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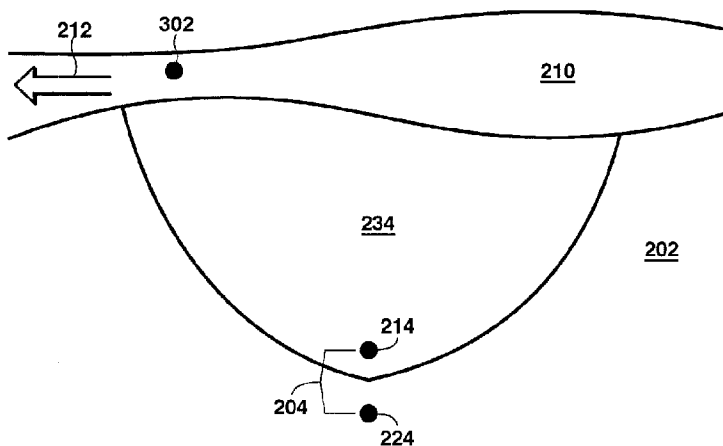
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(54) Title: METHOD AND SYSTEM FOR MANAGING PRESSURE IN A GAS CAP AND RECOVERING HEAVY OIL



(57) Abrégé/Abstract:

Methods and systems are disclosed for managing pressure and recovering heavy oil. A method may include providing a gas cap injection well in a gas cap raising a gas cap pressure in the gas cap to a target pressure by injecting a non-condensable gas into the gas cap via the gas cap injection well and maintaining the gas cap pressure at the target pressure by at least one of (i) injecting the non-condensable gas into the gas cap via the gas cap injection well and (ii) producing gas from the gas cap through the gas cap injection well.



ABSTRACT

Methods and systems are disclosed for managing pressure and recovering heavy oil. A method may include providing a gas cap injection well in a gas cap raising a gas cap pressure in the gas cap to a target pressure by injecting a non-condensable gas into the gas cap via the gas cap injection well and maintaining the gas cap pressure at the target pressure by at least one of (i) injecting the non-condensable gas into the gas cap via the gas cap injection well and (ii) producing gas from the gas cap through the gas cap injection well.

METHOD AND SYSTEM FOR MANAGING PRESSURE IN A GAS CAP AND RECOVERING HEAVY OIL

FIELD

[0001] The present disclosure relates to recovering heavy oil using gravity drainage processes. Specifically, the present disclosure relates to managing pressure in a gas cap and recovering heavy oil.

BACKGROUND

[0002] This section is intended to introduce various aspects of the art. This discussion is believed 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. Subterranean rock formations that can be termed “reservoirs” may contain resources, such as hydrocarbons, that can be recovered. Removing hydrocarbons from the subterranean reservoirs depends on numerous physical properties of the subterranean rock formations, such as the permeability of the rock containing the hydrocarbons, the ability of the hydrocarbons to flow through the subterranean rock formations, and the proportion of hydrocarbons present, among other things.

[0004] Easily produced sources of hydrocarbons are dwindling, leaving less conventional sources to satisfy future needs. As the costs of hydrocarbons increase, less conventional sources become more economical. One example of less conventional sources becoming more economical is that of oil sand production. The hydrocarbons harvested from less conventional sources may have relatively high viscosities, for example, ranging from 1000 centipoise (cP) to 20 million centipoise (cP) with American Petroleum Institute (API) densities ranging from 8 °API, or lower, up to 20 °API, or higher. The hydrocarbons recovered from less conventional

sources may include heavy oil. Hydrocarbons, like heavy oil, produced from the less conventional sources are difficult to recover using conventional techniques.

[0005] Several methods have been developed to recover heavy oil from, for example, oil sands. Strip or surface mining may be performed to access the oil sands. Once accessed, the oil sands may be treated to extract the oil. For subterranean reservoirs where heavy oil is not close to the Earth's surface, heat may be added and/or dilution may be used to reduce the viscosity of the heavy oil and recover the heavy oil from the subterranean reservoir. Heat may be supplied through a heating agent like steam. The heat may be injected into the subterranean reservoir via an injection well or wellbore. If the heating agent is steam, the steam may be condensed to water at the steam to cooler-oil-sands interface in the subterranean reservoir and latent heat of condensation supplied to heat the heavy oil in the oil sands, thereby reducing a viscosity of the heavy oil and causing the heavy oil to flow more easily. The heavy oil recovered from the subterranean reservoir may or may not be produced via a production well or wellbore. The production well or wellbore may be the same well or wellbore as the injection well or wellbore.

[0006] A number of thermal recovery techniques for recovery of heavy oil have been developed. These processes or techniques may include, for example, cyclic steam stimulation or cyclic solvent stimulation (CSS), steam flooding, steam assisted gravity drainage (SAGD), vapor extraction processes (VAPEX), heated VAPEX, in-situ combustion, thermal enhanced oil recovery and solvent assisted steam assisted gravity drainage (SA-SAGD). These processes may be cyclic recovery processes in which there is intermittent injection of a mobilizing fluid to lower a viscosity of the heavy oil followed by recovery of the reduced viscosity heavy oil.

[0007] Solvents may be used alone or in combination with steam in a thermal recovery process. As the solvents blend with the heavy oil, the viscosity of the heavy oil decrease, thereby allowing the heavy oil to flow downwards toward the production well. The mobility of the heavy oil obtained with a steam and solvent combination is greater than that obtained using steam alone under substantially similar formation conditions.

[0008] In a case where the subterranean reservoir is capped with a gas cap, a pressure in the gas cap may be managed to assist any gravity assisted drainage process occurring in the

subterranean reservoir. Many gas caps on subterranean reservoirs are found to be at naturally occurring low pressures (e.g., typically at atmospheric pressure, generally 0.101325 megapascals (MPa), to 2-3 MPa). The gas caps may have been depressurized by surrounding gas or hydrocarbon recovery processes. Most gravity assisted drainage processes generally occur under high pressure (e.g., 1.3 to 5 megapascals (MPa)) and at high temperatures (e.g., 200 to 250 Celsius (°C)) to increase a production rate of the heavy oil, especially when a vapor chamber of the gravity assisted drainage process is fully contained by heavy oil. However, once the vapor chamber grows within the subterranean reservoir such that the vapor chamber intersects the gas cap, an injection pressure of the vapor forming the vapor chamber may be reduced to a pressure approximately equivalent to the pressure of the gas cap. If the pressure of the gas cap is below a desired operating pressure of the gravity assisted drainage process, the production rate of the heavy oil may decrease. If vapor is injected at higher pressures, the vapor may invade into the gas cap, heating material above the gas cap, generally rock, that usually has little or no heavy oil present. Heating the material above the gas cap may reduce efficiency of the gravity assisted drainage process and increase operation cost of the gravity assisted drainage process.

[0009] Gas, such as a non-condensable gas (NCG), may be injected into a confined gas cap or a gas cap of limited extent using co-injection with vapor during a gravity assisted drainage process. The gas may be injected into the gas cap until the gas cap and/or vapor chamber reach a target pressure. Co-injection of an NCG with vapor is taught in, for example, U.S. Patent No. 8,387,691. While injecting gas as above may work well with gas caps of limited extent that can be pressurized with a limited volume of gas, if the gas cap is extensive and leaky such that a pressure increase is not maintained if injection of the gas ceases then another solution must be utilized. For subterranean reservoirs with leaky gas caps, forms of continuous or intermittent gas injection into the gas cap in a vicinity of production wells may be used to maintain the target pressure.

[0010] There is a need to manage the pressure in the gas cap during a gravity assisted drainage process. Raising and/or maintaining the pressure in the gas cap to a target pressure that may be closer to a pressure of the gravity assisted drainage process than the pressure in

the gas cap may improve various parameters of heavy oil recovery during the gravity assisted drainage process.

SUMMARY

[0011] The present disclosure provides systems and methods for managing pressure in a gas cap and recovery of heavy oil.

[0012] A method of managing pressure in a gas cap of a subterranean reservoir during a gravity assisted drainage process of heavy oil from the subterranean reservoir, may comprise providing a gas cap injection well in the gas cap; raising a gas cap pressure in the gas cap to a target pressure by injecting a non-condensable gas into the gas cap via the gas cap injection well; and maintaining the gas cap pressure at the target pressure by at least one of (i) injecting the non-condensable gas into the gas cap via the gas cap injection well and (ii) producing gas from the gas cap through the gas cap injection well.

[0013] A method of recovering heavy oil from a subterranean reservoir having a gas cap may comprise providing a gas cap injection well in the gas cap; providing a gravity assisted drainage well pair in the subterranean reservoir that comprises an injection well and a production well; forming a vapor chamber in the subterranean reservoir that expands in size by injecting vapor into the subterranean reservoir via the injection well; at least one of (i) raising a gas cap pressure in the gas cap to a target pressure and (ii) maintaining the gas cap pressure at the target pressure by injecting a non-condensable gas into the gas cap via at least one of the gas cap injection well and the injection well; and producing the heavy oil from the production well.

[0014] A method of recovering heavy oil from a subterranean reservoir having a gas cap may comprise providing exterior gravity assisted drainage well pairs surrounding an interior gravity assisted drainage well pair in the subterranean reservoir, each of the exterior gravity assisted drainage well pairs and the interior gravity assisted drainage well pair may comprise an injection well and a production well; reducing a viscosity of the heavy oil and raising a gas cap pressure in the gas cap to a target pressure by co-injecting a vapor and a non-condensable gas into the subterranean reservoir via the injection well of at least one of the exterior gravity

assisted drainage well pairs and the interior gravity assisted drainage well pair; producing the heavy oil via the production well; and maintaining the gas cap pressure at the target pressure while producing the heavy oil by co-injecting the vapor and the non-condensable gas via the injection well of at least one of the exterior gravity assisted drainage well pairs and the interior gravity assisted drainage well pair.

[0015] A system for managing pressure in a gas cap of a subterranean reservoir during a gravity assisted drainage process for recovering heavy oil from the subterranean reservoir may comprise gravity assisted drainage well pairs in the subterranean reservoir comprising exterior gravity assisted drainage well pairs surrounding an interior gravity assisted drainage well pair, each of the exterior gravity assisted drainage well pairs and the interior gravity assisted drainage well pairs may comprise an injection well and a production well; gas cap injection wells within the gas cap for injecting non-condensable gas into the gas cap; a gas cap pressure monitor configured to monitor a gas cap pressure in the gas cap; and a control apparatus in communication with the exterior gravity assisted drainage well pairs, the interior gravity assisted drainage well pair and the gas cap injection wells, the control apparatus configured to control injection of a non-condensable gas from at least one of the injection wells and the gas cap injection wells, the non-condensable gas being injected to at least one of (i) raise the gas cap pressure to a target pressure and (ii) maintain the gas cap pressure at the target pressure, the control apparatus may be further configured to adjust an injection rate of the injection wells and the gas cap injection wells based on the gas cap pressure.

[0016] The foregoing has broadly outlined the features of the present disclosure so that the detailed description that follows may be better understood. Additional features will also be described herein.

DESCRIPTION OF THE DRAWINGS

[0017] These and other features, aspects and advantages of the present disclosure will become apparent from the following description and the accompanying drawings, which are described briefly below:

[0018] Fig. 1 is a drawing of a steam assisted gravity drainage (SAGD) process used for recovering heavy oil in a subterranean reservoir;

[0019] Fig. 2 is an exemplary cross section of a gravity assisted drainage process in a subterranean reservoir having a gas cap;

[0020] Fig. 3A is an exemplary cross section of a gravity assisted drainage process having multiple gravity assisted drainage well pairs;

[0021] Fig. 3B is an exemplary cross section of the gravity assisted drainage process of Fig. 4A in an initial stage;

[0022] Fig. 3C is an exemplary cross section of the gravity assisted drainage process of Fig. 4A in an initial gas co-injection stage employing pressure management techniques;

[0023] Fig. 3D is an exemplary cross section of the gravity assisted drainage process of Fig. 4A in a pressure maintenance stage;

[0024] Fig. 4A is an exemplary cross section of the gravity assisted drainage process of Fig. 4A employing multiple gas cap injection wells in an initial gas injection stage;

[0025] Fig. 4B is an exemplary cross section of the gravity assisted drainage process of Fig. 5A in a pressure maintenance stage;

[0026] Fig. 5 is an exemplary top plan view of a subterranean reservoir having a gas cap showing a possible configuration of the gravity assisted drainage well pairs and gas cap injection wells of Fig. 5A;

[0027] Fig. 6 is an exemplary top plan view of a gas cap of a subterranean reservoir having a gas cap showing a possible configuration of multiple gravity assisted drainage well pairs and multiple gas cap injection wells;

[0028] Fig. 7 is an exemplary flow diagram showing a process for managing a pressure in a gas cap of a subterranean reservoir; and

[0029] Fig. 8 is an exemplary flow diagram showing a process for managing a pressure in a gas cap of a subterranean reservoir.

[0030] It should be noted that the figures are merely examples and that no limitations on the scope of the present disclosure are intended hereby. Further, the figures are generally not

drawn to scale but are drafted for the purpose of convenience and clarity in illustrating various aspects of the disclosure.

DETAILED DESCRIPTION

[0031] For the purpose of promoting an understanding of the principles of the disclosure, reference will now be made to the features illustrated in the drawings and specific language will be used to describe the same. It will nevertheless be understood that no limitation of the scope of the disclosure is thereby intended. Any alterations and further modifications, and any further applications of the principles of the disclosure as described herein are contemplated as would normally occur to one skilled in the art to which the disclosure relates. It will be apparent to those skilled in the relevant art that some features that are not relevant to the present disclosure may not be shown in the drawings for the sake of clarity.

[0032] At the outset, for ease of reference, certain terms used and their meaning as used in this context are set forth below. 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 processes are not limited by the usage of the terms shown below, as all equivalents, synonyms, new developments and terms or processes that serve the same or a similar purpose are considered to be within the scope hereof.

[0033] A “hydrocarbon” is an organic compound that primarily includes the elements of hydrogen and carbon, although nitrogen, sulfur, oxygen, metals, or any number of other elements may be present in small amounts. Hydrocarbons generally refer to components found in heavy oil or in oil sands. However, the techniques 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. Hydrocarbon compounds may be aliphatic or aromatic, and may be straight chained, branched, or partially or fully cyclic.

[0034] “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 weight (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 percentage of the hydrocarbon found in bitumen can vary. The term “heavy oil” includes bitumen as well as lighter materials that may be found in a sand or carbonate reservoir.

