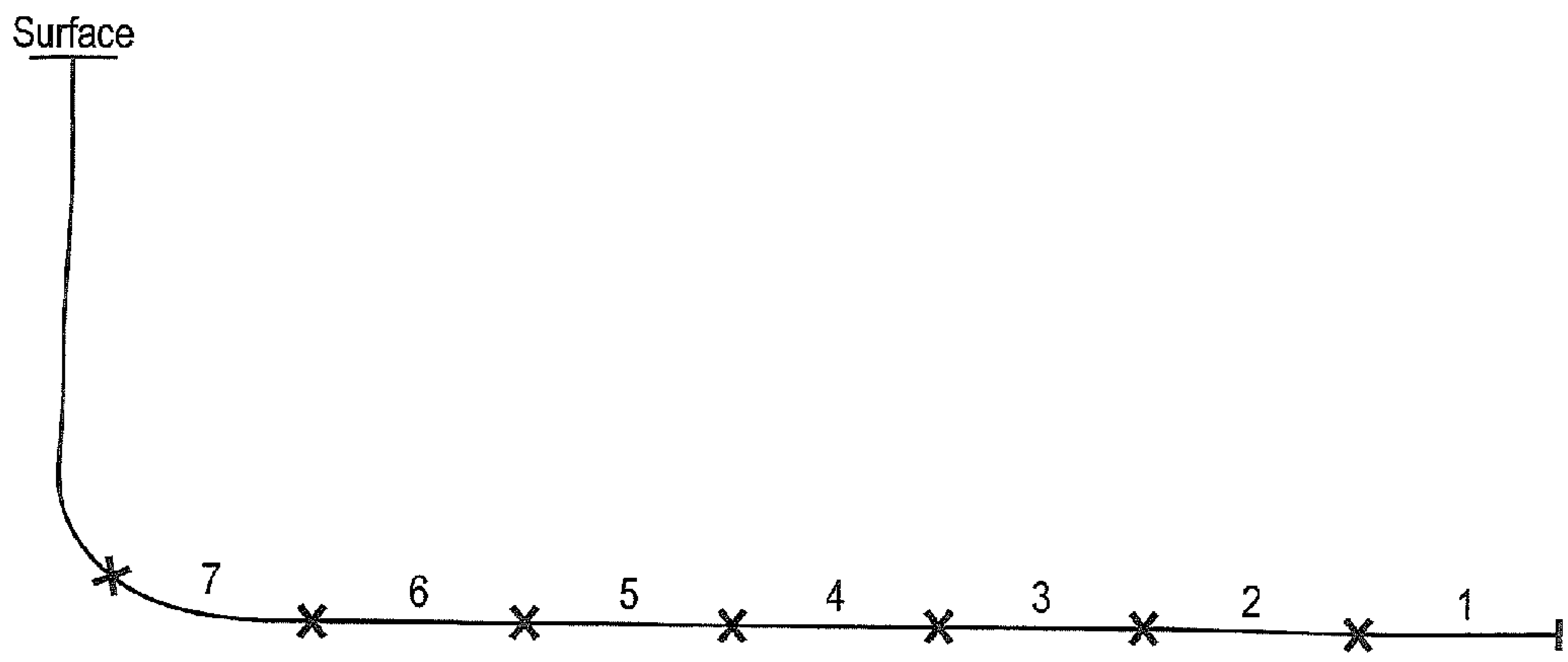

Surface
7
6
5
4
3
2
1

FIG. 7A

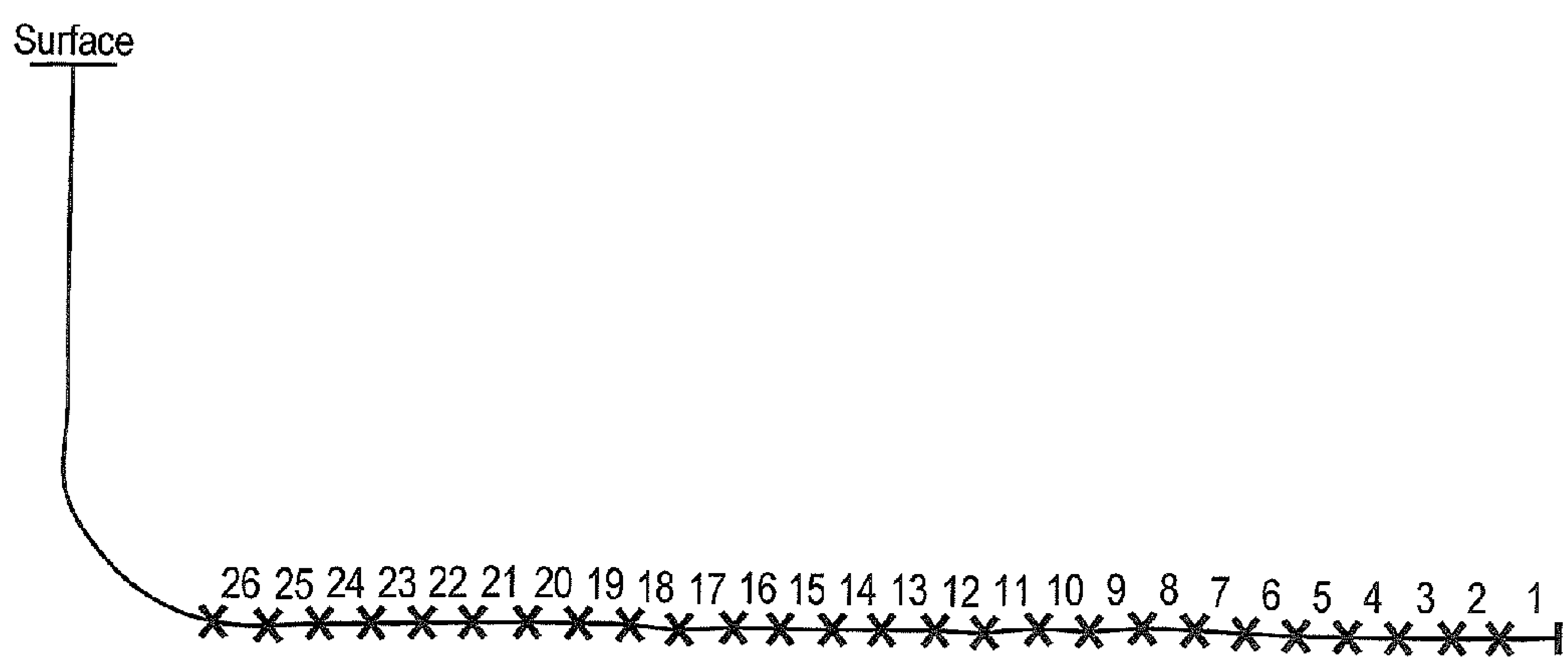
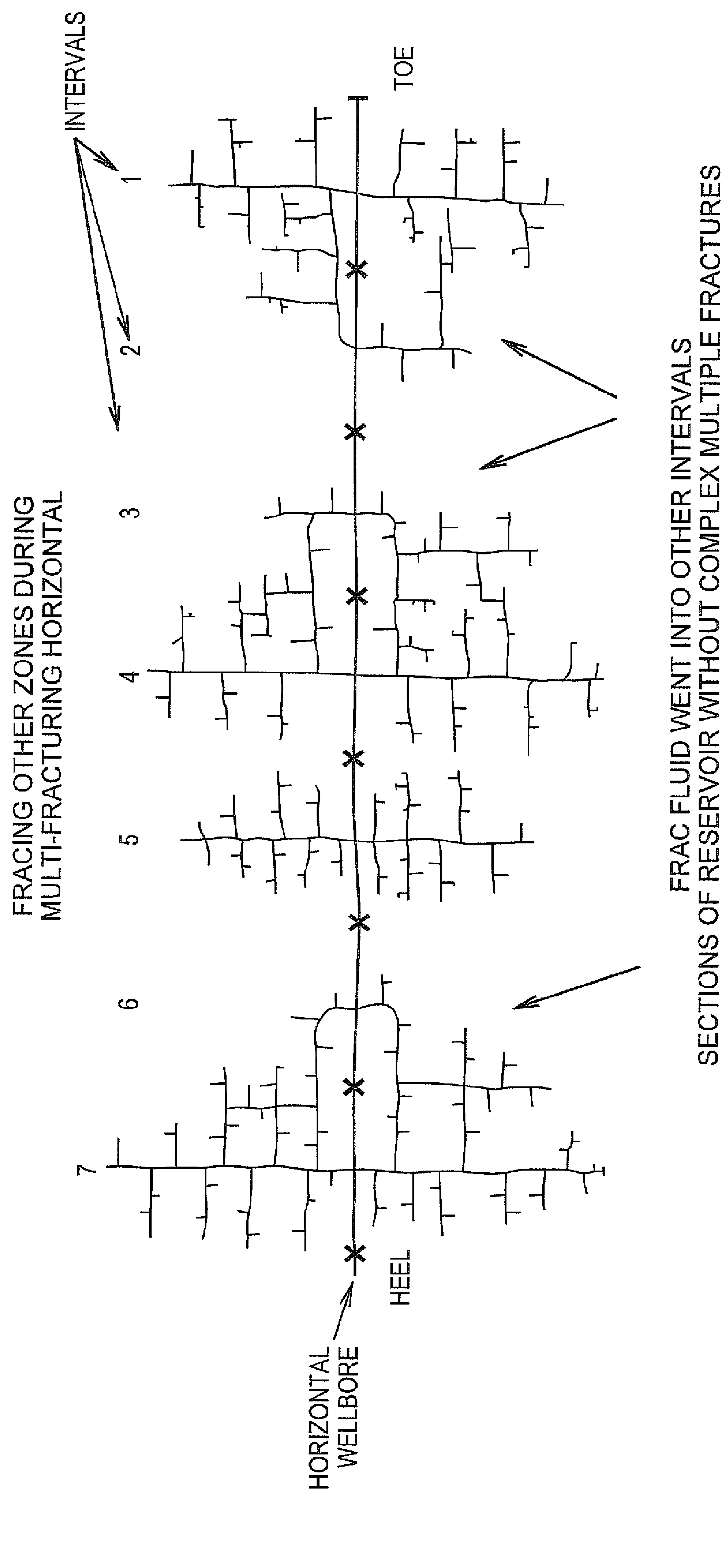

