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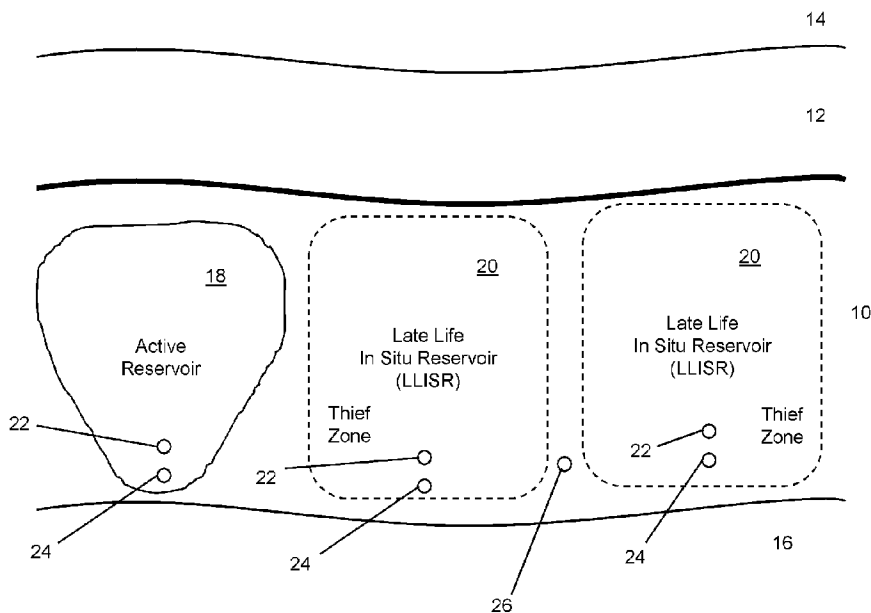
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(54) Titre : SYSTÈME ET MÉTHODE POUR ÉTABLIR DES BARRIÈRES EN SUBSURFACE

(54) Title: SYSTEM AND METHOD FOR ESTABLISHING SUBSURFACE BARRIERS



(57) **Abrégé/Abstract:**

A system and method are provided for creating subsurface barriers in a formation. The method includes injecting a waste stream and/or permeability reducing agent into at least one well to create a subsurface barrier in the formation by reducing permeability of at least a portion of the formation. A system and method are also provided for facilitating heavy oil production from a heavy oil reservoir. The method includes injecting a waste stream into a well in the heavy oil reservoir to plug wormholes or preferential paths created by a previously implemented primary extraction process to facilitate a secondary or tertiary extraction process in the heavy oil reservoir. A system and method are also provided for preparing a waste stream for injection to a formation to form a subsurface barrier. The method includes separating a source fraction into a fines fraction that is relatively smaller than a coarse fraction; and providing the fines fraction to injection equipment to inject the fines fraction into the formation.

## ABSTRACT

A system and method are provided for creating subsurface barriers in a formation. The method includes injecting a waste stream and/or permeability reducing agent into at least one well to create a subsurface barrier in the formation by reducing permeability of at least a portion of the formation. A system and method are also provided for facilitating heavy oil production from a heavy oil reservoir. The method includes injecting a waste stream into a well in the heavy oil reservoir to plug wormholes or preferential paths created by a previously implemented primary extraction process to facilitate a secondary or tertiary extraction process in the heavy oil reservoir. A system and method are also provided for preparing a waste stream for injection to a formation to form a subsurface barrier. The method includes separating a source fraction into a fines fraction that is relatively smaller than a coarse fraction; and providing the fines fraction to injection equipment to inject the fines fraction into the formation.

## SYSTEM AND METHOD FOR ESTABLISHING SUBSURFACE BARRIERS

### TECHNICAL FIELD

**[0001]** The following generally relates to establishing subsurface barriers, including by disposing of a waste stream such as waste water or mature fine tailings or a permeability reducing agent, for example to provide thief zone abatement.

### BACKGROUND

**[0002]** Oil sands are a natural mix of sand, clay, water, and bitumen. Bitumen is considerably viscous and does not flow like conventional crude oil. As such, bitumen is recovered from oil sands using either surface mining techniques or in situ techniques. In surface mining, overburden is removed to access the underlying bitumen reservoir, and the oil sands are transported to an extraction facility to separate the bitumen from the other components of the oil sands (i.e., tailings). For in situ techniques, the bitumen reservoir is heated and the bitumen within flows into one or more horizontal production wells, leaving the formation rock in the bitumen reservoir in place. In such techniques, the bitumen in the bitumen reservoir is often emulsified to enhance recovery. Both surface mining and in situ processes produce a bitumen product that is subsequently sent to an upgrading and/or refining facility, to be refined into one or more petroleum products.

**[0003]** Bitumen reservoirs that are too deep to feasibly permit bitumen recovery by mining techniques are typically accessed by drilling wellbores into the bitumen reservoir and implementing an in situ recovery technology. There are various in situ recovery technologies available that use thermal methods to liberate bitumen from the reservoir with heated fluids, e.g., steam, hydrocarbon solvent vapour, or steam and solvent in combination. In many conventional thermal in situ recovery techniques, the heated fluids can be injected into the reservoir. However, in newer techniques, e.g., electric resistive heating, EM radio frequency, and induction, reservoir fluids can be heated in situ. There are also various in situ recovery technologies available that use non-thermal methods, e.g., solvent injection.

**[0004]** Common in situ recovery techniques include Steam Assisted Gravity Drainage (SAGD) and Cyclic Steam Stimulation (CSS). In SAGD, a pair of horizontally oriented wells are drilled into the bitumen reservoir, such that the pair of horizontal wells are vertically aligned with respect to each other and separated by a relatively small distance, typically in the order of

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several meters. The well installed closer to the surface and above the other well is generally referred to as an injection well, and the well positioned below the injection well is referred to as a production well. The injection well and the production well are then connected to various subsurface equipment, such as electric submersible pumps (ESPs) and sensors, and to equipment installed at a surface site. The injection well facilitates steam injection into the reservoir. The injected steam propagates vertically and laterally into the reservoir to develop what is referred to as a steam chamber. Latent heat released by the injected steam mobilizes the bitumen by lowering its viscosity. The bitumen, in turn, drains due to gravity and is produced, along with condensed water, by the production well.

**[0005]** In CSS, a single, vertical or horizontal, production/injection well extending into a bitumen reservoir can be used for both steam injection and production. CSS typically involves three main phases, namely an injection phase, a shut in phase, and a production phase. During the injection phase, steam is injected through the production/injection well into the bitumen reservoir. Next, the bitumen reservoir is shut in to allow heat from the steam to reduce the viscosity of the bitumen in the reservoir. The bitumen of reduced viscosity can then be produced through the production/injection well, and the three phase cycle can be repeated.

**[0006]** Heavy oil more generally differs from light crude oil by having a higher viscosity and specific gravity, as well as a heavier molecular composition. In situ recovery techniques used in heavy oil reservoirs can include in situ cold flow recovery techniques such as Cold Heavy Oil Production with Sand (CHOPS). In CHOPS, heavy oil production is implemented through the deliberate initiation of sand influx into a perforated oil well, maintenance of sand influx during the productive life of the well, separation of the sand from the oil, and the disposal of the sand. CHOPS is typically implemented without sand exclusion devices (e.g., screens, liners, gravel packs, etc.) being used in wellbores, and no filters, cyclones, or high-pressure separators are used at the surface. As such, the sand is produced with the oil, water and gas, and separated from the oil by settling. CHOPS can be practiced in unconsolidated sand reservoirs containing viscous oil. These reservoirs are typically shallow. Production of sand results in formation of elongated, open or partially open channels emanating from the perforations in casing. These channels are commonly referred to as “wormholes” and can create communication channels between distant wellbores. High pressure gradients lead to sand liquefaction with advancement that penetrates into the reservoir to form enhanced permeability zones. Wormholes tend to grow

in preferred layers within the formation and wormhole networks can enable sand production to be continuous and substantial in volume.

**[0007]** The creation of such wormhole networks can be problematic. CHOPS wells are characterized by quick pressure depletion and decline in production rates. Despite demonstrating sustained low production rates for extended periods of time, CHOPS wells rarely recover more than 10–15% of the oil originally in place. Maximizing recovery factors from CHOPS fields requires implementing secondary and tertiary recovery techniques. However, wormhole networks can serve as short circuits between injection and production wells, resulting in fast breakthrough of injected water, polymer or steam and reducing the sweep efficiency and thermal efficiency. Wormhole networks result in fast dissipation of pressure and leak off of injected fluids, rendering application of cyclic solvent and cyclic steam methods ineffective. Essentially, wormholes represent a secondary porosity and permeability in the formation, not unlike a fracture network. However, the morphology of wormhole networks is a lot less predictable than fracture networks.

**[0008]** In bitumen reservoirs, a thief zone or a lean zone can occur as result of effects on fluid saturation, wherein a lower initial bitumen saturation leads to a higher gas or water saturation, which leads to higher relative permeability to steam. Thief zones may be a naturally occurring region of the reservoir, such as layers and fractures associated with a geological process. Other examples can include high water-saturated zones, high gas-saturated zones, regional pressure trends that promote flow in undesirable directions (i.e., towards a receptor), etc. However, thief zones can also be manmade, for example, a depleted or otherwise late life reservoir from which bitumen or heavy oil has been extracted.

**[0009]** The presence of thief zones can introduce certain challenges to hydrocarbon extraction. For example, thief zones can increase the risk of a production well in an active reservoir or reservoir zone producing large volumes of water, if such thief zones connect the production well to an aquifer. Thief zones are also known to be detrimental to the sweep efficiency. When a fluid is injected into the reservoir from an injection well to mobilize bitumen or heavy oil it is instead partially or wholly consumed by the thief zone. Thief/lean zones can also provide a more direct connection, creating a short-circuit between production and injection wells of a depleted or late life reservoir. In these aspects, wormholes can be likened to thief zones.

## SUMMARY

**[0010]** Systems and methods are described herein that can be used to create subsurface barriers by injecting waste streams such as fine tailings or waste water streams into a formation, for example, using existing and/or newly drilled wells in hydrocarbon-bearing reservoirs, including late life, unused or previously unexploited reservoirs (e.g., prior to production). In this way, one can both dispose of the waste streams and create preferential subsurface barriers to cordon off portions of the formation, such as a hydrocarbon-bearing reservoir, and abate thief zones to improve the sweep efficiency of adjacent and active reservoirs. The subsurface barriers can also be used for other purposes, such as in implementing water shut off in conventional wells, plugging high permeability zones such as in salt caverns, and for various flow mitigation purposes subsurface. Systems and methods are also described herein that use the injection of such waste streams to plug portions of wormhole networks created during a primary extraction process such as CHOPS to facilitate the implementation of a secondary extraction process. Also described herein is a process to separate such waste streams at a fine particle size of problematic tailings streams, to produce a fine tailings stream or fines fraction and a coarse fraction for terrestrial deposition.

**[0011]** In one aspect, there is provided a method of creating subsurface barriers in a formation, the method comprising: injecting a waste stream and/or permeability reducing agent into at least one well to create a subsurface barrier in the formation by reducing permeability of at least a portion of the formation.

**[0012]** In an implementation, the method further includes drilling one or more of the at least one well. At least one additional well can be drilled adjacent to a first well, and wherein injecting the waste stream and/or permeability reducing agent can include injecting the waste stream into the first well and injecting the waste stream into the at least one additional well to create the subsurface barrier in the formation.

**[0013]** In an implementation, one or more of the at least one well can be an existing well that has been used in a hydrocarbon production process in the formation.

**[0014]** In an implementation, one or more of the at least one well can be a new well drilled into the formation.

**[0015]** In an implementation, the at least one additional well can be drilled from the first well.

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**[0016]** In an implementation, the at least one additional well can be drilled adjacent to the first well after completing injection of the waste stream into the first well. The method can further include setting a bridge plug after completing injection of the waste stream into the first well. The waste stream can be injected in to the first well until at least one injection criterion has been met. The at least one injection criterion can include detecting a loss of injectivity of the waste stream. The at least one injection criterion can include establishing a target area for the barrier.

**[0017]** In an implementation, a plurality of additional wells can be drilled sequentially at a distance from the first well or a previously drilled additional well after injecting the waste stream into the first well or the previously drilled well. The method can further include setting a bridge plug after completing injection of the waste stream into the first well or previously drilled additional well.

**[0018]** In an implementation, the at least one additional well can be drilled from a build section of the first well.

**[0019]** In an implementation, the waste stream comprises fine tailings. The fine tailings can include mature fine tailings. The fine tailings can include thin fluid tailings. The method can further include selecting fine tailings that swell in the presence of fresh water downhole. The fine tailings in the presence of the water downhole can form clay and/or scale at high temperature and subsequently swells. The water and/or fine tailings can be treated by adding new chemicals or minerals or by increasing a concentration of existing chemicals and/or minerals to trigger a desired plugging reaction in the formation. The fine tailings in the presence of the water downhole can form smectite.

**[0020]** In an implementation, the waste stream can include a disposal water stream which reduces the permeability of the formation by forming subsurface clays and/or scales as a result of reactions between the injected disposal water stream and formation water and/or formation rock.

**[0021]** In an implementation, the subsurface barrier can be created in or adjacent to a hydrocarbon-producing reservoir. The hydrocarbon-producing reservoir can be a thermally depleted reservoir. The hydrocarbon-producing reservoir can be a non-thermally depleted reservoir. The subsurface barrier can be created in a late life in situ reservoir (LLISR). The LLISR can be located in a bitumen reservoir.

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**[0022]** In an implementation, the formation can be located adjacent an active reservoir, the subsurface barrier creating a preferential barrier to abate a thief zone. The thief zone can include any one or more of a bottom water zone, a lean zone or a gas zone.

**[0023]** In an implementation, the subsurface barrier can be created in or adjacent to a heavy oil reservoir. The heavy oil reservoir can have been subjected to an in situ cold flow recovery technique with sand as a primary extraction process. The waste stream can be injected prior to initiating at least one additional extraction process. The primary extraction process can include cold heavy oil production with sand (CHOPS). The waste stream can be injected to plug at least one wormhole created by implementing the CHOPS process. The waste stream can be injected to plug at least one portion of a wormhole network created by implementing the CHOPS process. The waste stream can be injected to plug at least one wormhole network created by implementing the CHOPS process.

**[0024]** In an implementation, the method can further include isolating a first interval of a CHOPS well; and injecting the waste stream via the first isolated interval to plug wormholes intersecting with the isolated interval.

**[0025]** In an implementation, the method can further include isolating at least one second interval; and injecting the waste stream via the at least one second isolated interval to plug wormholes intersecting with the at least one second isolated interval.

**[0026]** In an implementation, the subsurface barrier can be formed to counteract flow towards a receptor due to a pressure gradient subsurface. The subsurface barrier can be formed to mitigate contaminated groundwater flow to limit spread of contaminants towards the receptor.

