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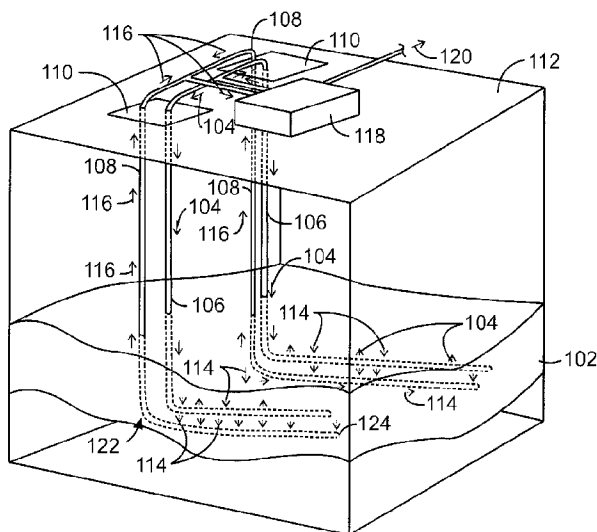
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(54) Titre : RECUPERATION D'UN RESERVOIR D'HYDROCARBURES UTILISANT UN MELANGE DE VAPEUR ET UN SOLVANT VOLATIL

(54) Title: RECOVERY FROM A HYDROCARBON RESERVOIR UTILIZING A MIXTURE OF STEAM AND A VOLATILE SOLVENT



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(57) **Abrégé/Abstract:**

A method and systems for using a non-volatile solvent to recover heavy oils are provided. In a method a solvent that includes a non-volatile component is injected into the reservoir. A mobilizing fluid is injected into the reservoir. Fluid is produced from the reservoir, wherein the fluid comprises the solvent, the mobilizing fluid, and the hydrocarbons from the reservoir.

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ABSTRACT

A method and systems for using a non-volatile solvent to recover heavy oils are provided. In a method a solvent that includes a non-volatile component is injected into the reservoir. A mobilizing fluid is injected into the reservoir. Fluid is produced from the
5 reservoir, wherein the fluid comprises the solvent, the mobilizing fluid, and the hydrocarbons from the reservoir.

RECOVERY FROM A HYDROCARBON RESERVOIR UTILIZING A MIXTURE OF STEAM AND A VOLATILE SOLVENT

FIELD

[0001] The present techniques relate to harvesting resources using gravity drainage processes. Specifically, techniques are disclosed for lowering the viscosity of bitumen without raising the temperature.

BACKGROUND

[0002] This section is intended to introduce various aspects of the art, which may be associated with exemplary embodiments of the present techniques. This discussion is believed to assist in providing a framework to facilitate a better understanding of particular aspects of the present techniques. Accordingly, it should be understood that this section should be read in this light, and not necessarily as admissions of prior art.

[0003] Modern society is greatly dependent on the use of hydrocarbons for fuels and chemical feedstocks. Hydrocarbons are generally found in subsurface rock formations that can be termed “reservoirs.” Removing hydrocarbons from the reservoirs depends on numerous physical properties of the rock formations, such as the permeability of the rock containing the hydrocarbons, the ability of the hydrocarbons to flow through the rock formations, and the proportion of hydrocarbons present, among others.

[0004] Easily harvested sources of hydrocarbon are dwindling, leaving less accessible sources to satisfy future energy needs. However, as the costs of hydrocarbons increase, these less accessible sources become more economically attractive. For example, the harvesting of oil sands to remove hydrocarbons has become more extensive as it has become more economical. The hydrocarbons harvested from these reservoirs may have relatively high viscosities, for example, ranging from 8 API, or lower, up to 20 API, or higher. Accordingly, the hydrocarbons may include heavy oils, bitumen, or other carbonaceous materials, collectively referred to herein as “heavy oil,” which are difficult to recover using standard techniques.

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[0005] Several methods have been developed to remove hydrocarbons from oil sands. For example, strip or surface mining may be performed to access the oil sands, which can then be treated with hot water or steam to extract the oil. However, deeper formations may not be accessible using a strip mining approach. For these formations, a well can be drilled to the reservoir and steam, hot air, solvents, or combinations thereof, can be injected to release the hydrocarbons. The released hydrocarbons may then be collected by the injection well or by other wells and brought to the surface.

[0006] A number of techniques have been developed for harvesting heavy oil from subsurface formations using well-based recovery techniques. These operations include a suite of steam based in-situ thermal recovery techniques, such as cyclic steam stimulation (CSS), steam flooding and steam assisted gravity drainage (SAGD) as well as surface mining and their associated thermal based surface extraction techniques.

[0007] For example, CSS techniques includes a number of enhanced recovery methods for harvesting heavy oil from formations that use steam heat to lower the viscosity of the heavy oil. These steam assisted hydrocarbon recovery methods are described in U.S. Patent No. 3,292,702 to Boberg, and U.S. Patent No. 3,739,852 to Woods, et al., among others. CSS and other steam flood techniques have been utilized worldwide, beginning in about 1956 with the utilization of CSS in the Mene Grande field in Venezuela and steam flood in the early 1960s in the Kern River field in California.

[0008] The CSS process may raise the steam injection pressure above the formation fracturing pressure to create fractures within the formation and enhance the surface area access of the steam to the heavy oil, although CSS may also be practiced at pressures that do not fracture the formation. The steam raises the temperature of the heavy oil during a heat soak phase, lowering the viscosity of the heavy oil. The injection well may then be used to produce heavy oil from the formation. The cycle is often repeated until the cost of injecting steam becomes uneconomical, for instance if the cost is higher than the money made from producing the heavy oil. However, successive steam injection cycles reenter earlier created fractures and, thus, the process becomes less efficient over time. CSS is generally practiced in vertical wells, but systems are operational in horizontal wells.

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[0009] Solvents may be used in combination with steam in CSS processes, such as in mixtures with the steam or in alternate injections between steam injections. These techniques are described in U.S. Patent No. 4,280,559 to Best, U.S. Patent No. 4,519,454 to McMillen, and U.S. Patent No. 4,697,642 to Vogel, among others.

5 **[0010]** Cyclic enhanced recovery techniques have been developed that are not based on thermal methods. For example, U.S. Patent No. 6,769,486 to Lim, et al., discloses a cyclic solvent process (CSP) for heavy oil production. In the process, a viscosity reducing hydrocarbon solvent is injected into a reservoir at a pressure sufficient to keep the hydrocarbon solvent in a liquid phase. The injection pressure may
10 also be sufficient to cause dilation of the formation. The hydrocarbon solvent is allowed to mix with the heavy oil at the elevated pressure. The pressure in the reservoir can then be reduced to allow at least a portion of the hydrocarbon solvent to flash, providing a solvent gas drive to assist in removing the heavy oil from the reservoir. The cycles may be repeated as long as economical production is achieved.

15 **[0011]** Another group of techniques is based on a continuous injection of steam through a first well to lower the viscosity of heavy oils and a continuous production of the heavy oil from a lower-lying second well. Such techniques may be termed "steam assisted gravity drainage" or SAGD. Various embodiments of the SAGD process are described in Canadian Patent No. 1,304,287 to Butler and its corresponding U.S. Patent
20 No. 4,344,485.

[0012] In SAGD, two horizontal wells are completed into the reservoir. The two wells are first drilled vertically to different depths within the reservoir. Thereafter, using directional drilling technology, the two wells are extended in the horizontal direction that result in two horizontal wells, vertically spaced from, but otherwise vertically aligned with
25 the other. Ideally, the production well is located above the base of the reservoir but as close as practical to the bottom of the reservoir, and the injection well is located vertically 10 to 30 feet (3 to 10 meters) above the horizontal well used for production.

[0013] The upper horizontal well is utilized as an injection well and is supplied with steam from the surface. The steam rises from the injection well, permeating the
30 reservoir to form a vapor chamber that grows over time towards the top of the reservoir,

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thereby increasing the temperature within the reservoir. The steam, and its condensate, raise the temperature of the reservoir and consequently reduce the viscosity of the heavy oil in the reservoir. The heavy oil and condensed steam will then drain downward through the reservoir under the action of gravity and may flow into the lower production well, whereby these liquids can be pumped to the surface. At the surface of the well, the condensed steam and heavy oil are separated, and the heavy oil may be diluted with appropriate light hydrocarbons for transport by pipeline.

[0014] A number of variations of the SAGD process have been developed in an attempt to increase the productivity of the process. Such processes may include new well placement techniques and tools used to enhance production of the heavy oil. In other variations, extensions similar to those used in CSS, such as including solvents in the process, have been made. For example, U.S. Pat. No. 6,230,814 to Nasr, et al., teaches how the SAGD process can be further enhanced through the addition of small amounts of solvent to the injected steam. Nasr teaches that as the planned SAGD operating pressure declines, the molecular weight of the solvent must be reduced in order to ensure that it is completely vaporized at the planned operating conditions. This approach results in the progressive exclusion of heavier solvents, such as naphtha, natural gas condensate and diesel for example, as lower operating pressures (and temperatures) are considered.

[0015] In some applications, the steam may be completely replaced with solvent. For example, Butler, et al., "A New Process (Vapex) for Recovering Heavy Oils," JCPT, Vol. 30, No. 1, 97-106, Jan-Feb 1991, teaches how solvent can be used instead of steam in a gravity drainage based recovery process to recover heavy oil from a subterranean reservoir.

[0016] A number of developments have focused on using solvents to lower the temperature of an extraction process. For example, Canadian Patent No. 2,243,105 to Mokrys discloses a non-thermal vapor extraction method for the recovery of hydrocarbons from deep, high pressure hydrocarbon reservoirs. The reservoirs may have been previously exploited by cold flow or may be virgin deposits. The target reservoirs are underlain by active aquifers. A mixture of a light hydrocarbon vapor

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solvent, such as ethane, propane, and butane, with reservoir natural gas is adjusted so that the dewpoint of the light hydrocarbon solvent matches the temperature and pressure conditions in the reservoir. The produced gas is analyzed for the solvent component, and enriched with the required amount of recycled solvent to match the dewpoint. The gas is then reintroduced into the reservoir as an injection gas. Both the recovered solvent and free gas are continuously circulated through the reservoir. The extraction can be accomplished by employing pairs of parallel horizontal injection/production wells, in a similar fashion to SAGD.

