

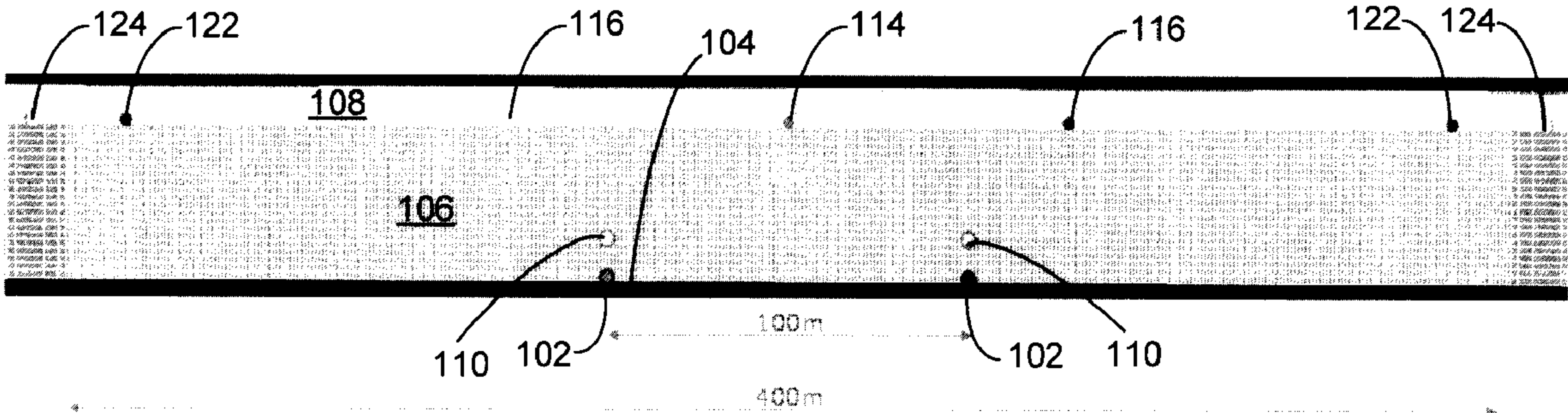


(12) **DEMANDE DE BREVET CANADIEN**
CANADIAN PATENT APPLICATION
(13) **A1**

(22) **Date de dépôt/Filing Date:** 2018/08/17
(41) **Mise à la disp. pub./Open to Public Insp.:** 2019/08/26
(30) **Priorité/Priority:** 2018/02/26 (US62/635,414)

(51) **Cl.Int./Int.Cl.** *E21B 43/16* (2006.01),
E21B 43/30 (2006.01)
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(54) **Titre : PROCÉDE DE PRODUCTION D~HYDROCARBURES A PARTIR D~UNE FORMATION RENFERMANT DES HYDROCARBURES SOUTERRAINS**
(54) **Title: PROCESS FOR PRODUCING HYDROCARBONS FROM A SUBTERRANEAN HYDROCARBON-BEARING FORMATION**



(57) **Abrégé/Abstract:**
A process for recovering hydrocarbons from a reservoir of a subterranean hydrocarbon-bearing formation, the reservoir having a top gas zone. The process includes injecting a mobilizing fluid into an injection well disposed in a lower portion of the hydrocarbon-bearing formation to create a chamber in the hydrocarbon-bearing formation, producing the hydrocarbons from the hydrocarbon-bearing formation, injecting a solvent vapour or liquid into the gas zone, and, after the chamber reaches the gas zone, discontinuing mobilizing fluid injection into the injection well, wherein the solvent spreads laterally to form a solvent blanket above the chamber, and condenses at lateral edges of the solvent blanket, delivering liquid solvent to the hydrocarbon-bearing formation to mobilize the hydrocarbons.

Abstract

A process for recovering hydrocarbons from a reservoir of a subterranean hydrocarbon-bearing formation, the reservoir having a top gas zone. The process includes injecting a mobilizing fluid into an injection well disposed in a lower portion of the hydrocarbon-bearing formation to create a chamber in the hydrocarbon-bearing formation, producing the hydrocarbons from the hydrocarbon-bearing formation, injecting a solvent vapour or liquid into the gas zone, and, after the chamber reaches the gas zone, discontinuing mobilizing fluid injection into the injection well, wherein the solvent spreads laterally to form a solvent blanket above the chamber, and condenses at lateral edges of the solvent blanket, delivering liquid solvent to the hydrocarbon-bearing formation to mobilize the hydrocarbons.

PROCESS FOR PRODUCING HYDROCARBONS FROM A SUBTERRANEAN HYDROCARBON-BEARING FORMATION

Technical Field

[0001] The present invention relates to the production of hydrocarbons such as heavy oils and bitumen from a hydrocarbon-bearing formation including a lean zone disposed above.

Background

[0002] Extensive deposits of viscous hydrocarbons exist around the world, including large deposits in the northern Alberta oil sands that are not susceptible to standard oil well production technologies. The hydrocarbons in reservoirs of such deposits are too viscous to flow at commercially relevant rates at the virgin temperatures and pressures present in the reservoir. For such reservoirs, thermal techniques may be utilized to heat the reservoir to mobilize the hydrocarbons and produce the heated, mobilized hydrocarbons from wells. One such technique for utilizing a horizontal well for injecting heated fluids and producing hydrocarbons is described in U.S. Patent No. 4,116,275, which also describes some of the problems associated with the production of mobilized viscous hydrocarbons from horizontal wells.

[0003] It is common practice to categorize petroleum substances of high viscosity and density into two categories, "heavy oil" and "bitumen". For example, some sources define "heavy oil" as a petroleum that has a mass density of greater than about 900 kg/m³. Bitumen is sometimes described as that portion of petroleum that exists in the semi-solid or solid phase in natural deposits, with a mass density greater than about 1,000 kg/m³ and a viscosity greater than 10,000 centipoise (cP; or 10 Pa.s) measured at original temperature in the deposit and atmospheric pressure, on a gas-free basis. Although these terms are in common use, references to heavy oil and bitumen represent categories of convenience and there is a continuum of properties between heavy oil and bitumen. Accordingly, references to heavy oil and/or bitumen herein include the continuum of such

substances, and do not imply the existence of some fixed and universally recognized boundary between the two substances. In particular, the term "heavy oil" includes within its scope all "bitumen" including hydrocarbons that are present in semi-solid or solid form. One thermal method of recovering viscous hydrocarbons utilizing spaced horizontal wells is known as steam-assisted gravity drainage (SAGD). In general, a SAGD process may be described as including three stages: the start-up stage; the production stage; and the wind-down (or blowdown) stage. The production stage may be described as including further stages such as, for example, a ramp-up stage and a plateau stage.

[0004] In the SAGD process, pressurized steam is delivered through an upper, horizontal, injection well (injector), into a viscous hydrocarbon reservoir while hydrocarbons are produced from a lower, parallel, horizontal, production well (producer) that is near the injection well and is vertically spaced from the injection well. The injection and production wells are situated in the lower portion of the reservoir, with the producer located close to the base of the hydrocarbon reservoir to collect the hydrocarbons that flow toward the base of the reservoir.

[0005] The SAGD process is believed to work as follows. The injected steam initially mobilizes the hydrocarbons to create a steam chamber in the reservoir around and above the horizontal injection well. The term steam chamber is utilized to refer to the volume of the reservoir that is saturated with injected steam and from which mobilized oil has at least partially drained. As the steam chamber expands, viscous hydrocarbons in the reservoir and water originally present in the reservoir are heated and mobilized and move with aqueous condensate, under the effect of gravity, toward the bottom of the steam chamber. The hydrocarbons, the water originally present, and the aqueous condensate are typically referred to collectively as emulsion. The emulsion accumulates such that the liquid / vapor interface is located below the steam injector and above the producer. The emulsion is collected and produced from the production well. The produced emulsion is separated into dry oil for sales and produced water, comprising the water originally present and the aqueous condensate.

[0006] Such processes, however, are complicated in hydrocarbon-bearing formations that are in fluid communication with a lean zone. Zones disposed towards the top of heavy oil or bitumen deposits may have distinct fluid mobility characteristics. These zones include, for example, top water zones or gas caps (including top gas zones that have been produced, and therefore have reduced pressure). Collectively these zones may be called "lean" or "thief" zones, reflecting the effect of these zones on hydrocarbon recovery processes that use an injected fluid to improve mobility of the oil. An example of a lean zone includes a water aquifer lying above the hydrocarbon-bearing formation. In such cases, an expanding steam chamber in the reservoir may breach, or hydraulically contact the aqueous fluid zone such that water flows into the steam chamber, cooling the steam chamber or even quenching the process.

[0007] Techniques may be employed to displace the aqueous fluid with a non-condensable gas, e.g., air, prior to the steam chamber establishing fluid communication with the aqueous fluid, thus reducing the chance of quenching the process and improving recovery.

[0008] Because of complications relating to the presence of water or the introduction of further gas into the steam chamber, recovery of hydrocarbons from such hydrocarbon-bearing formations may be relatively low as unrecovered viscous hydrocarbons spaced laterally from the injection and production wells are left unmobilized.

[0009] Improvements in recovery of hydrocarbons are desirable.

Summary

[0010] According to an aspect of an embodiment, a process is provided for recovering hydrocarbons from a reservoir of a subterranean hydrocarbon-bearing formation, the reservoir having a top gas zone. The process includes injecting a mobilizing fluid into an injection well disposed in a lower portion of the hydrocarbon-bearing formation to create a chamber in the hydrocarbon-bearing formation, producing the hydrocarbons from the hydrocarbon-bearing formation, injecting a solvent vapour or liquid into the gas zone, and, after the chamber

reaches the gas zone, discontinuing mobilizing fluid injection into the injection well, wherein the solvent spreads laterally to form a solvent blanket above the chamber, and condenses at lateral edges of the solvent blanket, delivering liquid solvent to the hydrocarbon-bearing formation to mobilize the hydrocarbons.

[0011] The process may include displacing, utilizing a gas, aqueous fluid in an aqueous fluid zone of the hydrocarbon-bearing formation, to form the gas zone. The solvent may be injected via a de-watering well utilized to produce aqueous fluid from the aqueous fluid zone during the displacing. A boundary of the gas zone and aqueous fluid may be maintained by producing aqueous fluid from a well near the boundary and re-injecting the aqueous fluid at a location in the aqueous fluid zone, away from the gas zone. Maintaining the boundary may be discontinued after reaching a target hydrocarbon production from the reservoir and the solvent injection discontinued. Hydrocarbon production may also be discontinued after reaching the target hydrocarbon production from the reservoir. At least some solvent injected may be recovered as the solvent vapour, produced, for example, via the de-watering well utilized to produce aqueous fluid from the aqueous fluid zone during the displacing and utilized for injecting the solvent.

[0012] The solvent may be superheated solvent vapour to create the solvent blanket above the chamber.

[0013] The mobilizing fluid may be steam. Optionally, the mobilizing fluid may include a further solvent vapour. The process may include monitoring the chamber and, based on the monitoring, determining a rate of growth of the chamber. A time at which the solvent injection begins may be based on the rate of growth of the chamber.

[0014] Mobilizing fluid injection into the injection well is discontinued in response to the chamber breaching the gas zone. The injection well may be shut in in response to the chamber breaching the gas zone. Production of hydrocarbons from the hydrocarbon-bearing formation continues after shutting in the injection well.