**[0027]** In an implementation, the subsurface barrier can be formed in or adjacent to a salt cavern to mitigate losses to the salt cavern.

**[0028]** In an implementation, the subsurface barrier can be formed in or adjacent to a conventional oil reservoir to implement bottom water shut off.

**[0029]** In an implementation, the subsurface barrier can be formed prior to implementing a hydrocarbon recovery process in the formation.

**[0030]** In an implementation, the method can further include preparing the waste stream for injection into the formation by: separating a source fraction into a fines fraction that is relatively smaller than a coarse fraction; and providing the fines fraction to injection equipment to inject the fines fraction into the formation.

**[0031]** In an implementation, the method can further include repeating the method to form a plurality of subsurface barriers.

**[0032]** In an implementation, a plurality of first additional wells can be drilled into the formation to form a first barrier and at least one plurality of second additional wells are drilled into the formation to form at least one second barrier. The first barrier can be formed from wells drilled in alignment with a first originating well and the at least one second barrier is formed from wells drilled in alignment with at least one second originating well.

**[0033]** In an implementation, the wells are substantially horizontal wells.

**[0034]** In an implementation, the wells are substantially vertical wells.

**[0035]** In an implementation, the wells can include at least one substantially horizontal well and at least one substantially vertical well.

**[0036]** In another aspect, there is provided a method of facilitating heavy oil production from a heavy oil reservoir, comprising: injecting a waste stream into a well in the heavy oil reservoir to plug wormholes or preferential paths created by a previously implemented primary extraction process to facilitate a secondary or tertiary extraction process in the heavy oil reservoir.

**[0037]** In an implementation, the method can include implementing the secondary or tertiary extraction process. The primary extraction process can include an in situ cold flow process with sand that has created wormholes. The primary extraction process can include cold heavy oil production with sand (CHOPS). The primary extraction process can include one that does not include sand production but creates preferential flow paths.

**[0038]** In another aspect, there is provided a method of preparing a waste stream for injection to a formation to form a subsurface barrier, the method comprising: separating a source fraction into a fines fraction that is relatively smaller than a coarse fraction; and providing the fines fraction to injection equipment to inject the fines fraction into the formation.

**[0039]** In an implementation, the source fraction can be separated using a fine particle separator. The fine particle separator can include a fine diameter cyclone. The fine particle separator can include a centrifuge.

**[0040]** In another aspect, there is provided a system for creating subsurface barriers in a formation, the system comprising: injection equipment configured to inject a waste stream and/or permeability reducing agent into at least one well to create a subsurface barrier in the formation by reducing permeability of at least a portion of the formation.

**[0041]** In another aspect, there is provided a system for facilitating heavy oil production from a heavy oil reservoir, comprising: injection equipment configured to inject a waste stream into a well in the heavy oil reservoir to plug wormholes or preferential paths created by a previously implemented primary extraction process to facilitate a secondary or tertiary extraction process in the heavy oil reservoir.

**[0042]** In another aspect, there is provided a system for preparing a waste stream for injection to a formation to form a subsurface barrier, the system comprising: a separator configured to separate a source fraction into a fines fraction that is relatively smaller than a coarse fraction; wherein the fines fraction is provided to injection equipment to inject the fines fraction into the formation.

#### BRIEF DESCRIPTION OF THE DRAWINGS

**[0043]** Embodiments will now be described with reference to the appended drawings wherein:

**[0044]** FIG. 1 is a schematic cross-sectional end view of a series of reservoirs in a bitumen reservoir.

**[0045]** FIG. 2a is a schematic cross-sectional end view of the reservoirs shown in FIG. 1 with a subsurface barrier created in a late life in situ reservoir (LLISR) adjacent an active reservoir.

**[0046]** FIG. 2b is a schematic cross-sectional end view of the reservoirs shown in FIG. 1 with a pair of subsurface barriers created in a pair of late life in situ reservoirs (LLISRs) adjacent the active reservoir.

**[0047]** FIGS. 3a-3d are schematic cross-sectional side views of a LLISR in a bitumen reservoir that has been injected with fine tailings to create a subsurface barrier using an original substantially horizontal well or well pair and a series of substantially horizontal lateral wells drilled from the original well or well pair.

**[0048]** FIG. 4 is a cross-sectional end view of an original well pair and a series of well pair laterals drilled above the original well pair in creating a subsurface barrier.

**[0049]** FIG. 5 is a schematic cross-sectional side view of an LLISR in a bitumen reservoir that has been injected with fine tailings to create a subsurface barrier using an original substantially vertical well and a series of additional substantially vertical wells drilled from the original vertical well.

**[0050]** FIG. 6 is a schematic cross-sectional side view of an LLISR in a bitumen reservoir that has been injected with fine tailings to create a subsurface barrier using an original substantially vertical well and a series of substantially horizontal lateral wells drilled from the original vertical well.

**[0051]** FIG. 7 is a schematic perspective view of a series of LLISRs in a bitumen reservoir that have been injected with fine tailings to create a set of subsurface barriers using one or more original substantially vertical wells and a series of substantially horizontal lateral wells drilled from each of the original vertical wells.

**[0052]** FIG. 8 is a flowchart illustrating operations performed in creating a subsurface barrier by injecting an original well or well pair with fine tailings and subsequent lateral or additional wells drilled from the original well or well pair.

**[0053]** FIG. 9a is a schematic diagram of a wormhole network adjacent a well having perforation intervals, with a first perforation interval being used to inject fine tailings into wormholes connected thereto.

**[0054]** FIG. 9b is a schematic diagram of the wormhole network and well shown in FIG. 9a, with a second perforation interval being used to inject fine tailings into wormholes connected thereto.

**[0055]** FIG. 10 is a block diagram of a fine particle size separation process.

**[0056]** FIG. 11a is a schematic cross-sectional view of a heel of a well in which a water migration barrier has been established.

**[0057]** FIG. 11b is a schematic cross-sectional view of a toe of a well in which a water migration barrier has been established.

#### DETAILED DESCRIPTION

**[0058]** Processes are described herein to inject waste streams such as fine tailings into existing and/or newly drilled wells in late life, unused or unexploited reservoirs to both dispose of the waste streams and create preferential subsurface barriers to cordon off such late life, unused or previously unexploited reservoirs and abate thief zones to improve the sweep efficiency of adjacent and active reservoirs. It can be appreciated that the principles described herein can also be applied using a permeability reducing agent with or instead of a waste stream.

**[0059]** Processes are also described herein that use the injection of such waste streams to plug portions of wormhole networks created during a primary extraction process such as CHOPS to facilitate the implementation of a secondary extraction process. For example, perforated intervals of a well can be selectively isolated to inject such waste streams into adjacent areas of the formation and wormhole networks that intersect or are otherwise near the isolated perforated interval.

**[0060]** Also described herein is a process to separate such waste streams at a fine particle size of problematic tailings streams, to produce a fine tailings stream or fines fraction and a coarse fraction for terrestrial deposition.

**[0061]** Turning now to the figures, FIG. 1 illustrates an example of a SAGD production site at a bitumen reserve or reservoir, referred to herein as the “pay” 10. In this example, a series of SAGD well pairs 22, 24 are drilled from a surface location 14 towards the pay 10 and each well pair 22, 24 is associated with a reservoir, which can be considered a portion, area, region or zone of the pay 10. In the illustrated example, the well pairs 22, 24 include an injection well 22 positioned above a production well 24. As will be appreciated, the injector well 22 is configured to inject steam into the pay 10 and the producer well 24 is configured to recover a bitumen-containing fluid that has been mobilized by the injected steam during the typical SAGD production stage. The injector well 22 is typically located about 4 to 6 meters above the

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producer well 24 to define an inter-well region therebetween, however, other relative distances between the wells are possible. The SAGD well-pairs 22, 24 are drilled vertically into an overburden 12 towards and into the underlying pay 10, and as they are drilled become oriented substantially horizontal, such that the producer well 24 is above but near a formation 16 underlying the pay 10 (hereinafter the “underlying formation 16”). The one or more SAGD well pairs 22, 24 are operated using a surface equipment (not shown) as is known in the art.

**[0062]** In the example shown in FIG. 1, an active reservoir 18 is shown adjacent to two late life in situ reservoirs (LLISRs) 20. It will be understood that the term LLISR 20 as used herein can mean any hydrocarbon bearing reservoir having a hydrocarbon depleted zone therein formed from an in situ recovery process. It can be appreciated that “late life” as used herein can mean pressure-depleted, but still with high oil saturation (e.g., post CHOPS). Heavy oil reservoirs can have top gas or bottom water zones with wormholes connecting these thief zones to the production wells. Late life can therefore also mean watered-out wells in that context. Other types of reservoirs applicable to the principles discussed herein can include cold heavy oil reservoirs without sand production having preferential flow paths. For example, horizontal wells in heavy oil may not produce sand or apply CHOPS if completed with sand controls in place, but such wells often result in depleting the reservoir unevenly along the length of a well. As such, subsequent water flooding or other secondary or tertiary recovery techniques that rely on any form of displacement can suffer from poor sweep efficiency and would benefit from plugging the preferential flow paths using the injection techniques described herein. Additionally, the principles discussed herein can be applied to creating subsurface barriers in any formation for a variety of purposes, including green field development for thief zone mitigation prior to hydrocarbon production in a reservoir, water shut off in conventional reservoirs, and to plug high permeability formations such as salt caverns, which can be a cause of lost circulation during drilling operations. The subsurface barriers can also be used in groundwater locations to mitigate contaminated groundwater flow towards receptors.

**[0063]** When it is stated that a fluid is stored in, injected into, or produced from an LLISR 20, it will be understood that such fluid is stored in, injected into, or produced from the hydrocarbon depleted pay zone (i.e., storage volume) in the LLISR 20. It can be appreciated that the LLISR 20 can be situated adjacent, between or otherwise positioned relative to one or more active in situ sites, such as wells positioned in pay regions that are at an earlier stage – for

example active reservoir 18 shown in FIG. 1. The LLISR 20 can be positioned adjacent to site(s) actively injecting steam, solvent, or steam plus solvent, and/or producing a hydrocarbon from the site(s).

**[0064]** The active reservoir 18 includes a first well pair 22, 24 that in this example depicts the implementation of a SAGD production process. The LLISRs 20 similarly include well pairs 22, 24 that in this example depict prior application of a SAGD production process. However, it will be appreciated that either or both the active reservoir 18 and LLISR(s) 20 can be currently implementing or have implemented other hydrocarbon recovery processes such as CSS, expanding solvent SAGD (ES-SAGD), steam flood, in situ combustion, electromagnetically assisted solvent extraction (EASE), thermal solvent recovery, electrical, electromagnetic, radio frequency, etc.

**[0065]** While FIG. 1 illustrates a pair of LLISRs 20 adjacent one active reservoir 18 this is for illustrative purposes. For example, another active reservoir 18 or yet another LLISR 20 can be adjacent the rightmost LLISR 20. Either or both of the LLISRs in this example can be or become thief zones relative to the active reservoir 18 due to their relatively higher permeability. As discussed above, such thief zones can reduce the sweep efficiency of the active reservoir 18, including attempts to target the inter-well pair regions by way of infill or step-out wells (not shown) or otherwise having a production chamber migrate towards unswept regions.

**[0066]** It can be appreciated that while the example shown in FIG. 1 includes an active reservoir 18 and LLISR reservoirs 20 associated with bitumen recovery using a SAGD production process, the principles discussed herein equally apply to other in situ bitumen recovery techniques such as CSS, as well as to any unused or previously unexploited reservoir, including heavy oil reservoirs such as those implementing or having implemented in situ cold flow techniques (e.g., CHOPS).

**[0067]** To abate or otherwise inhibit or control the impact of thief zones created by LLISRs 20 being adjacent active reservoirs 18 as shown in FIG. 1, fine tailings such as mature fine tailings (MFTs) or thin fluid tailings (TFTs) can be injected into the LLISR(s) 20 to create a subsurface barrier 30 as shown in FIG. 2a. The barrier 30 in this example is formed by first injecting such fine tailings into the original well pair 22, 24 and drilling additional lateral wells 34 at locations spaced from the original well pair 22, 24 and continuing to inject additional fine

tailings sequentially. In the example shown in FIG. 2a, the barrier 30 can be created between the active reservoir 18 and what could have been a thief zone in the central region that was an LLISR 20 and in the LLISR 20 located on the other side of the barrier 30. The barriers 30 can be created by plugging pores in the reservoir 18, 20 with particles suspended in the injected material (e.g., waste streams such as slurries, MFTs, TFTs, etc.)

**[0068]** While the examples described herein are provided making reference to fine tailings as mentioned above, the principles described herein can be equally applied to other streams for (separation and/or) disposal in LLISRs 20, such as other waste streams from extraction, upgrading, refinery or other wastes resulting from the upstream or downstream production of hydrocarbons. This could include streams such as slurried coke fines, precipitates, dusts, and other fine particle streams.

**[0069]** Referring to FIG. 2b, it can be appreciated that the fine tailings can also be injected into the remaining LLISR 20 to create a further barrier 30 (or a larger barrier). Similarly, additional wells such as an infill well 26 can be used to inject additional fine tailings between the barriers 30. Additional wells (not shown) can also be drilled above the infill well 26 to create an intermediate barrier 30. By injecting the fine tailings such as MFTs or TFTs into the LLISRs 20 (and/or inter-reservoir regions), not only can preferential barriers 30 be created to provide thief zone abatement or to otherwise cordon off depleted portions of the pay 10, but such fine tailings can be disposed of in the storage volume of the LLISR 20.

**[0070]** Since the radius of invasion of the fine tailings is expected to be limited and/or variable, the preferential barrier 30 created by injecting such tailings can be created by utilizing existing wells or creating new wells as a starting point and drilling multiple lateral or otherwise additional wells adjacent or near the existing or newly created well(s). That is, lateral or additional wells can be drilled from originating wells (e.g., SAGD producer, injector, or infill/step-out wells) in any pattern deemed sufficient to create a desired barrier. This can include additional wells that are vertically or laterally offset in any direction from the original wells as explained in greater detail below. In this way, the barrier 30 can be created to achieve a desired fine tailings saturation vertically and aurally throughout the target region of the LLISR 20. The creation of additional or more extensive barriers 30 also provides the added advantage of disposing of a greater amount of the tailings, which can avoid the need to apply additional processing and disposal processes. It can be appreciated that a set of originating wells,

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including a partial set (e.g., a first half followed by a second half) or a complete set of all wells used to create the barrier(s) 30 can also be drilled prior to injecting the waste stream(s).