[0017] Similarly, Canadian Patent No. 2,494,391 and Canadian Patent Application Publication No. 2,584,712 by Chung, et al., disclose a cold solvent-based extraction method for extracting heavy oil from a reservoir. The method involves forming a solvent fluid chamber by solvent fluid injection and heavy oil production using combinations of horizontal and/or vertical injection wells. The combination may increase the recovery of heavy oil contained in a reservoir.

[0018] Solvents may also be used in concert with steam addition to increase the efficiency of the steam in removing the heavy oils. U.S. Patent No. 6,230,814 to Nasr, et al., discloses a method for enhancing heavy oil mobility using a steam additive. The method included injecting steam and an additive into the formation. The additive includes a non-aqueous fluid, selected so that the evaporation temperature of the non-aqueous fluid is within about ± 150 °C of the steam temperature at the operating pressure. Suitable additives include C_1 to C_{25} hydrocarbons. At least a portion of the additive condenses in the formation. The mobility of the heavy oil obtained with the steam and solvent combination is greater than that obtained using steam alone under substantially similar formation conditions.

[0019] In solvent based recovery processes, a volatile solvent is injected into the reservoir to mix with the oil and thereby reduce the viscosity of the oil. In the case of cyclic solvent recovery process, such as CSP, the solvent may be injected into the reservoir as a liquid, where the increase in reservoir pressure that occurs during injection helps mix the solvent and oil. During production, the pressure in the reservoir declines, allowing a portion of dissolved solvent to flash. While this flashing does add

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an expanding gas drive recovery mechanism, it comes at the expense of an increase in the oil viscosity as progressively less solvent remains dissolved in the oil.

[0020] In a gravity drainage solvent recovery process, such as VAPEX, the pressure declines in the reservoir are concentrated near the production well. These pressure reductions can allow some of the dissolved solvent to flash, resulting in an increase in the oil viscosity. When the solvent recovery process relies on horizontal production wells, the additional pressure losses occur as the fluids flow inside the liner, allowing more dissolved solvent to be flashed and a further increase in the oil viscosity results. Due to the presence of two phase flow within the liner, i.e., gas and liquid, the pressure losses and oil viscosity increases are accentuated by the presence of vertical variations in the well trajectory. Typically, these pressure losses and associated increases on oil viscosity will be more pronounced where the fluid rate in the liner is highest, i.e., closest to the production suction point, and, thus, their occurrence can compromise inflow along the entire length of the well.

[0021] In processes utilizing steam or a heated solvent or both, transient operating conditions, such as when the injection, production or both wells are shut-in, will also have a detrimental impact on the oil viscosity as during these transient conditions the accumulated fluids can continue to cool and the chamber pressure can decline, potentially reducing the solubility of the solvent in the oil. An increase in oil viscosity can also compromise the performance of artificial lift systems, such as positive displacement pumps and electric submersible pumps, on the production well.

[0022] The factors that can cause an increase in oil viscosity discussed above may leave a substantial remainder of hydrocarbons in the reservoir. For example, if a lower pressure steam is used during the production, the resulting lower temperatures will result in a higher viscosity fluid, which may lower productivity.

[0023] Various approaches are currently used to manage cooler production temperatures during the operation of thermal recovery projects. For example, the production well may be restimulated by injecting steam and allowing the steam to reheat both the fluids within the well and the near wellbore area. However, there are limitations with this approach, such as temperature limitations on artificial lift systems, which

preclude direct steam stimulation. Further, unless the production well is completed with inflow control devices (ICDs) there is no certainty as to how much of the well and near wellbore region is being reheated by steam injection. A significant investment in steam is required to reheat fluids that were previously mobilized.

5 **[0024]** Hot water may be injected in the production well and used to reheat both the fluids within the well and the near well bore area. However, unless the production well is completed with inflow control devices (ICDs) there is no certainty as to how much of the well and near well bore region is being reheated by hot water injection. Also, due to the limited heat capacity of water, a much larger volume of water must be injected to provide the same
10 heat as a volume of steam. This hot water must also be subsequently produced.

[0025] Assuming the production well can continue to be operated, produced fluids can be reheated and reinjected into neighboring production wells, injection wells, or both, and the produced fluids will be reheated by falling through the steam chamber. This process will keep the production wells that are being produced hot, and will limit the potential cool fluid
15 production issues on the limited number of wells were the fluids are being reinjected. However, the reinjection process may result in plugging of the injection liner, for example, due to fine sand or the precipitation of asphaltene.

SUMMARY

[0026] Certain exemplary embodiments can provide a method of recovering
20 hydrocarbons from a reservoir, comprising: injecting a first solvent comprising a non-volatile component into a well in the reservoir, wherein the reservoir comprises a steam chamber; injecting a mobilizing fluid into the reservoir, wherein the mobilizing fluid comprises a second volatile solvent; and producing fluid from the reservoir, wherein the fluid comprises the first solvent, the mobilizing fluid, and the hydrocarbons from the reservoir.

25 **[0027]** Certain exemplary embodiments can provide a system for recovering heavy oil from a reservoir, comprising: a reservoir comprising heavy oil; an injection well configured to inject at least a mobilizing agent into the reservoir, wherein the mobilizing fluid comprises a second volatile solvent; a production well configured to produce at least the heavy oil and the mobilizing agent from the reservoir; and a tubular placed within the injection well, the
30 production well, or both, wherein the tubular is configured to convey a first solvent into a well, and wherein the first solvent comprises a non-volatile component.

[0028] Certain exemplary embodiments can provide a method for recovering hydrocarbons from a reservoir after a no-flow condition, comprising: injecting a first solvent comprising a non-volatile component into the reservoir, wherein the solvent contacts the reservoir; soaking the first solvent in contact with the reservoir; placing the reservoir back in
5 service; injecting a mobilizing fluid into the reservoir, wherein the mobilizing fluid comprises a second volatile solvent; and producing fluid from the reservoir, wherein the fluid comprises the first solvent, the mobilizing fluid, and the hydrocarbons from the reservoir.

[0028a] Certain exemplary embodiments can provide a method of recovering hydrocarbons from a reservoir, comprising: injecting steam into an injection well in the
10 reservoir, wherein the reservoir comprises a steam chamber; injecting a mobilizing fluid into the reservoir via the injection well, wherein the mobilizing fluid comprises a volatile solvent; and producing fluid from the reservoir via a production well, wherein the fluid comprises condensed steam, the mobilizing fluid, and the hydrocarbons from the reservoir; wherein:
15 the injection well is located in the steam chamber at a location vertically above the production well; and the volatile solvent flashes within the reservoir and at least a portion of the volatile solvent rises into the steam chamber and mixes with oil that is within the steam chamber.

DESCRIPTION OF THE DRAWINGS

[0029] The advantages of the present techniques are better understood by referring to
20 the following detailed description and the attached drawings, in which:

[0030] Fig. 1 is a drawing of a steam assisted gravity drainage (SAGD) process used for accessing hydrocarbon resources in a reservoir;

[0031] Fig. 2 is a drawing of a SAGD well pair in a reservoir;

[0032] Fig. 3 is a drawing of the SAGD well pair of Fig. 2 during a period in which
25 production operations have been halted;

[0033] Fig. 4 is a drawing of a SAGD drainage chamber, in which production fluids from neighboring patterns is injected to slow the cooling of the fluids in those source chambers;

[0034] Fig. 5 is a drawing of a horizontal portion of one possible configuration of a SAGD steam injection well;

[0035] Fig. 6 is a drawing of a path that an injected mobilizing agent, such as steam or a steam and solvent mixture, might travel through the drainage chamber before it encounters the interface with the undepleted oil of the reservoir;

[0036] Fig. 7 is a drawing of a path through the chamber that an injected mobilizing agent
5 that includes a nonvolatile component may travel through a chamber;

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[0037] Fig. 8 is a drawing of the horizontal portion of an injection well, in which a partially volatile solvent is injected via a separate tubing string that extends to the toe of the liner;

5 **[0038]** Fig. 9 is another drawing of a horizontal portion of an injection well, in which a partially volatile solvent is injected via a separate tubing string that extends to the toe of the liner;

[0039] Fig. 10 is a drawing of the horizontal portion of a production well, in which a partially volatile solvent is injected via a separate tubing string that extends to the toe of the liner;

10 **[0040]** Fig. 11 is a process flow diagram of a method for increasing hydrocarbon production by the injection of a non-volatile solvent into a reservoir to decrease a viscosity of the hydrocarbon;

[0041] Fig. 12 is a semi-log plot of viscosity versus temperature for an Athabasca heavy oil sample; and

15 **[0042]** Fig. 13 is a plot of viscosities versus solvent concentration in blends.

DETAILED DESCRIPTION

[0043] In the following detailed description section, specific embodiments of the present techniques are described. However, to the extent that the following description is specific to a particular embodiment or a particular use of the present techniques, this
20 is intended to be for exemplary purposes only and simply provides a description of the exemplary embodiments. Accordingly, the techniques are not limited to the specific embodiments described below, but rather, include all alternatives, modifications, and equivalents falling within the true spirit and scope of the appended claims.

[0044] At the outset, for ease of reference, certain terms used in this application and
25 their meanings as used in this context are set forth. To the extent a term used herein is not defined below, it should be given the broadest definition persons in the pertinent art have given that term as reflected in at least one printed publication or issued patent. Further, the present techniques are not limited by the usage of the terms shown below, as all equivalents, synonyms, new developments, and terms or techniques that serve

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the same or a similar purpose are considered to be within the scope of the present claims.

[0045] As used herein, the term “base” indicates a lower boundary of the resources in a reservoir that are practically recoverable, by a gravity-assisted drainage technique, for example, using an injected mobilizing fluid, such as steam, solvents, hot water, gas, and the like. The base may be considered a lower boundary of the payzone. The lower boundary may be an impermeable rock layer, including, for example, granite, limestone, sandstone, shale, and the like. The lower boundary may also include layers that, while not completely impermeable, impede the formation of fluid communication between a well on one side and a well on the other side. Such layers, which may include inclined heterolithic strata (IHS) of broken shale, mud, silt, and the like. The resources within the reservoir may extend below the base, but the resources below the base may not be recoverable with gravity assisted techniques.