[0015] A gas, such as methane, that is less dense than the solvent may be injected into the gas zone after reaching a target hydrocarbon production. At least some solvent injected as the solvent vapour may be produced via a production well utilized to produce the hydrocarbons.

[0016] According to another aspect, a process for removing fluids from a hydrocarbon reservoir utilizing an injection well extending into the hydrocarbon reservoir and a production well extending near a bottom of the reservoir is provided. The process includes injecting a mobilizing fluid into the reservoir through the injection well, creating a mobilizing fluid chamber and producing a portion of the fluids via the production well, injecting a solvent into a top gas zone above the hydrocarbon reservoir after the mobilizing fluid chamber breaches the top gas zone, and discontinuing injecting the mobilizing fluid to create the mobilizing fluid chamber and recovering a further portion of the fluids via the production well.

Brief Description of the Drawings

[0017] Embodiments of the present disclosure will be described, by way of example, with reference to the drawings and to the following description, in which:

[0018] FIG. 1 is a schematic sectional view through a reservoir, illustrating horizontal segments of wells utilized in a hydrocarbon recovery process in accordance with one example of the present disclosure;

[0019] FIG. 2A is a flowchart illustrating a process of recovering hydrocarbons from a hydrocarbon-bearing formation, in accordance with an embodiment of the present disclosure;

[0020] FIG. 2B is a flowchart illustrating a process of recovering hydrocarbons from a hydrocarbon-bearing formation, in accordance with another embodiment of the present disclosure;

[0021] FIG. 3 is a diagram illustrating the displacement of aqueous fluid, also referred to as de-watering, over 500 days of operation in accordance with an example of the process of FIG. 2A;

[0022] FIG. 4 is a diagram illustrating initial development of a steam chamber in accordance with an example of the process of FIG. 2A;

[0023] FIG. 5 shows the commencement of propane injection and growth of the steam chamber in accordance with an example of the process of FIG. 2A;

[0024] FIG. 6 shows the spread of propane in the gas zone in accordance with an example of the process of FIG. 2A;

[0025] FIG. 7 is a graph showing oil recovery for the process in accordance with an example of the process of FIG. 2A;

[0026] FIG. 8 is a graph showing oil production rates over time for an 800m long production well in accordance with an example of the process of FIG. 2A;

[0027] FIG. 9 is a graph showing cumulative produced water to oil ratio (PWOR) in accordance with an example of the process of FIG. 2A;

[0028] FIG. 10 is a graph showing a comparison of the energy equivalent steam to oil ratio (eCSOR) for a SAGD process and for an example in accordance with the process of FIG. 2A;

[0029] FIG. 11 is a graph showing a comparison of total time to achieve a 60% oil recovery for the processes compared in FIG. 10;

[0030] FIG. 12 illustrates a method in which propane recovery is carried out in accordance with an example of the process of FIG. 2A.

Detailed Description

[0031] For simplicity and clarity of illustration, reference numerals may be repeated among the Figures to indicate corresponding or analogous elements. Numerous details are set forth to provide an understanding of the examples described herein. The examples may be practiced without these details. In other instances, well-known methods, procedures, and components are not described in detail to avoid obscuring the examples described. The description is not to be considered as limited to the scope of the examples described herein.

[0032] The disclosure generally relates to a process for recovering hydrocarbons from a reservoir of a subterranean hydrocarbon-bearing formation, the reservoir having a top gas zone. The process includes injecting a mobilizing fluid into an injection well disposed in a lower portion of the hydrocarbon-bearing formation to create a chamber in the hydrocarbon-bearing formation, producing the hydrocarbons from the hydrocarbon-bearing formation, injecting a solvent vapour or liquid into the gas zone, and, after the chamber reaches the gas zone, discontinuing mobilizing fluid injection into the injection well, wherein the solvent spreads laterally to form a solvent blanket above the chamber, and condenses at lateral edges of the solvent blanket, delivering liquid solvent to the hydrocarbon-bearing formation to mobilize the hydrocarbons. A solvent blanket refers to a layer above the chamber in which the space is primarily dominated by solvent vapour.

[0033] As noted above, embodiments of the present disclosure include the injection of a mobilizing fluid, such as steam, to create a mobilizing fluid chamber. A "chamber" within a reservoir or formation is a region that is in fluid/pressure communication with a particular well or wells, such as an injection or production well. For example, in a SAGD process, a steam chamber is the region of the reservoir in fluid communication with a steam injection well, which is also the region that is subject to depletion, primarily by gravity drainage, into a production well.

[0034] A "reservoir" is a subsurface formation containing one or more natural accumulations of moveable petroleum, which are generally confined by relatively impermeable rock. An "oil sand" or "oil sands" reservoir is generally comprised of strata of sand or sandstone containing petroleum. A "zone" in a reservoir is an arbitrarily defined volume of the reservoir, typically characterized by some distinctive property. Zones may exist in a reservoir within or across strata or facies, and may extend into adjoining strata or facies. In some cases, reservoirs containing zones having a preponderance of heavy oil or bitumen are associated with zones containing a preponderance of natural gas. This "associated gas" is gas that is in pressure communication with the heavy oil or bitumen within the reservoir, either

directly or indirectly, for example through a connecting water zone. A pay zone is a reservoir volume having hydrocarbons that can be recovered economically.

[0035] In the present example, the process is generally described in relation to SAGD. The present process may be successfully implemented with other processes that utilize steam, such as processes involving solvent and steam, also referred to as a solvent-aided process (SAP), or cyclic steam stimulation (CSS), or solvent-based processes that utilize solvent as a mobilizing fluid.

[0036] In the SAGD process, well pairs, each including a hydrocarbon production well and a steam injection well are utilized. A hydrocarbon production well includes a generally horizontal segment that extends near the base or bottom of the hydrocarbon reservoir. The injection well also includes a generally horizontal segment that is disposed generally parallel to and is spaced generally vertically above the horizontal segment of the hydrocarbon production well.

[0037] During SAGD, steam is injected into the injection well to mobilize the hydrocarbons and create a mobilizing fluid (steam) chamber in the reservoir, around and above the generally horizontal segment. In addition to steam injection into the steam injection well, light hydrocarbons, such as the C3 through C10 alkanes, either individually or in combination, may optionally be injected with the steam such that the light hydrocarbons function as solvents in aiding the mobilization of the hydrocarbons. The volume of light hydrocarbons that are injected may be relatively small compared to the volume of steam injected, for example up to about 20 weight % solvent. The addition of light hydrocarbons is referred to as a solvent-aided process (SAP). Alternatively, or in addition to the light hydrocarbons, various non-condensing gases, such as methane, natural gas, carbon dioxide, air, nitrogen, or a combination thereof, may be injected. Viscous hydrocarbons in the reservoir are heated and mobilized and the mobilized hydrocarbons drain under the effect of gravity. Fluids, including the mobilized hydrocarbons along with connate water and condensed steam (aqueous condensate), are collected in the generally horizontal segment. The fluids may also include gases such as steam and production gases (e.g., methane, hydrogen sulfide) from the SAGD process.

[0038] A simplified schematic sectional view illustrating horizontal segments of injection and production wells utilized in a hydrocarbon recovery process in accordance with one example is shown in FIG. 1. For the purpose of the present example, a reservoir 106 of about 20 meters in depth is illustrated. An aqueous fluid zone 108, or aquifer, of about 5 meters in depth overlies the reservoir 106.

[0039] Such top water zones are of potential concern because they give rise to the potential for fluid communication between the top water zone and the underlying bitumen zone as a consequence of a hydrocarbon recovery operation. The top water may drain towards the bitumen recovery zone, particularly if the recovery zone is operated at a lower reservoir pressure than the top water zone. This draining of top water towards the well pair will cool the reservoir and make the solvent-based recovery process significantly less efficient.

[0040] If the bitumen recovery zone is being operated at a higher pressure than the top water zone during the recovery process, the injected steam (which may include solvent) may rise into the top water zone and increase the reservoir pressure, filling the available pore space until the top water zone is in pressure equilibrium with the bitumen zone. The volume of steam (which may include solvent) required to reach pressure equilibrium represents an inefficient injected fluid loss, reducing the efficiency of the bitumen recovery process.

[0041] In the example of FIG. 1, two pairs of injection and production wells are illustrated and are spaced apart by about 100 meters. Each of the production wells 102 includes a generally horizontal segment that extends near the base or bottom 104 of the hydrocarbon reservoir 106. Each injection well 110 also includes a generally horizontal segment that is disposed generally parallel to and is spaced generally vertically above the horizontal segment of a respective one of the hydrocarbon production wells 102. In the present example, the injection wells 110 are spaced about 5 meters above respective ones of the production wells 102 and are utilized to inject mobilizing fluids into the reservoir, creating a mobilizing fluid chamber in the reservoir.

[0042] FIG. 1 illustrates two pairs of injection and production wells. The present process may be carried out with additional or fewer pairs of injection and production wells. According to one example, the process may be carried out utilizing a single pair of injection and production wells.

[0043] In addition to the injection wells 110 and production wells 102, aqueous fluid displacement wells are also utilized to displace the aqueous fluid in the aqueous fluid zone 108 disposed above the reservoir 106, replacing it with a gas. The aqueous fluid displacement wells extend to a location near a bottom of the aqueous fluid zone 108, near the interface of the reservoir 106 with the aqueous fluid zone 108. These aqueous fluid displacement wells include an aqueous fluid production well 114 and non-condensable gas injection wells 116. The aqueous fluid production well 114 is utilized to remove the aqueous fluid from the region above the injection wells 110 and production wells 102 and the non-condensable gas injection wells 116 inject a non-condensable gas such as air to replace the aqueous fluid. The non-condensable gas is injected at a suitable pressure to create a gas zone, also referred to as a de-watered zone.

[0044] Fence wells, including producers 122 and re-injectors 124 are also utilized to maintain a non-condensable gas/aqueous fluid boundary near the edge of the gas (de-watered) zone. The producers 122 remove aqueous fluid ingress into the gas zone from the boundary and the re-injectors 124 are utilized to re-inject the aqueous fluid removed utilizing the producers 122, into an area of the aquifer away from the gas zone.

[0045] The locations of the non-condensable gas injection wells 116 relative to the fence wells and relative to the injection wells 110 and production wells 102 is shown as one example. Other relative locations of wells may be successfully implemented. For example, each of the non-condensable gas injection wells 116 may be located closer to the nearest fence wells, and thus laterally spaced farther from the near injection well 110 and production well 102.

[0046] A flowchart illustrating a process of recovering hydrocarbons from a subterranean hydrocarbon-bearing formation including an oil (thief) zone above,

such as the reservoir 106 shown in FIG. 1, is provided in FIG. 2A. For example, the present method may be employed for recovering hydrocarbons from a reservoir that has an aqueous fluid zone disposed above, or a reservoir that has a gas zone, referred to as a gas cap, disposed above. The process may contain additional or fewer subprocesses than shown or described, and parts of the process may be performed in a different order.