**[0071]** Referring now to FIGS. 3a-3d an example of a process for sequentially creating a subsurface barrier 30 is shown, beginning with one or more originating (e.g., new or existing well(s)), in this example an existing SAGD well pair 22, 24. As illustrated in FIG. 3a, fine tailings such as MFTs can be injected into the existing well pair 22, 24 until an injection criterion is met, such as when reaching a point when all injectivity is lost. At this point, the base of the barrier 30 has been created in which the fine tailings that have been injected have filled the wells 22, 24 and invaded the surrounding formation of the LLISR 20 to a particular radius. A bridge plug 32 can then be set in the build section at the end of the injected volume. It can be appreciated that as the barriers 30 are created by filling the LLISR 20, fluids that are present in the injected stream can migrate to neighbouring wells. Such fluids can be produced back to surface 14, using existing wells or additional wells if necessary, while the reservoir effectively filters the fluids by holding onto the fines/solids in the fluids to create the barrier 30.

**[0072]** A first additional lateral well 34a can then be drilled from a point along the build section of one or more of the wells 22, 24 as shown in FIG. 3b. For ease of illustration, numeral 34a in FIG. 3 can represent a single additional lateral well drilled from one of the injection well 22 and the production well 24 or a pair of additional lateral wells drilled from same. Furthermore, numeral 34a can also represent any other number of first additional laterals wells that are drilled from either or both the injection well 22 and the production well 24. For example, a series of first additional lateral wells 34a can be drilled such that each is vertically offset from the well pair 22, 24 and horizontally offset from each other to widen the barrier 30. The first additional later well(s) 34a are then injected with fine tailings until an injection criterion is met, in the same way as with the original well pair 22, 24.

**[0073]** As with the original well pair 22, 24, a bridge plug 32 can be set in the first lateral well(s) 34a and a second lateral well 34b can be drilled vertically (and possibly horizontally) offset from the first later well 34b as shown in FIG. 3c. It can be appreciated that the second lateral well 34b shown in FIG. 3c can also represent any one or more additional wells that are drilled from the build section and are vertically offset from the first additional later well(s) 34a. Again, fine tailings can be injected in the second additional lateral well(s) 34b until an injection criterion is met at which point a bridge plug 32 can be set and the process repeated. When

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comparing FIG. 3a to FIG. 3b and then to FIG. 3c, it can be seen that the barrier 30 continues to expand vertically towards the top of the pay region in the LLISR 20. FIG. 3d illustrates a third additional lateral well 34c that expands the barrier 30 to the top of the pay region. A bridge plug 32 can be set after injectivity is lost or any other injection criterion is met, such as reaching a target zone area, in this example reaching the top of the pay.

**[0074]** As noted above, while FIGS. 3a-3c illustrate a sequential creation of the subsurface barrier 30, the injection of the fine tailings (or other waste streams) can also be done after having drilled multiple ones of the wells 22, 24, include after a set of wells 22, 24 or after all wells 22, 24 used to create the subsurface barrier 30 have been drilled. Moreover, as also noted above, the originating wells 22, 24 (e.g., as shown in FIG. 3a) can be newly drilled or existing wells 22, 24.

**[0075]** FIG. 4 illustrates an end view of a barrier 30 created by drilling pairs of additional laterals 34a1, 34a2, 34b1, 34b2, 34c1, 34c2 from an originating injection well 22 that is both horizontally and vertically offset from an originating production well 24 to illustrate that any desired pattern of additional lateral wells 34 can be used to adapt the height and width of the barrier 30 to a desired target zone area. In this way, barriers 30 can be created while disposing of fine tailings between later life or unused and early stage reservoirs to section off areas of the reservoir and cordon off the late stage or unused reservoirs that would otherwise act as thief zones as noted above.

**[0076]** FIG. 5 illustrates another well pattern for creating a barrier 30. In this example, an existing, new or otherwise originating vertical well 40 is first injected with fine tailings as with the configurations described above, and multiple additional vertical wells 42a, 42b, and 42c are successively drilled from the build section of the originating vertical well 40 to be offset from the originating vertical well 40 or previously drilled additional vertical well 42 to achieve the desired target area for the barrier 30.

**[0077]** FIG. 6 illustrates yet another well pattern for creating a barrier 30a, 30b that also begins with an originating vertical well 40. In this example, after injecting fine tailings into the originating vertical well 40 to create a first barrier 30a, multiple lateral wells 34a, 34b, 34c, 34d are drilled from the build section of the originating vertical well 40 to create a second barrier 30b in the way shown in FIGS. 3a-3d described above.

**[0078]** Referring now to FIG. 7, a perspective view is shown in which multiple first barriers 30a1, 30a2, 30a3 are created from a set of originating vertical wells 40 (e.g., new or existing). After injecting fine tailings into these originating vertical wells, multiple lateral wells 34 are used in this example to create multiple second barriers 30b1, 30b2, 30b3. From this schematic view it can be appreciated that any combination of vertical and lateral wells can be drilled from any one or more originating wells, which can be substantially vertically or substantially horizontally oriented relative to surface 14 to create subsurface barriers 30. It can be appreciated that the number and type of wells used to create the subsurface barriers 30 can vary depending on the nature of the originating wells, the radius of invasion expected from the type of fine tailings being injected, the amount of fine tailings to be disposed of, among other factors specific to the application and environment.

**[0079]** The barriers 30 shown in FIGS. 2-7 can be created only along selected portions of the well 34, 40 by selectively plugging sections of the well 34, 40 as shown in FIGS. 11a and 11b. FIGS. 11a and 11b illustrate cross-sectional schematic diagrams of fluid migration barriers 304 and 300 respectively. Referring first to FIG. 11a, when creating the fluid migration barrier 304 at the heel 306 of the wells 30, 40 a leading packer 310 can be placed ahead of a trailing packer 310 connected to injection tubing 312 to enable a plugging slurry of MFTs, cement squeeze product, etc., can be pumped down into the void between the packers 310 and through the slotted liner, perforated liner, or other passages into the surrounding area of the formation, to create the barrier 304. The plugging slurry would typically progress outwardly into the formation following the permeability of the formation, however, a localized perforation or dilation can be used to initially guide the plugging slurry in a particular direction. It can be appreciated that a variety of packers 310 can be used, for example, straddle packers (wherein the packers 310 are connected in a single unit – as shown with dashed lines in FIG. 11a - with expanding sections to plug off the well), wireline packers, mechanical packers, inflatable packers, etc. These types of packers 310 allow fluid to pass through them via one or more ports. While a plug or other obstruction could be used for the leading packer 310 (and later drilled out or retrieved, packers 310 permitting fluid to flow through ports therein are particularly efficient in this implementation.

**[0080]** In the configuration shown in FIG. 11b, a packer 310 can be placed near the toe 302 of the wells 34, 40 and connected to injecting tubing 312 to enable the plugging slurry to be

pumped down into the toe 302 and then into the surrounding area of the formation via a slotted liner, perforated liner, or other passages as illustrated.

**[0081]** Referring now to FIG. 8, example operations that can be performed in creating a subsurface barrier 30 using a sequential drilling process, are shown. At 50, a new, existing or otherwise originating well is created or identified for fine tailings injection. This can include a single well (e.g., infill well, CSS well, etc.) or a SAGD well pair 22, 24 as illustrated herein. Tailings such as MFTs or TFTs are injected into the originating well at 52. Upon completion of the tailings injection, e.g., when injectivity is lost, the well into which tailings are being injected is plugged or otherwise abandoned at 54, e.g., using a bridge plug 32. The first or next lateral well 34, 42 is then drilled from the previous or originating well and tailings are injected at 56. This is done until the particular target is met at 58, which can include reaching the top of the pay region, an impermeable (or largely impermeable) barrier, or achieving the target area of the barrier 30. The target can also include a metric such as an amount of fine tailings that is to be disposed of. The process continues until the target is met at 58 and ends at 60. It can be appreciated that the process shown in FIG. 8 can be reconfigured to have sets of wells or all wells used to create the preferential barrier 30 to be drilled or identified prior to injecting the fine tailings such that block 56 would include targeting the next lateral well rather than requiring a sequential drilling operation.

**[0082]** The fine tailings injection process used herein to dispose of fine tailings and/or create a preferential subsurface barrier 30 or barriers 30 can also be applied to other reservoirs such as heavy oil reservoirs that create wormhole networks 70 as a result of an in situ cold flow technique such as CHOPS. One example implementation is shown in FIGS. 9a and 9b in which perforated intervals in a well are isolated to enable waste streams such as fine tailings to be injected into intervals as they are isolated, to plug wormholes that connect to the isolated interval of the well.

**[0083]** As discussed above, the creation of such wormhole networks 70 can be problematic. For example, since the recovery factors in CHOPS are typically quite low, CHOPS used as a primary extraction process can create difficulties in implementing a subsequent secondary or tertiary extraction process. That is, CHOPS wells are characterized by quick pressure depletion and decline in production rates. Despite demonstrating sustained low production rates for extended periods of time, CHOPS wells rarely recover more than 10–15%

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of the oil originally in place. Maximizing recovery factors from CHOPS fields requires implementing secondary and tertiary recovery techniques. However, wormhole networks 70 can serve as short circuits between injection and production wells, resulting in fast breakthrough of injected water, polymer or steam and reducing the sweep efficiency and thermal efficiency. Wormhole networks 70 result in fast dissipation of pressure and leak off of injected fluids, rendering application of cyclic solvent and cyclic steam methods ineffective. Essentially, wormholes 72 represent a secondary porosity and permeability in the formation, not unlike a fracture network. However, the morphology of wormhole networks 70 is a lot less predictable than fracture networks. The injection of fine tailings as described above can therefore be used to plug portions of wormhole networks 70 created during a primary extraction process such as CHOPS to facilitate the implementation of a secondary or tertiary extraction process.

**[0084]** Wormhole networks 70 created in a heavy oil reservoir can create problems with applying a secondary or tertiary recovery process by making it more difficult to maintain pressure in the reservoir due to leakage into the reservoir via the wormholes 72 of the wormhole network 70. Disposal of the fine tailings as discussed herein can be applied to such wormhole networks 70 to plug the wormholes 72. This can be done without the need to correctly model or determine the pattern or sizes of the wormholes, which are known to be difficult or impossible to model with any accuracy. That is, while the progression of wormholes is difficult to track, the origin is not, meaning that the processes described herein can be implemented in wormhole networks 70 by injecting fine tailings where they are presumed to originate or by drilling a well that is adjacent to where the wormholes 72 are presumed to exist. That is, the fine tailings can be injected into producer wells in a heavy oil reservoir since wormholes 72 originate at the perforation of a producer well while that well produces heavy oil with sand from the unconsolidated formation. When a new injection well is drilled for a new recovery scheme, such injection wells can intersect one or more wormholes 72. In such a scenario, it is advantageous to be able to plug the wormholes 72 (e.g., by injecting fine tailings) before the drilling is completed.

**[0085]** Moreover, by plugging the wormholes 72 with fine tailings and creating a first barrier 30a as shown in FIG. 9a, losses to that area as a thief zone can be avoided to improve the recovery rate. As illustrated in FIG. 9a, a CHOPS well 62 can include multiple perforated intervals 64 (64a and 64b shown for illustrative purposes). Each of these intervals 64a, 64b can

be isolated (e.g., temporarily with packers or permanently with cement plugs) such that the fine tailings injected through the perforated interval 64a can plug wormholes 72 of the wormhole network 70 that connect to that interval 64a. By having multiple perforated intervals 64a, 64b, multiple barriers 30a, 30b can be created in the wormhole network 70 by targeting different regions of the network 70 that connect to or are otherwise adjacent or near the perforated intervals 64a, 64b, as shown in FIG. 9b.

**[0086]** An aspect of the disposal of fine tailings as described herein is that, depending on proportion of clays and water in the stream being used, one can keep the tailings moving once they are moving (recognizing the non-Newtonian behaviour of clays). Once below a critical velocity (which is a function of concentration, etc.), the tailings become harder to move. This is an advantage because you can pump in the tailings and, as the radius increases, velocity slows such that the clays will slow the process and start to set. For any of the above processes described (e.g., for injecting into LLISRs 20 or wormhole networks 70), one can filter out certain sizes by centrifugation or cyclones. The process can then filter low enough so that injection can occur without, for example, plugging wormholes 72 immediately (i.e., around the wellbore). Smaller particles can travel through the bores, whereas the larger sizes can plug the bore. As such, the injection process used herein should use small enough particles. Also, the smaller tailings particles can be considered the most challenging to settle out and separate from water in disposal or reclamation processes requiring more time and/or more chemicals to settle, and thus disposing of them is an added benefit.

**[0087]** It can be appreciated that the processes described herein can also include selecting waste streams such as fine tailings with particular types of clays, such as swelling clays that react with steam conditions (e.g., kaolin). These swelling clays can be injected and, when interacting with steam, can help formulate permeability barriers 30. Such swelling clays may have been mined from different areas and have different properties (e.g., clay type and concentrations). Certain clays can also be manipulated to swell downhole, e.g., in the LLISR 20 or wormhole network 70. The swelling can be triggered downhole by changing the chemistry of the clay. For example, kaolinite plus aqueous quartz plus aqueous Ca and/or Mg and/or Fe from the injected water forms smectite at high temperature and subsequently swells in the presence of fresh water. Similarly, waste streams such as MFTs can be selected which includes fluids that react with formation water or formation rock to form clays and/or scales that reduce

permeability in the formation. The processes described herein can also include selecting any disposal water (e.g., a waste water stream) that reacts with the formation water or the formation rock to form clays and/or scales that reduce permeability.

**[0088]** Referring now to FIG. 10, fine particle separation process 80 is shown that can be applied to a source or input fraction 82 corresponding to or comprising a tailings stream for the processes described herein. The process 80 can be applied to separate the source fractions 82 at a fine particle size, e.g., of nominally minus 10 microns (or less) of problematic tailings streams such as MFTs or TFTs, to produce a fine tailings stream or fines fraction 86 at, e.g., nominally minus 10 micron for injection and a, e.g., plus 10 micron coarse fraction 88 for terrestrial deposition in a terrestrial deposition process 92. It is advantageous to adequately separate at these fine sizes of these particular source fractions 82. Since the separated fines fraction 86 would be non-settling, they could be pipelined from a base site to the locations of the wells used in the LLISRs 20 or other unused or previously unexploited reservoirs discussed herein.

**[0089]** It is also advantageous to be able to dispose of the separated fines fraction 86 through injection into such reservoirs using injection equipment 90 at that site. It is expected that after some effective period of injection, these fine fractions 86 would act to effectively seal the reservoir in proximity to the wellbores, thereby ultimately reaching end of life with a reduction in adverse outcomes for closure associated with these wells 22, 24 and/or in this example, LLISRs 20. It is also expected that the separated coarse fraction 88 would have unique properties for forming rapid deposits beneficial for more amenable closure and reclamation options.