[0046] “Bitumen” is a naturally occurring heavy oil material. Generally, it is the hydrocarbon component found in oil sands. Bitumen can vary in composition depending upon the degree of loss of more volatile components. It can vary from a very viscous, tar-like, semi-solid material to solid forms. The hydrocarbon types found in bitumen can include aliphatics, aromatics, resins, and asphaltenes. A typical bitumen might be composed of:

19 wt. % aliphatics (which can range from 5 wt. %-30 wt. %, or higher);
 19 wt. % asphaltenes (which can range from 5 wt. %-30 wt. %, or higher);
 30 wt. % aromatics (which can range from 15 wt. %-50 wt. %, or higher);
 32 wt. % resins (which can range from 15 wt. %-50 wt. %, or higher); and
 some amount of sulfur (which can range in excess of 7 wt. %).

In addition bitumen can contain some water and nitrogen compounds ranging from less than 0.4 wt. % to in excess of 0.7 wt. %. The metals content, while small, must be removed to avoid contamination of the product synthetic crude oil (SCO). Nickel can vary from less than 75 ppm (part per million) to more than 200 ppm. Vanadium can range from less than 200 ppm to more than 500 ppm. The percentage of the

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hydrocarbon types found in bitumen can vary. As used herein, the term “heavy oil” includes bitumen, as well as lighter materials that may be found in a sand or carbonate reservoir.

5 [0047] As used herein, a pressure “cycle” represents a sequential increase to peak operating pressure in a reservoir, followed by a release of the pressure to a minimum operating pressure. The elapsed time between two periods of peak operating pressure does not have to be the same between cycles, nor do the peak operating pressures and minimum operating pressures.

10 [0048] As used herein, two locations in a reservoir are in “fluid communication” when a path for fluid flow exists between the locations. For example, fluid communication between a production well and an overlying steam chamber can allow mobilized material to flow down to the production well for collection and production. As used herein, a fluid includes a gas or a liquid and may include, for example, a produced hydrocarbon, an injected mobilizing fluid, or water, among other materials.

15 [0049] As used herein, a “cyclic recovery process” uses an intermittent injection of injected mobilizing fluid selected to lower the viscosity of heavy oil in a hydrocarbon reservoir. The injected mobilizing fluid may include steam, solvents, gas, water, or any combinations thereof. After a soak period, intended to allow the injected material to interact with the heavy oil in the reservoir, the material in the reservoir, including the
20 mobilized heavy oil and some portion of the mobilizing agent may be harvested from the reservoir. Cyclic recovery processes use multiple recovery mechanisms, in addition to gravity drainage, early in the life of the process. The significance of these additional recovery mechanisms, for example dilation and compaction, solution gas drive, water flashing, and the like, declines as the recovery process matures. Practically speaking,
25 gravity drainage is the dominant recovery mechanism in all mature thermal, thermal-solvent and solvent based recovery processes used to develop heavy oil and bitumen deposits, such as steam assisted gravity drainage (SAGD). For this reason the approaches disclosed here are equally applicable to all recovery processes in which at the current stage of depletion gravity drainage is the dominant recovery mechanism.

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[0050] “Facility” as used in this description is a tangible piece of physical equipment through which hydrocarbon fluids are either produced from a reservoir or injected into a reservoir, or equipment which can be used to control production or completion operations. In its broadest sense, the term facility is applied to any equipment that may
5 be present along the flow path between a reservoir and its delivery outlets. Facilities may comprise production wells, injection wells, well tubulars, wellhead equipment, gathering lines, manifolds, pumps, compressors, separators, surface flow lines, steam generation plants, processing plants, and delivery outlets. In some instances, the term “surface facility” is used to distinguish those facilities other than wells.

[0051] “Heavy oil” includes oils which are classified by the American Petroleum Institute (API), as heavy oils, extra heavy oils, or bitumens. In general, a heavy oil has an API gravity between 22.3° (density of 920 kg/m³ or 0.920 g/cm³) and 10.0° (density of 1,000 kg/m³ or 1 g/cm³). An extra heavy oil, in general, has an API gravity of less than 10.0° (density greater than 1,000 kg/m³ or greater than 1 g/cm³). For example, a
15 source of heavy oil includes oil sand or bituminous sand, which is a combination of clay, sand, water, and bitumen. The thermal recovery of heavy oils is based on the viscosity decrease of fluids with increasing temperature or solvent concentration. Once the viscosity is reduced, the mobilization of fluids by steam, hot water flooding, or gravity is possible. The reduced viscosity makes the drainage quicker and therefore directly
20 contributes to the recovery rate.

[0052] A “hydrocarbon” is an organic compound that primarily includes the elements hydrogen and carbon, although nitrogen, sulfur, oxygen, metals, or any number of other elements may be present in small amounts. As used herein, hydrocarbons generally refer to components found in heavy oil or in oil sands. However, the techniques
25 described herein are not limited to heavy oils, but may also be used with any number of other reservoirs to improve gravity drainage of liquids.

[0053] “Inclined heterolithic strata” or IHS are layers of rock containing hydrocarbons that can form above or below sand layers in an oil sands reservoir. The layers of rock in IHS are often shale layers formed from clay or other sediments layered over or under
30 sand beds. The hydrocarbons may be trapped between the layers of rock. As IHS

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layers may be poorly drained, it may be problematic to produce hydrocarbons by gravity drainage from an IHS layer over a sand layer.

[0054] As used herein, “poorer quality facies” are intervals in a reservoir that can have poor drainage, often due to a difficulty in establishing a counter-current flow. In an oil sands reservoir, poorer quality facies may include IHS layers above the higher quality sands of a clean pay interval.

[0055] “Permeability” is the capacity of a rock to transmit fluids through the interconnected pore spaces of the rock. The customary unit of measurement for permeability is the millidarcy.

[0056] “Pressure” is the force exerted per unit area by the gas on the walls of the volume. Pressure can be shown as pounds per square inch (psi). “Atmospheric pressure” refers to the local pressure of the air. “Absolute pressure” (psia) refers to the sum of the atmospheric pressure (14.7 psia at standard conditions) plus the gauge pressure (psig). “Gauge pressure” (psig) refers to the pressure measured by a gauge, which indicates only the pressure exceeding the local atmospheric pressure (i.e., a gauge pressure of 0 psig corresponds to an absolute pressure of 14.7 psia). The term “vapor pressure” has the usual thermodynamic meaning. For a pure component in an enclosed system at a given pressure, the component vapor pressure is essentially equal to the total pressure in the system.

[0057] As used herein, a “reservoir” is a subsurface rock or sand formation from which a production fluid, or resource, can be harvested. The rock formation may include sand, granite, silica, carbonates, clays, and organic matter, such as bitumen, heavy oil, oil, gas, or coal, among others. Reservoirs can vary in thickness from less than one foot (0.3048 m) to hundreds of feet (hundreds of m). The resource is generally a hydrocarbon, such as a heavy oil impregnated into a sand bed.

[0058] As discussed herein, “Steam Assisted Gravity Drainage” (SAGD), is a thermal recovery process in which steam, or combinations of steam and solvents, is injected into a first well to lower a viscosity of a heavy oil, and fluids are recovered from a second well. Both wells are generally horizontal in the formation and the first well lies above the second well. Accordingly, the reduced viscosity heavy oil flows down to the

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second well under the force of gravity, although pressure differential may provide some driving force in various applications. Although SAGD is used as an exemplary process herein, it can be understood that the techniques described can include any gravity driven process, such as those based on steam, solvents, or any combinations thereof.

- 5 **[0059]** “Substantial” when used in reference to a quantity or amount of a material, or a specific characteristic thereof, refers to an amount that is sufficient to provide an effect that the material or characteristic was intended to provide. The exact degree of deviation allowable may in some cases depend on the specific context.

- 10 **[0060]** As used herein, “thermal recovery processes” include any type of hydrocarbon recovery process that uses a heat source to enhance the recovery, for example, by lowering the viscosity of a hydrocarbon. These processes may use injected mobilizing fluids, such as hot water, wet steam, dry steam, or solvents alone, or in any combinations, to lower the viscosity of the hydrocarbon. Such processes may include subsurface processes, such as cyclic steam stimulation (CSS), cyclic solvent
15 stimulation, steam flooding, solvent injection, and SAGD, among others, and processes that use surface processing for the recovery, such as sub-surface mining and surface mining. Any of the processes referred to herein, such as SAGD, may be used in concert with solvents.

- 20 **[0061]** A “tubular” refers to a fluid conduit having an axial bore, and includes, but is not limited to, a riser, a casing, a production tubing, a liner, and any other type of wellbore tubular known to a person of ordinary skill in the art.

- 25 **[0062]** A “wellbore” is a hole in the subsurface made by drilling or inserting a conduit into the subsurface. A wellbore may have a substantially circular cross section or any other cross-sectional shape, such as an oval, a square, a rectangle, a triangle, or other regular or irregular shapes. As used herein, the term “well,” when referring to an opening in the formation, may be used interchangeably with the term “wellbore.” Further, multiple pipes may be inserted into a single wellbore, for example, as a liner configured to allow flow from an outer chamber to an inner chamber.

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Overview

[0063] Simulations have shown that reductions in SAGD operation pressure enables a significant improvement in thermal efficiency, for example, as measured by steam-to-oil ratio (SOR), as the reservoir is heated to a lower temperature. However as the
5 operating temperature decreases, the viscosities of the bitumen and bitumen-water emulsion increase, impairing inflow near and within the production well. The differences in viscosity for a change in operating pressure, once an allowance for operating in a sub-cooled regime is applied, are even larger.

[0064] Further, as a hydrocarbon field matures, the amount of steam required to
10 completely fill the drainage chambers of the field may substantially increase, as the drainage chambers increase in size over time. If insufficient steam supply is available, this may also lead to a decrease in overall steam chamber pressure and, thus, lower the temperature of the chamber. The higher oil viscosity that results from the lower temperature operations can impair the performance of SAGD by reducing the drainage
15 of the oil. Longer well pairs or more well pairs for the project may be drilled to achieve the same oil production rate that could be achieved at higher pressures and temperatures.