[0047] In the example of an aqueous fluid zone above the reservoir, a volume of the aqueous fluid in the aqueous fluid zone is displaced by a non-condensable gas, such as air at 202 (FIG. 2A). The aqueous fluid is displaced utilizing the fluid production well 114 and the non-condensable gas is injected through the gas injection wells 116. The volume that is displaced or de-watered, is filled with gas and the gas is maintained in the gas zone that is created, utilizing the producer wells 122 on the outer perimeter of the gas zone. The producer wells 122 remove water ingress into the gas zone and the water is reinjected, utilizing the re-injection wells 124, into the aqueous fluid zone 108 that exists away from the gas zone, thus generally maintaining the gas zone. While some aqueous fluid may still remain, the majority of the aqueous fluid is displaced by the non-condensable gas.

[0048] In the example of a gas zone disposed above the reservoir, no displacement of aqueous fluid is carried out to form a gas zone above the reservoir. The pore space of such a gas zone may contain connate reservoir water (for example on the order of 20% v/v), residual bitumen (for example 20% v/v) and a significant concentration of natural gas (for example 60% v/v). The exact concentrations of the gas zone may vary significantly. The process of the present disclosure may be utilized with a de-watered zone, an intact gas zone, and a depleted gas zone.

[0049] A hydrocarbon recovery process such as SAGD or a solvent-aided process is initiated in which the mobilizing fluid, such as steam, is injected in an injection well and the mobilized fluids drain down to the lower well from which they are produced to the surface. The mobilizing fluid that is injected may be steam that is injected into the reservoir utilizing the injection wells 110 to create a

mobilizing fluid chamber and to mobilize the hydrocarbons in the reservoir at 204 of the process illustrated in FIG. 2A.

[0050] The mobilized hydrocarbons are produced, along with connate water and condensed steam (aqueous condensate), utilizing production wells 102 at 206. The horizontal segments of the injection and the production well pairs are generally located in a lower portion of the hydrocarbon-bearing formation, i.e., closer to a base than the top of the hydrocarbon-bearing formation, as illustrated in FIG. 1.

[0051] Reference is made herein to injection and production well pairs. The injection well 110 and the production well 102 may be physically separate wells. Alternatively, the production well and the injection well may be housed, at least partially, in a single physical wellbore, for example, a multilateral well. The production well and the injection well may be functionally independent components that are hydraulically isolated from each other, and housed within a single physical wellbore.

[0052] The mobilizing fluid chamber growth may be monitored and, based on the results of monitoring, a rate of growth of the mobilizing fluid chamber may be determined. In response to determining at 208 that the mobilizing fluid chamber is close to the gas zone, the process continues at 210. Alternatively, the process may continue at 210 after injection of mobilizing fluid into the injection wells for a period of time sufficient to cause the mobilizing fluid chamber to grow close to the gas zone.

[0053] One or more of the fluid production wells 114 (only one shown in FIG. 1) are switched to injecting solvent vapour at a temperature above the saturation temperature of the solvent at 210 (FIG. 2A). The vaporized solvent is injected at a suitable rate to maintain the de-watered gas zone pressure, diffuse away from the well through the gas zone, and create a solvent blanket over a zone targeted for hydrocarbon recovery by the well pairs in the reservoir at 210. Alternatively, a liquid solvent may be injected, optionally with a non-condensing gas to facilitate diffusion of the liquid solvent through the gas zone.

[0054] The distance between mobilizing fluid chamber and the gas zone that is considered "close" at 208, may vary depending on several factors, including the rate of growth of the mobilizing fluid chamber. The solvent injection at 210 is started at a time sufficient to create a layer when the mobilizing fluid chamber breeches the lean zone. For example, the steam chamber may be allowed to get very close to the lean zone, e.g., 1 m to 5 m, if the equipment utilized to pump the solvent is capable of pumping solvent quickly. Solvent may be injected well in advance of the mobilizing fluid chamber breeching the lean zone to ensure that the solvent is in place. Such injection, well in advance of the mobilizing fluid chamber reaching the lean zone, however is less economically efficient as the solvent is not utilized until the mobilizing fluid chamber reaches the lean zone.

[0055] The process of injecting mobilizing fluid via the injection well 110 and producing hydrocarbons via the production well 102 continues until the mobilizing fluid chamber formed by the injection of the mobilizing fluid, breaches the gas zone above. As indicated above, the mobilizing fluid chamber growth may be monitored at 212 and, in response to determining that the mobilizing fluid chamber has breached the gas zone at 212, the process continues at 214. The breach of the gas zone may be detected or may be determined or estimated based on the rate of growth of the mobilizing fluid chamber.

[0056] The injection of mobilizing fluid into the reservoir via the injection wells 110 is discontinued at 214 and the injection wells 110 are shut in. Production of hydrocarbons via the production wells 102 continues, however. The pressure within the reservoir to drive the hydrocarbon production is maintained by the injection of the solvent in the gas zone.

[0057] Thus, the injection of mobilizing fluid may be discontinued when breach of the gas zone is detected, determined, or estimated. Alternatively, injection of the mobilizing fluid may continue for a period of time after breach of the gas zone is detected, determined, or estimated. Injection of the mobilizing fluid may continue for months or even up to two years after breach of the gas zone. Continued injection of mobilizing fluid, such as steam is desirable in applications in which heat is injected to sustain the process for the duration of the solvent

injection. For example, in the case in which fluid communication is established between the mobilizing fluid chamber and the aqueous fluid zone or gas zone early in the process, continued injection of mobilizing fluid, such as steam, is desirable to provide heat and thus to increase the size of the mobilizing fluid chamber.

[0058] During an initial period after breach of the gas zone by the mobilizing fluid chamber, for example, in the case of a SAGD or a solvent-aided process (SAP), enhanced oil and water production rates may occur as the mobilizing fluid chamber cools. After such a transition period, the ratio of produced water to produced oil decreases steadily as eventually the only water that is produced is the connate water and water that bypasses the fence wells in the lean zone.

[0059] After desired oil recovery is achieved, the operation may be switched to a solvent recovery phase at 216 to recover solvent from the reservoir. Solvent vapour or liquid injection is discontinued. Recovery of the solvent may be accomplished utilizing any one of several methods. For example, if the portion of the reservoir and aqueous fluid zone is isolated, pressure boundary control at the fence wells is discontinued, allowing the aqueous fluid to enter the oil depleted zones. The fluid production well 114, also referred to as a de-watering well, that was utilized to inject the solvent, may be switched over to gas production, i.e., the same well that was utilized for water production is repurposed and utilized for gas production. As the chambers fill up with water, the solvent vapors are pushed out of the fluid production well 114, to the surface.

[0060] Alternatively, the fence wells may still be utilized to maintain the pressure isolation while fluid production well 114, which was utilized to inject the solvent, is switched to injecting a gas that is less dense than the solvent. For example, the fluid production well 114 may be switched to injecting an NCG such as methane or natural gas. Because natural gas is lighter than commercial solvents, the natural gas preferentially stays at the top while pushing the residual oil and solvent towards the production well 102 at the bottom of the reservoir, facilitating production of the residual oil and solvent via the production well 102. With both steam and solvent injection having been terminated by this point in the process, injection of the NCG commences the blowdown stage of operations.

[0061] Thus, an existing well, namely the fluid production well 114, may be utilized to recover the solvent. Use of an existing well is advantageous. A further well, other than the fluid production well 114, however, may be utilized to recover the solvent.

[0062] The solvent that is injected at 210 may be any suitable solvent, including light hydrocarbons such as alkanes. Solvents having 2 to 8 carbon atoms per molecule, such as ethane, propane, butane, pentane, hexane, heptane, or octane may be utilized.

[0063] Solvent injection may commence any time after the top water zone is displaced with gas, and before the steam chamber breaks through. The solvent injection may be timed to distribute the solvent to condense at the edges of the chamber when the chamber is at its largest volume and communicates with the gas zone.

[0064] The solvent diffuses and cools in the gas zone, condenses, and enters the mobilizing fluid chamber. The injection of solvent vapour facilitates movement of the solvent laterally within the gas zone, to edges of the mobilizing fluid chamber, where the solvent is beneficial. Once inside the chamber, liquid solvent absorbs latent heat from the reservoir and achieves thermodynamic equilibrium with a portion of the solvent dissolving in the oleic phase in the reservoir and the remainder of the solvent re-vaporizing.

[0065] Typical oil recovery from SAGD reservoirs that include a top aqueous fluid zone ranges from about 40-60% depending upon the thickness, or depth, of the reservoir. Additional recovery is limited by higher steam to oil ratios (SORs) rendering the process uneconomic. In a hydrocarbon recovery process as described with reference to FIG. 2A, much higher oil recoveries may be realized as a more uniform propagation of the mobilizing fluid chamber, which, in the example of SAGD is a steam chamber, in the lateral direction is achieved as a result of hydrocarbon mobilization by solvent dilution. Dissolution of solvent in bitumen reduces the viscosity and enhances mobility of the oleic phase.

[0066] In the above-described example, the aqueous fluid is displaced to form a gas zone as the aqueous fluid is produced through the producer wells 122 on the outer perimeter of the gas zone that is formed. Alternatively, the aqueous fluid may be produced after fluid communication of the aqueous fluid zone with the mobilizing fluid chamber is established, as illustrated in FIG. 2B. Many of the processes in the flowchart illustrated in FIG. 2B are similar to those described above with reference to FIG. 2A and are therefore not described again in detail. Similar reference numerals are utilized in FIG. 2B to describe similar processes.

[0067] Mobilizing fluid, such as steam in the case of SAGD, is injected utilizing the injection wells, such as the injection wells 110, to create a mobilizing fluid chamber and to mobilize the hydrocarbons in the reservoir at 204. The mobilized hydrocarbons are produced, along with connate water and condensed steam (aqueous condensate), utilizing production wells, such as the production wells 102, at 206. When the aqueous fluid zone is breached by the mobilizing fluid chamber at 220, the aqueous fluid is drained into the mobilizing fluid chamber, to the production well 102 at or near the bottom of the mobilizing fluid chamber. Aqueous fluid may optionally be displaced by non-condensable gas as the aqueous fluid drains via the mobilizing fluid chamber. Thus fluid communication of the aqueous fluid zone with the mobilizing fluid chamber is already established when the gas zone is formed. Solvent is then injected, as indicated at 210. Injection of the mobilizing fluid may continue for a period of time after fluid communication of the aqueous fluid zone with the mobilizing fluid chamber is established. The period of time may be, for example, months or even years to continue to provide heat to the hydrocarbon-bearing formation. The injection of mobilizing fluid is discontinued at 216 and a solvent recovery process may be carried out at 216.

Modelling

[0068] Reservoir simulations were performed to demonstrate the process. A live oil simulation model with methane dissolved in bitumen at reservoir conditions was utilized with Northern Alberta oil sands reservoir properties.

[0069] As an example, a relatively low pressure solvent such as propane may be injected in a vapor form at about 45°C. For the purpose of the reservoir simulations, the propane was superheated to about 55°C injection temperature. Thus, in the early stages of injection, while the gas zone into which the vapor was injected was at a relatively cool temperature, (e.g., about 12°C), the propane did not condense in the vicinity of the fluid production well 114 through which the solvent vapour was injected.

[0070] Simulation parameters utilized are included in Table 1 below.