**[0090]** To perform the separation of fine tailings at these fine particle sizes (e.g., nominally 10 microns or less) it is recognized that separation at these fine sizes has been carried out commercially with other finely sized materials such as clays and calcium carbonate for the purposes of producing products with unique properties. Such approaches can be used in the process shown in FIG. 10 for separating the fine fractions 86 of select fine tailings streams (source fraction 82) using, for example, fine diameter cyclones or centrifuges as the fine particle separator 84, to achieve a separation at these fine particle sizes. If the viscosity of these streams poses a challenge to performing the separation, dilution water can be added to effect these separations.

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**[0091]** Advantages of applying the process 80 shown in FIG. 10 can include that an alternate disposal method for the finest fractions of fine tailings streams 82 can be achieved, considering that such fine fractions 86 are considered to be problematic for settling in either aquatic or terrestrial deposits. Moreover, the co-disposal of stored tailings waters contained in these fine fractions 86, which can contain contaminants of potential concern for either release to the environment (and may alternatively require ongoing treatment during and after closure), can also be advantageous. The separation of a coarser fraction 88 from the fine tailings stream or source fraction 82, which is likely to be comparatively fast settling and more readily amenable for terrestrial deposits, can be ready for closure in less time than alternative methods. As noted above, the LLISRs 20 and the wells 22, 24 in those reservoirs can be leveraged and reused for disposal of a problematic waste stream. Also, the clay components of the injected waste streams could eventually bring these wellbores to a sealed end of life state in which there would be little or no residual concerns.

**[0092]** It can be appreciated that the processes of creating subsurface barriers 30 provides an attractive alternative to other approaches of disposing of fine tailings such as MFTs, by disposing of problematic fractions of fine tailings in a manner that does not require treatment and settling deposits. Also, co-disposing of tailings contaminated waters decreases the inventory of waters to be dealt with during closure and/or during reclamation. Moreover, utilizing and effectively ending the life of available LLISR wells 22, 24, which would otherwise also represent a concern or liability for closure.

**[0093]** For simplicity and clarity of illustration, where considered appropriate, reference numerals may be repeated among the figures to indicate corresponding or analogous elements. In addition, numerous specific details are set forth in order to provide a thorough understanding of the examples described herein. However, it will be understood by those of ordinary skill in the art that the examples described herein may be practiced without these specific details. In other instances, well-known methods, procedures and components have not been described in detail so as not to obscure the examples described herein. Also, the description is not to be considered as limiting the scope of the examples described herein.

**[0094]** It will be appreciated that the examples and corresponding diagrams used herein are for illustrative purposes only. Different configurations and terminology can be used without departing from the principles expressed herein. For instance, components and modules can be

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added, deleted, modified, or arranged with differing connections without departing from these principles.

**[0095]** The steps or operations in the flow charts and diagrams described herein are just for example. There may be many variations to these steps or operations without departing from the principles discussed above. For instance, the steps may be performed in a differing order, or steps may be added, deleted, or modified.

**[0096]** Although the above principles have been described with reference to certain specific examples, various modifications thereof will be apparent to those skilled in the art as outlined in the appended claims.

**Claims:**

1. A method of creating subsurface barriers in a formation, the method comprising:  
injecting a waste stream and/or permeability reducing agent into at least one well to create a subsurface barrier in the formation by reducing permeability of at least a portion of the formation.
2. The method of claim 1, further comprising drilling one or more of the at least one well.
3. The method of claim 2, wherein at least one additional well is drilled adjacent to a first well, and wherein injecting the waste stream and/or permeability reducing agent comprises injecting the waste stream into the first well and injecting the waste stream into the at least one additional well to create the subsurface barrier in the formation.
4. The method of any one of claims 1 to 3, wherein one or more of the at least one well is an existing well that has been used in a hydrocarbon production process in the formation.
5. The method of any one of claims 1 to 3, wherein one or more of the at least one well is a new well drilled into the formation.
6. The method of any one of claim 3 to 5, wherein the at least one additional well is drilled from the first well.
7. The method of any one of claims 3 to 6, wherein the at least one additional well is drilled adjacent to the first well after completing injection of the waste stream into the first well.
8. The method of claim 7, further comprising setting a bridge plug after completing injection of the waste stream into the first well.
9. The method of claim 7 or claim 8, wherein the waste stream is injected in to the first well until at least one injection criterion has been met.

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10. The method of claim 9, wherein the at least one injection criterion comprises detecting a loss of injectivity of the waste stream.
11. The method of claim 9 or claim 10, wherein the at least one injection criterion comprises establishing a target area for the barrier.
12. The method of any one of claims 3 to 11, wherein a plurality of additional wells are drilled sequentially at a distance from the first well or a previously drilled additional well after injecting the waste stream into the first well or the previously drilled well.
13. The method of claim 12, further comprising setting a bridge plug after completing injection of the waste stream into the first well or previously drilled additional well.
14. The method of any one of claims 6 to 13, wherein the at least one additional well is drilled from a build section of the first well.
15. The method of any one of claims 1 to 14, wherein the waste stream comprises fine tailings.
16. The method of claim 15, wherein the fine tailings comprise mature fine tailings.
17. The method of claim 15 or claim 16, wherein the fine tailings comprise thin fluid tailings.
18. The method of any one of claims 15 to 17, further comprising selecting fine tailings that swell in the presence of fresh water downhole.
19. The method of claim 18, wherein the fine tailings in the presence of the water downhole forms clay and/or scale at high temperature and subsequently swells.
20. The method of claim 19, wherein the water and/or fine tailings is treated by adding new chemicals or minerals or by increasing a concentration of existing chemicals and/or minerals to trigger a desired plugging reaction in the formation.

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21. The method of claim 19, wherein the fine tailings in the presence of the water downhole forms smectite.

22. The method of any one of claims 1 to 14, wherein the waste stream comprises a disposal water stream which reduces the permeability of the formation by forming subsurface clays and/or scales as a result of reactions between the injected disposal water stream and formation water and/or formation rock.

23. The method of any one of claims 1 to 22, wherein the subsurface barrier is created in or adjacent to a hydrocarbon-producing reservoir.

24. The method of claim 23, wherein the hydrocarbon-producing reservoir is a thermally depleted reservoir.

25. The method of claim 23, wherein the hydrocarbon-producing reservoir is a non-thermally depleted reservoir.

26. The method of any one of claims 23 to 25, wherein the subsurface barrier is created in a late life in situ reservoir (LLISR).

27. The method of claim 26, wherein the LLISR is located in a bitumen reservoir.

28. The method of any one of claims 1 to 27, wherein the formation is located adjacent an active reservoir, the subsurface barrier creating a preferential barrier to abate a thief zone.

29. The method of claim 28, wherein the thief zone comprises any one or more of a bottom water zone, a lean zone or a gas zone.

30. The method of any one of claims 1 to 22, wherein the subsurface barrier is created in or adjacent to a heavy oil reservoir.

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31. The method of claim 30, wherein the heavy oil reservoir has been subjected to an in situ cold flow recovery technique with sand as a primary extraction process.
32. The method of claim 31, wherein the waste stream is injected prior to initiating at least one additional extraction process.
33. The method of claim 31 or claim 32, wherein the primary extraction process comprises cold heavy oil production with sand (CHOPS).
34. The method of claim 33, wherein the waste stream is injected to plug at least one wormhole created by implementing the CHOPS process.
35. The method of claim 33, wherein the waste stream is injected to plug at least one portion of a wormhole network created by implementing the CHOPS process.
36. The method of claim 33, wherein the waste stream is injected to plug at least one wormhole network created by implementing the CHOPS process.
37. The method of any one of claims 34 to 36, further comprising:  
isolating a first interval of a CHOPS well; and  
injecting the waste stream via the first isolated interval to plug wormholes intersecting with the isolated interval.
38. The method of claim 37, further comprising:  
isolating at least one second interval; and  
injecting the waste stream via the at least one second isolated interval to plug wormholes intersecting with the at least one second isolated interval.
39. The method of any one of claims 1 to 22, wherein the subsurface barrier is formed to counteract flow towards a receptor due to a pressure gradient subsurface.

40. The method of claim 39, wherein the subsurface barrier is formed to mitigate contaminated groundwater flow to limit spread of contaminants towards the receptor.
41. The method of any one of claims 1 to 22, wherein the subsurface barrier is formed in or adjacent to a salt cavern to mitigate losses to the salt cavern.
42. The method of any one of claims 1 to 22, wherein the subsurface barrier is formed in or adjacent to a conventional oil reservoir to implement bottom water shut off.
43. The method of any one of claims 1 to 39, wherein the subsurface barrier is formed prior to implementing a hydrocarbon recovery process in the formation.
44. The method of any one of claims 1 to 43, further comprising preparing the waste stream for injection into the formation by:  
separating a source fraction into a fines fraction that is relatively smaller than a coarse fraction; and  
providing the fines fraction to injection equipment to inject the fines fraction into the formation.
45. The method of any one of claims 1 to 44, further comprising repeating the method to form a plurality of subsurface barriers.
46. The method of claim 45, wherein a plurality of first additional wells are drilled into the formation to form a first barrier and at least one plurality of second additional wells are drilled into the formation to form at least one second barrier.
47. The method of claim 46, wherein the first barrier is formed from wells drilled in alignment with a first originating well and the at least one second barrier is formed from wells drilled in alignment with at least one second originating well.
48. The method of any one of claims 1 to 47, wherein the wells are substantially horizontal wells.

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49. The method of any one of claims 1 to 47, wherein the wells are substantially vertical wells.

50. The method of any one of claims 1 to 47, wherein the wells comprise at least one substantially horizontal well and at least one substantially vertical well.

51. A method of facilitating heavy oil production from a heavy oil reservoir, comprising:  
injecting a waste stream into a well in the heavy oil reservoir to plug wormholes or preferential paths created by a previously implemented primary extraction process to facilitate a secondary or tertiary extraction process in the heavy oil reservoir.

52. The method of claim 51, further comprising implementing the secondary or tertiary extraction process.

53. The method of claim 51 or claim 52, wherein the primary extraction process comprises an in situ cold flow process with sand that has created wormholes.

54. The method of claim 53, wherein the primary extraction process comprises cold heavy oil production with sand (CHOPS).

55. The method of claim 51 or claim 52, wherein the primary extraction process does not include sand production but creates preferential flow paths.

56. A method of preparing a waste stream for injection to a formation to form a subsurface barrier, the method comprising:

separating a source fraction into a fines fraction that is relatively smaller than a coarse fraction; and

providing the fines fraction to injection equipment to inject the fines fraction into the formation.

57. The method of claim 56, wherein the source fraction is separated using a fine particle separator.
58. The method of claim 57, wherein the fine particle separator comprises a fine diameter cyclone.
59. The method of claim 57, wherein the fine particle separator comprises a centrifuge.
60. A system for creating subsurface barriers in a formation, the system comprising:  
injection equipment configured to inject a waste stream and/or permeability reducing agent into at least one well to create a subsurface barrier in the formation by reducing permeability of at least a portion of the formation.
61. The system of claim 60, wherein one or more of the at least one well has been drilled.
62. The system of claim 61, wherein at least one additional well is drilled adjacent to a first well, and wherein injecting the waste stream and/or permeability reducing agent comprises injecting the waste stream into the first well and injecting the waste stream into the at least one additional well to create the subsurface barrier in the formation.
63. The system of any one of claims 60 to 62, wherein one or more of the at least one well is an existing well that has been used in a hydrocarbon production process in the formation.
64. The system of any one of claims 60 to 62, wherein one or more of the at least one well is a new well drilled into the formation.
65. The system of any one of claim 62 to 64, wherein the at least one additional well is drilled from the first well.
66. The system of any one of claims 62 to 65, wherein the at least one additional well is drilled adjacent to the first well after completing injection of the waste stream into the first well.

67. The system of claim 66, further comprising a bridge plug set after completing injection of the waste stream into the first well.
68. The system of claim 66 or claim 67, wherein the waste stream is injected in to the first well until at least one injection criterion has been met.
69. The system of claim 68, wherein the at least one injection criterion comprises detecting a loss of injectivity of the waste stream.
70. The system of claim 68 or claim 69, wherein the at least one injection criterion comprises establishing a target area for the barrier.
71. The system of any one of claims 62 to 70, wherein a plurality of additional wells are drilled sequentially at a distance from the first well or a previously drilled additional well after injecting the waste stream into the first well or the previously drilled well.
72. The system of claim 71, further comprising a bridge plug set after completing injection of the waste stream into the first well or previously drilled additional well.
73. The system of any one of claims 65 to 72, wherein the at least one additional well is drilled from a build section of the first well.
74. The system of any one of claims 60 to 73, wherein the waste stream comprises fine tailings.
75. The system of claim 74, wherein the fine tailings comprise mature fine tailings.
76. The system of claim 74 or claim 75, wherein the fine tailings comprise thin fluid tailings.
77. The system of any one of claims 74 to 76, further comprising selecting fine tailings that swell in the presence of fresh water downhole.

78. The system of claim 77, wherein the fine tailings in the presence of the water downhole forms clay and/or scale at high temperature and subsequently swells.

79. The system of claim 78, wherein the water and/or fine tailings is treated by adding new chemicals or minerals or by increasing a concentration of existing chemicals and/or minerals to trigger a desired plugging reaction in the formation.

80. The system of claim 78, wherein the fine tailings in the presence of the water downhole forms smectite.

81. The system of any one of claims 60 to 73, wherein the waste stream comprises a disposal water stream which reduces the permeability of the formation by forming subsurface clays and/or scales as a result of reactions between the injected disposal water stream and formation water and/or formation rock.

82. The system of any one of claims 60 to 81, wherein the subsurface barrier is created in or adjacent to a hydrocarbon-producing reservoir.

83. The system of claim 82, wherein the hydrocarbon-producing reservoir is a thermally depleted reservoir.

84. The system of claim 82, wherein the hydrocarbon-producing reservoir is a non-thermally depleted reservoir.

85. The system of any one of claims 82 to 84, wherein the subsurface barrier is created in a late life in situ reservoir (LLISR).

86. The system of claim 85, wherein the LLISR is located in a bitumen reservoir.

87. The system of any one of claims 60 to 86, wherein the formation is located adjacent an active reservoir, the subsurface barrier creating a preferential barrier to abate a thief zone.