Surface
26 25 24 23 22 21 20 19 18 17 16 15 14 13 12 11 10 9 8 7 6 5 4 3 2 1

FIG. 7B



INTERVALS
TOE
1
2
3
4
5
6
7
FRACING OTHER ZONES DURING
MULTI-FRACTURING HORIZONTAL
FRAC FLUID WENT INTO OTHER INTERVALS
SECTIONS OF RESERVOIR WITHOUT COMPLEX MULTIPLE FRACTURES
HEEL
HORIZONTAL
WELLBORE

FIG. 8

METHOD OF INCREASING THE PERMEABILITY OF A SUBTERRANEAN FORMATION BY CREATING A MULTIPLE FRACTURE NETWORK

[0001] This application claims the benefit of U.S. Patent Application Ser. No. 61/623,515, filed on Apr. 12, 2012.

FIELD OF THE DISCLOSURE

[0002] A complex network of fractures may be created within a subterranean formation by pumping fracturing fluid into the formation in discrete stages. The stimulated rock volume (SRV) of the formation is increased by developing an extended area for migration of the fracturing fluid within the formation.

BACKGROUND OF THE DISCLOSURE

[0003] Hydraulic fracturing is widely used to create high-conductivity communication with a large area of a subterranean formation, thereby allowing for an increased rate of oil and gas production. The stimulation process enhances the permeability of the formation in order that entrapped oil or gas may be produced.

[0004] During hydraulic fracturing of low permeability formations (i.e. such as less than 1.0 md), a fracturing fluid is pumped at high pressures and at high rates into the wellbore penetrating the subterranean formation. During the process, fractures may be created and enlarged that increase the amount of fracture surface area. The efficiency of the process of increasing surface area is often measured by stimulated rock volume (SRV) of the formation.

[0005] The fluid used to initiate hydraulic fractures from the wellbore is often referred to as the "pad". In some instances, the pad may initially contain a heavy density fine particulate, such as fine mesh sand, for fluid loss control. In other instances, the pad may contain larger grain sand in order to abrade perforations or near-wellbore tortuosity.

[0006] Once the fracture in the reservoir is initiated, subsequent stages of viscous fluid containing chemical agents, such as proppants, may be pumped to further create and extend the primary (i.e. biwing) fracture. The fracture generally continues to grow during pumping and the proppants remain in the fracture in the form of a permeable "pack" that serves to "prop" the fracture open. Once the treatment is completed, the fracture closes onto the proppants. The fracturing fluid ultimately causes an increase in the leak-off rate of the fluid through the faces of fractures which improves the ability of the proppant to pack within the fracture. The proppants maintain the fracture open, providing a highly conductive pathway for hydrocarbons and/or other formation fluids to flow into the wellbore.

[0007] The treatment design of a hydraulic fracturing operation generally requires the fracturing fluid to reach maximum viscosity as it enters the fracture. The viscosity of the fluid affects fracture length and width of the primary fracture and the amount of secondary fractures formed (i.e. typically creates less complex fracture network).

[0008] The viscosity of most fracturing fluids may be attributable to the presence of a viscosifying agent, such as a viscoelastic surfactant or a viscosifying polymer. An important attribute of any fracturing fluid is its ability to exhibit reduced viscosity after injection. Typically, fracturing fluids contain breakers which are used to reduce viscosity.

[0009] Conventional viscosifying polymers include such water-soluble polysaccharides, such as galactomannans and cellulose derivatives. Further enhancement of fracturing fluid viscosity may be obtained by treating polymeric solutions with cross-linking agents, typically selected from titanium, aluminum, boron and zirconium based compounds, or mixtures thereof. Organometallic compounds are often used as a crosslinking agent in these polymer gels. After the viscosity of the fluid has been reduced, removal of the polymer is often difficult, often times resulting in residual polymer being left on the face of the formation and within the proppant pack. This causes clogging of the pores of the formation and proppant pack. Hydrocarbons may therefore be prevented from flowing freely through and from the formation and proppant pack.

[0010] The use of non-polymeric treatment fluids, such as those containing viscoelastic surfactants, has increased in recent years since such fluids typically exhibit the ability to transport proppant at lower viscosities than polymer-based treatment fluids. In addition, the amount of friction between the surfactant-based treatment fluid and the surfaces contacted by the fluid is often reduced. Further, since such fluids do not contain polymers, use of internal breakers typically rearrange the viscous VES-micelles into non-viscous spherical micelles in brine and the fluid is typically not obstructed as it passes through the pore throats of the formation and proppant pack.

[0011] More recently, low viscosity fluids known as slickwater have been used in the stimulation of low permeability or "tight" formations, including tight gas shale reservoirs. Such reservoirs may contain natural fractures or weaker stress planes that may contribute to a higher number of fractures (i.e. fracture network) during a hydraulic fracturing treatment.

[0012] Slickwater fluids typically do not contain a viscoelastic surfactant or viscosifying polymer but do contain a sufficient amount of a friction reducing agent to minimize tubular friction pressures. Such fluids, generally, have viscosities only slightly higher than unadulterated fresh water or brine. Typically, the presence of the friction reduction agent in slickwater does not increase the viscosity of the fluid by more than 1 to 2 centipoise (cP).

[0013] To effectively access hydrocarbons in tight formations, wells are often drilled horizontally and then subjected to one or more fracture treatments to stimulate production. Fractures propagated with low viscosity fluids exhibit smaller fracture widths than those propagated with higher viscosity fluids. In addition, low viscosity fluids facilitate reduced fracture height growth in the reservoir during stimulation. This often results in the development of greater created fracture area from which hydrocarbons may flow into. Further, such fluids introduce less damage into the formation in light of the absence of viscosifying polymer and/or viscoelastic surfactant in the fluid.

[0014] Slickwater fluids often contain proppants. In light of the low viscosity of the fluid, the proppant-carrying capacity of the fluid is low. A lower concentration of proppant requires a higher volume of fracturing fluid to place a sufficient amount of the proppant into the induced fractures.

[0015] Slickwater fracturing operations typically proceed by the continuous injection of slickwater into the wellbore. In some shale formations, an excessively long primary fracture often results along the minimum stress orientation. Typically, pumping of additional fracturing fluid into the wellbore simply extends the planar fracture. In most instances, primary fractures dominate and secondary fractures are limited. Fracturing treatments which create predominately long planar fractures are characterized by a low surface area, i.e., low SRV. Production of hydrocarbons from the fracturing network created by such treatments is limited by the low SRV.

[0016] Slickwater fracturing more commonly in shale formations create complex fracture networks near the wellbore and are generally considered to be inefficient in the opening or creation of complex network of fractures farther away from the wellbore. Lately, slickwater fracturing operations have been seen to be successful in producing hydrocarbons from shale. However, the secondary fractures created by the operation are near to the wellbore where the surface area is increased. While SRV is increased in slickwater fracturing, production is high only initially and then drops rapidly to a lower sustained production since there is little access to hydrocarbons far field from the wellbore.

[0017] Like slickwater fracturing, conventional fracturing operations typically render an undesirably lengthy primary fracture. While slightly more secondary fractures may be created farther from the wellbore using viscous fluids versus slickwater, fluid inefficiency, principally exhibited by a reduced number of secondary fractures generated near the wellbore, is common in conventional hydraulic fracturing operations.

[0018] Recently, attention has been directed to alternatives for increasing the productivity of hydrocarbons far field from the wellbore as well as near wellbore. Particular attention has been focused on increasing the productivity of low permeability formations, including shale. For instance, methods have been tailored to the stimulation of discrete intervals along the horizontal wellbore resulting in perforation clusters. While the SRV of the formation is increased by such methods, production areas between the clusters are often not affected by the operation. This decreases the efficiency of the stimulation operation. Methods of increasing the SRV by increasing the distribution of the area subjected to fracturing have therefore been sought.

SUMMARY OF THE DISCLOSURE

[0019] The stimulated rock volume (SRV) of a subterranean formation subjected to a hydraulic fracturing treatment may be increased by pumping the fracturing fluid into stages to provide a wider distribution fracturing pattern and an extended area for migration of the fluid. The method uses a high shear thinning fluid, i.e., a fluid having high viscosity at low shear rates, which may be diverted into secondary fractures. The viscosity of the fluid is typically greater than about 10,000 cP at a shear rate of 0.01 sec^{-1}.

[0020] The permeability of the subterranean reservoir subjected to the treatment may be less than or equal to 1.0 mD.

[0021] In an embodiment, a first stage containing a viscous fluid is pumped into the wellbore to enlarge the fracture. Pumping is then reduced or curtailed for a period of time for the viscosity of the injected fluid to increase within the fracture. Pumping is then resumed after the injected fluid is sufficiently viscous.