Table 1: Key Simulation Parameters	
Rich Pay thickness	20m
Lean Zone thickness	5m
Well Spacing	100m
Well Length	2m
Element of Symmetry	Full
Model grid Block Dimensions	1m wide x 2m thick x 1m long
Porosity	0.35
Reservoir Temperature	12°C
Reservoir Pressure	1300kPa
Initial Oil Saturation (rich pay)	80%
Initial Oil Saturation (lean zone)	20%
Vertical Permeability	8 darcies
Horizontal Permeability	10 darcies
Methane mole fraction in Oleic Phase	0.075
Oil API	8.0

Well Completions

[0071] The modelling was carried out utilizing grid blocks with properties selected to simulate a hydrocarbon reservoir with a top aquifer. The edge of the

lean zone was populated by grid blocks with infinite porosity to simulate the water aquifer. Well pairs in the hydrocarbon-bearing formation, also referred to as rich pay, were spaced 100m apart. Initial water saturation in the aqueous fluid zone, also referred to as the lean zone, was 80% while the initial oil saturation in the rich pay was 80%.

[0072] The general layout of wells and formation was as illustrated in FIG. 1. A 400m wide pattern was simulated with a 5m thick (depth) mobile water aquifer at the top and a 20m thick (depth) rich pay zone at the bottom. Water saturation in the aquifer was 80% while water saturation was 20% in the rich pay. Active de-watering was achieved utilizing a combination of fence wells, including the producers 122 and the re-injectors 124 for maintaining a pressure boundary, a fluid production well 114, and a gas injection well 116.

Results

[0073] FIG. 3 shows the results of displacing the aqueous fluid, also referred to as de-watering, over 500 days of operation. The process of displacing of the aqueous fluid, or de-watering, removed most of the water from a targeted zone though some water remained behind. In other simulations, the process of displacing the aqueous fluid was continued for longer durations of time but showed similar results. At least some of the water that is not displaced is expected to be produced during a recovery operation.

[0074] After 500 days of de-watering, SAGD was commenced in the 2 horizontal well pairs, i.e., the production wells 102 and the steam injection wells 110, near the bottom of the rich pay. In a commercial operation, de-watering and SAGD start-up may overlap at least partially in time; prior to communication of the mobilizing fluid chamber, which in this example is a steam chamber, with the gas zone, the processes are generally independent of each other.

[0075] FIG. 4 shows the initial development of the steam chamber. Approximately 230 days into SAGD operations, the steam chamber developed to within 3m of the bottom of the aqueous fluid zone. The intent of the initial recovery

process was to create communication between the steam chamber in the rich pay with the de-watered gas zone.

[0076] At 230 days, the two gas injection wells 116 were shut in and the fluid production well 114 was converted into a well for propane injection. The fence wells continued to operate to maintain the boundary. Propane was injected at 55°C, which was about 10°C superheated with respect to the saturation temperature for propane at the reservoir pressure. FIG. 5 shows the commencement of propane injection and simultaneous growth of the steam chamber (at 20 days of propane injection). Although propane was injected with superheat, the propane quickly cooled down and condensed not too far away from the well 114 through which the propane was injected. This was expected as the gas zone was at a much cooler temperature of 12°C.

[0077] Solvent utilization and recovery is important in any solvent-aided or solvent-based recovery process. The much cooler lean zone causing condensing of the propane is advantageous for the recovery process. At the outer edges of the propane blanket within the gas zone, the propane condenses. The gas zone effectively acts as a "bubble" within the aqueous fluid zone. The injected propane stays within the bubble. By controlling the injection rate, and hence pressure, of propane, the spread of propane may be controlled to cover the targeted oil recovery volume and without the solvent spreading out much further.

[0078] FIG. 6 shows that after 50 days of propane injection, spread of propane in the gas zone then covered the positions of the two well pairs in the rich pay. At this time, the steam chamber just breached the gas zone.

[0079] After establishing communication between the steam chamber and the gas zone, steam injection was discontinued, thus switching overall to a solvent process. The initial process created a steam chamber that expanded towards the gas zone and created a preferential flow path for the solvent in the gas zone.

[0080] The two steam injection wells 110 in the rich pay were shut in, leaving three wells operating, including, the fluid production well 114 utilized for propane injection, and the two production wells 102 at the bottom of the rich pay. A

pressure drive was thus created between the fluid production well 114 utilized for propane injection and the production wells 102 which were each about 54m apart diagonally from the fluid production well 114. This was in contrast to the pressure drive in SAGD where the injection and production wells of a well pair are typically roughly 5m apart.

[0081] FIG. 7 shows oil recovery for the process, after discontinuing steam injection, with time (from top to bottom, up to a total process time of 2950 days or about 8 years). During the transition period, in which the process was switched over to solvent injection without steam injection, enhanced hydrocarbon production rates were observed for some time as propane cooled down the steam chamber and accelerated condensation of steam. Lower temperatures also increased solubility of the propane that entered into the steam chamber. Additionally, oil that was mobilized by propane in the gas zone also drained down into the steam chamber. The efficiency of propane utilized as a solvent is indicated by the fact that, over an 8 year period, almost all the recoverable oil in the 100m spacing between the two SAGD well pairs was produced. At 8 years, the "drainage slope" of fluids in the reservoir reached the fence wells, which were laterally 150m away from either production well 102.

[0082] FIG. 8 shows the oil production rates (m^3/day) over an 8 year period. The rates are shown for an 800m long production well 102. As shown, production during SAGD averaged about 200m^3 oil per day. The oil produced during SAGD is dependent on permeabilities in the reservoir, however. During the transition period, elevated production rates were observed. After the transition period, steady production rates averaging about 150m^3 per day were observed for the next 6.5 years. In a conventional SAGD process, as the steam chamber develops further away from the production wells 102, steam to oil ratios increase rapidly and typically after about 60% oil is recovered, the wells are switched over to the blowdown stage. In the present process, steady production rates were observed for a significantly longer period of time as shown in FIG. 8.

[0083] FIG. 9 shows the cumulative produced water to oil ratio (PWOR) and illustrates an advantage of the process described herein over SAGD alone. Water to

oil ratios were higher for the initial SAGD and transition periods. After the transition period, however, PWOR dropped to a small fraction of the produced oil as only connate water and the small amounts of water that bypassed the fence wells were produced. Excluding the SAGD and transition periods, cumulative PWOR was 0.18 for the post-transition period solvent process.

[0084] In addition to very low PWOR, which advantageously facilitates the use of smaller water handling facilities, the energy intensity of the present process (denoted SAGD+Propane in FIG. 10 and FIG. 11) and the time to produce the same amount of oil were reduced by comparison to SAGD, as shown in FIG. 10 and FIG. 11, respectively. Specifically, simulations showed that the equivalent steam to oil ratio, CSOR, on an energy basis for SAGD was 3 on a cumulative basis for 60% of oil recovery, while the equivalent CSOR (eCSOR) was only 0.49 for the present process. In addition, it took 10 years to recover the oil in SAGD but only 4.7 years for the present process.

[0085] Economics of a solvent recovery process (solvent-aided or solvent-based) depend on solvent recovery / recycling because the solvent utilized is relatively expensive. Table 2 below summarizes the solvent material balance for the present process at the 60% oil recovery mark:

Table 2: Propane Material Balance	
Propane produced back	82%
Propane retained in the reservoir	16%
Propane produced at the fence wells	2%
Injected solvent to oil ratio	2.2

[0086] Propane remaining in the reservoir at end of the process is recoverable utilizing one or more of several methods. One method is illustrated in FIG. 12 in which, pressure maintenance utilizing the fence wells at the outer edges of the de-watered zone was discontinued, thus allowing aquifer water to ingress into the depleted reservoir. The fluid production well 114 that was utilized for propane

injection into the gas zone was then utilized for propane production and remaining propane was produced to surface as the depleted reservoir filled up with water.

[0087] Alternatively, a non-condensable gas may be injected into the fluid production well 114 that was utilized for propane injection. The gas, being lighter than propane, pushes the propane and additional residual oil to the production wells 102 at the bottom of the reservoir.

[0088] The described embodiments are to be considered in all respects only as illustrative and not restrictive. The scope of the claims should not be limited by the preferred embodiments set forth in the examples, but should be given the broadest interpretation consistent with the description as a whole. All changes that come with meaning and range of equivalency of the claims are to be embraced within their scope.

Claims

1. A process for recovering hydrocarbons from a reservoir of a subterranean hydrocarbon-bearing formation, the reservoir having a top gas zone, the process comprising:

injecting a mobilizing fluid into an injection well disposed in a lower portion of the hydrocarbon-bearing formation to create a chamber in the hydrocarbon-bearing formation;

producing the hydrocarbons from the hydrocarbon-bearing formation;

injecting a solvent vapour or liquid into the gas zone; and

after the chamber reaches the gas zone, discontinuing mobilizing fluid injection into the injection well, wherein the solvent spreads laterally to form a solvent blanket above the chamber, and condenses at lateral edges of the solvent blanket, delivering liquid solvent to the hydrocarbon-bearing formation to mobilize the hydrocarbons.

2. The process according to claim 1, comprising displacing, utilizing a gas, aqueous fluid in an aqueous fluid zone of the hydrocarbon-bearing formation, to form the gas zone.

3. The process according to claim 2, wherein injecting the solvent comprises injecting the solvent via a de-watering well utilized to produce aqueous fluid from the aqueous fluid zone during the displacing.

4. The process according to claim 2 or claim 3, comprising maintaining a boundary of the gas zone and aqueous fluid by producing aqueous fluid from a well near the boundary and re-injecting the aqueous fluid at a location in the aqueous fluid zone, away from the gas zone.
5. The process according to any one of claims 1 to 4, wherein injecting the solvent comprises injecting superheated solvent vapour to create the solvent blanket above the chamber.
6. The process according to any one of claims 1 to 5, wherein injecting the mobilizing fluid comprises injecting steam to create the chamber.
7. The process according to any one of claims 1 to 6, wherein injecting the mobilizing fluid comprises injecting a further solvent vapour to create the chamber.
8. The process according to any one of claims 1 to 7, comprising monitoring the chamber and, based on the monitoring, determining a rate of growth of the chamber.
9. The process according to claim 8, wherein a time at which injecting the solvent vapour into the gas zone begins is based on the rate of growth of the chamber.
10. The process according to any one of claims 1 to 9, wherein mobilizing fluid injection into the injection well is discontinued in response to the chamber breaching the gas zone.
11. The process according to claim 10, comprising shutting in the injection well in response to the chamber breaching the gas zone.
12. The process according to claim 11, comprising continuing producing the hydrocarbons from the hydrocarbon-bearing formation after shutting in the injection well.

13. The process according to claim 4, comprising discontinuing maintaining the boundary after reaching a target hydrocarbon production from the reservoir.
14. The process according to claim 13, comprising discontinuing injecting the solvent vapour after reaching the target hydrocarbon production.
15. The process according to claim 13 or claim 14, comprising discontinuing producing hydrocarbons after reaching the target hydrocarbon production from the reservoir.
16. The process according to any one of claims 13 to 15, comprising recovering at least some solvent injected as the solvent vapour.
17. The process according to claim 16, wherein the solvent vapour is produced via the de-watering well utilized to produce aqueous fluid from the aqueous fluid zone during the displacing and utilized for injecting the solvent.
18. The process according to any one of claims 1 to 12, comprising discontinuing injecting the solvent vapour after reaching a target hydrocarbon production.
19. The process according to claim 18, comprising injecting a gas that is less dense than the solvent into the gas zone.
20. The process according to claim 19, wherein the gas comprises methane.
21. The process according to any one of claims 18 to 20, comprising producing at least some solvent injected as the solvent vapour via a production well utilized to produce the hydrocarbons.