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88. The system of claim 87, wherein the thief zone comprises any one or more of a bottom water zone, a lean zone or a gas zone.
89. The system of any one of claims 60 to 81, wherein the subsurface barrier is created in or adjacent to a heavy oil reservoir.
90. The system of claim 89, wherein the heavy oil reservoir has been subjected to an in situ cold flow recovery technique with sand as a primary extraction process.
91. The system of claim 90, wherein the waste stream is injected prior to initiating at least one additional extraction process.
92. The system of claim 90 or claim 91, wherein the primary extraction process comprises cold heavy oil production with sand (CHOPS).
93. The system of claim 92, wherein the waste stream is injected to plug at least one wormhole created by implementing the CHOPS process.
94. The system of claim 92, wherein the waste stream is injected to plug at least one portion of a wormhole network created by implementing the CHOPS process.
95. The system of claim 92, wherein the waste stream is injected to plug at least one wormhole network created by implementing the CHOPS process.
96. The system of any one of claims 93 to 95, further configured to:  
isolate a first interval of a CHOPS well; and  
inject the waste stream via the first isolated interval to plug wormholes intersecting with the isolated interval.
97. The system of claim 96, further configured to:  
isolate at least one second interval; and

inject the waste stream via the at least one second isolated interval to plug wormholes intersecting with the at least one second isolated interval.

98. The system of any one of claims 60 to 81, wherein the subsurface barrier is formed to counteract flow towards a receptor due to a pressure gradient subsurface.

99. The system of claim 98, wherein the subsurface barrier is formed to mitigate contaminated groundwater flow to limit spread of contaminants towards the receptor.

100. The system of any one of claims 60 to 81, wherein the subsurface barrier is formed in or adjacent to a salt cavern to mitigate losses to the salt cavern.

101. The system of any one of claims 60 to 81, wherein the subsurface barrier is formed in or adjacent to a conventional oil reservoir to implement bottom water shut off.

102. The system of any one of claims 60 to 98, wherein the subsurface barrier is formed prior to implementing a hydrocarbon recovery process in the formation.

103. The system of any one of claims 60 to 43, further configured to prepare the waste stream for injection into the formation by:

separating a source fraction into a fines fraction that is relatively smaller than a coarse fraction; and

providing the fines fraction to injection equipment to inject the fines fraction into the formation.

104. The system of any one of claims 60 to 103, further configured to repeat a process to form a plurality of subsurface barriers.

105. The system of claim 104, wherein a plurality of first additional wells are drilled into the formation to form a first barrier and at least one plurality of second additional wells are drilled into the formation to form at least one second barrier.

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106. The system of claim 105, wherein the first barrier is formed from wells drilled in alignment with a first originating well and the at least one second barrier is formed from wells drilled in alignment with at least one second originating well.

107. The system of any one of claims 60 to 106, wherein the wells are substantially horizontal wells.

108. The system of any one of claims 60 to 106, wherein the wells are substantially vertical wells.

109. The system of any one of claims 60 to 106, wherein the wells comprise at least one substantially horizontal well and at least one substantially vertical well.

110. A system for facilitating heavy oil production from a heavy oil reservoir, comprising:  
injection equipment configured to inject a waste stream into a well in the heavy oil reservoir to plug wormholes or preferential paths created by a previously implemented primary extraction process to facilitate a secondary or tertiary extraction process in the heavy oil reservoir.

111. The system of claim 110, further configured to implement the secondary or tertiary extraction process.

112. The system of claim 110 or claim 111, wherein the primary extraction process comprises an in situ cold flow process with sand that has created wormholes.

113. The system of claim 112, wherein the primary extraction process comprises cold heavy oil production with sand (CHOPS).

114. The system of claim 110 or claim 111, wherein the primary extraction process does not include sand production but creates preferential flow paths.

115. A system for preparing a waste stream for injection to a formation to form a subsurface barrier, the system comprising:

a separator configured to separate a source fraction into a fines fraction that is relatively smaller than a coarse fraction;

wherein the fines fraction is provided to injection equipment to inject the fines fraction into the formation.