[0035] “Heavy oil” includes oils which are classified by the American Petroleum Institute (API), as heavy oils, extra heavy oils, or bitumens. The term “heavy oil” includes bitumen. Heavy oil may have a viscosity of 1,000 centipoise (cP) or more, 10,000 cP or more, 100,000 cP or more, or 1,000,000 cP or more. In general, a heavy oil has an API gravity between 22.3 °API (density of 920 kilograms per meter cubed (kg/m^3) or 0.920 grams per centimeter cubed (g/cm^3)) and 10.0 °API (density of 1,000 kg/m^3 or 1 g/cm^3). An extra heavy oil, in general, has an API gravity of less than 10.0 °API (density greater than 1,000 kg/m^3 or 1 g/cm^3). For example, a source of heavy oil includes oil sand or bituminous sand, which is a combination of clay, sand, water and bitumen. The 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 fluid by steam, hot water flooding, or gravity is possible. The reduced viscosity makes the drainage quicker and therefore directly contributes to the recovery rate.

[0036] Two locations in a subterranean reservoir are in “fluid communication” when a path for fluid flow exists between the two locations. For example, fluid communication exists between an injection well and a production well when mobilized material can flow down to the production well from the injection well for collection and production.

[0037] A “fluid” includes a gas or a liquid and may include, for example, a produced hydrocarbon, hot water, cold water, a produced or native reservoir hydrocarbon, an injected

mobilizing fluid, hot or cold hydrocarbons, solvent, steam, wet steam, gas (e.g., C₁, CO₂, etc., where C represents carbons and O represents oxygen) or a mixture of these among other materials. "Vapor refers to steam, wet steam, mixtures of steam and wet steam, any of which could possibly be used with a solvent and other substances, and any material in the vapor phase.

[0038] "Facility" is a tangible piece of physical equipment through which hydrocarbon fluids are either produced from a subterranean reservoir or injected into a subterranean reservoir, or equipment that can be used to control production or completion operations. In its broadest sense, the term facility is applied to any equipment that may be present along the flow path between a subterranean reservoir and its delivery outlets. Facilities may comprise production wells, injection wells, well tubulars, wellbore head 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.

[0039] "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) or kilopascals (kPa) or megapascals (MPa). "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.

[0040] A "reservoir" or "subterranean 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 (e.g., bitumen), gas, or coal, among others. Subterranean reservoirs can vary in thickness from less

than one foot (0.3048 meters (m)) to hundreds of feet (hundreds of meters). The resource is generally a hydrocarbon, such as a heavy oil impregnated, into a sand bed.

[0041] “Thermal recovery process” includes 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 fluid, 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 thermal steam-based processes, and processes that use surface processing for recovery, such as sub-surface mining and surface mining. Any of the thermal recovery processes may be used with solvents. For example, thermal recovery processes may include CSS, steam flooding, solvent injection, SAGD, SA-SAGD, thermal enhanced oil recovery, vapor extraction process (VAPEX), heated VAPEX, in-situ combustion and other such processes.

[0042] “Gravity assisted drainage process” includes any type of hydrocarbon recovery process that relies on an action of gravity to drain heavy oil or other hydrocarbons, having a reduced viscosity, down towards a well from which the heavy oil can be produced. Such processes may include CSS, SAGD, SA-SAGD, VAPEX, heated VAPEX, steam flooding and other such processes.

[0043] A “cyclic recovery process” uses an intermittent injection of mobilizing fluid selected to lower the viscosity of heavy oil in a subterranean reservoir. The injected mobilizing fluid may include steam, solvents, gas, water or any combinations of steam, solvent, gas and water. After a soak period intended to allow the injected mobilizing fluid to interact with the heavy oil in the subterranean reservoir, material in the subterranean reservoir, including the mobilized heavy oil and some portion of the injected mobilizing fluid, may flow down towards a well and be recovered from the subterranean reservoir via the well. 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 (e.g., dilation and compaction, solution gas drive water, water flashing, and the like) declines as the recovery process matures. Practically speaking, 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. For this reason, the approaches disclosed are equally applicable to all recovery processes in which the current stage of depletion gravity drainage is the dominant recovery mechanism. An exemplary cyclic recovery process is cyclic steam stimulation, which is described in U.S. Patent No. 4,280,559, U.S. Patent No. 4,519,454, and U.S. Patent No. 4,697,642.

[0044] “Solvent Assisted Steam Assisted Gravity Drainage” (SA-SAGD) is a SAGD process in which solvents are used in concert with vapor to increase the efficiency of the vapor in removing heavy oils from a subterranean reservoir. SA-SAGD may allow for higher oil production rates at lower pressures and lower temperatures than a SAGD process.

[0045] “Substantial” when used in reference to a quantity or amount of a material, or a specific characteristic of the material, 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.

[0046] 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. 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.

[0047] The term “base” indicates a lower boundary of the resources in a subterranean reservoir that are practically recoverable, by a gravity assisted drainage process, 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 may include inclined heterolithic strata (IHS) of broken shale, mud, silt, and the like. The resources within the subterranean reservoir may extend below the base, but

the resources below the base may possibly not be recoverable, or at least not easily recoverable, with gravity assisted drainage processes.

[0048] “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 (mD).

[0049] “Gas cap” refers to a porous formation containing gas that is located at or near an upper portion of a subterranean reservoir containing heavy oil. The upper portion of the subterranean reservoir is towards but underneath the Earth’s surface. The gas in the gas cap may be an in-situ natural gas or other gas evolved from the heavy oil during removal of the heavy oil. Other fluids such as liquid hydrocarbons and formation water may also be present in part or all of the gas cap. Gas caps are often found to be at naturally occurring low pressures (e.g., atmospheric pressure (0.101325 megapascals (MPa)) to 2-3 MPa). The gas cap may have been depressurized by surrounding heavy oil or gas recovery processes.

[0050] “Non-condensable gas” (NCG) refers to gas that is not easily condensed by cooling to an original temperature (e.g., 5 to 12 °C) of the subterranean reservoir. NCGs generally consist of nitrogen, light hydrocarbons, carbon dioxide or other gaseous materials and may include methane, ethane, propane, carbon dioxide, nitrogen, hydrogen-sulfide, air, flue gas or combinations of these gases.

[0051] A “small fraction” of NCG refers generally less than or equal to 5% NCG by volume. However, under some conditions small fraction NCG may be equal to or less than 10% of NCG by volume (e.g., when 10% by volume of NCG is injected for a short time period). The aforementioned ranges of NCG may include any number within or bounded by the aforementioned ranges. The precise numerical definition for “small fraction” of NCG can depend on various factors including, but is not limited to geological conditions and characteristics of the subterranean reservoir, a mechanical configuration of components of the recovery process, duration that the NCG is injected into the subterranean reservoir, etc.

[0052] A “large fraction” of NCG refers generally to greater than 5% NCG by volume. The aforementioned ranges of NCG may include any number within or bounded by the aforementioned ranges. However, the precise numerical definition of “large fraction” of NCG

correlates to the definition of small fraction of NCG which can vary with many factors as set out above in relation to the discussion of small fraction of NCG. As such, large fraction of NCG could be more than 10% of NCG by volume or some other value according to the definition of small fraction of NCG that is used.

[0053] In the following description, as an example of a gravity assisted drainage process, reference is made to a SAGD process for recovering heavy oil from a subterranean reservoir. For better understanding, a brief explanation of a SAGD process is provided below in order to highlight some general techniques of a gravity assisted drainage process. SAGD processes are described in Canadian Patent No. 1,304,287 and U.S. Patent No. 4,344,485.

[0054] Fig. 1 illustrates a SAGD process 100 used for accessing resources in a subterranean reservoir 102. The SAGD process 100 includes a well pair. The well pair includes an injection well 106 and a production well 108. In the SAGD process 100, vapor 104, such as steam, solvent and steam-solvent mixtures, can be injected through the injection well 106 into the subterranean reservoir 102. The injection well 106 may be vertically and then horizontally drilled through the subterranean reservoir 102 as shown. The production well 108 may be drilled vertically and then horizontally through the subterranean reservoir 102 such that the production well 108 may lie below the injection well 106 in the SAGD well pair. Specifically, a horizontal section of the production well 108 may lie below a horizontal section of the injection well 106. The injection well 106 and the production well 108 may be drilled from the same pad 110 at a surface 112 or from a different pad at the surface 112. The surface 112 may be a surface of the subterranean reservoir 102. Drilling the injection well 106 and the production well 108 from the same pad may make it easier for the production well 108 to track (i.e., follow a similar path of) the injection well 106. The injection well 106 and the production well 108 may be vertically separated by a suitable distance, such as, for example, about 3 to 10 m. For example, the injection well 106 and the production well 108 may be vertically separated by about 5 m. The injection well 106 and the production well 108 may be vertically separated by the aforementioned amounts in the horizontal section or horizontally separated by the aforementioned amounts in the vertical section of the respective injection well 106 and

production well 108. Any of the aforementioned ranges may be within a range that includes or is bounded by any of the preceding examples.

[0055] At start-up of the SAGD process, both the injection well 106 and the production well 108 may circulate the vapor 104 so that heavy oil between the injection well 106 and the production well 108 is heated enough to flow and be produced through at least one of the injection well 106 and the production well 108. Other start-up techniques may also be used such as liquid solvent injection from the injection well 106 and fluid production from the production well 108. Bull-heading techniques may also be used for start-up in which steam or hot water is injected at pressures, which are higher than normal operating pressures for the SAGD process (e.g., normal operating pressures typically being 1.3 to 5 MPa), through the injection well 106 and fluid is produced from the production well 108. Further, cyclic steam stimulation may be used in the injection well 106 and in the production well 108. Other methods not mentioned above may also be used for start-up of the SAGD process.

[0056] The injection of the vapor 104 via the injection well 106 may result in the mobilization of heavy oil as mobilized heavy oil. The mobilized heavy oil 114 may form a drainage chamber 118 (i.e., within a vapor chamber) having a generally triangular cross section with the production well 108 located at a lower apex 121 of the triangular cross section as the mobilized heavy oil 114 possibly drains to the production well 108. The production well 108 may be switched to a continuous production mode and the injection well 108 may be placed in a continuous injection mode, which involves injecting the injection vapor into the subterranean reservoir 102. The mobilized heavy oil 114 may be removed to the surface 112 via the production well 108 in a mixed fluid stream 116 that may contain heavy oil, condensate and other material, such as water, gases and the like. Sand filters may be used in the production wells 108 to decrease sand entrapment.

[0057] The injection well 106 may comprise injection wells. The production well 108 may comprise production wells. If the production well 108 comprises production wells, the mixed fluid stream 116 from the production wells may be combined and then sent to a processing facility 120. If the production well 108 comprises a single well, the mixed fluid stream 116 from the production well 108 may be sent to the processing facility 120. At the processing facility

120, the mixed fluid stream 116 may be separated. The heavy oil 114 in the mixed fluid stream 116 may be sent on for further refining 122. The vapor in the mixed fluid stream 116 may be recycled to a vapor generation unit within the processing facility 120, with or without further treatment, and used to generate the injection vapor 104 used for the SAGD process 100.

[0058] Although the injection well 106 may receive the vapor 104, the production well 108 may also receive the vapor 104 or the production well 108 may receive the vapor 104 instead of the injection well 106.

[0059] Performance of a gravity assisted drainage process may decrease when a subterranean reservoir, in which the gravity assisted drainage process is occurring, has a cap that is possibly at a lower pressure (e.g., atmospheric pressure (0.101325MPa) to 2 to 3 MPa) than an operating pressure of the gravity assisted drainage process (e.g., typically 1.3 to 5 MPa). The cap, such as a gas cap, may be found to be at naturally occurring low pressure or may have been depressurized by a surrounding heavy oil or gas recovery process. The gas recovery process may be any process used to recover gases that are present in the gas cap, such as for example a natural gas recovery process.

[0060] In the gravity assisted drainage process, when a vapor chamber, having a pressure of the operating pressure of the gravity assisted drainage process, intersects the cap, pressure in the vapor chamber may drop. After the drop in pressure, the operating pressure in the vapor chamber may be maintained at a lower operating pressure to reduce the vapor forming the vapor chamber from heating non-oil producing surrounding elements (e.g., rock). The heating of the non-oil producing surrounding elements may result in lower production rates of the heavy oil as heat from the vapor heats not only the heavy oil but also the non-oil producing surrounding elements. A lack of or low saturation of liquid hydrocarbon or heavy oil in the gas cap may mean that it is generally inefficient to allow the vapor to heat the gas cap. As such, attempts may be made to closely match the pressure in the gas cap with the operating pressure in the vapor chamber to improve efficiency of the gravity assisted drainage process when considering production rates of heavy oil versus injection rates and injection pressure of the vapor.

[0061] In the gravity assisted drainage process, vapor may rise more quickly to a gas cap if the gas cap is at a lower pressure than an injection pressure of the vapor. The vapor chamber, which forms an area depleted of heavy oil that has already been mobilized, may have greater height than width due to the emphasis on vertical growth. The gravity assisted drainage well pairs of the gravity assisted drainage process may be placed closer together (at an increased operational cost) to compensate for the increased vertical growth at the expense of horizontal growth of the vapor chambers. Alternatively, there may be larger amounts of unrecovered heavy oil in the subterranean reservoir that remains after the gravity assisted drainage process is finished.

[0062] When the gas cap is maintained at a pressure near the operational pressure of the gravity assisted drainage process, through the injection of a gas into the gas cap or into the subterranean reservoir to flow into the gas cap, higher temperatures and pressures may be used in the gravity assisted drainage process to possibly improve heavy oil production. However, if the gas cap is extensive or leaky, maintaining the higher pressure may become at least costly and possibly onerous or very difficult.

[0063] The present disclosure may include a method of managing pressure in a gas cap of a subterranean reservoir during a gravity assisted drainage process. The present disclosure may include methods of recovering heavy oil from a subterranean reservoir having a gas cap. The present disclosure may include a system for managing pressure in a gas cap of a subterranean reservoir during a gravity assisted drainage process of heavy oil from the subterranean reservoir.