22. The process according to any one of claims 1 to 6, wherein injecting the mobilizing fluid and producing the hydrocarbons are carried out in a steam-assisted gravity drainage (SAGD) process, a solvent-aided process (SAP), or a solvent-based process.
23. The process according to any one of claims 1 to 22, wherein injecting solvent vapour comprises injecting a solvent having 2 to 8 carbon atoms per molecule.
24. The process according to any one of claims 1 to 23, wherein injecting solvent vapour comprises injecting propane.
25. The process according to any one of claims 1 to 10, wherein injecting the mobilizing fluid and producing the hydrocarbons continues for a period of up to two years after the chamber reaches the gas zone.
26. The process according to claim 1, wherein the chamber formed by injecting the mobilizing fluid breaches a top aqueous fluid zone and aqueous fluid from the top aqueous fluid zone is drained via the chamber and produced from near a bottom of the chamber to form the top gas zone.
27. The process according to claim 26, wherein injecting the mobilizing fluid and producing the hydrocarbons continues for a period of up to two years after the chamber formed by injecting the mobilizing fluid breaches the top aqueous fluid zone, before discontinuing injecting the mobilizing fluid.
28. A process for removing fluids from a hydrocarbon reservoir utilizing an injection well extending into the hydrocarbon reservoir and a production well extending near a bottom of the reservoir, the process comprising:

injecting a mobilizing fluid into the reservoir through the injection well, creating a mobilizing fluid chamber and producing a portion of the fluids via the production well;

injecting a solvent into a top gas zone above the hydrocarbon reservoir after the mobilizing fluid chamber breaches the top gas zone; and

discontinuing injecting the mobilizing fluid to create the mobilizing fluid chamber and recovering a further portion of the fluids via the production well.

29. The process according to claim 28, comprising draining aqueous fluid from a top aqueous zone to form the top gas zone.

30. The process according to claim 29, wherein draining aqueous fluid from the top aqueous zone comprises draining the aqueous fluid through the mobilizing fluid chamber and producing the aqueous fluid via the production well.

31. The process according to claim 28, wherein draining aqueous fluid from the top aqueous zone comprises producing the aqueous fluid utilizing an aqueous fluid producer.