116. The system of claim 115, wherein the source fraction is separated using a fine particle separator.

117. The system of claim 116, wherein the fine particle separator comprises a fine diameter cyclone.

118. The system of claim 116, wherein the fine particle separator comprises a centrifuge.

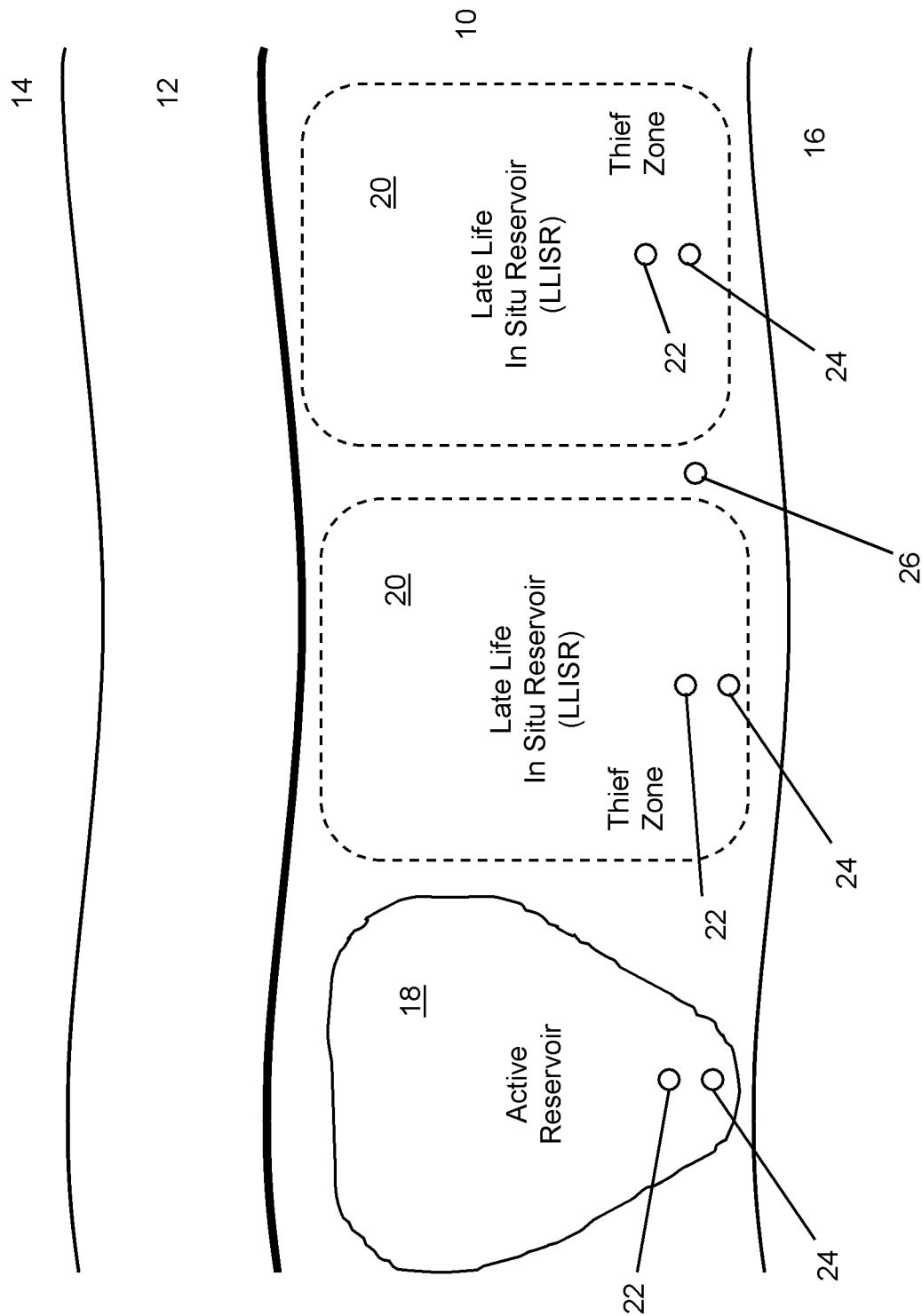


FIG. 1

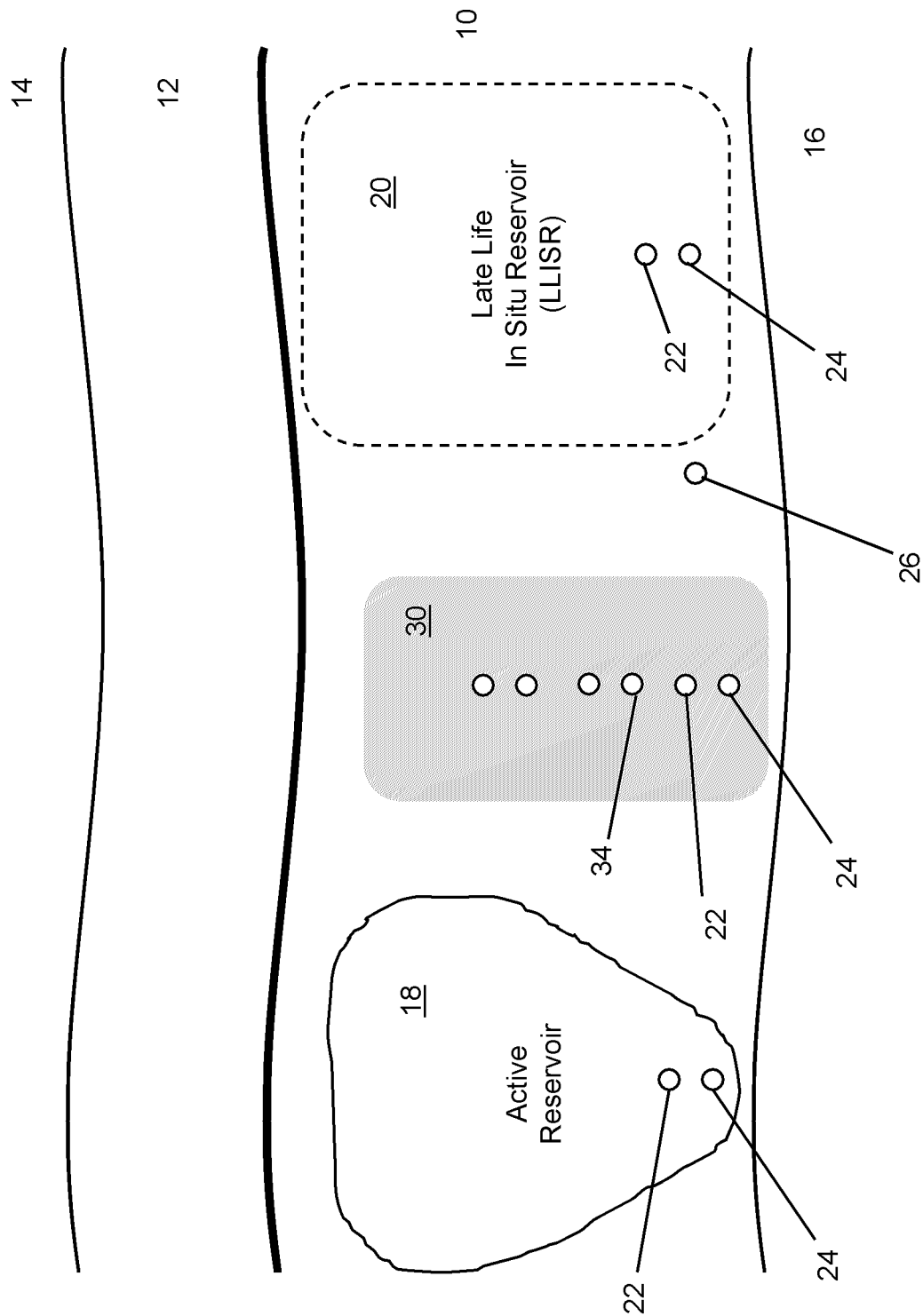


FIG. 2a