[0064] A gas cap 210 of a subterranean reservoir 202 may be large or extensive in size as illustrated by way of example in Fig. 2, which illustrates an example of a cross section of the subterranean reservoir 202 in which a gravity assisted drainage process is occurring. The gas cap 210 may have a leak source 212 through which gas that is present in the gas cap 210 may leak out of the gas cap 210 and into surrounding areas of the subterranean reservoir 202. The gas cap 210 may be at a lower pressure than a naturally occurring pressure in the subterranean reservoir 202 (e.g., atmospheric pressure less a few hundred kPa). The gas cap 210 may be at a lower pressure than an operating pressure of a gravity assisted drainage process occurring in

the subterranean reservoir 202. Components in the gas cap 210 may include, for example, an in-situ natural gas, other gases evolved from the heavy oil during removal of the heavy oil from the subterranean reservoir 202, liquid hydrocarbons, formation water and other such substances. The components of the gas cap 210 will be referred to herein as native gas as they are native to the gas cap 210.

[0065] The methods of the present disclosure may be particularly useful for gravity assisted drainage processes in which an operating pressure of the gravity assisted drainage process is constant (e.g., processes that are not cyclic, alternating between injecting vapor and producing fluids from the same well), but may also be applicable when an operating pressure of the gravity assisted drainage process is not constant. When the gravity assisted drainage process has a constant operating pressure, the methods of the present disclosure can attempt to match the operating pressure. The methods of the present disclosure are equally applicable to gravity assisted drainage processes that are cyclic with respect to changes in operating pressure.

[0066] The gravity assisted drainage process may employ a gravity assisted drainage well pair 204 in the subterranean reservoir 202, shown by way of example in Fig. 2, which illustrates an example cross section of the subterranean reservoir 202 and the gravity assisted drainage well pair 204. While Fig. 2 shows a single gravity assisted drainage well pair 204 as an example, there may be multiple gravity assisted drainage well pairs 204 performing the gravity assisted drainage process. The general discussion below will use the example of one gravity assisted drainage well pair 204. Further discussion of other examples will follow.

[0067] The gravity assisted drainage well pair 204 may be any suitable well pair in a gravity assisted drainage process. The gravity assisted drainage well pair 204 may include an injection well 214 and a production well 224. An upper horizontal well of the gravity assisted drainage well pair 204 may be the injection well 214. The injection well 214 may receive vapor. The injection well 214 may therefore be for injecting vapor into the subterranean reservoir 202. The vapor may be steam, solvent and mixtures of steam and solvent. The vapor injected into the subterranean reservoir 202 may form a vapor chamber 234 within which a viscosity of the heavy oil may be reduced. A lower horizontal well of the gravity assisted drainage well pair 204

may be the production well 224. The production well 224 may receive fluid, including heavy oil, water, and solvent, from the subterranean reservoir 202. The production well 224 may therefore be for recovering heavy oil from the subterranean reservoir 202. The production well 224 may be at an elevation below the injection well 214. Specifically, a horizontal portion of the production well 224 may be at an elevation below a horizontal portion of the injection well 214. The injection well 214 may include the horizontal portion of the injection well 214 (i.e., horizontal injection well portion) and a vertical portion of the injection well 214 (i.e., vertical injection well portion). Similarly, the production well 224 may include the horizontal portion of the production well 224 (i.e., horizontal production well portion) and a vertical portion of the production well 224 (i.e., vertical production well portion). The horizontal injection well portion may extend from the vertical injection well portion. The horizontal production well portion may extend from the vertical production well portion.

[0068] Injection rates of the vapor from the injection well 214 may be regulated to maintain a specified operating pressure in the vapor chamber 234. The injection pressure and the operating pressure will ideally be the same; however, there may be some loss of pressure in the subterranean reservoir 202 that reduces the operating pressure from the injection pressure. The operating pressure may depend on the characteristics of the subterranean reservoir 202, including but not limited to depth of the subterranean reservoir 202, the number of wells operating in the subterranean reservoir 202, the vapor capacity of each well injecting the vapor, the age of adjacent sections in the subterranean reservoir 202 and/or the pressure of the gas cap 210.

[0069] The gas cap 210 may have a lower or higher pressure than the pressure of the vapor chamber 234 prior to intersection between the vapor chamber 234 and the gas cap 210. However, once these the gas cap 210 and the vapor chamber 234 intersect any difference in pressure may result in vapor from the vapor chamber 234 invading into the gas cap 210 or gas (either native gas or a gas that has been injected) from the gas cap 210 invading into the vapor chamber 234. Further, the gas cap 210 may be extensive or have a leak source 212 by which pressure from the gas cap 210 leaks into surrounding areas in the subterranean reservoir 202, an adjacent well, and the like.

[0070] When the vapor chamber 234 and the gas cap 210 intersect they may reach a pressure equilibrium. If the gas cap 210 has a lower pressure than the vapor chamber 234, intersection with the vapor chamber 234 may reduce a pressure of the vapor chamber 234.

[0071] Methods may comprise providing a gas cap injection well in the gas cap. A gas cap injection well 302 may be shown by way of example in Fig. 2, which illustrates a single gas cap injection well 302. There may be multiple gas cap injections wells, as shown by way of example in Figs. 4A-4B. Figs. 8 and 9 illustrate exemplary flow diagrams of methods 800, 900. The general discussion below will use the example of one gas cap injection well 302. Further discussion of other examples will follow.

[0072] Fig. 8 illustrates a flow diagram of a method 800 of managing pressure in a leaky gas cap of a subterranean reservoir during a gravity assisted drainage process in the subterranean reservoir. Fig. 9 illustrates a flow diagram of a method 900 of managing pressure in a leaky gas cap of a subterranean reservoir during a gravity assisted drainage process in a subterranean reservoir using gravity assisted drainage gravity assisted drainage well pairs and gas cap injection wells. Gravity assisted drainage well pairs including injection wells paired with production wells are provided in the subterranean reservoir in steps 802 or 902. The gas cap injection wells are provided in the gas cap in step 904. It is possible that the gas cap injection wells may not be provided at this time in the case where it is unknown if the gas cap is leaky or to what degree the gas cap is leaky, both of which will be discussed below. The gravity assisted drainage process starts when vapor is injected from the injections wells in steps 804 and 906 producing vapor chambers above each of the injection wells. These vapor chambers will eventually intersect with the gas cap, which may have a lower pressure than the vapor chambers.

[0073] The gas cap injection well 302 may be, for example, an injector-producer well that can operate in an injection mode or a production mode. The gas cap injection well 302 has been termed as an "injection well" as the primary purpose of this well is to inject gas into the gas cap 210, although the gas cap injection well 302 may also produce from the gas cap 210 as will be described below. The gas cap injection well 302 operating in the injection mode may inject a gas or vapor directly into the gas cap 210. The gas cap injection mode 302 operating in

the production mode may produce gas or fluid from the gas cap 210. The injection mode and the production mode may be controlled, for example, by a facility on a surface of the subterranean reservoir 202. The gas cap injection well 302 shown in Fig. 2 is illustrated as a horizontal well, or a well having a horizontal portion, for purposes of convenient illustration. The gas cap injection well 302 may also be a vertical well.

[0074] The gas cap injection well 302 may be positioned anywhere in the gas cap 210 for injection of a material directly into the gas cap 210. However, placing the gas cap injection well 302 in proximity to the leak source 212 may help reduce pressure variation throughout the gas cap 210 as the leak source 212 may cause a local reduction in pressure in the gas cap 210 which can spread to a more general reduction in pressure in the gas cap 210. The gas cap injection well 302 may be positioned in response to a pressure map of pressure throughout the gas cap 210 where the pressure map may indicate areas of lower pressure or may indicate the leak source 212. A 3-dimensional seismic image of the subterranean reservoir 202 may be used to determine the location and size of the gas cap 210, as will be later described, to aid in placing the gas cap injection well 302.

[0075] The gas cap injection well 302 may be put in place prior to the commencement of the gravity assisted drainage process starting in the subterranean reservoir 202. Alternatively, the gas cap injection well 302 may be drilled after the gravity assisted drainage process has started. For example, when there is uncertainty regarding the presence of a gas cap and/or the amount of leakage of gas from the gas cap 210, the gas cap injection well 302 may be placed in the gas cap 210 after the gravity assisted drainage process has started and there has been an indication that the gas cap injection well 302 may be beneficial. Indications that the gas cap injection well 302 may be beneficial may include a pressure map of the gas cap 202 showing pressure variations throughout the gas cap 210, difficulty maintaining a pressure after that vapor chamber 234 and the gas cap 210 have merged (which may indicate a large gas cap or a larger than expected leak 212 in the gas cap 210), discovery of the gas cap, etc.

[0076] Methods may comprise raising a gas cap pressure in the gas cap to a target pressure. The gas cap pressure may be raised by injecting a NCG into the gas cap via the gas cap injection well. The NCG may be injected in small fraction or in large fraction according to

factors that include but are not limited to a size of the gas cap 210, the presence of a leak source 212, the location of the leak source 212, a position of the gas cap injection well 302 in the gas cap 210, and/or proximity of the gas cap injection well 302 to the leak source 212, among other geological considerations of the gas cap 210 and the subterranean reservoir 202.

[0077] The target pressure of the gas cap 210 may be a current or long term operating pressure of the gravity assisted drainage process. Alternatively, the target pressure for pressuring up the gas cap 210 prior to intersection of the vapor chamber 234 and the gas cap 210 may be higher than either the current or long term operating pressure of the gravity assisted drainage process. While the higher pressure in the gas cap 210 may be costly to achieve due to higher amounts of NCG required to reach the higher pressure, the higher pressure may provide an increased downward force on the vapor chamber 234 promoting the vapor chamber 234 to have increased horizontal growth and decreased vertical growth. Increased horizontal growth of the vapor chamber 234 may provide more even depletion of heavy oil in the subterranean reservoir 202 over the life of the gravity assisted drainage process in the subterranean reservoir 202 due to the vapor chamber 234 spreading with increased horizontal growth in addition to vertical growth. Alternatively, the operating pressure in the vapor chamber 234 may start out at a pressure sufficient to produce a high oil production rate until the vapor chamber 234 and the gas cap 210 intersect, at which time the operating pressure from the injection well 214 may be decreased. The drop in operating pressure may reduce a cost to maintain the operating pressure in the presence of an extensive or leaky gas cap 210 as a reduced amount of NCG would be required to maintain a lower pressure.

[0078] The pressure in the gas cap 210 may be determined by taking measurements at the gas cap injection well 302. If the gas cap injection well 302 is not put in place prior to intersection of the vapor chamber 234 and the gas cap 210, the exact pressure of the gas cap 210 may not be known unless, for example, a test or measurement well is drilled into the gas cap 210 such that measurements in the gas cap 210 can be taken. If the exact pressure of the gas cap 210 is not known, it may be assumed that there is pressure equilibrium between the vapor chamber 234 and the gas cap 210 after intersection so that pressure measurements from the injection well 214 may be used to determine the pressure in the gas cap 210.

[0079] The gas cap injection well 302 may inject NCG directly into the gas cap 210 prior to the start of the gravity assisted drainage process, prior to producing the heavy oil, or sometime after the gravity assisted drainage process has been in operation. Injections from the gas cap injection well 302 prior to the start of the gravity assisted drainage process may raise the pressure in the gas cap 210 to the target pressure. Injections from the gas cap injection well 302 after the gravity assisted drainage process has started may be performed either before or after the vapor chamber 234 and the gas cap 210 have intersected. Injections performed prior to intersection between the vapor chamber 234 and the gas cap 210 may function in a manner similar to injections performed prior to the gravity assisted drainage process starting in that the injections may be used to raise the pressure in the gas cap 210 to the target pressure. If the gas cap 210 is known to be large, the leak source 212 is known to be large, or the injection rate of the gas cap injection well 302 may not be sufficient (or sufficient in a timely manner) to increase pressure in the intersected vapor chamber 234 and gas cap 210, then the gas cap injection well 302 may begin injections of the NCG prior to the gas cap 210 and the vapor chamber 234 intersecting so as to decrease a time required to increase the pressure in the gas cap 210 after the intersection. Injections of NCG from the gas cap injection well 302 after the gas cap 210 and the vapor chamber 234 have intersected may function to raise the pressure in the intersected gas cap 210 and the vapor chamber 234 to a desired operating pressure for the gravity assisted drainage process (e.g., typically 1.3 to 5 MPa).

[0080] The precise timing of the start of the NCG injections varies according to numerous factors including, but not limited to, the size and extent of leakage of the gas cap 210, the amount of pressure increase required to bring the gas cap 210 to the target pressure and a delivery capacity of the gas cap injection well 302.

[0081] The methods may comprise maintaining the gas cap pressure at the target pressure by at least one of (i) injecting the non-condensable gas into the gas via the gas cap injection well and/or an injection well and (ii) producing gas from the gas cap through the gas cap injection well.

[0082] An injection rate of the gas cap injection well 302 may be adjusted to provide an equilibrium between the vapor chamber 234 and the gas cap 210. The gas cap injection well

302 may continuously or intermittently inject/co-inject NCG when raising the pressure in the gas cap 210 and when maintaining the pressure in the gas cap 210. The injection rate of the gas cap injection well 302 may be adjusted to reduce the amount of NCG injected while maintaining the target pressure. There may be attempts to balance a reduced amount of NCG to a lowest amount of NCG needed to maintain the target pressure. The lowest amount of NCG to maintain the target pressure may depend, for example but not limited to, on the size of the gas cap 210, the presence of the leak source 212, and/or an amount of leakage from the leak source 212. Reducing the amount of NCG that is injected may reduce a cost of employing the methods of the present disclosure.

[0083] The gas cap injection well 302 may produce gas from the gas cap 210. For example, if it is desirable to limit local expansion of the gas cap 210 then the gas cap injection well 302 may produce gas from the gas cap 210 in order to maintain or reduce the pressure in the gas cap 210. The gas produced from the gas cap injection well 302 may include native gas that is naturally present in the gas cap 210 and/or NCG that has been injected into the gas cap 210.

[0084] If bitumen is present in the gas cap 210 then it may be desirable to allow the vapor from the vapor chamber 234 to partially invade the gas cap 210 to reach the bitumen in the gas cap 210. Vapor invasion in the gas cap 210 may cause pressure changes elsewhere in the gas cap 210 (e.g., bulging in one area, depressions in another area, etc.). Gas may be removed from the gas cap 210 through the gas cap injection well 302 to enable local rebalancing of pressures in the gas cap 210.