32. The process according to claim 30 comprising maintaining the top gas zone utilizing fence wells.

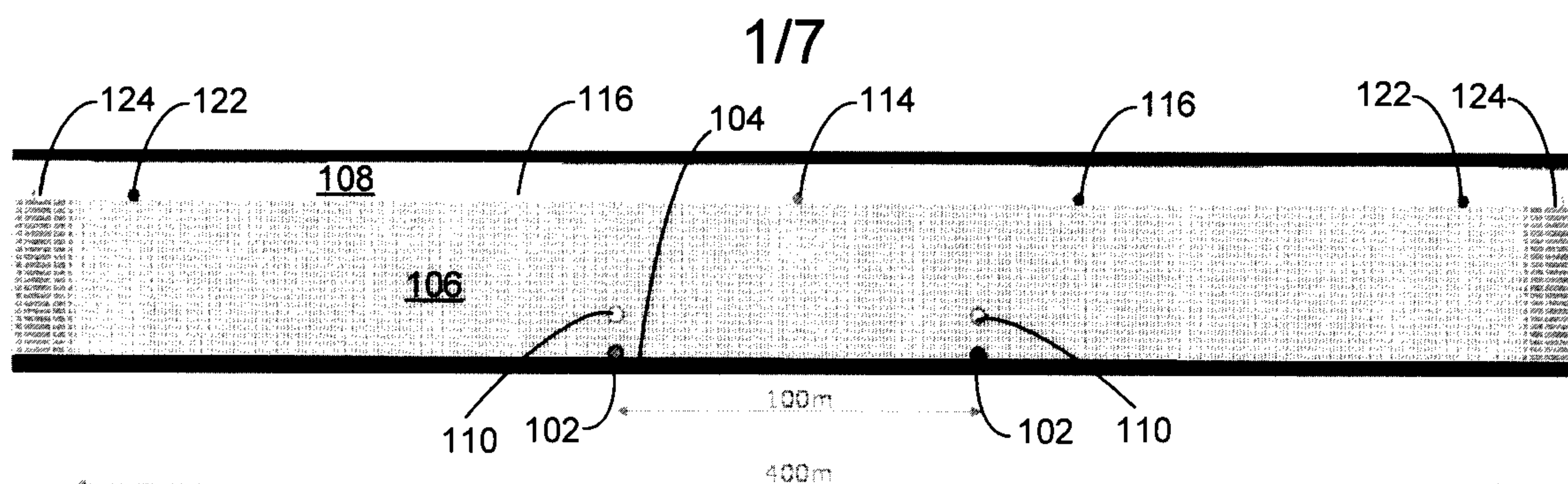


FIG. 1

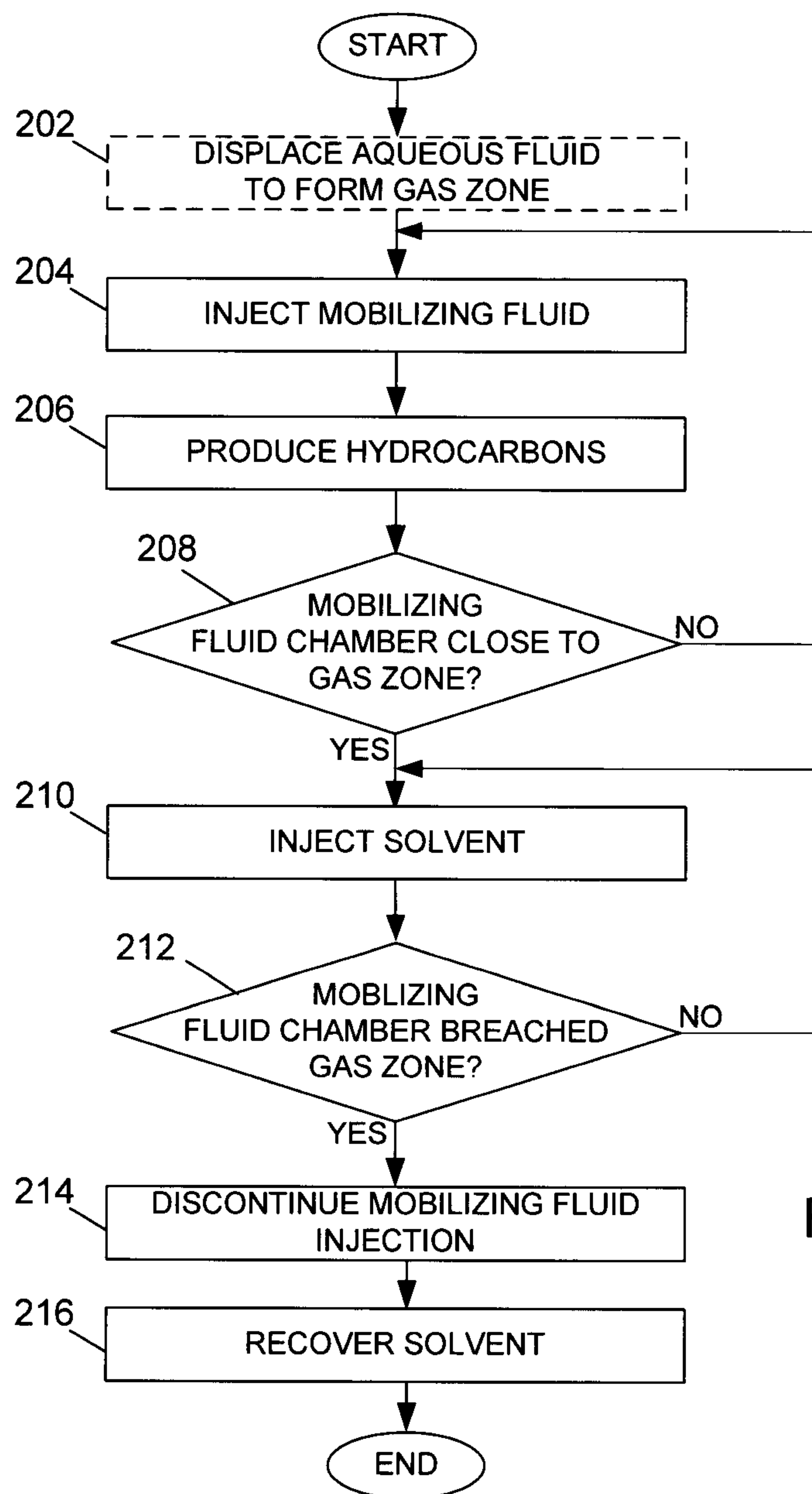


FIG. 2A

2/7

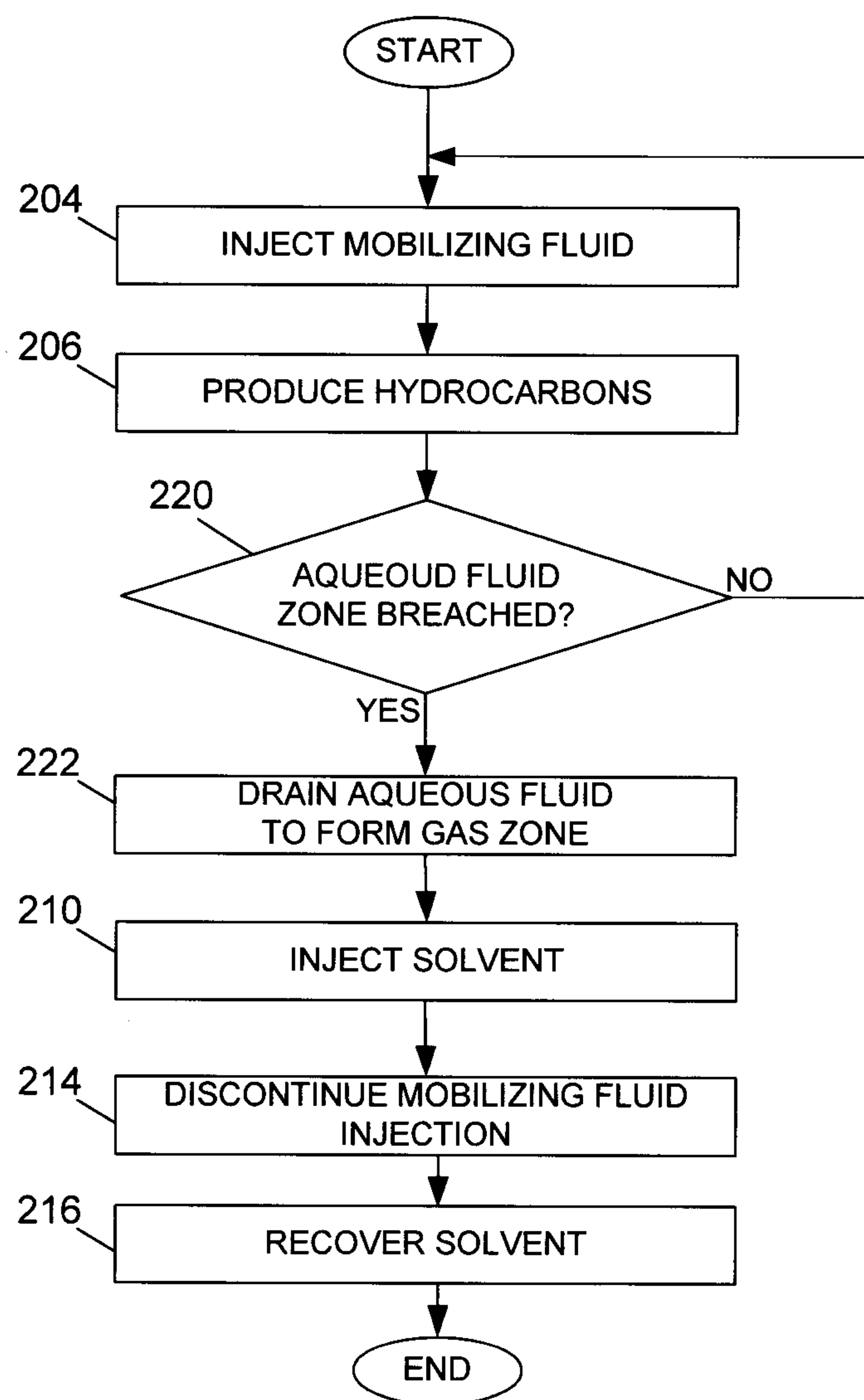


FIG. 2B

3/7