[0065] In embodiments described herein, a heavy solvent is injected into the well to maintain production rates at lower temperatures. The heavy solvent, such as diluent,
20 naphtha, or distillate, among others, does not materially vaporize, and can reduce the viscosity of the bitumen and emulsion, increasing the flow rates. This can reduce the pressure drop in the reservoir near and within the production well.

[0066] In some embodiments, the heavy solvent can be injected using a separate small diameter tubular within a production or injection well, for example, extending to
25 the toe of the injection well liner. The small diameter tubular can be completed with a series of smaller diameter holes which allow small volumes of the solvent to be injected uniformly along the liner length. In the case of an injection well, the solvent would then fall under the influence of gravity into the accumulation of the bitumen, emulsion and water present in the vicinity of the production well. Alternatively, all of the solvent can
30 be injected at the toe location. In the case of a production well, it will mix with the

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bitumen as it enters the liner and flow back along the length of the liner. However, near production well viscosities may be more substantially reduced from more even injection.

[0067] The reduced bitumen and emulsion viscosities in the near-production well reservoir area and within the production liner may enable the utilization of longer or smaller diameter liners in these environments. This may be useful in lower pressure SAGD and/or solvent assisted recovery process applications, such as Vapex and CSP, or when the oil is very viscous. In these cases, a reduction in pressure near and within the production wells may cause a light solvent to be flashed, thereby increasing the viscosity of the bitumen and impairing productivity.

[0068] The injection of either a partially volatile or a nonvolatile solvent to improve the performance of a thermal, thermal-solvent or solvent based recovery process can provide viscosity reduction from the blending of a volatile portion of the solvent with oil located within the reservoir and the non-volatile portion of the solvent blending with oil located in or near the production well. The benefits can be achieved during both normal operations or during periods in which production, injection or both operations are temporarily shut-in. For example, a small diameter tubing string in the production well may be used to introduce a small volume of non-volatile or partially volatile solvent into the production wellbore during production operations.

[0069] Although a portion of the solvent may flash due to the specific pressure and temperature conditions within the wellbore, the non-volatile portion of the solvent will mix with the produced oil, reducing its viscosity within the wellbore. The volatile portion of the solvent may leave the production liner and rise into the steam chamber. This portion of the solvent may mix with the oil located at the edges of the chamber and/or accumulate at the top of the chamber in the form of an insulating layer that helps reduce heat losses.

[0070] In the case of a horizontal well (HW), a small diameter tubing string can extend fully or partially into the production liner. The tubing can be configured to inject non-volatile or partially volatile solvent only at the toe of the liner, relying on continued production from the well to fully mix it with the incoming production from the reservoir as it moves towards the production location. In some embodiments, the small tubing string

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can contain a series of small openings along its lengths to enable the injection of a small quantity of non-volatile or partially volatile solvent along the length of the production well bore.

[0071] In the event of a planned production shut-in event, non-volatile or partially volatile solvent injection in the production well can occur, or be increased, over several days prior to the actual shut-in. In this way production contained in surface lines between the well and the central processing facility will see a viscosity benefit due to the solvent addition even as the surface production lines cool. During the shut-in period, additional non-volatile or partially volatile solvent can be injected on a continuous or intermittent basis, into the production well. Due to its slightly lighter density than the oil, the non-volatile portion of the solvent will slowly rise, leaving the liner and mix with the accumulating fluids located outside the production well.

[0072] In a gravity drainage based recovery process which relies on separate, but closely spacing wells for injection and production, it is possible to introduce the non-volatile or partially volatile solvent blended with the steam, steam-solvent blend or light solvent being injected, or via a separate small diameter tubing string that extends fully or partially into the injection liner. In this configuration, the non-volatile portion of the solvent will exit the injector well liner, under the influence of gravity, and fall into the accumulation of liquids above the production well. The volatile portion of the solvent will move through the chamber before condensing, or dissolving into the oil located, at the edges of the chamber. An advantage of this configuration is that it further reduces the oil viscosity in the region of converging flow near the production well.

[0073] In some embodiments, the pressure drop in the near wellbore area may be reduced, resulting in a further increase in production. The solvent can be blended with the production fluids on surface prior to injecting the fluids into neighboring wells. However, this procedure may result in plugging of the injection liner, for example, due to fine sand or asphaltene precipitation.

Steam Assisted Gravity Drainage

[0074] Fig. 1 is a drawing of a steam assisted gravity drainage (SAGD) process used for accessing hydrocarbon resources in a reservoir. In the SAGD process

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100, steam **104** can be injected through injection wells **106** to the reservoir **102**. As previously noted, the injection wells **106** may be horizontally drilled through the reservoir **102**. Production wells **108** may be drilled horizontally through the reservoir **102**, with a production well **108** underlying each injection well **106**. Generally, the injection wells
5 **106** and production wells **108** will be drilled from the same pad **110** at the surface **112**. This may make it easier for the production well **108** to track the injection well **106**. However, in some embodiments the wells **106** and **108** may be drilled from different pads **110**, for example, if the production well **108** is an infill well.

[0075] The injection of steam **104** into the injection wells **106** may result in the
10 mobilization of hydrocarbons **114**, which may drain to the production wells **108** and be removed to the surface **112** in a mixed stream **116** that can contain hydrocarbons, condensate and other materials, such as water, gases, and the like. Sand filters may be used in the production wells **108** to decrease sand entrainment.

[0076] The mixed stream **116** from a number of production wells **108** may be
15 combined and sent to a processing facility **118**. At the processing facility **118**, the water and hydrocarbons **120** can be separated, and the hydrocarbons **120** sent on for further refining. Water from the separation may be recycled to a steam generation unit within the facility **118**, with or without further treatment, and used to generate the steam **104** used for the SAGD process **100**.

[0077] The production wells **108** may have a segment that is relatively flat, which, in
20 some developments, may have a slight upward slope from the heel **122**, at which the pipe branches to the surface, to the toe **124**, at which the pipe ends. When present, an upward slope of this horizontal segment may result in the toe **124** being around one to five meters higher than the heel **122**, depending on the length of the horizontal
25 segment. The slight slope can assist in draining fluids that enter the horizontal segment to the heel **122** for removal.

[0078] In some embodiments, a temperature of the steam injected into the injection
well **106** may be lowered, for example, when production is started in new regions of the reservoir. As this may lead to lower recovery due to increased viscosity, a solvent with
30 a non-volatile component may be injected into the reservoir to lower the viscosity of

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materials. This may be performed through a tube reaching to the toe **124** of a well in the reservoir. The injection may be performed during startup, production, or during a shut-in period. In some embodiments, the solvent may be injected through a first well drilled through the reservoir and left to soak in the reservoir while other wells, and the surface facilities, are completed. For example, an injection well may be drilled into the reservoir, and the solvent injected while the production well is being completed.

[0079] A solvent may be injected into one or more wells after completion of multiple wells. For example, the drilling may be completed to the reservoir and a solvent may be injected to soak in the reservoir while the surface facilities are being completed. This can lower the time to fluid communication between the wells once steam injection has been started.

[0080] For the purposes of this description, SAGD is used as the representative recovery process. However, it can be noted that the approaches disclosed here are equally applicable to all thermal, thermal-solvent and solvent based recovery processes.

[0081] Fig. 2 is a drawing **200** of a SAGD well pair **202** in a reservoir **204**. The upper horizontal well is an injection well **206** that is used for the injection of materials, while the lower horizontal well is a production well **208** that is used for the production of fluids, including oil, water, and solvent. The production rates are regulated to minimize the volume of the liquids **210**, such as oil, condensed steam, and solvent that accumulates above the production well **208** in the base of the steam chamber **212**. Injection rates are regulated to maintain a specified operating pressure in the steam chamber **212**, for example, between about 150 kPa and 6500 kPa. The pressure selected depends on the characteristics of the field, including the depth of the reservoir, the number of wells operating, the steam capacity, the age of adjacent sections, and the like.

[0082] Fig. 3 is a drawing **300** of the SAGD well pair of Fig. 2 during a period in which production operations have been halted. Even without additional steam injection occurring, the steam present in the steam chamber **212** will continue to condense at the interface **302** between the steam chamber **212** and the undepleted reservoir **204**. Mobilized oil and condensed steam (condensate) will drain down the interface **302** and accumulate in the liquid sump **304**. Accordingly, the liquid sump **304** will progressively

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increase in depth, as indicated by an arrow **306**, as the duration of the shut-in increases. As the liquid sump **304** is the shape of an inverted triangle, the vertical rise rate will decline with time as the accommodation space in the liquid sump **304** per unit of height is increasing. When steam injection has also been shut-in, the decline in the pressure of the steam chamber **212**, along with the temperature, will also slow the gravity drainage rate along the interface **302**. This inverted triangle shape also influence the rate at which the accumulating fluids will cool.

[0083] Near the bottom of the liquid sump **304** the quantity of surface area for heat loss per volume of liquid in the liquid sump **304**, and the total time available for the liquids to cool, are higher than near the top. Thus, the top of the steam chamber **212** cools more slowly. As the cooler temperatures increase the density of both the oil and water, heat cannot be effectively redistributed vertically via convection cells. Thus, in one embodiment, the injection of a non-volatile solvent during the shut-in period may be used to maintain a lower viscosity of the materials in the liquid sump **304**. This may shorten the period of time it takes to restart production.

[0084] Fig. 4 is a drawing **400** of a SAGD drainage chamber **402**, in which production fluids from neighboring patterns is injected to slow the cooling of the fluids in those source chambers. Like numbered items are as described with respect to the previous figures. In the SAGD drainage chamber **402** receiving the injected production fluids, the injection helps mix the fluids **404**, and, thus, prevent the fluids **404** near the base of the liquid sump **304** from cooling too much. The total volume of fluids **404** that accumulate in this SAGD drainage chamber **402** is much higher than if production injection did not occur. Thus, in one embodiment, the injection of a non-volatile solvent during the shut-in period may be used to maintain a lower viscosity of the materials in the liquid sump **304**.

[0085] Fig. 5 is a drawing **500** of a horizontal portion of one possible configuration of a SAGD steam injection well. In this figure, the injection of steam or a steam and solvent mixture occurs via both the liner annulus **502** and via a tubing string **504** that extends to near the toe **506** of the liner **508**. Steam or a steam and solvent combination enters the reservoir along all portions of the liner **508**, as indicated by arrows **510**.