[0022] In one embodiment, a first stage consists of injecting into the wellbore a fluid containing a viscoelastic surfactant, a viscosifying polymer or both viscoelastic surfactant and viscosifying polymer at a pressure sufficient to enlarge or create a primary fracture. Pumping may then be reduced or stopped when the viscous fluid is within the enlarged or created primary fracture. The second stage of the operation consists of injecting into the wellbore a second fluid at a pressure sufficient to create at least one secondary fracture wherein the directional orientation of the secondary fracture is distinct from the directional orientation of the primary fracture. The total surface area of the fractured area is increased which provides an increase to the SRV. The flow of the second fluid is diverted into the secondary fracture due to resistance of the first fluid to flow or movement due to exhibiting very high viscosity at low shear rate. The diversion of the primary flow process is contrary to the continued high rate flow of viscous fluids in planar fractures. The fluid of the first stage and the fluid of the second stage may be the same or different.

[0023] In another embodiment, a multiple fracture network consisting of a primary fracture and a multitude of secondary fractures may be created by injecting into the wellbore in a first stage a fluid containing a viscoelastic surfactant, a viscosifying polymer or both viscoelastic surfactant and viscosifying polymer at a pressure sufficient to enlarge or create a primary fracture. Pumping of the fluid of the first stage may then be decreased or curtailed when the viscous fluid is within the enlarged or created primary fracture. The second stage of the operation consists of injecting into the wellbore a second fluid at a pressure sufficient to create at least one secondary fracture off the primary fracture. The directional orientation of the secondary fracture is distinct from the directional orientation of the primary fracture. A multitude of fractures may be created by pumping one or more additional stages into the wellbore. Each stage may be interrupted for a time sufficient for the fluid of the preceding stage to flow into the created or enlarged secondary fracture. A complex network of secondary fractures may therefore be created off the primary fracture and the SRV dramatically increased. The fluids of the first stage, the second stage and the additional stages may or may not be the same fluid.

[0024] The combination of the low shear high viscosity shear-thinning fluid and the multi-stage process wherein pumping of fracturing fluid is reduced or curtailed between stages provides for controlled placement of the fluid into the primary fracture. As such, the flow of the fluid of the first stage may be controlled such that it doesn't advance too far from the wellbore and yet does not remain within the immediate vicinity of the near wellbore.

[0025] In addition to varying the rate of pumping of the fluids of the stages, the network of fractures may be created and placement of the fluid may be controlled by varying the amount of pressure during injection of the fluid stages into the wellbore, varying the rate of injection of the fracturing fluid between the stages or varying the viscosity of the fracturing fluid between the stages. Any combination may further be used. Thus, for instance, a fracturing operation may proceed wherein one or more stages differ by (i) the amount of pressure during injection of the fluid into the wellbore; (ii) the rate of injection of pumping the stage fluid into the wellbore; (iii) the viscosity of the fluid introduced into the wellbore; or (iv) a combination of (i), (ii) and (iii). Further, any of these combinations may be used in conjunction with the procedure wherein reduced or curtailed pumping of the viscous fluid occurs between the pumping of viscous stages.

[0026] An illustrative embodiment of the disclosure may consist of developing a network of fractures at near-wellbore and far-wellbore locations within a subterranean formation by first injecting into the reservoir a fracturing fluid having a viscosity greater than about 10,000 cp at a shear rate of 0.01 sec^{-1} at a pressure sufficient to enlarge or create a primary fracture. The rate of injection may then be decreased for a sufficient time in order to increase the viscosity of the fluid within the created or enlarged fracture, particularly the portion of the fluid further from the wellbore that has less shear (e.g. flow) rate as fracture length increases. Additional fracturing fluid may then be injected into the reservoir at a rate different than the rate of the preceding stage to create one or more secondary fractures. The additional fracturing fluid diverts away from the primary fracture and into the created secondary fracture due to the viscosity property of the first fluid to resist flow to the force applied. These steps may then be repeated wherein each repetitive stage has a rate of injection of fluid distinct from the rate of injection of a previous stage to form a network of secondary fractures at near-wellbore and far-wellbore locations from the primary fracture and the secondary fractures.

[0027] In another illustrative embodiment, a network of fractures at near-wellbore and far-wellbore locations may be created within a subterranean formation by first injecting into the reservoir a fracturing fluid having a viscosity greater than about 10,000 cp at a shear rate of 0.01 sec^{-1} at a pressure sufficient to enlarge or create a primary fracture. The pressure may then be decreased for a sufficient time in order to increase the viscosity of the fluid within the created or enlarged fracture. Additional fracturing fluid may then be injected into the reservoir to create one or more secondary fractures at a higher or lower pressure than the pressure used in the injection of the preceding stage. The additional fracturing fluid diverts away from the primary fracture and into the created secondary fracture. These steps may then be repeated wherein the pressure of injection of each stage may be distinct from the pressure of another stage to form a network of secondary fractures at near-wellbore and far-wellbore locations from the primary fracture and the secondary fractures.

[0028] In another illustrative embodiment, a network of fractures at near-wellbore and far-wellbore locations may be created within a subterranean formation by first injecting into the reservoir a fracturing fluid having a viscosity greater than about 10,000 cp at a shear rate of 0.01 sec^{-1} at a pressure sufficient to enlarge or create a primary fracture. The rate of injection may then be decreased for a sufficient time in order to increase the viscosity of the fluid within the created or enlarged fracture. Additional fracturing fluid having a viscosity greater or less than the viscosity of the fluid of the preceding stage may then be injected into the reservoir to create one or more secondary fractures. The additional fracturing fluid diverts away from the primary fracture and into the created secondary fracture. These steps may then be repeated wherein the viscosity of each of the additional stages is distinct from the viscosity of the fluid of another stage to form a network of secondary fractures at near-wellbore and far-wellbore locations from the primary fracture and the secondary fractures.

[0029] In another embodiment, a network of fractures at near-wellbore and far-wellbore locations may be created within a subterranean formation by first pumping into the reservoir slickwater fluid having a viscosity greater than about 15 cP at a shear rate of 300 sec^{-1} at a pressure sufficient to enlarge or create a primary fracture. A viscous fluid having a viscosity greater than about 10,000 cP at a shear rate of 0.01 sec^{-1} may then be pumped behind the slickwater fluid and the primary fracture extended. Pumping of the viscous fluid may be decreased or stopped for a period of time for the viscosity of the fracturing fluid to increase within the primary fracture. Slickwater having a viscosity greater than about 15 cP at a shear rate of 300 sec^{-1} may then be pumped into the reservoir to divert the viscous fluid away from the primary fracture and to create one or more secondary fractures. A viscous fluid having a viscosity greater than about 10,000 cP at a shear rate of 0.01 sec^{-1} may then be pumped behind the slickwater fluid to extend the secondary fracture(s). The flow of the fluid pumped behind the slickwater fluid is then diverted away from the primary fracture into the secondary fracture(s). This process may be repeated in order to create a wider distribution of secondary fractures.

[0030] In any of the methodologies, the amount of viscosifying agent in the viscous fluid may be less than or equal to 6% by weight.

[0031] Further, in any of the methodologies, the viscous fluid of any of the stages may contain a low shear rate viscosity enhancer, such as a wormlike micelle associative agent.

BRIEF DESCRIPTION OF THE DRAWINGS

[0032] In order to more fully understand the drawings referred to in the detailed description of the present disclosure, a brief description of each drawing is presented, in which:

[0033] FIG. **1**A illustrates the fracturing network created by the prior art method wherein slickwater fracturing fluid is continuously injected into the wellbore.

[0034] FIG. **1**B illustrates the fracturing network created by the prior art method wherein a viscous fluid is continuously injected into the wellbore.

[0035] FIG. **1**C illustrates a complex network of multiple secondary fractures created from near wellbore to far-field by use of the method described herein.

[0036] FIG. **2** illustrates the increase in production and the improvement in stimulated reservoir volume (SRV) by use of the method described herein.

[0037] FIG. **3** illustrates the 2 sec^{-1} fluid viscosity after being left static for about 30 minutes.

[0038] FIG. **4** profiles viscosity vs. shear rates and illustrates the high viscosity at low shear rates exhibited by the fluids used in the method described herein.

[0039] FIG. **5** illustrates the reduction in pressure required for cleanup of a fracturing fluid used in the method described herein.

[0040] FIG. **6** illustrates higher sustainable hydrocarbon production rates attained by use of the method described herein when the fracturing fluid contains proppants.

[0041] FIG. **7**A illustrates the increased SRV in near wellbore regions and far-field regions within the wellbore which results from the method described herein in contrast to FIG. **7**B.

[0042] FIG. **8** illustrates the reduction in fracturing areas which are outside of intervals subjected to fracturing by use of the method described herein.

DETAILED DESCRIPTION OF THE PREFERRED EMBODIMENTS

[0043] Illustrative embodiments of the disclosure are described below as they might be employed in the operation and treatment of oilfield applications. In the interest of clarity, not all features of an actual implementation are described in this specification. It will of course be appreciated that in the development of any such actual embodiment, numerous implementation-specific decisions must be made to achieve the developers' specific goals, which will vary from one implementation to another. Moreover, it will be appreciated that such a development effort might be complex and time-consuming, but may nevertheless be a routine undertaking for those of ordinary skill in the art having the benefit of this disclosure. Further aspects and advantages of the various embodiments of the disclosure will become apparent from consideration of the following description.

[0044] The production of hydrocarbons from a subterranean formation is enhanced by the methods described herein. In addition to increasing the effectiveness of the fracturing operation, the methods described herein reduce intervention costs for remediation. In particular, the methods described herein may minimize the need for the removal of unwanted deposits by reducing accumulation and deposition of residual polymer within the wellbore and formation. Further, the methods described herein provide for a more efficient use of on-the-fly equipment and materials. In particular, the methods described herein provide a more efficient use of (i) hydraulic horsepower to place fluid into the created fractures; (ii) fracturing fluid by minimizing the volume of fracturing fluid introduced into the wellbore; and (iii) proppant by reducing the amount of proppant introduced into the reservoir while providing an increase in proppant placement within the formation.