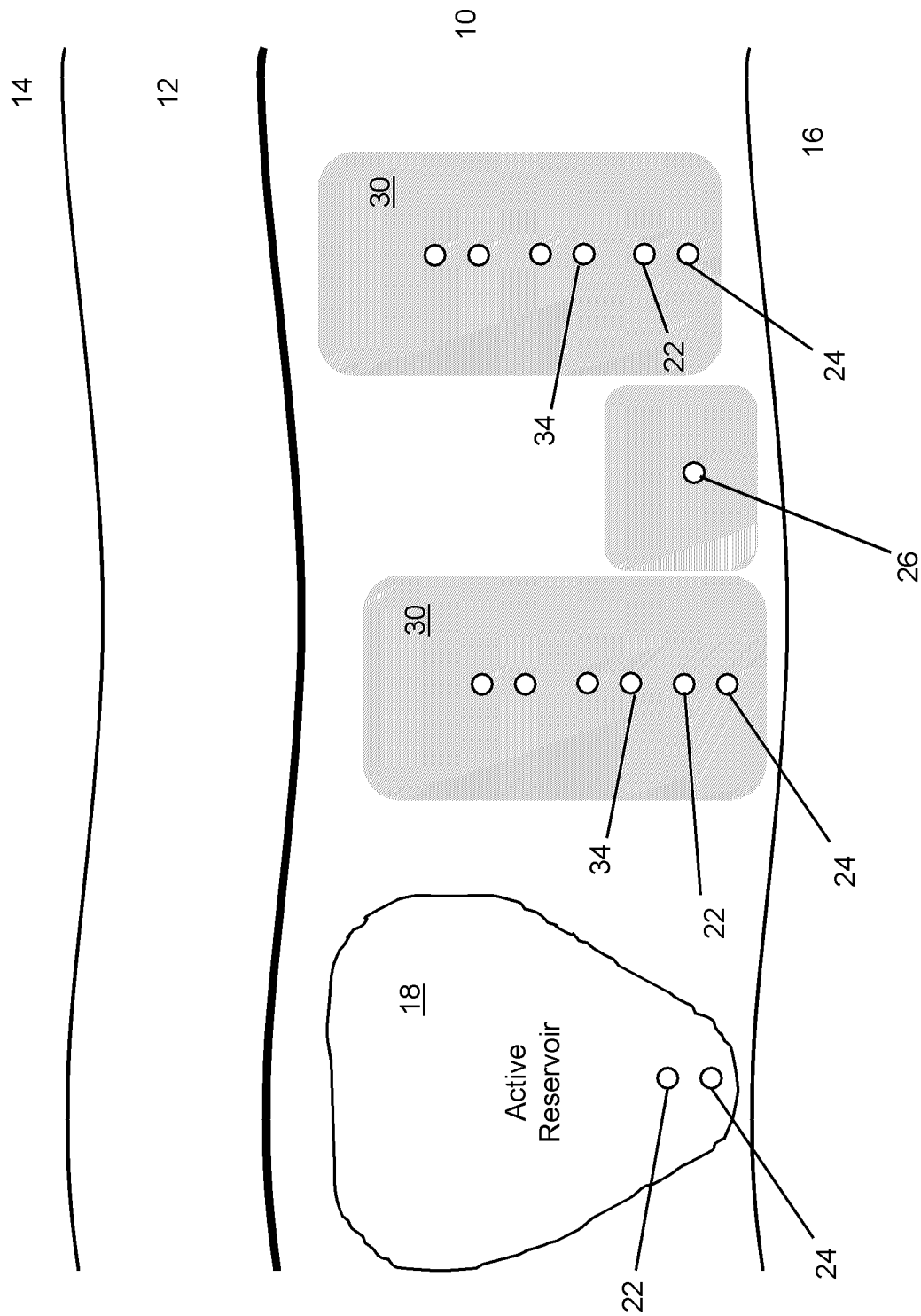


FIG. 2b

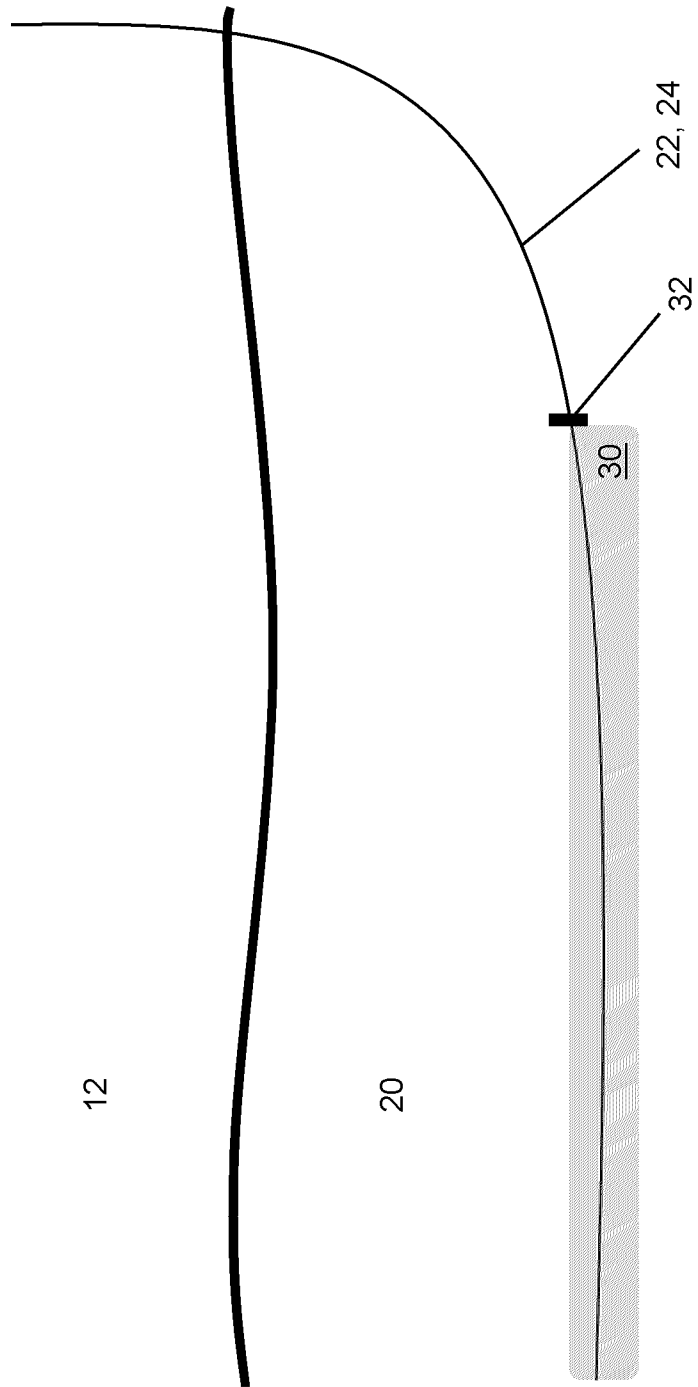


FIG. 3a

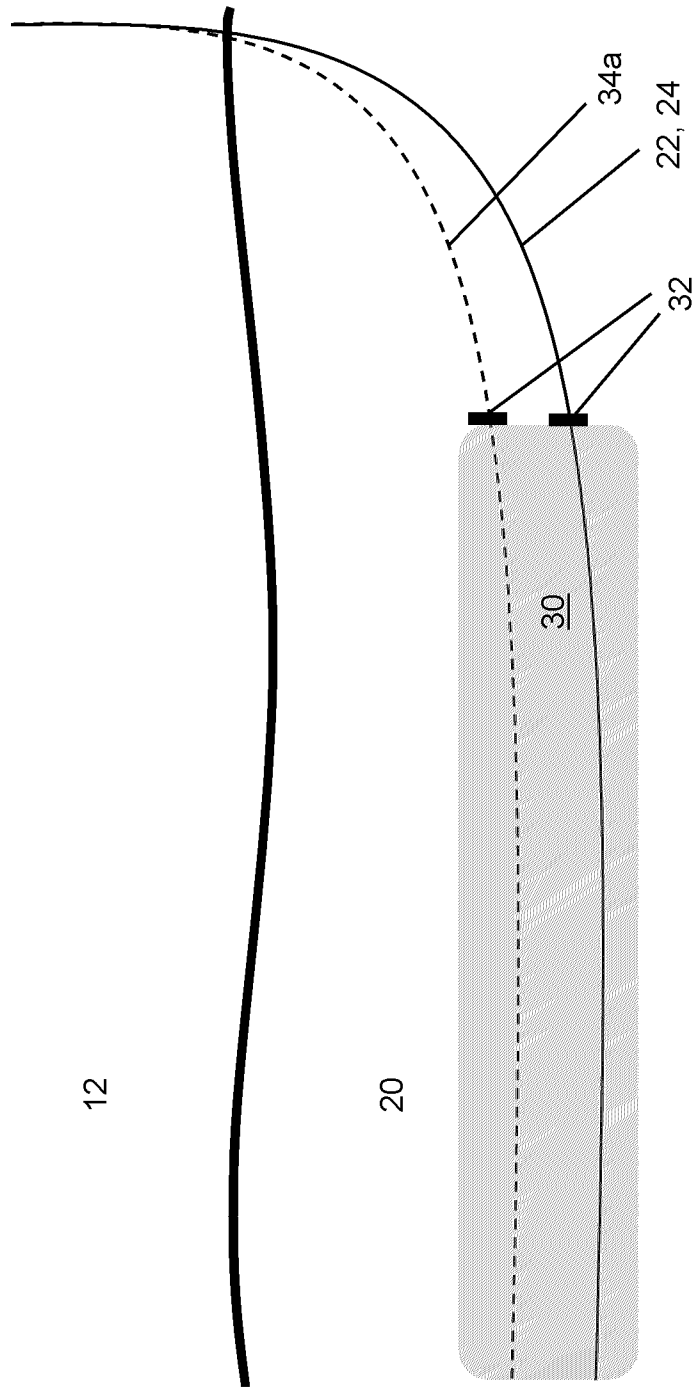


FIG. 3b

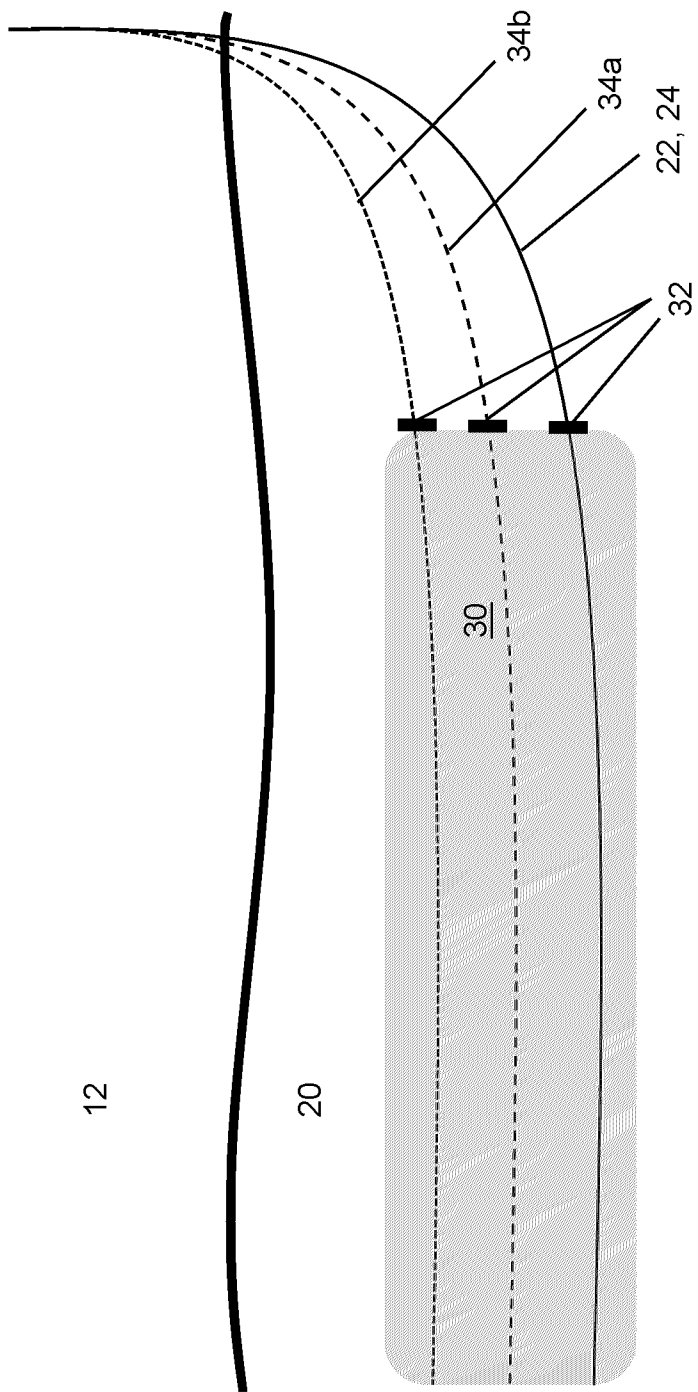


FIG. 3c

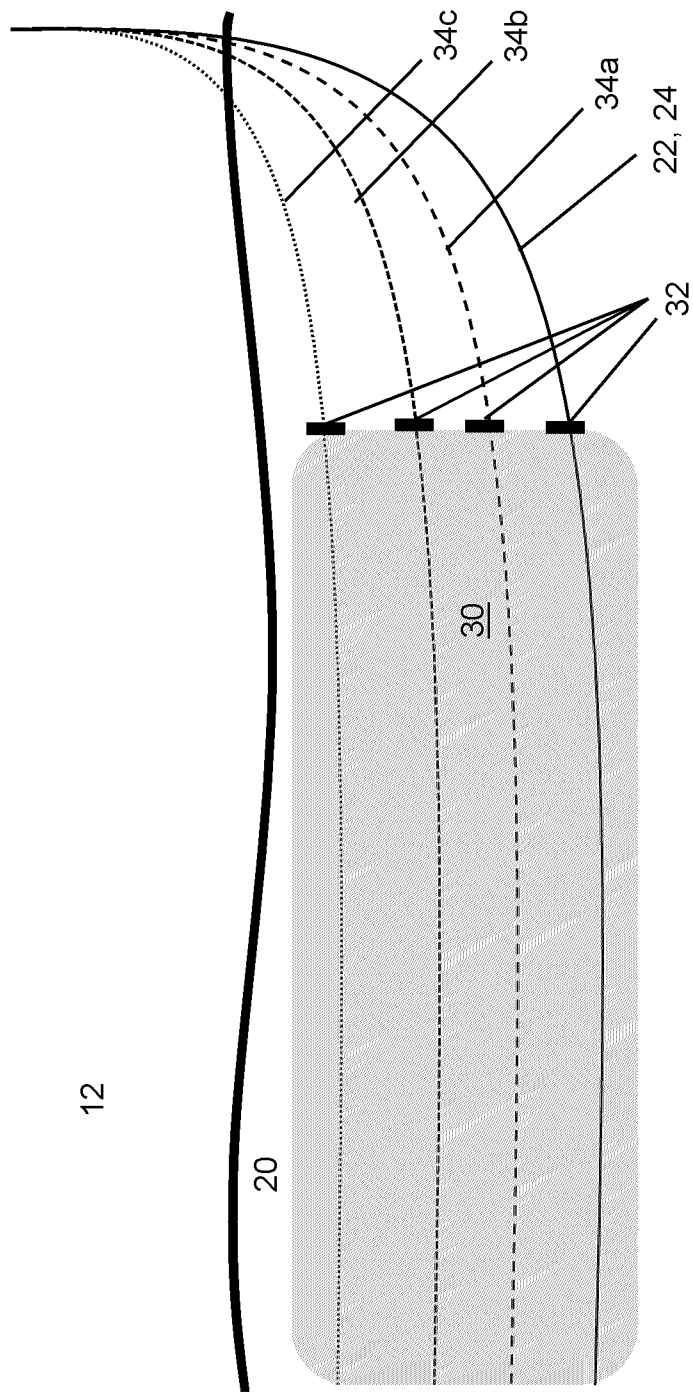


FIG. 3d

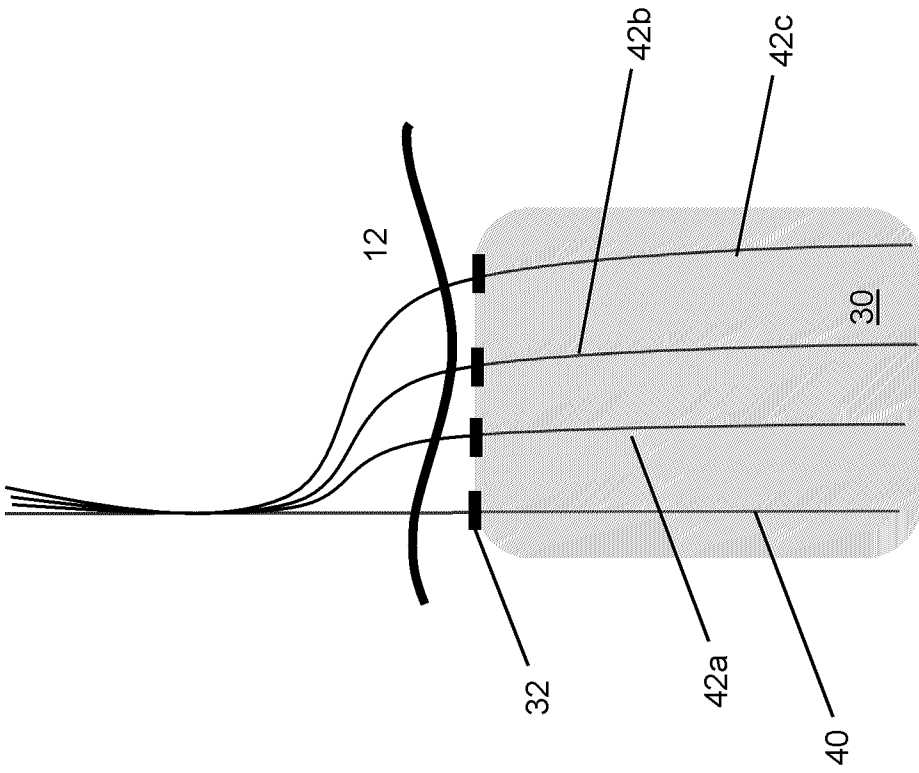


FIG. 5

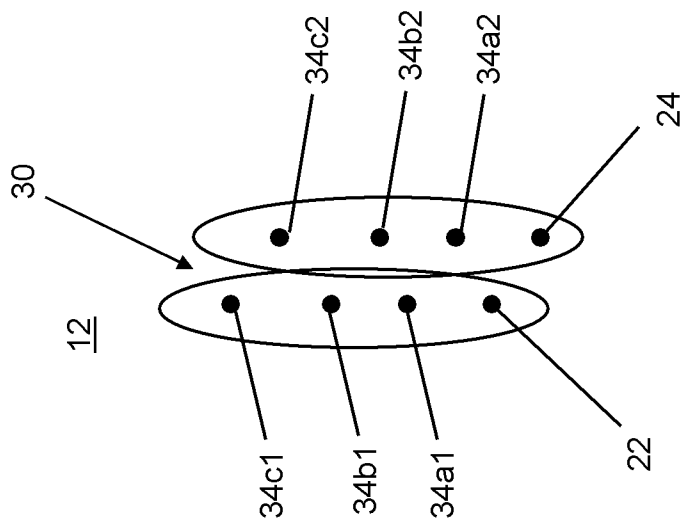
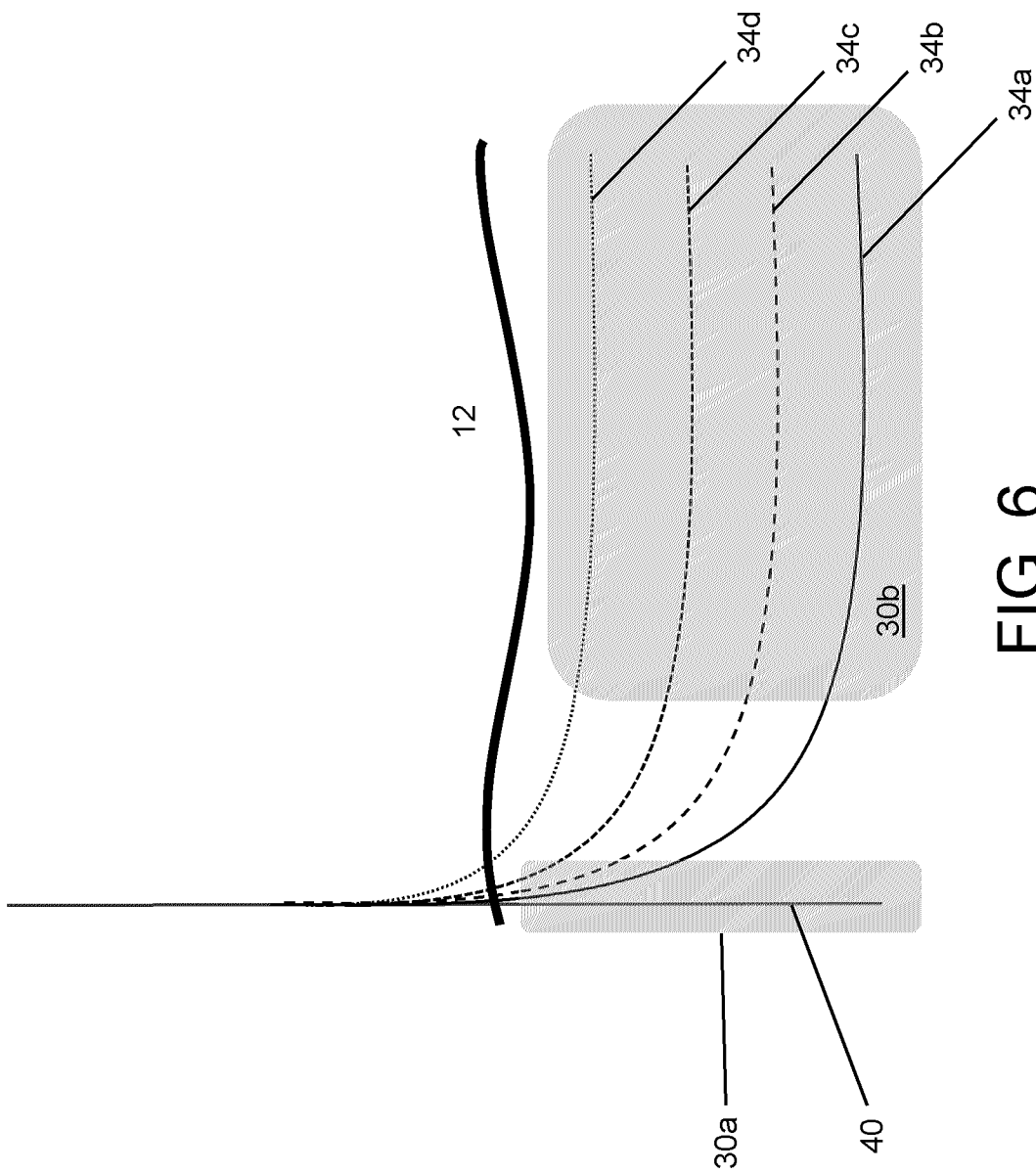