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[0086] Fig. 6 is a drawing **600** of a path that an injected mobilizing agent **602**, such as steam or a steam and solvent mixture, might travel through the drainage chamber **212** before it encounters the interface **302** with the undepleted oil of the reservoir **204**. Once the mobilizing agent **602** reaches the interface **302**, it will condense and the resulting fluids **604**, including water, heated oil, and any condensing solvent, will drain down the interface **302** of the chamber **212** to the liquid sump **304**. The use of a solvent may lower the viscosity of the oil in the chamber **212**, allowing the same production rates at lower temperatures.

[0087] Fig. 7 is a drawing of a path through the chamber **212** that an injected mobilizing agent that includes a nonvolatile component may travel through a chamber **212**. Like numbered items are as described with respect to previous figures. In this embodiment, the injected mobilizing agent may include both volatile components, such as steam or a steam and solvent mixture, and a non-volatile component, such as a non-volatile solvent. The volatile components may follow the same paths **602** and **604** discussed with respect to Fig. 6. Thus, once the steam and volatile portion **702** of the solvent reach the interface **302**, they will condense and the resulting mixture **704** will drain down the edge of the chamber **212** to the liquid sump **304**. The non-volatile portion **706** of the solvent will drain under the influence of gravity, directly into the liquid sump **304** located above the production well **202**. In the sump **304** the non-volatile portion of the solvent will mix with the drained oil, further reducing its viscosity.

[0088] A solvent does not need to be injected into a single inner tubular to travel to the toe of the well in a mixture with the steam. In some embodiments, multiple tubulars may be used to carry the solvent into the well, as discussed with respect to Figs. 8 and 9.

[0089] Fig. 8 is a drawing of the horizontal portion **800** of an injection well **202**, in which a partially volatile solvent **802** is injected via a separate tubing string **804** that extends to the toe **506** of the liner **508**. Like numbered items are as described with respect to the previous figures. In this configuration, the solvent is injected at a single location **806**, and flows down through the drainage chamber **212**. The short time that the solvent falls through the drainage chamber **212** may result in a reduction in the

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fraction of the solvent vaporized and, thus, the amount of solvent that is available for use at the interface **302** of the drainage chamber **212**.

[0090] Fig. 9 is another drawing of a horizontal portion **900** of an injection well **202**, in which a partially volatile solvent **902** is injected via a separate tubing string **904** that
5 extends to the toe **506** of the liner **508**. Like numbered items are as described with respect to the previous figures. In this embodiment, the separate tubing string **904** is completed with a number of holes along the length of the separate tubing string **904** and the end **906** of the separate tubing string **904** has been plugged. This creates a number of solvent injection points **908** along the length of the liner **508**, which is regulated by the
10 number, size, and distribution of the holes along the length of the separate tubing string **904**. This may result in an improvement in the distribution of solvent injection, both along the length of the liner **508**, and within the underlying liquid sump **304** relative to the configuration used in Fig. 8.

[0091] As a result of the addition of the non-volatile portion of the solvent to the
15 liquids accumulating in the liquid sump **304**, the viscosity of the oil is reduced in proximity to the production well **208**. As this is the region with the smallest cross-sectional area for flow as it converges to the production well **208**, the additional viscosity reduction will result in a reduction in the pressure drop required to produce the diluted oil and condensate.

[0092] The solvent does not have to be injected into the injection well **202**, but may
20 be injected into the production well **208**. This is discussed further with respect to Fig. 10.

[0093] Fig. 10 is a drawing of the horizontal portion **1000** of a production well **206**, in which a partially volatile solvent **902** is injected via a separate tubing string **904** that
25 extends to the toe **506** of the liner **508**. Like numbered items are as shown and described with respect to earlier figures. The separate tubing string **904** is completed with a number of holes along the length of the separate tubing string **904**, resulting in a more uniform distribution of solvent injection points **908** along the length of the liner **508**. This tubular configuration can be used to introduce small volumes of solvent into the
30 production liner **508** to mix with the production fluids **1002**, such as oil and water being

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produced from the reservoir. The lower viscosity of the resulting mixture **1004** will result in an increased flow capacity and/or lower pressure drop along the production well **206**.

[0094] When there is a volatile component to the solvent, buoyancy will allow it to leave the liner **508**, as indicated by arrows **1006**, and migrate into the overlying liquid sump **304**, where some of the solvent may be dissolved in the oil contained in sump **304**. The remainder will flow into the drainage chamber **212**. This solvent may travel to the interface **302** of the drainage chamber **212** and the surrounding reservoir **204** and used to reduce the viscosity of the draining oil. All, or a portion, may accumulate in the upper reaches of the drainage chamber **212** and act as a gas blanket to further reduce overburden heat losses.

[0095] To this point in the description, the focus has been on how the addition of a partially volatile solvent can be used during ongoing SAGD operations to beneficially improve the viscosity characteristics of the produced oil. These beneficial characteristics can be achieved at the interface **302** of the drainage chamber **212** with the reservoir **204**, in the liquid sump **304** located above the production well **206** and within the production well **206**.

[0096] The relative contributions of these sources of viscosity improvement can be optimized through the selection of the relative volatility of the solvent being injected. To increase the benefits observed inside the production well **208** and liquid sump **304**, a low volatility solvent, such as a naphtha, an alkane, and the like, can be used. The solvent can be introduced via a separate injection string in the injector and/or producer. To increase the benefits observed at the interface **302** of the drainage chamber **212** and the oil of the reservoir **204** a higher volatility solvent may be selected.

[0097] If a higher volatility solvent is used, the solvent can be selected so that some of the injected solvent always remains as a liquid. The higher volatility solvent may be introduced through the steam injection string in the injection well **206**. In some embodiments, the partially volatile solvent may be injected through both the injection and production wells on either a continuous or on a regular, but intermittent, basis to achieve the desired results.

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[0098] Fig. 11 is a process flow diagram of a method **1100** for increasing hydrocarbon production by the injection of a non-volatile solvent into a reservoir to decrease a viscosity of the hydrocarbon. The method **1100** begins at block **1102**, with the injection of a solvent comprising a non-volatile component. As described above, this may be done in concert with a steam injection or separately. The solvent may be injected through a separate tubular into the reservoir. The solvent may be injected during a shutdown, or before production is started from a field, to decrease the amount of time needed to start the production.

[0099] At block **1104**, a mobilizing fluid is injected into the reservoir. In some embodiments, the mobilizing fluid may be steam used to heat the reservoir. The mobilizing fluid can be injected at the same time as the non-volatile solvent.

[0100] At block **1106**, fluid is produced from the reservoir. The fluid may include oil, water, entrained gas and any injected solvent. The gas, water, and solvent may be separated from the oil and the solvent reused for further production. In some embodiments, the solvent may be left in a mixture with the oil, and used to lower the viscosity for shipping.

[0101] Fig. 12 is a semi-log plot **1200** of viscosity versus temperature for an Athabasca heavy oil sample. The y-axis **1202** represents the log of the viscosity in centipoise (cP), while the x-axis **1204** represents the temperature in °C. The semi-log plot **1200** shows that reducing the temperature from about 300 °C to about 200 °C causes the viscosity **1206** to increase from about 3 cP to about 11 cP, a fourfold increase. Decreasing the temperature from about 200 °C to about 100 °C, increases the viscosity **1206** from about 11 cP to about 370 cP, a thirty fold increase. Similarly, decreasing the temperature from about 100 °C to about 50 °C increases the viscosity **1206** from about 370 cP to about 22,000 cP, which is a sixty fold increase.

[0102] As previously noted, in thermal based recovery processes, the oil will tend to cool as it travels through the reservoir towards the production well. In the case of a cyclic steam recovery process, such as cyclic steam stimulation (CSS), the cooling is driven by the reduction in operating pressure that occurs during the production cycle as well as cooling of the oil that occurs as a result of heat losses as it travels along the

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underburden, or portion of the oil deposit that is still too cool/viscous to be effectively produced.

[0103] In a gravity drainage steam recovery process, such as SAGD, the maximum viscosity reduction is dictated by the operating pressure and temperature of the steam chamber, and the viscosity characteristics of the oil. For a given oil, the decision to operate at a lower steam chamber operating pressure will result in the draining oil having a higher viscosity than if a higher operating pressure was selected.

[0104] Additional cooling of the mobilized oil is driven by heat losses as it travels along the boundary with the portion of the oil deposit that is still too cool or viscous to be produced. Additional heat losses occur within the accumulation of fluids above the production well. When the thermal recovery process relies on horizontal production wells, the additional heat losses occur to the underburden as the fluids flow inside the liner. These heat losses will be more pronounced where the fluid rate along the liner is lowest, for example, furthest from the production suction point.

[0105] Because the viscosity of oil is a double log function of temperature, as shown in the semi-log plot **1200**, each incremental reduction in temperature has a progressively larger impact on viscosity. However, a lower chamber pressure, and the resulting lower temperature, also increases the productivity improvement that may be obtained for a dilution related viscosity reduction to be captured by incorporating a volatile portion to the solvent being injected.

[0106] This is because the volatile solvent component is able to contribute a more material increment to the viscosity reduction of the draining oil. The more rapid drainage shrinks the relative depth of penetration of the conductively heated region that would otherwise occur at lower operating temperatures. Reducing this stored heat component allows an improvement in the thermal efficiency of the injected steam.

[0107] The non-volatile portion of the solvent injected contributes more decreasing the viscosity as the desired operating pressure (and temperature) decreases. For this reason, various embodiments use higher molecular weight solvents, or solvent blends, that are either partially volatile or non-volatile at the planned operating conditions.

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[0108] While the description has focused on SAGD as the recovery process, the application of a nonvolatile or partially volatile solvent can be utilized in any number of recovery processes in which a viscosity reduction may allow for enhanced oil recovery. For example, a temperature based oil viscosity reduction may be replaced with a
5 dilution based oil viscosity reduction during a period of time where temperatures are expected to cool, such as a planned or unplanned interruption in production operations.