[0085] Gas in the gas cap 210 may expand due to an increase in temperatures in areas of the subterranean reservoir 202 that are near the gas cap 210 causing pressure in the gas cap 210 to increase (especially if a rate of leakage from the gas cap 210 is less than a rate of expansion the gas in the gas cap 210). Under a condition of increased temperature, gas (including both NCG and native gas) from the gas cap 210 can invade the vapor chamber 234 due to the pressure increase. Gas from the gas cap 210 invading the vapor chamber 234 may cause a decrease in performance of the gravity assisted drainage well pair 204 due to NCG in the vapor chamber 234 slowing drainage of heavy oil from the vapor chamber 234. The gas cap

injection well 302 can be used to produce NCG from the gas cap 210 resulting in a reduction in pressure of the gas cap 210, which may decrease or halt invasion of gas from the gas cap 210 into the vapor chamber 234.

[0086] Pressure unbalancing may also occur during operational upsets and vapor injection shut downs from the injection well 214. In such a case, pressure in the vapor chamber 234 can drop quickly due to vapor condensation and NCG may invade the vapor chamber 234. When vapor injection from the injection well 214 is resumed, the gas cap injection well 302 can produce gas allowing NCG that has invaded the vapor chamber 234 to be replaced by vapor as long as the leak rate from the gas cap 210 is less than a rate of which the vapor from the injection well 214 can pressurize the vapor chamber 234.

[0087] The gravity assisted drainage well pair 204 may inject the NCG into the subterranean reservoir 202 through either injections of the NCG or co-injections of the NCG with the vapor via the injection well 214. Injections of the NCG may be performed to raise the pressure in the gas cap 210 to the target pressure and/or maintain the pressure in the gas cap 210 at the target pressure.

[0088] Discussion below of injections of the NCG via the injection well 214 may refer to injections of the NCG alone (either intermittently, possibly in alternation with vapor injections, or continuously) or co-injections of the NCG with vapor. When the injection well 214 is injecting the NCG, a gas cap injection well 302 may or may not be present in the gas cap 210. If the gas cap injection well 302 is present then the gas cap injection well 302 and/or the injection well 214 may inject the NCG to raise and/or maintain the pressure in the gas cap 202. When the injection well 214 injects NCG, the gas cap injection well 302 may be placed in the gas cap 210 either before the NCG is co-injected via the injection well 214 or after the vapor chamber 234 of the injection well 214 intersects with the gas cap 210.

[0089] Injection of the NCG and the vapor from the injection well 214 may start either before or after intersection of the vapor chamber 234 and the gas cap 210 or before the gravity assisted drainage process starts to produce heavy oil. Once gas cap 210 and the vapor chamber 234 intersect, NCG may be co-injected with the vapor from the injection wells in step 808 of Fig. 8 and step 910 of Fig. 9. The co-injection of NCG may occur in all injection wells, or only a

subset of injection wells if there are multiple injection wells depending on, for example, injection rate of the injection wells, the amount of pressure change (and thus the amount of increase in pressure that must be attained to reach the target pressure), the geometry of the subterranean reservoir and the gas cap, etc. Although the method 800 shows co-injection occurring only after the gas cap and the vapor chamber intersect, co-injection of NCG may occur before this time to build up NCG within the vapor chamber. In step 910 of Fig. 910 NCG may be injected from the gas cap injection wells in addition to the injections from the injection wells.

[0090] The precise start time of vapor and NCG injections depends on numerous factors, including, but not limited to, the known or expected pressure in the gas cap 210, delivery capacity of the injection well 214, the number of wells (either injection wells 214 or gas cap injection wells 302) co-injecting/injecting NCG into the subterranean reservoir 202, the size and geometric configuration of the gas cap 210, operational and budgetary constraints and criteria for the gravity assisted drainage process, etc.

[0091] When the NCG is co-injected with the vapor (or when the NCG is injected in cyclical alternation with the vapor), the NCG may migrate towards the gas cap 210 and may accumulate at the top of the vapor chamber 234 and in the gas cap 210. This occurs because while the vapor will condense and drain away in the water phase, the NCG remains in the vapor phase and is stranded high in the vapor chamber 234.

[0092] Co-injection of NCG with vapor from an injection well of a SAGD process has been taught, for example, in Canadian Patent No. 2,769,189, in which the NCG is used high in the vapor chamber as an insulating layer. NCG is injected in small mole fractions to provide an insulating layer on top of the vapor chamber of the SAGD process. Common NCG co-injection techniques, such as those disclosed in Canadian Patent No. 2,769,189, teach only a small fraction of NCG being added to the vapor. Such small fraction injections of NCG are typically used to provide an insulation barrier of NCG at the top of the vapor chamber to keep the heat in an area from which heavy oil is being produced. Small fraction NCG injection teachings may be limited in the size of gas cap that can be pressured up (if they teach such pressuring up at all) or that can have pressure managed due to the use of only a small fraction of NCG.

[0093] Co-injection of a large fraction of NCG with vapor (or injection of a large fraction of NCG without vapor) in a SAGD process is generally considered to be undesirable in other teachings because the vapor chamber may relatively quickly become filled with NCG. NCG in the vapor chamber may reduce a temperature in the vapor chamber. The reduction of temperature in the vapor chamber may reduce a production rate of the heavy oil. But, in the presence of a leaky gas cap that is connected to the vapor chamber, injecting a large fraction of NCG, can enable maintenance of a higher pressure in a number of gravity assisted drainage well pairs, particularly for wells on a boundary of the gravity assisted drainage process where the NCG may leak off into the gas cap at higher rates than, for example, near a middle of a geographic area of the gravity assisted drainage process. By increasing and maintaining a pressure in the gas cap, the gravity assisted drainage well pairs can operate at a higher pressure with fewer of the efficiency losses that occur when the gas cap is left at a lower pressure, as outlined above. Due to the size of the gas cap or degree of leakage from the gas cap, small fractions of NCG may not be effective in increasing the pressure or managing the pressure in the gas cap and thus large fractions of NCG may be used.

[0094] With co-injection of the NCG and vapor, the temperature of the vapor may be reduced due to partial pressure effects. While injection of the NCG may enable the vapor chamber 234 to operate at a higher pressure and temperature, the partial pressure effects may offset the benefit. Lower temperatures due to partial pressure effects may reduce the expected oil production rates compared to vapor only injection at the same pressure. However, the vapor to oil ratio may be better with NCG co-injection since the NCG addition may limit steam invasion of the vapor into the gas cap 210 and thus loss of the vapor.

[0095] Maintaining the gas cap pressure at the target pressure may comprise at least one process selected from the group consisting of (i) at least one of continuously and intermittently injecting the NCG from the gas cap injection well, (ii) at least one of continuously and intermittently injecting the NCG from the injection well, and (iii) at least one of continuously and intermittently co-injecting the NCG with the vapor from the injection well.

[0096] Co-injection of the NCG with the vapor through the injection well 214 may be intermittent (i.e. co-injection of vapor and NCG and then injection of vapor only followed again

by co-injection of vapor and NCG.) Such an intermittent pattern of co-injection of the NCG and vapor provides for management of the temperature changes associated with the mixing of gases with the vapor. Co-injection of the NCG with the vapor from the injection well 214 may be continuous. The injection well 214 may at least one of continuously and intermittently inject the NCG without the vapor. The gas cap injection well 302 may continuously or intermittently inject/co-inject NCG when raising pressure in the gas cap 210 and when maintaining the pressure in the gas cap 210. Either of the gas cap injection well 302 or the injection well 214 may be used to raise or maintain the pressure in the gas cap 210. The above processes for maintaining the gas cap pressure at the target pressure may be selected accordingly to various factors including, but not limited to, a size of the gas cap 210, the presence of a leak source 212 in the gas cap 210, the number of leak sources 212 in the gas cap 210, the amount that the leak source(s) 212 leak gas, location of the leak sources 212, difficulty in maintaining the target pressure due to some of the above factors, other operational and cost concerns, among others.

[0097] Maintaining the gas cap pressure at the target pressure may comprise adjusting injection rates of the gas cap injection well 302 and the injection well 214 to equilibrate the pressure in the vapor chamber 234 and the pressure in the gas cap 210. The injection rates may be adjusted according to pressure maps, monitored pressures, etc. The injection rates may be adjusted to reduce local pressure variations in the merged vapor chamber 234 and gas cap 210 according to factors indicated above for selecting a process for maintaining the target pressure. The injection rates of the gas cap injection well 302 and the injection well 214 may be adjusted to reduce an amount of NCG that is injected while still maintaining the gas cap pressure at the target pressure.

[0098] A control apparatus may be in communication with the gravity assisted drainage well pairs, and the gas cap injection wells. The control apparatus may be configured to control injection of a non-condensable gas from at least one of the injection wells and the gas cap injection wells, the non-condensable gas being injected to at least one of (i) raise the gas cap pressure to a target pressure and (ii) maintain the gas cap pressure at the target pressure. For example, the control apparatus may adjust an injection rate of the injection wells and the gas cap injection wells based on the measured gas cap pressure by controlling or adjusting a rate at

which material, such as non-condensable gas and vapor, is delivered to the injection wells and the gas cap injection wells. Injections from the injection wells and the gas cap injection wells may be controlled or adjusted via a valve in the injections wells and the gas cap injection wells that can be controlled by a signal from the control apparatus. The control apparatus may be a facility on the surface that controls the functioning of the gravity assisted drainage well pairs and the gas cap injection wells. The control apparatus may receive pressure and temperature and other information from sensors on the gravity assisted drainage well pairs and the gas cap injection wells in the subterranean reservoir. The control apparatus can determine injection rates of vapor and NCG, among others.

[0099] If NCG is injected from the gas cap injection well 302 after the gravity assisted drainage process has started, the gravity assisted drainage process may continue until the vapor chamber 234 has intersected with the gas cap 210. Once the vapor chamber 234 and the gas cap 210 have intersected, the injection well 214 may co-inject NCG with the vapor to initially raise the pressure of the gas cap 210.

[00100] As the vapor chamber 234 grows and approaches a point at which the vapor chamber will intersect with the gas cap 210, this approach can be detected when at least one of the following is detected: an increase in temperature at the gas cap injection well, and a position and size of the vapor chamber is adjacent to a perimeter of the gas cap. The intersection between the vapor chamber and the gas cap may be detected when at least one of the following is detected: an increase in temperature at the gas cap injection well, a change in pressure at the gas cap injection well and the injection well, and a change in a composition of components that comprise the heavy oil. The point at which the gas cap and the vapor chamber intersect is detected in step 806 of Fig. 8 and in step 908 of Fig. 9.

[00101] A gas cap pressure monitor may be configured to monitor a gas cap pressure in the gas cap. The gas cap pressure monitor may be a pressure sensor from any of the gas cap injection wells that can determine the pressure in the gas cap as previously described. The gas cap pressure monitor may also be a pressure sensor in a test well that is drilled into the gas cap for the purposes of determining the gas cap pressure. The gas cap pressure monitor may also be a pressure sensor from any of the gravity assisted drainage well pair that can be used to

determine a pressure in both the vapor chamber and the gas cap after the gas cap and the vapor chamber have intersected and pressures have equilibrated as previously described.

[00102] Monitoring temperatures at the gas cap injection well 302 and/or at the injection well 214 can give an indication of whether the point of intersection is approaching or has occurred. The temperatures at the gas cap injection well 302 and/or at the injection well 214 may be detected by a sensor and relayed to the control apparatus. The control apparatus may receive temperature data from the sensor(s) and monitor for changes that fall outside of expected variations (e.g., greater than a few degrees). There can be a drop in temperature that may be detected by the injection well 214 when the vapor chamber 234 is no longer contained and has intersected with the gas cap 210 since the vapor would then be lost to the possibly extensive and leaky gas cap 210. As the vapor chamber 234 is approaching the gas cap 210, the gas cap injection well 302 may detect an increase in temperature as a result of heat from the vapor in the vapor chamber 234. A temperature increase that is greater than expected temperature variations (e.g., typical temperature being 5-12 °C) in the gas cap 210, as detected by the gas cap injection well 302, may indicate that the vapor chamber 234 is approaching the gas cap 210. A temperature increase that is sufficiently large to indicate that the vapor chamber 234 and the gas cap 210 have intersected may be detected by the control apparatus based on temperatures obtained from sensors at the gas cap injection well 302. A temperature decrease that is greater than expected temperature variations in the subterranean reservoir 202, as detected by the injection well 214 may indicate that the vapor chamber 234 and the gas cap 210 have intersected. The expected temperature variations may change with different subterranean reservoirs, different seasons, different geological conditions and different processes occurring in the subterranean reservoir 202 and surrounding subterranean reservoirs. For example, the normal temperature in the subterranean reservoir 202 may be 5-12 °C, the normal temperature in the gas cap may be 5-12 °C and the normal temperature in the vapor chamber 234 may be 200-250 °C. Expected deviations from these above temperatures may be, for example, a few degrees Celsius.

[00103] Three-dimensional seismic imaging can be used to detect when the point of intersection is approaching. Three-dimensional imaging may determine where gas is present

in the subterranean reservoir 202. As such, a three-dimensional image can be used to show a position and size of the vapor chamber 234 in the subterranean reservoir 202. Subsequent three-dimensional seismic images can give an indication of heavy oil depletion based on a change in gas location (i.e., how much heavy oil has been removed, the size of the vapor chamber 234, and as such how close the top of the vapor chamber 234 is to the gas cap 210 can be estimated). The three-dimensional images can be used to show when a position and size of the vapor chamber 234 is adjacent to a perimeter of the gas cap 210. A four-dimensional seismic image can be generated using a difference between two three-dimensional seismic images showing where gas or vapor is now present in the subterranean reservoir 202 to indicate that the vapor chamber 234 is approaching the gas cap 210.

[00104] Components in the fluids, including heavy oil, produced by the production well 224 may indicate when the vapor chamber 234 and the gas cap 210 have intersected. When the vapor chamber 234 and the gas cap 210 have intersected, there may be a change in a composition of components. The components may comprise the produced heavy oil due to the components of the gas (both native gas and NCG that may have been injected) in the gas cap 210 forming part of the produced fluids, along with heavy oil, that are produced by the production well 224. For example, there may be an increase in the amount of methane in the produced fluids after intersection between the gas cap 210 and the vapor chamber 234 if the gas in the gas cap 210 has a higher concentration of methane than is present elsewhere in the subterranean reservoir 202.