FIG. 4



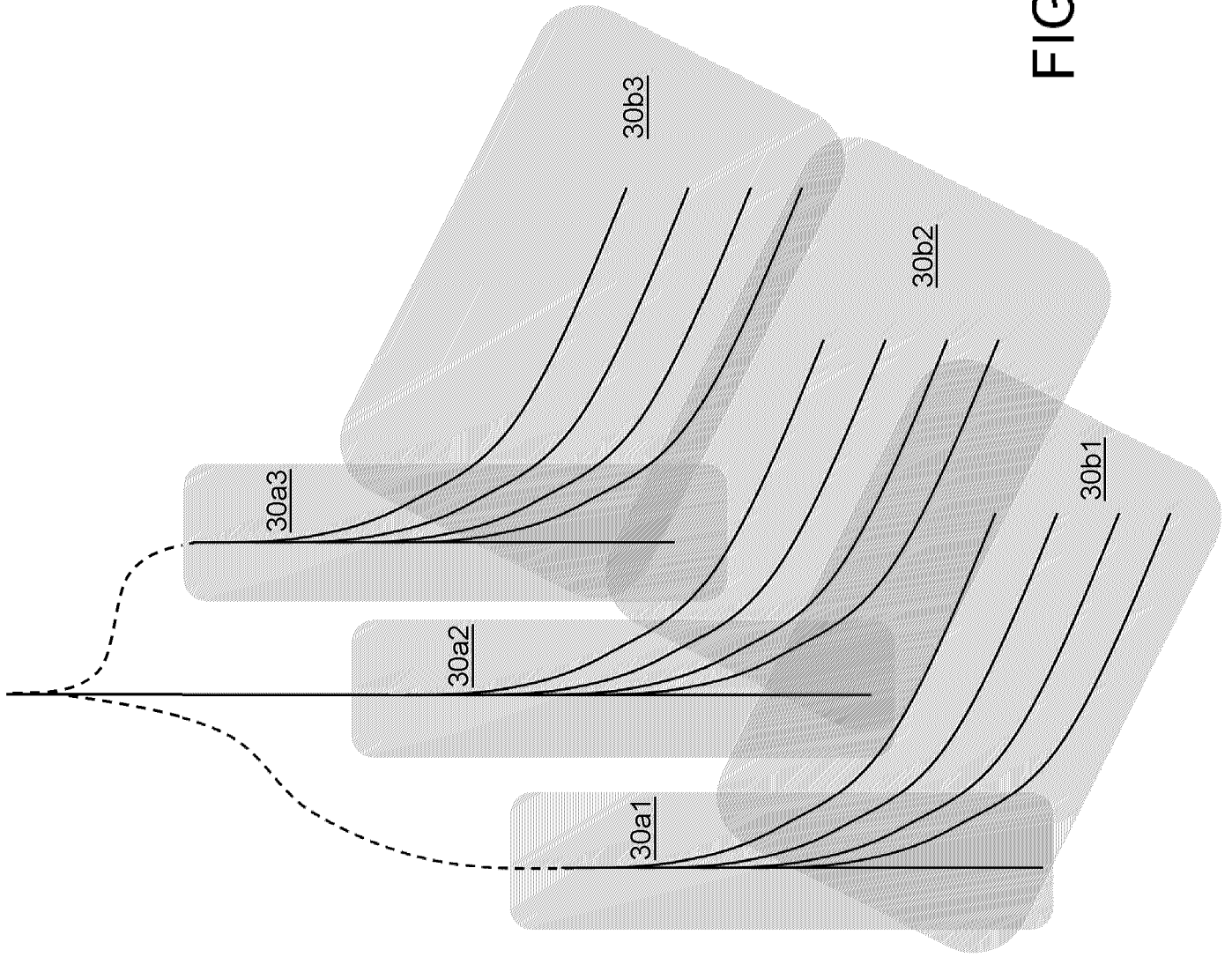


FIG. 7

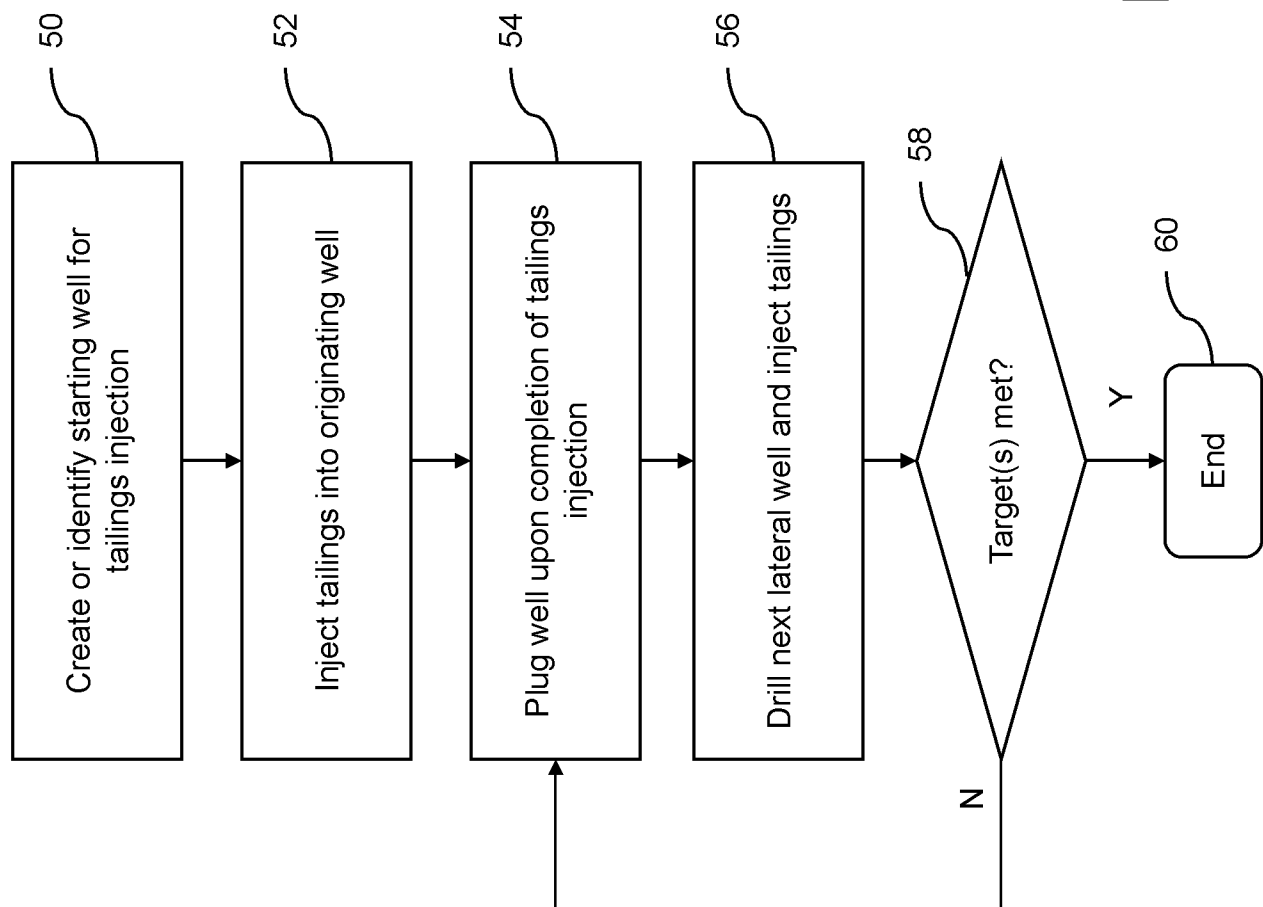


FIG. 8

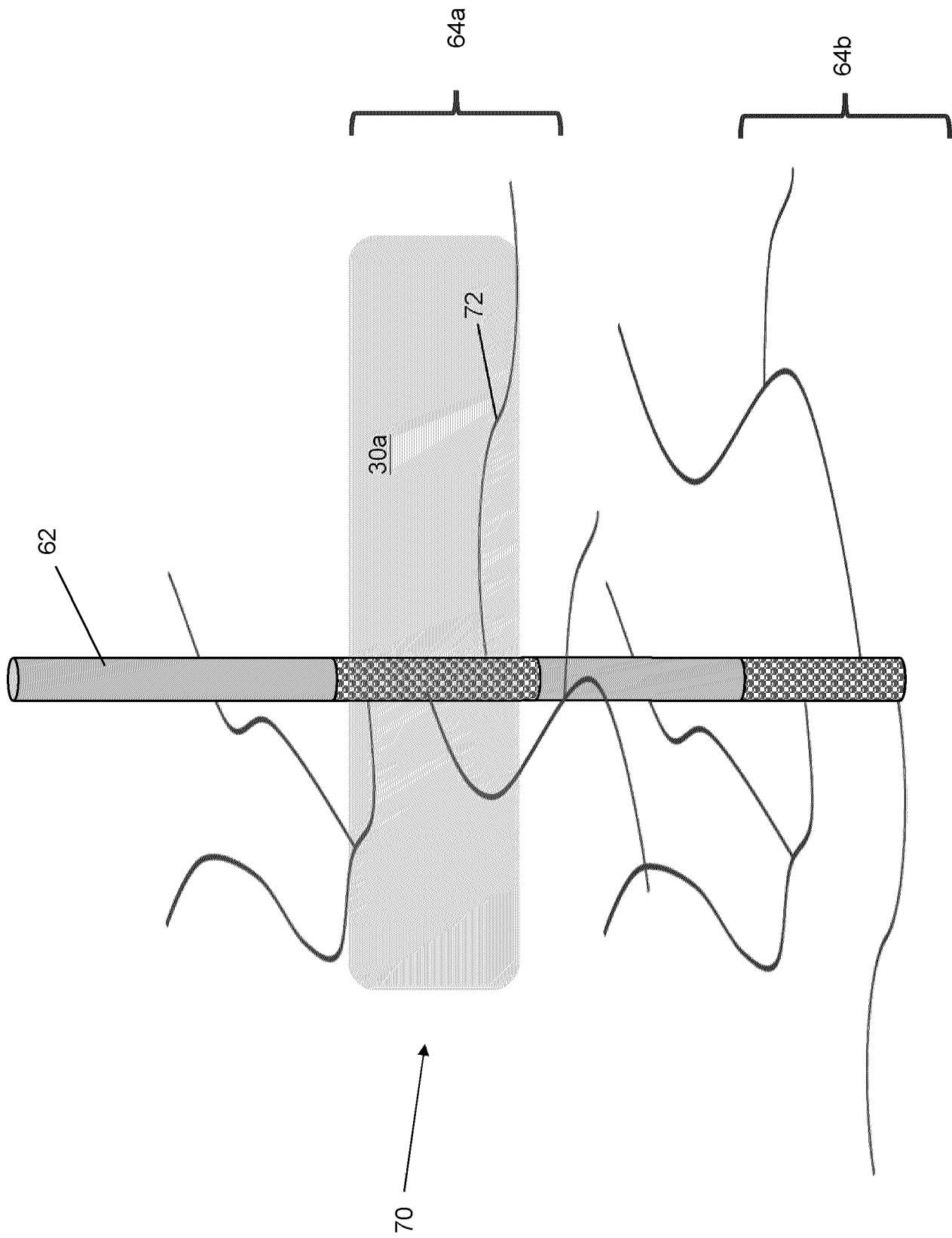


FIG. 9a

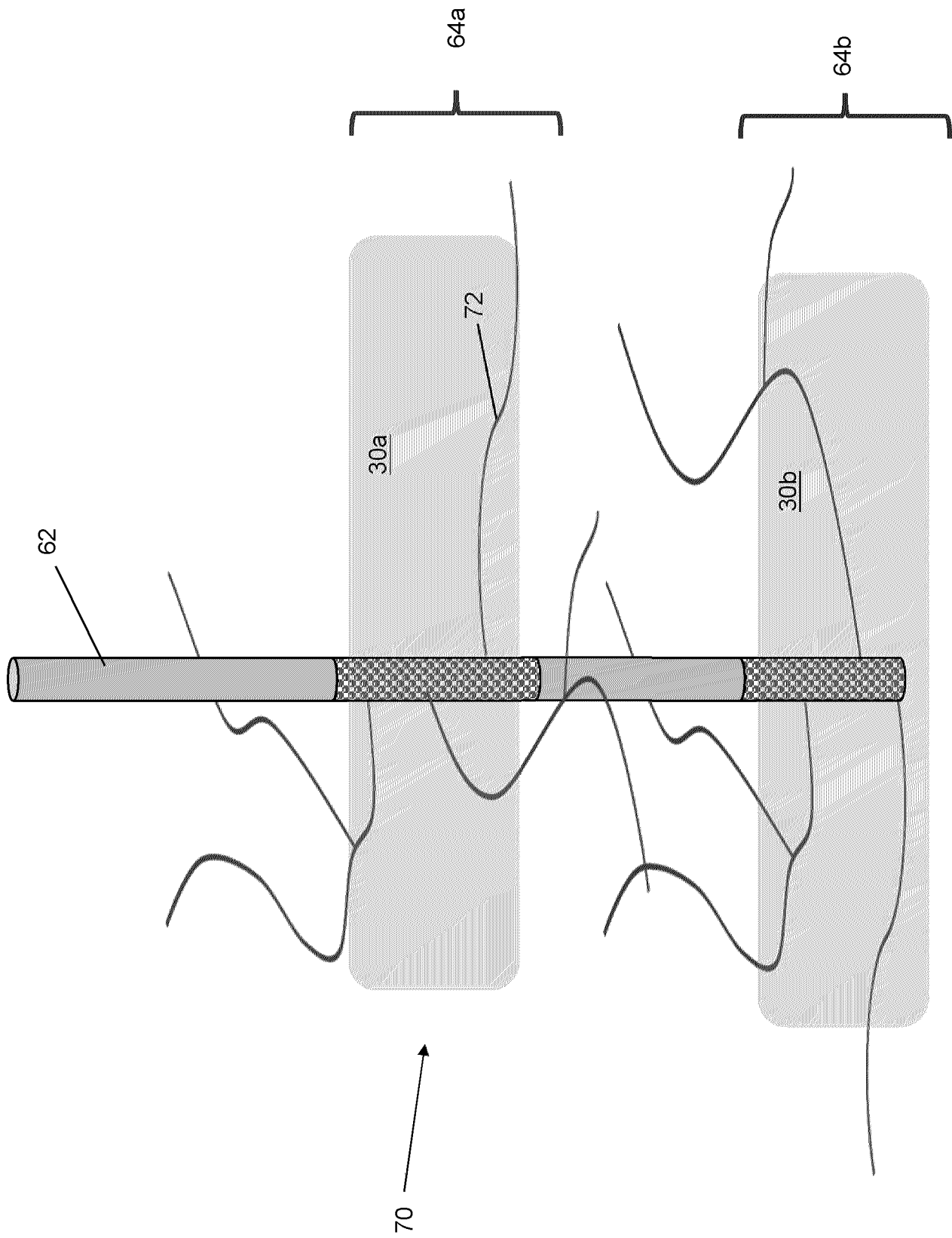


FIG. 9b

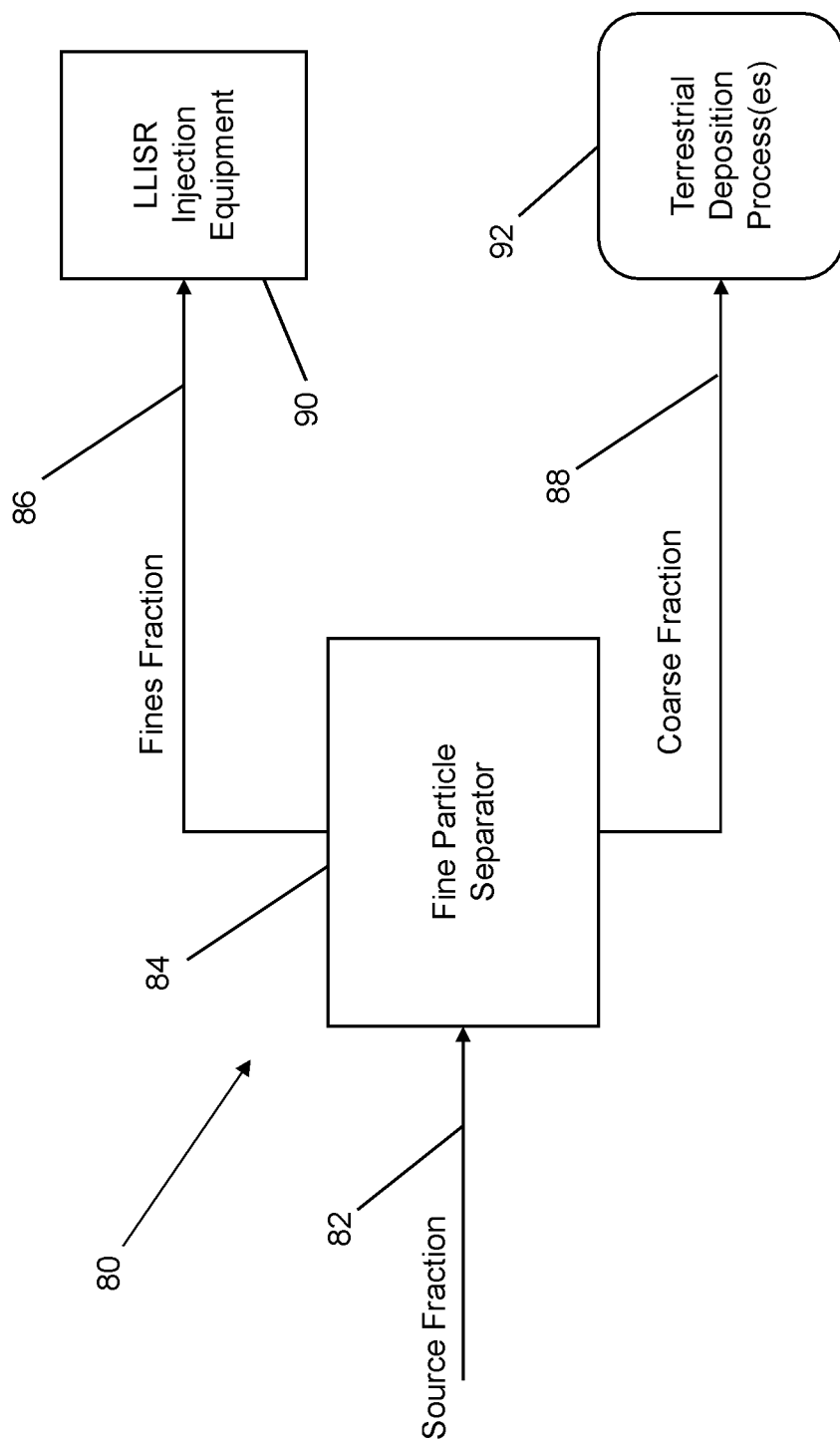
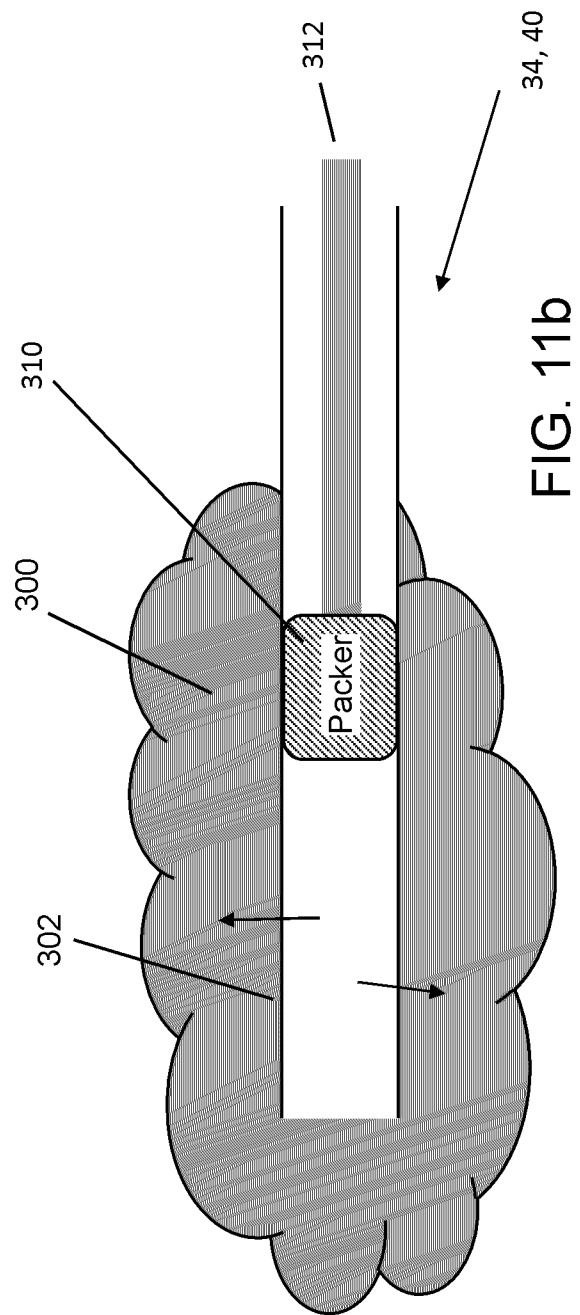
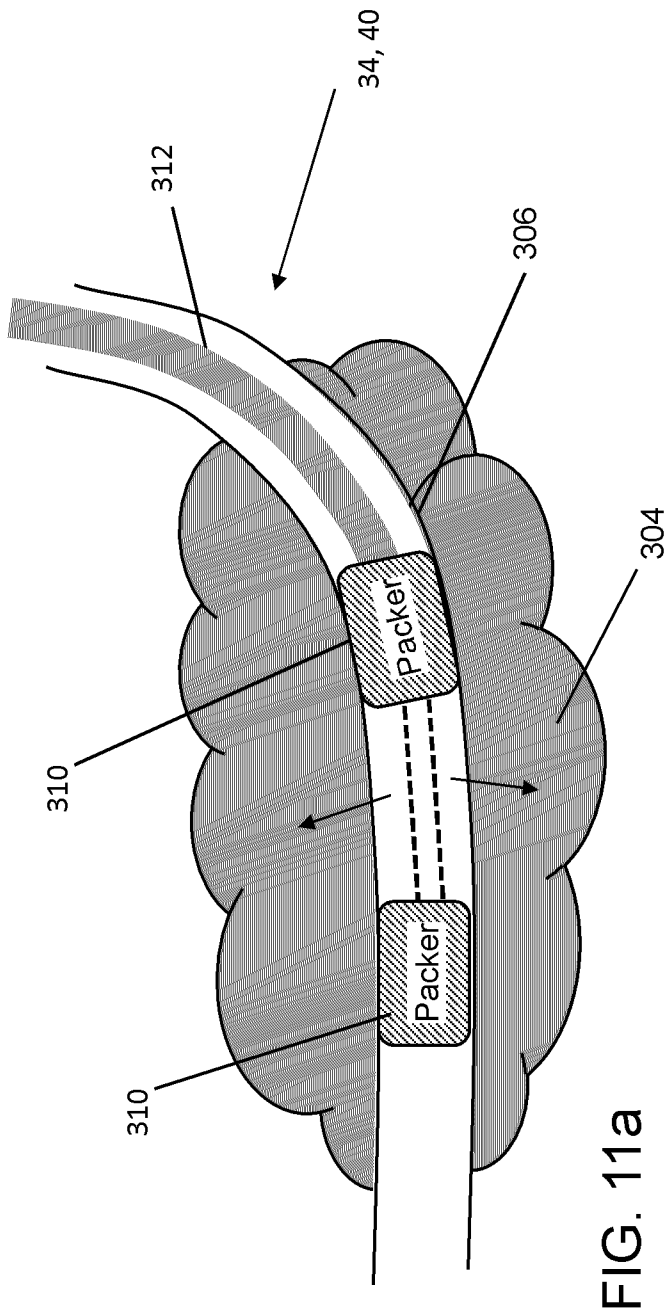


FIG. 10



14

12

10

16

18

Active  
Reservoir

20

Late Life  
In Situ Reservoir  
(LLISR)

20

Late Life  
In Situ Reservoir  
(LLISR)

Thief  
Zone

Thief  
Zone

22

22

22

24

24

26

24