[0109] Further, a volatile solvent based oil viscosity reduction may be replaced with a non-volatile or dilution based oil viscosity reduction during a period of time, or step in the recovery operation, where pressures are expected to decline. For example, this
10 may be done during a planned or unplanned interruption in injection operations or in association with a flow into, or within, the production well. The addition of the solvent can result in a substantial decrease in viscosity, as discussed with respect to Fig. 13.

[0110] Fig. 13 is a plot 1300 of viscosities versus solvent concentration in blends. In Fig. 13, the x-axis 1302 represents the temperature in Celsius, while the y-axis 1304
15 represents a log of the viscosity in centipoise (cP). The lowest viscosity curve 1306 represents the viscosity of a pure xylene solution, while the highest viscosity curve 1308 represents Athabasca heavy oil. As can be seen from the plot 1300, the addition of even small amounts of xylene to the heavy oil results in a substantial decrease in viscosity, wherein the effects are higher at lower temperatures.

20 *Embodiments*

[0111] Embodiments described herein include any combinations of the elements in the following numbered paragraphs.

1. A method of recovering hydrocarbons from a reservoir, including
injecting a solvent including a non-volatile component into a well in the reservoir;
25 injecting a mobilizing fluid into the reservoir; and
producing fluid from the reservoir, wherein the fluid includes the solvent, the mobilizing fluid, and the hydrocarbons from the reservoir.

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2. The method of paragraph 1, where the mobilizing fluid is steam, heated water, volatile solvent, or any combinations thereof.
3. The method of paragraphs 1 or 2, including co-injecting the solvent with the mobilizing fluid.
- 5 4. The method of paragraphs 1, 2, or 3, including injecting the solvent separately from the mobilizing fluid.
5. The method of any of the preceding paragraphs, including injecting the solvent on a continuous basis.
6. The method of any of the preceding paragraphs, including injecting the solvent
10 prior to the start of a process shutdown.
7. The method of any of the preceding paragraphs, including injecting the solvent during a restart period after a process shutdown.
8. The method of any of the preceding paragraphs, including heating the solvent before injection.
- 15 9. The method of any of the preceding paragraphs, including injecting the solvent using a tubular in either an injection well, a production well, or both.
10. The method of any of the preceding paragraphs, including injecting the same solvent into both an injection well and a production well.
11. The method of any of the preceding paragraphs, wherein the volume of solvent
20 injected into the reservoir is limited to an amount used to make a blend with the hydrocarbon for shipping.
12. The method of any of the preceding paragraphs, including:
 - injecting the solvent into a production well, an injection well, or both;
 - recovering the solvent; and
 - 25 reinjecting the solvent into an alternate injection or production well.
13. A system for recovering heavy oil from a reservoir, including:
 - a reservoir including heavy oil;

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an injection well configured to inject at least a mobilizing agent into the reservoir;
 a production well configured to produce at least the heavy oil and the mobilizing agent from the reservoir; and

5 a tubular placed within the injection well, the production well, or both, wherein the tubular is configured to convey a solvent into a well, and wherein the solvent includes a non-volatile component.

14. The system of paragraph 13, wherein the solvent is the same solvent used to dilute the heavy oil for shipping.

10 15. The system of paragraphs 13 or 14, wherein a different solvent is injected in each of the production well and the injection well.

16. The system of any of paragraphs 13-15, where at least 50 vol. % of the injected solvent remains as a liquid at the conditions in the reservoir.

17. The system of any of paragraphs 13-16, wherein the solvent includes an inorganic component.

15 18. The system of any of paragraphs 13-17, including an artificial lift system configured to remove production fluids from the production well.

19. The system of paragraph 18, where the volume of solvent injected lowers the viscosity of an oil/solvent blend to stay below a viscosity constraint associated with an artificial lift system.

20 20. The system of any of paragraphs 13-19, wherein the production well, the injection well, or both, are horizontal.

21. A method for recovering hydrocarbons from a reservoir after a no-flow condition, including:

25 injecting a solvent including a non-volatile component into the reservoir, wherein the solvent contacts the reservoir;
 soaking the solvent in contact with the reservoir;
 placing the reservoir back in service;

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injecting a mobilizing fluid into the reservoir; and

producing fluid from the reservoir, wherein the fluid includes the solvent, the mobilizing fluid, and the hydrocarbons from the reservoir.

22. The method of paragraph 21, wherein the mobilizing fluid is steam, heated water,
5 volatile solvent, or any combinations thereof.
23. The method of paragraphs 21 or 22, wherein the solvent is injected prior to starting a process shutdown.
24. The method of any of paragraphs 21-23, wherein the solvent is injected during a restart period after a process shutdown.
- 10 25. The method of any of paragraphs 21-24, wherein the solvent is continuously injected during a process shutdown.
26. The method of any of paragraphs 21-25, wherein the solvent is intermittently injected during a process shutdown, and wherein the solvent that is injected is from another interval of the reservoir.
- 15 **[0112]** While the present techniques may be susceptible to various modifications and alternative forms, the embodiments discussed above have been shown only by way of example. However, it should again be understood that the techniques are not intended to be limited to the particular embodiments disclosed herein. Indeed, the present techniques include all alternatives, modifications, and equivalents falling within the true
20 spirit and scope of the appended claims.

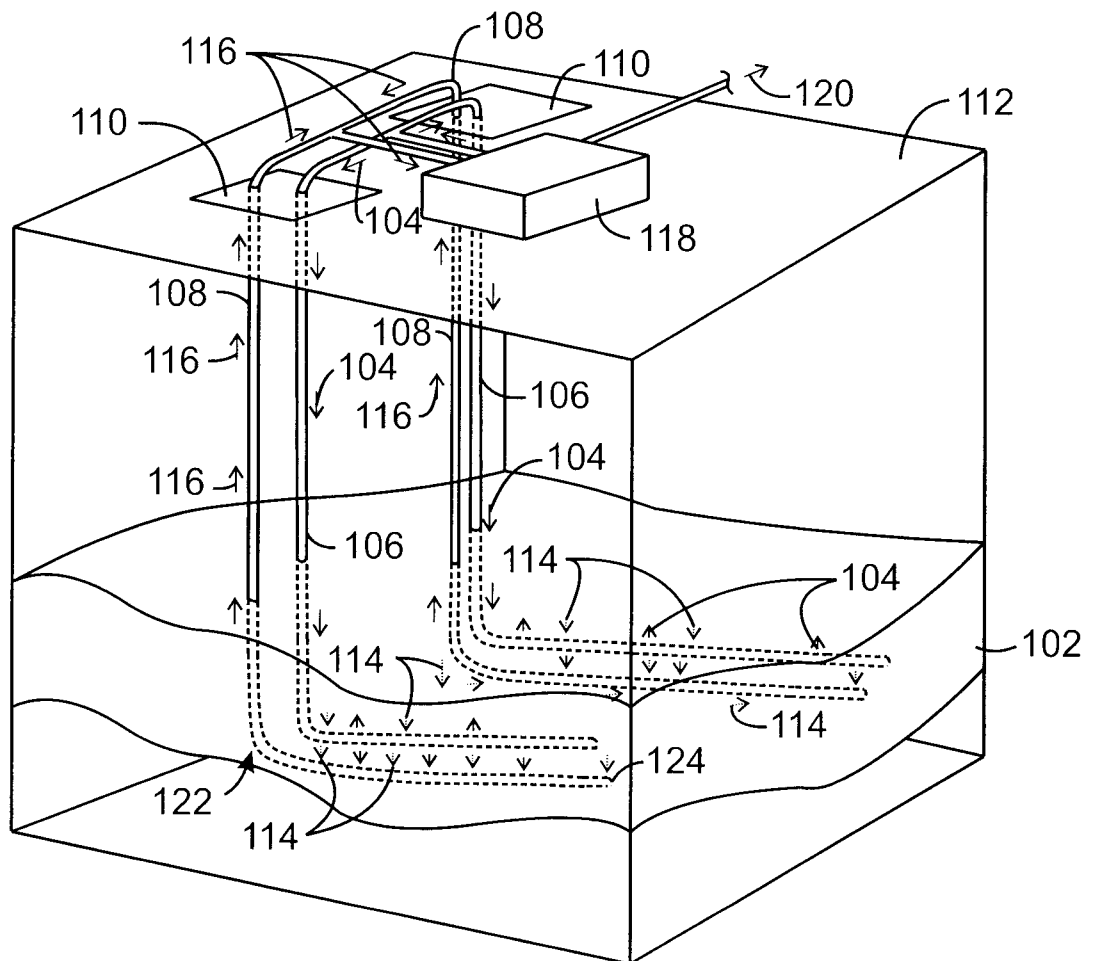
CLAIMS

What is claimed is:

1. A method of recovering hydrocarbons from a reservoir, comprising:
injecting a mixture of steam and a mobilizing fluid into an injection well in the reservoir, wherein the reservoir comprises a steam chamber and the mobilizing fluid comprises a volatile solvent; and
producing fluid from the reservoir via a production well, wherein the fluid comprises condensed steam, the mobilizing fluid, and the hydrocarbons from the reservoir;
wherein:
the injection well is located in the steam chamber at a location vertically above the production well; and
the volatile solvent flashes within the reservoir and at least a portion of the volatile solvent rises into the steam chamber and mixes with oil that is within the steam chamber.
2. The method of claim 1, further comprising injecting the steam on a continuous basis.
3. The method of claim 1, further comprising injecting the steam prior to the start of a process shutdown.
4. The method of claim 1, further comprising injecting the steam during a restart period after a process shutdown.
5. The method of claim 1, further comprising heating the steam before injection.
6. The method of claim 1, further comprising injecting the steam using a tubular in an injection well.