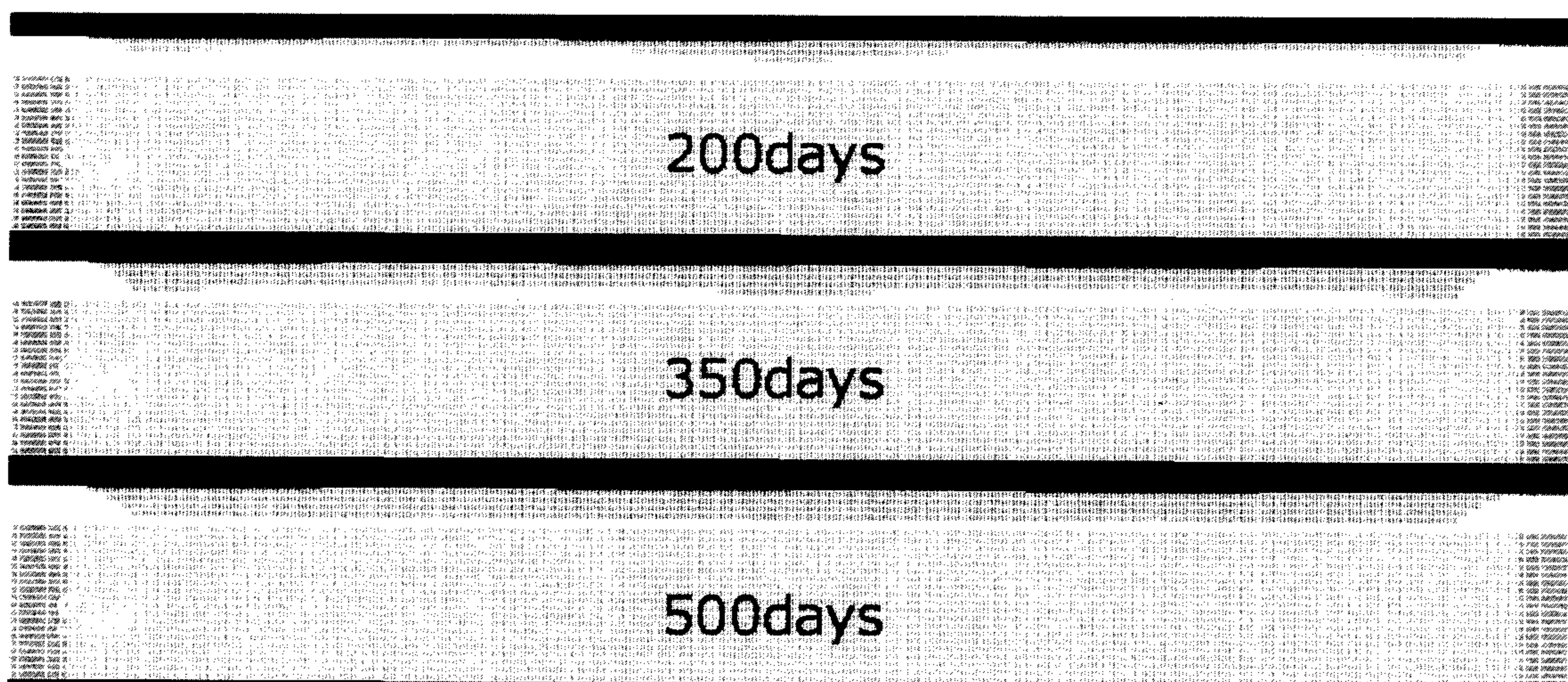


FIG. 3

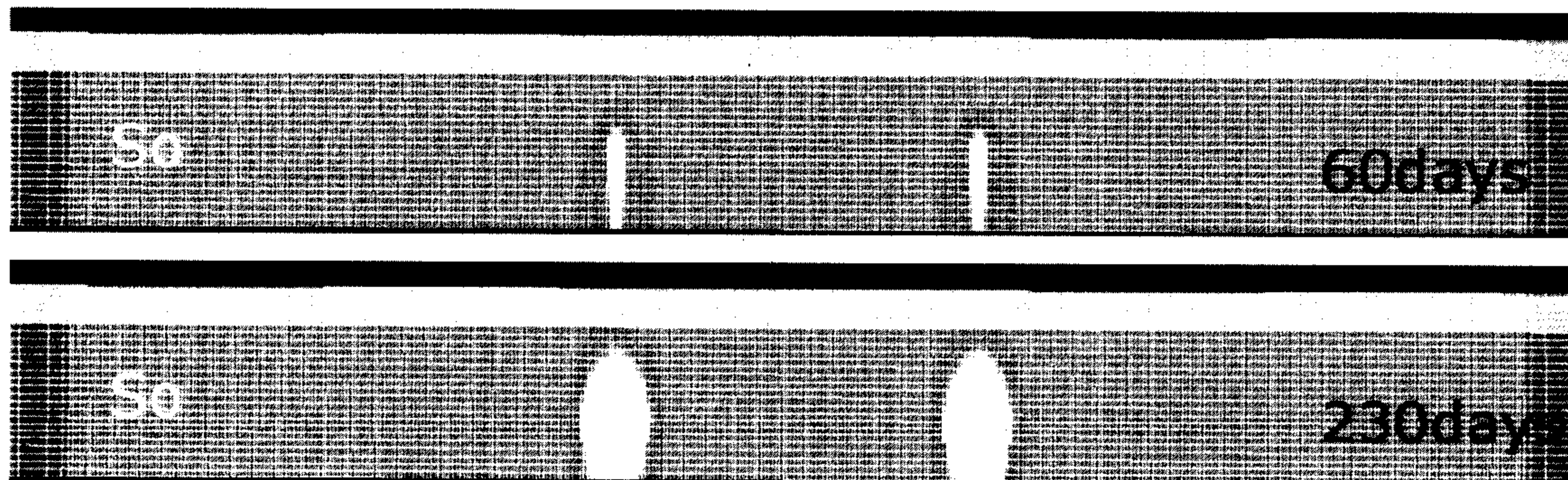


FIG. 4

4/7

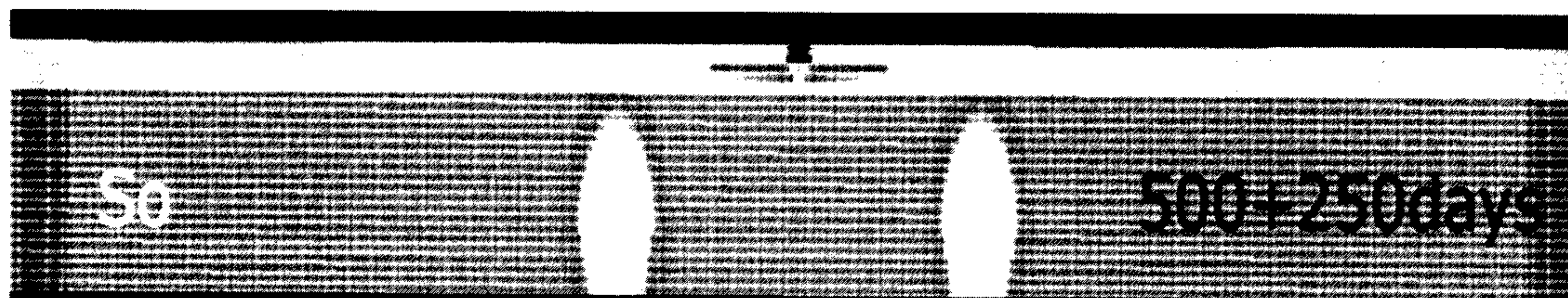


FIG. 5

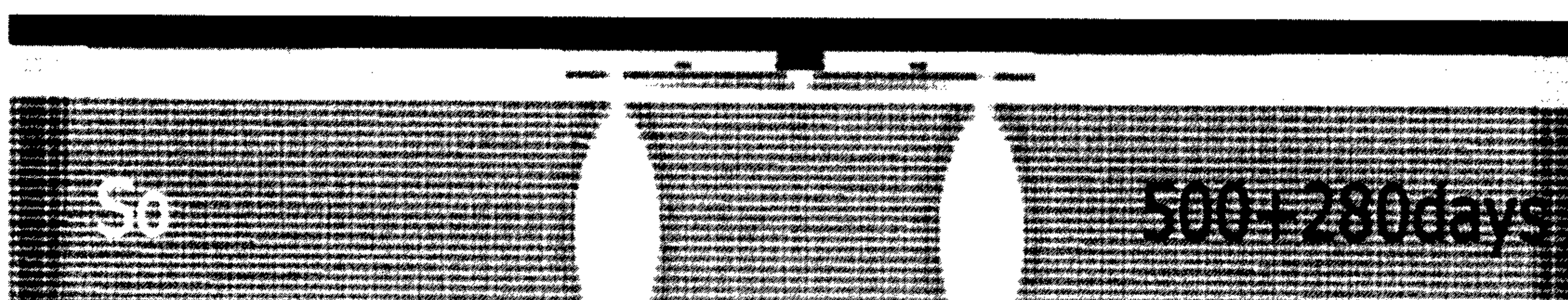


FIG. 6

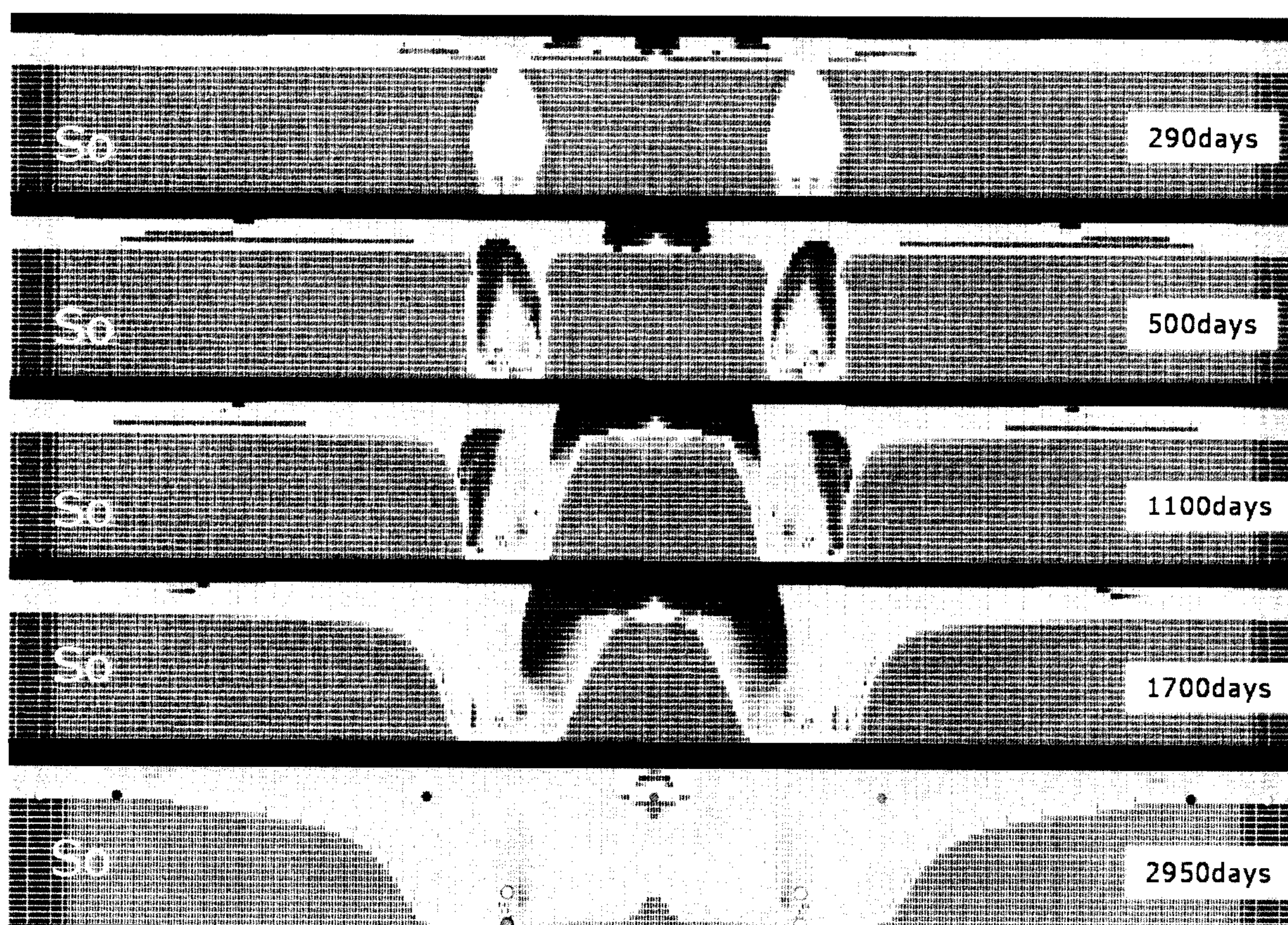


FIG. 7

5/7