[00105] There may be a change in the pressure that is detected by either the injection well 214 or the gas cap injection well 302 after the vapor chamber 234 and the gas cap 210 have been merged. The change in pressure should be more than (or outside of) expected variations in pressure as a result of the gravity assisted drainage process (e.g., if the gravity assisted drainage process is cyclic or has a constant pressure) and more than expected pressure variations in the gas cap 210 and the subterranean reservoir 202, which may vary with the same factors as those indicated above for temperature or other factors.

[00106] The method may comprise recovering the non-condensable gas from the gas cap by producing the non-condensable gas via the gas cap injection well. The gas cap injection well

302 may be operated in the production mode to remove the NCG from the gas cap to reduce pressure in the gas cap 210. The NCG may be produced from the gas cap 210 after the gravity assisted drainage process has finished to recover the NCG injected into the gas cap 210.

[00107] While much of the above description has been on examples with one gas cap injection well, as shown in Fig. 2, there may be multiple gas cap injection wells as shown and multiple gravity assisted drainage well pairs 404, 406, 408 with multiple gas cap injection wells 504, 506, 508 in the gas cap 210 (Figures 3A and 4A). The gas cap injection wells 504, 506, 508 may be configured like the gas cap injection well 302 shown in Fig. 2 and previously discussed. When there are gas cap injection wells, the method may comprise creating a pressure map of the gas cap using pressures determined at the gas cap injection wells. The multiple gravity assisted drainage well pairs may comprise exterior gravity assisted drainage well pairs surrounding an interior gravity assisted drainage well pair in the subterranean reservoir. Each of the exterior gravity assisted drainage well pairs and the interior gravity assisted drainage well pair may comprise an injection well and a production well. An interior gravity assisted drainage well pair may be any gravity assisted drainage well pair that is beside, on at least on two sides that are generally parallel to each other, other gravity assisted drainage well pairs. An exterior gravity assisted drainage well pair may be any gravity assisted drainage well pair that is beside at most one gravity assisted drainage well pair in a particular direction. The gravity assisted drainage well pairs 404, 406, 408 may be configured like the gravity assisted drainage well pair 204 shown in Fig. 2 as previously discussed.

[00108] There may be two exterior gas cap injection wells 504, 508 and one interior gas cap injection well 506 shown by way of example in Fig. 4A. While Figs. 4A-4B show three gas cap injection wells 504, 506, 508 as an example, there may be one gas cap injection well, or there may be two gas cap injection wells or there may be more than three gas cap injection wells. Further, it will be understood by those of ordinary skill in the art that the depiction in Figs. 4A-4B showing one interior gas cap injection well 506 is for illustrative purposes and that multiple interior gas cap injection wells may be present. The number of exterior gas cap injection wells 504, 508 is not limited to two but may be determined by the geometry of the subterranean reservoir 202 and configuration of the gravity assisted drainage well pairs 404,

406, 408 as well as the location of any leak sources 212 and other considerations. Although the gas cap injection wells 504, 506, 508 are illustrated as being horizontal wells, one of ordinary skill in the art will understand that they may also be vertical wells.

[00109] The gas cap injection wells 504, 506, 508 need not be perpendicular and/or parallel to the gravity assisted drainage well pairs 404, 406, 408. The gas cap injection wells 504, 506, 508 may be placed at any angle with respect to the gravity assisted drainage well pairs 404, 406, 406 according to what would be advantageous given the geometry of the subterranean reservoir 202 and the gas cap 210, such as being placed near known leak sources 212 and intermittently throughout the gas cap 210. The gas cap injection wells 504, 506, 508 may be placed and arranged in the subterranean reservoir 202 according to, for example, a pressure map of the gas cap 210 (which may have been created as previously described), a location of a known leak source 212, location of the gravity assisted drainage well pairs 404, 406, 408 and any of the gravity assisted drainage well pairs 404, 406, 408 having impaired function.

[00110] Each of the gas cap injection wells 504, 506, 508 may be paired with one of the gravity assisted drainage pair 404, 406, 408. Such a paired configuration may allow for improvement of performance of a gravity assisted drainage well pair 404, 406, 408 where performance of the gravity assisted drainage well pair 404, 406, 408 has been impaired due to the gas cap 210. Such gas cap injection wells can even be provided after the gravity assisted drainage process has started where it becomes noticeable that the performance of a gravity assisted drainage well pair has become impaired.

[00111] Once the vapor chambers 434, 436, 438 intersected with the gas cap 210 there may be a pressure equilibrium between the vapor chamber 434, 436, 438 and the gas cap 210. If it is known that the pressure of the vapor chamber 434, 436, 438 has equilibrated with the pressure of the gas cap 210, pressures can be mapped over the area of the subterranean reservoir 202 and over the expanse of the gas cap 210 by monitoring the pressure at the any of the injection wells 414, 416, 418 and the gas cap injection wells 504, 506, 508. Mapping of these pressures is taught in, for example, "Pressure Mapping as an Aid to Understanding Reservoir Drainage", JS Andrews, SPE 22962, Society of Petroleum Engineers, SPE Asia-Pacific

Conference, November 4-7 1991, p. 173-185 and "Fundamentals of Reservoir Engineering," L.P. Drake, Elsevier, UK, 1978. The map of these pressures over the gas cap 210 can be used to determine areas with high leakage in the gas cap 210 as well as gas flow distribution of the gas cap 210. For example, areas in the pressure map that show large variations in pressure either over time or in comparison with a known injection pressure at the injection well 414, 416, 418 and/or the gas cap injection wells 504, 506, 508, may indicate areas of high leakage in the gas cap 210.

[00112] Pressure measurements from the gas cap injection wells 504, 506, 508 can be used in creating pressure maps of the gas cap 210. The pressure map can be used to adjust injection rates of the gas cap injection wells 504, 506, 508 and/or the injection well 414, 416, 418 to equilibrate the gas cap pressure throughout the gas cap. Using the pressure maps this way can provide more consistent pressure through the subterranean reservoir 202, the gas cap 210 and/or the vapor chamber 434, 436, 438.

[00113] The methods may comprise providing an additional gas cap injection well based on the pressure map indicating at least one area in the gas cap having a pressure below the target pressure by a threshold. The pressure map created after the gravity assisted drainage process has started may indicate additional areas in the gas cap 210 that would benefit from additional gas cap injection wells, even if there were gas cap injection wells 302 already placed in the gas cap 210 earlier in the gravity assisted drainage process. If it is determined that the additional gas cap injection well (or additional wells in the gas cap 210) would be beneficial then the additional gas cap injection well may be drilled in place. Placement of the additional gas cap injection well may be determined according to considerations as indicated above with respect to the gas cap injection well 302, such as, for example, the pressure map, and three-dimensional seismic imaging among other techniques. An additional gas cap injection well may be beneficial, for example, if an increased pressure in the gas cap 210 cannot be attained or at least cannot be readily attained with the gas cap injection well(s) in place or if a leak source is identified or if an increased pressure cannot be maintained by the gas cap 210. The threshold amount by which the pressure in the gas cap 210 is below the target pressure may be determined according to geological considerations of the gap cap 210 and the subterranean

reservoir 202 as well as conditions of the gravity assisted drainage process in the subterranean reservoir 202.

[00114] Providing the gas cap injection well may comprise determining a placement of the gas cap injection well based on at least one of a previously created pressure map of the gas cap, a location of a known leak source in the gas cap, a location of a well from the gravity assisted drainage process having impaired function and a placement of wells from the gravity assisted drainage process. For example, the gas cap injection well may be placed in an area of the gas cap that has been indicated by a pressure map to show a difference in pressure from other areas of the gas cap or to be the location of a leak source, which may be determined as per the above discussion about determining locations of leak sources. The gas cap injection well may be placed in an area of the gas cap that contains a known leak source, such as for example, areas of previous gas extraction or beside areas of higher porosity in the subterranean reservoir 202 or beside areas of previous heavy oil production. The gas cap injection well may be placed in the gas cap above or near a gravity assisted drainage well pair that has, for example, lower steam-to-oil ratios than other gravity assisted drainage well pairs, which is an example of a metric that can be used to gauge the performance and function of a gravity assisted drainage well pair. The gas cap injection well may be placed in different configurations with the gravity assisted drainage well pairs, such as, for example, above a gravity assisted drainage well pair or in vertical and horizontal offset from the gravity assisted drainage well pairs.

[00115] Fig. 3A-3D illustrates a cross section drawing of multiple gravity assisted drainage well pairs 404, 406, 408 in a subterranean reservoir 202 having a gas cap 210. There are two exterior gravity assisted drainage well pairs 404, 408 and one interior gravity assisted drainage well pair 406. While Figs. 3A-3D show three gravity assisted drainage well pairs 404, 406, 408 as an example, there may be one gravity assisted drainage well pair as shown in Fig. 2 or there may be two gravity assisted drainage well pairs or there may be more than three gravity assisted drainage well pairs. Further, it will be understood by those of ordinary skill in the art that the depiction in Figs. 3A-3D showing one interior gravity assisted drainage well pair 406 is for illustrative purposes and that multiple interior gravity assisted drainage well pairs may be present. Additionally, the number of exterior gravity assisted drainage well pairs is not limited

to two but may be determined by the geometry of the subterranean reservoir and other considerations.

[00116] The gravity assisted drainage well pairs 404, 406, 408 may be configured in a manner similar to the gravity assisted drainage well pair 204 illustrated in Fig. 2. Each of the gravity assisted drainage well pairs 404, 406, 408 may include an upper injection well 414, 416, 418 and a lower production well 424, 426, 428. The injection wells 414, 416, 418 may be configured like the injection well 214 of the gravity assisted drainage well pair 204 from Fig. 2. The production wells 424, 426, 428 may be configured like the production well 224 of the gravity assisted drainage well pair 204 from Fig. 2. Each of the injection wells 414, 416, 418 may inject a vapor into the subterranean reservoir 202 to produce a separate vapor chamber 434, 436, 438. These vapor chambers 434, 436, 438 may expand from an initial size (not shown) until they intersect with each other as shown in Fig. 3A.

[00117] Figs. 3B-3D provide an illustrative example of injection of the NCG from the injection wells via co-injection of the NCG with the vapor to increase the pressure in the gas cap and/or to maintain the pressure in the gas cap.

[00118] Fig. 3B illustrates the multiple gravity assisted drainage well pairs 404, 406, 408 of Fig. 3A in an initial period of the gravity assisted drainage process. In the initial stages the vapor chambers 434, 436, 438 are separate and all injection wells 414, 416, 418 may be producing vapor at substantially the same rate. Further, none of the vapor chambers 434, 436, 438 has approached or intersected with the gas cap 210 from any of the injection wells 414, 416, 418. At this time there may or may not be an NCG that is co-injected with the vapor. Co-injection of the NCG with the vapor at this time might be used to create a barrier of the NCG between the gas cap 210 and the vapor chambers 434, 436, 438. Co-injection of the NCG with the vapor at the time illustrated in Fig. 4B may be used so that there is some NCG in the vapor chamber 434, 436, 438 when the vapor chamber 434, 436, 438 intersects with the gas cap 210. Having NCG in the vapor chamber 434, 436, 438 prior to intersection with the gas cap 210 may slow a vertical rise of the vapor chamber 434, 436, 438 thereby delaying intersection with the gas cap 210. Further, NCG in the vapor chamber 434, 436, 438 prior to intersection with the gas cap 210 may reduce a time required to increase the pressure of the gas cap 210 after intersection.

[00119] Fig. 3C illustrates the multiple gravity assisted drainage well pairs 404, 406, 408 of Fig. 4A in a period of the gravity assisted drainage process in which the vapor chambers 434, 436, 438 have initially intersected with each other and with the gas cap 210. Once the vapor chambers 434, 436, 438 have intersected with the gas cap 210, the NCG may be co-injected with the vapor from all injection wells 414, 416, 418 to increase the pressure in the gas cap 210. Fig. 3C shows all injection wells 414, 416, 418 co-injecting NCG with the vapor. However, depending upon the surrounding geology, the geometry of the subterranean reservoir 202 and the gas cap 210, pressure of the gas cap 210, location of leak sources 212 (only one of which is shown but multiple may be present), amount of leakage, etc., only a subset of the injection wells 414, 416, 418 may be used for the initial co-injection of NCG with the vapor which is used to raise the pressure of the gas cap 210 to the target pressure.

[00120] Once the target pressure has been reached, as determined in step 810 of Fig. 8 and step 912 of Fig. 9, then co-injection of the NCG with the vapor may cease from some of the injection wells, the injection rate may decrease, etc., in order to maintain the target pressure in step 812 and step 914. Pressure in the vapor chamber and the gas cap may be continuously monitored. The optimization of the injection well co-injections to maintain the target pressure may be frequently revised based on pressure changes so that the target pressure is maintained.

[00121] The NCG that is co-injected with the vapor may be small or large fraction. The fraction of NCG injected with vapor may be, for example, 0-10 volume% for the interior injection well 416 and 20-100 volume% for one or more of the exterior injection wells 414, 418. NCG co-injection with vapor may be performed intermittently (i.e., co-injection of NCG with vapor then injection of vapor only then co-injection of NCG with vapor again). This enables temperature changes in the vapor chamber associated with mixing of the NCG and vapor to be more easily managed.

[00122] Fig. 3D illustrates the multiple gravity assisted drainage well pairs 404, 406, 408 of Fig. 3A in a period of the gravity assisted drainage process in which the vapor chambers 434, 436, 438 have already intersected with each other and with the gas cap 210 and the pressure in the gas cap 210 has been increased to the target pressure. Injection rates for each of the injection wells 414, 416, 418 may be determined during maintenance of the gas cap pressure to

maintain the gas cap pressure at the target pressure and to reduce an amount of the non-condensable gas injected into the gas cap. For maintenance of the target pressure in the gas cap 210, co-injection of the NCG with the vapor may be ceased, for example, from the interior injection well 416. In this case, the interior injection well 416 may still continue to produce vapor without the NCG. The increased pressure in the gas cap 210 may be maintained by the exterior injection wells 414, 418 such that these wells continue co-injection of the NCG with the vapor. If the leak source 212 is located only on one side of the subterranean reservoir 202 then a configuration in which only the exterior injection well 414 closest to the leak source 212 continues with co-injection of the NCG and vapor while the other exterior injection well 418 furthest away from the leak source 212 may continue to inject vapor without the NCG. The exterior injection wells 414, 418 that continue co-injection of the NCG with the vapor may have higher injection rates than those injection wells 416 that are producing vapor without with NCG in order to maintain the increased pressure of the gas cap 210. The actual injection wells 414, 416, 418 used and their injection rates during maintenance of the target pressure may be determined using, for example, a pressure map, among others.