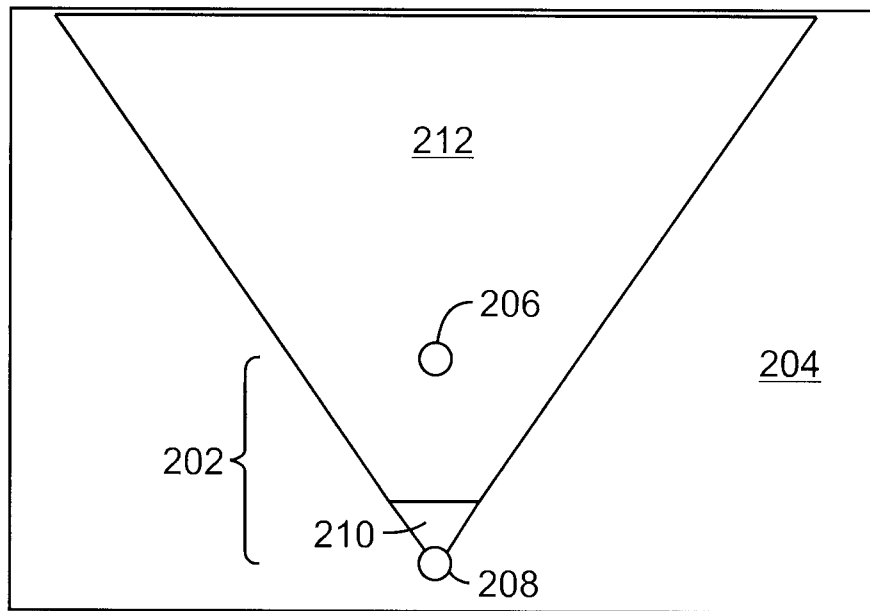
7. The method of any one of claims 1 to 6, wherein the volatile solvent is injected into the reservoir as a liquid.
8. The method of claim 7, wherein the volatile solvent comprises a naphtha.

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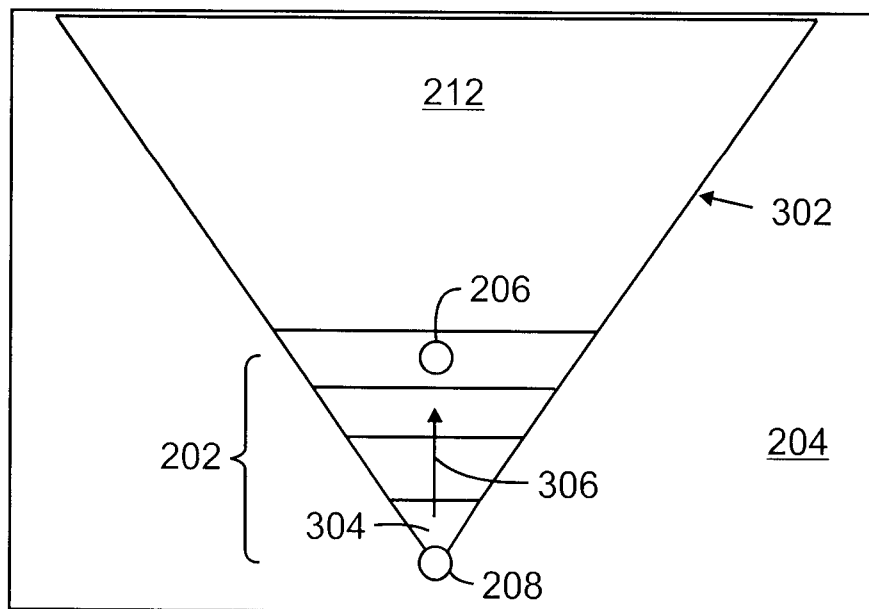


100
FIG. 1

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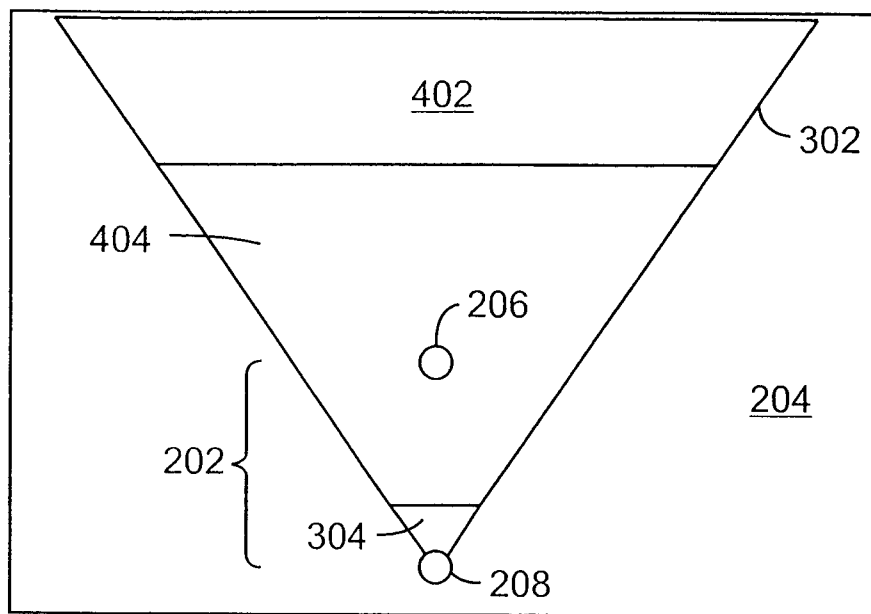
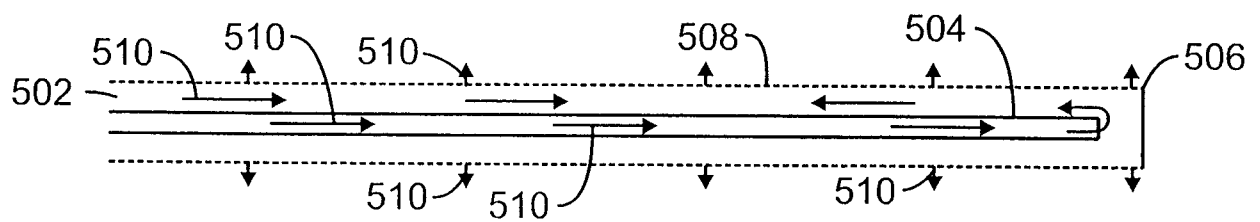
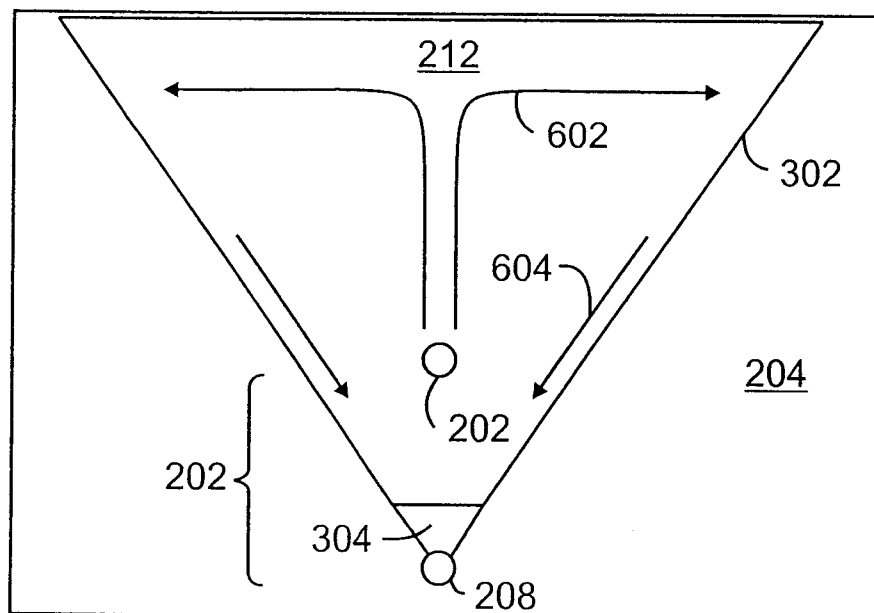


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FIG. 2

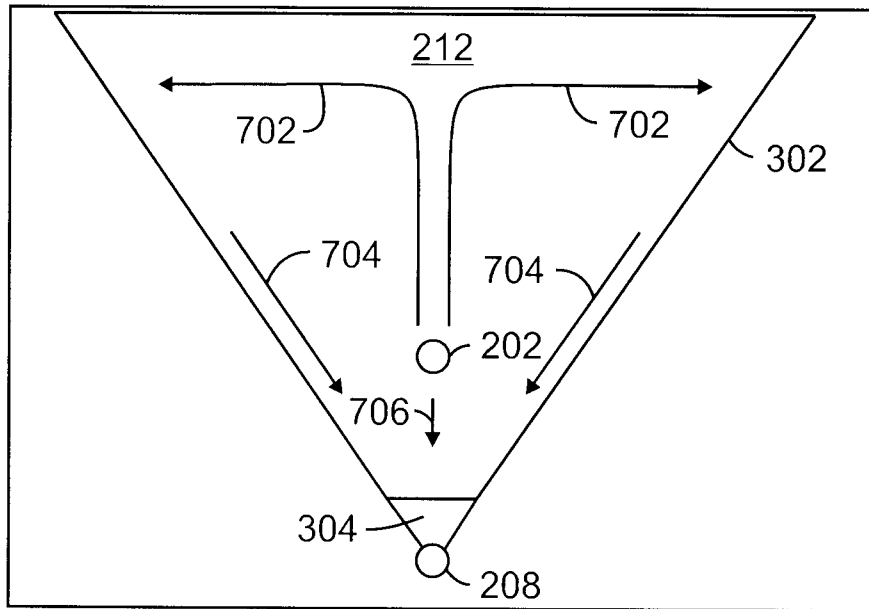


300
FIG. 3

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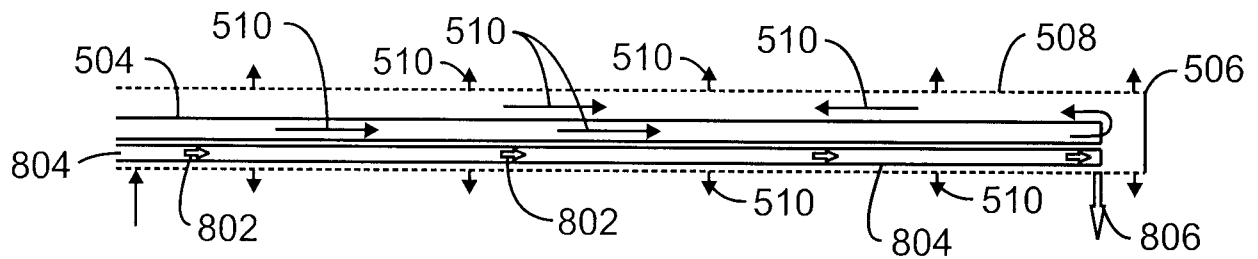
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FIG. 4500
FIG. 5600
FIG. 6