[0045] The methods described herein may be used in the fracturing of formations penetrated by horizontal as well as vertical wellbores.

[0046] The methods described herein provide for the creation of a multiple network of fractures such that oil and/or gas may be produced through the interconnected fractures. The first stage may consist of injecting into the wellbore a pad fluid at a pressure sufficient to either propagate or enlarge a primary fracture. Fracture conductivity may be improved by the incorporation of a small amount of proppant in the pad fluid. Typically, the amount of proppant in the pad fluid is between from about 0.12 to about 24, preferably between from about 0.6 to about 9.0, weight percent based on the total weight percent of the pad fluid.

[0047] The fluid of the first or pad stage may be water or brine and may contain a viscosifying agent such as a viscosifying polymer and/or viscoelastic surfactant.

[0048] Alternatively, the fluid of the pad stage or the first stage may contain slickwater. The viscosity of the fluid of the first stage is typically greater than about 10,000 cP at a shear rate of 0.01 sec^{-1}. The slickwater fluid typically contains a friction reduction agent. Suitable friction reduction agents include polyacrylamides, polyacrylates, as well as any of the viscoelastic surfactants described herein. Typically, the amount of friction reduction agent in the slickwater fluid is between from about 0.5 gpt to 2 gpt.

[0049] Following the injection of the pad fluid, a viscous fluid may then be introduced into the wellbore. The viscous fluid typically has a viscosity greater than about 10,000 cP at a shear rate of 0.01 sec^{-1}. The rate of pumping of the viscous fluid is then reduced or stopped for a sufficient time to allow the viscous fluid to increase viscosity within the fracture. This is to curtail additional growth of the primary fracture. Thus, for instance, if the primary fracture is desired to be limited to 500 feet, the volume of viscous fluid introduced into the wellbore may be selected to provide the desired length of the primary fracture. Reduction or suspension of the pumping causes the viscous fluid to gel within the fracture, particularly near the tips of the fracture where the fluid flow rate may be the slowest. In some cases, since the fluid in the fracture is highly viscous at low shear rate or is static (zero shear rate), increased pressure may be required in order to move the entire section of fluid from the wellbore to the fracture tip.

[0050] Additional fluid may then be injected into the wellbore as a second fracturing stage. When pumping is resumed to the levels used in the first fracturing stage, the additional fluid encounters a "viscosity wall" or "viscosity wedge" of fluid within the primary fracture. The force applied by the additional fluid will pressure divert fluid flow away from the fracture tip and thus promote a change in fracture orientation, thereby creating at least one secondary fracture. The flow of this additional fluid is diverted into the secondary fracture. The secondary fracture thus has a directional orientation distinct from the directional orientation of the primary fracture. Thus, at some point along the primary fracture the resistance to flow of the viscosity wall induces the second stage fluid to be diverted to a new area of the reservoir such that the increase in SRV occurs.

[0051] Multiple fracturing stages may then follow. Such additional stages will be referred to herein as the "successive stage" and the "penultimate stage" to refer to the latter and next to latter stages, respectively. For example, where three stages are employed and when reference is made to the third and second stages, the third stage may be referred to as the "successive stage" and the second stage as the "penultimate stage." Where four stages are employed and when referring to the fourth and third stages, the fourth stage may be referred to as the "successive stage" and the third stage may be referred to as the "penultimate stage," etc. The successive stage may be pumped into the wellbore following a period of time for the fluid of the penultimate stage to be diverted into the created fracture which results from the penultimate stage. The fracture created from the pumping of any penultimate stage shall be referred to as a "secondary fracture".

[0052] Where a fracturing operation proceeds in multiple stages, the pumping of fluid of a successive stage creates a secondary fracture off of the fracture created by the penultimate stage. In between each stage, pumping is stopped for a period sufficient for fluid to divert into the secondary fracture. Each of the secondary fractures created in the formation has a directional orientation distinct from the directional orientation of the fracture from which it extends. In other words, the fracture created from a successive stage has a directional orientation distinct from that of the fracture created from a penultimate stage.

[0053] Between any penultimate stage and successive stage, pumping may be stopped and a pad fluid containing a proppant may be pumped into the reservoir to assist in the creation or enlargement of secondary fractures.

[0054] The methods described herein can be used to create a multiple of fractures originating from the original primary fracture wherein each successive stage creates a fracture having an orientation distinct from the directional orientation of the fracture created by the penultimate fracture.

[0055] The term "secondary successive fracture" as used herein therefore refers to the fracture created in a successive fracturing stage which has an orientation distinct from the directional orientation of the fracture created in the penultimate stage. The term "secondary penultimate fracture" as used herein refers to the fracture created during a penultimate fracturing stage. Thus, where three stages are employed and when referring to the fractures created in the third and second stages, the fracture created from the third stage may be referred to as the "secondary successive fracture" and the fracture created by the second stage prior to the successive stage as the "secondary penultimate fracture". Where four stages are employed and when referring to the fourth and third stages, the fracture created by the fourth stage may be referred to as the "secondary successive fracture" and the fracture created by the third stage may be referred to as the "secondary penultimate fracture," etc. A successive stage may be pumped into the wellbore following a period of time for the fluid of the penultimate stage to be diverted into the secondary penultimate fracture.

[0056] The fracturing pattern generated by the method of the disclosure may be illustrated in FIG. **1**C which demonstrates that excessive primary fracture length may be reduced and well spacing tightened and optimized to maximize recovery and costs. This is in contrast to FIG. **1**B which represents the fracture pattern generated by the fracturing operation of the prior art wherein an identical fracturing fluid is used but wherein the rate of pumping between fracturing stages is not reduced or curtailed.

[0057] In an embodiment of the disclosure, a network of fractures are created at near-wellbore and far-wellbore by varying the rate of injection of the fluid and/or the viscosity of the fluid and/or the pressure during injection of the fluid for various stages. The rate of injection of the fluid pumped into the formation for each successive stage may be the same or different.

[0058] A reduction in injection rate may, for instance, be used to allow the shear thinning fluid to build sufficient low shear rate viscosity for adequate pressure diversion for the changing fracture orientation created by the secondary fractures. In addition, reduction in injection rate may contribute to the opening and connecting of secondary fractures.

[0059] Stages of fracturing may be separated by periods wherein pumping is reduced or stopped dramatically. In a first stage, fluid is pumped into the wellbore which enters into a primary fracture. The fluid of the second stage is diverted away from the primary fracture and creates or enlarges a secondary fracture. After pumping the first stage and prior to pumping the second stage, pumping may be reduced by at least 80%. In an embodiment, pumping between stages is shut down completely during this period. The duration of the reduced pumping is sufficient to allow the fluid in a first stage to be subjected to very low shear rates in the reservoir, particularly the fluid near the tip of the fracture which does not move as fast as the fluid at the wellbore during a treatment. This substantially increases the apparent viscosity of the fluid within the primary fracture. Upon resuming pumping, the fluid introduced in the second stage encounters a viscous wall within the fractured area created or enlarged by the first stage. The stress placed on the reservoir by second stage fluid meeting the viscosity wall causes the fluid of the second stage to be diverted away from the primary fracture. Secondary fracture (s) are thereby propagated and the SRV increases. Repeated stages may follow wherein a penultimate stage is separated from the successive stage by a period of reduced pumping.

[0060] The viscosity wall of the near-static fluid from the penultimate stage enhances placement of fluid of a successive stage into a secondary fracture. The fracture growth of the total surface area connected to the wellbore after the fluid of the second stage is pumped is greater than the total surface area connected to the wellbore after the primary fracture is created or enlarged. Likewise, the fracture growth of the total surface area connected to the wellbore after the fluid of a successive stage is pumped is greater than the total surface area connected to the wellbore after a successive fracture is created or enlarged.

[0061] In another embodiment, the rate of injection of the fluid between the first stage and the second stage or any penultimate stage and successive stage may be varied. The change in the rate of injection of the second fluid causes pressure diversion such that the flow of the second fluid is diverted away from the primary fracture. Likewise, the change in the rate of injection of fluid of a successive stage causes pressure diversion such that the flow of the fluid of the successive stage is diverted away from the secondary penultimate fracture.

[0062] In another embodiment, the injection pressure of the fluid of first stage and the injection pressure of the fluid of the second stage or any penultimate stage and successive stage may be varied. Increase of the injection pressure of the second stage induces additional pressure diversion to force open a secondary fracture. Thus, the change in the injection pressure of the second fluid causes diversion such that the flow of the second fluid is diverted away from the primary fracture. Likewise, the change in injection pressure of the fluid of a successive stage causes diversion such that the flow of the fluid of the successive stage is diverted away from the secondary penultimate fracture.

[0063] In an embodiment of the disclosure, the fluid volume of the fracturing stages may be set by an operator and the total volume of the fluid may be broken into two or more stages. Each stage may be separated by a period of reduced or suspended pumping for a sufficient duration to allow the staged fluid in the reservoir to flow into a created or enlarged fracture at very low shear rates.

[0064] In another embodiment, the treatment operation may use a constant viscosity of fluid for each stage or the viscosity may be tapered from high viscosity in a first stage to low viscosity in a second stage or low viscosity in a first stage to high viscosity in a second stage. Alternatively, the viscosity may be tapered from a low viscosity in a penultimate stage to high viscosity in a successive stage or the viscosity may be tapered from high viscosity in a penultimate stage to low viscosity in a successive stage. Varying the viscosity improves the amount of proppant the fluid may suspend. Proppant may therefore be placed deeper within the reservoir. This, in turn, increases the net fracture conductivity per treatment. This is in contrast to those prior art treatment, such as water fracturing operations, which are unable to carry high loadings of proppant and thus are ineffective at placement of proppant into far-field regions of the reservoir.