[00123] The methods may comprise injecting blocking agents into the gas cap through at least one of the plurality of gas cap injection wells to reduce permeability of the gas cap. The block agents may include, for example, polymer fluids, sodium silicate solutions, and forms of cement, among others.

[00124] Figs. 4A-4B provides an illustrative example of injection of the NCG from the plurality of gas cap injection wells to increase the pressure in the gas cap and/or to maintain the pressure in the gas cap.

[00125] The gas cap injection wells 504, 506, 508 may be drilled into the gas cap 210 after the vapor chambers 434, 436, 438 have intersected with the gas cap 210, taking place, for example, between Figs. 3C and 3D or before. Until such time as the gas cap injection wells 504, 506, 508 have been drilled and are operational, at least one of the injection wells 414, 416, 418 may co-inject the NCG with the vapor to raise and/or maintain the pressure of the gas cap 210. Delayed drilling of the gas cap injection wells 504, 506, 508 may be performed if, for example,

there is uncertainty regarding the presence of a gas cap, the presence of leakage in a gas cap, and/or the amount of leakage in the gas cap.

[00126] The gas cap injection wells 504, 506, 508 may be drilled into the gas cap 210 prior to the initiation of gravity assisted drainage process. If the gas cap injection wells 504, 506, 508 are in place prior to the start of gravity assisted drainage process then the gas cap injection wells 504, 506, 508 may inject NCG into the gas cap 210 to increase the pressure therein prior to the commencement of the gravity assisted drainage process. When the gas cap injection wells 504, 506, 508 are in place at the time of breakthrough of the vapor chambers 434, 436, 438 to the gas cap 210, then the gas cap injection wells 504, 506, 508 may be dedicated solely, or in coordination with the injection wells 414, 416, 418, to maintaining the pressure of the gas cap 210.

[00127] The coordination, distribution and injection rates of NCG injection from the gas cap injection wells 504, 506, 508 and NCG co-injection with vapor from the injection wells 414, 416, 418 may be optimized in various ways to equilibrate pressure in the gas cap 210 and the vapor chambers 434, 436, 438, maximize operating pressure in the vapor chambers 434, 436, 438 and maximize production of hydrocarbons from the production wells 424, 426, 428. This may be assisted, for example, by monitoring, simulating and modeling techniques based on monitored pressures and pressure maps, for example, in the injection wells as well as predictive models. One or more of any of the injection wells 414, 416, 418 and the gas cap injection wells 504, 506, 508 may be used to inject NCG during an initial stage of the gravity assisted drainage process or just after breakthrough the vapor chambers 434, 436, 438 with the gas cap 210 to raise pressure of the gas cap 210 to the target pressure.

[00128] Fig. 5B illustrates the multiple gravity assisted drainage well pairs 404, 406, 408 of Fig. 4A in the period of the gravity assisted drainage process in which the vapor chambers 434, 436, 438 have already intersected with each other and with the gas cap 210 and the pressure in the gas cap 210 has already been increased. Once the target pressure for the gas cap 210 has been reached, gas injection rates can be reduced and redistributed between the exterior and interior gas cap injection wells 504, 506, 508 to maintain the target pressure. For example, one or more of the exterior gas cap injection wells 504, 508 may have higher injection rates to

maintain the target pressure of the gas cap 210. As a further example, only those exterior gas cap injection wells 504 near the leak source 212 may have the higher injection rates with all other gas cap injection wells 506, 508 having a lower gas injection rate after the target pressure in the gas cap 210 has been attained. That is, one or more of the injection wells 414, 416, 418 and the gas cap injection wells 504, 506, 508 may be used to maintain the target pressure in the gas cap 210 and this one or more wells may be the same as or less than the number of wells used in Fig. 4A to increase the pressure in the gas cap 210 to the target pressure. Additionally, the pressure between the injection wells 414, 416, 418 and nearby gas cap injection wells 504, 506, 508 may be closely matched to improve efficiency of the hydrocarbon recovery process. For example, injection rates for the gas cap injection well 504 may be increased or decreased to closely match the pressure in the vapor chamber 434 as determined from the injection well 414.

[00129] The process illustrated in Figs. 4A-4B may be used separate from or in conjunction with the process illustrated in Figs. 3A-3D where the gas cap injections wells 504, 506, 508 and the injection wells 414, 416, 418 may continuously or intermittently inject/co-inject NCG when raising the pressure and/or when monitoring the pressure in the gas cap 210.

[00130] The plurality of gas cap injection wells and the at least one gravity assisted drainage well pair may have numerous configurations relative to each other.

[00131] Fig. 5 illustrates a top plan view of a possible configuration of multiple gravity assisted drainage well pairs 414/424, 416/426, 418/428 as shown in Figs. 3A-3D and 4A-4D. In the illustrated configuration, the gravity assisted drainage well pairs 414/424, 416/426, 418/428 are all parallel to each other with there being two exterior gravity assisted drainage well pairs 414/424, 418/428 and one interior gravity assisted drainage well pair 416/426. Gas cap injection wells 504, 506, 508, 602, 604 are distributed around the perimeter of the subterranean reservoir 202 with exterior gas cap injection wells 504, 508, 602, 604 outlining the general perimeter of the subterranean reservoir 202 and at least one interior gas cap injection well 506 being placed within the area bounded by the exterior gas cap injection wells 504, 508, 602, 604. Two of the exterior gas cap injection wells 504, 508 are illustrated as being parallel

with the gravity assisted drainage well pairs 414/424, 416/426, 418/428 while the other exterior gas cap injection wells 602, 604 are perpendicular thereto.

[00132] Fig. 6 illustrates a top plan view of an alternate configuration of multiple gravity assisted drainage well pairs 414/424, 416/426, 418/428, 702/712, 704/714, 706/716 showing multiple interior gravity assisted drainage well pairs 416/426, 702/712, 704/714, 706/716. Like the depiction in Fig. 5, in the illustrated configuration, the gravity assisted drainage well pairs 414/424, 416/426, 418/428, 702/712, 704/714, 706/716 are all parallel to each other with there being two exterior gravity assisted drainage well pairs 414/424, 418/428 and multiple interior gravity assisted drainage well pair 416/426, 702/712, 704/714, 706/716. Gas cap injection wells 504, 506, 508, 602, 604 are distributed around the perimeter of the subterranean reservoir 202 with exterior gas cap injection wells 504, 508, 602, 604 outlining the general perimeter of the subterranean reservoir 202 and at least one interior gas cap injection well 506 being placed within the area bounded by the exterior gas cap injection wells 504, 508, 602, 604. Two of the exterior gas cap injection wells 504, 508 are illustrated as being parallel with the gravity assisted drainage well pairs 414/424, 416/426, 418/428, 702/712, 704/714, 706/716 while the other exterior gas cap injection wells 602, 604 are perpendicular thereto.

[00133] As shown in Figs. 5 and 6, the geometry of the gravity assisted drainage well pairs relative to each other, the geometry of the gas cap injection wells relative to each other and the geometry of the gravity assisted drainage well pairs relative to that of the gas cap injection wells are for illustration purposes only. One of ordinary skill in the art would understand that various geometric configurations and permutations are possible that will still achieve the aforementioned purposes. The exact configuration can vary according to previously mentioned factors and pressure maps of the subterranean reservoir and the gas cap.

[00134] When a solvent is used for a subterranean reservoir with a gas cap, it can be difficult to recover the solvent after the SA-SAGD process in the subterranean reservoir has finished. NCG co-injection with vapor and solvent provides a mechanism for managing lost solvent as the NCG forms a cloud separating the vapor from the injection well from the gas cap so that the solvent and gasses in the gas cap do not mix, making retrieval of the solvent easier.

[00135] It should be clear from the above that the exact number and placement of the gap cap injection wells is to be determined according to the particulars of the subterranean reservoir, gas cap and hydrocarbon removal operations. The above techniques can be used to plug leaks in a gas cap, even if there are no gravity assisted drainage well pairs in the vicinity. The overall operations in the subterranean reservoir can be considered examining operational performance of gravity assisted drainage well pairs to improve operational efficiencies through strategic placement of multiple gas cap injection wells and possibly placed near gravity assisted drainage well pairs whose performance may be impaired by the gas cap or leak source.

[00136] In the present disclosure, a pressure in the gas cap during the gravity assisted drainage process may be managed at a higher pressure than an original pressure of the gas cap, through the injection of a non-condensable gas (NCG) into the gas cap. The NCG may be co-injected with the vapor, such as steam, solvent vapor, or combinations thereof through a well of the gravity assisted drainage process, or may be injected separately from the vapor through a gas cap injection well placed directly in the gas cap. The NCG injected into the gas cap may be injected in small fraction or large fraction. The NCG may be initially injected into the gas cap via multiple wells to raise the pressure of the gas cap to a target pressure. Maintenance of the target pressure in the gas cap may be performed by a subset of the multiple wells used in the initial injection of the NCG. This subset of wells may be determined according to the geometry of the subterranean reservoir and gas cap, and location(s) of leak source(s), among other factors.

[00137] While the above description has been discussed with reference to the SAGD process, any gravity assisted drainage process may be used with the above discussed techniques. These techniques can be particularly useful in combination with any constant pressure drainage process (e.g. steam flooding, etc.) where these techniques attempt to match the pressure of the process. However, the above techniques can still be used with cyclic drainage processes (e.g., CSS) as well.

[00138] As utilized herein, the terms "approximately," "about," and similar terms are intended to have a broad meaning in harmony with the common and accepted usage by those of ordinary skill in the art to which the subject matter of this disclosure pertains. It should be

understood by those of skill in the art who review this disclosure that these terms are intended to allow a description of certain features described without restricting the scope of these features to any numerical ranges provided. Accordingly, these terms should be interpreted as indicating that insubstantial or inconsequential modifications or alterations of the subject matter described and are considered to be within the scope of the disclosure.

[00139] It should be understood that numerous changes, modifications, and alternatives of the preceding disclosure can be made without departing from the scope of the disclosure. The preceding description, therefore, is not meant to limit the scope of the disclosure. It is also contemplated that structures and features in the present examples can be altered, rearranged, substituted, deleted, duplicated, combined, or added to each other.

[00140] The articles "the," "a," and "an" are not necessarily limited to mean only one, but rather are inclusive so as to include, optionally, multiple such elements.

CLAIMS

1. A method of managing pressure in a gas cap of a subterranean reservoir during a gravity assisted drainage process of heavy oil from the subterranean reservoir, the method comprising:
 - providing a gas cap injection well in the gas cap;
 - raising a gas cap pressure in the gas cap to a target pressure by injecting a non-condensable gas into the gas cap via the gas cap injection well;
 - maintaining the gas cap pressure at the target pressure by at least one of (i) injecting the non-condensable gas into the gas cap via the gas cap injection well and (ii) producing gas from the gas cap through the gas cap injection well;
 - providing a gravity assisted drainage process well pair comprising an injection well and a production well;
 - forming a vapor chamber in the subterranean reservoir that expands in size by injecting vapor into the subterranean reservoir via the injection well; and
 - detecting when the vapor chamber is approaching an intersection between the vapor chamber and the gas cap when at least one of the following is detected:
 - an increase in temperature at the gas cap injection well; and
 - a position and size of the vapor chamber is adjacent to a perimeter of the gas cap.
2. The method of claim 1, further comprising detecting the intersection between the vapor chamber and the gas cap when at least one of the following is detected:
 - the increase in temperature at the gas cap injection well;
 - a change in pressure at the gas cap injection well and the injection well; and
 - a change in a composition of components that comprise the heavy oil.
3. The method of any one of claims 1-2, wherein injecting the non-condensable gas comprises injecting the non-condensable gas with the vapor via the injection well at a time equal to at least one of before and after detecting the intersection between the vapor chamber and the gas cap.

4. The method of any one of claims 1-3, wherein maintaining the gas cap pressure comprises at least one process selected from the group consisting of:
- (i) one of continuously and intermittently injecting the non-condensable gas from the gas cap injection well,
 - (ii) one of continuously and intermittently injecting the non-condensable gas from the injection well, and
 - (iii) one of continuously and intermittently co-injecting the non-condensable gas with the vapor from the injection well.
5. The method of any one of claims 1-4, wherein maintaining the gas cap pressure comprises adjusting injection rates of the gas cap injection well and the injection well to equilibrate a vapor chamber pressure in the vapor chamber and the gas cap pressure in the gas cap.
6. The method of any one of claims 1-5, wherein providing the gas cap injection well and injecting the non-condensable gas occur prior to the producing the heavy oil.
7. The method of any one of claims 1-6, further comprising:
recovering the non-condensable gas from the gas cap by producing the non-condensable gas via the gas cap injection well.
8. The method of claim 1, wherein the gas cap injection well comprises gas cap injection wells, the method further comprising:
creating a pressure map of the gas cap using pressures at the gas cap injection wells.
9. The method of claim 8, further comprising:
adjusting the injection rates of the gas cap injection wells by using the pressure map to equilibrate the gas cap pressure throughout the gas cap.

10. The method of any one of claims 8-9, further comprising:
providing an additional gas cap injection well when at least one area in the gas cap has a pressure below the target pressure by a threshold amount.
11. The method of any one of claims 1-7 wherein providing the gas cap injection well comprises:
determining a placement of the gas cap injection well based on at least one of a previously created pressure map of the gas cap, a location of a known leak source in the gas cap, a location of a well from the gravity assisted drainage process having impaired function and a placement of wells from the gravity assisted drainage process.
12. The method of claim 1 wherein injecting the non-condensable gas from the injection well comprises co-injecting the non-condensable gas with the vapor from the injection well.
13. The method of claim 12, wherein the non-condensable gas is co-injected with the vapor one of continuously and intermittently.
14. The method of any one of claims 1-13, further comprising:
reducing permeability of the gas cap by injecting blocking agents into the gas cap.
15. The method of any one of claims 1-14, wherein the target pressure is greater than or equal to an operating pressure of the gravity assisted drainage process.
16. The method of any one of claims 1-15, wherein the non-condensable gas comprises one of methane, ethane, propane, carbon dioxide, nitrogen, hydrogen-sulfide, or air or a combination of methane, ethane, propane, carbon dioxide, nitrogen, hydrogen-sulfide, or air.
17. The method of any one of claims 1-16, wherein the gravity assisted drainage process is a steam assisted gravity drainage process.