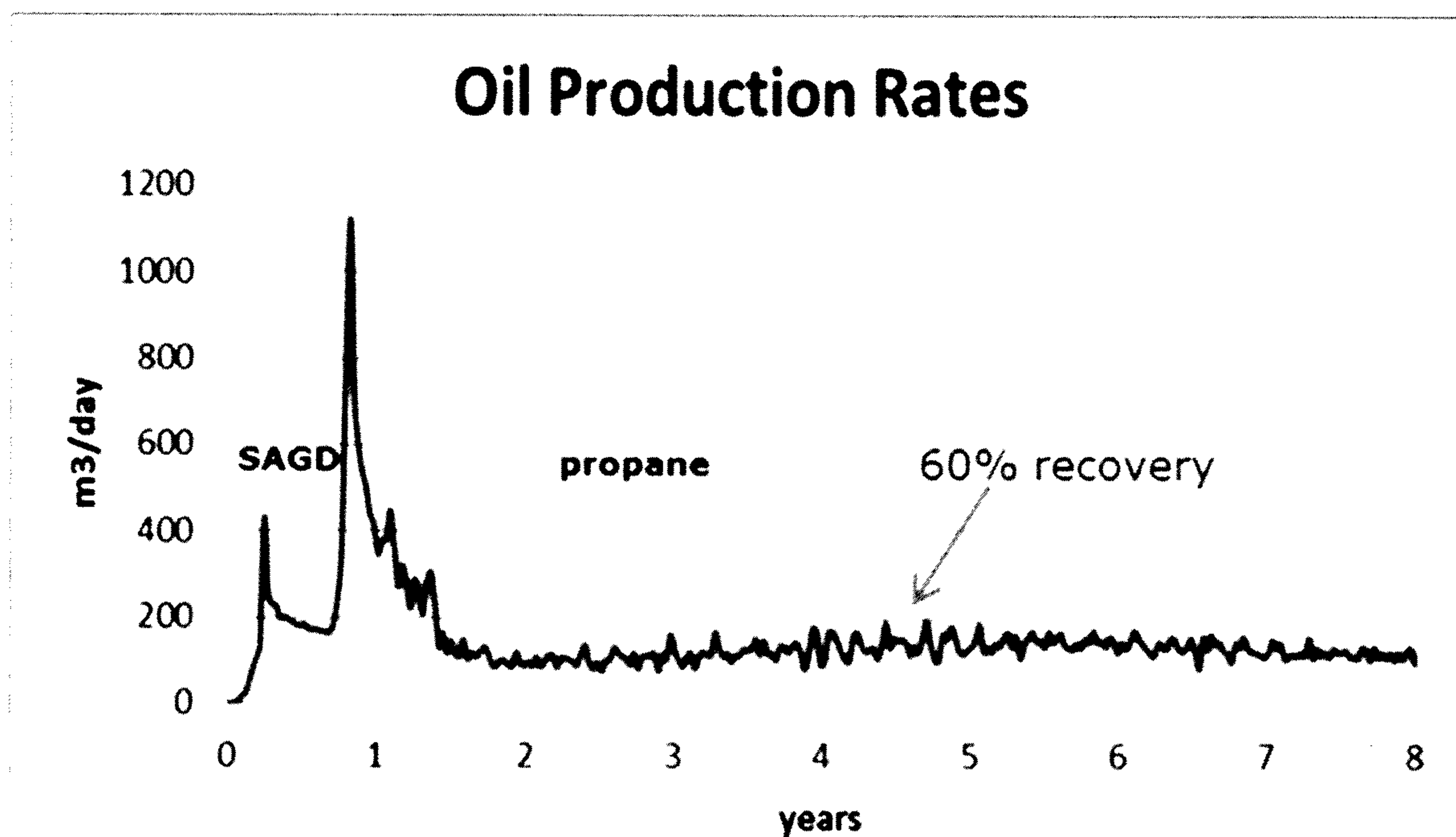


FIG. 8

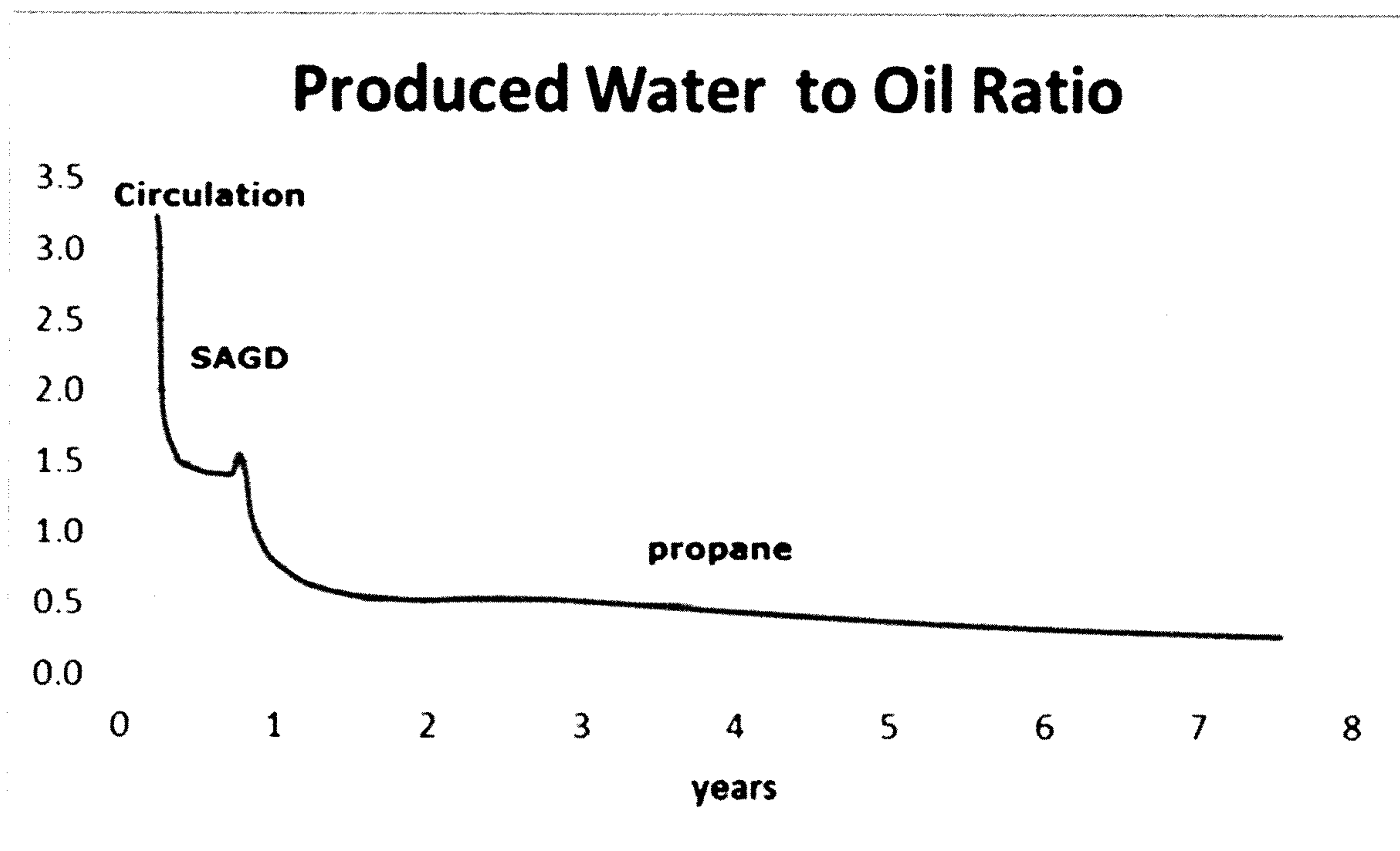


FIG. 9

6/7

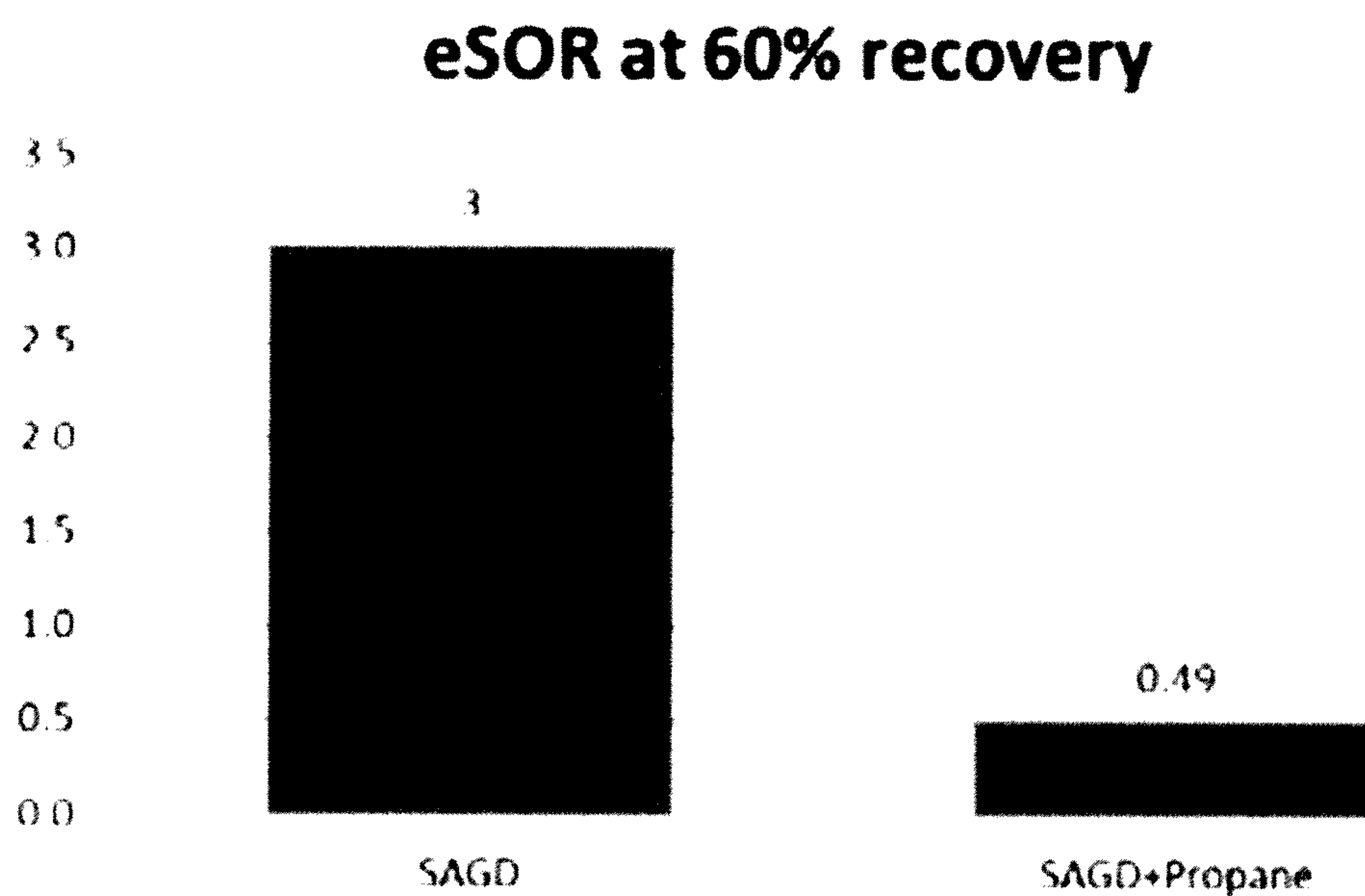


FIG. 10

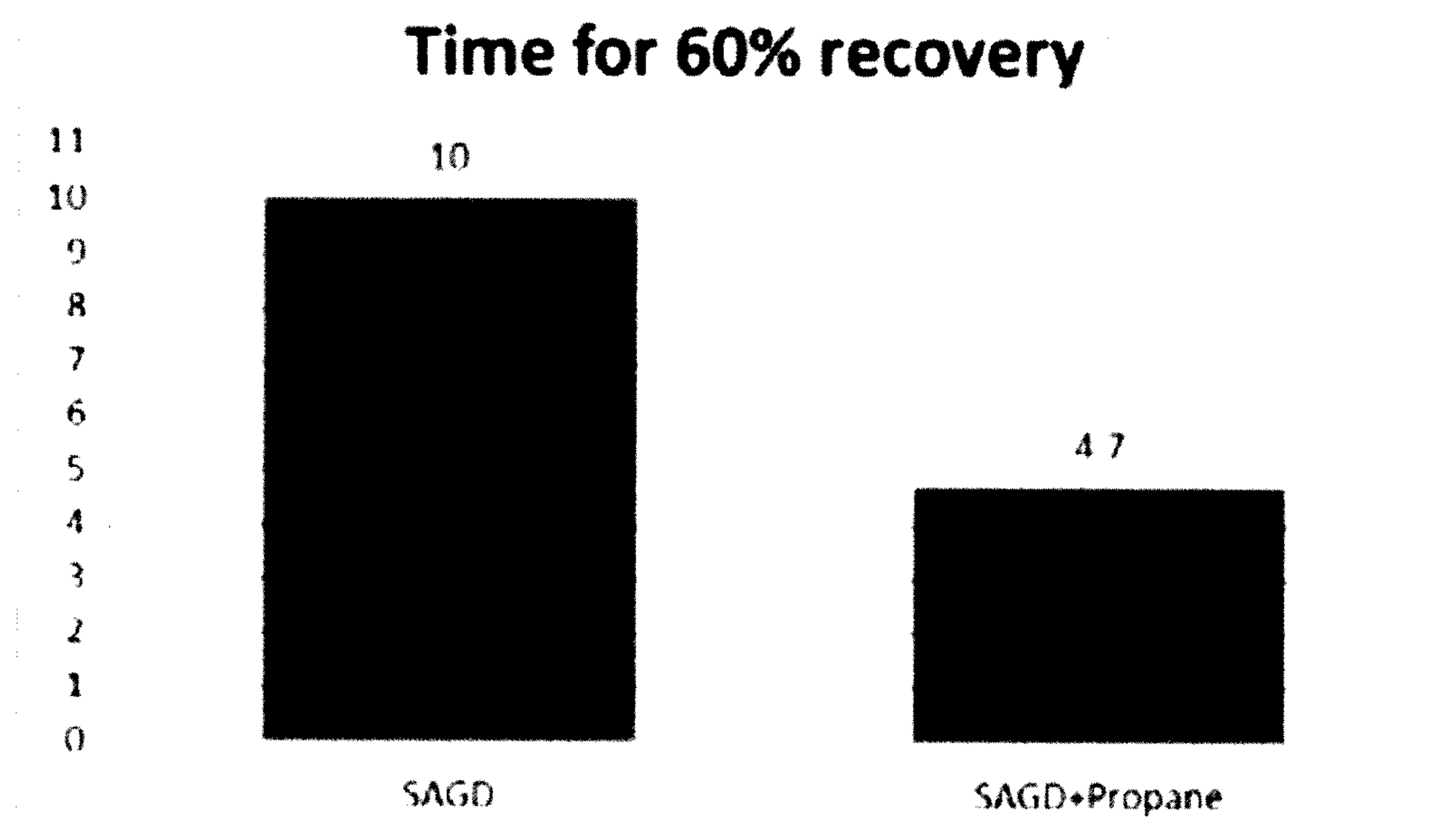


FIG. 11

7/7

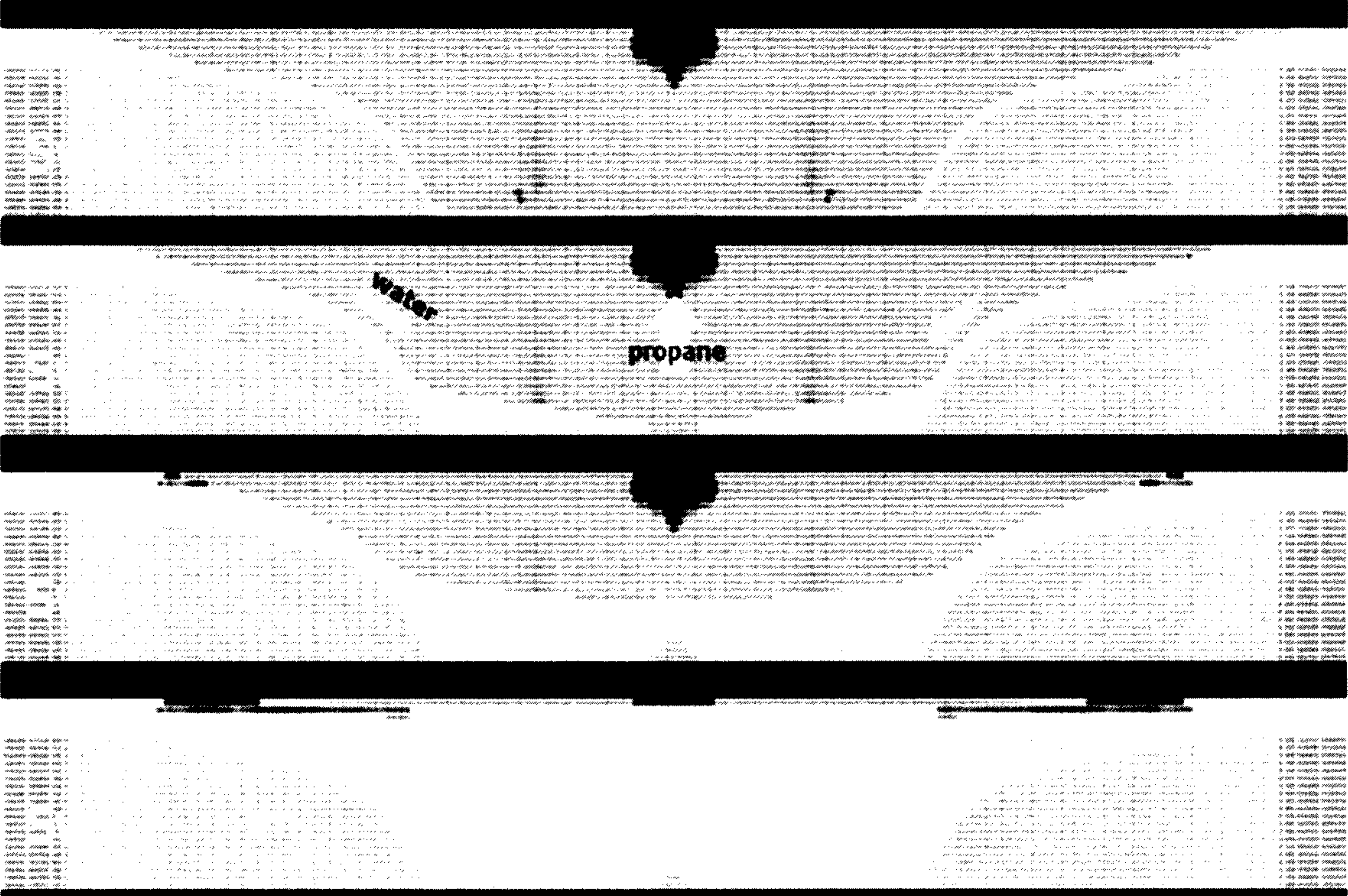


FIG. 12