[0065] The apparent fluid viscosity of the fluid therefore increases. The fluid of each of the stages exhibits high viscosity at low shear rates, such as below 1 sec^{-1}. The fluid of each of the stages may typically be between from about 1000 cP to about 2,000,000 cP at a shear rate of 0.01 sec^{-1}.

[0066] A complex network of multiple secondary fractures may be created from near wellbore to far-field regions by the methods described herein. The length of the primary fracture is curtailed and the depth of the network is increased in the near wellbore as well as the far-field areas. In addition, the total amount of opened and connected fractures to the wellbore is increased as well as the depth distribution of the opened and connected fractures. This provides for increased initial production near the wellbore and sustained production of fluids near the wellbore and far field from the wellbore, as illustrated in FIG. **2**. FIG. **2** further illustrates the increase in production resulting from the increased surface area near wellbore and far field compared to a conventional fracturing operation. The increase in surface area improves SRV and provides a higher initial and sustained hydrocarbon production over time.

[0067] As described, the multiple network of fractures may be created by varying the rate of pumping of the fluids of the stages, the rate of injection of the fracturing fluid between the stages or varying the viscosity of the fracturing fluid between the stages or any combination. In other words, a fracturing operation may proceed wherein one or more stages differ by (i) the amount of pressure during injection of the fluid into the wellbore; (ii) the rate of injection of pumping the stage fluid into the wellbore; (iii) the viscosity of the fluid introduced into the wellbore; or (iv) a combination of (i), (ii) and (iii). Further, any of these combinations may be used in conjunction with the procedure wherein reduced or curtailed pumping of the viscous fluid occurs between the pumping of viscous stages in order to obtain a network of fractures at near-wellbore and far-wellbore locations.

[0068] In an embodiment, a network of fractures may be created at near-wellbore and far-wellbore locations by varying the pressure during injection of the fluid for various stages. For instance, the pressure used in injecting the fluid in the stage wherein the primary fracture is enlarged or created may be greater than or less than the pressure when injecting the fluid in the additional stage. The fluid is preferably allowed to divert into the enlarged or created primary fracture.

[0069] Thus, the viscosity of the fluid of successive stages may be the same or different. For instance, the viscosity of the fluid and/or pumping pressure of the fluid in the initial step causing the creation or enlargement of the primary fracture may be the same as a subsequent stage. Alternatively, the viscosity of the fluid and/or pumping pressure of the fluid in the initial step may be greater than the viscosity and/or pumping pressure of the fluid in a successive stage. The viscosity of the fluid and/or pumping pressure of the fluid in the initial step may be less than the viscosity and/or pumping pressure of the fluid in a successive stage. For instance, the viscosity and/or pressure of the fluid in each successive stage may decrease with each additional stage.

[0070] The loading of the viscosifying agent in the fluid in each of the stages may also be the same or may be different. While typically the amount of viscosifying agent in the viscous fluid may be less than or equal to 6% by weight, the amount may vary from one stage to another.

[0071] The first fracturing fluid, additional fluids and any of the penultimate fluids or successive fluids referred to herein, may also contain other conventional additives common to the well service industry such as surfactants, biocides, gelling agents, cross-linking agents, foaming agents, demulsifiers, buffers, clay stabilizers, fines migration control agents, VES-micelle associate agents, chelants, internal VES-micelle breakers, or mixtures thereof. In the practice of the disclosure, the fracturing fluid may be any carrier fluid suitable for transporting a mixture of proppant into a formation fracture in a subterranean well. Such fluids include, but are not limited to, carrier fluids comprising salt water, fresh water, liquid hydrocarbons, and/or nitrogen or other gases.

[0072] The viscosity of the viscous fluid of any or all of the stages of the method described herein may be the same or different. For instance, the viscosity of the fluid of the pad fluid and the second stage may be the same. The constituency of the fluid of each of the stages may be the same or different. Thus, for example, in a method having nine different stages, three of the nine stages may be of the same fluid while the remaining six stages may all be different fluids.

[0073] The amount of viscosifying agent in the viscous fluid of any of the described stages may be less than or equal to 6% by weight.

[0074] The methods described herein may be used in the treatment of conventional rock formations such as carbonate formations (like limestone, chalk and dolomite), sandstone or siliceous substrate minerals, such as quartz, clay, shale, silt, chert, zeolite, or a combination thereof. The methods have particular applicability in the treatment of unconventional hydrocarbon reservoir formations, such as shale, tight sandstone and coal bed methane wells.

[0075] The methods described herein are especially effective with those subterranean reservoirs having a permeability less than or equal to 1.0 mD and most especially those subterranean reservoirs having a permeability less than or equal to 0.1 mD.

[0076] The viscosifying polymer may be a hydratable polymer like, for example, one or more polysaccharides capable of forming linear or crosslinked gels. These include galactomannan gums, guars, derivatized guars, cellulose and cellulose derivatives, starch, starch derivatives, xanthan, derivatized xanthan and mixtures thereof.

[0077] Specific examples include, but are not limited to, guar gum, guar gum derivative, locust bean gum, welan gum, karaya gum, xanthan gum, scleroglucan, diutan, cellulose and cellulose derivatives, etc. More typical polymers or gelling agents include guar gum, hydroxypropyl guar (HPG), carboxymethyl hydroxypropyl guar (CMHPG), hydroxyethyl cellulose (HEC), carboxymethyl hydroxyethyl cellulose (CMHEC), carboxymethyl cellulose (CMC), dialkyl carboxymethyl cellulose, etc. Other examples of polymers include, but are not limited to, phosphomannans, scleroglucans and dextrans.

[0078] The fluid containing the viscosifying polymer may further include a crosslinking agent. Typically, a low loading of the polymer is used in order to minimize polymer residue and conductivity damage. Where the fluid uses a viscosifying polymer, the loading of the polymer or crosslinked polymer is low, typically between from about 0.1 to about 6% by weight.

[0079] Any crosslinking agent suitable for crosslinking the hydratable polymer may be employed. Examples of suitable crosslinking agents include metal ions such as aluminum, antimony, zirconium and titanium-containing compounds, including organotitanates. Examples of suitable crosslinkers may also be found in U.S. Pat. No. 5,201,370; U.S. Pat. No. 5,514,309, U.S. Pat. No. 5,247,995, U.S. Pat. No. 5,562,160, and U.S. Pat. No. 6,110,875, incorporated herein by reference. Further examples of crosslinking agents are borate-based crosslinkers such as organo-borates, mono-borates, poly-borates, mineral borates, etc.

[0080] In an embodiment, the viscosifying agent may be non-polymeric such as a viscoelastic surfactant. The viscoelastic surfactant suitable for use as the viscosifying agent may be micellular, such as worm-like micelles, nano-size particle associated worm-like micelles, micron-size particle associated worm-like micelles, surfactant aggregations or vesicles, lamellar micelles, etc. Such micelles include those set forth in U.S. Pat. Nos. 6,491,099; 6,435,277; 6,410, 489; 7,115,546; 7,343,972; 7,550,413; 7,723,272; 8,114,820; and 8,278,252.

[0081] Suitable viscoelastic surfactants include cationic, amphoteric and anionic surfactants. Suitable cationic surfactants include those having only a single cationic group which may be of any charge state (e.g., the cationic group may have a single positive charge or two positive charges). The cationic group preferably is a quaternary ammonium moiety (such as a linear quaternary amine, a benzyl quaternary amine or a quaternary ammonium halide), a quaternary sulfonium moiety or a quaternary phosphonium moiety or mixtures thereof. Preferably the quaternary group is quaternary ammonium halide or quaternary amine, most preferably, the cationic group is quaternary ammonium chloride or a quaternary ammonium bromide.

[0082] The amphoteric surfactant preferably contains a single cationic group. The cationic group of the amphoteric surfactant is preferably the same as those listed in the paragraph above. The amphoteric surfactant may be one or more of glycinates, amphoacetates, propionates, betaines and mixtures thereof. Preferably, the amphoteric surfactant is a glycinate or a betaine and, most preferably, the amphoteric surfactant is a linear glycinate or a linear betaine. Amine oxide type surfactants are also most preferable, such as those disclosed in U.S. Pat. No. 7,723,272.

[0083] The cationic or amphoteric surfactant has a hydrophobic tail (which may be saturated or unsaturated). Preferably the tail has a carbon chain length from about C12-C18. Preferably, the hydrophobic tail is obtained from a natural oil from plants, such as one or more of coconut oil, rapeseed oil and palm oil. Exemplary of preferred surfactants include N,N,N trimethyl-1-octadecammonium chloride: N,N,N trimethyl-1-hexadecammonium chloride; and N,N,N trimethyl-1-soyaammonium chloride, and mixtures thereof.

[0084] Exemplary of anionic surfactants are sulfonates, phosphonates, ethoxysulfates and mixtures thereof. Preferably the anionic surfactant is a sulfonate. Most preferably the anionic surfactant is a sulfonate such as sodium xylene sulfonate and sodium naphthalene sulfonate.

[0085] In one embodiment, a mixture of surfactants are utilized to produce a mixture of (1) a first surfactant that is one or more cationic and/or amphoteric surfactants set forth above and (2) at least one anionic surfactant set forth above.

[0086] The relative amounts of the viscosifying agent in the stages referenced herein may be determined based upon the desired viscosity of the fluid. In particular, in operation, the viscosity of the fluid may first be determined. Further, the volume of the fluid which is required may be determined at this time. The requisite amount of viscosifying agent to obtain the predetermined viscosity may then be combined with the requisite amount of water to produce the fluid.