18. A system for managing pressure in a gas cap of a subterranean reservoir during a gravity assisted drainage process for recovering heavy oil from the subterranean reservoir, the system comprising:

- gravity assisted drainage well pairs in the subterranean reservoir comprising exterior gravity assisted drainage well pairs surrounding an interior

- gravity assisted drainage well pair, each of the exterior gravity assisted drainage well pairs and the interior gravity assisted drainage well pair comprising an injection well and a production well;

- gas cap injection wells within the gas cap for injecting a non-condensable gas into the gas cap;

- a gas cap pressure monitor configured to monitor a gas cap pressure in the gas cap;

- a gas cap temperature monitor configured to monitor a gas cap temperature in the gas cap; and

- a control apparatus in communication with the exterior gravity assisted drainage well pairs, the interior gravity assisted drainage well pair and the gas cap injection wells, the control apparatus configured to control injection of the non-condensable gas from at least one of the injection wells and the gas cap injection wells, the non-condensable gas being injected to at least one of (i) raise the gas cap pressure to a target pressure and (ii) maintain the gas cap pressure at the target pressure, the control apparatus being further configured to adjust an injection rate of the injection wells and the gas cap injection wells based on the gas cap pressure;

wherein the system is configured to determine when a vapor chamber associated with each of the gravity assisted drainage well pairs is approaching an intersection between the vapor chamber and the gas cap when at least one of the following is detected:

- an increase in temperature at the gas cap injection well; and

- a position and size of the vapor chamber is adjacent to a perimeter of the gas cap.

19. The system of claim 18, wherein the gas cap injection wells are in a paired configuration with the exterior gravity assisted drainage well pairs and the interior gravity assisted drainage well pair such that each of the exterior gravity assisted drainage well pairs and interior gravity assisted drainage well pair has a corresponding one of the gas cap injection wells placed within the gas cap substantially vertically above but in vertical alignment with the corresponding one of the exterior gravity assisted drainage well pairs and the interior gravity drainage well pair.

20. The system of claim 18, wherein the gas cap injection wells are in a paired configuration with the exterior gravity assisted drainage well pairs and the interior gravity assisted drainage well pair such that each of the exterior gravity assisted drainage well pairs and interior gravity assisted drainage well pair has a corresponding one of the gas cap injection wells placed within the gas cap substantially vertically above but vertically offset from the exterior gravity assisted drainage well pairs and the interior gravity assisted drainage well pair.

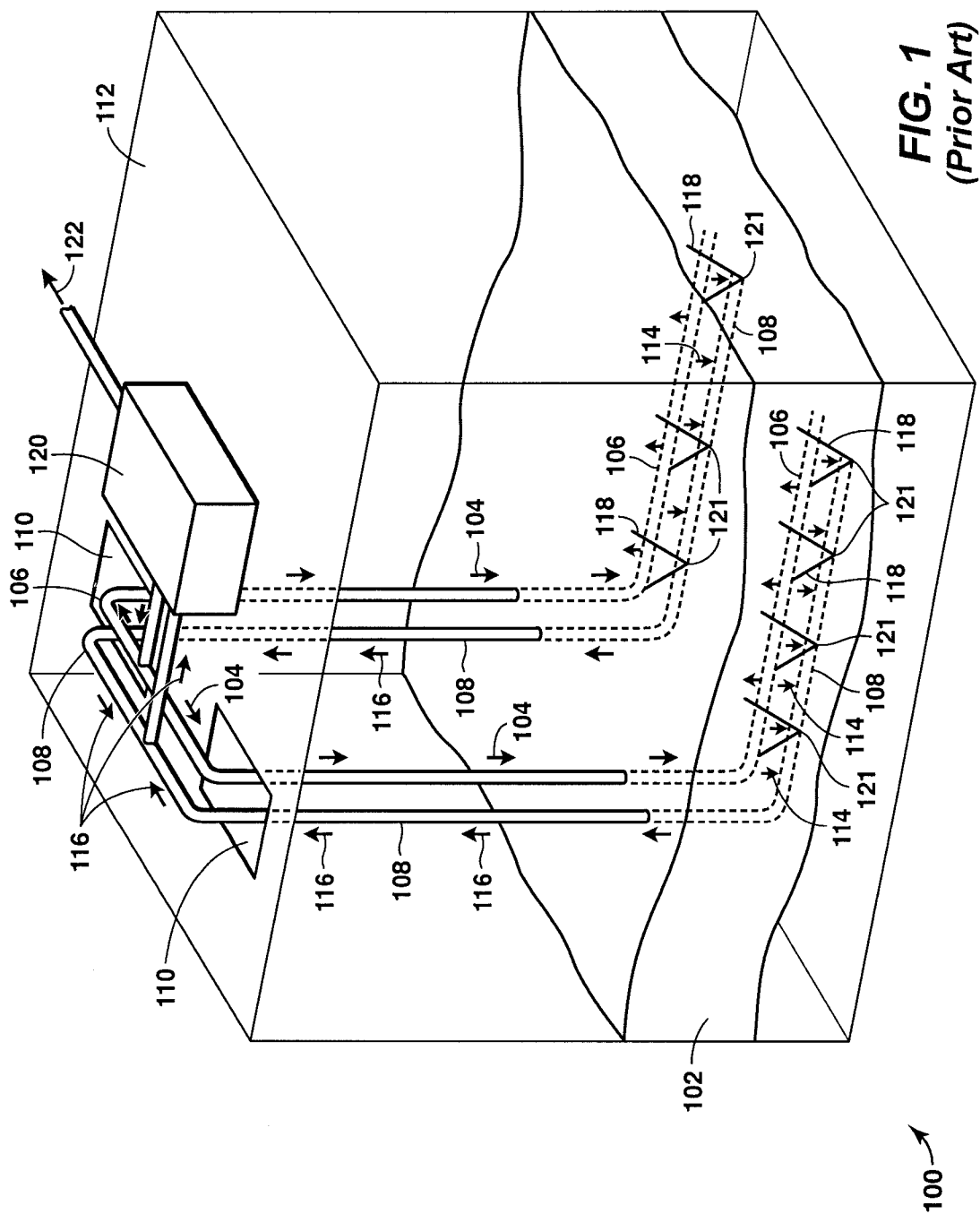
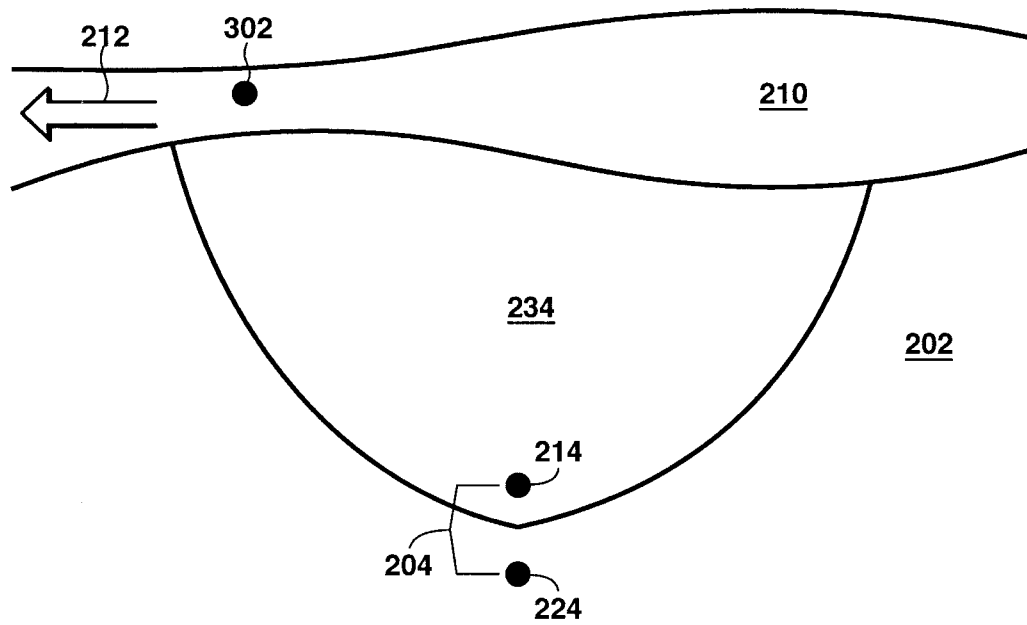
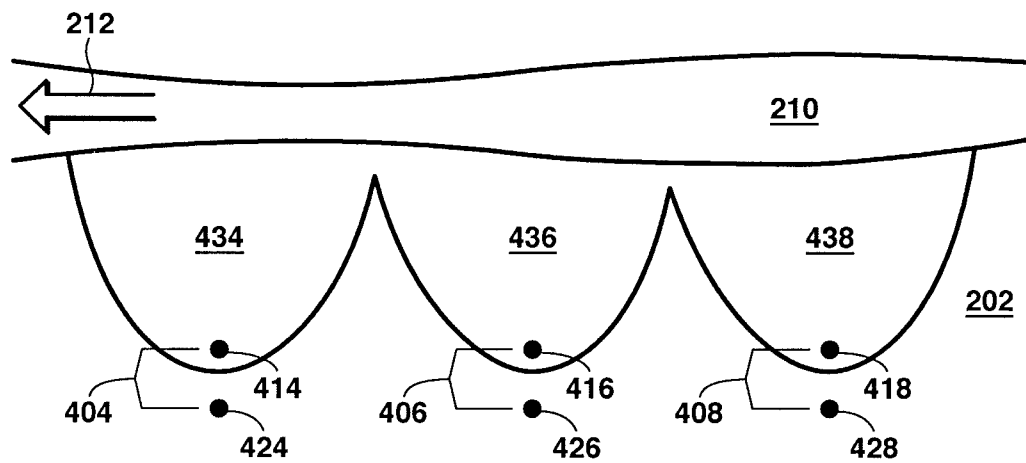
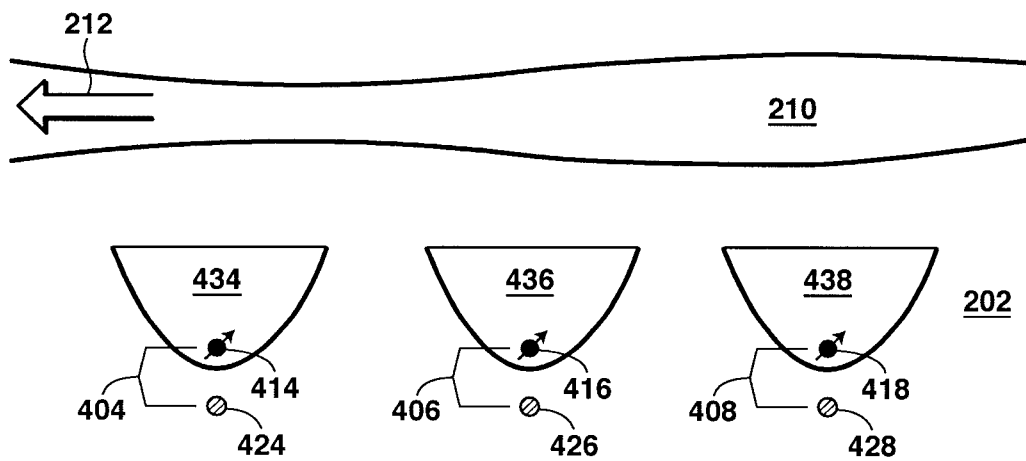


FIG. 1
(Prior Art)

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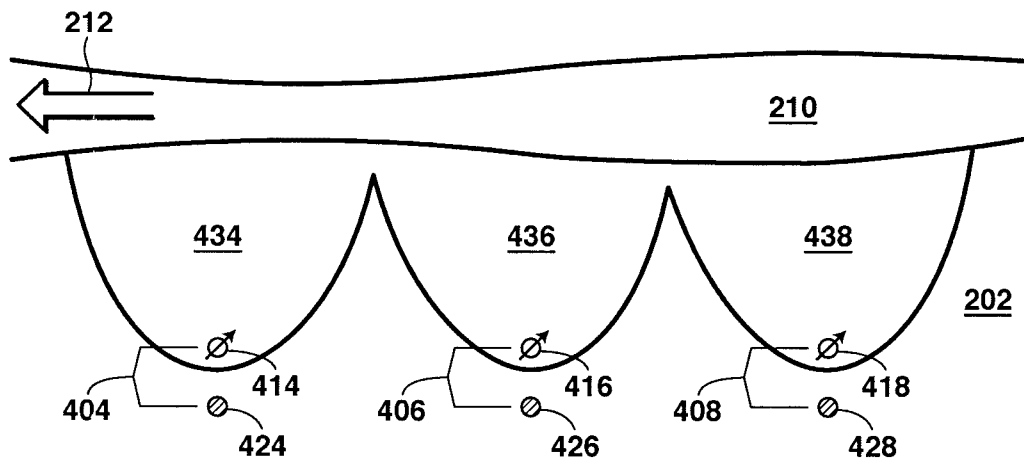
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**FIG. 3A**

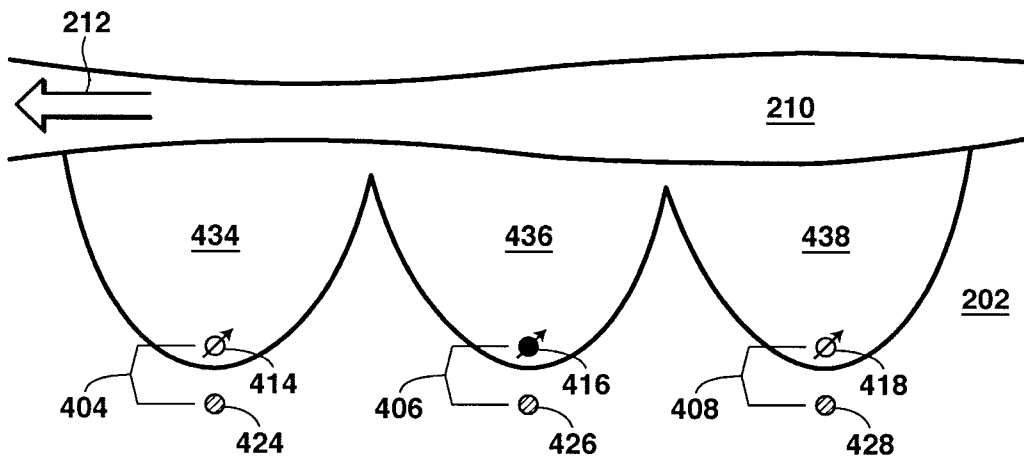
- Active injector well
(Vapor injection)
- ⊘ Production well