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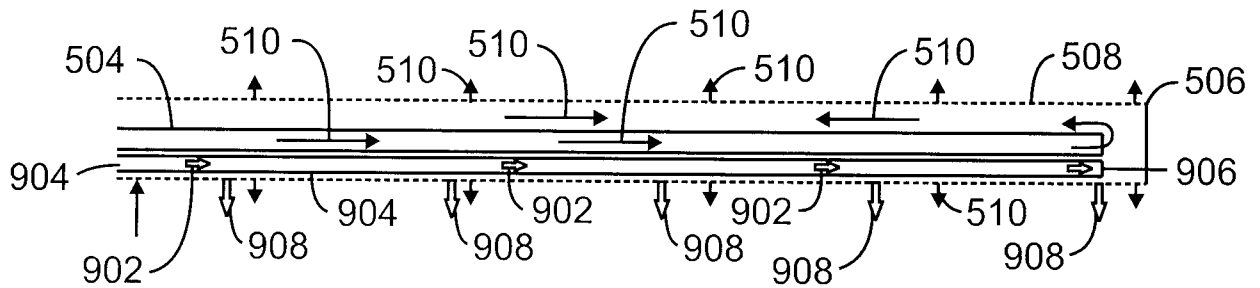


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FIG. 7

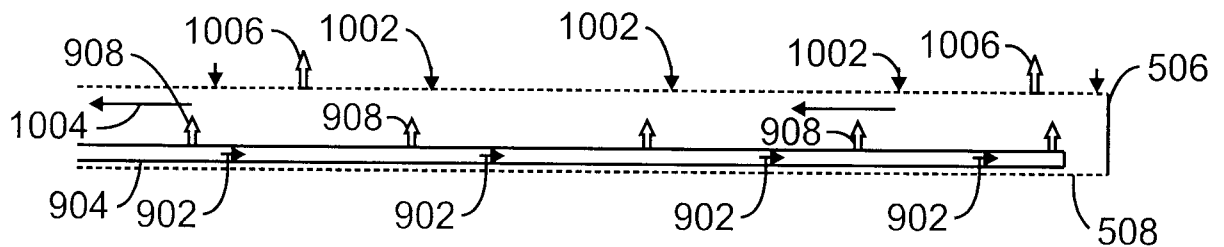
5/8



800
FIG. 8

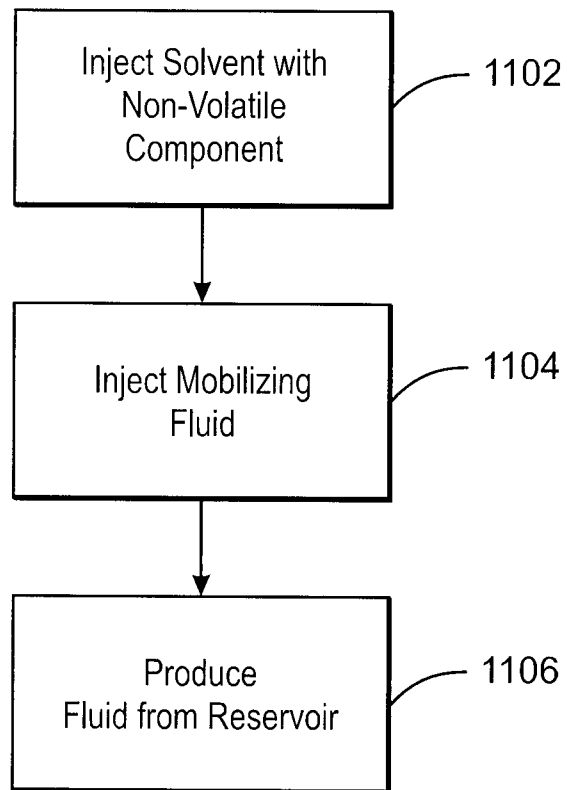


900
FIG. 9



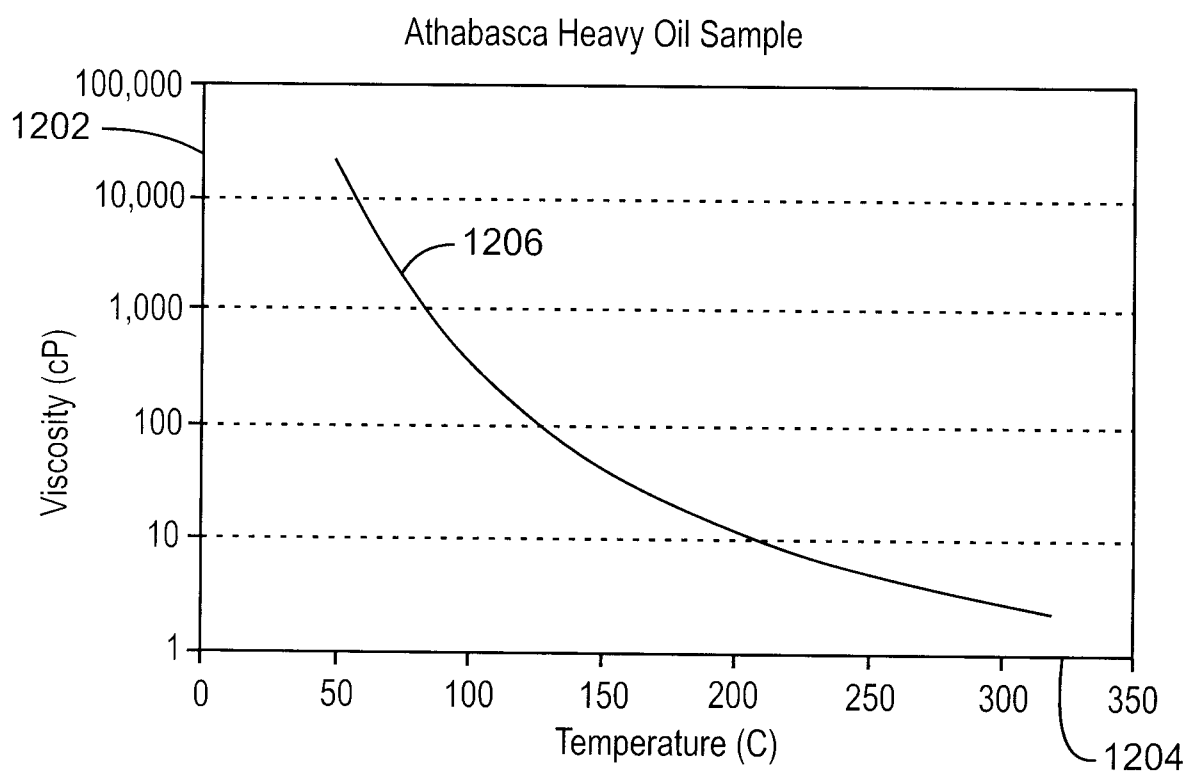
1000
FIG. 10

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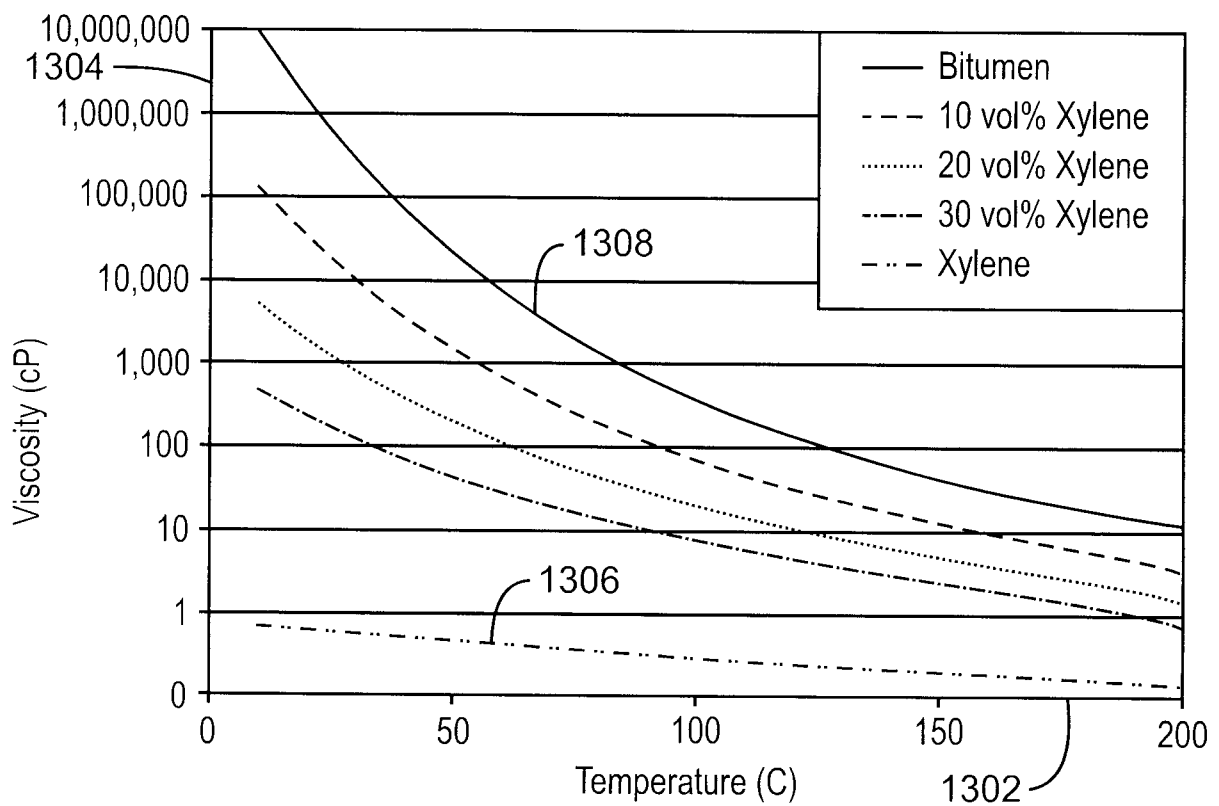
1100
FIG. 11

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1200
FIG. 12

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1300
FIG. 13