[0087] Preferably where a mixture of surfactants are used, such as those disclosed in U.S. Pat. No. 6,875,728 or 6,410, 489 (herein incorporated by reference), the amount of the cationic/amphoteric surfactant and the amount of anionic surfactant which are used is preferably sufficient to neutralize, or at least essentially neutralize, the charge density of the surfactants. Accordingly, if the cationic surfactant is N,N,N, trimethyl-1-octadecammonium chloride and the anionic surfactant is sodium xylene sulfonate, then the surfactants may be combined in a ratio from about 1:4 to about 4:1 by volume to obtain a clear viscoelastic gel which is capable of transporting a proppant. Typically of such viscoelastic surfactants are AquaClear, a product of Baker Hughes Incorporated.

[0088] Any breaker known in the hydraulic fracturing art may also be included in the fluid. The breaker is selected such that it is capable of degrading, enhancing the degradation of or reducing the viscosity of the viscosifying agent in one or more of the stages. Preferred breakers are delayed internal breakers such as peroxides, enzymes, and esters or mixtures thereof. Such delayed internal breakers include encapsulated breakers.

[0089] Any amount or concentration of breaker suitable for degrading or reducing the viscosity of the viscosifying agent or filter cake or other solids may be used. Often, the concentration of breaker used is that amount sufficient to cause complete degradation of the filter cake which is formed at the fracture face of the formation.

[0090] Typically, such breakers are included in their respective fluid in a concentration of between about 0.1 lb/1000 gals. and about 10 lb/100 gals.

[0091] Suitable breakers may include oils, such as mineral oil. Oil breakers have particular applicability in the breaking of surfactant-gelled fluids. At other times, the breaker may be an enzyme or oxidative breaker and may include enzyme precursors as well as enzymatically catalyzed oxidizers.

[0092] Examples of suitable types of oxidizing breakers include, but are not limited to, ammonium persulfate, sodium persulfate, ammonium peroxydisulfate, encapsulated ammonium persulfate, potassium persulfate, encapsulated potassium persulfate, inorganic peroxides, sodium bromate, sodium perchlorate, encapsulated inorganic peroxides, organic peroxides, encapsulated organic peroxides, sodium perborate, magnesium perborate, calcium perborate, encapsulated sodium perborate. Specific examples of suitable oxidizing materials include, but are not limited to, breakers available from Baker Hughes Incorporated as GBW5 (ammonium persulfate), GBW7 (sodium perborate), GBW23 (magnesium peroxide), GBW24 (calcium peroxide), GBW36 (encapsulated potassium persulfate), HIGH PERM CRB (encapsulated potassium persulfate), HIGH PERM CRB LT (encapsulated persulfate), ULTRA PERM CRB (encapsulated potassium persulfate), SUPER ULTRA PERM CRB (encapsulated potassium persulfate), and TRIGINOX (organic peroxide).

[0093] Further, any enzyme suitable for degrading or otherwise reducing the viscosity of a filter cake and/or gel residue may be employed. Such enzymes include those described in U.S. Pat. No. 5,165,477; U.S. Pat. No. 5,201,370; U.S. Pat. No. 5,247,995; and/or U.S. Pat. No. 5,562,160; and/or U.S. Pat. No. 6,110,875. Suitable enzymes include hydrolases, lyases, transferases and oxidoreductases.

[0094] The presence of breakers in the fluid dramatically decreases the low shear rate viscosity of the fluid. As illustrated in FIG. **4**, as shear rate decreases, the viscosity of the fluid increases. Thus, as the fluid in the fracture starts to slow down at very low shear rate, the viscosity of the fluid increases.

[0095] Preferred fluids of the disclosure preferably include viscoelastic surfactants since such surfactants typically minimize damage to the formation. In addition, since the methods described herein extend complex fractures farther away from the wellbore, the use of such viscosifying agents enables easier treatment fluid cleanup once a fracturing job is complete. For instance, reservoir fluid flow decreases with increasing distance from the wellbore, and the amount of reservoir cleanup energy also decreases from the wellbore. Thus a clean breaking, easy to cleanup viscoelastic surfactant treatment fluid is most preferred for this art. The clean-up of the treatment fluids in far-field and near-wellbore complex fracture networks can be improved by the use of viscoelastic surfactant fluids with internal breakers. This is illustrated in FIG. **5** wherein low reservoir pressure is seen to displace internally broken viscoelastic fluids. In particular, by degrading the low shear rate viscosity by internal breakers, the amount of pressure required for fluid cleanup can be significantly reduced, such as far-field complex fracture networks with low reservoir cleanup energy. FIG. **5** demonstrates the Berea core cleanup test data. Such VES-micelles internal breakers include those set forth in U.S. Pat. Nos. 7,343,266; 7,595,284; 7,615,517; 7,645,724; 7,696,134; 7,696,135; 7,728,044 and 7,967,068. In one non-limiting embodiment, the internal breaker works by rearrangement of the worm-like (i.e. long) micelle structure rather than surfactant molecule decomposition or alteration, although the alteration method of reducing VES-micelle viscosity may also be used.

[0096] In an embodiment, for greater than about 225° F. applications the fracturing fluids of the disclosure contain a viscoelastic surfactant in combination with temperature stabilizers as set forth in U.S. Patent Publication No. 2009/0272534, herein incorporated by reference. Suitable stabilizers include alkaline earth metals selected from magnesium, calcium, strontium, barium and mixtures thereof, and alkali metals selected from lithium, sodium, potassium and mixtures thereof. Preferred temperature stabilizers include MgO, TiO_2, Al_2O_3 and mixtures thereof. Nanoparticles of such stabilizers are especially preferred.

[0097] Any of the stages described herein may further include a low shear rate viscosity enhancer. Suitable viscosity enhancers include, but are not limited to, pyroelectric particles, piezoelectric particles, and mixtures thereof. In one non-limiting embodiment, specific viscosity enhancers may include, but are not necessarily limited to, ZnO, berlinite ($AlPO_4$), lithium tantalate ($LiTaO_3$), gallium orthophosphate ($GaPO_4$), $BaTiO_3$, $SrTiO_3$, $PbZrTiO_3$, $KNbO_3$, $LiNbO_3$, $LiTaO_3$, $BiFeO_3$, sodium tungstate, $Ba_2NaNb_5O_5$, $Pb_2KNb_5O_{15}$, potassium sodium tartrate, tourmaline, topaz and mixtures thereof.

[0098] The viscosity enhancer particles may be very small so they do not readily settle out of the fluid. This permits their removal from the formation to be easy and complete causing little or no damage to the formation.

[0099] Some or all of the stages may further contain proppant. Typically, the amount of proppant in a stage is greater than the amount of proppant in the pad fluid. The addition of proppant to the fracturing fluid in combination with the stop-start cycle described herein provides an increase in the amount of secondary fractures (Fs) that are propped (Fsp). The increase in the ratio of Fsp/Fs provides greater net fracture conductivity for the secondary fractures formed. FIG. **6** illustrates that greater Fs conductivity provides an improvement in higher sustainable hydrocarbon production rates.

[0100] In some treatment operations, it may be desirable to taper the loading of proppant to the viscosity of the fluid. In other treatment operations, it may be desirable to use proppant only with stages using a viscous fluid. In another embodiment, each fluid stage between stop-start may be designated like a typical frac treatment, i.e., a pad followed by increasing proppant loadings with small amount of displacements by slickwater fracturing operation. In this scenario, it may be desirable to not completely displace the fluid to the fractures but only have the slickwater displace 10 to 30% by volume of the fracture. Still further, it may be desirable to utilize smaller proppant size in the initial stages and follow with larger proppant sizes for the latter stages.

[0101] Examples of proppants include, but are not limited to, ceramics, silica, quartz sand grains, glass and ceramic beads, walnut shell fragments, aluminum pellets or needles, nylon pellets, resin-coated sand, synthetic organic particles, glass microspheres, sintered bauxite, mixtures thereof and the like.

[0102] In a preferred embodiment, the proppant is a relatively lightweight or substantially neutrally buoyant particulate material or a mixture thereof. Such proppants may be chipped, ground, crushed, or otherwise processed. By "relatively lightweight" it is meant that the proppant has an apparent specific gravity (ASG) that is substantially less than a conventional proppant employed in hydraulic fracturing operations, e.g., sand or having an ASG similar to these materials. Especially preferred are those proppants having an ASG less than or equal to 3.25. Even more preferred are ultra lightweight proppants having an ASG less than or equal to 2.25, more preferably less than or equal to 2.0, even more preferably less than or equal to 1.75, most preferably less than or equal to 1.25 and often less than or equal to 1.05.

[0103] The proppant may further be a resin coated ceramic proppant or a synthetic organic particle such as nylon pellets, ceramics. Suitable proppants further include those set forth in U.S. Patent Publication No. 2007/0209795 and U.S. Patent Publication No. 2007/0209794, herein incorporated by reference. The proppant may further be a plastic or a plastic composite such as a thermoplastic or thermoplastic composite or a resin or an aggregate containing a binder.