FIG. 3B

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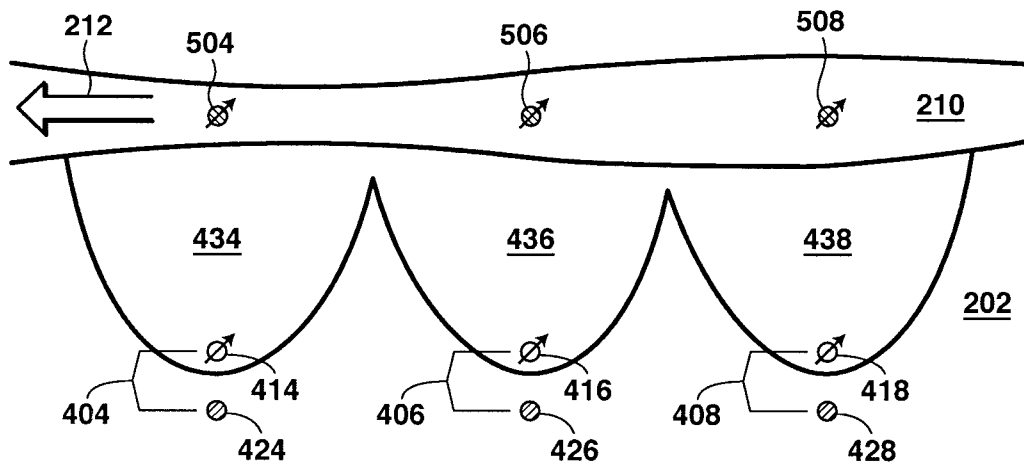
- ♂ Active injector well
 (Vapor and NCG injection)
 ⊙ Production well

FIG. 3C

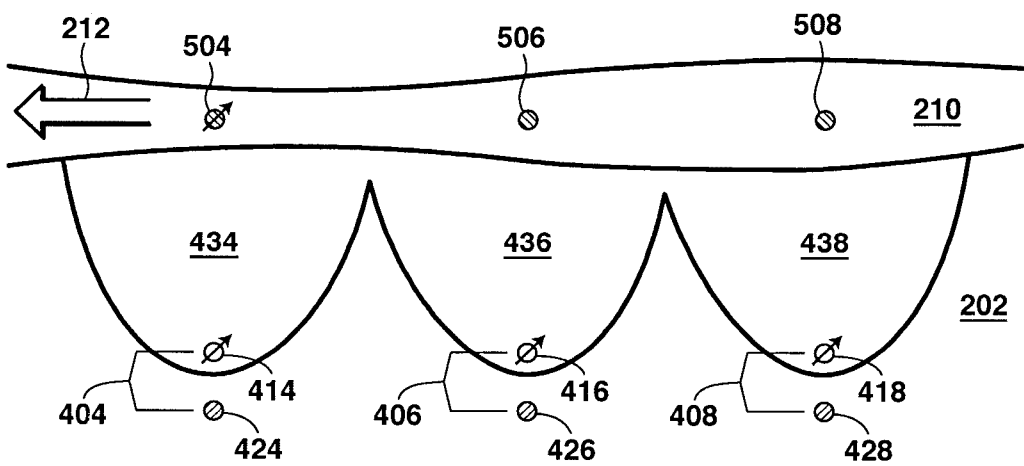
- ♂ Active injector well
 (Vapor and NCG injection)
 ● Active injector well
 (Vapor injection)
 ⊙ Production well

FIG. 3D

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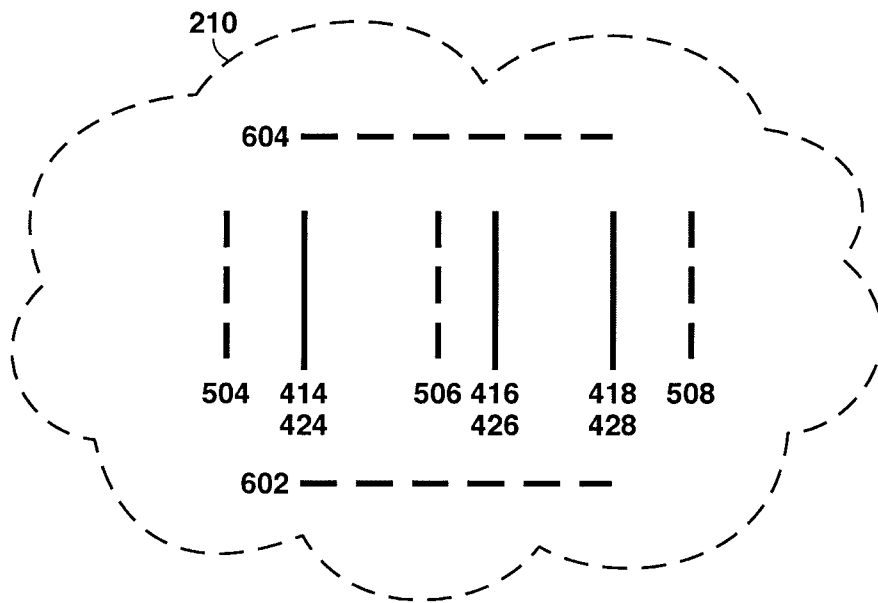
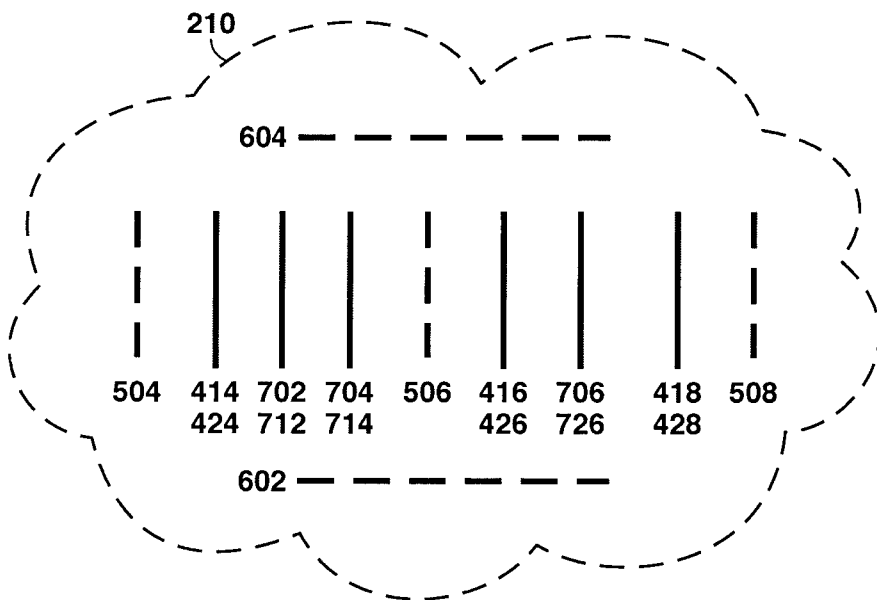
- ⌀ Active injector well
(Vapor injection)
- ⊙ Production well
- ⊗ Active gas cap
injection well

FIG. 4A

- ⌀ Active injector well
(Vapor injection)
- ⊙ Production well
- ⊗ Active gas cap
injection well
- ⊙ Inactive gas cap
injection well

FIG. 4B

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**FIG. 5****FIG. 6**

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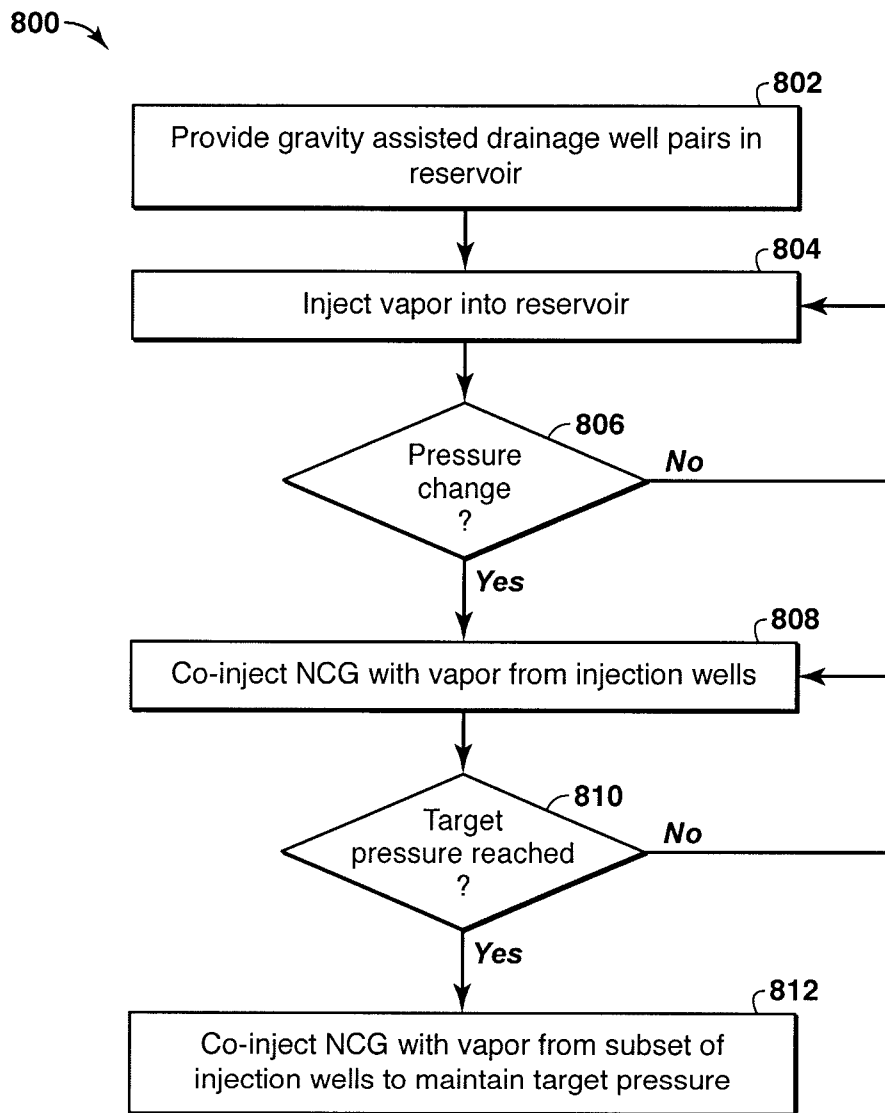
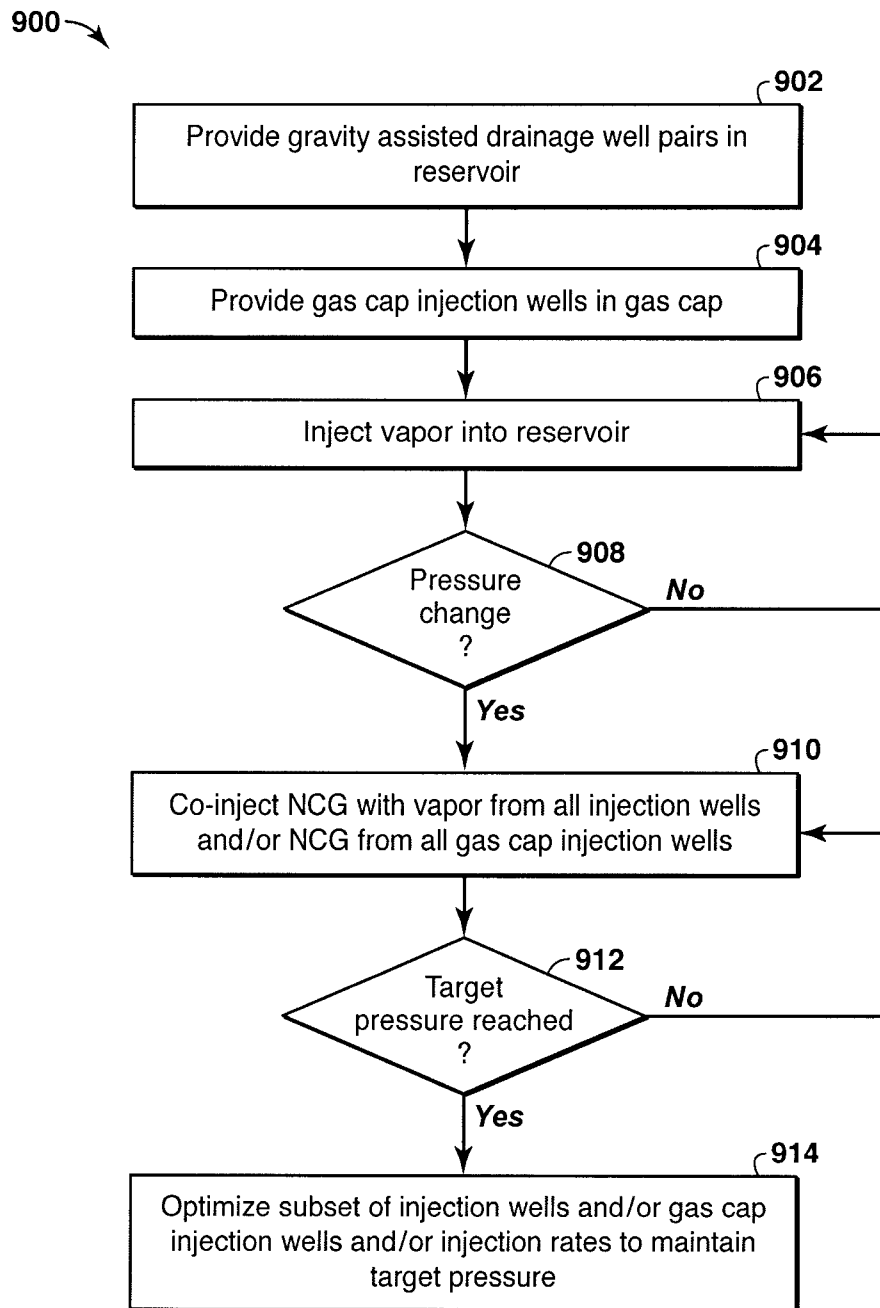


FIG. 7

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