[0104] By "substantially neutrally buoyant", it is meant that the proppant has an ASG close to the ASG of an ungelled or weakly gelled carrier fluid (e.g., ungelled or weakly gelled completion brine, other aqueous-based fluid, or other suitable fluid) to allow pumping and satisfactory placement of the proppant using the selected carrier fluid. For example, urethane resin-coated ground walnut hulls having an ASG of from about 1.25 to about 1.35 may be employed as a substantially neutrally buoyant proppant particulate in completion brine having an ASG of about 1.2. As used herein, a "weakly gelled" carrier fluid is a carrier fluid having minimum sufficient polymer, viscosifier or friction reducer to achieve friction reduction when pumped down hole (e.g., when pumped down tubing, work string, casing, coiled tubing, drill pipe, etc.), and/or may be characterized as having a polymer or viscosifier concentration of from greater than about 0 pounds of polymer per thousand gallons of base fluid to about 10 pounds of polymer per thousand gallons of base fluid, and/or as having a viscosity of from about 1 to about 10 centipoises. An ungelled carrier fluid may be characterized as containing about 0 pounds per thousand gallons of polymer per thousand gallons of base fluid. (If the ungelled carrier fluid is slickwater with a friction reducer, which is typically a polyacrylamide, there is technically 1 to as much as 8 pounds per thousand of polymer, but such minute concentrations of polyacrylamide do not impart sufficient viscosity (typically <3 cP) to be of benefit).

[0105] Other suitable relatively lightweight proppants are those particulates disclosed in U.S. Pat. Nos. 6,364,018, 6,330,916 and 6,059,034, all of which are herein incorporated by reference. These may be exemplified by ground or crushed shells of nuts (pecan, almond, ivory nut, brazil nut, macadamia nut, etc); ground or crushed seed shells (including fruit pits) of seeds of fruits such as plum, peach, cherry, apricot, etc.; ground or crushed seed shells of other plants such as maize (e.g. corn cobs or corn kernels), etc.; processed wood materials such as those derived from woods such as oak, hickory, walnut, poplar, mahogany, etc. including such woods that have been processed by grinding, chipping, or other form of particalization. Preferred are ground or crushed walnut shell materials coated with a resin to substantially protect and water proof the shell. Such materials may have an ASG of from about 1.25 to about 1.35.

[0106] Further, the relatively lightweight particulate for use in the disclosure may be a selectively configured porous particulate, as set forth, illustrated and defined in U.S. Pat. No. 7,426,961, herein incorporated by reference.

[0107] The particle size of the proppants in the fluid of each of the stages may be the same or different. For instance, the particle size of the proppants in the stage wherein the primary fracture is created or enlarged may be less than the particle size of the proppants in subsequent stages. Further, the particle size of the proppants in each successive stage may increase as the number of stages increases. Typically, the size of the proppants range from 12 microns to 4 millimeters.

[0108] An advantage of the methods disclosed herein is that less fracturing intervals are required during a treatment operation in order to obtain the same amount of hydrocarbons as those produced in conventional operations which use a greater number of fracturing intervals. For example, where the treatment operation consists of decreasing the rate of injection after the fluid of a first stage is introduced into the wellbore and then continuing with the same rate of injection of additional fluid into the formation after pumping has been reduced or stopped and diverting the additional fracturing fluid away from the primary fracture to create a secondary fracture, the amount of hydrocarbons recovered is greater than the amount of hydrocarbons recovered from a primary fracture and secondary fractures which had been created in a fracturing operation performing an equivalent number of stages but wherein each stage is introduced into the formation at the same rate of injection. This may be observed in a treatment operation producing multiple fractures by the methods defined herein wherein the number of stages of the inventive method are the same number of stages as the conventional method.

[0109] Since the amount of hydrocarbons produced is greater under such conditions, fewer stages in a fracturing operation are required in order to produce an equivalent amount of hydrocarbons. Since the number of intervals may be increased across the wellbore, the methods described herein provide the ability to effectively fracture longer frac interval lengths. The phenomena is attributable to the multiple fracture network providing a wider distribution pattern which is created by a reduced fluid volume. In other words, assuming that the treatment operation used successive fracturing stages wherein the rate of injection remained the same for each fracturing stage, a greater number of fracturing intervals may be required to obtain a given volume than in the method described herein wherein the rate of injection of a successive fracturing stage is greater or less than the rate of injection of a penultimate fracturing stage. The reduction in the number of hydraulic fracturing treatments across a given horizontal wellbore by use of the methods described herein is illustrated in FIG. **7**A and comparative FIG. **7**B. The reduction may be attributable to improved distribution of fluid in the zones.

[0110] The method has particular applicability with the treatment of shale oil and/or gas reservoirs. In previous methods, shale reservoirs were fractured using short intervals and thus an increased number of fracturing treatments. Such fracturing treatments have become closer together. The method described herein may provide for a decrease in interval per a given length. For instance, the methods described herein may provide 8 intervals (and fracturing treatments) per 3,000 ft. of horizontal wellbore compared to 30 intervals (and fracturing treatments) per 3,000 ft. This reduction is possible without compromising the net surface area increase and SRV provided by the methods described herein and without extending the hydrocarbon drainage area of the reservoir. Further, reducing the number of intervals required for a treatment operation provides a cost savings to the operator since the number of interval isolation tools is decreased.

[0111] The methodology described herein may increase the net surface area far-field and near wellbore. Most conventional viscous fluid shale fracs induce mostly long planar fractures with few secondary fractures (FIG. **1**A). Alternately, most slickwater fracs (i.e. fluids with <15 cps at 100 sec^{-1}) typically induce near wellbore complex fracture network and SRV, and in some cases with long primary fractures with very few secondary fractures (FIG. **1**B). However, the methodology described herein by controlling pump rate and fluid viscosity can induce more secondary fractures further away from the wellbore (far-field) and near wellbore by low shear rate fluid viscosity pressure diversion (FIG. **1**C). The bottom line in FIG. **2** represents typical production data for conventional fracturing (i.e. using single pump rate with a viscous frac fluid), complex fractures that develop primarily near the wellbore typical of slickwater fracs (middle line), and near wellbore and far-field complex fracture network SRV achievable by adjusting or hesitating pumping rate with a viscous fluid (top line). In practicing this method, the viscous fracturing fluid may be high shear thinning with greater than 10,000 cP viscosity at 0.01 sec^{-1} shear. FIG. **3** shows the 2 sec^{-1} shear rate viscosity at 150° F. of a 13.0 brine fluid having 4 volume % viscoelastic surfactant, 6 pounds per thousand gallons (pptg) of viscosity enhancer and 2 gallons per thousand gallons (gptg) breaker after setting static for 30 minutes. FIG. **4** shows how unbroken shear thin fluid can have much higher apparent viscosity at low shear rates, and how the use of internal breaker is preferred to reduce low shear rate fluid viscosity after the treatment, particularly the low shear rate fluid viscosity. FIG. **5** shows how unbroken viscoelastic surfactant fluid can take a significant amount of pressure to flow from 6 in. Berea core buts much less pressure is needed with use of internal breaker.

[0112] The methodology described herein may further be used in a slickwater-viscous fluid fracturing operation. Unlike the fracturing pattern generated by conventional slickwater fracturing (illustrated in FIG. **1**B), the slickwater fracturing operation defined herein provides a optimized primary fracture length and multiple secondary fractures (illustrated in FIG. **1**C).

[0113] For instance, in one embodiment, prior to pumping of the pad fluid, a slickwater fluid may be pumped into the reservoir. The slickwater fluid typically has a viscosity less than or equal to 15 cP at a shear rate of 300 sec^{-1}. This may be followed by the pad fluid and then the (first) treatment using the viscous fluid. In such embodiments, the amount of slickwater fluid introduced into the wellbore is typically between from about 10 to about 60 volume percent of the combination of slickwater fluid, pad fluid and viscous fluid.

[0114] Thus, in an embodiment, hydrocarbons may be recovered from a fracturing operation by first pumping slickwater fluid into the reservoir for a time and at a pressure sufficient to create a primary fracture in the reservoir. A viscous fluid containing an aforementioned viscosifying agent may then be pumped behind the slickwater fluid in order to extend the created primary fracture. The viscous fluid typically has a viscosity greater than about 10,000 cP at a shear rate of 0.01 sec^{-1}. In an embodiment, the pumping of the viscous fluid may be suspended for a sufficient time to allow the viscous fluid to be diverted within the primary fracture. Additional slickwater fluid may then be pumped into the reservoir for a time and at a pressure sufficient to divert the viscous fluid away from the primary fracture and to create one or more secondary fractures in the subterranean reservoir. The pumping of the additional slickwater fluid is usually at a higher injection rate than the injection rate of the viscous fluid. The process creates a multiple fracture network near the wellbore than when the fracturing is limited to slickwater treatment. In addition, the process provides for the creation of a more complex network of secondary fractures near the wellbore (FIG. **1**B).

[0115] The viscosifying agent used in the method is preferably a viscoelastic surfactant. An internal breaker is also preferable to induce a clean breaking fluid that does not leave apparent residual mass that impairs fracture conductivity, such as polymer residue. Since the fluid is laden with a viscosifying agent with internal breaker, the water load recovery after the staged treatment is high. This results in an improved SRV and enhances gas connectivity to the wellbore from a higher percentage of the hydraulically induced fractures.

[0116] In an embodiment, additional viscous fluid is then pumped behind the slickwater fluid in order to extend the secondary fracture. Pumping may then be suspended in order to divert the flow of slickwater away from the primary fracture into the one or more secondary fractures. This process may be continuously repeated to create a network of far-field and near wellbore secondary fractures from the primary fracture (FIG. **1**C). Typically, the volume percent of slickwater fluid pumped in penultimate stage to viscous fluid pumped in a successive stage is between from about 10:90 to about 50:50.

[0117] In another embodiment, hydrocarbons may be recovered from a fracturing operation by a series of slickwater fracturing stages wherein slickwater fluid is first pumped into the reservoir for a time and at a pressure sufficient to create a primary fracture in the reservoir. Pumping may then be suspended for the fluid to divert into the created fracture. Additional slickwater fluid may then be pumped into the reservoir for a time and at a pressure sufficient to extend fluid and to create one or more secondary fractures in the reservoir. Pumping may then be suspended in order to divert the flow of slickwater away from the primary fracture into the one or more secondary fractures. This process may be continuously repeated to create a network of secondary fractures from the primary fracture. Increased water recovery from the slickwater fracturing stages allows for greater gas connectivity to the reservoir.

[0118] The viscosity of the slickwater fluid in a slickwater stage may be the same or different from the viscosity of the slickwater fluid in another slickwater stage. Likewise, the viscosity of the viscous fluid may be different or the same from one viscous fluid stage versus another viscous fluid stage. Further, the rate of injection of the pumping of the fluids and the pumping pressure of the stages may be the same or different from one slickwater stage to the next or from one viscous fluid stage to another viscous fluid stage.

[0119] Any combinations of the methods disclosed herein may be used in a fracturing operation. For instance, a diversion process as described herein may be used in combination with a slickwater fracturing operation. Specifically, a viscous fluid containing a viscosifying agent may be alternated with a slickwater fracturing fluid. In such an instance, for example, the first stage may be a viscous fluid containing a viscoelastic surfactant followed by a slickwater fracturing stage wherein the total volume of viscous fluid stage to slickwater fracturing stage may be 50:50 or 75:25 volume percent.

[0120] As another example, a series of viscous fluid stages may be injected into the wellbore with a suspension of pumping between each stage and the last stage of the operation may be a slickwater fracturing stage. In this scenario, the viscosity of the viscous fluid of each of the stages may be the same or different. Likewise, the viscous fluid may exhibit greater viscosity in the first few stages and less viscous in the latter stages. Conversely, a series of fluid stages may be injected into the wellbore wherein the first fluid is a slickwater fracturing fluid and the last stage is a viscous fluid. Similarly, alternating stages between a viscous fluid and a slickwater fracturing fluid may be injected and repeated for two or more cycles. In this scenario, the viscosity of the viscous fluid may be the same for each fluid stage or the viscosity may be tapered.

[0121] The methods described herein may further limit the fracturing of zones in formations such as shale formations which are known to exhibit non-uniform interval coverage. Microseismic mapping and well temperature logging often show poor frac fluid distribution across each interval and re-fracturing of nearby intervals. By directing the placement of fluid within the fractured zones, out of intervals fracturing areas may be reduced. This is shown in FIG. **8**.

[0122] The foregoing disclosure and description of the disclosure is illustrative and explanatory thereof and it can be readily appreciated by those skilled in the art that various changes in the size, shape, and materials, as well as in the details of illustrative methodologies described herein may be made without departing from the spirit of the disclosure.

What is claimed is:

1. A method for improving the recovery of hydrocarbons from a subterranean reservoir having a permeability less than 0.1 mD which comprises:

(a) pumping a fluid into the subterranean reservoir at a pressure sufficient to enlarge or create a primary fracture, wherein the fluid has a viscosity greater than about 10,000 cP at a shear rate of 0.01 sec^{-1} and further wherein the fluid contains a viscoelastic surfactant and/or a viscosifying polymer;

(b) stopping the pumping when the viscous fluid is within the enlarged or created primary fracture;

(c) pumping additional fluid having a viscosity greater than about 10,000 cP at a shear rate of 0.01 sec^{-1} into the subterranean reservoir at a pressure sufficient to create at least one secondary fracture, wherein the least one secondary fracture is has a directional orientation distinct from the directional orientation of the primary fracture; and

(d) diverting the flow of the additional fluid of step (c) into the at least one secondary fracture.

2. The method of claim **1**, further comprising:

(e) stopping the pumping of the additional fluid; and further wherein steps (c), (d) and (e) are continuously repeated for a time sufficient to create a multiple fracture network consisting of the primary fracture and a multitude of secondary fractures.

3. The method of claim **1**, wherein the viscosity of the viscous fluid is between from about 10,000 cP to about 2,000, 000 cP at a shear rate of 0.01 sec^{-1}.

4. The method of claim **3**, wherein the viscosity of the viscous fluid of step (a) and the additional fluid of step (c) is the same.

5. The method of claim **2**, wherein the additional fluid of step (c) is the same for each repetition of step (c).

6. The method of claim **2**, wherein the additional fluid of step (c) is the same as the viscous fluid of step (a).

7. The method of claim **1**, wherein the viscous fluid of step (a) enlarges a created primary fracture and further wherein a pad fluid is pumped into the subterranean reservoir prior to step (a) in order to initiate the primary fracture.

8. The method of claim **1**, wherein the viscous fluid of step (a) and/or the additional fluid of step (c) contains a viscoelastic surfactant as viscosifying agent.

9. The method of claim **8**, wherein the viscous fluid further contains an internal breaker.

10. The method of claim **8**, wherein the viscous fluid further contains a low shear rate viscosity enhancer.

11. The method of claim **10**, wherein the viscosity enhancer is a wormlike micelle associative agent.

12. The method of claim **1**, wherein the viscous fluid of step (a) and/or the additional fluid of step (c) contains proppants.

13. The method of claim **1**, wherein the viscous fluid of step (a) and/or the additional fluid of step (c) contains a polymeric viscosifying agent.

14. The method of claim **13**, wherein the viscous fluid and/or additional fluid, in addition to containing a polymeric viscosifying agent, further contains a crosslinking agent.

15. The method of claim **13**, wherein the amount of polymeric viscosifying agent in the viscous fluid is less than or equal to 6% by weight.

16. The method of claim **1**, wherein the pressure in step (a) and step (c) is approximately the same.

17. The method of claim **1**, wherein the pressure in step (c) is greater than the pressure in step (a).

18. The method of claim **1**, wherein the injection rate of the additional fluid pumped into the subterranean reservoir in step (c) is greater than the injection rate of the viscous fluid pumped into the subterranean reservoir in step (a).

19. A method of fracturing a subterranean formation penetrated by a wellbore by creating a network of fractures at near-wellbore and far-wellbore locations wherein the subterranean formation has a permeability less than 0.1 mD, the method comprising the following sequential steps:

(a) injecting into the subterranean reservoir a fracturing fluid having a viscosity greater than about 10,000 cp at a shear rate of 0.01 sec^{-1} at a pressure sufficient to enlarge or create a primary fracture;

(b) decreasing the rate of injection of the fracturing fluid for a time sufficient for the viscosity of the fracturing fluid to increase within the created or enlarged fracture;

(c) injecting additional fracturing fluid into the subterranean reservoir to create one or more secondary fractures, wherein the additional fracturing fluid diverts away from the primary fracture and into the one or more secondary fractures;

(d) repeating steps (b) and (c) at least twice; and

(e) forming a network of secondary fractures at near-wellbore and far-wellbore locations from the primary fracture and the secondary fractures.

20. The method of claim **19**, wherein at least one of the following conditions prevail:

(i) the rate of injection of the additional fracturing fluid of step (c) is different from the rate of injection of the fracturing fluid of step (a);

(ii) the viscosity of the additional fracturing fluid of step (c) is different from the viscosity of the fracturing fluid of step (a); or

(iii) the amount of pressure used to inject the additional fracturing fluid of step (c) is different from the pressure used to inject the fracturing fluid of step (a).

21. The method of claim **19**, wherein the fracturing fluid of step (a) and/or the additional fracturing fluid of step (c) contains proppants.

22. The method of claim **21**, wherein the particle size of the proppants in the fracturing fluid of step (a) is less than the particle size of the proppants in the additional fracturing fluid of step (c).

23. The method of claim **21**, wherein the size of the proppants range from 12 microns to 4 millimeters.

24. The method of claim **23**, wherein the injection of the fracturing fluid is stopped in step (b) for a time sufficient for the viscosity of the fracturing fluid to increase within the created or enlarged fracture.

25. A fracturing operation for recovering hydrocarbons from a subterranean reservoir penetrated by a wellbore, wherein the subterranean reservoir has a permeability less than 0.1 mD which comprises:

(a) pumping a fluid into the subterranean reservoir at a pressure sufficient to enlarge or create a primary fracture in the reservoir wherein the fluid has a viscosity greater than about 10,000 cP at a shear rate of 0.01 sec^{-1};

(b) temporarily stopping the pumping when the viscous fluid is within the primary fracture;

(c) resuming the pumping of the fluid; and

(d) diverting the flow of the fluid pumped in step (c) away from the primary fracture to create one or more secondary fractures in the subterranean reservoir.

26. The method of claim **25**, further comprising continuously repeating steps (a), (b), (c) and (d).

27. The method of claim **25**, wherein the fracture growth of the total surface area connected to the wellbore after step (d) is greater than the total surface area connected to the wellbore after step (a).

28. The method of claim **25**, wherein the viscosity of the fluid and/or pumping pressure of the fluid in steps (a) and (c) is the same.

29. The method of claim **25**, wherein the viscosity of the fluid and/or pumping pressure of the fluid in step (a) is greater than the viscosity of the fluid in step (c).

30. The method of claim **25**, wherein the viscosity and/or pressure of the fluid in each of repeating steps (a) and (c) in the fracturing operation decreases with each repetition.

31. The method of claim **25**, wherein the viscosity and/or pressure of the fluid in step (a) is less than the viscosity of the fluid in step (c).

32. The method of claim **26**, wherein the viscosity and/or pressure of the fluid in each of repeating steps (a) and (c) in the fracturing operation increases with each repetition.

33. The method of claim **25**, wherein the fluid pumped into the wellbore contains a viscosifying polymer.

34. The method of claim **25**, wherein prior to pumping of the pad fluid, a slickwater fluid having a viscosity less than or equal to 15 cP at a shear rate of 300 sec^{-1} is pumped into the subterranean reservoir.

35. The method of claim **34**, wherein the amount of slickwater fluid is between from 10 to 60 volume percent of the combination of slickwater fluid, pad fluid and viscous fluid.

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